California ISO

DEPARTMENT OF MARKET MONITORING

2023 Annual Report on Market Issues & Performance

July 29, 2024

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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 California's wholesale energy markets and the Western Energy Imbalance Market (WEIM). The CAISO and WEIM continued to perform efficiently and competitively in 2023. Key highlights include the following:

- **The total estimated wholesale cost of serving California ISO area load in 2023 decreased by about 32 percent, due to substantially lower natural gas prices**. Total costs for the CAISO footprint were about $14.5 billion, or about $65/MWh. After adjusting for lower natural gas costs and changes in greenhouse gas prices, wholesale electric costs per megawatt-hour decreased by about 10 percent.
- **Gas prices across the West decreased significantly in 2023 compared to 2022.** Average gas prices at NW Sumas, PG&E Citygate, and SoCal Citygate decreased by 46 percent, 36 percent, and 28 percent, respectively, compared to 2022.
- **The California ISO instantaneous peak load was the third lowest since 2010.** The peak load of 44,534 MW on August 16 was about 7,500 MW less than the peak of 2022. Average load continued to decrease in 2023, due in part to increases in behind-the-meter solar generation.
- **Expansion of the Western Energy Imbalance Market helped improve the overall structure of the real-time market** in the CAISO and other participating balancing areas. In 2023, three new balancing areas (Avangrid, El Paso Electric, and Western Area Power Administration –Desert Southwest) joined the market, adding an average of 6,970 MW of transfer capacity between areas.
- **Total WEIM load peaked at 130,448 MW** during hour-ending 18 on August 16. Of this load, 68 percent was in non-California ISO balancing areas. WEIM transfers between participating areas helped manage the large load, with power flowing from the rest of the system to areas in the Pacific Northwest during the peak hour.
- **Summer supply margins were bolstered by the integration of additional capacity**. The California ISO added about 5.6 GW of capacity between June 2022 and June 2023, and 6.4 GW of additional capacity has been added since June 2023. Batteries and solar grew the most out of any resource type in CAISO, adding 3.8 GW and 2.3 GW, respectively, since June 2023.
- **Despite sufficient available capacity to supply its load during all hours of 2023, the CAISO balancing area declared a level 1 Energy Emergency Alert for hour-ending 20 on July 20**, after having scheduled about 8,000 MW of exports over its interties in the day-ahead and hour-ahead markets.
- **Net imports into the California ISO continued to fall significantly,** as exports increased. On an average hourly basis, net imports were about 2,027 MW lower in 2023 than in 2022. The California ISO exported more power than it imported over its interties in July, and was an overall net exporter of Western Energy Imbalance Market transfers during most months. Prices at the Mid-Columbia hub in the Northwest were higher than California ISO prices throughout the year, and prices at the Palo Verde Hub in the Southwest were higher than California ISO prices during summer months.
- **Prices in the California ISO were competitive**, averaging close to what DMM estimates would result under highly efficient and competitive conditions. Most supply in the Western Energy Imbalance Market footprint offered at or near marginal operating cost.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $59 million in 2023.** These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Changes to the auction

implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. Ratepayer losses have averaged about $62 million per year from 2019 to 2023, compared to average losses of $114 million per year in the seven years before the reforms.

California ISO operator interventions and out-of-market costs and allocations both played a significant role in overall market outcomes in 2023:

- **The California ISO balancing area restricted most WEIM transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 15.** CAISO area operators did not limit transfers in the 5-minute market. This modeling difference contributed to greater congestion and lower prices for many Desert Southwest balancing areas in the 15-minute market relative to the 5-minute market.
- **California ISO operator adjustments to residual unit commitment requirements increased by 154 percent**. This followed an increase of 147 percent in 2022 compared to average 2021 RUC adjustments. In the third quarter of 2023, the average RUC adjustment was about 2,360 MW per hour compared to 1,384 MW in the same quarter in 2022. These large increases were caused by the CAISO area changing its method for determining the uncertainty portion of the RUC load adjustment in the summer of 2023.
- **Bid cost recovery payments in the California ISO balancing area increased to the highest value since 2011,** totaling $289 million, up from $255 million in 2022, despite significantly lower gas prices. Most of this increase is from the $60 million increase in bid cost recovery attributable to the residual unit commitment process. This was largely driven by the increase in operator adjustments to residual unit commitment requirements described above. Bid cost recovery payments for units in the Western Energy Imbalance Market totaled about $33 million, down from $42 million in 2022.
- **California ISO operator adjustments to the hour-ahead market load forecast** averaged over 1,800 MW over the net load peak. Adjustments to the 15-minute market load forecast were similar. This continued the use of large load adjustments during solar ramping hours that began in 2017. The load adjustments in the 5-minute market over the net load peak were on average 1,450 MW lower than the hour-ahead and 15-minute market adjustments. This large difference in load adjustments, as well as the limitations on transfer capacity into CAISO in the 15-minute market described above, contributed to average 15-minute market prices being significantly higher than average 5-minute market prices over peak net load hours in the CAISO balancing area.
- **CAISO real-time imbalance offset costs totaled $322 million in 2023.** This was less than the $401 million in 2022, but still significantly higher than the $176 million in offset costs in both 2021 and 2020. Congestion offset costs, at $194 million, were largely generated by significant reductions in constraint limits between the day-ahead and 15-minute markets. Energy offset costs, at $101 million, were largely caused by load settling on an average real-time price which can differ significantly from the real-time market prices that generating resources are settled on. A systematic error in the prices used to settle California ISO balancing area load also contributed to the energy offset costs, and the ISO is in the process of correcting this error.
- **Congestion rents and uplift from Western Energy Imbalance Market transfer constraints in the 5-minute market were misallocated between WEIM entities in some intervals between July 26 and December 11, 2023.** The ISO has corrected around $5 million of the incorrect allocation from trade date November 5. If this error had impacted all 5-minute market intervals, the maximum additional congestion rent that may have been impacted is about $19 million. However, it is not clear to DMM how many intervals were impacted by the error.

Other key trends in 2023 include the following:

- **Day-ahead market congestion rent decreased** to $866 million, about 19 percent lower than the $1.07 billion from 2022. This decrease was driven by a $135 million reduction in intertie congestion and lower congestion prices on key internal constraints. Real-time market congestion shifted to a predominantly south-to-north flow pattern. This was a change from 2022, when the flow pattern was more predominantly from northern areas to southern areas. The 2023 congestion pattern resulted in increased prices in the Pacific Northwest, Intermountain West, and Northern California, with lower prices in the Desert Southwest and Southern California.
- **The number of system-level structurally uncompetitive hours in the day-ahead market in 2023 was similar to 2022.** Uncompetitive hours decreased significantly from 2020 to 2022. The day-ahead market accounts for most of the California ISO total wholesale energy market costs. This downward trend in uncompetitive hours is due in part to the significant additions in battery capacity for suppliers that have not been pivotal at the system level in recent years.
- **Ancillary service costs decreased to $151 million,** down from $237 million in 2022. On March 1, 2023, CAISO operators began procuring 20 percent of operating reserves as spinning reserves and the rest as less-expensive non-spinning reserves following changes in WECC and NERC reliability standards. Historically, operating reserve requirements were split equally between spinning and non-spinning reserves.
- **Energy subject to mitigation increased in both the California ISO and Western Energy Imbalance Market.** In CAISO, less generation became controlled by entities considered "net buyers," which the ISO's automated market power mitigation procedures assume do not have incentives to exercise market power. In the WEIM, tighter conditions outside of CAISO over the summer and through October—particularly in the Pacific Northwest—caused more congestion into WEIM areas with limited supply competition. Most resources subject to mitigation submitted competitive offer prices, so a very low portion of bids were lowered as a result of the bid mitigation process.
- **Nodal pricing for the flexible ramping product was implemented in February 2023.** Between February and December of 2023, the frequency of non-zero prices for system-level flexible ramping capacity was slightly higher compared to the same period of the previous year, prior to the enhancements. However, since the enhancements, 15-minute market system-level prices for upward flexible capacity were still non-zero in only around 0.8 percent of intervals for 2023. Seventy-seven percent of these intervals occurred during the peak net load hours (hours 18 through 21).
- **The mosaic quantile regression method for calculating uncertainty for flexible ramping product and resource sufficiency evaluation was also implemented in February 2023**. Over the year, the mosaic regression requirements covered between 96 and 97 percent of actual net load errors. Compared to the previous histogram method, the mosaic regression calculated lower average flexible ramping product uncertainty but a larger spread in results. The ceiling or floor designed to cap questionable results of the mosaic regression triggered in roughly 10 percent of 15-minute market intervals and 9 percent of 5-minute market intervals in 2023.

This report also highlights key aspects of market performance, and issues relating to longer-term resource investment and planning.

