DEPARTMENT OF MARKET MONITORING

2025
ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

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Executive summary

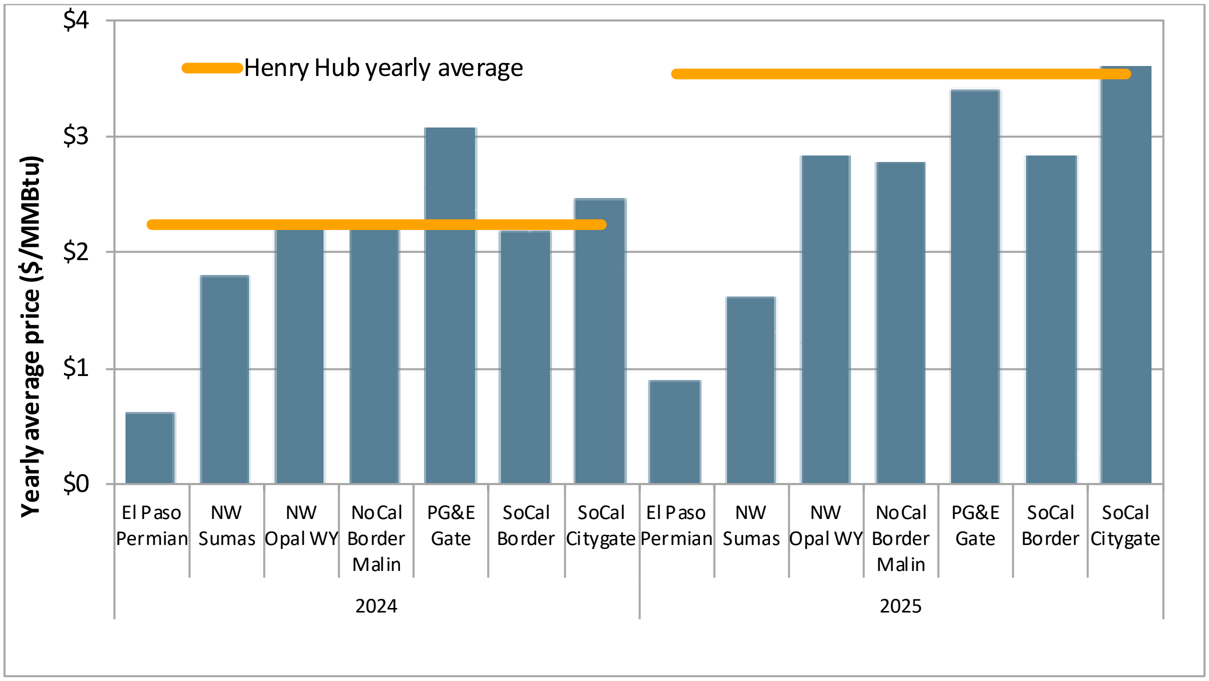
This annual report provides analysis and recommendations by the Department of Market Monitoring (DMM) on market issues and performance of the ISO's day-ahead wholesale energy market and real-time Western Energy Imbalance Market (WEIM). The report includes a summary of DMM's recommendations on key issues after the executive summary.

These markets continued to perform efficiently and competitively in 2025. Key highlights include the following:

Load and resources

Natural gas prices in the West increased compared to 2024, with prices at most major hubs rising between 11 percent and 45 percent. Figure E. 1 shows prices at Henry Hub, the national reference point, were up 59 percent. NW Sumas prices declined by about 11 percent. The percent changes in gas prices appeared significant because prices in 2024 were unusually low. However, the nominal changes in gas prices were relatively small.

Figure E. 1 Yearly average natural gas prices compared to Henry Hub



Other highlights from the chapter covering load and resources include:

- **Load across the WEIM averaged 78.3 GW, almost identical to average system load in 2024.** Load increased in the Pacific Northwest, Intermountain West, and Desert Southwest compared to 2024. Load in California decreased by 2 percent in 2025 compared to 2024.
- **Peak 5-minute market load for the year was 130.1 GW on August 22, 2025, hour-ending 18, interval 10,** a 3.8 percent decrease from the 2024 peak load (135.3 GW).

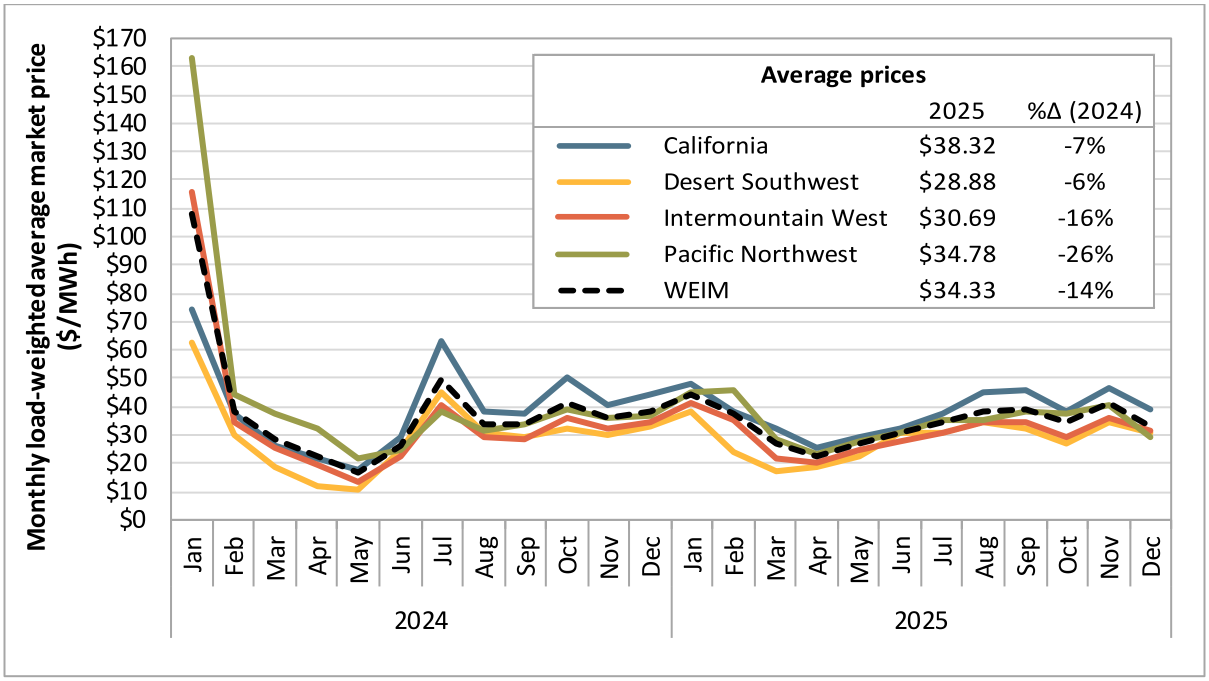
- **Battery charging reached nearly 10 percent of system load on average during mid-day hours**, reflecting the growing role of storage in absorbing excess solar generation.
- **The largest sources of generation in 2025 in the California region** were natural gas and non-hydro renewables. Hydroelectric generation dominated the generation mix in the Pacific Northwest, accounting for about 68 percent of total generation. In the Intermountain West, generation was primarily from coal (33 percent), non-hydro renewables (30 percent), and natural gas (26 percent). Natural gas remained the largest source of generation in the Desert Southwest.
- **The Pacific Northwest region was a net exporter during most months.** The California region was a net importer throughout 2025. The Desert Southwest and Intermountain West regions were net exporters during non-summer months.
- **Hydroelectric production increased significantly in the Pacific Northwest while declining in other regions,** highlighting growing regional variation in hydrologic conditions and their impact on supply.
- **In the Pacific Northwest, solar and hydroelectric generation increased in 2025 compared to 2024,** with hydroelectric generation increasing by about 1,170 MW (8 percent). Nuclear and natural gas generation decreased. Net interchange increased during solar hours and decreased during non-solar hours.
- **In the California region, natural gas generation decreased on average across all hours in 2025 compared to 2024**. Solar generation increased by about 630 MW (11 percent). Batteries increasingly participated in energy arbitrage by charging during high solar hours and discharging during evening peak net load periods. Net imports increased across all hours by an average of about 430 MW (17 percent).
- **In the Intermountain West, coal generation increased by about 560 MW (19 percent),** reversing prior-year declines, while natural gas generation decreased by about 200 MW (7 percent). Wind, solar, and battery generation increased, contributing to decreases in net imports and net dynamic transfers across all hours.
- **In the Desert Southwest region, solar generation increased by about 630 MW (31 percent)** in 2025. Net imports decreased by about 240 MW, while net dynamic transfers increased by about 200 MW.
- **Over 376,000 GWh of generation in the WEIM system came from renewable resources.** 49 percent of that generation was from non-hydroelectric resources. Renewable resources produced over 42.9 GW of power on average across the year, accounting for more than 54 percent of total WEIM system load.
- **Total downward dispatch of wind and solar resources increased by about 22 percent in 2025** compared to 2024. Downward dispatch of economic bids accounted for about 4,780 GWh (89 percent) of total curtailment, while curtailment of self-schedules accounted for about 480 GWh (9 percent), with all other curtailment categories remaining minimal.
- **Total battery capacity reached approximately 25,700 MW by the end of 2025**. Average battery discharge peaked at about 9,100 MW in the evening hours, compared to about 5,700 MW in 2024, reflecting increased participation of storage in energy shifting and peak demand periods.
- **California greenhouse gas allowance prices averaged about \$29.89/mtCO2e in 2025,** down 22 percent from 2024, representing an incremental cost of about \$12.70/MWh for a relatively efficient gas unit.
- **Washington greenhouse gas allowance prices averaged about \$61.43/mtCO2e in 2025,** representing a 94 percent increase from 2024 and an incremental cost of about \$26.10/MWh for a relatively efficient gas unit.

- **DMM estimates that net energy market revenues for a hypothetical new gas unit in 2025 ranged from $3 to $20/kW-yr for a typical combined cycle unit and $1 to $4/kW-yr for a typical combustion turbine unit.** Net market revenues remained well below estimated going-forward fixed costs, indicating the continued need for resources to recover fixed costs through long-term contracts.
- **DMM's simulated revenues for hypothetical batteries averaged about $39/kW-yr for energy and $39/kW-yr for ancillary services.** Actual batteries in the CAISO balancing area earned approximately $35/kW-yr in energy revenues and $9/kW-yr for regulation in 2025.

Energy market prices

Prices across the WEIM were about 14 percent lower in 2025 compared to 2024 in the 15-minute market. Figure E. 2 shows prices in the 15-minute market averaged about $34/MWh, while prices in the 5-minute market averaged about $35/MWh. Day-ahead market prices averaged about $39/MWh. Lower prices in 2025 occurred despite higher natural gas prices due to the absence of extreme conditions that led to high prices in January 2024, increased renewable generation, and lower greenhouse gas costs in California.

Figure E. 2 Weighted average monthly 15-minute market prices by region



Other key findings in the chapter on energy market prices include:

- **ISO markets continued to perform efficiently and competitively in 2025.**
- **Prices were highest on average in the California region, at about $38/MWh, while prices in other regions ranged between about $29/MWh and $35/MWh,** with the Desert Southwest recording the lowest prices. This price spread was driven primarily by greenhouse gas compliance costs in California and south-to-north congestion during solar production hours, which reduced prices in the Desert Southwest relative to northern regions of the WEIM.
- **During mid-day solar hours, prices were generally higher in the Pacific Northwest, Northern California, and the Intermountain West than in the Desert Southwest and Southern California.** This pattern was primarily driven by congestion on major transmission corridors in the south-to-north direction during solar production hours.
- **During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM** due mainly to California greenhouse gas pricing.
- **January continued to have the highest monthly average 15-minute and 5-minute market prices** for most balancing areas, although prices were significantly lower than the elevated levels observed during January 2024.
- **15-minute market prices were higher than 5-minute market prices during the evening peak net load hours, particularly in California balancing areas.** This difference was driven in part by California ISO operators adjusting the load forecast upward more in the 15-minute market than in the 5-minute market during these hours.
- **For most of the year, day-ahead bilateral prices from the Intercontinental Exchange at Mid-Columbia and Palo Verde were generally higher than prices at comparable locations from the ISO's day-ahead and 15-minute markets.**
- **Frequencies of power balance constraint infeasibilities remained low across the WEIM in 2025 and declined compared to 2024.** System-wide undersupply infeasibilities decreased to approximately 0.02 to 0.03 percent of intervals, while oversupply infeasibilities remained lower. Balancing areas in the Desert Southwest continued to experience relatively higher frequencies of infeasibilities than other regions.
- **The frequency of high-price intervals declined significantly in 2025 across both day-ahead and real-time markets,** with nearly no intervals exceeding $250/MWh in the day-ahead market and sharp reductions in real-time price spikes. These declines reflect less frequent tight supply conditions compared to 2024.
- **The frequency of negative prices declined across both day-ahead and real-time markets in 2025,** decreasing by roughly 20 percent in CAISO and about 15 percent in other WEIM balancing areas, despite continued growth in renewable generation.
- **DMM estimates the total wholesale cost of serving load for balancing areas in the day-ahead market. Total wholesale costs for the CAISO balancing area decreased by about 6 percent to $8.45 billion, or about $42/MWh, in 2025.** Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs decreased by about 24 percent, due mainly to lower load, increased renewable and storage generation, and the absence of tight supply conditions that contributed to elevated prices in January 2024.

Energy market competitiveness and mitigation

Overall prices in the day-ahead and real-time markets were competitive, averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating cost.

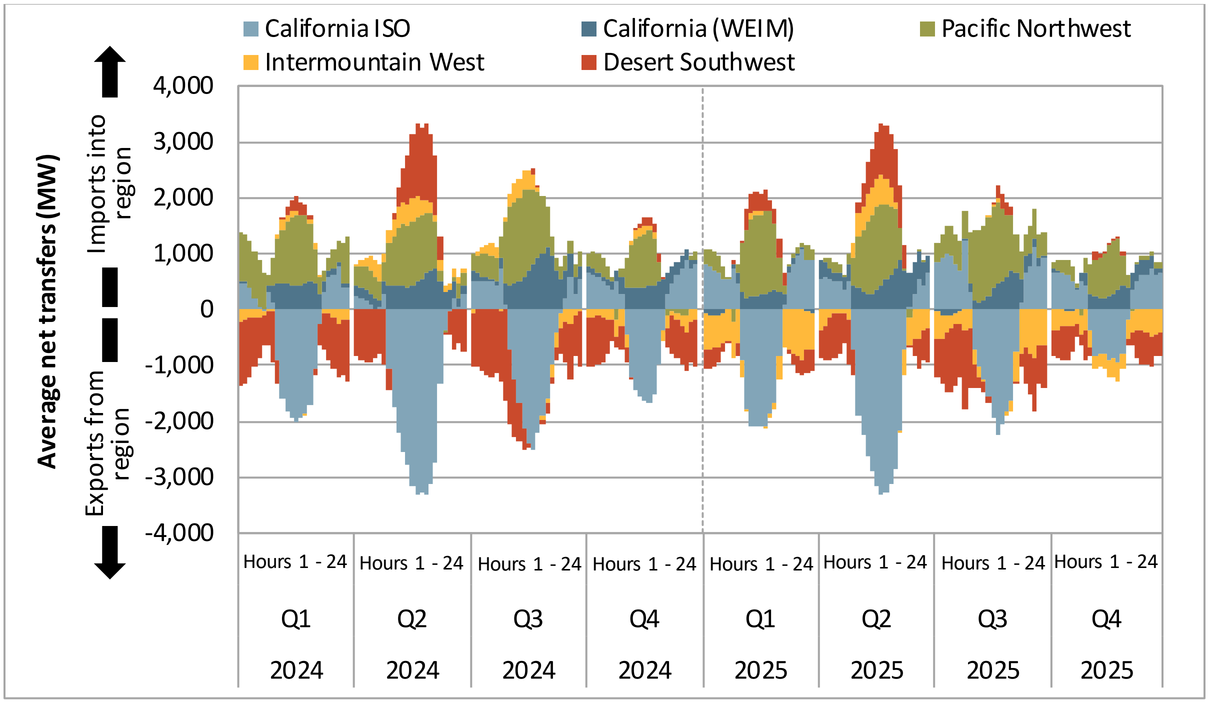
Other highlights of the chapter on energy market competitiveness and mitigation include:

- **The number of structurally uncompetitive hours in the day-ahead market was down significantly in 2025.** Continued additions of battery (and hybrid) capacity offset decreases in gas capacity and helped reduce the number of potentially non-competitive hours. Lower loads also contributed to this increase in competitiveness.
- **The WEIM real-time market residual supply index with the three largest suppliers removed was less than one during 535 15-minute intervals (1.5 percent) in 2025.** There were more structurally uncompetitive real-time market intervals in 2025 than in 2024 (363 intervals) and 2023 (472 intervals).
- **The amount of energy downstream of non-competitive constraints—and therefore subject to potential mitigation—decreased overall in the day-ahead and real-time markets.** Bids subject to potential mitigation declined in the CAISO balancing area from elevated levels observed in 2024, while changes across other WEIM regions were more mixed.
- **Most resources subject to mitigation submitted competitive offer prices, so a low portion of bids were lowered as a result of the bid mitigation process.** Roughly 28 percent (1,074 MW) of the day-ahead bids and 19 percent (990 MW) of 15-minute market bids that were subject to mitigation were changed.
- **The potential increase in dispatch from bids lowered by mitigation remained very low.** In the day-ahead market, the average potential increase in dispatch averaged 27 MW. In the 15-minute market, system-wide potential increase in dispatch from mitigation averaged 75 MW.
- **Battery resources accounted for a substantial share of bids subject to mitigation,** reflecting their growing role in participating in congested intervals and locations.

WEIM transfers and transfer limits

WEIM transfers between regions continued to be significantly different during mid-day solar hours than during the non-solar hours. Figure E. 3 shows during solar hours, regional WEIM transfers were typically highest, with significant levels of exports from the CAISO balancing area. During non-solar hours, transfers were lower and largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest.

Figure E. 3 Average inter-regional WEIM transfers by hour (5-minute market)



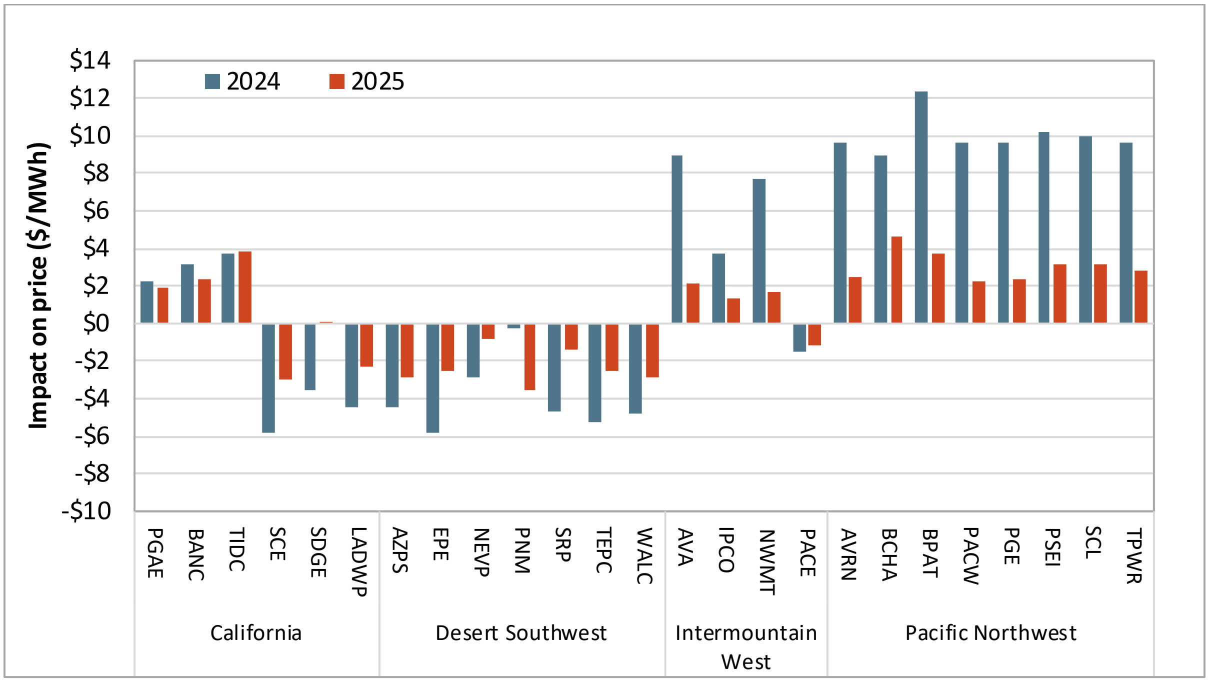
Other highlights from the chapter on WEIM transfers and transfer limits include:

- **The average volume of transfers across the system was 4,480 MW during 2025,** about 100 MW higher than the previous year when it was 4,380 MW.
- **In 2025, transfers out of the Intermountain West region increased during morning and evening non-solar hours compared to the previous year.** This coincided with increased generation from wind, coal, and battery resources in the region.
- **The Pacific Northwest region continued to have the lowest transfer capacity into and out of their region.** Additional transfer capacity in the 5-minute market between the Pacific Northwest and California regions resulted in less WEIM import congestion in the 5-minute market relative to the 15-minute market, but balancing areas in the Pacific Northwest region were still frequently separated by congestion from the larger WEIM system.

Congestion

Real-time market price separation driven by transmission congestion was less pronounced in 2025 than 2024, as shown in Figure E. 4. Price separation in the day-ahead market was also less pronounced in 2025.

Figure E. 4 Average impact of total congestion on real-time market prices (2024–2025)



Other key trends from the chapter covering congestion include:

- **Most balancing areas in the Pacific Northwest, plus Avista and NorthWestern in the Intermountain West, were import transfer constrained relative to the CAISO balancing area in more than 10 percent of 15-minute market intervals.** Limited transfer capacity into these regions contributed to their relatively high rate of WEIM transfer congestion.
- **El Paso Electric and Tucson Electric Power experienced a relatively high frequency of transfer congestion in the Desert Southwest region.** These balancing areas were frequently transfer constrained because of intertie constraints that these balancing areas use to manage WEIM transfers into or out of their system.
- **Congestion rent in 2025 was $485 million, down 10 percent** from 2024. This reduction was primarily due to a significant decrease in congestion rent from intertie constraints. Intertie congestion rent decreased from $164 million in 2024 to $26 million in 2025. The decrease largely reflects normal system conditions in 2025, without a severe weather event similar to the one in Q1 2024.

Resource sufficiency evaluation

- **Resource sufficiency evaluation failures were rare overall, but were concentrated in a small number of balancing areas and specific months, particularly for flexibility tests**. Most balancing areas failed each test in less than 0.5 percent of intervals. Exceptions were Idaho Power, which failed the upward flexibility test in about 0.5 percent of intervals, and El Paso Electric, which failed the downward flexibility test in about 0.5 percent of intervals.
- **Ten balancing areas opted in to the assistance energy transfer program on at least one day during the year.** Eight of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Additional WEIM transfers received by each balancing area over the year ranged from 99 MWh to 1,118 MWh.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[1]

Real-time imbalance offset costs and bid cost recovery

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $48 million credit to WEIM entities in 2025, compared to a $154 million credit in 2024. Figure E. 5 shows the congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $65 million credit. The energy portion of the offset was a $19 million charge.

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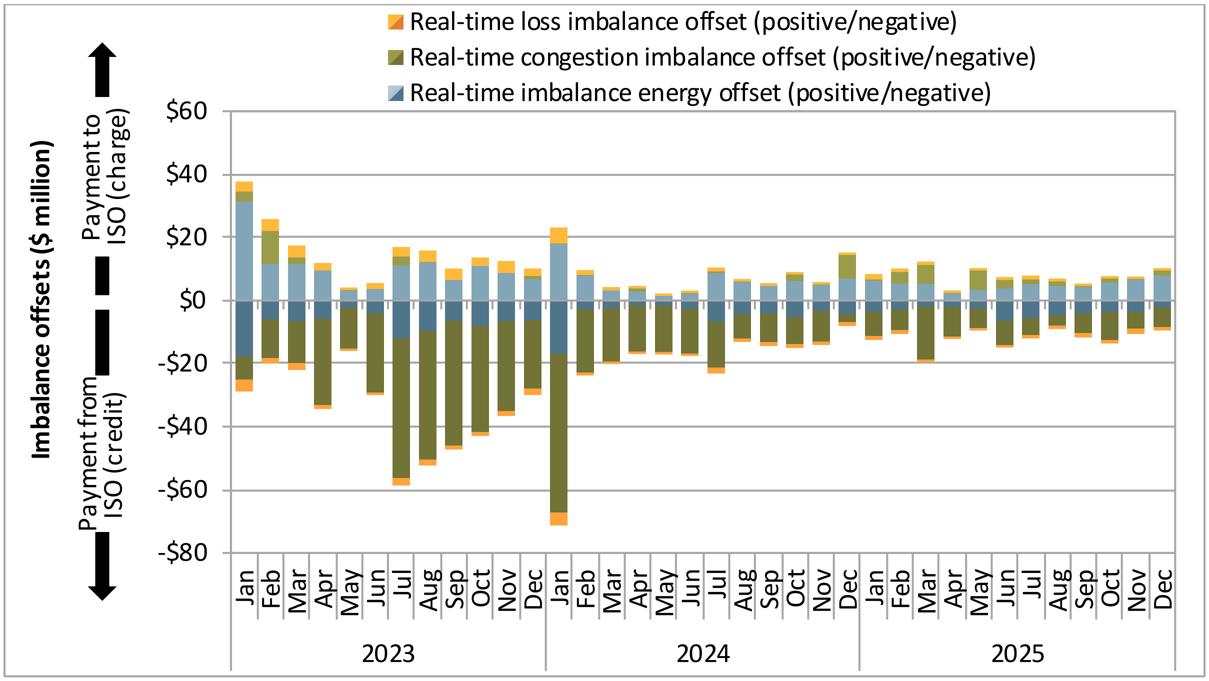
[1] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations#weim-resource

Figure E. 5 **Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)**



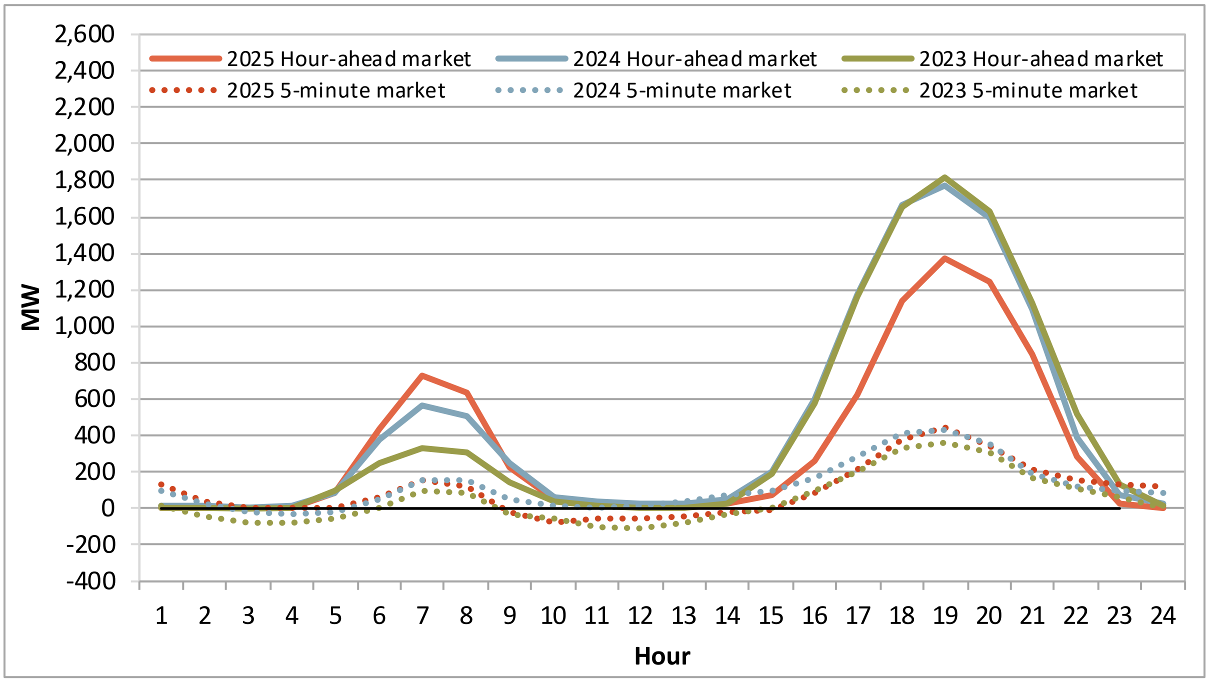
Other highlights from the chapters on real-time imbalance offsets and bid cost recovery include:

- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market (CAISO) were $205 million** in 2025. This was a decrease from $234 million in 2024. During 2025, real-time *congestion* imbalance offset costs made up the majority of these costs ($199 million).
- **Bid cost recovery payments totaled $151 million for all balancing areas in 2025, down 4 percent** from 2024. Most of these payments ($137 million) came from the one balancing area (CAISO) participating in the day-ahead market.
- **Of the $14.3 million in bid cost recovery paid to generation in balancing areas only participating in the WEIM, $9.5 million went to the Desert Southwest region.**
- **Bid cost recovery payments associated with residual unit commitment during 2025 totaled about $47.4 million, or about $19.9 million (72 percent) higher than in 2024.**
- **The majority of bid cost recovery payments in every region went to gas resources.** The share of total bid cost recovery payments going to batteries in the CAISO balancing area decreased to 5 percent in 2025 from 13 percent in 2024.

Market adjustments

The CAISO balancing area's adjustments to load forecasts during the evening peak net load hours declined in 2025 relative to the prior two years, but remained significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. As shown in Figure E. 6, for hour-ending 19, average hourly adjustments in the 15-minute market were about 1,400 MW, compared to 430 MW in the 5-minute market. This contributed to higher prices in the 15-minute market than in the 5-minute market over these hours.

Figure E. 6 Average CAISO balancing area hourly load forecast adjustment (2023–2025)



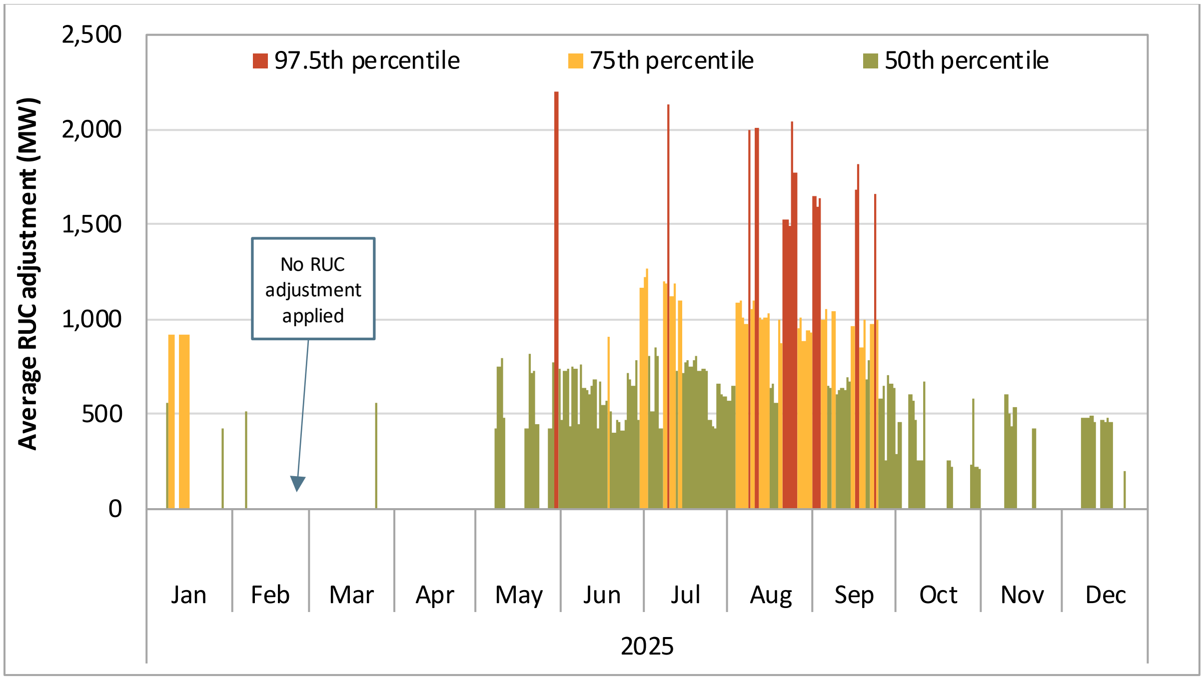
Other key trends from the chapter covering market adjustments include:

- **Adjustments to load forecasts were generally much higher in the 5-minute market than the 15-minute market,** with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).
- **Combined incremental and decremental manual dispatch energy** increased from 2024 to 2025 in the California (non-CAISO) and Desert Southwest regions by 24 percent and 3 percent, respectively. In contrast, total manual dispatch energy declined in the Intermountain West and Pacific Northwest regions by 10 percent and 7 percent, respectively.
- **Total energy from exceptional dispatches in the CAISO balancing area averaged 0.41 percent of system loads in 2025**, up from 0.34 percent of system loads in 2024.

Incorporating net load uncertainty

The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on only 4 percent of days in the year. As shown in Figure E. 7, the 75th percentile target was applied on 11 percent of days. The 50th percentile target was applied on 33 percent of days. No adjustment was applied on 52 percent of days. The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address this same uncertainty. However, after an initial period of being set to cover the 90th percentile of uncertainty, the ISO will assess if it will set the requirement to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in the residual unit commitment uncertainty adjustment prior to EDAM implementation indicates that the imbalance reserve product demand curve may be much too high during most hours.

Figure E. 7 Average residual unit commitment adjustment by day



Other highlights of the chapter covering how the ISO is incorporating net load uncertainty into its markets include:

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the histogram method.**
- **For the flexible ramping product, the rate at which the regression method uncertainty requirements covered realized uncertainty was below the target coverage rate of 97.5 percent for each direction and market.** The regression coefficients were statistically different from zero in only 31 percent of intervals.

- **For the resource sufficiency evaluation, the coverage rate varied between 88 percent and 92 percent across balancing areas.** The target coverage rate is 95 percent. 36 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.
- **The low rates of statistically significant regression coefficients** indicates that the mosaic quantile regression method identified weak or inconsistent relationships between forecast variables and realized uncertainty in most intervals across its application in the flexible ramping product, resource sufficiency evaluation, and residual unit commitment process.

Ancillary services, available balancing capacity, and flexible ramping product

ISO markets procure ancillary services for balancing areas participating in the day-ahead markets. Available balancing capacity is available to balancing areas only participating in the WEIM, while all balancing areas in the ISO's markets must procure the flexible ramping product in real-time.

- **Ancillary service costs decreased to $94.5 million,** down from $106.5 million in 2024.
- **Regulation up, regulation down, and operating reserve requirements increased compared to 2024.** Regulation up requirements increased 7 percent to 470 MW, while regulation down requirements increased 3 percent to 960 MW and operating reserves increased 1 percent to 1,630 MW.
- **Despite increasing ancillary service requirements, day-ahead prices for upward ancillary services declined in 2025.** Day-ahead prices for regulation down increased compared to 2024. Real-time ancillary service prices increased for most products in 2025, although the majority of procurement and costs continued to occur in the day-ahead market.
- **Provision of ancillary services from battery resources continued to increase, replacing procurement from natural gas resources.** Average hourly procurement of ancillary services from battery resources increased by 9 percent compared to 2024, and batteries now provide 53 percent of CAISO balancing area ancillary service requirements.
- **There were eleven ancillary service scarcity events in 2025.** Each event occurred for regulation down in the expanded region north of Path 26 in the first five months of the year. There were zero intervals with ancillary service scarcities in 2024, two in 2023, and six in 2022.
- **Seven percent of resources failed** unannounced ancillary service performance audits and compliance tests, compared to 12 percent in 2024, 15 percent in 2023, and 22 percent in 2022.
- **Most WEIM entities offered available balancing capacity into the market throughout 2025.** However, available balancing capacity was rarely dispatched to resolve capacity insufficiencies.
- **For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in this system during 0.4 percent of intervals in 2025.** At the balancing area level, El Paso Electric (EPE) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 0.8 percent of intervals.

- **Battery and hydro resources made up 62 percent and 25 percent of upward flexible ramping product, respectively.** Wind and solar combined provided 41 percent of downward flexible capacity, and batteries provided 33 percent of downward flexible capacity.
- **The CAISO balancing area continued to make up the majority of upward and downward flexible ramping product awards,** at around 57 percent in the upward direction and about 61 percent in the downward direction. Balancing areas in the Pacific Northwest made up 25 percent of upward flexible capacity and 15 percent of downward flexible capacity.
- **Payments for upward and downward uncertainty awards were $4.1 million during 2025.** Total payments associated with flexible ramping product were $11.2 million, up sharply from around $1 million in 2024. The California and Desert Southwest regions were paid about 31 and 30 percent, respectively, of the $4.1 million. Battery resources were paid 40 percent of this figure, consistent with their large share of flexible capacity provision.

Residual unit commitment

- **Increases in residual unit commitment requirements in 2025 were primarily driven by higher net virtual supply.** Operator adjustments declined significantly from 2024 levels but remained elevated during the third quarter.
- **The average volume of capacity procured through the residual unit commitment process was 440 MW, up 15 percent from 2024.** The volume of procured capacity in 2024 decreased 47 percent compared with 2023.
- **The total direct cost of non-resource adequacy capacity procured in the residual unit commitment process decreased to about $1.1 million in 2025**, from a direct cost of about $1.6 million in 2024.
- **There was enough supply to meet the residual unit commitment requirement in all intervals in 2025.**

Convergence bidding and congestion revenue rights

- **Annual profits paid to convergence bidders totaled about $58.6 million** after accounting for $22.0 million in bid cost recovery charges allocated to virtual bids, an increase of about $8.2 million from 2024. Convergence bidders lost $12.1 million from virtual demand, and virtual supply earned $92.7 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 840 MW per hour,** compared to 430 MW in 2024. The percent of bid-in virtual supply and demand clearing was around 55 percent, an increase from about 50 percent in 2024.
- **Financial entities and marketers continued to earn the most profits from virtual bidding,** receiving about 88 percent and 11 percent of positive net revenues, respectively. Load serving entities lost money from virtual positions overall. Physical generators received just under 2 percent of positive net revenues.
- **Financial participants held the majority of cleared virtual positions (about 81 percent) throughout 2025,** continuing a multi-year trend. As with previous years, financial participants bid more virtual supply than demand.

- **Payouts to congestion revenue rights (CRRs) sold in the California ISO auction exceeded auction revenues received for these rights by about $48 million in 2025,** down from $66 million in 2024. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. The Department of Market Monitoring (DMM) continues to recommend further changes to eliminate or further reduce these losses.

Resource adequacy and wheeling-through capacity in the CAISO balancing area

Resource adequacy capacity provided sufficient coverage of annual instantaneous peak load. The annual instantaneous peak load in 2025 reached 44,506 MW on August 21 during hour-ending 19. During that hour, the maximum 15-minute market CAISO balancing area load requirement including operating reserve (2,700 MW) and regulation up (690 MW) requirements was around 46,800 MW. Available capacity from resource adequacy resources in the real-time market exceeded 68,400 MW. This was sufficient to cover both the market requirement and the instantaneous peak load. This included solar, wind, and other schedules in excess of a resource's resource adequacy capacity.

Other highlights of the chapters covering resource adequacy and high priority wheel-through capacity in the CAISO balancing area include:

- **The nameplate capacity of wind and solar grew the most out of any resource type in the CAISO balancing area, adding 4.1 GW and 2.6 GW, respectively, since June 2025**. This is a departure from batteries being the largest driver of new capacity over the past couple of years. The CAISO fleet currently has 16.8 GW of capacity from battery resources, which is an increase of around 2 GW from last year. Overall, nameplate capacity has had a net increase of 8.8 GW since June 2025. In comparison, CAISO added 5.7 GW of nameplate capacity from June 2024 to June 2025.
- **Between June 2025 and April 2026, only 360 MW of capacity withdrew from CAISO.** This was primarily driven by the loss of the batteries involved in the Moss Landing Power Plant fire in January 2025.
- **Four of the CAISO balancing area's local capacity areas were not structurally competitive** because there was at least one supplier that was pivotal and controlled a significant portion of capacity needed to meet local requirements.
- **There was only one California ISO restricted maintenance operation (RMO) emergency notification in 2025.** This event spanned 42 hours from January 20 to January 21. This was a significant decrease in hours from 2024, which had 332 hours.
- **Resource adequacy capacity was the most scarce during the spring months of 2025,** when the difference between resource adequacy capacity and market load was the lowest. Resource adequacy procurement requirements are the lowest during these months.
- **Capacity available after reported outages and de-rates was 95 percent in the day-ahead market and 93 percent in the real-time market for the analysis hours**. Average resource adequacy capacity was around 46,169 MW during this time.
- **Resources that are not availability-limited accounted for just 30 percent of system capacity.** About 13,804 MW of system capacity was subject to California ISO bid insertion during all hours. Gas-fired

generation in this category made up about 12,860 MW (28 percent) of total resource adequacy capacity. Other generators accounted for around 2 percent.

- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 26,446 MW (57 percent) of system resource adequacy procurement, community choice aggregators contributed 24 percent, municipal utilities contributed 7 percent, and direct access services contributed 8 percent. The remaining percentage was a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Both year-ahead and actual flexible resource adequacy requirements were not sufficient to meet the actual maximum three-hour net load ramp for most months in 2025.** The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps depends on the ability to predict the size and timing of the maximum net load ramp. This analysis suggests the 2025 requirements and must-offer hours were insufficient in reflecting actual ramping needs. The shortfall was at least 1,200 MW and up to around 6,100 MW during these months. Despite shortfalls in flexible resource adequacy requirements, total flexible capacity procurement and must-offer obligations were sufficient to meet actual maximum three-hour net load ramps in all months of 2025.
- **Resource adequacy availability incentive mechanism penalties totaled $93 million in 2025, an increase of about $20.3 million from 2024.** Much of this is attributable to flexible resource adequacy charges increasing to $66 million in 2025 from about $49 million in 2024.
- **Monthly resource adequacy from demand response programs scheduled by load-serving entities averaged 820 MW in 2025.** Monthly third-party demand response resource adequacy capacity averaged about 102 MW in 2025.
- **Scheduling coordinators reserved 250 MW of priority wheel-through capacity on the CAISO balancing area transmission system in June, 425 MW in July, 344 MW in August, and 365 MW in September.**
- **Priority wheel-through reservations plus native load needs exceeded the final available transmission capacity on the NOB and Malin interties in August due to outages**. The transmission reliability margin for August would have covered full usage of priority wheel-through reservations plus native load need in August at the Malin intertie, but not at NOB.
- **The ISO overestimated native load needs on the set of interties that market participants made priority wheel-through reservations on.** The ISO overestimated native load needs by about 1,500 MW (or 42 percent) in June, 900 MW (22 percent) in July, 1,600 MW (39 percent) in August, and 2,100 MW (52 percent) in September.

Recommendations

As the independent market monitor for the California ISO and for the Western Energy Markets, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives.[2] DMM actively participates in the ISO stakeholder process and provides recommendations in written comments throughout this process. DMM also provides recommendations in quarterly, annual, and other special reports, which are also posted on the ISO website. This chapter summarizes DMM's current recommendations on key market design initiatives and issues. Additional details on many of DMM's recommendations are provided in comments and other reports posted on DMM's page on the ISO website.[3]

Extended day-ahead energy market

On May 1, 2026, the ISO implemented an extended day-ahead market (EDAM) and day-ahead market enhancements (DAME). DMM strongly supports development of an extended day-ahead market to other balancing areas across the West. Adding a day-ahead market to the WEIM has the potential to provide significant efficiency, reliability, and greenhouse gas reduction benefits by facilitating trade between diverse areas and resource types.

Congestion revenue allocation

Under the EDAM design approved by FERC in 2024, congestion revenue would be allocated to the balancing authority area (BAA) where the transmission constraint creating the congestion is located. This approach mirrors how congestion revenues from the real-time WEIM are allocated. During the EDAM stakeholder process, DMM understood that this rent allocation approach was intended to be transitional and that alternatives would be considered after EDAM was in operation.

In early 2025, Powerex and a group of other entities intending to join SPP's Markets+ day-ahead market filed objections to this approach at FERC. Citing data showing that the largest portion of congestion charges in WEIM has occurred due to congestion within the CAISO system, these entities contended that the EDAM design would be inequitable for other EDAM balancing areas. These entities also argue that it would be inequitable for entities purchasing firm transmission rights from these EDAM balancing areas, since the EDAM areas would not collect enough congestion revenue to provide a full hedge against EDAM congestion charges for entities using firm transmission sold by EDAM balancing areas.

In response to these concerns, the ISO initiated a stakeholder process in early 2025 to modify the congestion revenue allocation rules for EDAM. Under revisions made through this initiative, congestion revenue associated with balanced self-schedules on long-term firm and network integration transmission service rights are allocated to the BAA where the energy is scheduled, rather than where the constraint is located. All other congestion revenue will continue to be allocated to the BAA in which the congestion occurs.

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[2] California ISO, *Tariff Appendix P, California ISO Department of Market Monitoring*, Section 5.1: http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

[3] Department of Market Monitoring reports, presentations, and stakeholder comments can be found on the California ISO website: http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

These revisions are intended to be in place on an interim basis until a more permanent long-term approach is developed. These interim congestion allocation rules are likely to create economic incentives for some inefficient self-scheduling of resources. While this will reduce the efficiency benefits from managing congestion over an expanded EDAM footprint relative to the currently approved design, DMM believes there will still be significant benefits from an expanded market relative to the pre-EDAM market. Therefore, DMM supported these revisions as an acceptable alternative on a transitional basis.[4]

In May 2026, DMM completed analysis aimed at gauging the potential for the interim EDAM congestion revenue allocation rules to create incentives to self-schedule in the EDAM.[5] This analysis suggests that while incentives for self-scheduling may be limited in the initial market footprint at EDAM go-live (PacifiCorp and Portland General), these incentives may grow significantly as the market footprint expands (e.g., to include NV Energy and the Idaho Power areas). Therefore, DMM recommends that a replacement to the interim CRA approach should be developed to remove these potential incentives as soon as possible.

In 2026, the ISO initiated a stakeholder process aimed at developing a more efficient and longer-term approach for congestion revenue allocation as the EDAM expands. The ISO has identified two conceptual approaches which DMM believes can represent a significant improvement over the current interim rules. One of these approaches (Concept #2) involves creating flow entitlements between balancing areas. Another approach (Concept #3) would create allocated congestion revenue rights (CRRs) for the eligible open access transmission tariff rights in a common simultaneous feasibility test used for allocating CRRs within the CAISO balancing area.

DMM believes that Concept #3 is the best solution, particularly in the longer run.[6] CRRs are designed to allocate congestion revenue without creating significant incentives to distort bidding behavior in the energy market. Allocating CRRs would also be more flexible over time, allowing the allocation of rent to change as generation, load, and transmission conditions change. However, transmission ratepayers across the EDAM balancing authority areas will need to come to an agreement on how the allocation of these rights will work.

Key details of any approach under Concept #3 will need to be developed and analyzed in order to assess the impacts and appropriateness of any specific proposal. DMM has recommended that the ISO assemble and provide specific data for each likely or potential EDAM transmission provider needed to assess and understand the potential effects of different design details.

Because of the uncertainty about how long it may take to develop a new CRA approach based on congestion revenue rights, DMM recommends that the ISO continue working on Concept #2 in parallel with Concept #3 to maintain near term options for replacing the current approach. DMM believes that creating flow entitlements between balancing areas could be a workable path forward in the near term.

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[4] Memo to ISO Board of Governors and Western Energy Markets Governing Body, June 12, 2025, Re: Department of Market Monitoring report: https://www.caiso.com/documents/decision-on-edam-congestion-revenue-allocation-dmm-comments-june-2025.pdf

[5] Analysis of interim EDAM congestion revenue allocation using 15-minute market data, May 11, 2026: https://www.caiso.com/documents/dmm-analysis-of-interim-edam-congestion-revenue-allocation-may-11-2026.pdf

[6] *Comments on Extended Day-Ahead Market Congestion Revenue Allocation Phase 2 Design Working Group Meeting - May 11, 2026*, May 22, 2026: https://www.caiso.com/documents/dmm-comments-on-edam-congestion-revenue-allocation-phase-2-design-may-11-2026-working-group-may-22-2026.pdf

If designed correctly, these flow entitlements would avoid the poor incentives created by the current approach.

Day-ahead imbalance reserve product

A key element of the EDAM and DAME design is the introduction of a day-ahead imbalance reserve product intended to ensure sufficient ramping capacity is available in the real-time market. DMM supports development of products to manage uncertainty but has provided several key recommendations regarding potential changes to the initial proposal, as summarized below.

Demand curve for imbalance reserve

The ISO initially planned on setting the demand for imbalance reserve based directly on a mosaic quantile regression model of net load uncertainly (at a 97.5 percent confidence level). DMM believed this level was likely to be unnecessarily high in many (if not most) hours, and recommended a lower level. Following market simulation and parallel operations prior to implementation of the extended day-ahead market, the ISO decided to use the 90th percentile of modeled net load uncertainty to set the imbalance reserve demand curve. DMM continues to recommend that the ISO be prepared to lower this percentile and other key configurable imbalance reserve parameters (such as envelope multipliers, and the deployment reserve factor) if market results indicate inefficiently high imbalance reserve or reliability capacity prices.

DMM also continues to recommend that the ISO work on developing more appropriate methods for determining the demand curve for imbalance reserves in the day-ahead market. The mosaic model used by the ISO to set requirements for the imbalance reserve product and the residual unit commitment (RUC) process is a regression model that estimates uncertainty about net loads (i.e., load minus solar and wind output) between the day-ahead market and real-time. In practice, however, grid operators consider a much wider range of factors when assessing the need to have capacity available to defend against uncertainty on a day-ahead basis. These factors include:

- Demand response
- Fire danger
- Weather changes
- Availability of imports
- Reliability Coordinator next-day analysis
- Potential loss of supply resources
- Stranded capacity

Thus, DMM believes the dependent variable in the mosaic regression model (net load uncertainty) is not the most appropriate variable upon which to base the amount of imbalance reserve procured in the day-ahead market. DMM has also noted that the mosaic model essentially assumes that the only way to defend against this net load uncertainty is to procure imbalance reserve (or RUC capacity) on a day-ahead basis. This approach does not account for the fact that operators can take additional actions after the day-ahead market to make capacity available as uncertainties unfold up until real-time. If the flexibility to take additional actions after the day-ahead market are taken into account, the demand for imbalance reserve (or RUC) capacity procured should be lower.

Day-ahead resource sufficiency evaluation

As noted above, the ISO ultimately decided to use the 90th percentile of modeled net load uncertainty to set the imbalance reserve demand curve shortly before EDAM was implemented. During the stakeholder process on this issue, the main entity initially participating in balancing areas in EDAM (PacifiCorp) expressed concern about the potential impact of lowering the imbalance reserve requirements below the 90th percentile in non-CAISO balancing areas that do not have resource adequacy programs with must-offer obligations.

This concern stems from the fact that the ISO implemented EDAM in a manner that requirements used in the day-ahead resource sufficiency evaluation must be set equal to imbalance reserve requirements used in the day-ahead market. Thus, if imbalance reserve requirements are lowered, this also lowers requirements used in the day-ahead resource sufficiency evaluation. PacifiCorp has expressed concern that lowering requirements used in the day-ahead resource sufficiency evaluation below the 90th percentile of net load uncertainty could result in insufficient capacity being offered in the EDAM areas that do not have resource adequacy programs with must-offer obligations.

To address this concern, DMM is recommending that the ISO initiate any software changes needed to allow a different level of uncertainty to be used in setting imbalance reserve requirements than is used in the resource sufficiency evaluation. This added flexibility could help guard against unnecessarily high imbalance reserve requirements in the day-ahead market while still allowing use of a higher percentile in the resource sufficiency evaluation to support the reliability needs of non-CAISO balancing areas.

Virtual supply and RUC procurement

Much of the potential benefit of procuring imbalance reserve capacity in the day-ahead energy market could be offset by virtual supply, which can displace more expensive and slower ramping physical supply in the day-ahead energy market. This could still require the subsequent residual unit commitment process to procure sufficient on-line physical capacity to address net load uncertainty. If significant procurement of extra capacity continues to occur in the residual unit commitment process, DMM recommends that the ISO reconsider whether it would be more efficient to procure imbalance reserves in the residual unit commitment market.

Utilizing day-ahead imbalance reserves in the real-time market

DMM continues to recommend that the ISO consider developing a real-time uncertainty product, so that there is a mechanism to maintain day-ahead reserves in real-time until the peak net load hours. Without such a mechanism in the real-time market, the value of procuring imbalance energy reserves in the day-ahead market could be significantly reduced. DMM's recommendation on developing a real-time uncertainty product is discussed later in this section of this report.

Non-source specific supply used to meet resource sufficiency evaluation

The EDAM design allows contracts for non-source specific energy to count toward an EDAM balancing area's resource sufficiency evaluation. DMM recommends that the ISO and stakeholders consider more nuanced rules and design changes that could better prevent the same capacity from being counted more than once towards EDAM balancing areas' resource sufficiency evaluations. For example, the overall design may benefit from crafting more explicit rules prohibiting supply that has received an EDAM energy or capacity award—and thus has a real-time must-offer obligation—from supporting a non-source specific import that was counted towards each balancing area's EDAM resource sufficiency evaluation requirements.

Congestion revenue rights

From 2009 through 2018, payouts to non-load serving entities purchasing congestion revenue rights (CRRs) in the California ISO auction exceeded the auction revenues by about $860 million. If the ISO did not auction these congestion revenue rights, these congestion revenues would be credited back to transmission ratepayers who pay for the cost of the transmission system through the transmission access charge (TAC). Most of these losses have resulted from profits received by purely financial entities that do not serve any load or schedule any generation in the CAISO system.

In response to the consistently large losses from sales of congestion revenue rights, the ISO instituted significant changes to the auction starting in the 2019 settlement year. Although changes implemented in 2019 reduced ratepayer auction losses, these losses have continued to be very significant.

- In the seven years since the ISO implemented CRR reforms in 2019, ratepayers have lost an additional $427 million (or an average of $61 million per year) and have received only 70 cents in auction revenues per dollar paid out.
- In 2025, ratepayer auction losses were around $47.6 million, or about 10 percent of day-ahead market congestion rent. Ratepayers received an average of 77 cents in auction revenue per dollar paid to auctioned congestion revenue rights holders.
- In 2025, Track 1B revenue deficiency offsets reduced payments to non-load serving entity auctioned rights by about $92 million. These deficit offsets were part of the changes implemented in 2019, and appear to account for most of the reduction in losses that resulted from the 2019 changes.

When changes to the auction were implemented in 2019, the ISO and Market Surveillance Committee (MSC) committed to reviewing the effectiveness of these changes and making additional changes if significant losses continued. The ISO and MSC began some analysis and discussion of causes of losses from congestion revenue rights in November 2023. The ISO provided a 217-page presentation on results of this analysis in February 2025, which identified three factors contributing to auction losses.[7]

1. Shift factors truncated by the minimum threshold;
2. Non-settled loop flows consuming transmission capacity; and
3. Differences between the CRR and day-ahead transmission models.

All of these three contributing factors have existed as long as the ISO has auctioned CRRs and have already been subject to extensive analysis. The ISO has not been able to identify any additional steps that could be taken based on this analysis to eliminate or significantly reduce transmission ratepayer auction losses. Thus, DMM believes that continuing to dedicate time and resources in an attempt to make small improvements in these three areas will not eliminate or significantly reduce transmission ratepayer losses from CRRs auctioned by the ISO. Moreover, all other regional transmission operators

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[7] *Congestion Revenue Rights Enhancements Working Group Meeting #3,* February 27, 2025, slides 8 to 225: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Congestion-Revenue-Rights-Enhancements-Feb-27-2025.pdf

(RTOs) with similar market designs have also incurred hundreds of millions of dollars in losses on financial rights sold by the RTOs.[8]

Willing seller market design for CRRs

DMM continues to believe that the current auction should be changed to a market for congestion revenue rights based only on bids submitted by entities willing to buy or sell congestion revenue rights. This approach (referred to as a *willing seller* market design) would provide a market in which load serving entities could continue to voluntarily sell back any congestion revenue rights acquired in the allocation process and any entity could buy or sell additional contracts.

In 2025, DMM has clarified that DMM is not proposing to "eliminate the CRR auction". Under DMM's recommended approach, the ISO would continue to allocate CRRs to load serving entities (LSEs) and exporters under the current allocation process. Since the willing seller design is guaranteed to eliminate losses from auctioned CRRs, additional CRRs could be allocated to LSEs in this allocation process without causing revenue inadequacy.[9] Entities that are allocated CRRs could continue to sell (or buy) additional CRRs as willing counterparties in the subsequent willing seller market. Over the last three years, load serving entities have resold about 25 percent of the CRRs received in the allocation process.[10]

Under the willing seller approach, the restrictions implemented in 2019 on CRR allocations, bidding, and payouts would be removed, while also ensuring that CRR revenue inadequacy would be eliminated. For example, restrictions placed to lower transmission limits used in the CRR allocation process in 2019 would be raised, thereby increasing the amount of CRR nominations that would clear in the allocation process. The *deficit offset* charge that was implemented in 2019 to reduce CRR losses would also be eliminated. These deficit offset charges have averaged over 25 percent of the nominal value of CRRs allocated to load serving entities.[11]

The combined impact of these changes would be to increase the ability of LSEs to acquire the CRRs and CRR payments needed to hedge their sources of supply.[12] The willing seller approach is guaranteed to be revenue neutral for transmission ratepayers, and would allow the ISO to eliminate the need for deficit offset charges that occur when congestion revenues are not sufficient to fully fund congestion revenue rights sold in the auction by the ISO.

In October 2024, DMM released a detailed report on the proposed willing seller approach. The report included analysis of this market design using only bids to sell and buy CRRs submitted by market participants, and without additional transmission that represents additional CRRs being offered by the

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[8] *Comments on Congestion Revenue Rights Enhancements Working Group Meeting #5 – April 1, 2025*, submitted April 16, 2025, p 1: https://www.caiso.com/documents/dmm-comments-on-crr-enhancements-apr-1-2025-working-group-meeting-no-5-apr-16-2025.pdf

[9] *Willing seller congestion revenue rights auction design,* presentation to Congestion Revenue Rights Working Group, April 22, 2026, p 3: https://stakeholdercenter.caiso.com/InitiativeDocuments/DMM-Presentation-Congestion-Revenue-Rights-%20Enhancements-Apr22-2026.pdf

[10] Op. cit. p 4.

[11] Thus, even if an LSE manages to acquire CRRs that perfectly fit the LSE's actual supply sources and load sinks, the LSE could end up receiving a hedge of only 75 percent of the LSE's actual congestion costs after the 25 percent deficit offsets are applied.

[12] *Comments on Congestion Revenue Rights Enhancements Scoping Discussion,* Department of Market Monitoring, December 13, 2024: https://www.caiso.com/documents/dmm-comments-on-congestion-revenue-rightsenhancements-scoping-discussion-nov-14-2024-working-group-dec-13-2024.pdf

ISO at a $0/MW bid price.[13] This analysis shows that under this proposed design, significant volumes of congestion revenue rights could be sold by financial entities, as well as by load serving entities selling a portion of their allocated congestion revenue rights which are not needed to hedge their actual energy procurement. These results show that the willing seller design is workable and can provide an effective and efficient alternative to the current auction design. This approach eliminates losses from the current auction and allows all congestion rents to be returned to transmission ratepayers.

Backstop mechanism for willing seller market

The ISO and some stakeholders have expressed concern about the degree of liquidity that may exist under a willing seller market, and how this could limit the ability of entities seeking CRRs as actual hedges to procure CRRs. To address these concerns, DMM has outlined a potential backstop mechanism that could be implemented with the willing seller auction to provide opportunities for entities to obtain CRRs to hedge energy transactions if they do not receive them in the allocation or auction.[14] Participation in the backstop mechanism would be limited to entities that have either paid the TAC, or a fixed rate per megawatt hour to allow access to the backstop mechanism.

With this approach, eligible entities would pay a variable CRR rate depending on the *expected value* of the CRR path they would like to purchase or sell. The variable backstop rate to buy CRRs would consist of the expected value of the CRR path plus a premium. The premium included in the variable rate would be set large enough to incentivize efficient participation in the willing seller auction since the backstop mechanism should not provide a "better deal" on any given CRR than purchasing in the willing seller auction if available.

DMM has outlined this concept as a starting point for creating a design that addresses the concerns raised about a willing seller design. The specific design features could be altered and improved, or additional design elements added, based on stakeholder and ISO input.

Another option suggested by DMM to help increase liquidity in the willing seller auction would be to allow and facilitate buyers and sellers to disclose the paths on which they are interested in buying or selling CRRs in an iterative process prior to clearing of the willing seller market. This information would include the type of CRR they are interested in buying or selling, but not the price. This would allow buyers and sellers to focus bidding activity on common CRR paths for which the potential supply and demand is highest and most likely to clear.

Auction with minimum reserve prices

In the ongoing CRR stakeholder process, the ISO has suggested setting a single uniform reserve price for positively priced CRRs and a different uniform reserve price for negatively priced CRRs in the auction. This approach would be aimed at reducing the sales of relatively low priced CRRs, which can result in significant losses when congestion occurs due to unexpected conditions. DMM is skeptical that this approach addresses the fundamental flaws underlying the current auction design. Uniform reserve prices, as described by the ISO, cannot represent the value or costs of all the various CRRs offered by the ISO, whose values vary significantly. While this may be marginally better than the current design—which

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[13] https://www.caiso.com/documents/willing-counterparty-whitepaper-oct-23-2024.pdf

[14] *DMM comments on Congestion Revenue Rights Enhancements Stakeholder Meeting Session #9*, May 9, 2026: https://www.caiso.com/documents/dmm-comments-on-congestion-revenue-rights-enhancements-stakeholder-meeting-session-9-may-06-2026.pdf

essentially offers CRRs at $0 bid prices—such a blunt reserve price seems unlikely to be very effective and seems similarly susceptible to adverse selection as the current auction.

A more effective variation of this approach would be for the ISO to set reserve prices for all CRRs made available in the auction by the ISO based on the *expected value* of each CRR path—or possibly set some higher percentile and/or include a risk premium. This reserve price would be set based on the actual congestion values over a prior period (e.g., 1 to 3 years), normalized for gas and/or energy prices. This normalization could account for past gas and/or energy prices, as well as gas and energy futures prices. The ISO could also maintain the ability to adjust reserves prices to differ from historical prices when market or transmission system conditions warrant such changes—i.e., a large transmission outage or upcoming extreme weather conditions. This is essentially the same approach DMM envisions could be used to set prices for any CRRs available under the willing seller backstop mechanism suggested by DMM.

Battery resources

The amount of battery storage resources in the CAISO and WEIM has increased significantly in recent years, and is projected to continue increasing in coming years.[15] By the end of 2025, there was over 17 GW of installed battery capacity in the CAISO area and about 8 GW of battery capacity in the rest of the WEIM.

Bid cost recovery rules

DMM continues to encourage the ISO to modify bid cost recovery (BCR) rules for battery resources as a top priority. As explained in this section, current bid cost recovery rules can lead to unwarranted BCR payments, gaming opportunities, and can create inefficient bidding incentives in the real-time market.

The main purpose of BCR for traditional generators is to incentivize efficient bidding by alleviating the risk that the net revenues from the difference between the locational marginal price (LMP) and the resource's energy bid costs will provide insufficient revenue to cover the unit's start-up and minimum load costs. Batteries do not have start-up, shut-down, minimum load, or transition costs—and thus lack the traditional drivers of BCR. However, in 2025, batteries received over $9 million in real-time bid cost recovery (or about 7 percent of all bid cost recovery).

The main limitations on battery dispatch that lead to real-time bid cost recovery payments stem from state-of-charge constraints that limit charging and discharging. For example, when a battery does not have sufficient real-time state-of-charge to deliver a day-ahead market award, the real-time market software may force a battery to forgo charging or discharging out of merit order to "buy back" or "sell back" the day-ahead market award.

Under the ISO's settlement rules, this can lead to payment of real-time bid cost recovery due to the difference between the battery's bid price and the real-time market clearing price. This design essentially removes the economic incentive for battery operators to bid in a way that ensures batteries are fully charged at the start of the peak net load hours when prices are highest and batteries are most needed for system reliability (e.g., hours 18 to 22).

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[15] *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

When the state-of-charge constraint and other unit limitations were being designed for battery resources, DMM raised concerns about the potential use of these limitations and recommended that the ISO revisit this topic in future initiatives to address potential settlement implications. DMM and the California ISO's Market Surveillance Committee have noted that the current real-time BCR design incentivizes inefficient battery bidding behavior by removing batteries' exposure to real-time prices, and reduces the reliability benefits of these resources.[16,17]

The current BCR design creates gaming opportunities, especially through manipulation of various biddable parameters used to manage state-of-charge. Gaming concerns are exacerbated by the fact that bid cost recovery payments are partly driven by submitted bid prices, meaning that inflated bids can cause BCR payments to drastically exceed any economic losses caused by reversal of day-ahead schedules.

In November 2024, this gaming concern led the ISO to file a tariff amendment that caps battery bids when calculating bid cost recovery payments.[18] This policy change largely addresses the ability of batteries to inflate unwarranted BCR payments. However, because the largest driver of real-time battery BCR is lost revenues of buying or selling back day-ahead schedules, unwarranted BCR payments will continue after the policy change is implemented and batteries with day-ahead schedules will continue to have distorted bidding incentives in the real-time market.[19]

DMM continues to encourage the ISO to address the storage bid cost recovery concerns as a top priority, before undertaking additional storage design enhancements that may considerably slow the pace of development for storage bid cost recovery enhancements.[20] Rather than continuing to consider specific conditions under which it might be inappropriate for batteries to receive BCR, DMM recommends that the ISO start from the premise that batteries should generally be ineligible for BCR, and to then consider a limited number of conditions under which it may be appropriate to receive BCR. As a general principle, when batteries are constrained by operational parameters set by unit operators to manage battery operation, batteries should be ineligible for BCR payments.

Two specific situations in which DMM believes it makes sense for batteries to be eligible for out-of-market payments are when batteries are (1) subject to bid mitigation, or (2) dispatched manually by CAISO grid operators. In both these situations, a relatively simple settlement rule can be applied to

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[16] *Opinion on Storage Bid Cost Recovery*, James Bushnell, Scott M. Harvey, Benjamin F. Hobbs; Members of the Market Surveillance Committee, November 1, 2024: https://www.caiso.com/documents/market-surveillance-committee-final-opinion-storage-bid-cost-recovery-nov-01-2024.pdf

[17] *Comments of the Department of Market Monitoring of the California Independent System Operator Corporation,* Department of Market Monitoring, ER25-576-000, December 17, 2024: https://www.caiso.com/documents/dmm-comments-on-er25-576-storage-bcr-dec-17-2024.pdf

[18] *Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resources, and Request for Effective Date on Shortened Notice,* California Independent System Operator Corporation, November 26, 2024: https://www.caiso.com/documents/nov-26-2024-tariff-amendment-bid-cost-recovery-to-storage-resources-er25-576.pdf

[19] *Storage Bid Cost Recovery Presentation,* Department of Market Monitoring, June 30, 2025: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-StorageDesignandModeling-Jun30-2025.pdf

[20] *Comments on Storage Design and Modeling Working Group Session 2 and 3*, submitted March 7, 2025: dmm-comments-on-storage-design-and-modeling-working-group-sessions-2-and-3-mar-07-2025.pdf

compensate battery resources for any lost opportunity costs from being discharged in lower priced hours due to mitigation or operator dispatches.

Local market power mitigation for batteries

In practice, most batteries are not frequently subject to bid mitigation under the ISO's local market power mitigation procedures. And when subject to mitigation, the impact of mitigation on the dispatch of batteries has been very low.[21] Nevertheless, DMM has recommended that default energy bids (DEBs) used when batteries are subject to mitigation be enhanced to reduce the potential for mitigation to cause batteries to be discharged prior to the evening hours when prices and reliability concerns are highest.

Default energy bids for energy storage resources are currently based on the estimated opportunity costs of discharging based on batteries' maximum discharge duration. For example, a battery with a four-hour discharge duration in the real-time market would have opportunity costs based on the fourth highest price in the ISO's day-ahead market. The calculation is similar for the day-ahead default energy bid but based upon prices from the day-ahead market's advisory market power mitigation pass.

DMM has provided three main recommendations for how mitigation of batteries can be improved, as described below.

Establish different default energy bids for different periods of the day

Currently, batteries can only have a single default energy bid that is static for all hours of the day. DMM has recommended allowing default energy bids to vary for different hours of the day. This would allow additional headroom to be included in default energy bids to capture estimated intraday opportunity costs during hours of the day when batteries are not usually discharging and potential market power is lowest. This would also allow use of lower default energy bids during the highest priced peak net load hours when batteries are typically scheduled to discharge, and potential market power is highest and intraday opportunity costs are lowest.

While DMM supports the ISO implementing the ability for battery default energy bids to vary hourly, a default energy bid that varies across even a few blocks of hours would be a significant improvement over a default energy bid that remains static over all hours of the day. For example, in 2026, DMM completed an analysis of a series of simple DEB formulations where DEBs were increased from current levels during hours 12-17 and lowered during hours 18-24. This analysis showed that modifying the current DEB up or down by only about 20 to 30 percent during these different periods could result in a significant improvement in the dispatch efficiency when bids are being capped at the DEBs.[22]

Create a standardized default energy bid for storage resources in the WEIM

Currently, there are no default energy bids for batteries in the WEIM, and each battery must work with the ISO and DMM to establish a specially calculated default energy bid. This stems from the fact that that the ISO's methodology for setting default energy bids for batteries uses prices from the ISO's day-

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[21] *Comments on Storage Bid Cost Recovery and Default Energy Bid Enhancements Revised Straw Proposal*, Department of Market Monitoring, Figure 1, September 23, 2024: https://www.caiso.com/documents/dmm-comments-on-storage-bid-cost-recovery-and-default-energy-bid-enhancements-revised-straw-proposal-sep-23-2024.pdf

[22] *Comments on Storage Design and Modeling Working Group Presentation on March 16, 2026*, submitted April 3, 2026: https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-mar-16-2026-working-group-presentation-apr-03-2026.pdf

ahead market as a basis for estimating opportunity costs of discharging. Currently, default energy bids for WEIM batteries are based on day-ahead default generation aggregation point (DGAP) prices that are produced by the ISO's day-ahead market software.

In 2026, DMM completed a comprehensive analysis of the negotiated default energy bids currently used by battery resources in WEIM balancing areas. Results of this analysis show that the current NDEBs used for WEIM battery resources are reasonable and have had extremely limited impact on the actual bids and dispatch of WEIM resources.[23] DMM's analysis shows that DEBs for batteries in WEIM areas tend to have significantly more headroom than DEBs for batteries in the CAISO area since the DGAP prices used for WEIM areas tend to be significantly higher than actual real-time prices in WEIM areas.

However, as with the standard storage DEB option currently in use for CAISO resources, DMM believes that DEBs for batteries in WEIM areas could be enhanced by allowing DEBs to be scaled up or down during different periods of the day to reduce the potential for uneconomic dispatch prior to the peak net load hours, while continuing to ensure effective market power mitigation during the highest priced net load hours.

Extend mitigation to include hybrid resources

Currently, hybrid resources are not subject to any mitigation because the ISO has not developed a default energy bid for these resources. DMM believes that some reasonable approximation of the marginal or opportunity costs of hybrid resources could be developed for use in mitigation. This would be easier if default energy bids could vary by hour or time of day, rather than having to be a single static value for the entire day.

Given the lack of progress that has been made on modifying BCR rules for batteries in an ongoing stakeholder process on battery issues, DMM has recommended that the ISO prioritize making these relatively simple enhancements to DEBs for batteries as soon as practicable. DMM recommends the ISO fast-track these enhancements separately, while continuing to discuss storage uplift issues and further refinements to the storage DEB, such as the specific values the DEB may take on at different times of the day.

Batteries providing resource adequacy capacity

Batteries are part of a more general category of energy-limited or availability-limited resources that are being relied upon to meet an increasing portion of resource adequacy requirements. A battery resource's ability to deliver energy across peak net load hours depends on the resource's state-of-charge and its market awards in preceding hours. During critical periods in recent years, battery resources providing resource adequacy often do not have sufficient charge to provide resource adequacy values for three or four consecutive hours across peak net load periods.

The slice-of-day framework adopted by the California Public Utilities Commission (CPUC) for California's resource adequacy program addresses this issue from the perspective of capacity portfolio planning. Under this slice-of-day approach, resource adequacy portfolios of load serving entities will need to

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[23] *Supplemental Comments on Storage Design and Modeling Working Group Presentation on March 16*, 2026, submitted April 14, 2026. https://www.caiso.com/documents/dmm-supplemental-comments-on-storage-design-and-modeling-mar-16-2026-working-group-presentation-apr-14-2026.pdf

include sufficient surplus energy to ensure that batteries can be used to meet the 24-hour resource adequacy obligation.

On an operational level, however, additional software and rule enhancements are also needed to ensure that batteries are available when needed for reliability. A longer real-time look ahead horizon could help position storage resources to be able to meet demand in peak net load hours. Battery resources should also be incentivized to be charged for peak net load hours when the CAISO and WEIM systems will rely on storage capacity the most. This requires changing bid cost recovery rules, as previously described, to ensure that battery resources have an incentive to accurately reflect their real-time intra-day opportunity costs in energy bids during the hours preceding the highest net load hours of the day.

The current resource adequacy availability incentive mechanism (RAAIM) framework does not provide very strong financial incentive for resource availability. However, the current RAAIM framework could be improved by considering the impact of various parameters that can limit the actual availability of storage resources, such as the connection to availability through state-of-charge.[24]

Flexible ramping product

The ISO's flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the real-time market software. This product is aimed at increasing reliability and efficiency, while reducing the need for manual load adjustments and other actions by grid operators to create sufficient ramping capacity to meet ramping needs and defend against uncertainty. Since being implemented in 2016, the ISO has expended considerable time and resources correcting and enhancing the flexible ramping product design.

In February 2023, the California ISO implemented nodal procurement as part of the flexible ramping product refinements stakeholder initiative. Even after locational procurement was correctly implemented, the flexible ramping product does not seem to effectively address net load uncertainty in the real-time market. The flexible ramping product continues to have a positive shadow price during a very small portion of intervals, indicating that the product is not changing the dispatch of resources significantly.

Moreover, grid operators continue to address the need for ramping capacity by entering a very high upward bias in the hour-ahead and 15-minute load forecast in the hours leading up to the peak net load hours each morning and evening. In addition to this very large upward load bias, operators take other manual actions to ensure additional ramping capacity is available during the afternoon peak net load hours. These operator actions include (1) increasing residual unit commitment requirements in the day-ahead market, (2) manually committing additional units after the day-ahead market, and (3) dispatching some slower ramping units out-of-sequence in the hours prior to the net load peak.

When the flexible ramping product was implemented in 2016, DMM has recommended that the ISO consider increasing the time horizon of real-time flexible ramping product beyond the 5-minute and 15-minute timeframe of the current product to address expected ramping needs and net load uncertainty

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[24] DMM has previously recommended that the CAISO include how the following parameters limit a battery's availability when calculating the resource adequacy availability incentive mechanism (RAAIM): de-rates to maximum state-of-charge (SOC) values below a resource's 4-hour resource adequacy value; de-rates to minimum state-of-charge such that (maximum SOC – minimum SOC) is less than a resource's 4-hour resource adequacy value; and re-rates to PMIN or not offering a charging bid range such that resources are unable to charge for later hours.

over a longer time frame (e.g., 30, 60, and 120 minutes out from a given real-time interval). A detailed explanation of this recommendation was provided in DMM's 2021 Annual Report.[25]

DMM continues to believe that the current 15-minute timeline of the flexible ramping product is too short to effectively address net load uncertainty in the real-time market. DMM continues to recommend that the ISO consider addressing net load uncertainty through a real-time product with a longer time horizon (e.g., from 1 to 4 hours). The following section provides additional discussion of how a real-time uncertainty product with a longer time horizon than the flexible ramping product could improve price formation in the real-time market.

Real-time uncertainty product

DMM continues to recommend that the ISO place a high priority on developing a new hour-ahead uncertainty product that would allow the real-time market to better reflect real-time conditions and provide earlier price signals prior to a scarcity event. An uncertainty product with a time horizon longer than one interval, as exists today with the uncertainty horizon of the flexible ramping product, would allow capacity and energy prices to rise gradually and reflect upcoming scarcity in more distant advisory intervals.

The real-time markets are cleared with a multi-interval optimization. This optimization creates a set of prices for all intervals in the run. However, only the prices in one interval, the binding interval, are used for settlements. The prices from further out advisory intervals are not used for settlements. Resources can receive dispatches in the binding interval to procure sufficient capacity to make it feasible to meet expected net load in an advisory interval.

With this multi-interval optimization, the marginal cost of meeting the expected future net load is reflected in the advisory interval energy price, but not the settled binding interval energy price. In the subsequent market runs when this advisory interval becomes a binding interval, the actions taken to make meeting expected net load feasible have already occurred, and there is no longer a cost to meet that need in the optimization run that creates the binding prices. Because the costs to meet that need have already occurred, i.e., are sunk, the energy price the resource is actually settled on does not include the marginal cost of making it feasible to meet the expected net load.

DMM believes development of such a product should be a very high priority from the perspective of price formation, as well as from the perspective of overall market design. For example, this type of real-time uncertainty product could be designed to help ensure that imbalance reserve capacity procured in the extended EDAM is actually available in the real-time market. In addition, such a product appears to be the only viable way to reduce the need for grid operators to utilize an extremely large load bias to create the capacity needed to manage real-time uncertainty and flexibility. Thus, a real-time uncertainty product would address a variety of the most important market design issues that remain following the implementation of EDAM.

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[25] *2021 Annual Report on Market Issues & Performance*, Department of Market Monitoring, July 27, 2022, pp 276-278: https://www.caiso.com/documents/2021-annual-report-on-market-issues-performance.pdf

Scarcity pricing

DMM supports the ISO's efforts to consider changes to its scarcity pricing provisions. DMM has cautioned that if scarcity pricing provisions are not well designed and do not accurately account for all available capacity, such provisions could encourage withholding of supply in order to trigger scarcity pricing.

DMM also notes that a real-time uncertainty product with an extended time horizon would also serve a scarcity pricing purpose. Because there is a tradeoff between procuring capacity or energy, prices for both capacity and energy start to rise when the amount of available capacity declines. This allows prices to increase as available capacity falls, even before there is insufficient energy supply to meet load in the market. However, because the flexible ramping product currently only looks out to one advisory interval, real-time energy and flexible capacity prices do not reflect the potential scarcity of available capacity over a longer and more relevant timeframe.

An uncertainty product with a time-horizon longer than one interval (e.g., 1 to 4 hours) would allow capacity and energy prices to reflect upcoming scarcity in more distant advisory intervals. A longer horizon uncertainty product would improve price formation by allowing prices for energy and capacity to better reflect supply and demand conditions in the real-time market, and allow energy prices to rise as available unloaded capacity becomes scarcer.

Gas resource management

Increasing gas price multipliers used setting cost-based bid caps

In 2025, the ISO finalized a package of proposed near-term enhancements designed to address concerns of regional market participants with natural gas-fired resources participating in the Western Energy Imbalance Market (WEIM) and the extended day-ahead market (EDAM).[26] DMM supports the proposed changes as incremental improvements that regional participants in the ISO markets have indicated will improve their ability to procure and manage their gas supply and generation resources. In practice, DMM believes the effectiveness of these measures will hinge largely on additional details that will need to be developed or clarified as these measures are implemented. DMM supports providing the ISO with this implementation flexibility, but recommends that the ISO be prepared to perform significant additional analysis of market and other data as it implements these measures.

The current *reference level change request* process allows resources to request that the ISO use a higher gas price for calculating commitment cost bid caps and default energy bids. The automated process allows commitment cost bid caps that include total headroom of more than 35 percent above gas price indexes, and default energy bids that include total headroom of more than 20 percent above gas price indexes. Resources can request use of gas prices above the reasonableness threshold through the manual reference level change request process.

As part of the stakeholder process on this issue, DMM submitted extensive analysis of how frequently participants have utilized this process. This analysis shows that the reference level change request process has very rarely been used by participants within the ISO balancing area and in other WEIM

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[26] Memo to Western Energy Markets Governing Body, Re: Comments on proposed changes to gas resource management December 9, 2025, https://www.caiso.com/documents/decision-on-gas-resource-management-and-extended-day-ahead-market-congestion-department-of-market-monitoring-comments-dec-2025.pdf

balancing areas. This process has only been used by resources in WEIM areas outside of California on just one day by one participant.[27]

Historical experience indicates that the current level of headroom incorporated in commitment cost bid caps and default energy bids has covered almost all the variability between actual fuel costs and gas prices used to set cost based bid caps. However, gas resources participating in the new extended day-ahead market may face additional challenges procuring gas in less liquid regional gas markets outside of the CAISO area. These include (1) increased uncertainty about gas procurement requirements, (2) greater need to purchase gas after the close of the morning gas market, and (3) greater exposure to higher levels of gas price variability.

To address these concerns, the gas resource management proposal approved in 2025 will create customizable multipliers that will be applied to minimum load bid caps and default energy bids to account for the fact that some gas resources face higher gas price volatility and costs than others. DMM supports providing this flexibility, but recommends that the ISO be prepared to perform significant additional analysis of gas price data as it implements these options.

For example, multipliers should not be set at very high levels based on extreme but infrequent historical outcomes or future scenarios. DMM believes it is reasonable to set thresholds so that participants may need to utilize the reference level change request on a limited basis. The manual reference level change request process and after-the-fact cost recovery provisions are designed to address extreme but infrequent events.

The approved changes also provide the ISO with the flexibility to increase the reasonableness thresholds based on differences between the D+2 forecast of gas usage and subsequent updated forecasts of gas usage. DMM suggests that this flexibility be expanded to include other indicators of extreme gas and electric market conditions that warrant an increase in reasonableness thresholds, in the same manner that the ISO makes many out-of-market decisions based on such conditions.

Finally, DMM notes that it seems several of the key problems cited by participants with the reference level change request process could be addressed through relatively easy enhancements to the ISO or participants' software. These issues include (1) the complexity of the software system for submitting bids and requests (called SIBR); and (2) that the automated process requires that a separate request be submitted for each unit.

Dynamic mitigation of commitment costs

An initiative approved by the ISO Board of Governors and WEM Governing Body in 2018 included a policy to pursue changing the current static caps on start-up and minimum load bids (which include a 25 percent adder above costs) to a dynamic cap on commitment costs. This dynamic approach would seek to mirror how energy bids are currently subject to mitigation. First, a structural test for local market power is applied. If this test indicates the potential for local market power, then bids are capped at cost-based levels plus a modest adder. Otherwise, bids are only subject to a much higher cap. The ISO never developed details needed to gain FERC approval and implement this type of dynamic mitigation for commitment costs due to the complexity of developing and implementing such an approach.

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[27] *Supplemental comments on gas resource management – Draft Final Proposal*, Department of Market Monitoring, October 15, 2025: https://www.caiso.com/documents/dmm-supplemental-comments-on-gas-resource-management-draft-final-proposal-oct-15-2025.pdf

In comments on the ISO's 2025 gas management changes, the ISO's Market Surveillance Committee (MSC) expressed concern that "increased scheduling of resources in the extended day-ahead market increases the potential for large amounts of gas-fired generation to be scheduled … to support exports that might not have been anticipated by the EDAM participant when they bought gas in the morning gas market."[28] The MSC noted that this risk could cause regional participants (which are not subject to must-offer requirements) to avoid offering all available gas-fired capacity into EDAM. To address this concern, the MSC encouraged the ISO to place a high priority on implementing the dynamic market power mitigation approach for commitment cost bids.

In 2026, the ISO indicated it will pursue implementation of this policy. The ISO has noted that implementation challenges include (1) the implementation costs; (2) limited solution times; (3) competing priorities; and (4) risk that approaches don't work as intended or have unintended consequences.[29] The ISO has noted that implementing this policy will require technology trade-offs that increase with solution complexity, and that a simplified solution could create risk of market power or over-mitigation.

As summarized in DMM's memo to the ISO Board in 2018 on this issue, a variety of factors make dynamic mitigation of commitment costs significantly more difficult than mitigation of energy bids.[30] While DMM recognizes that EDAM may increase challenges associated with gas procurement facing regional participants, DMM also notes there is limited evidence that the current commitment cost bid caps have created significant issues or inefficiencies in the CAISO or WEIM. As noted in DMM's 2024 annual report, about 20 percent of startup capacity and only 2 percent of minimum load capacity for resources in the WEIM was bid in at or near the current commitment cost bid caps (which include an adder of 125 percent above total estimated commitment costs).[31] And as previously noted, WEIM participants have used the reference level change request process to increase these bids on only one occasion.

Consequently, DMM has recommended that the ISO carefully design and test any approach for mitigating commitment costs before implementation. In terms of ensuring system reliability and efficiency during extreme gas events, DMM believes that it is more important to implement design and process enhancements to increase the ability of participants and the ISO to quickly increase gas prices and reasonableness thresholds used in limiting commitment cost bids. These enhancements would help ensure that commitment cost bid caps are not too low even when mitigation is applied.

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[28] *Opinion on Gas Resource Management*, Market Surveillance Committee, market-surveillance-committee-draft-opinion-gas-resource-management-dec-12-2025.pdf

[29] *Commitment cost bidding flexibility*, CAISO presentation, March 26, 2026: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Committment-Cost-Bidding-Flexibility-Mar-26-2026.pdf

[30] *Department of Market Monitoring Comments on Commitment Costs and Default Energy Bid Enhancements Proposal*, March 14, 2018: https://www.caiso.com/documents/decision_ccdebeproposal-department_marketmonitoringmemo-mar2018.pdf

[31] *2024 Annual Report on Market Issues and Performance*, Department of Market Monitoring, August 7, 2025, p 156. https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf

Balancing area market power mitigation

DMM recommends changing the market power mitigation (MPM) process from one that tests balancing authority areas (BAAs) individually without accounting for supply from neighboring BAAs in the pivotal supplier calculation, to a grouping approach where competitiveness is determined by testing groups of interconnected BAAs with uncongested transfer constraints. Testing BAAs together, rather than individually, may indicate that the group as a whole is competitive and would avoid unnecessarily subjecting individually non-competitive BAAs to mitigation. The specific algorithm adopted to implement a grouping approach to BAA-level mitigation will have implications on which scenarios may be subject to over or under mitigation in some situations. Therefore, DMM recommends the ISO be explicit in clarifying why any particular chosen algorithm would be the preferable approach.

In developing a BAA-level mitigation approach, the CAISO BAA should be treated consistently with other BAAs by testing the CAISO area in any new grouping approach, as opposed to assuming the CAISO area is competitive by default. DMM disagrees with the conclusion of some stakeholders that the CAISO area is always competitive and therefore needs not be subject to BAA-level market power mitigation.

The structural measures of system competitiveness for the day-ahead market in DMM's 2024 annual report show residual supply index (RSI) values when a single pivotal supplier (RSI1) is removed, two pivotal suppliers are removed (RSI2), and when three pivotal suppliers are removed (RSI3).[32] These results indicate that the CAISO area should not be assumed competitive in all hours, and support the inclusion of the CAISO area in the BAA-level mitigation process.

DMM supports changes to consideration of net supply position when calculating the withholdable capacity in testing BAA-level competitiveness, but notes that there may be significant computational and implementation challenges in doing this accurately. An entity's net supply position can fluctuate substantially from hour to hour and day to day. Accurately evaluating this position would likely require comprehensive visibility into the entity's full supply portfolio, including the availability of all resources as well as its bilateral positions. Because these factors can shift significantly across time, complete and reliable information—particularly on actual available supply after accounting for physical and financial bilateral commitments—may not be fully available until shortly before the day-ahead and real-time markets.

When considering any change to the structure of BAA-level mitigation, DMM recommends the ISO consider that in many cases, state regulatory oversight may serve as a backstop for any inaccuracies in measuring the net supply position of regulated entities. DMM acknowledges that load serving utilities subject to state regulation may have limited incentives to withhold available capacity in an attempt to raise prices. However, implementing MPM rules that rely in part on regulatory agencies to prevent non-competitive behavior is a fundamental shift from previous market power mitigation design. Determining a lack of need for mitigation based on assumptions about regulatory incentives is introducing a reliance on state regulation into the MPM process that does not currently exist and may warrant further consideration.

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[32] *2024 Annual Report on Market Issues and Performance*, Department of Market Monitoring, August 7, 2025, pp 142-144: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf

Fast-start pricing

DMM has previously outlined reasons it believes fast-start pricing is inconsistent with the features of locational marginal pricing that maximize market surplus and provide incentives for units to bid and operate at the most efficient, socially optimal dispatch level.[33] DMM understands that in response to requests from some stakeholders, the ISO has recently examined the possibility of adopting some form of fast-start pricing in the CAISO and WEIM. However, the ISO's revised 2025 policy initiatives roadmap reports that further work on the fast-start pricing initiative has been suspended until at least 2027.

The ISO has provided analysis which suggests the impacts of fast-start pricing are small on average, but can be large in a limited number of intervals.[34] The ISO's current analysis does not consider many of the complexities of the CAISO and WEIM markets. If stakeholders and the ISO decide to move forward with fast-start pricing, additional testing in the actual market software will be needed.

DMM believes further analysis is needed for the ISO to assess whether the pattern of estimated price impacts could actually lead to meaningful increases of import bids into the WEIM. This is the main potential efficiency benefit cited by proponents of fast-start pricing. Unlike most other RTOs, the ISO's real-time market and WEIM already allow imports and exports between balancing areas to be offered and cleared based on bid prices, rather than requiring imports and exports to be scheduled as price takers. DMM supports the ISO's suspension of further policy work on the fast-start pricing initiative, and focusing resources instead on other design enhancements.

Demand response

Since 2020, DMM has provided numerous special reports focusing on demand response in the California ISO during the most critical summer periods.[35] DMM also provides comments in ISO stakeholder processes and California Public Utilities Commission (CPUC) proceedings on demand response. In addition to reports and comments, DMM has engaged with WEIM and EDAM entities on the topic of demand response and its role in their respective balancing areas.

Demand response accounted for about 2.5 percent (or 1,140 MW) of total California ISO system resource adequacy capacity the summer of 2025, compared to about 2.6 percent of total system resource adequacy capacity in 2024. Demand response also plays a role in meeting the capacity needs of WEIM and EDAM entities. However, assessing demand response outside of the CAISO area is more difficult because it does not participate as a market resource.

In 2024, the ISO completed some limited penalty enhancements for demand response that include explicit deadlines and well-defined penalty structures regarding the submission of demand response monitoring data. DMM supported these enhancements, as it will improve the ability to monitor since it increases incentives to submit demand response monitoring data. The changes were in effect as of January 6, 2025.

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[33] *Comments of the Department of Market Monitoring for the California Independent System Operator* in RM17-3-000: https://www.caiso.com/Documents/Feb28_2017_DMMComments-Fast-StartPricingNOPR_RM17-3.pdf

[34] *Price Formation Enhancements, Analysis on Fast Start Pricing*, California ISO, April 8, 2024: https://www.caiso.com/InitiativeDocuments/Presentation-Price-Formation-Enhancements-Apr8-2024.pdf

[35] *Demand response issues and performance 2024*, Department of Market Monitoring, February 20, 2025: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

The ISO, CPUC, and California Energy Commission (CEC) also continue to work on addressing some additional issues pertaining to demand response, including enhancing resource adequacy counting methodologies to account for the variable nature of some demand response resources. DMM continues to recommend that the ISO consider other potential changes to enhance the reliability of demand response capacity. These include:

- **Re-examine demand response counting methodologies.** Demand response appeared to be over-counted in terms of these resources' contribution towards meeting resource adequacy requirements and their reported load curtailments. DMM supports efforts to better capture the capacity contribution of demand response resources whose load reduction capabilities vary across the day, and who may have limited output in general. The CPUC and CEC are currently working to develop an incentive-based qualifying capacity valuation for supply-side demand response resources.[36] DMM has recommended considering a performance-based penalty or incentive structure for resource adequacy resources. An incentive-based methodology for awarding qualifying capacity to resource adequacy demand response resources may improve the trend in recent years where availability and performance of proxy demand response resources fall below resource adequacy capacity.

- **Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment (RUC) process.** This exemption does not exist for other types of long-start resources providing resource adequacy. Long-start resources continue to make up a significant portion of the resource adequacy proxy demand response fleet. In July through September of 2025, about 26 percent of supply plan demand response was registered with start-up times of over 255 minutes.[37] If this capacity is not scheduled economically in the integrated forward market, then per the ISO tariff, this capacity has no obligation to be available in RUC.

- **Ensure that non-CPUC jurisdictional load serving entities that manage utility demand response programs used to meet resource adequacy requirements communicate the available capacity to the ISO on a daily basis, so that the ISO is aware of and can call this capacity when needed.** DMM understands that the ISO has reached out to non-CPUC jurisdictional load serving entities using demand response crediting to better ensure that the ISO has insight into these demand response programs. It will be important that the ISO have the same insight into other local regulatory authority demand response programs which are counted towards meeting resource adequacy, as the ISO does with CPUC-jurisdictional load serving entity demand response programs.

In addition to the above recommendations for the California ISO balancing area, DMM recommends the development and enhancement of demand response models for WEIM (and ultimately EDAM) entities. Currently, demand response for WEIM entities is implemented through load adjustments, and as a result are not incorporated into the market. As a result, the

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[36] *Decision adopting local capacity obligations for 2024-2026, flexible capacity obligations for 2024, and program refinements (D.23-06-029)*, CPUC Docket R.21-10-002, June 29, 2023, pp 79-81: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

[37] Long-start resources have a cycle time greater than 240 minutes, where cycle time is a resource's startup time plus minimum run time.

WEIM entities do not have a method or market data to assess availability or performance for their demand response resources. DMM recommends the ISO develop a WEIM demand response model to improve the access and validity of the WEIM demand response resources.

California resource adequacy

California relies on the state's long-term integrated resource planning process and resource adequacy program to maintain adequate system capacity and help mitigate market power through forward energy contracting. However, the state's resource adequacy framework needs significant changes to accommodate numerous regulatory and structural market changes in recent years.

Resource adequacy imports

DMM has warned that existing California ISO rules could allow imports that may not be available during critical system and market conditions to meet resource adequacy requirements. For instance, under current ISO resource adequacy rules, imports can routinely bid significantly above projected prices in the day-ahead market to help ensure they do not clear, thus relieving the imports of any further offer obligations in the real-time market.[38]

The California Public Utilities Commission (CPUC) has addressed this concern with CPUC-jurisdictional entities using imports to meet resource adequacy requirements. In 2020, the CPUC issued a decision specifying that non-resource specific import resource adequacy resources must be self-scheduled or bid into the CAISO markets at or below $0/MWh during peak net load hours of 4-9 p.m.[39] DMM supports the CPUC's approach as an effective interim mechanism for ensuring delivery of import resource adequacy during peak net load hours. Monitoring and analysis by DMM indicate this approach has proven effective at ensuring delivery of resource adequacy imports since being implemented in 2020.

DMM continues to recommend that the ISO, CPUC, and stakeholders consider alternative solutions to allow resource adequacy imports to participate more flexibly in the market. For example, DMM supported development of a recent proposal in CPUC proceedings to allow resource adequacy imports to bid up to the marginal cost of a typical gas resource rather than at or below $0/MWh during peak net load hours.[40] Over the longer term, DMM supports development of a more source-specific framework for resource adequacy imports that ensures other balancing areas cannot recall import energy, particularly when they also face supply shortages.

New slice-of-day resource adequacy framework

In April 2023, the CPUC issued a decision adopting implementation details for a 24-hour *slice-of-day* framework, which includes adopting compliance tools, resource counting rules, and a methodology to

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[38] *Import Resource Adequacy*, Department of Market Monitoring Special Report, September 10, 2018, pp 1-2: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

[39] *Decision adopting resource adequacy import requirements (D.20-06-028)*, CPUC Docket R.17-09-020, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.pdf

[40] *Reply comments on proposed decision adopting local capacity obligations for 2024-2026, flexible capacity obligations for 2024, and program refinements*, Department of Market Monitoring, CPUC Docket R.21-10-002, June 19, 2023: http://www.caiso.com/Documents/Reply-Comments-R21-10-002-Adopting-Local-2024-26-and-Flexible-2024-Capacity-Obligations-and-ProgramRefinements-Jun-19-2023.pdf

translate the current Planning Reserve Margin to the slice-of-day framework.[41] The CPUC has implemented the framework starting in the 2025 compliance year. DMM supports the CPUC's decision to adopt the slice-of-day framework because it aligns capacity sufficiency throughout the year with energy sufficiency throughout the day. DMM also supports the requirement to offset battery storage usage with excess energy and capacity from other resources needed to charge these storage resources.

DMM also supports the proposal to change the capacity counting methodology for solar and wind resources to the *exceedance* values, rather than values based on the *effective load carrying capacity* (ELCC) approach. Although exceedance values for wind and solar are conservatively low, DMM believes that too much reliance on these variable energy resources that may not actually be available during peak net load hours is a reliability risk.

Resource adequacy performance incentives

An availability incentive uses bids to determine resource availability, while a performance incentive uses schedules and delivered supply to determine resource performance. The distinction between these two mechanisms is important because it leads to two separate behavioral incentives, and thus potentially two different outcomes.

The ISO's current mechanism for incentivizing the availability of resource adequacy capacity is the resource adequacy availability incentive mechanism (RAAIM). Resource unavailability can cause financial penalties associated with RAAIM based on 60 percent of the ISO's capacity procurement mechanism (CPM) soft offer cap, which has been $7.34/kW-month since June 1, 2024.[42]

As capacity becomes more limited and prices increase in the West, the difference between capacity payments and potential RAAIM penalties also increases. DMM is concerned that if RAAIM penalties become insignificant compared to potential resource adequacy payments, suppliers may be willing to sell resource adequacy capacity that is more likely to be unavailable, or to incur forced outages for a significant portion of the month. Since the RAAIM penalty is not performance based, a supplier could also avoid current availability penalties by offering capacity into the market, even though this capacity fails to perform when called upon.

Availability incentives provide financial motivation for resources to bid into the market, but do not provide a financial motivation to perform, i.e., meet the resource's schedule. As a result, DMM recommends the ISO additionally consider a performance incentive mechanism that would be a measure of a resource's schedule against their metered contribution to the system. A performance mechanism and an availability incentive are complementary, and could be considered as a package to meet the operational needs of the system. DMM believes the penalty structure should be priced to claw-back RA capacity payments that are associated with the difference between the obligation and their availability and performance. Because the penalty is a claw-back, the penalty price should be designed as a function of resource adequacy market prices.

Incentivizing availability and performance of resource adequacy capacity could become increasingly important as resource adequacy payments increase compared to the magnitude of potential RAAIM

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[41] *Decision on Phase 2 of the Resource Adequacy Reform Track (D.23-04-010)*, CPUC Docket No. R.21-10-002, April 7, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF

[42] California ISO Tariff Section 40.9.6.1(c): Section40-RADemonstration-for-SchedulingCoordinatorsintheCAISOBalancingAuthorityArea-asof-Nov1-2023.pdf

charges. The addition of a performance mechanism could better incentivize suppliers to sell highly available, and dependable, capacity up front.

Outage management enhancements

Currently, the ISO requires resources to acquire substitute resource adequacy capacity for planned outages. Due to tight conditions in the capacity market, acquiring substitution capacity is difficult. As a result, DMM has identified that under the current outage substitution rules, resources are transferring their outages into the forced outage timeframe (7 days or less) that does not require substitute capacity. Since forced outages receive less scrutiny and will be automatically approved, DMM is concerned a discretionary outage transferred into the forced timeframe may compromise reliability during tight grid conditions.

To address this concern, DMM recommends the ISO enhance outage reporting requirements to more clearly require the resource scheduling coordinator to identify if a forced outage is either (1) necessary immediately for plant operation or (2) if the forced outage is for discretionary plant maintenance that could be postponed in the case of imminent system reliability concerns. DMM supports these policy developments. DMM recommends that if the ISO establishes an outage substitution pool, such a pool be established as an auction.[43]

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[43] *Comments on Resource Adequacy Modeling and Program Design Working Group*, Department of Market Monitoring, March 13, 2025: https://www.caiso.com/documents/dmm-comments-on-resource-adequacy-modeling-and-program-design-working-group-mar-13-2025.pdf

1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. Electricity prices declined in 2025 despite higher natural gas prices, reflecting the increasing influence of renewable generation and battery storage across the WEIM. Since June 2021, roughly 122 GW of capacity has been added to the WEIM, 34 percent hydroelectric and about 21 percent batteries.

Specific trends highlighted in this chapter include the following:

- **Load across the WEIM averaged 78.3 GW, almost identical to average system load in 2024.** Load increased in the Pacific Northwest, Intermountain West, and Desert Southwest compared to 2024. Load in California decreased by 2 percent in 2025 compared to 2024.
- **Peak 5-minute market load for the year was 130.1 GW on August 22, 2025, hour-ending 18, interval 10,** a 3.8 percent decrease from the 2024 peak load (135.3 GW).
- **Battery charging reached nearly 10 percent of system load during midday hours**, reflecting the growing role of storage in absorbing excess solar generation.
- **The largest sources of generation in 2025 in the California region** were natural gas and non-hydro renewables. Hydroelectric generation dominated the generation mix in the Pacific Northwest, accounting for about 68 percent of total generation. In the Intermountain West, generation was primarily from coal (33 percent), non-hydro renewables (30 percent), and natural gas (26 percent). Natural gas remained the largest source of generation in the Desert Southwest.
- **The Pacific Northwest region was a net exporter during most months.** The California region was a net importer throughout 2025. The Desert Southwest and Intermountain West regions were net exporters during non-summer months.
- **Hydroelectric production increased significantly in the Pacific Northwest while declining in other regions,** highlighting growing regional variation in hydrologic conditions and their impact on supply.
- **In the Pacific Northwest, solar and hydroelectric generation increased in 2025 compared to 2024,** with hydroelectric generation increasing by about 1,170 MW (8 percent). Nuclear and natural gas generation decreased. Net interchange increased during solar hours and decreased during non-solar hours.
- **In the California region, natural gas generation decreased in all hours in 2025 compared to 2024**. Solar generation increased by about 630 MW (11 percent). Batteries increasingly participated in energy arbitrage by charging during high solar hours and discharging during evening peak net load periods. Net imports increased across all hours by an average of about 430 MW (17 percent).
- **In the Intermountain West, coal generation increased by about 560 MW (19 percent),** reversing prior-year declines, while natural gas generation decreased by about 200 MW (7 percent). Wind, solar, and battery generation increased, contributing to decreases in net imports and net dynamic transfers across all hours.
- **In the Desert Southwest region, solar generation increased by about 630 MW (31 percent)** in 2025. Net imports decreased by about 240 MW, while net dynamic transfers increased by about 200 MW
- **Over 376,000 GWh of generation in the WEIM system came from renewable resources.** 49 percent of that generation was from non-hydroelectric resources. Renewable resources produced over 42.9

GW of power on average across the year, accounting for more than 54 percent of total WEIM system load.

- **Total downward dispatch of wind and solar resources increased by about 22 percent in 2025** compared to 2024. Downward dispatch of economic bids accounted for about 4,780 GWh (89 percent) of total curtailment, while curtailment of self-schedules accounted for about 480 GWh (9 percent), with all other curtailment categories remaining minimal.
- **Total battery capacity reached approximately 25,700 MW by the end of 2025**. Average battery discharge peaked at about 9,100 MW in the evening hours, compared to about 5,700 MW in 2024, reflecting increased participation of storage in energy shifting and peak demand periods.
- **Natural gas prices in the West increased compared to 2024,** with prices at most major hubs rising between 11 percent and 45 percent. Prices at Henry Hub, the national reference point, were up 59 percent. NW Sumas prices declined by about 11 percent. The percent changes in gas prices appeared significant because prices in 2024 were unusually low. However, the nominal changes in gas prices were relatively small.
- **California greenhouse gas allowance prices averaged about $29.89/mtCO2e in 2025,** down 22 percent from 2024, representing an incremental cost of about $12.70/MWh for a relatively efficient gas unit.
- **Washington greenhouse gas allowance prices averaged about $61.43/mtCO2e in 2025,** representing a 94 percent increase from 2024 and an incremental cost of about $26.10/MWh for a relatively efficient gas unit.
- **DMM estimates that net energy market revenues for a hypothetical new gas unit in 2025 ranged from $3 to $20/kW-yr for a typical combined cycle unit and $1 to $4/kW-yr for a typical combustion turbine unit.** Net market revenues remained well below estimated going-forward fixed costs, indicating the continued need for resources to recover fixed costs through long-term contracts.
- **DMM's simulated revenues for hypothetical batteries averaged about $39/kW-yr for energy and $39/kW-yr for ancillary services.** Actual batteries in the CAISO balancing area earned approximately $35/kW-yr in energy revenues and $9/kW-yr for regulation in 2025.

1.1 Load conditions

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

The balancing areas are divided into four geographical regions:

- **California**: includes all balancing areas in California: California ISO (CAISO), the Balancing Authority of Northern California (BANC), Los Angeles Department of Water and Power (LADWP), and Turlock Irrigation District (TIDC).
- **Desert Southwest**: includes Arizona Public Service (AZPS), El Paso Electric (EPE), NV Energy (NEVP), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric (TEPC), and WAPA-Desert Southwest.

- **Intermountain West**: includes Avista Corporation (AVA), Idaho Power Company (IPCO), NorthWestern Energy (NWMT), and PacifiCorp East (PACE).
- **Pacific Northwest**: includes Avangrid Power (AVRN), Bonneville Power Administration (BPA), PacifiCorp West (PACW), Portland General Electric (PGE), Powerex, Puget Sound Energy (PSE), Seattle City Light (SCL), and Tacoma Power (TPWR).

1.1.1 Average load and load distribution

Figure 1.1 shows the total market load distribution in the 5-minute market. The distribution incorporates all 5-minute load data for 2025 (blue line) and 2024 (grey dashed line).

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

The distribution shows how the load values are distributed. Higher points on the curve represent load levels that occurred more frequently during the year. For instance, if the curve peaks around 70 GW, this indicates that load levels around 70 GW were most commonly observed.

The distribution shows very similar load patterns in 2024 and 2025. Between load levels of 70 and 100 GW the blue line lies slightly above the gray dotted line, indicating that these loads occurred with somewhat greater frequency in 2025 than in 2024. Load levels of 55 to 60 GW occurred more often in 2024 than in 2025. These differences are modest, and load profiles between both years are largely similar.

Figure 1.1 Annual system-wide total load distribution

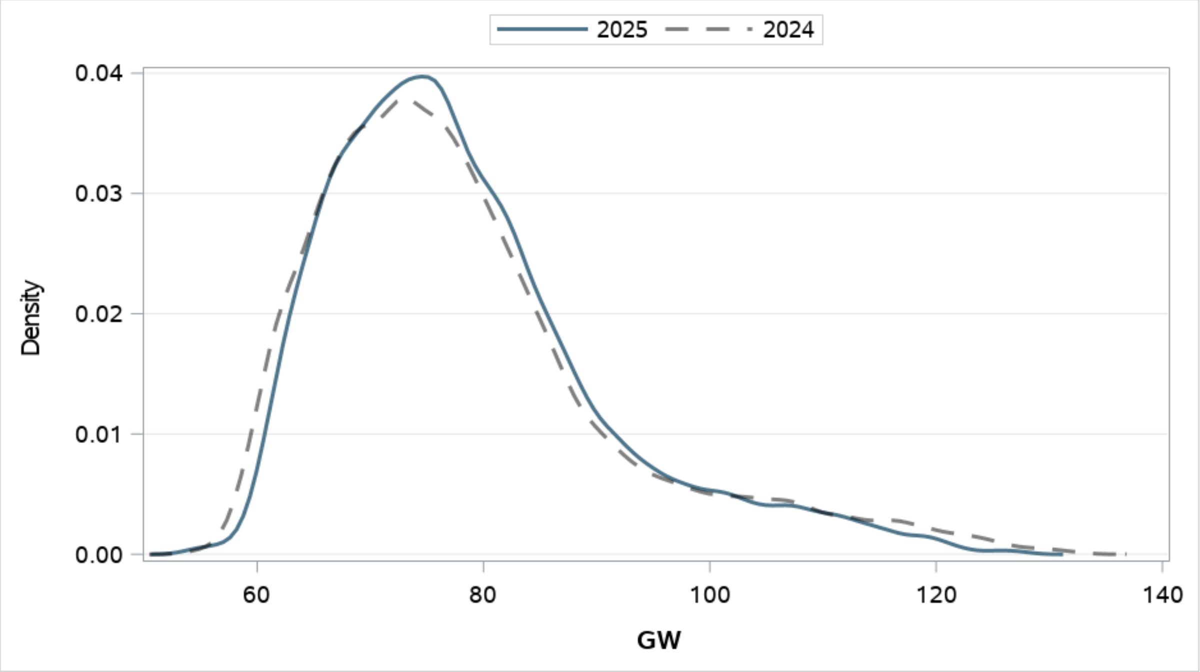

Figure 1.2 shows the quarterly average 5-minute market load categorized by region from Q1 2022 to Q4 2025. In 2025, the total system load averaged 78.3 GW, reflecting no change in average load compared to the previous year. Apart from California, each region's average load increased in 2025 relative to 2024:

- **Pacific Northwest** (green) averaged **23.2 GW**, a 1.9 percent increase.
- **Desert Southwest** (yellow) averaged **16.9 GW**, a 0.2 percent increase.
- **Intermountain West** (red) averaged **10.3 GW** and rose by 0.8 percent.
- **California** (blue) averaged **27.9 GW**, a 2 percent decrease.

The WEIM total market load tends to be highest in Q3. Regions such as California, Intermountain West, and Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, showing higher loads during the summer quarters. However, in the Pacific Northwest, quarterly average loads are highest in the winter, with comparatively low load during summer.

Figure 1.2 Quarterly average 5-minute market load by region (GW)

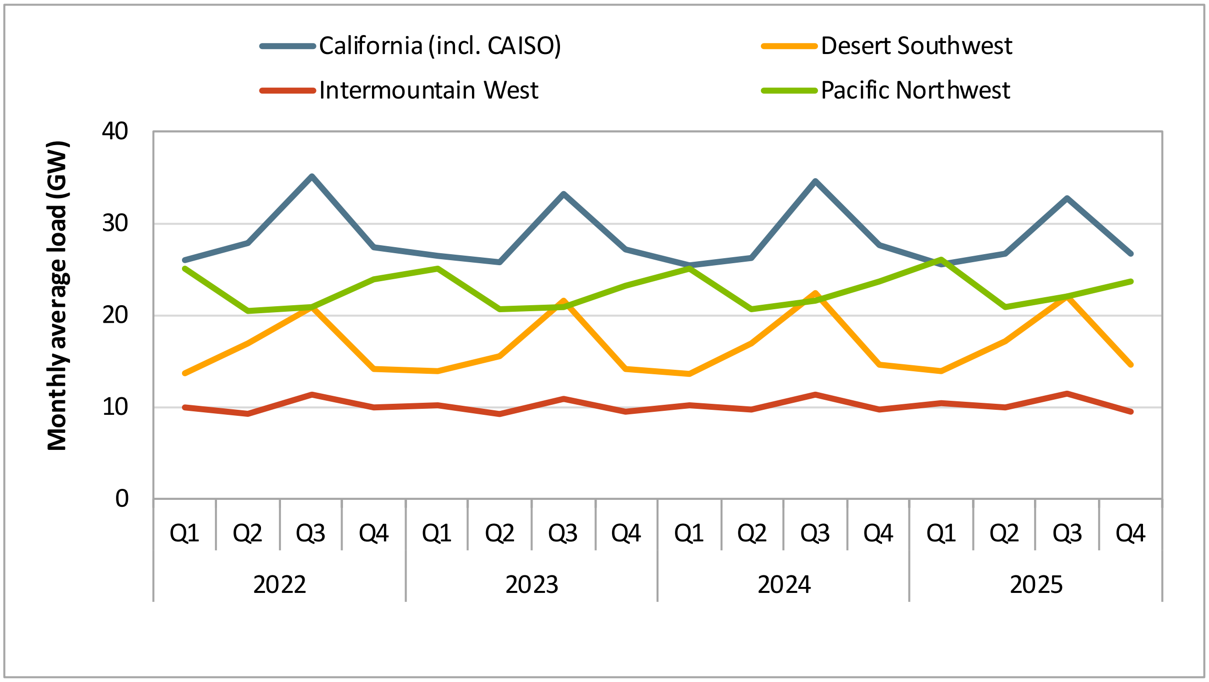

Figure 1.3 displays the hourly average 5-minute market load across different regions in 2025. Each color represents the average hourly load for a given region, and the gray shaded area represents the same for the entire WEIM system. The black dashed line indicates the average hourly WEIM system-wide load for 2024.

Figure 1.4 shows the percentage change in hourly average 5-minute market load across each region from 2024 to 2025. Percent change is computed for each hour by taking the difference in average load levels between 2025 and 2024 and then dividing the difference by the average load level in 2024. Each series shows the hourly percent change in average load from 2024 to 2025. Each color represents the percent change in hourly average 5-minute market load for a given region, and the gray dotted line represents the same for the entire WEIM system.

The total WEIM hourly average load peaked at hour-ending 19, reaching 91.7 GW, while the lowest load occurred at hour-ending 4, at 67.0 GW. California recorded the largest loads across all hours, followed by the Pacific Northwest.

In 2025, the peak average hourly load for each region was:

- **Pacific Northwest:** peak load of 25.6 GW at hour-ending 19.
- **Desert Southwest:** peak load of 20.8 GW at hour-ending 18.
- **Intermountain West:** peak load of 11.7 GW at hour-ending 18.
- **California:** peak load of 33.8 GW at hour-ending 19.

Figure 1.3 Hourly average 5-minute market load by region (GW)

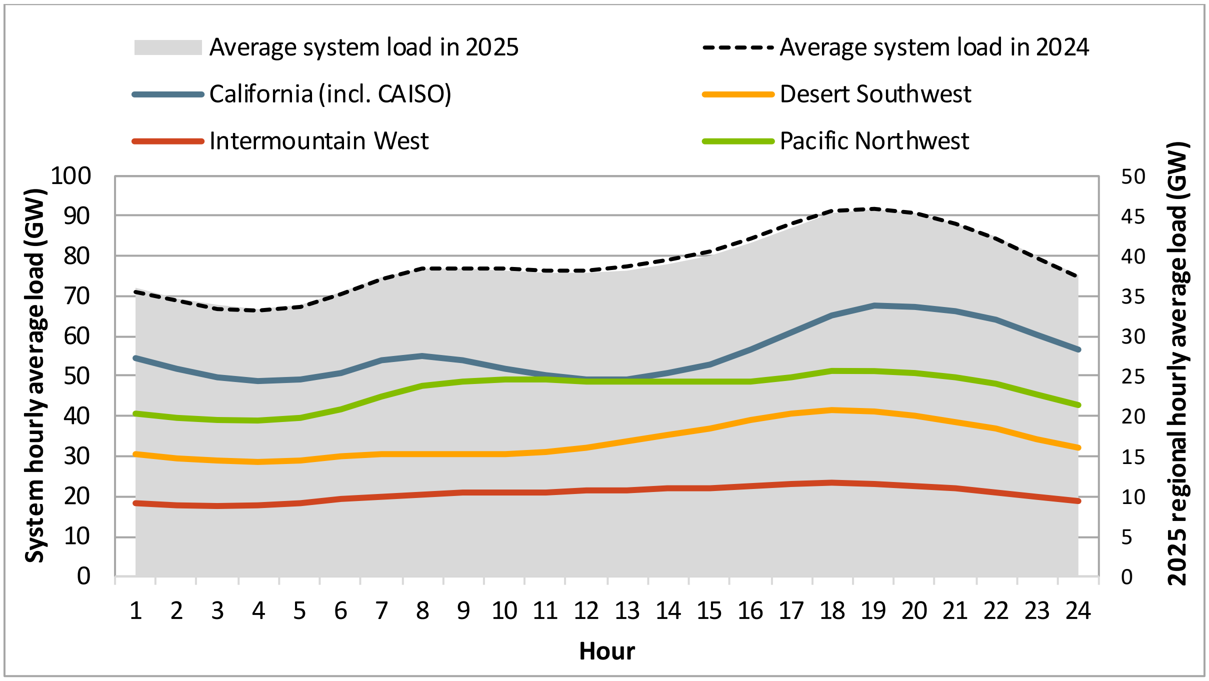

Figure 1.4 Percent change in hourly average 5-minute market load by region (2024-2025)

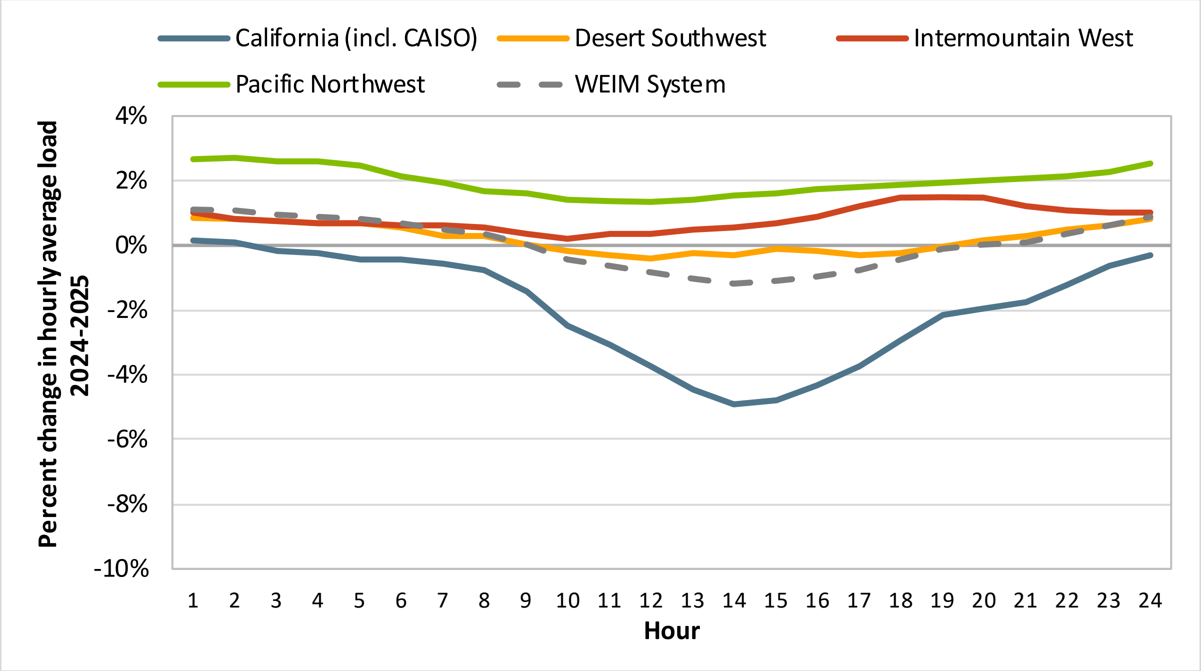

Figure 1.5 shows the hourly average system-wide net load in the 5-minute market from 2021 to 2025. Net-load is calculated by subtracting scheduled solar and wind resources from total load schedules. Year-over-year changes in the net load profile can be partially explained by the expansion of the WEIM, as additional BAAs joined the market.[44]

From 2022 to 2025, net-load during solar hours declined, consistent with increased solar generation across the footprint. In 2025, the peak average net load reached 81,008 MW at hour-ending 20, representing a one-half percent decrease from 2024, whose average hourly net load also peaked at hour-ending 20. Over the past five years, the peak net load consistently occurred in hour-ending 20.

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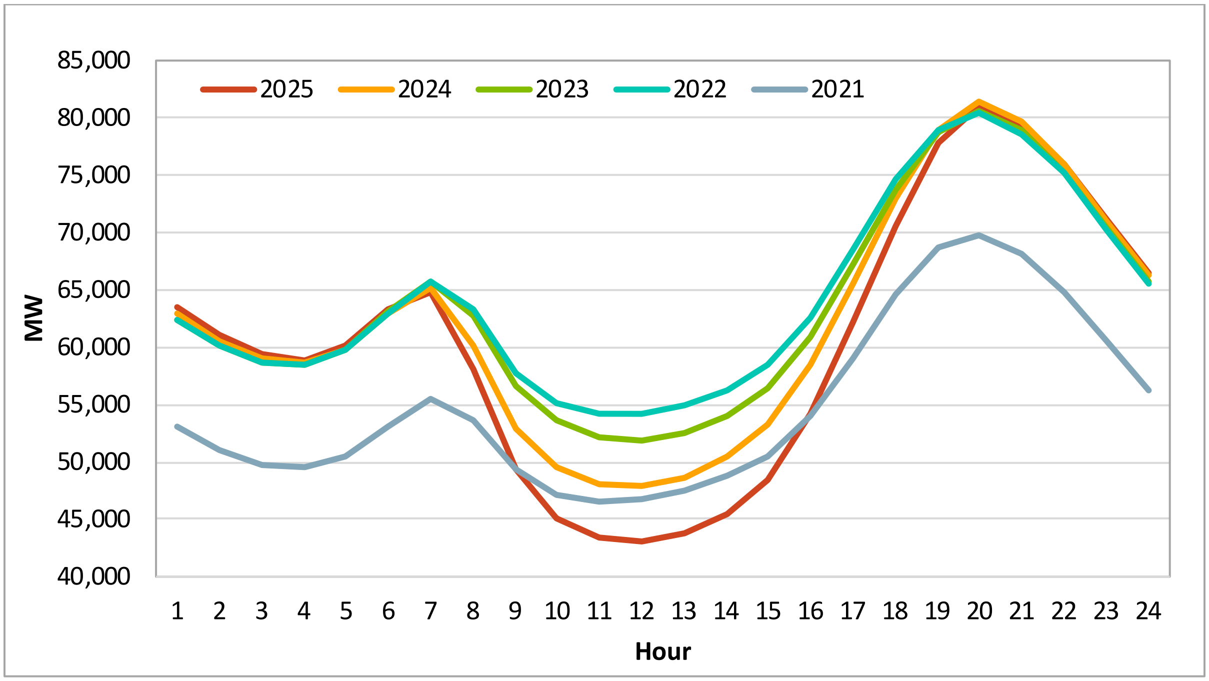
[44] Since 2021, a total of 12 new BAAs have joined the WEIM market.

- 2021: BANC (Mar 2nd phase), TIDC (Mar), PNM (Apr), LADWP (Apr), NWMT (Jun).
- 2022: AVA (Mar), TPWR (Mar), BPAT (May), TEPC (May).
- 2023: AVRN (Apr), EPE (Apr), WALC (Apr).

Figure 1.5 Average hourly system-wide net load in the 5-minute market by year

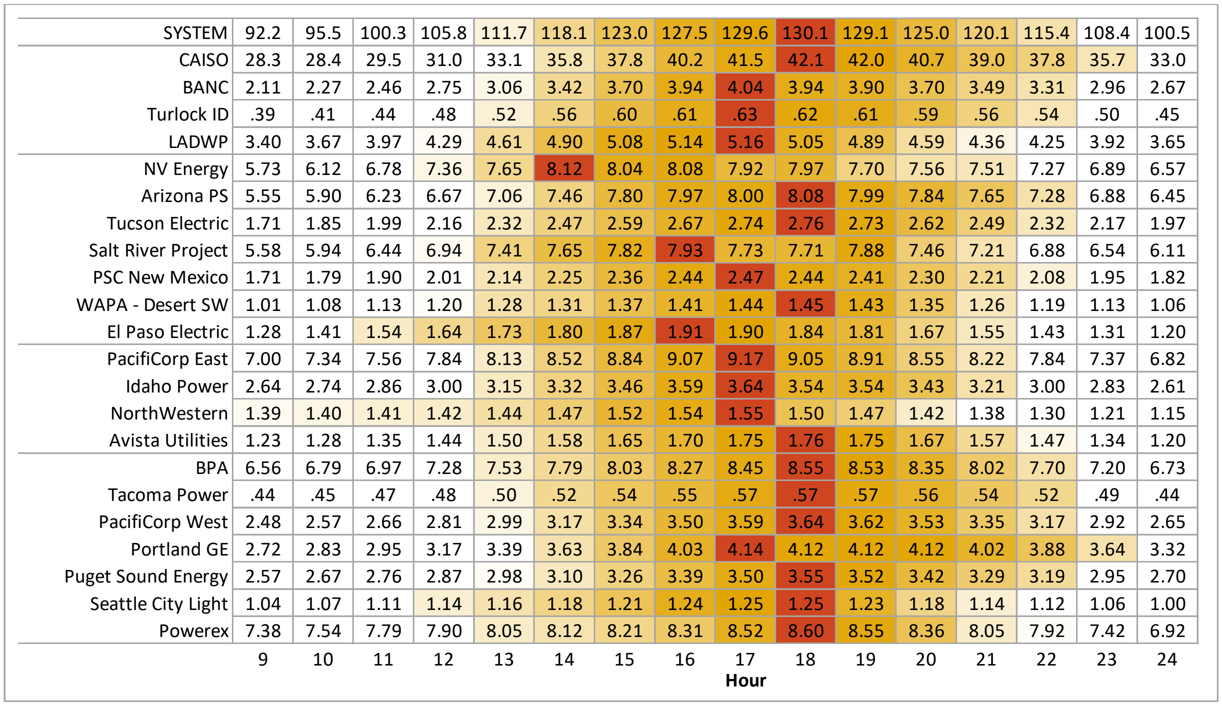


1.1.2 Peak load

Figure 1.6 shows the highest 5-minute market *system* load forecast for each hour on August 22, 2025, the day with the highest system load during 2025. The figure also shows corresponding load forecast data for each balancing area for the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 130.1 GW during hour-ending 18, interval 10. This was lower than the 2024 WEIM system load peak of 135.3 GW, which occurred during hour 18, interval 10 on July 10, 2024.

This heatmap highlights the hour with the peak load for each balancing area on this day. Red indicates the hour of highest load for each balancing area and yellow indicates hours with above-average load for that day. Peak load for balancing areas varied across hours. While the system peak occurred during hour-ending 18, nearly half of all balancing areas reached their peak in hours-ending 16 and 17, and NV Energy recorded peak load in hour-ending 14.

Figure 1.6 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market August 22, 2025)



	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SYSTEM	92.2	95.5	100.3	105.8	111.7	118.1	123.0	127.5	129.6	130.1	129.1	125.0	120.1	115.4	108.4	100.5
CAISO	28.3	28.4	29.5	31.0	33.1	35.8	37.8	40.2	41.5	42.1	42.0	40.7	39.0	37.8	35.7	33.0
BANC	2.11	2.27	2.46	2.75	3.06	3.42	3.70	3.94	4.04	3.94	3.90	3.70	3.49	3.31	2.96	2.67
Turlock ID	.39	.41	.44	.48	.52	.56	.60	.61	.63	.62	.61	.59	.56	.54	.50	.45
LADWP	3.40	3.67	3.97	4.29	4.61	4.90	5.08	5.14	5.16	5.05	4.89	4.59	4.36	4.25	3.92	3.65
NV Energy	5.73	6.12	6.78	7.36	7.65	8.12	8.04	8.08	7.92	7.97	7.70	7.56	7.51	7.27	6.89	6.57
Arizona PS	5.55	5.90	6.23	6.67	7.06	7.46	7.80	7.97	8.00	8.08	7.99	7.84	7.65	7.28	6.88	6.45
Tucson Electric	1.71	1.85	1.99	2.16	2.32	2.47	2.59	2.67	2.74	2.76	2.73	2.62	2.49	2.32	2.17	1.97
Salt River Project	5.58	5.94	6.44	6.94	7.41	7.65	7.82	7.93	7.73	7.71	7.88	7.46	7.21	6.88	6.54	6.11
PSC New Mexico	1.71	1.79	1.90	2.01	2.14	2.25	2.36	2.44	2.47	2.44	2.41	2.30	2.21	2.08	1.95	1.82
WAPA - Desert SW	1.01	1.08	1.13	1.20	1.28	1.31	1.37	1.41	1.44	1.45	1.43	1.35	1.26	1.19	1.13	1.06
El Paso Electric	1.28	1.41	1.54	1.64	1.73	1.80	1.87	1.91	1.90	1.84	1.81	1.67	1.55	1.43	1.31	1.20
PacifiCorp East	7.00	7.34	7.56	7.84	8.13	8.52	8.84	9.07	9.17	9.05	8.91	8.55	8.22	7.84	7.37	6.82
Idaho Power	2.64	2.74	2.86	3.00	3.15	3.32	3.46	3.59	3.64	3.54	3.54	3.43	3.21	3.00	2.83	2.61
NorthWestern	1.39	1.40	1.41	1.42	1.44	1.47	1.52	1.54	1.55	1.50	1.47	1.42	1.38	1.30	1.21	1.15
Avista Utilities	1.23	1.28	1.35	1.44	1.50	1.58	1.65	1.70	1.75	1.76	1.75	1.67	1.57	1.47	1.34	1.20
BPA	6.56	6.79	6.97	7.28	7.53	7.79	8.03	8.27	8.45	8.55	8.53	8.35	8.02	7.70	7.20	6.73
Tacoma Power	.44	.45	.47	.48	.50	.52	.54	.55	.57	.57	.57	.56	.54	.52	.49	.44
PacifiCorp West	2.48	2.57	2.66	2.81	2.99	3.17	3.34	3.50	3.59	3.64	3.62	3.53	3.35	3.17	2.92	2.65
Portland GE	2.72	2.83	2.95	3.17	3.39	3.63	3.84	4.03	4.14	4.12	4.12	4.12	4.02	3.88	3.64	3.32
Puget Sound Energy	2.57	2.67	2.76	2.87	2.98	3.10	3.26	3.39	3.50	3.55	3.52	3.42	3.29	3.19	2.95	2.70
Seattle City Light	1.04	1.07	1.11	1.14	1.16	1.18	1.21	1.24	1.25	1.25	1.23	1.18	1.14	1.12	1.06	1.00
Powerex	7.38	7.54	7.79	7.90	8.05	8.12	8.21	8.31	8.52	8.60	8.55	8.36	8.05	7.92	7.42	6.92

Table 1.1 shows the peak 5-minute market load and date for each balancing area (or region) during 2025. The California and Desert Southwest balancing areas all recorded peak load during the summer—typically in July, August, and September. In contrast, balancing areas in the Intermountain West and Pacific Northwest peaked either in January or July/August, indicating the presence of both summer- and winter-peaking BAAs in these regions. The last two columns show each balancing area’s load during the system-wide peak on August 22, 2025. WEIM system-wide 5-minute-market load on that day reached 130,122 MW.

Table 1.1 Peak WEIM load (January–December 2025)

	Peak load (2025)		Load during WEIM system peak (22-Aug-2025)	
Region/balancing area	**Date**	**Load (MW)**	**Load (MW)**	**Percent**
WEIM system	**22-Aug-25**	**130,122**	**130,122**	
California	**21-Aug-25**	**52,190**	**51,740**	**40%**
California ISO	21-Aug-25	42,549	42,121	32%
BANC	11-Jul-25	4,115	3,944	3%
LADWP	22-Aug-25	5,186	5,054	4%
Turlock Irrig. District	2-Sep-25	660	621	.5%
Desert Southwest	**7-Aug-25**	**35,224**	**32,250**	**25%**
Arizona Public Service	9-Jul-25	8,764	8,077	6%
El Paso Electric	6-Aug-25	2,313	1,838	1.4%
NV Energy	14-Jul-25	9,305	7,971	6%
PSC New Mexico	6-Aug-25	2,690	2,437	2%
Salt River Project	7-Aug-25	8,699	7,713	6%
Tucson Electric	6-Aug-25	3,119	2,762	2%
WAPA - Desert SW	6-Aug-25	1,671	1,452	1.1%
Intermountain West	**8-Jul-25**	**17,537**	**15,848**	**12%**
Avista Utilities	12-Feb-25	2,222	1,762	1%
Idaho Power	8-Jul-25	4,028	3,542	3%
NorthWestern Energy	12-Feb-25	1,994	1,495	1%
PacifiCorp East	14-Jul-25	9,775	9,048	7%
Pacific Northwest	**12-Feb-25**	**38,283**	**30,285**	**23%**
BPA	12-Feb-25	11,421	8,551	7%
PacifiCorp West	12-Feb-25	4,202	3,640	3%
Portland General Electric	12-Aug-25	4,481	4,122	3%
Powerex	4-Feb-25	11,504	8,597	7%
Puget Sound Energy	12-Feb-25	4,986	3,549	3%
Seattle City Light	12-Feb-25	1,800	1,252	1%
Tacoma Power	27-Jan-25	923	574	.4%

1.2 Supply conditions

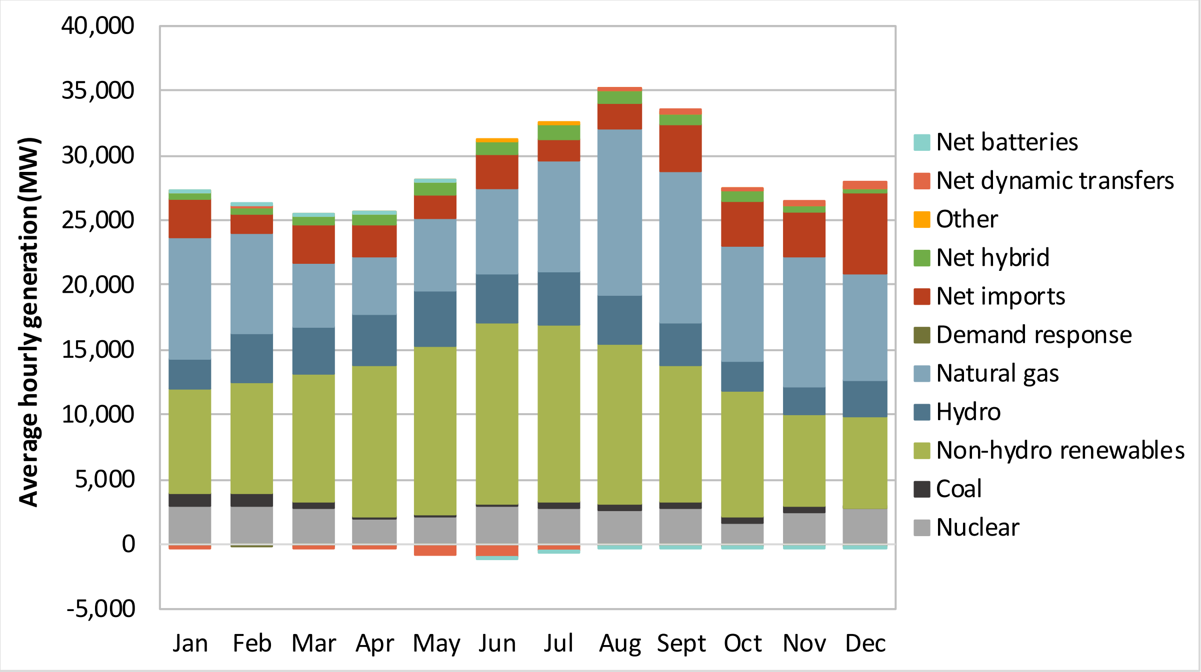
1.2.1 Generation mix

Monthly generation by fuel type

Figure 1.7, Figure 1.9, Figure 1.11, and Figure 1.13 provide a profile of average hourly generation by month and fuel type in 2025 for the California, Desert Southwest, Intermountain West, and Pacific Northwest regions. Figure 1.8, Figure 1.10, Figure 1.12, and Figure 1.14[45] illustrate the same data on a percentage basis. These figures show the following:

- Natural gas and non-hydro renewables were the largest sources of generation in the California region in 2025, similar to 2024. In the Desert Southwest, natural gas was the largest source of generation, accounting for about half of total generation. The Intermountain West relied on a mix of fuel sources, the largest of which was coal (about 33 percent of generation), followed by non-hydro renewables (30 percent), and natural gas (26 percent). Hydroelectric generation dominated the generation mix in the Pacific Northwest, accounting for about 68 percent of total generation.
- The California region was a net importer over each month of 2025, and the Pacific Northwest region was a net exporter during most months. The Desert Southwest and Intermountain West were net exporters during the non-summer months.

Figure 1.7 California - Average generation by month and fuel type (MW) in 2025



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[45] These figures show each region's generation mix used to meet the load in each region. Net dynamic transfers, net hybrids, and net imports are only included if they are net positive.