- **The estimated net operating revenues for typical new gas-fired generation in 2023 were less than DMM's estimates of the going-forward fixed costs of gas capacity** and remained substantially below the annualized fixed cost of new generation. These results continue to underscore the need for gas resources needed for local or system reliability to recover additional costs from long-term bilateral contracts.

- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2023**. During the 12 Energy Emergency Alert hours, average hourly load was about 38-39 GW, while average procured resource adequacy capacity was over 51 GW. Ninety-four percent of this capacity was available in real-time during these hours, after accounting for outages.
- **New battery and solar capacity far exceeded gas capacity retiring from the market.** The California ISO anticipates a continued increase in renewable generation and storage to meet state goals.
- **Since 2016, total battery capacity participating in the CAISO balancing area has increased significantly and totaled about 11,100 MW of discharge capacity by June 2024.** Batteries participate as stand-alone resources or paired with other resources as hybrid or co-located resources.
- **The market for capacity needed to meet local resource adequacy requirements continues to be structurally uncompetitive in half of the local areas.**

Total wholesale market costs

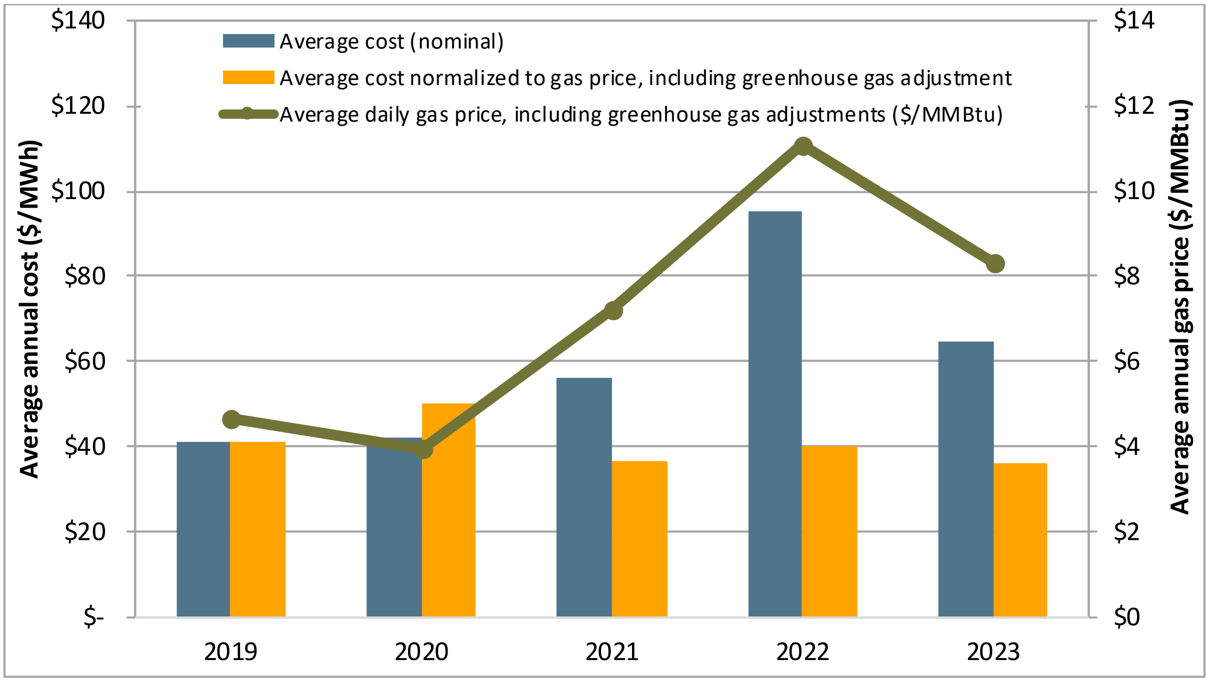
The total estimated wholesale cost of serving load in 2023 was about $14.5 billion, or about $65/MWh. This represents a 32 percent decrease from about $95/MWh or $21.6 billion in 2022. After normalizing for natural gas prices and greenhouse gas compliance costs, and using 2019 as a reference year, DMM estimates that total normalized wholesale energy costs decreased by about 10 percent from about $40/MWh in 2022 to just over $36/MWh in 2023.

A variety of factors contributed to the decrease in total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to lower prices include the following:

- **Decreased natural gas prices.** Overall for 2023, average gas prices at NW Sumas, PG&E Citygate, and SoCal Citygate decreased by 46 percent, 36 percent, and 28 percent, respectively, compared to 2022 (Section 1.2.7);
- **Average hourly load continued to decrease in 2023**, due in part to increases in behind-the-meter solar generation and lower average temperatures (Section 1.1.1);
- **New generation capacity.** The CAISO added more than 6.4 GW of capacity between June 2023 and June 2024. This was mainly battery and solar capacity (Section 1.2.9); and
- **Higher hydroelectric production.** Hydroelectric production increased by about 69 percent from 2022 (Section 1.2.2).

Figure E.1 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.

Figure E.1 Total annual wholesale costs per MWh of load (2018–2022)



Energy market prices

California ISO day-ahead and real-time market prices decreased in 2023, driven primarily by a significant decrease in natural gas prices. Other factors contributing to lower prices included lower average load and higher renewable and storage generation. Figure E.2 and Figure E.3 highlight the following:

- Electricity prices in the Western states typically follow natural gas price trends. This is because natural gas prices set the marginal cost of natural gas resources and other units in the California ISO and other regional markets. Figure E.2 shows both electricity prices and the quarterly gas price inclusive of greenhouse gas compliance costs.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets. Day-ahead prices averaged $63/MWh, 15-minute prices were about $61/MWh, and 5-minute prices were about $55/MWh. Convergence bidding provides incentives for financial arbitrage to converge day-ahead and 15-minute prices. Lower 5-minute prices reflect the difference between 15-minute and 5-minute load adjustments made by operators, as well as operators limiting WEIM transfers into the CAISO balancing area in the 15-minute market during peak hours for most of the second half of 2023.
- Hourly prices in the day-ahead and real-time markets followed the shape of the net load curve, which subtracts utility scale wind and solar generation from load. The evening peak net load was 4 percent lower than in 2022. Peak prices in 2023 were 29 percent lower than those in 2022, and occurred during the highest net load hour, in hour-ending 20.

Figure E.2 Comparison of quarterly gas prices with load-weighted average energy prices

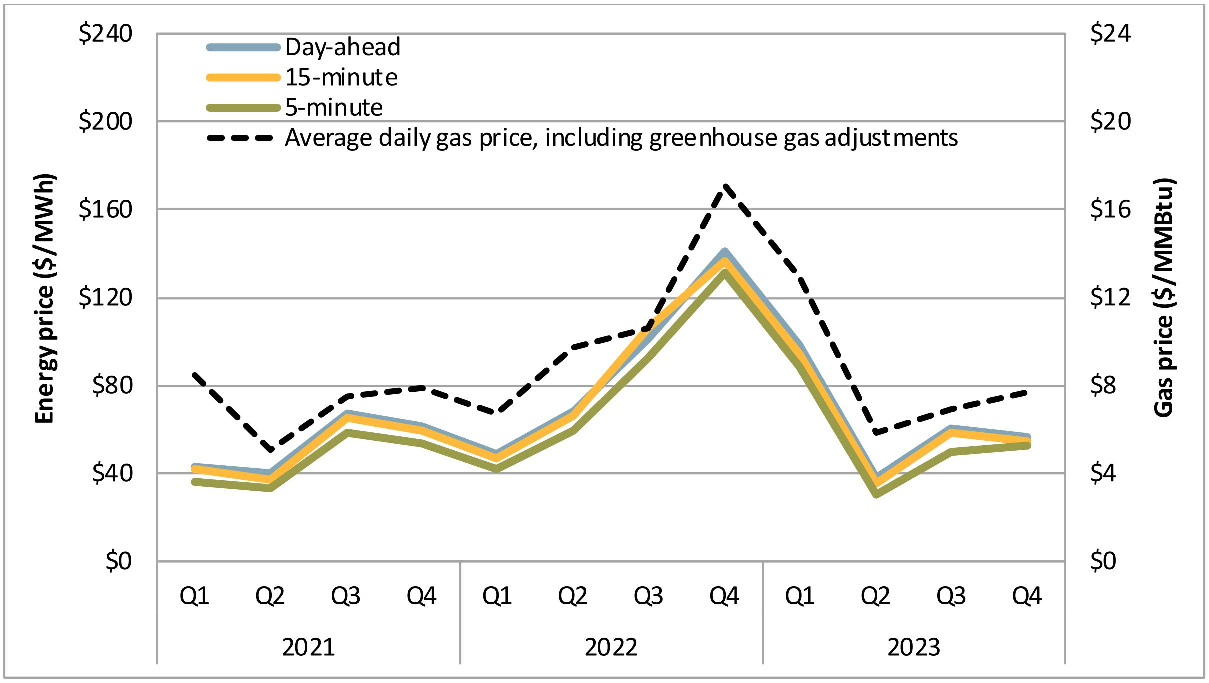
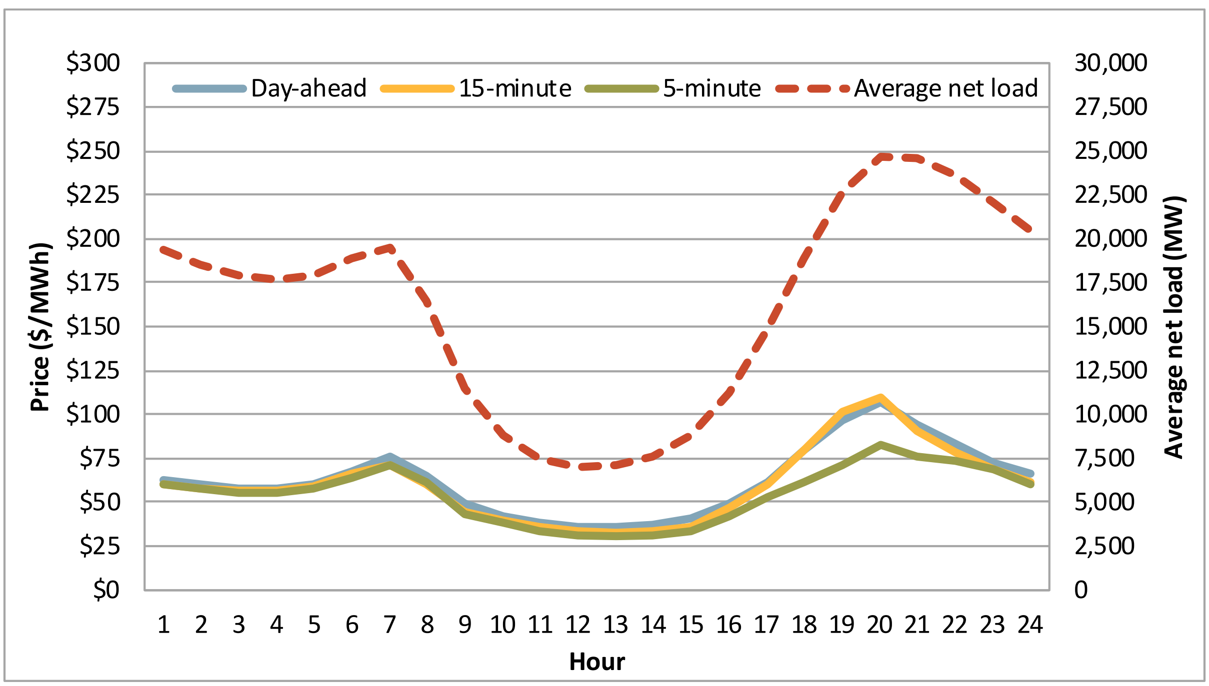


Figure E.3 Hourly system energy prices (2023)



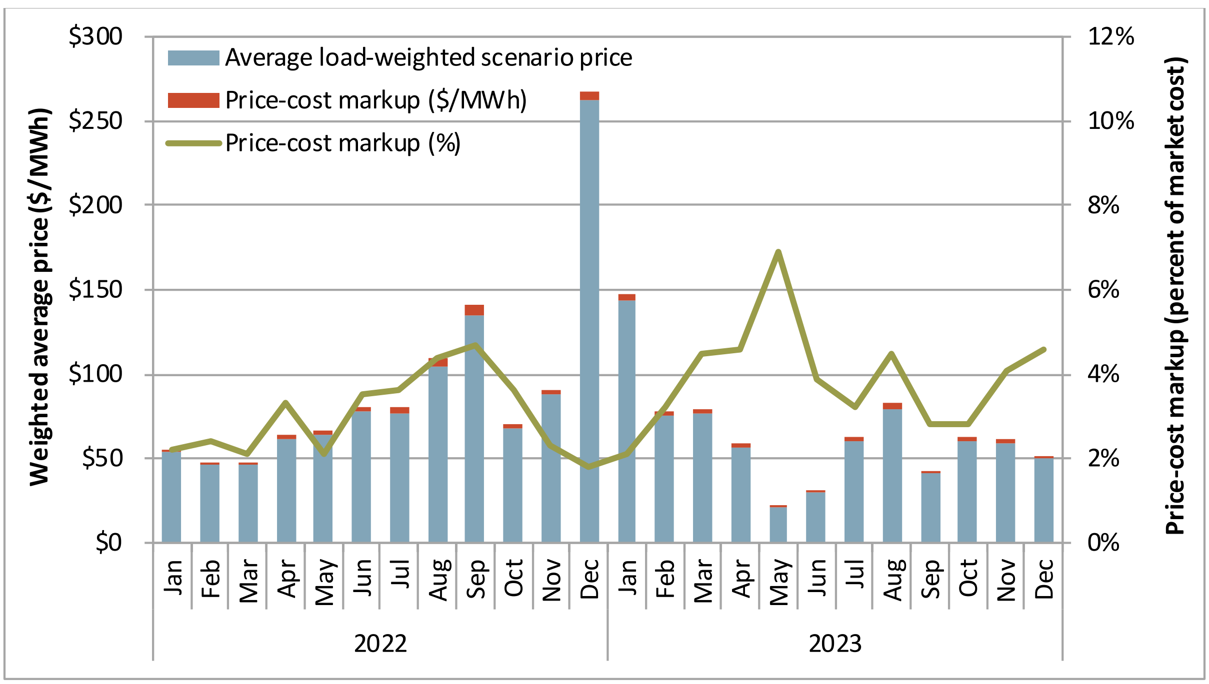
Market competitiveness

Prices in the California ISO energy markets were competitive in 2023. Overall, wholesale energy prices were about equal to competitive baseline prices that DMM estimates would result under perfectly competitive conditions.

The competitiveness of overall market prices can be assessed based on the price-cost markup, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all imports with the lower of their bid and a generous default energy bid (DEB), and replacing the energy and commitment cost bids of other units with the lower of their submitted bids or their DEB or estimated commitment cost with a 10 percent adder. This methodology assumes competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.

DMM estimates an average price-cost markup of $2.38/MWh or 3.6 percent, as shown in Figure E.4. This slight positive markup indicates that prices have been very competitive, overall, for the year.[1]

Figure E.4 Day-ahead market price-cost markup – competitive baseline scenario



1 DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under this competitive baseline scenario. For example, if base case prices averaged $55/MWh and the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

Transfer limitations

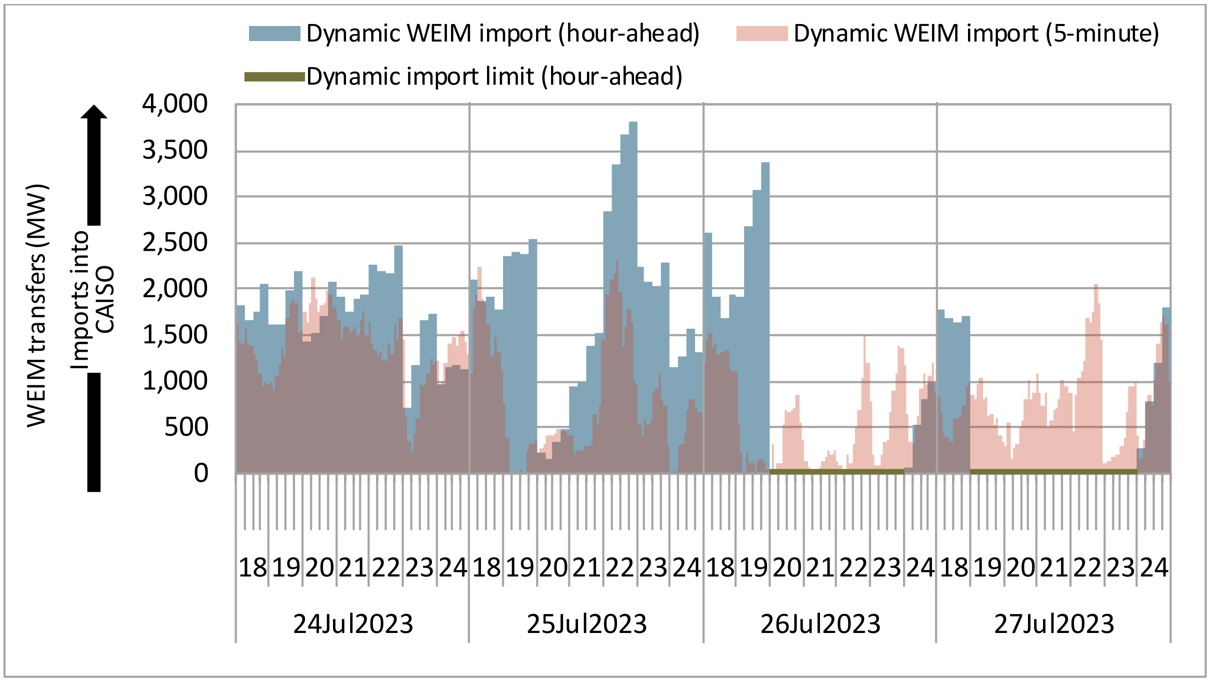
On July 26, CAISO balancing area operators began limiting WEIM import transfers into the CAISO balancing area each day during the peak net load hours. This limitation was put in place for the hour-ahead and 15-minute markets, to mitigate the risk during the critical hours that internal generation and hourly-block intertie schedules might be displaced by WEIM imports that may not materialize in real-time. This limitation typically lasted five hours each day and continued through November 15, 2023.