Figure 1.8 California - Average generation by month and fuel type (percentage) in 2025

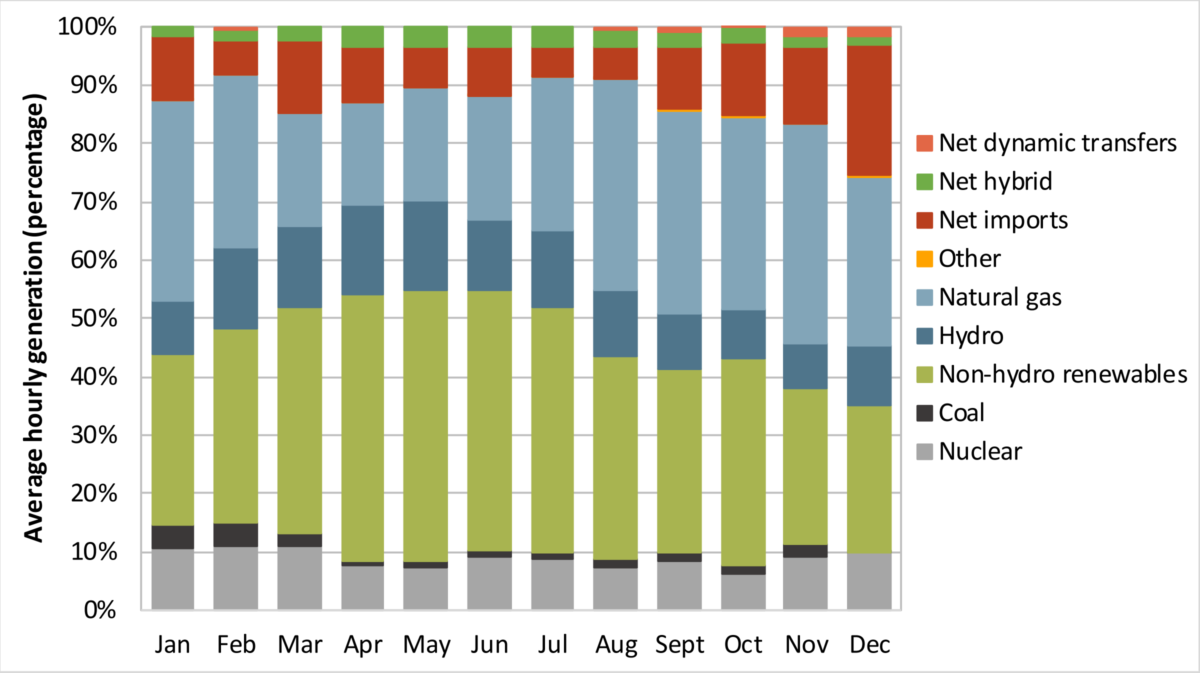


Figure 1.9 Desert Southwest - Average generation by month and fuel type (MW) in 2025

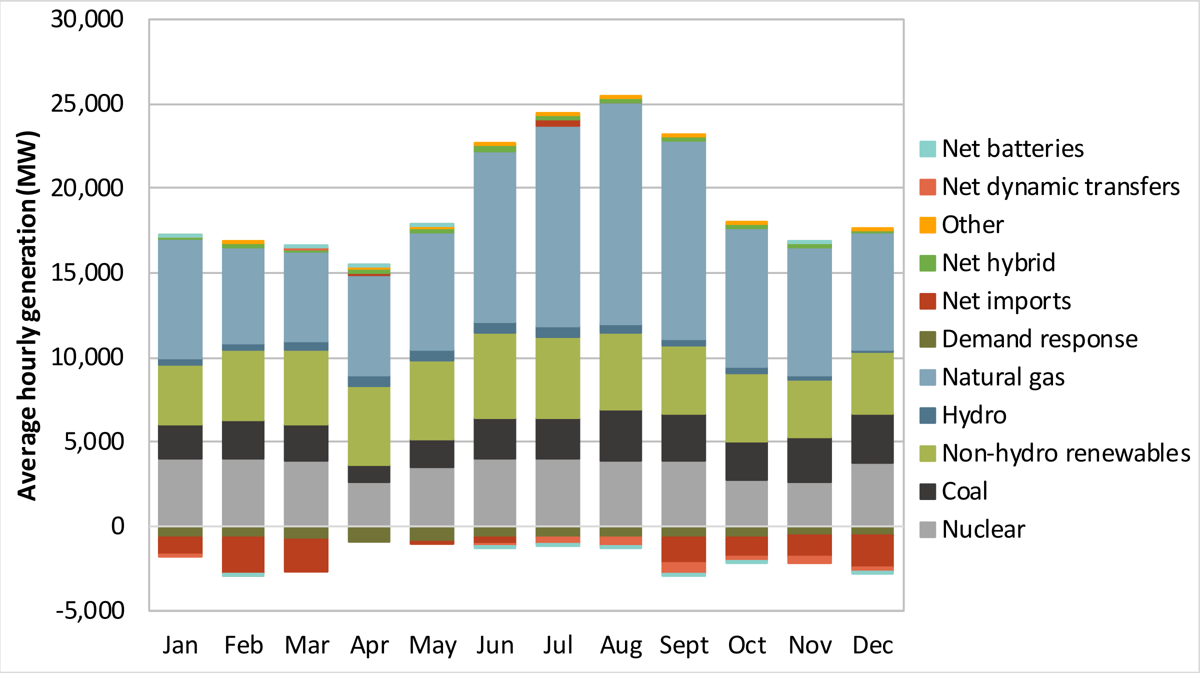


Figure 1.10 Desert Southwest - Average generation by month and fuel type (percentage) in 2025

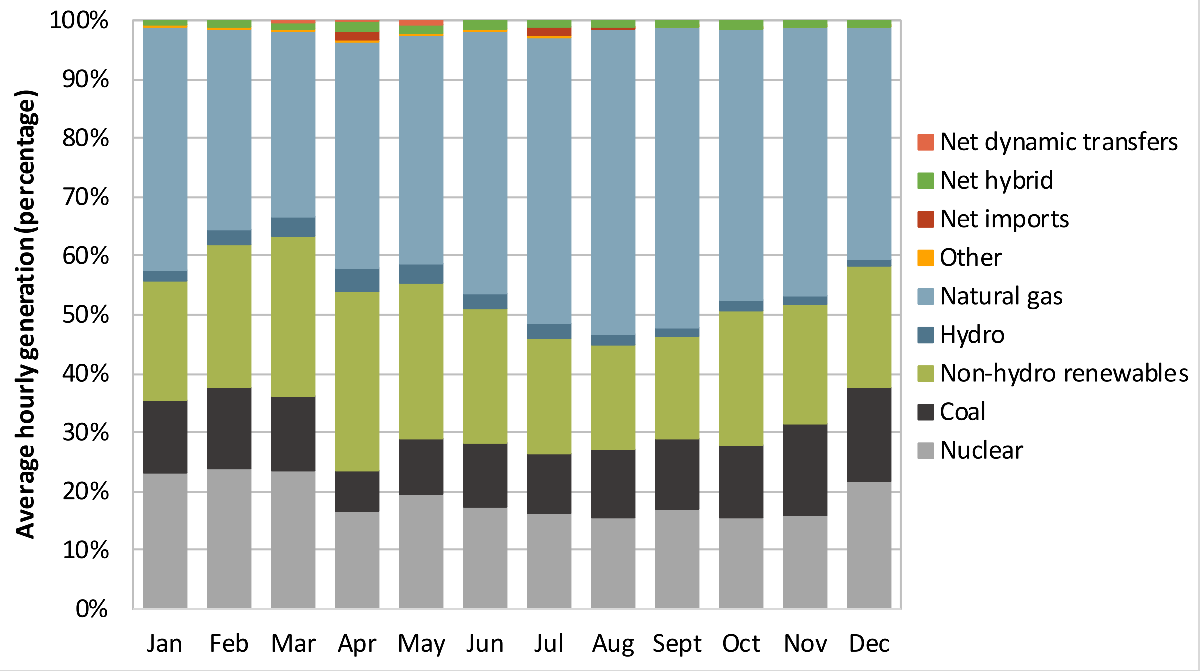


Figure 1.11 Intermountain West - Average generation by month and fuel type (MW) in 2025

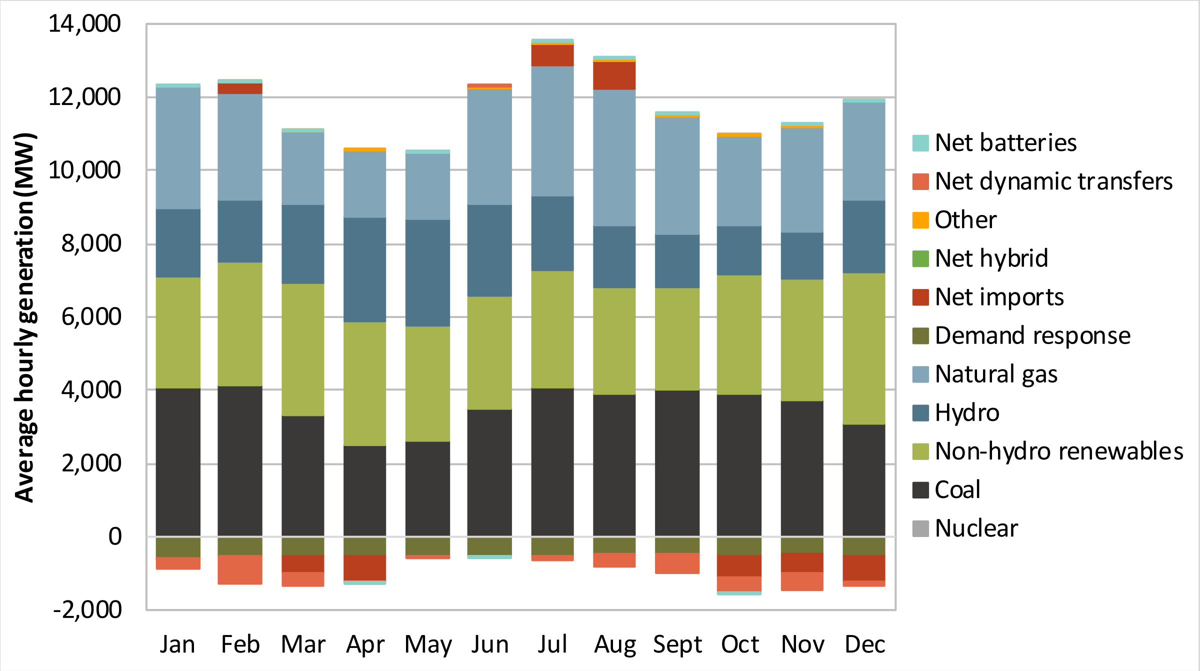


Figure 1.12 Intermountain West - Average generation by month and fuel type (percentage) in 2025

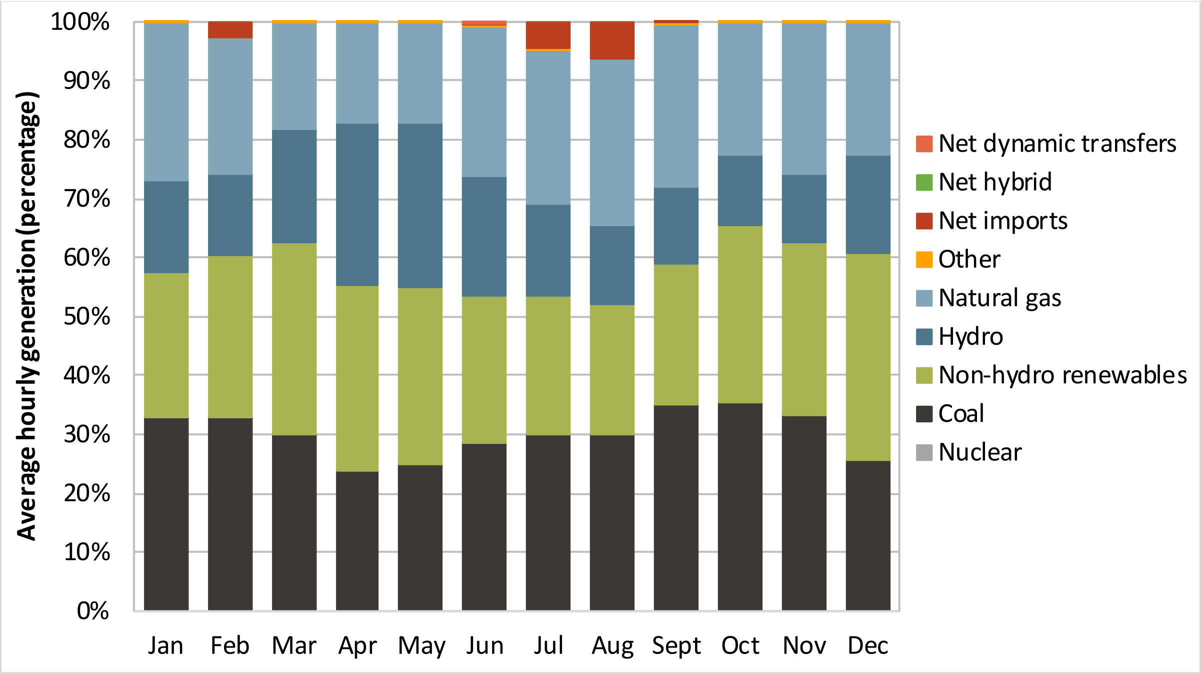


Figure 1.13 Pacific Northwest - Average generation by month and fuel type (MW) in 2025

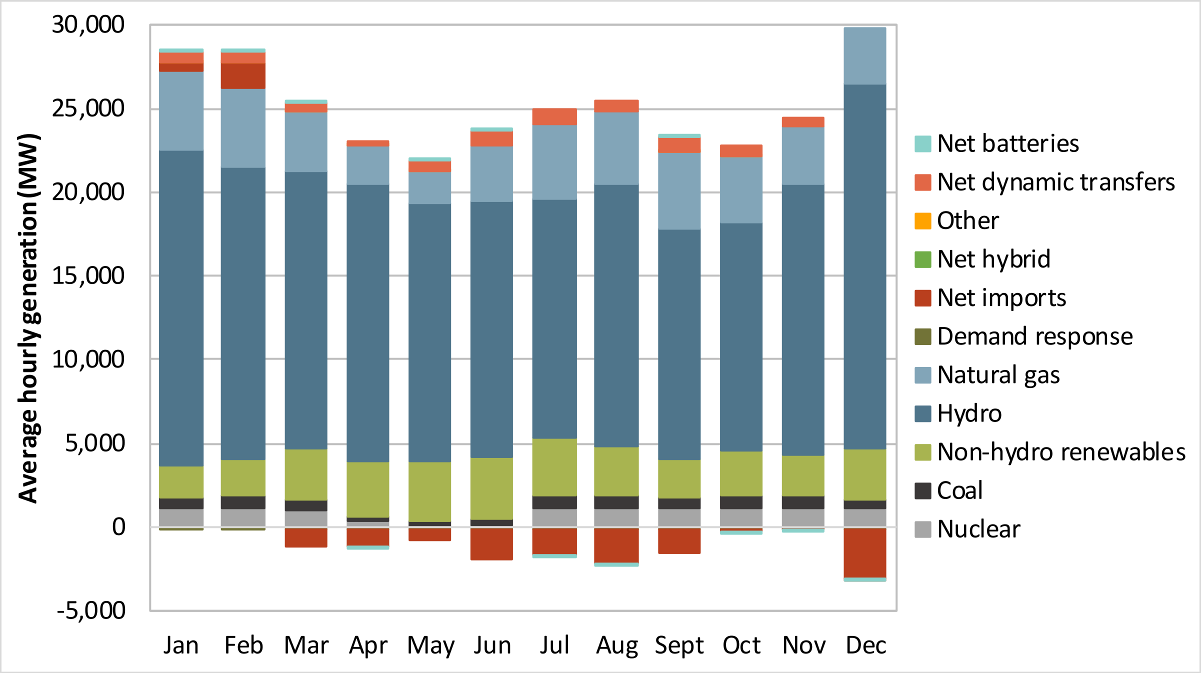
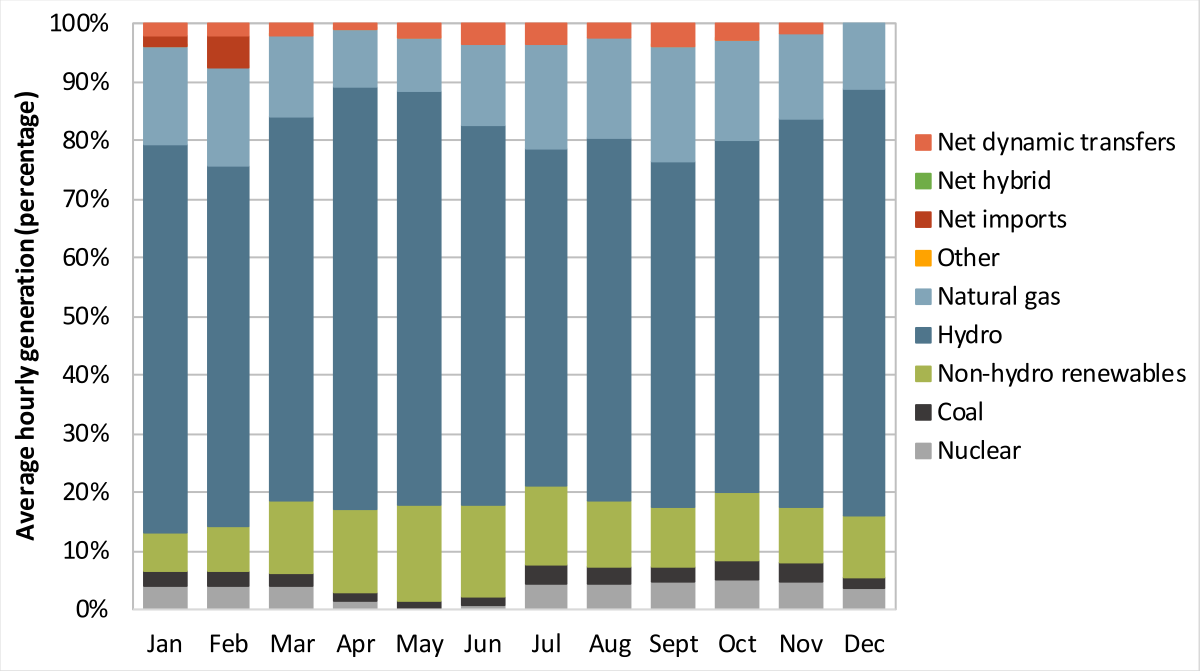


Figure 1.14 Pacific Northwest - Average generation by month and fuel type (percentage) in 2025



Hourly generation by fuel type

Figure 1.15, Figure 1.17, Figure 1.19, and Figure 1.21 show average hourly generation by fuel type over the year. Generation peaked in hours 18 or 19 for all regions. Figure 1.16, Figure 1.18, Figure 1.20, and Figure 1.22 show the change in hourly generation by fuel type between 2024 and 2025. Positive values represent increased generation compared to 2024, while negative values represent a decrease in generation. Change in total load is denoted by the black line.

In the California region, natural gas generation decreased on average across all hours in 2025 compared to 2024, as it did in 2024 compared to 2023. Solar generation increased by an average of 630 MW (11 percent), and batteries increasingly participated in energy arbitrage by charging during the high solar hours and discharging during the high net load periods in the evening hours and some morning hours. Net imports increased in all hours by an average of 430 MW (17 percent).

In the Desert Southwest region, natural gas generation averaged about 8,400 MW per hour. Solar generation increased by about 630 MW (31 percent) from 2024 to 2025, following a 700 MW (51 percent) increase from 2023 to 2024. Battery charging increased during solar hours and discharging increased during non-solar hours, similar to the pattern seen in the California region. Net imports decreased by about 240 MW per hour, and net dynamic transfers increased by about 200 MW per hour.

In the Intermountain West, wind, solar, and battery generation increased about 410 MW (25 percent), 210 MW (26 percent), and 90 MW (1,050 percent), respectively. Coal generation increased by an average of 560 MW (19 percent), reversing the prior year’s trend, where coal generation decreased by about 650 MW (18 percent) from 2023 to 2024. Higher natural gas prices combined with relatively steady coal prices contributed to this reversal, as coal resources displaced some natural gas generation, which decreased about 200 MW (7 percent) from 2024 to 2025. Net imports and net dynamic transfers decreased by about 560 MW and 310 MW, respectively.

Solar and hydroelectric generation increased in all hours in the Pacific Northwest in 2025, about 65 MW (27 percent) and 1,170 MW (8 percent), respectively, while nuclear and natural gas generation decreased in all hours, by about 250 MW (22 percent) and 260 MW (6 percent), respectively. Net imports and net dynamic transfers increased during solar hours and decreased during non-solar hours.

Figure 1.15 Average hourly generation by fuel type in the California region in 2025

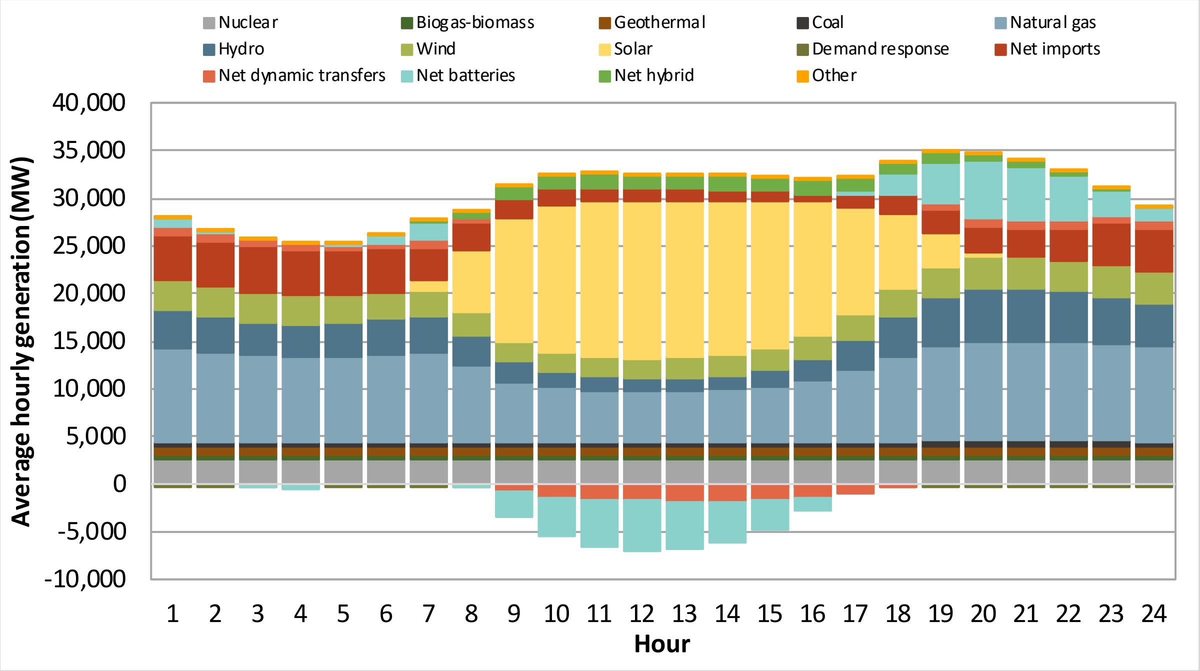


Figure 1.16 Change in average hourly generation by fuel type in the California region (2025 compared to 2024)

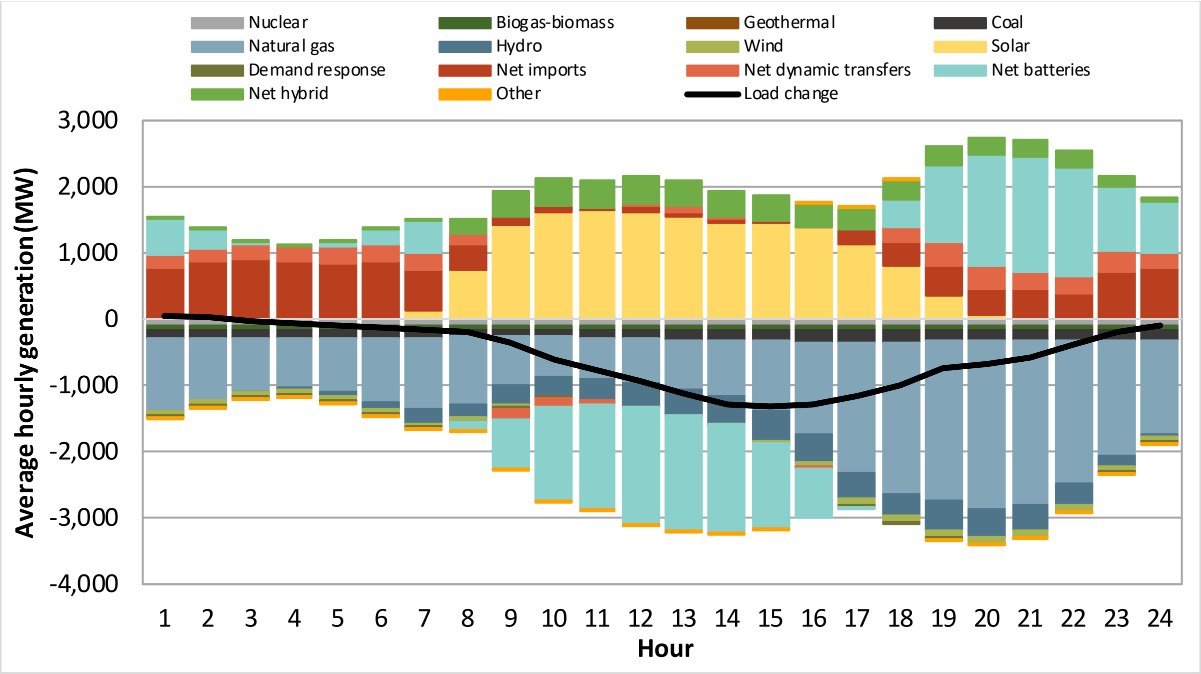


Figure 1.17 Average hourly generation by fuel type in the Desert Southwest region in 2025

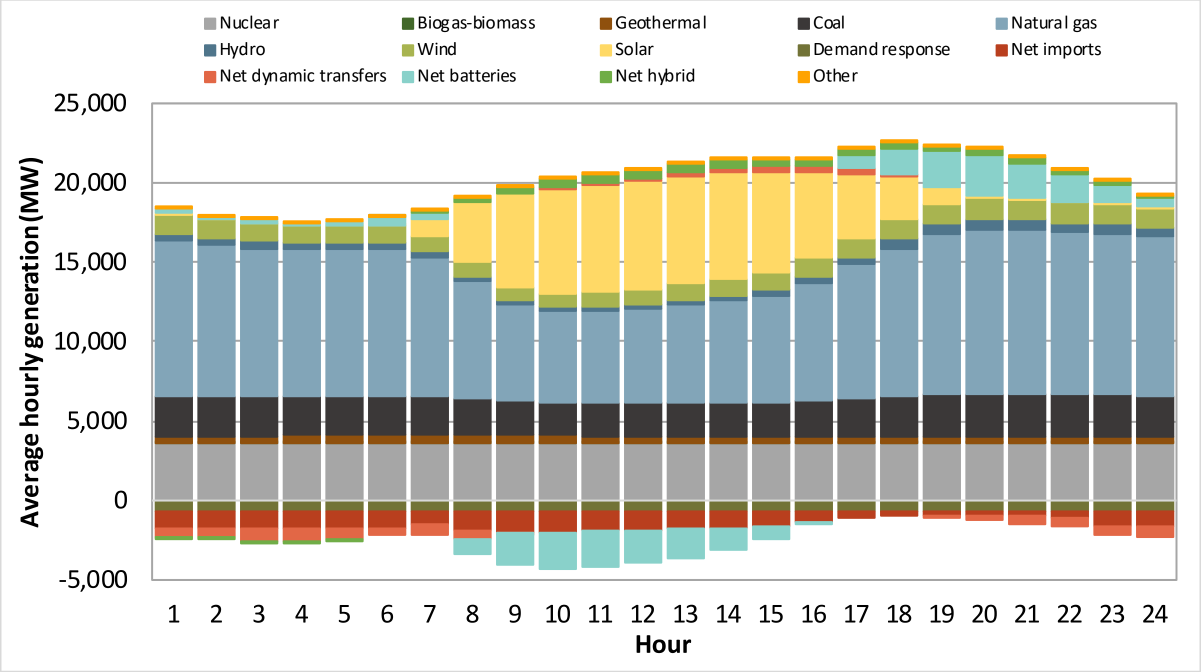


Figure 1.18 Change in average hourly generation by fuel type in the Desert Southwest region (2025 compared to 2024)

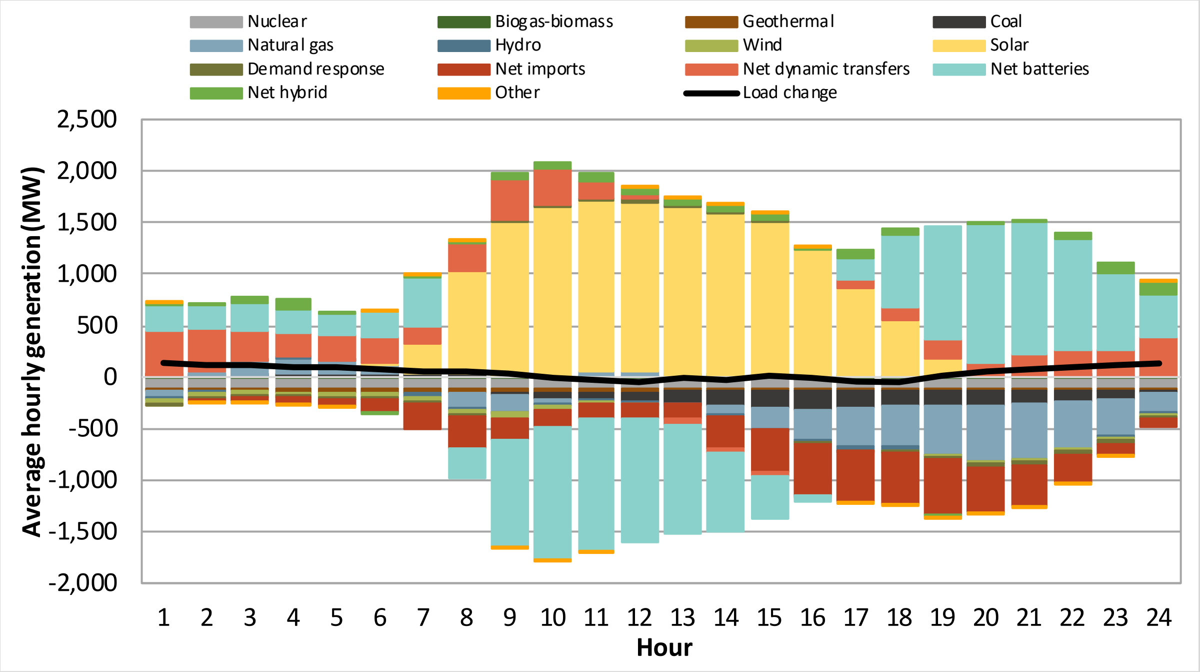


Figure 1.19 Average hourly generation by fuel type in the Intermountain West region in 2025

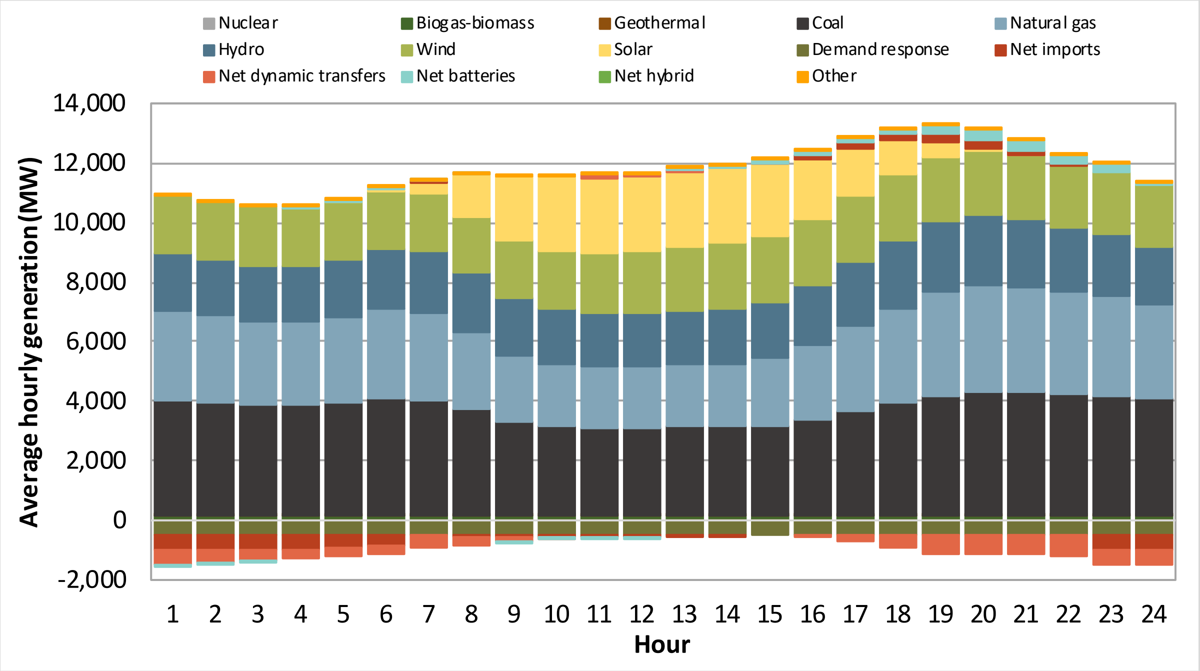


Figure 1.20 Change in average hourly generation by fuel type in the Intermountain West region (2025 compared to 2024)

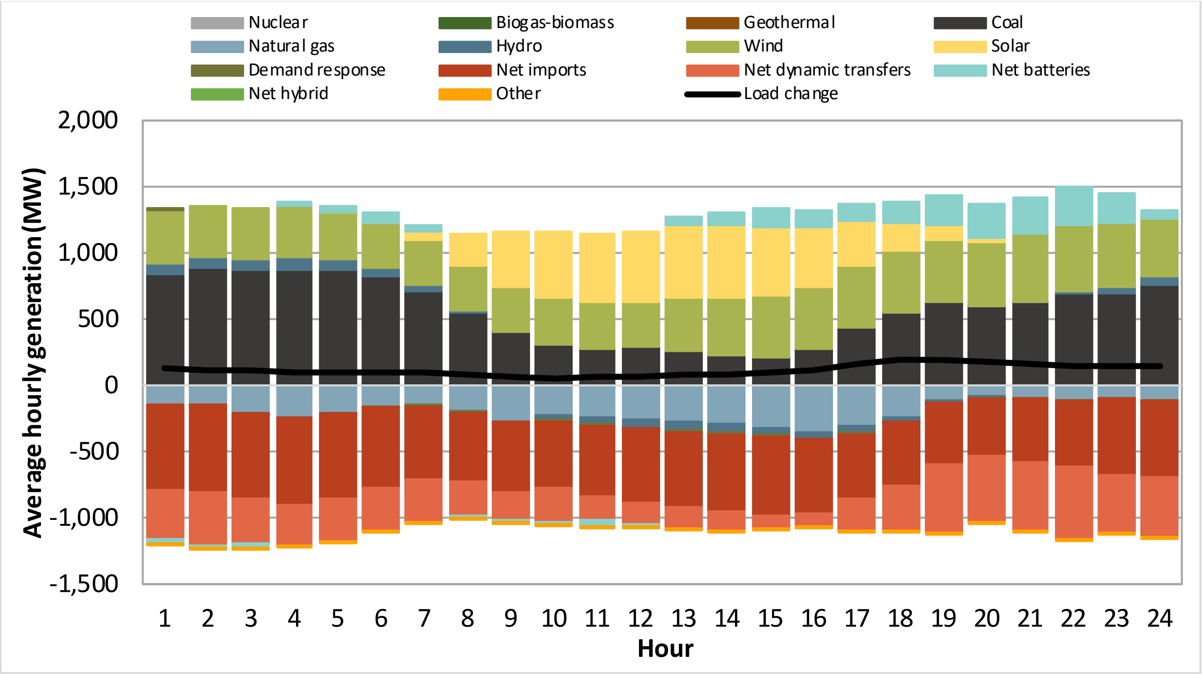


Figure 1.21 Average hourly generation by fuel type in the Pacific Northwest region in 2025

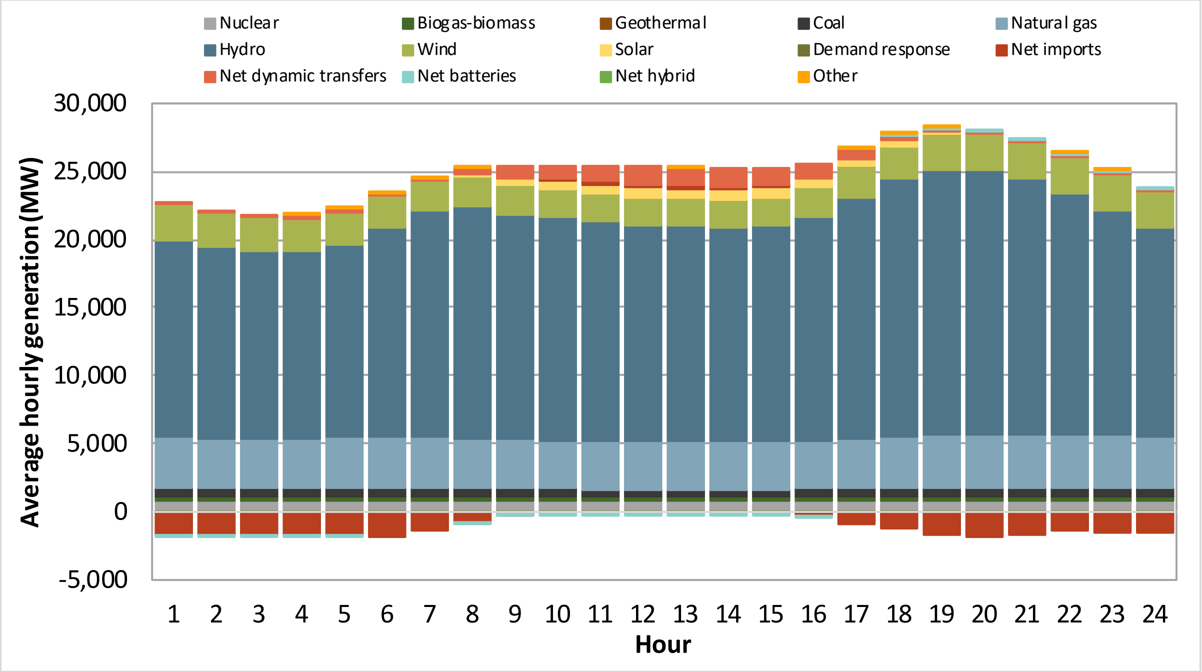
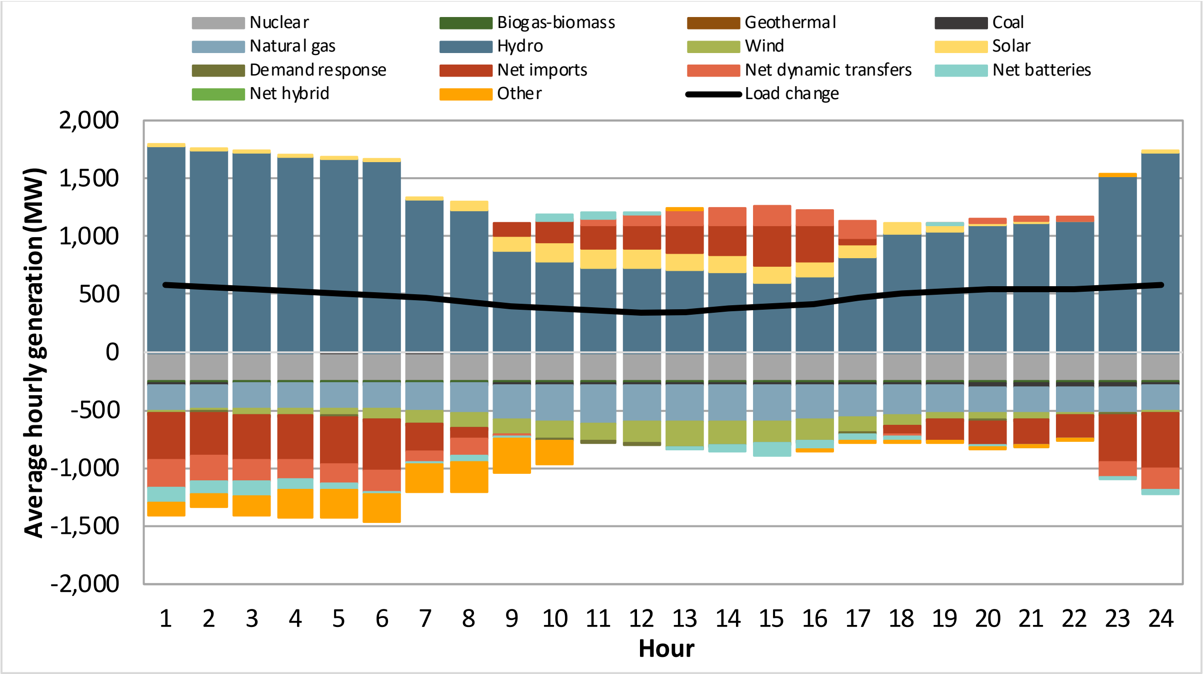


Figure 1.22 Change in average hourly generation by fuel type in the Pacific Northwest region (2025 compared to 2024)



1.2.2 Renewable generation

In 2025, over 376,000 GWh of generation in the WEIM came from renewable resources. Of that renewable generation, 49 percent was from non-hydroelectric resources. This section provides additional detail about trends in renewable generation and the factors influencing renewable resource availability.

Figure 1.23 through Figure 1.26 provide a detailed breakdown of non-hydro renewable generation, including imports that are specifically identified as wind and solar resources.[46] These figures also illustrate:

- In 2025, generation from solar resources increased in every region in the WEIM. In the California and Desert Southwest regions, generation from solar resources accounted for 61 percent and 63 percent, respectively, of their total non-hydro renewable output. Solar generation increased by 11 percent in California and 31 percent in the Desert Southwest compared to 2024.
- Wind generation makes up a large share of the renewable fuel mix for the Intermountain West and Pacific Northwest regions. Wind output increased by 25 percent in the Intermountain West to account for 63 percent of its non-hydro renewable output in 2025. Although wind generation decreased 4 percent in the Pacific Northwest compared to 2024, it still accounts for 82 percent of the region's non-hydro renewable output.

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[46] In addition to values reported here, renewable and hydro resource generators provide energy through behind-the-meter generation. These values are excluded due to lack of input data.

- The overall output from geothermal generation decreased by 1 percent across the WEIM compared to 2024, though it continued to provide around 7 percent of all non-hydro renewable generation.
- Biogas, biomass, and waste generation decreased by 9 percent compared to 2024. Together, they accounted for around 4 percent of all non-hydro renewable generation in the WEIM.

Figure 1.23 California - Total renewable generation by type (2021–2025)

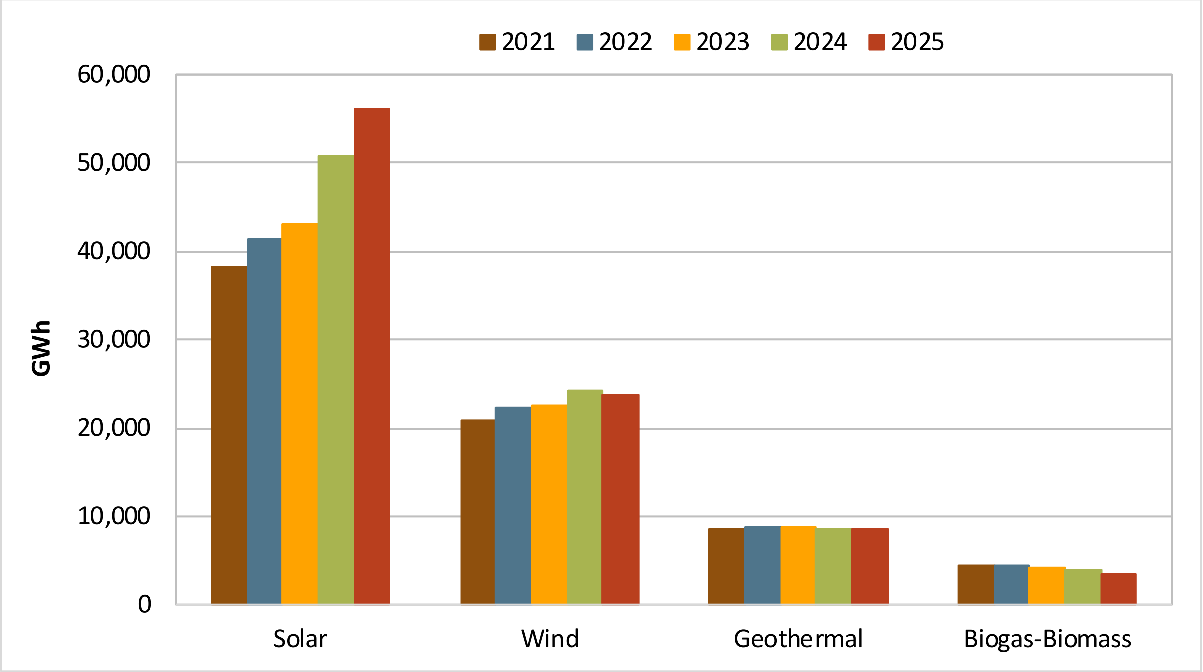


Figure 1.24 Desert Southwest - Total renewable generation by type (2021–2025)

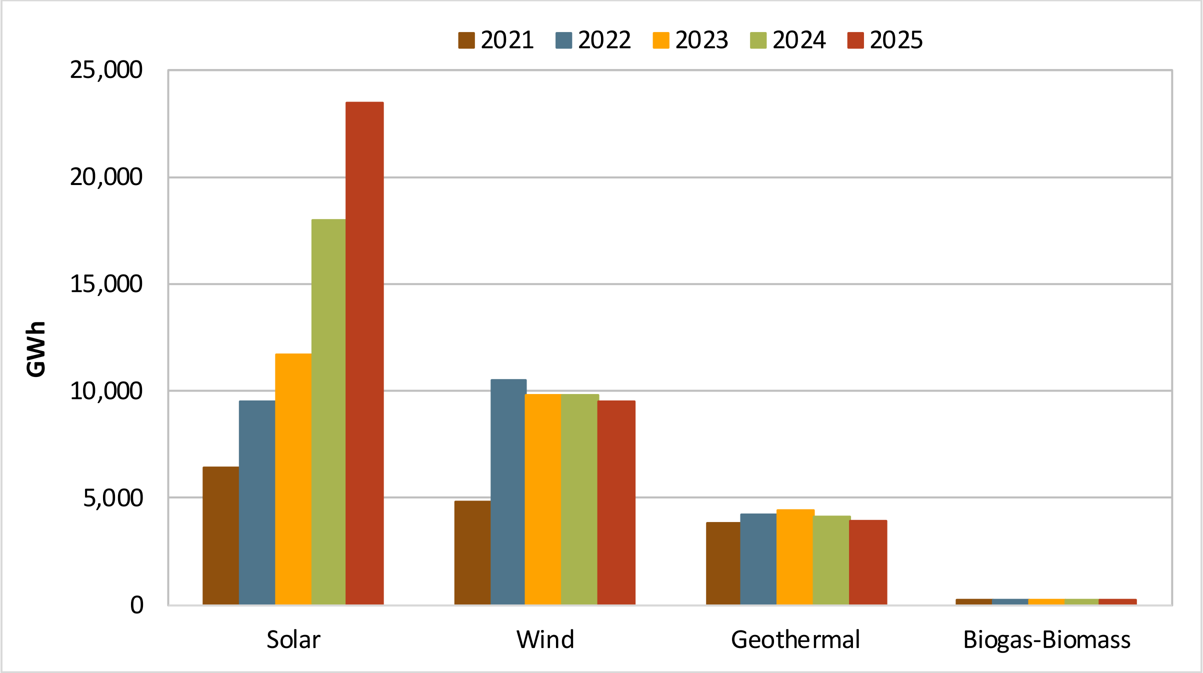


Figure 1.25 Intermountain West - Total renewable generation by type (2021–2025)

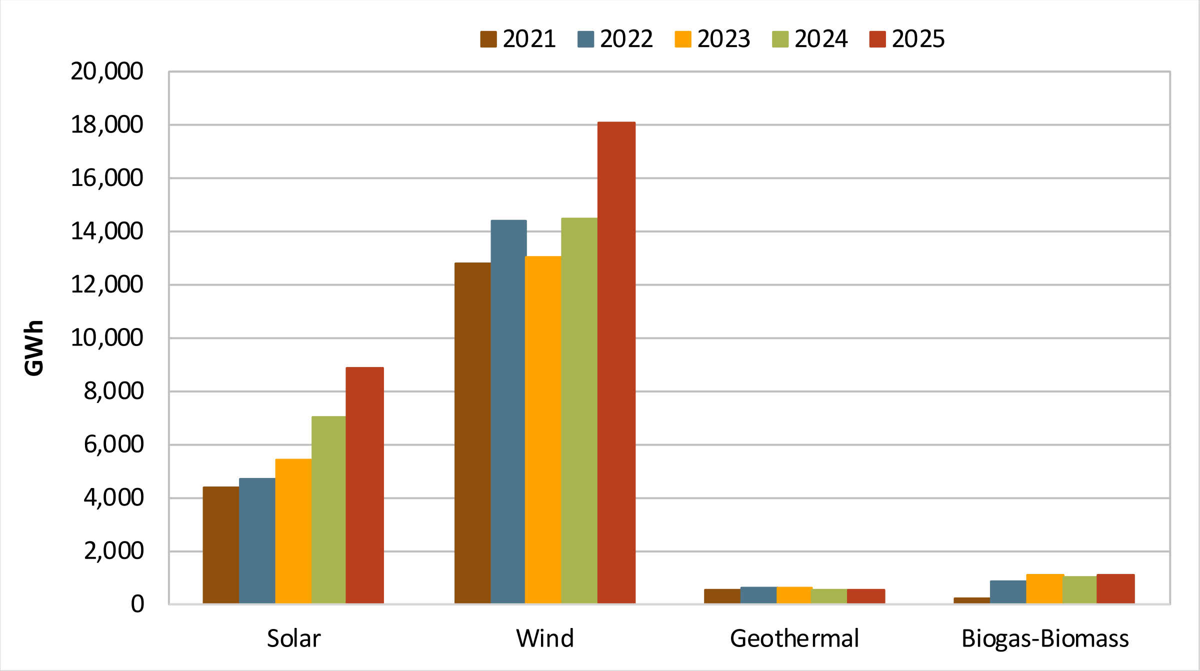
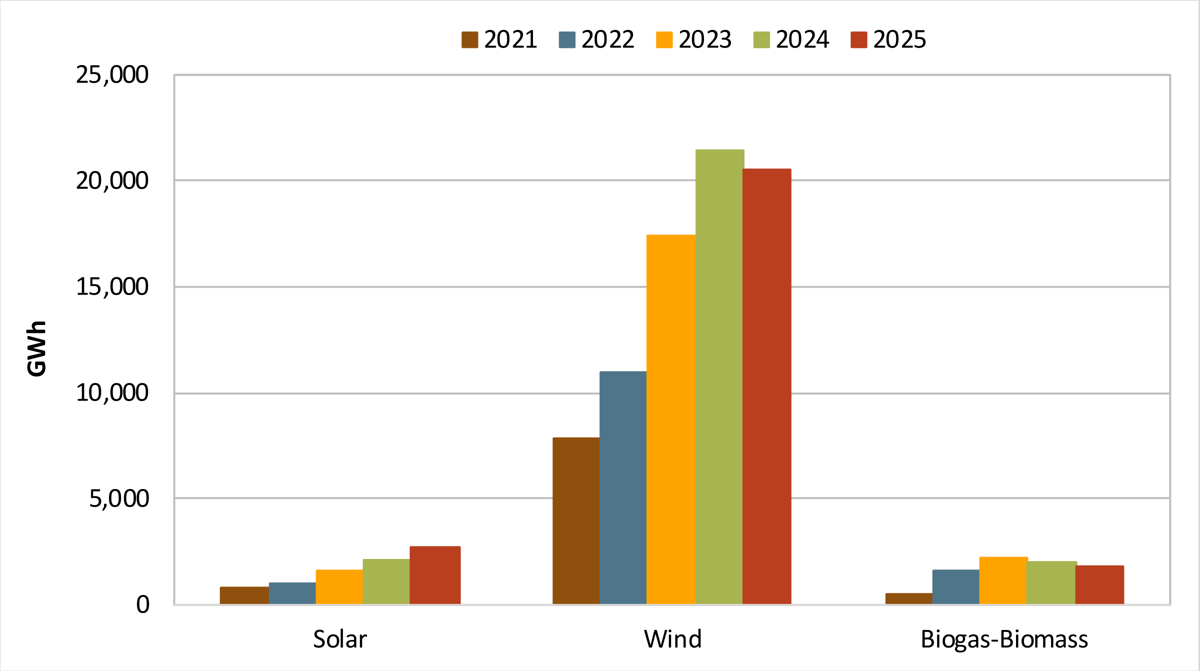


Figure 1.26 Pacific Northwest - Total renewable generation by type (2021–2025)[47]



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[47] There is no geothermal generation in the Pacific Northwest.

Figure 1.27 through Figure 1.30 compare average monthly generation of hydro, wind, and solar resources.

In 2025, average hourly solar generation peaked in June in the California and Desert Southwest regions, and peaked in July in the Intermountain West and Pacific Northwest. Hydroelectric generation peaked in December for the Pacific Northwest, and during April or May for the other regions. Wind generation peaked in June for both the California and Pacific Northwest regions, while wind generation in the Desert Southwest and Intermountain West peaked in March and December, respectively.

Figure 1.27 California - Monthly comparison of hydro, wind, and solar generation (2025)

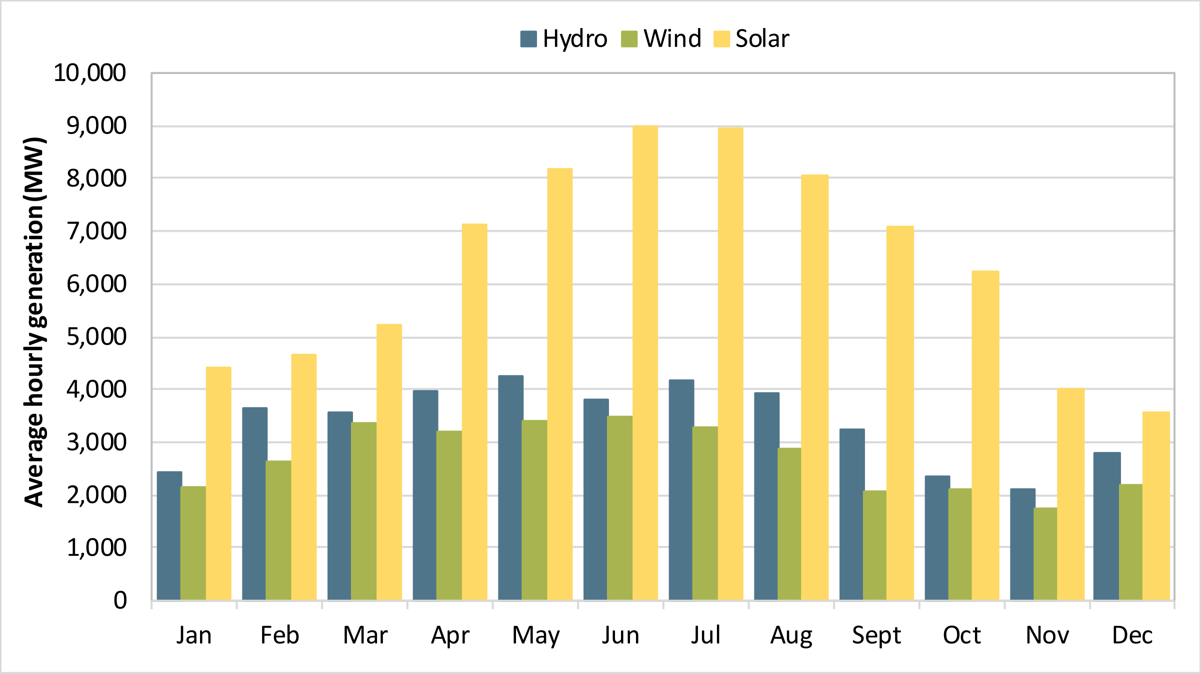


Figure 1.28 Desert Southwest - Monthly comparison of hydro, wind, and solar generation (2025)

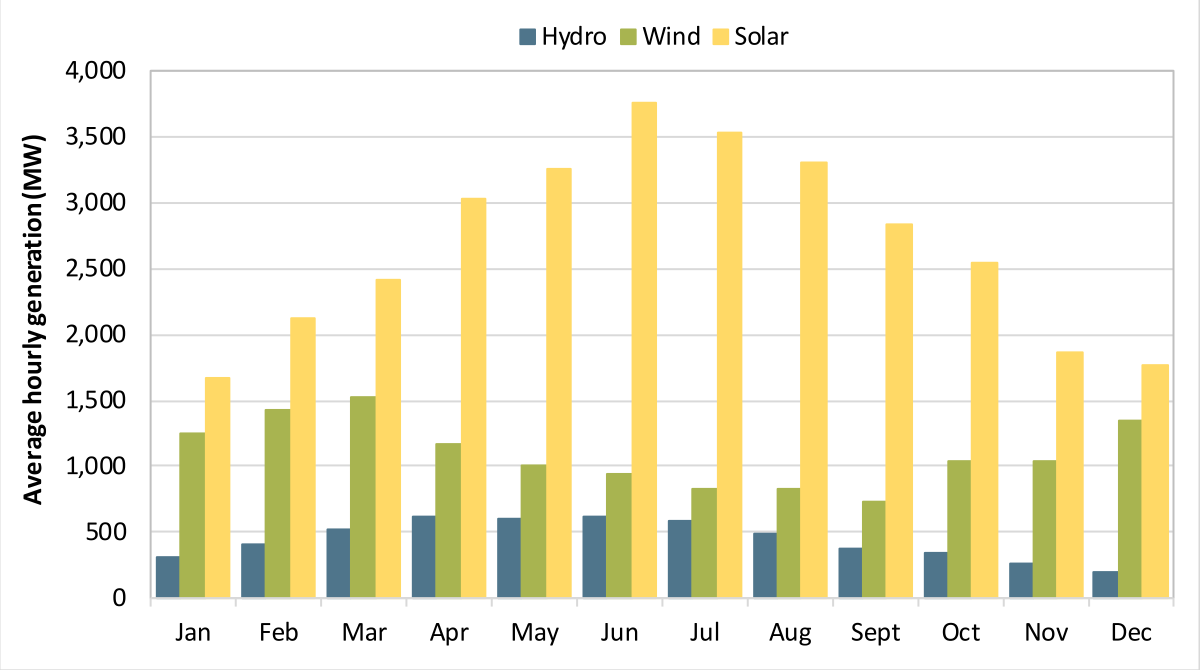


Figure 1.29 Intermountain West - Monthly comparison of hydro, wind, and solar generation (2025)

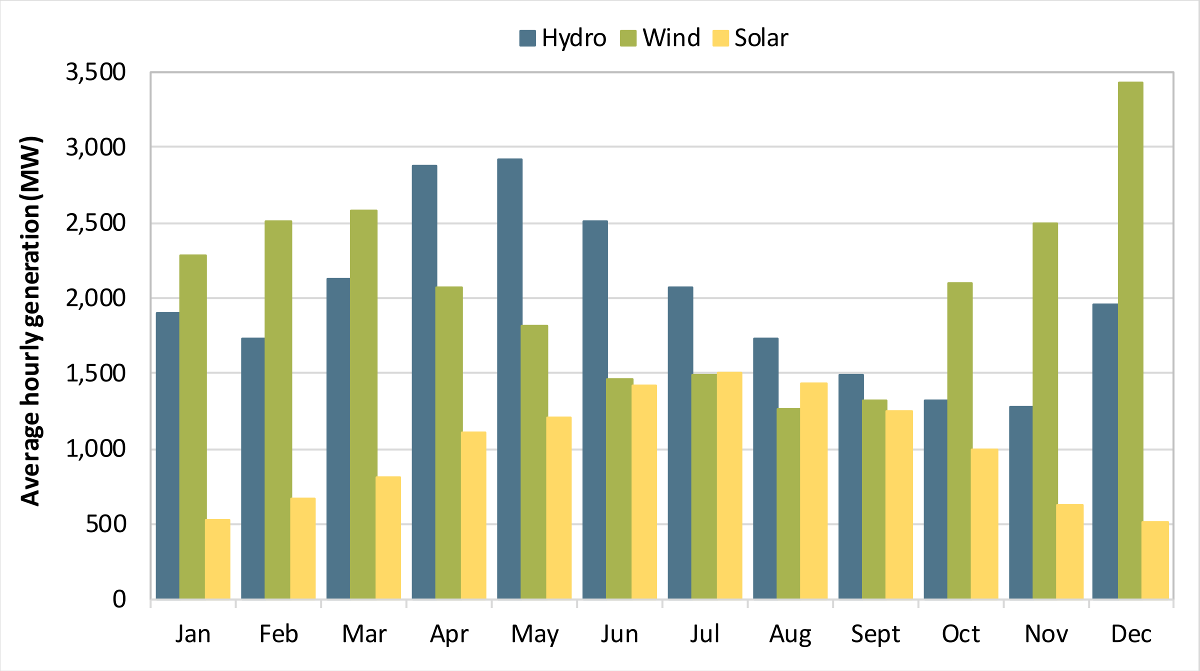
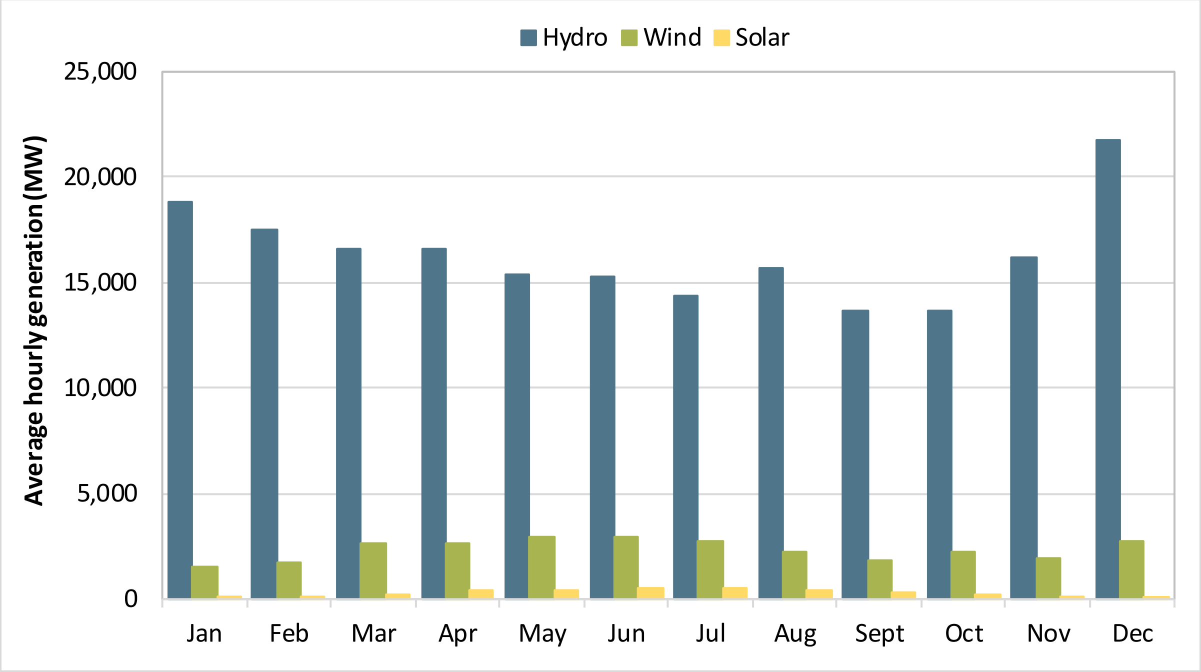


Figure 1.30 Pacific Northwest - Monthly comparison of hydro, wind, and solar generation (2025)



Downward dispatch and curtailment of variable energy resources

In the WEIM, total downward dispatch in 2025 increased by 22 percent relative to 2024. The majority of the downward dispatch was economic.

When the amount of supply on-line exceeds demand, the real-time market dispatches generation down. Generally, generators are dispatched down in merit order from highest bid to lowest. As with typical incremental dispatch, the last unit dispatched sets the system price, and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, wind and solar resources, which generally have very low or negative bids, are dispatched down economically.

If the supply of bids to decrease energy is completely exhausted in the real-time market, the software may curtail self-scheduled generation, including self-scheduled wind and solar generation.

Figure 1.31 through Figure 1.34 shows the curtailment of wind and solar resources by month in each of the WEIM regions. Curtailments fall into six categories:[48]

- **Economic downward dispatch**, in which an economically bid resource is dispatched down, and the market price falls below or within one dollar of a resource's bid, or the resource's upper limit is binding;[49]

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[48] Exceptional economic downward dispatch and exceptional self-schedule curtailment is only applicable to the California ISO.

[49] A resource's upper limit is determined by a variety of factors and can vary throughout the day.

- **Exceptional economic downward dispatch**, in which a resource receives an exceptional dispatch or out-of-market instruction to decrease dispatch;
- **Other economic downward dispatch**, in which the market price is greater than one dollar above a resource bid and that resource is dispatched down;
- **Self-schedule curtailment**, in which a price-taking self-scheduled resource receives an instruction to reduce output while not exceptionally dispatched;
- **Exceptional self-schedule curtailment**, in which a self-scheduled resource receives an exceptional dispatch or out-of-market instruction to reduce output; and
- **Other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the bid floor.

The majority of the reduction in wind and solar output during the year was a result of economic downward dispatch rather than self-schedule curtailment. In the California and Desert Southwest regions, total downward dispatch was higher in 2025 than in 2024. Most renewable generation dispatched down in the California and Desert Southwest regions was from solar resources, as these resources typically bid more economic downward capacity than wind resources.

Economic downward dispatch accounted for about 4,780 GWh (89 percent) of curtailment during the year in the WEIM, while self-scheduled curtailment accounted for about 480 GWh (9 percent). Exceptional dispatch curtailments for both self-scheduled and economic bid resources remained low and were together about 5.5 GWh (less than 1 percent). The roughly 83 GWh (1.6 percent) of remaining curtailment came from "other" economic and self-scheduled curtailment. March was the highest month of downward dispatch in 2025 at 1,120 GWh.

Figure 1.31 Reduction of wind and solar generation by month (California)

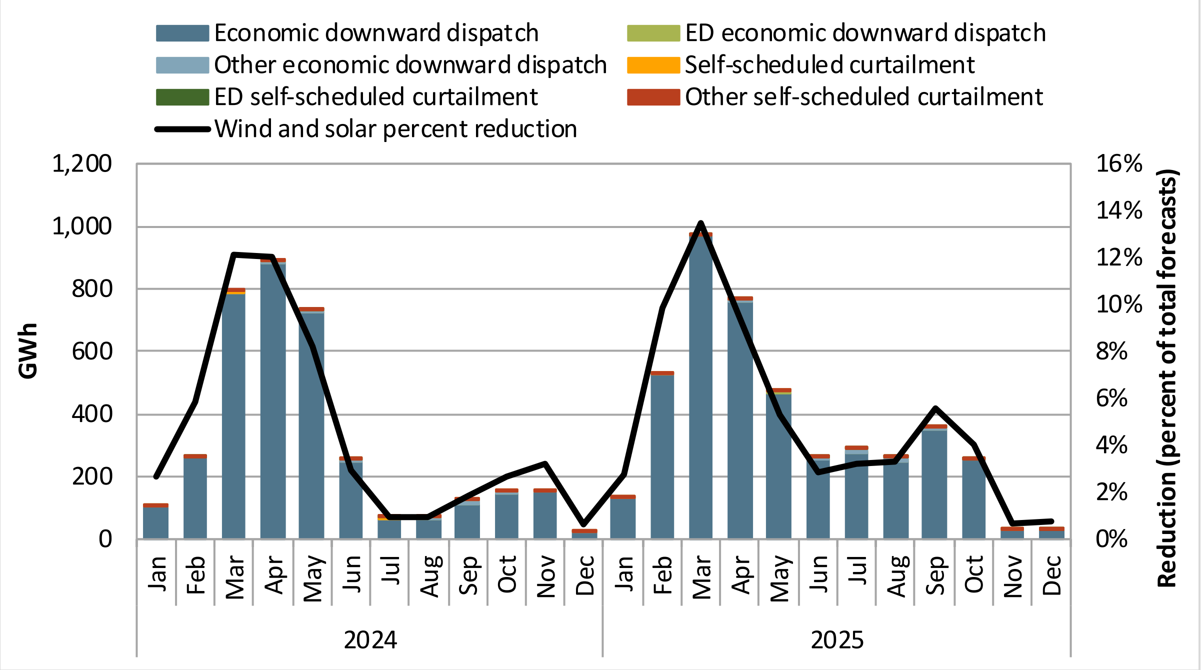


Figure 1.32 Reduction of wind and solar generation by month (Desert Southwest)

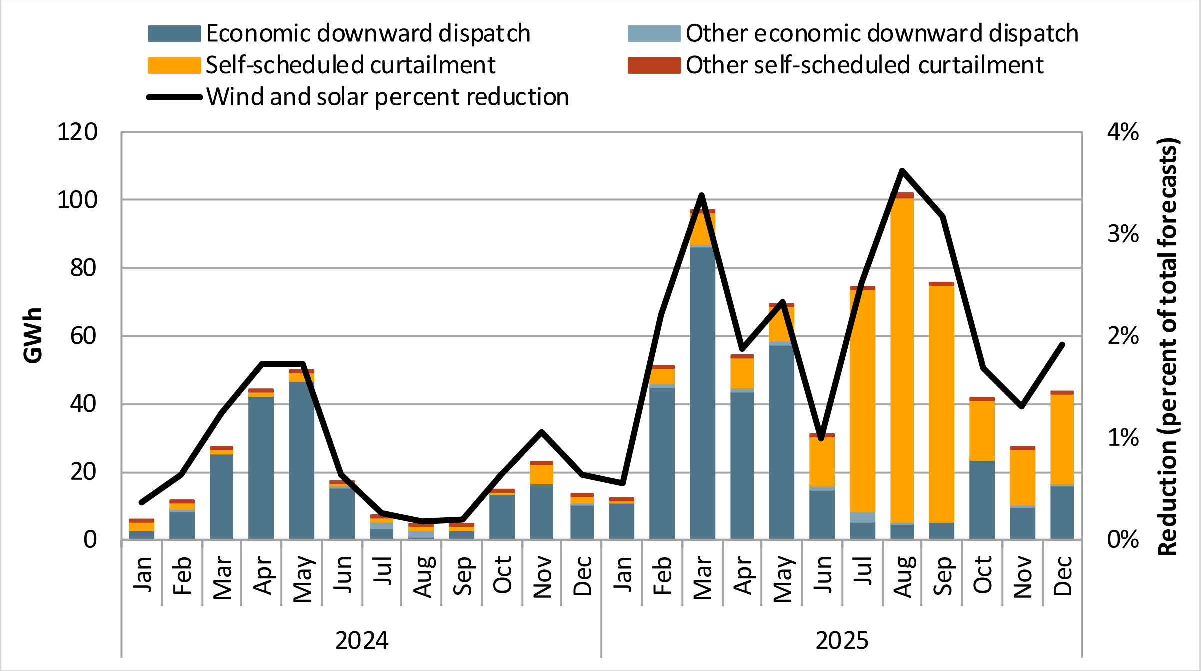


Figure 1.33 Reduction of wind and solar generation by month (Intermountain West)

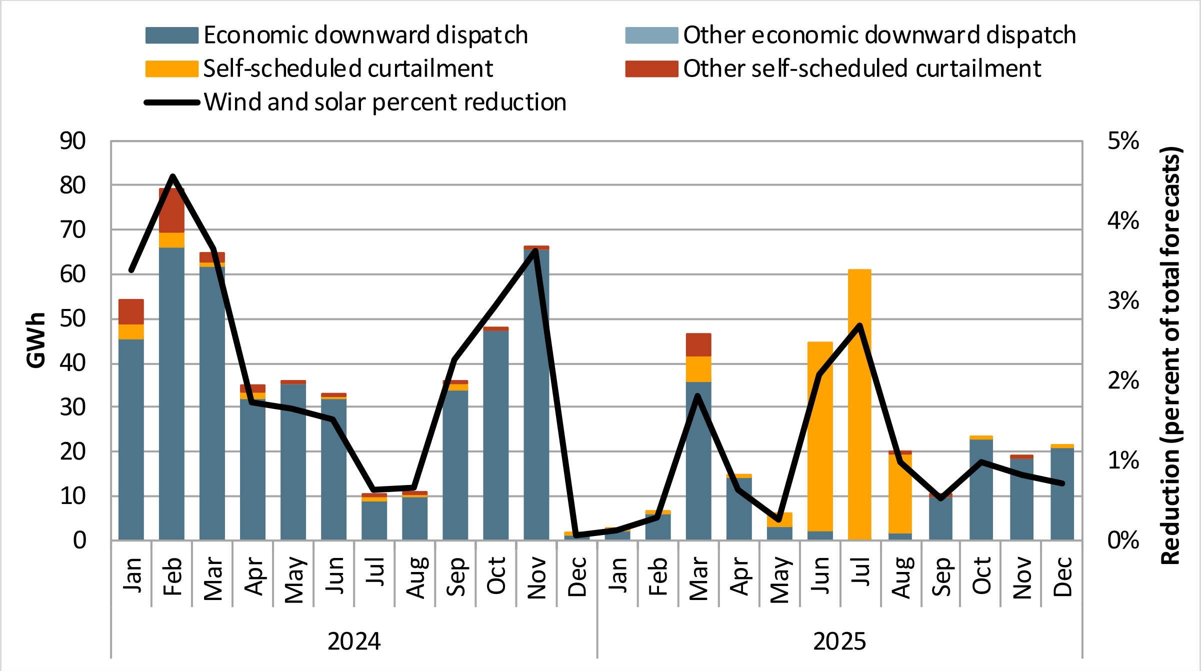
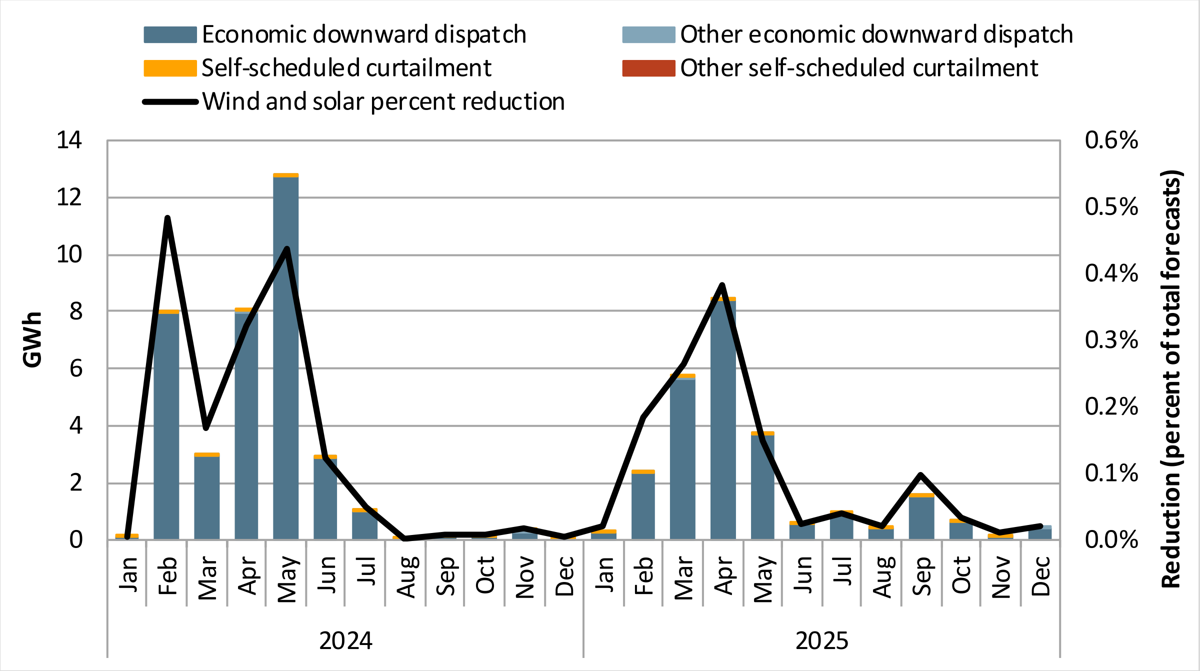


Figure 1.34 Reduction of wind and solar generation by month (Pacific Northwest)



When the market dispatches a wind or solar resource below its forecasted value, scheduling coordinators receive a downward dispatch instruction indicating the need to adjust the resource output. Figure 1.35 through Figure 1.42 show monthly solar and wind compliance with economic downward dispatch instructions during the year. The blue bars represent the quantity of renewable generation that complied with economic downward dispatch, while the gold bars represent the quantity that did not comply. The green line represents the monthly rate of compliance.

In 2025, downward dispatch compliance across the WEIM remained stable, with solar and wind resources at approximately 96 percent and 93 percent compliance, respectively, which is unchanged from 2024. Under market rules, all market participants and resources are expected to follow dispatch instructions.

Figure 1.35 Compliance with dispatch instructions in the California region – solar generation

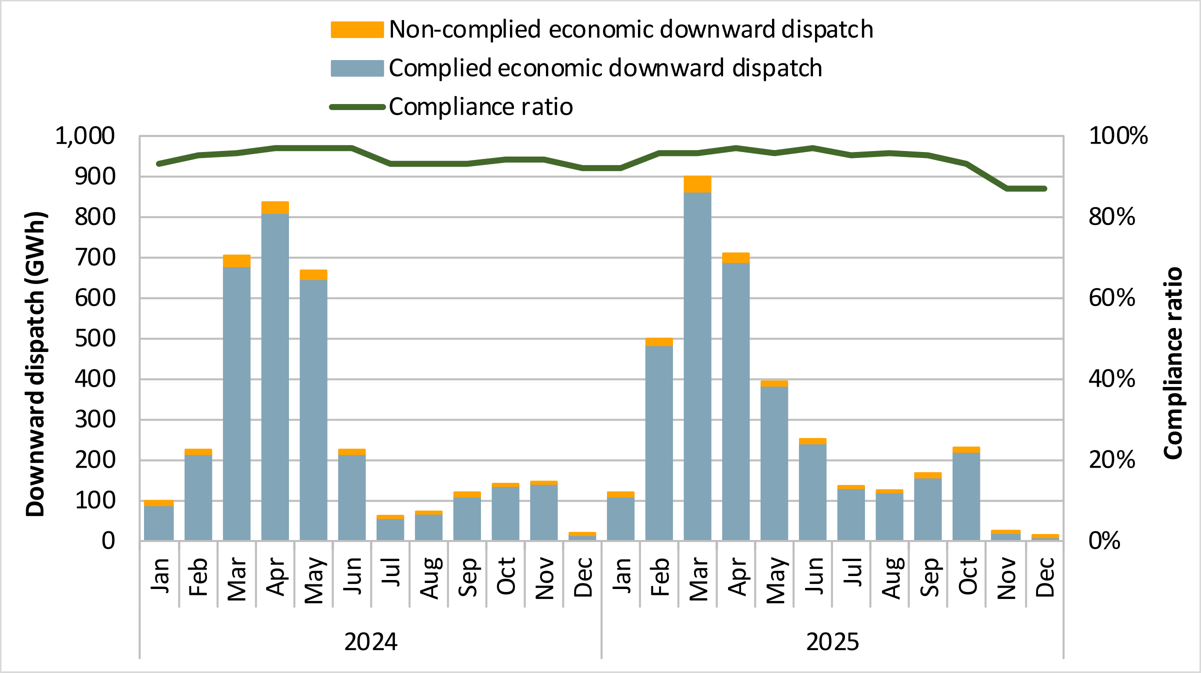


Figure 1.36 Compliance with dispatch instructions in the California region – wind generation

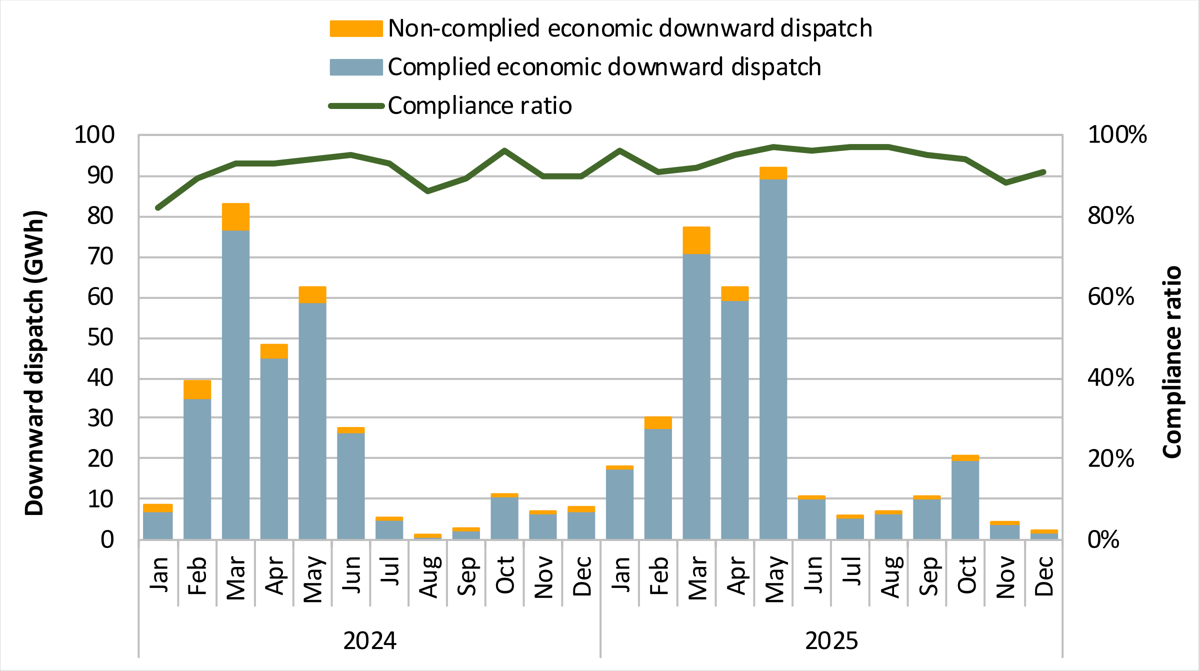


Figure 1.37 Compliance with dispatch instructions in the Desert Southwest region – solar generation

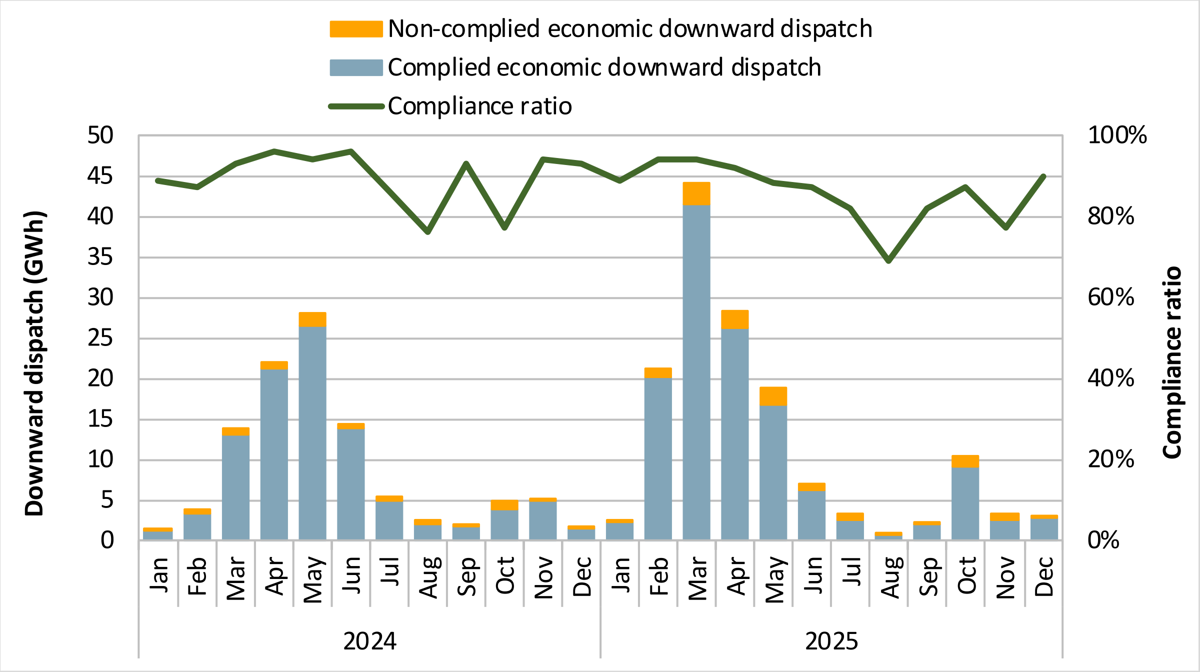


Figure 1.38 Compliance with dispatch instructions in the Desert Southwest region – wind generation

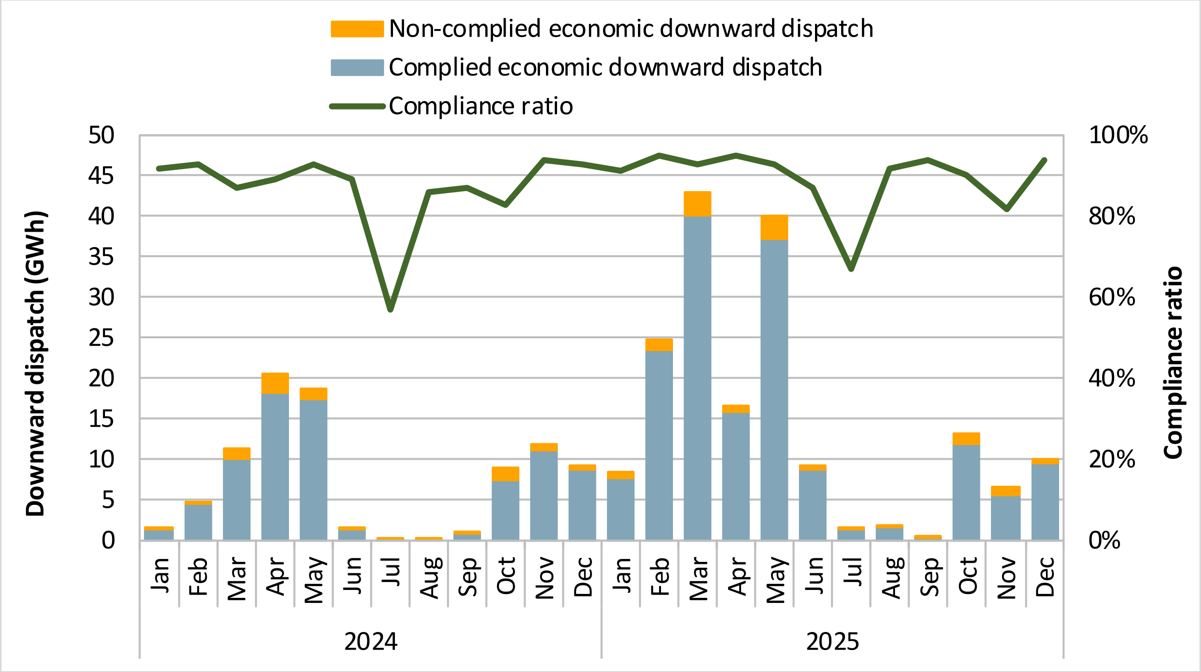


Figure 1.39 Compliance with dispatch instructions in the Intermountain West region – solar generation

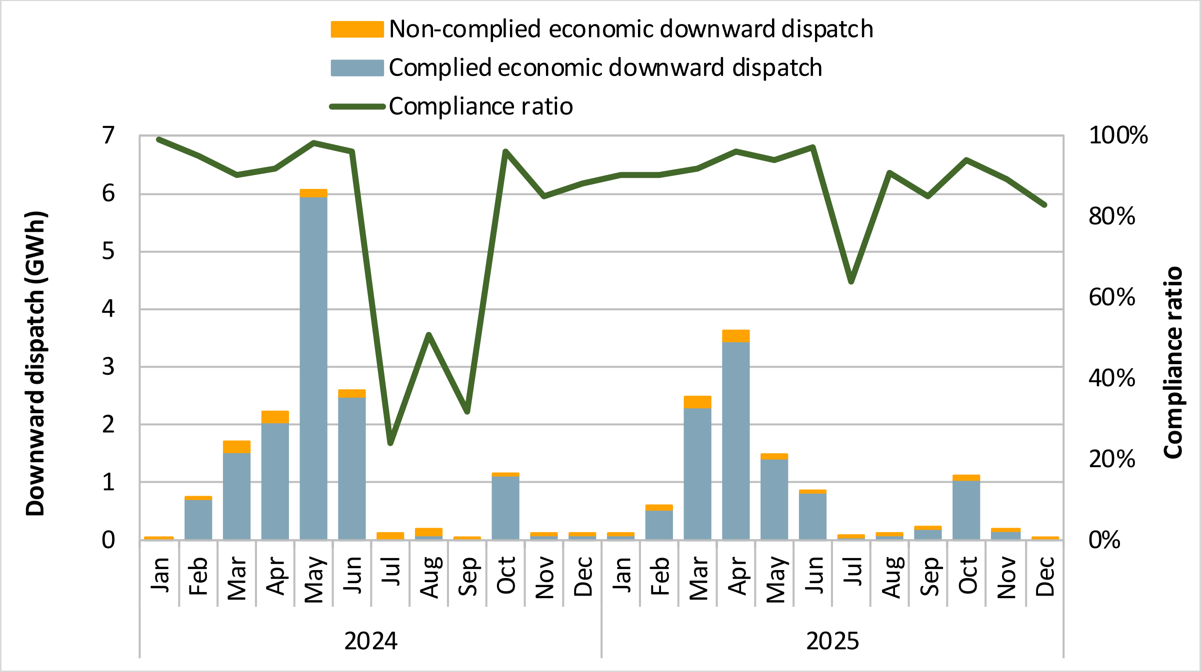


Figure 1.40 Compliance with dispatch instructions in the Intermountain West region – wind generation

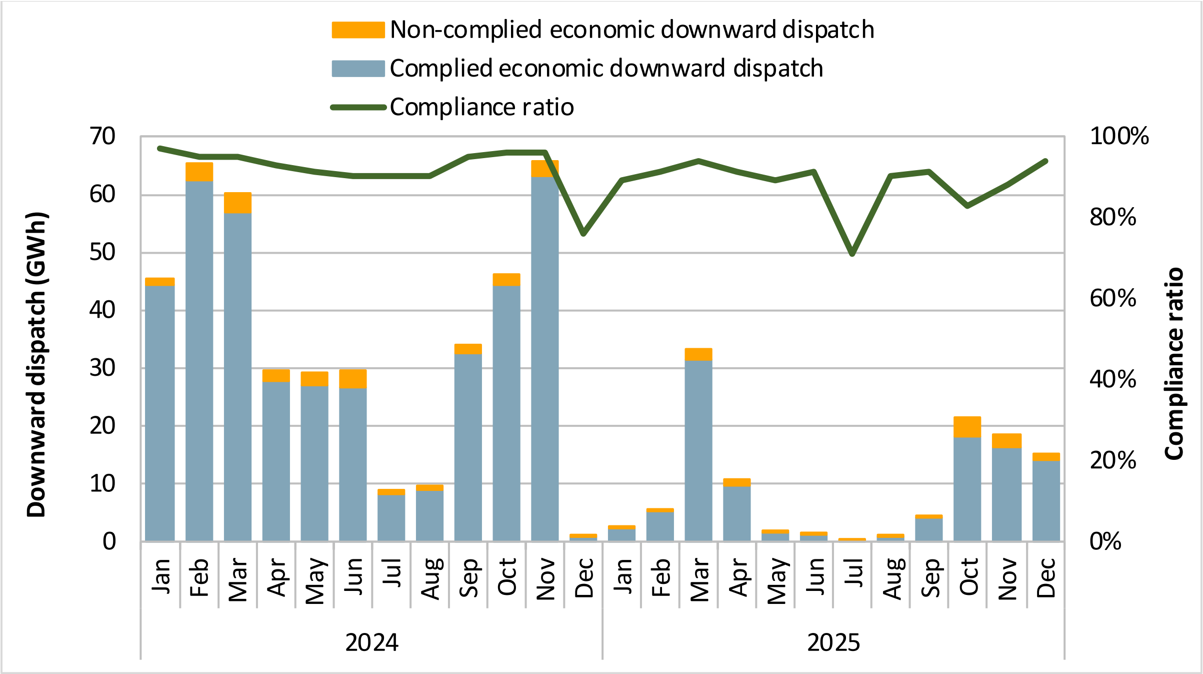


Figure 1.41 Compliance with dispatch instructions in the Pacific Northwest region – solar generation

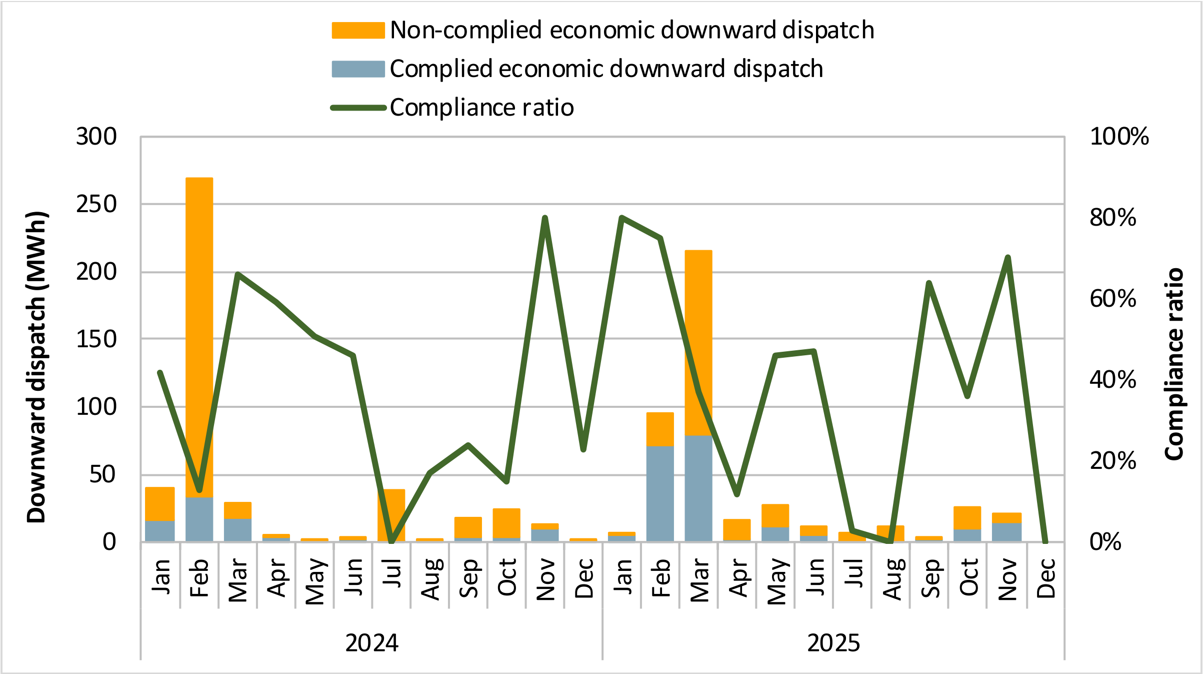
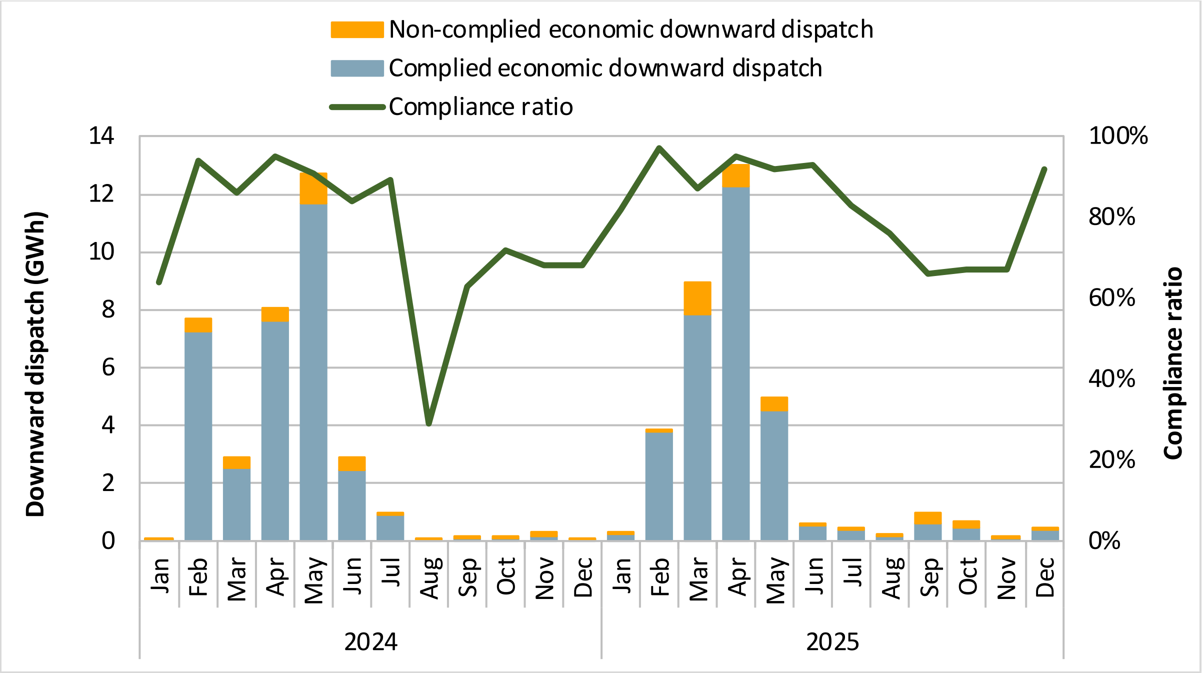


Figure 1.42 Compliance with dispatch instructions in the Pacific Northwest region – wind generation



Hydroelectric supplies

In 2025, total WEIM hydroelectric production increased about 4 percent from 2024.[50] Most of this increase is from the Pacific Northwest region, which saw a 9,850 GWh increase in hydroelectric generation. Generation from hydro resources decreased in the California region by around 2,270 GWh.

Year-to-year variation in hydroelectric power supply in the WEIM can have a significant impact on prices and the performance of the wholesale energy market. Run-of-river hydroelectric power generally reduces the need for baseload generation and imports. Hydro conditions also impact the amount of hydroelectric power and ancillary services available during peak hours from units with reservoir storage.

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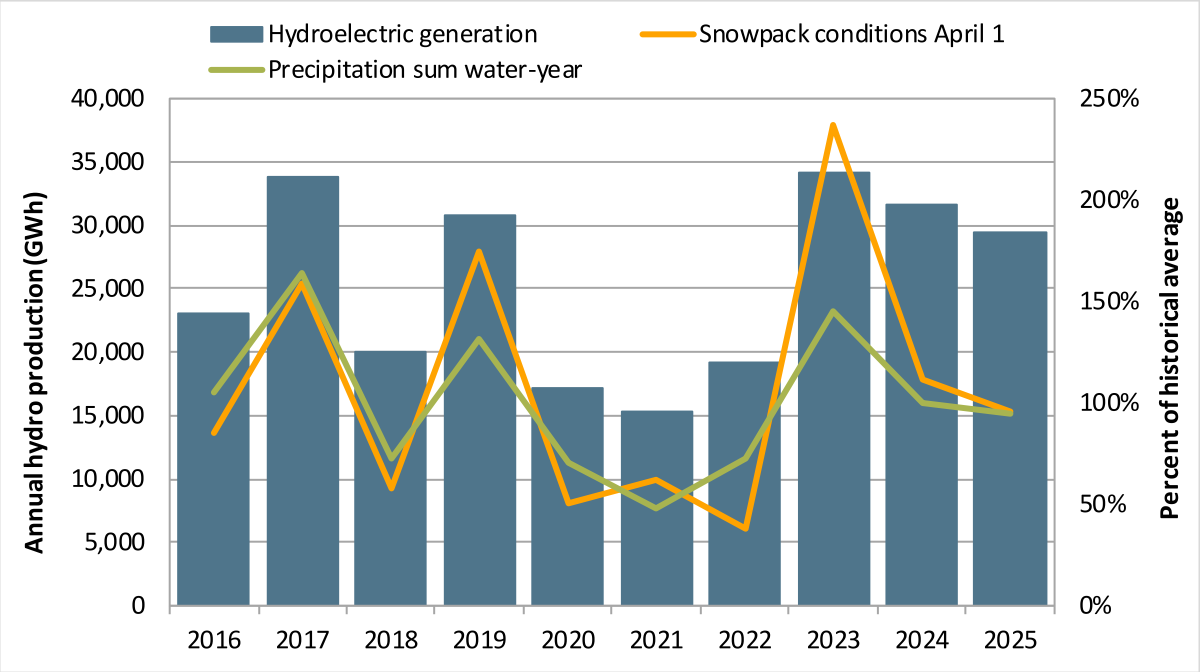
[50] Annual hydroelectric production includes tie generators.

Figure 1.43 shows total annual hydroelectric production in the California region alongside the April 1 snowpack level[51] and precipitation[52] in California from 2016 to 2025.[53] Figure 1.44 through Figure 1.46 show the total annual hydroelectric production in the rest of the WEIM regions. Figure 1.47 compares monthly hydroelectric output from resources within the WEIM system for each month during the last three years. Similar to 2023 and 2024, hydro generation in 2025 followed a seasonal pattern with generation generally peaking in the spring months, particularly April through June, across most WEIM regions. In the Pacific Northwest, hydro output peaked during the winter months with smaller increases in the summer as well. This seasonal pattern reflects snowmelt-driven runoff in most regions, while the Pacific Northwest exhibits distinct winter-driven hydro patterns.

Figure 1.43 California - Annual hydroelectric production (2016–2025)



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[51] This table uses the April 1 measurement of snow water equivalent as a percent of long-term average. For more information, please see California Department of Water Resources, *California Data Exchange Center*: https://cdec.water.ca.gov/snowapp/sweq.action

[52] For precipitation, this table uses the statewide weighted average precipitation as a percent of historic average for the October–September water year. For more information, please see: https://cdec.water.ca.gov/reportapp/javareports?name=PRECIPSUM

[53] BANC joined the WEIM in two phases. The first was in April 2019 with SMUD, and the second phase was in 2021 with Modesto Irrigation District, the City of Redding, the City of Roseville, and the WAPA Sierra Nevada Region. TIDC and LADWP both joined the WEIM in 2021.

Figure 1.44 Desert Southwest - Annual hydroelectric production (2016–2025)[54]

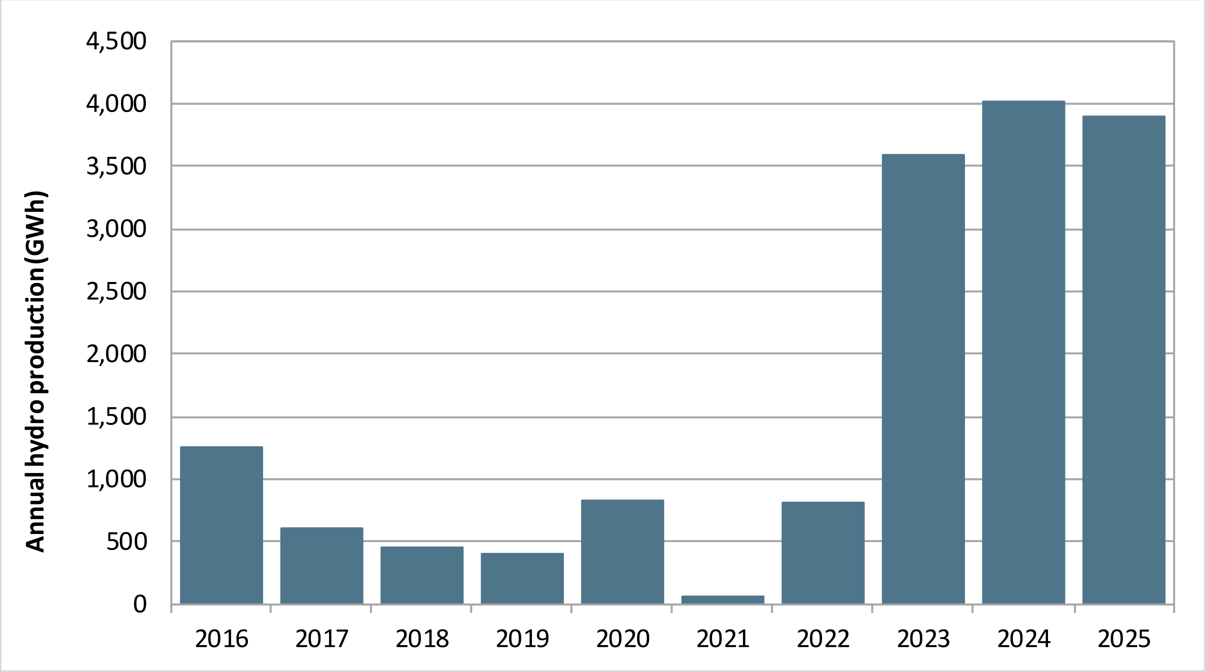
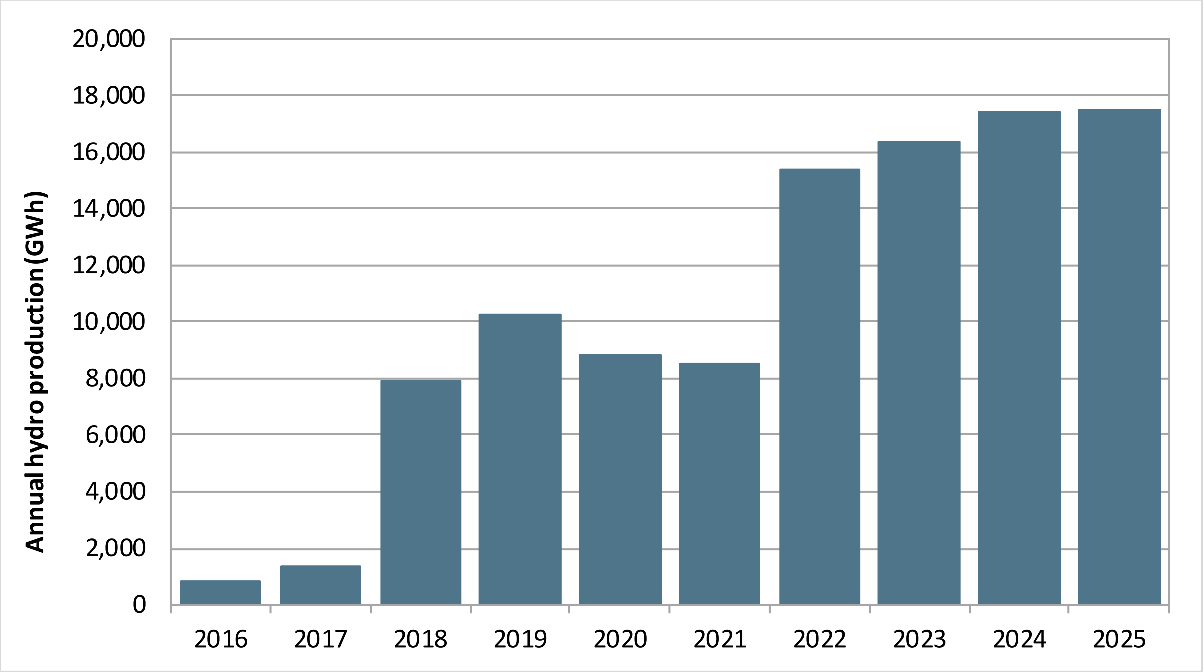


Figure 1.45 Intermountain West - Annual hydroelectric production (2016–2025)[55]



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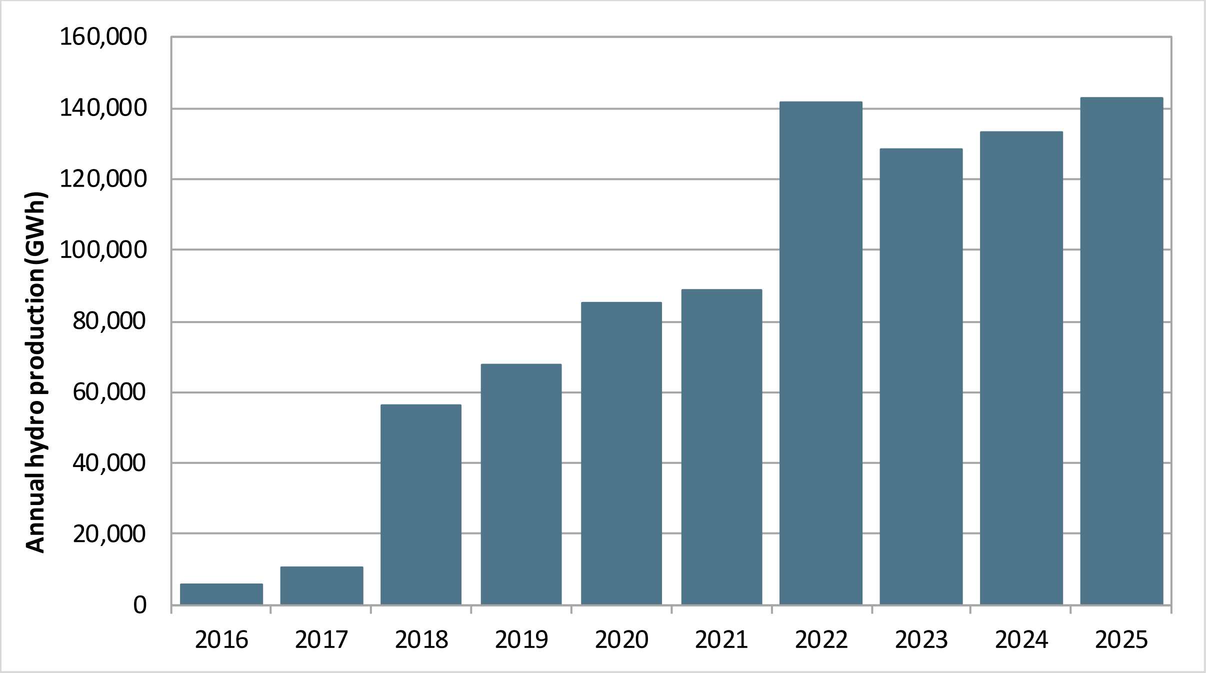
[54] AZPS joined the WEIM in 2016. SRP joined in 2020. PNM joined in 2021. TEPC joined in 2022. WALC and EPE joined in 2023.

[55] IPCO joined the WEIM in 2018. NWMT and AVA joined in 2021 and 2022, respectively.

Figure 1.46 Pacific Northwest - Annual hydroelectric production (2016–2025)[56]



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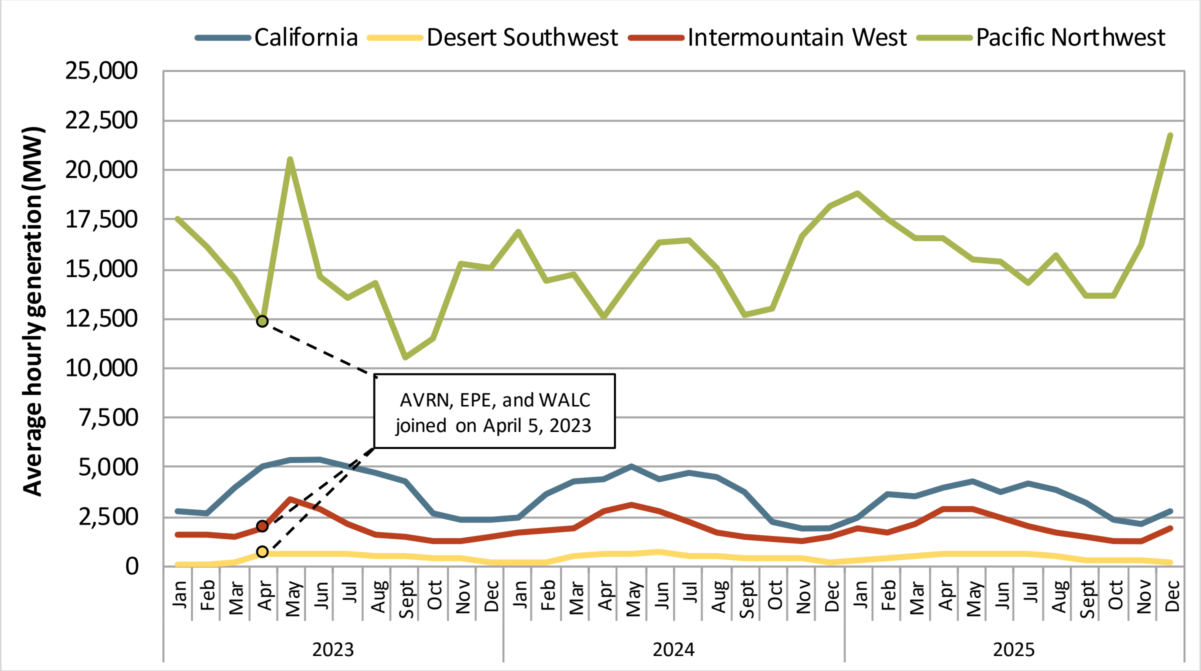
[56] PSEI joined the WEIM in 2016. PGE joined in 2017. BCHA joined in 2018. SCL joined in 2020. BPAT and TPWR joined in 2022. AVRN joined in 2023.

Figure 1.47 Average hydroelectric production by month (2023–2025)



1.2.3 Net interchange

Figure 1.48 through Figure 1.59 show average 5-minute market imports, exports, and WEIM transfers (collectively, "interchange") for each region in the WEIM.

Figure 1.48 through Figure 1.51 show the net interchange by quarter for each region. Figure 1.52, Figure 1.54, Figure 1.56, and Figure 1.58 show the total hourly imports and exports, and Figure 1.53, 1.55, Figure 1.57, and Figure 1.59 show the hourly net interchange.[57] Power flowing into a balancing area (or region) is represented as a positive value, while power flowing out of a balancing area (or region) is shown as negative. This energy is categorized as follows:

- **Interchange before dynamic transfers** (solid black line) represents the net interchange into the region before accounting for dynamic WEIM transfers. This includes:
  - **Base WEIM intertie schedules** (stacked blue bars) are fixed intertie transactions between two non-CAISO balancing areas within the WEIM. These transfers are not optimized in the market.
  - **Non-WEIM intertie schedules** (stacked aqua bars) are fixed intertie transactions between a WEIM and a non-WEIM balancing area. These transfers are not optimized in the market.

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

  - **CAISO intertie schedules** (stacked green bars) are import and export schedules into or out of the CAISO balancing area that result from bid-in or self-scheduled participation in the market.[58] Most CAISO intertie schedules are scheduled in hourly blocks where the hour-ahead scheduling process (HASP) is the final opportunity for these schedules to be optimized in the market.[59, 60]
- **Interchange after dynamic transfers** (red line) represents the final net interchange into and out of the region, including WEIM transfers that are optimized in the market. This includes the categories above, plus dynamic WEIM transfers:
  - **Dynamic WEIM transfers** (stacked gold bars) are energy transfers between any two WEIM balancing areas that are optimized in the real-time market.[61]

Quarterly interchange and average prices

The California region was a net importer throughout 2025, and the net interchange after dynamic transfers into this region increased by 26 percent in 2025 compared to 2024. The Desert Southwest, Intermountain West, and Pacific Northwest regions were net exporters for three or all quarters in 2025.

The figures in this section also show the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. Bilateral prices peaked in the third quarter of 2025 at both hubs.

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

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

[60] The Intermountain West region does not have CAISO intertie schedules.

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

Figure 1.48 California - Net interchange and average day-ahead price (2024–2025)

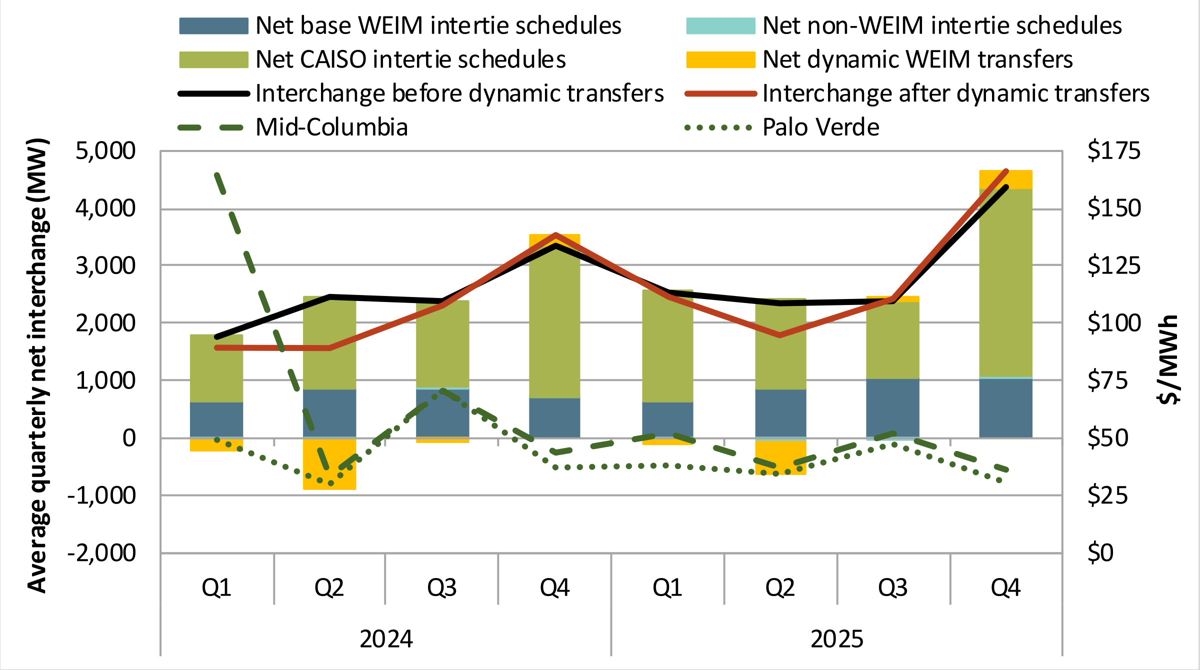


Figure 1.49 Desert Southwest - Net interchange and average day-ahead price (2024–2025)

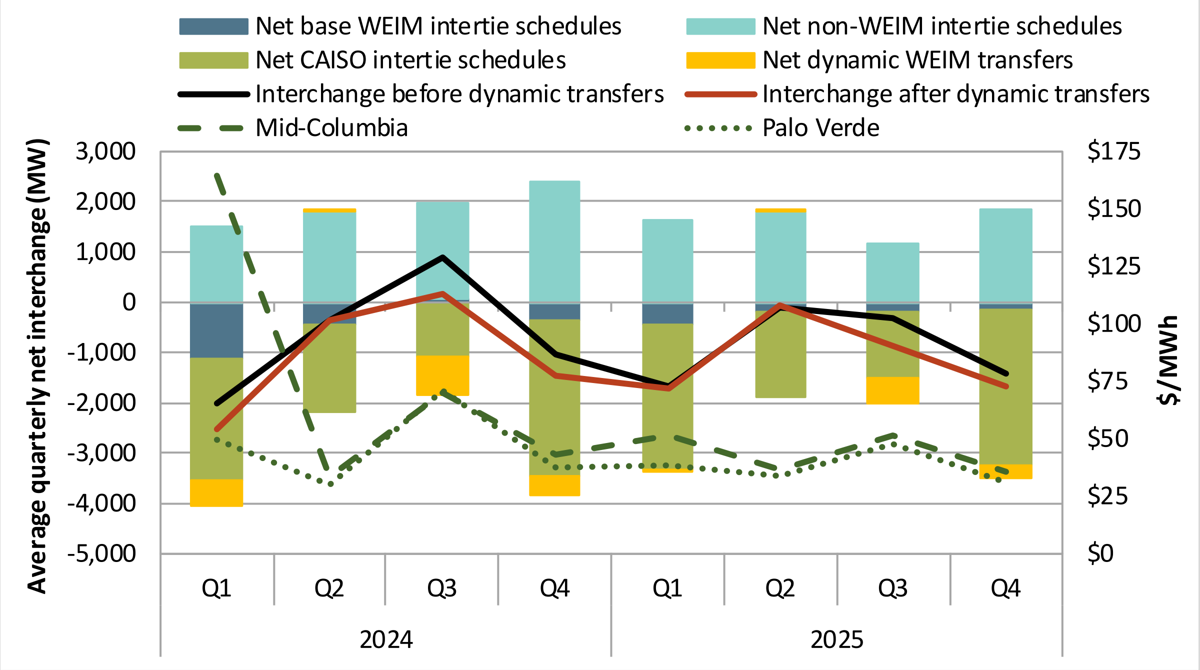


Figure 1.50 Intermountain West - Net imports and average day-ahead price (2024–2025)

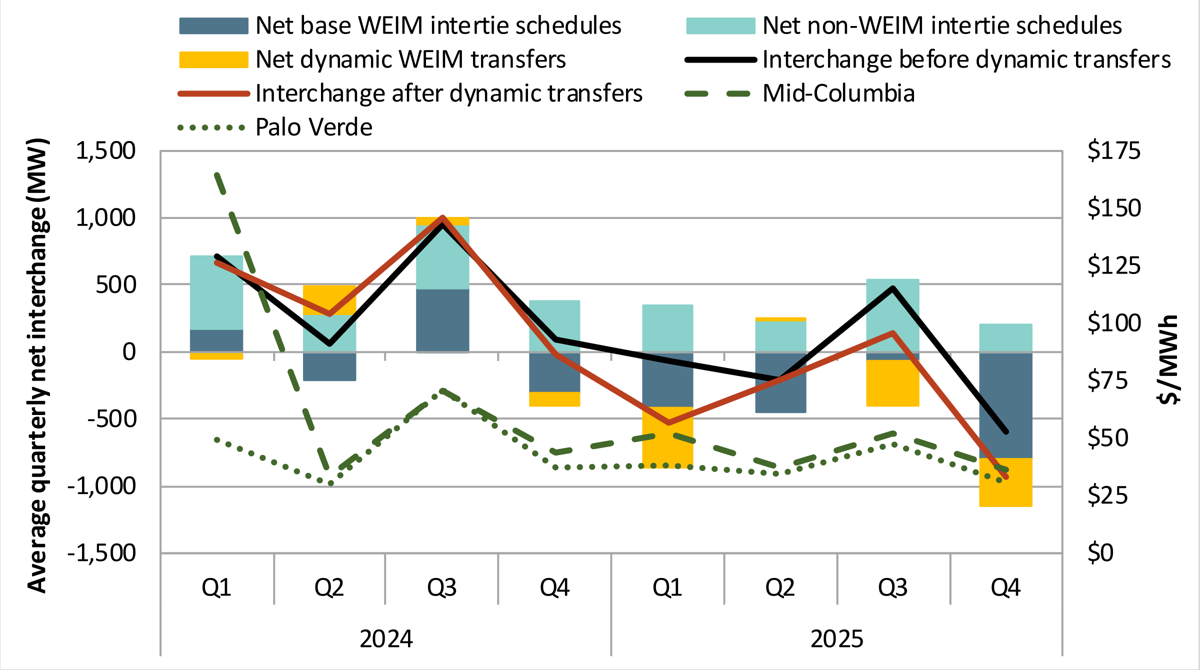
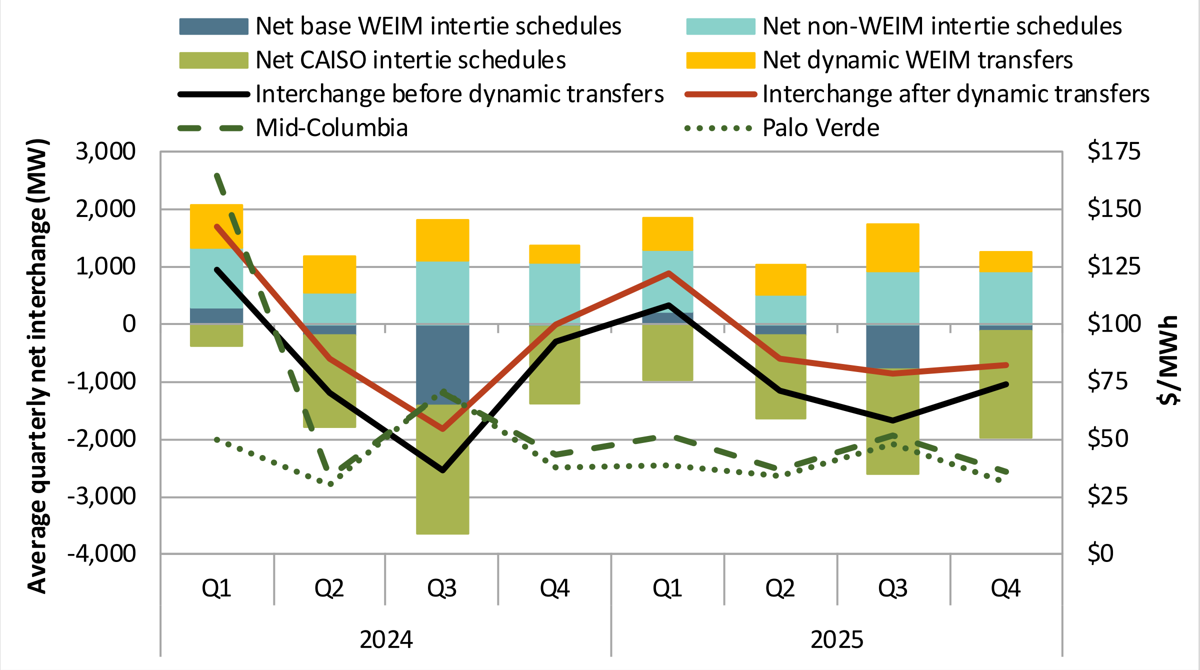


Figure 1.51 Pacific Northwest - Net imports and average day-ahead price (2024–2025)



Hourly net interchange – imports, exports, and WEIM transfers

In California, most transfers reflected CAISO intertie schedules associated with bid-in or self-scheduled participation. In all other regions, the majority of imports and exports consisted of fixed intertie transactions between two non-CAISO balancing areas within the WEIM.

In all quarters of 2025, the California region was a net importer both before (black line) and after (red line) WEIM dynamic transfers. In contrast, the Desert Southwest was a net exporter in every quarter, both before and after dynamic WEIM transfers. The Intermountain West was a net exporter in all quarters except the third quarter, when it was a net importer. The Pacific Northwest was a net importer in the first quarter and a net exporter in the remaining quarters.

On an annual basis, after dynamic transfers, California's net imports increased by approximately 580 MW (26 percent). Net interchange decreased (i.e., net exports increased) in the Desert Southwest by about 40 MW (4 percent), in the Intermountain West by roughly 870 MW, and in the Pacific Northwest by about 140 MW, increasing net exports from roughly 200 MW to 340 MW. These changes reflect shifts toward net exports in the Desert Southwest, Intermountain West, and Pacific Northwest, consistent with Figure 1.54, Figure 1.56, and Figure 1.58, which show these regions having increased exports across nearly all hours from 2024 to 2025. The increased net exports observed in these regions were driven by higher wind and coal generation in the Intermountain West, greater hydroelectric generation in the Pacific Northwest, and increased solar generation and battery charging and discharging in the Desert Southwest.

Figure 1.52 California - Average hourly interchange by quarter

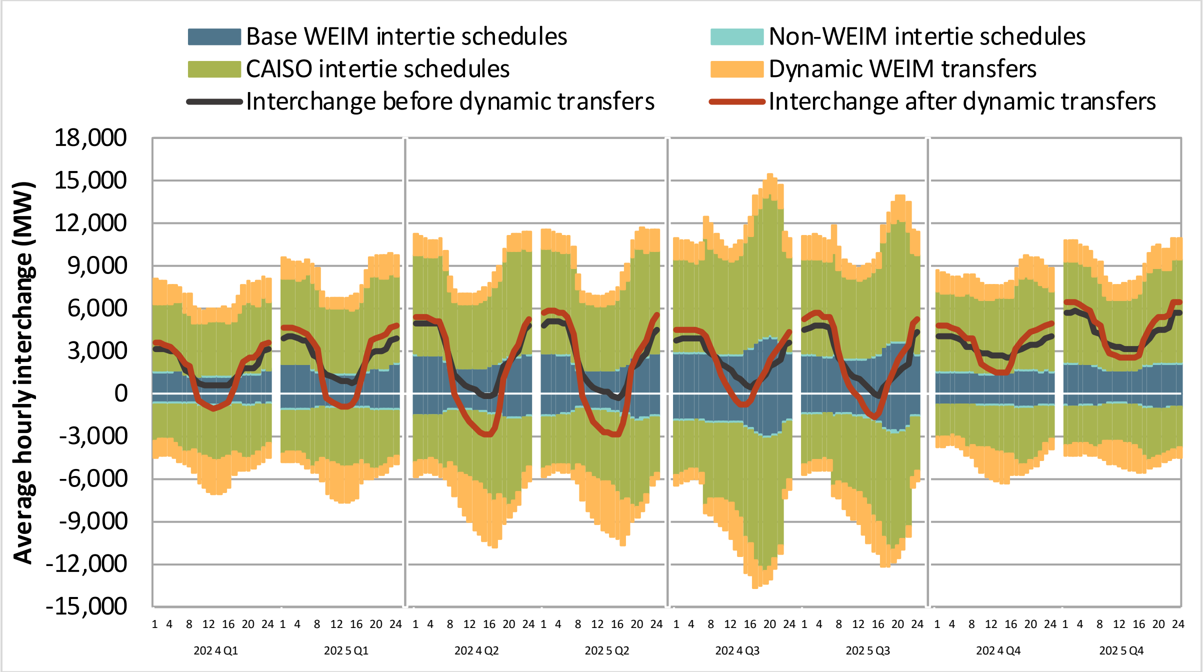


Figure 1.53 California - Average hourly net interchange by quarter

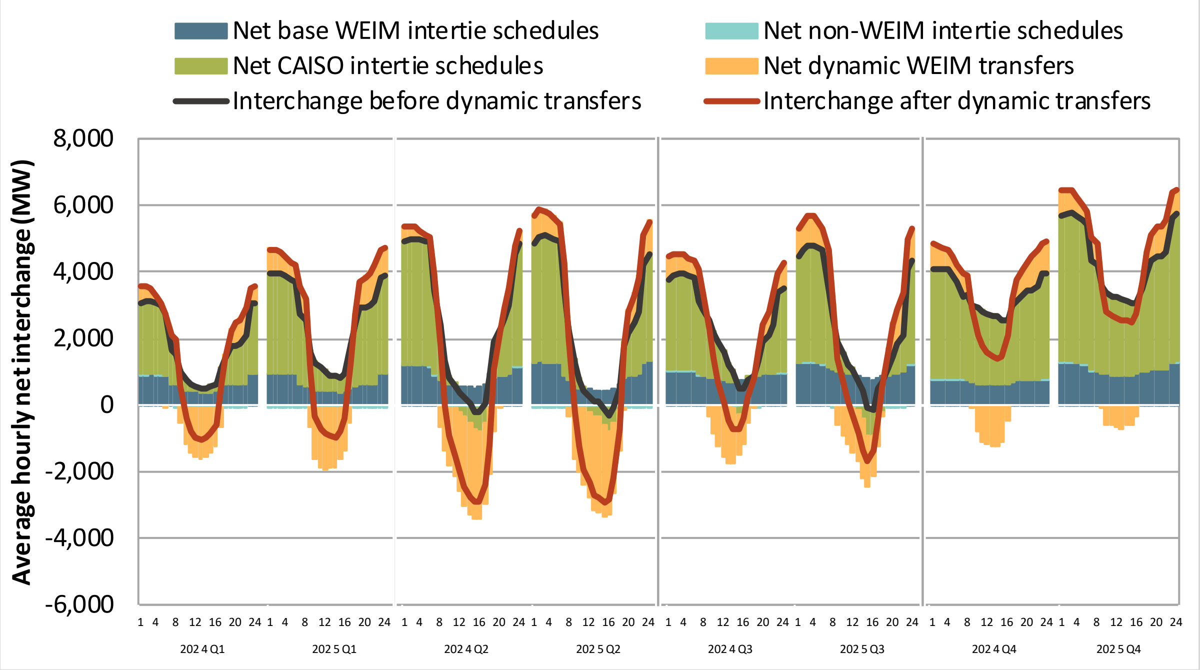


Figure 1.54 Desert Southwest - Average hourly interchange by quarter

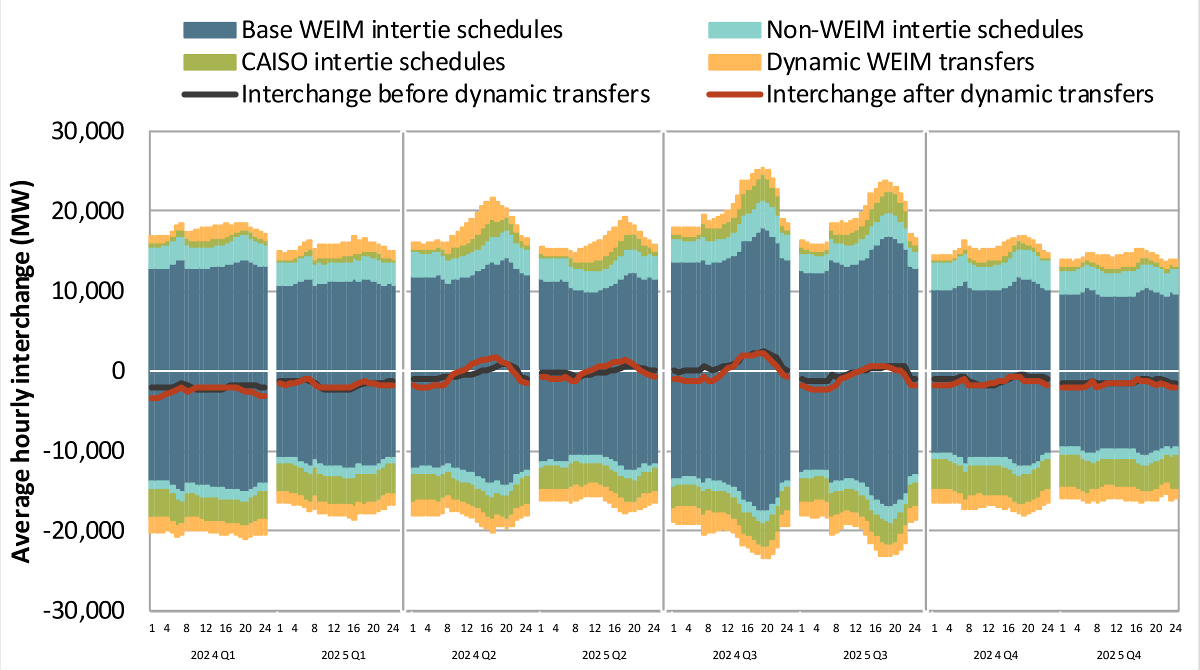


Figure 1.55 Desert Southwest - Average hourly net interchange by quarter

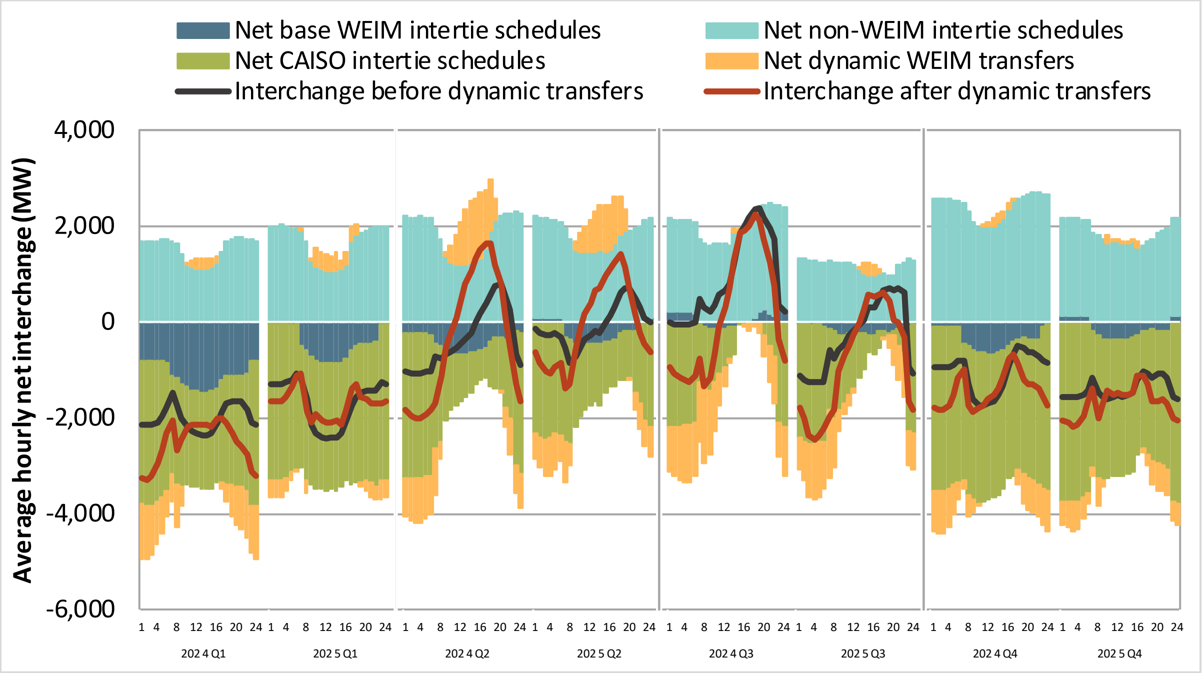


Figure 1.56 Intermountain West - Average hourly interchange by quarter

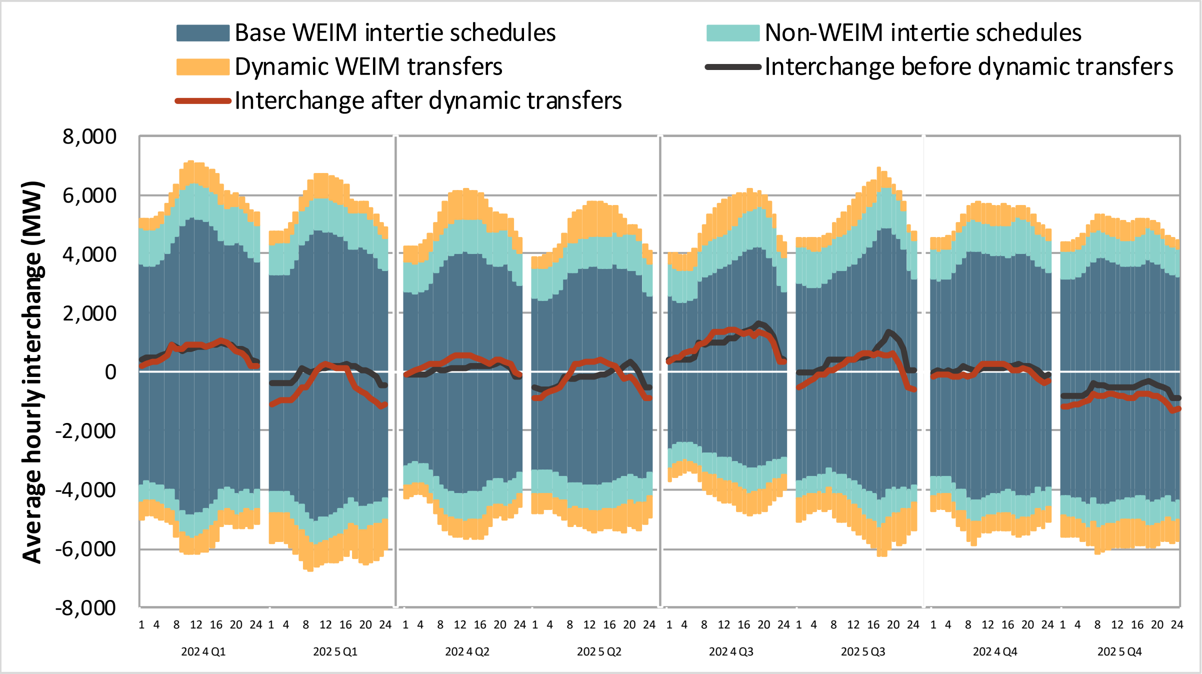


Figure 1.57 Intermountain West - Average hourly net interchange by quarter

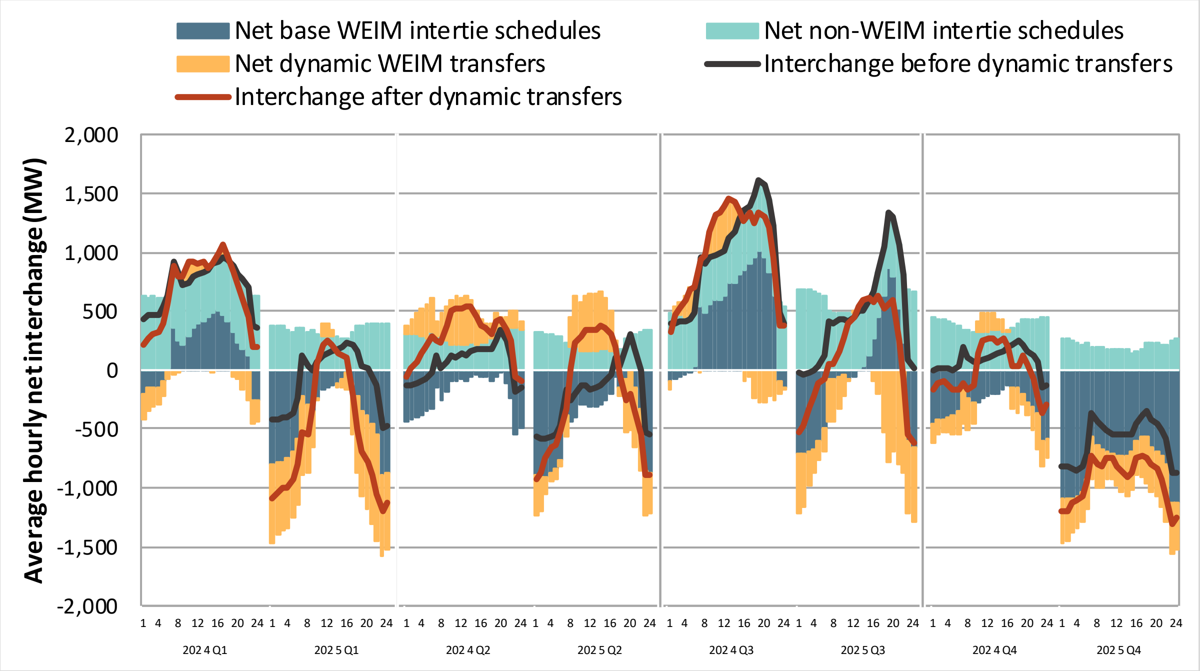
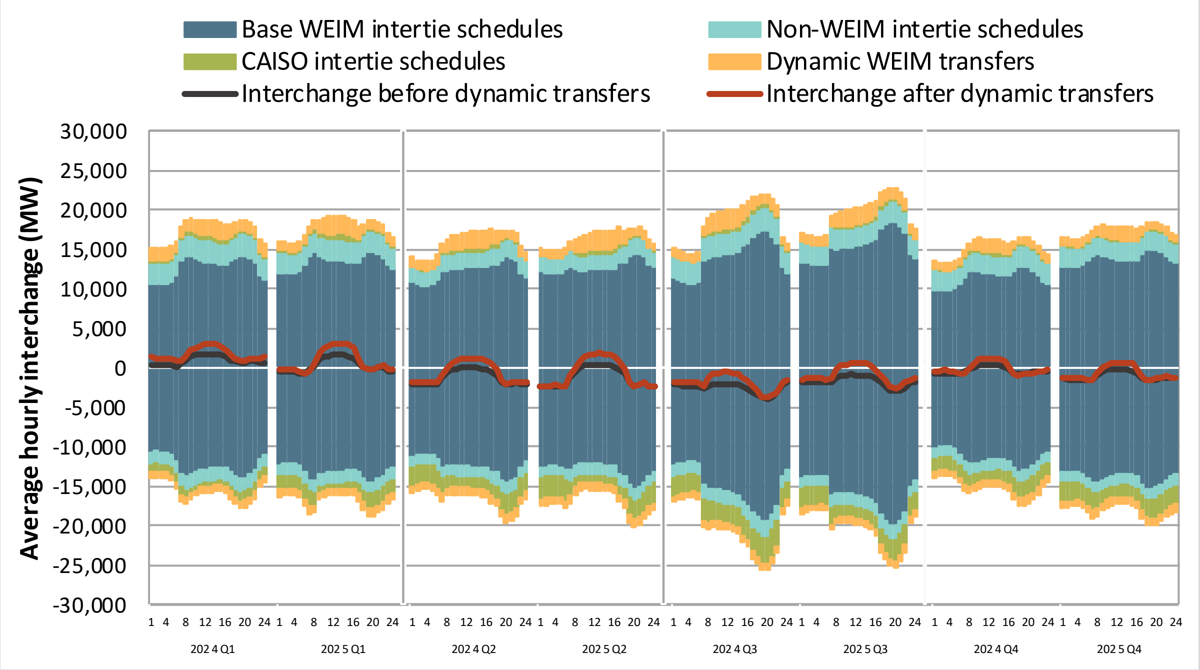


Figure 1.58 Pacific Northwest - Average hourly interchange by quarter



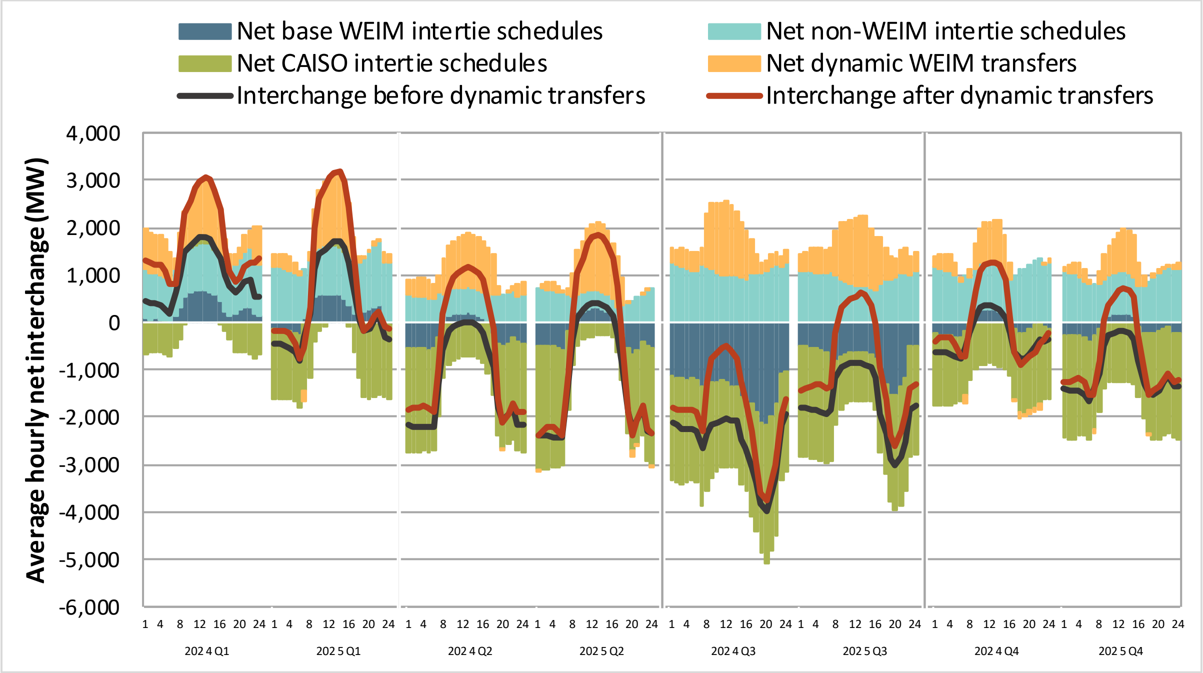


Figure 1.59 Pacific Northwest - Average hourly net interchange by quarter

1.2.4 Storage resources

Capacity from battery storage resources has increased significantly in recent years.[62] Storage resources typically participate under the non-generator resource model. Non-generator resources are resources that operate as generation, and bid into the market using a single supply curve with prices for negative capacity (charging) and positive capacity (discharging).