Figure E.5 shows dynamic WEIM imports into the CAISO balancing area in the evening hours between July 24 and July 27. The blue bars show advisory WEIM imports in the hour-ahead market. The red bars show WEIM imports in the 5-minute market. The green line shows the transfer lock periods in which imports were limited to zero in the hour-ahead market. Outside the lock periods, WEIM transfers into the CAISO balancing area in the hour-ahead market significantly exceeded what was realized in the 5-minute market in most intervals. During the lock periods, hour-ahead (and 15-minute market) transfers into the CAISO balancing area were limited to zero, but substantial 5-minute market imports were still able to flow in those peak evening hours.

The transfer limitation had the intended effect of increasing hourly block imports into the CAISO area and decreasing hourly block exports out of the CAISO area to protect reliability during peak net load hours in late July through mid-August. However, this modeling difference contributed to greater congestion and lower prices for many Desert Southwest balancing areas in the 15-minute market relative to the 5-minute market. It may have resulted in inefficient unit commitment in the 15-minute market.

DMM understands that the transfer limitations were needed in July and August for reliability reasons. CAISO continued the transfer limitations through November 15, when it implemented software enhancements to better address hourly block export curtailments and to provide operators with more accurate information on dispatchable capacity. DMM has recommended that CAISO provide greater transparency on when and why it may implement these limitations in the future. DMM also recommends that CAISO work with stakeholders to consider other methods of achieving the intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and 5-minute markets.

Figure E.5 Dynamic WEIM imports into ISO area (evening hours, July 24-July 27)



Ancillary services

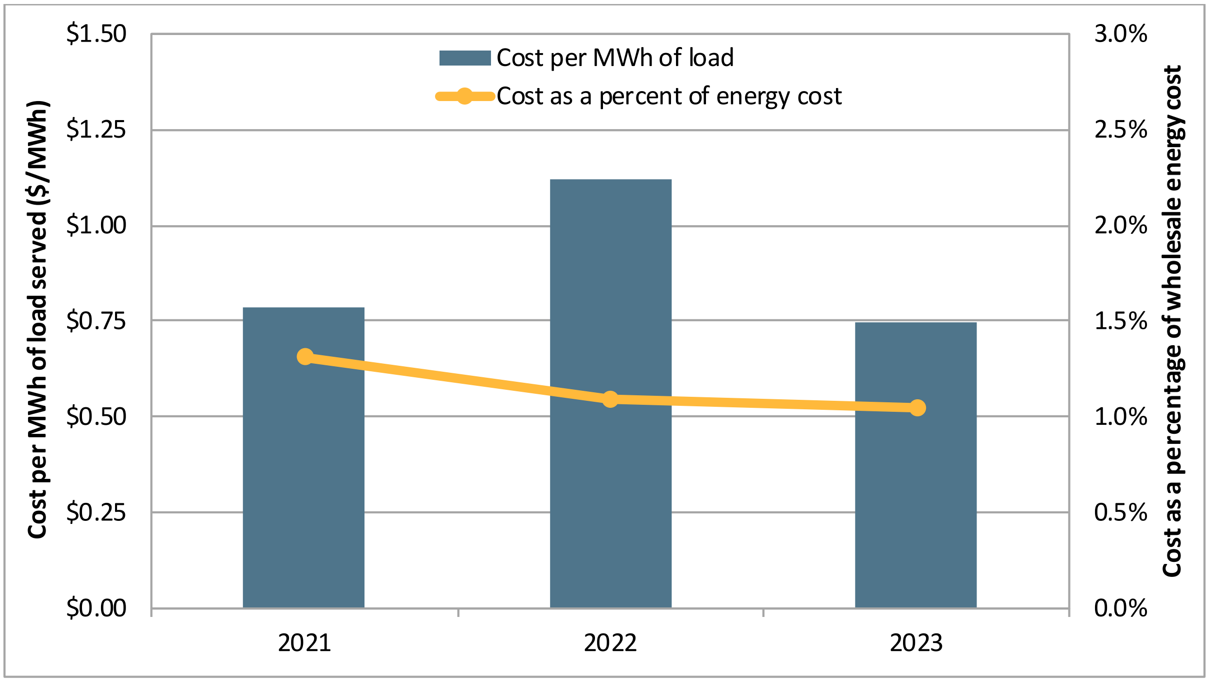
Ancillary service costs decreased from $1.12/MWh to $0.75/MWh of load in 2023 and decreased from 1.1 to 1.0 as a percent of total wholesale energy cost, as shown in Figure E.6. The cost of each individual ancillary service product decreased in 2023, with total ancillary service costs at $151 million, down from $237 million in 2022. The cost of spinning reserve saw the largest decrease, dropping by 63 percent, which is $47 million less than the procurement cost in 2022. This was largely the result of new operating reserve procurement targets, where the CAISO procured spinning reserves at a lower percentage compared to total operating reserve requirements.

Average regulation down requirements increased 10 percent to 901 MW and average regulation up requirements remained nearly the same at 407 MW. Average combined requirements for spinning and non-spinning operating reserves decreased by 10 percent from the previous year to about 1,618 MW.

Fifteen percent of resources failed ancillary service performance audits and unannounced compliance tests, compared to 22 percent in 2022. The frequency of ancillary service scarcity intervals continued to decrease in 2023. There were two intervals in the 15-minute market with an ancillary service scarcity event in 2023, compared to six in 2022, 55 in 2021, and 129 in 2020.

Provision of ancillary services from limited energy storage resources continued to increase, replacing procurement from all other sources. Battery storage resources have provided the majority of regulation requirements since 2022.

Figure E.6 Ancillary service cost as a percentage of wholesale energy cost



Load forecast adjustments

Operators in the California ISO and Western Energy Imbalance Market can manually modify load forecasts used in the market through load adjustments, sometimes referred to as load bias or load conformance. The CAISO uses the term imbalance conformance to describe the adjustments that are used to account for potential modeling inconsistencies and inaccuracies.

In the CAISO, load adjustments are routinely used in the hour-ahead and 15-minute scheduling processes to increase the supply of ramping capacity within the CAISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the CAISO by increasing hourly imports and committing additional units.

As shown in Figure E.7, load forecast adjustments in the hour-ahead market routinely mirror the pattern of net loads over the course of the day. These adjustments averaged 330 MW during the peak morning hour and about 1,820 MW during the peak evening hour. Adjustments in the 15-minute market are very similar to hour-ahead and are not included in the figure.

Operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. During 2023, there were significant changes to how these amounts were determined, as summarized in Figure E.8. This figure shows the average RUC adjustment on each day of 2022 (red) and 2023 (blue). Adjustments to the RUC load requirement increased by 154 percent overall in 2023 compared to the prior year.