The California ISO has increasingly seen participation of hybrid resources, which typically pair renewable generation with battery storage components. Hybrids are modeled as a single resource, in that they have a single bid curve that applies to all their component parts and receive one dispatch instruction from the ISO. The hybrid resource operator self-optimizes the components of its resource to meet that dispatch instruction.

Co-located resources are those that share a point of interconnection with another resource. Similar to hybrids, co-located points of interconnection typically contain groupings of battery and intermittent renewable resources. Since they are modeled as separate resources, co-located facilities have separate metering arrangements, submit separate outages, receive separate dispatch instructions, and may be operated by different entities. Several market constraints only apply to co-located resources. For example, the aggregate capability constraint exists to ensure that dispatch instructions to co-located resources behind a common point of interconnection do not exceed interconnection limits. In addition,

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[62] For more information, see DMM's special report: *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

co-located resources may use an optional parameter which allows their battery components to restrict grid charging. This helps resources capture tax benefits meant to incentivize batteries to not charge beyond what their co-located solar component is producing. In 2025, the maximum observed hourly amount of co-located battery capacity that restricted grid charging was nearly 870 MW, compared to 750 MW in 2024.

As of December 31, 2025, there are 195 co-located resources across 87 points of interconnection. Around 39 percent of installed co-located capacity consists of batteries, and all but four of these 87 points of interconnection have at least one battery resource.

Figure 1.60 shows total battery capacity by balancing authority area as of December 31, 2025.[63] Stand-alone batteries are defined as resources that consist solely of battery storage components and do not share a point of interconnection with other resources. In December 2025, active battery capacity totaled nearly 25,700 MW—11,900 MW from stand-alone projects, 11,500 MW from co-located projects, and about 2,300 MW from the storage components of hybrid resources and co-located hybrids. Aggregate maximum state-of-charge for the battery fleet was nearly 93 GWh.

Figure 1.60 Battery capacity by balancing area (2025)

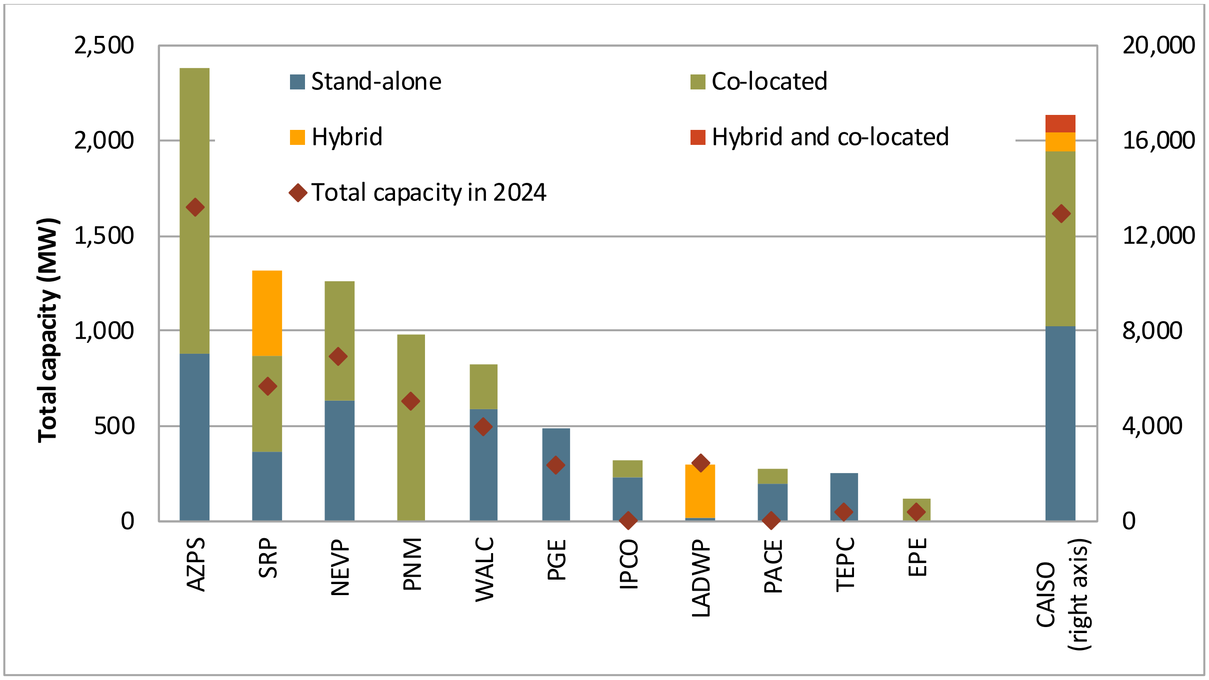

Figure 1.61 shows average net battery energy schedules in the 5-minute market from 2023 to 2025, where points below the zero axis represent charging and points above represent discharging. The average net energy output from batteries peaked at about 9,100 MW during hour-ending 20 in 2025, compared to 5,700 MW in 2024.

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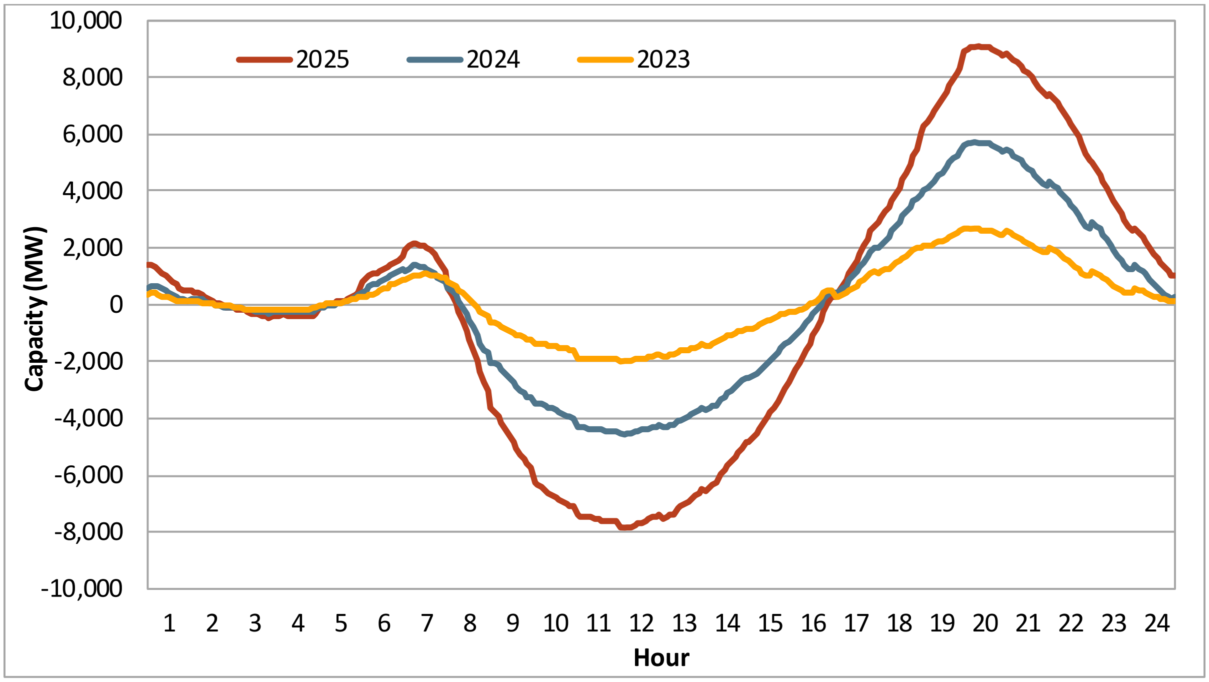
[63] These values may differ from other battery capacity measures. This metric only includes capacity of participating batteries, defined as being scheduled at least once in the respective year. These data track co-located and hybrid status as of December 2021 and February 2023, respectively, though these types of capacity may have been participating sooner.

Figure 1.62 shows hourly average 5-minute market load across different regions and average net 5-minute market battery schedules during periods of net charging. Load data in this chart represent load inputs into the real-time market and do not include battery charging. Average battery charging as a percentage of load in 2025 was highest in hour 12, at nearly 10 percent.

Batteries provide most of the CAISO balancing area's ancillary services. However, in terms of total scheduled capacity from batteries, ancillary services provision has decreased in favor of energy with the rapid growth in batteries.[64]

Figure 1.61 Average 5-minute market battery energy schedules



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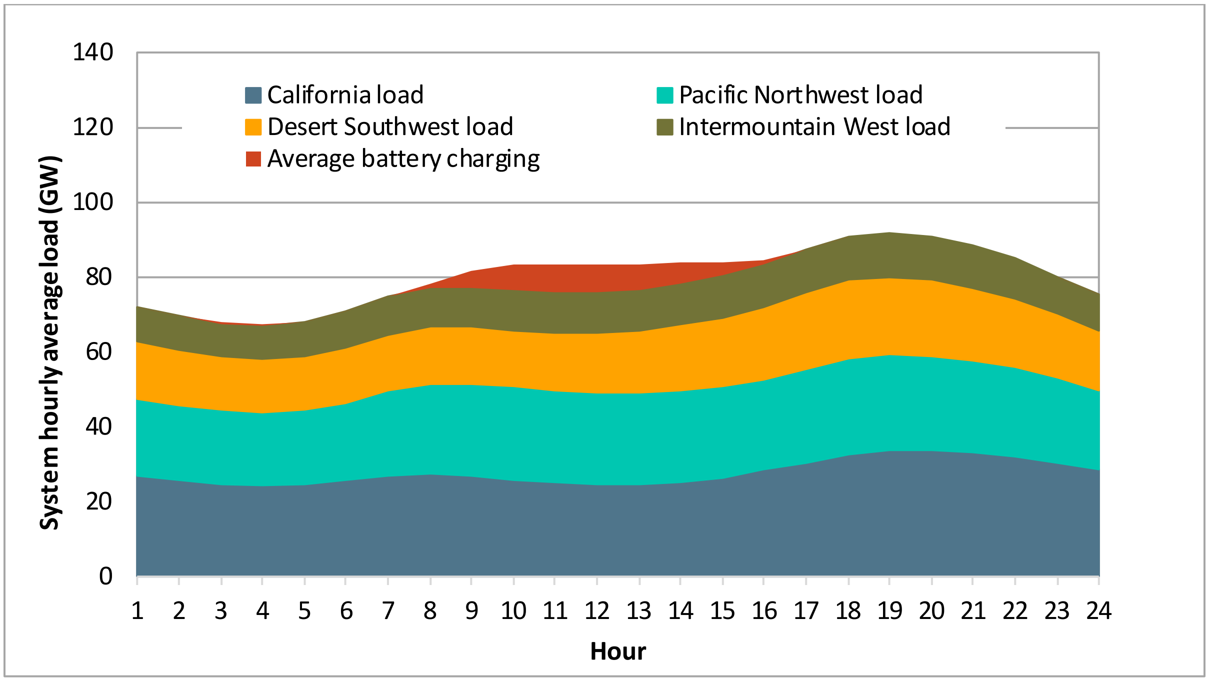
[64] *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

Figure 1.62 **Average hourly load by region and battery charging**



1.2.5 Generation outages

This section summarizes generation outages across the WEIM by region.[65]

CAISO balancing area outages were 11 percent higher in 2025 than in 2024. The average level of outages in the other California WEIM balancing areas, Desert Southwest region, and Intermountain West increased by over three percent, 14 percent, and 13 percent, respectively, in 2025. The Pacific Northwest region saw a decrease of approximately four percent in average outages.

Outage volumes in the CAISO, California (non-CAISO), and Desert Southwest regions followed a seasonal pattern of higher outage levels in non-summer months than in summer months. The Pacific Northwest and Intermountain West had the most outages in Q2, second most outages in Q4, and the least amount of outages during the regions' high load periods in Q1 and Q3.

Under the current California ISO outage management system, known as WebOMS, all outages are categorized as either planned or forced. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of these categories are plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations, and unit cycling.

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

California ISO balancing area outages

Figure 1.63 and Figure 1.64 show the quarterly and monthly averages of maximum daily outages by type during peak hours. Generation outages follow a seasonal pattern, with most taking place in the non-summer months. This pattern is driven by planned outages as maintenance is performed in preparation for the higher summer load period.

In 2025, average total generation outages for peak hours in the California ISO balancing area were about 16,300 MW, up from 14,700 MW in 2024. Outages for planned maintenance averaged about 2,700 MW during peak hours, while all other types of planned outages averaged about 1,210 MW. Some common types of outages in this category are ambient de-rates (both due to temperature and not due to temperature) and transmission-related outages. Forced outages for plant maintenance or trouble averaged about 5,000 MW, while all other types of forced outages averaged about 7,400 MW. Included in the "Other" category of forced outages are ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

Figure 1.63 CAISO quarterly average of maximum daily generation outages by type – peak hours

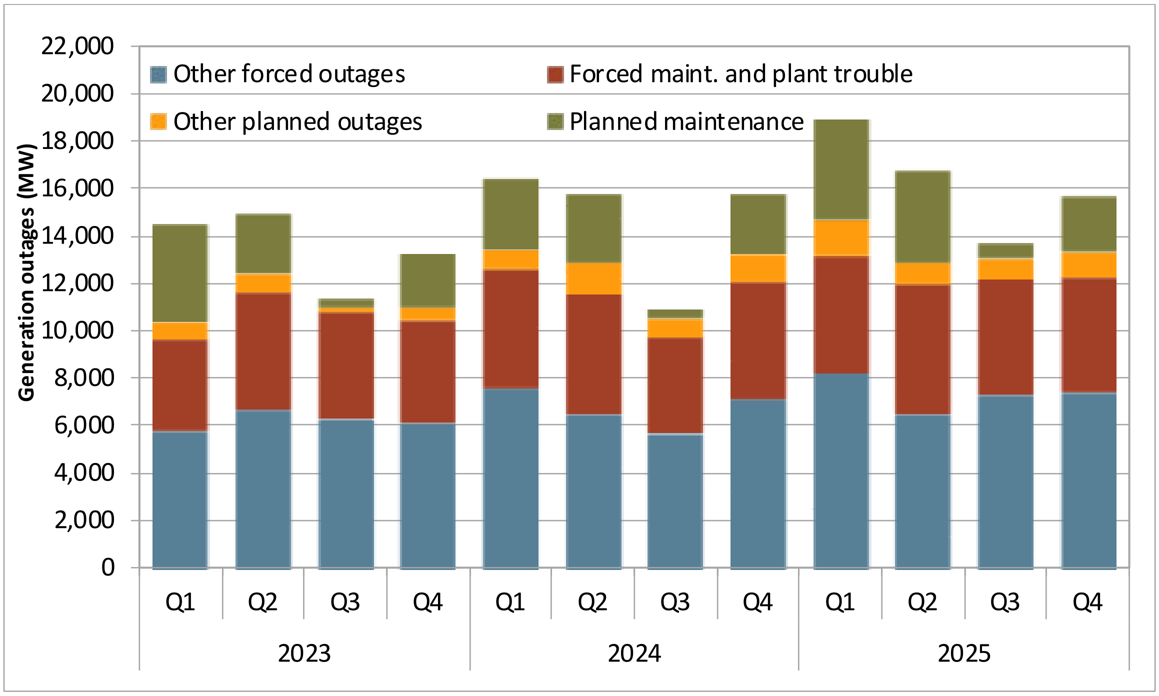
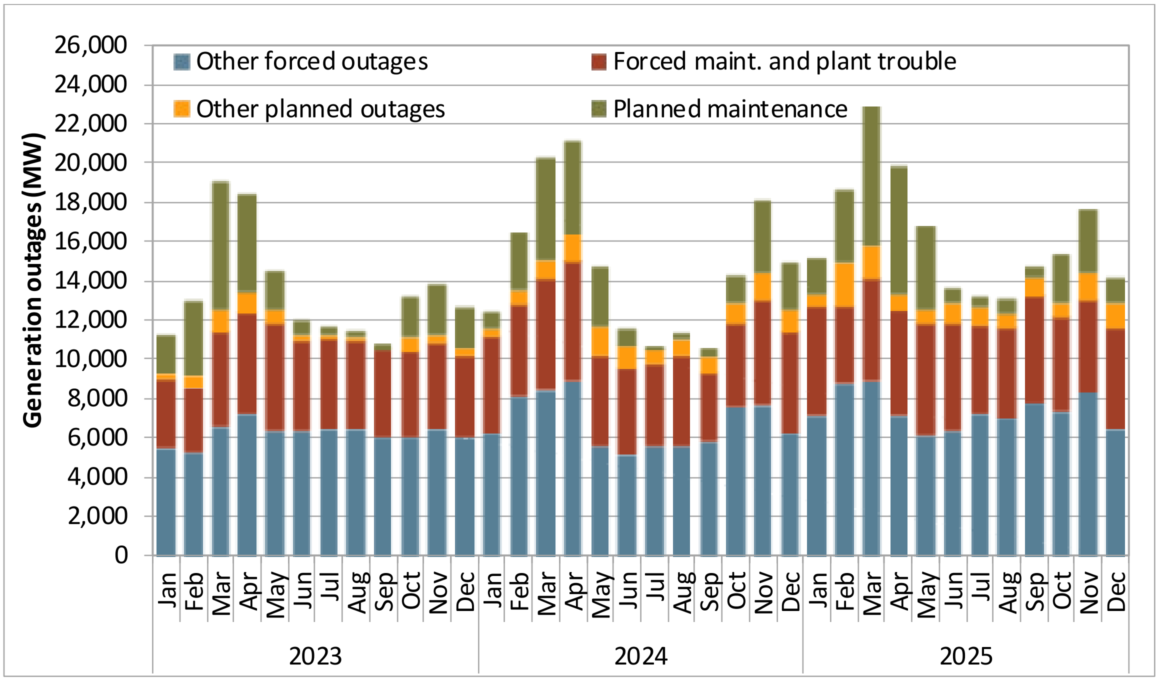


Figure 1.64 CAISO monthly average of maximum daily generation outages by type – peak hours

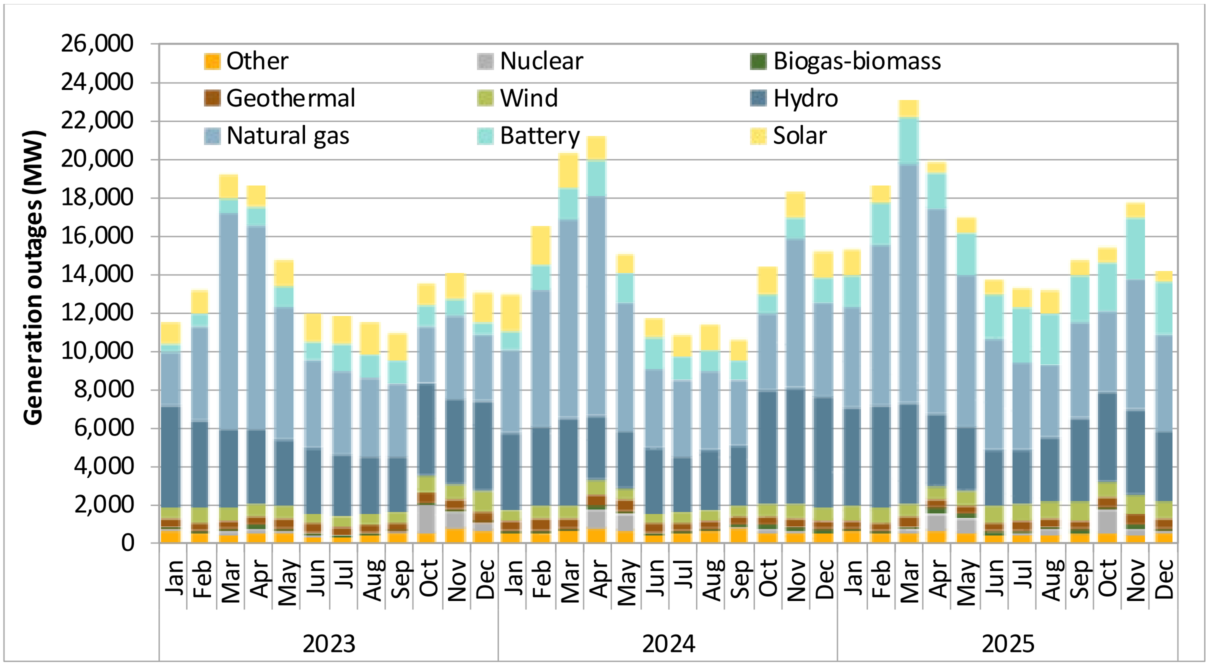


Generation outages by fuel type

CAISO balancing area natural gas and hydroelectric generation outages averaged 6,700 MW and 4,100 MW during 2025, respectively. Together, these two fuel types accounted for about 66 percent of the generation on outage for the year.

Figure 1.65 shows the monthly average generation on outage by fuel type during peak hours. Similar to 2024, the spring months experienced the highest monthly average generation on outage. This trend is driven by outages taken by gas resources for maintenance and other reasons, in preparation for the high load summer months. It is also worth noting that battery outages increased from an average of approximately 1,300 MW in 2024 to 2,450 MW in 2025, an 88 percent increase. An increase in storage outages is expected given the rapidly growing size of the battery storage fleet.

Figure 1.65 CAISO monthly average of maximum daily generation outages by fuel type – peak hours



California (non-CAISO) WEIM region

Figure 1.66 and Figure 1.67 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for entities in the California WEIM region, excluding the CAISO balancing area.[66] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2025. Average total outages for 2025 increased by less than 200 MW, an increase of less than four percent.

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

Figure 1.66 **California (non-CAISO) WEIM region quarterly average of maximum daily generation outages by type – peak hours**

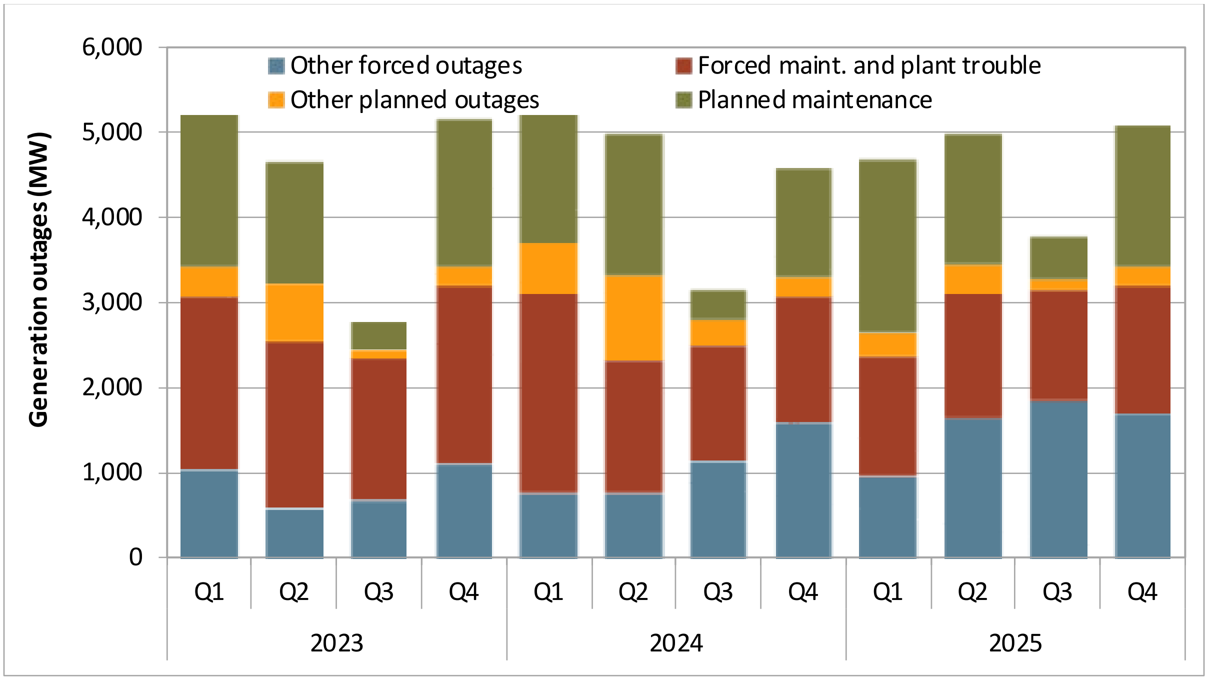
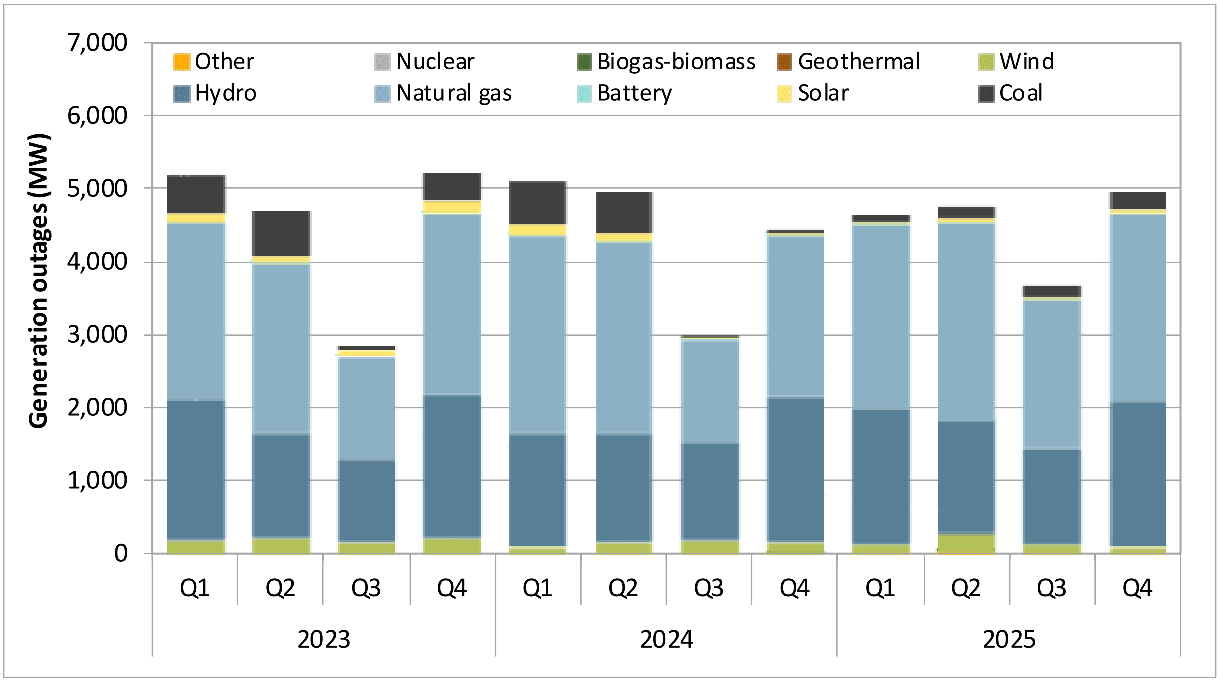


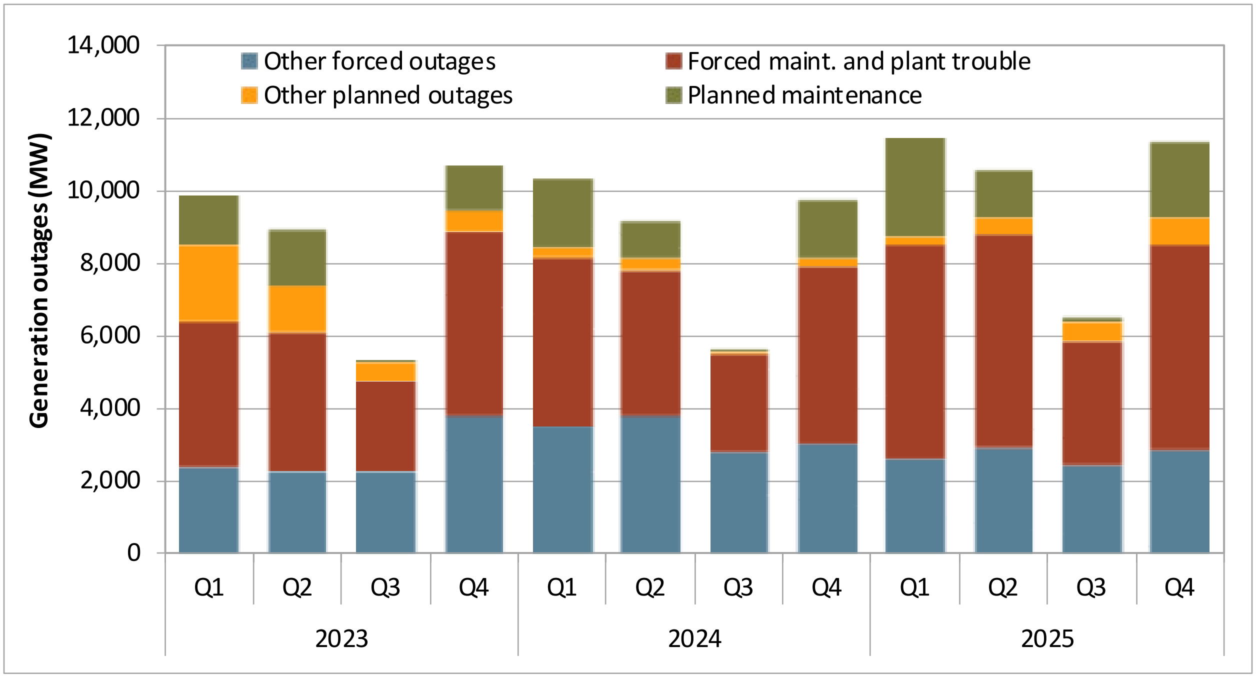
Figure 1.67 **California (non-CAISO) WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours**



Desert Southwest WEIM region

Figure 1.68 and Figure 1.69 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for entities in the Desert Southwest WEIM region.[67] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2025. Average total outages for the year increased by about 1,250 MW, or 14 percent. Battery storage resources increased from an average of 292 MW to 324 MW of reported outages. The increase in battery outages is likely driven by an increase in the number of participating battery resources in the Desert Southwest WEIM region.

Figure 1.68 Desert Southwest WEIM region quarterly average of maximum daily generation outages by type – peak hours



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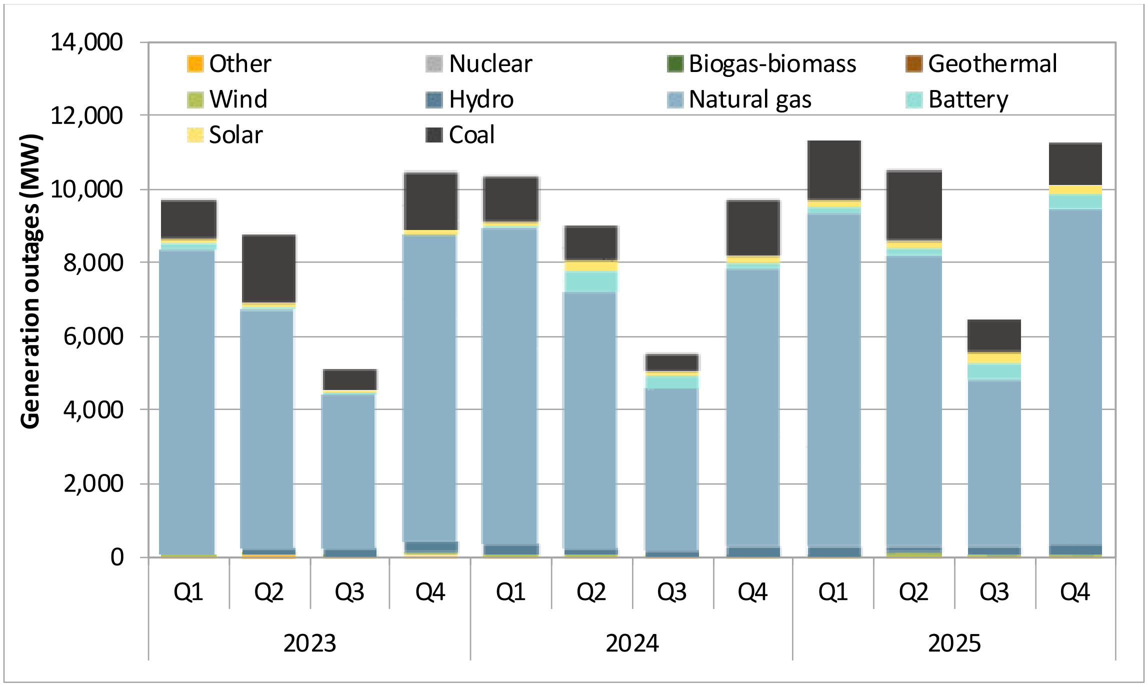
[67] The Desert Southwest region includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC.

Figure 1.69 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Intermountain West WEIM region

Figure 1.70 and Figure 1.71 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for entities in the Intermountain West WEIM region.[68] The typical seasonal outage pattern for the Intermountain West WEIM region diverges from the others, with outages typically peaking in the second quarter while outages in all other quarters remain low. Average total outages in 2025 increased by approximately 320 MW or 13 percent. The increase in outages between 2024 and 2025 was primarily due to a 20 percent increase in the average amount of natural gas outages from 1,040 MW in 2024 to 1,260 MW in 2025.

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

Figure 1.70 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours

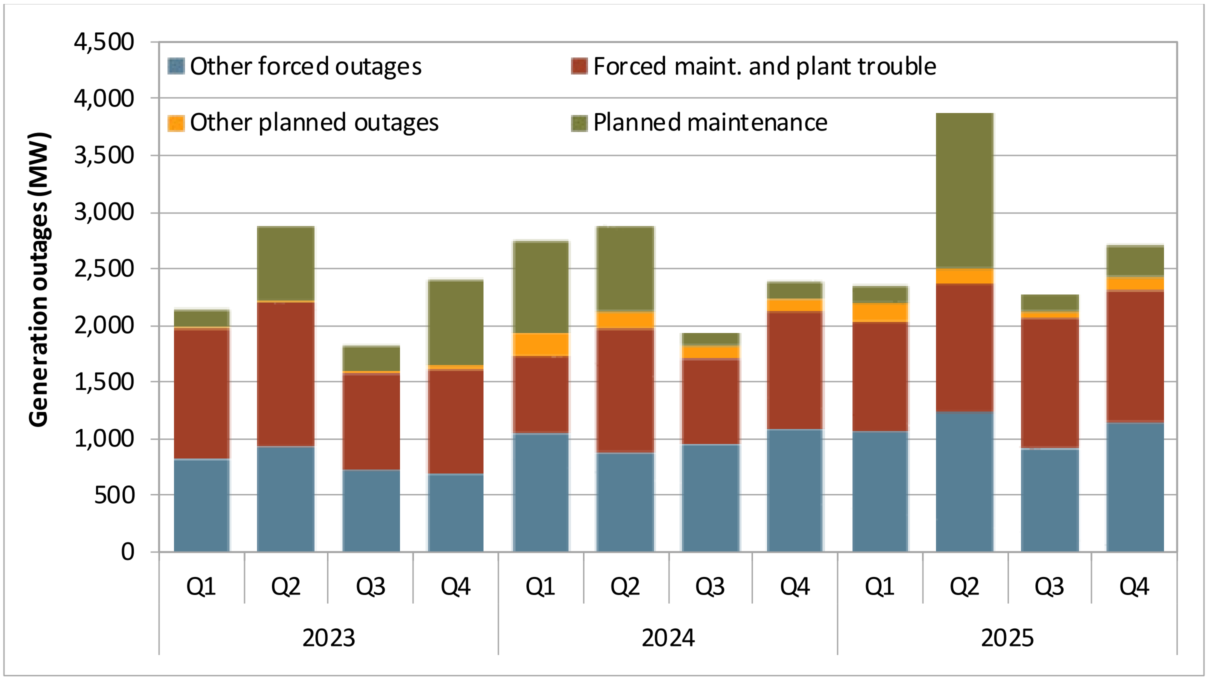
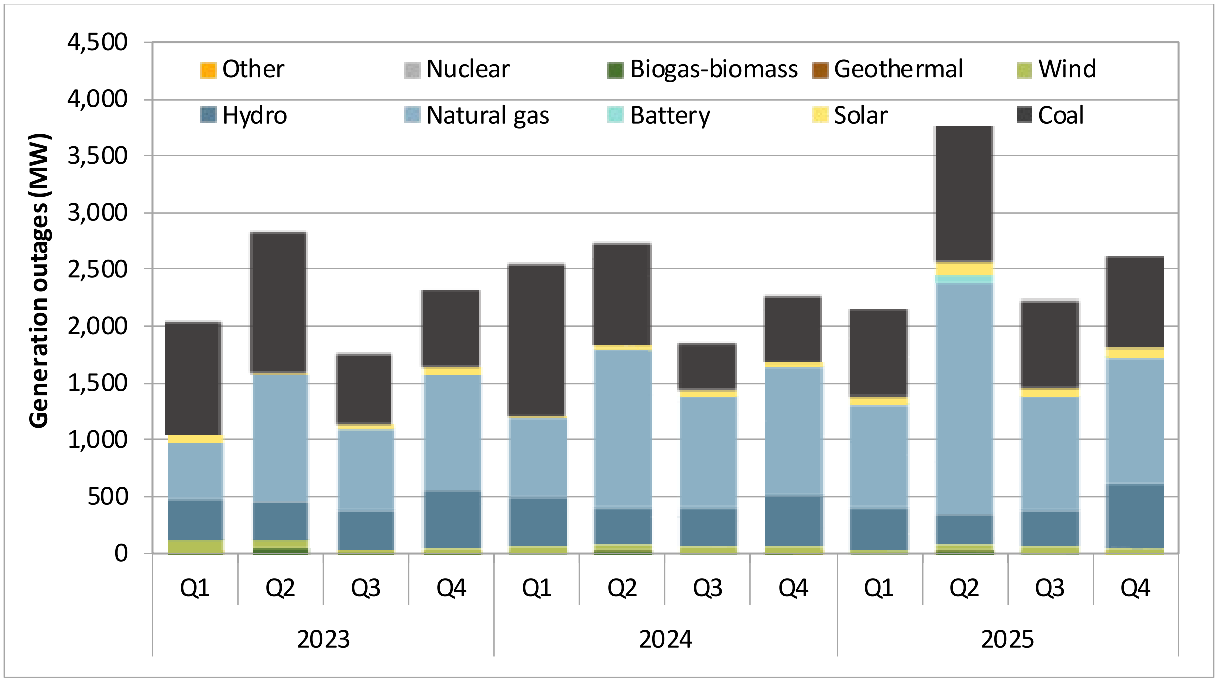


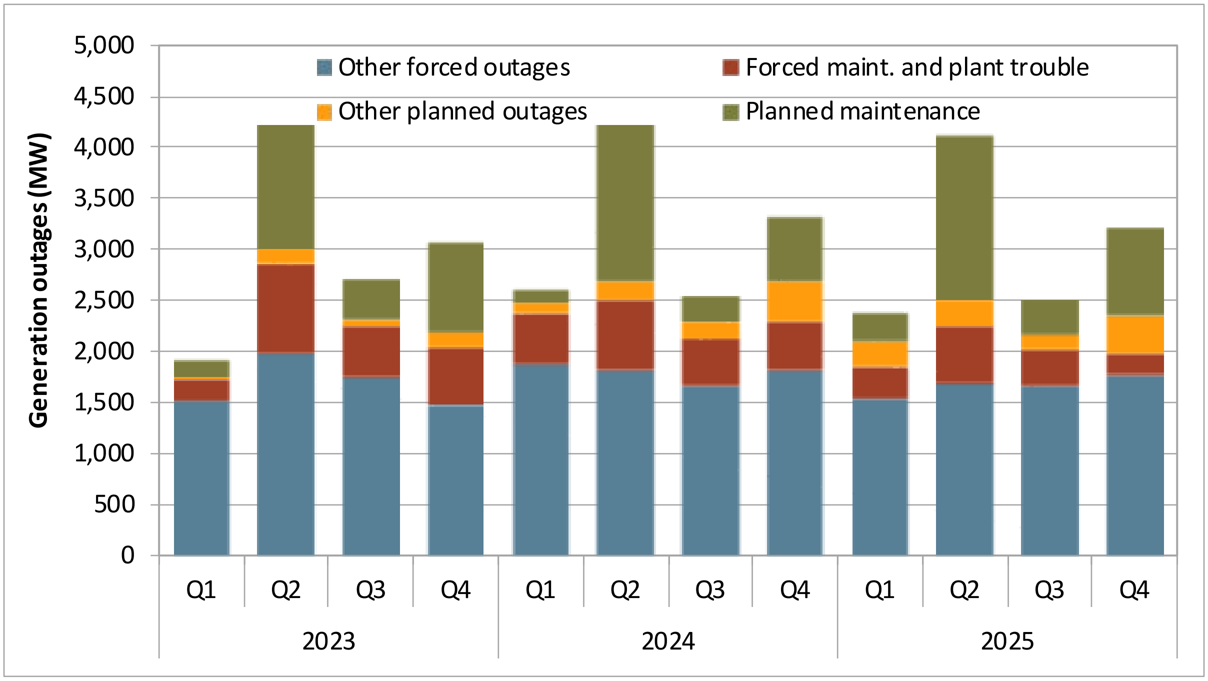
Figure 1.71 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Pacific Northwest WEIM region

Figure 1.72 and Figure 1.73 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for entities in the Pacific Northwest WEIM region.[69] The typical seasonal outage pattern for the Pacific Northwest region diverges from the others, similar to the Intermountain West region, with outages typically peaking in the second quarter while outages in all other quarters remain low. The trend is still primarily driven by planned outages for maintenance, which are generally performed outside of the higher load periods. Average total outages in 2025 were approximately 3,050 MW, a four percent decrease from 2024.

Figure 1.72 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours



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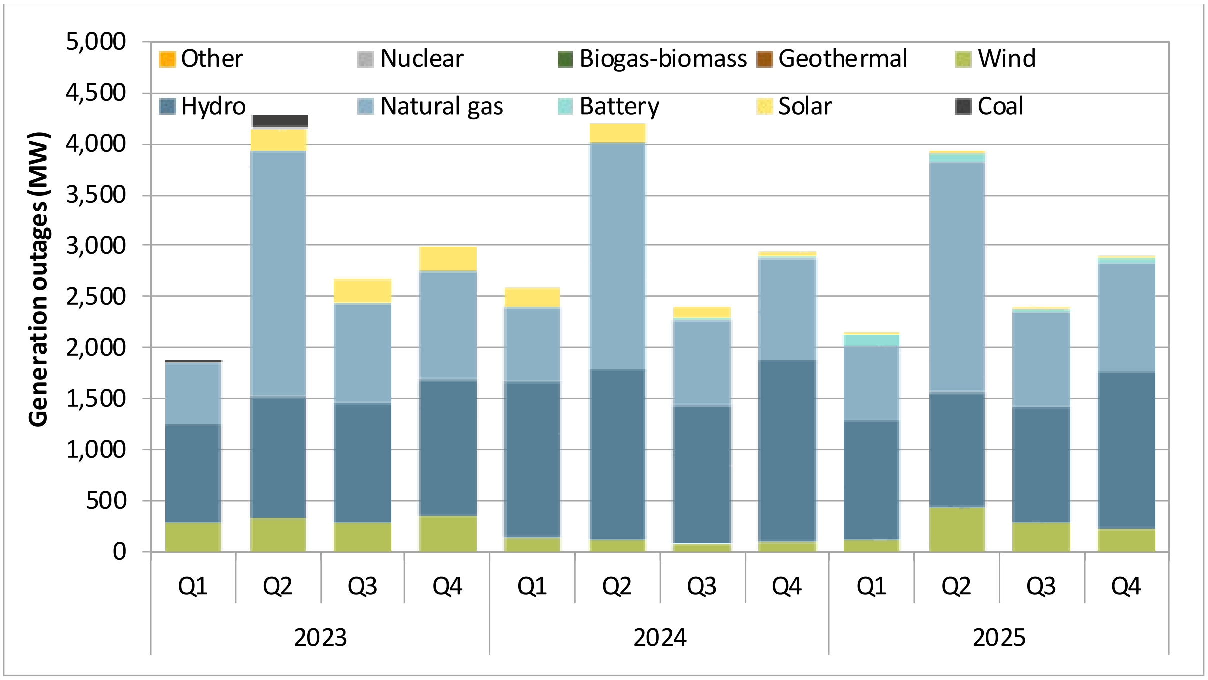
[69] The Pacific Northwest region includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Figure 1.73 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



1.2.6 Natural gas prices

Electricity prices in the Western states have historically followed natural gas price trends. This is because natural gas units are often the marginal source of generation in the ISO's markets and other regional markets. With the exception of NW Sumas, average natural gas prices at major Western hubs were up between 11 percent and 45 percent in 2025 compared to 2024. Electricity prices were down in 2025 despite higher natural gas prices in much of the West due to several factors. These factors include lower greenhouse gas prices in California, increased renewable production, and the absence of tight supply conditions that caused abnormally high electricity prices in January 2024.

Figure 1.74 shows monthly average natural gas prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, Opal, and El Paso Permian, as well as the Henry Hub trading point, which serves as a point of reference for the national market for natural gas.

As shown in Figure 1.74, natural gas prices at most major western gas hubs were slightly higher on average in 2025 compared to levels in 2024, when prices were unusually low. Natural gas prices were elevated in January 2024 due to extreme cold weather in the Pacific Northwest over the Martin Luther King Jr. Day weekend. The El Paso trading hub was consistently the lowest-priced hub and recorded negative[70] average monthly prices for several months at the end of 2025, primarily because of a force majeure on a key pipeline that constrained flow capacity.

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[70] *Nationwide Natural Gas Prices Spike, but Pipeline Bottleneck Helps Send Permian to Negative $4*, Natural Gas Intelligence, December 11, 2025: https://www.naturalgasintel.com/news/nationwide-natural-gas-prices-spike-but-pipeline-bottleneck-helps-send-permian-to-negative-4/

Figure 1.74 Monthly average natural gas prices (2023–2025)

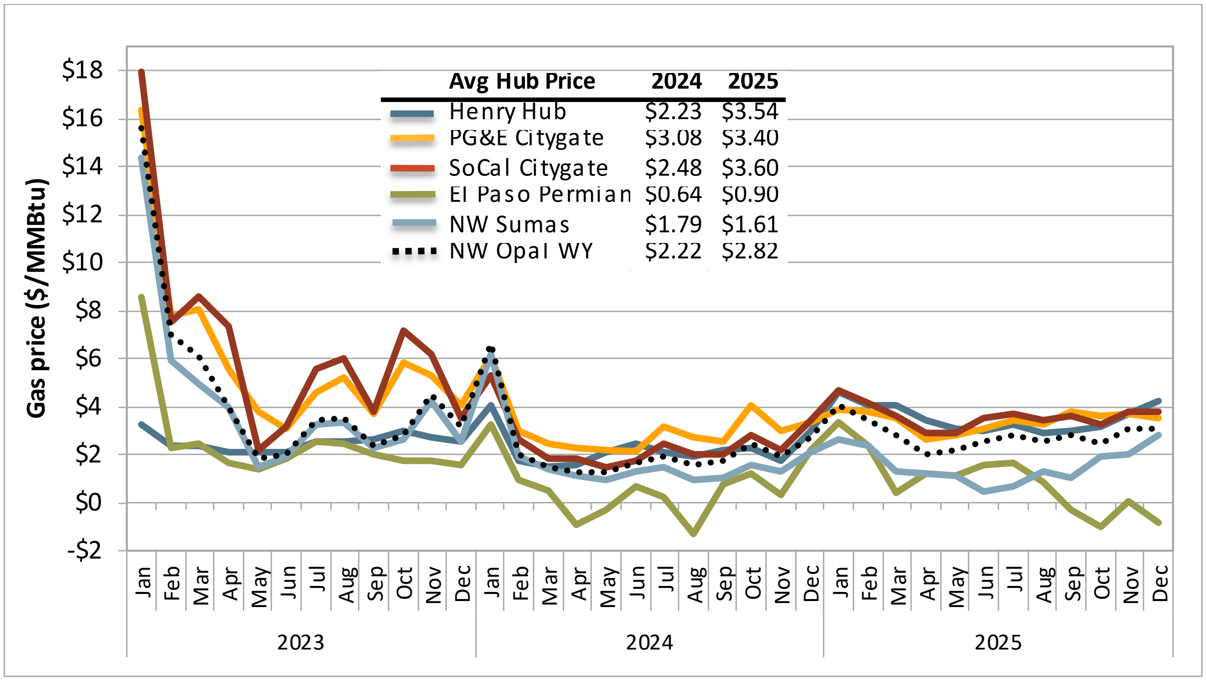
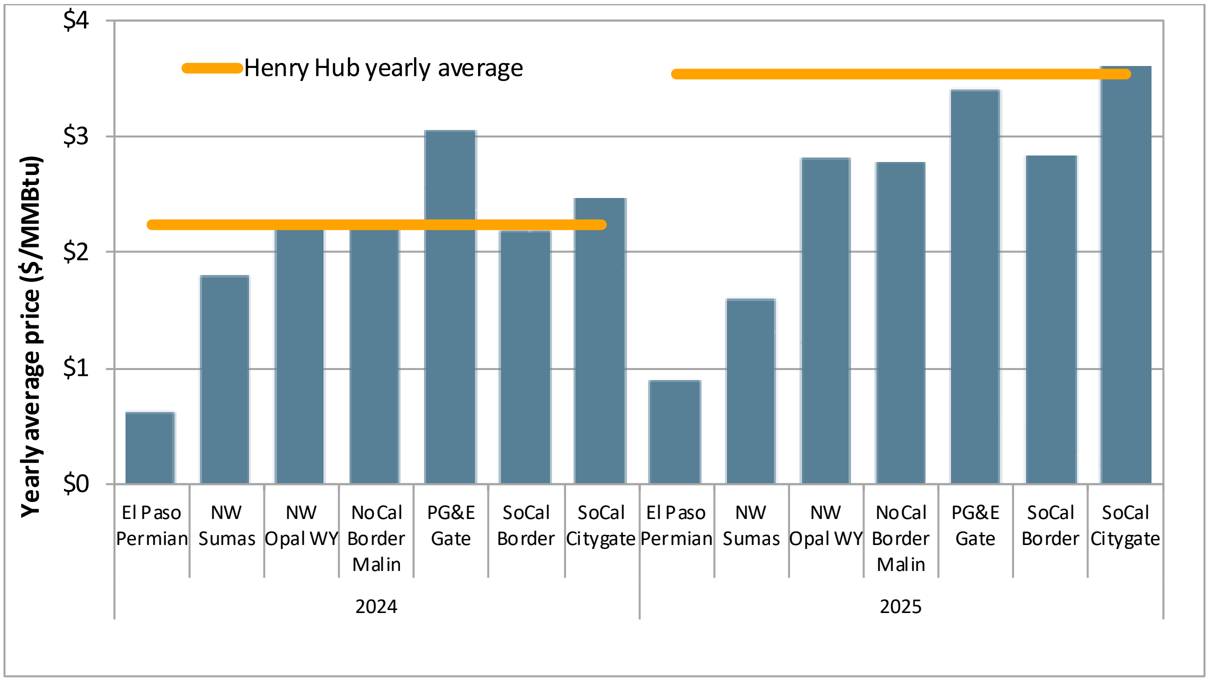


Figure 1.75 compares yearly average natural gas prices at six major western trading points to the Henry Hub average for 2024 and 2025. In 2025, prices at Henry Hub increased by 59 percent compared to 2024. SoCal Citygate and El Paso Permian prices were up 45 percent and 43 percent, respectively, while prices at SoCal Border, NW Opal WY, NorCal Border Malin, and PG&E Gate were up between 11 percent and 29 percent. NW Sumas prices were down 11 percent. The percent changes in natural gas prices in 2025 compared to 2024 were significant. However, the nominal changes in average gas prices were relatively small. This is because natural gas prices in 2024 were very low. As a result, even small changes in the nominal values of gas prices in 2025 represent large percentage changes compared to 2024.

Figure 1.75 Yearly average natural gas prices compared to Henry Hub



1.2.7 Greenhouse gas prices

This section provides background on California and Washington's greenhouse gas (GHG) allowance markets under the states' cap-and-trade and cap-and-invest programs, which were applied to the wholesale electric market in 2013 and 2023, respectively.[71] Greenhouse gas compliance costs are included in the calculation of cost-based bids used in commitment cost bid caps, and local market power mitigation of energy for resources located in California and Washington. This section also addresses greenhouse gas compliance costs that are attributed to resources that participate in the WEIM and serve load of WEIM balancing areas in California. This facilitates compliance with California's cap-and-trade program and mandatory reporting regulations. Resource specific compliance obligations are determined by the market optimization based on energy bids and greenhouse gas bid adders. They are reported to participating resource scheduling coordinators for compliance. Further detail on greenhouse gas compliance in the Western Energy Imbalance Market is provided later in this section. It is important to note that the GHG attribution process as it is currently implemented only considers GHG costs for California and does not apply to Washington's GHG compliance.

Greenhouse gas allowance prices in California

When calculating various cost-based bids used in the market software for supply resources in California, a calculated greenhouse gas allowance index price is used as a daily measure for greenhouse gas

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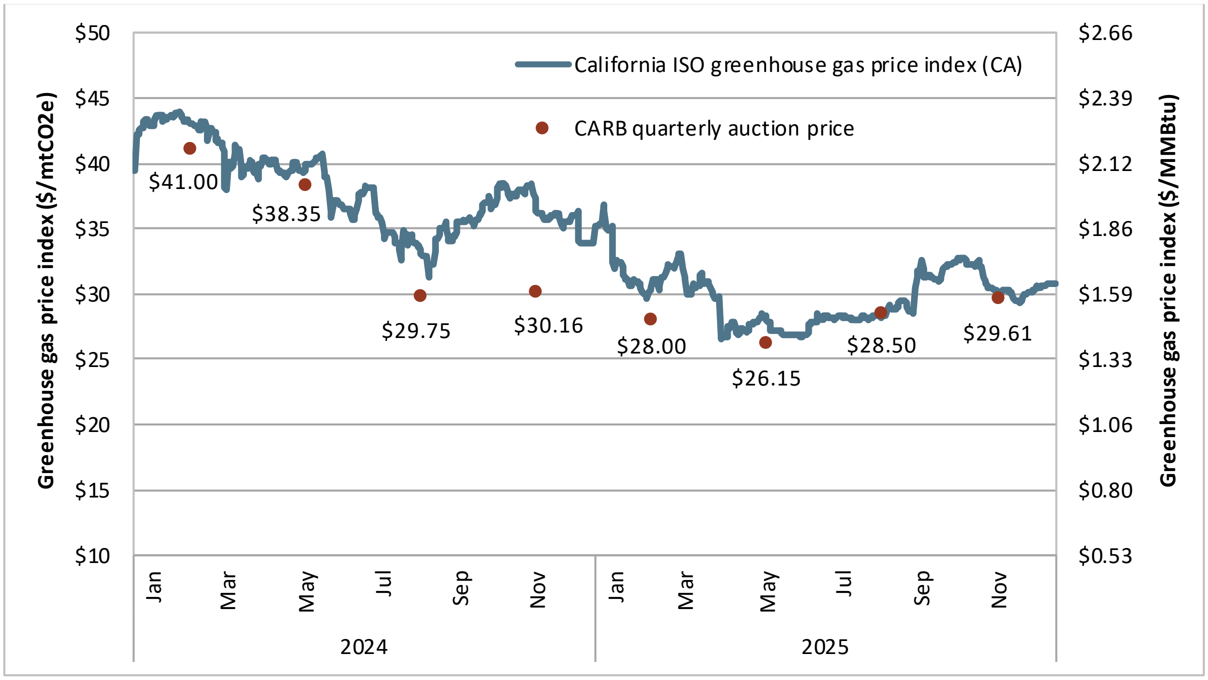
[71] A more detailed description of the cap-and-trade program and its impact on wholesale electricity prices was provided in DMM's 2015 annual report. *2015 Annual Report on Market Issues & Performance*, Department of Market Monitoring, May 2016, pp 45-48: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

allowance costs. The index price is calculated as the average of two market-based indices.[72] Daily values of this greenhouse gas allowance index are plotted in Figure 1.76. Also indicated in Figure 1.76 are market clearing prices in the California Air Resources Board's (CARB) quarterly auctions of emission allowances that can be used for the 2024 or 2025 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder in dollars per MMBtu, by multiplying the greenhouse gas allowance price by an emissions factor that is a measure of the greenhouse gas content of natural gas.[73]

Figure 1.76 California ISO greenhouse gas allowance price index for California and CARB auction prices



As shown in Figure 1.76, the average cost of greenhouse gas allowances in bilateral markets decreased 22 percent from a load-weighted average of $38.09/mtCO$_2$e in 2024 to $29.89/mtCO$_2$e in 2025. In 2025, the California Air Resources Board's quarterly allowance cleared at an average auction settlement price of $28.07/mtCO$_2$e, compared to $34.82/mtCO$_2$e the prior year, a 19 percent decrease.

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[72] The indices are from ICE and ARGUS Air Daily. As the California ISO noted in a market notice issued on May 8, 2013, the ICE index is a settlement price, but the ARGUS price was updated from a settlement price to a volume-weighted price in mid-April of 2013. For more information, see the California ISO tariff section 39.7.1.1.1.4: http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

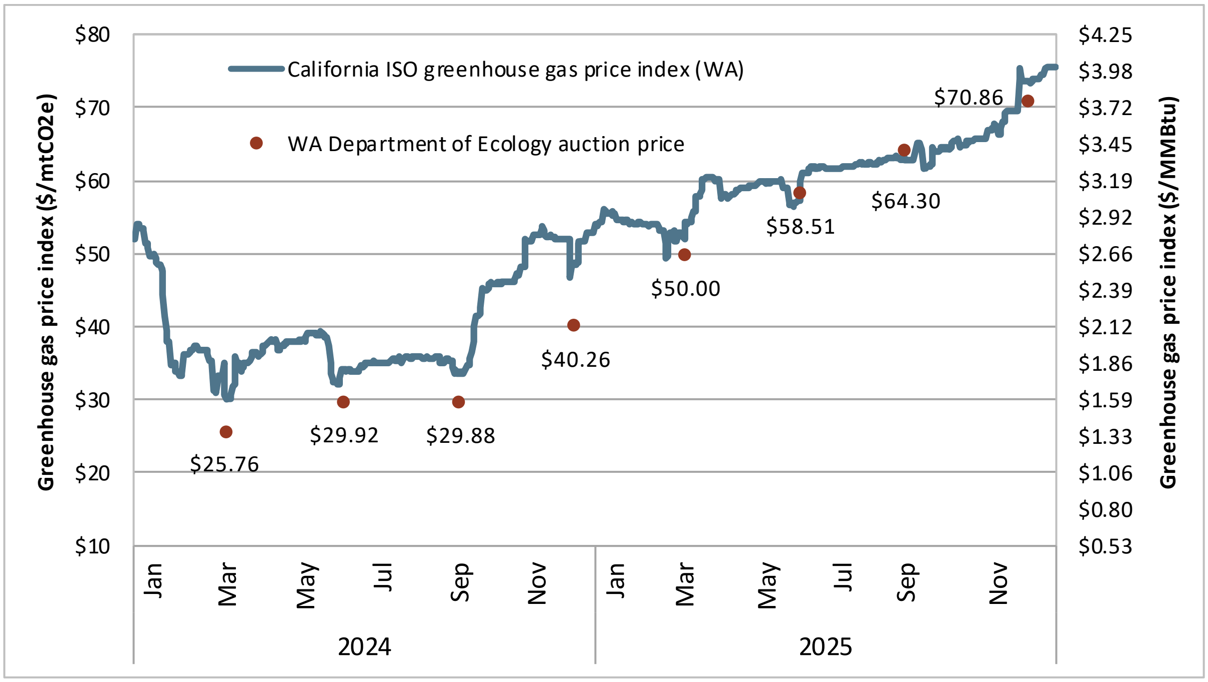
[73] The emissions factor, 0.0531145 mtCO$_2$e/MMBtu, is the sum of the product of the global warming potential and emission factor for CO$_2$, CH$_4$, and N$_2$O for natural gas. Values are reported in tables A-1, C-1, and C-2 of Code of Federal Regulations, *Title 40 – Protection of Environment, Chapter 1 – Environmental Protection Agency, Subchapter C – Air Programs (Continued), Part 98 – Mandatory Greenhouse Gas Reporting*, available here: http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl

A detailed analysis of the impact of the state's cap-and-trade program on wholesale electric prices in 2013 was provided in DMM's 2013 annual report.[74] The greenhouse gas compliance cost expressed in dollars per MMBtu in 2025 ranged from about $1.41/MMBtu to $1.96/MMBtu. The $29.89/mtCO$_2$e average compliance cost index in 2025 represents an additional cost of about $12.70/MWh for a relatively efficient gas unit.[75] This is a decrease from 2024 when the average price was $38.09/mtCO$_2$e, or about $16.19/MWh for the same relatively efficient gas resource.

Greenhouse gas allowance prices in Washington

For supply resources in Washington, cost-based reference level compliance costs are incorporated using a similar method. The Washington Cap-and-Invest program started in 2023 and allowances can be bought and sold through bilateral markets or the quarterly auctions hosted by the Washington Department of Ecology. The daily index values for Washington and its allowance auction prices are shown in Figure 1.77. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder in dollars per MMBtu following the same method used in Figure 1.76.

Figure 1.77 California ISO greenhouse gas price index for Washington and Washington Department of Ecology auction prices[76]



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[74] *2013 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2014, pp 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

[75] DMM calculates this cost by multiplying the average index price by the heat rate of a relatively efficient gas unit (8,000 Btu/kWh) and an emissions factor for natural gas: 0.0531145 mtCO$_2$e/MMBtu, derived in footnote 73.

[76] The California ISO began calculating the index used for Washington greenhouse gas allowance costs in November 2023.

In 2025, the average cost of greenhouse gas allowances in bilateral markets for Washington was \$61.43/mtCO$_2$e. The Washington Department of Ecology quarterly allowance auction cleared at an average of \$60.92/mtCO$_2$e in 2025 compared to an average price of \$31.46/mtCO$_2$e in 2024, a 94 percent increase in price. The greenhouse gas compliance cost expressed in dollars per MMBtu in 2025 ranged from about \$2.62/MMBtu to \$4.01/MMBtu. The \$61.43/mtCO$_2$e compliance cost index average in 2025 represents an additional cost of about \$26.10/MWh for a relatively efficient gas resource.

Greenhouse gas compliance costs

Background

Under the current Western Energy Imbalance Market design, all energy delivered to serve California load is subject to California's cap-and-trade regulation.[77] A participating resource must submit a separate bid representing the cost of compliance for energy attributed to the participating resource as serving California load. These bids are included in the optimization for WEIM dispatch. Resource specific market results determined within the market optimization are reported to participating resource scheduling coordinators. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

The optimization minimizes the cost of serving system load, taking into account greenhouse gas compliance cost for all energy delivered to California. In November 2018, the California ISO implemented a policy change to address concerns regarding secondary dispatch. Secondary dispatch is defined as low-emitting resources that are outside of California scheduling as imports into California—as opposed to meeting their own demand—and in turn, these areas outside of California must dispatch higher-emitting resources to account for the difference. The policy change limited the amount of capacity that can be deemed delivered into California to the difference between a resource's base schedule and their upper economic bid limit.

The greenhouse gas price in each 15-minute or 5-minute interval is 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 can contribute to higher prices for WEIM areas in California.[78]

Scheduling coordinators who deliver energy receive revenue as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market greenhouse gas quantity priced at the 15-minute price *plus* the incremental greenhouse gas dispatch in the 5-minute market valued at the 5-minute market price. Incremental dispatch in the 5-minute market may be either positive or negative. Scheduling coordinators can guarantee that greenhouse gas compliance costs are covered by bidding in marginal compliance costs for their resource. Because prices are set at or equal to the highest cleared bid, participating resources with low emissions are incentivized to export energy into California.

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[77] Further information on Western Energy Imbalance Market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on the ARB's website here: https://ww2.arb.ca.gov/mrr-data

[78] Further detail on the determination of deemed delivered greenhouse gas megawatts within the WEIM optimization is available in the Western Energy Imbalance Market Business Practice Manual Change Management, Energy Imbalance Market: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

Greenhouse gas prices

Figure 1.78 shows monthly average cleared WEIM greenhouse gas prices and hourly average quantities for energy delivered to California from January 2024 to December 2025. As the market is currently configured, California is the only GHG-regulation area where the marginal cost of greenhouse gas applies. Average 15-minute market greenhouse gas prices are weighted by greenhouse gas delivered in the 15-minute market. Alternatively, average 5-minute market prices are weighted by the absolute incremental megawatts delivered in the 5-minute market. Hourly average 15-minute and 5-minute delivered quantities are represented by the blue and green bars in the chart, respectively.

In 2025, weighted 15-minute greenhouse gas prices averaged $12.78/MWh, while 5-minute prices averaged $8.72/MWh. Prices decreased in the 15-minute market by 6.1 percent from $13.61/MWh in 2024, but increased by 6.5 percent from $8.18/MWh in the 5-minute market. Price differences between markets may occur if resources are procured in the 15-minute market and are then subsequently decrementally dispatched in the 5-minute market. This price separation is often correlated with operator imbalance conformance adjustments—described in Chapter 9 of this report—which are consistently higher in the CAISO balancing area in the 15-minute market than the 5-minute market during peak net load hours.

Figure 1.78 WEIM greenhouse gas price and cleared quantity

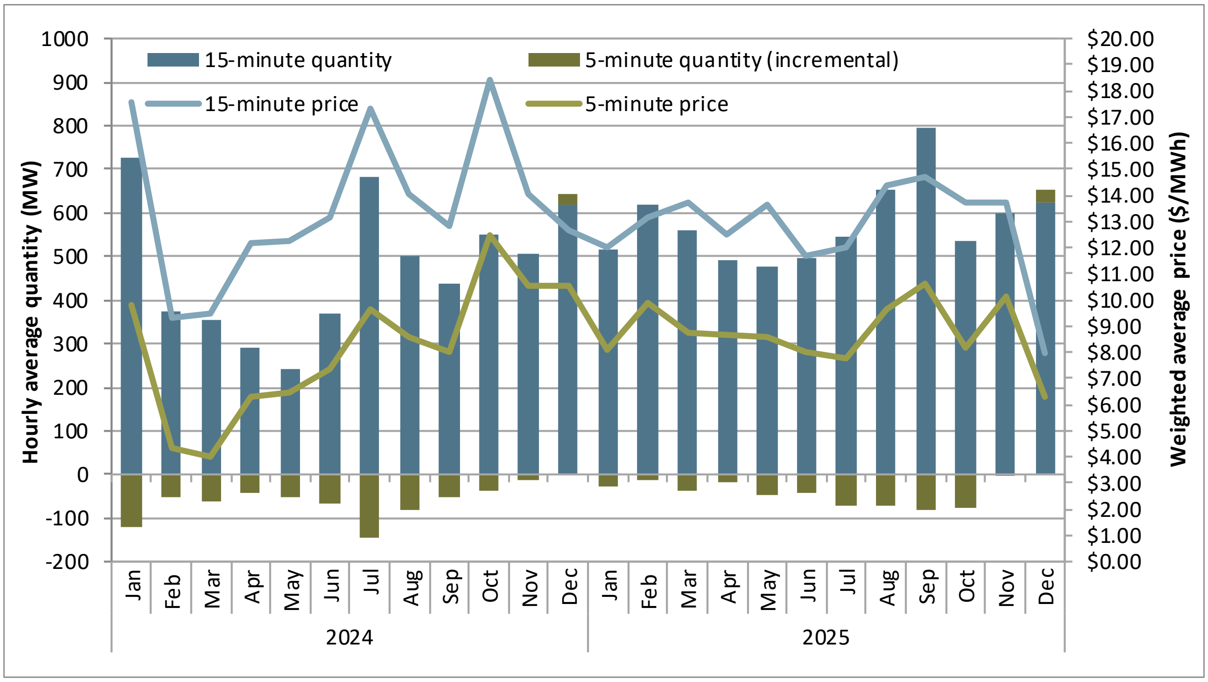
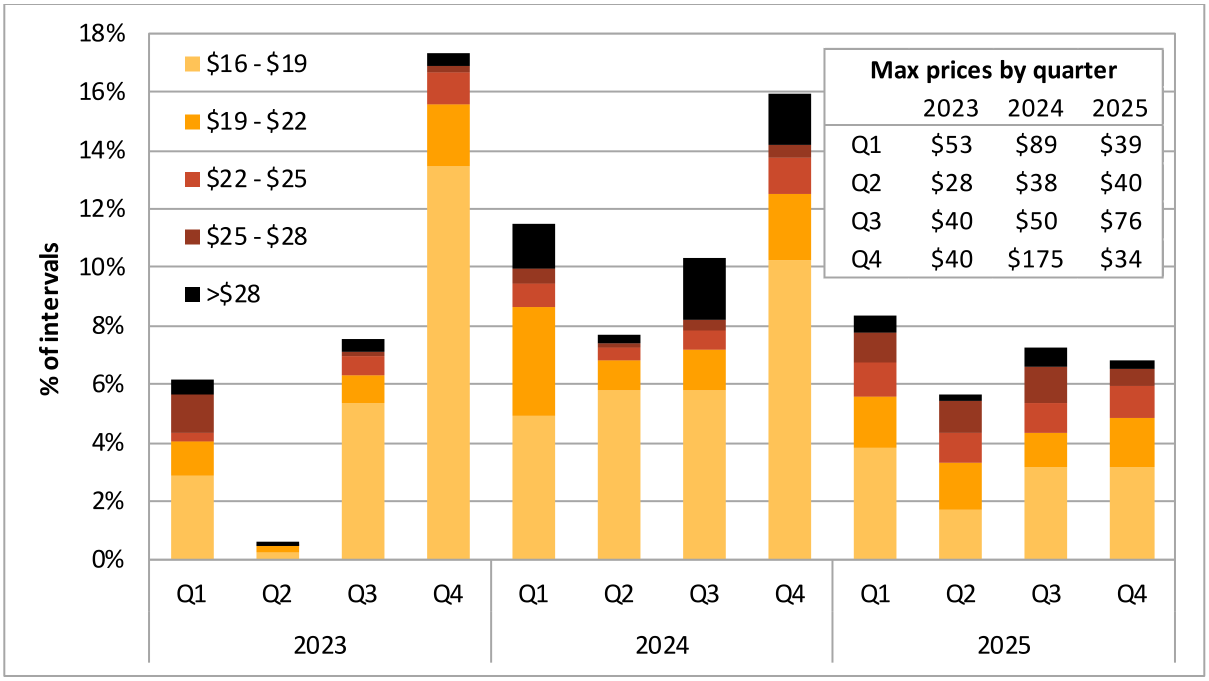


Figure 1.79 and Figure 1.80 illustrate the frequency of prices greater than $16/MWh for each market during each quarter of the last three years, as well as the maximum price by quarter. Figure 1.79 shows that all quarters in 2025 had a lower percentage of intervals in the fifteen-minute market with prices above $16/MWh compared to 2024. The first quarter of 2025 had the largest percent of intervals with greenhouse gas prices over $16/MWh, while the second quarter had the smallest, 8 and 6 percent, respectively. In 2025, the percentage of intervals with prices above $16/MWh was slightly lower in the 5-minute market than in the 15-minute market.

After the secondary dispatch policy change in November 2018, which limited the capacity that could be deemed delivered, there were some price spikes that were not set by bids from emitting generators. Greenhouse gas supply can be exhausted, limiting the total transfer of energy imported to California through the WEIM and setting greenhouse gas prices that exceed the highest cleared bid. The highest 15-minute and 5-minute prices in 2025 were $76/MWh and $56/MWh, respectively.

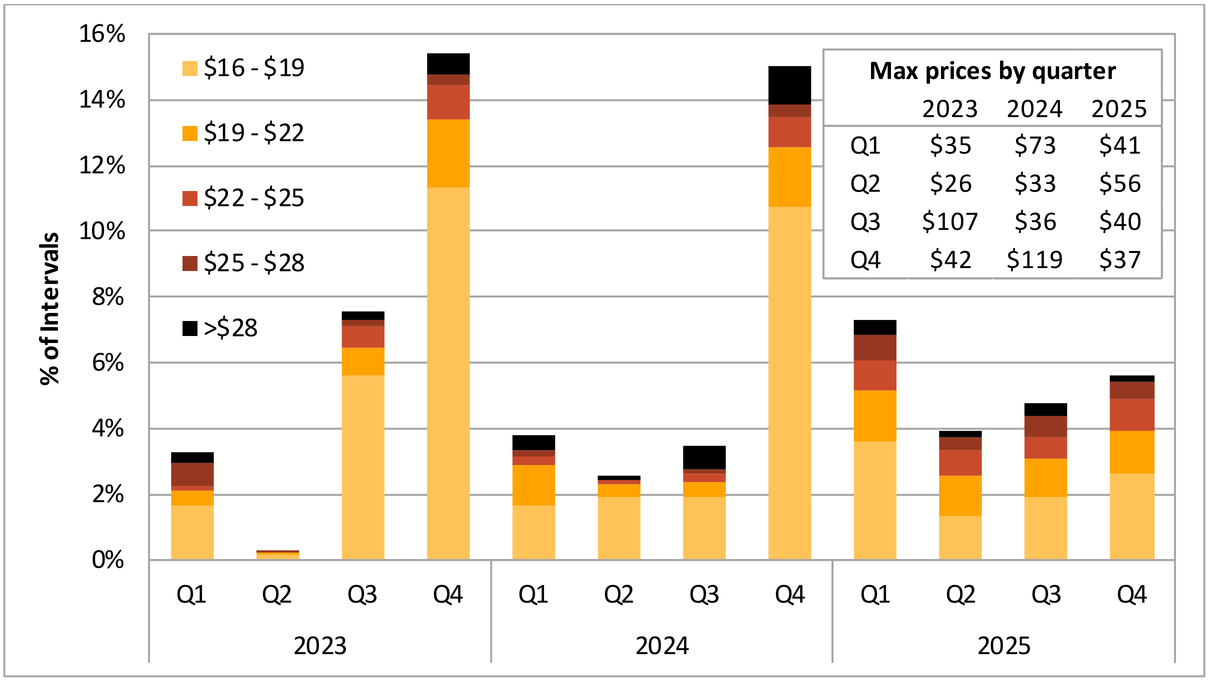
Figure 1.79 High 15-minute WEIM greenhouse gas prices



Max prices by quarter

	2023	2024	2025
Q1	$53	$89	$39
Q2	$28	$38	$40
Q3	$40	$50	$76
Q4	$40	$175	$34

Figure 1.80 High 5-minute WEIM greenhouse gas prices



Energy delivered to California by fuel type and balancing area

Figure 1.81 shows hourly average greenhouse gas energy by fuel type. In 2025, about 51 percent of WEIM greenhouse gas compliance obligations were assigned to hydro resources, lower than the approximately 57 percent in 2024. The next two fuel types most frequently assigned compliance obligations were natural gas with 35 percent and wind with 8 percent.

Figure 1.81 Percentage of greenhouse gas energy delivered to California by fuel type

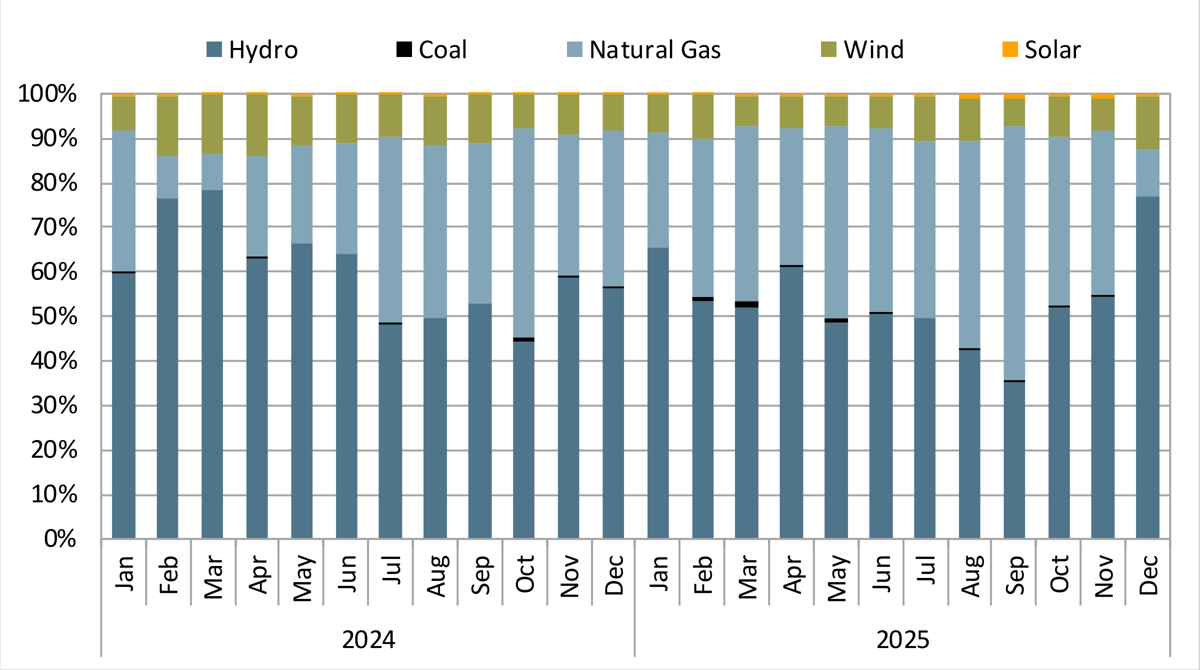
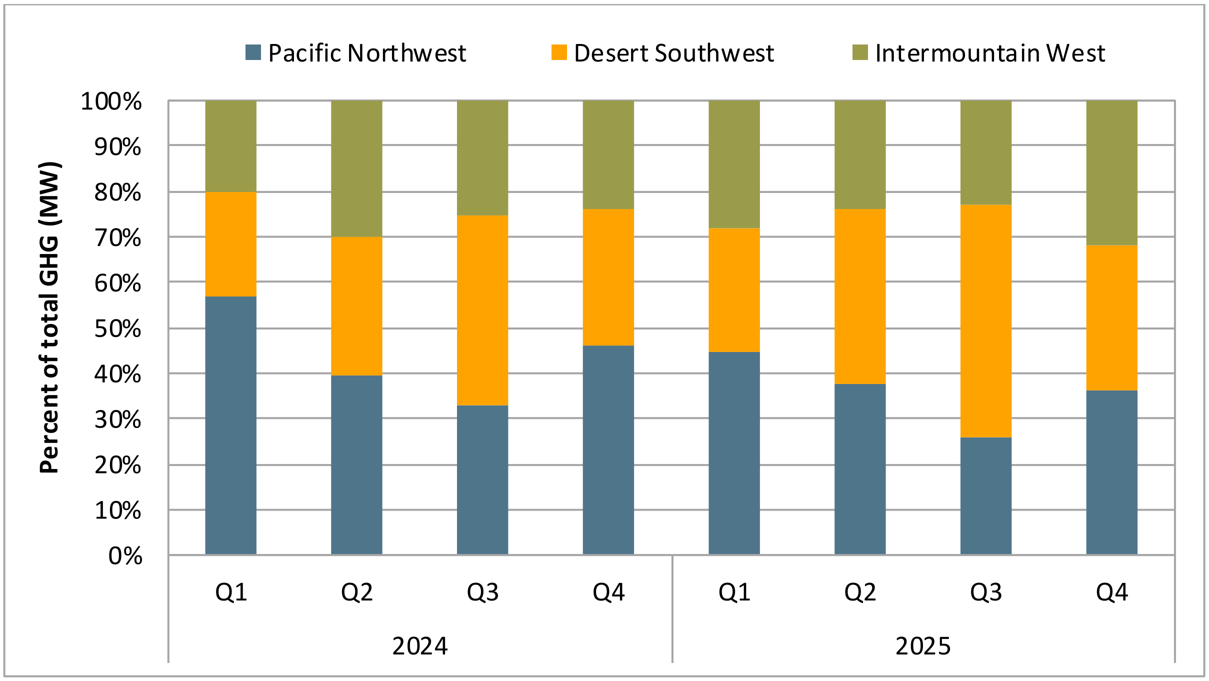


Figure 1.82 shows the percentage of total greenhouse gas energy cleared by region. In 2025, entities in the Pacific Northwest and Intermountain West with large fleets of hydroelectric resources accounted for 63 percent of greenhouse gas energy, down from 69 percent in 2024. Table 1.2 provides details on the percentage of total greenhouse gas energy cleared by WEIM balancing area. In 2025, Idaho Power, Arizona Public Service, and Portland General Electric were the three balancing area authorities with the most GHG attribution and accounted for approximately 43 percent of the total greenhouse gas energy deemed delivered.

Figure 1.82 Percentage of greenhouse gas energy delivered to California by region[79]



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[79] The Desert Southwest region includes Arizona Public Service, El Paso Electric, NV Energy, Public Service Company of New Mexico, Salt River Project, Tucson Electric Power, and WAPA Desert Southwest. Intermountain West includes Avista Corporation, Idaho Power Company, NorthWestern Energy, and PacifiCorp East. Pacific Northwest includes Avangrid Power, Bonneville Power Administration, 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.

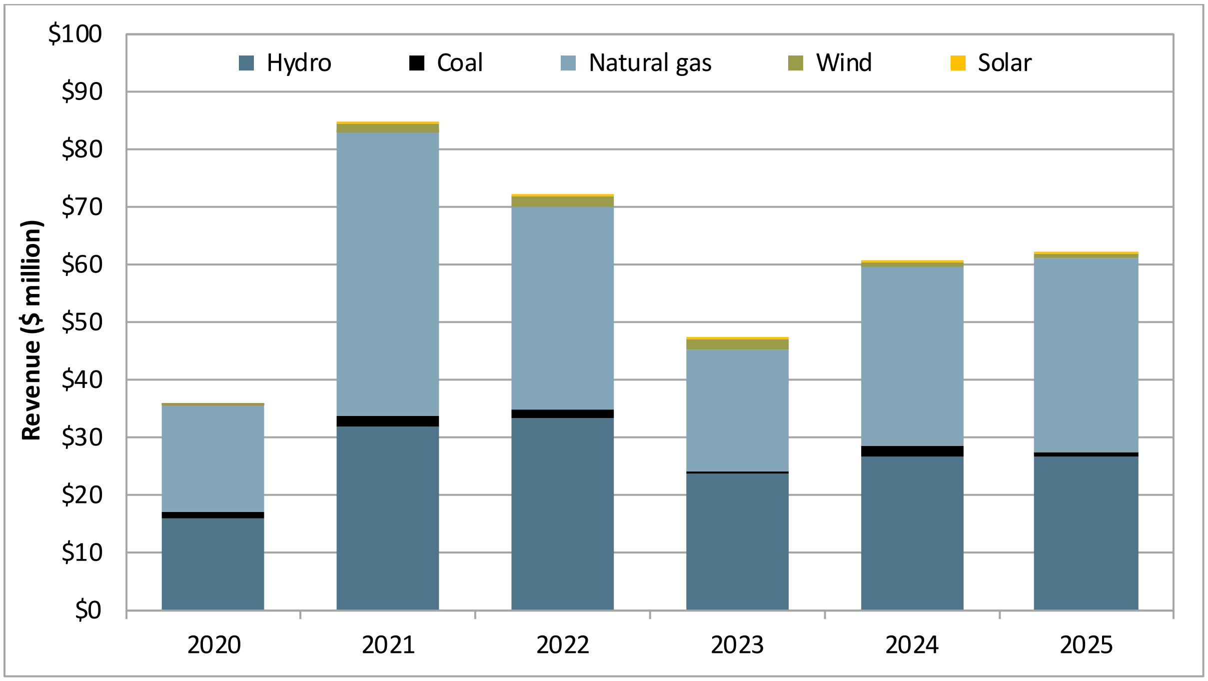
Table 1.2 Percentage of greenhouse gas energy delivered to California by area

Region	2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Pacific Northwest								
Avangrid Power	3%	2%	1%	1%	1%	0%	0%	0%
Bonneville Power Administration	6%	10%	4%	8%	13%	8%	2%	8%
PacifiCorp West	1%	1%	4%	5%	4%	5%	4%	2%
Portland General Electric	10%	10%	12%	10%	12%	11%	10%	7%
Powerex	0%	0%	0%	0%	0%	0%	0%	0%
Puget Sound Energy	23%	0%	0%	7%	1%	0%	0%	0%
Seattle City Light	6%	7%	5%	7%	7%	7%	5%	11%
Tacoma Power	7%	9%	6%	8%	7%	7%	4%	8%
Desert Southwest								
Arizona Public Service	6%	11%	20%	10%	8%	9%	20%	9%
El Paso Electric	0%	0%	0%	0%	0%	0%	0%	0%
NV Energy	4%	2%	5%	5%	5%	7%	9%	5%
Public Service Company of New Mexico	3%	6%	5%	5%	9%	7%	7%	10%
Salt River Project	7%	11%	9%	7%	4%	13%	13%	6%
Tucson Electric Power	2%	1%	3%	2%	2%	2%	2%	2%
WAPA Desert Southwest	1%	0%	0%	0%	0%	0%	0%	0%
Intermountain West								
Avista Corporation	0%	0%	0%	0%	0%	0%	0%	0%
Idaho Power Company	19%	29%	24%	20%	17%	21%	20%	29%
NorthWestern Energy	0%	0%	0%	1%	5%	0%	0%	0%
PacifiCorp East	1%	0%	1%	3%	7%	3%	3%	3%

WEIM greenhouse gas revenues

Figure 1.83 shows revenues accruing to WEIM resources for energy delivered to California by fuel type. In 2025, revenues totaled roughly $62 million, a 2 percent increase from 2024, when revenues were $60.2 million. In 2025, natural gas revenues comprised 54 percent of revenues, while hydroelectric revenues comprised 43 percent. Coal and wind revenues comprised 2 and 1 percent, respectively. It is important to note that resources can receive greenhouse gas revenues without being deemed as serving California load if they are scheduled in the 15-minute market but decrementally dispatched in the 5-minute market.

Figure 1.83 Annual greenhouse gas revenues



1.2.8 Capacity changes

Figure 1.84 through Figure 1.87 show the total nameplate capacity by fuel type for each WEIM region from June 2021 through April 2026. Historically, graphs in this section reflect capacity between Junes of one year to the next to reflect changes to summer capacity. Due to the timing of this report, changes in capacity from 2025 to 2026 will be from June 1, 2025 to April 1, 2026. These amounts include capacity from WEIM participating resources as well as non-participating resources, which are neither bid nor optimized in the market.[80] Since 2021, roughly 122 GW of capacity has been added to the WEIM, 34 percent of which was hydroelectric and about 21 percent batteries.

Since June 2025, battery capacity has increased significantly in most regions in the WEIM. Nameplate battery capacity increased 2 GW (14 percent) and 3.1 GW (55 percent) in the California and Desert Southwest regions, respectively. In the Intermountain West, battery capacity more than tripled to 1,627 MW. In the Pacific Northwest, wind capacity increased by 180 MW (13 percent). Capacity from solar resources has also increased in every region.

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[80] Previous versions of this report only included participating capacity.

Figure 1.84 California – Total capacity by fuel type and year (as of April 1, 2026)[81]

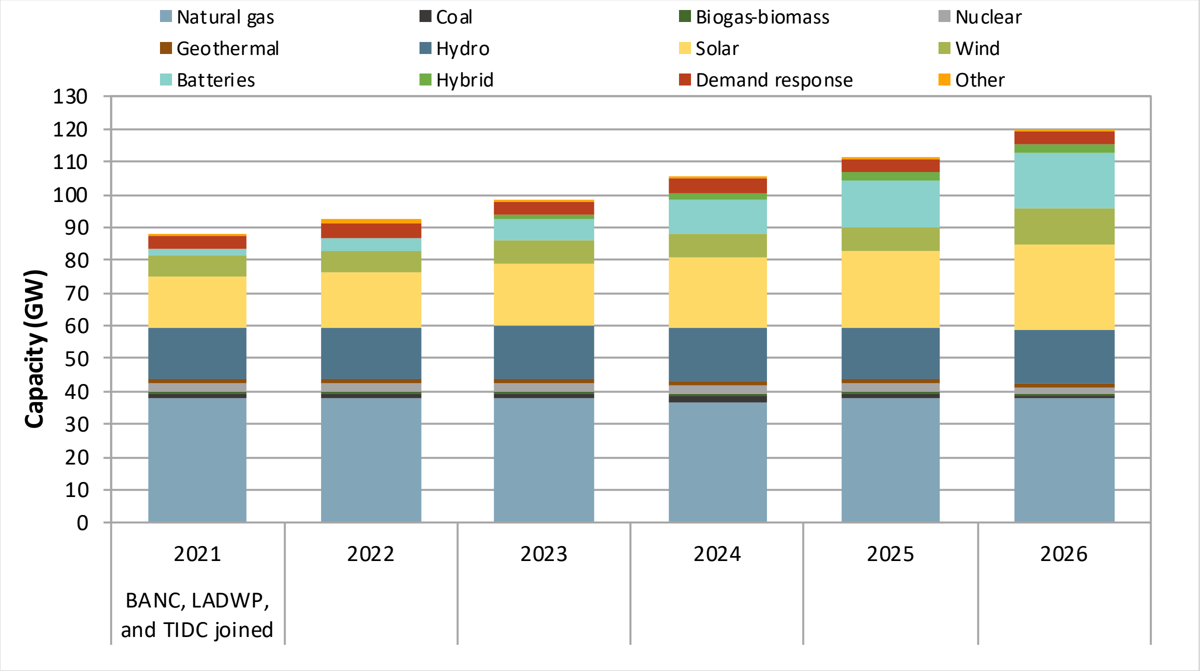
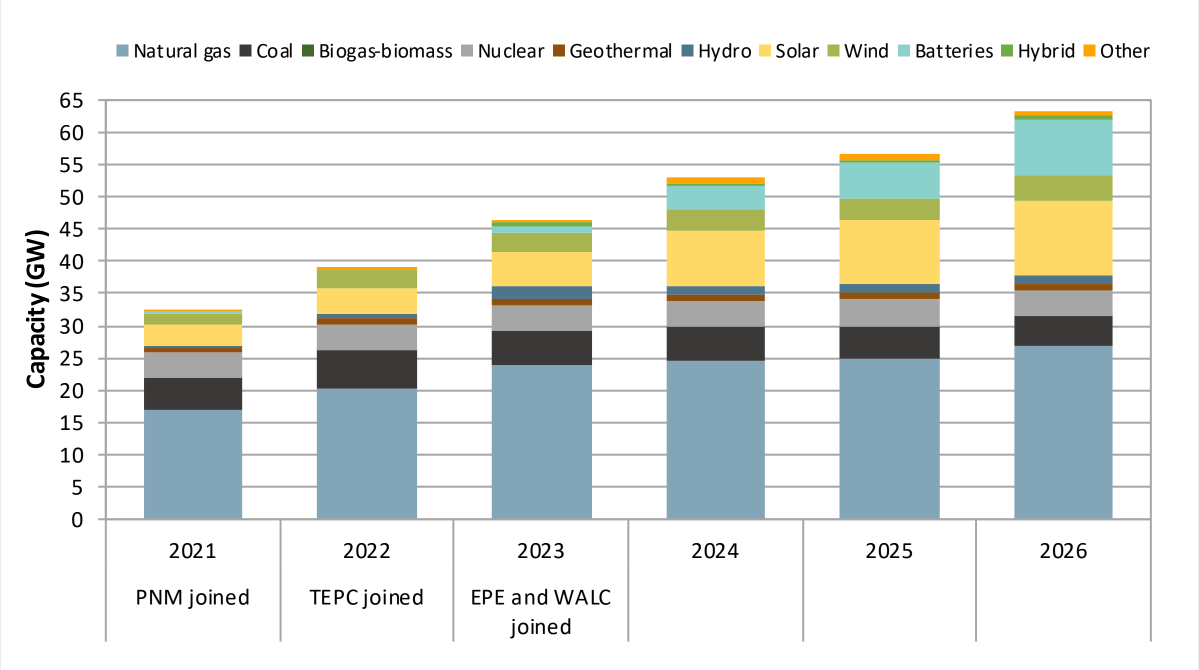


Figure 1.85 Desert Southwest – Total capacity by fuel type and year (as of April 1, 2026)



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[81] BANC joined in two phases. The first was in April 2019 with SMUD, and the second phase was in 2021 with Modesto Irrigation District, the City of Redding, the City of Roseville, and the WAPA Sierra Nevada Region.

Figure 1.86 Intermountain West – Total capacity by fuel type and year (as of April 1, 2026)

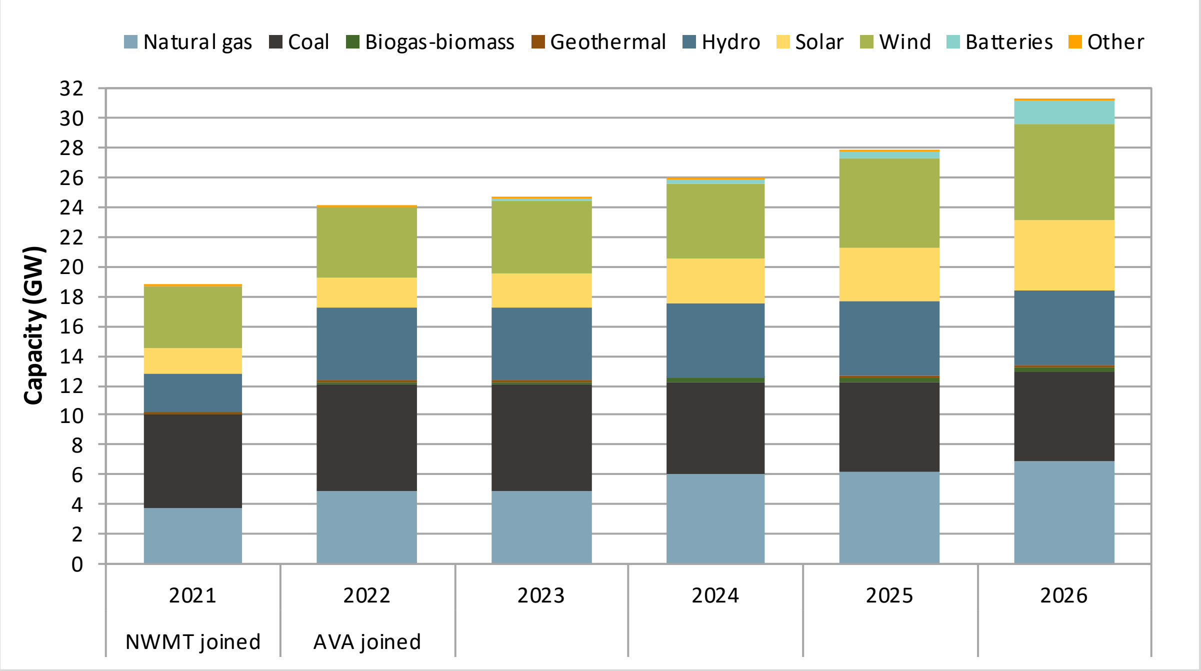


Figure 1.87 Pacific Northwest – Total capacity by fuel type and year (as of April 1, 2026)

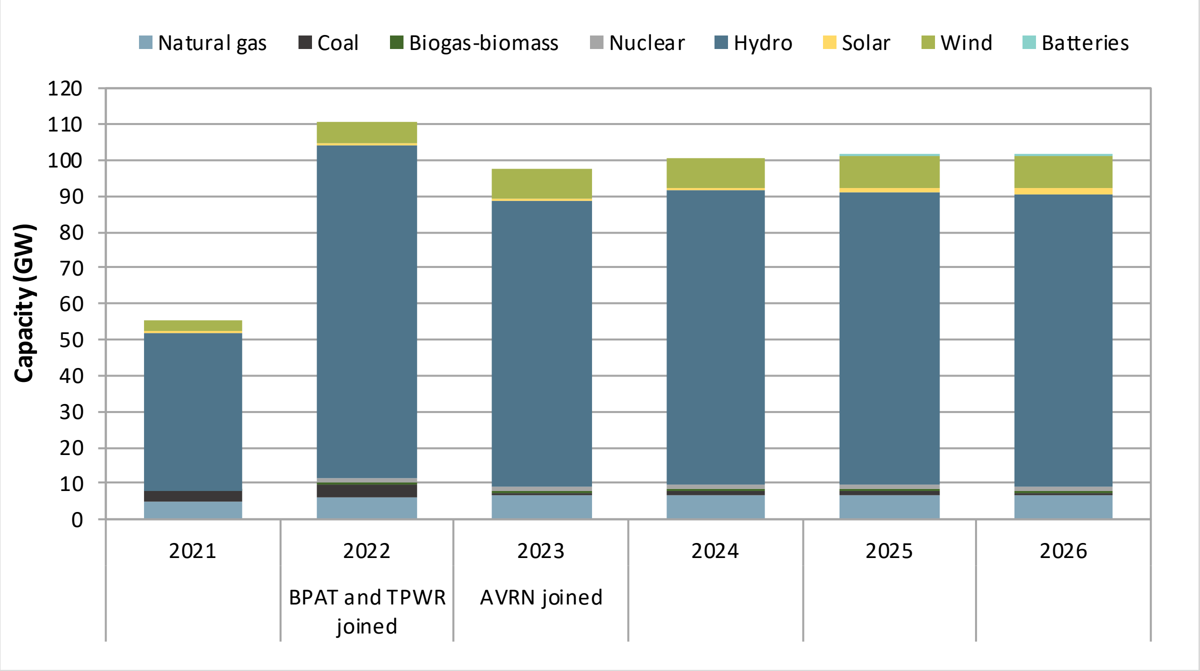


Figure 1.88 shows the fuel mix of all capacity for each balancing authority area in the WEIM as of April 1, 2026. The California ISO has the most capacity in the WEIM with 103.5 GW, with the next highest being Bonneville Power Administration at 41.4 GW. Figure 1.89 shows the change in capacity across the WEIM BAAs by fuel type from June 2025 to April 2026. In the chart, positive values represent increased capacity, while negative values represent decreases in capacity from the previous summer. The total net change in capacity was around 18.8 GW. The California ISO and Arizona Public Service netted the biggest increase in capacity at 9 GW and 2.5 GW, respectively. Across all BAAs, battery capacity saw the most growth at 6.3 GW, followed by solar with 6.1 GW.

Figure 1.88 Fuel mix of WEIM capacity by BAA (as of April 1, 2026)

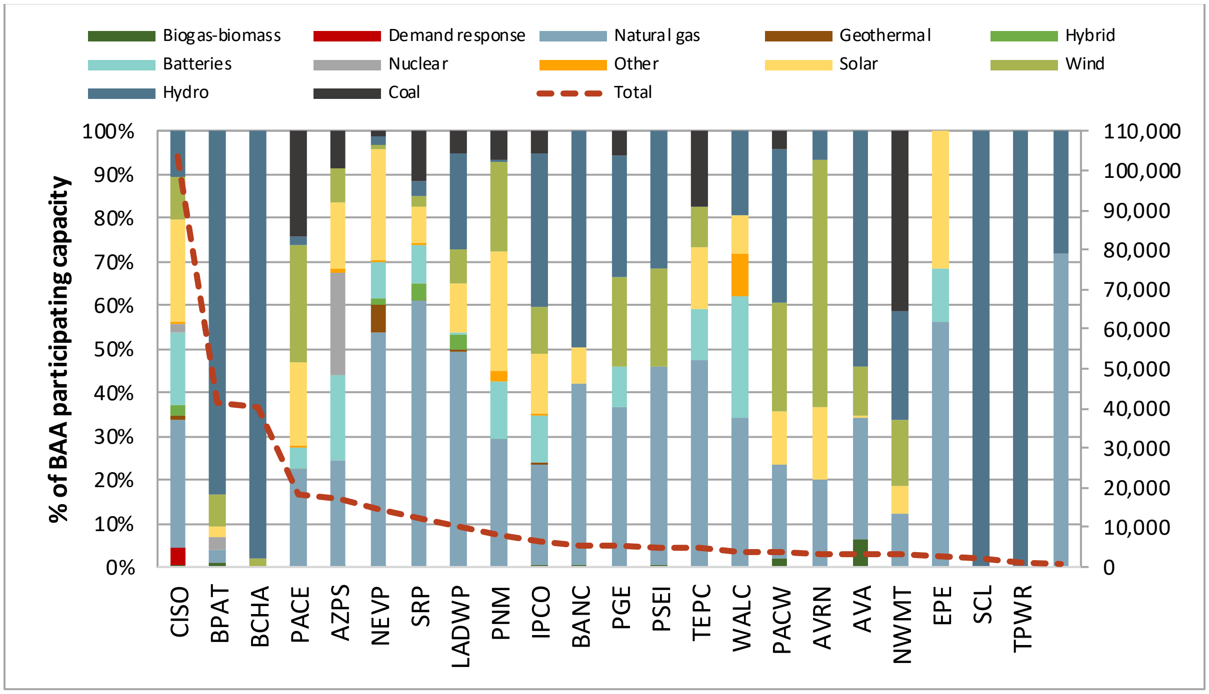
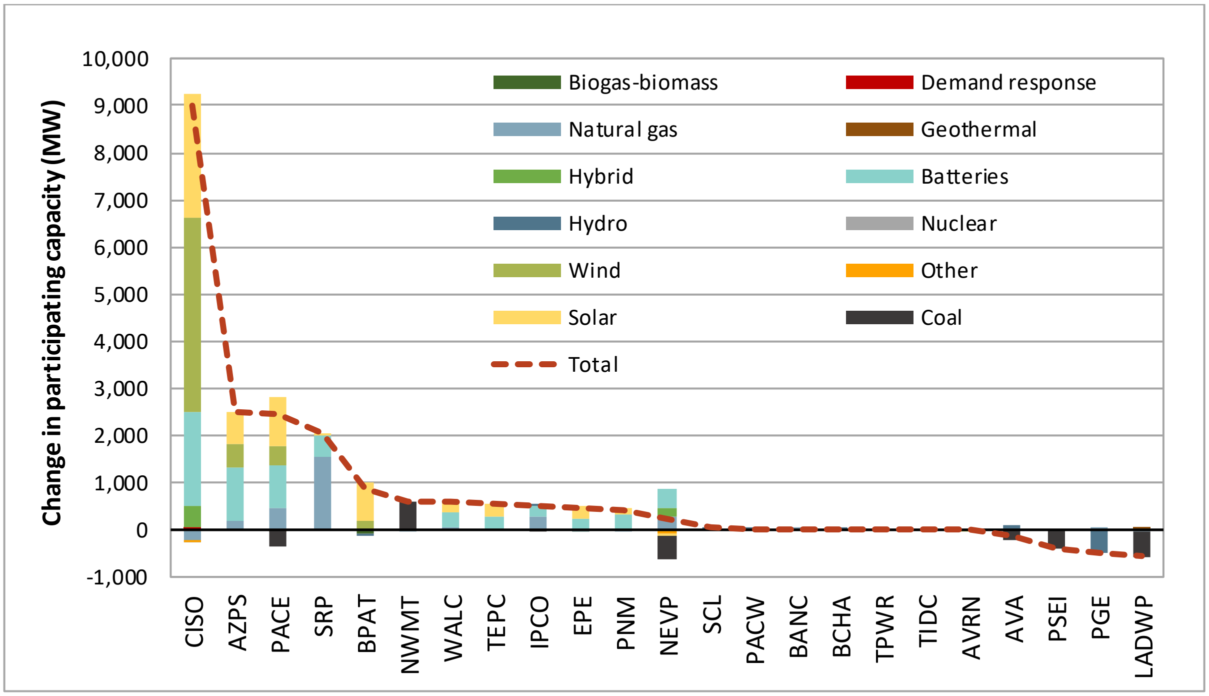


Figure 1.89 Change in WEIM capacity by BAA (as of April 1, 2026)



1.3 Net market revenues of new generation

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. In California, the CPUC's long-term procurement process and resource adequacy program are currently the primary mechanisms to ensure investment in new capacity when and where it is needed. Given this regulatory framework, annual fixed costs for existing and new units critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and other energy market revenues.

Each year, DMM examines the extent to which revenues from the California ISO day-ahead and real-time markets contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents a market metric tracked by FERC and all other ISOs.

For new gas-fired units, net revenues earned through the California ISO energy market continued to be lower than DMM's estimate of levelized fixed costs. For 2025, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $3 to $20/kW-yr compared to total annualized fixed costs of about $145/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $1 to $4/kW-yr compared to total annualized fixed costs of about $176/kW-yr.

In addition, estimated net energy market revenues of gas units in 2025 were, on average, lower than DMM's estimate of the annual going-forward fixed costs of gas generation. DMM estimates that the annual going-forward fixed costs of a typical combined cycle unit are about $33 to $43/kW-yr. For a typical combustion turbine unit, DMM estimates annualized going-forward fixed costs of about $34 to

$35/kW-yr. These results continue to underscore the need for any new gas resources needed for local or system reliability to recover additional costs from long-term bilateral contracts.

Existing gas units that cannot recover their going-forward fixed costs from their energy market revenues would be expected to mothball or retire if they did not receive additional revenues from a resource adequacy contract, the capacity procurement mechanism (CPM), or a reliability must-run contract. The California ISO soft cap for CPM, as of June 1, 2024, is set at $88/kW-yr, which DMM estimates is nearly twice the annual going-forward fixed costs of gas units. Under the capacity procurement mechanism, units also retain all net market revenues from market operations.

On December 17, 2021, in response to a CPUC challenge of a FERC order, the U.S. Court of Appeals determined that FERC's reliance on an earlier order approving a 20 percent adder for bids at or below the CPM soft offer cap was misplaced. In addition, the court also determined that FERC failed to adequately justify its decision to allow a 20 percent adder for bids above the CPM soft offer cap.[82] On April 22, 2022, FERC issued an order reversing its original determination. In the April 22, 2022 order, FERC found that the California ISO had not demonstrated that the proposed 20 percent adder was just and reasonable.[83] On May 23, 2022, the California ISO submitted a compliance filing excluding the 20 percent adder from the compensation methodology.[84] After undergoing a stakeholder process for issues regarding the CPM, the California ISO Board of Governors approved an increase of the CPM soft offer cap to $88/kW-yr in 2023.[85]

Gas optimization methodology

In 2016, DMM revised the methodology used to perform this analysis for new gas units to more accurately model total production costs and energy market revenues using a SAS/OR optimization tool.[86] Incremental energy costs are calculated using default energy bids used in local market power

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[82] U.S. Court of Appeals, Order No. 20-1388 on *Petition for Review of Orders Regarding Bids Above CPM Soft Offer Cap*, December 17, 2021: https://media.cadc.uscourts.gov/opinions/docs/2021/12/20-1388-1927124.pdf

[83] FERC Docket No. ER20-1075-002, *Order on Remand on Compensation for Resources with Bids Above CPM Soft Offer Cap,* April 22, 2022: http://www.caiso.com/Documents/Apr22-2022-Order-on-Remand-CPM-Soft-Offer-Cap-ER20-1075.pdf

[84] *Compliance Filing to Enhance the Capacity Procurement Mechanism (ER20-1075)*, California ISO, May 23, 2022: http://www.caiso.com/Documents/May23-2022-ComplianceFiling-CapacityProcurementMechanism-CPM-above-SoftOfferCap-ER20-1075.pdf

[85] Capacity procurement mechanism enhancements initiative page: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Capacity-procurement-mechanism-enhancements

[86] Net revenues due to ancillary services and flexible ramping capacity are not modeled in the optimization model. For combined cycle units in the California ISO area, 2025 total average annual net revenues for regulation (up and down), spinning reserves, and flexible ramping capacity were around $0.12/kW-yr on average. Similarly, for combustion turbine units, 2025 average net revenues for operating reserves and flexible ramping capacity were $0.77/kW-yr. Therefore, ancillary service and flexible ramping revenues would have had a small impact on the overall net revenues for both the combined cycle and combustion turbine units.

mitigation.[87] Commitment costs are calculated using proxy start-up and minimum load cost methodology.[88]

For a combined cycle unit, energy market revenues are estimated based on day-ahead and 5-minute real-time market prices. For a combustion turbine unit, estimated energy market revenues are based on a generator's commitment and dispatch in the 15-minute real-time market, and any incremental dispatch using the 5-minute prices. The analysis includes estimated net revenues for hypothetical combined cycle and combustion turbine units based on NP15 and SP15 prices, independently.

In 2017, the optimization horizon for these new gas units was changed from daily to annual. The objective of the optimization problem was revised to maximize annual net revenues subject to resource operational constraints. The characteristics and constraints for a combined cycle unit and combustion turbine unit are listed in Table 1.3 and Table 1.4, respectively.

In 2019, DMM updated several resource characteristic assumptions and financial parameters for gas units, and re-ran analysis for prior years. The most significant change was to revise estimates of the fixed annual going-forward costs of gas units. DMM continued to use estimates from a report by the California Energy Commission (CEC) for most components of a unit's going-forward fixed costs (insurance and *ad valorem*).[89] However, instead of fixed annual operating and maintenance (O&M) costs from the CEC report, DMM now uses estimates derived from its review of California-specific and nationwide sources.[90] DMM's analysis indicates that the annual fixed O&M from the CEC report, which is used to set the California ISO capacity procurement mechanism soft offer cap, significantly overstates the actual fixed annual operating and maintenance costs of combined cycle gas units. In this report,

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[87] Default energy bids are calculated using the variable cost option as described in: *Business Practice Manual Change Management, Market Instruments, Appendix F, Example of Variable Cost Option Bid Calculation*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

[88] Start-up and minimum load costs are calculated using the proxy cost option as described in: *Business Practice Manual Change Management, Market Instruments, Appendix G.2, Proxy Cost Option*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

The energy price index used in the proxy start-up costs is calculated using the retail rate option described in: *Business Practice Manual Change Management, Market Instruments, Appendix M.2, Retail Region Price*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

[89] The annual fixed costs used by DMM represent the average between IOU, POU, and Merchant fixed costs reported by the CEC. See CEC Staff Report, *Estimated Cost of New Utility-Scale Generation in California: 2018 Update, Appendix D, Levelized Cost by Developer Type*, May 2019 | CEC-200-2019-500: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf

[90] *Answer and Motion for Leave to Answer, Comments on CPM Tariff Filing (ER20-1075)*, Department of Market Monitoring, April 3, 2020: http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

FERC Docket No. ER18-240, *Metcalf RMR Agreement Filing Attachment A – Part 2, Schedule F, Article II Part B*, November 2, 2017, p 57: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20171102-5246&optimized=false

FERC Docket No. ER18-230, *Gilroy RMR Agreement Filing Attachment A – Part 2, Schedule F, Article II Part B,* November 2, 2017, p 57: https://elibrary.ferc.gov/eLibrary/docfamily?accessionnumber=20171102-5142&optimized=false

S&P Global Average (2019). Data downloaded from S&P Global online screener tool. S&P Global Market Intelligence (*subscription required*): https://platform.mi.spglobal.com

DMM estimates that annual going-forward fixed costs range from $33 to $43/kW-yr for a typical combined cycle resource, and $34 to $35/kW-yr for a typical combustion turbine.[91]

1.3.1 Hypothetical combined cycle unit

Table 1.3 shows the key assumptions used in this analysis for a typical new combined cycle unit. This includes the technical parameters for two configurations of a hypothetical new combined cycle unit, which were used in the optimization model. The table also provides a breakdown of financial parameters that contribute to the estimate of total annualized fixed costs for a new 2x1 combined cycle unit.

The hypothetical combined cycle unit was modeled as a multi-stage generating resource with two configurations. A constraint was enforced in the optimization model to ensure that only one configuration could be committed and optimized based on the most profitable configuration during each hour of the optimization horizon.

Table 1.4 shows the optimization model results using the parameters specified in Table 1.3. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2025.

The first scenario in Table 1.4 modeled unit commitment and dispatch based on day-ahead energy prices and the unit's default energy bids. In 2025, for a unit located in NP15 with the above assumptions, net revenues were $14/kW-yr with a 32 percent capacity factor.[92] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $3/kW-yr with a 8 percent capacity factor.

The second scenario in Table 1.4 optimized the unit's commitment and dispatch instructions with day-ahead market prices combined with default energy bids, excluding the 10 percent adder that is included under the tariff. The 10 percent adder was removed in this scenario because the default energy bid with the 10 percent adder may overstate the true marginal cost of some resources.[93] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2025 for a hypothetical unit in the NP15 area were $20/kW-yr with a 44 percent capacity factor. In the SP15 area, net annual revenues were $5/kW-yr with a 14 percent capacity factor.

The third scenario in Table 1.4 is based on the same assumptions as the first scenario to commit and start the combined cycle resource, but based the dispatch of energy above minimum operating level on the higher of the day-ahead and 5-minute real-time prices (rather than day-ahead prices alone). This reflected how, after the day-ahead market, gas units can re-bid and be re-dispatched in the real-time

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[91] The upper end of DMM's estimate of going-forward fixed costs for each technology type is based on the average of reported annual fixed O&M ($19.8/kW for combined cycle and $8.7/kW for combustion turbine) for all gas-fired units in California listed in S&P Global data (which includes 71 combined cycle units and 160 combustion turbines). The lower end of DMM's estimate of going-forward fixed costs is based on the average reported annual fixed O&M ($11.7/kW for combined cycle and $7.8/kW for combustion turbine) values for a subset of all units in California, which are most similar to the size of the hypothetical units used in this analysis. This subset includes 20 combined cycle units and 60 combustion turbines in California listed in the S&P Global data.

[92] The capacity factor was derived using the following equation:
Net generation (MWh) / (facility generation capacity [MW] * hours/year).

[93] See Section 3.2 for further discussion on price-cost markup.

market. Under this scenario, net revenues for a hypothetical unit located in the NP15 area were $16/kW-yr with a 41 percent capacity factor. In the SP15 area, net annual revenues were $4/kW-yr with a 10 percent capacity factor.

Table 1.3 Assumptions for typical new 2x1 combined cycle unit[94]

Technical Parameters	Configuration 1	Configuration 2
Maximum capacity	360 MW	720 MW
Minimum operating level	150 MW	361 MW
Heat rates (Btu/kWh)		
Maximum capacity	7,500 Btu/kWh	7,100 Btu/kWh
Minimum operating level	7,700 Btu/kWh	7,300 Btu/kWh
Variable O&M costs	$2.40/MWh	$2.40/MWh
GHG emission rate	0.053165 mtCO_2e/MMBtu	0.053165 mtCO_2e/MMBtu
Start-up gas consumption	1,400 MMBtu	2,800 MMBtu
Start-up time	35 minutes	50 minutes
Start-up auxiliary energy	5 MWh	5 MWh
Start-up major maintenance cost adder (2025)	$7,237	$14,474
Minimum load major maintenance cost adder (2025)	$362	$724
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	40 MW/minute	40 MW/minute
Financial Parameters (2025)		
Financing costs		$100/kW-yr
Insurance		$8 /kW-yr
Ad Valorem		$10 /kW-yr
Fixed annual O&M		$15 /kW-yr
Taxes		$12 /kW-yr
Total Fixed Cost Revenue Requirement		**$145 /kW-yr**

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[94] Start-up and minimum load major maintenance adders are derived based on Siemens SGT6-5000F5 gas turbine technology and costs reported in a NYISO study and adjusted each year for inflation. See Analysis Group Inc. Lummus Consultants International, Inc. *Study to Establish New York Electricity Market ICAP Demand Curve Parameters*, September 13, 2016: https://www.nyiso.com/documents/20142/1391705/Analysis Group NYISO DCR Final Report - 9_13_2016 - Clean.pdf/55a04f80-0a62-9006-78a0-9fdaa282cfc2

The cost of actual new generators varies significantly due to factors such as ownership, location, and environmental constraints. The remaining technical characteristics were assumed based on the resource operational characteristics of a typical combined cycle unit within the California ISO balancing area.

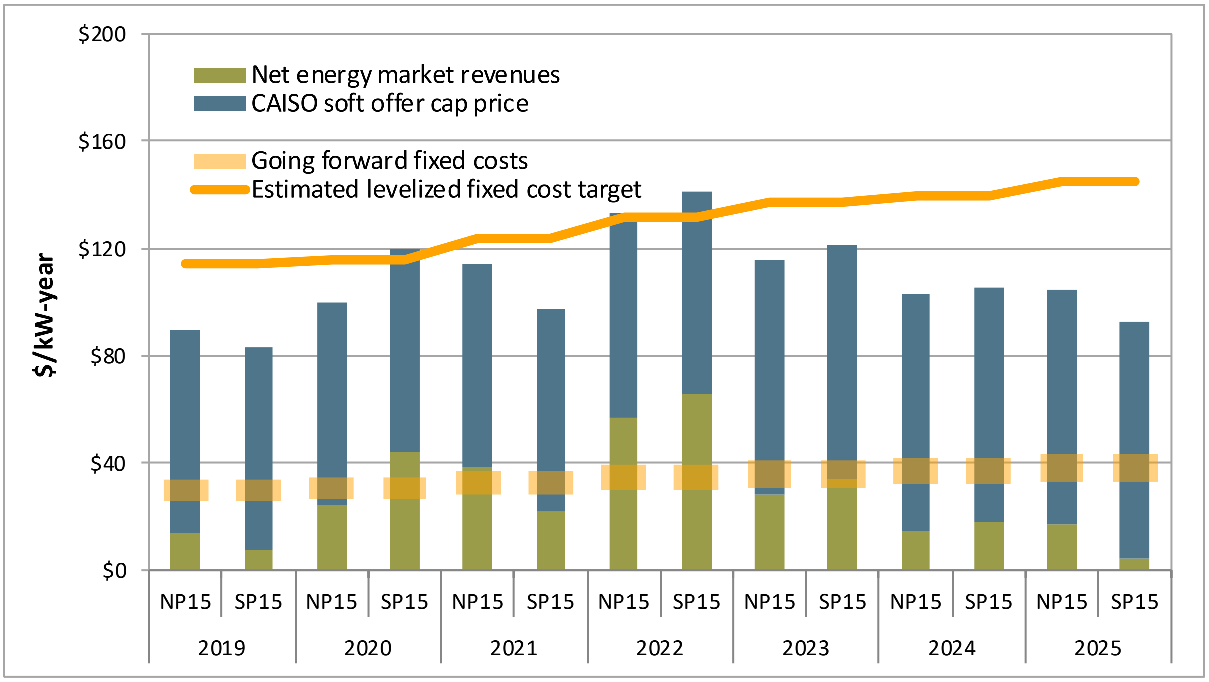
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

Table 1.4 Financial analysis of new combined cycle unit (2025)

Zone	Scenario	Capacity factor	Total energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	Day-ahead prices and default energy bids	32%	$147.42	$133.38	$14.04
	Day-ahead prices and default energy bids without adder	44%	$195.37	$174.97	$20.40
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	41%	$184.77	$168.58	$16.18
SP15	Day-ahead prices and default energy bids	8%	$39.56	$36.28	$3.29
	Day-ahead prices and default energy bids without adder	14%	$64.02	$58.89	$5.14
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	10%	$48.54	$44.09	$4.45

Figure 1.90 shows how net revenue results from the optimization model compared to the estimated annual fixed costs of a hypothetical combined cycle unit over the last seven years. The green bars in this chart show the average net revenue estimates over all the scenarios listed in Table 1.4. The blue bars in the chart show the potential capacity payment a unit would receive based on the California ISO soft offer cap price for the capacity procurement mechanism ($88.08/kW-yr).

Figure 1.90 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.90, compared to 2024, net revenues in 2025 were lower for SP15 and slightly higher in NP15. DMM changed gas fuel regions for the SP15 and NP15 scenarios in the 2025 analysis to better reflect comparable gas resources in the market.

Figure 1.90 also shows that net revenue estimates for a combined cycle unit continued to fall substantially below the annualized fixed cost estimate, shown by the solid yellow line. As noted above, fixed costs for existing and new units should be recoverable through a combination of long-term bilateral contracts and spot market revenues. The blue bars, equal to the California ISO soft offer cap price for the capacity procurement mechanism ($88.08/kW-yr), represent the potential additional contribution of a capacity payment up to the capacity procurement mechanism soft cap.

The net revenues of a combined cycle resource can be sensitive to the unit's realized capacity factor. We compared the hypothetical combined cycle capacity factors from Table 1.4 with existing combined cycle resources in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2025 ranged between 35 and 67 percent with an average of 51 percent capacity factor. In the SP15 area, actual capacity factors ranged between 2 and 28 percent, with an average capacity factor of 15 percent.

These differences in hypothetical capacity factors compared to existing resource capacity factors stem from several conditions. First, the model optimally shuts the unit down if it is not economic during any hour. We noted that the hypothetical dispatch would frequently cycle resources during the mid-day hours when solar generation was highest and prices were lowest. This can differ from actual unit performance, as many units have a limited number of starts per day and longer minimum run times. The average minimum run time for comparable combined cycle units in the CAISO BAA is nearly four hours.

Additionally, some combined cycle units may also operate at minimum load during off-peak hours instead of completely shutting down because participants may be concerned about wear-and-tear on units and increased maintenance costs from frequent shutting down and starting up.[95]

1.3.2 Hypothetical combustion turbine unit

Table 1.5 shows the key assumptions used in this analysis for a typical new combustion turbine unit. Also included in the table is the breakdown of financial parameters that contribute to the estimated annualized fixed costs for a hypothetical combustion turbine unit.

Table 1.6 shows the optimization model results using the parameters specified in Table 1.5. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2025.

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[95] While we have observed this in practice, we note that major maintenance adders exist to cover the costs of start-up and run-hour major maintenance. Not all participants have availed themselves of these adders.

Table 1.5 Assumptions for typical new combustion turbine[96]

Technical Parameters	
Maximum capacity	48.6 MW
Minimum operating level	24.3 MW
Heat rates (Btu/kWh)	
Maximum capacity	9,300 Btu/kWh
Minimum operating level	9,700 Btu/kWh
Variable O&M costs	$4.80 /MWh
GHG emission rate	0.053165 mtCO$_2$e/MMBtu
Start-up gas consumption	50 MMBtu
Start-up time	5 minutes
Start-up auxiliary energy	1.5 MWh
Start-up major maintenance cost adder (2025)	$0
Minimum load major maintenance cost adder (2025)	$232
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters (2025)	
Financing costs	$130 /kW-yr
Insurance	$10 /kW-yr
Ad Valorem	$13 /kW-yr
Fixed annual O&M	$10 /kW-yr
Taxes	$13 /kW-yr
Total Fixed Cost Revenue Requirement	**$176 /kW-yr**

Table 1.6 Financial analysis of new combustion turbine (2025)

Zone	Scenario	Capacity factor	Real-time energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	15-minute prices and default energy bids	3.43%	$23.25	$19.73	$3.52
	15-minute prices and default energy bids without adder	4.37%	$28.58	$24.17	$4.41
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	4.08%	$26.67	$23.03	$3.65
SP15	15-minute prices and default energy bids	1.32%	$8.99	$8.21	$0.78
	15-minute prices and default energy bids without adder	1.82%	$11.85	$10.68	$1.17
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	1.47%	$9.91	$9.08	$0.84

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[96] Start-up and minimum load major maintenance adders are derived based on an aeroderivative GE LM6000 PH Sprint technology and costs reported in a NYISO study and adjusted each year for inflation. *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator*, NERA Economic Consulting, September 3, 2010: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B25745D07-C958-42EA-AC1A-A1BB0D80FF52%7D

In the first scenario, we simulated commitment and dispatch instructions the combustion turbine would receive given 15-minute prices, using default energy bids as costs. In this scenario, for a hypothetical unit located in the NP15 area and using 2025 prices, net annual revenues were approximately $3.5/kW-yr with a 3.4 percent capacity factor. Using SP15 prices for the same scenario, net revenues were $0.78/kW-yr with a 1.3 percent capacity factor.

The second scenario assumes that 15-minute prices are used for commitment and dispatch instructions, but does not factor the 10 percent scalar into the default energy bids as a measure of incremental energy costs.[97] In this scenario, the hypothetical unit in NP15 earned net revenues of about $4/kW-yr with a 4.4 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $1.17/kW-yr with a capacity factor of 1.8 percent.

The third scenario includes all of the unit assumptions made in the first scenario, but also includes 5-minute prices for calculating unit revenues in addition to 15-minute prices. Specifically, this methodology commits the resource based on 15-minute market prices and then re-optimizes the dispatch based on 15-minute and 5-minute market prices. As in the first scenario, default energy bids were used for incremental energy costs. Simulating this scenario in the NP15 area, net revenues were about $3.7/kW-yr with a 4.1 percent capacity factor. In the SP15 area, net revenues were about $0.84/kW-yr with a 1.5 percent capacity factor.

Figure 1.91 shows how net revenue results from the optimization model compare to estimated annualized fixed costs of a hypothetical combustion turbine unit.[98] The green bars in this chart show estimated net revenues over the past seven years.

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[97] As noted above, we frequently find resources that bid in excluding the full 10 percent adder in their incremental energy bids.

[98] More information on the capacity procurement mechanism can be found in Section 43A of the California ISO tariff: https://www.caiso.com/legal-regulatory/tariff

Figure 1.91 Estimated net revenues of new combustion turbine

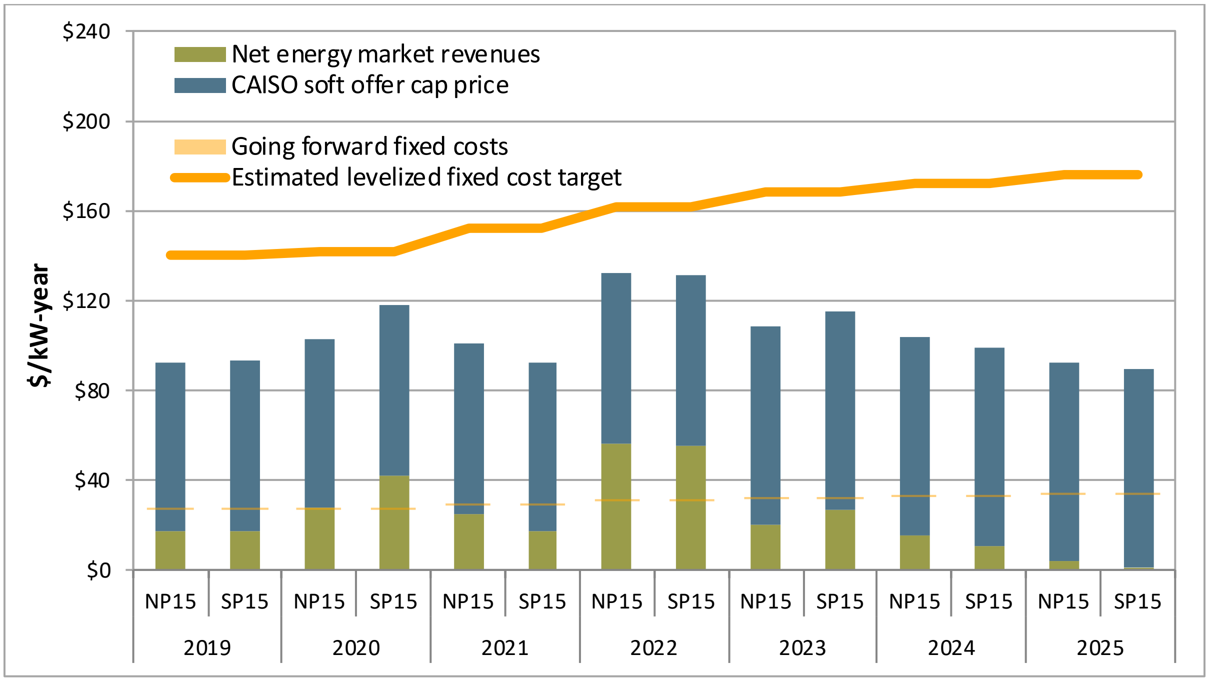

Figure 1.91 shows that, from 2019 through 2025, net revenue estimates for a hypothetical combustion turbine unit in both the NP15 and SP15 regions fall substantially below the annualized fixed cost estimate, shown by the solid yellow line. As noted above, fixed costs for existing and new units should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

In practice, the net revenues of a combustion turbine resource can be sensitive to the unit's realized capacity factor. Therefore, DMM compared the capacity factors for the hypothetical combustion turbine from Table 1.6 with existing combustion turbines as a benchmark. Actual capacity factors in 2025 ranged between 1.5 and 13 percent, with an average capacity factor of 3.4 percent. DMM's estimates ranged from 1.3 to 1.8 percent.

1.3.3 Hypothetical battery energy storage system

For a battery energy storage system, potential market revenues are evaluated under two scenarios using a profit maximization model. The first scenario co-optimizes energy and ancillary services products (regulation up and down) to maximize profit in the day-ahead market across over 280 pricing nodes, independently. The second scenario maximizes profit from energy awards only in the fifteen-minute market using SP15 prices, NP15 prices, and EIM load aggregation point prices. Both scenarios use one year's worth of pricing data across those nodes with a monthly optimization horizon window. Both models optimize revenues using a mixed integer linear programming algorithm.

Charging costs and discharging revenues in the model scenarios are calculated based on price data and the energy award chosen by the optimization. For market revenues in the first scenario (energy and ancillary service co-optimization), regulation up and down ancillary service marginal prices are used in addition to day-ahead market nodal prices to calculate market revenues.

Table 1.7 shows the key assumptions used in the profit maximization model for a new fast-ramping typical lithium-ion (Li-ion) battery energy storage system. Similar to the actual market model, DMM's model observes battery constraints related to state-of-charge and other operational characteristics. The state-of-charge is defined as a function of charging and discharging decision variables where round-trip efficiency (losses) is only applied while charging. In addition, state-of-charge is bound between minimum and maximum limits as shown in Table 1.7. The model excludes any variable operations and maintenance costs related to cycling the battery. The ISO market does allow battery operators to reflect variable operations costs as an adder in their default energy bid. However, as of December 2025, only 16 percent of registered batteries have these adders. In practice, most batteries likely reflect variable operations costs in their submitted bids.

Table 1.7 Assumptions for typical Li-ion battery energy storage system

Technical Parameters	
Maximum capacity	100 MW
Minimum capacity	-100 MW
Battery duration	4 hours
State-of-charge (SOC)	
Minimum SOC	0 MWh
Maximum SOC	400 MWh
Variable O&M costs	$0 /MWh
Round-trip efficiency	0.85

Revenues for regulation awards include a capacity payment as well as any revenues from following automatic generation control signals in the real-time market. The model assumes that day-ahead regulation up and regulation down awards are deployed in real-time according to hourly attenuation factors published by the ISO.[99] Hence, the model includes the costs and revenues associated with this fraction of regulation deployed in real-time in its profit maximization objective function.

Similar to the actual market model, DMM's model tracks two state-of-charge values. The conventional state-of-charge constraint only reflects the impact of energy awards. The "attenuated" state-of-charge additionally includes the impact of the regulation award multiplied by attenuation factors, as well as round-trip efficiency in the case of regulation down.[100] In the day-ahead market, batteries are subject to the ancillary service state-of-charge constraints, which limit regulation awards based on modeled state-of-charge. In DMM's optimization, the attenuated state-of-charge value controls for feasibility of regulation awards within the ancillary service state-of-charge constraints.

Table 1.8 shows quarterly average day-ahead energy and ancillary service revenues by local capacity area for hypothetical batteries at all utilized pricing nodes. On average, simulated revenues across all pricing nodes were $39/kW-yr for energy and $39/kW-year for regulation. Actual batteries in the CAISO

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[99] Attenuation factors are multipliers which model the state-of-charge of a battery as being depleted or increased by a certain percentage of the regulation schedule. The ISO chooses multipliers based on historical usage of regulation and updates the multipliers on a quarterly basis to account for seasonality of regulation usage.

[100] Initially, the ISO had planned to model the impact of energy and regulation in a single state-of-charge parameter. However, this resulted in negative regulation down prices since regulation down deployment could support future energy awards, which the CAISO tariff prohibits. DMM's model takes prices as given and thus has no such issue.

balancing area with a full year of operation in 2025 had nearly $35/kW-yr in market revenues for energy and $9/kW-yr for regulation.

Table 1.8 New battery net day-ahead market revenues by local capacity area

Local capacity area	TAC Area	Net energy market revenues for energy and regulation ($/kW-yr) 2025 Q1	2025 Q2	2025 Q3	2025 Q4	Total
Greater Bay Area	PG&E	33.2	25.0	12.7	9.8	80.7
Big Creek/Ventura	SCE	22.9	19.3	11.2	10.8	64.2
CAISO System		28.8	22.8	14.2	11.5	77.3
Greater Fresno	PG&E	39.6	33.7	24.0	14.5	111.7
Humboldt	PG&E	34.2	27.0	16.0	11.7	88.8
Kern	PG&E	39.2	29.5	18.4	14.8	101.9
LA Basin	SCE	21.9	19.1	11.0	10.5	62.6
North Coast & North Bay	PG&E	33.2	28.0	15.0	11.1	87.2
San Diego/Imperial Valley	SDG&E	22.3	19.6	12.8	11.5	66.3
Sierra	PG&E	33.1	26.7	13.9	10.0	83.7
Stockton	PG&E	32.9	25.3	13.1	9.8	81.1

Hourly average energy and regulation awards for the day-ahead optimization are shown in Figure 1.92. DMM’s model likely overstates potential revenue from ancillary services for an actual battery resource. DMM’s optimization does not limit the amount of regulation a battery can receive in an interval beyond the standard ancillary service constraints observed in the actual market optimization. While the high level of regulation procurement in DMM’s model may theoretically be profit-maximizing, in practice there is a large amount of battery capacity competing to provide a relatively low amount of required regulation, making it unlikely that a single battery will procure the level of regulation shown in Figure 1.92.[101]

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[101] *2023 Special Report on Battery Storage*, Department of Market Monitoring, July 16, 2024, p 25: https://www.caiso.com/documents/2023-special-report-on-battery-storage-jul-16-2024.pdf

Figure 1.92 Average hourly hypothetical battery day-ahead market awards

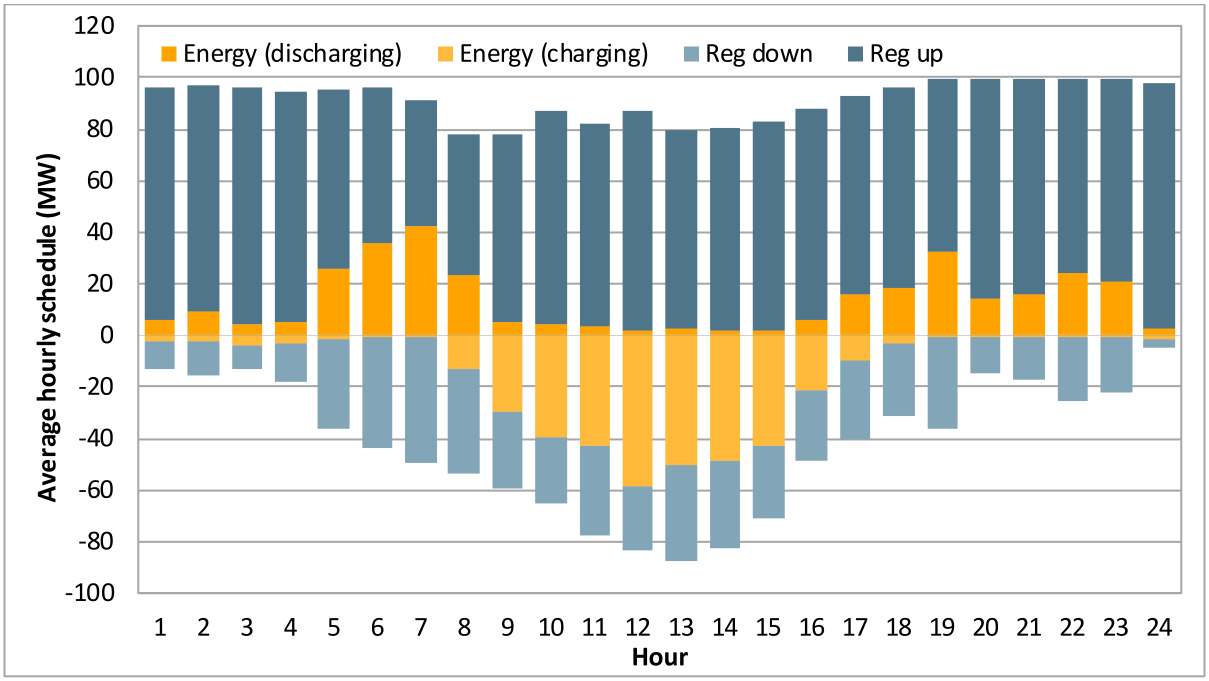

Table 1.9 shows quarterly average energy revenue for the real-time optimization scenario by area. Average simulated revenues were $25/kW-year across all areas. By region, the highest average simulated revenue figure was $33/kW-year in the Desert Southwest. Because revenue settlements outside of the CAISO BA are determined by energy imbalance, and actual EIM batteries' dispatch usually follows their base schedules, the model's simulated revenues are not comparable to actual net market revenues paid to EIM-participating batteries in 2025.[102]

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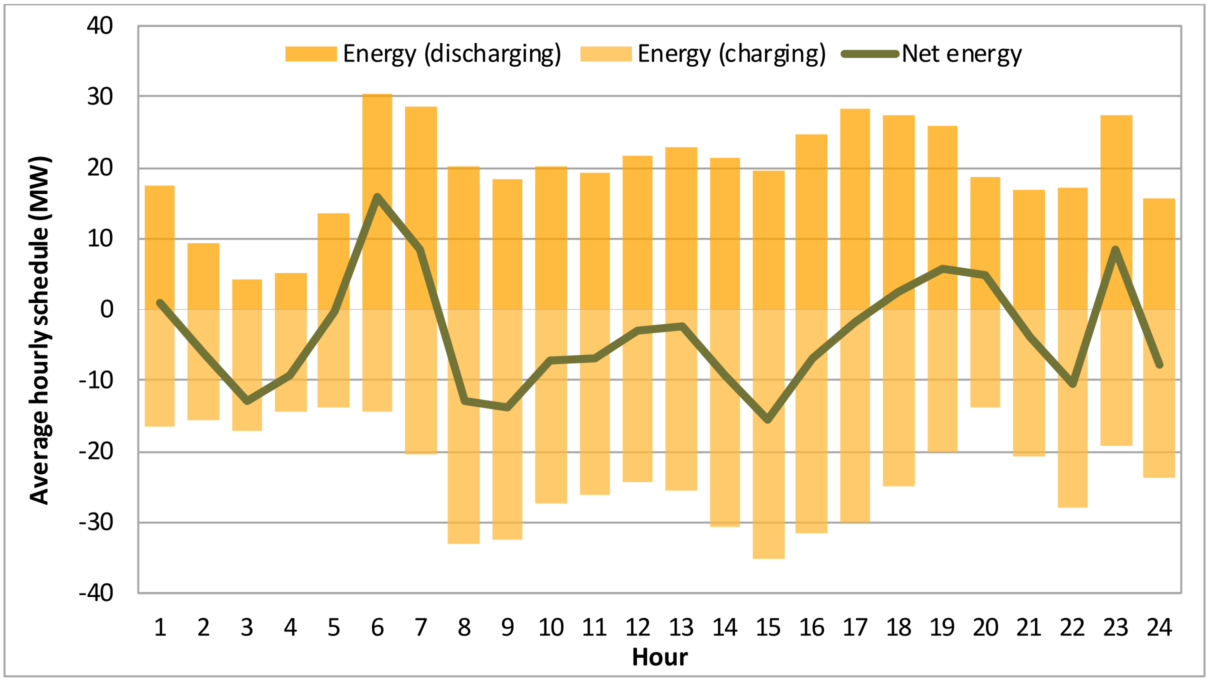
[102] *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025, p 25: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

Table 1.9 New battery net 15-minute market revenues by area

Region	Area	Net energy market revenues ($/kW-yr)				
		2025Q1	2025Q2	2025Q3	2025Q4	Total
Desert Southwest	Arizona Public Service	8.9	5.8	4.2	4.8	23.8
	El Paso Electric	11.4	13.2	10.0	15.5	50.2
	NV Energy	8.1	8.0	4.7	4.4	25.2
	PSC New Mexico	14.6	12.3	8.7	10.4	46.0
	Salt River Project	11.1	13.5	4.9	4.7	34.2
	Tucson Electric	8.9	5.9	4.5	5.2	24.4
	WAPA - Desert Southwest	10.4	5.8	4.2	6.9	27.3
Intermountain West	Avista Utilities	5.5	4.7	3.8	3.7	17.7
	Idaho Power	7.2	11.2	3.7	4.0	26.0
	NorthWestern Energy	6.4	4.7	3.9	4.2	19.2
	PacifiCorp East	7.0	5.8	3.8	5.0	21.6
Pacific Northwest	Avangrid	6.5	5.1	4.2	3.8	19.5
	Powerex	2.4	2.8	2.6	2.9	10.7
	Bonneville Power Admin.	7.6	7.0	7.1	5.7	27.4
	PacifiCorp West	6.4	5.0	3.9	3.7	19.0
	Portland General Electric	6.2	4.8	3.7	3.3	17.9
	Puget Sound Energy	6.1	6.6	6.3	3.6	22.7
	Seattle City Light	6.6	4.9	6.2	4.3	22.1
	Tacoma Power	6.2	5.4	5.1	3.7	20.5
California	BANC	7.9	7.2	4.8	3.6	23.5
	LADWP	11.2	7.7	5.3	5.9	30.1
	Turlock Irrigation District	7.9	6.9	5.5	3.9	24.3
CAISO	NP15	8.0	7.4	5.2	4.1	24.8
	SP15	8.9	7.3	5.3	5.5	27.0

Figure 1.93 shows hourly average charging, discharging, and net energy schedules for a hypothetical battery located in the El Paso Electric balancing area (EPE). Intra-hour differences in the 15-minute prices allow for arbitrage opportunities in more hours compared to the day-ahead price model shown in Figure 1.92.

Figure 1.93 Average hourly hypothetical battery 15-minute market awards



2 Energy market prices

- **ISO markets continued to perform efficiently and competitively in 2025.**
- **Prices across the WEIM were about 14 percent lower in 2025 compared to 2024** in the 15-minute market. Prices in the 15-minute market averaged about $34/MWh, while prices in the 5-minute market averaged about $35/MWh. Day-ahead market prices averaged about $39/MWh. Lower prices in 2025 occurred despite higher natural gas prices due to the absence of extreme conditions that led to high prices in January 2024, increased renewable generation, and lower greenhouse gas costs in California.
- **Prices were highest on average in the California region, at about $38/MWh, while prices in other regions ranged between about $29/MWh and $35/MWh,** with the Desert Southwest recording the lowest prices. This price spread was driven primarily by greenhouse gas compliance costs in California and south-to-north congestion during solar production hours, which reduced prices in the Desert Southwest relative to northern regions of the WEIM.
- **During mid-day solar hours, prices were generally higher in the Pacific Northwest, Northern California, and the Intermountain West than in the Desert Southwest and Southern California.** This pattern was primarily driven by congestion on major transmission corridors in the south-to-north direction during solar production hours.
- **During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM** due mainly to California greenhouse gas pricing.
- **January continued to have the highest monthly average 15-minute and 5-minute market prices** for most balancing areas, although prices were significantly lower than the elevated levels observed during January 2024.
- **15-minute market prices were higher than 5-minute market prices during the evening peak net load hours, particularly in California balancing areas.** This difference was driven in part by California ISO operators adjusting the load forecast upward more in the 15-minute market than in the 5-minute market during these hours.
- **For most of the year, day-ahead bilateral prices from the Intercontinental Exchange at Mid-Columbia and Palo Verde were generally higher than prices at comparable locations from the ISO's day-ahead and 15-minute markets.**
- **Frequencies of power balance constraint infeasibilities remained low across the WEIM in 2025 and declined compared to 2024.** System-wide undersupply infeasibilities decreased to approximately 0.02 to 0.03 percent of intervals, while oversupply infeasibilities remained lower. Balancing areas in the Desert Southwest continued to experience relatively higher frequencies of infeasibilities than other regions.
- **The frequency of high-price intervals declined significantly in 2025 across both day-ahead and real-time markets,** with nearly no intervals exceeding $250/MWh in the day-ahead market and sharp reductions in real-time price spikes. These declines reflect less frequent tight supply conditions compared to 2024.
- **The frequency of negative prices declined across both day-ahead and real-time markets in 2025,** decreasing by roughly 20 percent in CAISO and about 15 percent in other WEIM balancing areas, despite continued growth in renewable generation.
- **DMM estimates the total wholesale cost of serving load for balancing areas in the day-ahead market. Total wholesale costs for the CAISO balancing area decreased by about 6 percent to $8.45**

billion, or about $42/MWh, in 2025. Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs decreased by about 24 percent, due mainly to lower load, increased renewable and storage generation, and the absence of tight supply conditions that contributed to elevated prices in January 2024.

2.1 Real-time energy market prices by region

This section analyzes real-time market prices across the Western Energy Imbalance Market (WEIM). The analysis focuses on monthly and hourly load-weighted average prices at the regional level.[103] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[104]

Figure 2.1 and Figure 2.2 display the weighted average monthly electricity prices in the 15-minute and 5-minute markets by region from January 2024 to December 2025. Prices in the 15-minute market across the WEIM averaged about $34/MWh, down 14 percent. Prices in the 5-minute market were $35/MWh, a 10 percent decrease compared to 2024. Severe cold weather and strained supply conditions in January 2024 contributed to elevated prices in the WEIM.

In 2025, the California region recorded the highest average price at $38/MWh, while other regions ranged between $29/MWh and $35/MWh. The Desert Southwest region recorded the lowest average price at $29/MWh. This price difference largely reflects the south-to-north congestion pattern during solar production hours, which decreased prices in the Desert Southwest relative to northern regions of the WEIM.

Compared to 2024, prices across the WEIM were lower despite higher natural gas prices. As discussed in Chapter 1, natural gas prices increased across major Western U.S. trading hubs in 2025 compared to 2024. As gas-fired units frequently set electricity market prices, higher natural gas prices would typically be expected to increase real-time prices across the WEIM; however, other factors, including the absence of tight conditions that caused high prices in January 2024, increased renewable generation, and lower greenhouse gas costs in California, contributed to lower prices in 2025.

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

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

Figure 2.1 Weighted average monthly 15-minute market prices by region

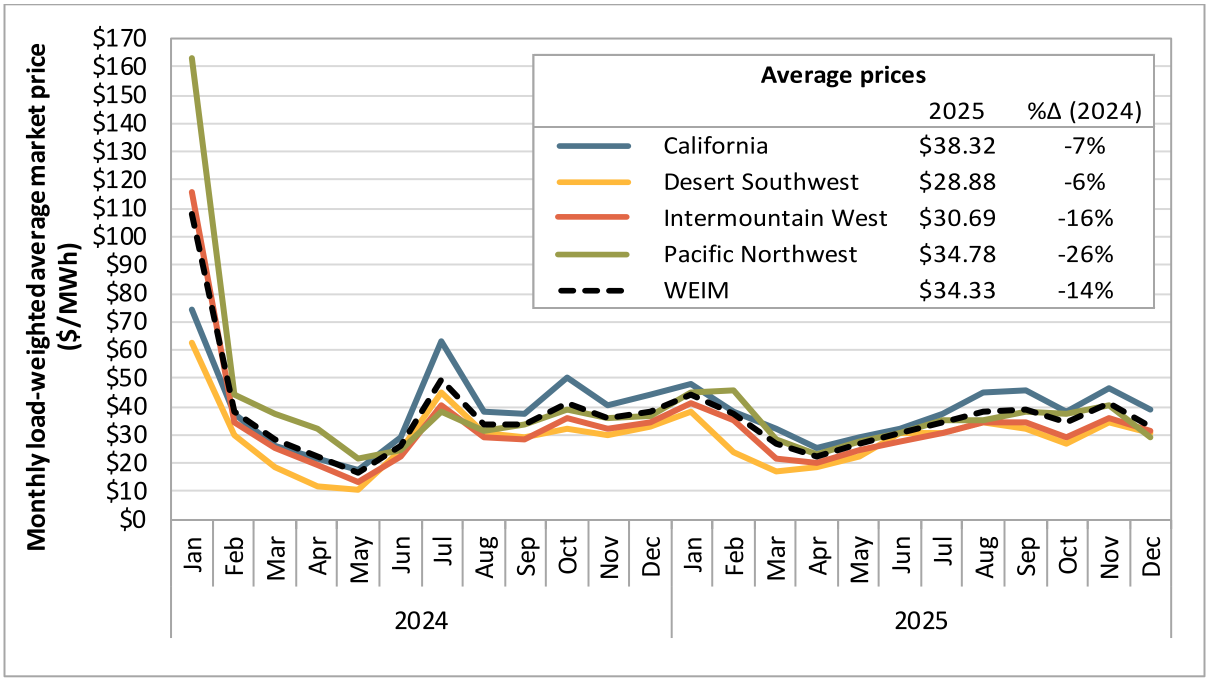


Figure 2.2 Weighted average monthly 5-minute market prices by region

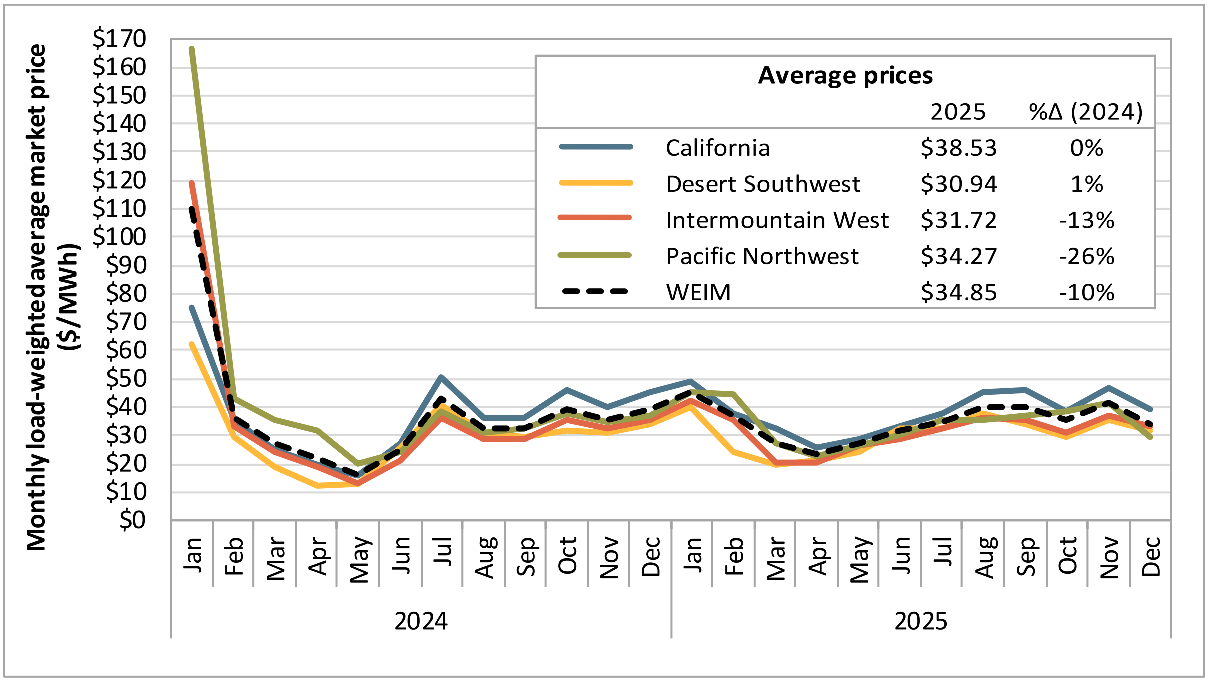


Figure 2.3 and Figure 2.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net-load schedules. The shape of hourly prices

tended to follow the net-load pattern. This trend was most prominent for prices in the California, Desert Southwest, and Intermountain West regions, with relatively high prices during the morning and evening ramping hours, and lower prices during solar production hours.

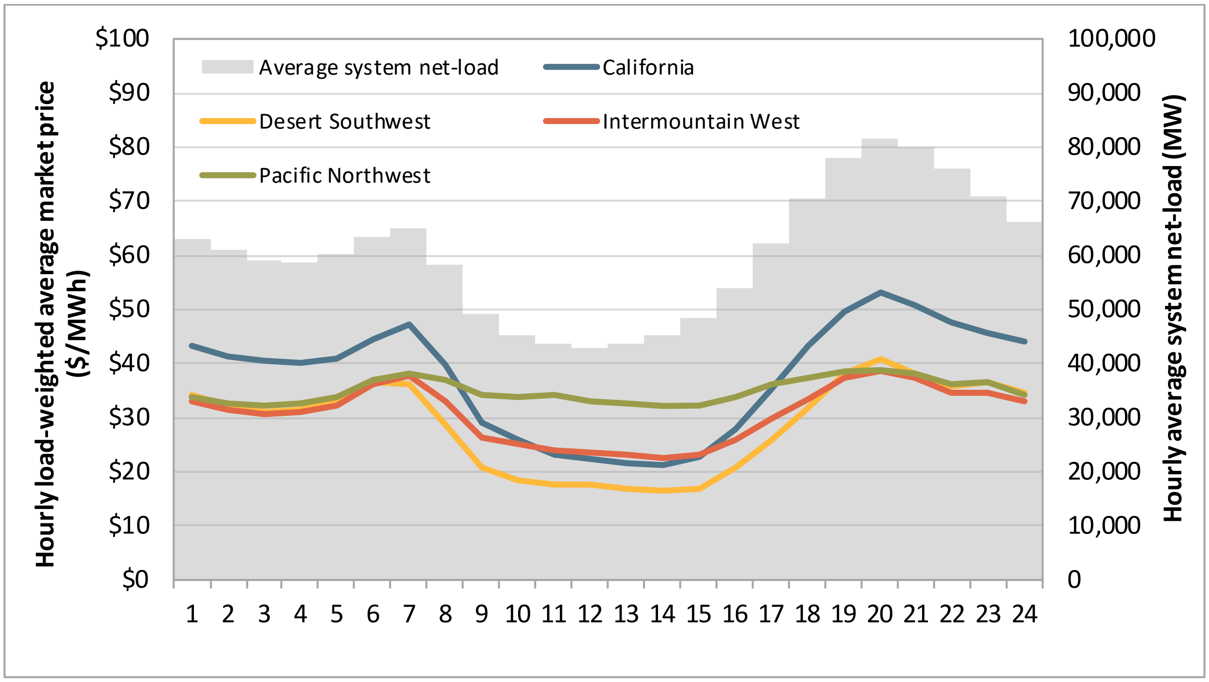
The system's peak net load occurred at hour-ending 20 in both the 15-minute and 5-minute markets, reaching around 81.6 GW and 81 GW, respectively. In both markets, all regions experienced peak average prices around the evening ramping hours.

Prices in the California region were higher than prices in other regions in both markets, especially during the morning and evening non-solar hours. The main contributor for higher prices in California is the greenhouse gas (GHG) cost, which tends to lower prices in non-California regions relative to California during hours when WEIM transfers are flowing into California.

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

Comparing prices between the 15-minute and 5-minute markets, the 15-minute market had higher prices during peak net load hours, particularly in California. Around hour-ending 20, California's peak average price in the 15-minute market reached $53/MWh, compared to $50/MWh in the 5-minute market. One factor that contributed to this price difference was the CAISO balancing area using higher load conformance in the 15-minute market than in the 5-minute market during these hours.[105]

Figure 2.3 Weighted average hourly 15-minute market prices by region (2025)



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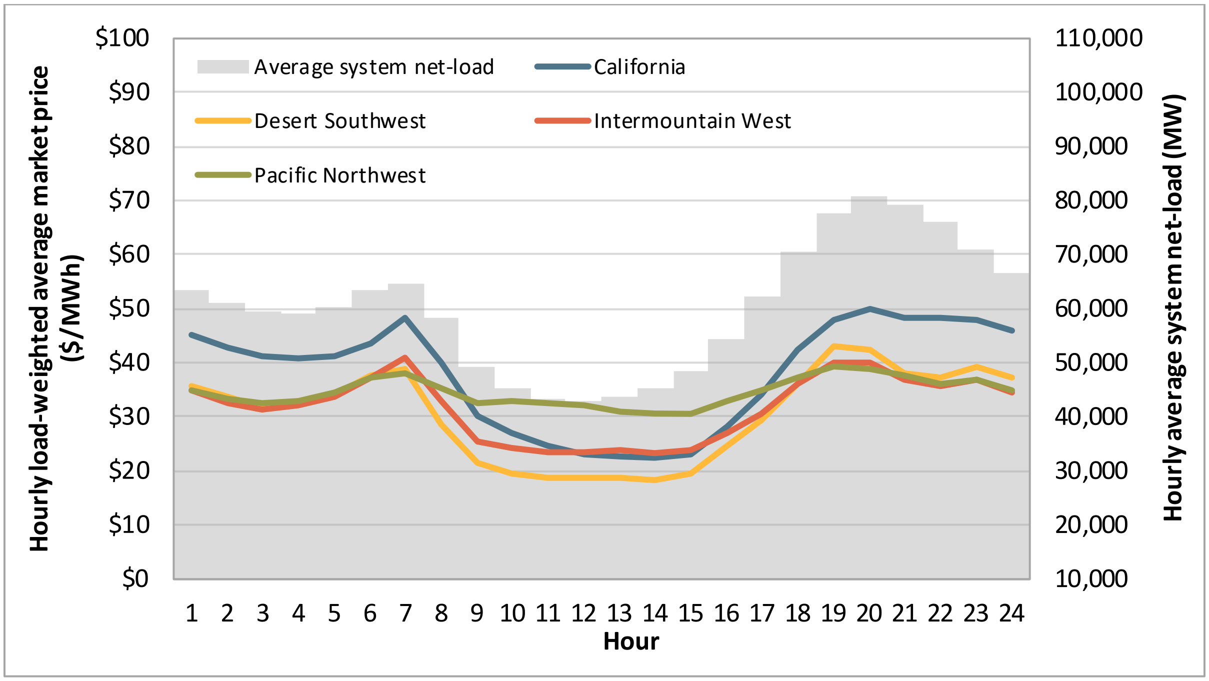
[105] For more information on load conformance, see Chapter 9.

Figure 2.4 Weighted average hourly 5-minute market prices by region (2025)



2.2 Real-time energy market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during 2025. Figure 2.5 and Figure 2.6 show the average 15-minute and 5-minute market price by component for each balancing authority area in this year. These figures highlight how price differences between regions are determined by differences in transmission losses, greenhouse gas compliance costs, and congestion. These components are listed below.

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

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

Figure 2.5 and Figure 2.6 show LMP separation across balancing authority areas (BAAs) and regions in both the 15-minute and 5-minute markets. The charts highlight that the GHG component (green bars) contributed to lower LMPs across most BAAs, except those located in the California region. Internal flow-based constraints in the California balancing area impacted prices in both the 15-minute and 5-minute markets. As a result, prices in Northern California were higher relative to Southern California. Congestion on WEIM transfer constraints resulted in higher prices in the Pacific Northwest and Intermountain West regions.

Figure 2.5 Average 15-minute market prices by balancing area (2025)

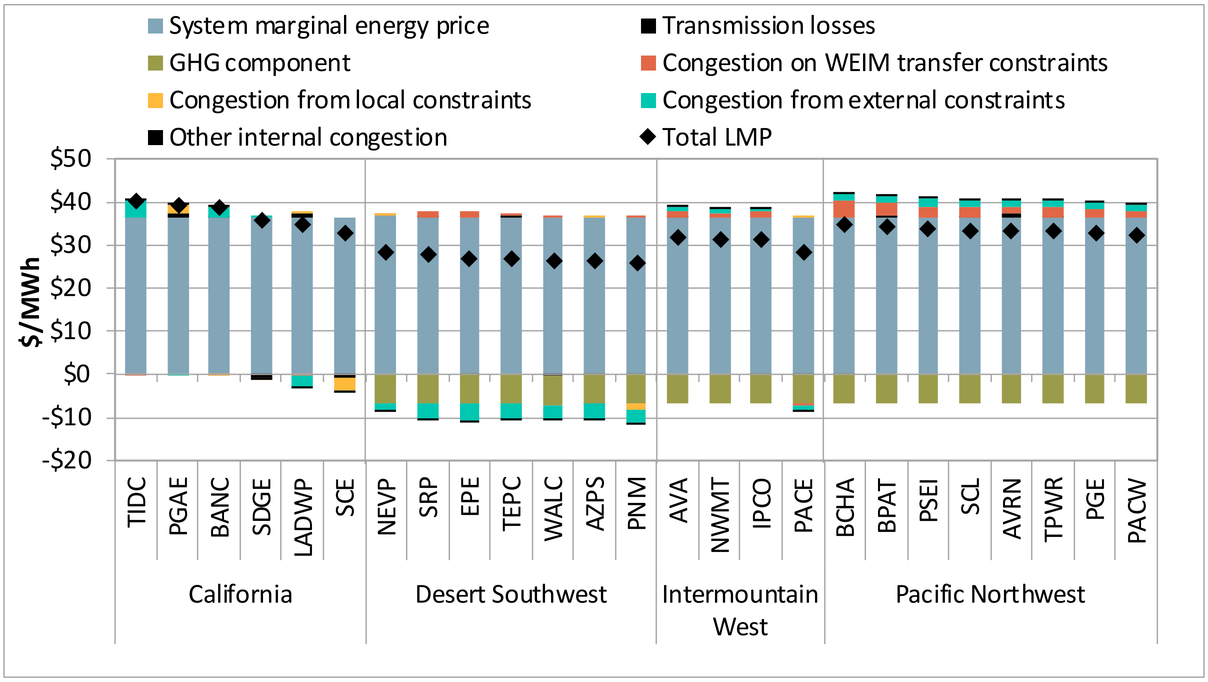


Figure 2.6 Average 5-minute market prices by balancing area (2025)

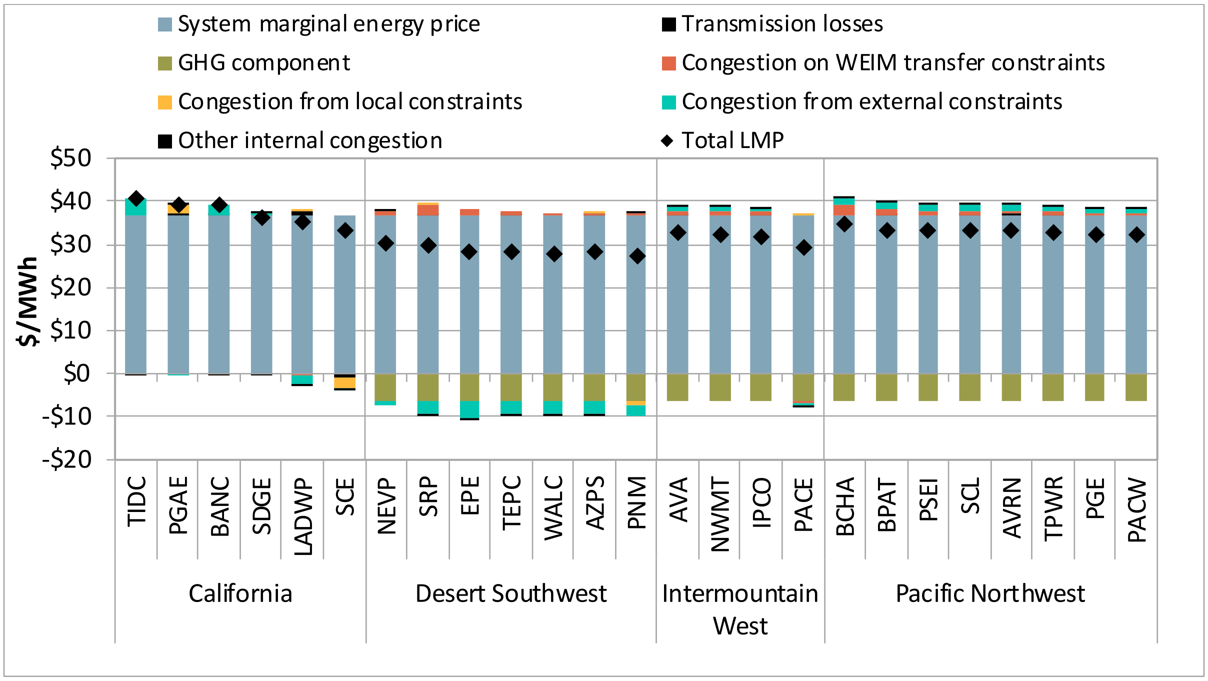
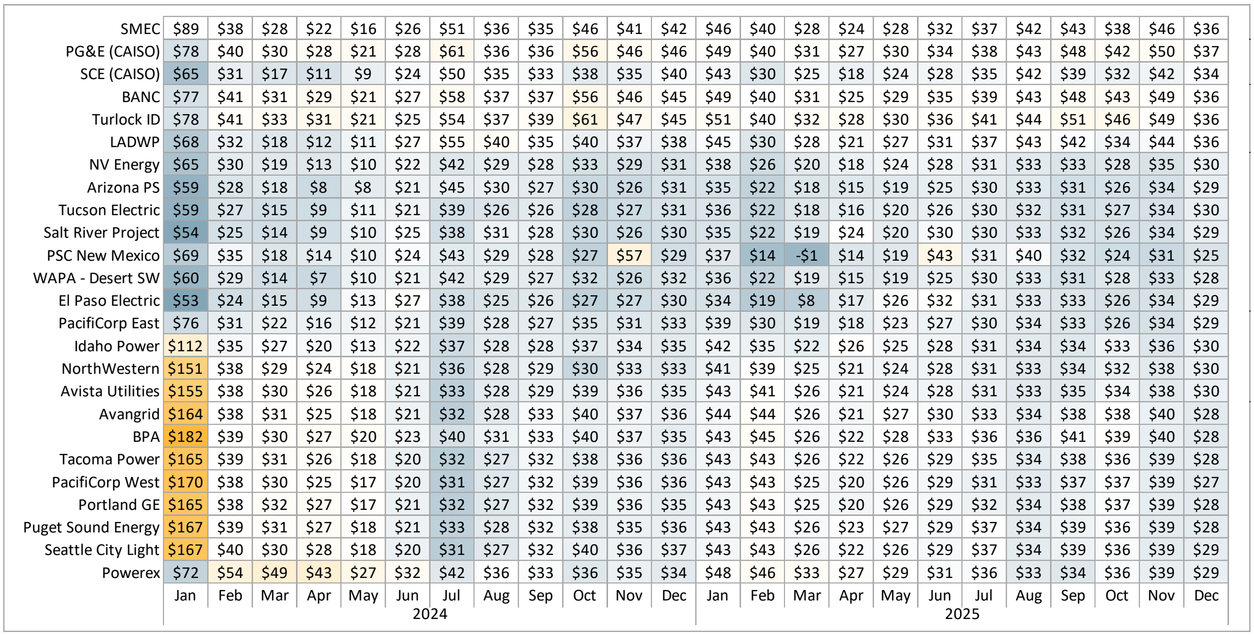


Table 2.1 and Table 2.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Blue indicates prices below that month’s average system price and orange indicates prices above. As shown in these tables, average prices in California balancing areas were generally higher than those in other regions in both the 15-minute and 5-minute markets over 2025. Greenhouse gas compliance costs contribute to higher prices in California relative to the rest of the system.

Table 2.3 and Table 2.4 show average hourly prices in the 15-minute and 5-minute markets in 2025. During mid-day solar hours, prices were generally higher in the Intermountain West, Pacific Northwest, and Northern California than in the Desert Southwest and Southern California. This pattern was primarily driven by south-to-north congestion on WEIM transfer and internal flow-based constraints. When internal or transfer constraints limit the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply.

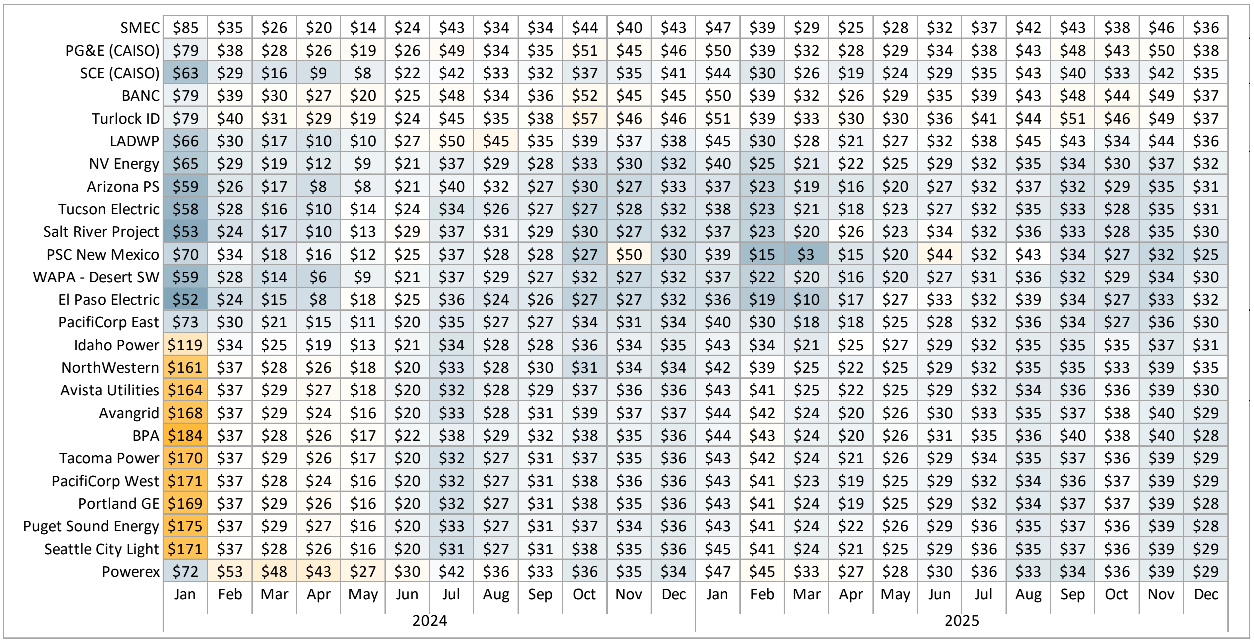
During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM due mainly to California greenhouse gas pricing.

Table 2.1 Average monthly 15-minute market prices



	2024												2025											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$89	$38	$28	$22	$16	$26	$51	$36	$35	$46	$41	$42	$46	$40	$28	$24	$28	$32	$37	$42	$43	$38	$46	$36
PG&E (CAISO)	$78	$40	$30	$28	$21	$28	$61	$36	$36	$56	$46	$46	$49	$40	$31	$27	$30	$34	$38	$43	$48	$42	$50	$37
SCE (CAISO)	$65	$31	$17	$11	$9	$24	$50	$35	$33	$38	$35	$40	$43	$30	$25	$18	$24	$28	$35	$42	$39	$32	$42	$34
BANC	$77	$41	$31	$29	$21	$27	$58	$37	$37	$56	$46	$45	$49	$40	$31	$25	$29	$35	$39	$43	$48	$43	$49	$36
Turlock ID	$78	$41	$33	$31	$21	$25	$54	$37	$39	$61	$47	$45	$51	$40	$32	$28	$30	$36	$41	$44	$51	$46	$49	$36
LADWP	$68	$32	$18	$12	$11	$27	$55	$40	$35	$40	$37	$38	$45	$30	$28	$21	$27	$31	$37	$43	$42	$34	$44	$36
NV Energy	$65	$30	$19	$13	$10	$22	$42	$29	$28	$33	$29	$31	$38	$26	$20	$18	$24	$28	$31	$33	$33	$28	$35	$30
Arizona PS	$59	$28	$18	$8	$8	$21	$45	$30	$27	$30	$26	$31	$35	$22	$18	$15	$19	$25	$30	$33	$31	$26	$34	$29
Tucson Electric	$59	$27	$15	$9	$11	$21	$39	$26	$26	$28	$27	$31	$36	$22	$18	$16	$20	$26	$30	$32	$31	$27	$34	$30
Salt River Project	$54	$25	$14	$9	$10	$25	$38	$31	$28	$30	$26	$30	$35	$22	$19	$24	$20	$30	$30	$33	$32	$26	$34	$29
PSC New Mexico	$69	$35	$18	$14	$10	$24	$43	$29	$28	$27	$57	$29	$37	$14	-$1	$14	$19	$43	$31	$40	$32	$24	$31	$25
WAPA - Desert SW	$60	$29	$14	$7	$10	$21	$42	$29	$27	$32	$26	$32	$36	$22	$19	$15	$19	$25	$30	$33	$31	$28	$33	$28
El Paso Electric	$53	$24	$15	$9	$13	$27	$38	$25	$26	$27	$27	$30	$34	$19	$8	$17	$26	$32	$31	$33	$33	$26	$34	$29
PacifiCorp East	$76	$31	$22	$16	$12	$21	$39	$28	$27	$35	$31	$33	$39	$30	$19	$18	$23	$27	$30	$34	$33	$26	$34	$29
Idaho Power	$112	$35	$27	$20	$13	$22	$37	$28	$28	$37	$34	$35	$42	$35	$22	$26	$25	$28	$31	$34	$34	$33	$36	$30
NorthWestern	$151	$38	$29	$24	$18	$21	$36	$28	$29	$30	$33	$33	$41	$39	$25	$21	$24	$28	$31	$33	$34	$32	$38	$30
Avista Utilities	$155	$38	$30	$26	$18	$21	$33	$28	$29	$39	$36	$35	$43	$41	$26	$21	$24	$28	$31	$33	$35	$34	$38	$30
Avangrid	$164	$38	$31	$25	$18	$21	$32	$28	$33	$40	$37	$36	$44	$44	$26	$21	$27	$30	$33	$34	$38	$38	$40	$28
BPA	$182	$39	$30	$27	$20	$23	$40	$31	$33	$40	$37	$35	$43	$45	$26	$22	$28	$33	$36	$36	$41	$39	$40	$28
Tacoma Power	$165	$39	$31	$26	$18	$20	$32	$27	$32	$38	$36	$36	$43	$43	$26	$22	$26	$29	$35	$34	$38	$36	$39	$28
PacifiCorp West	$170	$38	$30	$25	$17	$20	$31	$27	$32	$39	$36	$36	$43	$43	$25	$20	$26	$29	$31	$33	$37	$37	$39	$27
Portland GE	$165	$38	$32	$27	$17	$21	$32	$27	$32	$39	$36	$35	$43	$43	$25	$20	$26	$29	$32	$34	$38	$37	$39	$28
Puget Sound Energy	$167	$39	$31	$27	$18	$21	$33	$28	$32	$38	$35	$36	$43	$43	$26	$23	$27	$29	$37	$34	$39	$36	$39	$28
Seattle City Light	$167	$40	$30	$28	$18	$20	$31	$27	$32	$40	$36	$37	$43	$43	$26	$22	$26	$29	$37	$34	$39	$36	$39	$29
Powerex	$72	$54	$49	$43	$27	$32	$42	$36	$33	$36	$35	$34	$48	$46	$33	$27	$29	$31	$36	$33	$34	$36	$39	$29

Table 2.2 Average monthly 5-minute market prices



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

Table 2.3 Average hourly 15-minute market prices (2025)

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

Table 2.4 Average hourly 5-minute market prices (2025)

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

2.3 Day-ahead market price comparison

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

In 2025, prices in the CAISO balancing area's day-ahead, 15-minute, and 5-minute markets dropped by about 2 percent compared to the previous year. The simple average price of the three markets this year decreased to $38/MWh from $39/MWh in 2024.

Figure 2.7 shows load-weighted average monthly energy prices during all hours across all Aggregated Pricing Nodes (APnodes). Prices are calculated based on the load schedules and corresponding prices at these pricing nodes.[106] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from January 2024 to December 2025.

In 2025, day-ahead prices averaged $39/MWh, 15-minute prices averaged $38/MWh, and 5-minute prices averaged $38/MWh. January had the highest prices, with an average over the three markets of about $48/MWh.

Figure 2.7 also shows monthly average natural gas prices at PG&E Citygate from January 2024 to December 2025. The chart shows that the monthly variation of the energy prices is correlated with gas prices. Over the past 24 months, both gas and energy prices generally moved in similar directions, although with notable differences in some months. The correlation was less pronounced over the second half of 2025. The PG&E Citygate gas price averaged about $3.41/MMBtu in 2025.

This 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.

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

Figure 2.7 **Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market (CAISO)**

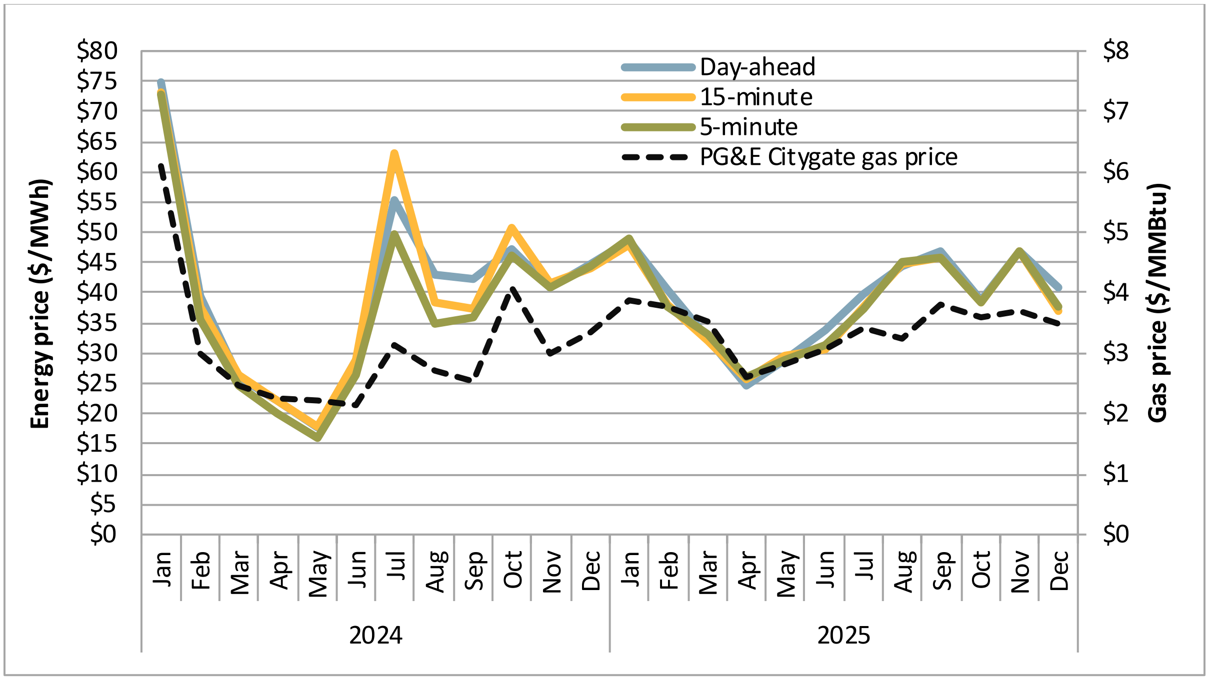

Figure 2.8 illustrates the hourly load-weighted average energy prices for 2025 compared to the average hourly net-load.[107] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average hourly net-load (grey bars) is measured by the right axis.

Average hourly prices continue to follow the net-load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening. Prices peaked at hour-ending 20 in all three markets, when demand was still high but solar generation was substantially below its peak. The average net-load in this year reached 24,430 MW at hour-ending 21.

During hour-ending 20, the day-ahead load-weighted average energy price was $55/MWh, the 15-minute price was $53/MWh, and the 5-minute price was $50/MWh. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

One cause of price separation between the 15-minute and 5-minute markets this year was load conformance during evening peak net load hours. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over these hours.[108]

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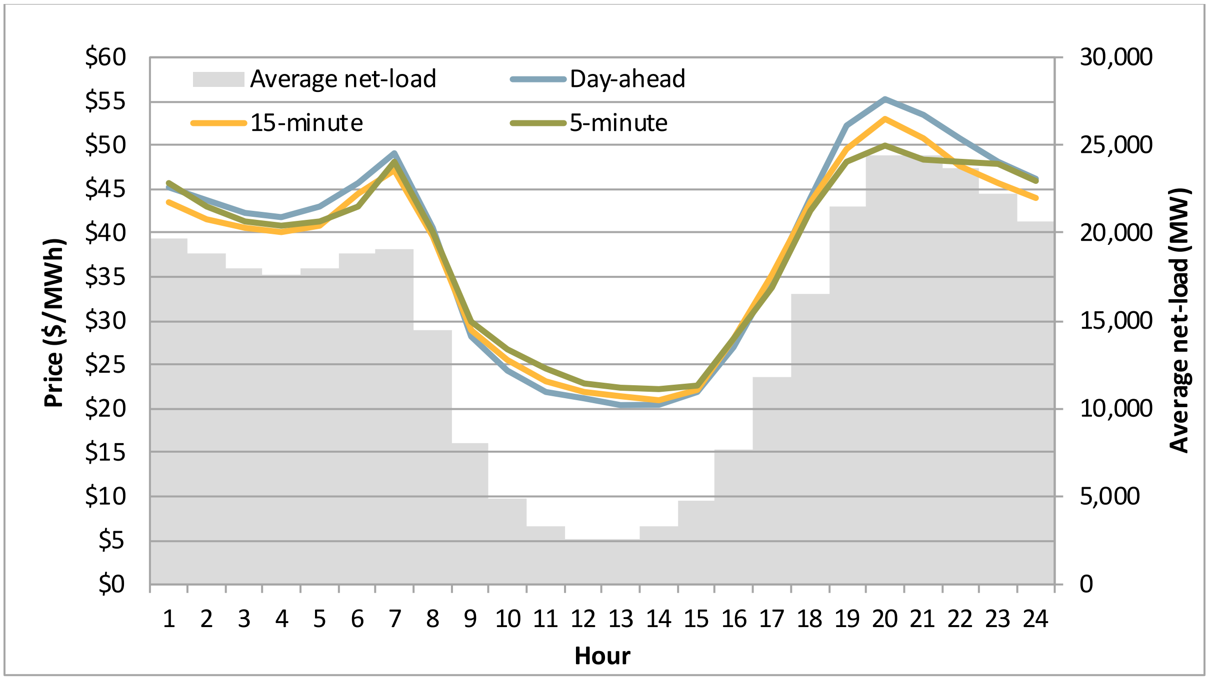
[107] Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the California ISO grid from actual load.

[108] Please see Chapter 9 for a detailed discussion on load conformance.

Figure 2.8 **Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO 2025)**



2.4 Bilateral price comparison

Figure 2.9 and Figure 2.10 compare 15-minute prices in different regions of the WEIM during peak hours (hours-ending 7 through 22) to day-ahead prices for comparable markets. These figures show the monthly average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

With the exception of March, during the first 10 months of 2025 day-ahead prices at the Intercontinental Exchange for the Mid-Columbia hub generally exceeded ISO day-ahead and 15-minute market prices at the Pacific Gas and Electric load node, as well as ISO 15-minute market prices in the Pacific Northwest. Similarly, day-ahead bilateral prices at the Palo Verde hub on the Intercontinental Exchange were generally higher than ISO 15-minute market prices in the Desert Southwest in every month except December, and were higher than both ISO day-ahead and fifteen-minute market prices at Southern California Edison from January through August.

Figure 2.9 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)

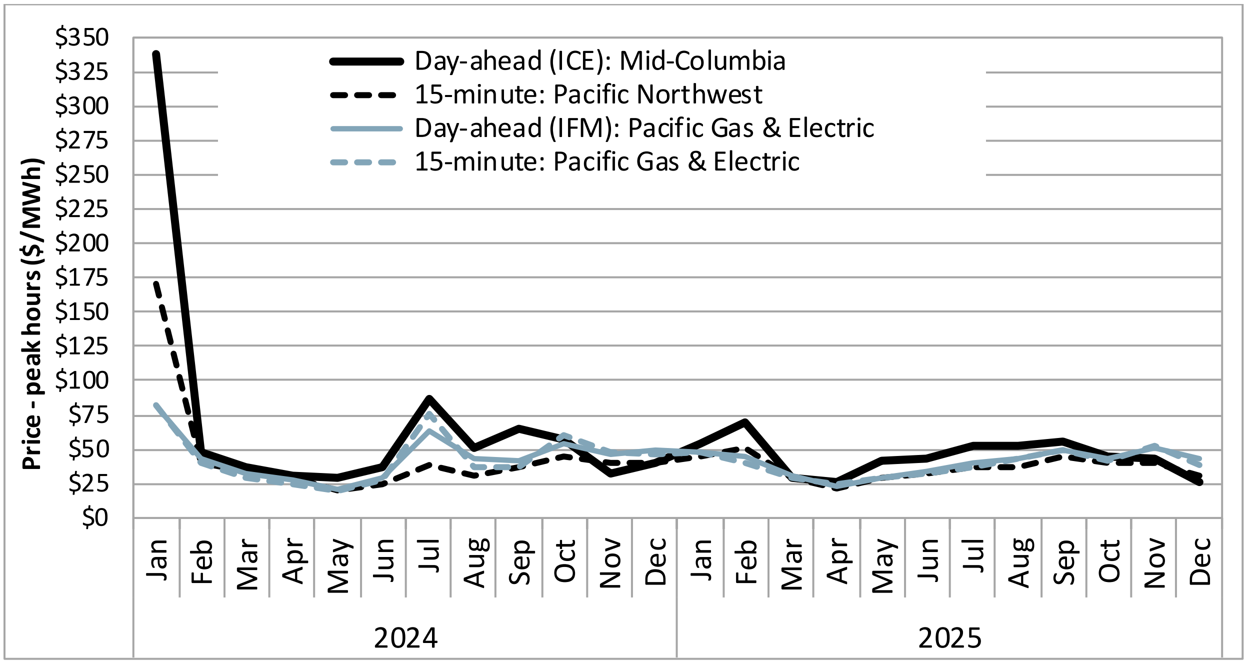


Figure 2.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)

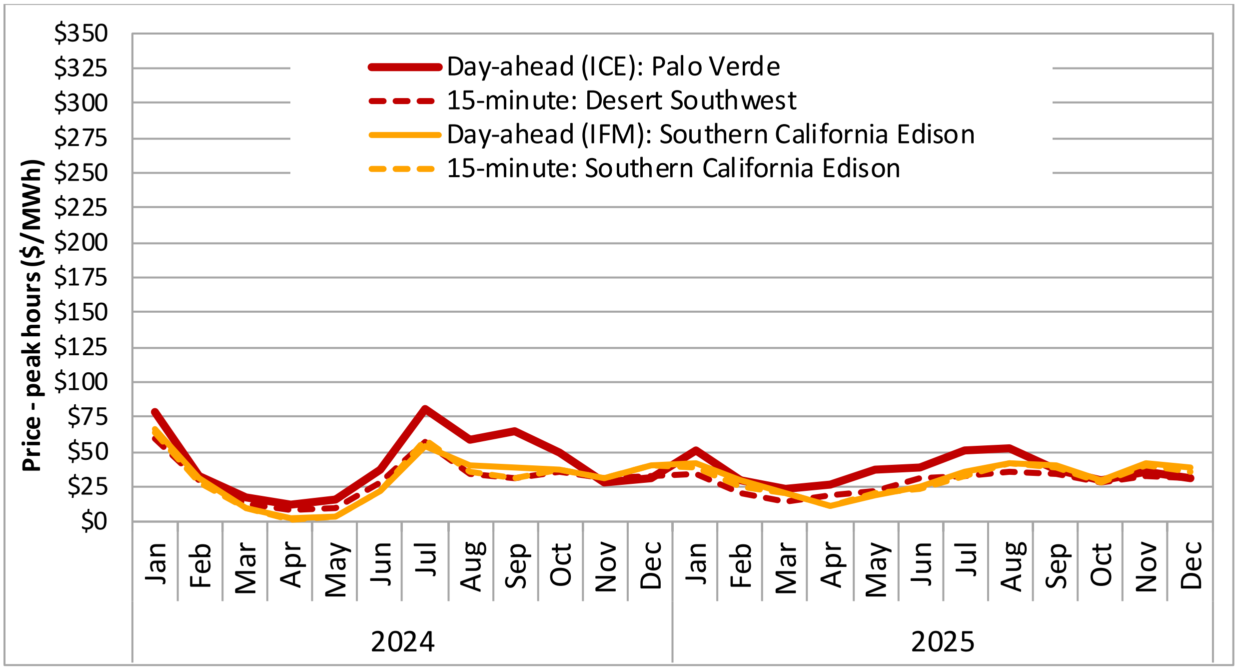


Figure 2.11 compares monthly average prices in the bilateral and ISO day-ahead market for 2024 and 2025. The California ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Figure 2.12 shows daily California ISO

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

Figure 2.11 Monthly average day-ahead and bilateral market prices

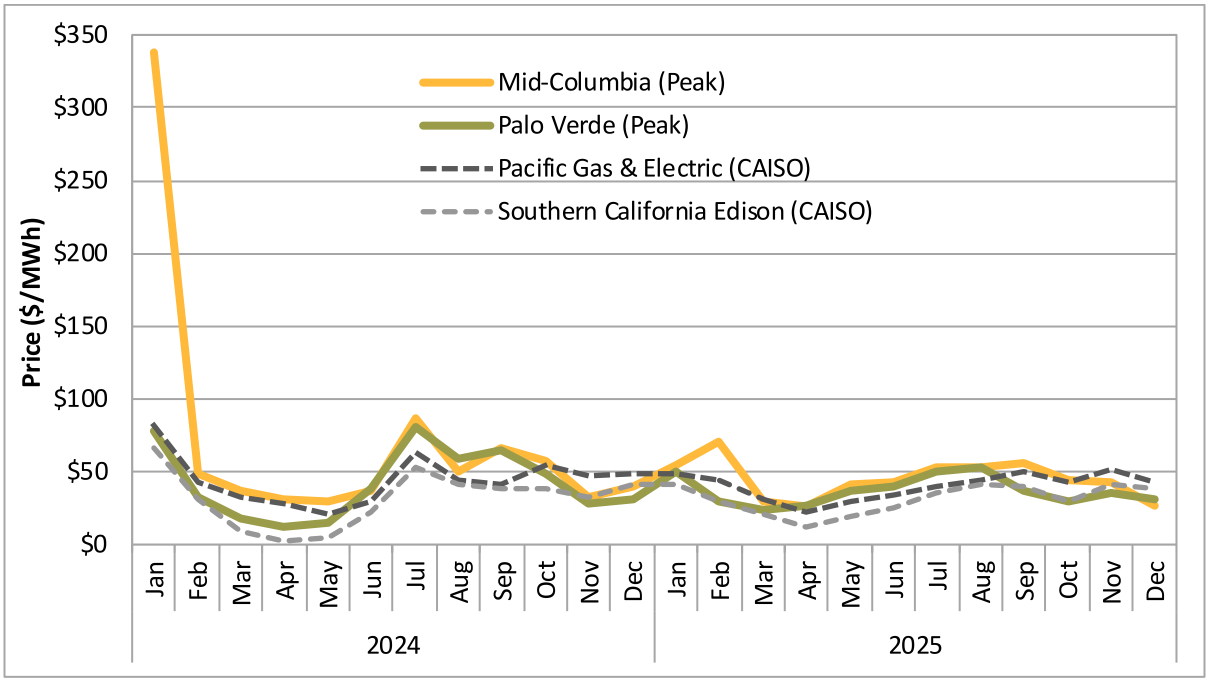
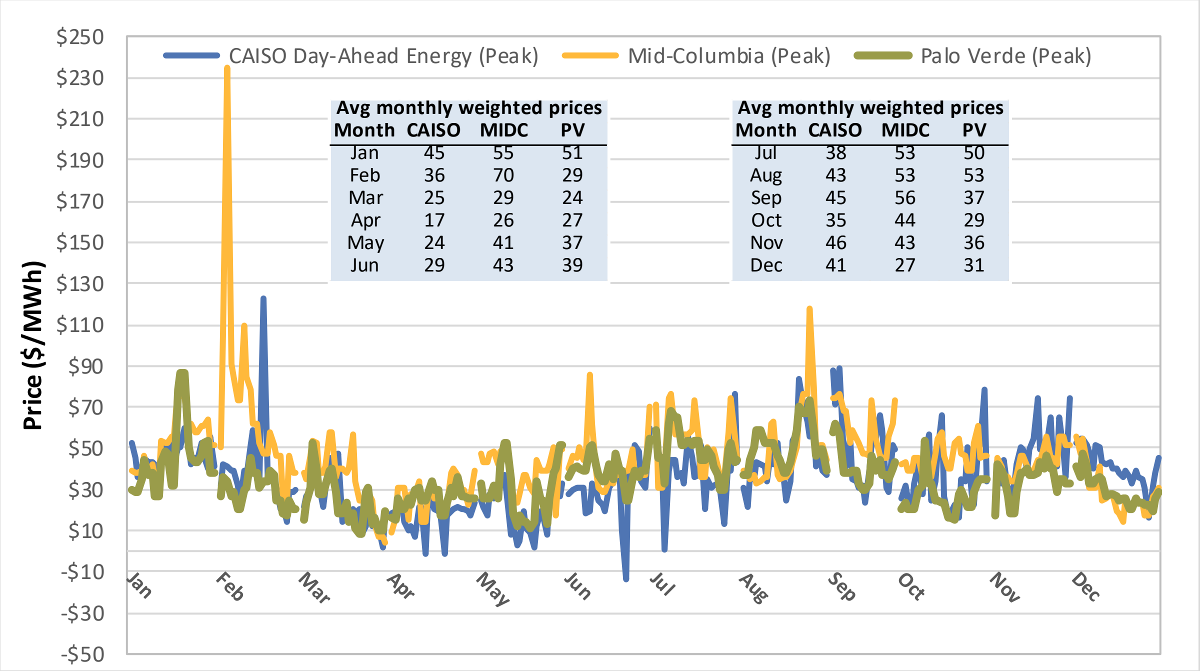


Figure 2.12 Daily average day-ahead California ISO & bilateral market prices (January–December)



Month	CAISO	MIDC	PV
Jan	45	55	51
Feb	36	70	29
Mar	25	29	24
Apr	17	26	27
May	24	41	37
Jun	29	43	39

Month	CAISO	MIDC	PV
Jul	38	53	50
Aug	43	53	53
Sep	45	56	37
Oct	35	44	29
Nov	46	43	36
Dec	41	27	31

Average day-ahead bilateral prices from the Intercontinental Exchange (ICE) at these bilateral hubs were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the year using data published by Powerdex. The average day-ahead ICE prices at Mid-Columbia were greater than the average real-time Powerdex Mid-Columbia prices by about $4.70/MWh. Average day-ahead ICE prices at Palo Verde were higher than real-time Powerdex Palo Verde prices by about $0.45/MWh.

2.5 Price variability

This section analyzes the frequency of prices exceeding $250/MWh and the occurrence of negative prices. Two groups of balancing authority areas (BAAs) were included: the first group consists of those participating in both the day-ahead and real-time markets, which as of this year includes only the California ISO balancing area.[109] The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the California ISO balancing area.

High prices

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

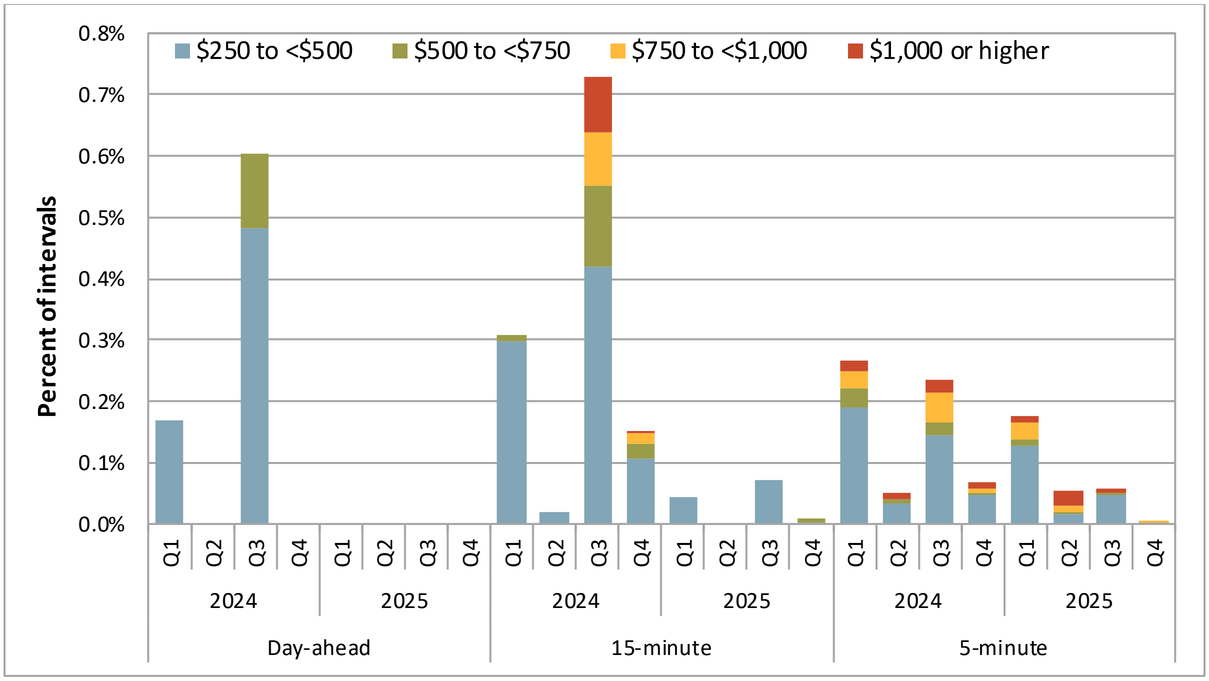
Figure 2.13 shows the quarterly frequency of high prices across all three markets for the balancing area participating in both the day-ahead and real-time markets from Q1 2024 to Q4 2025.[110] Figure 2.14 illustrates the quarterly frequency of high prices for balancing areas participating only in the real-time markets during the same period.[111]

In the day-ahead market, the frequency of high prices over $250/MWh decreased compared to 2024. In 2025, the day-ahead market recorded zero percent of intervals with an average price exceeding $250/MWh. In the previous year, 0.2 percent of intervals had prices above $250/MWh.

In the 15-minute market, the frequency of high prices for the balancing area participating in both the day-ahead and real-time markets decreased from 0.3 percent in 2024 to 0.03 percent in 2025. Similarly, for balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices decreased from 0.8 percent in 2024 to 0.1 percent in 2025.

In the 5-minute market, the frequency of high prices for the balancing area participating in the day-ahead and real-time markets decreased from 0.15 percent in 2024 to 0.07 percent in 2025. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market decreased from 0.7 percent to 0.1 percent.

Figure 2.13 Frequency of high prices in BAAs participating in the day-ahead market (CAISO)



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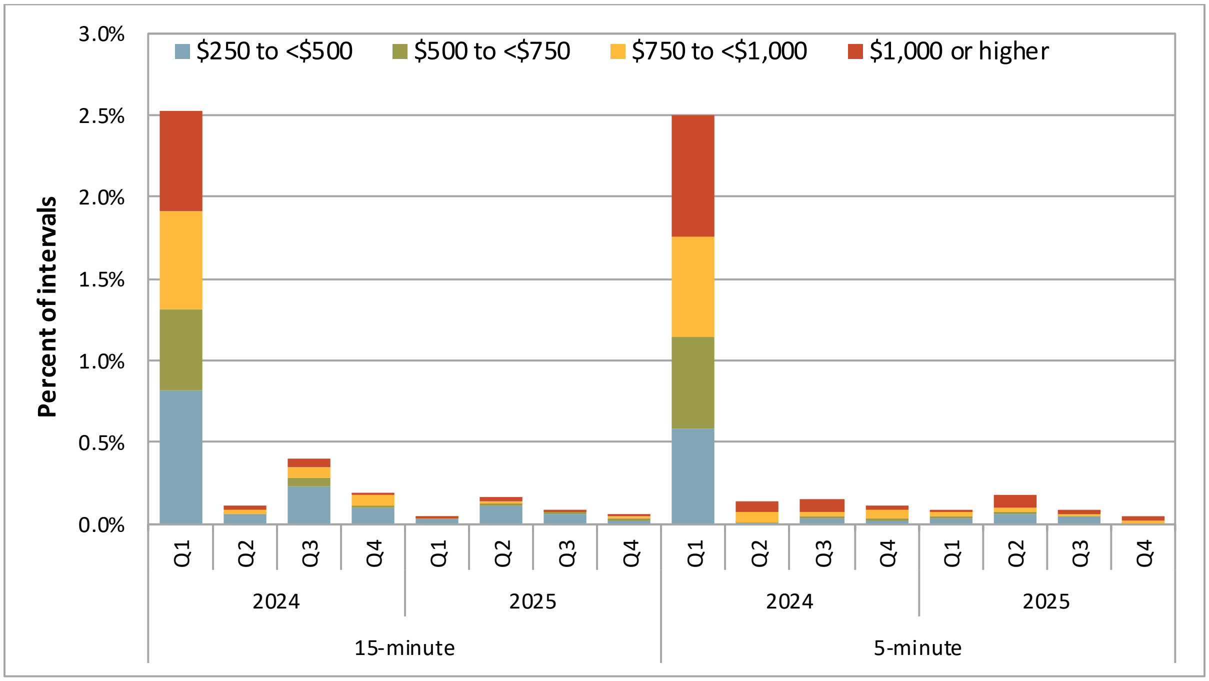
[110] The frequency of high prices was measured at the three largest DLAPs within the California ISO balancing area: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

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

Figure 2.14 Frequency of high prices in BAAs participating only in the real-time markets



Negative prices

Figure 2.15 and Figure 2.16 show the frequency of negative prices across two groups of balancing areas—those participating in the day-ahead market and those participating only in the real-time markets—spanning the period from Q1 2024 to Q4 2025 for each market. Overall, the frequency of negative prices decreased for both the day-ahead and real-time market participating groups.

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

For balancing areas participating in the day-ahead and real-time market—currently just the CAISO balancing area—the frequency of negative prices decreased, with an average decrease of about 20 percent compared to the previous year. In the day-ahead market, the frequency decreased from 8.8 percent to 7.1 percent compared to the previous year. In the 15-minute market, it decreased from 10 percent to 8.2 percent, and in the 5-minute market, it decreased from 10.7 percent to 8.4 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in the WEIM besides CAISO—the frequency of negative prices decreased across the 15-minute and 5-minute markets, with an average reduction of about 16 percent compared to the previous year.

For instance, in the 15-minute market, the frequency decreased from 5.4 percent to 4.6 percent and in the 5-minute market, it decreased from 6.4 percent to 5.3 percent in 2025.

Figure 2.15 Frequency of negative prices in BAAs participating in the day-ahead market (CAISO)

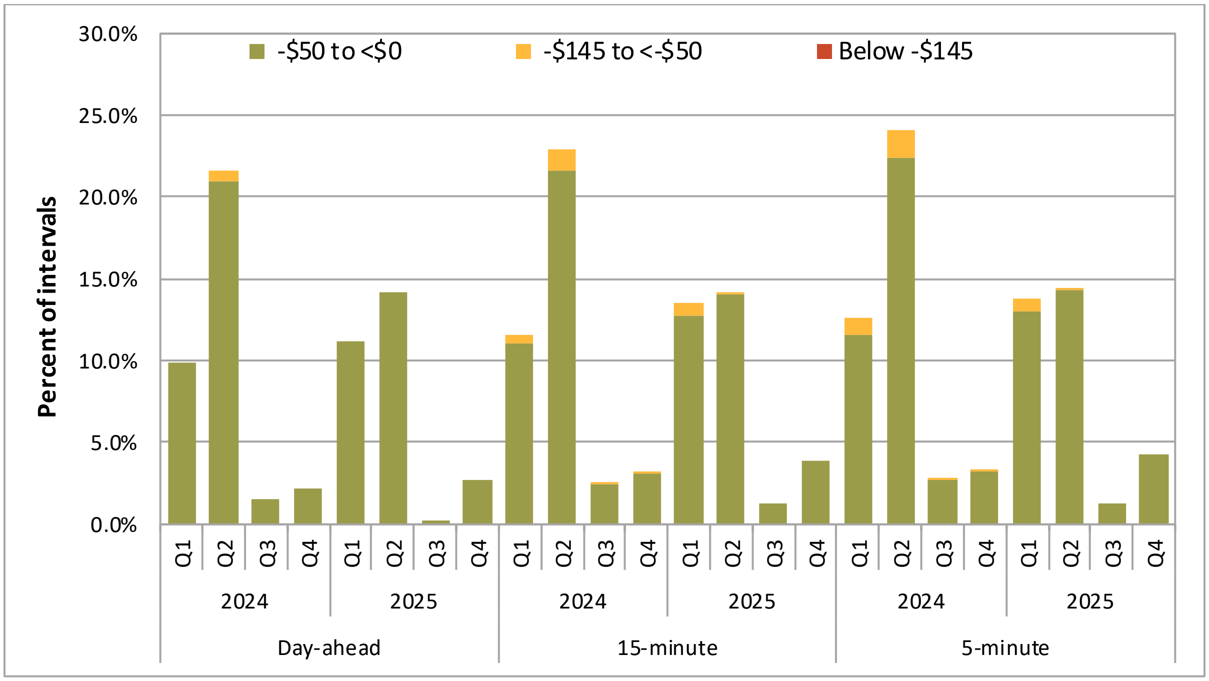
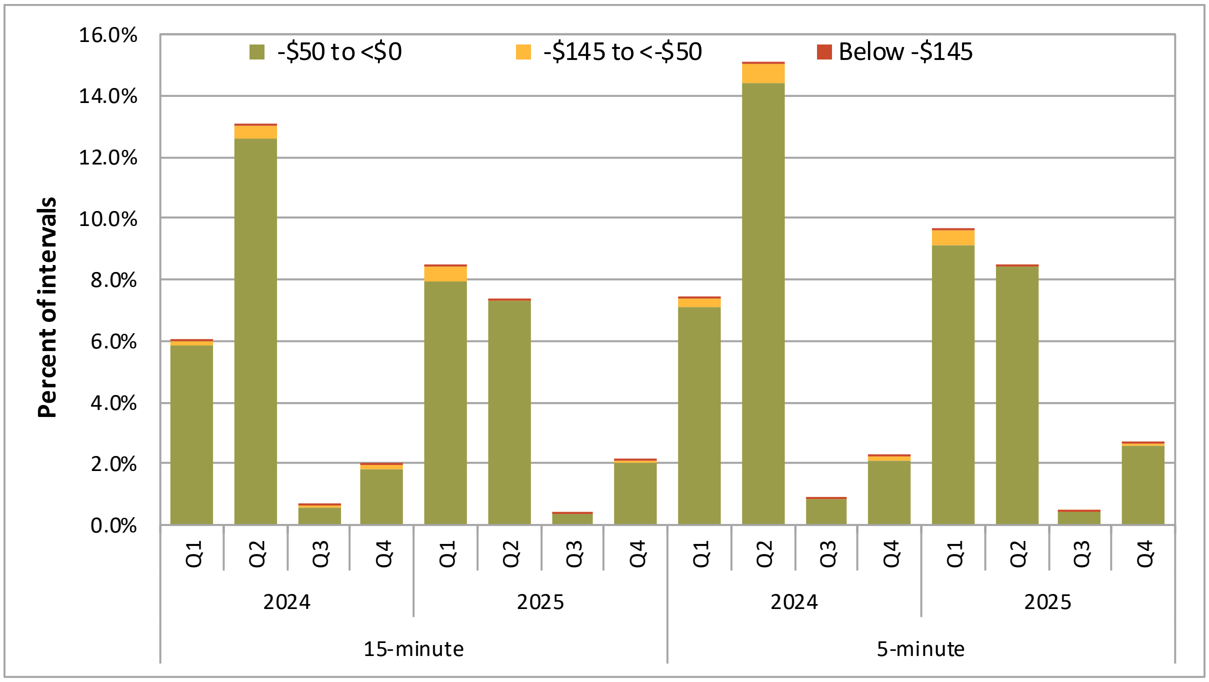


Figure 2.16 Frequency of negative prices in BAAs participating only in the real-time markets



2.5.1 FERC Order No. 831

The California ISO FERC Order 831 policy will increase the ISO market energy bid cap to $2,000/MWh if either of two conditions are met. The bid cap will rise to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of ISO market hourly prices, exceeds $1,000/MWh. The bid cap will also rise to $2,000/MWh if a cost-verified energy bid from a resource-specific resource is greater than the $1,000/MWh bid cap.

The California ISO did not raise the energy bid cap and penalty prices to $2,000/MW in 2025. In comparison, in 2024 the energy bid cap and penalty prices were raised to $2,000/MWh for many hours in both the day-ahead and real-time markets during an extreme cold temperature period from January 13 through 16, as well as during hours ending 19 and 20 on September 5.

2.6 Power balance constraint

WEIM area prices can be significantly impacted by the frequency with which the power balance constraint (PBC) is relaxed, also referred to as a *power balance infeasibility*.[112] When the power balance constraint is relaxed for undersupply conditions in an area, prices are set using the $1,000/MWh penalty price for this constraint in the pricing run of the market model.[113] During the initial six months of joining the Western Energy Imbalance Market, *transition period pricing* instead sets prices for new WEIM balancing areas at the highest dispatched economic bid, rather than a penalty parameter, when the power balance constraint is relaxed.

Table 2.5 shows the frequency of power balance constraint relaxations in the 15-minute and 5-minute markets by balancing area for undersupply (shortage) and oversupply (excess) conditions throughout 2025. The color shading indicates frequency: darker colors represent relatively higher frequency, lighter colors indicate lower frequency, and white areas signify near-zero frequency.

Balancing authority areas in the Desert Southwest region, including El Paso Electric and Salt River Project had a relatively high frequency of PBC relaxations. El Paso Electric and Salt River Project had high frequencies of undersupply infeasibilities and oversupply infeasibilities. In California, LADWP had relatively high frequencies of oversupply infeasibilities.

Most infeasibilities occurred following a resource sufficiency evaluation failure. Reduced transfer capability as a result of failing the test can affect an area’s ability to balance load, as there is less flexibility to import or export to neighboring areas. As a result, there is often a strong correlation between WEIM areas failing a resource sufficiency evaluation test and having a power balance constraint relaxation.

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[112] This analysis excludes infeasibilities that were resolved by the load conformance limiter, mitigated by available balancing capacity, or identified as invalid.

[113] The penalty parameter while relaxing the constraint for power shortages may rise from $1,000/MWh to $2,000/MWh depending on system conditions, per phase 2 implementation of FERC Order 831.

Table 2.5 Frequency of power balance constraint relaxations by market

Balancing area	Oversupply infeasibility		Undersupply infeasibility	
	15-minute	5-minute	15-minute	5-minute
El Paso Electric	.11%	.14%	.16%	.23%
Salt River Project	.07%	.08%	.10%	.20%
LADWP	.08%	.10%	.01%	.00%
Idaho Power	.00%	.00%	.05%	.09%
Tucson Electric	.00%	.00%	.01%	.07%
WAPA - Desert SW	.02%	.01%	.03%	.03%
Arizona PS	.00%	.00%	.00%	.06%
PacifiCorp East	.00%	.04%	.00%	.02%
NorthWestern	.00%	.01%	.00%	.04%
PSC New Mexico	.00%	.00%	.01%	.05%
Seattle City Light	.02%	.02%	.01%	.02%
Puget Sound Energy	.00%	.00%	.02%	.02%
NV Energy	.00%	.00%	.00%	.02%
PacifiCorp West	.00%	.00%	.01%	.01%
Tacoma Power	.00%	.00%	.01%	.01%
Avista Utilities	.00%	.00%	.00%	.01%
Turlock ID	.02%	.00%	.00%	.00%
Portland GE	.00%	.00%	.00%	.01%
BPA	.01%	.00%	.00%	.00%
Avangrid	.00%	.00%	.00%	.00%
CAISO	.00%	.00%	.00%	.00%
BANC	.00%	.00%	.00%	.00%
Powerex	.00%	.00%	.00%	.00%
Average	**.01%**	**.02%**	**.02%**	**.04%**

Figure 2.17 shows the frequency of system-wide power balance constraint infeasibilities identified by market from Q1 2023 through Q4 2025. These percentages reflect how often any PBC was violated across all BAAs, based on the total number of possible BAA-interval combinations.[114] The yellow bars indicate the frequency of undersupply infeasibilities (shortage), while the green bars represent the frequency of oversupply infeasibilities (excess) for each quarter.

In 2025, average infeasibility frequency for undersupply was 0.02 percent in the 15-minute market and 0.03 percent in the 5-minute market. For oversupply, the rates were lower: 0.01 percent in the 15-minute and 0.02 percent in the 5-minute markets. Undersupply infeasibilities declined compared to 2024, when undersupply occurred at rates of 0.05 percent and 0.08 percent in the 15-minute and 5-minute markets, respectively. Oversupply infeasibilities slightly decreased in the 15-minute market,

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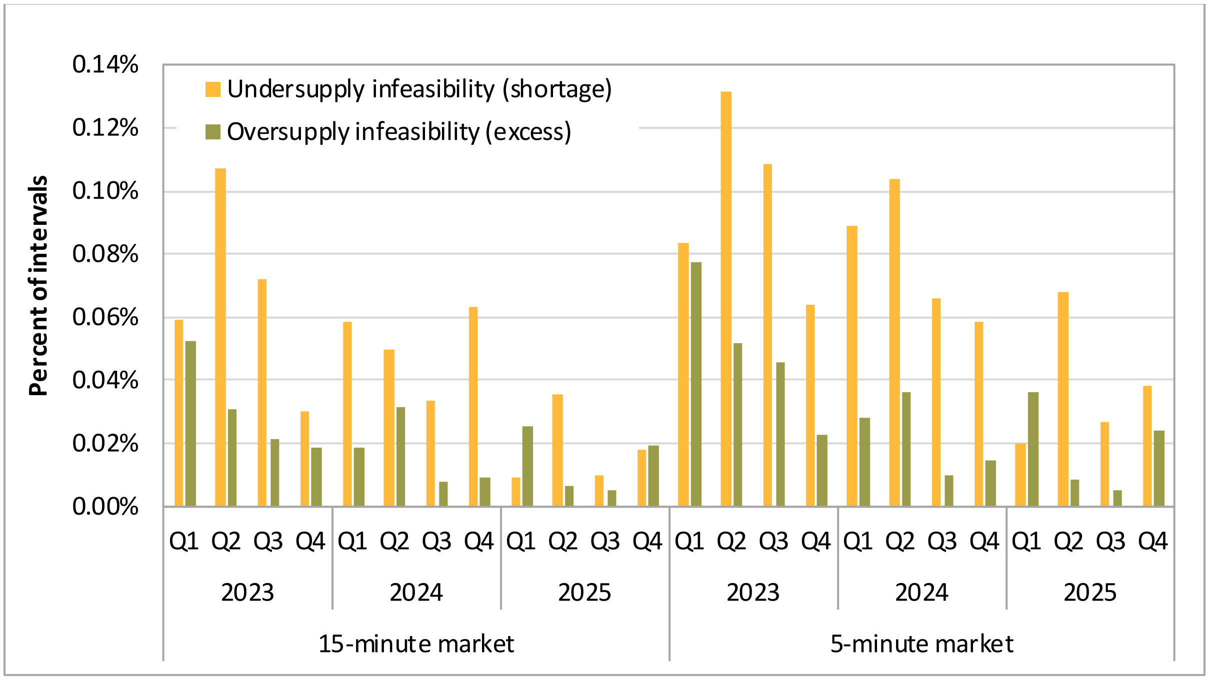
[114] The frequency is based on the formula: PBC frequency = (Total PBC occurrences in the quarter) / (Number of BAAs × Number of intervals in the quarter).

from 0.02 percent to 0.01 percent in the 15-minute market and the 5-minute market remained at a similar level this year, at 0.02 percent, similar to 2024.

Overall, there were more power balance constraint relaxations due to undersupply (shortage) than oversupply. WEIM areas had more infeasibilities in the 5-minute market than in the 15-minute market.

Figure 2.17 Frequency of system-wide power balance constraint infeasibilities by market



2.7 Total wholesale market costs

DMM estimates the total wholesale cost of serving load for balancing areas in the day-ahead market. The total estimated wholesale cost for the California ISO balancing authority area in 2025 was about $8.45 billion, or about $42/MWh. This represents a 6 percent decrease from about $44/MWh or $9.1 billion in 2024. After normalizing for natural gas prices and greenhouse gas compliance costs, using 2021 as a reference year, DMM estimates that total normalized wholesale energy costs decreased by about 24 percent from about $67/MWh in 2024 to about $51/MWh in 2025.

Historically, decreases in natural gas prices have been a primary driver of lower nominal wholesale electricity costs. However, in 2025, nominal wholesale costs declined despite increases in natural gas prices. This was due to several factors discussed in Chapter 1, including significantly lower load in the CAISO balancing area, particularly during typically high priced peak net load hours, as well as significant increases in renewable and storage generation. The absence of tight conditions that led to high prices in January 2024 also contributed to lower nominal wholesale costs in 2025.

Figure 2.18 shows total estimated wholesale costs per megawatt-hour of system load for the previous five years. Wholesale costs are provided in nominal terms (blue bar), and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is included to account for the estimated cost of compliance with California’s greenhouse gas cap-and-trade program. The green line represents the annual average daily natural gas price, including greenhouse gas compliance.[115]

Figure 2.18 Total annual wholesale costs per MWh of load (2021–2025)

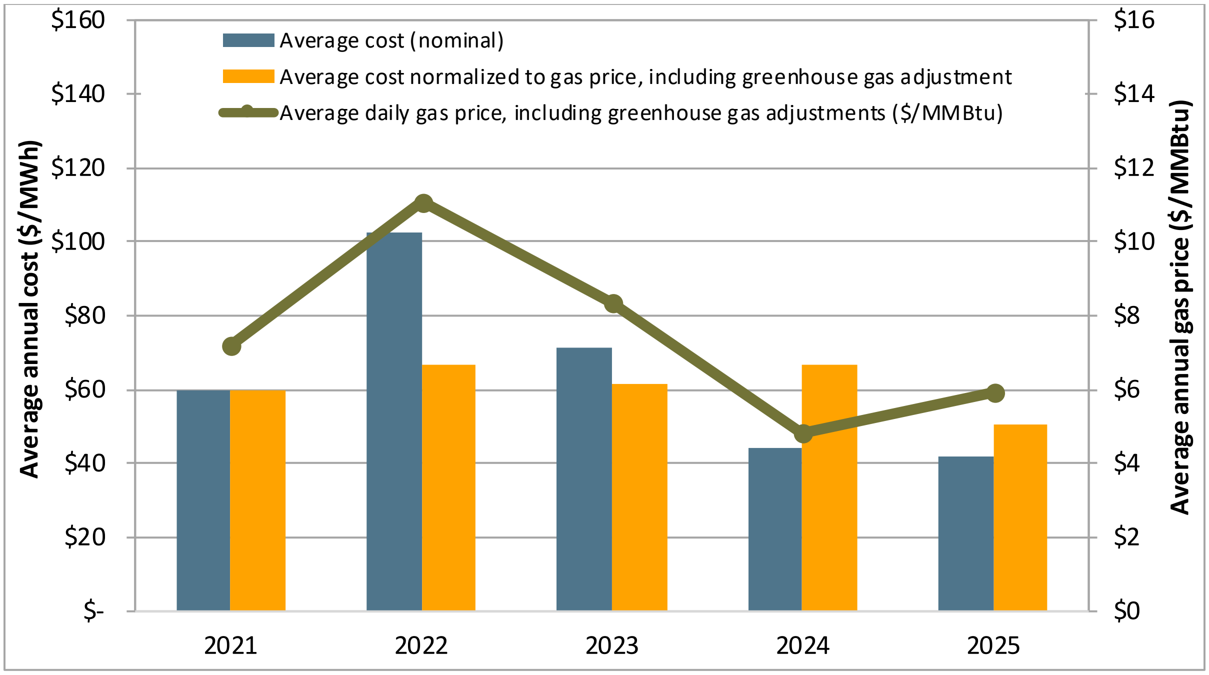


Table 2.6 provides annual summaries of nominal total wholesale costs by category for the previous five years.[116] The total wholesale energy cost also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping product, and grid management charges.[117]

As shown in Table 2.6, the 6 percent decrease in total nominal cost in 2025 reflected an overall trend in lower costs over nearly all categories. Day-ahead energy costs decreased by $2.43/MWh or roughly 6 percent. Real-time energy costs decreased about 17 percent, from $1.70/MWh down to $1.42/MWh. Reserve costs and bid cost recovery decreased by 11 percent and 1 percent, respectively, while backstop capacity costs remained unchanged at zero. Grid management charge costs saw an increase of about 18

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[115] For the wholesale energy cost calculation, an average of annual gas prices was used from the SoCal Citygate and PG&E Citygate hubs. Electricity costs have tended to move with changes in gas costs, as illustrated by the ratio between the blue bar and the green line. A gas cost factor of 0.8 (80 percent) has historically been incorporated into the normalization calculations to account for this relation between electricity costs and gas prices. In recent annual reports, we have adjusted this factor to one. This allows for a more straightforward interpretation of the normalized wholesale cost: increases or decreases relative to the reference year indicate significant factors other than gas and greenhouse gas compliance costs driving changes in wholesale electricity costs.

[116] Values shown in this section represent cost to California ISO load only and do not include costs to load in the WEIM.

[117] Costs for each of these categories is calculated based on settlements data available at the time of this publication. In annual reports prior to 2018, the costs were calculated using a methodology as described in Appendix A of DMM's *2009 Annual Report on Market Issues & Performance*, with modifications over time to account for changes in market structure as outlined in later reports. *2009 Annual Report on Market Issues & Performance,* Department of Market Monitoring, April 2010: http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf

percent, from $0.51/MWh in 2024 to $0.60/MWh in 2025. Combined natural gas and greenhouse gas costs increased about 23 percent.

Day-ahead energy costs remain the largest proportion of wholesale costs at just over 92 percent, similar to 2024. The remaining components continue to represent a relatively small portion of the total. Real-time energy costs remained about 3.4 percent of overall costs, similar to 2024. Overall reliability costs remained at zero in 2025—when resources with existing reliability must-run (RMR) contracts transitioned into resource adequacy contracts, and no new capacity procurement mechanism designations were made for 2024 or 2025. Bid cost recovery totals remained about the same as a percentage of total cost, at about 1.6 percent in 2024 and 2025. Reserve costs decreased as a percentage of total cost to 1.2 percent from almost 1.3 percent in 2024.[118]

Table 2.6 Estimated average wholesale energy costs per MWh (2020–2024)

	2021	2022	2023	2024	2025	Change '24-'25
Day-ahead energy costs	$ 56.37	$ 96.06	$ 65.92	$ 40.93	$ 38.50	$ (2.43)
Real-time energy costs (incl. flex ramp)	$ 1.28	$ 3.51	$ 2.42	$ 1.71	$ 1.42	$ (.29)
Grid management charge	$ .45	$ .45	$ .50	$ .51	$ .60	$ .09
Bid cost recovery costs	$ .74	$ 1.18	$ 1.36	$ .69	$ .68	$ (.01)
Reliability costs (RMR and CPM)	$ .19	$ .23	$ .07	$ .00	$ -	$ (.00)
Average total energy costs	**$ 59.03**	**$ 101.43**	**$ 70.26**	**$ 43.84**	**$ 41.20**	**$ (2.64)**
Reserve costs (AS and RUC)	$ .84	$ 1.20	$ .81	$ .56	$ .50	$ (.06)
Average total costs of energy and reserve	**$ 59.87**	**$ 102.63**	**$ 71.08**	**$ 44.40**	**$ 41.70**	**$ (2.70)**

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[118] Additional information on bid cost recovery and ancillary service costs is included in Chapters 8 and 12, respectively.

3 Energy market competitiveness and mitigation

This chapter assesses the competitiveness of ISO energy markets and the impact and effectiveness of various market power mitigation provisions. Key findings include:

- **Overall prices in the day-ahead and real-time markets were competitive,** averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating cost.
- **The number of structurally uncompetitive hours in the day-ahead market was down significantly in 2025.** Continued additions of battery (and hybrid) capacity offset decreases in gas capacity and helped reduce the number of potentially non-competitive hours. Lower loads also contributed to this increase in competitiveness.
- **The WEIM real-time market residual supply index with the three largest suppliers removed was less than one during 535 15-minute intervals (1.5 percent) in 2025.** There were more structurally uncompetitive real-time market intervals in 2025 than in 2024 (363 intervals) and 2023 (472 intervals).
- **The amount of energy downstream of non-competitive constraints—and therefore subject to potential mitigation—decreased overall in the day-ahead and real-time markets.** Bid subject to potential mitigation declined in the CAISO balancing area from elevated levels observed in 2024, while changes across other WEIM regions were more mixed.
- **Most resources subject to mitigation submitted competitive offer prices, so a low portion of bids were lowered as a result of the bid mitigation process.** Roughly 28 percent (1,074 MW) of the day-ahead bids and 19 percent (990 MW) of 15-minute market bids that were subject to mitigation were changed.
- **The potential increase in dispatch from bids lowered by mitigation remained very low**. In the day-ahead market, the average potential increase in dispatch averaged 27 MW. In the 15-minute market, system-wide potential increase in dispatch from mitigation averaged 75 MW.
- **Battery resources accounted for a substantial share of bids subject to mitigation**, reflecting their growing role in participating in congested intervals and locations.

3.1 Structural measures of competitiveness

Market structure refers to the ownership of available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the *pivotal supplier test* and the *residual supply index*. Both measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test:** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal; this is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal supplier test, supply of the three largest suppliers is removed.

- **Residual supply index:** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[119] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI_1. With the two or three largest suppliers excluded, we refer to these results as RSI_2 and RSI_3, respectively.

3.1.1 Structural competitiveness in the day-ahead market

The day-ahead residual supply index analysis considers balancing areas participating in the day-ahead market.[120] This analysis includes the following elements to account for supply and demand:

- Day-ahead bids for physical generating resources (adjusted for outages and de-rates). Virtual bids are excluded.
- Maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- Demand includes the day-ahead load forecast, non-dispatchable pump load, self-scheduled exports, and upward ancillary service requirements.[121]
- Ancillary services bids in excess of energy bids are included to account for additional supply available to meet ancillary service requirements in the day-ahead market.
- CPUC jurisdictional investor-owned utilities are excluded as potentially pivotal suppliers.

During 2025, the number of hours with a day-ahead residual supply index less than one was significantly lower compared to the previous three years, indicating more competitive conditions in the day-ahead market. Table 3.1 shows the number of hours each year with a residual supply index ratio less than one since 2022, based on the assumptions listed above. Figure 3.1 shows the same information graphically by quarter. For 2025, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during only 23 hours. In comparison, the RSI_3 index was less than one during 176 hours in 2024 and 129 hours in 2023.

Figure 3.2 summarizes non-pivotal supply with the three largest suppliers excluded in the 500 hours with the lowest RSI_3 values. In particular, continued additions of battery (and hybrid) capacity increased available non-pivotal supply. This helped to offset decreases in gas capacity and reduced the number of potentially non-competitive hours. Lower loads also contributed to more competitive conditions during 2025.

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[119] For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

[120] Prior to May 1, 2026, CAISO was the only balancing area participating in the day-ahead market.

[121] The day-ahead load forecast factors in losses.

Table 3.1 **Hours with day-ahead residual supply index less than one by year (balancing areas in the day-ahead market)**

Year	RSI_1	RSI_2	RSI_3
2022	44	79	130
2023	26	75	129
2024	24	97	176
2025	0	7	23

Figure 3.1 **Hours with day-ahead residual supply index less than one by quarter (balancing areas in the day-ahead market)**

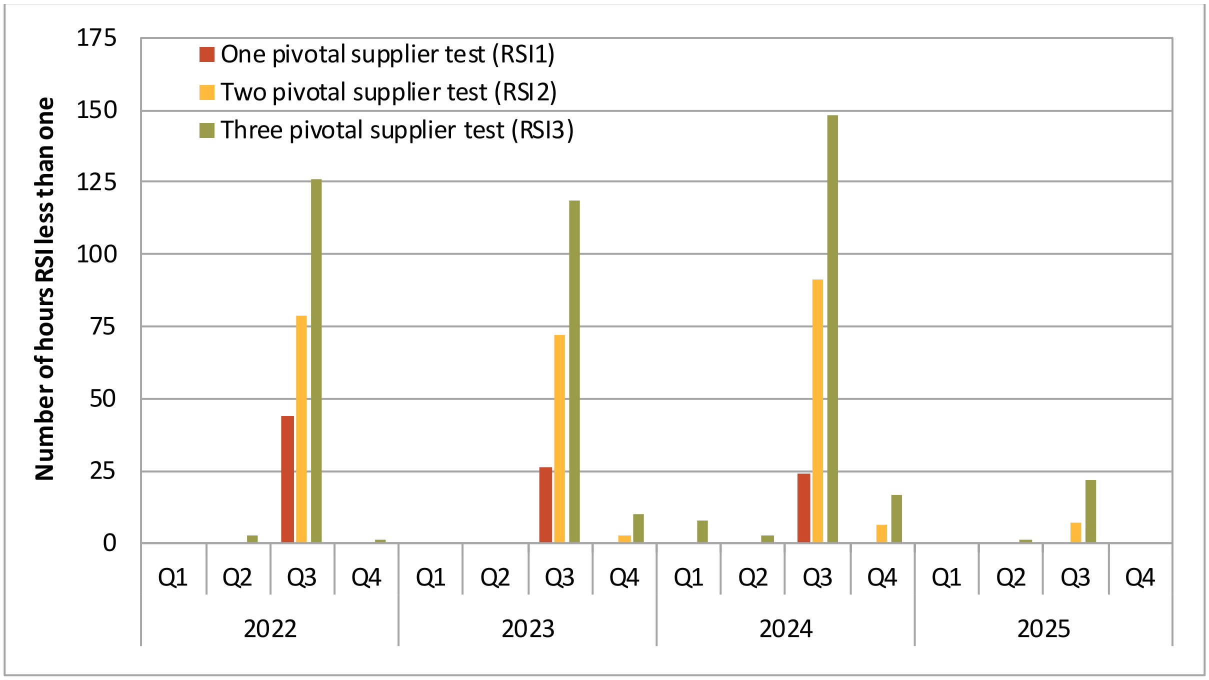
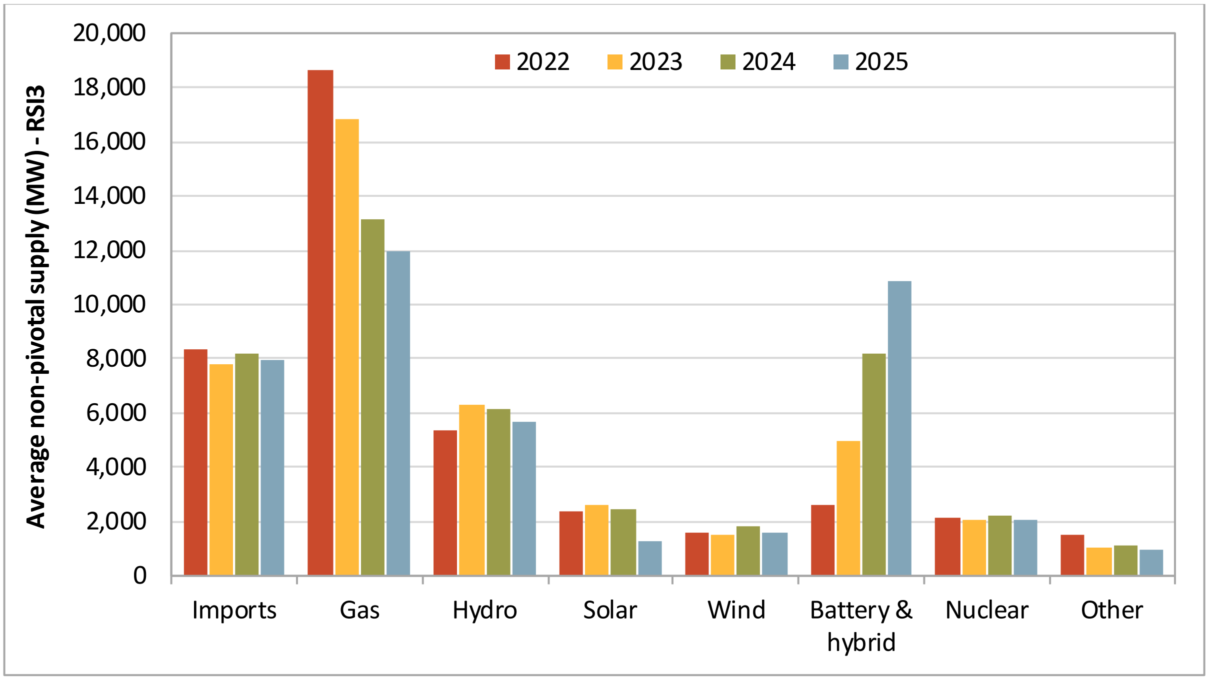


Figure 3.2 **Non-pivotal supply with the largest three suppliers excluded (balancing areas in the day-ahead market, lowest 500 hours)**



3.1.2 Structural competitiveness in the real-time market

The real-time residual supply index analysis instead considers all balancing areas in the greater Western Energy Imbalance Market system. This analysis includes the following elements to account for supply and demand:

- The hour-ahead scheduling process (HASP) is used in the real-time market to account for the competitive pressure of hourly block imports that bid into the market.[122]
- The analysis includes all balancing areas that are part of the greater WEIM system that includes the CAISO balancing area. Demand is total market load for this system. Balancing areas that are either import or export constrained relative to this system are only counted as fixed WEIM transfers with this larger system.
- Imports are considered competitive and account for the maximum availability relative to import transmission constraint limits. Exports are fixed at their schedules as demand.

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[122] Supply offers cannot change between HASP and the subsequent 15-minute and 5-minute markets. Using HASP to assess real-time competitiveness is consistent with the system market power mitigation proposal that was developed in 2020. System Market Power Mitigation – Revised Draft Final Proposal, California ISO, September 18, 2020: https://stakeholdercenter.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-SystemMarketPowerMitigation.pdf

- All other supply conditions are consistent with how they are counted as part of the dynamic competitive path assessment (DCPA) that is used in the local market power mitigation process.[123]
- Unlike the day-ahead assessment—which assumes that all capacity from non-pivotal suppliers is available and all capacity from pivotal suppliers is withholdable within the 24-hour optimization—the real-time assessment considers resource constraints and conditions in real-time. The three largest suppliers are identified from net sellers based on withholdable capacity in each interval.[124] Supply from the three largest suppliers is then counted only at the minimum supply point (considering ramp constraints, ancillary service obligations, etc.). Supply from all other non-pivotal suppliers is counted at the maximum supply point.

As an example, Figure 3.3 shows the residual supply index components for the greater WEIM system during an example real-time interval when the RSI_3 was lowest. During this interval, four balancing areas were export constrained toward this system and are shown only as net WEIM transfers into the greater system (teal). The yellow, blue, and red bars show the load and non-WEIM transfers for the remaining 19 balancing areas participating in the WEIM. The dark green bar shows the minimum supply point for generation from the three largest potentially pivotal suppliers, while the lighter green bar shows the maximum available generation from the non-pivotal suppliers. In total, the residual supply index was 0.95, indicating failure of the three pivotal supplier test and a potentially non-competitive interval.

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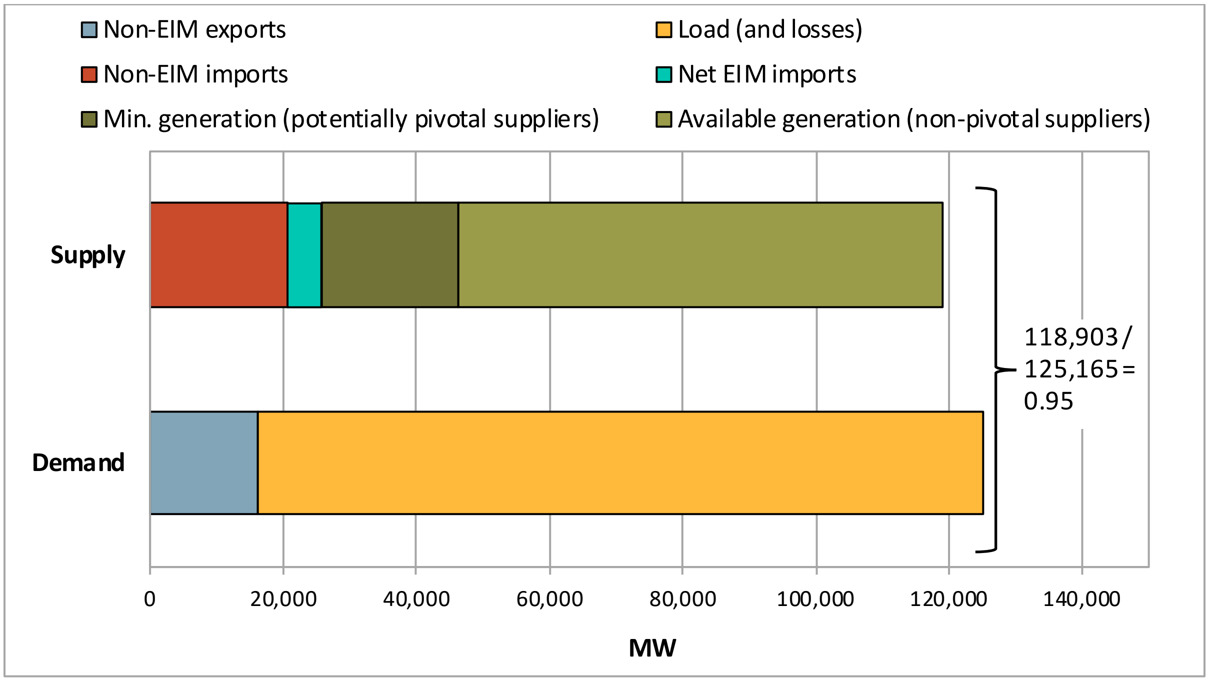
[123] For more information on the DCPA calculation used for local market power mitigation, see the Business Practice Manual attachment for Market Operations, Appendix B, Competitive Path Assessment: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations

[124] This can include supply from WEIM balancing areas that are part of the unconstrained greater WEIM system.

Figure 3.3 Example — Three pivotal suppliers test (August 21, 2025, hour-ending 19, interval 4)



During 2025, the number of intervals with a real-time residual supply index less than one was higher compared to the previous two years, indicating somewhat less competitive conditions in the real-time market. Here, there were 535 15-minute intervals (or 1.5 percent of intervals) in which the RSI was less than one with the three largest suppliers accounted for. In comparison, there were 363 intervals during 2024 and 472 intervals during 2023.

Figure 3.4 shows the number of 15-minute intervals and percent of intervals with a RSI_3 ratio less than one for each quarter since 2023.[125] In these intervals, the number of balancing areas evaluated in the greater WEIM system varied. There were all or almost all balancing areas accounted for in this system in around 43 percent of these intervals. In the remaining intervals, balancing areas in the Pacific Northwest region were often export constrained relative to the larger WEIM system. Further, the large majority of these intervals (when the RSI was less than one with the three largest suppliers accounted for) occurred between hours-ending 19 and 21, during peak net load conditions.

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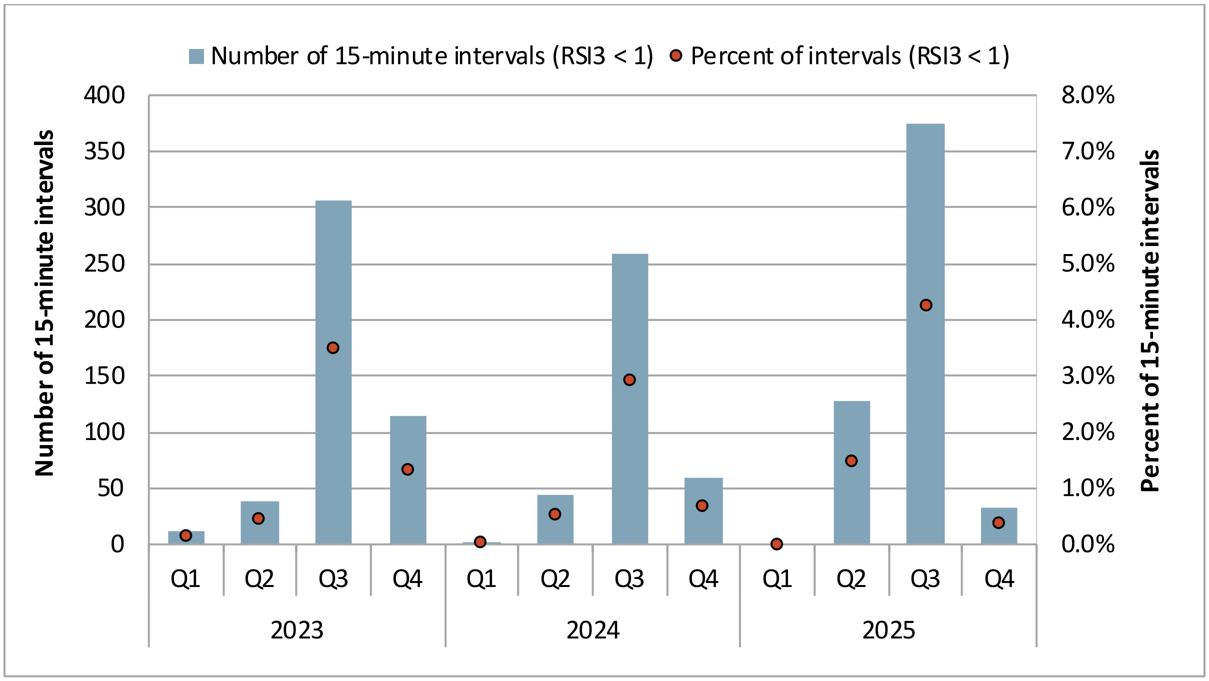
[125] The analysis includes all balancing areas that are part of the greater WEIM system that includes CAISO (not separated by WEIM transfer congestion). Between July 26 and November 15, 2023, the CAISO balancing area frequently restricted most WEIM transfers into the CAISO area in the hour-ahead and 15-minute markets. The result is that many of the intervals assessed in Q3 and Q4 of 2023 only included the CAISO balancing area, with other balancing areas export constrained relative to this.

Figure 3.4 Intervals with failed three pivotal supplier test (greater WEIM system)



3.2 Bidding conduct and price-cost markup

The previous section assessed whether suppliers had the ability to exercise market power based on the structure of the market. This section reviews *bidding conduct*—to what degree suppliers actually raised offers above marginal costs and what the impact was on market prices. DMM assesses this based on the *price-cost markup.* This measurement is a comparison between actual market prices and an estimate of prices that would result from a highly competitive market in which all suppliers bid at or near their marginal costs.

3.2.1 Day-ahead market price-cost markup

This section reviews the competitiveness of the ISO's day-ahead wholesale energy market.[126] The performance of the day-ahead market remained competitive, with prices during most hours near the marginal cost of generation. Price-cost markup for the comprehensive competitive scenario averaged around $4.66/MWh or about 12 percent, compared to $4.08/MWh or 9.6 percent the previous year. This increase in markup was largely the result of adjusting commitment costs in the competitive scenario. There was generally less on-line gas generation in 2025 in the actual market. This was due to increases in storage and renewable generation. The comprehensive competitive scenario adjusts commitment cost bids down to cost-based estimates. As a result, this competitive scenario was more likely to commit additional gas generation, shifting the supply stack and decreasing prices. This reduction in simulated competitive prices increased the measured price-cost markup, even though actual market prices remained close to marginal cost.

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[126] Prior to May 1, 2026, the day-ahead market consisted only of the CAISO balancing area.

For the day-ahead price-cost markup, DMM calculates estimated competitive prices by using a version of the day-ahead market software to simulate a competitive day-ahead market after replacing bids or other market inputs. First, DMM performs a base case re-run where no changes are made to the inputs from the original day-ahead market run.[127] DMM then compares these results to those simulated under a number of different competitive scenarios.[128] The day-ahead price-cost markup is calculated by comparing prices from each competitive scenario to prices from the base case re-run, using load-weighted average prices for all energy transactions in the day-ahead market.[129] When the price-cost markup is positive, this indicates that using competitive inputs (such as replacing high-priced energy bids with cost-based bids) lowered the price.

The analysis below highlights the results of *two* of the competitive scenarios that DMM performs:

> **Gas cost-based scenario:** Replace market bids of gas-fired units with the lower of the submitted bids or their default energy bids (DEBs) to capture the effect of competitive bidding of energy by gas resources.
> **Comprehensive scenario:** This is the most comprehensive scenario. It replaces market bids of all generation and imports with the lower of their submitted bids or their default energy bids *and* adjusts commitment costs to competitive levels to capture the effect of competitive bidding for energy and commitment costs.[130] DMM uses this scenario as the primary observation to assess the competitiveness of the market.

Figure 3.5 shows results for the first scenario that caps energy bids for gas resources at the lower of their submitted bid or default energy bid. The red bars show the difference between the competitive scenario price and the base case price (price-cost markup). Actual market prices were very close to these estimated scenario prices, indicating that replacing only high-priced energy bids from gas resources with cost-based bids did not significantly lower prices. During high-priced hours, gas-fired resources were generally not setting prices. Price-cost markup values for this scenario were similar to the previous year, at about $0.67/MWh or 1.7 percent in 2025 compared to $0.66/MWh or 1.6 percent in 2024.

This scenario may be a low-end measure of system market power for the following reasons:

- The only change in market inputs in this scenario was to cap energy bids of gas-fired resources at their default energy bid, which includes a 10 percent adder above estimated marginal costs.
- All other bids were assumed to be competitive, including those of non-resource specific imports.

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[127] Trade dates that were unable to successfully complete the re-simulation of the market or were unable to replicate original market prices during this base case re-run were excluded from this analysis. In 2025, a total of 35 trade dates were excluded.

[128] Detailed descriptions of all of these scenarios can be found in the *Q4 2020 Report on Market Issues and Performance*, Department of Market Monitoring, April 28, 2021: http://www.caiso.com/Documents/2020-Fourth-Quarter-Report-on-Market-Issues-and-Performance-April-28-2021.pdf

[129] DMM calculates the price-cost markup as the percent difference from cost-based competitive scenario prices to base case market prices. For example, if the competitive price averaged $50/MWh and the base case price was $55/MWh, this would represent a price-cost markup of 10 percent.

[130] Bids for all generating resources subject to mitigation were set to the minimum of their submitted bid or default energy bid. Bids for import resources were set to the minimum of their bid or an estimated default energy bid (based on an opportunity cost default energy bid option offered by the ISO for hydro resources). Commitment costs were set to the minimum of their bid or 110 percent of the proxy price.

- This analysis did not change commitment cost bids for gas-fired resources, which are capped at 125 percent of each resource’s estimated start-up and minimum load bids.

Figure 3.5 Day-ahead market price-cost markup (gas cost-based scenario)

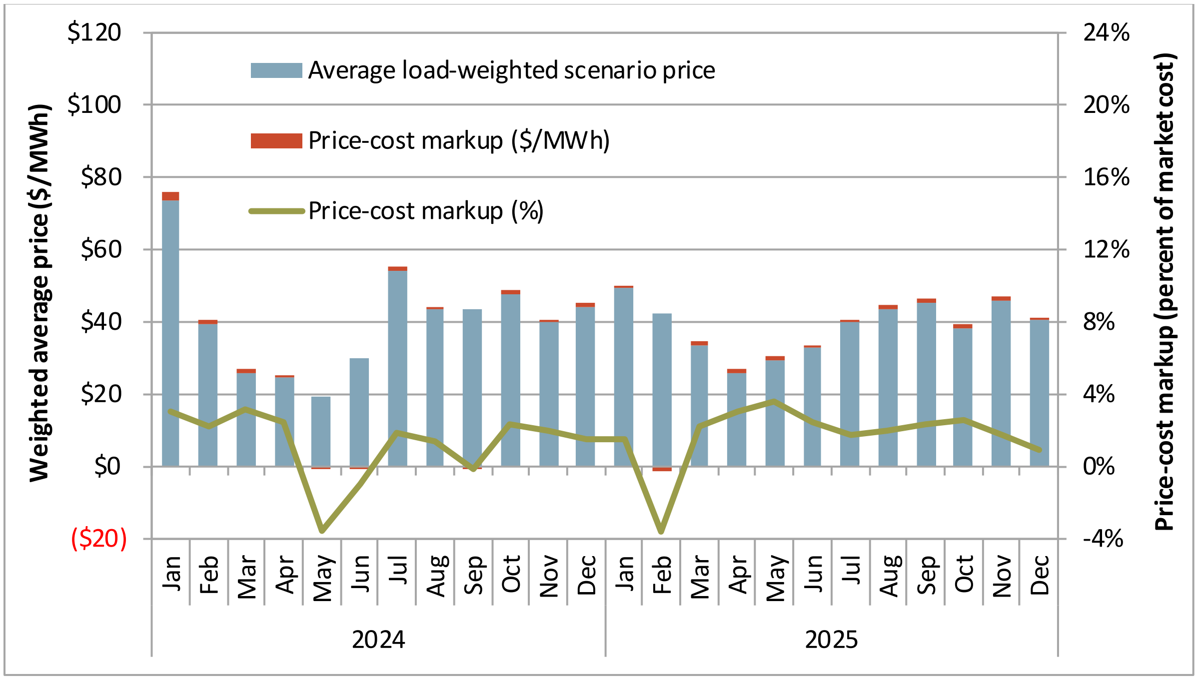
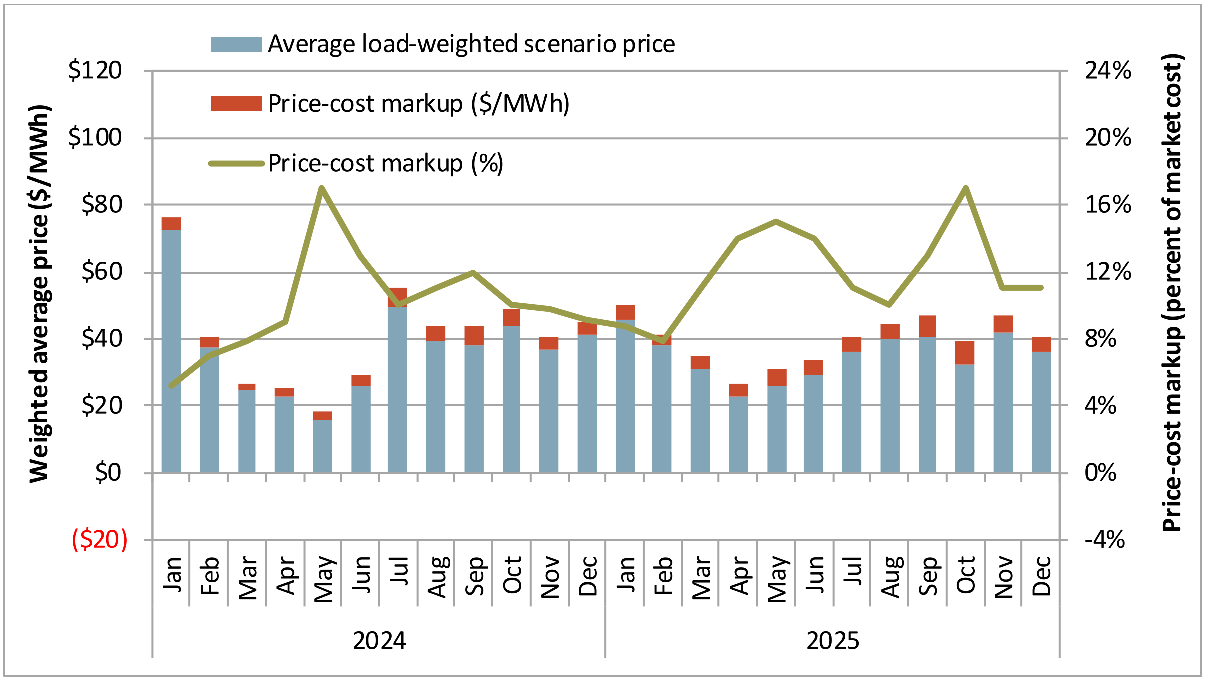


Figure 3.6 instead shows results for the comprehensive competitive scenario, which represents competitive bidding of energy and commitment costs for all resources, including imports. Overall, price-cost markup was low, indicating that prices were competitive for the year. However, compared to the scenario summarized in Figure 3.5, monthly average day-ahead market prices (base case prices) were higher above estimated competitive prices from this scenario. The average price-cost markup from this scenario was also higher compared to 2024. The average price-cost markup was about $4.66/MWh (or 12 percent), compared to $4.08/MWh (or 9.6 percent) the previous year.

The increased markup in this scenario compared to the scenario summarized above is largely from the adjustment of commitment costs. In particular, there continued to be more storage and renewable generation, resulting in less gas generation on-line in 2025 compared to 2024. As a result, the competitive scenario which caps the commitment costs had a bigger impact in 2025. Here, the scenario was more likely to commit additional generation (that was otherwise off-line with high commitment costs), shifting the supply stack and decreasing scenario prices. Lower simulated competitive prices mechanically increase the measured markup compared to actual market prices. In addition, storage and renewable generation also contributed to lower prices in 2025 compared to 2024. So, since the *percent* markup is calculated as a percent of the market price, the percent markup will tend to increase as the market price decreases.

Figure 3.6 Day-ahead market price-cost markup (comprehensive scenario)



3.2.2 Real-time market price-cost markup

This section assesses bidding conduct in the real-time market by looking at the composition of supply and demand in the greater Western Energy Imbalance Market footprint. This approach uses the intersection of supply with demand to estimate the marginal resource (and system marginal price), and then uses an alternate supply curve where energy is offered at marginal cost to identify the price-cost markup. This analysis constructs system-wide supply curves based on available resources and market bids in each interval. Similar to the structural analysis, this analysis includes all balancing areas that are part of the greater WEIM system that includes the CAISO balancing area. Balancing areas that are either import or export constrained relative to this system are only counted as fixed WEIM transfers with this larger system.

Example interval and methodology

Starting with an example interval, Figure 3.7 shows the composition of supply by fuel (or resource) type on September 1, 2025.[131] In the 15-minute market, much of the supply that meets system-wide energy needs are self-scheduled (price-taking supply), including significant amounts from hydro generation,

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

solar, and imports.[132] Looking instead at the economic portion of the curve, bid-in supply at or below $0/MWh is largely from renewable resources. Moving up the supply stack, most of the incremental bid-in supply in the range of $0/MWh to $100 is from gas, coal, and storage resources. At the upper end of the supply stack (between $100/MWh and $1,000/MWh), bid-in supply is typically mostly from storage and hydro resources.

Figure 3.7 15-minute market system supply by fuel type (September 1, 2025, 16:45)

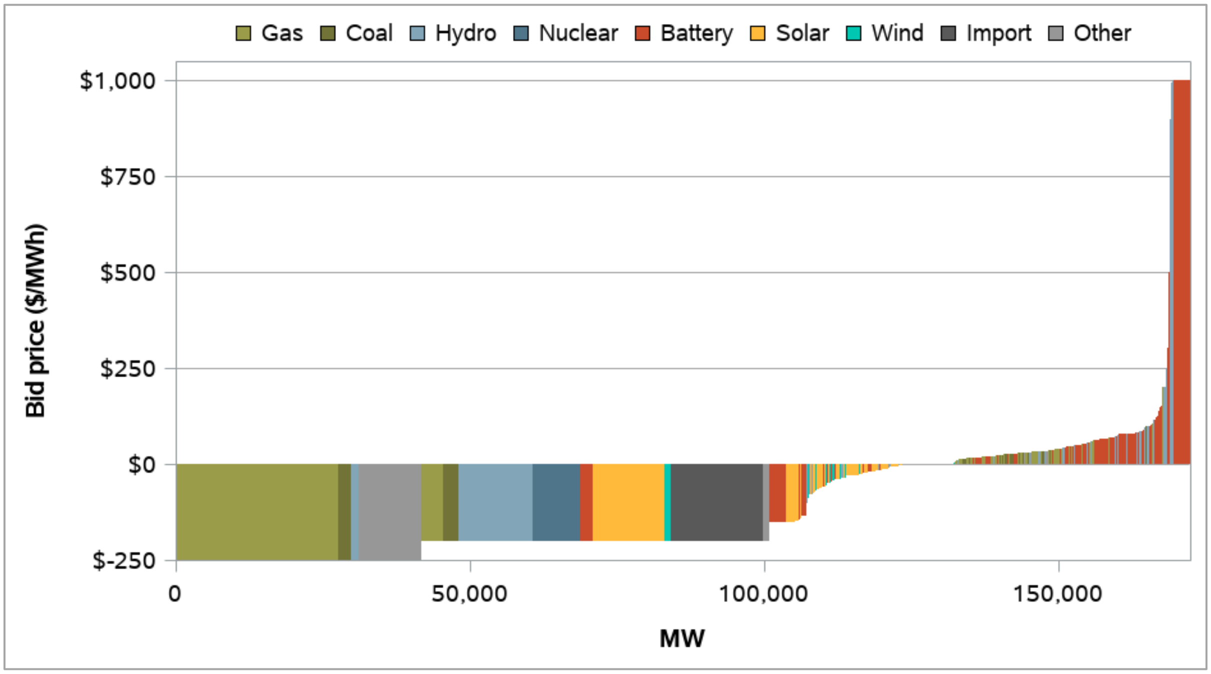

Figure 3.8 adds the demand curve, and shows the intersection of supply and demand during the example September interval.[133] In the 15-minute market, demand is mostly inelastic, illustrated by the vertical line. In this interval, the system marginal price equaled the intersection of the curves shown in this figure, at around $63/MWh. The marginal resource here was likely a storage resource.

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[132] Self-scheduled supply consists of any supply that does not have a price associated with it. This includes generation and imports that clear an earlier market process and are not re-bid in the real-time (such as California ISO balancing area imports that clear the hour-ahead scheduling process). This category also includes base-scheduled non-participating generation and imports in the WEIM.

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

Figure 3.8 15-minute market supply and demand (September 1, 2025, 16:45)

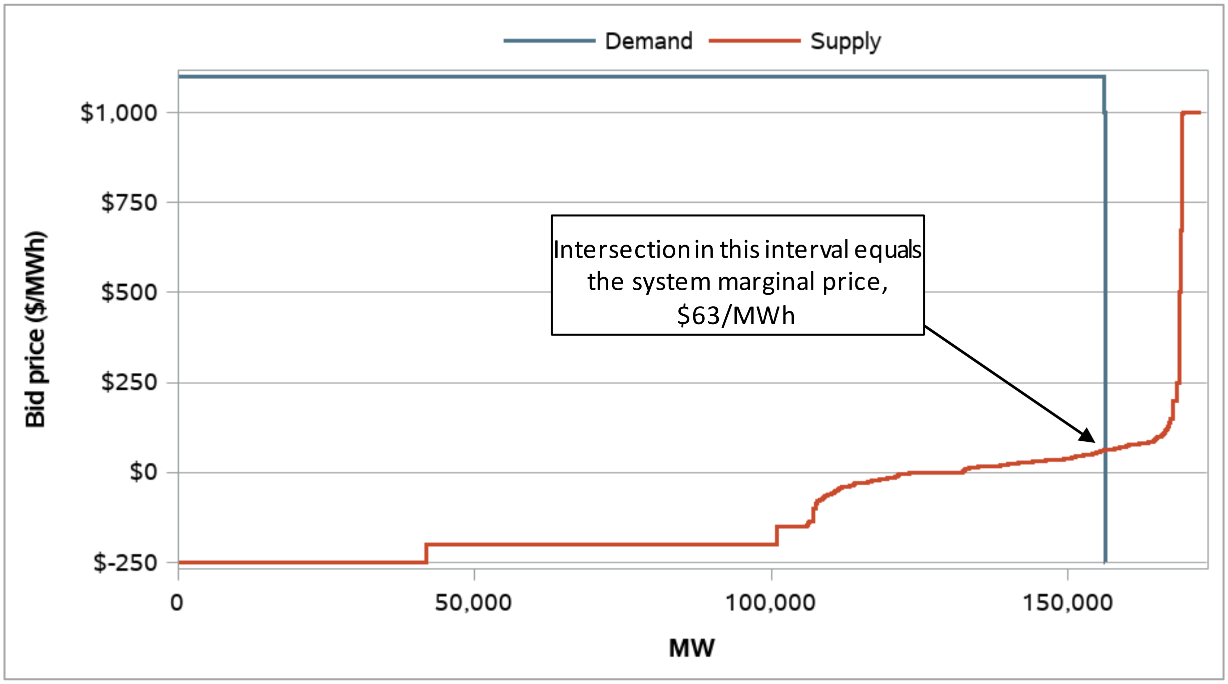

Figure 3.9 shows the upper section of the supply and demand curves, including a "competitive" supply curve with all supply set to the lower of their submitted market bid, or their *default energy bid* (DEB). The default energy bid is designed to reflect a unit's marginal energy cost.[134] As shown in the figure, market bids can exceed competitive prices at the upper portion of the supply curve. This difference is largely from storage and hydro resources. In the example interval, moving all generation to competitive levels would have had a relatively small impact on the market clearing price, based on the level of demand and the relatively flat nature of the supply curve at this price range. However, at higher levels of demand, resources bidding above competitive levels would be more likely to have a larger impact on prices.

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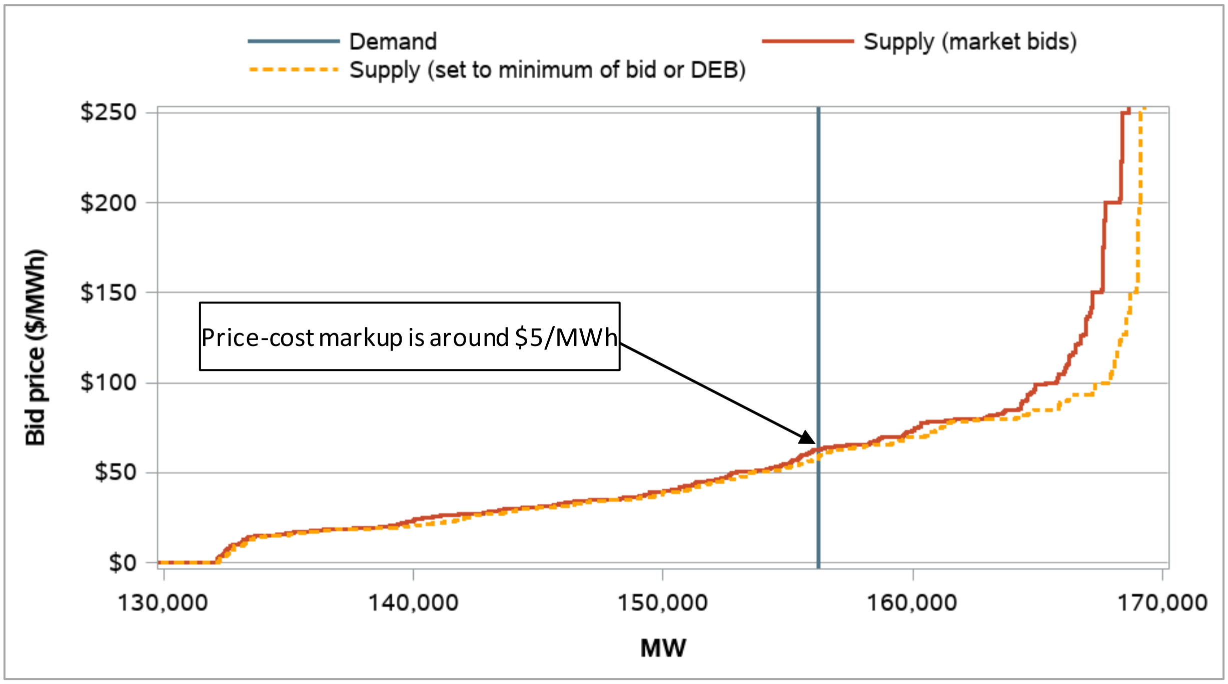
[134] Default energy bids are used in local market power mitigation.

Figure 3.9 15-minute market supply and demand with generation at competitive reference levels (September 1, 2025, 16:45)



Marginal resource

The intersection of these supply and demand curves estimate the system marginal price and marginal resource for each interval. Figure 3.10 summarizes the marginal fuel in 2025 by hour, estimated from this intersection in the 15-minute market for the greater WEIM system.[135] In each interval, the marginal resource was identified from the intersection of supply and demand. The figure shows the percent of intervals for each hour in which a unit from the specified fuel was marginal based on this intersection. On average for the year, storage and hybrid resources were estimated marginal in 37 percent of intervals while gas resources were marginal in 31 percent of intervals.

Figure 3.11 instead summarizes the marginal fuel by price range based on the estimated system marginal price. In 2025, there were only 27 intervals in which the marginal cost estimate from the intersection was above $100/MWh, and the marginal resource in these intervals was most frequently hydro, storage, or gas.

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[135] The greater WEIM system reflects all balancing areas, including the CAISO balancing area, that are not import or export constrained. Balancing areas that are either import or export constrained relative to this system are only counted as fixed WEIM transfers with this larger system.

Figure 3.10 Percent of intervals each fuel type is marginal by hour (2025)

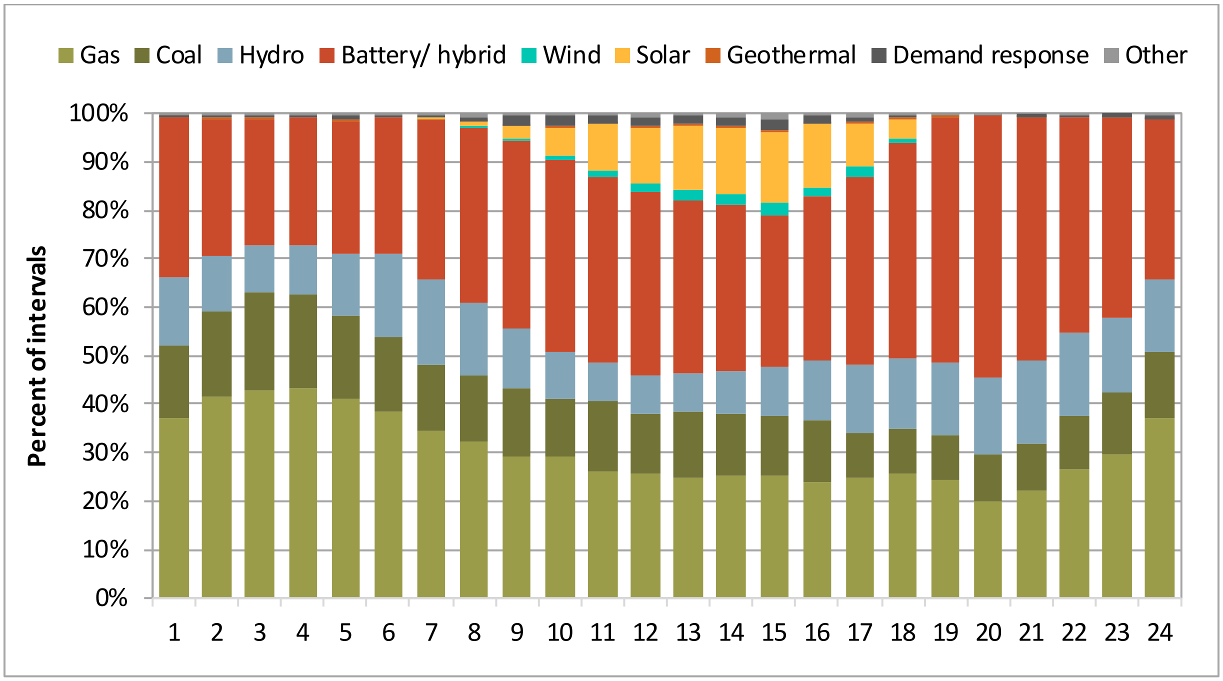
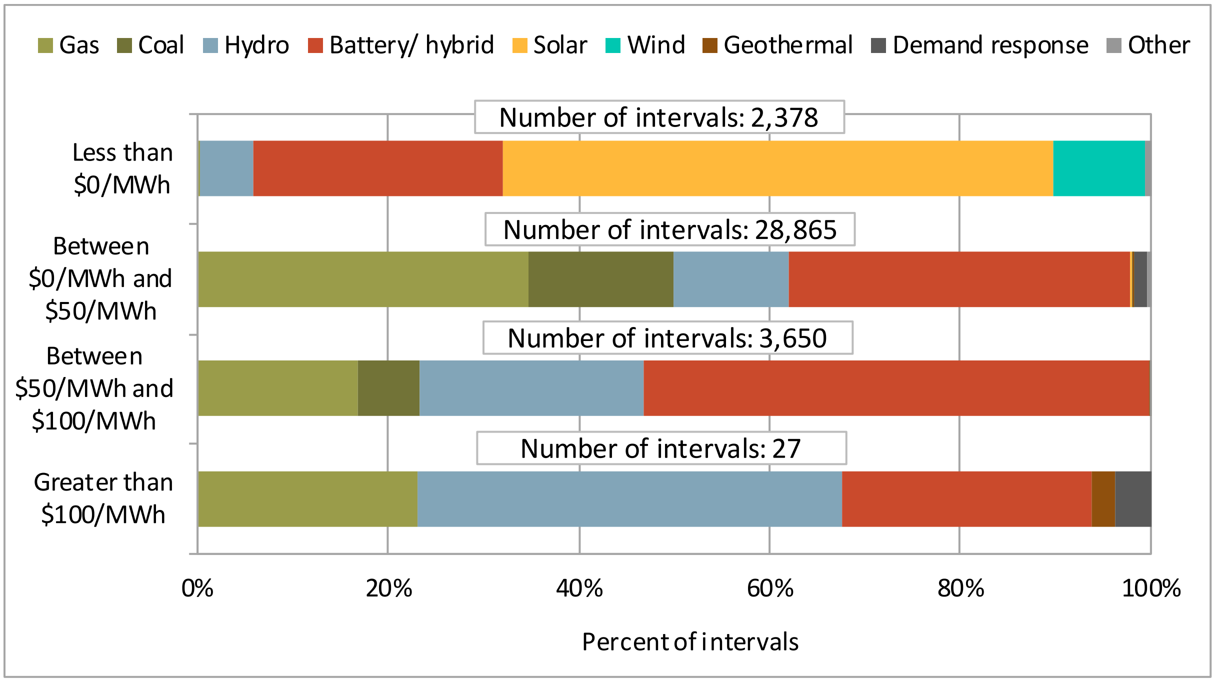


Figure 3.11 Percent of intervals each fuel type is marginal by price range (2025)

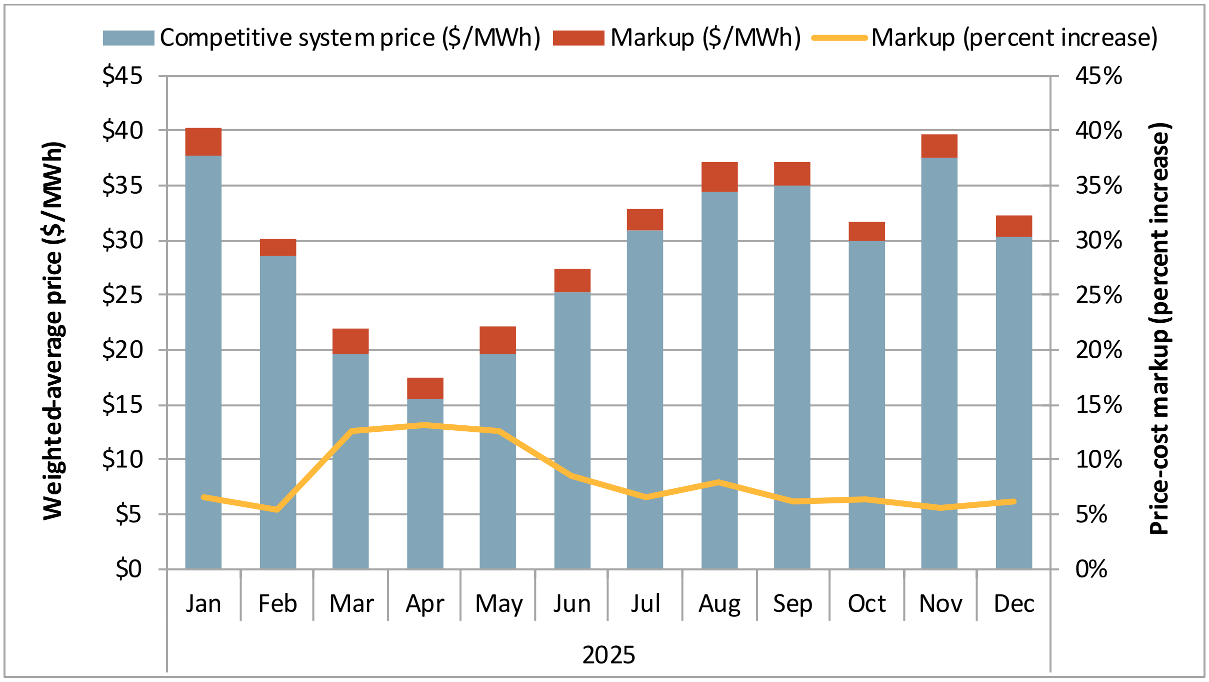


Price-cost markup

The price-cost markup summarizes the impact of using suppliers' actual offers relative to a scenario in which supply is offered at or below marginal costs. In the real-time market, DMM calculates these prices by creating supply curves. The "baseline" price—which is an estimate of the system marginal energy cost—is calculated from the intersection of real-time demand and available supply unchanged at market bids.[136] The "competitive" price is calculated from the intersection of real-time demand and instead available supply set to the lower of its submitted market bid or default energy bid.[137]

Figure 3.12 shows the price-cost markup in the real-time market by month in 2025, using average prices weighted by system load from each interval. The figure also shows the price-cost markup as a percent increase relative to the competitive price which was calculated using marginal cost estimates. The markup above the competitive price was less than $3/MWh in each month, indicating that real-time market outcomes were generally close to competitive levels throughout the year.