Figure E.7 Average hourly load adjustment (2021 - 2023)

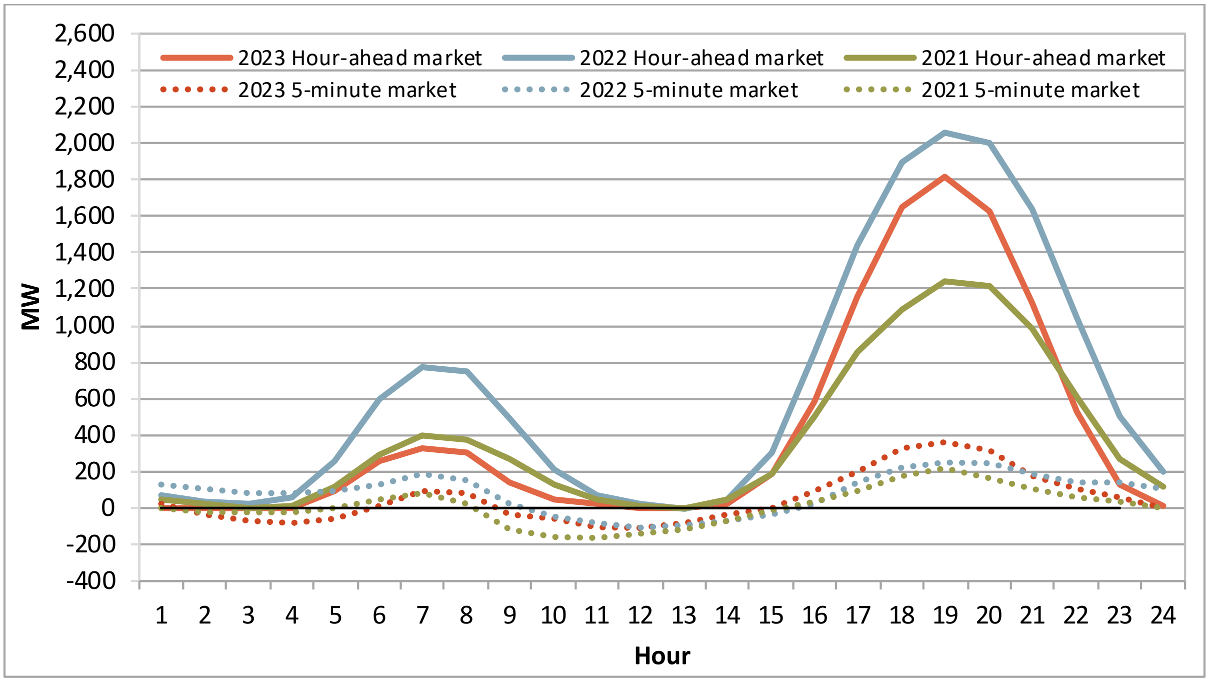
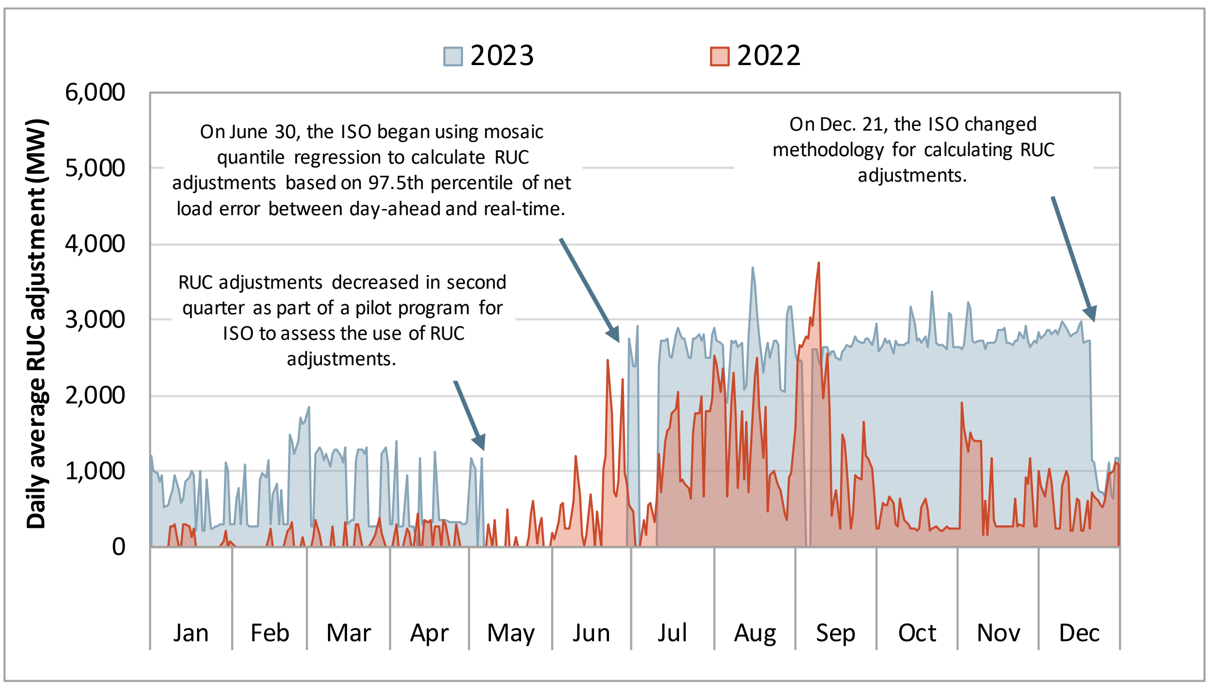


Figure E.8 Average residual unit commitment adjustment by day (2022 versus 2023)



Real-time imbalance offset costs

The real-time imbalance offset cost is the difference between the total money paid by the ISO and the total money collected by the ISO for energy settled at real-time prices. The charge is allocated as an uplift to load serving entities and exporters based on measured system demand.

The real-time imbalance offset charge consists of three components. Any revenue imbalance made from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge*. Likewise, any revenue imbalance from the loss component of real-time energy settlement prices is now collected through the *real-time loss imbalance offset charge*. Any remaining revenue imbalance is recovered through the *real-time imbalance energy offset charge*.

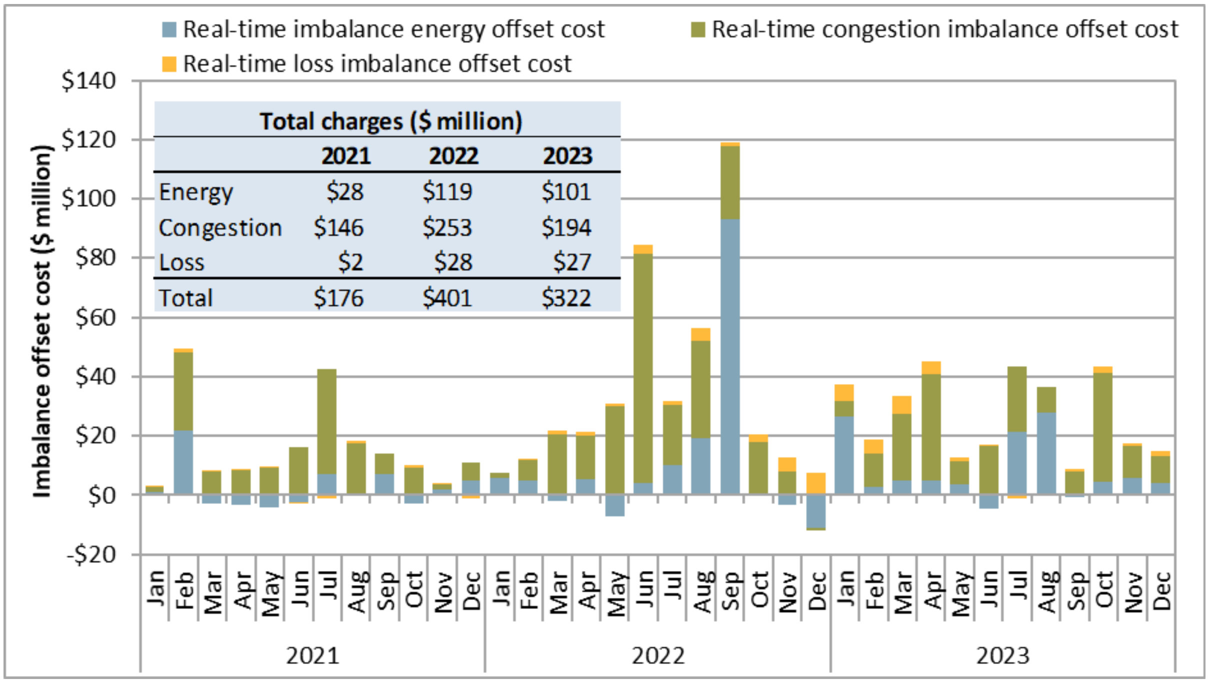
Total CAISO real-time imbalance offset costs totaled $322 million in 2023, as shown in Figure E.9. This was less than the $401 million in 2022, but still significantly higher than the $176 million in offset costs in both 2021 and 2020.

Real-time imbalance energy offset costs were $101 million in 2023, down from $121 million in 2022, but still up significantly from $38 million in 2021 and $62 million in 2020. Much of this uplift was caused by load settling on an average real-time price that can differ significantly from the real-time market prices on which generating resources are settled (Section 2.7). A systematic error in the prices used to settle California ISO balancing area load also contributed to the energy offset costs (Section 2.7).

The majority of the offset costs were from real-time congestion imbalance offsets ($194 million). As in each year since 2018, much of the congestion offset charges appear to have been caused by differences in the network model used in the day-ahead and real-time markets. Many of these differences are caused by significant reductions in constraint limits by grid operators in the 15-minute market relative to limits used in the day-ahead market.