Figure 3.12 Real-time market price-cost markup



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[136] Bids that were below locational price and did not clear the market (because of ancillary service obligation, resource constraint, etc.) are not included. Conversely, bids that were above locational price and cleared the market regardless (because of ancillary service obligation, resource constraint, etc.) are moved to the bottom of the supply stack and treated as a self-schedule.

[137] The default energy bid is designed to reflect a unit's marginal energy cost. These are used in local market power mitigation.

3.3 Local market power mitigation – frequency and impact of automated bid mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures across all balancing areas in the ISO's day-ahead and real-time markets.

Average incremental energy subject to mitigation decreased in 2025 relative to 2024 in all markets. The megawatt amount of bids that were mitigated decreased in real-time markets but slightly increased in the day-ahead market. The potential increase in dispatch due to mitigation decreased in all markets.

Background

The California ISO automated local market power mitigation (LMPM) procedures have been enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. Most recently, effective November 1, 2021, a new default energy bid option and local market power mitigation for battery energy storage resources was implemented.

The automated local market power mitigation procedures trigger when congestion occurs on a constraint that is determined to be uncompetitive. When this occurs, bids are mitigated to the higher of the system energy price, or a default energy bid designed to reflect a unit's marginal energy cost.

The impact of mitigated bids on market prices can only be assessed precisely by re-running the market software without bid mitigation. Currently, DMM does not have the ability to re-run the day-ahead and real-time market software under this scenario. Instead, DMM developed a variety of metrics to estimate the frequency with which mitigation is triggered, and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and estimate the additional energy dispatched from these bid changes.[138]

The following sections provide analysis on the frequency and impact of bid mitigation in the day-ahead and real-time markets.[139]

Day-ahead market

As shown in Figure 3.7, in 2025, the average incremental energy subject to mitigation decreased by 15 percent relative to 2024.

- Bids for an average of 3,855 MW per hour were subject to mitigation in 2025, a decrease from 4,534 MW in 2024. Out of these bids subject to mitigation, 43 percent were battery resources, 29 percent were gas resources, and 12 percent were hydro resources.
- The amount of bids lowered due to mitigation with no impact on dispatch averaged 1,047 MW in 2025, compared to 953 MW in 2024. About 28 percent of bids subject to mitigation had their bids lowered in 2025.

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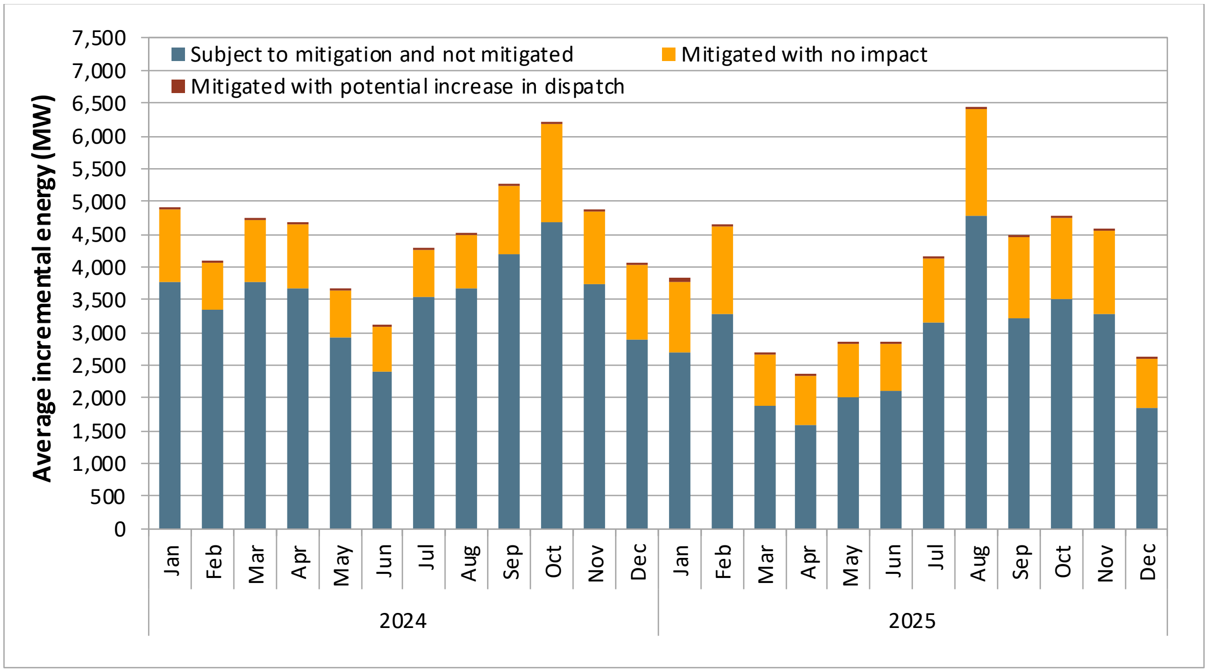
[138] Since 2019, the methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. The potential increase in the unit's dispatch due to bid mitigation can be measured by the difference between the unit's actual market dispatch and its estimated dispatch level if its bid had not been mitigated. DMM has updated the methodology for this year's report to better account for outages and address data issues, so the values in this report are different from the previous year's.

[139] Prior to May 1, 2026, CAISO was the only balancing area participating in the day-ahead market.

- Potential increase in dispatch from bid mitigation averaged about 27 MW per hour in 2025, compared to 35 MW per hour in 2024.
- On average, about 1,620 MW of bids from battery resources were subject to mitigation per hour in 2025, while only about 430 MW of bids were lowered.[140]

Figure 3.13 Average incremental energy considered for mitigation in day-ahead market



Real-time market

Figure 3.8 through Figure 3.17 highlight the frequency and volume of 15-minute and 5-minute market mitigation across the WEIM footprint. Average incremental energy subject to mitigation decreased from 5,373 MW in 2024 to 5,217 MW in 2025 (3 percent) in the 15-minute market across the overall WEIM, and decreased from 5,400 MW to 4,726 MW (12 percent) in the 5-minute market. Average incremental energy with bids changed by mitigation without an impact on dispatch decreased from 958 MW in 2024 to 915 MW in 2025 (4 percent) in the 15-minute market and decreased from 829 MW to 697 MW (16 percent) in the 5-minute market. Average potential increase in dispatch due to mitigation decreased from 89 MW in 2024 to 75 MW in 2025 (16 percent) in the 15-minute market and decreased from 106 MW to 86 MW (19 percent) in the 5-minute market.

- In the CAISO balancing area, an average of 2,195 MW of incremental energy bids were subject to mitigation in the 15-minute market in 2025, which was an 18 percent decrease from 2,686 MW in 2024. Average incremental energy with bids changed by mitigation with no impact on dispatch was 533 MW in 2025, which was a 17 percent decrease from 646 MW in 2024. Average potential

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[140] For battery energy storage units, both charge and discharge bid curves are subject to mitigation if local market power mitigation measures are triggered.

increase in 15-minute dispatch from bid mitigation was around 41 MW in 2025 which is a 28 percent decrease from 57 MW in 2024.

- In the rest of the California region, an average of only 18 MW of incremental energy bids were subject to mitigation in the 15-minute market in 2025, which was a 37 percent decrease from 29 MW in 2024. Average incremental energy with bids changed by mitigation with no impact on dispatch was 1 MW in 2025 which was a decrease from 5 MW in 2024. Average potential increase in 15-minute dispatch from bid mitigation was less than 1 MW in both 2024 and 2025.
- In the Desert Southwest region, an average of 170 MW of incremental energy bids were subject to mitigation in the 15-minute market, which was an increase of 25 percent from 136 MW in 2024. Out of these bids, about 20 MW on average were lowered with no impact in 2025 (15 MW in 2024). Average potential increase in 15-minute dispatch from bid mitigation was around 7 MW in 2025 which is an increase from 4 MW in 2024.
- In the Intermountain West region, an average of 387 MW of incremental energy bids were subject to mitigation in the 15-minute market in 2025, which was an 18 percent decrease from 470 MW in 2024. Average incremental energy with bids changed by mitigation with no impact on dispatch was around 116 MW in 2025 and 160 MW in 2024. Average potential increase in 15-minute dispatch from bid mitigation was around 21 MW in 2025 which is a slight decrease from 24 MW in 2024.
- In the Pacific Northwest region, an average of 2,447 MW of incremental energy bids were subject to mitigation in the 15-minute market in 2025 which was a 19 percent increase from 2,052 MW in 2024. Average incremental energy with bids changed by mitigation with no impact on dispatch was around 245 MW in 2025, up from 132 MW in 2024. Average potential increase in 15-minute dispatch from bid mitigation was around 6 MW (5 MW in 2024).

Figure 3.14 Average incremental energy considered for mitigation in 15-minute market (CAISO)

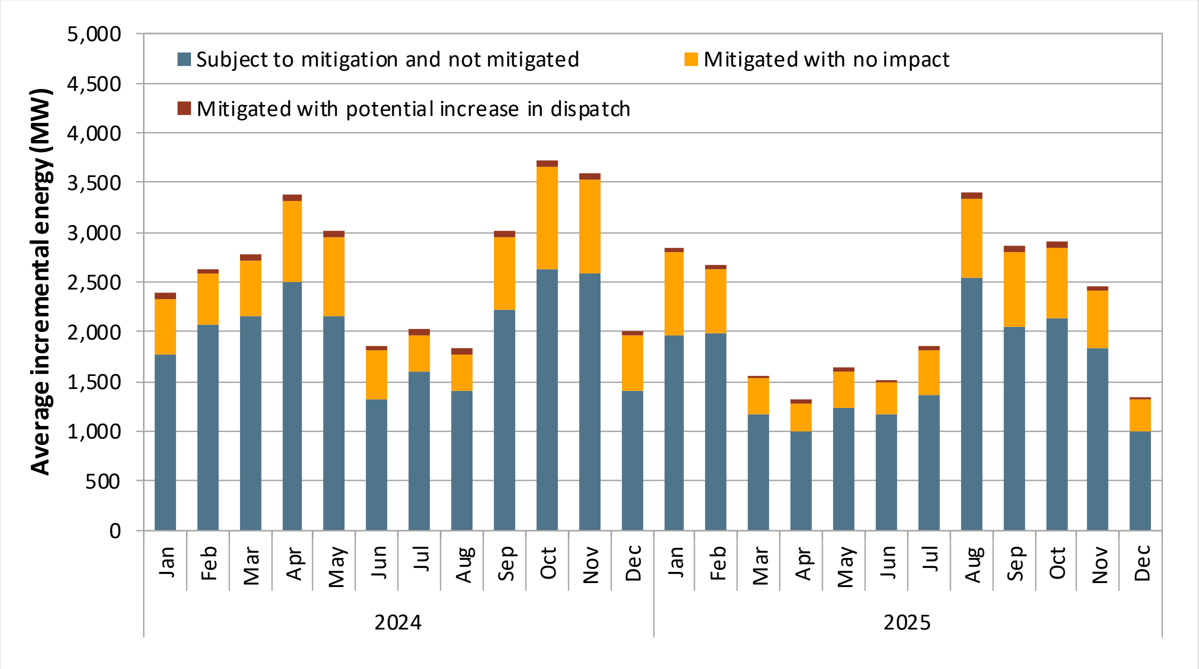


Figure 3.15 Average incremental energy considered for mitigation in 15-minute market (California non-CAISO)

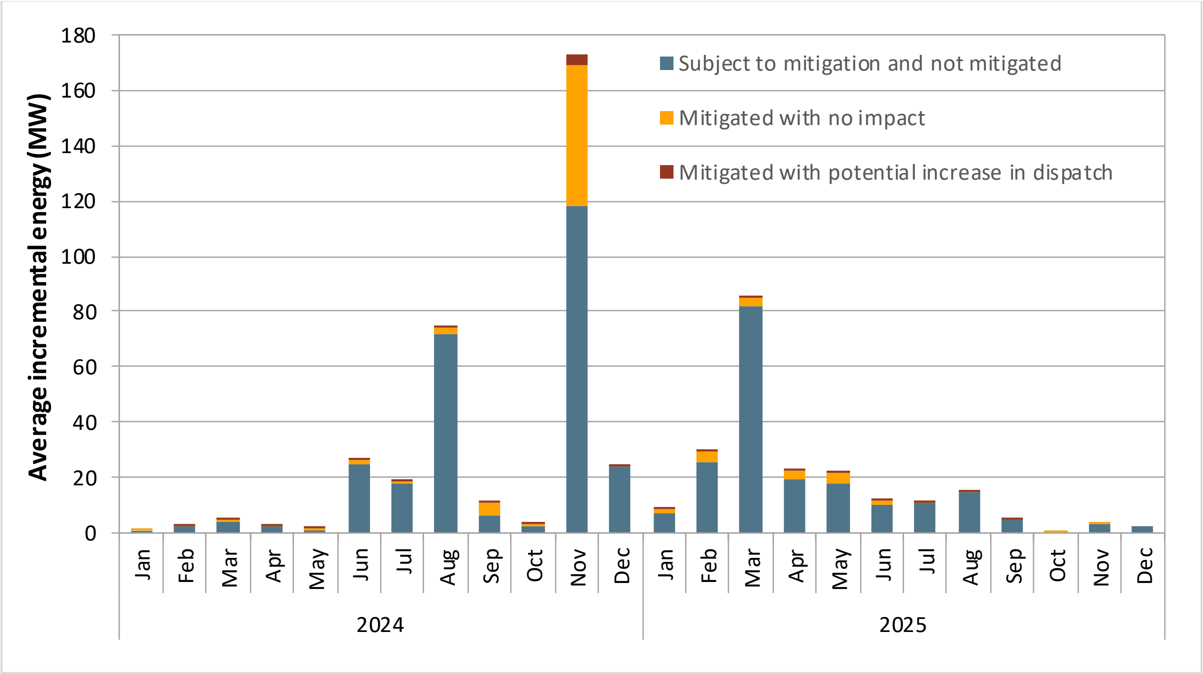


Figure 3.16 Average incremental energy considered for mitigation in 15-minute market (Desert Southwest)

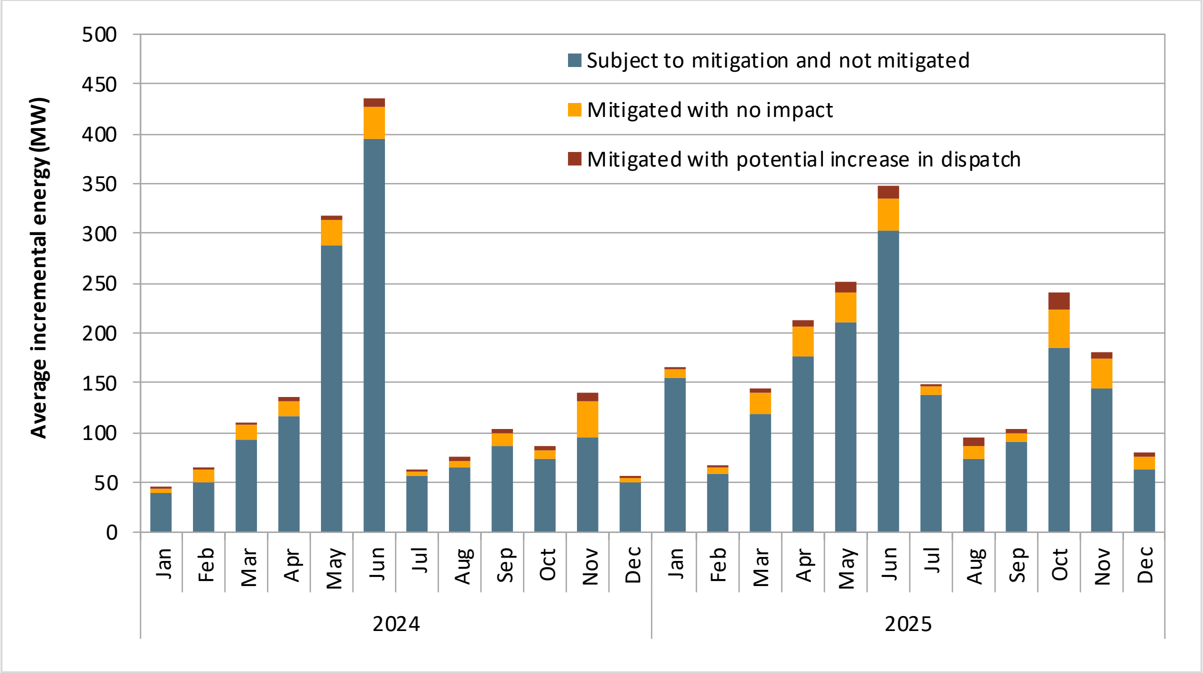


Figure 3.17 Average incremental energy considered for mitigation in 15-minute market (Intermountain West)

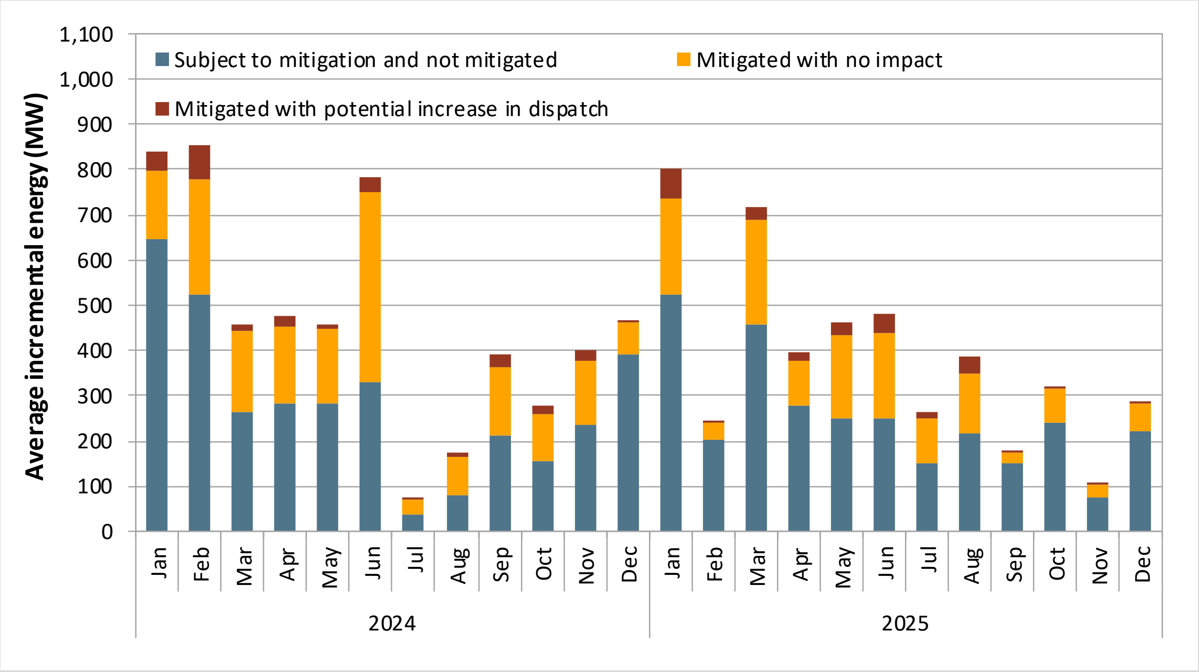


Figure 3.18 Average incremental energy considered for mitigation in 15-minute market (Pacific Northwest)

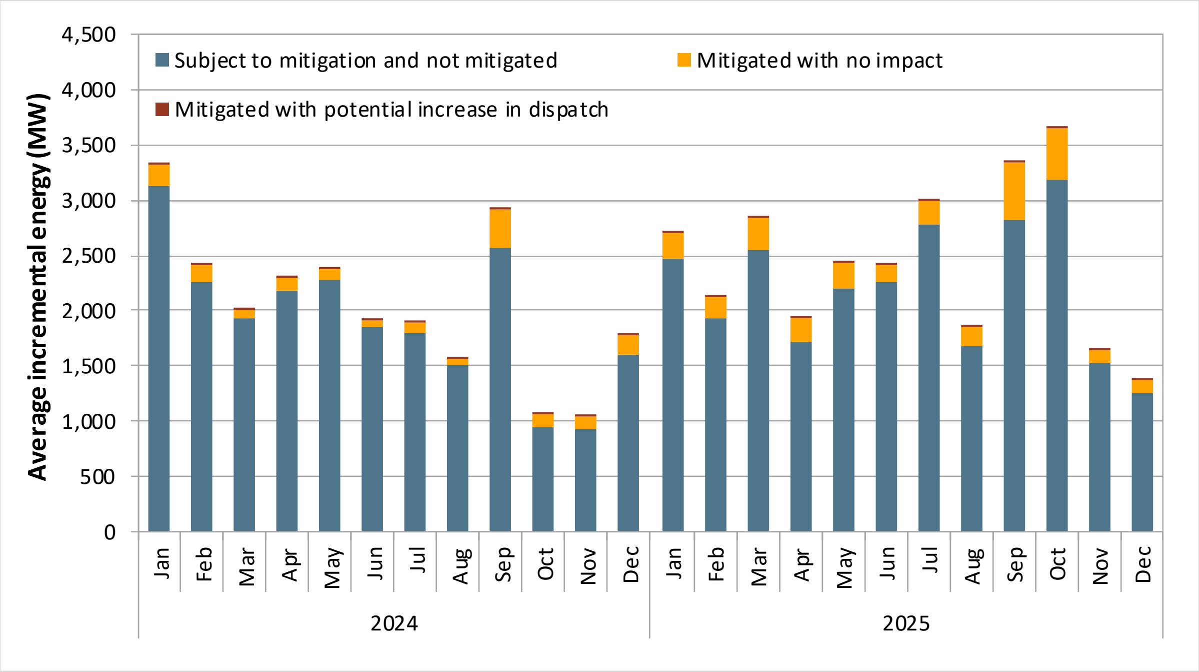


Figure 3.19 Average incremental energy considered for mitigation in 5-minute market (CAISO)

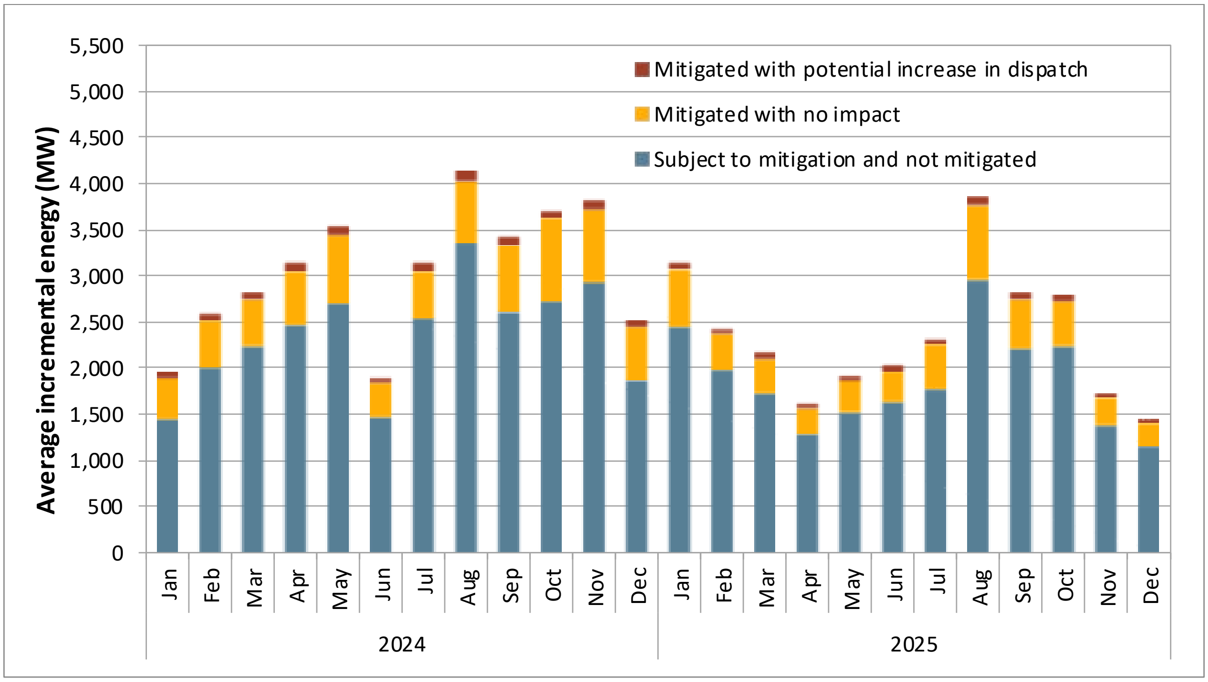


Figure 3.20 Average incremental energy considered for mitigation in 5-minute market (California non-CAISO)

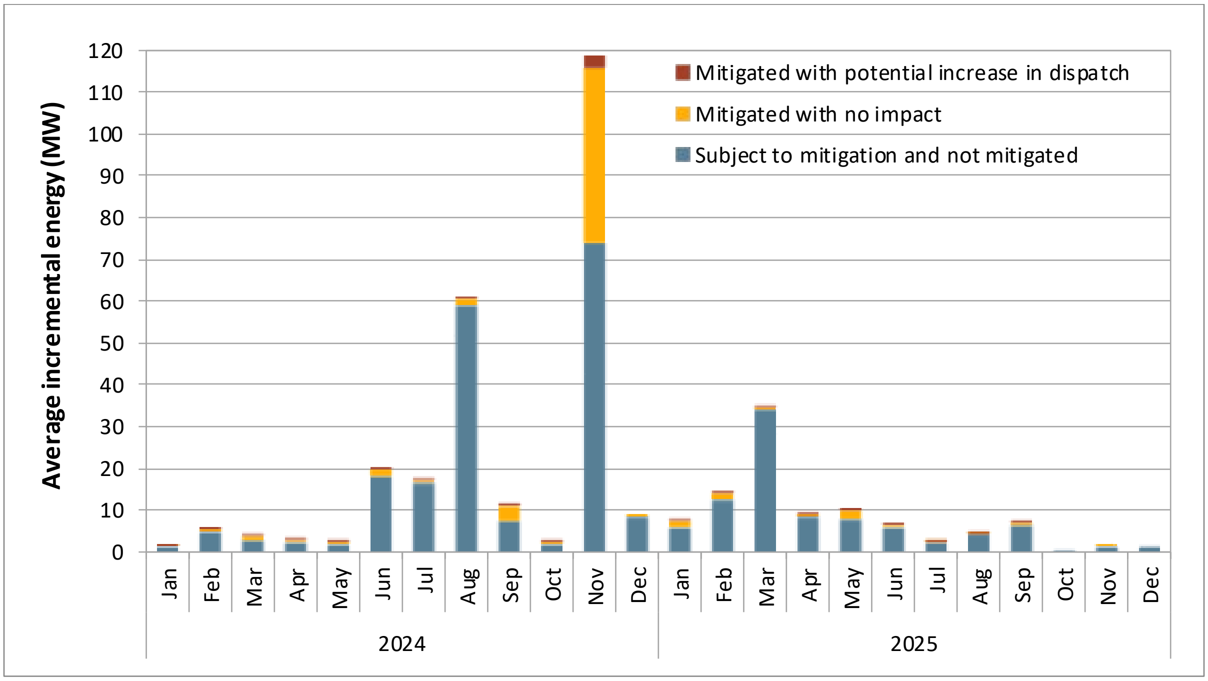


Figure 3.21 Average incremental energy considered for mitigation in 5-minute market (Desert Southwest)

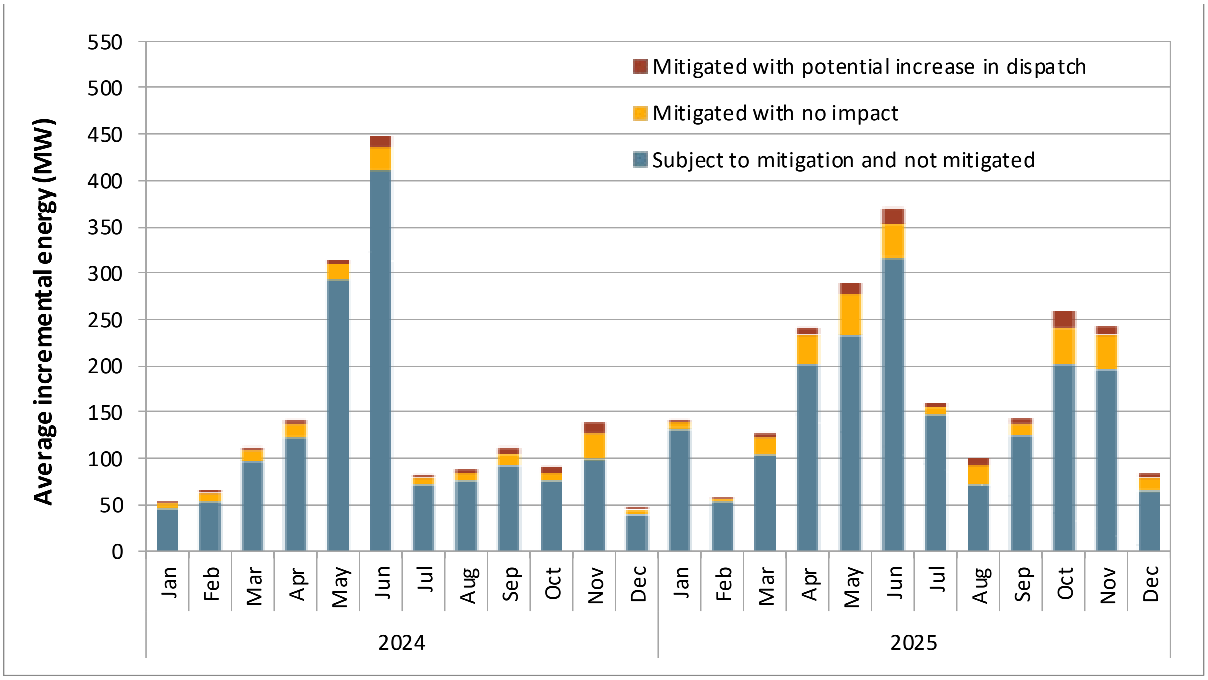


Figure 3.22 Average incremental energy considered for mitigation in 5-minute market (Intermountain West)

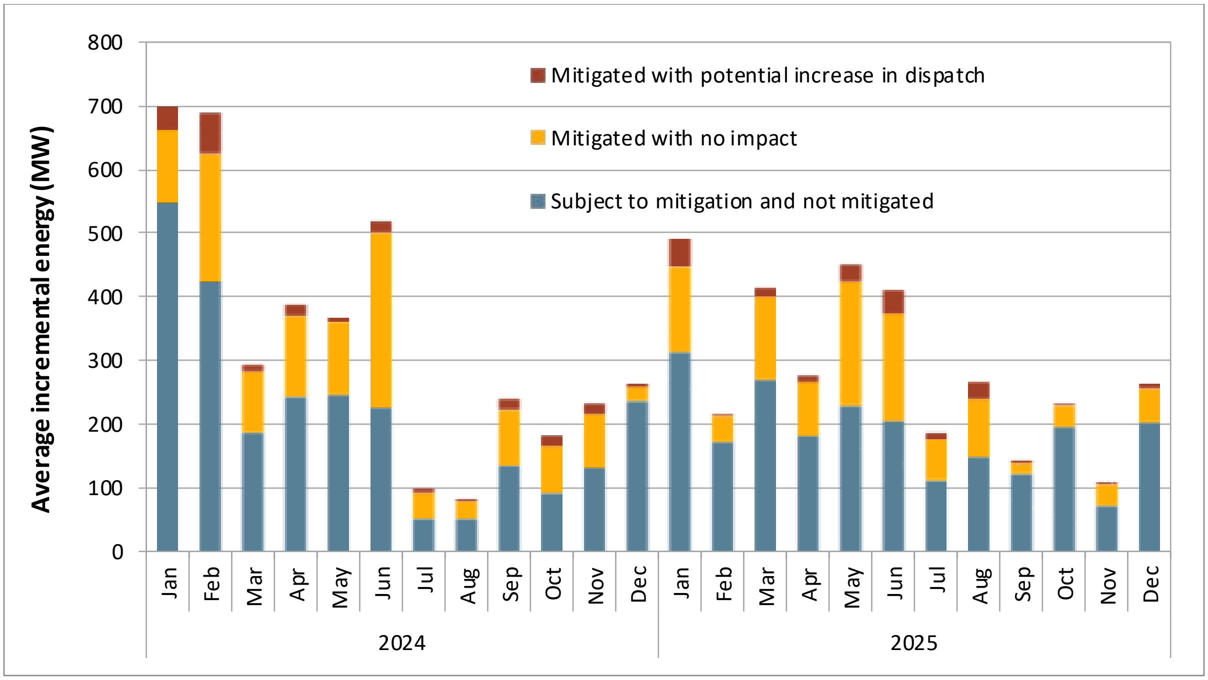
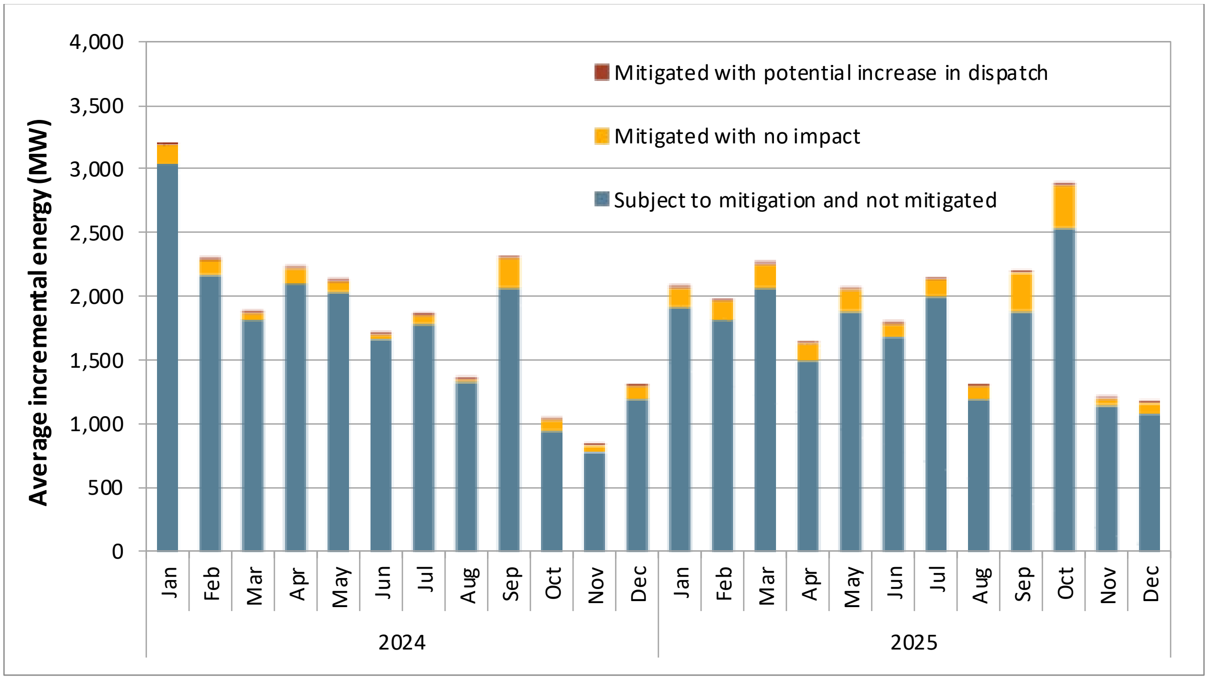


Figure 3.23 Average incremental energy considered for mitigation in 5-minute market (Pacific Northwest)



3.4 Start-up and minimum load bids

This section analyzes commitment cost bid behavior for gas capacity—excluding use-limited resources—under the proxy cost option.[141] For 2025, DMM estimates that 54 percent of total bid cost recovery paid to gas resources, or approximately $72 million, was paid to resources that bid their commitment costs above 120 percent of their proxy costs. In comparison, around 61 percent of total bid cost recovery paid to gas resources was paid to resources that bid their commitment costs above 120 percent of the proxy costs in 2024.

Figure 3.18 and Figure 3.19 compare DMM's estimate of proxy commitment costs to gas resources' real-time market bids for each balancing area, and to both day-ahead and real-time bids for the CAISO

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[141] Background on start-up and minimum load bidding rules can be found in the *Q1 2021 Report on Market Issues and Performance,* Department of Market Monitoring, July 27, 2022, p 195: http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

balancing area.[142,143] These figures show the distribution of capacity across bid levels relative to proxy costs for 2025.

The amount of start-up capacity bid into the real-time market above 120 percent of proxy costs increased 17 percent from 2024. Resources in the NV Energy (NEVP) balancing area bid 430 MW of start-up capacity above 120 percent of proxy costs on average in 2025, and at a nearly five-fold increase from 2024 had the highest percentage increase in this category of any balancing area. Nearly 70 percent of all start-up capacity bid into the real-time market above 120 percent of proxy costs in 2025 was participating in the CAISO balancing area. As shown in Figure 3.24, CAISO balancing area resources submitted 45 percent of start-up capacity bids above 120 percent of proxy costs in the real-time market and 46 percent in the day-ahead market.

The amount of minimum load capacity bid into the real-time market above 120 percent of proxy costs decreased 9 percent from 2024. Resources in NorthWestern Energy (NWMT) balancing area bid 26 MW of minimum load capacity above 120 percent of proxy costs on average in 2025, and at a nearly four-fold increase from 2024 had the highest percentage increase in this category of any balancing area. Nearly 77 percent of all minimum load capacity bid into the real-time market above 120 percent of proxy costs was participating in the CAISO balancing area. As shown in Figure 3.25, CAISO balancing area resources submitted 29 percent of minimum load capacity bids above 120 percent of proxy costs in the real-time market and 28 percent in the day-ahead market.[144]

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[142] For start-up capacity, resource Pmin (only startable configurations Pmin for multi-stage generating units) is used to calculate total start-up capacity. For minimum load capacity, Pmin of resources (or configurations) is used to calculate total minimum load capacity.

[143] The analysis excludes days with commitment cost and default energy bid enhancements (CCDEBE) automated and manual reference level adjustment requests. This is because automated requests are evaluated against resource-specific reasonableness thresholds and manual requests are evaluated on a case-by-case basis with supporting documentation.

[144] DMM's estimate of proxy commitment cost are based on the methodology described in the ISO's Business Practice Manual for Market Instruments and may not reflect all Scheduling Infrastructure Business Rules (SIBR) that can cause commitment cost bids to exceed or fall short of estimated values. https://www.caiso.com/systems-applications/portals-applications/scheduling-infrastructure-business-rules-sibr-bidding

Figure 3.24 Real-time gas-fired capacity under the proxy cost option for start-up cost bids (percentage)

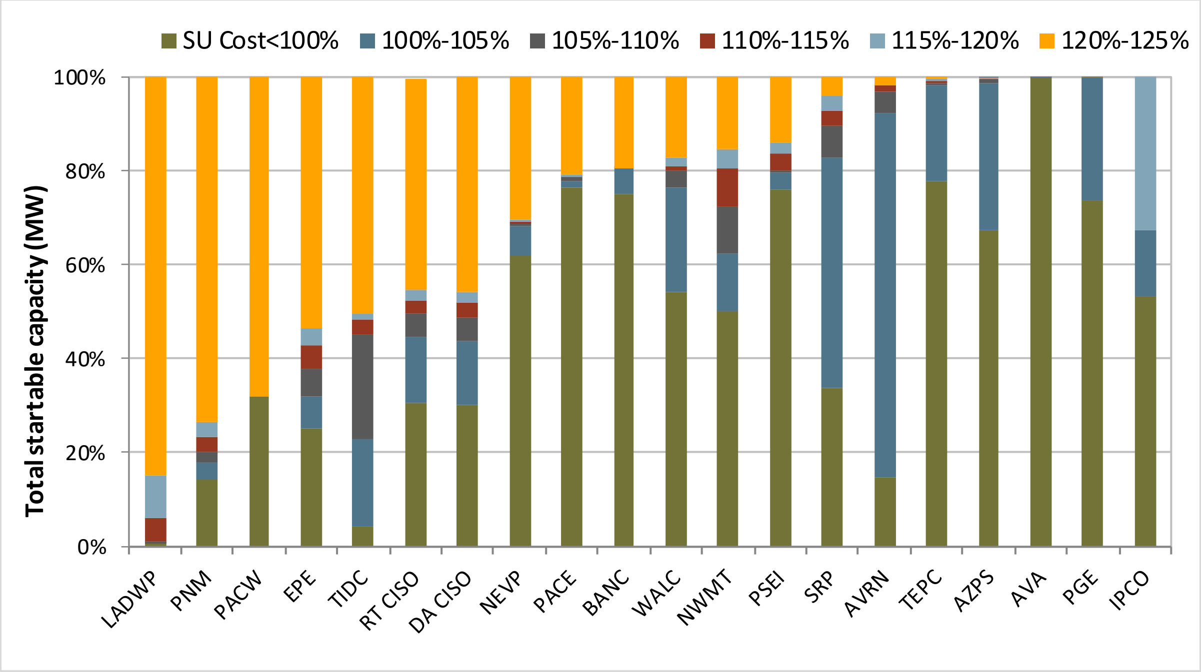
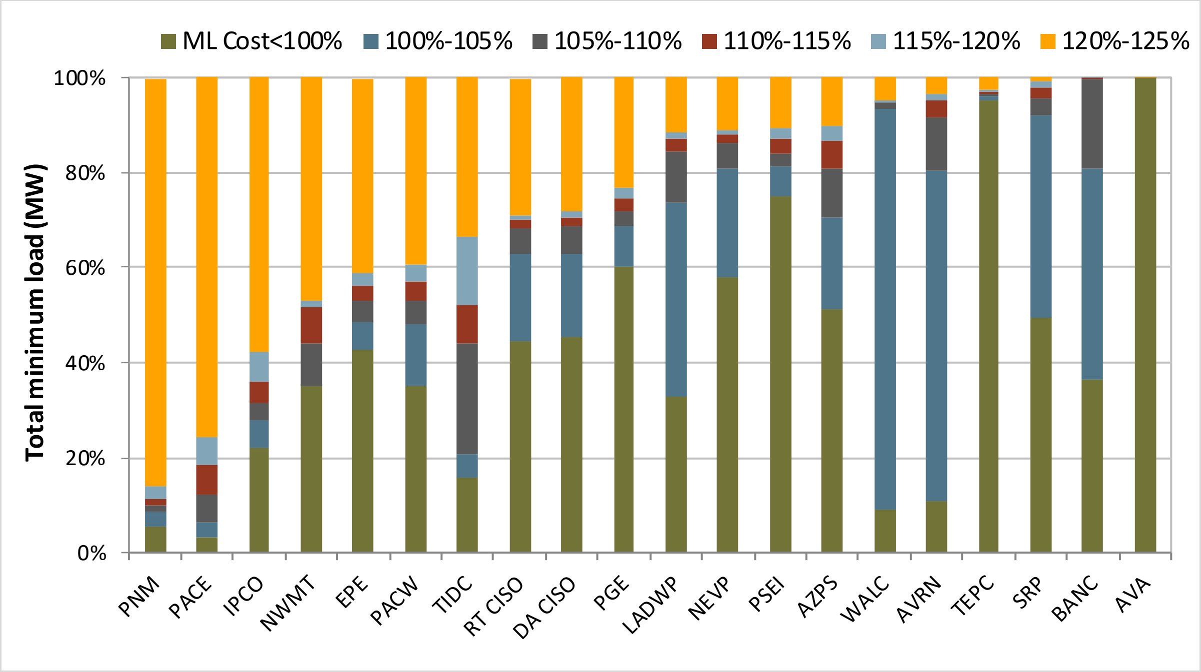


Figure 3.25 Real-time gas-fired capacity under the proxy cost option for minimum load cost bids (percentage)



Commitment cost and default energy bid enhancements (CCDEBE)

For resources utilizing the proxy-cost option, start-up and minimum-load bids are capped at 125 percent of estimated costs. After the implementation of CCDEBE on February 16, 2021, resources can submit requests to adjust their commitment costs in order to use a start-up or minimum-load bid above this cap.[145,146] This process can be automated or manual, depending on the resource's bid and reasonableness threshold. The reasonableness threshold is a measure that includes an additional multiplier meant to reflect variability in fuel or fuel-equivalent costs.[147] For requests below this reasonableness threshold, resources submit automated requests that automatically flow into the market and are subject to audit after the fact. For requests above this reasonableness threshold, resources submit manual requests, and scheduling coordinators must provide evidence of the higher fuel or fuel-equivalent cost driving the commitment cost over the proxy-cost calculation.

Manual reference level change requests were limited to eight resources, all in the same fuel region, across three days in January 2025. Automated requests for increased commitment cost bids were limited to a single resource on 11 trade dates in September and December 2025.

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[145] *Commitment Cost and Default Energy Bid Enhancements Phase 1: Deployment Effective for Trade Date 2/16/21*, California ISO Market Notice, February 14, 2021: http://www.caiso.com/Documents/CommitmentCost-DefaultEnergyBidEnhancementsPhase1-DeploymentEffective-TradeDate21621.html#search=market%20notice%202%2F16%2F21

[146] For additional DMM analysis, see the *Q1 2021 Report on Market Issues and Performance,* Department of Market Monitoring, June 9, 2021, pp 90-93: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

[147] *Tariff Amendment to Enable Updates to Default Commitment Cost and Default Energy Bids*, California ISO, filed with FERC on July 9, 2020, pp 33-37: http://www.caiso.com/Documents/Jul9-2020-TariffAmendment-CommitmentCostsandDefaultEnergyBidEnhancements CCDEBE-ER20-2360.pdf

4 WEIM transfers and transfer limits

This chapter analyzes transfers between WEIM balancing areas, including the transfer limits that constrain the amount of power that can flow between areas. Key findings include:

- **The average volume of transfers across the system was 4,480 MW during 2025,** about 100 MW higher than the previous year when it was 4,380 MW.
- **WEIM transfers between regions continued to be significantly different during mid-day solar hours than during the non-solar hours.** During solar hours, regional WEIM transfers were typically highest, with significant levels of exports from the CAISO balancing area. During non-solar hours, transfers were lower and largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest.
- **In 2025, transfers out of the Intermountain West region increased during morning and evening non-solar hours compared to the previous year.** This coincided with increased generation from wind, coal, and battery resources in the region.
- **The Pacific Northwest region continued to have the lowest transfer capacity into and out of their region.** Additional transfer capacity in the 5-minute market between the Pacific Northwest and California regions resulted in less WEIM import congestion in the 5-minute market relative to the 15-minute market, but balancing areas in the Pacific Northwest region were still frequently separated by congestion from the larger WEIM system.
- **Transfers for El Paso Electric, Salt River Project, and Tucson Electric Power were regularly constrained by intertie constraints that each balancing area can use to manage total or net WEIM transfers into or out of their system.** Net transfers for Salt River Project were constrained in roughly 4 percent of intervals, while net transfers for El Paso Electric were constrained in around 3 percent of intervals because of a limit set on net transfers by the balancing area. For Tucson Electric Power, total imports were constrained in around 4 percent of intervals while total exports were constrained in around 3 percent of intervals.

4.1 WEIM 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.

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

Figure 4.1 summarizes the average volume of WEIM transfers in the 5-minute market by hour during the last two years.[148] The average volume of transfers across the system was 4,480 MW during 2025, about 100 MW higher from the previous year when it was 4,380 MW.

Figure 4.2 summarizes average inter-regional transfers during the year.[149] The bars show *net* WEIM transfers for each region by hour.[150] Net WEIM exports for a region are shown as negative and net WEIM imports for a region are shown as positive. During the mid-day hours, regional WEIM transfers are typically highest with significant levels of exports from the CAISO balancing area. During the peak evening hours—when net load in the WEIM system is highest—regional WEIM transfers were lower. In 2025, transfers out of the Intermountain West region increased during morning and evening non-solar hours compared to the previous year. This coincided with increased generation from wind, coal, and battery resources in the region.

Figure 4.3 and Figure 4.4 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during 2025.[151] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area.

As shown in Figure 4.3, the CAISO balancing area exported on average over 1,800 MW out to neighboring balancing areas during the mid-day hours. These hours typically contain the highest levels of exports out of the CAISO balancing area because of significant solar production. During the peak period (Figure 4.4), balancing areas in the Desert Southwest and Intermountain West regions were exporting overall out to balancing areas in the California and Pacific Northwest regions.

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

[149] See Appendices of DMM's quarterly reports for figures on the average hourly transfers by quarter for each WEIM balancing area.

[150] 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.

[151] In Figure 4.3 and Figure 4.4, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 4.1 Average WEIM transfer volume by hour and quarter (5-minute market)

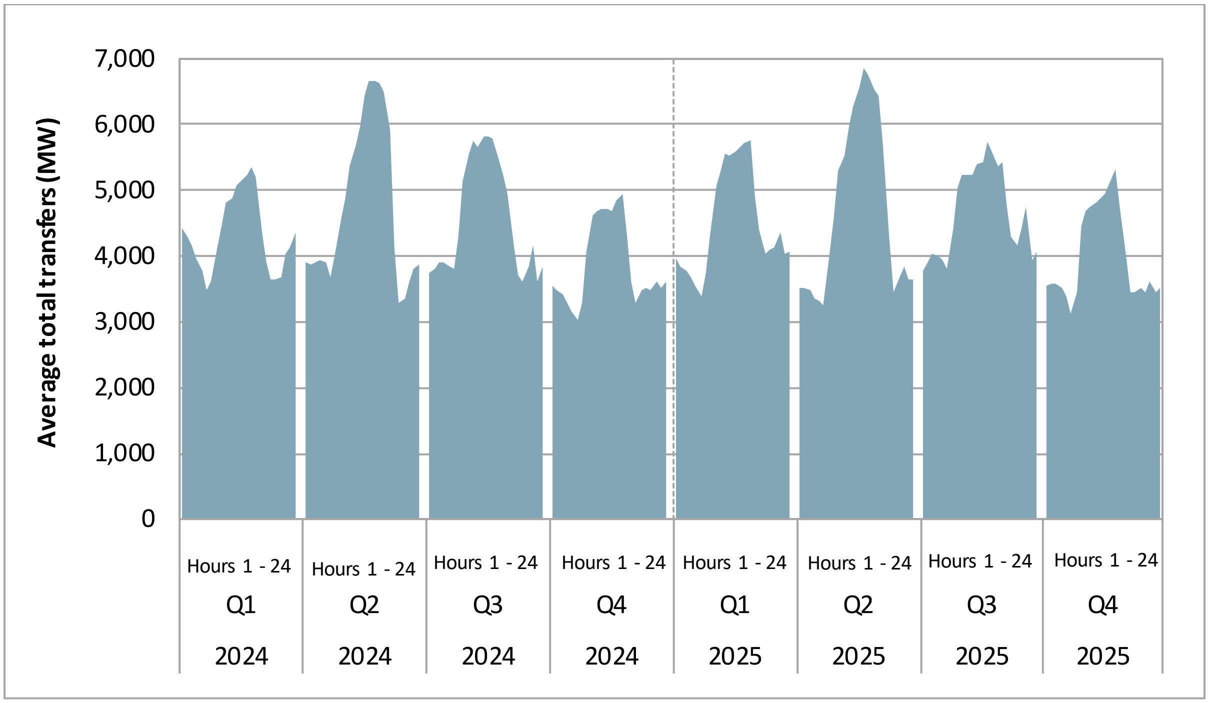


Figure 4.2 Average inter-regional WEIM transfers by hour (5-minute market)

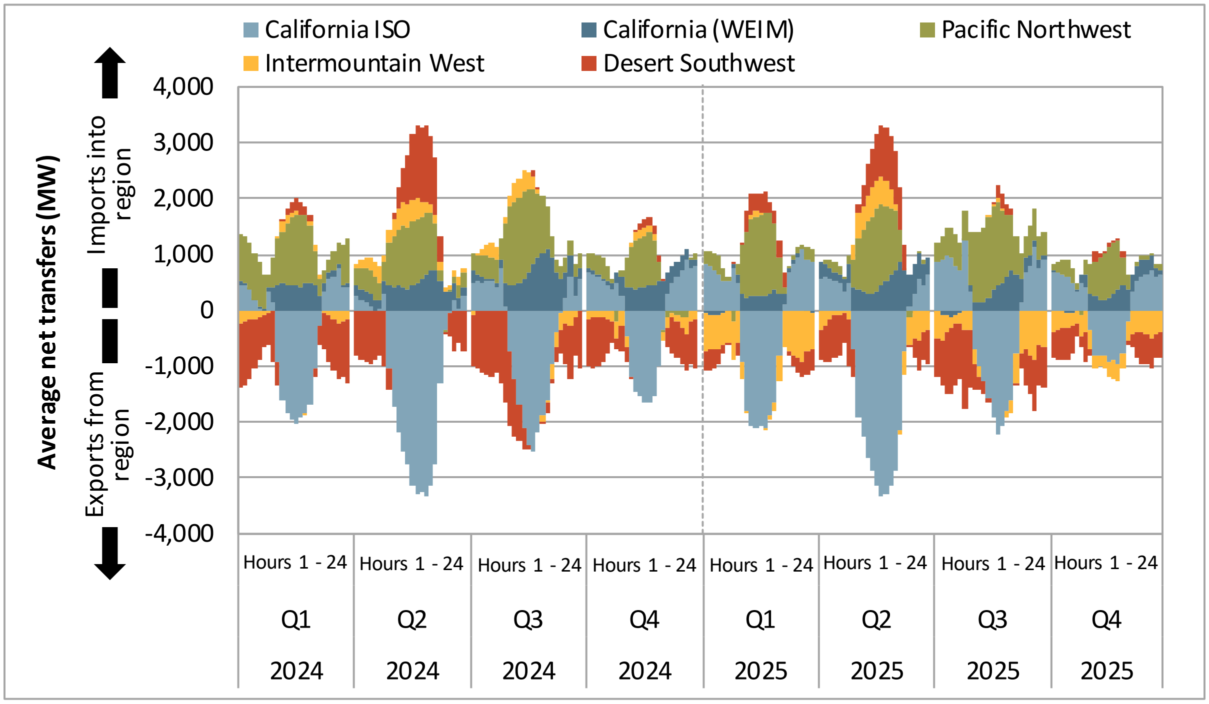


Figure 4.3 Average 5-minute market WEIM exports (mid-day hours, 2025)

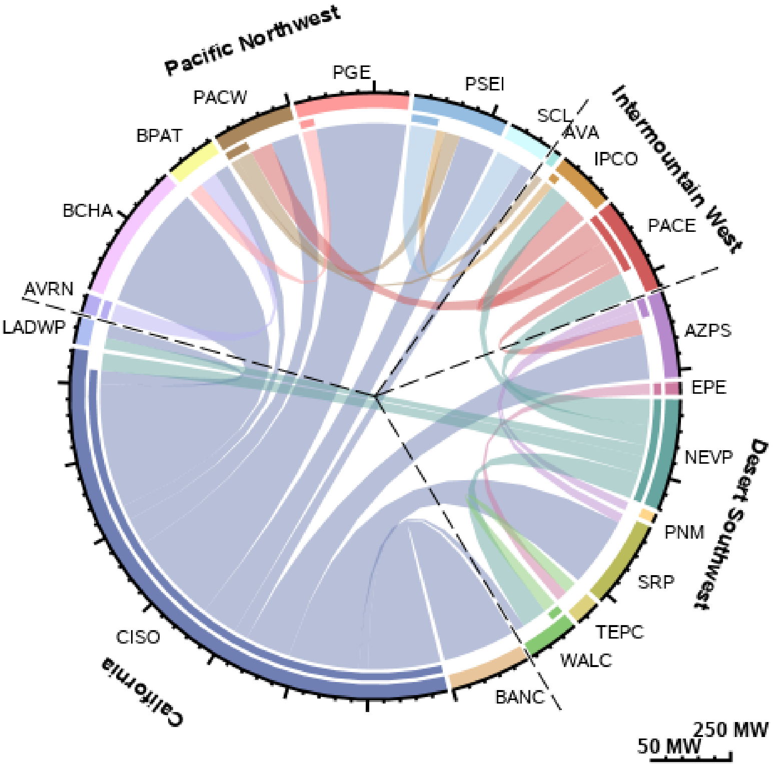
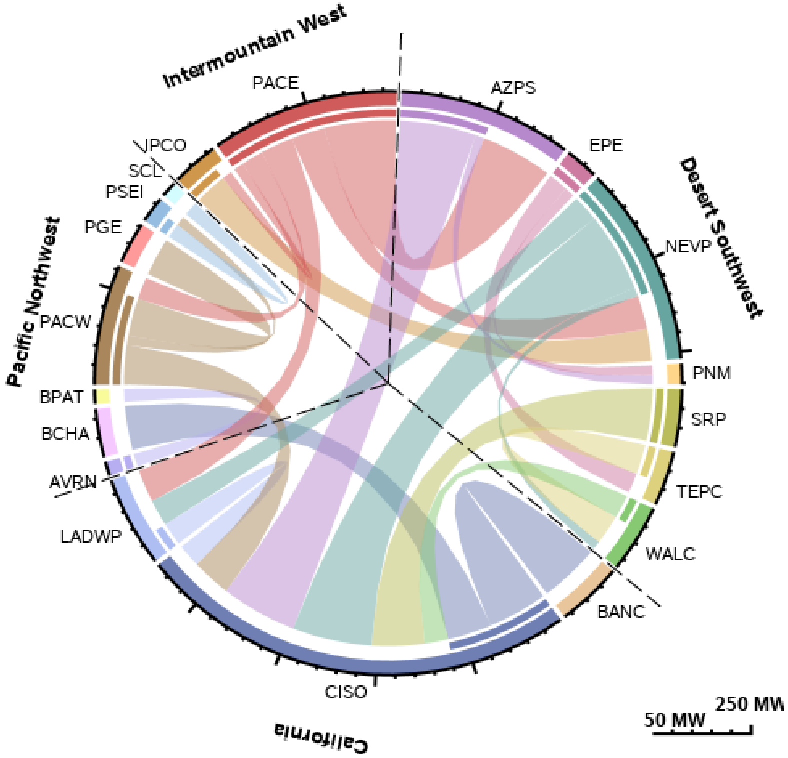


Figure 4.4 Average 5-minute market WEIM exports (peak load hours, 2025)



4.2 WEIM transfer limits

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

Figure 4.5 shows WEIM transfer capacity (or transfer limits) available in the 5-minute market to support the transfer of energy between balancing areas and regions in the Western Energy Imbalance Market.[152] The width of each path reflects the size of the WEIM transfer capacity. WEIM transfer capacity between each balancing area within a region is shown in gray, while transfer capacity from a balancing area into and out of the region is aggregated, and shown in the colored paths.

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

Figure 4.5 Average 5-minute market WEIM transfer limits by balancing area (2025)

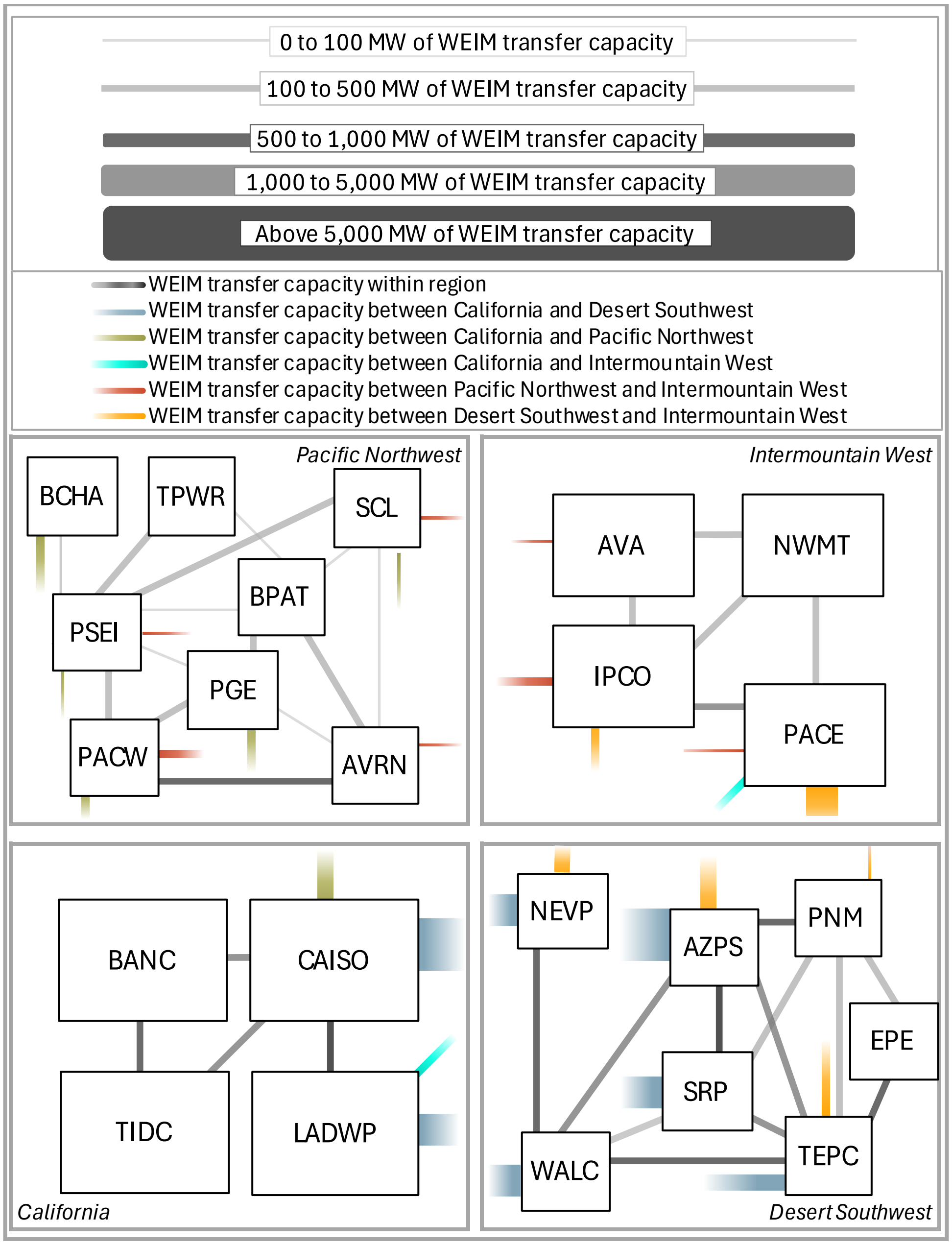

Table 4.1 summarizes average regional transfer capacity.[153] Total WEIM transfer capacity between balancing areas *within a region* is shown in the gray cells. Transfer capacity instead *between regions* is

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

shown in the remaining cells. The sum of each column reflects the average total import capacity into the region, while the sum of each row reflects the average total export capacity out of the region.

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

For the Pacific Northwest region, there was an average of around 1,374 MW of import transfer capacity and 833 MW of export transfer capacity into or out of the region in the 15-minute market. The lack of transfer capacity out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Table 4.1 Average regional WEIM transfer limits (2025)

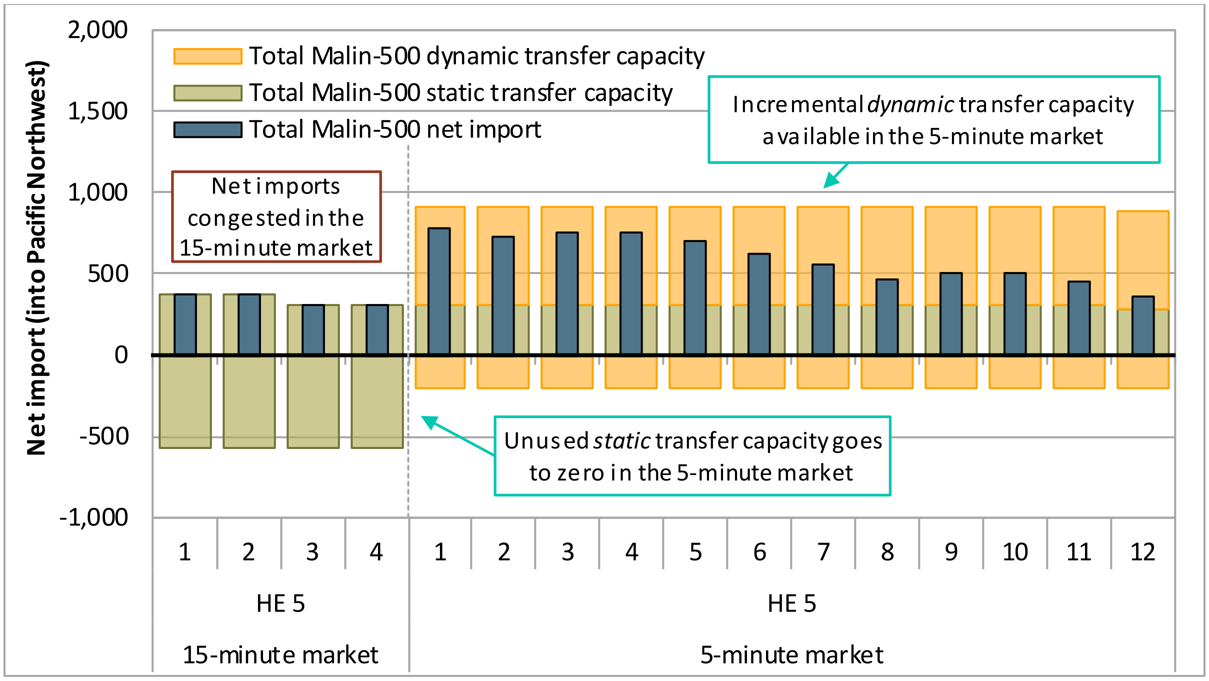
▨ Dynamic WEIM transfer capacity within region (15-minute market)
☐ Dynamic WEIM transfer capacity out of region (15-minute market)
🟩 Static WEIM transfer capacity out of region (15-minute market) / Incremental dynamic capacity out of region (5-minute market)

	To region				*Total out-of-region export limit*
From region	**California**	**Desert Southwest**	**Intermountain West**	**Pacific Northwest**	
California	22,628	25,071	174	897 / 441	26,141 / 441
Desert Southwest	32,062	54,546	1,781		33,842
Intermountain West	210	1,714	4,279	477	2,402
Pacific Northwest	546 / 260		286	4,396	833 / 260
Total out-of-region import limit	32,818 / 260	26,785	2,241	1,374 / 441	

During the year, additional transfer capacity in the 5-minute market between the Pacific Northwest and California helped to alleviate WEIM transfer congestion in the Pacific Northwest. In particular, around 440 MW of additional import capacity on dynamic WEIM transfer paths from California into the Pacific Northwest resulted in less WEIM import congestion in the 5-minute market relative to the 15-minute market.

As an example, Figure 4.6 shows net transfer capacity and imports going into the Pacific Northwest on the Malin 500 intertie for an hour (hour-ending 5). The green bars show the static transfer capacity in the 15-minute and 5-minute markets. The yellow bars show incremental dynamic transfer capacity that was available in the 5-minute market. The dark blue bars show the net import that was optimized in both markets. Here, imports on the static transfers going into the Pacific Northwest in the 15-minute market reached their limits, contributing to congestion and higher prices in the 15-minute market. In the 5-minute market, around 600 MW of additional import capacity in this hour on the dynamic transfers alleviated the congestion between the balancing areas in the Pacific Northwest and the rest of the WEIM system. DMM has asked the ISO to review why this transfer capacity can’t be made available in the 15-minute market.

Figure 4.6 Total transfer capacity and net imports on Malin 500 into the Pacific Northwest (November 25, 2025, HE5)



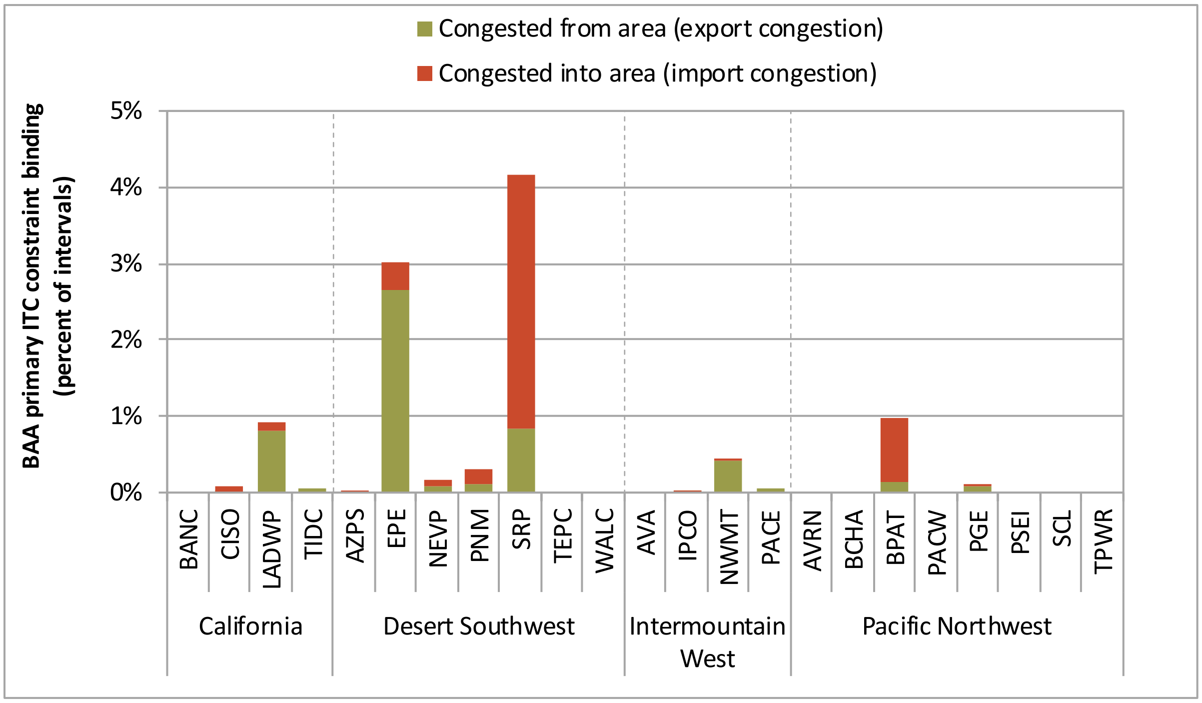
WEIM intertie constraints

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

Figure 4.7 shows the percent of intervals in the 5-minute market in which the primary intertie constraint—that limits all dynamic WEIM transfers on net for a balancing area—was binding in either the import or export direction, resulting in congestion. Of note, the constraint limiting net transfers for Salt River Project was binding in roughly 4 percent of intervals (or 3 percent for only net import direction). When this constraint was binding in either direction, net transfers were limited to 1,050 MW or less. Net exports for El Paso Electric were constrained in around 3 percent of intervals (with net exports limited to 300 MW or less).

A WEIM entity can also set up intertie constraints that are mapped to a subset of their WEIM transfers (non-primary). For example, the entity can set up an intertie constraint that is mapped to only WEIM transfers at a specific intertie. A WEIM entity can also create an intertie constraint that is mapped to either only WEIM imports or only WEIM exports, which will limit total imports or total exports rather than net WEIM transfers. During the year, Tucson Electric enforced an intertie constraint that was binding for total WEIM imports in around 4 percent of intervals and for total WEIM exports in around 3 percent of intervals. The limit was around 500 MW on average in both directions when these constraints were binding.

Figure 4.7 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, 2025)



5 Congestion

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

Key findings in this chapter include:

- **Most balancing areas in the Pacific Northwest, plus Avista and NorthWestern in the Intermountain West, were import transfer constrained relative to the CAISO balancing area in more than 10 percent of 15-minute market intervals.** Limited transfer capacity into these regions contributed to their relatively high rate of WEIM transfer congestion.
- **El Paso Electric and Tucson Electric Power experienced a relatively high frequency of transfer congestion in the Desert Southwest region.** These balancing areas were frequently transfer constrained because of intertie constraints that these balancing areas use to manage WEIM transfers into or out of their system.
- **WEIM balancing area price separation driven by congestion on internal transmission constraints was less pronounced in 2025** than 2024. This price separation in the day-ahead market was also less pronounced in 2025.
- **Congestion rent in 2025 was $485 million, down 10 percent** from 2024. This reduction was primarily due to a significant decrease in congestion rent from intertie constraints. Intertie congestion rent decreased from $164 million in 2024 to $26 million in 2025. The decrease largely reflects normal system conditions in 2025, without a severe weather event similar to the one in Q1 2024.

Figure 5.1 through Figure 5.3 show the average impact of congestion on real-time market prices in 2024 and 2025. Blue bars represent the 2024 impact, while red bars represent the 2025 values. The congestion impact was calculated as the average price impact across both the 15-minute and 5-minute markets for all intervals during the quarter.

Figure 5.1 shows the total price impact from all congestion sources—WEIM transfers and internal flow-based constraints. Figure 5.2 isolates the impact from WEIM transfer constraints. Figure 5.3 shows the impact from internal flow-based constraints.

Similar to 2024, the 2025 congestion pattern showed a south-to-north trend, but with lower magnitude compared to 2024. In 2025, higher prices in the Northern California, Intermountain West, and Pacific Northwest regions, and lower prices in the Desert Southwest and Southern California regions, were driven by congestion.

WEIM transfer constraints remained a key contributor to the overall price impact, with prices elevated across most BAAs both in 2025 and 2024. Overall, the net price impact from transfer congestion was smaller in 2025 compared to 2024.

Internal congestion contributed to a south-to-north price separation in 2025, following the same general trend as 2024, with lower magnitude. Prices in Northern California, the Intermountain West, and the Pacific Northwest were elevated due to internal congestion, while prices in Southern California and the Desert Southwest were suppressed.

Figure 5.1 Average impact of total congestion on real-time market price (2024–2025)

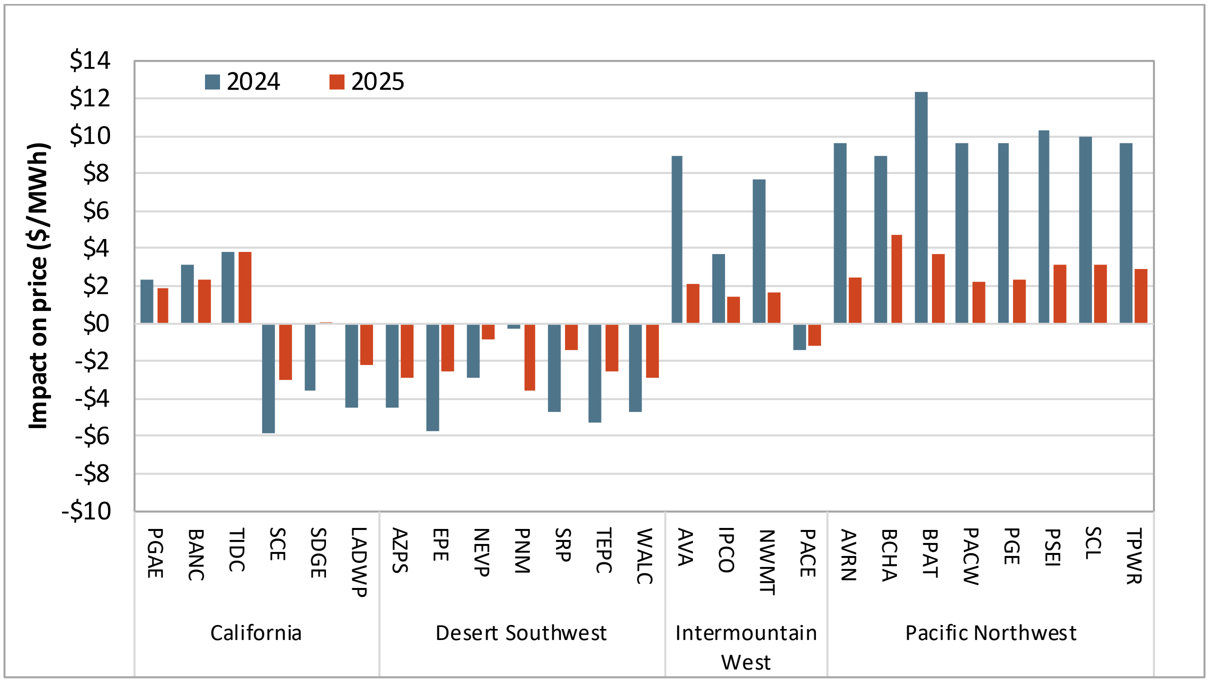


Figure 5.2 Average impact of transfer congestion on real-time market price (2024–2025)

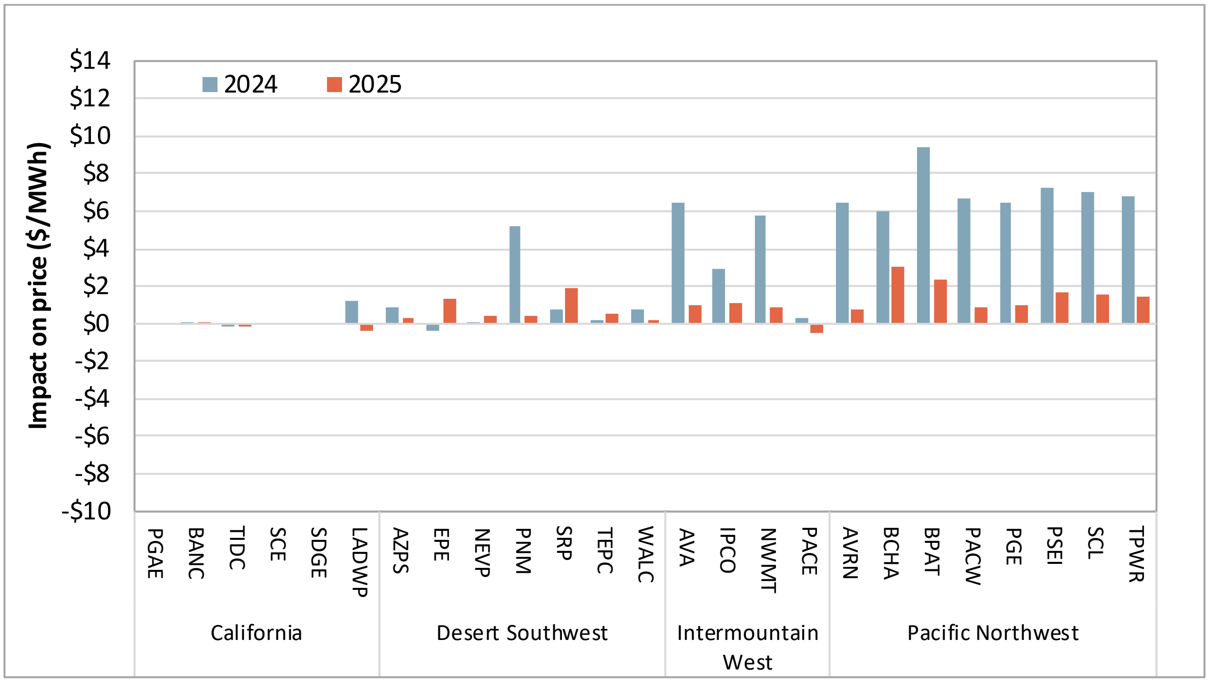
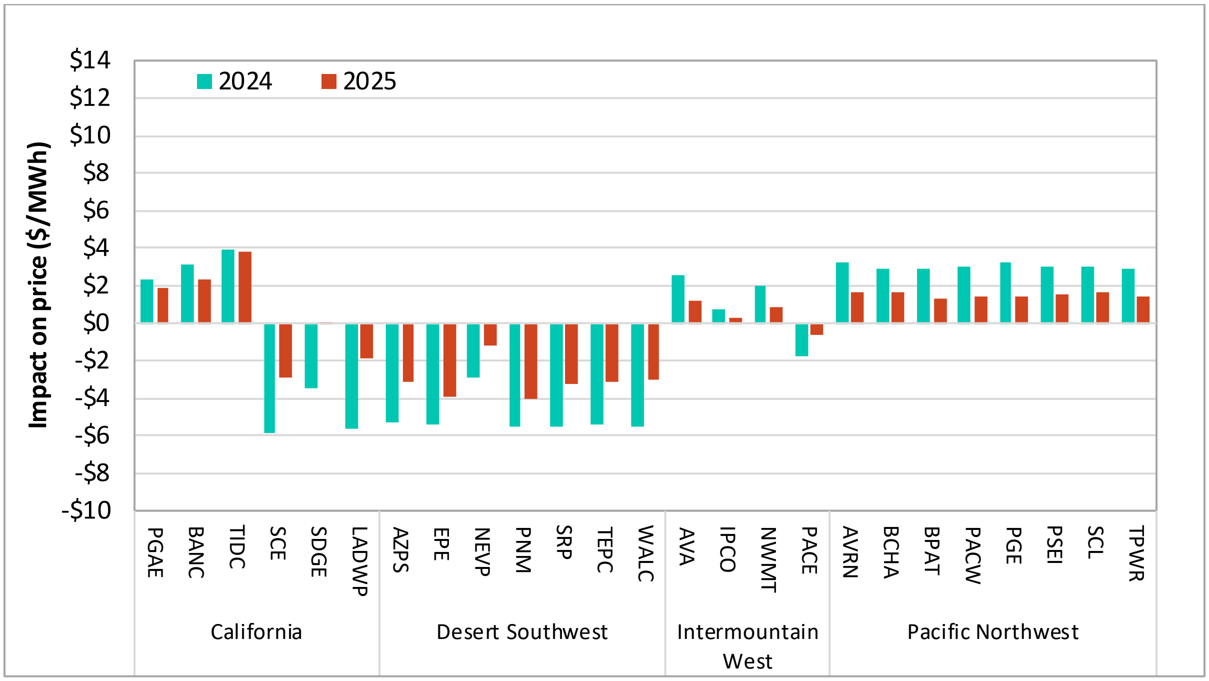


Figure 5.3 Average impact of internal congestion on real-time market price (2024–2025)



The following sections present further details on price impacts from different sources of congestion. Section 5.1 addresses congestion on the constraints limiting WEIM transfers between balancing areas in the real-time market. Section 5.2 addresses real-time market internal congestion.[154] Section 5.3 analyzes day-ahead market congestion rent and loss surpluses. Section 5.4 addresses intertie constraint congestion in the day-ahead market. Lastly, Section 5.5 addresses the impact of internal congestion on the day-ahead market.

5.1 WEIM transfer constraint congestion

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Figure 5.4 shows the percent of intervals and overall price impact of 15-minute market WEIM transfer constraint congestion in each balancing area during the quarter.[155] Figure 5.5 shows the same information for the 5-minute market. The congestion on the WEIM transfer constraints is measured

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[154] 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.

[155] 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.

relative to a reference price in the CAISO balancing area. Congested from area reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the CAISO (and connected WEIM system). Congestion into an area reflects that prices are higher within an area or region because of limited import capability into the area or region.[156]

WEIM transfer congestion was most prevalent in 2025 in the Pacific Northwest. The average frequency of congested intervals reached 22 percent in the import direction and 10 percent in the export direction, measured across both the 15-minute and 5-minute markets. As a result, prices in the Pacific Northwest were elevated by an average of $2.33/MWh in the 15-minute market, and $0.86/MWh in the 5-minute market.

In the Pacific Northwest, transfer congestion occurred more often in the 15-minute market than in the 5-minute market. Average binding frequency across both import and export directions reached 17 percent in the 15-minute market, compared to 15 percent in the 5-minute market. This difference reflects additional transfer capacity between the Pacific Northwest and California regions in the 5-minute market, as discussed further in Chapter 4.

Powerex (BCHA) was frequently constrained relative to the CAISO balancing area because of WEIM transfer congestion during this year. In the 5-minute market, Powerex was import constrained during around 45 percent of intervals and export constrained during around 28 percent of intervals. On average for this year, Powerex prices were $3.7/MWh higher because of WEIM transfer congestion in the 15-minute market, and $2.4/MWh higher in the 5-minute market.

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

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

Figure 5.4 Frequency and impact of WEIM transfer congestion in the 15-minute market (2025)

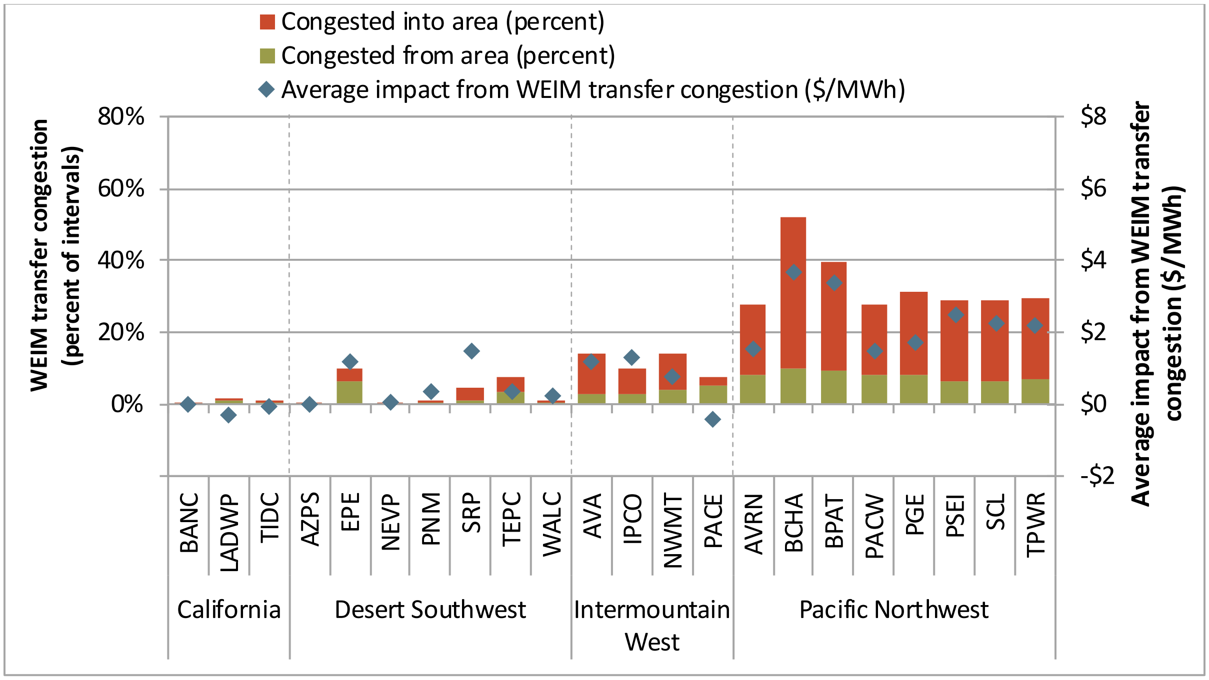
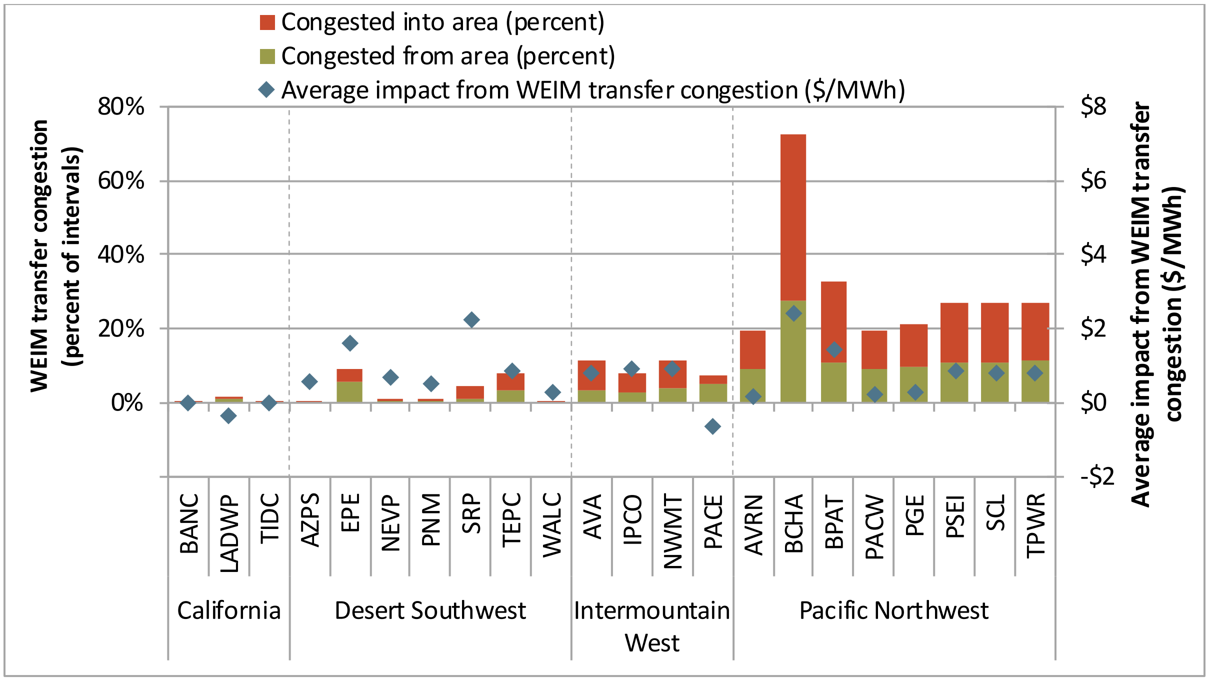


Figure 5.5 Frequency and impact of WEIM transfer congestion in the 5-minute market (2025)



5.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM. [157] This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas.

The impact of congestion on each pricing node in the system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas. [158]

In 2025, internal congestion created a south-to-north price separation, with prices pushed higher in Northern California, the Intermountain West, and the Pacific Northwest, while prices in Southern California and the Desert Southwest were pulled lower due to constraint binding.

Figure 5.6 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) in 2025. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

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

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

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

Figure 5.6 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (2025)

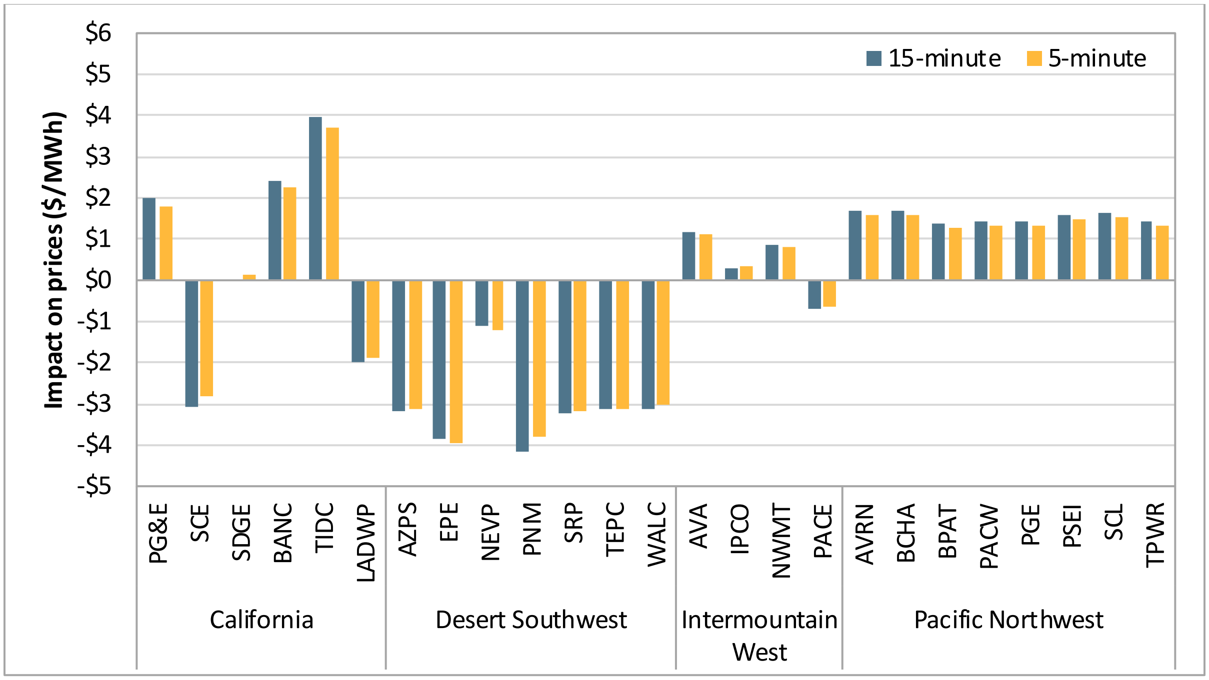
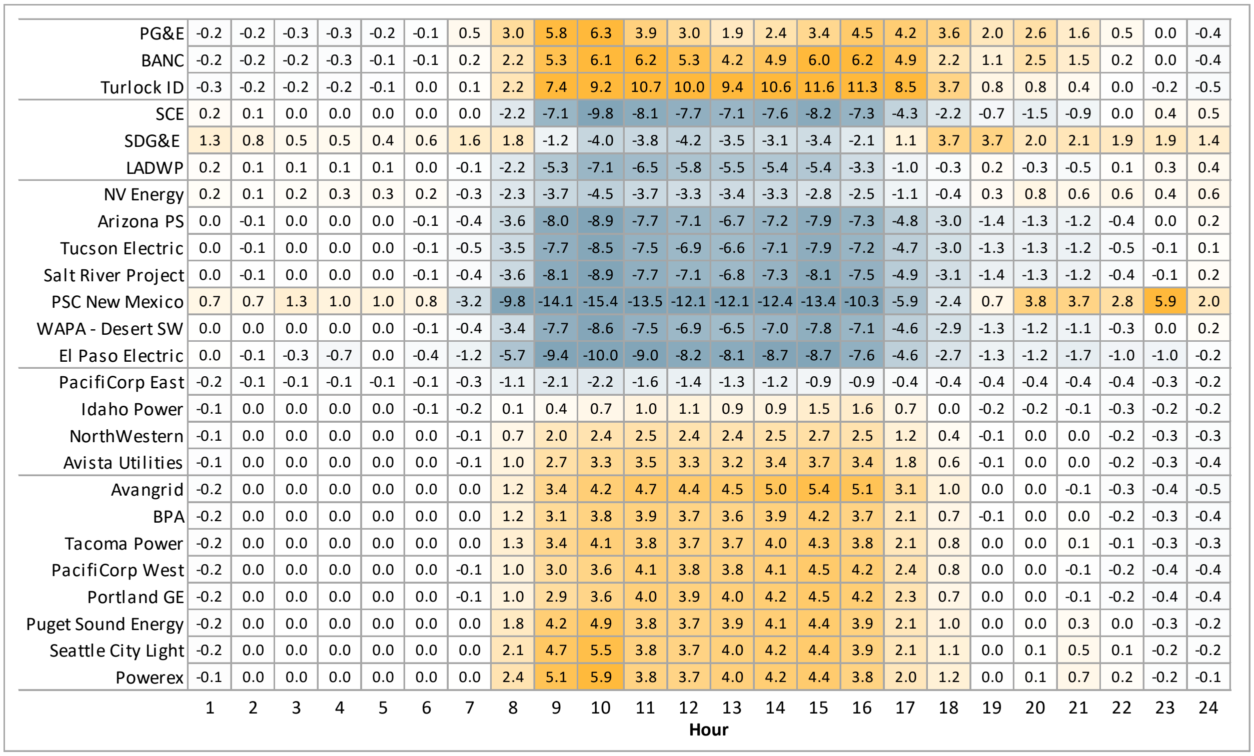


Figure 5.7 and Figure 5.8 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for 2025 and 2024, respectively. Overall, both years exhibited south-to-north congestion during solar production hours. The magnitude of price separation was modest this year compared to last year. Notable changes were observed in SDG&E and PNM, where internal congestion contributed more to higher prices during non-solar hours in 2025 than in 2024.

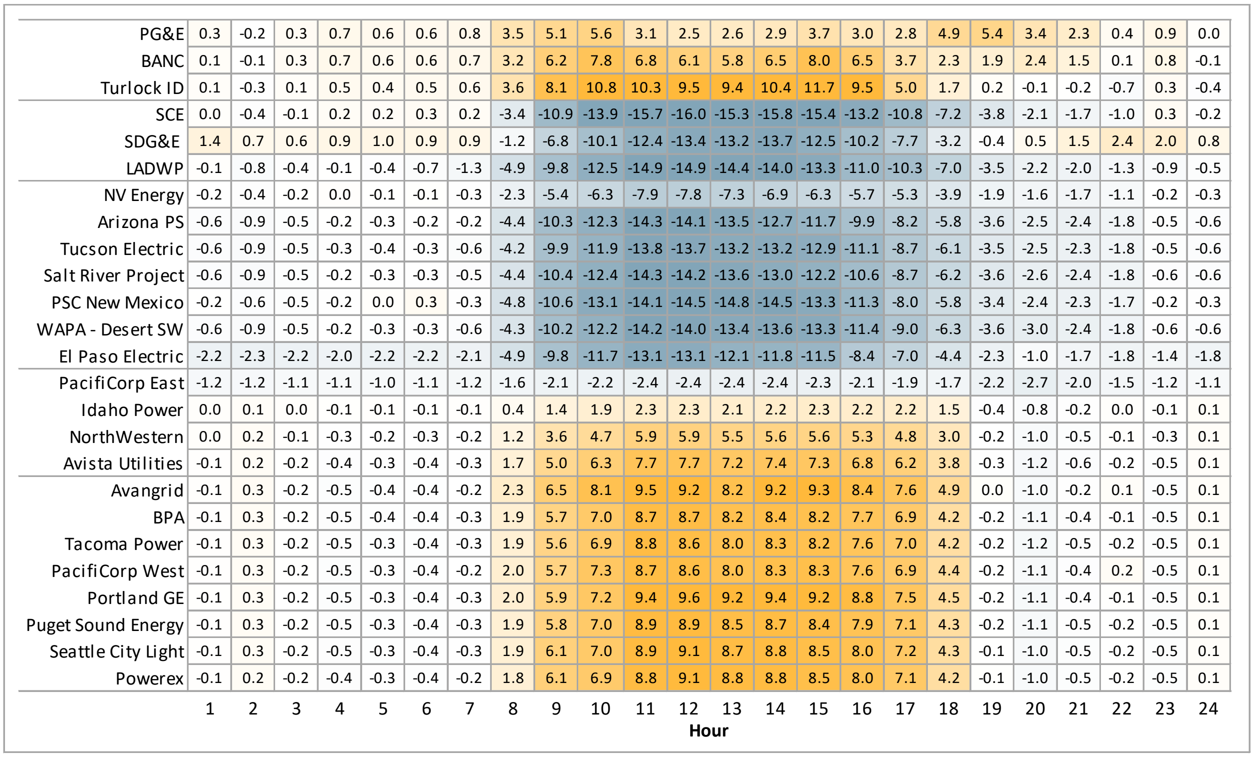
Figure 5.7 Overall impact of internal congestion on price separation in the 15-minute market by hour (2025)



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	-0.2	-0.2	-0.3	-0.3	-0.2	-0.1	0.5	3.0	5.8	6.3	3.9	3.0	1.9	2.4	3.4	4.5	4.2	3.6	2.0	2.6	1.6	0.5	0.0	-0.4
BANC	-0.2	-0.2	-0.2	-0.3	-0.1	-0.1	0.2	2.2	5.3	6.1	6.2	5.3	4.2	4.9	6.0	6.2	4.9	2.2	1.1	2.5	1.5	0.2	0.0	-0.4
Turlock ID	-0.3	-0.2	-0.2	-0.2	-0.1	0.0	0.1	2.2	7.4	9.2	10.7	10.0	9.4	10.6	11.6	11.3	8.5	3.7	0.8	0.8	0.4	0.0	-0.2	-0.5
SCE	0.2	0.1	0.0	0.0	0.0	0.0	0.0	-2.2	-7.1	-9.8	-8.1	-7.7	-7.1	-7.6	-8.2	-7.3	-4.3	-2.2	-0.7	-1.5	-0.9	0.0	0.4	0.5
SDG&E	1.3	0.8	0.5	0.5	0.4	0.6	1.6	1.8	-1.2	-4.0	-3.8	-4.2	-3.5	-3.1	-3.4	-2.1	1.1	3.7	3.7	2.0	2.1	1.9	1.9	1.4
LADWP	0.2	0.1	0.1	0.1	0.1	0.0	-0.1	-2.2	-5.3	-7.1	-6.5	-5.8	-5.5	-5.4	-5.4	-3.3	-1.0	-0.3	0.2	-0.3	-0.5	0.1	0.3	0.4
NV Energy	0.2	0.1	0.2	0.3	0.3	0.2	-0.3	-2.3	-3.7	-4.5	-3.7	-3.3	-3.4	-3.3	-2.8	-2.5	-1.1	-0.4	0.3	0.8	0.6	0.6	0.4	0.6
Arizona PS	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.4	-3.6	-8.0	-8.9	-7.7	-7.1	-6.7	-7.2	-7.9	-7.3	-4.8	-3.0	-1.4	-1.3	-1.2	-0.4	0.0	0.2
Tucson Electric	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.5	-3.5	-7.7	-8.5	-7.5	-6.9	-6.6	-7.1	-7.9	-7.2	-4.7	-3.0	-1.3	-1.3	-1.2	-0.5	-0.1	0.1
Salt River Project	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.4	-3.6	-8.1	-8.9	-7.7	-7.1	-6.8	-7.3	-8.1	-7.5	-4.9	-3.1	-1.4	-1.3	-1.2	-0.4	-0.1	0.2
PSC New Mexico	0.7	0.7	1.3	1.0	1.0	0.8	-3.2	-9.8	-14.1	-15.4	-13.5	-12.1	-12.1	-12.4	-13.4	-10.3	-5.9	-2.4	0.7	3.8	3.7	2.8	5.9	2.0
WAPA - Desert SW	0.0	0.0	0.0	0.0	0.0	-0.1	-0.4	-3.4	-7.7	-8.6	-7.5	-6.9	-6.5	-7.0	-7.8	-7.1	-4.6	-2.9	-1.3	-1.2	-1.1	-0.3	0.0	0.2
El Paso Electric	0.0	-0.1	-0.3	-0.7	0.0	-0.4	-1.2	-5.7	-9.4	-10.0	-9.0	-8.2	-8.1	-8.7	-8.7	-7.6	-4.6	-2.7	-1.3	-1.2	-1.7	-1.0	-1.0	-0.2
PacifiCorp East	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.3	-1.1	-2.1	-2.2	-1.6	-1.4	-1.3	-1.2	-0.9	-0.9	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.3	-0.2
Idaho Power	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.2	0.1	0.4	0.7	1.0	1.1	0.9	0.9	1.5	1.6	0.7	0.0	-0.2	-0.2	-0.1	-0.3	-0.2	-0.2
NorthWestern	-0.1	0.0	0.0	0.0	0.0	0.0	-0.1	0.7	2.0	2.4	2.5	2.4	2.4	2.5	2.7	2.5	1.2	0.4	-0.1	0.0	0.0	-0.2	-0.3	-0.3
Avista Utilities	-0.1	0.0	0.0	0.0	0.0	0.0	-0.1	1.0	2.7	3.3	3.5	3.3	3.2	3.4	3.7	3.4	1.8	0.6	-0.1	0.0	0.0	-0.2	-0.3	-0.4
Avangrid	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.2	3.4	4.2	4.7	4.4	4.5	5.0	5.4	5.1	3.1	1.0	0.0	0.0	-0.1	-0.3	-0.4	-0.5
BPA	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.2	3.1	3.8	3.9	3.7	3.6	3.9	4.2	3.7	2.1	0.7	-0.1	0.0	0.0	-0.2	-0.3	-0.4
Tacoma Power	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.3	3.4	4.1	3.8	3.7	3.7	4.0	4.3	3.8	2.1	0.8	0.0	0.0	0.1	-0.1	-0.3	-0.3
PacifiCorp West	-0.2	0.0	0.0	0.0	0.0	0.0	-0.1	1.0	3.0	3.6	4.1	3.8	3.8	4.1	4.5	4.2	2.4	0.8	0.0	0.0	-0.1	-0.2	-0.4	-0.4
Portland GE	-0.2	0.0	0.0	0.0	0.0	0.0	-0.1	1.0	2.9	3.6	4.0	3.9	4.0	4.2	4.5	4.2	2.3	0.7	0.0	0.0	-0.1	-0.2	-0.4	-0.4
Puget Sound Energy	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.8	4.2	4.9	3.8	3.7	3.9	4.1	4.4	3.9	2.1	1.0	0.0	0.0	0.3	0.0	-0.3	-0.2
Seattle City Light	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	2.1	4.7	5.5	3.8	3.7	4.0	4.2	4.4	3.9	2.1	1.1	0.0	0.1	0.5	0.1	-0.2	-0.2
Powerex	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	2.4	5.1	5.9	3.8	3.7	4.0	4.2	4.4	3.8	2.0	1.2	0.0	0.1	0.7	0.2	-0.2	-0.1

Hour

Figure 5.8 Overall impact of internal congestion on price separation in the 15-minute market by hour (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	0.3	-0.2	0.3	0.7	0.6	0.6	0.8	3.5	5.1	5.6	3.1	2.5	2.6	2.9	3.7	3.0	2.8	4.9	5.4	3.4	2.3	0.4	0.9	0.0
BANC	0.1	-0.1	0.3	0.7	0.6	0.6	0.7	3.2	6.2	7.8	6.8	6.1	5.8	6.5	8.0	6.5	3.7	2.3	1.9	2.4	1.5	0.1	0.8	-0.1
Turlock ID	0.1	-0.3	0.1	0.5	0.4	0.5	0.6	3.6	8.1	10.8	10.3	9.5	9.4	10.4	11.7	9.5	5.0	1.7	0.2	-0.1	-0.2	-0.7	0.3	-0.4
SCE	0.0	-0.4	-0.1	0.2	0.2	0.3	0.2	-3.4	-10.9	-13.9	-15.7	-16.0	-15.3	-15.8	-15.4	-13.2	-10.8	-7.2	-3.8	-2.1	-1.7	-1.0	0.3	-0.2
SDG&E	1.4	0.7	0.6	0.9	1.0	0.9	0.9	-1.2	-6.8	-10.1	-12.4	-13.4	-13.2	-13.7	-12.5	-10.2	-7.7	-3.2	-0.4	0.5	1.5	2.4	2.0	0.8
LADWP	-0.1	-0.8	-0.4	-0.1	-0.4	-0.7	-1.3	-4.9	-9.8	-12.5	-14.9	-14.9	-14.4	-14.0	-13.3	-11.0	-10.3	-7.0	-3.5	-2.2	-2.0	-1.3	-0.9	-0.5
NV Energy	-0.2	-0.4	-0.2	0.0	-0.1	-0.1	-0.3	-2.3	-5.4	-6.3	-7.9	-7.8	-7.3	-6.9	-6.3	-5.7	-5.3	-3.9	-1.9	-1.6	-1.7	-1.1	-0.2	-0.3
Arizona PS	-0.6	-0.9	-0.5	-0.2	-0.3	-0.2	-0.2	-4.4	-10.3	-12.3	-14.3	-14.1	-13.5	-12.7	-11.7	-9.9	-8.2	-5.8	-3.6	-2.5	-2.4	-1.8	-0.5	-0.6
Tucson Electric	-0.6	-0.9	-0.5	-0.3	-0.4	-0.3	-0.6	-4.2	-9.9	-11.9	-13.8	-13.7	-13.2	-13.2	-12.9	-11.1	-8.7	-6.1	-3.5	-2.5	-2.3	-1.8	-0.5	-0.6
Salt River Project	-0.6	-0.9	-0.5	-0.2	-0.3	-0.3	-0.5	-4.4	-10.4	-12.4	-14.3	-14.2	-13.6	-13.0	-12.2	-10.6	-8.7	-6.2	-3.6	-2.6	-2.4	-1.8	-0.6	-0.6
PSC New Mexico	-0.2	-0.6	-0.5	-0.2	0.0	0.3	-0.3	-4.8	-10.6	-13.1	-14.1	-14.5	-14.8	-14.5	-13.3	-11.3	-8.0	-5.8	-3.4	-2.4	-2.3	-1.7	-0.2	-0.3
WAPA - Desert SW	-0.6	-0.9	-0.5	-0.2	-0.3	-0.3	-0.6	-4.3	-10.2	-12.2	-14.2	-14.0	-13.4	-13.6	-13.3	-11.4	-9.0	-6.3	-3.6	-3.0	-2.4	-1.8	-0.6	-0.6
El Paso Electric	-2.2	-2.3	-2.2	-2.0	-2.2	-2.2	-2.1	-4.9	-9.8	-11.7	-13.1	-13.1	-12.1	-11.8	-11.5	-8.4	-7.0	-4.4	-2.3	-1.0	-1.7	-1.8	-1.4	-1.8
PacifiCorp East	-1.2	-1.2	-1.1	-1.1	-1.0	-1.1	-1.2	-1.6	-2.1	-2.2	-2.4	-2.4	-2.4	-2.4	-2.3	-2.1	-1.9	-1.7	-2.2	-2.7	-2.0	-1.5	-1.2	-1.1
Idaho Power	0.0	0.1	0.0	-0.1	-0.1	-0.1	-0.1	0.4	1.4	1.9	2.3	2.3	2.1	2.2	2.3	2.2	2.2	1.5	-0.4	-0.8	-0.2	0.0	-0.1	0.1
NorthWestern	0.0	0.2	-0.1	-0.3	-0.2	-0.3	-0.2	1.2	3.6	4.7	5.9	5.9	5.5	5.6	5.6	5.3	4.8	3.0	-0.2	-1.0	-0.5	-0.1	-0.3	0.1
Avista Utilities	-0.1	0.2	-0.2	-0.4	-0.3	-0.4	-0.3	1.7	5.0	6.3	7.7	7.7	7.2	7.4	7.3	6.8	6.2	3.8	-0.3	-1.2	-0.6	-0.2	-0.5	0.1
Avangrid	-0.1	0.3	-0.2	-0.5	-0.4	-0.4	-0.2	2.3	6.5	8.1	9.5	9.2	8.2	9.2	9.3	8.4	7.6	4.9	0.0	-1.0	-0.2	0.1	-0.5	0.1
BPA	-0.1	0.3	-0.2	-0.5	-0.4	-0.4	-0.3	1.9	5.7	7.0	8.7	8.7	8.2	8.4	8.2	7.7	6.9	4.2	-0.2	-1.1	-0.4	-0.1	-0.5	0.1
Tacoma Power	-0.1	0.3	-0.2	-0.5	-0.3	-0.4	-0.3	1.9	5.6	6.9	8.8	8.6	8.0	8.3	8.2	7.6	7.0	4.2	-0.2	-1.2	-0.5	-0.2	-0.5	0.1
PacifiCorp West	-0.1	0.3	-0.2	-0.5	-0.3	-0.4	-0.2	2.0	5.7	7.3	8.7	8.6	8.0	8.3	8.3	7.6	6.9	4.4	-0.2	-1.1	-0.4	0.2	-0.5	0.1
Portland GE	-0.1	0.3	-0.2	-0.5	-0.3	-0.4	-0.3	2.0	5.9	7.2	9.4	9.6	9.2	9.4	9.2	8.8	7.5	4.5	-0.2	-1.1	-0.4	-0.1	-0.5	0.1
Puget Sound Energy	-0.1	0.3	-0.2	-0.5	-0.3	-0.4	-0.3	1.9	5.8	7.0	8.9	8.9	8.5	8.7	8.4	7.9	7.1	4.3	-0.2	-1.1	-0.5	-0.2	-0.5	0.1
Seattle City Light	-0.1	0.3	-0.2	-0.5	-0.3	-0.4	-0.3	1.9	6.1	7.0	8.9	9.1	8.7	8.8	8.5	8.0	7.2	4.3	-0.1	-1.0	-0.5	-0.2	-0.5	0.1
Powerex	-0.1	0.2	-0.2	-0.4	-0.3	-0.4	-0.2	1.8	6.1	6.9	8.8	9.1	8.8	8.8	8.5	8.0	7.1	4.2	-0.1	-1.0	-0.5	-0.2	-0.5	0.1

Hour

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

Table 5.1 shows the annual impact of congestion from individual constraints on prices across the WEIM for the 15-minute market. The table reports the top 50 constraints based on their aggregate impact and price separation across DLAPs and ELAPs. Constraints with minimal impact are consolidated under the “other” category, which appears in the second-to-last row of the second column.

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

Gates-Midway #1 500 kV line

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

Tesla-Los Banos #1 500 kV line

The Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) contributed to south-to-north congestion. As a result, prices in Northern California, the Intermountain West, and the Pacific Northwest were pushed upward relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hours-ending 10 to 16.

Los Banos-Gates #1 500 kV line

The Los Banos-Gates #1 500 kV line (30050_LOSBANOS_500_30055_GATES1_500_BR_1_3) contributed to south-to-north congestion. As a result, prices in Northern California, the Intermountain West, and the Pacific Northwest were elevated relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hours-ending 11 to 16.

Table 5.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, 2025)[159]

BAA	Constraint	Average quarter impact ($/MWh)																								
		California						Desert Southwest							Intermountain West				Pacific Northwest							
		PG&E	BANC	TIDC	SCE	SDG&E	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	Line_FC-CH1_345KV	.01	.	.	.02	.02	.01	.02	-.06	.	-.13	.03	.01	.02	.	-.03	.00	-.04	.	.	.	.	.	.	.	.
	Line_FC-CH2_345KV	.00	.	.	.01	.01	.01	.01	-.04	.	-.07	.01	.	.01	.	-.01	.00	-.02	.	.	.	.	.	.	.	.
BPAT	INTNEL	-.06	-.06	-.06	-.06	-.06	-.06	-.06	-.05	-.06	-.05	-.06	-.06	-.06	-.02	-.05	.00	-.05	-.06	.39	.00	-.06	-.06	.20	.30	.06
	NOPE	.	-.01	-.01	.	.	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.00	.00	.00	-.01	-.01	.01	.01	.00	.03	.02	.01	.02
CISO	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	.44	.51	.53	-.59	-.57	-.58	-.52	-.48	-.35	-.46	-.52	-.51	-.52	.31	.03	.23	-.15	.40	.33	.34	.36	.36	.34	.34	.34
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	.15	.29	.21	-.44	-.42	-.43	-.38	-.35	-.26	-.33	-.38	-.37	-.38	.25	.08	.20	-.06	.31	.26	.27	.29	.28	.27	.27	.27
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	.19	.32	.33	-.35	-.33	-.34	-.30	-.28	-.20	-.26	-.30	-.29	-.30	.23	.07	.18	-.04	.29	.24	.25	.26	.26	.25	.25	.25
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	.09	1.00	2.25	-.53	-.51	-.27	-.14	-.06	-.01	-.04	-.14	-.12	-.14	.02	.	.00	.	.22	.03	.05	.08	.07	.04	.04	.04
	6110_COI_S-N	-.30	-.32	-.31	-.22	-.21	-.22	-.19	-.17	-.14	-.15	-.18	-.18	-.19	.23	.11	.19	.00	.27	.24	.25	.25	.25	.24	.24	.24
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	.21	.27	.33	-.24	-.23	-.22	-.16	-.11	-.05	-.09	-.16	-.15	-.16	.05	.	.01	.	.11	.06	.06	.08	.07	.06	.06	.06
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	.11	.13	.14	-.13	-.12	-.13	-.11	-.10	-.08	-.10	-.11	-.11	-.11	.09	.03	.07	-.03	.12	.10	.10	.10	.10	.10	.10	.10
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	.09	.09	.09	.06	.04	.09	-.31	-.27	-.08	-.24	-.32	-.29	-.25	.00	.00	.	-.08	.02	.00	.00	.00	.00	.00	.00	.00
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	.52	.01	.01	-.61	-.58	-.14	-.03	-.01	.	-.01	-.03	-.03	-.03	.	.	.	.	.00	.00	.00	.00	.00	.00	.00	.00
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	.10	.09	.10	-.10	-.10	-.10	-.09	-.08	-.06	-.08	-.09	-.09	-.09	.06	.01	.05	-.02	.08	.06	.07	.07	.07	.07	.07	.07
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-.10	-.10	-.10	.07	.06	.07	.06	.05	.04	.05	.06	.05	.06	-.07	-.04	-.05	-.01	-.08	-.07	-.07	-.07	-.07	-.07	-.07	-.07
	MIGUEL_BKs_MXFLW_NG	.02	.	.	.06	.50	.	-.14	-.12	.	-.11	-.14	-.13	-.13	.	.	.	.	.	.	.	.	.	.	.	.
	92321_SYCATP2_230_22832_SYCAMORE_230_BR_2_1	.02	.	.	.05	.45	.	-.11	-.10	.	-.09	-.11	-.11	-.10	.	.	.	.	.	.	.	.	.	.	.	.
	7820_TL230S_OVERLOAD_NG	.01	.00	.00	.03	.43	.00	-.08	-.08	-.03	-.07	-.09	-.08	-.07	.	-.01	.	-.03	.	.	.	.	.	.	.	.
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1_1	.03	.	.	.06	.16	.	-.12	-.11	.	-.09	-.12	-.12	-.11	.	.	.	.	.	.	.	.	.	.	.	.
	6110_COI_N-S	.03	.03	.03	.02	.02	.02	.02	.02	.01	.02	.02	.02	.02	-.04	-.01	-.03	.00	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	.	.	.	.	.60	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22886_SUNCREST_230_92861_SUNCTP2_230_BR_2_1	.01	.	.	.03	.23	.	-.06	-.05	.	-.04	-.06	-.06	-.05	.	.	.	.	.	.	.	.	.	.	.	.
	30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P	-.04	-.07	-.03	-.02	-.02	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.03	.01	.02	.	.03	.03	.03	.03	.03	.03	.03	.03
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.01	.	.	.03	.20	.	-.06	-.05	.00	-.04	-.06	-.05	-.05	.	.	.	-.01	.	.	.	.	.	.	.	.
	24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	-.04	-.04	-.04	.11	.08	.00	.	.	.	.	.	.	.	-.02	.00	-.01	.	-.03	-.02	-.02	-.02	-.02	-.02	-.02	-.02
	24801_DEVERS_500_99014_CALCAPS2_500_BR_2_1	.01	.01	.01	.03	.02	.02	-.05	-.04	-.01	-.04	-.05	-.04	-.04	.00	.	.	-.01	.01	.01	.01	.01	.01	.01	.01	.01
	7760_DEV_RDB_ALIS	.02	.01	.02	.04	.00	.02	-.06	-.05	.00	-.04	-.06	-.05	-.05	.	.	.	-.01	.00	.	.	.00	.00	.	.	.
	99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	.01	.01	.01	.01	.00	.02	-.04	-.06	.02	-.06	-.04	-.04	-.03	.00	.00	.	-.01	.01	.00	.01	.01	.01	.01	.01	.01
	7430_CP6_NG	.05	.20	.	-.06	-.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30879_HENTAP1_230_30885_MUSTANGS_230_BR_1_1	.08	.05	.02	-.04	-.04	-.03	-.02	-.02	.	-.01	-.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.
	30900_GATES_230_30970_MIDWAY_230_BR_1_1	.02	.02	.02	-.02	-.02	-.02	-.02	-.01	-.01	-.01	-.02	-.02	-.02	.01	.00	.01	.00	.02	.01	.01	.01	.01	.01	.01	.01
	30765_LOSBANOS_230_30766_PADRFLT_230_BR_1_1	-.02	.00	.20	-.07	-.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	32214_RIOOSO_115_32225_BRNSWKT1_115_BR_1_1	-.07	-.02	.00	.00	.00	.	.	.	.24	.	.	.	.	.	.	.	.	.00	.	.	.	.	.	.	.
	34214_LOSBANS_70.0_30765_LOSBANOS_230_XF_3	.00	.	.22	-.06	-.05	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	7820_TL23040_IV_SPS_NG	.00	.	.	.01	.11	.	-.02	-.02	.00	-.02	-.02	-.02	-.02	.	.	.	.00	.	.	.	.	.	.	.	.
	30015_TABLEMT_500_30068_TBMT5M_1.0_XF_5	-.05	-.06	-.02	-.01	-.01	.	.	.	-.03	.	.	.	.	.00	.	.	.	.01	.01	.01	.01	.01	.01	.01	.01
	24086_LUGO_500_26105_VICTORVL_500_BR_1_1	.01	.01	.01	.01	.01	-.02	-.02	-.02	-.02	-.02	-.02	-.02	-.02	.00	.00	.00	-.01	.01	.00	.00	.00	.00	.00	.00	.00
	22464_MIGUEL_230_22468_MIGUEL_500_XF_81	.00	.	.	.01	.09	.	-.02	-.02	.	-.01	-.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.
	7820_PK_EC_OVERLOAD_NG	.00	.00	.00	.01	.09	.00	-.02	-.02	.00	-.01	-.02	-.02	-.02	.	.	.	-.01	.	.	.	.	.	.	.	.
IPCO	MPSNT342	.00	.00	.00	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.02	-.02	-.02	.03	.11	.01	-.06	.02	.03	.02	.03	.03	.03	.03	.03
LADWP	HWD_FARAREA	.	.	.	.	.	.25	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
PACE	CLOVER_MONA_345_1	.00	.	.	-.03	-.03	.	-.04	-.04	.00	-.04	-.04	-.04	-.03	.	.06	.00	.09	.	.	.	.	.	.	.	.
PACW	HURRICAW_WALAWALA_230	.00	.	.	-.01	-.01	.	.00	-.01	-.02	-.02	.00	.00	.00	.02	-.07	.	-.03	.00	.02	.02	.02	.02	.02	.02	.02
PNM	CZ345kV	.05	.	.	.04	.03	.	.	-.95	.	-2.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	WMesaWT2_448MVA	-.03	.	.	-.03	-.03	.	.	-.21	.	1.56	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115WTGatPEGS	.00	.	.	.01	.03	.	.	-.24	.	-.87	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	WMesaET1_448MVA	-.02	.	.	-.02	-.02	.	.	-.11	.	.89	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	FRCE-PINT1	.01	.	.	.01	.01	.	.	-.22	.	-.52	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvSOC_BeBe	.	.	.	.	.	.	.	.60	.	-.05	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvNH	.	.	.	.	.	.	.	-.08	.	-.13	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	.41	.03	-.01	-.13	.31	.13	-.10	.24	.04	-.33	-.15	-.15	-.16	.01	.01	-.03	-.09	-.02	.00	-.02	-.01	-.01	-.02	-.02	-.02
	Total	1.98	2.40	3.95	-3.06	0.00	-1.97	-3.20	-3.83	-1.11	-4.18	-3.25	-3.15	-3.10	1.19	.30	.85	-.69	1.69	1.70	1.36	1.41	1.41	1.56	1.65	1.42

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

5.3 Congestion rent and loss surpluses

Figure 5.9 shows that in 2025, annual congestion rent and loss surpluses were $485 million and $143 million, respectively.[160, 161] These amounts represent a decrease of 10 percent and an increase of 7 percent relative to 2024. The reduction in the congestion component can be attributed to a significant decrease in congestion rent from intertie constraints.

Congestion rent consists of rents from internal constraints and interties. Internal congestion rent increased from $373 million in 2024 to $459 million in 2025. Intertie congestion rent decreased from $164 million in 2024 to $26 million in 2025. The primary driver of the significant decline in intertie congestion rent in 2025 was the absence of the severe weather event in the Pacific Northwest in Q1 2024, which had led to unusually high intertie congestion in 2024.

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

The loss surplus represents the difference between what load pays and what generators receive for the loss component of the locational marginal price (LMP) in the day-ahead market. Because the loss component is proportional to the energy component of LMP, loss surplus typically tracks changes in energy prices and load over time.[162]

In 2025, average day-ahead energy prices declined by 5 percent from 2024, while loss surplus increased by 7 percent. This divergence was driven primarily by the first quarter of 2025, when loss surplus increased by 24 percent despite a 15 percent decline in energy prices compared to the same quarter in 2024. In the remaining quarters of 2025, loss surplus and energy prices generally moved in the same direction relative to the prior year, making the first quarter an outlier.

Several factors may explain this result. Aggregate load levels affect total loss surplus. Although load in Q1 2025 was similar to that in Q1 2024, more load may have occurred during hours when marginal losses were higher. In addition, changes in system conditions, such as power being rerouted over less efficient paths during outages, may have increased loss surplus. Because the loss component of LMP depends on both the energy price and the marginal loss factor (MLF), these changes likely raised the loss surplus despite lower energy prices.[163]

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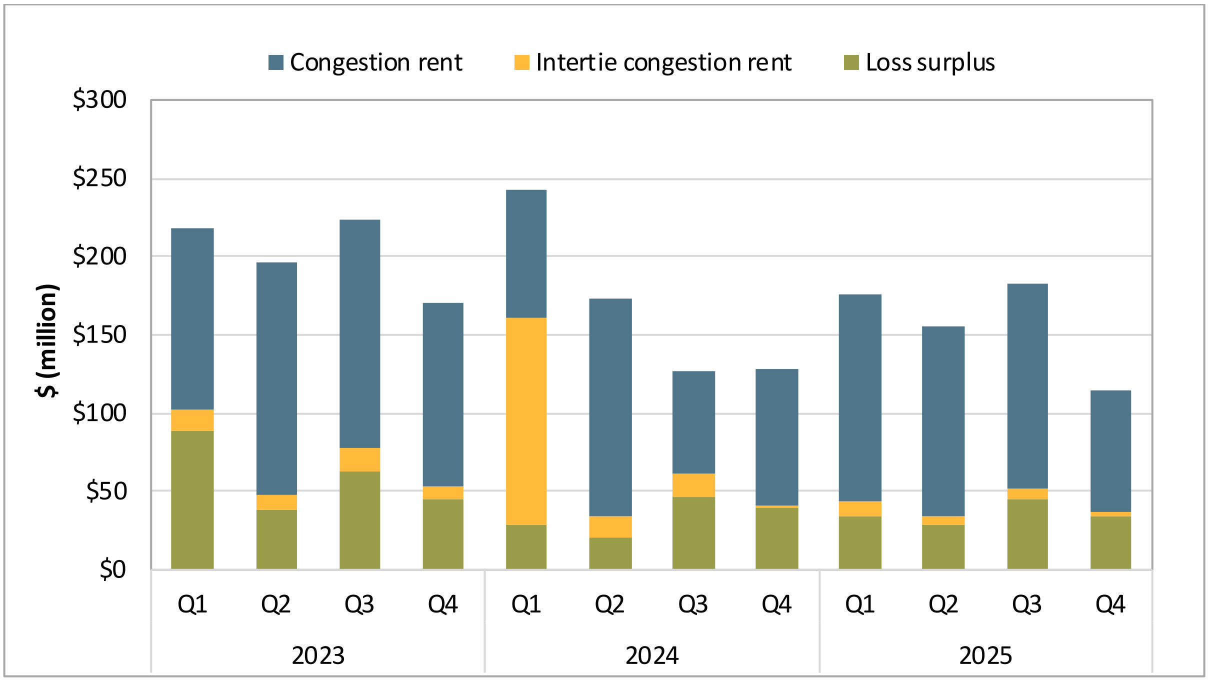
[160] Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after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

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

[162] 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

[163] For additional detail on marginal loss component calculation, see California ISO Tariff – Appendix C: https://www.caiso.com/documents/appendixc-locationalmarginalprice-asof-feb1-2023.pdf

Figure 5.9 Day-ahead congestion rent and loss surplus by quarter (2023–2025)[164]



5.4 Congestion on interties

In 2025, total intertie congestion rent in the day-ahead market was $26 million, a significant decrease from $164 million in 2024. The primary driver of the significant decline in intertie congestion rent in 2025 was the absence of the severe weather event in the Pacific Northwest in Q1 2024, which contributed to unusually high intertie congestion in 2024.

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

Figure 5.10 shows total intertie congestion charges in the day-ahead market from 2021 to 2025. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 5.11 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 5.2 provides a detailed summary of congestion rent and

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

frequency over a broader set of interties distinguished by imports and exports. As highlighted in these charts and table:

Compared with 2024, the most notable change was the sharp decline in export congestion rent at Malin, which fell from about $126 million to about $1.2 million in 2025. Most of the $126 million in export congestion rent at Malin accrued in Q1 2024 during the severe weather event. Total import congestion rent was $16 million in 2025, down from $30 million in 2024. Total export congestion rent was $10 million in 2025, well below $134 million in 2024.

Total intertie congestion rent has fluctuated over the past five years, ranging from a low of $47 million in 2023 to a high of $182 million in 2022. A notable trend is the steady increase in export congestion rent, with an exceptional spike observed in 2024.

Malin and NOB interties accounted for 68 percent of total congestion rent in 2025. Over the past five years, these two interties represented the majority of congestion rent. From 2021 to 2025, Malin and NOB together averaged 82 percent of total annual congestion rent. The Mona ITC showed rapid growth in export congestion rent, reaching $3 million in 2025.

Figure 5.10 Day-ahead congestion charges on major interties

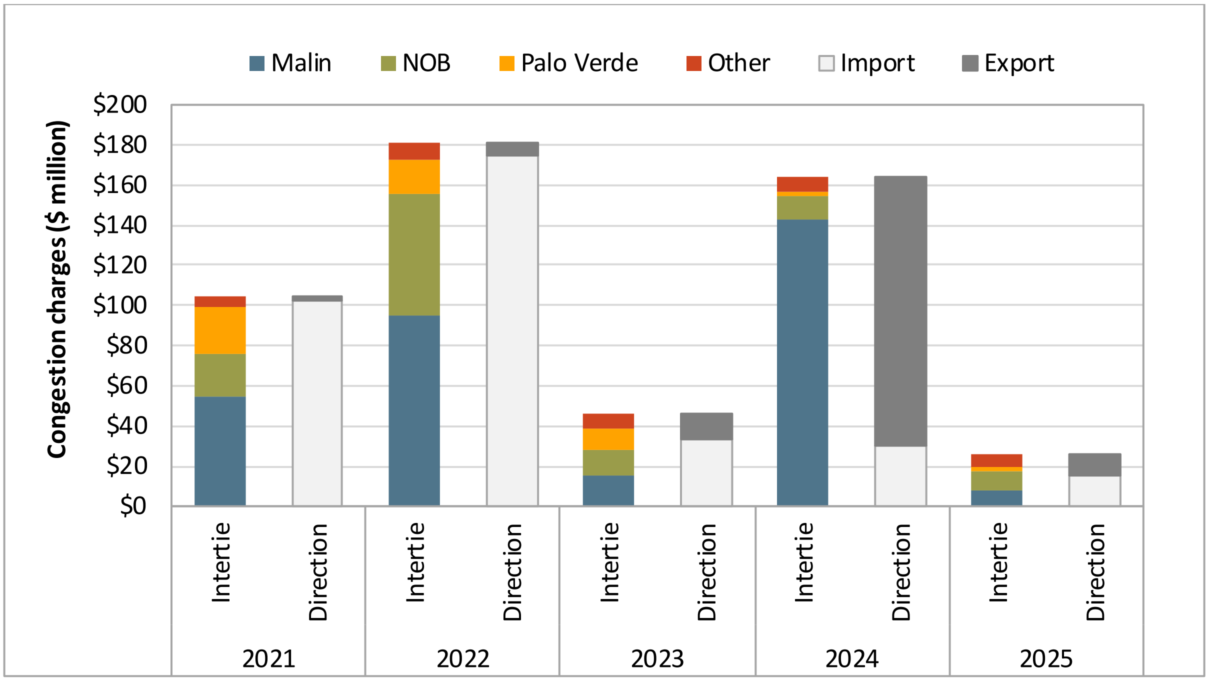


Figure 5.11 Frequency of congestion on major interties in the day-ahead market

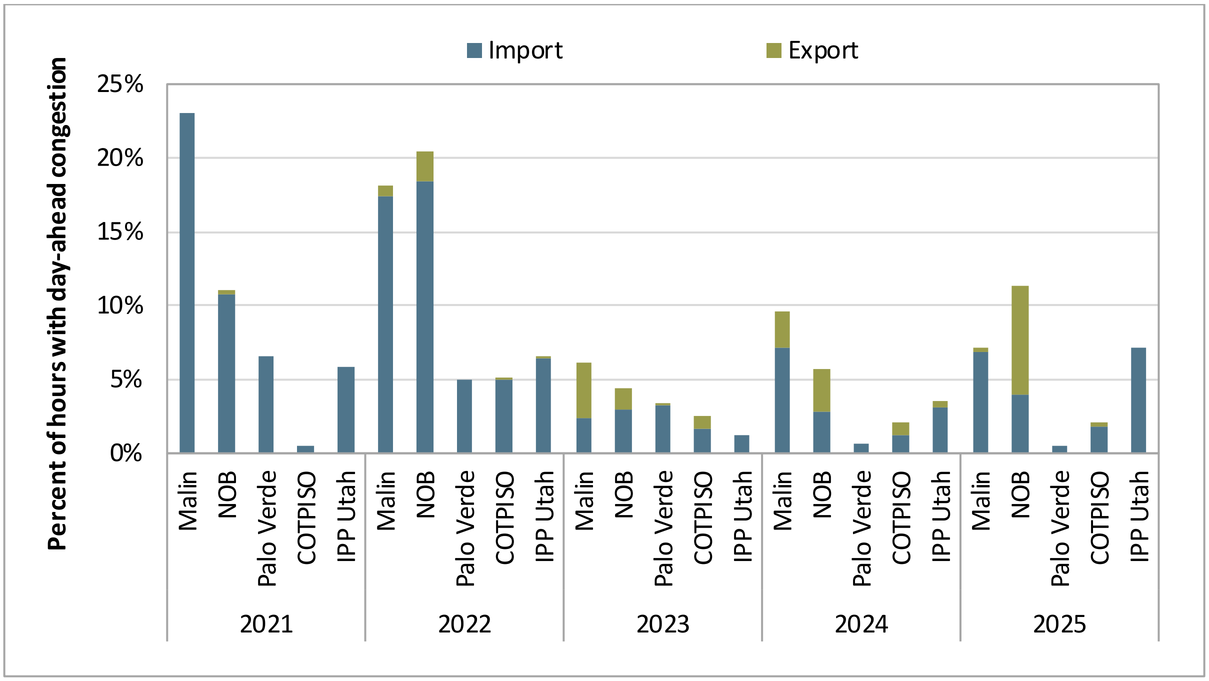


Table 5.2 Summary of intertie congestion in day-ahead market (2021–2025)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
Northwest											
Malin	I	$54,927	$90,385	$6,367	$17,429	$6,641	23.%	17.4%	2.4%	7.1%	6.8%
	E		$4,826	$8,658	$125,863	$1,222		.8%	3.8%	2.5%	.3%
NOB	I	$20,429	$58,510	$11,832	$8,631	$4,554	10.7%	18.4%	2.9%	2.9%	3.9%
	E	$267	$1,398	$1,170	$2,341	$4,853	.3%	2.%	1.5%	2.8%	7.4%
COTPISO	I	$31	$813	$232	$140	$144	.5%	5.%	1.7%	1.3%	1.8%
	E		$1	$89	$1,367	$397		.1%	.8%	.9%	.3%
Cascade	I		$72					.7%			
	E			$0	$2,147				.%	2.%	
Summit	I		$20	$57	$14	$34		.4%	.5%	.2%	.2%
	E		$0					.01%			
Southwest											
Palo Verde	I	$24,128	$18,000	$10,582	$2,382	$1,864	6.6%	4.9%	3.3%	.7%	.5%
	E			$243					.%		
IPP Utah	I	$1,625	$5,636	$264	$1,038	$2,225	5.8%	6.4%	1.2%	3.2%	7.1%
	E		$20		$401			.2%		.4%	
IPP DC Adelanto	I	$40	$685	$2,996			.2%	1.6%	1.7%		
	E				$1,071	$125				1.%	.4%
Mona	I				$23					.1%	
	E	$1,060	$83	$220	$968	$3,124	.1%	.1%	.3%	1.%	1.6%
Mead	I	$84	$182	$75	$24	$9	.1%	.2%	.1%	.1%	.%
	E	$665	$308	$2,370		$155	.1%	.1%	.4%		.1%
Merchant	I	$150	$101				.1%	.02%			
	E										
Silver Peak	I										
	E		$34	$16		$12		.6%	.7%		.4%
Mercury	I		$10					.01%			
	E										
Other	I	$1,511	$0	$1,357	$8	$104					
	E	$72	$0	$0	$129	$65					
Import total (I)		$102,925	$174,414	$33,762	$29,689	$15,575					
Export total (E)		$2,065	$6,669	$12,765	$134,285	$9,954					
Total		$104,990	$181,084	$46,527	$163,974	$25,529					

* I: import, E: export

5.5 Internal congestion in the day-ahead market

Figure 5.12 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2023 to Q4 2025. Figure 5.13 shows the frequency of congestion. Highlights for this year include:

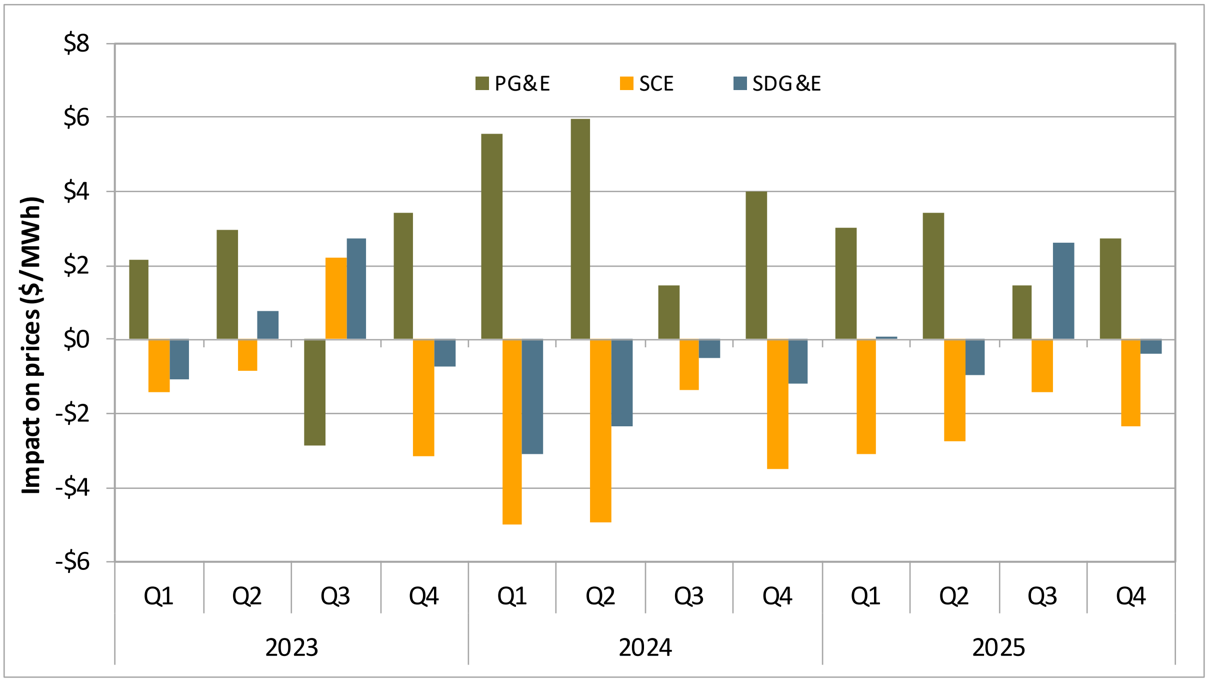
The overall impact of day-ahead congestion on price separation in 2025 was lower compared to 2024, with a general trend of south-to-north congestion.

In 2025, prices in PG&E and SDG&E were elevated by $2.7/MWh and by $0.3/MWh, while prices in SCE were reduced by $2.4/MWh due to internal congestion.[165]

The percentage of hours in which congestion impacted DLAP prices increased each year from 2023 to 2025. Overall, in 2025, PG&E experienced congestion in 78 percent of hours—an increase from 75 percent in 2024. Across all CAISO balancing area default load aggregation points (DLAPs), congestion frequency ranged between 72 percent and 80 percent during 2025.

The primary constraints affecting day-ahead market prices were the Moss Landing-Las Aguilas #1 230 kV line, Panoche-Gates #2 230 kV line, and Gates-Midway #1 500 kV line.

Figure 5.12 Overall impact of congestion on price separation in the day-ahead market



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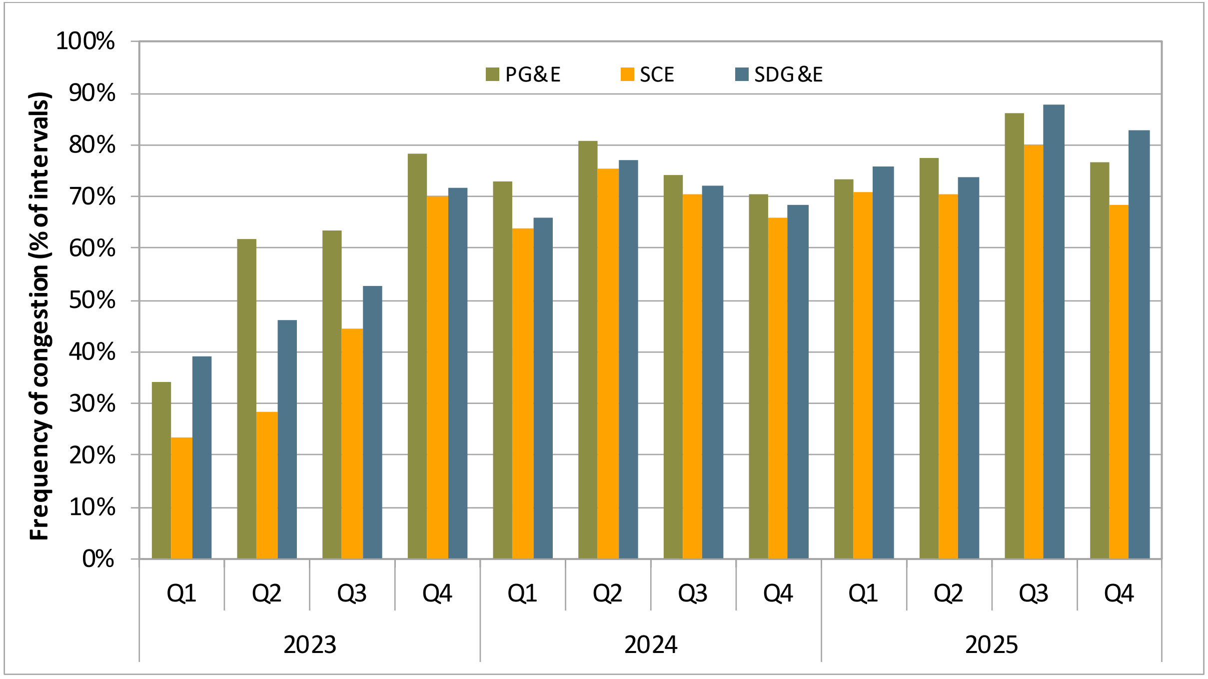
[165] Language in the report describing congestion as “increasing" or “decreasing” a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus—distributed amongst load nodes according to the load at each node’s percentage of total 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 5.13 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 5.3 breaks down the congestion effect on price separation during 2025 by constraint.[166] 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 on 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 2025 were the Moss Landing-Las Aguilas #1 230 kV line, Panoche-Gates #2 230 kV line, and Gates-Midway #1 500 kV line.

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 24 percent of hours. In 2025, on average, prices in PG&E were pushed upward by $0.8/MWh and prices in SCE and SDG&E were pushed down by $0.57/MWh and $0.55/MWh, respectively, due to this constraint. This transmission line was generally binding during solar generation hours, from hour-ending 9 through hour-ending 17.

Panoche-Gates #2 230 kV line

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

The Panoche-Gates #2 230 kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) bound in 12 percent of hours over this year. In 2025, on average, prices in PG&E were elevated by $0.39/MWh and prices in SCE and SDG&E were lowered by $0.3/MWh and $0.29/MWh, respectively, due to this constraint. This transmission line was generally binding during solar generation 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 5 percent of hours over the year. In 2025, on average, prices in PG&E were pushed upward by $0.37/MWh and prices in SCE and SDG&E were pushed down by $0.3/MWh and $0.28/MWh, respectively, due to this constraint. This transmission line was most frequently binding during solar generation hours, from hour-ending 9 through hour-ending 16.

Other notable constraints include transmission lines through the Imperial Valley to the San Diego metropolitan area. These constraints frequently experienced congestion, which put upward pressure on prices in the SDG&E DLAP.

Table 5.3 Impact of congestion on day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	23.8%	.8	-.57	-.55
30790_PANOCHE_230_30900_GATES_230_BR_2_1	12.2%	.39	-.3	-.29
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	5.3%	.37	-.3	-.28
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	4.2%	.36	-.3	-.28
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	17.1%	.34	-.26	-.24
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	32.1%	-.02	-.02	.55
7820_TL23040_IV_SPS_NG	9.7%	-.06	-.02	.43
MIGUEL_BKs_MXFLW_NG	2.3%	-.04	-.01	.32
7820_TL230S_OVERLOAD_NG	10.7%	-.04	-.02	.31
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	6.2%	.1	-.09	-.09
92321_SYCATP2_230_22832_SYCAMORE_230_BR_2_1	3.5%	-.03	-.01	.23
OMSIV-SXOUTAGE_NG	2.1%	-.03	-.01	.2
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	0.9%	.08	-.07	-.06
24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	3.6%	-.1	.09	.02
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	11.9%	-.02	.03	-.1
30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	1.2%	.06	-.04	-.04
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	3.9%	.05	-.04	-.04
22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1_1	1.8%	-.02	.00	.10
34214_LOSBANS_70.0_30765_LOSBANOS_230_XF_3	3.1%	.05	-.04	-.03
22886_SUNCREST_230_92861_SUNCTP2_230_BR_2_1	1.1%	-.01	.	.09
7430_CP6_NG	5.9%	.03	-.03	-.02
30900_GATES_230_30970_MIDWAY_230_BR_1_1	.6%	.03	-.02	-.02
OMS50004IV-MLOUTAGE_NG	0.6%	-.01	.	.06
35642_METCALF_115_30735_METCALF_230_XF_2	1.2%	.03	-.02	-.02
35352_WHISMAN_115_35356_MNTAVSA_115_BR_1_1	2.6%	.02	-.02	-.02
Other		.32	-.32	.11
Total		2.65	-2.39	.34

6 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.[167] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

Key findings from this chapter include:

- **Resource sufficiency evaluation failures were rare overall, but were concentrated in a small number of balancing areas and specific months, particularly for flexibility tests**. Most balancing areas failed each test in less than 0.5 percent of intervals. Exceptions were Idaho Power, which failed the upward flexibility test in about 0.5 percent of intervals, and El Paso Electric, which failed the downward flexibility test in about 0.5 percent of intervals.
- **Ten balancing areas opted in to the assistance energy transfer program on at least one day during the year.** Eight of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Additional WEIM transfers received by each balancing area over the year ranged from 99 MWh to 1,118 MWh.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[168]

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[167] Normally, if an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval. The assistance energy transfers (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Balancing areas can opt in to AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge. For more on AETs, see Section 6.2.

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

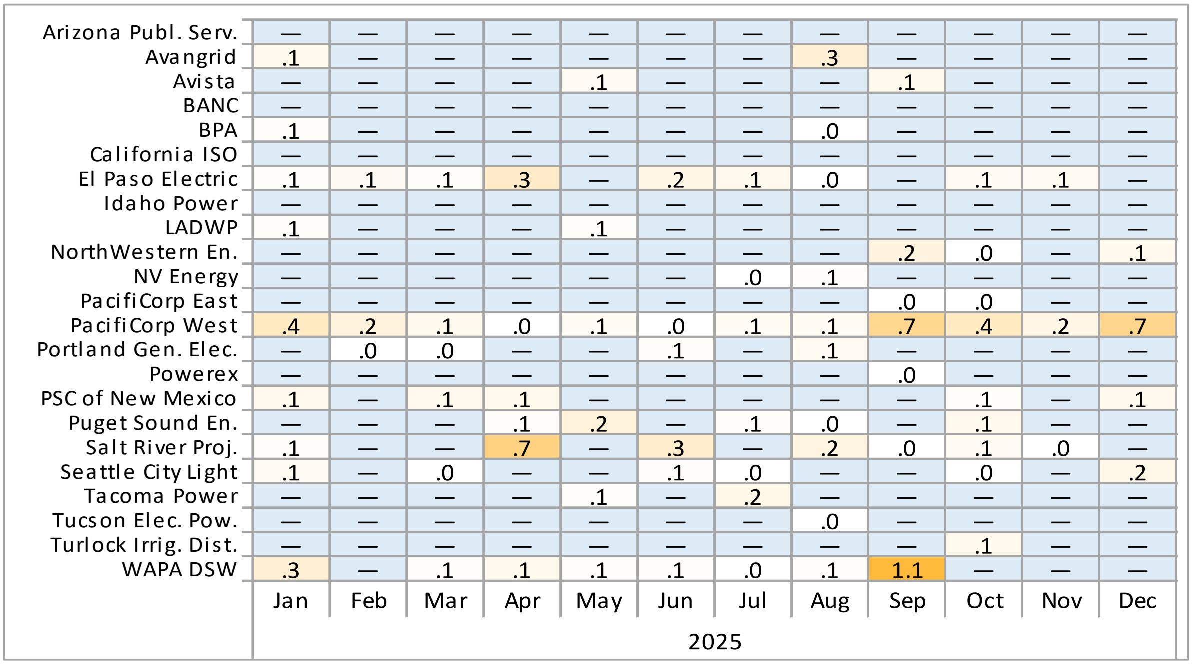
6.1 Frequency of resource sufficiency evaluation failures

Figure 6.1 and Figure 6.2 show the percentage of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 6.3 and Figure 6.4 provide the same information for the downward direction.[169] The dash indicates the area did not fail the test during the month.

During 2025:

- Idaho Power failed the upward flexibility test in 0.5 percent of all intervals. Idaho Power failed all other test types in either direction in less than 0.5 percent of all intervals.
- El Paso Electric failed the downward flexibility test in 0.5 percent of all intervals. El Paso Electric failed all other test types in either direction in less than 0.5 percent of all intervals.
- All other balancing areas failed each test type in either direction in less than 0.5 percent of intervals.

Figure 6.1 Frequency of upward capacity test failures by month and area (percent of intervals)



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

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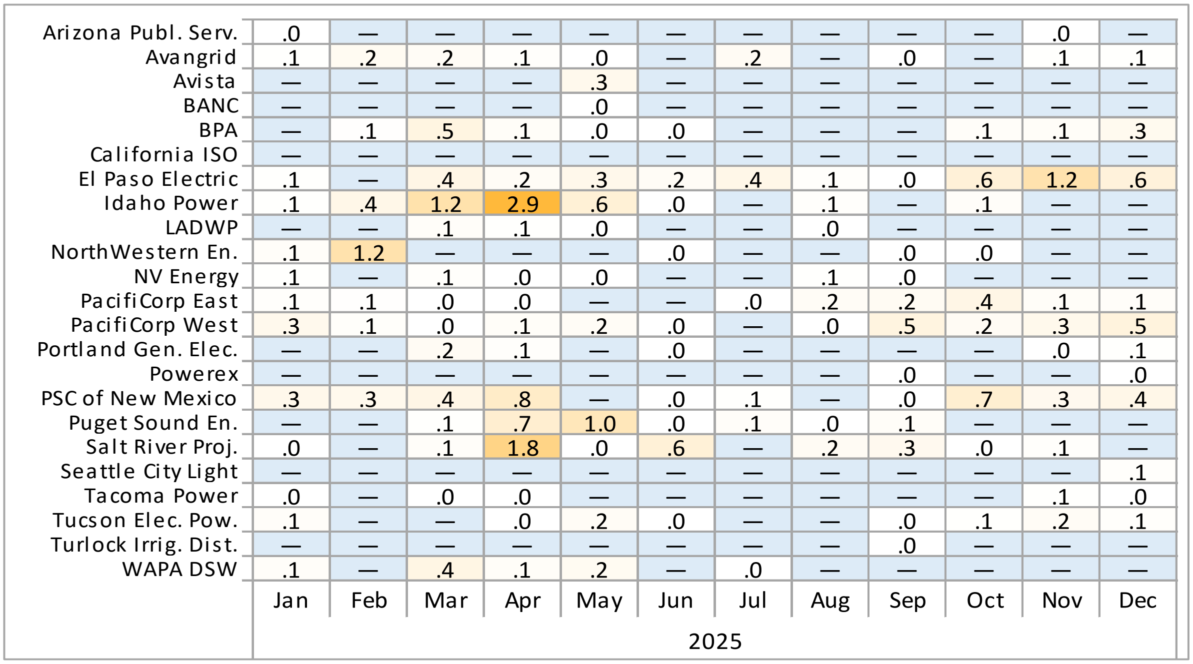
[169] Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

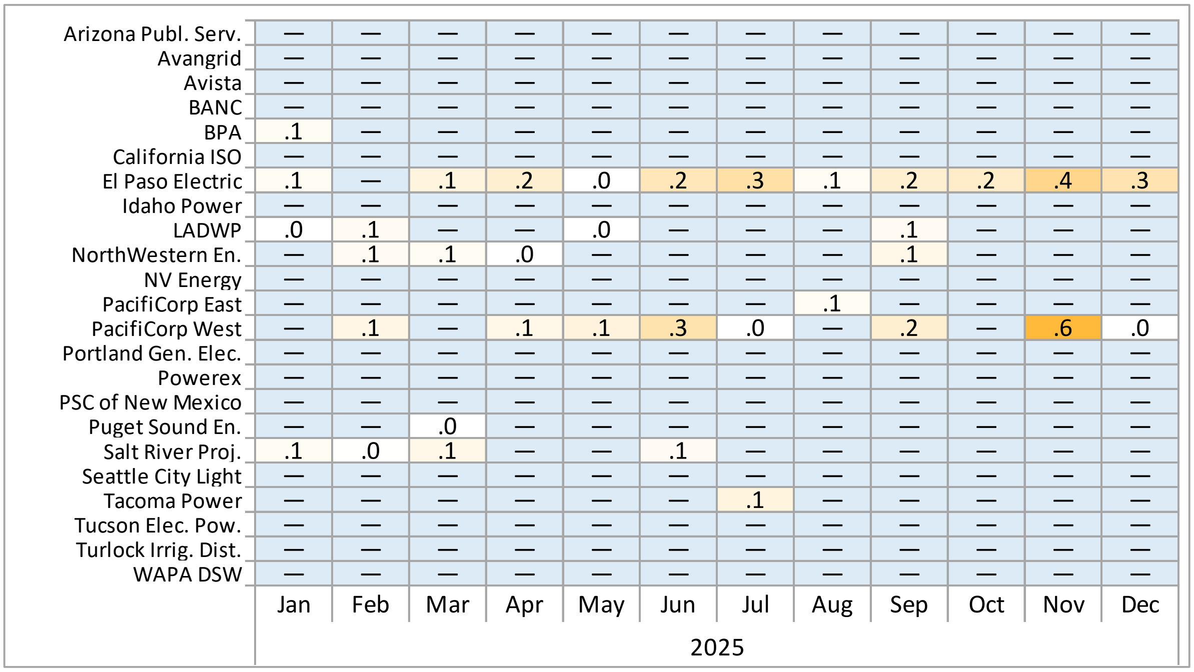
Figure 6.2 **Frequency of upward flexibility test failures by month and area (percent of intervals)**



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

2025

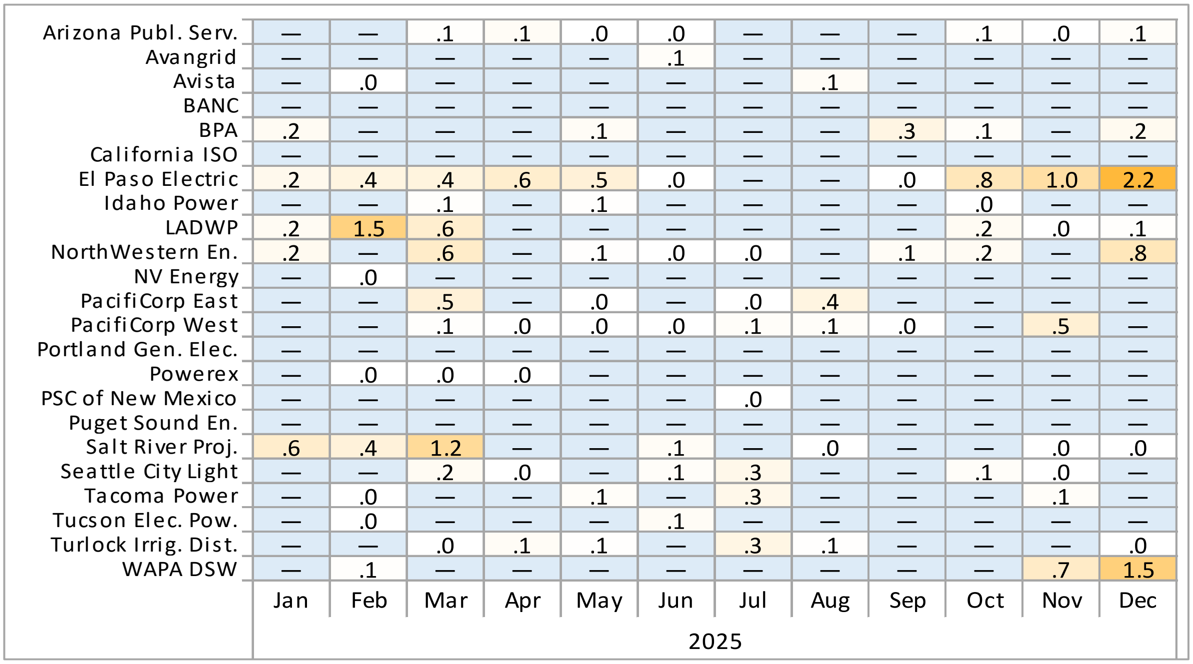
Figure 6.3 **Frequency of downward capacity test failures by month and area (percent of intervals)**



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

2025

Figure 6.4 Frequency of downward flexibility test failures by month and area (percent of intervals)



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

2025

6.2 Assistance energy transfers

The assistance energy transfer (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[170]

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* multiplied by the real-time bid cap.[171] 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

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[170] 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

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

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 6.1 shows the days in which a balancing area was opted in to receiving assistance energy transfers during 2025. Ten balancing areas were opted in to the program on at least one day during this period: Avangrid, the Balancing Authority of Northern California, CAISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, PNM, and WAPA Desert Southwest.[172] Avangrid was opted in to AET on all days of the year, while NorthWestern Energy, PacifiCorp East, and PacifiCorp West were opted in on almost all days in 2025. Idaho Power and NV Energy opted in to AET on more than half of all days in 2025.

Table 6.1 Assistance energy transfer opt-in designations by balancing area (2025)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Jan. 1 - Dec. 31	365
Balancing Authority of Northern California	Jun. 15 - Sep. 30	108
California ISO	Jul. 1 - Sep. 30	92
Idaho Power	Jan. 1 - Feb. 28, Jun. 5 - Nov. 4, Nov. 9 - Dec. 31	265
NorthWestern Energy	Jan. 6 - Dec. 31	243
NV Energy	Jan. 1 - Aug. 31	360
PacifiCorp East	Jan. 1 - May. 31, Jun. 22 - Dec. 31	344
PacifiCorp West	Jan. 1 - May. 31, Jun. 22 - Dec. 31	344
PSC of New Mexico	Jan. 20 - Feb. 9, Jun. 13 - Sep. 29	130
WAPA Desert Southwest	May. 15 - Sep. 30	139

Table 6.2 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during 2025 and its impact following a resource sufficiency evaluation failure. First, the table shows the number of 15-minute intervals in which a balancing area failed the upward resource sufficiency evaluation after opting in to AET. These are the intervals in which the WEIM import limit following the test failure was removed—giving the WEIM entity access to WEIM supply that may not have been available otherwise. Apart from the Balancing Authority of Northern California (BANC) and CAISO, all balancing areas failed the resource sufficiency evaluation during at least one interval while opted in to the program.

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

Table 6.2 also shows the percentage of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. Also shown in the table are average and maximum WEIM imports added in the 5-minute market because of AET. During the year, PacifiCorp East added the most WEIM imports as a result of opting in to receiving assistance energy transfers (1,118 MWh). PacifiCorp East failed the resource sufficiency evaluation during 40 intervals while opted in and achieved an additional 112 MW on average during these intervals (and a maximum of 594 MW).

Table 6.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (2025)

Balancing area	Days opted in to AET	RSE failures under AET (15-min. intervals)	Percent of failure intervals with additional WEIM imports due to AET	Average WEIM imports added (MW)	Max WEIM imports added (MW)	Total WEIM imports added (MWh)
Avangrid	365	40	33%	15	115	151
BANC	108	0	N/A	N/A	N/A	N/A
California ISO	92	0	N/A	N/A	N/A	N/A
Idaho Power	265	19	39%	46	292	220
NorthWestern Energy	360	51	46%	20	140	252
NV Energy	243	11	52%	92	532	253
PacifiCorp East	344	40	53%	112	594	1,118
PacifiCorp West	344	143	32%	18	196	631
PSC of New Mexico	130	16	65%	144	634	575
WAPA Desert Southwest	139	41	14%	10	164	99

Table 6.3 summarizes the total cost from assistance energy transfers. AET is settled during any interval in which the balancing area both opted in to receiving assistance energy transfers and failed the resource sufficiency evaluation. The applicable quantity that is settled for AET is based on the lower of either the resource sufficiency evaluation insufficiency or the WEIM imports.[173] The price is the real-time bid cap, typically $1,000/MWh. Table 6.3 also shows the total cost per *WEIM imports added*. WEIM imports added are measured as net WEIM imports in the 5-minute market above what the limit would have been following the resource sufficiency evaluation failure without opting in to AET. The cost per MWh of added imports varied significantly across balancing areas, ranging from a few hundred dollars per MWh to several thousand dollars per MWh.

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

Table 6.3 Cost of assistance energy transfers (2025)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers ($)	Total cost per added WEIM imports ($/MWh)
Avangrid	40	151	$194,923	$1,294
BANC	0	N/A	N/A	N/A
California ISO	0	N/A	N/A	N/A
Idaho Power	19	220	$127,743	$581
NorthWestern Energy	51	252	$70,823	$281
NV Energy	11	253	$81,445	$322
PacifiCorp East	40	1,118	$485,905	$435
PacifiCorp West	143	631	$982,602	$1,557
PSC of New Mexico	16	575	$347,015	$604
WAPA Desert Southwest	41	99	$537,405	$5,431

CAISO balancing area's new determination process for opting in to receive assistance energy transfers

On June 25, 2025, the Business Practice Manual covering the Energy Imbalance Market was revised to reflect that the CAISO balancing area now plans to opt in to receive assistance energy transfers during the entire summer season of July–September.[174] During the shoulder seasons of spring (April–June) and fall (October–December), CAISO will opt in based on an analysis of resource adequacy availability, variable energy resources, and load requirements for individual days. This analysis was the previous determination process for all days of the year, prior to the update on June 25, 2025. During the winter season (January–March), CAISO now plans to opt in based on a subjective evaluation of operational conditions, not subject to the resource adequacy analysis required during the shoulder seasons.

Figure 6.5 provides a timeline of all instances when CAISO opted in to receive assistance energy transfers since the beginning of the program in July 2023. The blue dots indicate all such instances. The background is shaded gray during the summer seasons (July–September), and the green line indicates the date of the change in determination process for opting in based on seasons. In accordance with the new approach, the CAISO balancing area opted in to receive assistance energy transfers on all days during the summer season of 2025.

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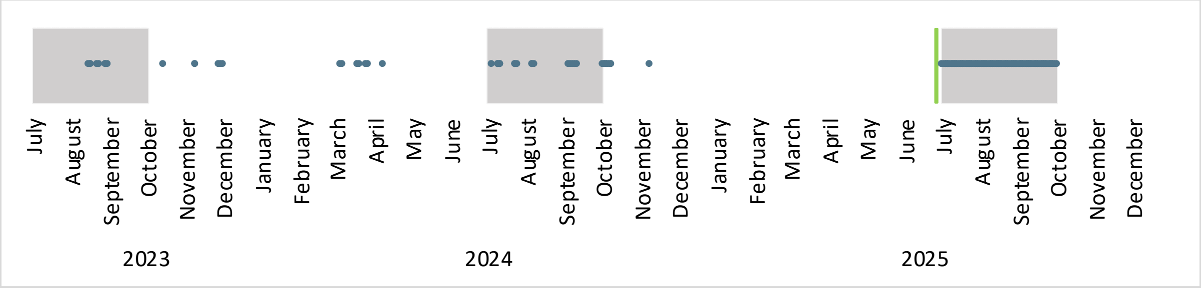
[174] *Business Practice Manual For The Western Energy Imbalance Market*, November 24, 2025, pp 62-64: https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V36_Clean.docx

Figure 6.5 Timeline of assistance energy transfer program and CAISO opt-in designation (July 2023–December 2025)



Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in quarterly reports specific to this topic.[175] 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.

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

7 Real-time imbalance offset costs

Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $205 million in 2025.[176,177] Real-time *congestion* imbalance offset costs made up the large majority of the costs in 2025 ($199 million). The energy portion of the offset was a $15 million credit while the loss portion was a $21 million charge. Total real-time imbalance offset costs in 2025 were lower compared to 2024, when they were $234 million.

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $48 million credit to WEIM entities in 2025, much lower compared to 2024, when credits for real-time imbalance offset costs were $154 million. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $65 million credit. The energy portion of the offset was a $19 million charge.

Balancing areas across the WEIM showed a wide range of congestion and energy offsets. For example, Northwestern Energy recorded a $14 million charge while Puget Sound Energy recorded a $14 million credit for the energy portion of the offset. For the congestion portion of the offset, Public Service Company of New Mexico recorded a $21 million charge while Powerex recorded a $19 million credit.

The real-time imbalance offset cost is the difference between the total money *paid out* and the total money *collected* by the California ISO settlement process for energy in the real-time markets. This charge is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this charge is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[178]

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 7.1 shows monthly imbalance offset costs for balancing areas participating in the day-ahead market by component since 2023.

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[176] 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.

[177] Prior to May 1, 2026, CAISO was the only balancing area participating in the day-ahead market.

[178] Measured demand is physical load plus exports.

Figure 7.1 Monthly real-time imbalance offset costs (balancing areas in day-ahead market)

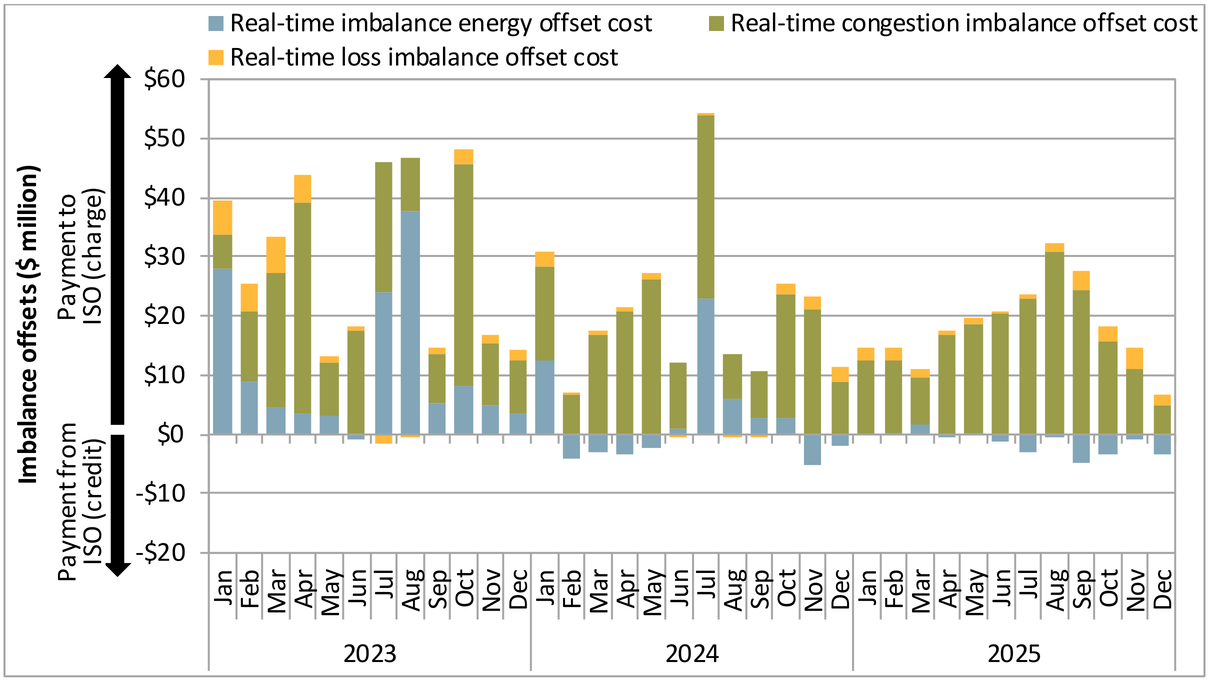


Figure 7.2 shows monthly imbalance offset costs for balancing areas only participating in the WEIM real-time markets. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus). Total imbalance offsets in 2024 and 2025 were largely lower compared to 2023.

Figure 7.3 through Figure 7.5 show the quarterly real-time energy, congestion, or loss imbalance offsets for each balancing area participating only in the WEIM. Figure 7.6 shows the *total* real-time imbalance offset charges for each quarter and balancing area. Charges for revenue shortfall are shown in red, while credits for revenue surplus are shown in black. The color gradient highlights balancing areas with either greater revenue shortfall (orange) or revenue surplus (blue) over the period. Of note in 2025:

- Revenue *shortfall* from imbalance energy offsets for NorthWestern Energy was $14 million (charge).
- Revenue *shortfall* from imbalance energy offsets for Arizona Public Service was $12 million (charge).
- Revenue *surplus* from imbalance energy offsets for Puget Sound Energy was $14 million (credit).
- Revenue *shortfall* from congestion imbalance offsets for the Public Service Company of New Mexico (PNM) was a $21 million (charge), compared to around a $1 million credit in 2024.
- Revenue *surplus* from congestion imbalance offsets for Powerex was $19 million (credit), though down significantly from $47 million in the previous year.
- Revenue *surplus* from congestion imbalance offsets for PacifiCorp East was $14 million (credit), though down significantly from $48 million in the previous year.

Figure 7.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)

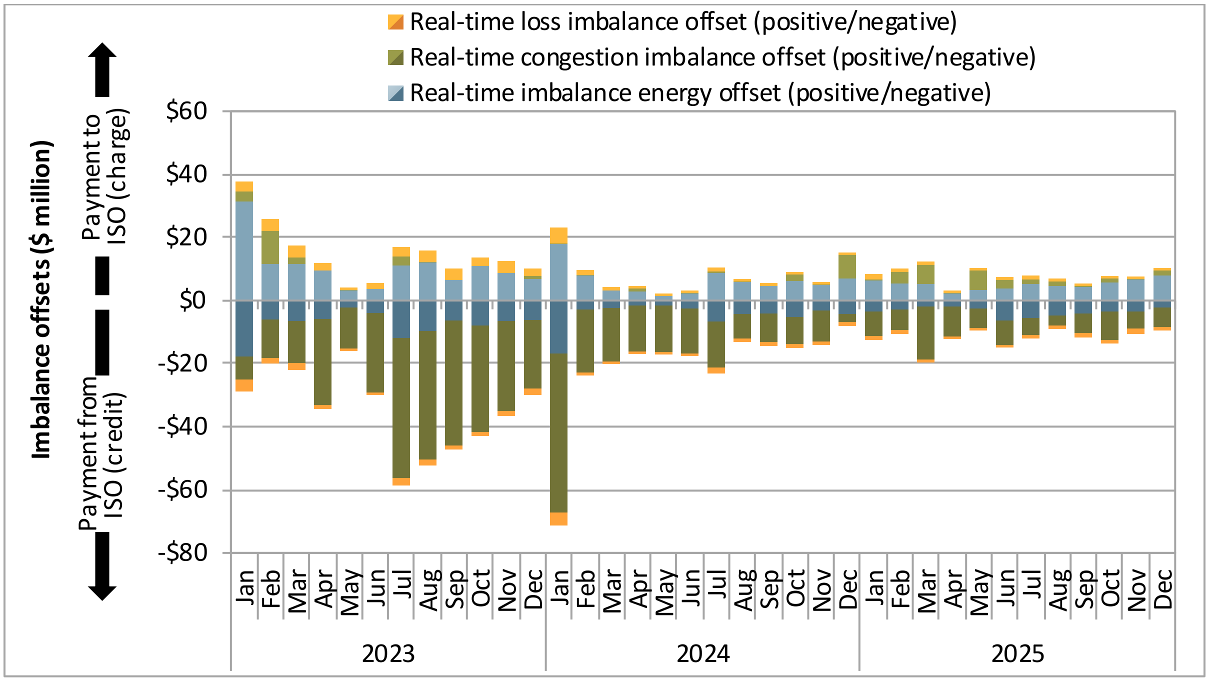
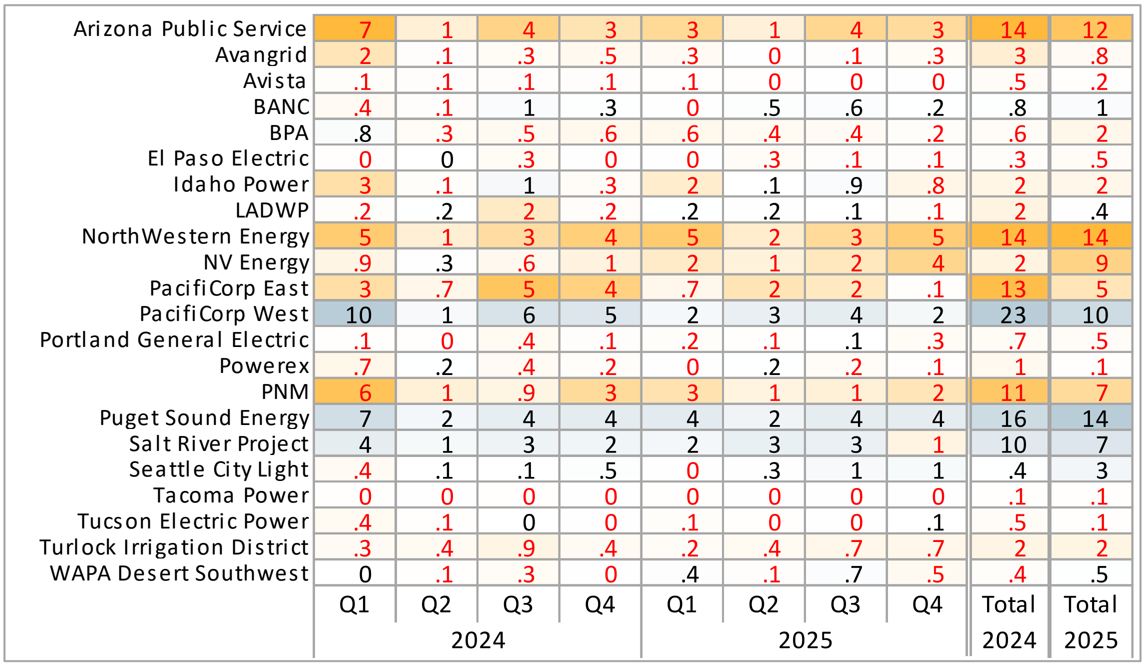
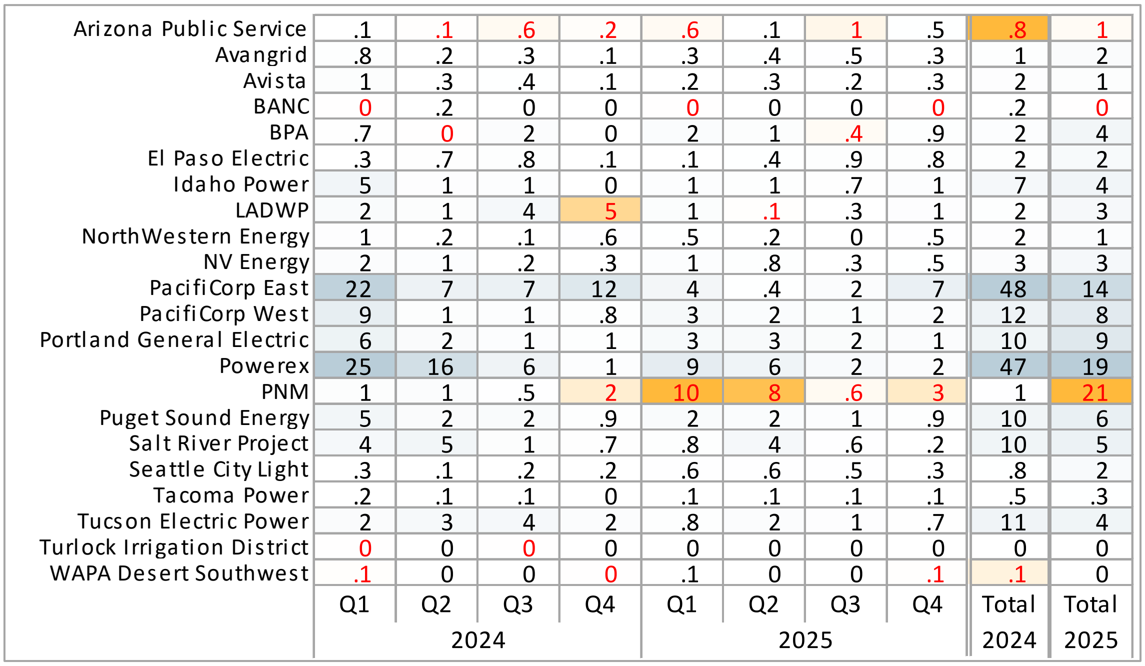


Figure 7.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)



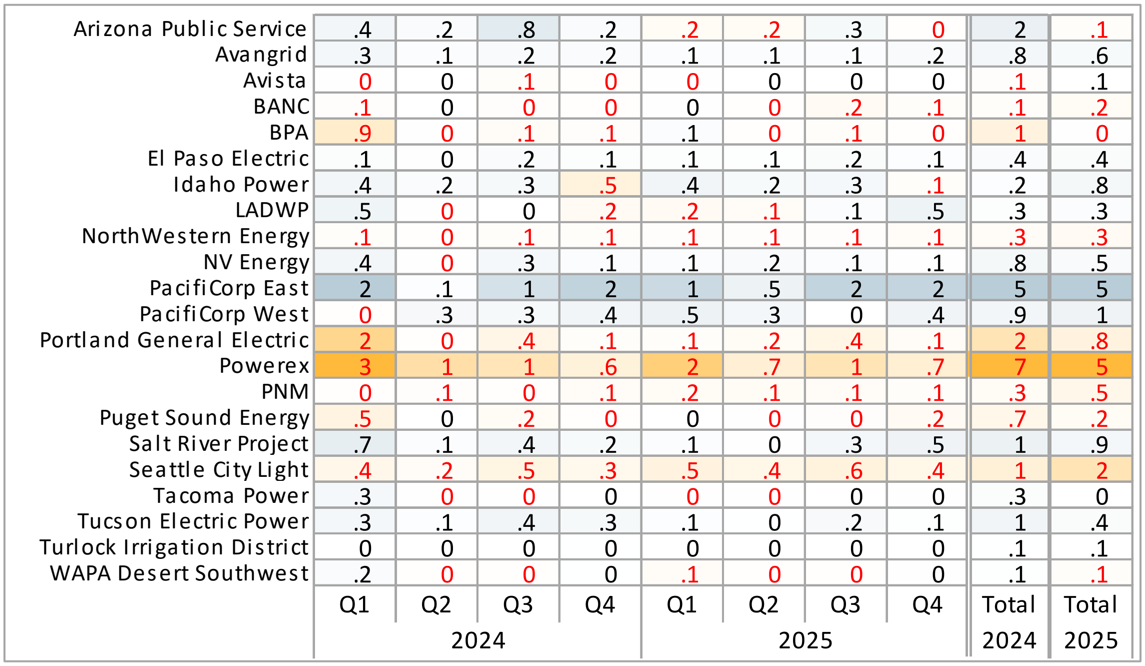
	2024				2025				Total 2024	Total 2025
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
Arizona Public Service	7	1	4	3	3	1	4	3	14	12
Avangrid	2	.1	.3	.5	.3	0	.1	.3	3	.8
Avista	.1	.1	.1	.1	.1	0	0	0	.5	.2
BANC	.4	.1	1	.3	0	.5	.6	.2	.8	1
BPA	.8	.3	.5	.6	.6	.4	.4	.2	.6	2
El Paso Electric	0	0	.3	0	0	.3	.1	.1	.3	.5
Idaho Power	3	.1	1	.3	2	.1	.9	.8	2	2
LADWP	.2	.2	2	.2	.2	.2	.1	.1	2	.4
NorthWestern Energy	5	1	3	4	5	2	3	5	14	14
NV Energy	.9	.3	.6	1	2	1	2	4	2	9
PacifiCorp East	3	.7	5	4	.7	2	2	.1	13	5
PacifiCorp West	10	1	6	5	2	3	4	2	23	10
Portland General Electric	.1	0	.4	.1	.2	.1	.1	.3	.7	.5
Powerex	.7	.2	.4	.2	0	.2	.2	.1	1	.1
PNM	6	1	.9	3	3	1	1	2	11	7
Puget Sound Energy	7	2	4	4	4	2	4	4	16	14
Salt River Project	4	1	3	2	2	3	3	1	10	7
Seattle City Light	.4	.1	.1	.5	0	.3	1	1	.4	3
Tacoma Power	0	0	0	0	0	0	0	0	.1	.1
Tucson Electric Power	.4	.1	0	0	.1	0	0	.1	.5	.1
Turlock Irrigation District	.3	.4	.9	.4	.2	.4	.7	.7	2	2
WAPA Desert Southwest	0	.1	.3	0	.4	.1	.7	.5	.4	.5

Figure 7.4 Real-time congestion imbalance offsets by quarter and balancing area ($ millions)



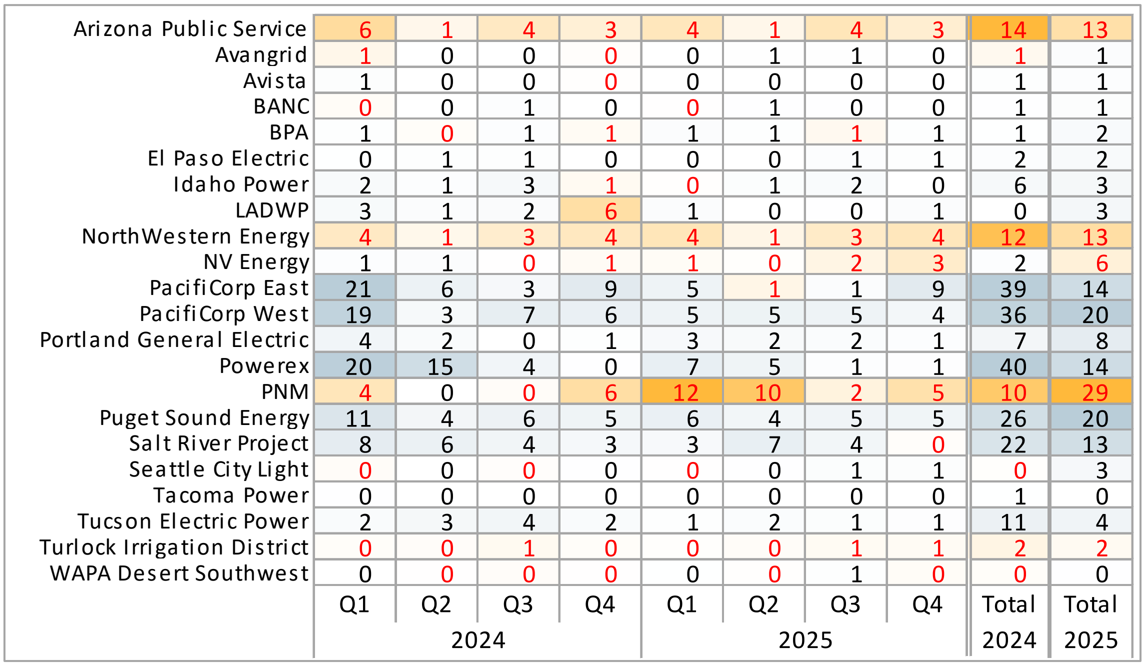
	2024				2025				Total 2024	Total 2025
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
Arizona Public Service	.1	.1	.6	.2	.6	.1	1	.5	.8	1
Avangrid	.8	.2	.3	.1	.3	.4	.5	.3	1	2
Avista	1	.3	.4	.1	.2	.3	.2	.3	2	1
BANC	0	.2	0	0	0	0	0	0	.2	0
BPA	.7	0	2	0	2	1	.4	.9	2	4
El Paso Electric	.3	.7	.8	.1	.1	.4	.9	.8	2	2
Idaho Power	5	1	1	0	1	1	.7	1	7	4
LADWP	2	1	4	5	1	.1	.3	1	2	3
NorthWestern Energy	1	.2	.1	.6	.5	.2	0	.5	2	1
NV Energy	2	1	.2	.3	1	.8	.3	.5	3	3
PacifiCorp East	22	7	7	12	4	.4	2	7	48	14
PacifiCorp West	9	1	1	.8	3	2	1	2	12	8
Portland General Electric	6	2	1	1	3	3	2	1	10	9
Powerex	25	16	6	1	9	6	2	2	47	19
PNM	1	1	.5	2	10	8	.6	3	1	21
Puget Sound Energy	5	2	2	.9	2	2	1	.9	10	6
Salt River Project	4	5	1	.7	.8	4	.6	.2	10	5
Seattle City Light	.3	.1	.2	.2	.6	.6	.5	.3	.8	2
Tacoma Power	.2	.1	.1	0	.1	.1	.1	.1	.5	.3
Tucson Electric Power	2	3	4	2	.8	2	1	.7	11	4
Turlock Irrigation District	0	0	0	0	0	0	0	0	0	0
WAPA Desert Southwest	.1	0	0	0	.1	0	0	.1	.1	0

Figure 7.5 Real-time loss imbalance offsets by quarter and balancing area ($ millions)



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

Figure 7.6 Total real-time imbalance offsets by quarter and balancing area ($ millions)



	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Total	Total
	2024				2025				2024	2025
Arizona Public Service	6	1	4	3	4	1	4	3	14	13
Avangrid	1	0	0	0	0	1	1	0	1	1
Avista	1	0	0	0	0	0	0	0	1	1
BANC	0	0	1	0	0	1	0	0	1	1
BPA	1	0	1	1	1	1	1	1	1	2
El Paso Electric	0	1	1	0	0	0	1	1	2	2
Idaho Power	2	1	3	1	0	1	2	0	6	3
LADWP	3	1	2	6	1	0	0	1	0	3
NorthWestern Energy	4	1	3	4	4	1	3	4	12	13
NV Energy	1	1	0	1	1	0	2	3	2	6
PacifiCorp East	21	6	3	9	5	1	1	9	39	14
PacifiCorp West	19	3	7	6	5	5	5	4	36	20
Portland General Electric	4	2	0	1	3	2	2	1	7	8
Powerex	20	15	4	0	7	5	1	1	40	14
PNM	4	0	0	6	12	10	2	5	10	29
Puget Sound Energy	11	4	6	5	6	4	5	5	26	20
Salt River Project	8	6	4	3	3	7	4	0	22	13
Seattle City Light	0	0	0	0	0	0	1	1	0	3
Tacoma Power	0	0	0	0	0	0	0	0	1	0
Tucson Electric Power	2	3	4	2	1	2	1	1	11	4
Turlock Irrigation District	0	0	1	0	0	0	1	1	2	2
WAPA Desert Southwest	0	0	0	0	0	0	1	0	0	0

8 Bid cost recovery payments

This chapter analyzes bid cost recovery for balancing areas participating in the ISO's day-ahead and real-time markets. 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.

Key findings in this chapter include:

- **Bid cost recovery payments totaled $151 million for all balancing areas in 2025, down 4 percent** from 2024. Most of these payments ($137 million) came from the one balancing area (CAISO) participating in the day-ahead market.
- **Of the $14.3 million in bid cost recovery paid to generation in balancing areas only participating in the WEIM, $9.5 million went to the Desert Southwest region.**
- **Bid cost recovery payments associated with residual unit commitment during 2025 totaled about $47.4 million, or about $19.9 million (72 percent) higher than in 2024.**
- **The majority of bid cost recovery payments in every region went to gas resources.** The share of total bid cost recovery payments going to batteries in the CAISO balancing area decreased to 5 percent in 2025 from 13 percent in 2024.

Bid cost recovery

Bid cost recovery payments totaled $151 million in 2025 across the Western Energy Imbalance Market (WEIM), 4 percent lower than the $157 million in total payments for 2024. Estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market (CAISO) totaled about $137 million.[179] This was a 3 percent decrease from the $141 million in bid cost recovery in 2024. Bid cost recovery for units in areas participating only in the WEIM totaled about $14.3 million. WEIM area bid cost recovery payments decreased about 11 percent from $16 million in 2024.[180]

Figure 8.1 shows monthly bid cost recovery payments in 2025 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $33.7 million, down from $37.9 million in 2024. Bid cost recovery payments associated with residual unit commitment during 2025 totaled about $47.4 million, or about $19.9 million (72 percent) higher than in 2024. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $55.7 million, which was about $20.2 million lower than in 2024.

Figure 8.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM. Bid cost recovery payments to these units in 2025 were greatest in the Desert Southwest and

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[179] Prior to May 1, 2026, CAISO was the only balancing area participating in the day-ahead market.

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

California[181] regions at $9.5 million and $3.5 million, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $675,000 and $642,000, respectively.

Figure 8.1 Monthly bid cost recovery payments for day-ahead market area (CAISO)

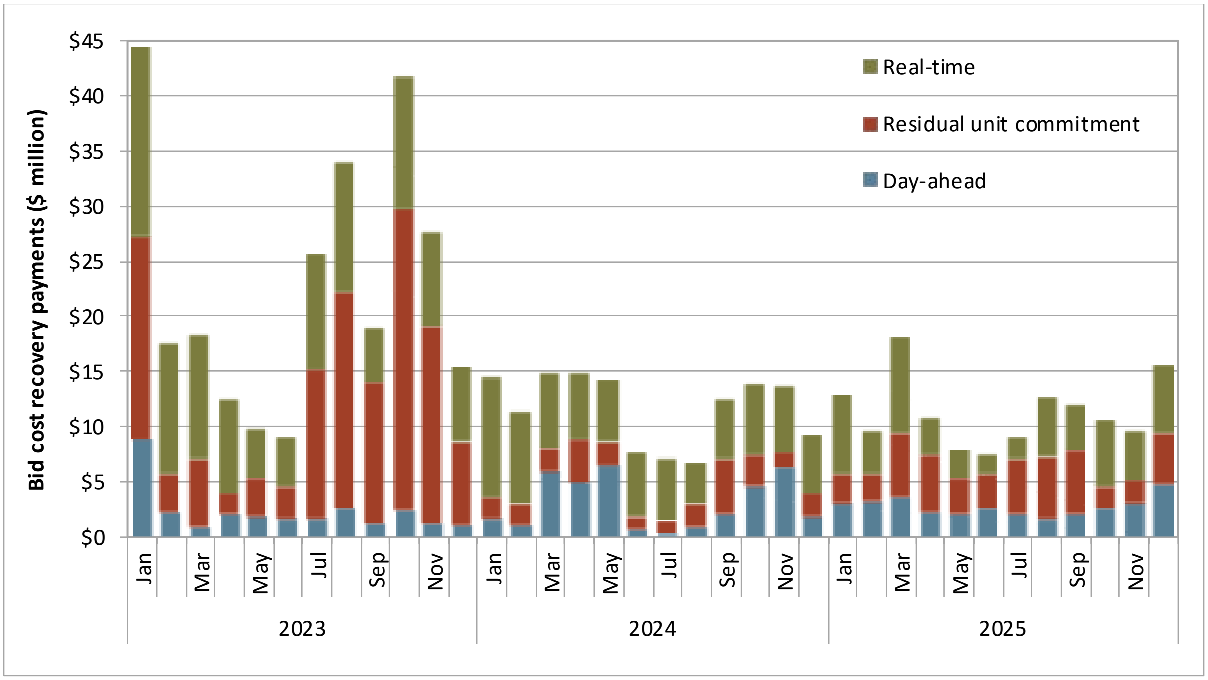
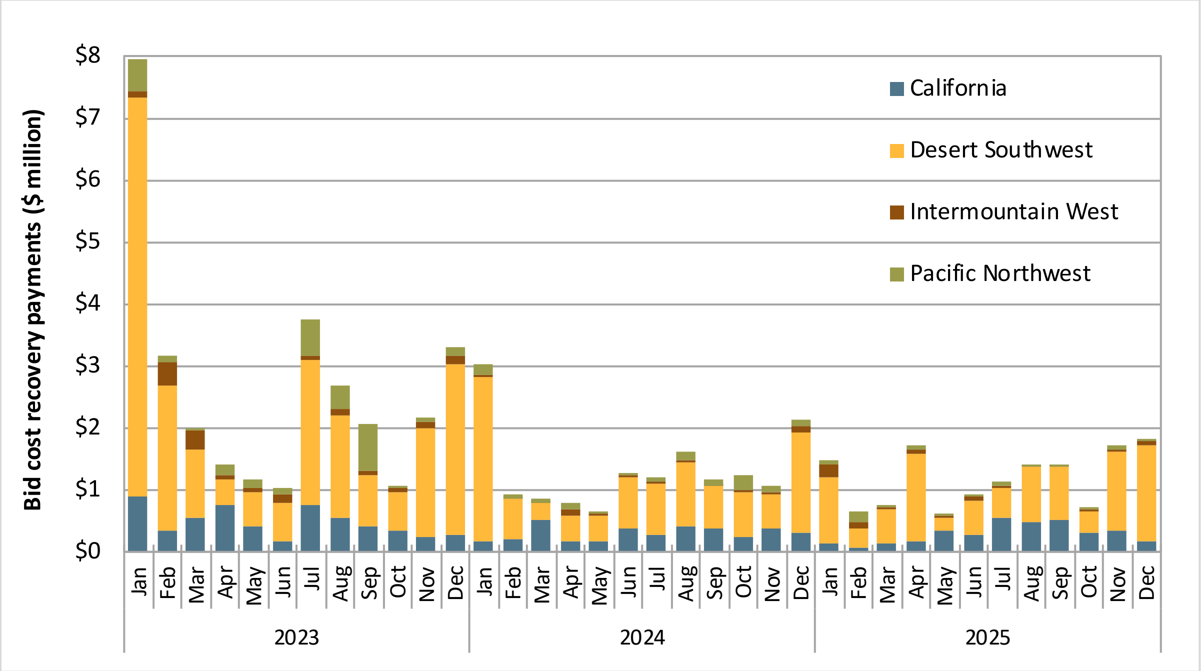


Figure 8.2 Monthly bid cost recovery payments for the WEIM (non-CAISO)



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[181] Figure 8.2 includes only non-CAISO balancing authority areas.

Table 8.1 through Table 8.5 show bid cost recovery payments in the CAISO and WEIM balancing areas by fuel type. In the CAISO balancing area, gas resources made up 88 percent of the total bid cost recovery payments, an increase from 77 percent in 2024. Batteries' share of total bid cost recovery payments decreased to 5 percent in 2025 from 13 percent in 2024. Gas resources made up the majority of payments in all regions, and coal resources represented the next largest share in the Desert Southwest and Intermountain West regions. In the California and Pacific Northwest regions, hydro resources made up 36 and 6 percent of bid cost recovery payments, respectively.

Table 8.1 Bid cost recovery payments in the day-ahead market area (CAISO) by fuel type (2023–2025)

Region	Fuel type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2023	2024	2025	2023	2024	2025
California ISO	Gas	$238,149,217	$109,017,185	$120,893,688	86%	77%	88%
California ISO	Batteries	$20,657,089	$18,155,285	$6,292,450	7%	13%	5%
California ISO	Hydro	$12,684,843	$4,797,253	$6,621,012	5%	3%	5%
California ISO	Solar	$2,550,003	$5,688,524	$1,583,240	1%	4%	1%
California ISO	Wind	$598,904	$477,719	$343,535	0%	0%	0%
California ISO	Hybrid	$311,479	$1,583,097	$197,452	0%	1%	0%
California ISO	Geothermal	$193,591	$169,421	$222,555	0%	0%	0%
California ISO	Biogas-biomass	$6,786	$5,829	$613	0%	0%	0%
California ISO	Coal	$11,239	$9,456	$30,310	0%	0%	0%
California ISO	Other	$265,423	$1,318,782	$532,197	0%	1%	0%
	Total:	**$275,428,572**	**$141,222,551**	**$136,717,051**			

Table 8.2 Bid cost recovery payments in the California (non-CAISO) region by fuel type (2023–2025)

Region	Fuel type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2023	2024	2025	2023	2024	2025
California	Gas	$4,481,993	$2,957,932	$2,170,644	79%	81%	62%
California	Batteries	$4,900	$2,542	$286	0%	0%	0%
California	Hydro	$1,147,170	$553,229	$1,266,348	20%	15%	36%
California	Solar	$162	$104	$12,452	0%	0%	0%
California	Wind	$2,182	$1,361	$174	0%	0%	0%
California	Hybrid	$0	$6,343	$41,570	0%	0%	1%
California	Coal	$4,927	$112,468	$2,584	0%	3%	0%
California	Demand response	$0	$0	$34	0%	0%	0%
	Total:	**$5,641,335**	**$3,633,978**	**$3,494,094**			

Table 8.3 Bid cost recovery payments in the Desert Southwest region by fuel type (2023–2025)

Region	Fuel type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2023	2024	2025	2023	2024	2025
Desert Southwest	Gas	$15,729,156	$6,781,697	$8,576,098	73%	64%	91%
Desert Southwest	Batteries	$17,008	$257,510	$122,390	0%	2%	1%
Desert Southwest	Hydro	$0	$193	$1,515	0%	0%	0%
Desert Southwest	Solar	$72,037	$410,738	$125,593	0%	4%	1%
Desert Southwest	Wind	$167,419	$331,502	$77,740	1%	3%	1%
Desert Southwest	Hybrid	$8,834	$8,342	$3,755	0%	0%	0%
Desert Southwest	Geothermal	$0	$6	$0	0%	0%	0%
Desert Southwest	Biogas-biomass	$17	$145	$2	0%	0%	0%
Desert Southwest	Coal	$5,399,301	$2,582,783	$418,974	25%	24%	4%
Desert Southwest	Demand response	$0	$14	$105	0%	0%	0%
Desert Southwest	Other	$59,105	$219,833	$145,293	0%	2%	2%
	Total:	**$21,452,878**	**$10,592,761**	**$9,471,465**			

Table 8.4 Bid cost recovery payments in the Intermountain West region by fuel type (2023–2025)

Region	Fuel type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2023	2024	2025	2023	2024	2025
Intermountain West	Gas	$763,989	$294,435	$514,919	47%	63%	76%
Intermountain West	Hydro	$121,859	$97,198	$46,112	8%	21%	7%
Intermountain West	Solar	$3	$4	$789	0%	0%	0%
Intermountain West	Wind	$56,293	$9,458	$5,068	3%	2%	1%
Intermountain West	Biogas-biomass	$269	$216	$7	0%	0%	0%
Intermountain West	Coal	$660,884	$67,966	$108,269	41%	14%	16%
Intermountain West	Demand response	$8,257	$553	$139	1%	0%	0%
	Total:	**$1,611,553**	**$469,829**	**$675,301**			

Table 8.5 Bid cost recovery payments in the Pacific Northwest region by fuel type (2023–2025)

Region	Fuel type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2023	2024	2025	2023	2024	2025
Pacific Northwest	Gas	$1,287,425	$957,864	$559,797	42%	74%	87%
Pacific Northwest	Batteries	$0	$0	$70	0%	0%	0%
Pacific Northwest	Hydro	$1,744,328	$284,994	$40,470	57%	22%	6%
Pacific Northwest	Solar	$274	$64	$3	0%	0%	0%
Pacific Northwest	Wind	$30,378	$49,295	$41,891	1%	4%	7%
Pacific Northwest	Other	$2	$0	$89	0%	0%	0%
	Total:	**$3,062,406**	**$1,292,217**	**$642,320**			

9 Market adjustments

Given the complexity of market models and systems, all ISOs allow operators to adjust the inputs and outputs of market models and processes. For example, load forecasts may be adjusted to account for potential differences in modeled versus actual demand and supply conditions, including uninstructed deviations by generation resources.

This chapter reviews the frequency of, and reasons for, key market adjustments made by California ISO and WEIM operators, including exceptional dispatches, adjustments to modeled loads, and blocked dispatch instructions in the real-time market. Over the last few years, the California ISO has placed a priority on reducing its market adjustments.

Findings from this chapter include the following:

- **Adjustments to load forecasts were generally much higher in the 5-minute market than the 15-minute market,** with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).
- **In the CAISO balancing area, adjustments to load forecasts during the evening peak net load hours declined in 2025 relative to the prior two years, but remained significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market.** For hour-ending 19, average hourly adjustments in the 15-minute market were about 1,400 MW, compared to 430 MW in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.
- **Combined incremental and decremental manual dispatch energy** increased from 2024 to 2025 in the California (non-CAISO) and Desert Southwest regions by 24 percent and 3 percent, respectively. In contrast, total manual dispatch energy declined in the Intermountain West and Pacific Northwest regions by 10 percent and 7 percent, respectively.
- **Total energy from exceptional dispatches in the CAISO balancing area averaged 0.41 percent of system loads in 2025**, up from 0.34 percent of system loads in 2024.

9.1 Imbalance conformance

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

9.1.1 Imbalance conformance by balancing area

The figures below show the 2025 15-minute market and 5-minute market average hourly imbalance conformance by quarter for each balancing area as a percentage of the average load of the balancing area.[182] Generally, imbalance conformance levels were much higher in the 5-minute market than the 15-minute market, with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).

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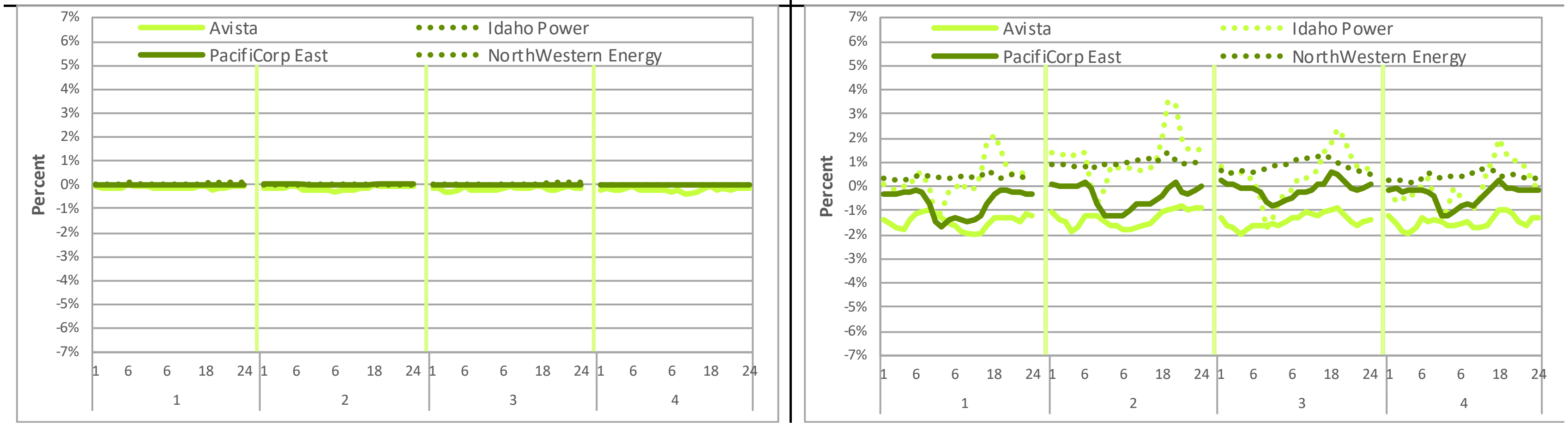
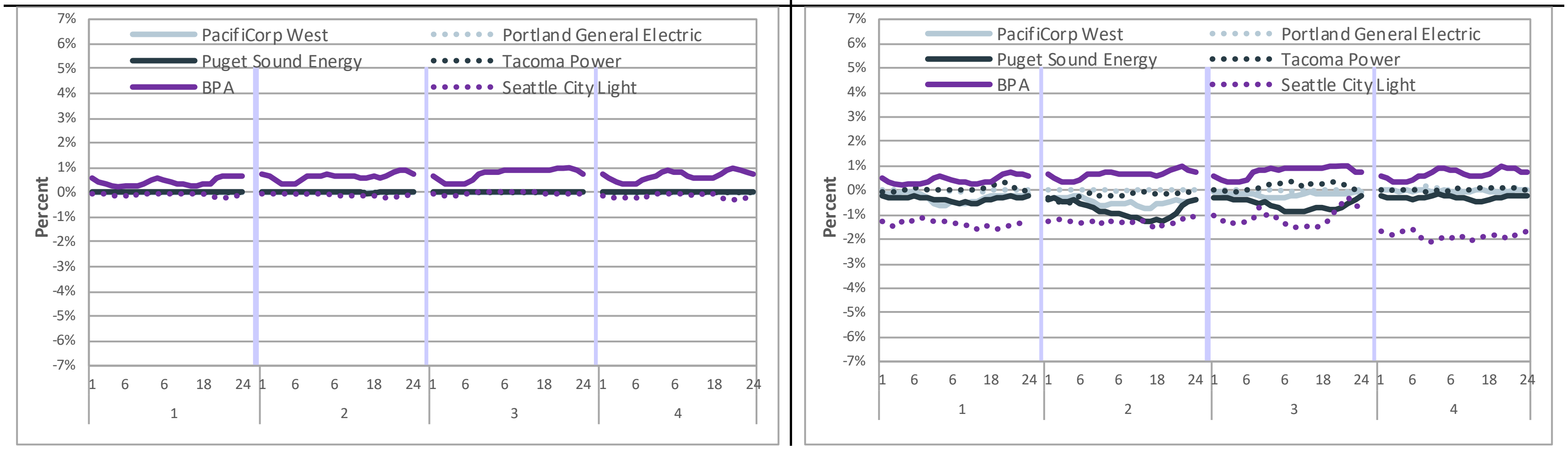
[182] Avangrid and Powerex are not shown in this figure. Avangrid is a generation-only entity and therefore load conformance cannot be measured as a percent of load. Powerex is not a balancing authority area like other participating WEIM entities and instead uses residual capability of the BC Hydro system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

Figure 9.1 Intermountain West: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2025)


15-minute market

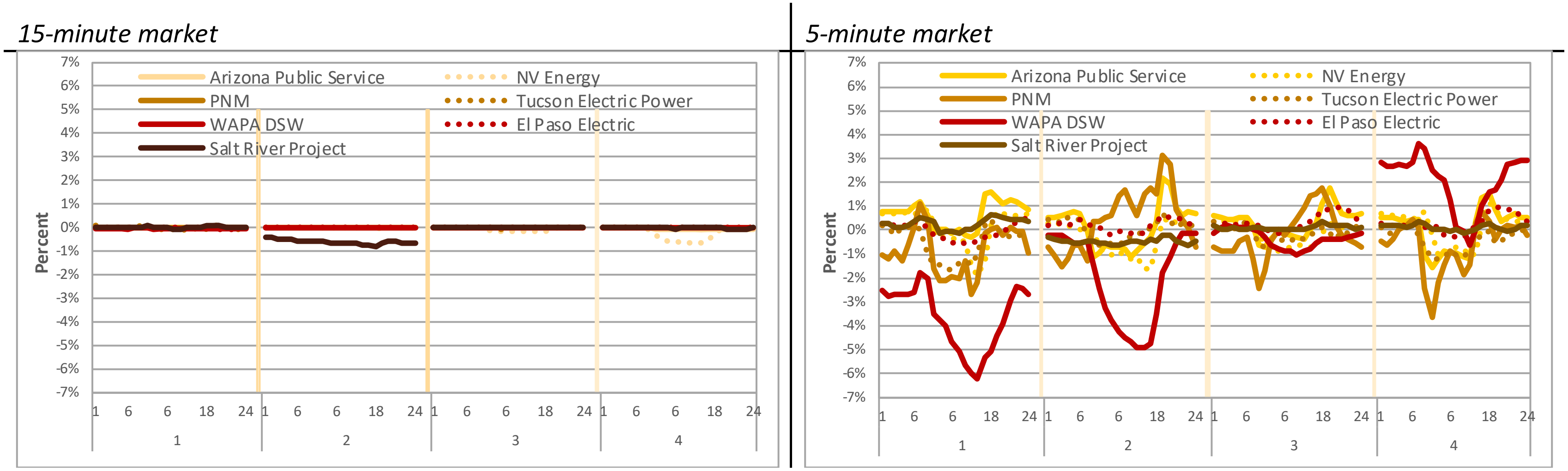
5-minute market

Figure 9.2 Pacific Northwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2025)


15-minute market

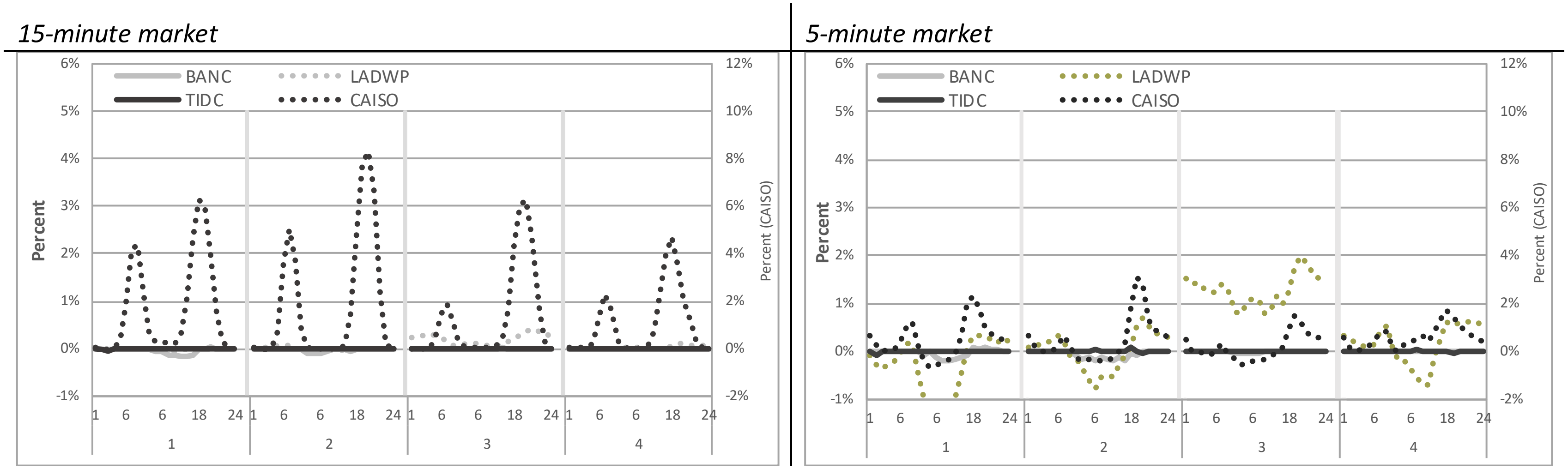
5-minute market

Figure 9.3 Desert Southwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2025)


15-minute market

5-minute market

Figure 9.4 California: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2025)


15-minute market

5-minute market

9.1.2 Imbalance conformance — special report on CAISO balancing area

In 2025, the use of imbalance conformance in the 15-minute market by operators in the CAISO balancing area, in both size and frequency, is an outlier amongst WEIM areas. This section analyzes the use of imbalance conformance by CAISO balancing area operators.

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 9.5 shows CAISO area imbalance conformance adjustments in real-time markets for 2023 to 2025. Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased in the morning ramp in 2025 compared to 2024, while the 2023 levels were the lowest of the reporting period. During the morning hours, the highest average hourly adjustments were around 770 MW. This was an increase from a maximum of about 70 MW over the morning hours in 2024. Hour-ahead and 15-minute market imbalance conformance during the evening ramp in 2025 was lower than both the 2024 and 2023 levels. Imbalance conformance over the evening peak hours reached about 1,400 MW, or about 400 MW lower than the largest average hourly evening adjustments in 2023 and 2024.

The 5-minute market adjustments in 2025 were very similar to both 2024 and 2023. These adjustments peaked in hour-ending 19 at about 430 MW.

Figure 9.5 Average CAISO balancing area hourly imbalance conformance adjustment (2023–2025)

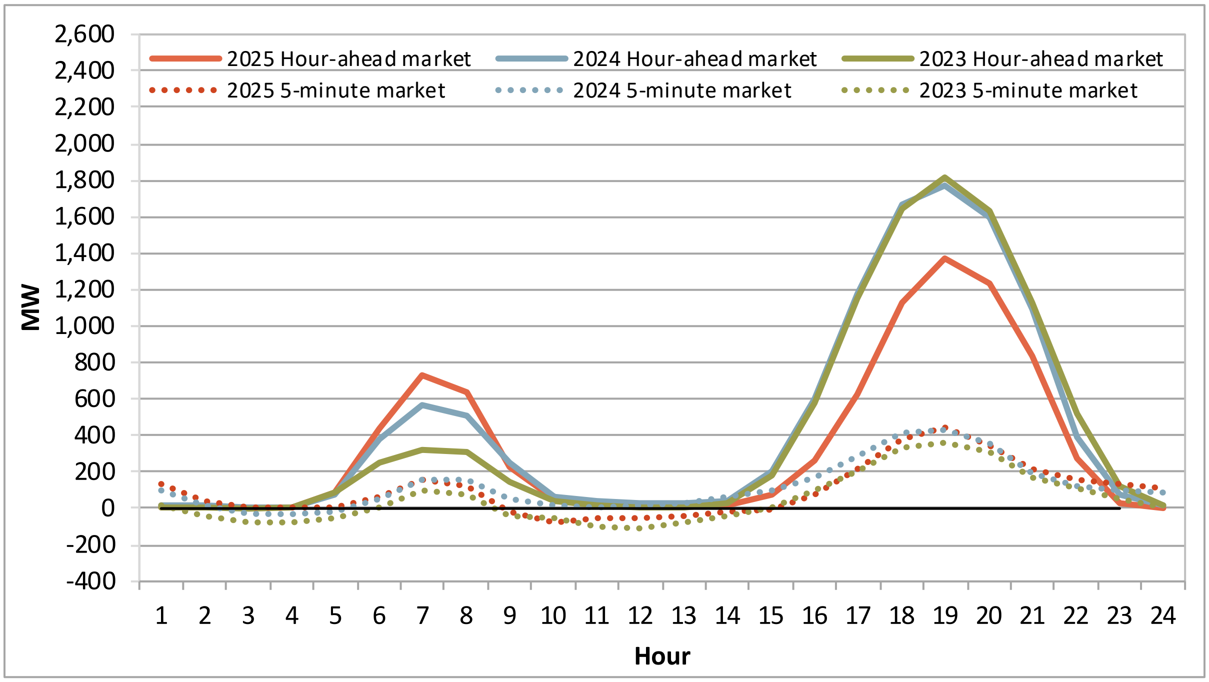
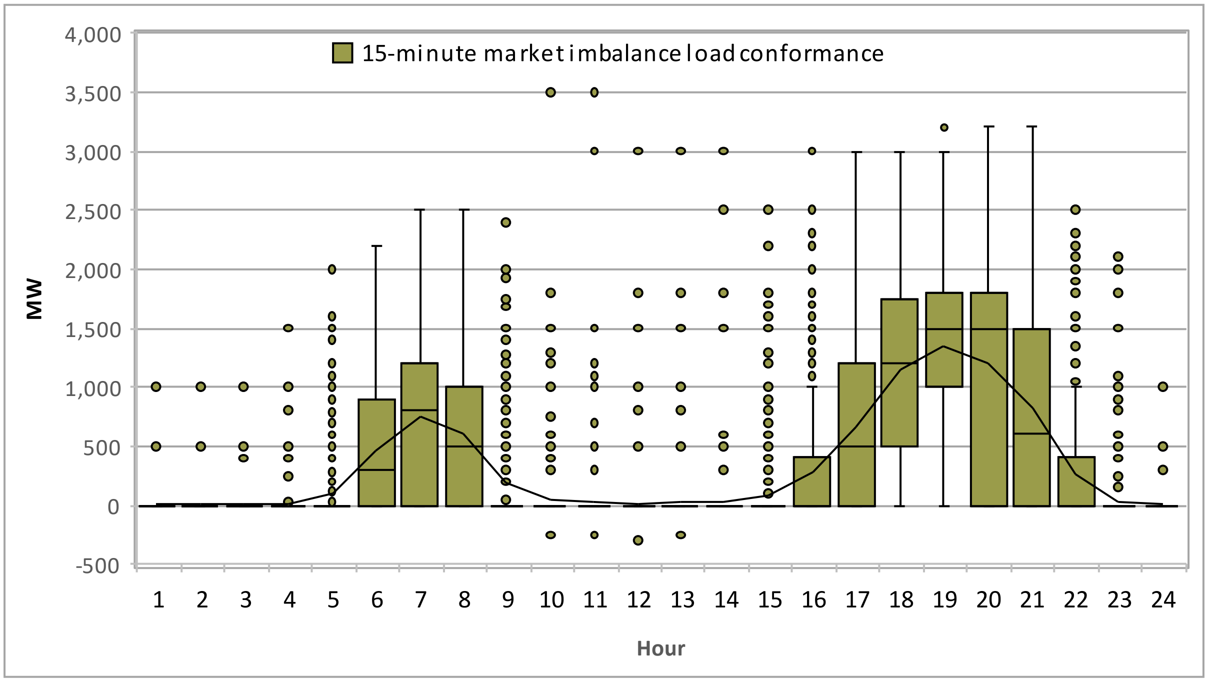


Figure 9.6 shows an hourly distribution of the 15-minute market load adjustments for 2025. This box and whisker graph shows the minimum and maximum values excluding outliers, the lower and upper quartiles, the median, and the mean (line), with extreme positive and negative outliers indicated by filled dots. The outside whiskers do not include these outliers. For the year, the maximums and major outliers in hours-ending 10 to 15, e.g., 2,500 MW or greater, primarily occurred between March 14 and March 15, and were associated with resource deviations potentially related to weather conditions and unusually low solar generation. Most of the outliers during the evening ramping period occurred in late May, associated with a short-lived but record-breaking heat wave in the western United States.[183]

Figure 9.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (2025)



9.2 Manual dispatch

This section analyzes manual dispatches for the California ISO balancing area, known as exceptional dispatches, as well as manual dispatches in balancing areas across the WEIM. CAISO balancing area exceptional dispatches are covered in a separate subsection from the rest of the WEIM because of significant differences in how manual dispatches are settled in the CAISO balancing area relative to other balancing areas in the WEIM.

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[183] *National Climate Report May 2025 – U.S. Selected Significant Climate Anomalies and Events*, National Oceanic and Atmospheric Administration (NOAA): https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202505

9.2.1 California ISO exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

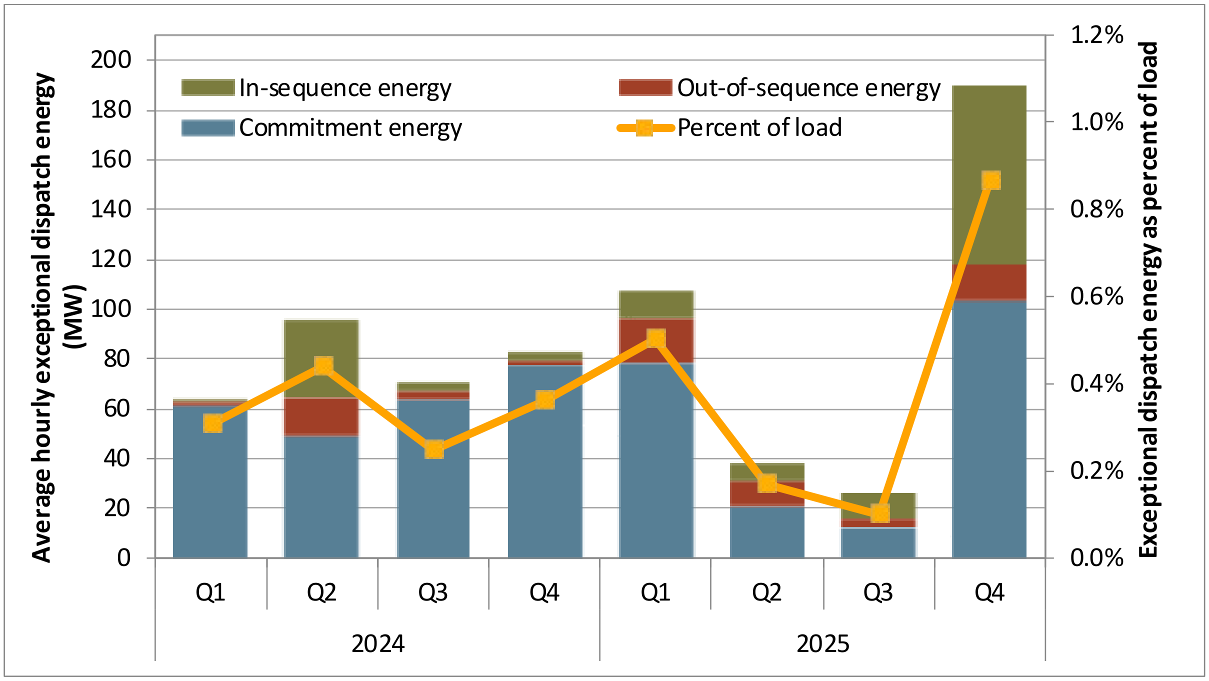
Energy from exceptional dispatch

Energy from exceptional dispatches continued to account for under 1 percent of total load in 2025 in the California ISO balancing area, represented by the yellow line in Figure 9.7. Total energy from exceptional dispatches, including minimum load energy from unit commitments, increased by approximately 15 percent in 2025 compared to 2024. Total energy from exceptional dispatches averaged 0.41 percent of system loads in 2025, compared to 0.34 percent of system loads in 2024.

Exceptional dispatch energy above minimum load increased by approximately 28 percent in 2025 from 2024, while minimum load energy from unit commitments decreased by about 15 percent. As shown in Figure 9.7, minimum load energy from units committed via exceptional dispatch (blue) accounted for 59 percent of all exceptional dispatch energy in 2025. About 13 percent of energy from exceptional dispatches was from out-of-sequence energy above minimum load (red), and the remaining 28 percent was from in-sequence energy above minimum load (green).

The in-sequence energy portion of the exceptional dispatches above minimum load increased by 157 percent in 2025 compared to 2024. Out-of-sequence energy from exceptional dispatch increased by 116 percent year-over-year between 2024 and 2025.

Figure 9.7 Average hourly energy from exceptional dispatch

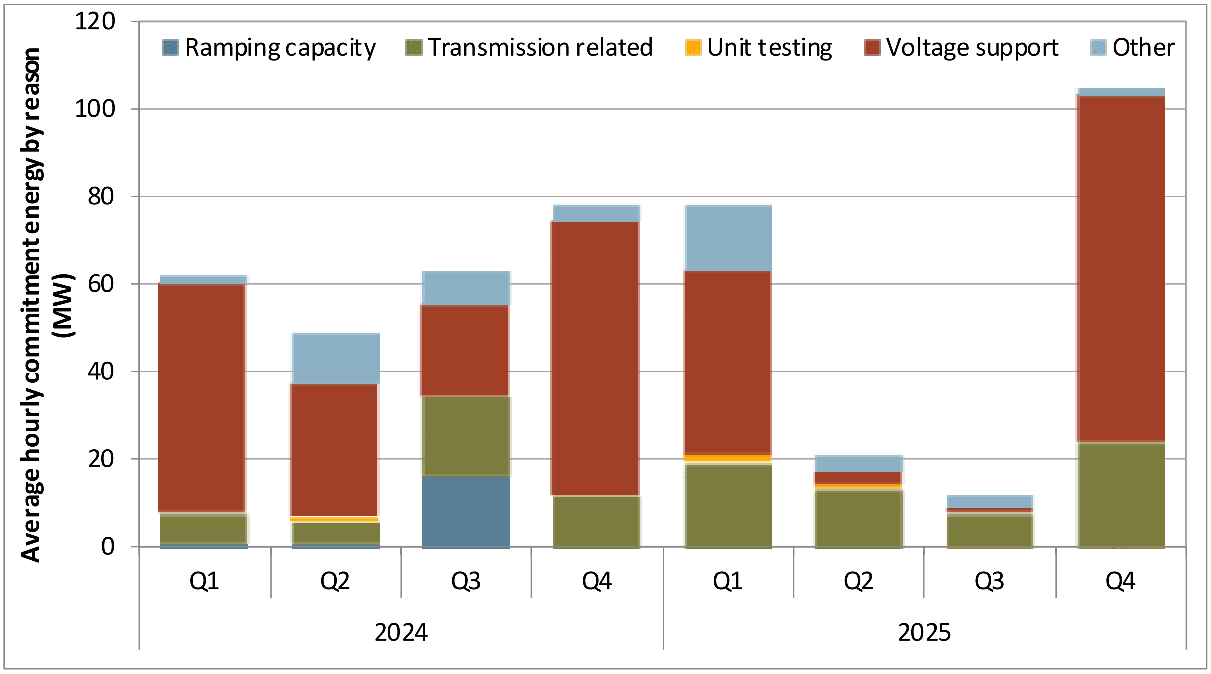


Exceptional dispatches for unit commitment

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 multi-stage generator configuration, e.g., one-by-one or duct firing.

Figure 9.8 shows the reasons for minimum load energy exceptional dispatches—ramping capacity (blue), transmission related (green), unit testing (yellow), and voltage support (red). Overall, minimum load energy from exceptional dispatch unit commitments decreased in 2025 compared to 2024, with significant volumes occurring in the second and third quarters of 2025, largely related to voltage support. 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.

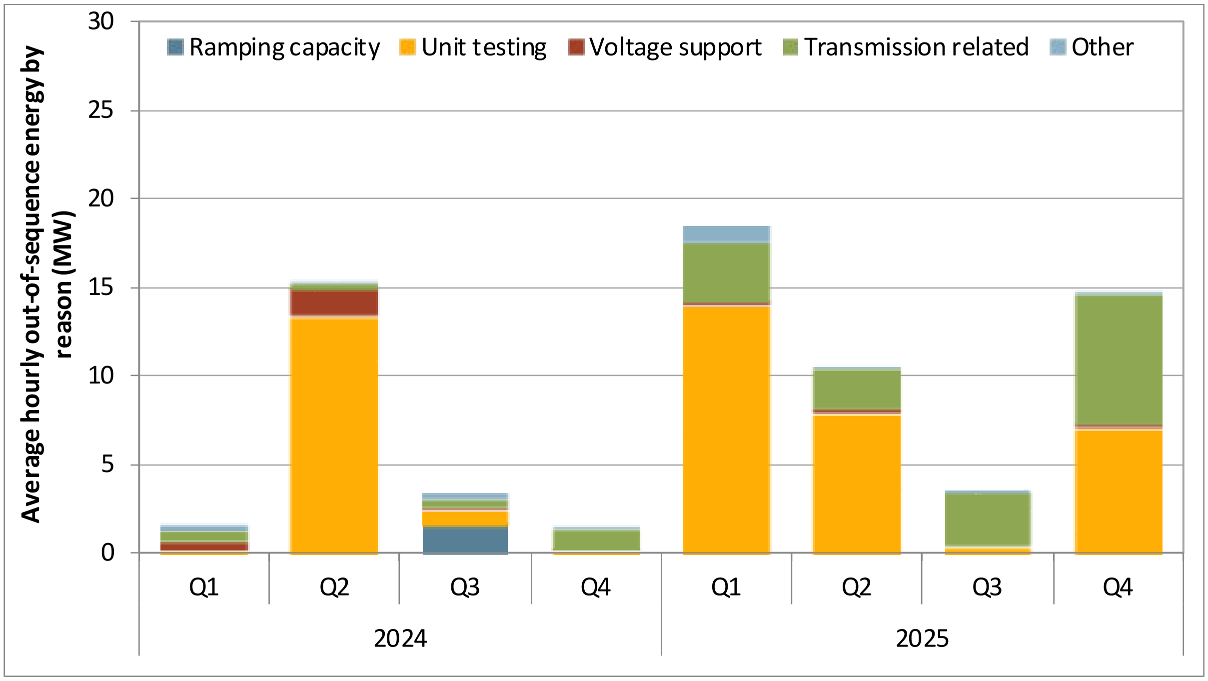
Figure 9.8 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Figure 9.9 shows the out-of-sequence exceptional dispatch energy by quarter for 2024 and 2025. Overall, out-of-sequence exceptional dispatch energy increased by 116 percent in 2025 when compared to 2024. Out-of-sequence exceptional dispatch energy in 2025 increased in every quarter other than the second quarter, when compared to 2024. Unit testing was the primary reason logged for out-of-sequence energy exceptional dispatches in 2025 and increased by 103 percent in 2025 compared to 2024. This increase is largely due to pre-commercial unit testing for new resources. As these new resources were in a pre-commercial testing phase, they did not submit any bids to the market. Therefore, the identified out-of-sequence energy is due to the resources' default energy bid being out-of-sequence. Exceptional dispatches for unit testing are settled at the higher of the resource's default energy bid or its locational marginal price.

Figure 9.9 Out-of-sequence exceptional dispatch energy by reason



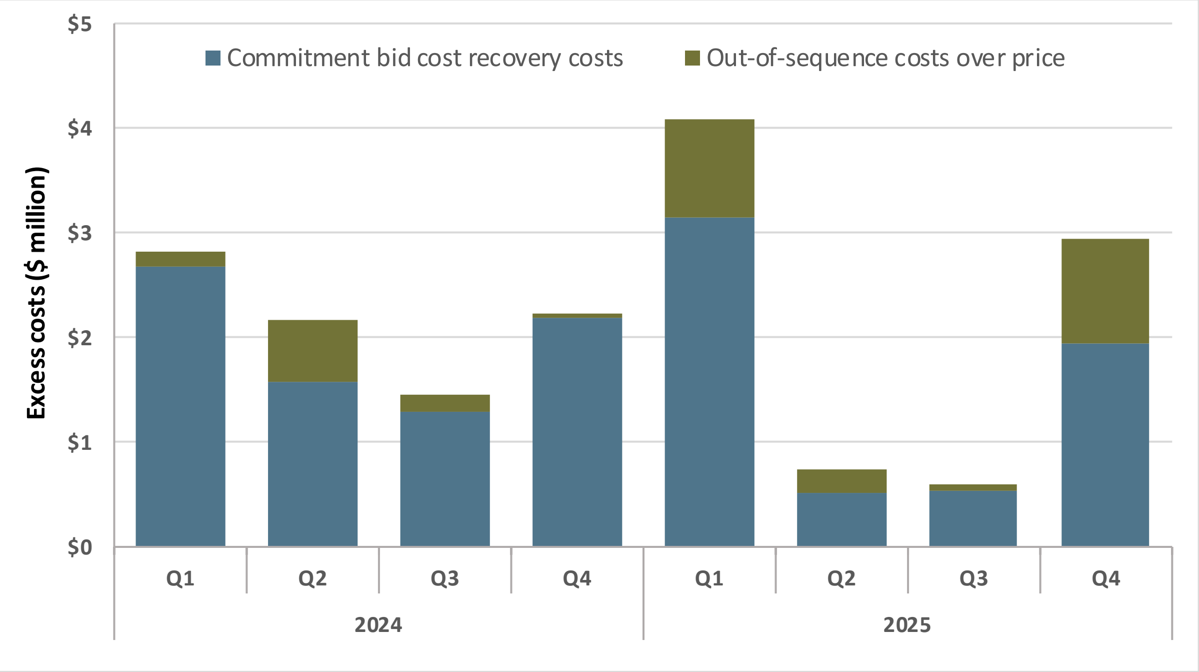
Exceptional dispatch costs

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 9.10 shows the estimated costs for unit commitment and out-of-sequence energy. Commitment and additional energy costs for exceptional dispatch paid through bid cost recovery decreased from $7.7 million in 2024 to $6.2 million in 2025, while out-of-sequence energy costs increased from $0.94 million in 2024 to $2.2 million in 2025. Total excess costs for exceptional dispatches decreased by about 4 percent—to about $8.4 million in 2025 from $8.7 million in 2024.

Figure 9.10 Excess exceptional dispatch cost by type



9.2.2 Mitigation of exceptional dispatches

Overview

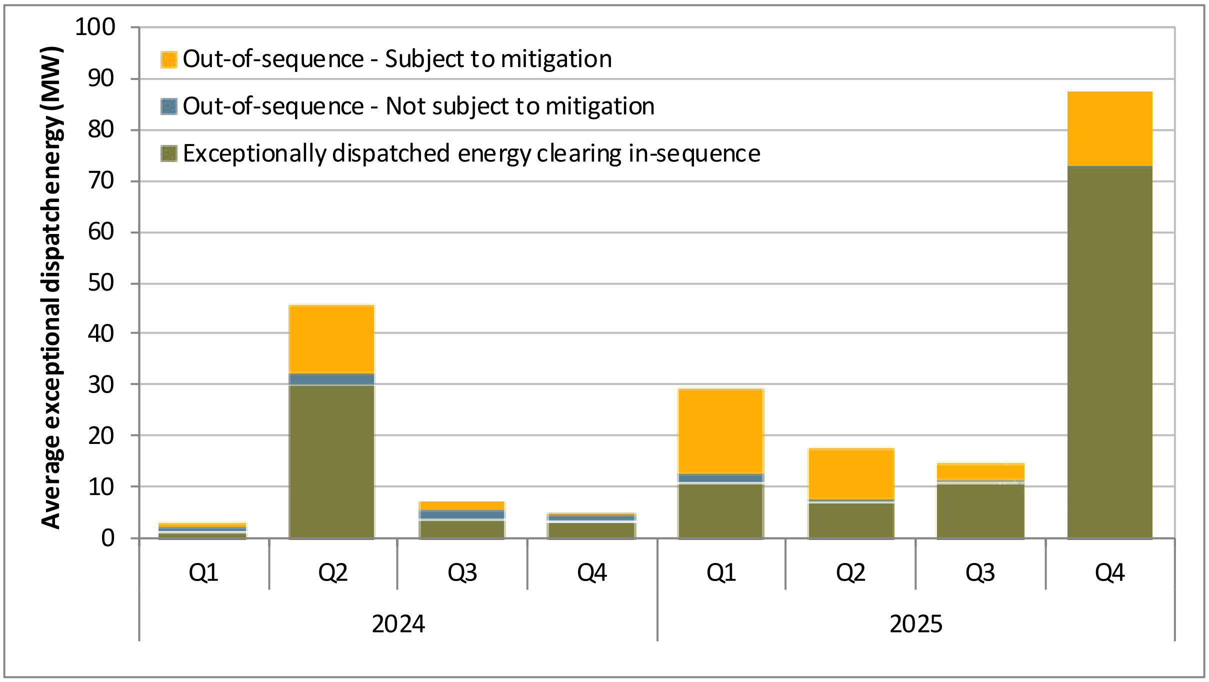
Commitment cost bids for units that are committed via exceptional dispatch are not subject to any additional mitigation beyond the commitment cost bid caps, which include 25 percent headroom above estimated start-up and minimum load costs. Exceptional dispatches for energy above minimum load are subject to mitigation if a grid operator indicates the dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real-time;
- Ramp resources to their minimum dispatch level in real-time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the market software that affect the dispatch of units in the Sacramento Delta, commonly known as *Delta Dispatch*.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 9.11, the overall volume of exceptional dispatch energy above minimum load increased by about 145 percent in 2025 when compared to 2024. As previously discussed in Section 9.2.1, out-of-sequence energy is energy with bid prices or default energy bids above the market clearing price. Out-of-sequence exceptional dispatches not subject to mitigation decreased by about 50 percent in 2025 compared to 2024. Out-of-sequence exceptional dispatches subject to mitigation increased by about 175 percent in 2025 compared to 2024. Exceptionally dispatched in-sequence energy dispatches are used to ensure a unit generates above its minimum operating level. In the fourth quarter of 2025, the SunZia wind resources accounted for over 60 percent of in-sequence exceptionally dispatched energy, as reflected in the large increase in in-sequence energy in Q4 2025.

Figure 9.11 Exceptional dispatches subject to bid mitigation



9.2.3 Western Energy Imbalance Market manual dispatch

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

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

Figure 9.12 through Figure 9.15 summarize average hourly incremental and decremental manual dispatch activity for participating and non-participating resources across the WEIM region. The California region, however, has no manual dispatch energy from non-participating resources.

Between 2024 and 2025, incremental manual dispatch energy from participating resources (yellow bars) decreased in all regions, declining by 78 percent in the Pacific Northwest, 34 percent in the Intermountain West, 18 percent in California, and nine percent in the Desert Southwest. Incremental manual dispatch energy from non-participating resources (red bars), also declined over this period, decreasing by 78 percent in the Desert Southwest, 76 percent in the Intermountain West, and 28 percent in the Pacific Northwest.

Decremental manual dispatch energy from participating resources (green bars) increased between 2024 and 2025 in the Pacific Northwest region and California region, by 95 percent and 77 percent respectively, while decreasing in the Intermountain West region and Desert Southwest region by 27 percent and 6 percent, respectively. These percentage changes in California and the Intermountain West reflect relatively small absolute volumes.

Overall, combined incremental and decremental manual dispatch energy increased from 2024 to 2025 in the California (non-CAISO) and Desert Southwest regions by 24 percent and 3 percent, respectively. In contrast, total manual dispatch energy declined in the Intermountain West and Pacific Northwest regions by 10 percent and 7 percent, respectively.

Figure 9.12 WEIM manual dispatches – California

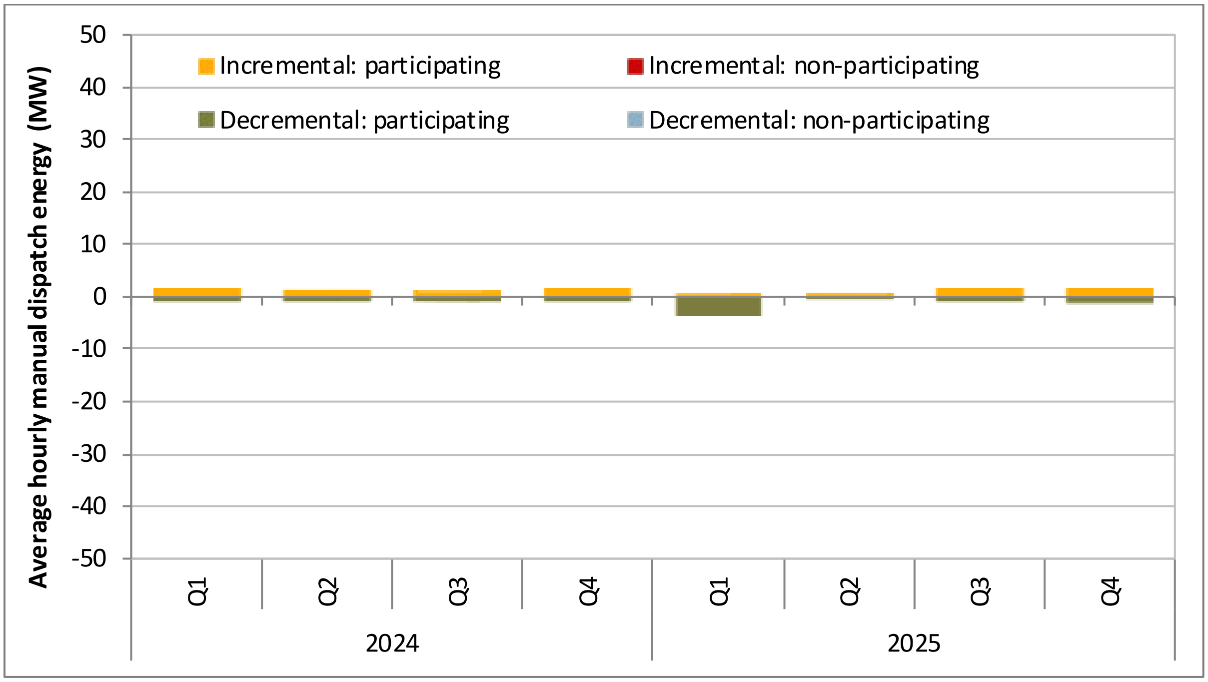


Figure 9.13 WEIM manual dispatches – Desert Southwest

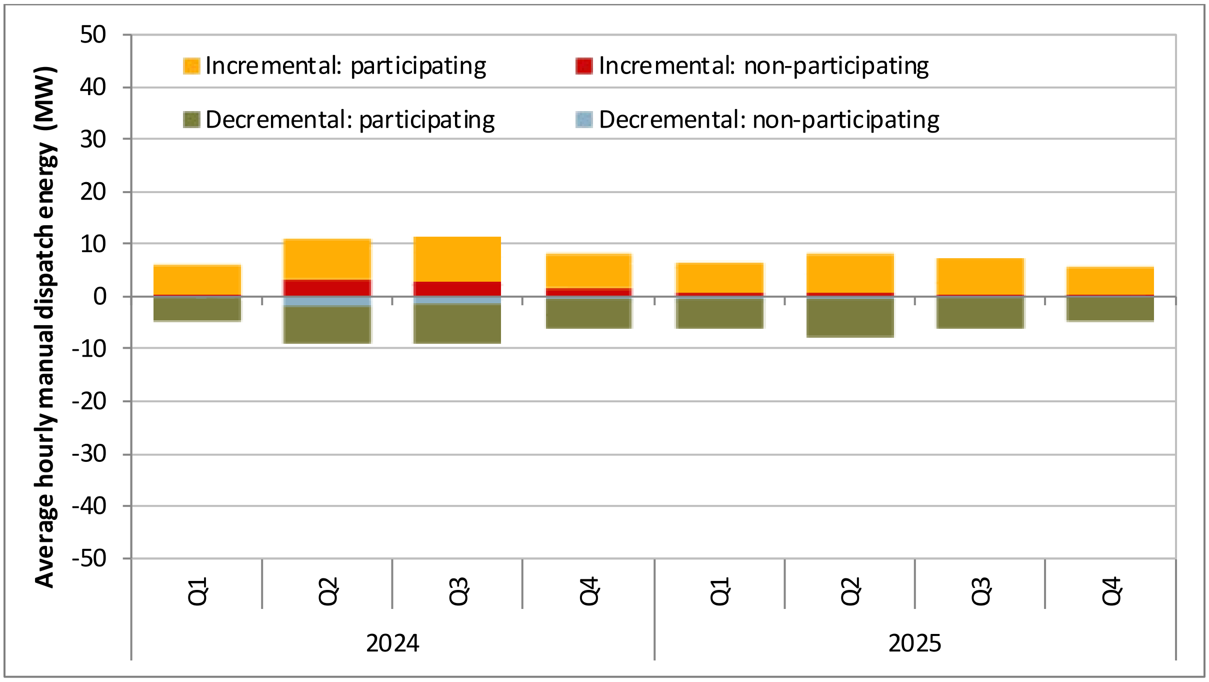


Figure 9.14 WEIM manual dispatches – Intermountain West

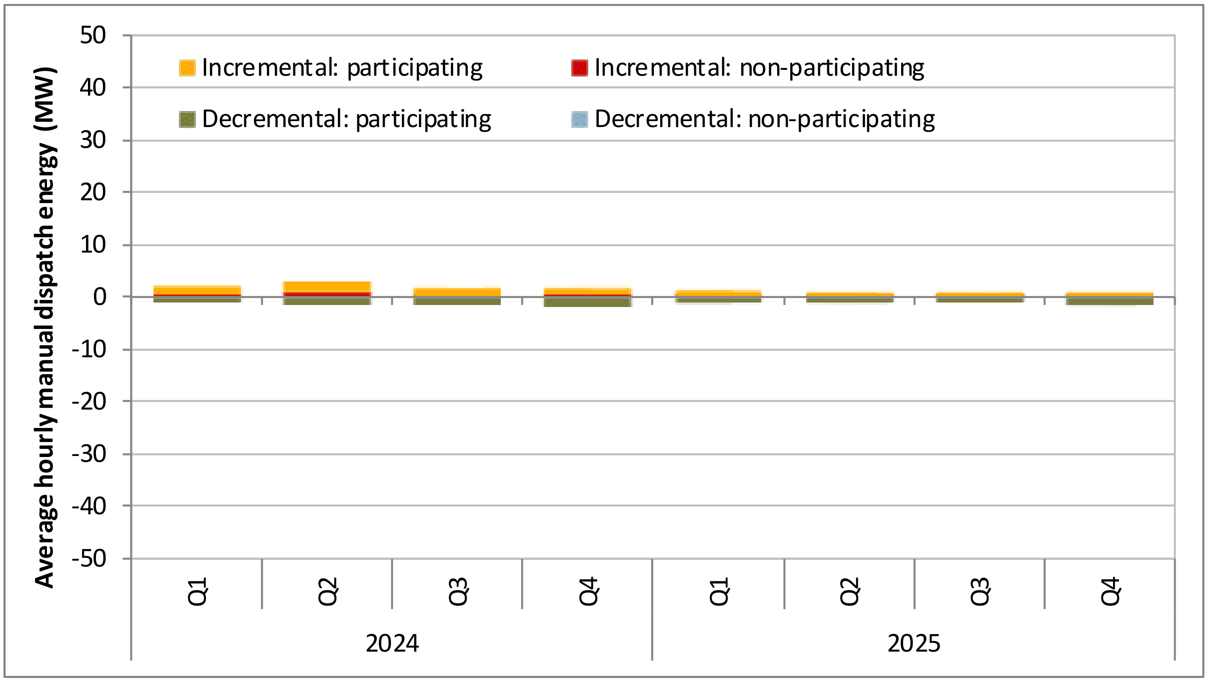
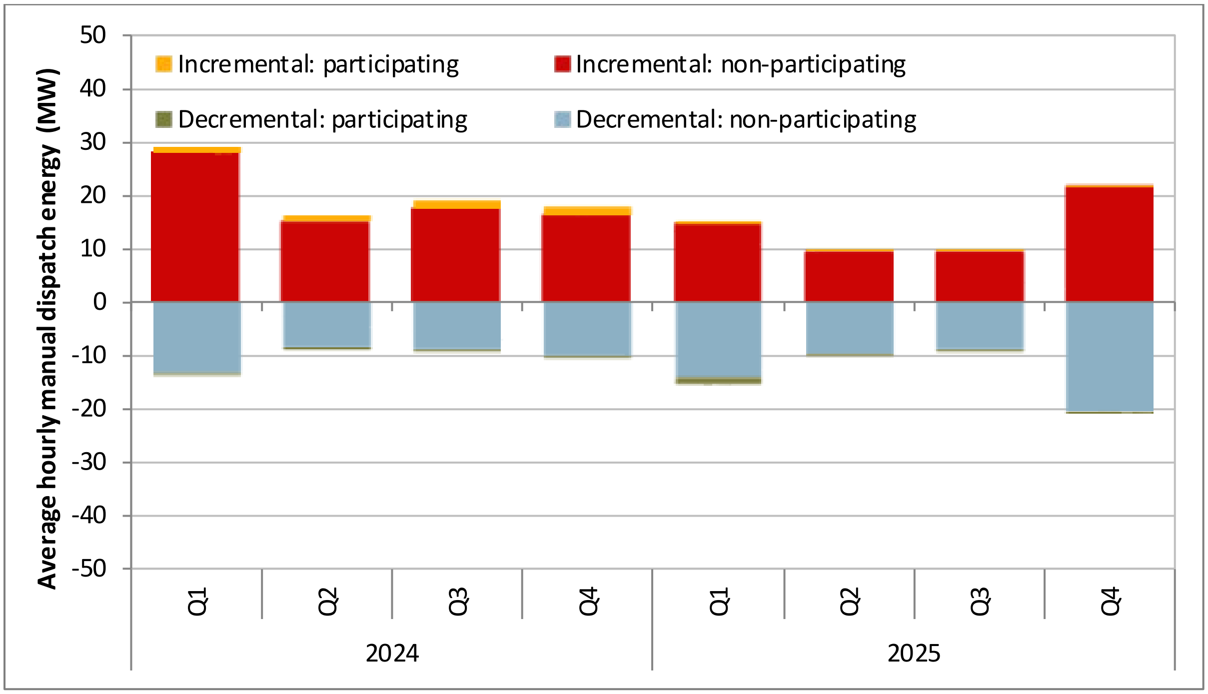


Figure 9.15 WEIM manual dispatches – Pacific Northwest



9.3 Blocked instructions and dispatches

Instruction types and reasons

The real-time market functions use a series of processes in real-time, including the 15-minute and 5-minute markets. During each of these processes, the market model occasionally issues commitment or dispatch instructions that are inconsistent with actual system or market conditions. In such cases, operators may cancel or *block* commitment or dispatch instructions generated by the market software.[184] This can occur for a variety of reasons, including the following:

- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, telemetry data is an input to the real-time market system. If that telemetry is incorrect, the market model may try to commit or de-commit units based on the bad telemetry data. Operators may act accordingly to stop the instruction from being incorrectly sent to market participants.
- **Software limitations of unit operating characteristics.** Software limitations can also cause inappropriate commitment or dispatch decisions. For example, some unit operating characteristics of certain units are also not completely incorporated in the real-time market models. For instance, the California ISO software has problems with dispatching pumped storage units, as the model does not reflect all of their operational characteristics.
- **Information systems and processes.** In some cases, problems can occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

Figure 9.16 through Figure 9.20 show the frequency of blocked real-time commitment instructions for both the CAISO balancing area and other WEIM regions.[185]

Within the CAISO area, blocked commitment instructions increased by 12 percent from 2024 to 2025. Blocked shut-down instructions continued to be the most common reason for blocked instructions, at about 63 percent in 2025. This was a decrease from about 76 percent of all blocked commitment instructions in 2024.

Within the California (non-CAISO) WEIM region, blocked commitment instructions increased by 13 percent from 2024 to 2025. Blocked shut-down instructions continued to be the most common reason for blocked instructions, at about 44 percent in 2025. This was a decrease from about 50 percent of all blocked commitment instructions in 2024.

Within the Desert Southwest region, blocked commitment instructions decreased by 17 percent from 2024 to 2025. Blocked transition instructions continued to be the most common reason for blocked

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[184] *Market performance metric catalog 2020*, California ISO. Blocked instruction information can be found in the later sections of the catalog reports: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9

[185] The data presented in this section may differ from prior annual publications due to a miscalculation in the methodology used previously. This issue has been identified and corrected, and all results shown here reflect the corrected calculations. Values reported in earlier publications may have been overstated.

instructions, at about 51 percent in 2025. This is a decrease from 59 percent of all blocked commitment instructions in 2024.

Within the Intermountain West region, blocked commitment instructions increased by 40 percent from 2024 to 2025. Blocked shut-down instructions continued to be the most common reason for blocked instructions, at about 54 percent in 2025. This is an increase from 52 percent of all blocked commitment instructions in 2024.

Within the Pacific Northwest region, blocked commitment instructions increased by 75 percent from 2024 to 2025. Blocked transition instructions became the most common reason for blocked instructions in 2025. Blocked transition instructions made up 83 percent of all blocked commitment instructions in 2025. This is a decrease from 100 percent of all blocked commitment instructions in 2024.

Figure 9.16 Frequency of blocked real-time commitment instructions in CAISO

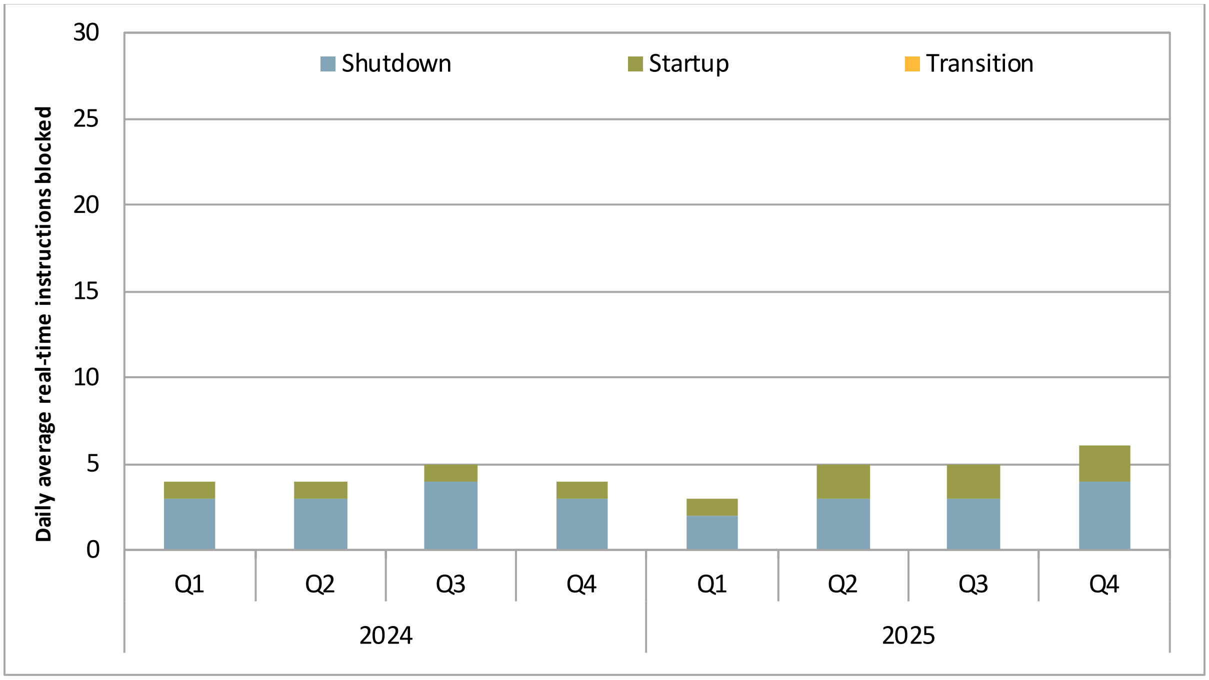


Figure 9.17 Frequency of blocked real-time commitment instructions in California (non-CAISO) WEIM

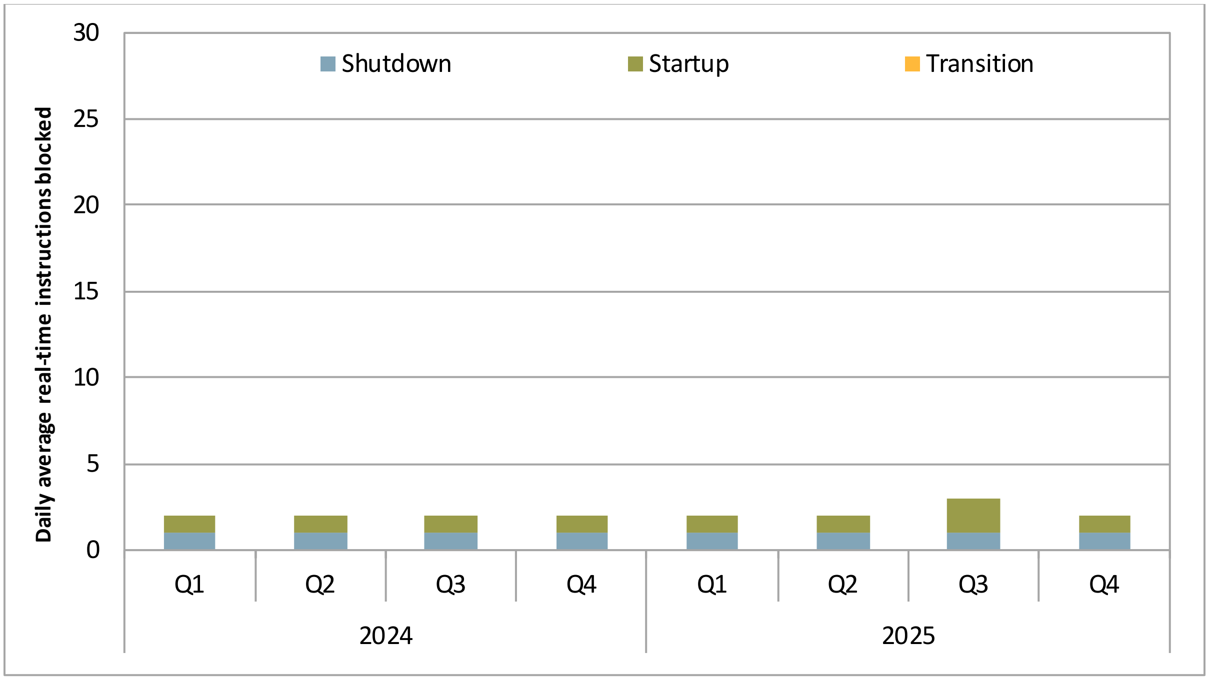


Figure 9.18 Frequency of blocked real-time commitment instructions in Desert Southwest

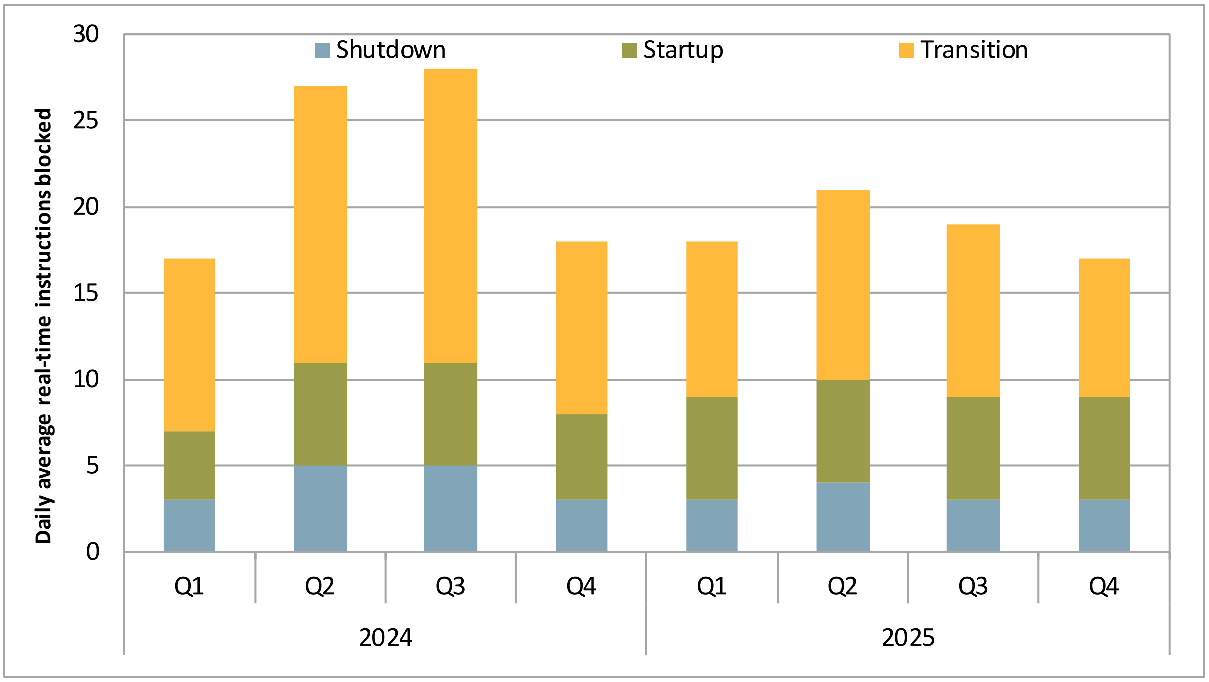


Figure 9.19 Frequency of blocked real-time commitment instructions in the Intermountain West

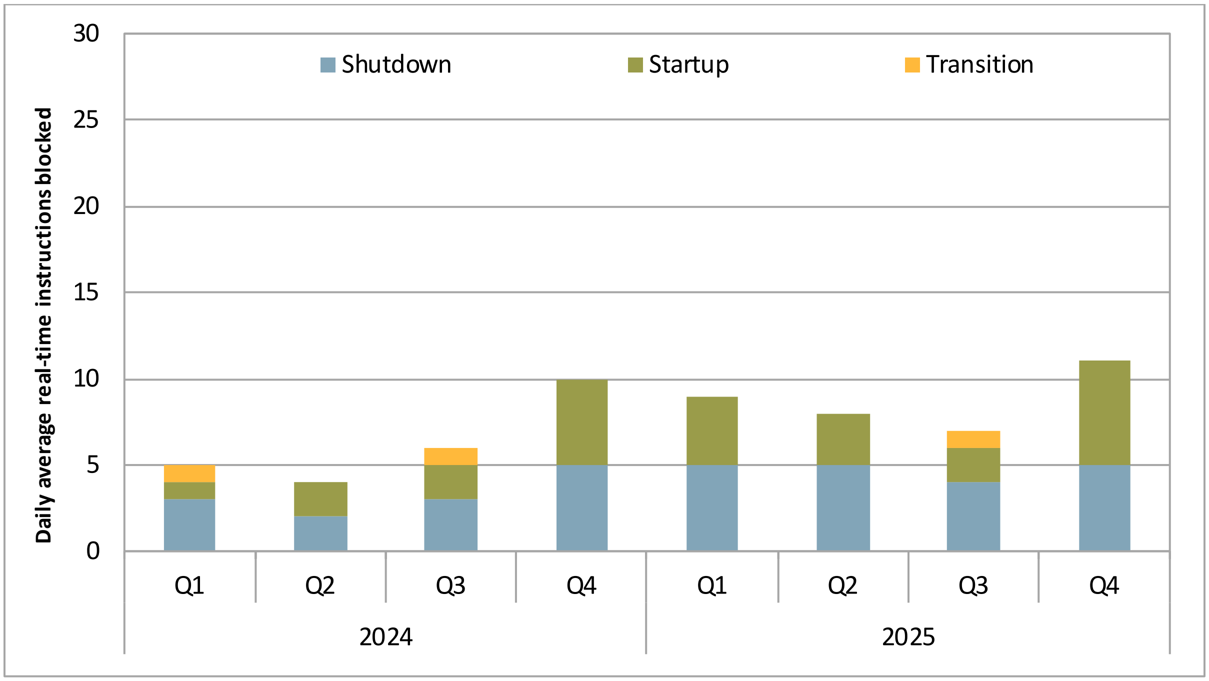
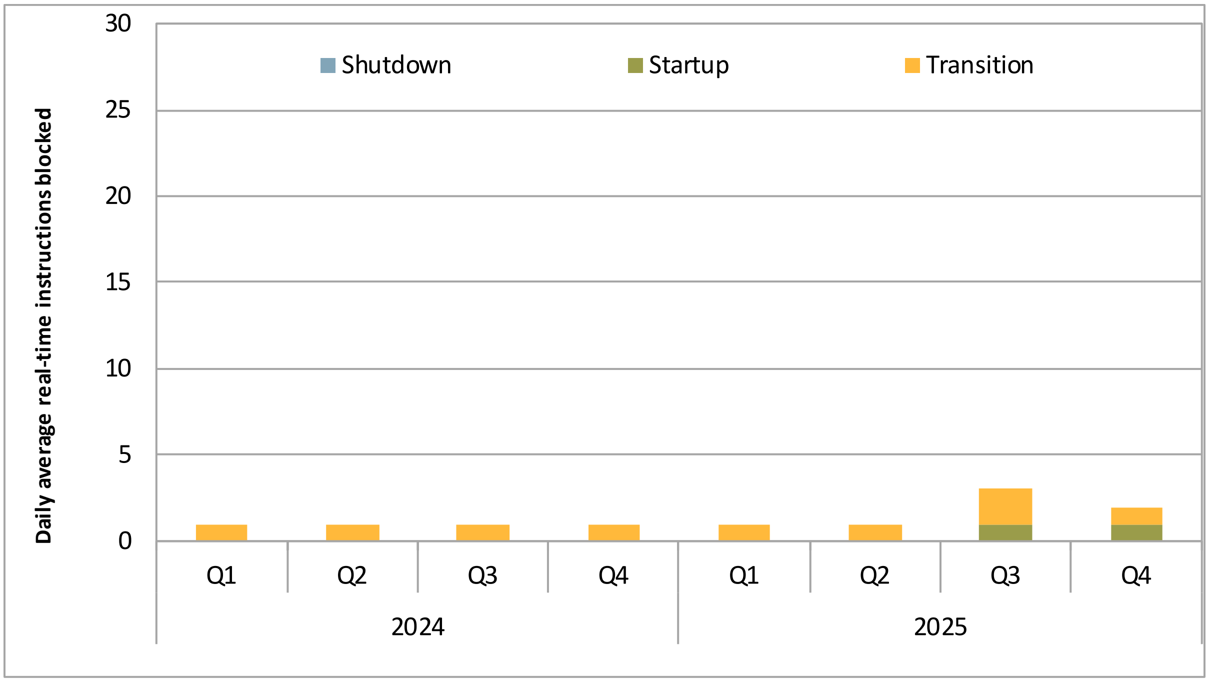


Figure 9.20 Frequency of blocked real-time commitment instructions in the Pacific Northwest



Dispatches

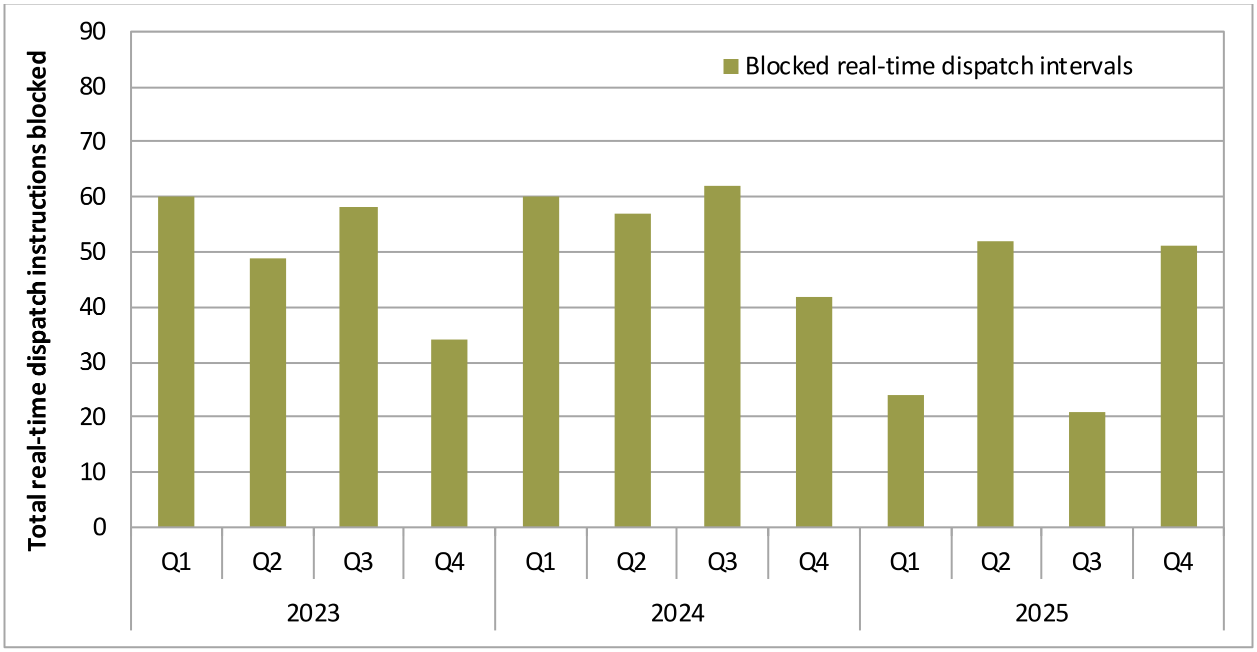
Grid operators review dispatches issued in the real-time market before these dispatch and price signals are sent to the market. If the California ISO operators determine that the 5-minute dispatch results are inappropriate, they are able to block real-time dispatch instructions and prices from reaching the market.

The California ISO began blocking dispatches in 2011, as both market participants and California ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often have caused participants to exacerbate issues with system conditions that were not modeled. Frequently, many of the blocked intervals eliminated the need for a subsequent price correction.

Operators can choose to block the entire market result to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, intertie scheduling information, or load forecasting data. Furthermore, the market software is also capable of automatically blocking a solution when market results exceed threshold values.[186]

Figure 9.21 shows the frequency that operators blocked price results in the real-time dispatch from 2023 through 2025. The total number of blocked intervals in 2025 increased by about 33 percent from the previous year.

Figure 9.21 Frequency of blocked real-time dispatch intervals



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[186] For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

10 Flexible ramping product

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

- **For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in this system during 0.4 percent of intervals in 2025.** At the balancing area level, El Paso Electric (EPE) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 0.8 percent of intervals.
- **Battery and hydro resources made up 62 percent and 25 percent of upward flexible ramping product, respectively.** Wind and solar combined provided 41 percent of downward flexible capacity, and batteries provided 33 percent of downward flexible capacity.
- **The CAISO balancing area continued to make up the majority of upward and downward flexible ramping product awards**, at around 57 percent in the upward direction and about 61 percent in the downward direction. Balancing areas in the Pacific Northwest made up 25 percent of upward flexible capacity and 15 percent of downward flexible capacity.
- **Payments for upward and downward uncertainty awards were $4.1 million during 2025**. Total payments associated with flexible ramping product were $11.2 million, up sharply from around $1 million in 2024. The California and Desert Southwest regions were paid about 31 and 30 percent, respectively, of the $4.1 million. Battery resources were paid 40 percent of this figure, consistent with their large share of flexible capacity provision.

10.1 Background

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market, to help manage volatility and uncertainty surrounding net load forecasts.[187] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs. Flexible capacity is procured and priced at a nodal level to better ensure that sufficient transmission is available for the capacity to be utilized.

The flexible ramping product demand curves are implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This “requirement” for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[188] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

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[187] 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.

[188] Based on a 95 percent confidence interval.

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). These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

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

10.2 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[189] 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.[190] 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 and nomogram constraints were modeled in the deployment scenarios for most of 2024. Contingency flowgate constraints were activated on June 4, 2024, and de-activated on June 12 due to performance issues with the solution run-times.[191] Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore not able to address materialized uncertainty.

The pass-group constraint maintains that the sum of flexible capacity in the group of balancing areas that pass the resource sufficiency evaluation equals the group's uncertainty requirement (minus any

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

[190] 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.

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

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.[192] 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.[193] The more flexibility forgone, the greater the likelihood of a power balance constraint violation and therefore greater expected cost. For a balancing area in the pass-group, the slack variable (or end of the demand curve) is limited by its distributed share of the pass-group uncertainty requirement.

The shadow price on the constraint for procuring flexible capacity in the pass-group has frequently been zero. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[194] Here, the flexible capacity requirement for the group of balancing areas that passed the resource sufficiency evaluation can be met by resources with zero opportunity cost for providing that flexibility.

Figure 10.1 shows the percent of intervals in which the shadow price on the pass-group constraint was non-zero (constraint binding) for upward and downward flexible capacity. This reflects more widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation, but does not account for any congestion that may affect the price of flexible capacity at the nodal level.[195] The pass-group constraint for procuring *downward* flexible capacity in the 5-minute market was binding in 1.2 percent of intervals during January. In all other months of 2025, the constraint for procuring flexible capacity within the pass-group was binding very infrequently.

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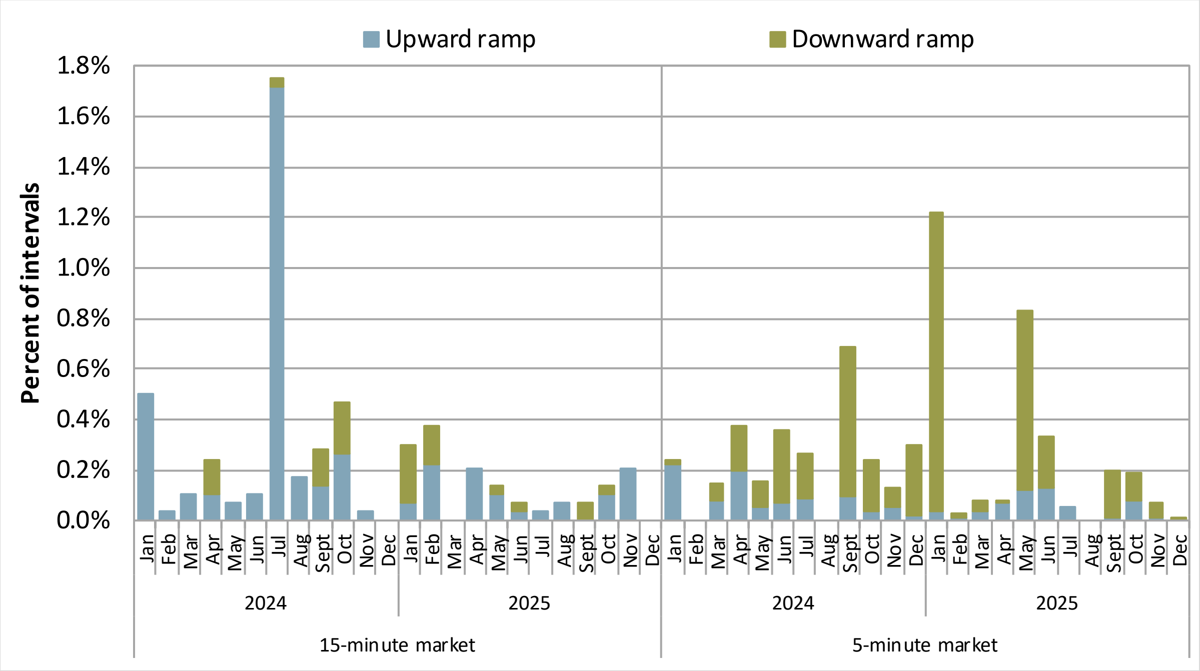
[192] Or for each surplus zone in the case of the CAISO balancing area (by TAC area) and BANC (by custom load aggregation point).

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

[194] 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.

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

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



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

Figure 10.2[196] summarizes the frequency of flexible ramping product prices in either the wider pass-group or transfer-constrained balancing areas within the pass-group. The blue bars are identical to the 15-minute market upward ramping capacity information shown in Figure 10.1, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of intervals in which the constraint that reflects WEIM transfer congestion in the deployment scenario was binding for one or more balancing areas in the pass-group—*and the pass-group constraint was not also binding*. This reflects additional flexible ramping product prices within at least one balancing area. In most cases, these prices were within one isolated balancing area in the pass-group.

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

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

about 0.4 percent of intervals in 2025, compared to 0.5 percent of intervals during 2024. In most intervals when upward flexible ramping product prices did occur, they were associated with WEIM transfer constraints rather than system-wide scarcity of flexible capacity, as evidenced by the predominance of transfer-constraint-related price intervals relative to pass-group constraint binding. In March, September, and December, there were no intervals in which the constraint for meeting pass-group upward flexible capacity requirements was binding. In June, there were no intervals in which the WEIM transfer constraint was binding but the pass-group constraint was not binding.

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

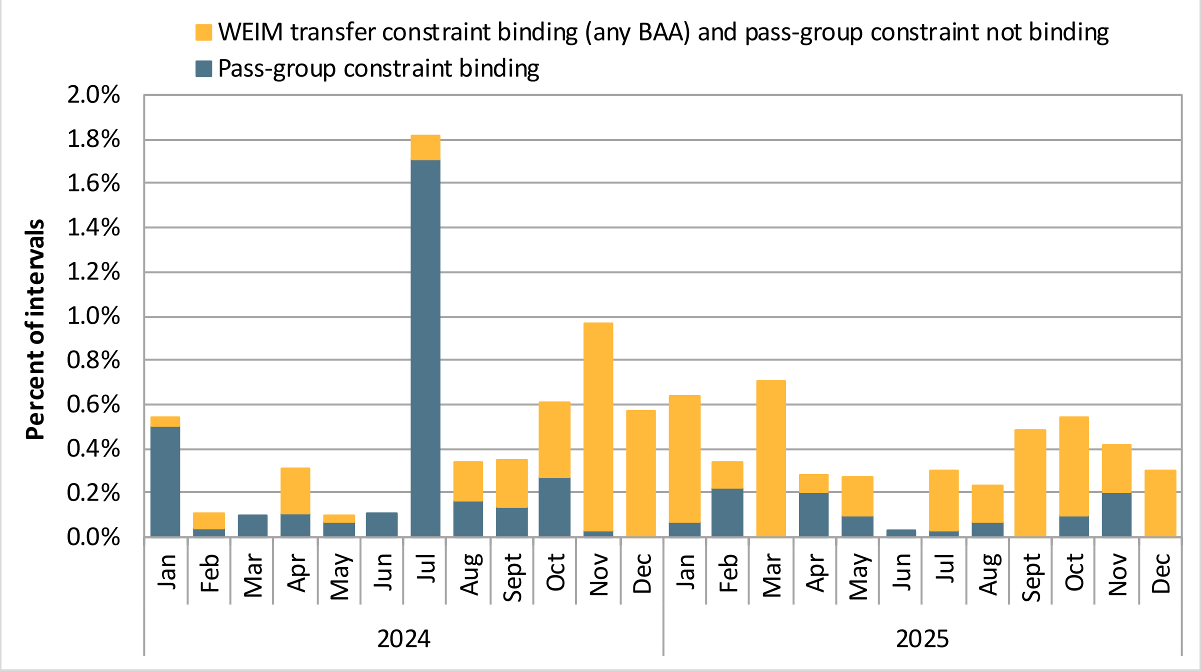

Figure 10.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area during 2025. These results are shown separately by the constraint contributing to that price:

- **Balancing area constraint binding (failed resource sufficiency evaluation)** indicates that the balancing area failed the resource sufficiency evaluation and there is a price for upward flexible capacity within the balancing area. When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. This is shown by the red bars in Figure 10.3.