Congestion offset costs, at $194 million, were largely generated by significant reductions in constraint limits between the day-ahead and 15-minute markets. Energy offset costs, at $101 million, were largely caused by load settling on an average real-time price that can differ significantly from the real-time market prices on which generating resources are settled. The main impact of this difference is to shift payments by load serving entities from the price they pay for real-time energy to charges for imbalance offset costs.

Figure E.9 Real-time imbalance offset costs



Bid cost recovery

Generating units and batteries 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.

Bid cost recovery payments totaled $320 million, the highest total since 2011 and a notable increase from 2022, when payments were $297 million.[2] Around $289 million of bid cost recovery payments in 2022 were for units in the California ISO area (CAISO), and $33 million were for units in the Western Energy Imbalance Market (WEIM).[3] The CAISO portion of these payments represents about 2.2 percent of total CAISO wholesale energy costs, an increase from about 1.4 percent in 2022. Most of this increase is from bid cost recovery attributable to the residual unit commitment process. RUC bid cost recovery in 2023 was around $60 million higher than in 2022.

About 81 percent of these payments, or $260 million, went to gas resources, followed by roughly $32 million to battery energy storage resources, and about $14 million to hydro resources. In 2022, these figures were roughly $235 million, $30 million, and $17 million, respectively.

[2] Bid cost recovery payments reported in earlier DMM reports did not include payments from flexible ramping product and greenhouse gas. Including these reduces the shortfall amount that is paid out as bid cost recovery.

[3] All values reported in this section refer to DMM estimates for bid cost recovery totals.

Bid cost recovery payments in 2023 were highest in January, when gas prices were extremely high, and from July to December, when the CAISO balancing area significantly increased its adjustments to the residual unit commitment process load requirement.

Congestion

Locational price differences due to congestion on internal constraints in both the day-ahead and real-time markets decreased in 2023, within the California ISO and other Western Energy Imbalance Market balancing areas. Key congestion trends during the year include the following:

- **Day-ahead market congestion rent and average impact on prices decreased in 2023, even though the percentage of hours in which congestion impacted major load area prices increased to 51 percent** from 36 percent in 2022. Total day-ahead congestion rent for 2023 was $866 million, about 19 percent less than the $1.07 billion in 2022. This decrease was driven by a $135 million reduction in intertie congestion and lower congestion prices on key internal constraints.
- **Real-time market congestion shifted to a predominantly south-to-north flow pattern.** This was a change from 2022, when the flow pattern was more predominantly from northern areas to southern areas. The 2023 congestion pattern resulted in increased prices in the Pacific Northwest, Intermountain West, and Northern California relative to prices in the Desert Southwest and Southern California, particularly during solar hours. During evening hours, average congestion was from north-to-south.
- **Total day-ahead California ISO intertie congestion decreased, but export congestion increased**. The total congestion charges on interties in the day-ahead market amounted to $46.5 million, a decrease from $181 million in 2022. There was an increase in export congestion on interties, particularly on interties connecting CAISO to the Pacific Northwest. The frequency of export congestion on major interties nearly doubled in 2023 compared to 2022, and the associated export congestion charges in the day-ahead market rose from $7 million in 2022 to $13 million in 2023.

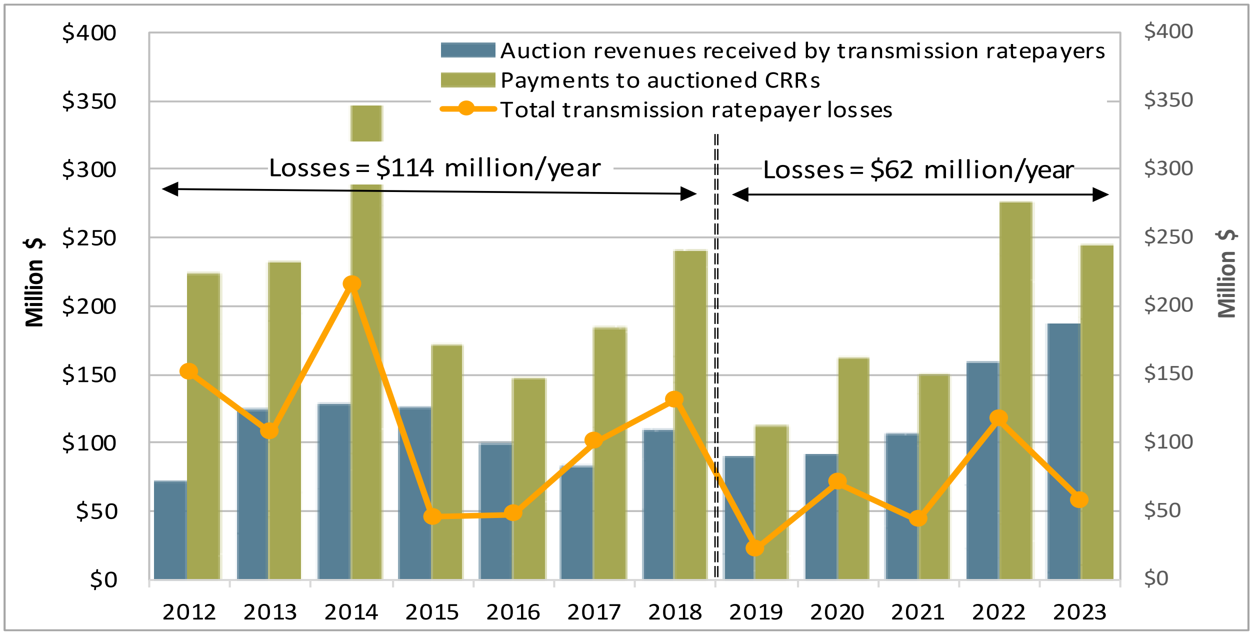
Congestion revenue rights

As shown in Figure E.10, in 2023, ratepayer losses from the auctions totaled $59 million. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). The losses were $117 million in 2022, $43 million and 2021, and $71 million in 2020.

Transmission ratepayers received about 76 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2023. Track 1B revenue deficiency offsets reduced payments to non-load-serving entity auctioned CRRs by about $97 million. Losses from auctioned congestion revenue rights totaled about 7 percent of total day-ahead congestion rent in 2023.

DMM believes the current auction is unnecessary and could be eliminated.[4,5] If the CAISO believes it is necessary to facilitate financial hedging, the current auction format should 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.

Figure E.10 Ratepayer losses from auctioned CRRs



Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the California Public Utilities Commission (CPUC) to provide sufficient capacity to ensure reliability. The resource adequacy program includes CAISO tariff requirements that work in conjunction with regulatory requirements, and processes adopted by the CPUC and other local regulatory authorities.

For over 16 years, long-term procurement has contributed to CAISO market competitiveness. Despite the lack of any bid mitigation for system market power, the CAISO energy markets have been highly competitive at a system level since the early 2000s due to a high level of forward bilateral energy

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4 Department of Market Monitoring, *Problems in the performance and design of the congestion revenue rights auction*, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

5 Department of Market Monitoring, *Market alternatives to the congestion revenue rights auction*, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

contracting by the CAISO load serving entities, relatively high supply margins, and access to imports from other balancing areas.

The California ISO 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). For the years 2022 and 2023, the CPUC set an effective PRM between 20 and 22.5 percent.[6]

Analysis in this report shows that:

- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2023.** There were 72 total hours with RMO+ emergency notifications, and 12 EEA Watch+ hours in 2023, all occurring in July or August 2023. Average hourly load was about 38-39 GW during these hours, while average resource adequacy capacity was 51-52 GW. Of this capacity, 93-94 percent was available in the real-time market after accounting for resource outages.
- **The proportion of system resource adequacy capacity procured by investor-owned utilities decreased significantly in 2023** to 52 percent, down from 61 percent in 2022. Community choice aggregators contributed 25 percent, municipal utilities contributed 9 percent, and direct access services contributed 7 percent. The remaining 6 percent was procured by a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Use-limited resources comprised over 60 percent of resource adequacy capacity.** This capacity is exempt from California ISO bid insertion in all hours.
- **The amount of resource adequacy procured from storage resources increased significantly in 2023.** In 2023, procured storage megawatts increased by around 170 percent. Storage resources comprised 9 percent of the total resource adequacy capacity, up from 6 percent in 2022.
- **Both year-ahead and actual flexible resource adequacy requirements were sufficient to meet the actual maximum three-hour net load ramp for all months in 2023.** 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 2023 requirements and must-offer hours were sufficient in reflecting actual ramping needs in all cases.
- **Sufficient dependable generation existed in all 10 local capacity areas to meet or exceed local requirements.**