- **Pass-group constraint not binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is no price for upward flexible capacity within the wider pass-group; but, because of WEIM transfer congestion into the balancing area, there is a price for upward flexible capacity within the balancing area. This is shown in yellow.

- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group. This is shown in light blue below.
- **Pass-group constraint binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group; but, because of WEIM transfer congestion out of the balancing area, there is typically no price for upward flexible capacity within the balancing area. This is shown in dark blue.

During 2025, the pass-group constraint was binding very infrequently for upward flexible capacity in the 15-minute market (light and dark blue bars), during around 0.1 percent of intervals. In some of these intervals, balancing areas in the Pacific Northwest region had sufficient flexible capacity, but because of congestion on WEIM transfer constraints out of the balancing area in the deployment scenario, flex ramp prices here were typically zero.

Figure 10.3 also summarizes flexible capacity prices that can exist following a resource sufficiency evaluation failure (red bars). When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. El Paso Electric (EPE) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 0.8 percent of intervals. Most of these were associated with failure of the second run of the resource sufficiency evaluation at 55 minutes prior to the hour, which impacts the first interval of each hour.[197]

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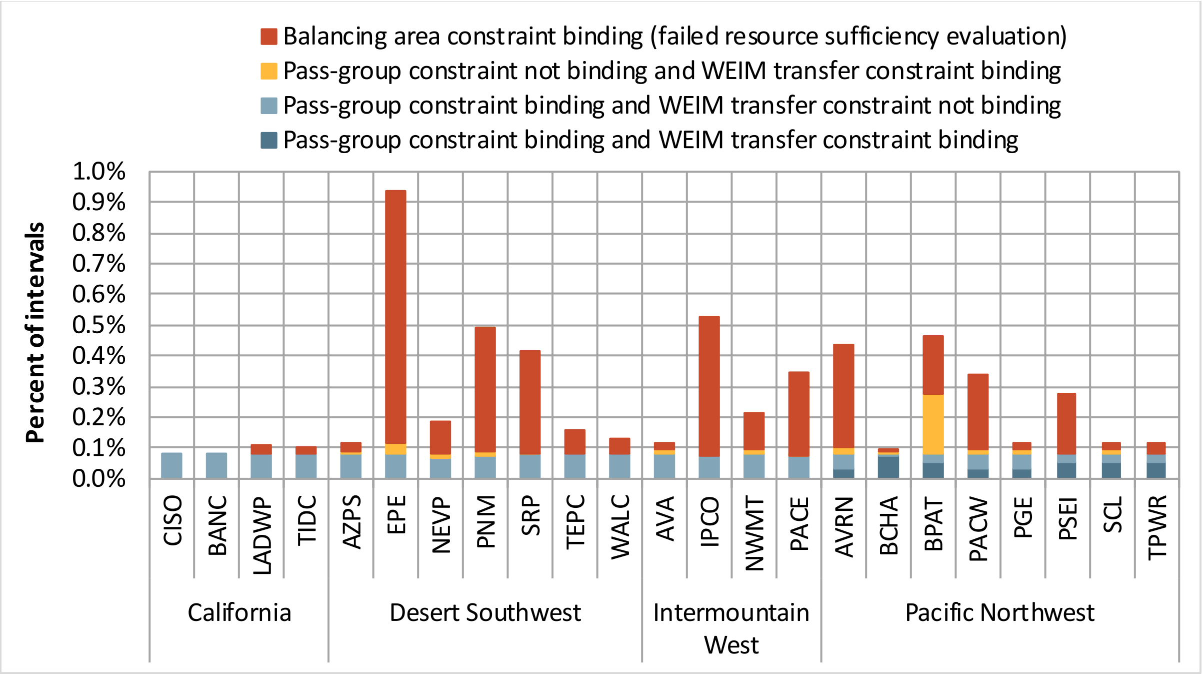
[197] There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation. The first and second runs are sometimes considered the advisory runs, with the final evaluation occurring at 40 minutes prior to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

Figure 10.3 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, 2025)



10.3 Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that pass the resource sufficiency evaluation.

Figure 10.4 and Figure 10.5 show average upward or downward flexible capacity that was procured in various regions.[198] 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 year, the California ISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 57 percent in the upward direction and about 61 percent in the downward direction. Balancing areas in the Pacific Northwest made up 25 percent of upward flexible capacity and 15 percent of downward flexible capacity.

Flexible ramp procurement patterns generally followed net load profiles, with higher procurement levels during morning and evening ramping hours when uncertainty is greatest, as visible in the hourly profiles of Figures 10.4 and 10.5.

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[198] 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. Intermountain West includes Idaho Power, NorthWestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

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

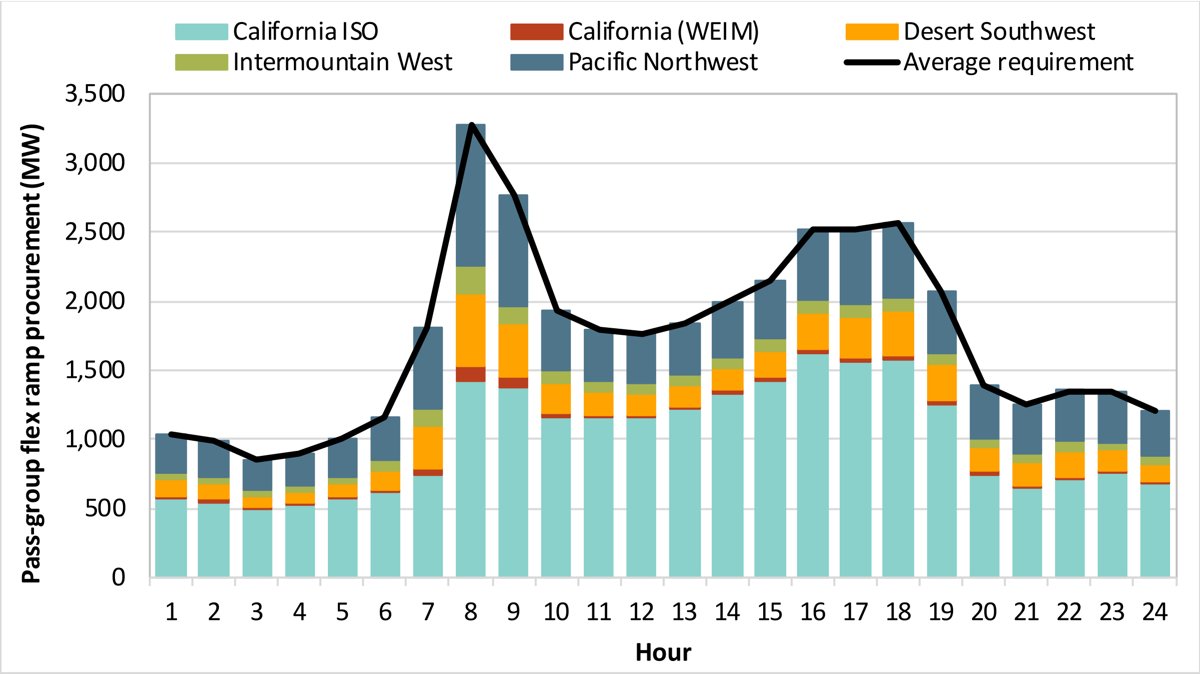


Figure 10.5 Average downward pass-group flexible ramp procurement by region (15-minute market, 2025)

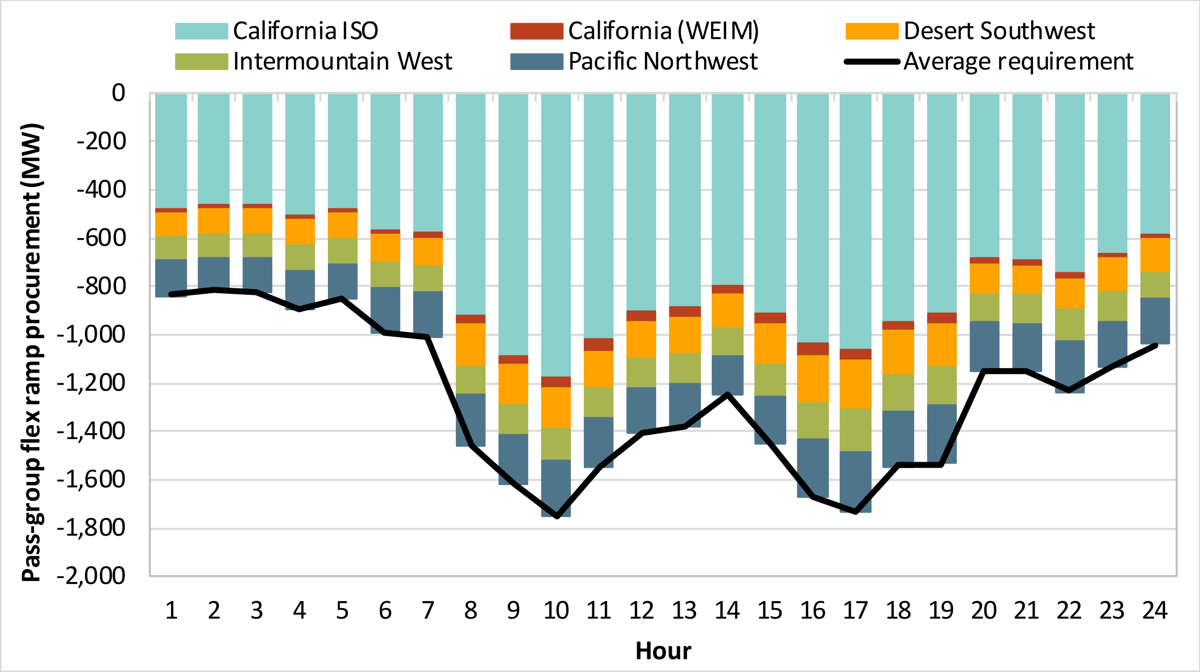


Figure 10.6 and Figure 10.7 show the average upward or downward flexible capacity that was procured from various fuel types. During the year, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up around 62 percent of upward flexible capacity and 33 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (25 percent). Wind and solar resources combined made up around 41 percent of downward flexible capacity.

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

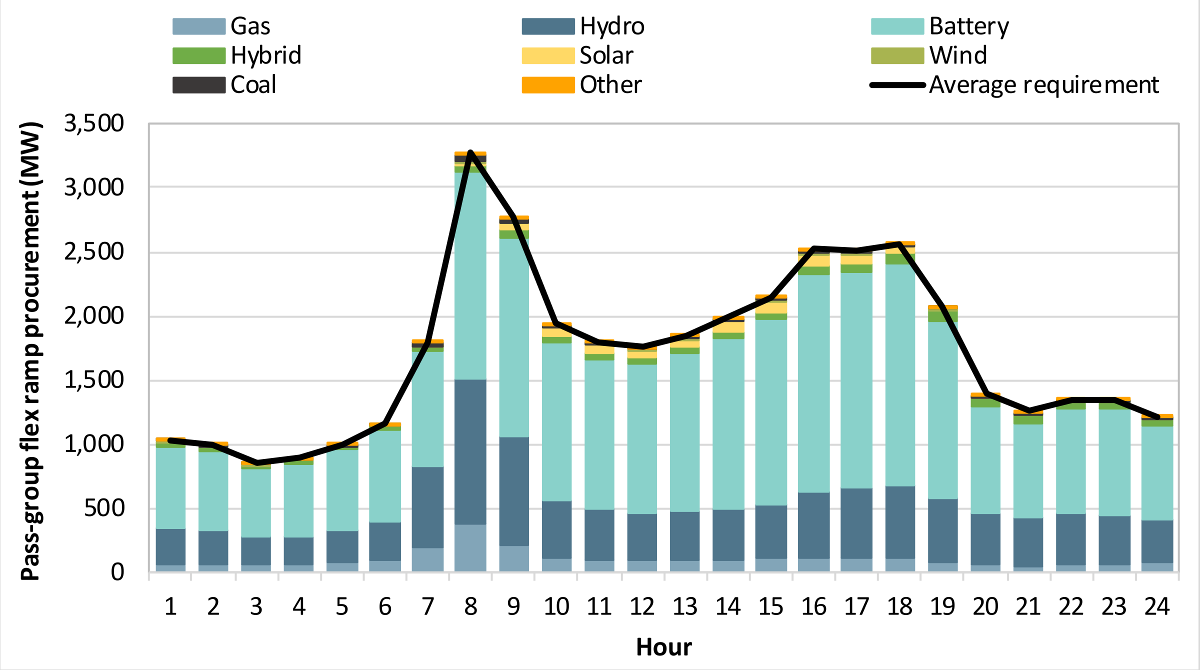
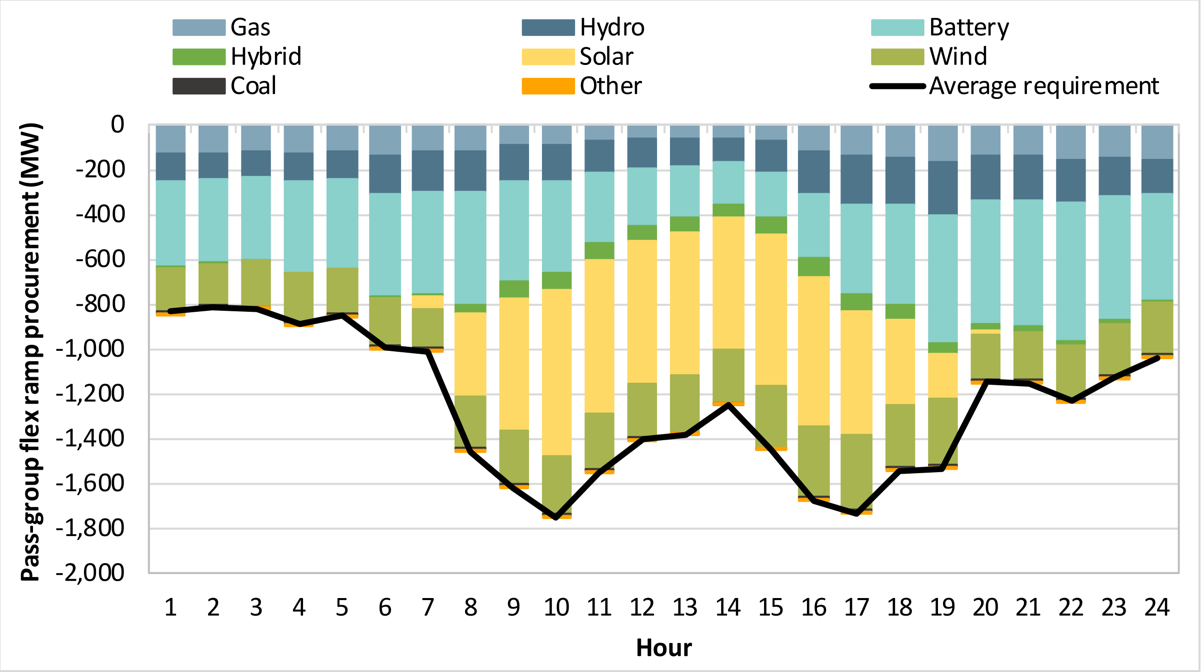


Figure 10.7 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, 2025)



10.4 Flexible ramping product costs

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

Flexible ramping capacity awards reflect the ability for a resource to ramp above or below their expected schedule in the next interval to address uncertainty that might materialize. Flexible ramping capacity that satisfies the demand for upward or downward flexibility receives payments based on the price for flexible capacity at that node. In addition, the flexible ramping product price is used to pay or charge for forecasted movements. Forecasted movement is a resource's expected change in schedule in the next interval.[199] A payment indicates that the resource was given an advisory dispatch by the market in the same direction as the demand for flexibility (i.e., supporting flexibility). A charge indicates that the resource was given an advisory dispatch by the market in the opposite direction as the demand for

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

flexibility (i.e., consuming flexibility). The following section looks at flexible ramping product payments from three different perspectives: (1) by payment type, (2) by area, and (3) by fuel type.

Figure 10.8 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. Payments associated with the flexible ramping product were $11.2 million during 2025 after accounting for forecasted movement, compared to around $1 million in 2024. Payments for only upward and downward uncertainty awards were $4.1 million during 2025, compared to around $5.4 million in the previous year.

Figure 10.8 Monthly flexible ramping product payments by type

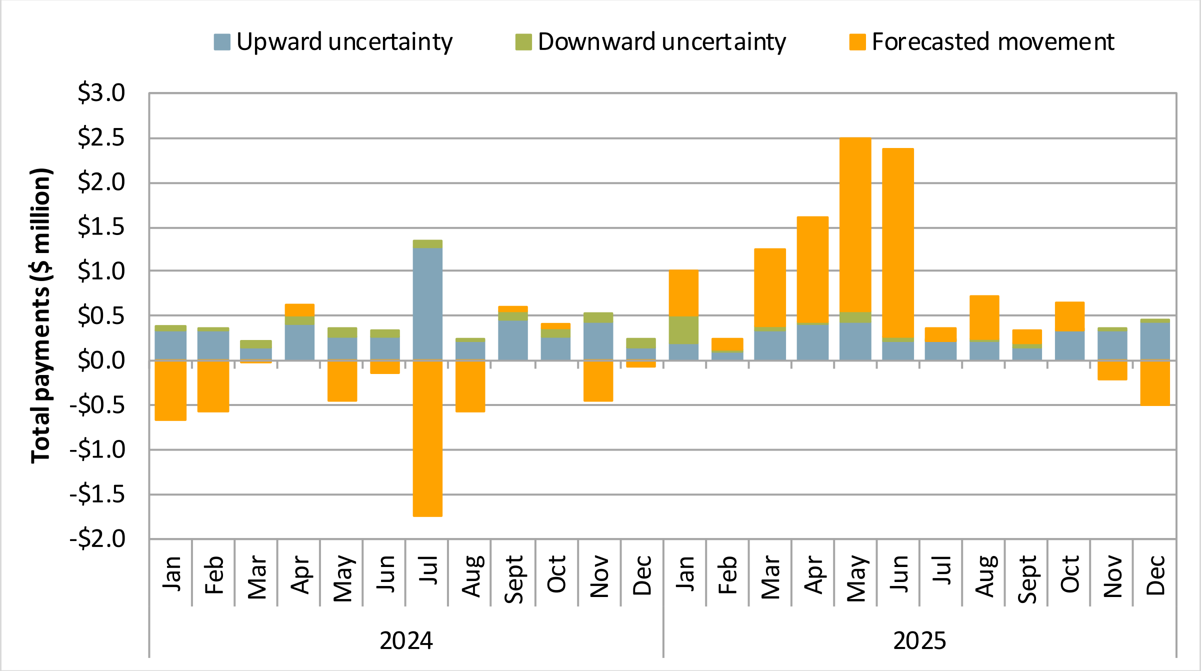


Figure 10.9 and Figure 10.10 do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs.

Figure 10.9 shows these payments by WEIM region. Payments for this capacity may have been procured to satisfy system-level demand, area-specific demand, or both. During 2025, about 31 percent of payments for flexible ramping capacity went to resources in the California region, and about 30 percent of payments went to resources in the Desert Southwest. Payments to the Intermountain West increased from about 6 percent of the total payments in 2024 to about 21 percent of total payments in 2025.

Figure 10.10 shows the same information by fuel type. In 2025, 40 percent of flexible capacity payments for upward and downward uncertainty went to battery generators, an increase from 32 percent in 2024. Batteries appear to be displacing some of the flexible capacity payments to natural gas generators, which decreased from 25 percent in 2024 to 21 percent in 2025. Hydroelectric generators received 14 percent of payments in 2025.

Figure 10.9 Monthly flexible ramping product uncertainty payments by region

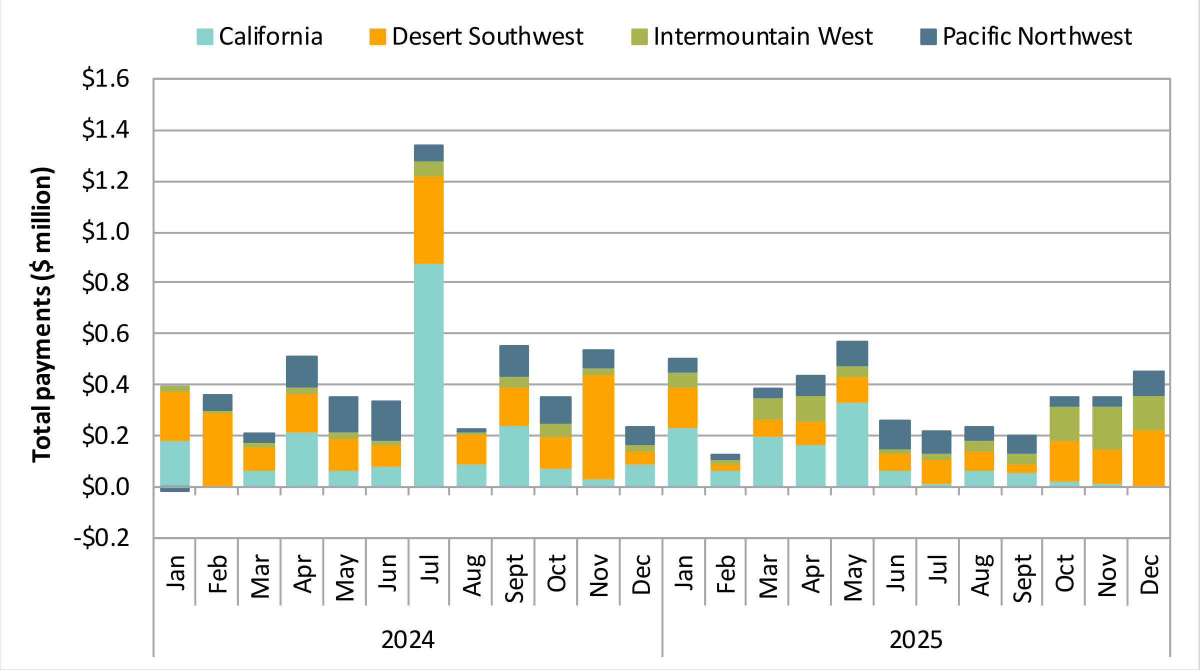
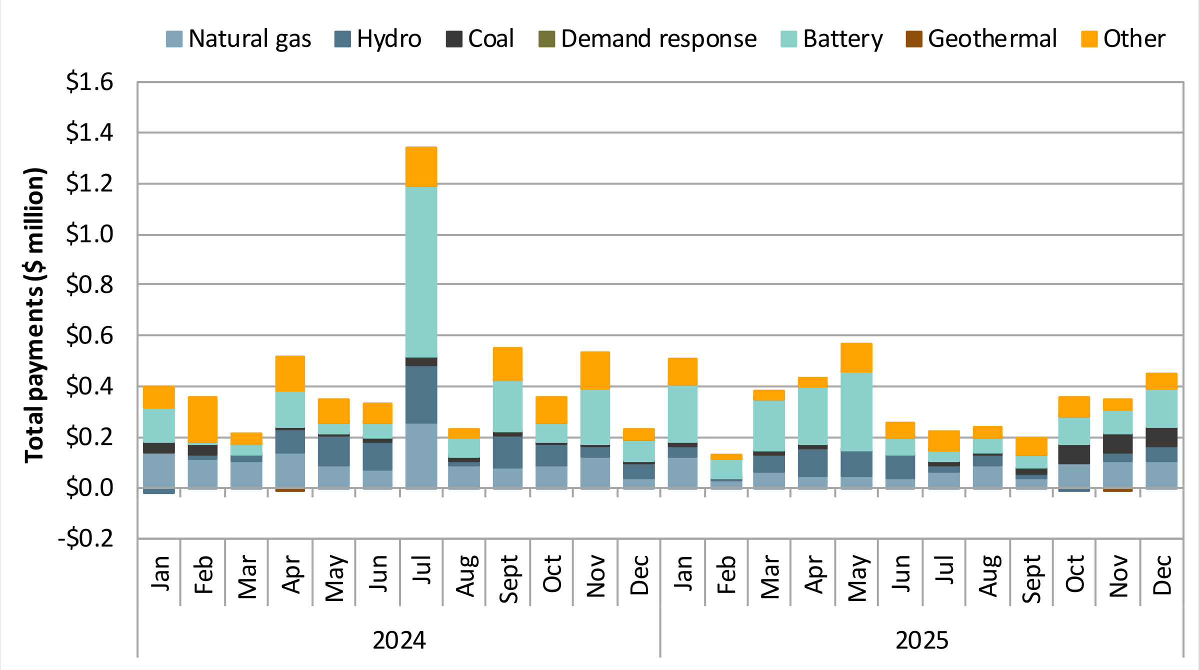


Figure 10.10 Monthly flexible ramping product uncertainty payments by fuel type



11 Uncertainty

This section discusses uncertainty considered in different applications of the market, including the flexible ramping product (FRP), resource sufficiency evaluation (RSE), and the residual unit commitment (RUC) adjustment. Each of these market processes use a method called *mosaic quantile regression* to calculate and account for uncertainty that may materialize.[200] This chapter reviews the results of the uncertainty calculation and assesses the regression method.

Key findings in this chapter include:

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the histogram method.**
- **For the flexible ramping product, the rate at which the regression method uncertainty requirements covered realized uncertainty was below the target coverage rate of 97.5 percent for each direction and market.** The regression coefficients were statistically different from zero in only 31 percent of intervals.
- **For the resource sufficiency evaluation, the coverage rate varied between 88 percent and 92 percent across balancing areas.** The target coverage rate is 95 percent. 36 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.
- **The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on only 4 percent of days in the year.** The 75th percentile target was applied on 11 percent of days. The 50th percentile target was applied on 33 percent of days. No adjustment was applied on 52 percent of days. The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address this same uncertainty. However, after an initial period of being set to cover the 90th percentile of uncertainty, the ISO will assess if it will set the requirement to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in the residual unit commitment uncertainty adjustment prior to EDAM implementation indicates that the imbalance reserve product demand curve may be much too high during most hours.
- **The low rates of statistically significant regression coefficients** indicates that the mosaic quantile regression method identified weak or inconsistent relationships between forecast variables and realized uncertainty in most intervals across its application in the flexible ramping product, resource sufficiency evaluation, and residual unit commitment process.

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

In this chapter, DMM evaluates the performance of the uncertainty calculation model using three main criteria:

- **Accuracy:** accuracy is measured using the coverage rate, which reflects the percentage of realized uncertainties that falls within the forecast prediction interval.
- **Efficiency:** a forecast is considered efficient if it maintains the target coverage (e.g., 95 percent) while producing a relatively narrow prediction interval (requirement).
- **Validity:** DMM tests whether regression coefficients are statistically different from zero at the 10 percent significance level (p<0.1).[201]

Measurements of the uncertainty requirements and coverage in this section are based on actual market results. The statistical significance metrics are based on DMM's replication of the ISO's mosaic quantile regression method.[202]

11.1 Flexible ramping product uncertainty

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

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

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

The range from the upper 2.5 percent of uncertainty to its maximum spans from 2,400 MW to over 6,400 MW, reflecting a long tail distribution. These long tails in the distribution could indicate that the uncertainty is influenced by rare, extreme events rather than typical fluctuations. The distribution was

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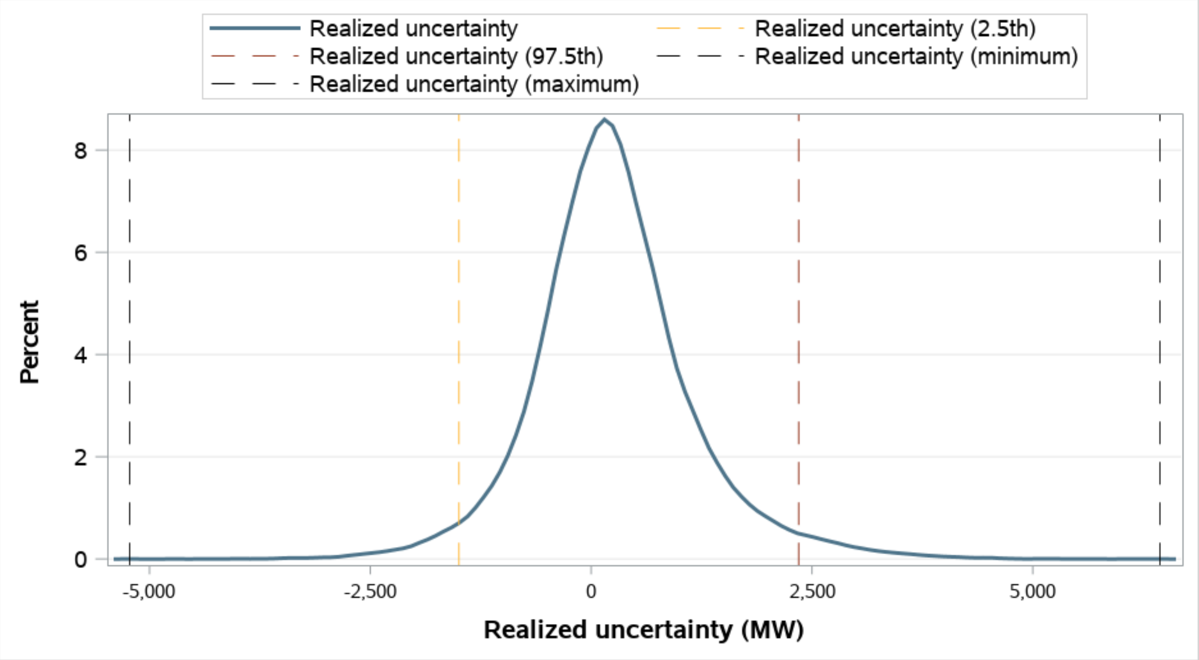
[201] Statistical testing is used to determine whether a regression coefficient is significantly different from zero, which suggests the presence of a non-random pattern in historical data. This relationship may be useful for forecasting *if* the historical pattern continues into the future. However,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

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

skewed upward, resulting in a longer tail on the upper end. This may indicate the influence of systematic patterns, rather than purely random variations. These factors may provide valuable information for forecasting uncertainty.

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

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



11.1.1 Results of flexible ramping product uncertainty calculation

Figure 11.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the historical 180-day period) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the year. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.[203]

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

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

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

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

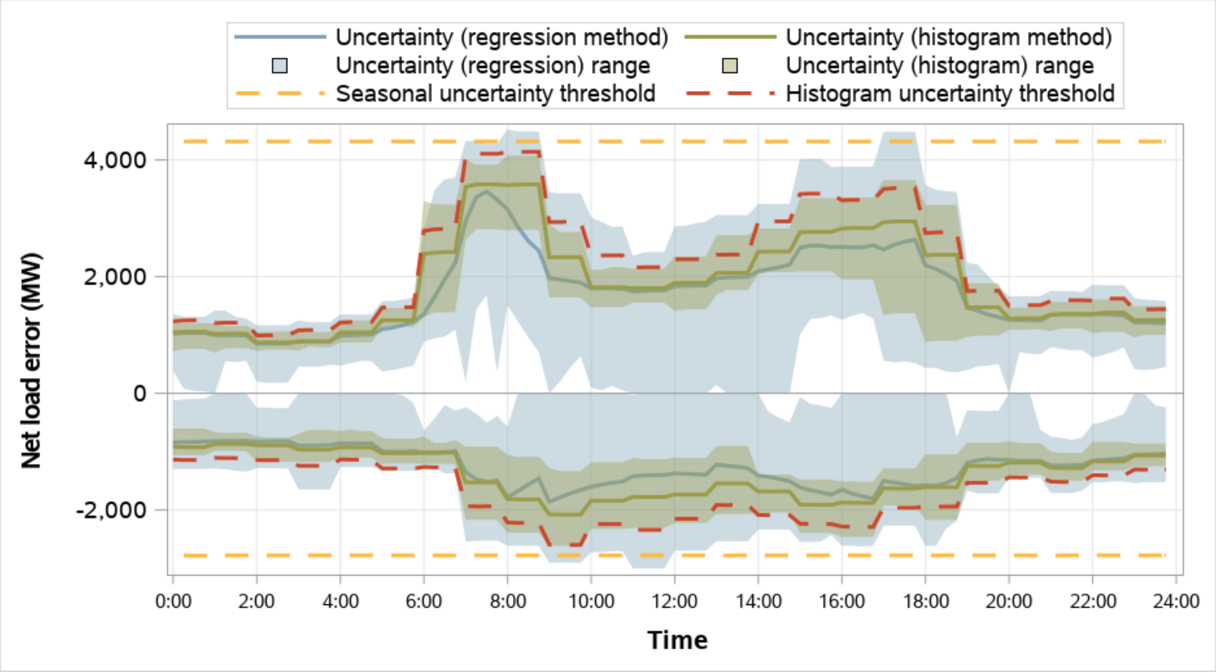

Figure 11.3 5-minute market pass-group uncertainty requirements (2025)

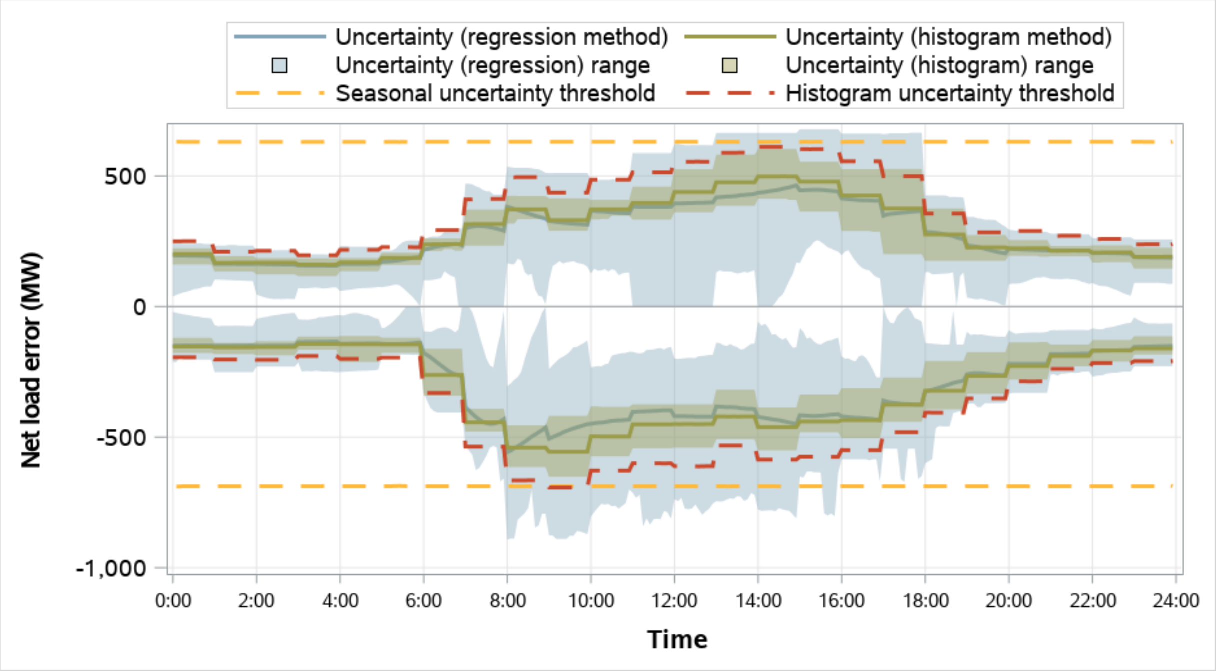

Table 11.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the pass-group (based on a 95 percent confidence interval). The *coverage* shows how often the realized uncertainty fell within the requirement for the same interval.[204]

In flexible ramping product (FRP), due to the different composition of the upward and downward RSE pass-group, each direction is evaluated with a target coverage of 97.5 percent.[205] In the 15-minute market, uncertainty forecasted by mosaic regression generally had slightly lower coverage and requirements, whereas the histogram method showed slightly higher coverage and requirements. The rate at which the regression method uncertainty requirements covered realized uncertainty was below the target coverage for each direction and market.

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

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

Table 11.1 Average pass-group uncertainty requirements (2025)

Market	Direction	Requirement			Coverage		
		Histogram	Mosaic	*Difference*	Histogram	Mosaic	*Difference*
15-minute market	Up	1,907	1,729	-178	97.4%	96.7%	-0.7%
	Down	1,399	1,263	-137	97.6%	96.7%	-0.8%
5-minute market	Up	296	282	-14	97.3%	97.0%	-0.4%
	Down	315	295	-20	97.6%	97.2%	-0.4%

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

The mosaic regression is primarily designed to forecast net load uncertainty, with the mosaic variable serving as the main predictor in this regression. The three additional quantile regressions—load, solar, and wind—function as intermediate regressions used to construct the mosaic variable.[206]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimation in this year. Each regression includes two primary coefficients: a quadratic term and a linear term.[207] The percentages represent the proportion of regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

Table 11.2 Test for statistical significance of mosaic quantile regression in FRP (2025)

Regression type	All hours	Peak hours(1)
Mosaic	31%	40%
Load	30%	36%
Solar	64%	77%
Wind	44%	52%

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

The coefficient for the mosaic variable was statistically significant during only 31 percent of intervals. This means that in 69 percent of cases, the mosaic variable does not show a strong pattern with

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

[207] 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.

historical uncertainty.[208] Whether the mosaic variable is high or low, the uncertainty does not consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

Low statistical significance suggests that the regression often fails to identify a meaningful relationship. This failure could stem from either no relationship or inconsistent relationship. While it is difficult to quantify the proportion of cases due to no relationship versus inconsistency, mathematically, if no relationship exists, the quantile regression outcomes will converge to the histogram results.[209] Intuitively, this occurs because a no relationship implies that the mosaic variable provides no additional information for forecasting. As a result, the forecast relies solely on the historical net load uncertainty data, which is the histogram method.

In Figure 11.2 and Table 11.1, the average hourly requirement and performance metrics show a high degree of similarity between the histogram and mosaic regression method. This resemblance can be explained by the low percentage of statistically significant coefficients.

11.1.2 Threshold for capping flexible ramping product uncertainty

Flexible ramping product and resource sufficiency evaluation uncertainty calculated from the quantile regressions is capped by the lesser of two ceiling thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from a 180-day period.[210] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. For the upward seasonal threshold, the 99th percentile is calculated separately for each of the 24 hours in a day. The maximum value out of these 24 hours is used as the threshold for all hours.[211]

During the year, the ceiling thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 7 percent of intervals in the 15-minute market and 4 percent of intervals in the 5-minute market. *Downward uncertainty* was capped by the ceiling thresholds in around 8 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. The ceiling threshold implies that the requirement is set at the highest 1 percent of uncertainty over the past 90 or 180 days. The expected frequency of reaching this

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

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

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

[211] 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.

threshold is around 1 percent of the time. However, the observed frequency significantly exceeded this expectation.

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

11.2 Resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Here, balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand *as well as uncertainty*.[212] This additional requirement in the flexibility test is also based on a 95 percent confidence interval for uncertainty that might materialize. This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation.

Figure 11.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for 2025. Here, realized uncertainty is defined as the net load forecast difference between the forecasts used in the resource sufficiency evaluation and those in the binding 5-minute market runs. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.[213] 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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[212] The flexibility test also includes a discount to account for *diversity benefit*. System-level flexible ramping needs are smaller than the sum of the needs of individual balancing areas because of reduced uncertainty across a larger footprint. Balancing areas therefore receive a prorated diversity benefit discount in the test based on this proportion.

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

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

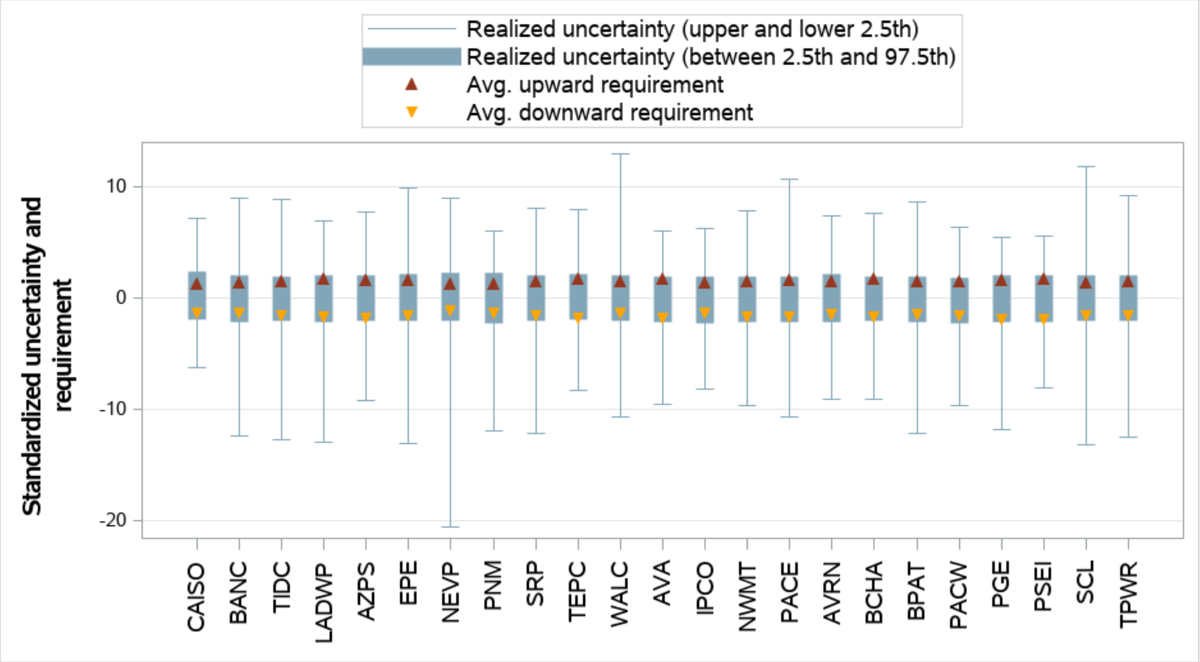

Figure 11.4 provides a comparison of the realized uncertainty across different BAAs for this year. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th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

Key observations include:

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

11.2.1 Results of resource sufficiency evaluation uncertainty calculation

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

In the RSE, both the histogram and mosaic regression showed overall coverage levels significantly below the 95 percent target. Of note, coverage using the regression method remained at or below 92 percent across all balancing areas , ranging from approximately 88 percent to 92 percent. This is largely due to a disparity with the underlying data used to estimate resource sufficiency evaluation uncertainty, as discussed in the following section. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for all of the WEIM entities.

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

	Upward uncertainty			Downward uncertainty			Coverage		
Balancing area	**Histogram**	**Mosaic**	**Difference**	**Histogram**	**Mosaic**	**Difference**	**Histogram**	**Mosaic**	**Difference**
Arizona Public Service	283	254	-29	233	216	-17	93%	92%	-1%
Avangrid	217	178	-39	178	133	-45	93%	91%	-1%
Avista	58	56	-3	66	63	-4	93%	92%	-1%
BANC	44	40	-5	44	38	-6	93%	90%	-3%
Bonneville Power Admin.	230	198	-33	253	205	-48	93%	91%	-2%
California ISO	1,320	1,165	-155	816	707	-109	92%	90%	-2%
El Paso Electric	48	43	-5	42	39	-3	94%	91%	-3%
Idaho Power	138	129	-9	163	147	-16	90%	88%	-2%
LADWP	168	154	-14	153	145	-9	93%	92%	-1%
NorthWestern Energy	75	68	-7	84	75	-9	92%	90%	-2%
NV Energy	268	215	-53	231	185	-46	93%	91%	-3%
PacifiCorp East	459	420	-39	621	582	-40	92%	90%	-2%
PacifiCorp West	97	89	-8	146	119	-28	92%	91%	-1%
Portland General Electric	130	119	-12	126	120	-6	93%	91%	-2%
Powerex	146	141	-5	152	146	-6	92%	91%	-1%
PNM	205	177	-28	187	175	-12	91%	89%	-2%
Puget Sound Energy	159	139	-20	152	150	-2	94%	92%	-1%
Salt River Project	144	137	-8	133	119	-15	93%	91%	-2%
Seattle City Light	19	18	-1	20	19	-2	92%	90%	-2%
Tacoma Power	12	11	-1	12	11	-1	92%	90%	-2%
Tucson Electric Power	105	97	-8	90	84	-6	94%	92%	-2%
Turlock Irrigation District	7	7	0	8	7	0	92%	90%	-2%
WAPA Desert Southwest	31	28	-3	25	24	-1	90%	88%	-2%

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

Table 11.4 Test for statistical significance of mosaic quantile regression in RSE (2025)

BAA	Percent of significant coefficients	
	All hours	Peak hours(1)
Avangrid	84%	85%
PacifiCorp West	66%	67%
BPA	59%	52%
Arizona PS	48%	46%
Idaho Power	47%	54%
NorthWestern	45%	44%
CAISO	41%	50%
NV Energy	40%	52%
Avista Utilities	38%	37%
PacifiCorp East	37%	43%
Salt River Project	35%	35%
PSC New Mexico	32%	36%
LADWP	32%	34%
El Paso Electric	32%	39%
Portland GE	31%	30%
Puget Sound Energy	30%	32%
BANC	26%	25%
Tucson Electric	26%	30%
WAPA - Desert SW	19%	24%
Powerex	16%	20%
Seattle City Light	14%	23%
Tacoma Power	14%	18%
Turlock ID	13%	14%
Average	36%	39%

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

11.2.2 RSE uncertainty special issue — time horizon for predicting uncertainty

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

The resource sufficiency evaluation uses exactly the same underlying historical data to perform the regressions and calculate uncertainty as the flexible ramping product in the 15-minute market.[214] This data is based on the difference from advisory forecasts in the 15-minute market to the corresponding binding forecasts in the 5-minute market. The regressions use this data to produce hourly coefficients that define the relationship between the forecasts and uncertainty. This calculation reflects 45 to 55 minutes in which uncertainty may materialize between the applicable 15-minute and 5-minute market runs.

However, the resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 11.5 illustrates the timeframe of uncertainty considered for the flexible ramping product in the 15-minute market, and how it compares with the timeframe of the resource sufficiency evaluation.[215] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the resource sufficiency evaluation considers forecast information from *four* 15-minute intervals within an hour. When comparing the forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute market intervals, there exists a larger gap of time for uncertainty to materialize.

In comparing the first 15-minute test interval of the RSE to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty to materialize is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. However, in the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes. The current determination of the regression coefficients for predicting net load uncertainty for the resource sufficiency evaluation (based on short-term historical data) does not capture the increased net load uncertainty associated with the longer-term horizon of this market process.[216]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 11.6 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized

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

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

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

uncertainty from the forecasts considered in the resource sufficiency evaluation to the 5-minute market forecasts fell within the calculated uncertainty requirement for the same interval. The calculated uncertainty covered the realized uncertainty much less for intervals at the end of the hour compared to the beginning of the hour because the current calculation is not designed to capture uncertainty that can realize over a longer-term horizon.

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

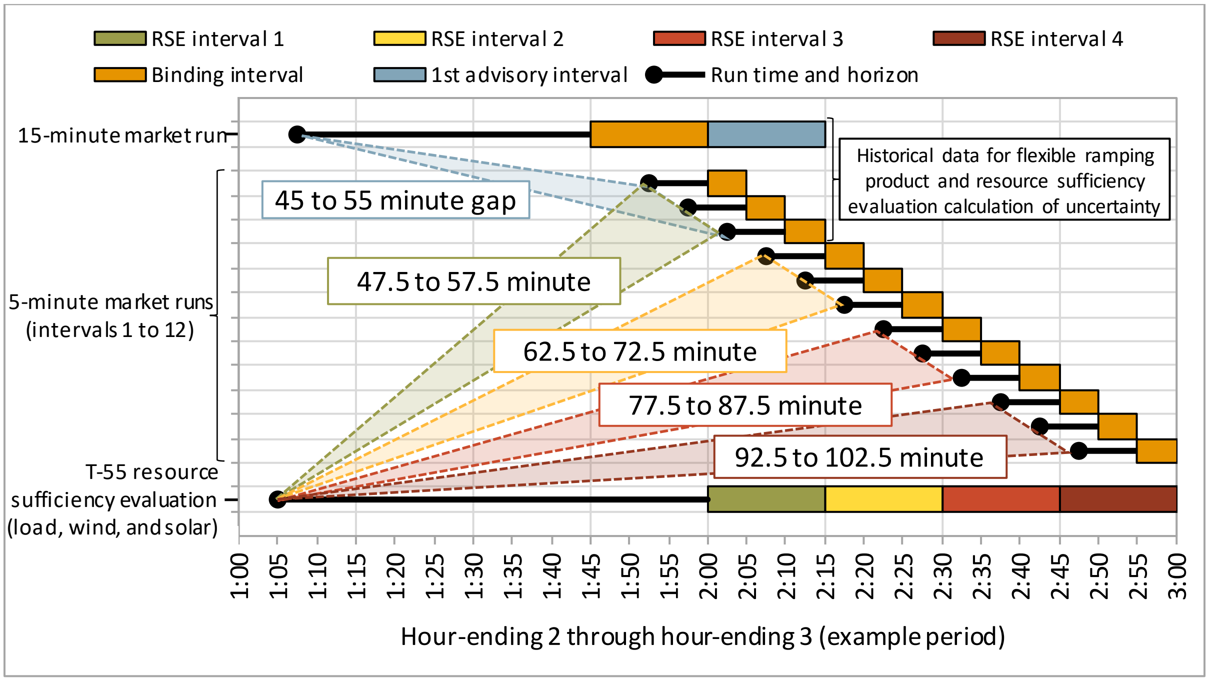
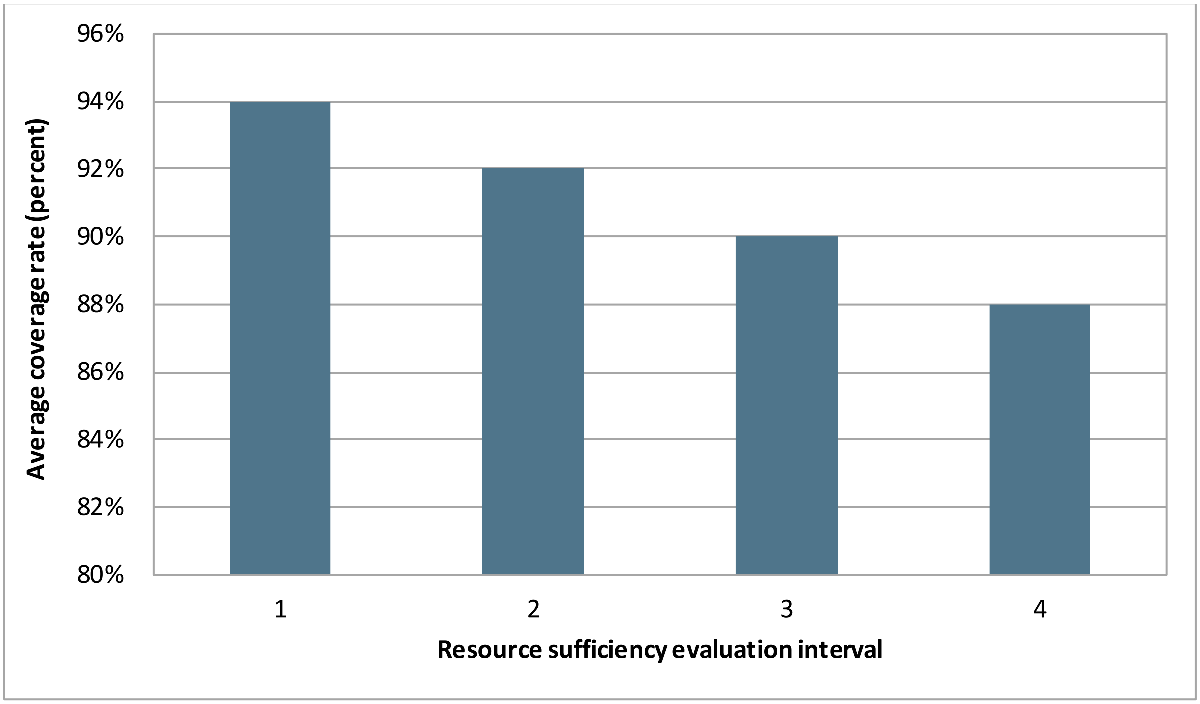


Figure 11.6 Average coverage rate by resource sufficiency evaluation interval (2025)



11.3 Residual unit commitment uncertainty

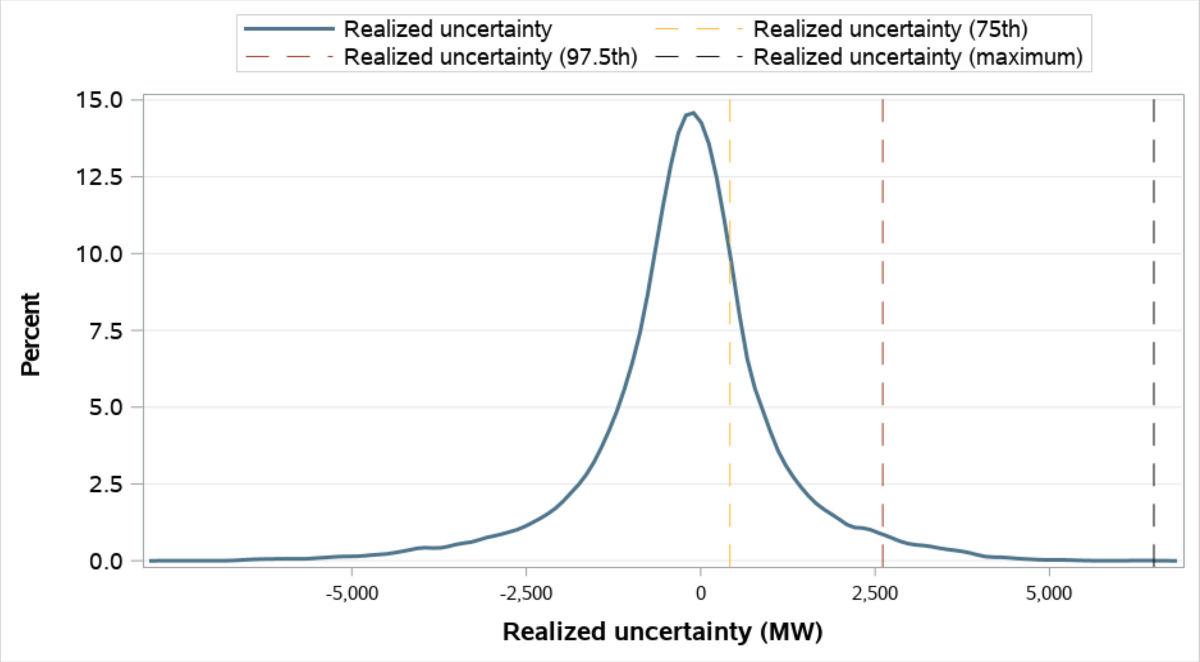
Uncertainty is often added to the residual unit commitment (RUC) target load requirement. This adjustment is used to ensure there is sufficient capacity to account for uncertainty that may materialize between the day-ahead and real-time markets. For the residual unit commitment market adjustment, uncertainty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

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

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

Figure 11.7 shows this year’s distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. This distribution represents all uncertainties observed in the 15-minute market intervals for 2025 and serves as the forecasting target. The first notable feature is that net load uncertainty in the day-ahead time horizon ranged from -7,600 MW to 6,500 MW. The distribution shows a long tail, with the area between the red dashed line and the black dashed line highlighting the range from the 97.5th percentile of uncertainty up to the maximum value. This area ranged from 2,600 MW to 6,500 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

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



11.3.1 Results of uncertainty calculation for residual unit commitment

Figure 11.8 shows the average RUC adjustment on each day, across all hours.[217] The figure also shows the estimated percentile that was used to determine the additional requirements for the peak hours of each day.[218] During the year, the 97.5th percentile target was applied on 4 percent of days. The 75th percentile target was applied on 11 percent of days while the 50th percentile target was applied on 33 percent of days. No adjustment was applied on the remaining 52 percent of days. The frequency of these elected percentiles were similar to the previous year.

Figure 11.9 adds the number of hours in which the adjustment was applied. Adjustments are generally applied for either all hours, mid-day hours (roughly 16 hours), or peak morning and evening hours

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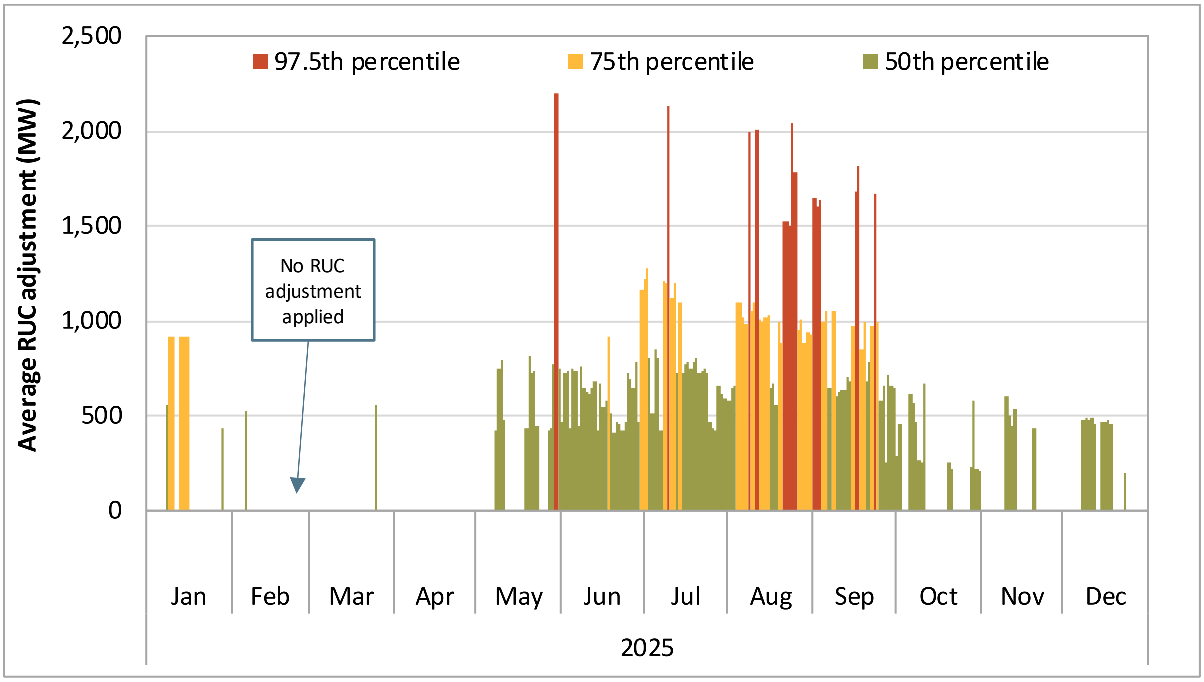
[217] In the hours when no adjustment is applied, the residual unit commitment adjustment for uncertainty is 0 MW, resulting in a lower daily average.

[218] 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.

(roughly six or seven hours).[219] During the year, the regression-based adjustment was applied to the mid-day hours in 35 percent of days and the peak hours in 13 percent of days.[220] The adjustment was never applied to all 24 hours.

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty that the RUC load adjustment was intended to address prior to EDAM. However, after an initial period of being set to cover the 90th percentile of uncertainty, the ISO will assess if it will set the requirement to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in the residual unit commitment uncertainty adjustment prior to EDAM implementation indicates that the imbalance reserve product demand curve may be much too high during most hours.

Figure 11.8 Average residual unit commitment adjustment by day



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

[220] Mid-day hours were typically between hours 7 and 22 (16 hours). Peak hours were only the peak morning and evening hours (typically 6 hours).

Figure 11.9 Average residual unit commitment adjustment and applied hours by day

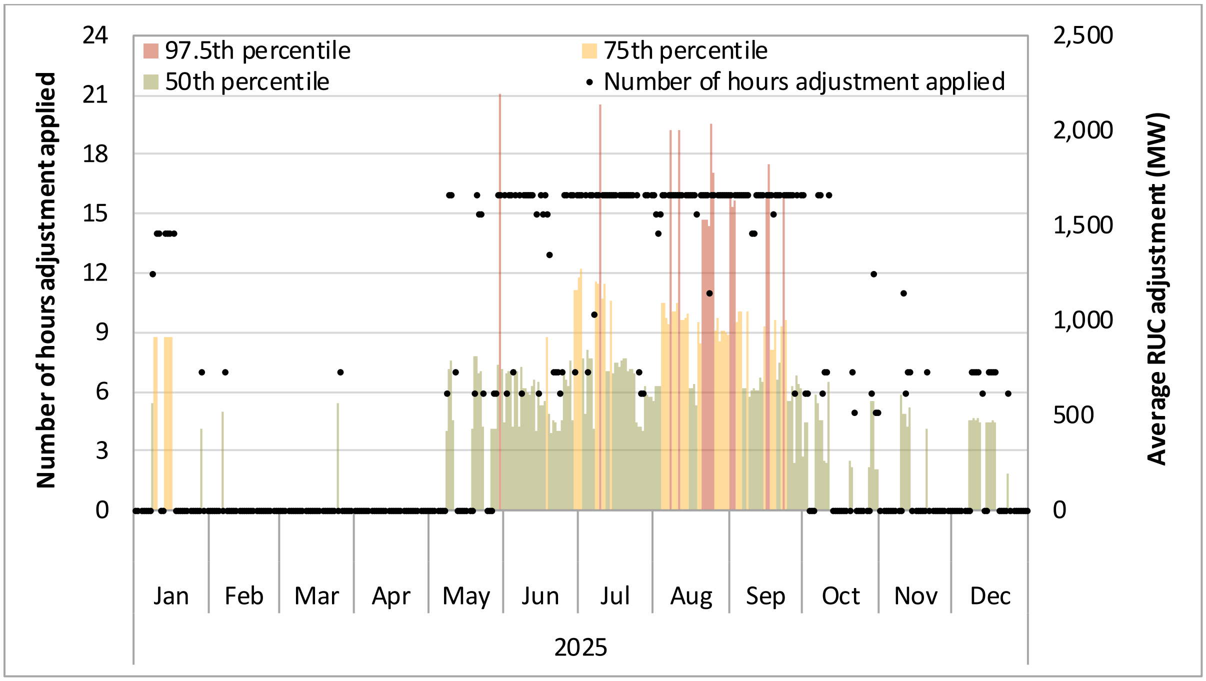

Table 11.5 summarizes the average requirement and coverage based on the percentile target that was selected and the hours it was applied (either mid-day hours or peak hours). Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to the real-time market was below the RUC adjustment quantity. The average requirement and coverage were assessed only in hours the uncertainty adjustment was applied. Average requirements using the 97.5th percentile target were significantly higher than those using the 75th percentile target while coverage was higher.

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

Percentile target	Hours applied	Number of days	Percent of days	Average requirement (MW)	Coverage
97.5th percentile	Mid-day hours	15	4%	2,732	98%
75th percentile	Mid-day hours	41	11%	1,558	89%
50th percentile	Mid-day hours	71	19%	1,052	79%
	Peak hours	48	13%	1,538	81%

Table 11.6 represents DMM’s simulation of the RUC adjustment using the mosaic quantile regression. It provides insight into the different percentiles used in the market and illustrates the likely outcomes if a specific percentile were applied to forecast the RUC adjustment.

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

The 97.5th percentile regression showed only one percent of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[221] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in only one percent of statistical significance.

The coverage rates for regression were notably inflated. For example, the 50th percentile regression, designed to capture 50 percent of realized uncertainty, showed coverage rates of 74 percent and 79 percent during peak hours.

This inflation arises from two key factors. First, while the realized uncertainty represents the difference between day-ahead and 15-minute net load forecasts, available as four uncertainty realizations per hour, the regression model forecasts the maximum uncertainty for each hour. This discrepancy inflated the result. As shown in Figure 11.7, the realized uncertainty distribution indicated the 50th percentile value was around -150 MW, meaning that a -150 MW requirement would effectively achieve 50 percent coverage. However, the 50th percentile regression averaged around 700 MW (as shown in Table 11.6). This means that the regression is producing about 850 MW more than ideal, due to the practice of forecasting the maximum uncertainty per hour. Second, the regression in RUC estimates only the upper bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

Table 11.6 DMM simulation for RUC adjustment using mosaic quantile regression (2025)

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours(1)	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,224	2,857	1%	2%	98%	99%
Replication (75th)	1,212	1,842	24%	47%	88%	90%
Replication (50th)	697	1,311	36%	57%	74%	79%
Replication (25th)	183	760	38%	53%	55%	64%

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

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

12 Ancillary services

This chapter analyzes ancillary services for balancing areas in the day-ahead market (CAISO) and available balancing capacity for balancing areas participating only in the WEIM. Key findings in this chapter include the following:

- **Ancillary service costs decreased to $94.5 million,** down from $106.5 million in 2024.
- **Regulation up, regulation down, and operating reserve requirements increased compared to 2024**. Regulation up requirements increased 7 percent to 470 MW, while regulation down requirements increased 3 percent to 960 MW and operating reserves increased 1 percent to 1,630 MW.
- **Despite increasing ancillary service requirements, day-ahead prices for upward ancillary services declined in 2025.** Day-ahead prices for regulation down increased compared to 2024. Real-time ancillary service prices increased for most products in 2025, although the majority of procurement and costs continued to occur in the day-ahead market.
- **Provision of ancillary services from battery resources continued to increase, replacing procurement from natural gas resources.** Average hourly procurement of ancillary services from battery resources increased by 9 percent compared to 2024, and batteries now provide 53 percent of CAISO balancing area ancillary service requirements.
- **There were eleven ancillary service scarcity events in 2025.** Each event occurred for regulation down in the expanded region north of Path 26 in the first five months of the year. There were zero intervals with ancillary service scarcities in 2024, two in 2023, and six in 2022.
- **Seven percent of resources failed** unannounced ancillary service performance audits and compliance tests, compared to 12 percent in 2024, 15 percent in 2023, and 22 percent in 2022.
- **Most EIM entities offered available balancing capacity into the market throughout 2025.** However, available balancing capacity was rarely dispatched to resolve capacity insufficiencies.

The California ISO ancillary service market design includes co-optimizing energy and ancillary service bids provided by each resource in the day-ahead market. With co-optimization, units are able to bid all of their capacity into the energy and ancillary service markets without risking the loss of revenue in one market when their capacity is sold in the other. Co-optimization allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services in both the day-ahead and real-time markets. A detailed description of the ancillary service market design is provided in DMM's 2010 annual report.[222]

12.1 Ancillary service requirements and procurement

The California ISO procures four ancillary services for its balancing authority area in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.[223] Ancillary service 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

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[222] *2010 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2011, pp 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf

[223] In addition, in June 2013, the California ISO added a performance payment—referred to as mileage—to the regulation up and down markets, in addition to the existing capacity payment system.

Electric Reliability Corporation's (NERC) control performance standards. The CAISO attempts to procure all ancillary services in the day-ahead market to the extent possible.

The CAISO 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. The expanded regions are identical to the corresponding internal regions but include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are all nested within the system and corresponding expanded regions. Therefore, ancillary services procured in a more inward region also count toward meeting the minimum requirement of the wider outer region. Ancillary service requirements are then met by both internal resources and imports, where imports are indirectly limited by the minimum requirements from the internal regions.

Six of these regions are typically utilized: expanded system (or expanded CAISO), internal system, expanded South of Path 26, internal South of Path 26, expanded North of Path 26, and internal North of Path 26.

Regulation requirements

The California ISO calculates regulation requirements based on observed regulation needs during the same time period in the prior year and in the previous month. Requirements are calculated for each hour of the day on a monthly basis. Furthermore, the California ISO can adjust requirements manually for periods when conditions indicate higher net load variability.

Operating reserve requirements

Operating reserve requirements in the day-ahead market are typically set by the maximum of three factors: (1) 6.3 percent of the load forecast, (2) the most severe single contingency, and (3) 10 percent of forecasted solar production.[224] 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.[225] 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.

Historically, operating reserve requirements were split equally between spinning and non-spinning reserves. However, 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 all months after the procurement target

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[224] On June 8, 2017, the North American Electric Reliability Corporation published a report that found a previously unknown reliability risk related to a frequency measurement error that can potentially cause a large loss of solar generation. Only solar forecasts from resources that have the potential for the inverter issue are considered.

[225] Beginning January 1, 2018, operating reserve requirements account for the contingency of the loss of projected schedules on the Pacific DC Intertie sinking in the CAISO balancing area. The Federal Energy Regulatory Commission approved a set of requirements in BAL-002-2 (since replaced by BAL-002-3) that required the California ISO to reevaluate the most severe single contingency. Both poles of the Pacific DC Intertie were agreed upon as a credible multiple contingency that qualifies as a single event for the purpose of the most severe single contingency. Further information on the NERC BAL-002-3 reliability standard is available here: https://www.nerc.com/globalassets/standards/reliability-standards/bal/bal-002-3.pdf.

changed, CAISO operators procured 20 percent of operating reserves as spinning reserves, and the rest as non-spinning reserves.

Figure 12.1 shows average ancillary service requirements by quarter. Regulation up requirements averaged 470 MW in 2025, a 7 percent increase from 2024, and regulation down requirements averaged 960 MW, a 3 percent increase. Total operating reserve requirements (spinning and non-spinning reserves) in the day-ahead market averaged 1,630 MW in 2025, compared to 1,610 MW in 2024.

Figure 12.1 Quarterly average day-ahead ancillary service requirements

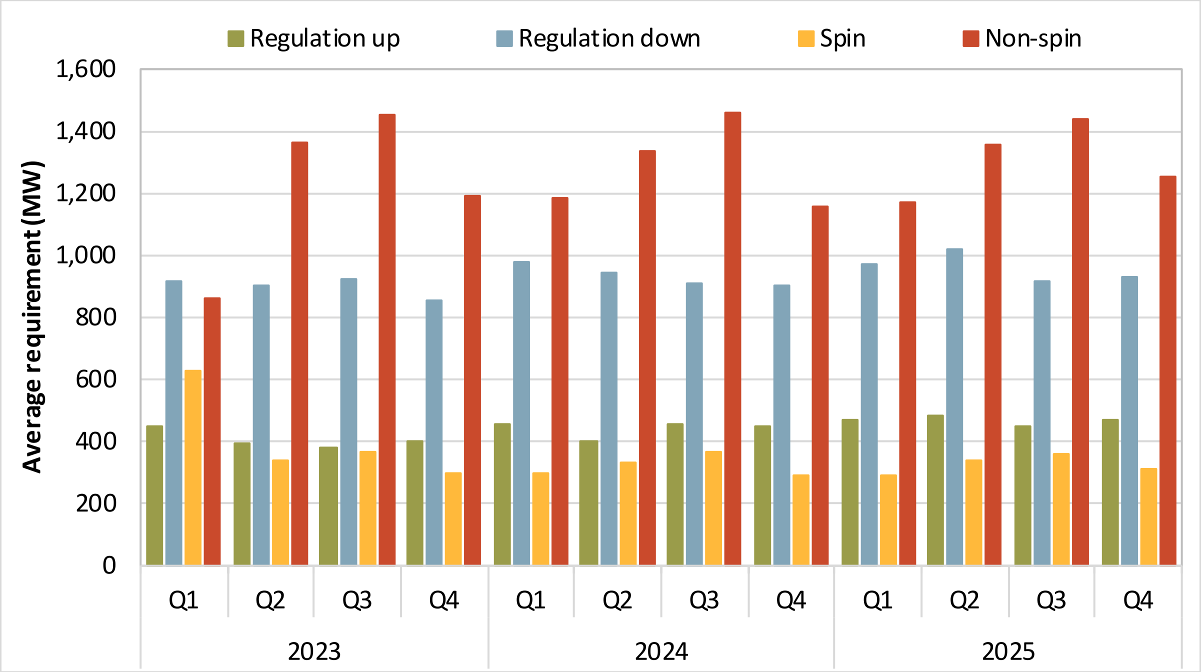
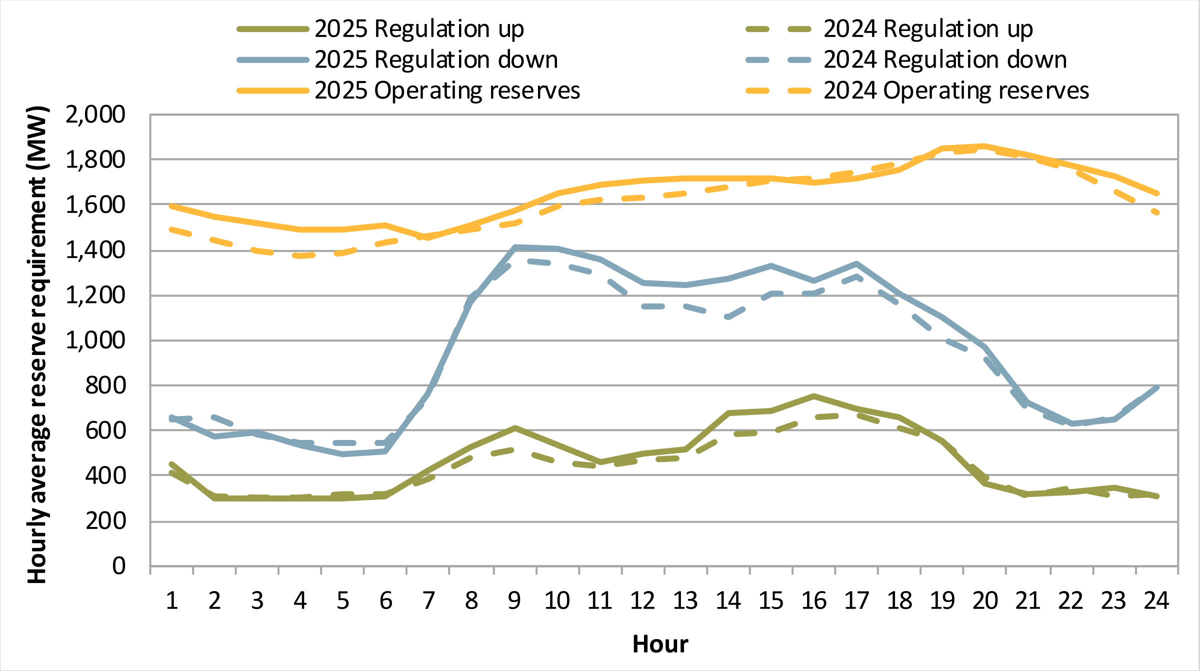


Figure 12.2 summarizes the average hourly profile of the day-ahead ancillary service requirements in 2024 and 2025. Average hourly requirements for regulation up and down both peaked during ramping hours, while operating reserve requirements peaked in the evening hours. Regulation up requirements increased most notably during afternoon ramping hours, while regulation down requirements were highest during morning ramping periods.

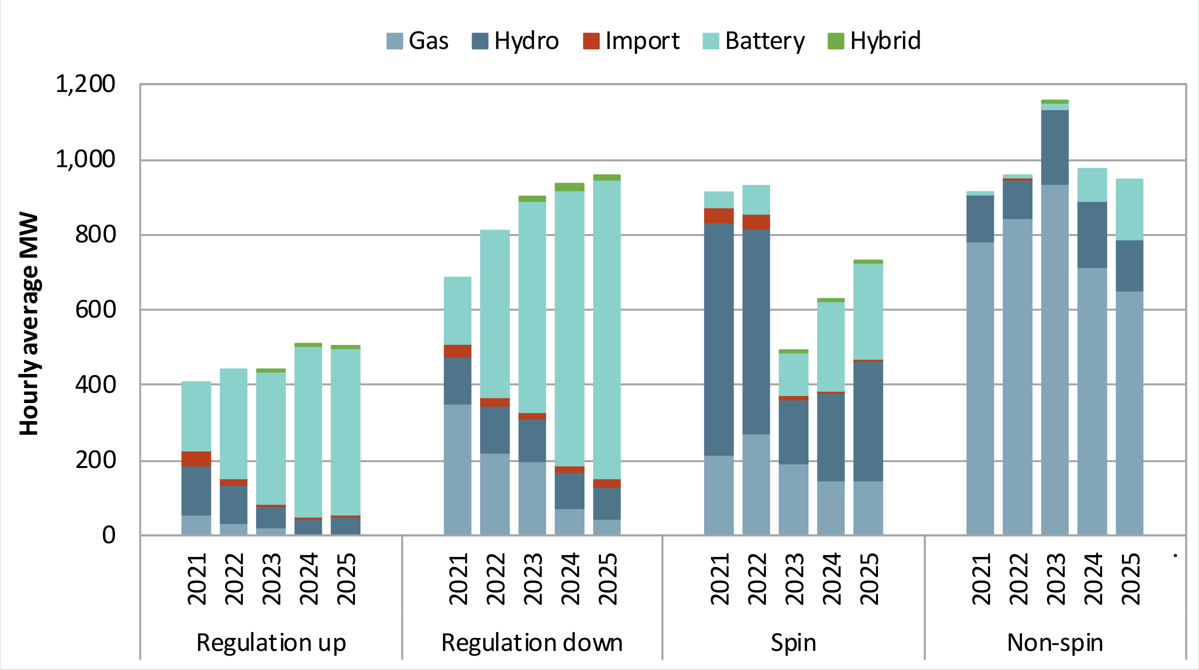
Figure 12.2 Hourly average day-ahead ancillary service requirements



Ancillary service procurement by fuel

Figure 12.3 shows the portion of ancillary services procured by fuel type from 2021 through 2025. Ancillary service requirements are met by both internal resources and imports (tie generation), which are indirectly limited by minimum requirements set for the procurement of ancillary services from within the CAISO system. In addition, ancillary services that bid across interties have to compete for transmission capacity with energy. Most ancillary service requirements continue to be met by California ISO resources.

Figure 12.3 Ancillary service procurement by fuel type



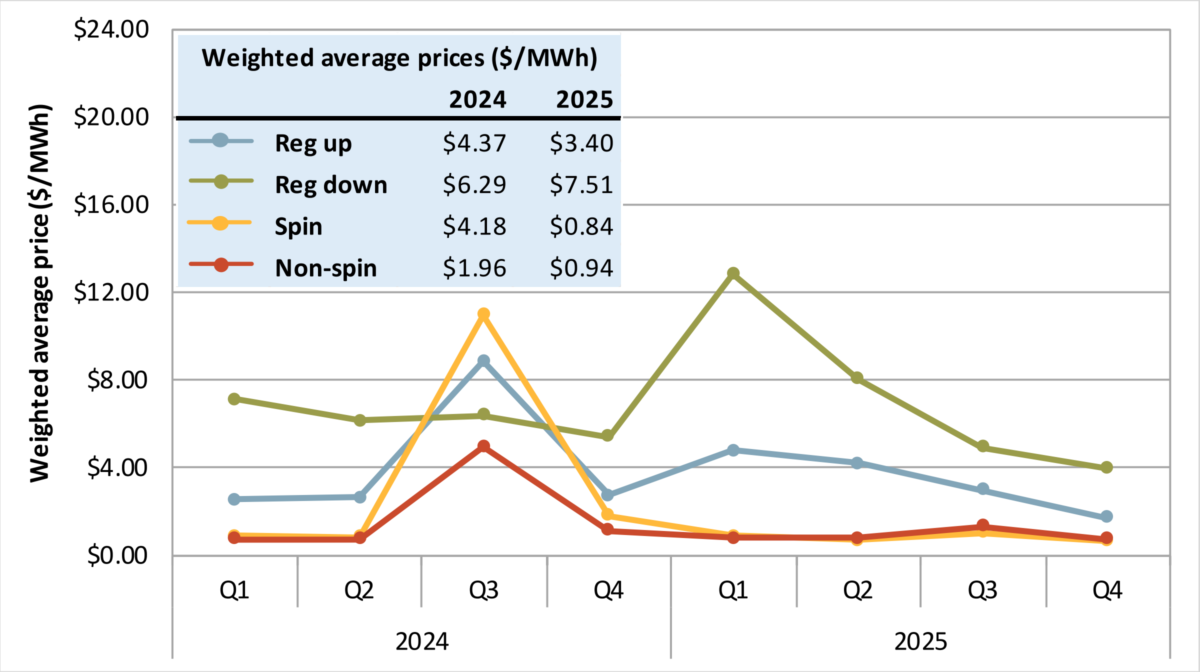
As in previous years, the vast majority of required ancillary service capacity was supplied by a mix of CAISO gas, hydroelectric, and battery resources. Battery participation continued to rise, with average ancillary service hourly procurement increasing from 400 MW (14 percent) in 2021 to 1,650 MW (53 percent) in 2025. Average ancillary service procurement from gas resources dropped from 31 percent in 2024 to 27 percent in 2025, while those procured by hydroelectric resources remained the same. Hourly average ancillary service procurement served by imports was 35 MW compared to 27 MW in 2024. Battery resources provided the majority of ancillary service capacity in 2025, reflecting their increasing role in supplying fast-response balancing services.

12.2 Ancillary service pricing

Resources providing ancillary services receive a capacity payment at market clearing prices in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 12.4 and Figure 12.5 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2024 and 2025, weighted by the quantity settled.

As shown in Figure 12.4, weighted average day-ahead prices for all upward ancillary service products (spinning reserve, non-spinning reserve, and regulation up) decreased compared to 2024, despite small increases in requirements. In contrast, regulation down prices increased from an average of about $6.30/MWh in 2024 to $7.50/MWh in 2025, a 19 percent increase. This increase was due in part to large battery outages that occurred in Northern California in January 2025. Because battery resources provide the majority of regulation down, these outages led to higher prices as the market adjusted to the reduction in available battery capacity.

Figure 12.4 Day-ahead ancillary service market clearing prices

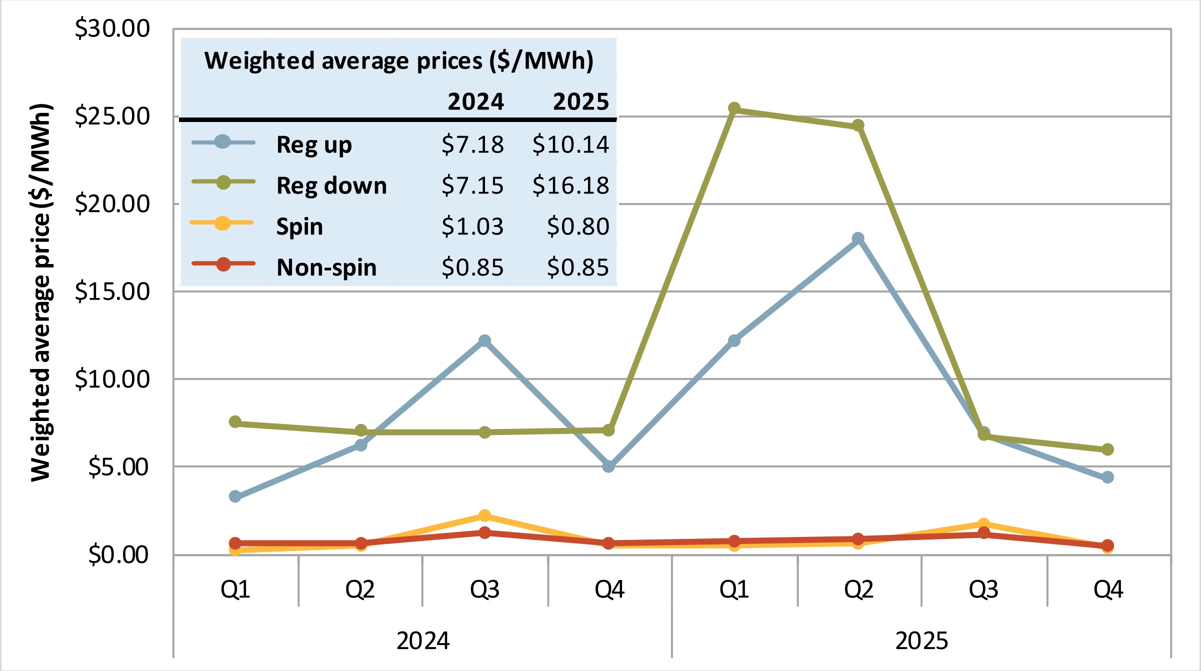


Weighted average prices ($/MWh)

	2024	2025
Reg up	$4.37	$3.40
Reg down	$6.29	$7.51
Spin	$4.18	$0.84
Non-spin	$1.96	$0.94

Figure 12.5 shows that the weighted average prices for ancillary services increased for most products in the real-time market. In general, ancillary service costs are largely determined by day-ahead market prices since most ancillary services are procured in the day-ahead market. In 2025, only 10 percent of ancillary service costs were incurred in the real-time market.

Figure 12.5 Real-time ancillary service market clearing prices



12.3 Ancillary service costs

The costs reported in this section account for rescinded ancillary service payments—penalties incurred when resources providing ancillary services do not fulfill the availability requirement associated with the awards. The ISO rescinded about 5.7 percent of ancillary service payments in 2025.

Costs for ancillary services totaled about $94.5 million in 2025, a decrease from $106.5 million in 2024.

Figure 12.6 shows ancillary service costs both as percentage of wholesale energy costs and per megawatt-hour of load from 2021 to 2025. The cost per megawatt-hour decreased from $0.52 in 2024 to $0.47 in 2025. Ancillary service costs as a percentage of energy costs also decreased slightly from 1.2 percent in 2024 to 1.1 percent in 2025.

Figure 12.6 Ancillary service cost as a percentage of wholesale energy costs (2021–2025)

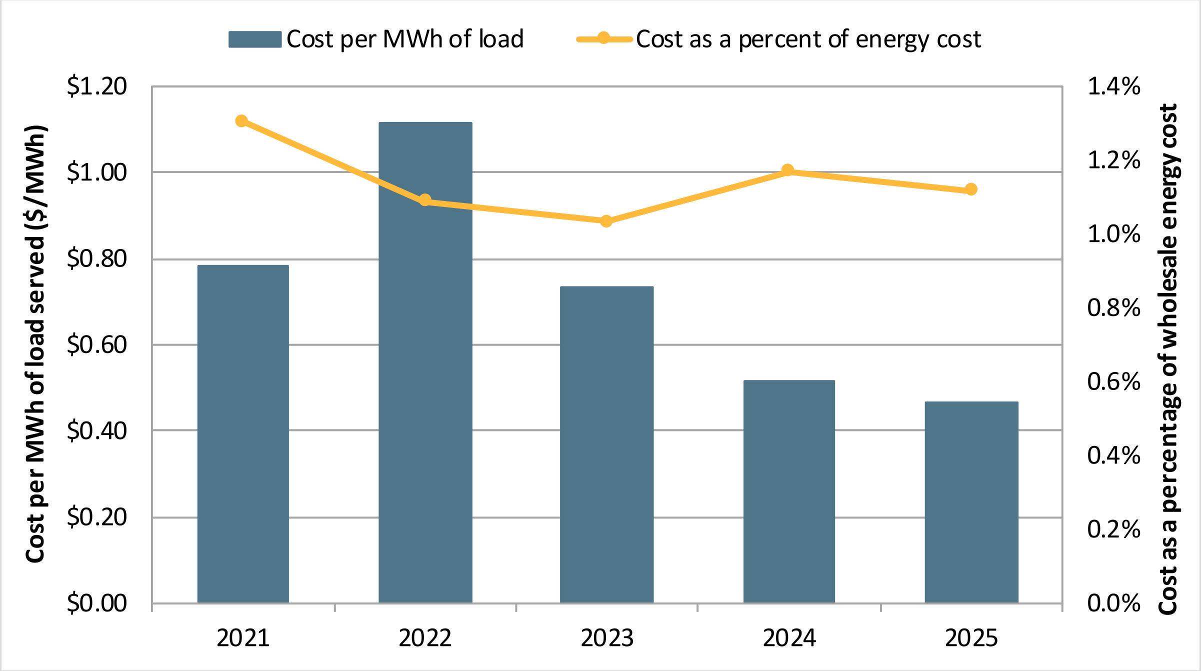
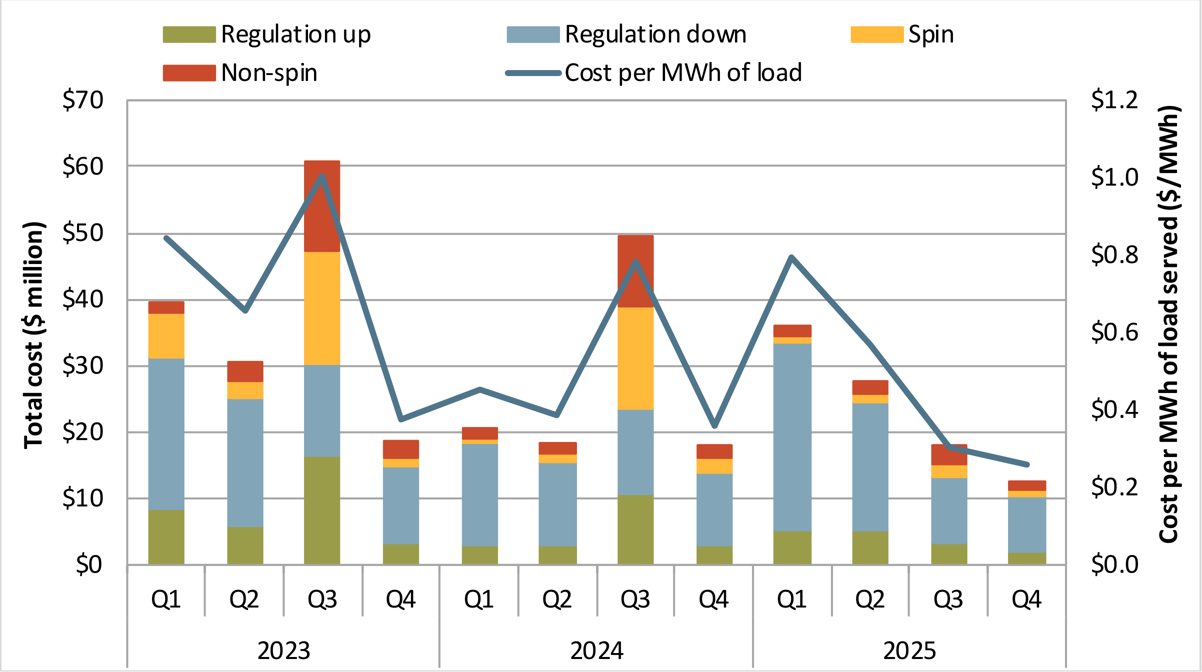


Figure 12.7 shows the total cost of procuring ancillary service products by quarter, as well as the total ancillary service cost for each megawatt-hour of load served. In previous years, ancillary service costs were typically highest in the third quarter, corresponding with summer peak loads.

In 2024, payments for regulation down, regulation up, spinning reserves, and non-spinning reserves decreased by 24 percent, 42 percent, 29 percent, and 27 percent, respectively. Of all ancillary service products, regulation down costs had the largest decrease in absolute terms, at around $16 million less than what was paid in 2023.

Figure 12.7 shows the total cost of procuring ancillary service products by quarter, as well as the total ancillary service cost for each megawatt-hour of load served. In contrast to previous years, when ancillary service costs peaked during high summer loads in the third quarter, total ancillary service costs in 2025 were highest in the first quarter, driven by increased regulation down costs. Regulation down costs increased by about $14.5 million, up 28 percent from 2024. Payments for regulation up, spinning reserves, and non-spinning reserves decreased by 19 percent, 74 percent, and 52 percent, respectively, in 2025. Of all ancillary service products, spinning reserve costs had the largest decrease in absolute terms, falling by about $14.7 million compared to what was paid in 2024.

Figure 12.7 Total ancillary service cost by quarter and type



Similar to past years, the value of self-provided ancillary services was less than 1 percent of the total cost of ancillary services in 2025. Scheduling coordinators are assigned a share of the ancillary service requirement based on their metered demand. The cost of procuring ancillary services is charged to demand using a system-wide user rate, based on the average cost of procuring each type of ancillary service. Scheduling coordinators may self-provide all or a portion of their obligation. Scheduling coordinators pay the remainder of their obligation, less their self-provided quantity. The value of self-provided ancillary services is the reduction in obligation costs, totaling around $194,000 in 2025.

12.4 Special issues

12.4.1 Ancillary service scarcity

Ancillary service scarcity pricing occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the CAISO balancing authority area pays a pre-determined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

There were eleven scarcity events in 2025, six in February, one in April, and four in May, compared to zero scarcity events in 2024. Each event occurred for regulation down in the expanded region north of Path 26 and were likely driven by the previously noted large battery outages in Northern California.

12.4.2 Ancillary service compliance testing

Resources may be subject to two types of testing: performance audits and compliance tests. A performance audit occurs when a resource is flagged for failing to meet dispatch during a contingency run. The compliance test is an unannounced test when a resource is called upon to produce energy at a time when it is scheduled to hold reserves. Failing either of these tests results in a warning notice. Failing a second test, while a warning is in effect, will immediately disqualify the resource from providing the relevant ancillary service. In addition, payments that were made to the resource for the impacted ancillary service will be rescinded.[226]

During 2025, the California ISO performed a combined total of 835 performance audits and unannounced compliance tests for resources holding ancillary services, which was an increase from the 715 tests performed in 2024. The failure rate was 7 percent for unannounced tests, an improvement over 12 percent in 2024. The failure rate for performance tests was 2 percent in 2025.

12.5 Available balancing capacity

Available balancing capacity (ABC) allows for market recognition and accounting of capacity that WEIM participants have available for reliable system operations, but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each WEIM entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO’s system software to deploy such capacity through the market, and prevents market infeasibilities that may arise without the availability of this capacity.[227]

Table 12.1 and Table 12.2 summarize the annual frequency of upward and downward available balancing capacity, both offered and scheduled, in each area during 2025.[228] Similar to 2024, around half of the WEIM participants offered upward and downward available balancing capacity in at least 95 percent of hours or greater. However, Avangrid, El Paso Electric, Idaho Power, LADWP, Portland General Electric, PSC New Mexico, Puget Sound Energy, and Seattle City Light offered available balancing capacity in less than 10 percent of hours for one or both directions. The table also shows the average size of the available balancing capacity when offered in their hourly resource plan. Similar to previous years, Powerex offered an average of 1,159 and 599 MW of upward and downward available balancing capacity, respectively, during 2025.

Overall, available balancing capacity was dispatched very infrequently for scarcity conditions during 2025. Scheduling of available balancing capacity occurred in less than one percent of intervals across all balancing areas, indicating that this capacity was rarely needed to address system conditions.

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[226] For more information about the California ISO ancillary service testing procedures including updates to regulation performance audits, see *Operating Procedure 5370*, California ISO: http://www.caiso.com/Documents/5370.pdf

[227] FERC Docket No. ER15-861-006, *Order on Compliance Filing – Available Balancing Capacity*, December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf

[228] Dispatched available balancing capacity without scarcity pricing in the scheduling run is omitted from this table. In some cases, a resource may be required to cross the operational range where available balancing capacity is defined, therefore “scheduling” it in the real-time market without scarcity conditions.

Table 12.1 Frequency of upward available balancing capacity offered and scheduled (2025)

		Offered		Scheduled	
		Percent of hours	Average MW	Percent of intervals (15-min.)	Percent of intervals (5-min.)
California	BANC	99.8%	85	.0%	.0%
	LADWP	72.6%	56	.0%	.0%
	Turlock Irrigation District	99.8%	15	.0%	.0%
Desert Southwest	Arizona Public Service	99.8%	95	.1%	.1%
	El Paso Electric	14.2%	25	.0%	.0%
	NV Energy	96.6%	70	.0%	.1%
	PSC New Mexico	.0%	N/A	.0%	.0%
	Salt River Project	99.6%	99	.2%	.4%
	Tucson Electric	99.8%	33	.1%	.1%
	WAPA - Desert Southwest	10.7%	15	.0%	.0%
Intermountain West	Avista Utilities	99.8%	10	.0%	.0%
	Idaho Power	.0%	N/A	.0%	.0%
	NorthWestern Energy	98.5%	5	.1%	.1%
	PacifiCorp East	85.5%	99	.0%	.0%
Pacific Northwest	Avangrid	99.8%	59	.0%	.0%
	Powerex	99.8%	1,159	.0%	.0%
	Bonneville Power Admin.	99.8%	320	.0%	.1%
	PacifiCorp West	25.3%	28	.0%	.0%
	Portland General Electric	99.1%	30	.0%	.0%
	Puget Sound Energy	.0%	N/A	.0%	.0%
	Seattle City Light	.0%	N/A	.0%	.0%
	Tacoma Power	88.1%	9	.0%	.0%

Table 12.2 Frequency of downward available balancing capacity offered and scheduled (2025)

		Offered		Scheduled	
		Percent of hours	Average MW	Percent of intervals (15-min.)	Percent of intervals (5-min.)
California	BANC	99.8%	101	.0%	.0%
	LADWP	.2%	101	.0%	.0%
	Turlock Irrigation District	99.8%	5	.0%	.0%
Desert Southwest	Arizona Public Service	99.8%	95	.0%	.0%
	El Paso Electric	.0%	N/A	.0%	.0%
	NV Energy	84.5%	67	.0%	.0%
	PSC New Mexico	32.9%	42	.0%	.0%
	Salt River Project	98.5%	50	.1%	.1%
	Tucson Electric	99.8%	34	.0%	.0%
	WAPA - Desert Southwest	10.8%	15	.0%	.0%
Intermountain West	Avista Utilities	99.8%	10	.0%	.0%
	Idaho Power	.0%	N/A	.0%	.0%
	NorthWestern Energy	98.4%	5	.0%	.0%
	PacifiCorp East	98.8%	198	.0%	.1%
Pacific Northwest	Avangrid	.0%	N/A	.0%	.0%
	Powerex	99.8%	599	.0%	.1%
	Bonneville Power Admin.	99.8%	335	.0%	.1%
	PacifiCorp West	67.9%	53	.0%	.0%
	Portland General Electric	.2%	36	.0%	.0%
	Puget Sound Energy	.0%	N/A	.0%	.0%
	Seattle City Light	.0%	N/A	.0%	.0%
	Tacoma Power	94.6%	6	.0%	.0%

13 Residual unit commitment

This chapter provides information on residual unit commitment (RUC) requirements, procurement volume, costs, and undersupply infeasibilities. Further analysis of the method used to determine adjustments to the RUC load forecast to address uncertainty between day-ahead and real-time net load is in Chapter 11 on Uncertainty.

Highlights of this chapter include:

- **Increases in residual unit commitment requirements in 2025 were primarily driven by higher net virtual supply.** Operator adjustments declined significantly from 2024 levels but remained elevated during the third-quarter.
- **The average volume of capacity procured through the residual unit commitment process was 440 MW, up 15 percent from 2024.** The volume of procured capacity in 2024 decreased 47 percent compared with 2023.
- **The total direct cost of non-resource adequacy capacity procured in the residual unit commitment process decreased to about $1.1 million in 2025**, from a direct cost of about $1.6 million in 2024.
- **There was enough supply to meet the residual unit commitment requirement in all intervals in 2025.**

Background

The purpose of the residual unit commitment process is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment (RUC) process is run directly after the integrated forward market run (IFM) of the day-ahead market. The RUC process procures sufficient capacity to bridge the gap between the amount of physical supply cleared in the IFM run and the day-ahead forecast load. Capacity procured through residual unit commitment must be bid into the real-time market.

13.1 Residual unit commitment requirement adjustments

Figure 13.1 shows the average hourly determinants of capacity requirements used in the residual unit commitment process by quarter in 2024 and 2025.

The residual unit commitment process includes an automated adjustment to account for the need to replace net virtual supply clearing in the integrated forward market (IFM) run of the day-ahead market, which can offset physical supply in that run. The automated adjustment for net virtual supply, shown in the green bars in Figure 13.1, was the largest positive contributor to residual unit commitment requirements in 2025. Average residual unit commitment requirements due to net virtual supply increased to 840 MW in 2025 from 427 MW in 2024.

California ISO operators can also make adjustments to increase the amount of residual unit commitment requirements above the day-ahead load forecast. These are made to address uncertainty in load and supply between the day-ahead market and real-time markets. These adjustments, shown in the red bars in Figure 13.1, contributed an average of 370 MW per hour to the requirements in 2025, a decrease of about 43 percent from 656 MW per hour in 2024. These adjustments were largest in the third quarter.

The blue bars in Figure 13.1 show the portion of the residual unit commitment requirement that is calculated based on the difference between cleared supply (both physical and virtual) in the IFM run of the day-ahead market and the CAISO day-ahead load forecast. This represents the difference between the CAISO day-ahead load forecast and the physical load that cleared the IFM. This difference increased residual unit commitment requirements by about 220 MW on a yearly average basis in 2025, down from about 240 MW in 2024.

The residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of 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. This automated adjustment is represented by the yellow bars in Figure 13.1.

Figure 13.1 Determinants of residual unit commitment procurement

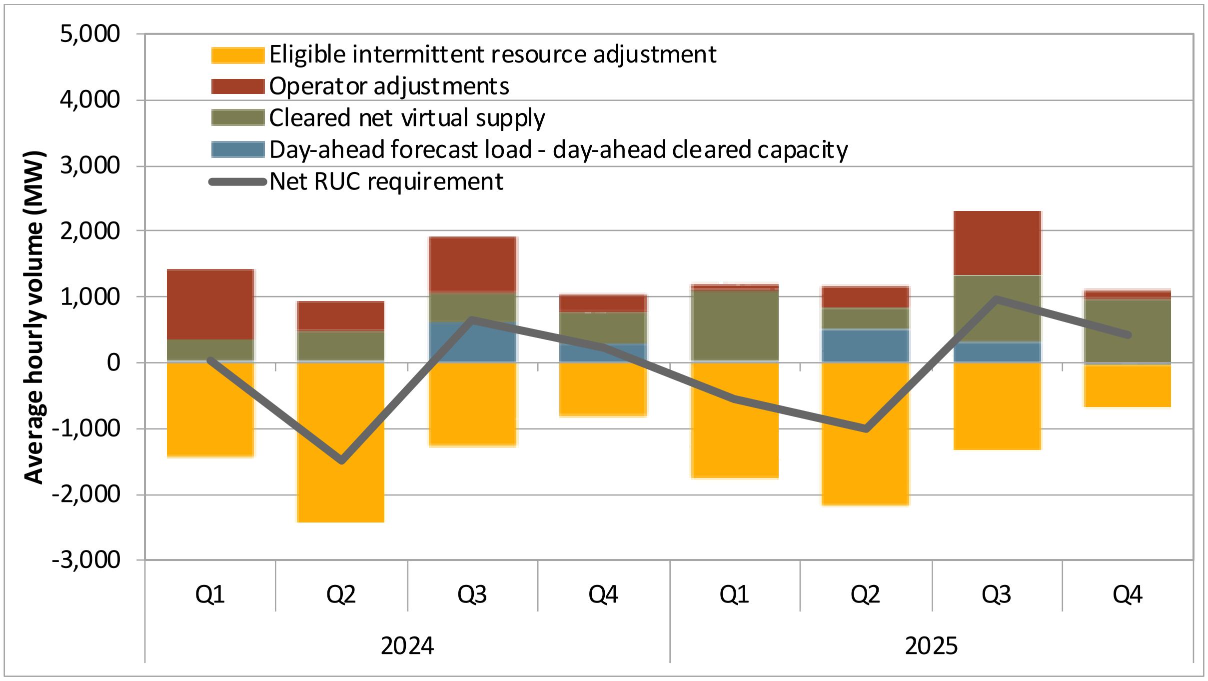
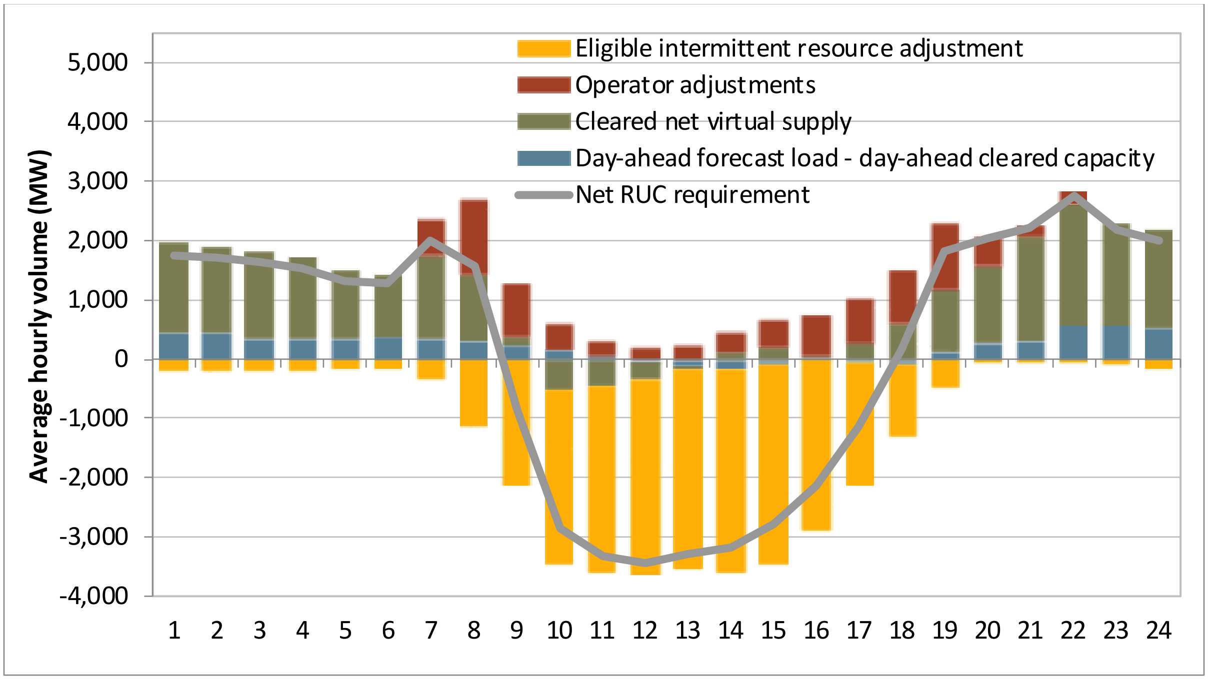


Figure 13.2 shows these same four determinants of the residual unit commitment requirements for 2025 by hour. As shown by the red bars, adjustments to the requirement by grid operators did not occur in the off-peak hours of 1 to 6, as well as 23 and 24. Generally, adjustments occur throughout the mid-day period but tend to be greatest in the morning and evening solar ramp periods.

Net virtual supply was a major driver of residual unit commitment procurement across most hours, including off-peak hours. On average, day-ahead load forecast was greater than day-ahead cleared capacity (i.e., cleared IFM load) during all hours except 12 through 18 in 2025. Similar to 2024, the bulk of the intermittent resource adjustments occurred in hours-ending 8 to 19.

Figure 13.2 Average hourly determinants of residual unit commitment procurement (2025)



13.2 Residual unit commitment procurement and costs

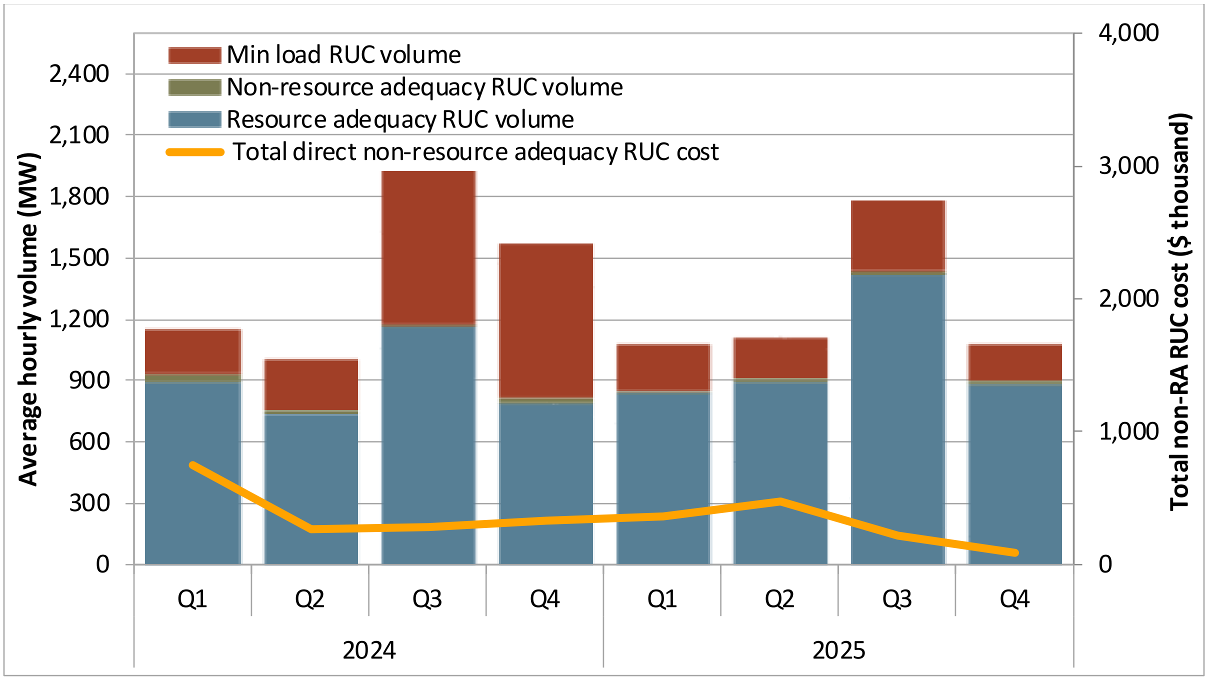
Figure 13.3 shows average hourly volume of capacity procured in the residual unit commitment process by quarter for 2024 and 2025. The blue bars show RUC capacity procured from resource adequacy resources. The green bars show non-resource adequacy capacity procured in RUC, and the red bars show the amount of RUC procurement from resources' minimum load.

The total volume of capacity procured in the residual unit commitment process increased moderately in 2025 compared to 2024. The average hourly RUC procurement was 440 MW in 2025, up 15 percent from the 385 MW average hourly procurement in 2024. For comparison, RUC procurement volume decreased 47 percent from 2023 to 2024. This large decrease in 2024 was due to significant changes the CAISO balancing area made in its procedures for determining adjustments to RUC load forecasts to address load and supply uncertainty.

Some of the capacity procured by the residual unit commitment process in excess of the integrated forward market schedules comes from resources' minimum load levels. This is represented by the red bars in Figure 13.4. Minimum load capacity procured in RUC averaged about 280 MW in 2025, up from about 240 MW in 2024. Most of this capacity is from short-start units that do not need to receive a binding startup instruction from the RUC process. The real-time markets can issue these units startup instructions if they are ultimately needed in real-time. Only long-start units without IFM schedules are actually committed to be on-line by the residual unit commitment process.[229] In 2025, about 5 percent of the 280 MW of minimum load capacity procured in RUC was from long-start units, up from 4 percent in 2024.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs because only awards to non-resource adequacy capacity resources receive RUC capacity payments.[230] As shown by the small green segment of each bar in Figure 13.3, the non-resource adequacy volume averaged about 19 MW per hour in 2025, down from about 24 MW procured in 2024. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in the same figure, decreased to about $1.1 million in 2025, from a direct cost of about $1.6 million in 2024.

Figure 13.3 Residual unit commitment (RUC) costs and volume (2024–2025)



13.3 Residual unit commitment undersupply infeasibilities

In 2025, the residual unit commitment undersupply power balance constraint was feasible in all intervals compared to nine hours on five separate days in 2024. This indicates that there was sufficient

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[229] Long-start units are resources with a cycle time of more than 255 minutes (Start-Up Time plus Minimum Run Time is more than 255 minutes) and require between five and up to 18 hours to start up and synchronize to the grid. The definition can be found in Appendix A of the ISO Fifth Replacement Electronic Tariff: https://www.caiso.com/documents/appendixa-masterdefinitionsupplement-asof-jan1-2024.pdf. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, but the actual unit commitment decision for these units occurs in real-time.

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

supply available to meet residual unit commitment requirements throughout 2025, with no instances requiring relaxation of the power balance constraint.

In cases where there is not sufficient supply in the residual unit commitment process (RUC) to meet the load requirement and self-scheduled exports, the power balance constraint can be relaxed. This results in RUC prices being set by a penalty price. The situation is called an undersupply infeasibility.

In September 2020, the California ISO revised the residual unit commitment process to address the treatment of economic and self-scheduled exports that clear the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to adjust procurement of economic and lower priority self-scheduled exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds the California ISO real-time load, and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[231]

Effective August 4, 2021, further changes were implemented to designate self-schedule exports as either a low or high priority export. High-priority price taking (PT) exports are those supported by non-resource adequacy capacity, while low-priority price taking (LPT) exports are not.[232] High priority exports receive equal priority to CAISO balancing area load. All low-priority exports that clear the residual unit commitment process will be prioritized below internal load. In addition, the California ISO will prioritize low priority exports that bid into the day-ahead market and clear the residual unit commitment process over new low priority exports that self-schedule into the real-time market.

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[231] The California ISO provided details and examples of this change in the *Market Performance and Planning Forum* meeting on September 9, 2020: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum

[232] Additional information and analysis on market changes implemented in August 2021 is provided in: *Q3 2021 Report on Market Issues and Performance,* Department of Market Monitoring, December 9, 2021, pp 94-102: http://www.caiso.com/Documents/2021-Third-Quarter-Report-on-Market-Issues-and-Performance-Dec-9-2021.pdf

14 Convergence bidding

Convergence bidding is designed to align day-ahead and 15-minute market prices by allowing financial arbitrage between the two markets. Throughout 2025, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. Convergence bidding was profitable on an annual basis and in every month of 2025.

Other key findings in this chapter include:

- **Annual profits paid to convergence bidders totaled about $58.6 million** after accounting for $22.0 million in bid cost recovery charges allocated to virtual bids, an increase of about $8.2 million from 2024. Convergence bidders lost $12.1 million from virtual demand, and virtual supply earned $92.7 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 840 MW per hour,** compared to 430 MW in 2024. The percent of bid-in virtual supply and demand clearing was around 55 percent, an increase from about 50 percent in 2024.
- **Financial entities and marketers continued to earn the most profits from virtual bidding,** receiving about 88 percent and 11 percent of positive net revenues, respectively. Load serving entities lost money from virtual positions overall. Physical generators received just under 2 percent of positive net revenues.
- **Financial participants held the majority of cleared virtual positions (about 81 percent) throughout 2025**, continuing a multi-year trend. As with previous years, financial participants bid more virtual supply than demand.

14.1 Convergence bidding revenues

Historically, net convergence bidding revenues have been positive for most months in a given year. In 2025, net convergence bidding revenues were positive for all months. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $80.5 million, compared to $62.8 million in 2024. Net revenues for virtual supply and demand increased to $58.6 million from about $50.4 million in 2024, after accounting for bid cost recovery charges associated with virtual supply.[233]

Figure 14.1 shows total monthly net revenues for virtual supply (green bars), total net 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 (black line). Virtual supply generated positive net revenues in most months, while virtual demand generated net losses in most months, and bid cost recovery charges consistently reduced total convergence bidding revenues.

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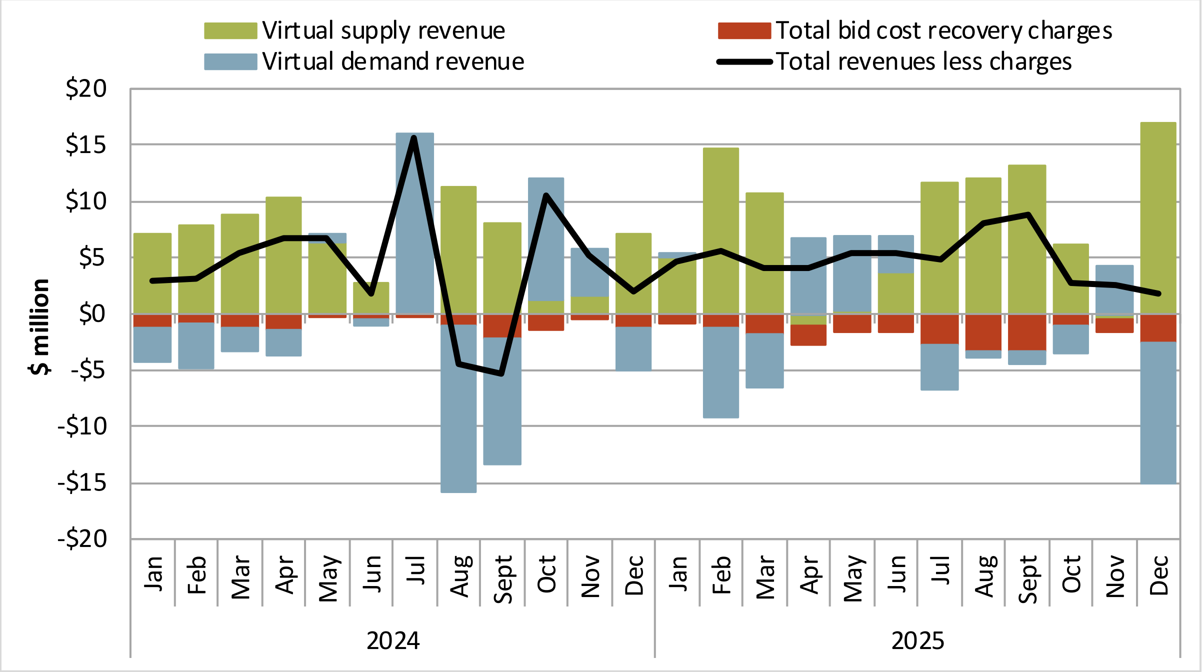
[233] For more information on how bid cost recovery charges are allocated, please refer to: *Q3 2017 Report on Market Issues and Performance*, Department of Market Monitoring, December 8, 2017, pp 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf

Figure 14.1 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 14.1 compares the distribution of convergence bidding cleared volumes and net revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[234,235]

Following a trend from past years, most virtual bidding was conducted by entities engaging in purely financial trading that do not serve load or transact physical supply. Financial entities and marketers accounted for about 82 percent and 10 percent, respectively, of the cleared volume of virtual trades in 2025. The quantity of cleared virtual bids increased 46 percent from 2024 due to increased participation from all types of entities.

After accounting for bid cost recovery, financial entities received about 88 percent of the total revenue earned from convergence bidding.

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[234] 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.

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

Table 14.1 Convergence bidding volumes and revenues by participant type – 2025 vs. 2024

Trading entities	Average hourly megawatts			Revenues/losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2025								
Financial	4,268	4,726	8,994	-$9.58	$75.27	-$14.02	$61.25	$51.67
Marketer	528	604	1,133	-$1.28	$9.56	-$1.57	$7.99	$6.71
Physical load	56	142	198	-$.64	$1.75	-$2.05	-$.30	-$.94
Physical generation	249	444	693	-$.62	$5.70	-$3.98	$1.72	$1.10
BAA	0	22	22	$0.00	$.37	-$.36	$.01	$.01
Total	**5,101**	**5,938**	**11,040**	**-$12.12**	**$92.65**	**-$21.98**	**$70.67**	**$58.55**

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								
Financial	2,997	3,259	6,256	-$3.43	$62.62	-$9.39	$53.23	$49.80
Marketer	420	460	880	-$4.83	$7.14	-$.92	$6.22	$1.39
Physical load	44	93	137	-$.18	$1.61	-$.93	$.68	$.50
Physical generation	100	176	275	-$1.63	$1.50	-$1.18	$.32	-$1.31
BAA	0	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**3,561**	**3,988**	**7,548**	**-$10.07**	**$72.87**	**-$12.42**	**$60.45**	**$50.38**

15 Congestion revenue rights

Background

Congestion revenue rights (CRRs) are paid (or charged) for each megawatt held, based on the difference between the hourly day-ahead congestion prices at the sink and source node defining the revenue right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices.

Congestion revenue rights are either allocated or auctioned to market participants. Participants serving load are allocated rights monthly, annually (with seasonal terms), or for 10 years (for the same seasonal term each year). All participants can procure congestion revenue rights in the auctions. Annual auctions are held prior to the year in which the rights will settle; rights sold in the annual auctions have seasonal terms. Monthly auctions are held the month prior to the settlement month; rights sold in the monthly auction have monthly terms.[236]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. Allocating congestion revenue rights is a means of distributing the congestion rent to entities serving load, to then be passed on to ratepayers. Any congestion rent remaining after the distribution to allocated congestion revenue rights are allocated based on load share, or are used to pay congestion revenue rights procured at auctions. In exchange for backing the auctioned rights, ratepayers receive the net auction revenue, which is allocated by load share.

Congestion revenue right holdings

Figure 15.1 shows the congestion revenue right megawatts by allocated, seasonally auctioned, and monthly auctioned rights; this figure includes all peak and off-peak rights. In 2025 the share of allocated congestion revenue rights was about 54 percent of the total megawatts held. Auctioned rights were about 46 percent of total CRRs. As shown in the figure, in 2019, the quantity of auctioned CRRs reduced significantly compared to prior years. This was because of the Track 1A changes implemented for the 2019 auction. These Track 1A changes limited allowable source and sink pairs to “delivery path” combinations.

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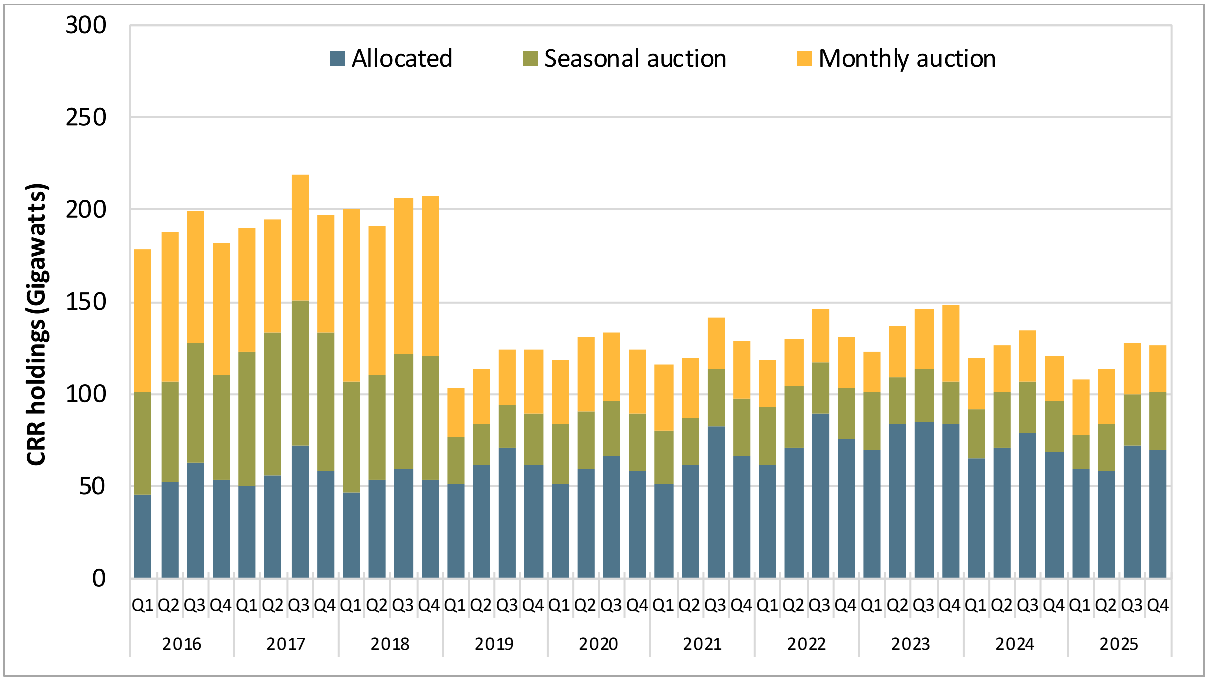
[236] For a more detailed explanation of the congestion revenue right processes, see *Business Practice Manual Change Management, Congestion Revenue Rights*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Congestion%20Revenue%20Rights

Figure 15.1 Congestion revenue rights held by procurement type (2016–2025)[237]



Allocated congestion revenue right sales and payment

Figure 15.2 shows the total allocated CRRs and the portion of those allocated CRRs sold by load serving entities each year, evaluated by notional dollar payment.[238] In 2025, the total payouts to allocated CRRs amounted to $448 million, with load serving entities selling $161 million—representing 36 percent of the total allocated CRR revenue. Over the past four years, load serving entities sold an average of 27 percent of their allocated CRRs—24 percent in 2024, 27 percent in 2023, and 22 percent in 2022.

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[237] Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs).

[238] Allocated CRRs exclude CAISO allocation holdings.

Figure 15.2 Annual summary of allocated CRRs and sales by load serving entities

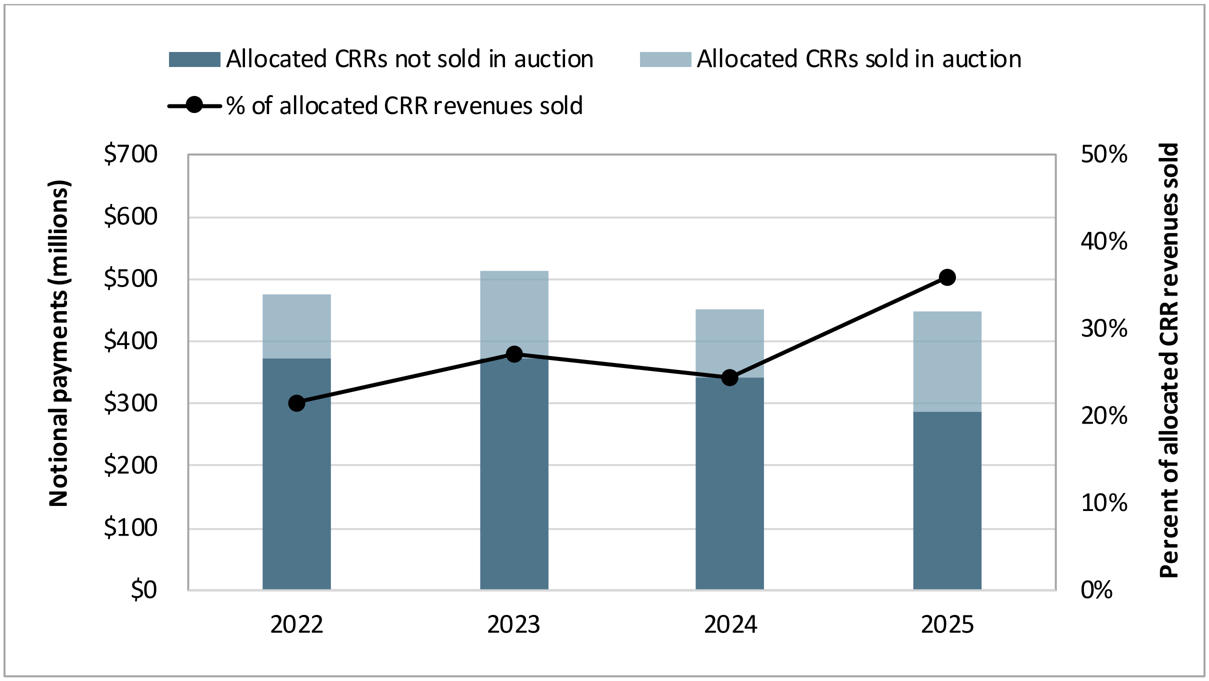

Figure 15.3 compares the total notional payment of allocated CRRs for LSEs with day-ahead congestion rent.[239] Allocated CRR notional payment represents the estimated payments associated with allocated CRRs, based on day-ahead market prices. Results are shown quarterly from the third quarter of 2020 through the fourth quarter of 2025.

Over this period, allocated CRR notional payments totaled $2,444 million, compared with $2,898 million in day-ahead congestion rent. The difference, or revenue surplus, was $455 million. Allocated CRR notional payments accounted for about 84 percent of day-ahead congestion rent, while revenue surplus accounted for 16 percent of the rent.

In 2025, allocated CRR notional payment totaled $448 million, compared with $487 million in day-ahead congestion rent, resulting in a revenue surplus of $39 million.

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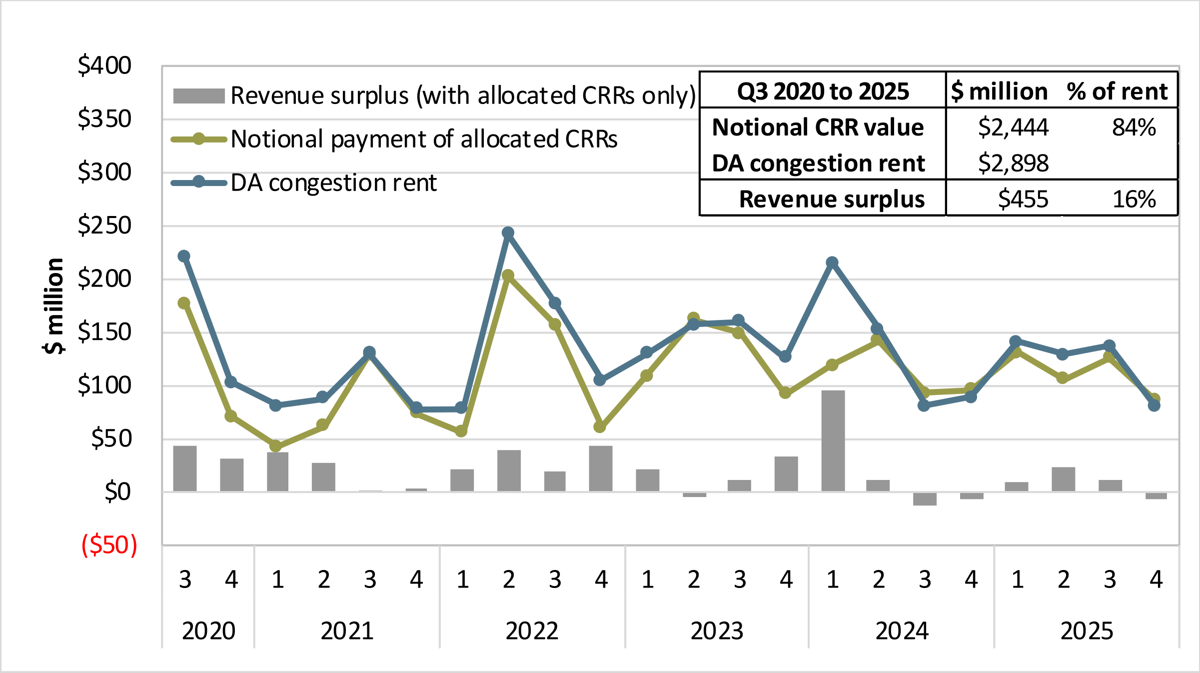
[239] Allocated CRRs exclude CAISO allocation holdings.

Figure 15.3 Quarterly total notional payment of allocated CRRs and day-ahead congestion rent



Congestion revenue rights auction results

In response to persistent ratepayer losses since the auction began, the California ISO instituted significant changes to the auction starting in the 2019 settlement year.[240] These changes include the following:

- **Track 0** – Increasing the number of constraints enforced by default in the congestion revenue right models, identifying potential enforcement of "nomogram" constraints in the day-ahead market to include in the congestion revenue right models, and other process improvements.[241]
- **Track 1A** – Limiting allowable source and sink pairs to "delivery path" combinations.[242]

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[240] For further information, see *Shortcomings in the congestion revenue right auction design*, DMM whitepaper, November 28, 2016: http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-Congestion RevenueRightAuctionDesign.pdf.

[241] *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, California ISO, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

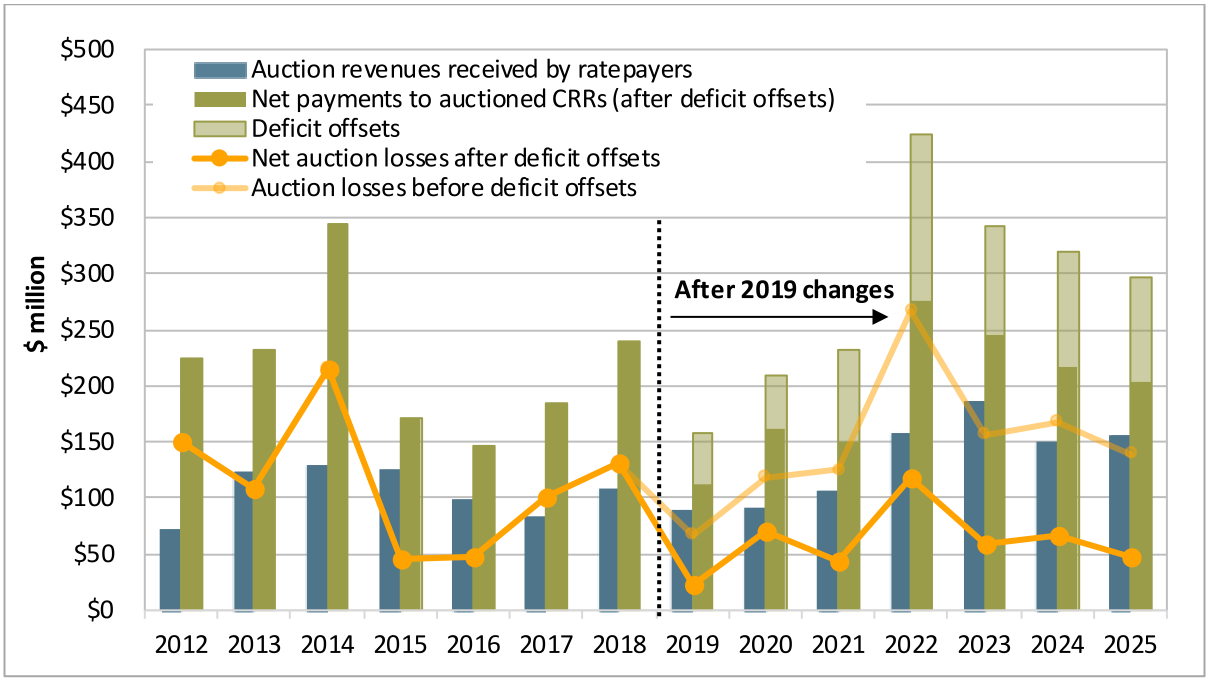
[242] *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, California ISO, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

- **Track 1B** – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[243]

The performance of the congestion revenue rights auction from the perspective of ratepayers can be assessed by comparing the revenues received for auctioning transmission rights to the day-ahead congestion payments to these rights. Figure 15.2 compares the following for each of the last several years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars).[244]
- Net payments made to the non-load serving entities purchasing congestion revenue rights in auction (green bars).
- Deficiency offsets are the amount that reduce payments to CRR holders when congestion rents are not enough to cover those payments, as implemented under Track 1B reforms (transparent portion of green bars and yellow line).
- Total ratepayer losses are the difference between auction revenues received and payments made to non-load serving entities (yellow line).

Figure 15.4 Auction revenues and payments to non-load serving entities



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

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

In 2025, ratepayer auction losses were around $47.6 million, or about 10 percent of day-ahead market congestion rent. Ratepayers received an average of 77 cents in auction revenue per dollar paid to auctioned congestion revenue rights holders. Track 1B revenue deficiency offsets reduced payments to non-load serving entity auctioned rights by about $92 million.

Figure 15.2 also illustrates revenues, payments, and losses in the absence of Track 1B reforms (transparent green bars and yellow line). Without the implementation of the revenue deficiency offset, payments to auctioned CRRs would have totaled $296 million in 2025, resulting in about $140 million in losses to ratepayers.

With the implementation of the constraint specific allocation of revenue inadequacy offsets to congestion revenue rights holders, under the Track 1B changes, it is not possible to know precisely how much of the ratepayer losses are from the ISO sales (through the auction transmission model) versus load serving entity trades. This is because it is not possible to directly tie the offsets actually paid by congestion revenue rights purchasers to the sales of specific congestion revenue rights. DMM has developed a simplified estimate of these offsets by estimating the notional revenue that would have been paid to the sold rights had they been kept, and applying the average ratio of offsets to notional revenues.

Figure 15.3 shows the estimated breakout of ratepayer auction losses by ISO sales (the blue bars) and load serving entity trades (the green bars). The losses are mostly from ISO sales. On net, DMM estimates that trades made by load serving entities (LSEs) increased ratepayer losses by $6.5 million in 2025 compared to decreasing losses by $20.5 million in 2024.

Figure 15.5 Estimated auction losses from CRRs offered by ISO and CRRs sold by LSEs

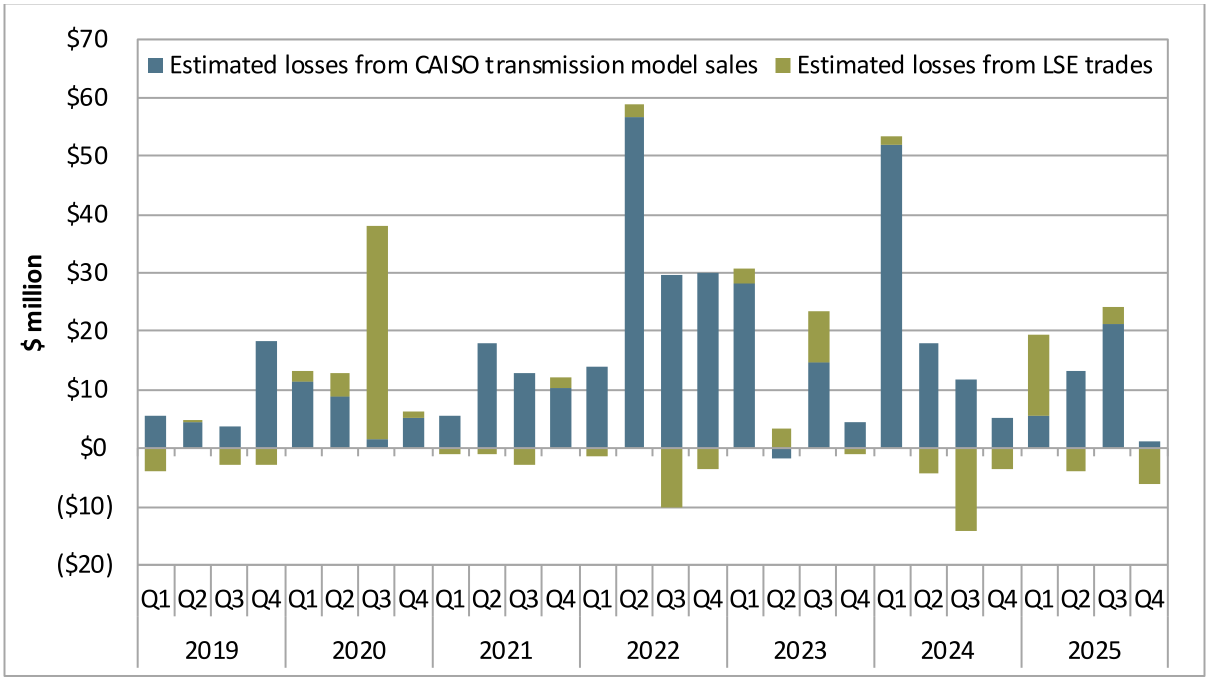

Figure 15.4 through Figure 15.6 compare the auction revenues paid and day-ahead market payments received from congestion revenue rights traded in the auction by market participant type.[245] The difference between auction revenues paid and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities received net revenues of about $41 million in 2025, up from $38 million in 2024. Total revenue deficit offsets were about $73 million.
- Marketers received net revenues of about $4 million from auctioned rights in 2025, down from $10 million in 2024. Total revenue deficit offsets were nearly $15 million.
- Physical generation entities received about $2 million in net revenue from auctioned rights in 2025, a significant decrease from about $18 million in 2024. Total revenue deficit offsets were about $4 million.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2025, physical generators as a group continued to account for a relatively small portion of congestion revenue rights held. Financial entities received the highest overall payments from congestion revenue rights.