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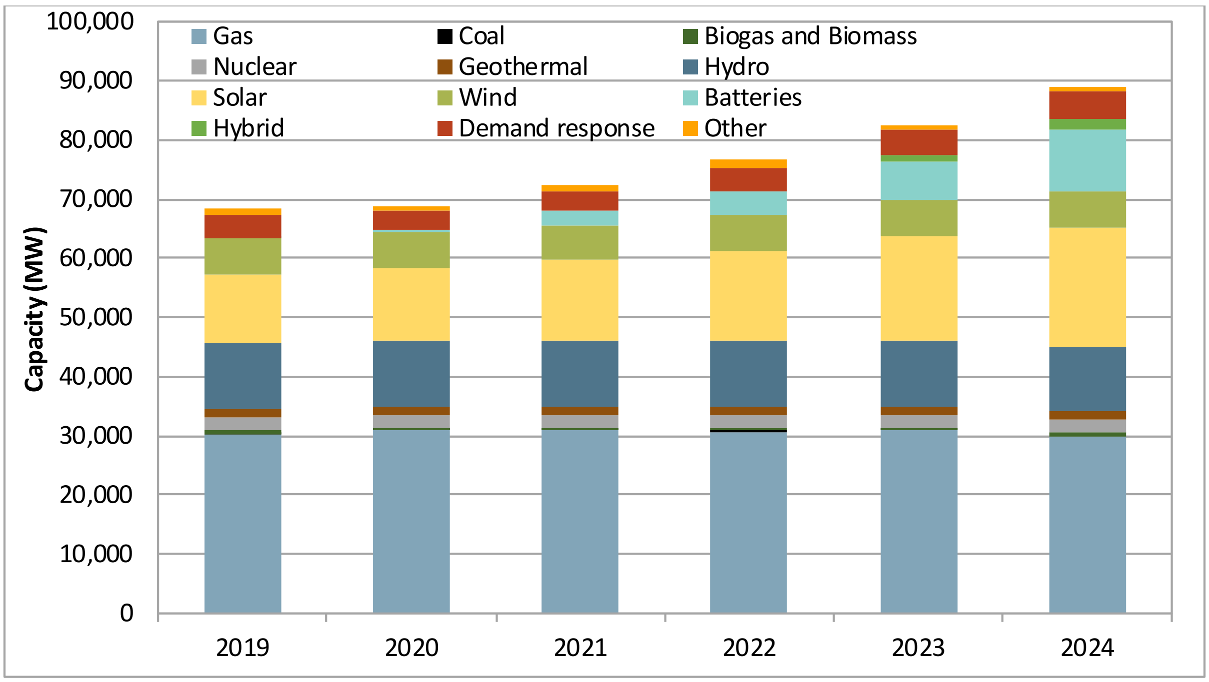
6 The planning reserve margin reflects operating reserve requirements and additional capacity that may be needed to cover forced outages and potential load forecast error. The CPUC determined that, under extreme weather conditions, there would be a need for contingency resources ranging from 2,000 MW to 3,000 MW during the summers of 2022-2023. To address this need, the CPUC continued the approach initiated in Decision D.21-03-056, authorizing the three major Investor-Owned Utilities (IOUs) to procure additional resources. This procurement aimed to meet an effective planning reserve margin between 20 and 22.5 percent, as outlined in *CPUC decision 21-12-015:* https://efiling.energy.ca.gov/GetDocument.aspx?tn=242875&DocumentContentId=76458

Capacity additions and withdrawals

California currently relies on long-term procurement planning and resource adequacy requirements placed on load serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements. CPUC policies also have a major impact on the type of different generating resources retained and added to the CAISO system.

Figure E.11 summarizes the trends in available nameplate capacity from June 2019 through June 2024 for the California ISO balancing area. At 30 GW, natural gas capacity has decreased around 770 MW since last year. Batteries and solar grew the most out of any resource type in CAISO, adding 3.8 GW and 2.3 GW, respectively, since June 2023. The CAISO fleet currently has 1.9 GW of capacity from resources with multiple generation technologies participating under the hybrid model, nearly double the amount from last year. Overall, nameplate capacity has increased by 6.4 GW since June 2023. In comparison, the CAISO added 5.6 GW of nameplate capacity from June 2022 to June 2023.

Figure E.11 Total CAISO participating capacity by fuel type and year (as of June 1)



The California ISO anticipates a continued increase in renewable generation in the coming years to meet the state's goal to have 50 percent renewable generation by 2025 and 60 percent by 2030. Going forward, significant reductions in total gas-fired capacity may continue, if conditions allow, because of the state's restrictions on once-through cooling technology as well as other retirement risks. The California ISO emphasized the need to maintain adequate flexibility from both conventional and renewable generation resources to maintain reliability as more renewable resources come on-line.

Under the CAISO market design, fixed costs for existing and new units critical for meeting reliability needs can be recovered through a combination of spot market revenues and bilateral contracts, both multi-year and short-term. Each year, DMM analyzes the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources.

This market metric is tracked by all independent system operators and the Federal Energy Regulatory Commission.

DMM estimates net revenues for new gas-fired generating resources using market prices for gas and electricity. As shown in Figure E.12 and Figure E.13, in 2023, estimated net revenues for both combined cycles and combustion turbines in both Southern and Northern California were slightly below estimated going-forward fixed costs. Net revenues were substantially below annualized fixed costs. These findings highlight the critical importance of capacity payments including resource adequacy contracts and other bilateral contracts, and the importance of long-term contracting as the primary means for investment in any new generation or retrofit of existing generation needed under the current California ISO market design. Net revenues combined with a capacity payment equal to the CAISO backstop capacity soft offer cap ($88/kW-yr) are well in excess of going-forward fixed costs in all years but fall short of annualized fixed costs in most years, with the exception of combined cycles in SP15 in 2020 and 2017, and in both regions in 2022.

Figure E.12 Estimated net revenue of hypothetical combined cycle unit

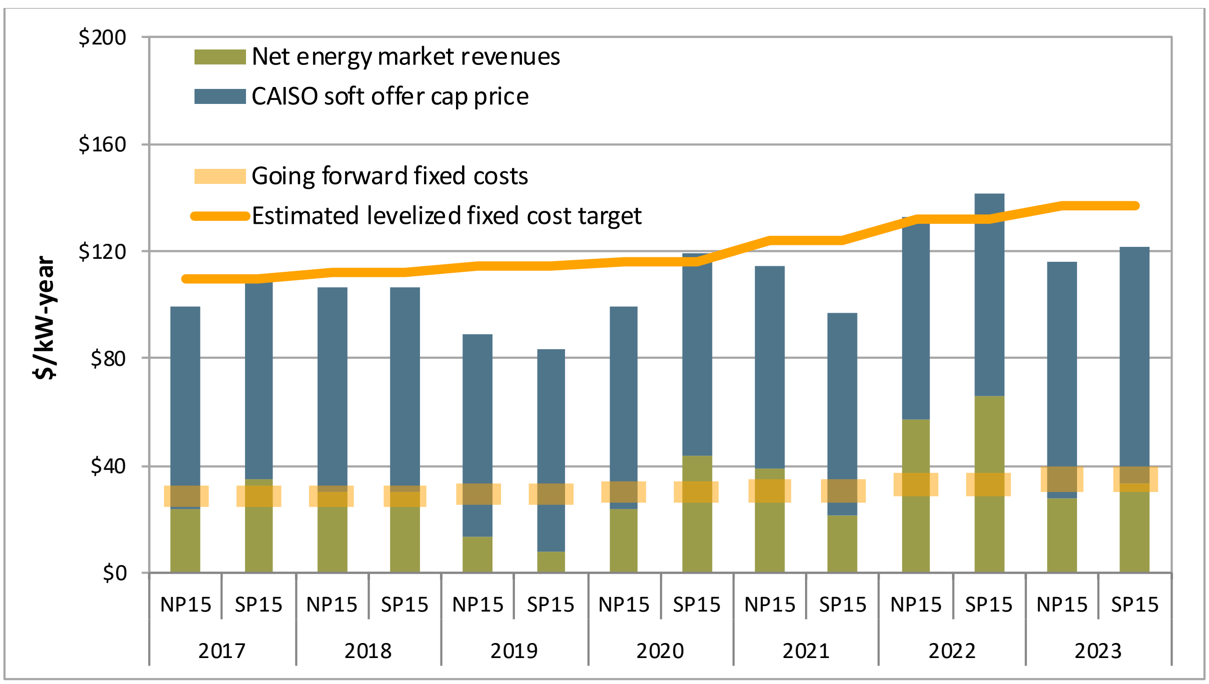
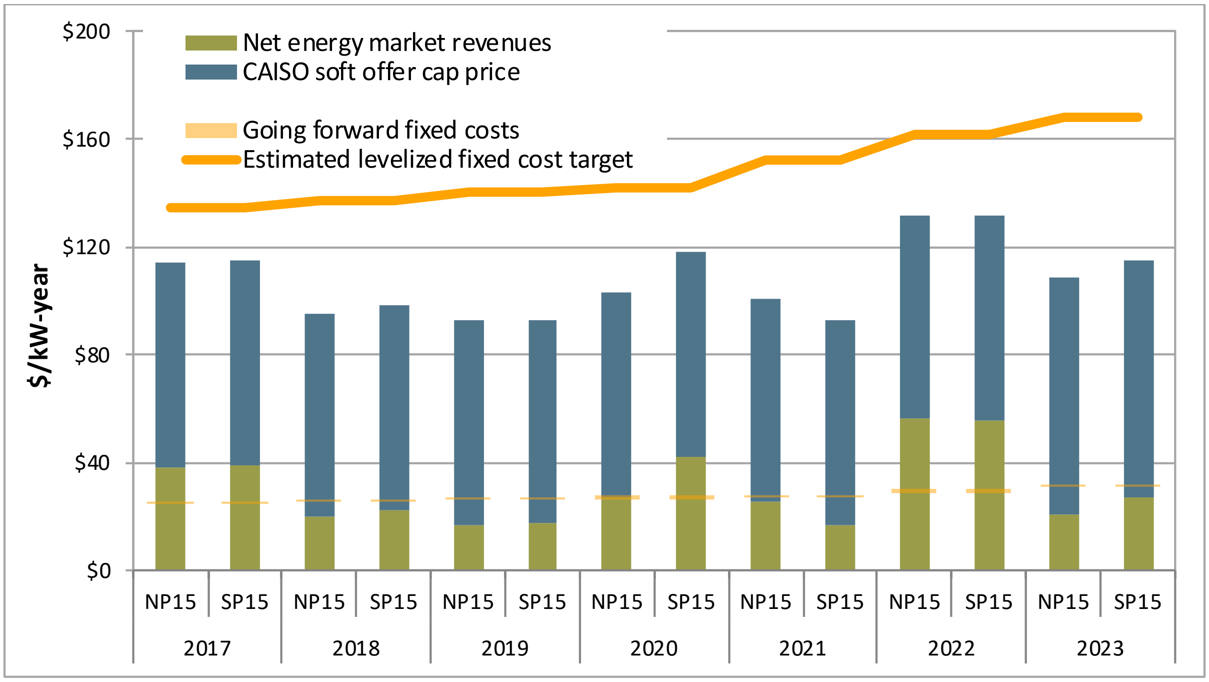