DMM believes the current auction is fundamentally flawed and should be redesigned.[246,247] If the ISO believes it is beneficial to the market to facilitate hedging, the current auction format could be changed to a market for congestion revenue rights or locational price swaps, based on bids submitted by entities willing to buy or sell congestion revenue rights. DMM believes it would be more appropriate to design the auction so load serving entities will only enter obligations to pay other participants if they are actively willing to enter these obligations at the prices offered by the other entities. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase it directly from the load serving entities, financial entities, or other participants.

DMM's recommendations for redesign of the CRR auction are described in more detail in the Recommendations section of the Executive Summary of this report.

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[245] DMM has defined financial entities as participants who own no physical energy, and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the 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 ISO markets. Balancing authority areas are participants that are balancing authority areas outside the CAISO. With the exception of financial entities, the classification of the other groups is based on the primary function, but could include instances where a particular entity performs a different function. For example, a generating entity that has load serving obligations may be classified as a generator and not a load serving entity.

[246] *Problems in the performance and design of the congestion revenue right auction,* DMM whitepaper, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

[247] *Market alternatives to the congestion revenue rights auction,* DMM whitepaper, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

Figure 15.6 Auction revenues and payments (financial entities)

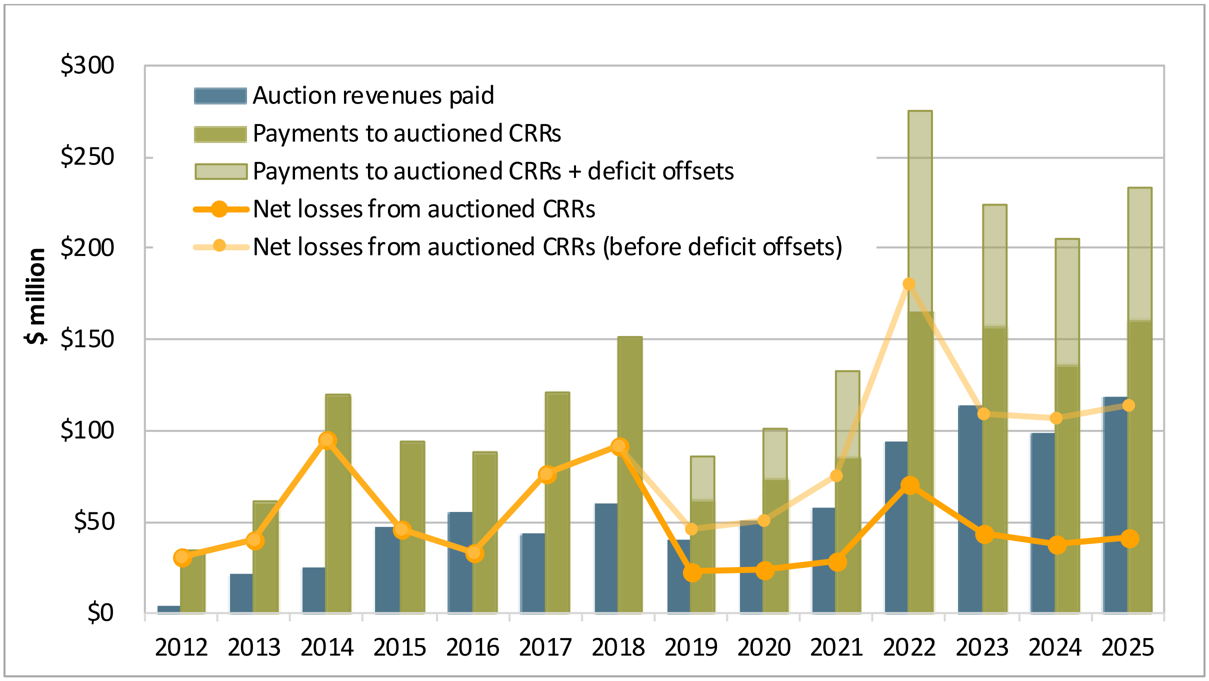


Figure 15.7 Auction revenues and payments (marketers)

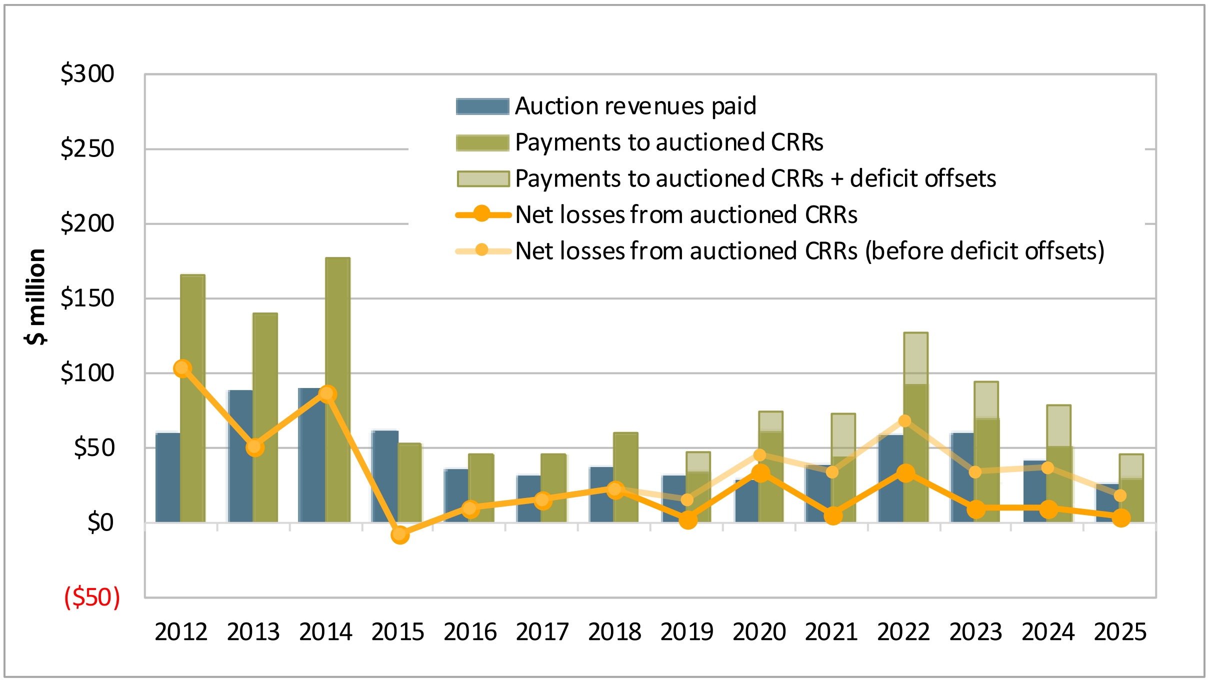
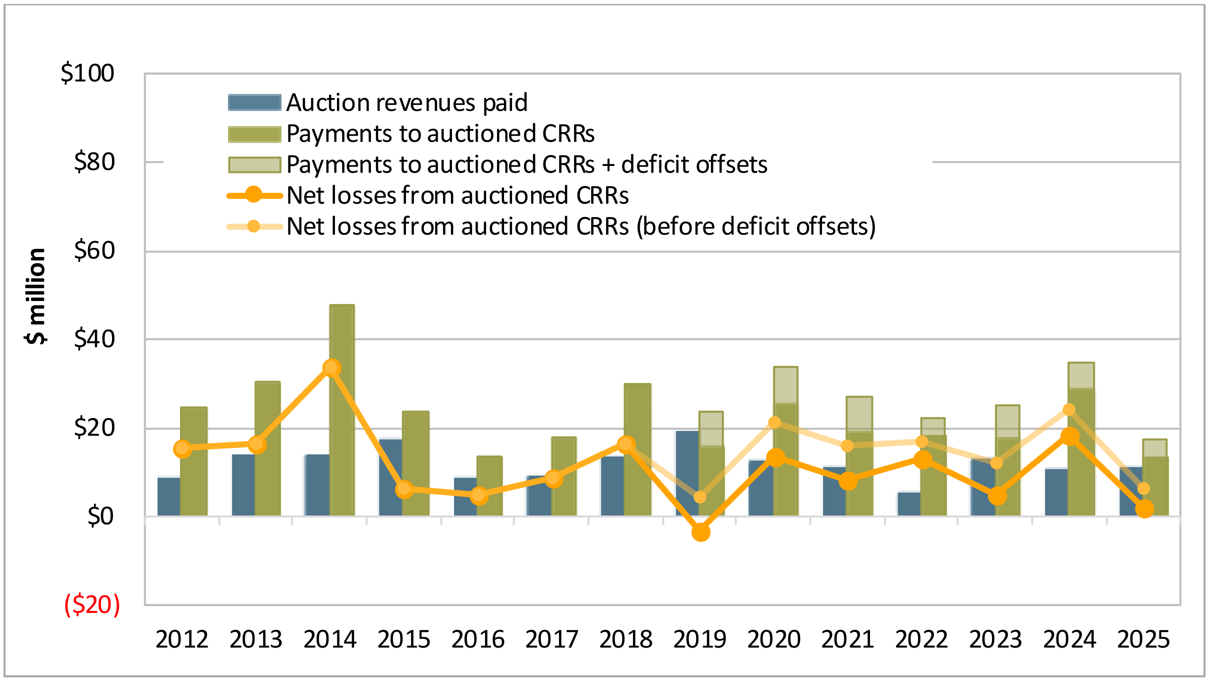


Figure 15.8 Auction revenues and payments (generators)



16 Resource adequacy

The purpose of the resource adequacy program is to ensure the California ISO balancing area has enough resources to operate the grid safely and reliably in real-time. Key findings in this chapter include:

- **The nameplate capacity of wind and solar grew the most out of any resource type in the CAISO balancing area, adding 4.1 GW and 2.6 GW, respectively, since June 2025**. This is a departure from batteries being the largest driver of new capacity over the past couple of years. The CAISO fleet currently has 16.8 GW of capacity from battery resources, which is an increase of around 2 GW from last year. Overall, nameplate capacity has had a net increase of 8.8 GW since June 2025. In comparison, CAISO added 5.7 GW of nameplate capacity from June 2024 to June 2025.
- **Between June 2025 and April 2026, only 360 MW of capacity withdrew from CAISO**. This was primarily driven by the loss of the batteries involved in the Moss Landing Power Plant fire in January 2025.
- **Four of the CAISO balancing area's local capacity areas were not structurally competitive** because there was at least one supplier that was pivotal and controlled a significant portion of capacity needed to meet local requirements.
- **Resource adequacy capacity provided sufficient coverage of annual instantaneous peak load.** The annual instantaneous peak load in 2025 reached 44,506 MW on August 21 during hour-ending 19. During that hour, the maximum 15-minute market CAISO balancing area load requirement including operating reserve (2,700 MW) and regulation up (690 MW) requirements was around 46,800 MW. Available capacity from resource adequacy resources in the real-time market exceeded 68,400 MW. This was sufficient to cover both the market requirement and the instantaneous peak load. This included solar, wind, and other schedules in excess of a resource's resource adequacy capacity.
- **There was only one California ISO restricted maintenance operation (RMO) emergency notification in 2025.** This event spanned 42 hours from January 20 to January 21. This was a significant decrease in hours from 2024, which had 332 hours.
- **Resource adequacy capacity was the most scarce during the spring months of 2025,** when the difference between resource adequacy capacity and market load was the lowest. Resource adequacy procurement requirements are the lowest during these months.
- **Capacity available after reported outages and de-rates was 95 percent in the day-ahead market and 93 percent in the real-time market for the analysis hours**. Average resource adequacy capacity was around 46,169 MW during this time.
- **Resources that are not availability-limited accounted for just 30 percent of system capacity.** About 13,804 MW of system capacity was subject to California ISO bid insertion during all hours. Gas-fired generation in this category made up about 12,860 MW (28 percent) of total resource adequacy capacity. Other generators accounted for around 2 percent.
- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 26,446 MW (57 percent) of system resource adequacy procurement, community choice aggregators contributed 24 percent, municipal utilities contributed 7 percent, and direct access services contributed 8 percent. The remaining percentage was a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Both year-ahead and actual flexible resource adequacy requirements were not sufficient to meet the actual maximum three-hour net load ramp for most months in 2025.** The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps

depends on the ability to predict the size and timing of the maximum net load ramp. This analysis suggests the 2025 requirements and must-offer hours were insufficient in reflecting actual ramping needs. The shortfall was at least 1,200 MW and up to around 6,100 MW during these months. Despite shortfalls in flexible resource adequacy requirements, total flexible capacity procurement and must-offer obligations were sufficient to meet actual maximum three-hour net load ramps in all months of 2025.

- **Resource adequacy availability incentive mechanism penalties totaled $93 million in 2025, an increase of about $20.3 million from 2024.** Much of this is attributable to flexible resource adequacy charges increasing to $66 million in 2025 from about $49 million in 2024.
- **Monthly resource adequacy from demand response programs scheduled by load-serving entities averaged 820 MW in 2025.** Monthly third-party demand response resource adequacy capacity averaged about 102 MW in 2025.

16.1 Background

The purpose of the resource adequacy program is to ensure the California ISO balancing area has enough capacity to operate the grid reliably. Along with the California ISO and the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other local regulatory authorities (LRAs) establish procurement obligations for all load serving entities within their respective jurisdictions.

The bilateral transactions between load serving entities and electricity suppliers that result from resource adequacy requirements provide revenue to compensate the fixed costs of existing generators. The resource adequacy program includes California ISO tariff requirements that work in conjunction with requirements and processes adopted by the CPUC and other local regulatory authorities.

The resource adequacy program includes procurement requirements for three types of capacity:

1. System resource capacity for reliability during system-level peak demand each month;
2. Local resource capacity for reliability in specific areas with limited import capability; and
3. Flexible resource capacity for reliability during ramping periods.

Load serving entities make filings with the California ISO to demonstrate they have procured enough capacity to fulfill their obligations for all three types of resource adequacy. Once established in a supply plan, supplying entities must make capacity available to the California ISO market according to rules that depend on requirement and resource type.

16.2 CAISO load conditions

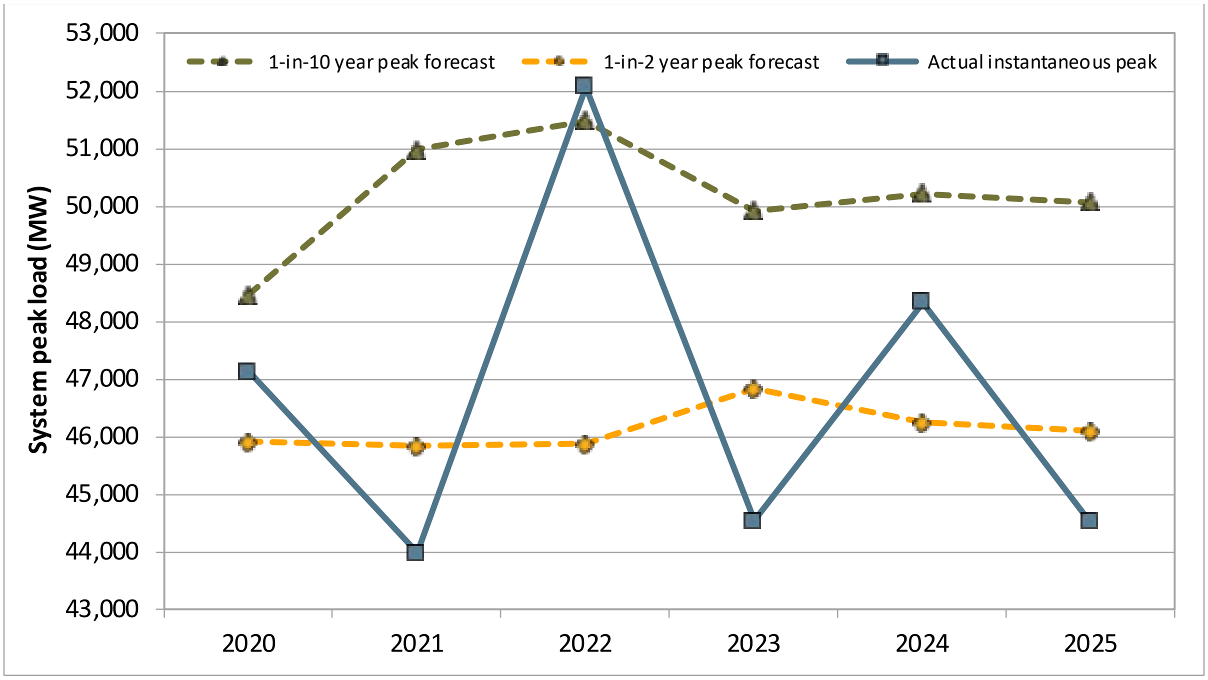
This section provides an overview of load conditions in the California ISO balancing authority area. CAISO total annual energy load decreased from 207,000 GWh in 2024 to 202,600 GWh in 2025. Load conditions and forecasts are used in determining resource adequacy requirements.

CAISO peak load

Instantaneous summer loads peaked at 44,506 MW on August 21, about 3,800 MW lower than the 2024 peak.

The instantaneous peak load in 2025 was 3.5 percent lower than the CAISO 1-in-2 year load forecast (46,094 MW) and 11 percent lower than the 1-in-10 year forecast (50,061 MW), as shown in Figure 16.1. The California ISO works with the California Public Utilities Commission and other local regulatory authorities to set system-level resource adequacy requirements. These requirements are based on the 1-in-2 year (or median year) forecast of peak demand plus a planning reserve margin. Resource adequacy requirements for local areas are based on the 1-in-10 year (or 90th percentile year) peak forecast for each area.

Figure 16.1 Actual instantaneous load compared to planning forecasts



CAISO local transmission constrained areas

The California ISO has defined ten local capacity areas (LCAs) for use in establishing local reliability requirements for the state's resource adequacy program. Local capacity areas are by definition transmission constrained, and are therefore an important point of focus for reliability reasons as well as for the potential for market power. Section 16.4 of this report assesses the structural competitiveness of the market for capacity in local areas. Section 3.3 assesses the frequency and impact of local energy market power mitigation procedures. This section provides a high-level perspective of supply and demand conditions in each local area.

Table 16.1 presents forecasted peak load, net qualifying capacity (NQC), and capacity requirements for these LCAs. Figure 16.2 shows the location of each LCA and the proportion of each area's load, relative to the total system peak load.[248] The local capacity requirement (LCR) is defined as the resource capacity needed to serve load reliably within a local capacity area.

Table 16.1 Load and supply within local capacity areas in 2025[249]

Local capacity area	LAP	Peak load (1-in-10 year) MW	%	Total NQC resources (MW)	Local capacity requirement (MW)	Requirement as percent of total NQC
Greater Bay	PG&E	11,992	24%	8,389	7,441	89%
Greater Fresno	PG&E	3,888	8%	3,267	2,532	78%
Sierra	PG&E	2,000	4%	1,925	1,532	80%
North Coast/North Bay	PG&E	1,483	3%	985	967	98%
Stockton	PG&E	1,129	2%	740	735	99%
Kern	PG&E	950	2%	449	434	97%
Humboldt	PG&E	214	.4%	175	164	94%
LA Basin	SCE	19,297	38%	10,296	4,123	40%
Big Creek/Ventura	SCE	5,075	10%	4,350	2,145	49%
San Diego/Imperial Valley	SDG&E	4,780	9%	5,469	2,709	50%
Total		**50,808**		**36,045**	**22,782**	

*Resource deficient LCA (or with sub-area that is deficient)—deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

The California ISO performs annual studies to identify the minimum local resource capacity requirements in each local area to meet established reliability criteria. An updated criterion is used in the study to match the NERC transmission planning standards for resource adequacy in year 2025. As a result, local capacity requirements increased to 22,782 MW for 2025 compared to 22,080 MW in 2024. NQC and peak load increased overall in these areas. The final column in Table 16.1 shows the local reliability requirement as a percentage of NQC in each local capacity area. One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant.

Requirements decreased in the LA Basin by 290 MW and increased in the Greater Bay Area by 112 MW. Requirements decreased in the San Diego/Imperial Valley area by 125 MW and increased in the Greater Fresno area by 504 MW. In 2025, the 1-in-10 year peak load increased in the Greater Bay and Greater Fresno areas by 911 MW and 534 MW, respectively. The peak load decreased in the LA Basin and San Diego/Imperial Valley areas by 340 MW and 128 MW, respectively.

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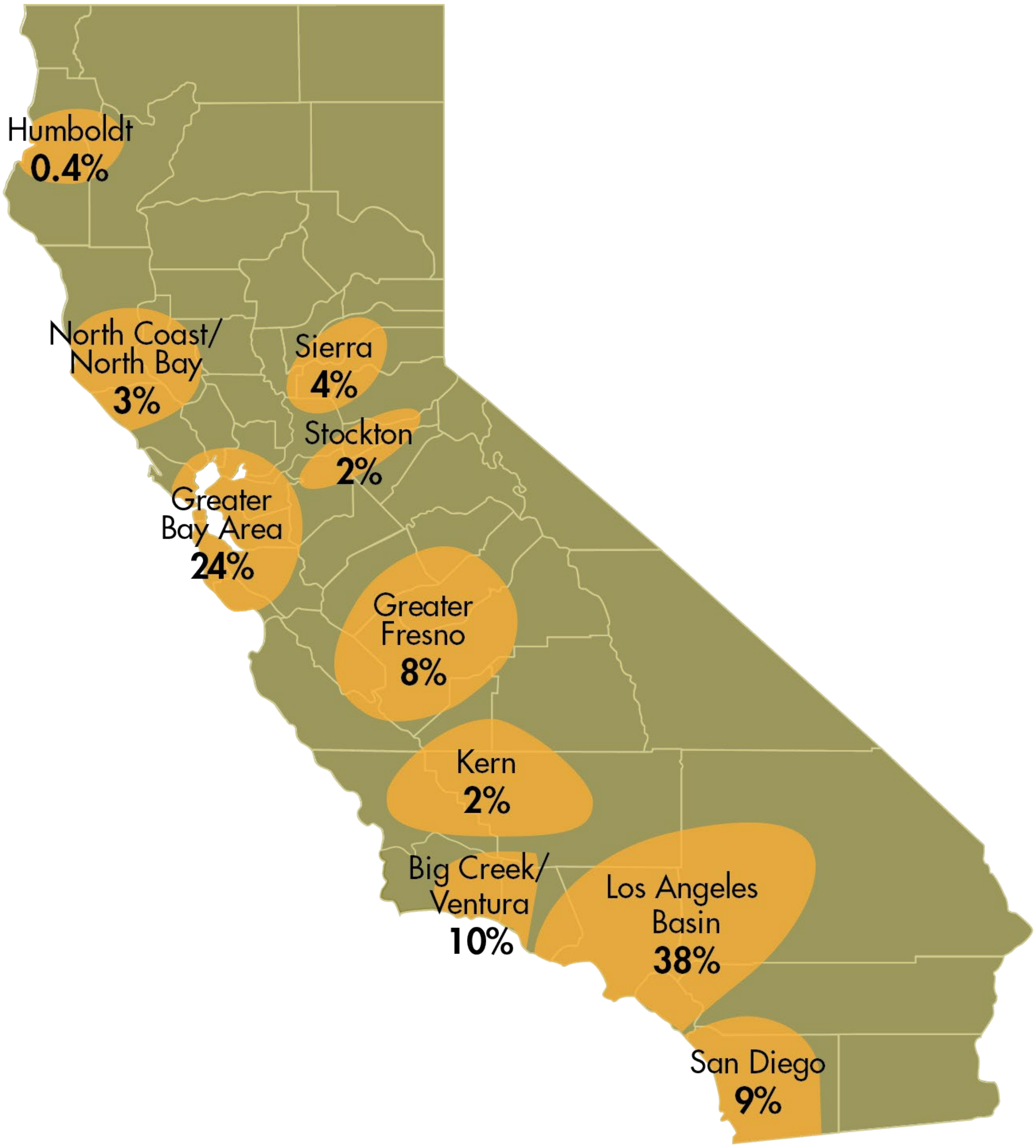
[248] Note that the total local area peak load figure, as well as a proportion of each local capacity area's load of the total, is illustrative. Each local area's load will peak at a different time from one another and from the system-coincident peak load.

[249] *2025 Local Capacity Technical Study*, California ISO, April 30, 2024, p 27, Table 3.1-1: https://stakeholdercenter.caiso.com/InitiativeDocuments/Final2025LocalCapacityTechnicalReport.pdf

Figure 16.2 Local capacity areas



Percentages represent the portion of system peak load in each local capacity area.

16.3 CAISO capacity changes

California currently relies on long-term procurement planning and resource adequacy requirements placed on load serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas. The primary trend in capacity changes has been increased battery capacity, up until this past year, when the ISO saw a significant increase in wind capacity.

Values reported here may differ from those reported elsewhere. First, these figures evaluate changes to the market, rather than exclusively the decommissioning or new interconnection of a unit. A generation withdrawal represents a resource that was once participating in the California ISO markets and no longer participates. In addition to decommissioned units, withdrawals may include resources that exit the market for a short period before returning (also known as mothballing), resources that withdraw to upgrade the unit and then repower, and resources whose contracts have expired with the California ISO regardless of the units' capability to provide power.

Historically, graphs in this section reflect nameplate capacity and changes between Junes of one year to the next to reflect changes to summer capacity.[250] Due to the timing of this year's report, changes in capacity from 2025 to 2026 will be from June 1, 2025 to April 1, 2026.

Total California ISO registered and participating capacity

Figure 16.3 summarizes the trends in available nameplate capacity from June 2021 through April 2026 for the California ISO balancing area. At 30.2 GW, natural gas capacity slightly decreased by around 210 MW since the previous year. Wind and solar grew the most out of any resource type in CAISO, adding 4.1 GW and 2.6 GW, respectively, since June 2025. The CAISO fleet currently has 2.6 GW of capacity from resources with multiple generation technologies participating under the hybrid model, which was an increase of around 420 MW from 2025. Overall, nameplate capacity has had a net increase of 8.8 GW since June 2025. In comparison, the CAISO added 5.7 GW of nameplate capacity from June 2024 to June 2025.

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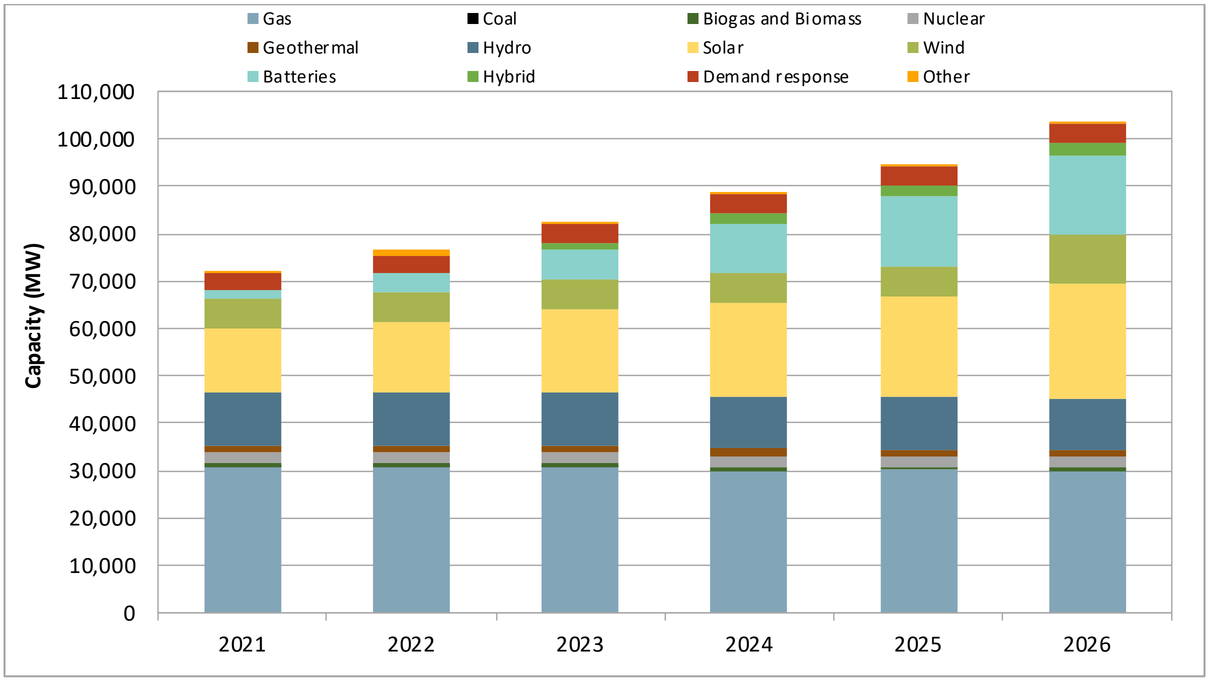
[250] A resource's start, withdraw, or return date can vary by source due to different milestones associated with generation interconnection procedures. The figures represent a rough estimate of the timeline when resources were added, withdrawn, or returned to the market, and may differ from other reports.

Figure 16.3 Total California ISO participating capacity by fuel type and year[251]



Withdrawal and retirement of California ISO participating capacity

In recent years, the California ISO (ISO) and several California state agencies have taken steps to ensure there is enough capacity to meet peak summer load, resulting in a historically low number of resource retirements. In addition, the State Water Resources Control Board adopted a resolution amending its policy on once-through cooling (OTC) to delay the retirement of six natural gas generating units, with nearly 3,000 MW of capacity, from December 2023 until 2026.[252]

Figure 16.4 shows the withdrawal and retirement of capacity from June 2021 through April 2026. Between June 2021 and June 2023, only around 190 MW of capacity withdrew from the market. Resources that didn't have their OTC policy compliance date extended drove a large amount of capacity retirement between June 2023 and 2024. Between June 2025 and April 2026, around 360 MW of capacity withdrew from the market, primarily driven by the loss of battery resources impacted by the Moss Landing fire in January 2025.

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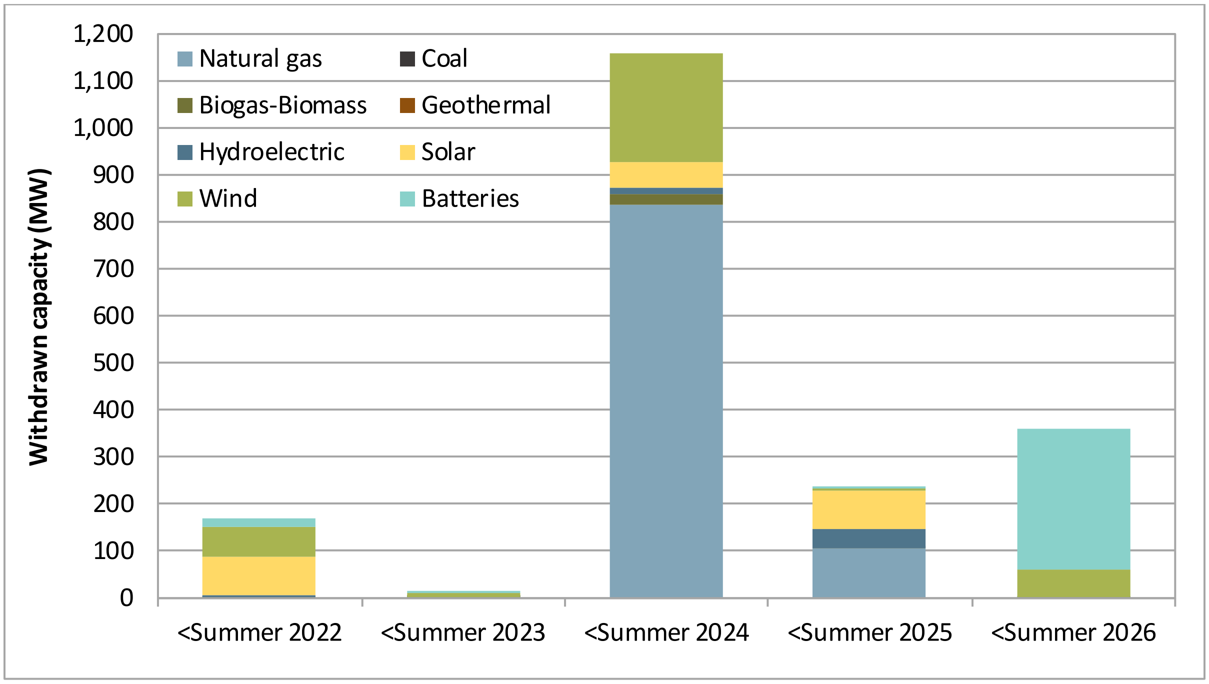
[251] From 2021 to 2025, capacity amounts for each year are as of June 1. Capacity for 2026 in this figure is current as of April 1, 2026.

[252] State Water Resources Control Board, Resolution No. 2023-0025, August 15, 2023, pp 3-4: https://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2023/rs2023-0025.pdf

Figure 16.4 Withdrawals from California ISO market participation by fuel type



Additions to participating capacity

Figure 16.5 shows additions to California ISO market participation. A generation addition is reported whenever a market participant enters the market, which includes resources that re-enter after a period of mothballing.[253]

From June 2020 to April 2026, around 12.2 GW of solar, 0.5 GW of natural gas, 5.1 GW of wind, 2.7 GW of hybrid,[254] and 16.9 GW of battery capacity were added or returned to the market.[255] Around 4.1 GW of wind was added since June 2025, primarily from the SunZia Wind project.

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[253] These figures do not account for generation outages, despite being similar in nature.

[254] The growth in hybrid in this figure does not include resources that converted from solar capacity.

[255] Resource additions often transition into the market with various phases of testing, so the exact date of market entry reported can vary.

Figure 16.5 Additions to California ISO market participation by fuel type[256]

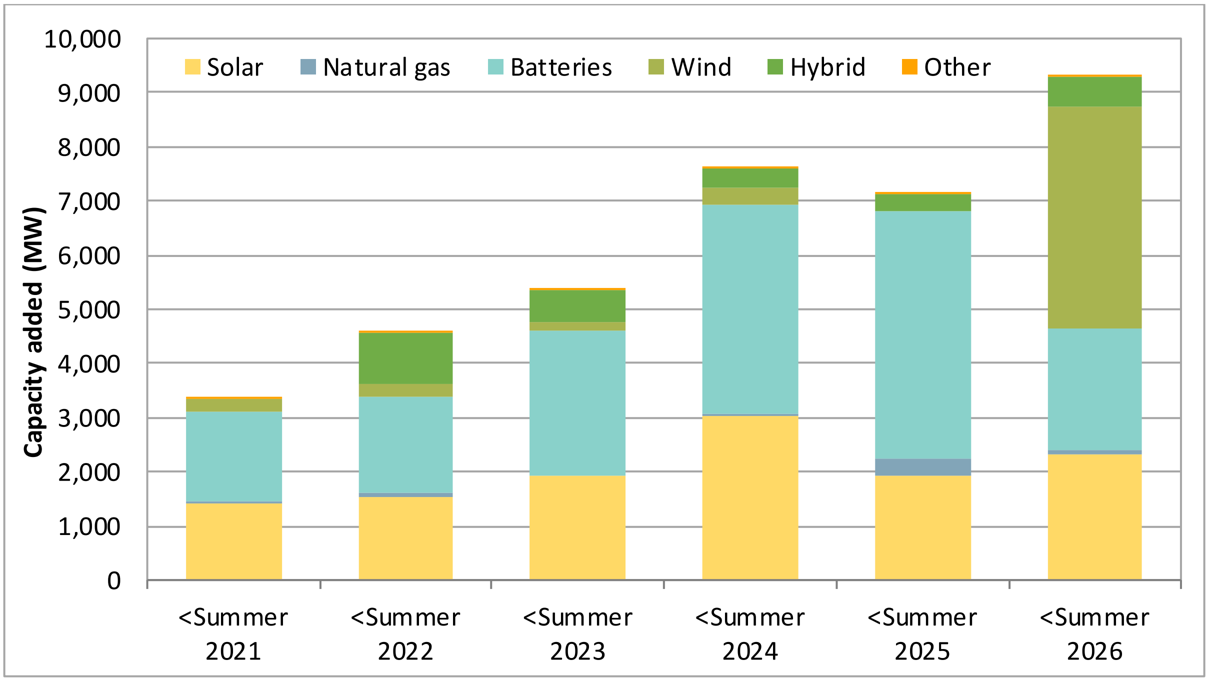

Figure 16.6 shows additions by local area according to local resource adequacy showings. Resources shown for system resource adequacy (RA) are labeled as CAISO System and are represented by the light olive bars.[257] In the last couple of years, a significant amount of the new capacity came in as system RA, with around 4.1 GW added from June 2023 to June 2024, and 4.2 GW added from June 2024 to June 2025. The majority of added capacity from June 2025 to June 2026 has no RA contract as of this report's drafting, though this is subject to change.

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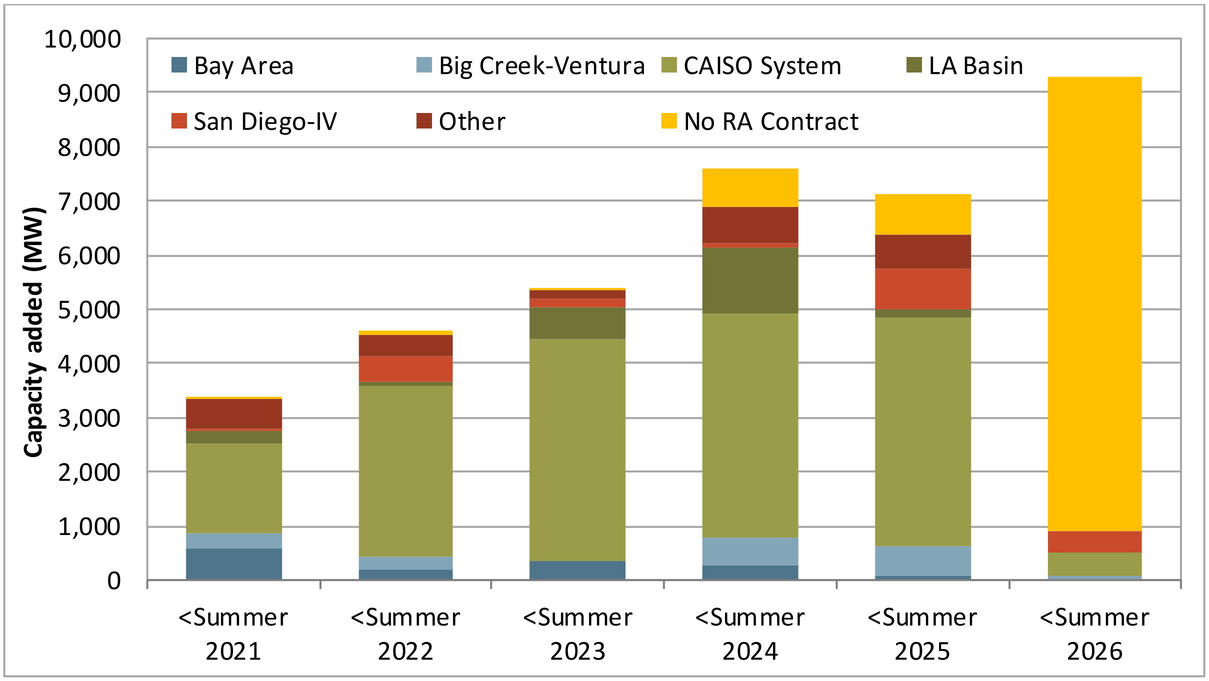
[256] Please note that this is not a complete picture of capacity changes and resource availability in the California ISO system. Other changes in available capacity that are not included in this metric include (1) generation outages, (2) increases and decreases to capacity without changes in participation status, (3) changes associated with qualifying facilities, demand response, tie-generators, or any other non-typical participating generator type.

[257] New resources are unable to sell resource adequacy until they receive net qualifying capacity. Many of the new resources do not have resource adequacy contracts, and are therefore not assigned to the designated local areas.

Figure 16.6 Additions to California ISO market participation by local area



The California ISO requires projects to undergo a series of impact studies before they can be connected to the grid. The list of projects in this process is known as the "interconnection queue." The interconnection queue currently includes about 88 GW of planned capacity, around 60 percent of which comes from mixed-fuel projects. All mixed-fuel projects currently in the interconnection queue contain a battery, with 96 percent of them being paired with a wind or solar resource. The most common project types in the interconnection queue are battery only and battery/solar combination projects, making up 30 GW and 48 GW of all planned capacity, respectively. Among non-battery projects, wind and solar projects are most common and make up 4 GW of all planned capacity.

The ISO's 20-year transmission outlook calls for 165.1 GW of capacity additions to meet its 2045 resource portfolio, including 70 GW of solar, 35 GW of wind, and around 53 GW of energy storage resources.[258] Historically, the median wait time for completed projects has been around 2,200 days, while the median wait time for projects currently in the queue is around 3,600 days. About 1 GW of capacity has come on-line since June 2025. However, many projects drop out of the interconnection queue before their interconnection studies are finished. In 2025, 50 projects totaling 15 GW of planned capacity withdrew from the interconnection queue. The median wait time for projects that have dropped out of the CAISO interconnection queue historically has been 365 days from their queue start date until dropping out.

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[258] *2024 20-Year Transmission Outlook*, California ISO, July 31, 2024, p 17: https://www.caiso.com/documents/2024-20-year-transmission-outlook-jul-31-2024.pdf

16.4 CAISO local capacity requirements and structural measures of competitiveness

In 2025, four of the local capacity areas were not structurally competitive because there was at least one supplier that was pivotal and controlled a significant portion of capacity needed to meet local requirements.

The California ISO has defined 10 local capacity areas for which local reliability requirements are established under the state's resource adequacy program. In most of these areas, a high portion of the available capacity is needed to meet peak reliability planning requirements. In most local capacity areas, one or two entities own most of the generation needed to meet local capacity requirements.

Table 16.2 provides a summary of the residual supply index for local capacity areas in which the total local resource adequacy requirement exceeds capacity held by load serving entities. These areas have a net non-load serving entity capacity requirement, where load serving entities must procure capacity from other entities to meet local resource adequacy requirements.

Load serving entities meet local resource adequacy requirements through a combination of self-owned generation and capacity procured through bilateral contracts. For this analysis, we assume that all capacity scheduled by load serving entities will be used to meet these requirements, with any remainder procured from non-load serving entities that own generation in the local area.[259]

Table 16.2 shows the areas in which the total local resource adequacy requirement exceeds capacity held by load serving entities. Most of these areas have sufficient non-load serving entity capacity to meet their net non-load serving entity capacity requirement. In most of the local capacity areas in the table, at least one supplier is individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of a single supplier's capacity is needed to meet the portion of local requirements not covered by load serving entities' supply. In the case of Stockton, there is not enough non-LSE capacity in their respective local capacity areas to meet the requirement. There are no individually pivotal suppliers for Sierra and Greater Fresno, and furthermore, the capacity from three different suppliers combined would still not be pivotal to meet the remaining requirement.

The California ISO performs annual studies to identify the minimum local resource capacity requirements in each local area to meet established reliability criteria. An updated criterion is used in the study to match the NERC transmission planning standards for resource adequacy in year 2025.[260] As a result, the total local capacity requirement increased by 702 MW (3 percent) between 2024 and 2025, with a considerable increase to the Greater Fresno and Sierra local capacity area requirements.

Key findings of this analysis include the following:

- The Greater Bay, Kern, North Coast/North Bay, and Stockton local areas are not structurally competitive because there is at least one supplier that is pivotal and controls a significant portion of capacity needed to meet local requirements.

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[259] This analysis assumes load serving entities show resources at their net qualifying capacity on resource adequacy supply plans. However, based on actual resource availability, entities may show resources at less than net qualifying capacity values in a given month. Therefore, this analysis likely overestimates competitiveness in local areas.

[260] *2025 Local Capacity Technical Study*, California ISO, April 30, 2024: https://stakeholdercenter.caiso.com/InitiativeDocuments/Final2025LocalCapacityTechnicalReport.pdf

- The Greater Fresno and Sierra local areas are structurally competitive and pass the three pivotal supplier test.

In addition to the capacity requirements for each local area used in this analysis, additional reliability requirements exist for numerous sub-areas within local capacity areas. Some sub-areas require that capacity be procured from specific individual generating plants. Other sub-areas require various combinations of units that have different levels of effectiveness at meeting sub-area reliability requirements.

These sub-area requirements are not reflected in local capacity procurement requirements. However, these additional sub-area requirements represent additional sources of local market power. If a unit needed for a sub-area requirement is not procured in the resource adequacy program, the California ISO may need to procure capacity from the unit using the backstop procurement authority under the capacity procurement mechanism of the tariff.[261]

Table 16.2 Residual supply index for local capacity areas based on net qualifying capacity

Local capacity area	Net non-LSE capacity requirement (MW)	Total non-LSE capacity (MW)	Total residual supply ratio	RSI_1	RSI_2	RSI_3	Number of individually pivotal suppliers
PG&E TAC area							
Greater Bay	5051	5899	1.17	0.49	0.12	0.08	2
Kern	329	347	1.06	0.13	0.01	0	2
North Coast/North Bay	822	877	1.07	0.05	0.02	0.01	1
Stockton	515	510	0.99	0.34	0.08	0.05	3
Sierra	21.66	442.35	20.42	9.82	5.45	3.15	0
Greater Fresno	43.54	1281.9	29.44	26.61	23.86	21.4	0

*Available capacity is insufficient to meet the LCA requirement; all supply is needed to contribute toward the LCA requirement

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive in each market run. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. Section 3.3 examines the frequency and impact of these automated bid mitigation procedures.

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[261] For further information on the capacity procurement mechanism, see Section 16.8.

16.5 System resource adequacy

This section analyzes the availability and performance of system resource adequacy resources throughout the year, with a focus on tight system hours when the California ISO balancing area issued energy emergency alerts and experienced high prices and load.

Regulatory requirements

The California ISO balancing area works with the CEC, CPUC, and other local regulatory authorities to set system resource adequacy requirements. These requirements are specific to individual load serving entities based on their forecasted peak load in each month (based on a *1-in-2 year* peak forecast) plus a planning reserve margin (PRM). The CPUC local regulatory authority planning reserve margin for 2025 was set at 17 percent, with an "effective" planning reserve margin procurement target of 1,700 to 3,200 MW, which would translate to 21 to 23.5 percent.[262,263] Load serving entities then procure capacity to meet these requirements and file annual and monthly supply plans to the California ISO.

For annual supply plan showings, CPUC-jurisdictional load serving entities are required to demonstrate they have procured 90 percent of their system resource adequacy obligations for the five summer months in the upcoming compliance year.[264] For monthly supply plan showings, CPUC-jurisdictional entities must demonstrate they have procured 100 percent of their monthly system obligation. Table 16.3 shows recent CPUC decisions that affected the procurement, availability, or performance of resource adequacy resources in 2025:

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[262] The planning reserve margin reflects operating reserve requirements and additional capacity to cover potential forced outages and load forecast error.

[263] For the summers of 2024 and 2025, CPUC decision D.23-06-029 determined an "effective" PRM target of 1,700 to 3,200 MW by requiring extra procurement from the three investor owned utilities (IOUs). See Table 16.3 for more details.

[264] A showing is the list of resources and procured capacity that load serving entities and suppliers show to the California ISO in annual and monthly resource/supply plans.

Table 16.3 Recent CPUC decisions relevant to 2025 resource adequacy year[265]

Decision	Title	Description
D.23-06-029	Decision Adopting Local Capacity Obligations for 2024 - 2026, Flexible Capacity Obligations for 2024, and Program Refinements	Adopts the local and flexible RA requirements. Adopts a planning reserve margin (PRM) of 17% from 2024 and 2025, and further extends the Effective PRM to stay at approximately 22.5%. Requires all import RA to procure available transfer capacity (ATC). Reliability Demand Response Resources (RDRR) are enabled to bid into periods in the day-ahead when the system is under EEA Watch conditions, or greater. Demand response cannot bid above RDRR, and a bid cap of $949/MWh has been adopted.
D.24-06-004	Decision Adopting Local Capacity Obligations for 2025 - 2027, Flexible Capacity Obligations for 2025, and Program Refinements	Adopts local and flexible RA obligations for 2025 to 2027. Maintains the PRM set to 17% for the 2025 resource adequacy compliance year. Adopts the 17% PRM to the Slice-of-Day (SOD) framework. Affirms Slice-of-Day implementation for 2025 with no delay. Determines hybrid and co-located resources' qualifying capacity methodology. The renewable component's QC value will be calculated the same as other renewables and the storage component's QC value will be calculated the same as other storage resources. The sum of the two components will be the total QC value of the reosurce and limited by the Point-of-Interconnection limit and the SOD compliance tool's state-of-charge test.
D.25-06-048	Decision Adopting Local Capacity Obligations for 2026 - 2028, Flexible Capacity Obligations for 2026, and Program Refinements	Adopts local and flexible RA obligations for 2026 to 2028. Increases the PRM to 18% for 2026 and 2027 and extends the effective PRM target (approximately 22.5%) for June to October in 2026 and 2027. The availability assessment hours (AAH) for system and local resource adequacy were modified. Beginning in 2026, the RA measurement hours will be from 5:00 PM to 10:00 PM in the winter months (November to February), while the spring and summer RA measurements have not changed.

Bid, schedule, and meter data processing for generic resource adequacy

For the following system and local resource adequacy analysis, day-ahead market bids include energy bids and non-overlapping ancillary service bids, while real-time market bids include energy bids only.[266] Day-ahead cleared schedules include total energy, spin reserves, non-spin reserves, and regulation up schedules; real-time market cleared schedules include energy schedules only.[267] This analysis caps bids, schedules, and meter amounts at the resource adequacy capacity values of individual resources, unless otherwise indicated in the tables, to measure the availability of capacity that load serving entities

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[265] More information is available on the CPUC's Resource Adequacy Homepage: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage

[266] Due to data issues, hourly real-time bid amounts reflect the maximum of average hourly bids in the hour-ahead, 15-minute, and 5-minute markets, adjusted for de-rates.

[267] Due to data issues, hourly real-time cleared schedule amounts reflect the maximum of average hourly energy schedules in the hour-ahead, 15-minute, and 5-minute markets, adjusted for de-rates.

secured during the planning timeframe. The analysis also caps bids and schedules according to individual resource outages and de-rates.

Availability and performance during availability assessment hours

The California ISO is a summer peaking balancing area with a generation mix that is becoming increasingly intermittent. California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. Load serving entities can meet a portion of their resource adequacy requirements with availability-limited generation. Reliability rules typically focus on making sure these resources are available when loads and net loads are highest.

Although planning for the highest loads of the year is important for reliability, the California ISO grid can also experience stressed conditions in non-summer months when there are relatively lower loads. This is because generation and transmission capacity are more likely to be on outage for maintenance, and winter conditions may threaten the supply of natural gas to California.

The California ISO issues emergency notifications when operating reserves or transmission capacity limitations threaten the ability to operate the grid reliably, regardless of what time of year it is. On April 1, 2022, the California ISO moved from the Alert, Warning, and Emergency (AWE) notification system to the Energy Emergency Alert (EEA) system to align with NERC emergency levels.[268] Table 16.4 provides descriptions of the EEA systems.

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[268] This series of notifications matches the North American Electric Reliability Corporation's (NERC) Energy Emergency Alert (EEA) system. To learn more about EEAs and AWEs, go to: http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

Table 16.4 Emergency notification categories (effective on 4/1/2022)[269]

Notification category	Description
Flex Alert	A call to consumers to voluntarily conserve energy when demand for power could outstrip supply. This generally occurs during heatwaves when electrical demand is high. The California ISO can declare a Flex Alert whenever there is expected stress on the system.
Restricted Maintenance Operations (RMO)	Requires generators and transmission operators to postpone any planned outages for routine equipment maintenance, ensuring all grid assets are available for use.
EEA Watch	When the day-ahead analysis is forecasting that one or more hours may be energy deficient.
Energy Emergency Alert 1 (EEA 1)	When real-time analysis is forecasting that one or more hours may be energy deficient.
Energy Emergency Alert 2 (EEA 2)	When all resources are in use and emergency load management programs are needed.
Energy Emergency Alert 3 (EEA3)	When all actions listed above have been taken and expected energy and contingency reserve requirements still cannot be met. Notice issued to utilities of potential electricity interruptions through firm load shedding.
Transmission Emergency	Declared by the California ISO for any event threatening or limiting transmission grid capability, including line or transformer overloads or loss. A Transmission Emergency notice can be issued on a system-wide or regional basis.

In addition to the California ISO emergency notification categories, the ISO annually updates the availability assessment hours (AAH) to reflect the hours of greatest reliability need as part of the resource adequacy availability incentive mechanism (RAAIM). In 2025, the availability assessment hours for system and local resource adequacy were:

- Hours-ending 18 through 22 for spring (March 1 through May 31)
- Hours-ending 17 through 21 for summer (June 1 through October 31) and winter (January 1 through February 28 and November 1 through December 31)

Previous versions of this report based the analysis of this section on the hours with active emergency notifications at least as severe as Restricted Maintenance Operations (RMO). In 2025, there was only one such emergency notification declared by the ISO, which was an RMO notification in January. In order to address the limited number of events and hours, the analysis in this section of this year's report measures availability and performance during the availability assessment hours within analysis days

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[269] Upon declaration of EEA3, all impacted entities will be alerted without delay, within a maximum timeframe of 30 minutes. Notifications will be sent to all BAAs, TOPs, and Western RCs via a GMS WECC-Wide message. Market participants within the RC area will receive notifications via GMS. These notifications should include the name of the BAA, the EEA level, and contact information that other BAAs can use to provide emergency assistance. The California ISO's reliability coordinator procedure: https://www.caiso.com/Documents/RC0410.pdf

where grid conditions may be strained.[270] These days are based on the days with the highest load forecast, day-ahead system marginal energy cost, and resource adequacy capacity scarcity. Table 16.5 shows each of the days that meet these criteria.

Table 16.5 Resource adequacy analysis days

Date	RMO	Highest load forecast	Highest day-ahead system marginal energy cost	Greatest resource adequacy scarcity
January 20, 2025	x			
January 21, 2025	x		x	
March 9, 2025				x
March 23, 2025				x
March 24, 2025				x
April 21, 2025				x
May 30, 2025				x
August 21, 2025		x	x	
August 22, 2025		x	x	
September 1, 2025		x		
September 2, 2025		x	x	
September 3, 2025		x	x	

Descriptions of each of the criteria used to select the days used in the analysis:

- **RMO** days are when there was an active California ISO issued alert. In 2025, there was a notification that spanned 43 hours from January 20 through January 21.
- **Highest load forecast** days are determined from the 5-minute market intervals. All intervals in 2025 are arranged from highest to lowest values of load. The first five unique days are indicated in the table.
- **Highest day-ahead system marginal energy cost (SMEC)** days are determined from each hour in 2025. All hours of 2025 are arranged from highest to lowest day-ahead SMEC values. The first 5 unique days are indicated in the table. Four out of the five days in this category overlap with the highest load forecast and the remaining day overlaps with an RMO day.
- **Greatest resource adequacy scarcity** days are determined from each 15-minute market interval in 2025. Resource adequacy scarcity represents the difference between FMM bids from resource adequacy resources and load requirements.[271] All intervals in 2025 are arranged from highest to lowest scarcity amounts. The first five unique days are indicated in the table. All of these days occur during the spring AAH period. Figure 16.7 shows the average margin between

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[270] The availability assessment hours for system and local resource adequacy apply only to trading days that are weekdays and non-holidays. The hours used in the analysis in this section do not exclude weekends or holidays.

[271] Includes bids from long start resources and non-dynamic resources that submitted bids in the day-ahead market and didn't receive a RUC or IFM award. Also includes bid amounts from variable energy resources (VERs) above their resource adequacy capacity.

RA capacity and load during the spring months. RA scarcity is the highest during hour-ending 21 at around 12,000 MW.

Figure 16.7 Average hourly resource adequacy capacity and market load (March 1 – May 31)

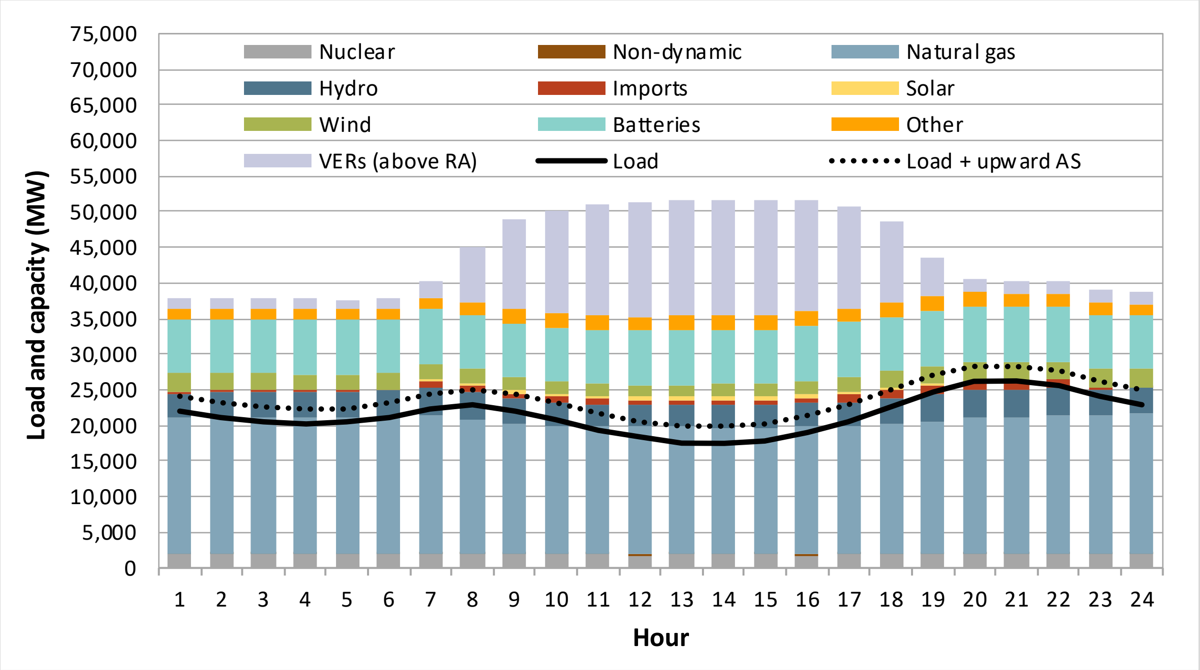

Table 16.6 shows capacity procurement, de-rates, availability, and performance of system resource adequacy resources during emergency notification hours from 2022 to 2025. Bids and self-schedules, cleared schedules, and meter amounts are capped by resource adequacy capacity at the resource level, unless otherwise indicated.[272,273]

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[272] The current metrics for schedules and bids only consider the discharge megawatt for all storage and hydro resources. In contrast, reports from previous years included both discharge and charge megawatt in bids and schedules for these resources.

[273] Due to the change in the ISO's notification system, this analysis uses the Alert+ category before April 1, 2022, and the EEA Watch+ category after. The Alert+ category includes hours when the California ISO issued a notification at least as severe as an alert notification; these hours mostly occur during the evening peak, although the analysis includes some hours during the middle of the day.

Table 16.6 Average total system resource adequacy capacity, availability, and performance by analysis category

Year	Alert category	Number of hours	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter	Uncapped meter + AS
				Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules	Uncapped schedules + AS			
2022	RMO+	151	49,799	95%	90%	75%	94%	89%	69%	83%	89%	64%	77%	83%
	Flex Alert+	56	49,509	95%	91%	85%	93%	89%	77%	88%	95%	72%	81%	88%
	EEA Watch+	35	49,390	95%	90%	87%	93%	89%	79%	89%	95%	74%	81%	88%
	EEA 2+	17	49,490	95%	91%	89%	93%	90%	82%	92%	98%	78%	85%	92%
2023	RMO+	72	41,480	94%	90%	73%	93%	89%	67%	82%	88%	62%	75%	81%
	EEA Watch+	12	48,878	96%	94%	68%	94%	92%	58%	80%	86%	54%	75%	81%
2024	RMO+	332	52,646	95%	89%	57%	94%	87%	53%	70%	75%	49%	64%	69%
	AAH (RMO+)	94	52,805	95%	92%	77%	94%	91%	71%	87%	93%	66%	80%	86%
	EEA Watch+	7	52,649	96%	90%	73%	94%	88%	74%	83%	89%	69%	75%	81%
2025	RMO+	42	38,970	92%	88%	36%	90%	86%	36%	55%	59%	31%	63%	52%
	AAH (RMO+)	10	38,970	92%	90%	48%	91%	88%	47%	58%	63%	45%	45%	58%
	AAH (All)	60	46,169	95%	88%	60%	93%	87%	58%	69%	74%	54%	54%	68%

Key findings of this analysis include:

- **There were a total of 60 availability assessment hours during the analysis days in 2025.** These hours are denoted by "AAH (All)" in Table 16.6. Total resource adequacy capacity during this time was around 46 GW, notably lower than in previous years that use the different methodology. System resource adequacy obligations are lower in the non-summer months so less RA capacity is required. Many of the analysis hours for 2025 occur in the spring season, unlike in previous years which would only contain summer days.
- **The California ISO declared just one RMO alert for a total of 42 hours in 2025.** Ten of these hours occurred during availability assessment hours. This is a significant decrease from the 18 RMO alerts and 332 hours from 2024. Unlike previous years, there were no events in 2025 that were at least as severe as an EEA Watch.
- **A small percentage of procured capacity was on outage during stressed hours from 2022 to 2025.** The day-ahead and real-time markets could access between 93 and 95 percent of procured capacity during these hours. In 2025, just 58 to 60 percent of procured capacity got scheduled in the day-ahead and real-time markets.
- **Resource availability, as measured by capped bids and self-schedules during the analysis hours, was moderately high in 2025.** On average, between 87 and 90 percent of procured capacity bid or self-scheduled into the day-ahead and real-time markets from 2022 to 2025. In 2025, 88 percent of the procured capacity was bid or self-scheduled into the day-ahead market, and 87 percent was bid or self-scheduled into the real-time market.
- **Accounting for the remaining capacity of partial resource adequacy resources increases performance when compared to procured capacity amounts.** The table shows real-time cleared schedules and meter data not capped, or "uncapped", by individual resource adequacy values. Solar resources drive this increase in performance since their production can surpass net qualifying capacity values.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 16.7 and Figure 16.8 show capacity procurement by resource type, capacity de-rates, availability, and performance of system resource adequacy resources during the analysis hours in

2025.[274] Separate sub-totals are provided for the resources that the California ISO creates bids for when market participants do not submit a bid or self-schedule (must-offer), as well as the sub-totals for the resources the California ISO does *not* create bids for (other).

Table 16.7 Average system resource adequacy capacity, availability, and performance by fuel type during availability assessment hours (among analysis days)

Resource type	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter	Uncapped meter + AS
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules	Uncapped schedules + AS			
Must-Offer:												
Gas-fired generators	12,860	94%	94%	59%	91%	91%	56%	59%	62%	54%	56%	59%
Other generators	944	92%	92%	89%	90%	90%	87%	103%	103%	85%	99%	99%
Subtotal	13,804	93%	93%	61%	91%	91%	58%	62%	64%	56%	59%	62%
Other:												
Imports	1,710	96%	89%	86%	100%	87%	86%	88%	88%	86%	87%	87%
Imports-MSS	201	100%	46%	46%	100%	47%	46%	58%	58%	46%	58%	58%
Use-limited gas units	8,597	94%	94%	52%	93%	93%	46%	48%	55%	43%	44%	51%
Hydro generators	4,361	96%	88%	77%	87%	79%	65%	87%	97%	63%	83%	93%
Nuclear generators	2,249	100%	97%	97%	100%	99%	99%	111%	111%	99%	111%	111%
Solar generators	2,234	99%	47%	47%	98%	53%	49%	148%	148%	44%	124%	124%
Wind generators	1,934	100%	45%	44%	99%	59%	58%	88%	88%	46%	68%	68%
Qualifying facilities	602	92%	75%	64%	94%	75%	63%	68%	68%	60%	66%	66%
Demand response (PDR)	108	100%	83%	1%	96%	45%	2%	2%	2%	2%	3%	3%
Storage	8,864	95%	94%	49%	94%	93%	51%	54%	65%	42%	44%	55%
Other non-dispatchable	1,506	95%	87%	60%	93%	83%	65%	76%	77%	60%	67%	68%
Subtotal	32,365	96%	86%	59%	94%	85%	58%	72%	79%	53%	65%	71%
Total	**46,169**	**95%**	**88%**	**60%**	**93%**	**87%**	**58%**	**69%**	**74%**	**54%**	**63%**	**68%**

Key findings of this analysis include:

- **Gas-fired generators accounted for about 47 percent of capacity procurement.** Gas-fired resources (gas-fired must-offer generators and use-limited gas units) supplied about 21,500 MW of resource adequacy capacity during the AAH hours within the analysis days of 2025.
- **Resources that are not availability-limited accounted for just 30 percent of system capacity.** About 13,804 MW of system capacity was subject to California ISO bid insertion 24x7.[275] Gas-fired generation in this category made up about 12,860 MW (28 percent) of total resource adequacy capacity. Other generators accounted for around 2 percent.
- **Storage units made up the largest portion of resource adequacy capacity with limited availability not subject to California ISO bid insertion.** These resources contributed about 8,900 MW of total capacity (19 percent). Use-limited gas resources contributed 19 percent, hydro generators contributed 9 percent, nuclear resources contributed 5 percent, solar resources contributed 5 percent, wind resources contributed 4 percent, imports (including metered sub-systems) contributed 4 percent, demand response contributed less than one percent, and other non-dispatchable resources contributed 3 percent of system capacity.
- **Storage and hydro resources contributed to the provision of ancillary services during the analysis hours.** The "uncapped schedules + AS" column presents real-time scheduling for RA and partial RA

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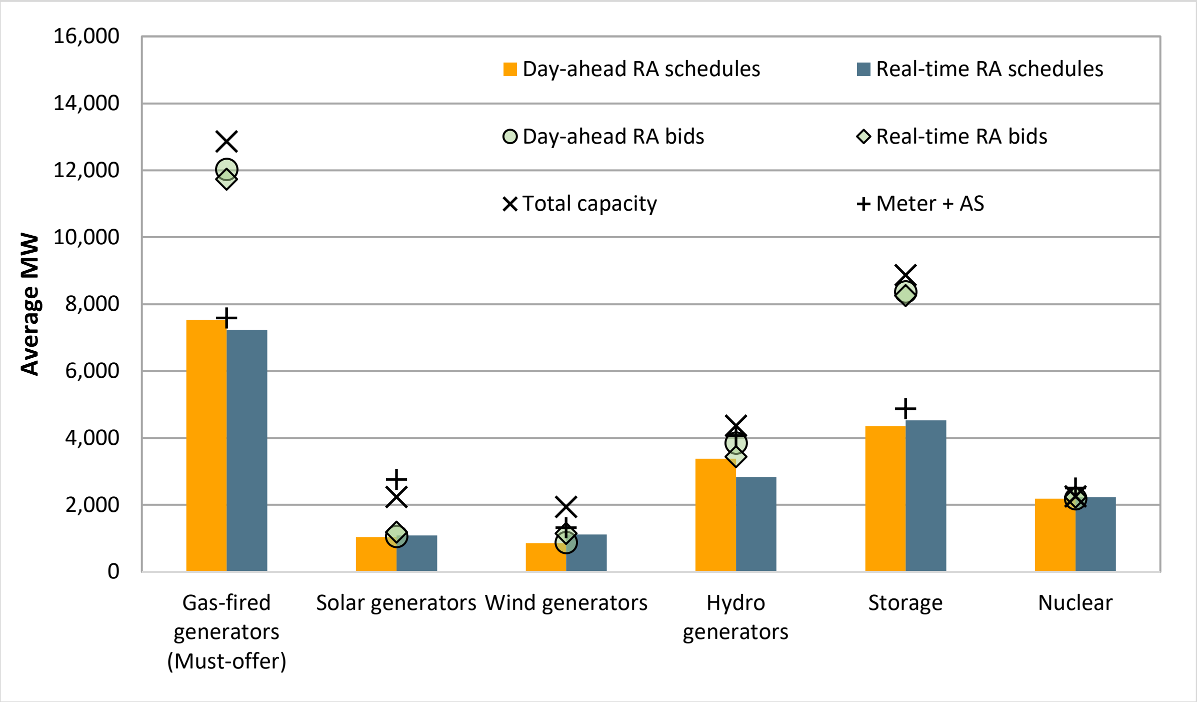
[274] Availability and performance in the day-ahead and real-time markets are reported as the proportion of total resource adequacy capacity.

[275] When scheduling coordinators did not submit bids for these resources, the California ISO automatically generated them. Generation was excluded from the bidding requirement when an outage was reported to the California ISO.

resources with their 15-minute ancillary service schedules. Storage resources' uncapped energy schedules in real-time were only 54 percent of their RA capacity. However, upon inclusion of ancillary service schedules, the percentage of scheduled capacity rose to 65 percent. Hydro units were scheduled for 97 percent of their RA capacity, incorporating RA and partial RA energy and ancillary service schedules.

- **Capacity available after reported outages and de-rates was 95 percent in the day-ahead market and 93 percent in the real-time market**. Average resource adequacy capacity was around 46,169 MW during the analysis hours in 2025.
- **The day-ahead market showed high capacity availability in 2025.** In the day-ahead market, 93 percent of must-offer and 96 percent of non-must-offer resources were available after de-rates. Must-offer resources bid in about 100 percent of day-ahead de-rated capacity. Non-must-offer resources bid in about 90 percent of the day-ahead de-rated capacity. Additionally, most of the availability assessment hours include evening peak hours, when solar resources and other non-must-offer resources have limited availability.
- **After accounting for outages and de-rates, most capacity was available in the real-time market**. About 91 percent of must-offer and 85 percent of non-must-offer capacity bid or self-scheduled in the real-time market. These totals are capped by individual resource adequacy values. About 83 percent of proxy demand response (PDR) bid in the day-ahead market, and 45 percent bid into the real-time market. Demand response resources typically exhibit low bid availability as a percentage of procured capacity.
- **A similar percentage of procured must-offer resources cleared in the real-time market compared to non-must-offer resources.** About 91 percent bid into the real-time, and a little over 58 percent of procured must-offer capacity cleared the real-time market. About 85 percent of non-must-offer capacity bid into the real-time market, and just under 58 percent of capacity cleared in the real-time market. These percentages are capped by individual resource adequacy values.

Figure 16.8 Average system resource adequacy by fuel type during availability assessment hours (within RMO+ hours)



Key findings of this analysis include:

- **Solar and nuclear resources performed greater than their total resource adequacy capacity and schedules during the analysis hours.** Including their above RA production, solar and nuclear resources generated 124 percent and 111 percent of their capacity, respectively.
- **Including ancillary services, all resources types performed above their resource adequacy schedules.** Resource adequacy units on average produced 118 percent of their real-time schedule and 92 percent of their uncapped schedules plus ancillary service requirements.

Table 16.8 shows the availability and performance of resources aggregated by the type of load serving entity that contracted with them. This analysis uses supply plans to proportionally assign resource bid availability and performance to load serving entities based on corresponding contracted capacity.[276] Bids, schedules, and meter values are aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government entity. Capacity labeled as “not on a plan” represents resources that were not originally on a load serving entity’s supply plan. This could be substituted for a capacity procurement mechanism designation, or resources held by the Central Procurement Entity.

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[276] Since a single resource can contract with multiple load serving entities, bidding behavior and performance metrics for individual resources were distributed proportionately among entities according to their contracted share of a resource’s capacity. For example, if Generator A has 100 MW of resource adequacy capacity in total and contracted 60 MW of capacity to LSE 1 and 40 MW to LSE 2, then 60 percent of Generator A’s bids are assigned to LSE 1 and 40 percent to LSE 2. Load serving entity assigned bids and performance are then aggregated up to the type of load the entity serves.

Table 16.8 Average system resource adequacy capacity and availability by load type (RMO+ hours)

Load Type	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter	Uncapped meter + AS
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules	Uncapped schedules + AS			
Community choice aggregator	11,087	95%	89%	51%	93%	88%	54%	65%	68%	49%	57%	60%
Direct access	3,731	95%	88%	51%	93%	88%	53%	70%	73%	48%	60%	63%
Investor-owned utility	26,446	95%	89%	65%	93%	88%	61%	69%	75%	57%	63%	70%
Municipal/government	3,721	94%	81%	59%	93%	77%	56%	80%	85%	55%	76%	81%
Not on a plan	1,184	96%	93%	46%	96%	95%	49%	87%	91%	44%	79%	83%
Total	**46,169**	**95%**	**88%**	**60%**	**93%**	**87%**	**58%**	**69%**	**74%**	**54%**	**63%**	**68%**

Key findings of this analysis include:

- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 26,446 MW (57 percent) of system resource adequacy procurement, community choice aggregators contributed 24 percent, direct access services contributed 8 percent, and municipal utilities contributed 8 percent as well. The remaining is a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Capacity availability for all load types was similar across the real-time and day-ahead markets.** Resources bid on average 87 to 88 percent of procured capacity from the four load types in these markets. These bids are capped by individual resource adequacy values.
- **Investor-owned utilities, municipal utilities, and community choice aggregators contracted with a majority of resources with availability limitations that are not subject to California ISO bid insertion.** Investor-owned utilities procured 75 percent of their resource adequacy capacity from these resources, while municipal utilities procured 79 percent, community choice aggregators procured 59 percent, and direct access services procured 61 percent.
- **All load types procured a limited amount of imports to meet system resource adequacy requirements.** Municipal utilities procured 7 percent of their resource adequacy capacity from imports, while community choice aggregators procured 4 percent, direct access services procured less than 1 percent, and investor-owned utilities procured 4 percent.

Table 16.9 shows the availability of resource adequacy capacity in the California ISO markets based on whether the capacity was exempt from charges under the resource adequacy availability incentive mechanism (RAAIM). This analysis uses settlements data to identify resources exempt from RAAIM charges if they were unavailable during the availability assessment hours.[277]

Table 16.9 Average system resource adequacy capacity and availability by RAAIM category during availability assessment hours (within RMO+ hours)

RAAIM category	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter	Uncapped meter + AS
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules	Uncapped schedules + AS			
Non-RAAIM exempt	38,172	95%	93%	61%	93%	91%	58%	63%	69%	55%	59%	65%
RAAIM exempt	7,998	97%	65%	53%	96%	67%	56%	97%	99%	50%	81%	83%
Total	**46,169**	**95%**	**88%**	**60%**	**93%**	**87%**	**58%**	**69%**	**74%**	**54%**	**63%**	**68%**

Key findings of this analysis include:

- **RAAIM exempt resources accounted for about 17 percent of overall resource adequacy capacity during the analysis hours of 2025.** This was mostly solar, wind, and non-must-offer gas resources.
- **RAAIM exempt resources bid at a lower percentage in the markets**. In the day-ahead market and real-time markets, RAAIM exempt capacity bid about 65 to 67 percent of their capacity, while non-RAAIM exempt bid 91 to 93 percent of their capacity into the markets. This considers bids capped at individual resource adequacy values. Including the remaining capacity from partial resource adequacy resources and ancillary services, around 99 percent of the procured capacity from RAAIM exempt resources got scheduled into the real-time market. This is due to solar resources that bid significantly above their net qualifying capacity (NQC) values.

Resource adequacy imports

Load serving entities can use imports to meet system resource adequacy requirements. Imports can bid at any price up to the $1,000/MWh bid cap, as they are not subject to market power mitigation and do not have any further bid obligation in the real-time market if not scheduled in the day-ahead energy or residual unit commitment process.[278]

DMM expressed concern that these rules could allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions. For example, imports could routinely bid significantly above projected prices in the day-ahead market to ensure they do not clear, and would then have no further obligation to be available in the real-time market.

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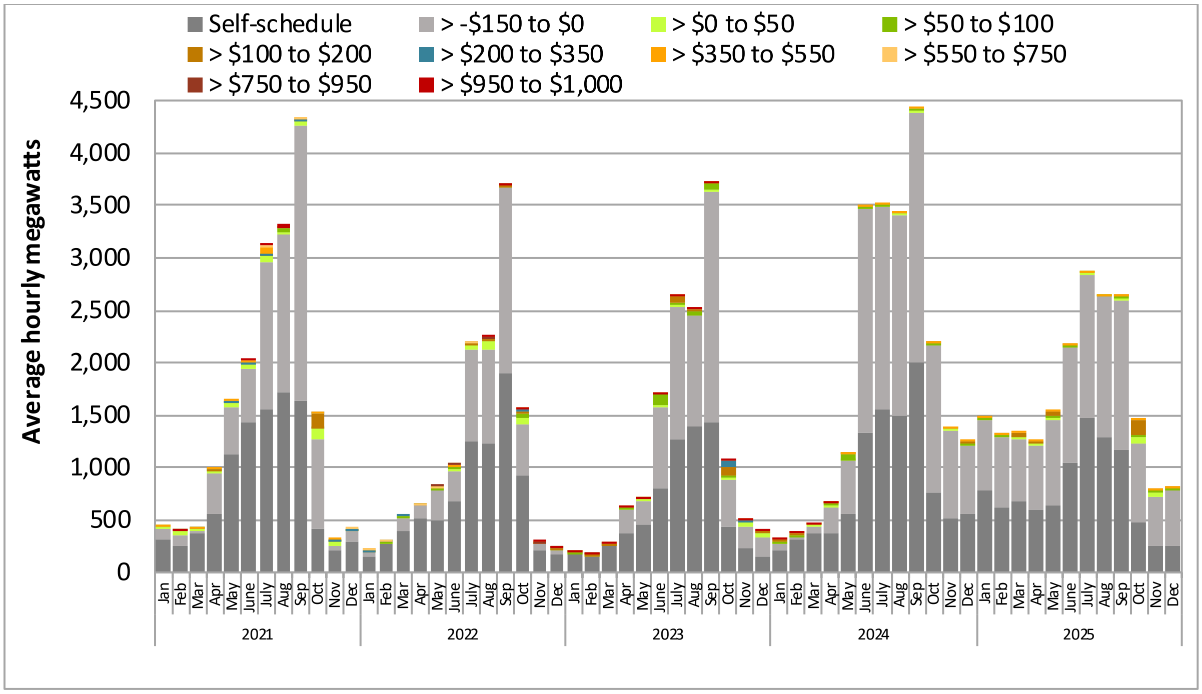
[277] There are many reasons why a resource may be exempt from RAAIM charges in general or on any particular day. This includes the resource's maximum generation capacity, generation type, or outage type, among others. For more information on RAAIM exemptions, refer to Section 40.9 of the ISO tariff. http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

[278] 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 MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

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.[279] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices. An overall decline in volumes began in late 2020 and continued throughout 2022. Imports in 2025 were lower during the summer months but higher during other periods compared to 2024. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports. In 2025, CPUC-jurisdictional entities submitted import bids exceeding $0/MWh during only a limited number of hours within the availability assessment hours period.

Figure 16.9 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market during peak hours.[280] The grey bars reflect import capacity that was either self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

Figure 16.9 Average hourly resource adequacy imports by price bin



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[279] *Decision Adopting Resource Adequacy Import Requirements (D.20-06-028)*, CPUC Docket No. R.17-09-020, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

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

16.6 Flexible resource adequacy

The purpose of flexible resource adequacy capacity is to ensure the system has enough flexible resources available to meet forecasted net load ramps, plus contingency reserves. With increased reliance on renewable generation, the need for flexible capacity has increased to manage changes in net load. The system typically needs this ramping capability in the downward direction in the morning when solar generation ramps up and replaces gas generation. In the evening, the system needs upward ramping capability as solar generation rapidly decreases while system loads are increasing. The greatest need for three-hour ramping capability occurs during evening hours.

The CPUC and the California ISO developed flexible resource adequacy requirements to address flexibility needs for changing system conditions. FERC approved the flexible resource adequacy framework in 2014 and it became effective in January 2015. This framework now serves as an additional tool to help maintain grid reliability.[281]

Requirements

The California ISO determines flexible capacity needs through the annual flexible capacity needs assessment study. This study identifies the minimum amount of flexible capacity that must be available to the California ISO to address ramping needs for the upcoming year. The California ISO uses the results to allocate shares of the system flexible capacity need to each local regulatory authority that has load serving entities responsible for load in the California ISO balancing authority area.

The flexible resource adequacy framework provides capacity with the attributes required to manage the grid during extended periods of ramping needs. This framework calculates the monthly flexible requirement as the maximum contiguous three-hour net load ramp forecast plus a capacity factor.[282,283] Because the grid commonly faces two pronounced upward net load ramps per day, flexible resource adequacy categories address both the maximum primary and secondary net load ramp.[284]

For annual showings, load serving entities are required to demonstrate they have procured 90 percent of their flexible resource adequacy requirements for each month of the coming compliance year. Load serving entities submit annual supply plans to the California ISO by the last business day of October prior to the coming compliance year. For the monthly showings, load serving entities must demonstrate they have procured 100 percent of their flexible resource adequacy obligation.

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[281] For additional information, see: *149 FERC ¶ 61,042, Order on Tariff Revisions,* FERC Docket No. ER14-2574, October 16, 2014: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf

[282] The capacity factor is the greater of the loss of the most severe single contingency or 3.5 percent of expected peak load for the month.

[283] Net load is total load less wind and solar production.

[284] The California ISO system typically experiences two extended periods of net load ramps, one in the morning, and one in the evening. The magnitude and timing of these ramps change throughout the year. The larger of the two three-hour net load ramps (the primary ramp) generally occurs in the evening. The must-offer obligation hours vary seasonally based on this pattern for Category 2 and 3 flexible resource adequacy.

Bidding and scheduling obligations

All resources providing flexible capacity are required to submit economic energy and ancillary service bids to the day-ahead and real-time markets, and to participate in the residual unit commitment process. However, the must-offer obligations for these resources differ by category. Below is a brief description of each category, its purpose, requirements, and must-offer obligations.[285]

- **Category 1 (base flexibility):** Category 1 resources must be able to address both the primary and secondary net load ramps each day. These resources must submit economic bids for 17 hours a day from HE 6 through HE 22 and be available 7 days a week. The Category 1 requirement covers 100 percent of the secondary net load ramp and a portion of the primary net load ramp. Therefore, the forecasted maximum three-hour secondary ramp sets this category's requirement. There is no limit to the amount of Category 1 resources that can be used to meet the total system flexible capacity requirement.
- **Category 2 (peak flexibility):** Category 2 resources must be able to address the primary net load ramp each day. These resources must submit economic bids for 5 hours a day (which vary seasonally) and be available 7 days a week. The Category 2 operational need is the difference between the forecasted maximum three-hour secondary net load ramp (the Category 1 requirement) and 95 percent of the forecasted maximum three-hour net load ramp. The calculated Category 2 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.
- **Category 3 (super-peak flexibility):** Category 3 resources must be able to address the primary net load ramp. These resources must submit economic bids for 5 hours (which vary seasonally) on non-holiday weekdays. The Category 3 operational need is 5 percent of the forecasted three-hour net load ramp. The calculated Category 3 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.

Requirements compared to actual maximum net load ramps

Figure 16.10 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2025 by comparing the requirements and the actual maximum three-hour net load ramp on a monthly basis.[286] The blue bars represent total three-hour requirements for the month and the gold line represents the maximum three-hour net load ramp. The green bars represent the requirement *during* the period of the maximum three-hour net load ramp.

Because each category of flexible resource adequacy capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.[287] Therefore, this analysis first

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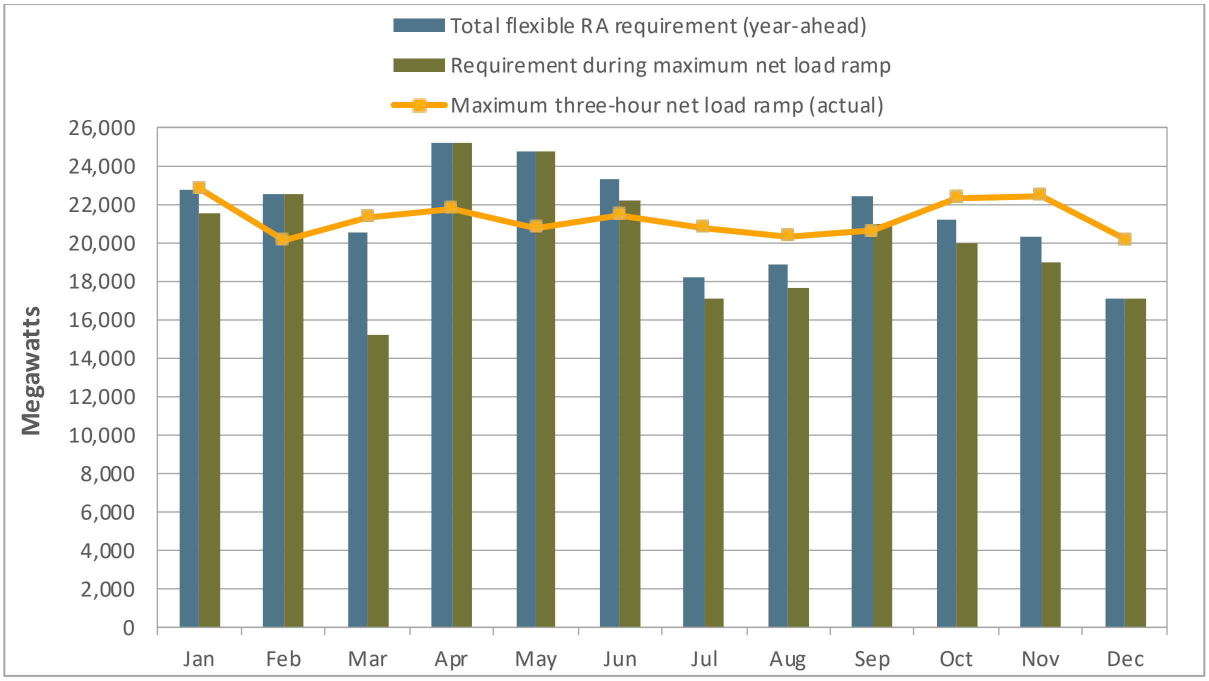
[285] For more information, see: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Flexible-capacity-needs-assessment-2025

[286] Estimates of the net load ramp may vary slightly from the California ISO calculations because DMM uses 5-minute interval data and the California ISO uses one-minute interval data. For the 5-minute net load calculation, DMM incorporates a range of renewable resources including California ISO's solar, wind, and co-located resources from the 5-minute interval data.

[287] For example, because Category 3 resources do not have must-offer obligations on weekends and holidays, the effective requirement during the net load ramps on those days will be less than the total flexible requirement set for the month.

identified the day and hours the maximum net load ramp occurred, and then averaged the flexible capacity requirements for the categories with must-offer obligations during those hours.

Figure 16.10 Flexible resource adequacy requirements during the actual maximum net load ramp



Key findings of this analysis include:

- **Year-ahead flexible resource adequacy requirements were not sufficient to meet the actual maximum three-hour net load ramp in seven months of 2025.** This is where the blue bars are lower than the gold line. In most of these cases, the maximum ramp occurred on a weekend or holiday.
- **Actual flexible resource adequacy requirements set at the time of the peak ramp were not sufficient to meet actual maximum three-hour net load ramps in seven months of 2025.** This is where the green bars are lower than the gold line.

The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps depends on the ability to predict the size and timing of the maximum net load ramp. This analysis suggests the 2025 requirements and must-offer hours were not sufficient in reflecting actual ramping needs.

Table 16.10 provides another comparison of actual net load ramping times to flexible resource adequacy capacity requirements and must-offer hours. The average requirement during the maximum net load ramp is calculated by summing Category 1, 2, and 3 requirements for each of the three hours in the max net load ramp (as applicable) and finding the average.

Table 16.10 Maximum three-hour net load ramp and flexible resource adequacy requirements

Month	Maximum 3-hour net load ramp (MW)	Total flexible RA requirement (MW)	Average requirement during maximum net load ramp (MW)	Date of maximum net load ramp	Ramp start time	Average requirement met ramp? (Y/N)	Why average requirement during max net load ramp was less than the maximum 3-hour net load ramp
Jan	22,823	22,703	21,569	1/20/2025	14:20	N	Max ramp occurred on a holiday
Feb	20,128	22,567	22,567	2/26/2025	14:45	Y	
Mar	21,334	20,532	15,236	3/7/2025	14:50	N	Ramp start time occurred before Category 2 requirement
Apr	21,765	25,191	25,191	4/22/2025	16:25	Y	
May	20,775	24,740	24,740	5/2/2025	16:20	Y	
Jun	21,434	23,316	22,151	6/21/2025	16:55	Y	
Jul	20,782	18,253	17,113	7/6/2025	16:55	N	Max ramp occurred on a Sunday
Aug	20,367	18,863	17,687	8/3/2025	16:40	N	Max ramp occurred on a Sunday
Sep	20,611	22,380	21,027	9/6/2025	15:55	Y	
Oct	22,345	21,240	19,945	10/5/2025	15:45	N	Max ramp occurred on a Sunday
Nov	22,469	20,269	19,016	11/1/2025	14:55	N	Max ramp occurred on a Saturday
Dec	20,175	17,135	17,135	12/29/2025	14:00	N	

Key results of this analysis include:

- **There were seven months in 2025 when the average requirement during the maximum net load ramp was not sufficient to meet the actual maximum three-hour net load ramp.** This occurred in all seasons, and the shortfall was at least 1,200 MW and up to around 6,100 MW during these months.
- **The average maximum three-hour net load ramp across all months in 2025 is around 21,251 MW.** This is about 2,211 MW higher than in 2024, while the average requirement during the net load ramp is 1,976 MW lower.

Procurement

Table 16.11 shows what types of resources provided flexible resource adequacy, and details the average monthly flexible capacity procurement in 2025 by fuel type. The flexible resource adequacy categories and must-offer rules are technology neutral, allowing a variety of resources to provide flexibility to the California ISO to meet ramping needs. While the CPUC and California ISO created counting criteria for a variety of resource types, natural gas-fired generation has historically composed the majority of flexible ramping procurement. However, procurement of energy storage resources has risen significantly in 2025 and now represents the largest share of flexible resource adequacy capacity.

Table 16.11 Average monthly flexible resource adequacy procurement by resource type

Resource type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
Gas-fired generators	7,957	32%	32	1%	0	0%
Use-limited gas units	6,007	24%	493	8%	0	0%
Use-limited hydro generators	462	2%	71	1%	0	0%
Other hydro generators	140	1%	0	0%	0	0%
Geothermal	460	2%	0	0%	0	0%
Energy storage	9,831	39%	4,620	77%	378	100%
Hybrid	131	1%	780	13%	0	0%
Total	**24,988**		**5,996**		**378**	

Key findings of this analysis include:

- **Gas-fired resources (both use-limited and non-use limited) accounted for the most Category 1 flexible resource adequacy capacity procurement.** About 14,500 MW (or 54 percent) of total flexible capacity across all categories came from these resources. Almost all (96 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2025.
- **Energy storage resources made up the largest volume of flexible resource capacity in 2025.** These generators accounted for about 9,800 MW (39 percent) of Category 1 capacity in 2025. They also provided 77 percent of Category 2 capacity and were the only fuel type procured as Category 3.
- **Load serving entities procured more flexible capacity across Category 1 and Category 2 compared to the previous year.** In 2025, load serving entities procured 2,356 MW more capacity in Category 1 and 1,794 MW more in Category 2 compared to 2024.

Table 16.12 shows flexible resource adequacy procurement by load serving entity type in 2025, including community choice aggregator (CCA), direct access service (DA), investor-owned utility (IOU), and municipal/government entity (Muni). The analysis uses supply plans to determine monthly LSE procurement and average it over the year by flexible resource adequacy category.

Table 16.12 Average monthly flexible resource adequacy procurement by load type and flex category

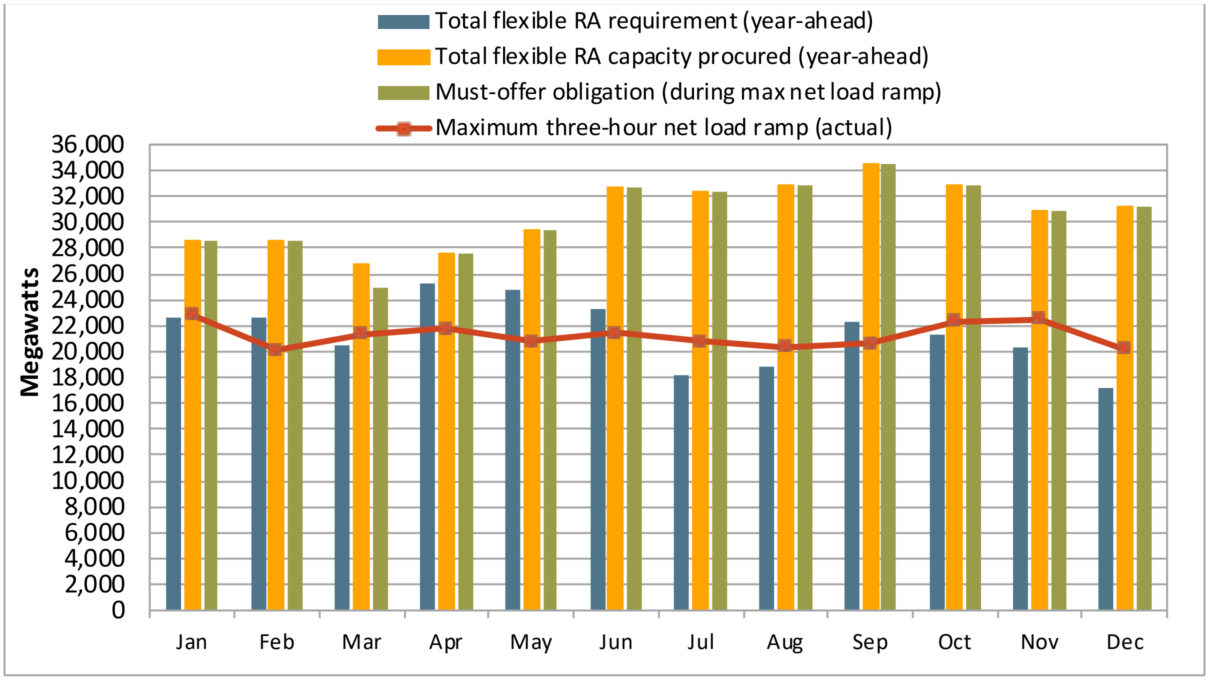
Load type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
CCA	5,338	21%	1,756	29%	41	11%
DA	1,033	4%	1,061	18%	0	0%
IOU	17,925	72%	2,981	50%	337	89%
Muni	692	3%	199	3%	0	0%
Total	**24,988**	**100%**	**5,997**	**100%**	**378**	**100%**

Key findings of this analysis include:

- **Investor-owned utilities procured the highest proportion of each flexible resource adequacy category**. Investor-owned utilities procured 68 percent of total flexible capacity, community choice aggregators procured 23 percent, direct access services procured 7 percent, and municipal utilities procured 3 percent. Investor-owned utilities procured at least 50 percent of the capacity of each category. IOUs procured a large majority of Category 3 flexible resource adequacy at 89 percent.
- **Community choice aggregators procured the second highest proportion of all flexible resource adequacy capacity**. CCAs procured 21 percent of Category 1, 29 percent of Category 2, and 11 percent of Category 3 capacity.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2025. Figure 16.11 shows total monthly flexible requirements and procured capacity, which are determined a year ahead. It also shows the total capacity that should be offered during the actual maximum three-hour net load ramp.[288] Must-offer obligations differ from the total flexible capacity procured because the actual net load ramps can occur outside of Category 2 and 3 must-offer hours.

Figure 16.11 Flexible resource adequacy procurement during the maximum net load ramp



Key findings of this analysis include:

- **Year-ahead total flexible resource adequacy procurement exceeded total requirements**. Total flexible resource adequacy procurement (gold bars) exceeded the total requirement (blue bars) in all months of the year.
- **The must-offer obligation for procured resources during the maximum three-hour net load ramp is the same as total procurement in most months.** Must-offer obligations during maximum net load ramps (green bars) are the same as total procurement (gold bars) for all months except for March. For March, the must-offer obligation is about 1,854 MW lower than the amount procured.
- **The must-offer obligation for procured capacity was sufficient to meet the maximum net load ramp in all months**. The must-offer obligation during actual maximum net load ramp (green bars) exceeded the actual three-hour net load ramp (red line) for all months in 2025 by an average of 9,300 MW.

Availability

Table 16.13 presents an assessment of the availability of flexible resource adequacy capacity in the day-ahead and real-time markets. Average capacity represents the must-offer obligation of flexible

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[288] The must-offer obligation estimate used in this chart includes long-start and extra-long-start resources, regardless of whether or not they were committed in the necessary time frame to actually have an obligation in real-time.

capacity. Availability is measured by assessing economic bids and outages in the day-ahead and real-time markets. For the resources where minimum output qualified as flexible capacity, the minimum output was only assessed as available if no part of the resource was self-scheduled.

Extra-long-start resources are required to participate in the extra-long-start commitment process and economically bid into the day-ahead and real-time markets when committed. This analysis considers extra-long-start resources as available in the day-ahead market to the extent that the resource did not have outages limiting its ability to provide its full obligation. The analysis considers long-start and extra-long-start resources as available in the real-time market analysis if they received schedules in the day-ahead market or the residual unit commitment process. Day-ahead energy schedules are excluded from real-time economic bidding requirements in this analysis, as in the resource adequacy availability incentive mechanism (RAAIM) calculation.

This is a high-level assessment of the availability of flexible resource adequacy capacity to the day-ahead and real-time markets in 2025. This analysis is not intended to replicate the method by which the resource adequacy availability incentive mechanism measures availability.

Table 16.13 Average flexible resource adequacy capacity and availability

Month	Average DA flexible capacity (MW)	Average DA availability		Average RT flexible capacity (MW)	Average RT availability	
		MW	% of DA capacity		MW	% of RT capacity
January	25,090	17,915	71%	22,654	19,950	88%
February	25,223	17,124	68%	23,099	19,192	83%
March	23,055	14,275	62%	20,294	17,472	86%
April	23,789	16,310	69%	20,669	19,192	93%
May	25,149	17,288	69%	22,336	20,659	92%
June	27,871	20,511	74%	24,178	22,448	93%
July	27,535	20,770	75%	24,479	22,503	92%
August	28,049	21,231	76%	25,187	22,797	91%
September	29,265	21,424	73%	26,199	23,802	91%
October	28,250	20,726	73%	25,284	23,533	93%
November	26,193	17,929	68%	23,823	21,433	90%
December	26,525	18,623	70%	23,109	20,076	87%
Total	**26,333**	**18,677**	**71%**	**23,443**	**21,088**	**90%**

Key findings of this analysis include:

- **Flexible resource adequacy resources had fairly high levels of availability in both the day-ahead and real-time markets in 2025**. Average availability in the day-ahead market was 71 percent and ranged from 62 percent to 76 percent. This is lower than 2024, when average availability in the day-ahead market was about 75 percent, with a range from 70 percent to 80 percent. Average availability in the real-time market was 90 percent and ranged from 83 percent to 93 percent. This is higher than 2024, when average real-time availability was 88 percent and ranged from 84 percent to 91 percent.
- **The real-time average must-offer obligation is much lower than the day-ahead obligation**. Flexible capacity must-offer requirements were about 26,333 MW in the day-ahead market and only about 23,443 MW in the real-time market on average. This reflects several factors. First, resources may

receive ancillary service awards in the day-ahead market covering all or part of their resource adequacy obligation. Second, long-start and extra-long-start resources do not have an obligation in the real-time market if they are not committed in the day-ahead market, residual unit commitment process, or the extra-long-start commitment process. In addition, day-ahead energy awards are excluded from the real-time availability requirement for the incentive mechanism calculation.

Table 16.14 includes the same data summarized in Table 16.13, but aggregates average flexible resource adequacy availability by the type of load serving entity contracting the capacity. Supply plans were used to proportionally assign bidding behavior to load serving entities based on their corresponding contracted flexible capacity. Bid availability was then aggregated by load type, depending on whether the entity was a community choice aggregator (CCA), direct access service (DA), investor-owned utility (IOU), or a municipal/government entity (Muni).

Table 16.14 Average flexible resource adequacy capacity and availability by load type

Load type	Average DA flexible capacity (MW)	Average DA availability		Average RT flexible capacity (MW)	Average RT availability	
		MW	% of DA capacity		MW	% of RT capacity
CCA	5,851	4,557	78%	4,980	4,542	91%
DA	1,350	1,121	83%	1,182	1,084	92%
IOU	18,383	12,345	67%	16,595	14,853	90%
Muni	750	655	87%	686	610	89%
Total	**26,333**	**18,677**	**71%**	**23,443**	**21,088**	**90%**

Key findings from this analysis include:

- **Flexible resource adequacy resources in the day-ahead had lower availability on average than in real-time markets across load types**. In both markets, most of the flexible resource adequacy capacity was contracted with investor-owned utilities. These resources that were contracted with IOUs had far higher availability in the real-time market than in the day-ahead market.

16.7 Incentive mechanism payments

The purpose of the resource adequacy availability incentive mechanism (RAAIM) is to provide an incentive for resource adequacy resources to meet their bidding obligations and provide energy bids to the market. Resources that are designated as either system, local, or flexible resource adequacy capacity are subject to RAAIM. The monthly performances of these resources are measured by the availability of bids and self-schedules in the market during designated availability assessment hours. The 2025 availability assessment hours for:

System and local resource adequacy resources:

- Spring (March 1 through May 31) – hours-ending 18 to 22
- Summer (June 1 through October 31) – hours-ending 17 to 21
- Winter (November 1 through December 31 and January 1 through February 28) – hours-ending 17 to 21

Flexible resource adequacy resources:

- Base ramping (Category 1) – hours-ending 6 to 22 in all months.
- Peak ramping (Category 2) – hours-ending 15 to 19 in January through February and November through December, hours-ending 17 to 21 in March through August, and hours-ending 16 to 20 in September through October.
- Super-peak ramping (Category 3) – hours-ending 15 to 19 in January through February and November through December, hours-ending 17 to 21 in March through August, and hours-ending 16 to 20 in September through October. Excludes holidays and weekends.

Resources that provide local, system, or flexible resource adequacy are either charged or paid each month, depending on their average capacity availability during the availability assessment hours. Resources whose average monthly capacity availability is more than 2 percent *less* than the availability standard of 96.5 percent are *charged* a non-availability charge for the month. Resources whose average capacity availability is more than 2 percent *greater* than the availability standard are *paid* an incentive payment for the month. The RAAIM price is set at 60 percent of the capacity procurement mechanism (CPM) soft offer cap price, or about $4.40/kW-month.[289,290]

Figure 16.12 summarizes monthly RAAIM charges and payments to resource adequacy resources from January 2023 through December 2025. Financial sums are presented in relation to how money flows through the California ISO. RAAIM penalties that resources pay the California ISO are in the positive direction on the graph, while RAAIM payments where the California ISO pays resources are in the negative direction. Charges and payments are presented for generic and flex resource adequacy resources.

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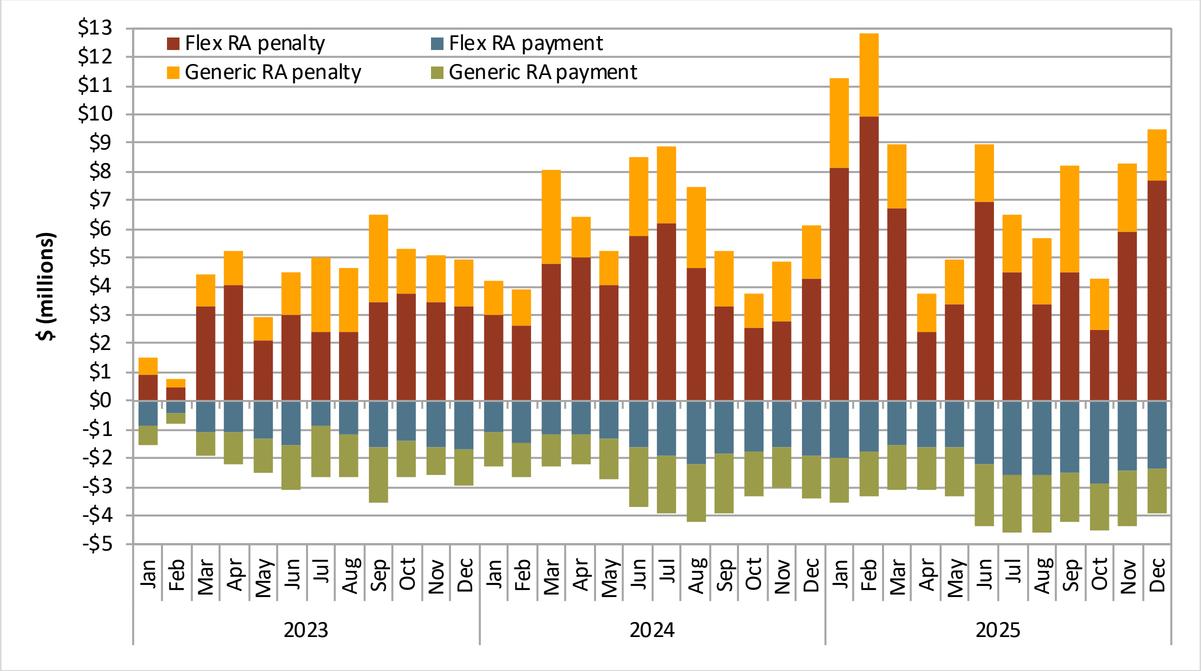
[289] These payments (charges) are set at the resource's monthly average resource adequacy capacity multiplied by the difference between the lower (upper) bound of the monthly availability standard of 94.5 (98.5) percent and the resource's monthly availability percentage multiplied by the RAAIM price.

[290] Effective June 1, 2024, the CPM soft offer cap increased to $7.34/kW-month.

Figure 16.12 Monthly RAAIM penalties and payments[291]



Key findings from this analysis include:

- **In 2025, RAAIM penalties were about double that of payments.** RAAIM charges totaled about $93 million while RAAIM payments totaled around $47 million. Both incentive payments and penalties were higher for flexible resource adequacy resources.
- **RAAIM penalties increased by around $20.3 million from 2024.** Much of this is attributable to flexible resource adequacy charges increasing to $66 million in 2025 from about $49 million in 2024. Generic resource adequacy charges increased to $27 million from $23.7 million.
- **In 2025, most RAAIM charges occurred in the first quarter while most payments occurred in the third quarter.** In the first quarter, the RAAIM charges averaged $11 million per month. RAAIM payments averaged $4.5 million per month in the third quarter. The second quarter had the lowest average RAAIM charges at $5.9 million per month and the payments were lowest during the first quarter at $3.3 million.

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[291] The values for 2024 and 2025 differ from previous versions of the report due to re-settlements.

16.8 Capacity procurement mechanism

Background

The capacity procurement mechanism (CPM) provides backstop procurement authority to ensure that the California ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism facilitates pay-as-bid competitive solicitations for backstop capacity and establishes a price cap at which the California ISO can procure backstop capacity to meet resource adequacy requirements that are not met through load serving entity showings.

Scheduling coordinators may submit competitive solicitation process bids for three offer types: yearly, monthly, and intra-monthly. In each case, the quantity offered is limited to the difference between the resource's maximum capacity, and capacity already procured as either resource adequacy capacity or through the California ISO capacity procurement mechanism. Effective June 1, 2024, the soft offer cap increased to $7.34/kW-month ($88.09/kW-year).[292]

The California ISO inserts bids above the soft offer cap for each resource with qualified resource adequacy capacity not offered in the competitive solicitation process up to the maximum capacity of each resource as additional capacity that could be procured. If capacity in the California ISO generated bid range receives a designation through the capacity procurement mechanism, its clearing price is set at the soft offer cap. Resources can also file at FERC for costs that exceed the soft offer cap. A scheduling coordinator receiving a designation for capacity with a California ISO generated bid may choose to decline that designation within 24 hours of receiving notice.

The California ISO uses the competitive solicitation process to procure backstop capacity in three distinct processes:

- First, if LSEs and suppliers show insufficient cumulative system, local, or flexible capacity in annual resource adequacy plans, the California ISO may procure backstop capacity through a year-ahead competitive solicitation process using annual bids. The California ISO may also use the year-ahead process to procure backstop capacity to resolve a collective deficiency in any local area.
- Second, the California ISO may procure backstop capacity through a monthly competitive solicitation process in the event of insufficient cumulative capacity in monthly plans for local, system, or flexible resource adequacy. The California ISO may also use the monthly process to procure backstop capacity in the event that cumulative system capacity is insufficient due to planned outages.
- Third, exceptional dispatch or other significant events can also trigger the intra-monthly competitive solicitation process.

Annual designations

There were no annual capacity procurement designations in 2025. Since the implementation of the current capacity procurement mechanism framework in 2016, the only annual designations were made in 2018.

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[292] For additional information, see: FERC Docket No. ER24-1225-000, April 25, 2024: https://www.caiso.com/documents/apr25-2024-letterorderacceptingcapacityprocurementmechanism-soft-offer-cap-tariffamendment-er24-1225.pdf

Monthly designations

There were no monthly capacity procurement designations in 2025. Since the implementation of the current capacity procurement mechanism framework in 2016, the only monthly designations were made in 2023.

Intra-monthly designations

There were no intra-monthly capacity procurement designations that were accepted in 2025.

Multiple intra-monthly designations were declined. Scheduling coordinators who receive an exceptional dispatch for capacity not designated through the resource adequacy process may choose to decline the designation by contacting the California ISO through appropriate channels within 24 hours of the designation. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation, which could reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

16.9 Reliability must-run contracts

From 1998 through 2007, reliability must-run contracting played a significant role in the California ISO market, ensuring the reliable operation of the grid. In 2007, the CPUC implemented the resource adequacy program and provided a cost-effective alternative to reliability must-run contracting by the California ISO. By the end of 2023, there was no capacity designated as reliability must-run (RMR). Please refer to the previous year’s report for the history of the end of recent RMR contracts.[293]

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[293] 2024 Annual Report on Market Issues & Performance, Department of Market Monitoring, August 7, 2025, pp 317–319: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf

16.10 Demand response

Demand response programs are operated and scheduled by load serving entities as well as third-party providers. Only demand response resources scheduled by third-party providers are shown in monthly resource supply plans. In contrast, demand response scheduled by CPUC-jurisdictional load serving entities are not shown in monthly resource adequacy supply plans; instead, under local regulatory authority provisions, all demand response scheduled by utilities is credited against (a reduction from) load serving entity resource adequacy obligations.

Monthly utility demand response resource adequacy averaged 820 MW in 2025. During the peak summer months (July, August, and September), utility-operated demand response programs reported curtailing 94 percent of their real-time schedules. Monthly third-party demand response resource adequacy capacity averaged about 102 MW in 2025, and their self-reported performance during the peak summer months of 2025—including load curtailments in excess of individual resource schedules—averaged 177 percent of their real-time schedules. In general, demand response resources are primarily scheduled on days with high loads and tight supply conditions.

Figure 16.13 shows the total third-party demand response resource adequacy capacity (shown on monthly supply plans) in 2024 and 2025. Third-party demand response participating in the California ISO market decreased from 2024, with a monthly average of 102 MW across 2025.

Figure 16.13 Third-party demand response shown on monthly resource adequacy supply plans

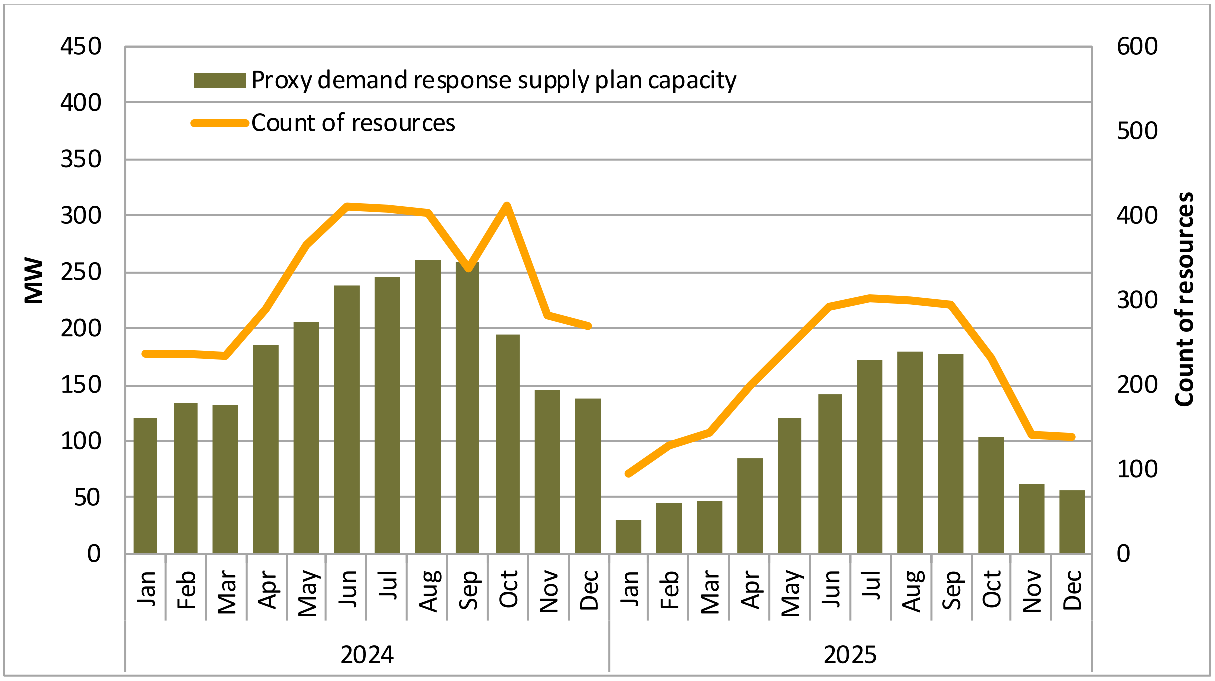
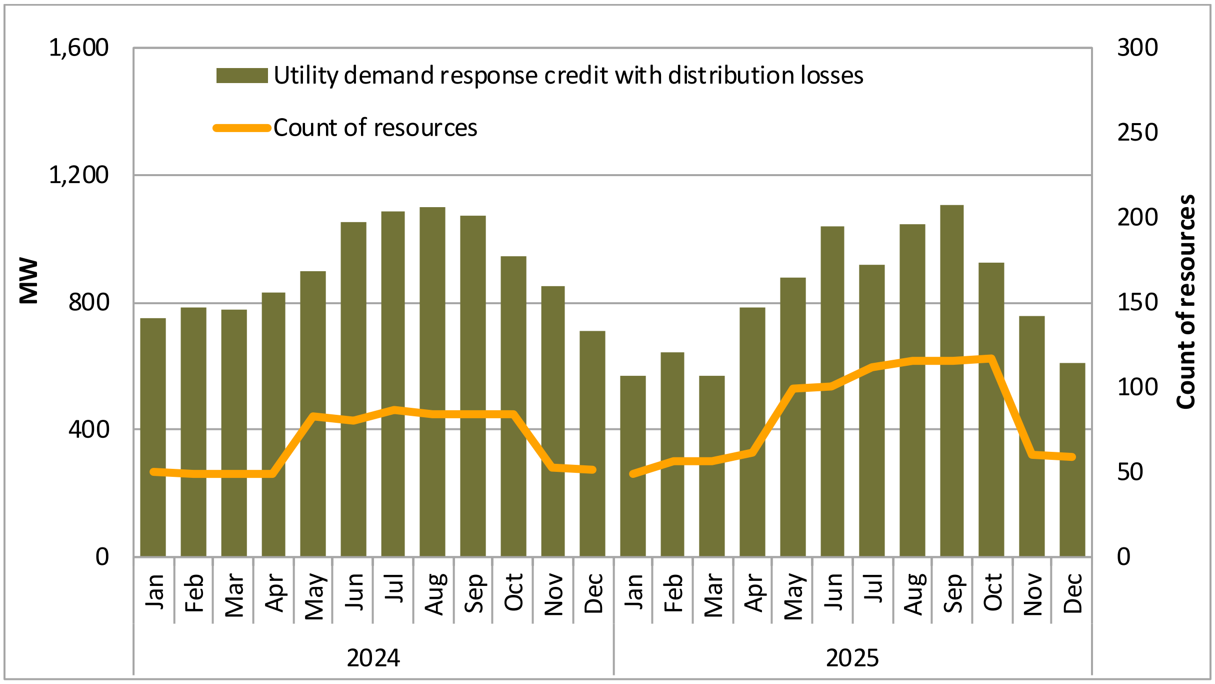


Figure 16.14 shows the total demand response resource adequacy capacity (including both proxy demand response and reliability demand response resources) scheduled and operated by CPUC-jurisdictional utility demand response programs. Any demand response capacity scheduled by a utility-operated demand response program is credited against that utility's resource adequacy obligations, reducing the amount of resource adequacy capacity that load serving entity is required to procure. In

previous years, credits received by utilities for demand response capacity included adders for transmission and distribution line losses. Beginning in 2024, transmission loss gross-ups and planning reserve margin adders were removed from credited utility demand response resource adequacy values. Utility demand response capacity is not shown on resource adequacy supply plans and therefore is not subject to the California ISO must-offer obligations or resource adequacy availability incentive mechanism.

The majority of utility demand response resource adequacy capacity is scheduled from reliability demand response resources. While these resources are generally only dispatched under emergency conditions, they may bid economically in the day-ahead market. In the real-time market, however, reliability demand response resources can only be dispatched if the California ISO is in an EEA Watch or higher, regardless of their bids.

Figure 16.14 CPUC-jurisdictional utility demand response resource adequacy credits



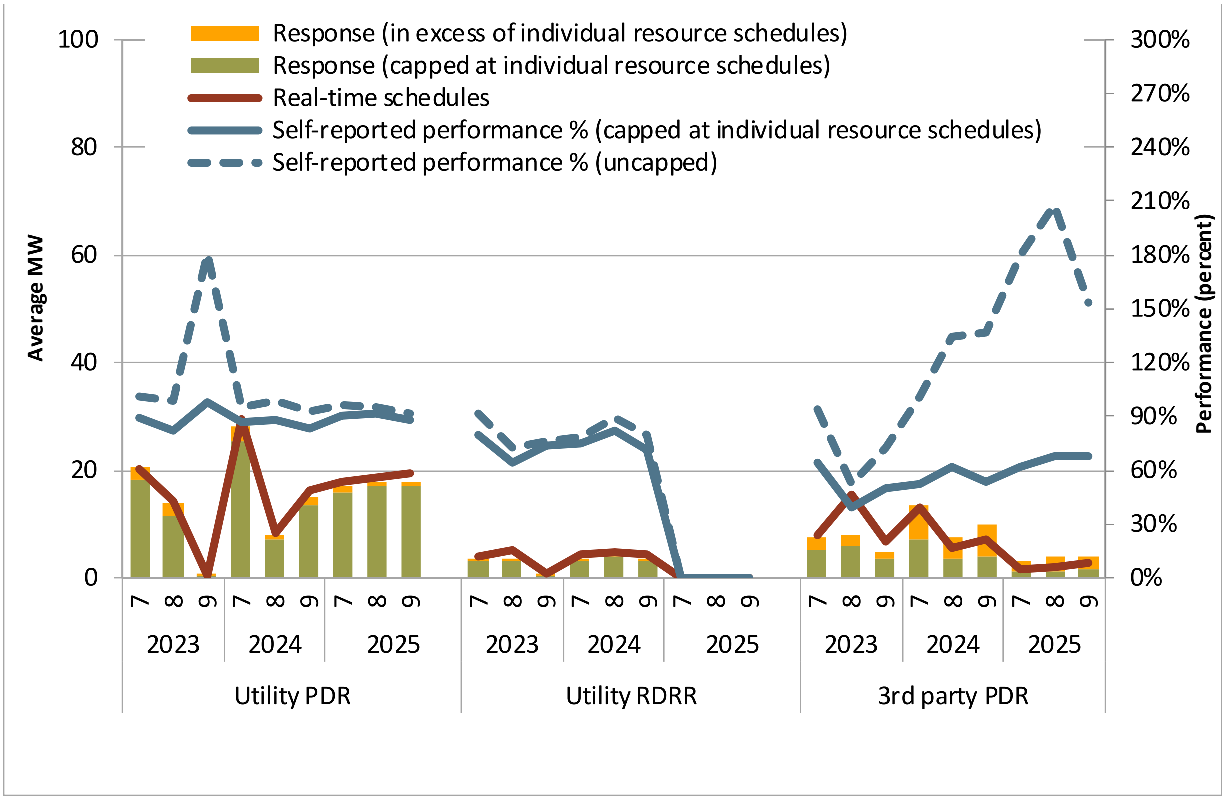
Dispatch and performance of demand response

The California ISO scheduled demand response resources during high load days from July through September in 2025. The ISO economically scheduled proxy demand response (PDR) resources throughout the summer. However, there were no EEA or RMO days during the summer of 2025, and no reliability demand response resources were scheduled.

Figure 16.15 shows the expected load curtailment (schedule) of demand response resource adequacy resources compared to reported performance from July to September of 2023–2025 in peak net load hours (4 to 9 p.m.). In 2025, self-reported performance for utility demand response resources was much lower compared to third-party demand response resources, a trend which began in 2024. During July through September of 2025, uncapped performance of utility proxy demand response (PDR) averaged 94 percent of their real-time schedule. Third-party demand response resources, however, averaged 177 percent across July, August, and September of 2025, but averaged only 67 percent of real-time schedules during high load days.

In summer of 2025, there were no days when reliability demand response resources (RDRR) were dispatched. In 2024, these resources were dispatched on four days.[294]

Figure 16.15 Demand response resource adequacy performance – July to September (4–9 p.m.)



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[294] *Demand response issues and performance 2024*, Department of Market Monitoring, February 20, 2025, p 17: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

17 Wheeling rights

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO balancing area following the power outages in the summer of 2020. In July 2021, the ISO started the Transmission Service and Market Scheduling Priorities (TSMSP) initiative that had two phases: an interim phase to establish wheeling-through priorities for the challenging system conditions in the summer of 2022, and a longer-term framework that started in 2024. External suppliers and load serving entities can now reserve the capacity to self-schedule wheel-through transactions that have the same scheduling priority as CAISO demand in advance of the market runs on rolling monthly and daily timeframes.[295]

This chapter provides analysis on priority wheel-through capacity and reservations. Key findings include:

- **Scheduling coordinators reserved 250 MW of priority wheel-through capacity on the CAISO balancing area transmission system in June, 425 MW in July, 344 MW in August, and 365 MW in September.**
- **Priority wheel-through reservations plus native load needs exceeded the final available transmission capacity on the NOB and Malin interties in August due to outages.** The transmission reliability margin for August would have covered full usage of priority wheel-through reservations plus native load need in August at Malin intertie, but not at NOB.
- **The ISO overestimated native load needs on the set of interties that market participants made priority wheel-through reservations on.** The ISO overestimated native load needs by about 1,500 MW (or 42 percent) in June, 900 MW (22 percent) in July, 1,600 MW (39 percent) in August, and 2,100 MW (52 percent) in September.

17.1 Implementation details

Transmission capacity reservations and usage

Table 17.1 shows all the monthly priority wheel-through reservations by CAISO market tie point in all months where these reservations were made in 2025.

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

Table 17.1 2025 monthly high priority wheel-through reservations by CAISO market tie point[296]

Month	Constraint	Monthly PWT (MW)
Jun	NOB_ITC	250
Jul	ADLANTOVICTVL-SP_ITC	40
	MALIN500_ISL	60
	NOB_ITC	325
Aug	PALOVRDE_ITC	25
	ADLANTOVICTVL-SP_ITC	40
	MALIN500_ISL	50
	NOB_ITC	229
Sep	PALOVRDE_ITC	25
	ADLANTOVICTVL-SP_ITC	40
	MALIN500_ISL	50
	NOB_ITC	250

Market participants may reserve priority wheel-through capacity closer to the operation date on the daily horizon if there is available transmission capacity left over after the monthly reservation horizon. Incremental daily reservations of 10 MW were made for two days in December 2025, with the import portion of the wheel-through at Malin intertie. This was the only instance of incremental daily reservations in 2025.

Figure 17.1 and Figure 17.2 show available transmission capacity (ATC)—i.e., total transmission capacity left after accounting for outages and existing transmission rights—for NOB and Malin interties, respectively. Malin and NOB are the primary interties used to wheel from north-to-south across the CAISO system and both are important sources of import capacity into the CAISO system from the Pacific Northwest. Scheduling coordinators can reserve available priority wheel-through (PWT) capacity (yellow bars) at interties if there is leftover ATC after accounting for native load need (dark blue bars), a transmission reliability margin (light blue bars), and any previously reserved priority wheel-through capacity (green bars).

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[296] Table 17.1 reports priority wheel-through reservations for the CAISO market tie point of the wheel import leg. OASIS reports priority wheel-through reservations by the relevant intertie constraints that can limit intertie capacity. Multiple intertie constraints can affect the flows over different tie points and, therefore, OASIS reports the same priority wheel-through reservation amount for each related intertie constraint. This section reports transmission and priority wheel-through capacity for the most limiting intertie constraint related to the CAISO market tie point of the wheel import legs to avoid double counting. See CAISO Operating Procedure 2510A for additional detail on the relationship between CAISO market tie points and intertie constraints: https://www.caiso.com/documents/2510a.pdf

Figure 17.1 2025 monthly transmission capacity at NOB intertie

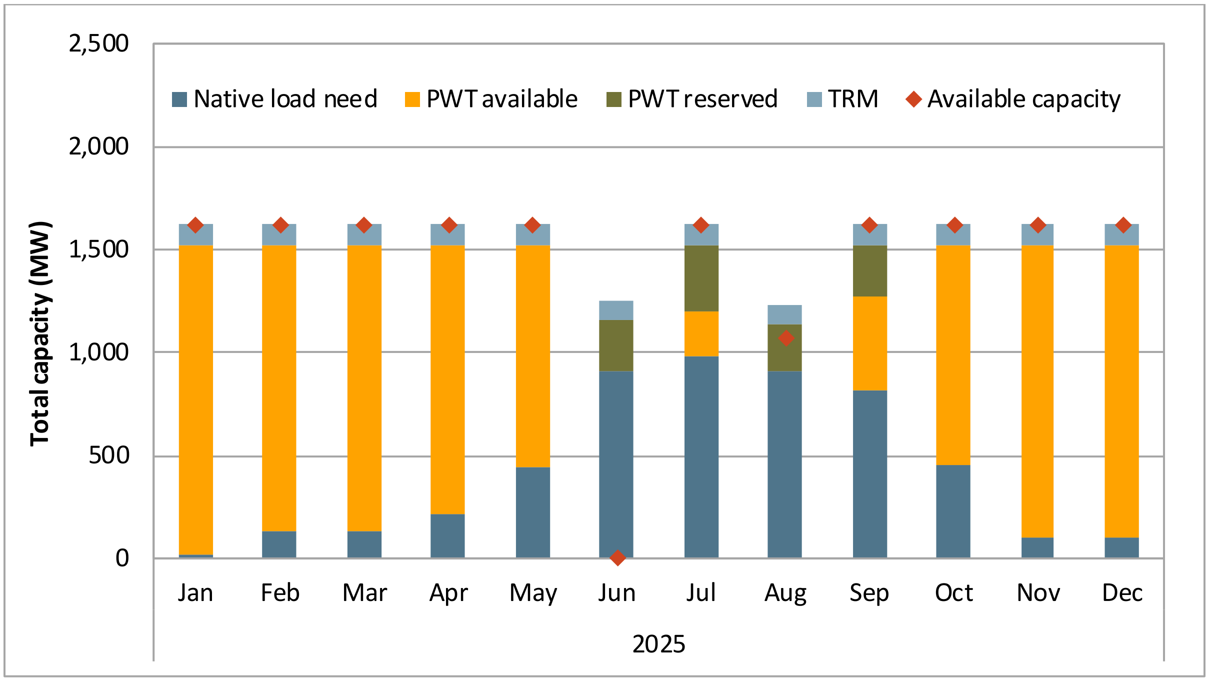
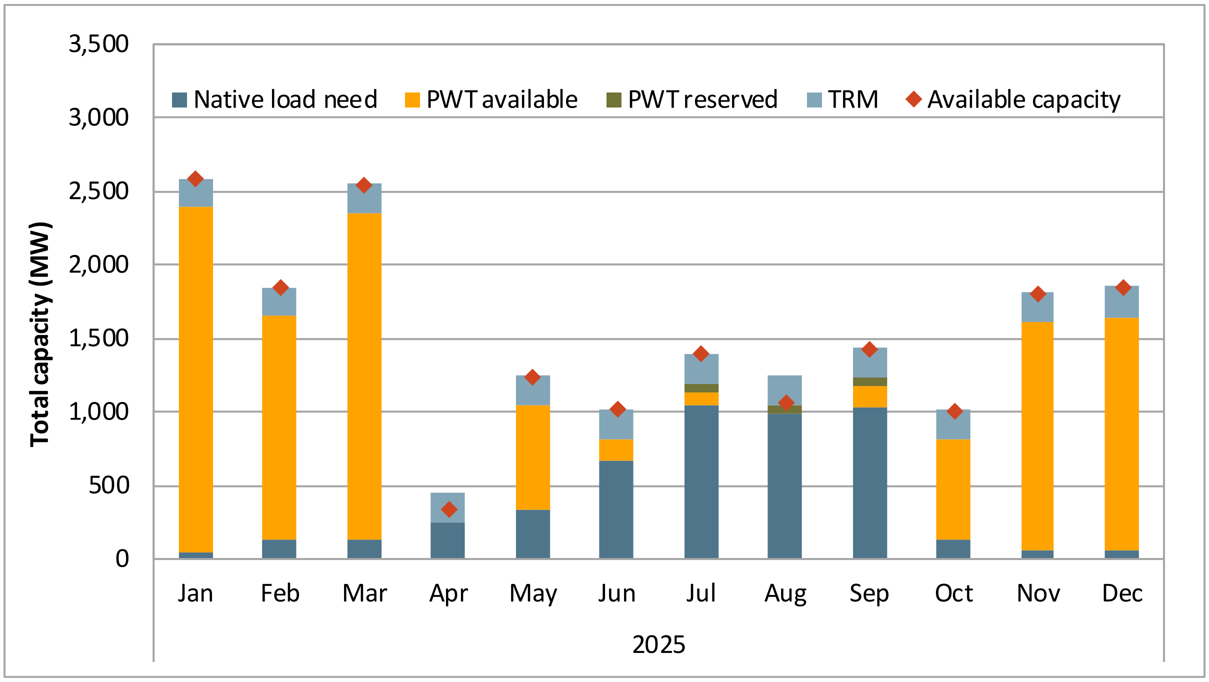


Figure 17.2 2025 monthly transmission capacity at Malin intertie



The total volume of capacity in these four categories (shown by the stacked bars) can total more than the available capacity of an intertie if outage conditions or native load need values change between reservation windows. Specifically, this occurs if the ISO underestimates the native load need before the final resource adequacy (RA) showings, or if new intertie outages lower intertie availability below levels the ISO projected would be available for the month in previous reservation windows.

In June 2025, the ISO updated available transmission capacity at the NOB intertie to zero to account for transmission outages after 250 MW of priority wheel-through capacity had already been reserved for import during a submission window in 2024. The outages at NOB resolved in time for ATC to open up in the daily horizon. However, the reservations failed to carry over to the daily horizon due to a software glitch, ultimately causing the market to not recognize the original monthly reservations.

In August 2025, outages for Malin and NOB caused capacity values to exceed the final available transmission capacity at these interties. The transmission reliability margin for August would have covered full usage of priority wheel-through reservations plus native load need in August at Malin intertie, but not at NOB.

Priority wheel-through reservation values, or awards, are dependent on the supply contract parameters that scheduling coordinators submit to the ISO. Scheduling coordinators may reserve available transmission capacity for priority wheel-throughs for hourly blocks that correspond to the service hours in these contracts. In 2025, scheduling coordinators with priority wheel-through reservations only used that reserved capacity, via day-ahead self-schedules, in July on NOB intertie.

Wheel-through reservation resales

The ISO included resale and assignment provisions for priority wheel-through reservations in the TSMSP framework that FERC accepted in October 2023. On April 12, 2024, the ISO requested a waiver from FERC to extend the effective date of the tariff provisions that allow for resale of monthly wheel-through priority until no later than December 17, 2024. This was because the ISO needed additional time to modify its systems to ensure that the market correctly recognizes when a scheduling coordinator receives priority wheel-through status following a resale, and that settlements accurately reflect the wheeling access charge for the appropriate parties. There were no wheel-through reservation resales in 2025.

Native load need

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

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

Figure 17.3 shows the cumulative native load need estimates and final values on all of the interties that had priority wheel-through reservations throughout the year. Figure 17.4 and Figure 17.5 compare the ISO's native load need estimate and the final shown RA import value at Malin and NOB interties, respectively, for months where there were reservations. Overall, in 2025 the ISO overestimated native load needs in months where there were high priority wheel-through reservations.

Figure 17.3 Native load need estimate vs. final import RA at all relevant market tie points (2025)

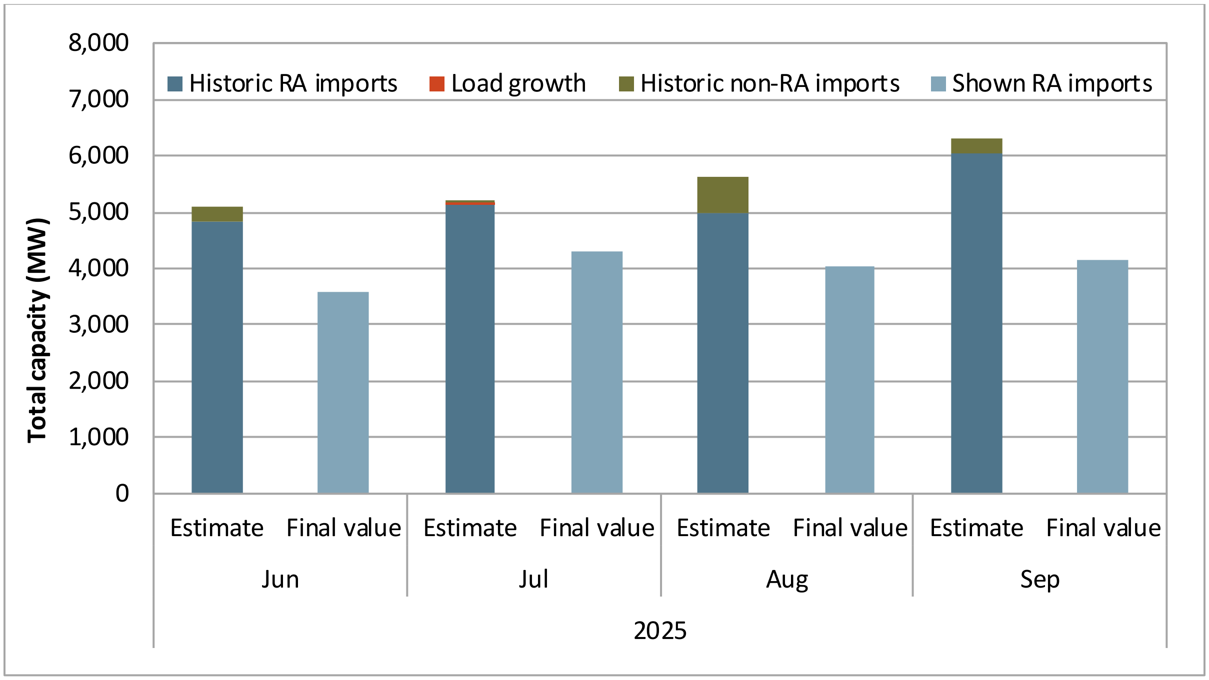


Figure 17.4 Native load need estimate vs. final import RA at Malin intertie

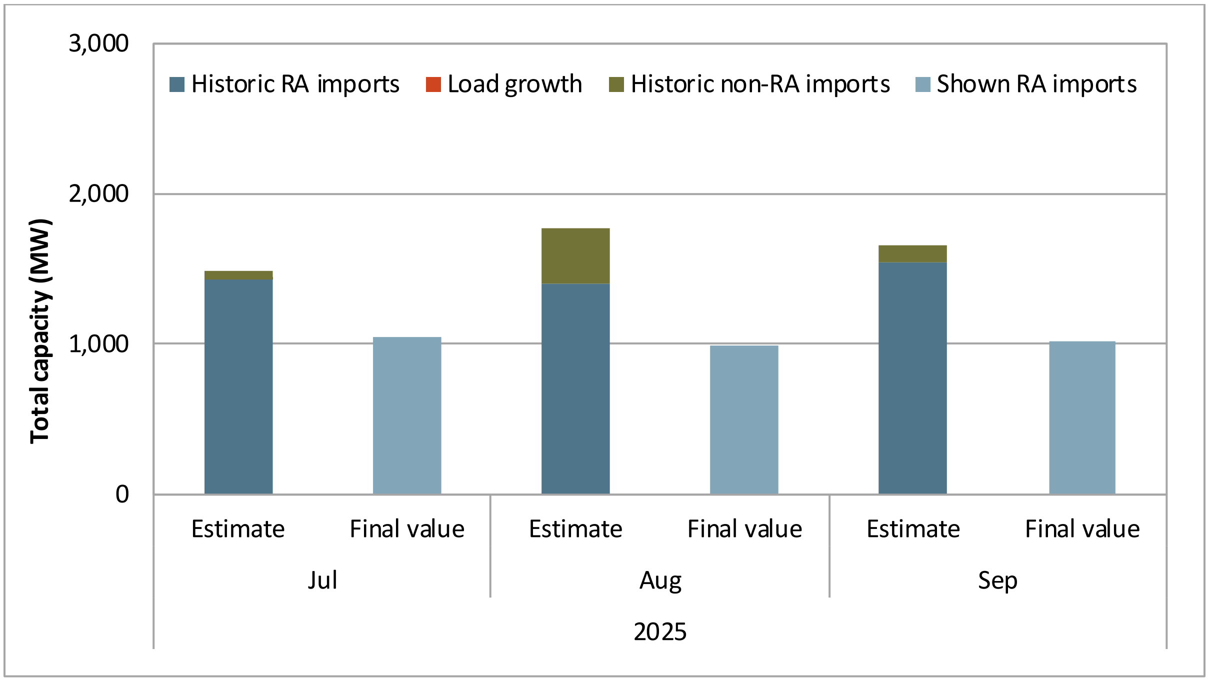


Figure 17.5 Native load need estimate vs. final import RA at NOB intertie