Figure E.13 Estimated net revenues of hypothetical combustion turbine



Recommendations

As the independent market monitor for the California ISO and the Western Energy Imbalance Market, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives.[7] 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 section 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.[8] A more detailed summary of DMM's recommendations is provided in Section 9 of this report.

Extended day-ahead energy market

In 2023, the ISO Board and WEIM Governing Body approved proposed designs for an extended day-ahead market (EDAM) and day-ahead market enhancements (DAME). These proposals were approved by FERC and are scheduled for implementation in 2026. 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. A more detailed summary of DMM's recommendations are provided in DMM's memo to the ISO Board and WEIM Governing Body on the EDAM proposal.[9]

Some important unresolved issues remain in the design that, if not adequately addressed, could have reliability or efficiency costs that could significantly limit the net benefits of EDAM for participating entities during this initial implementation phase. However, DMM believes the main unresolved issues can be addressed through a combination of further stakeholder and tariff processes prior to implementation, and design enhancements within the first few years of implementation.

The ISO's final proposal recognizes that further details of both EDAM and DAME design will need to be developed and adapted based on testing the full software model prior to implementation, and on operational experience after implementation. The final proposal also includes a set of specific configurable software parameters, which can be adjusted before and after implementation in consultation with stakeholders. DMM supports this approach and looks forward to continuing to collaborate with the ISO and stakeholders on the remaining steps towards developing and implementing a regional day-ahead market.

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7 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

8 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

9 Memorandum ISO Board of Governors and WEIM Governing Body, Department of Market Monitoring, January 25, 2023: http://www.caiso.com/Documents/DepartmentofMarketMonitoringReport-Feb2023.pdf

Day-ahead imbalance reserve product

A key element of the EDAM and DAME proposals 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 such a product, but has provided several key recommendations regarding potential changes to the initial proposal, as summarized below.

- **Demand curve for imbalance reserve.** DMM recommends that the ISO continue to work on developing more accurate methods for determining the demand curve for imbalance reserves in the day-ahead market, and prepare to potentially reduce the initial $55/MWh cap after EDAM implementation.
- **Virtual supply.** 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 will require that sufficient on-line physical capacity to address net load uncertainty continues to be procured through the subsequent residual unit commitment process. 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 extending the uncertainty horizon of the real-time flexible ramping product or developing a real-time imbalance reserve 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.

Market power in transmission access

The EDAM design requires generation in a *source* balancing area to have firm transmission to the *sink* balancing area before each day's EDAM run. This can limit the pool of resources within EDAM balancing areas that can compete to meet a sink balancing area's resource sufficiency evaluation requirements. Resources affiliated with the large transmission rights holder could exercise market power in the resource sufficiency evaluation supply market, charging excessively high prices for the capacity that the sink balancing area needs to pass the resource sufficiency evaluation.

The potential for such market power is likely to be mitigated during the initial EDAM implementation due to a limited number of balancing areas initially participating in EDAM. However, before a substantial number of balancing areas join EDAM, DMM recommends that the ISO prioritize assessing the extent to which this market power can exist on specific transmission paths, and develop market design enhancements to mitigate this market power where it has the potential to be exercised.

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 as part of the process of enhancing the initial EDAM design, the ISO and stakeholders consider more nuanced rule 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 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 five years since the ISO implemented CRR reforms aimed at reducing these losses in 2019, ratepayers have lost $312 million (or an average of $62 million per year) and have received only 67 cents in auction revenues per dollar paid out.
- In 2023, ratepayer losses from congestion revenue rights auctioned off by the ISO totaled $58 million and have received only 76 cents in auction revenues per dollar paid out.[10]

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 losses from congestion revenue rights in November 2023. Analysis presented by the ISO to the MSC also shows that auction revenues have equaled only about 65 percent of congestion revenue payouts since 2019, compared to about 49 percent in the years prior to the 2019 changes.[11] However, no further action has been taken on this issue as of June 2024.

DMM continues to believe that the current auction is unnecessary and could be eliminated, with all congestion rents being returned to transmission ratepayers. If the ISO and stakeholders believe it is beneficial to the market to facilitate hedging, then the current auction format should be changed to a market for congestion revenue rights, or locational price swaps based only on bids submitted by entities willing to buy or sell congestion revenue rights.

This approach—based on willing sellers and buyers—would replace the current auction with the same type of market through which all other financial derivatives are bought and sold. This approach would provide a market in which load serving entities could continue to voluntarily sell back any congestion revenue rights acquired in the allocation process. This approach is guaranteed to be revenue neutral for transmission ratepayers, and would allow the ISO to eliminate the need for deficit offset charges that

10 See *2022 Annual Report on Market Issues and Performance*, July 11, 2023, pp 18, 183-190: https://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf

11 *Congestion Revenue Rights discussion*, Market Surveillance Committee Meeting, November 29, 2023, slide 33: https://www.caiso.com/Documents/CongestionRevenueRights-Presentation-Nov29-2023.pdf

occur when congestion revenues are not sufficient to fully fund congestion revenue rights sold in the auction by the ISO.

Battery resources

The amount of energy storage resources (batteries) on the CAISO system has increased significantly in recent years, and is projected to continue increasing in coming years. While battery resources are generally very fast responding and flexible, the availability of these resources depends on their state of charge levels. For example, battery resources providing resource adequacy often do not have sufficient charge to provide their full resource adequacy capacity values for four consecutive hours across peak net load periods. DMM has suggested potential changes to CPUC and CAISO rules that could help mitigate availability concerns related to battery resources.

Bid cost recovery rules

The main purpose of bid cost recovery (BCR) for traditional generators is to alleviate the risk that the net revenues from the difference between the 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 2023, batteries received nearly $28 million of bid cost recovery (primarily from the real-time market), or about 10 percent of all bid cost recovery.

The main limitations on battery dispatch that lead to BCR payments derive from state-of-charge limitations that are set by battery operators. These state-of-charge limitations can result in uneconomic market dispatches that are eligible for bid cost recovery payments. When these unit limitations were being designed for battery operators, 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 continues to recommend that the ISO place a high priority on developing more general revisions to BCR rules for batteries as soon as practicable. New BCR rules are specifically needed to address BCR payments stemming from a range of actions by battery operators that can constrain a battery's state of charge, or otherwise force uneconomic dispatch by the market software. When a battery's day-ahead state of charge value deviates significantly from actual state of charge value in real-time, this creates inefficient dispatch, reduces reliability, and creates opportunities for gaming of bid cost recovery payments.

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 new slice-of-day framework being developed 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 include sufficient surplus energy to ensure that batteries can be fully charged over the four most critical net peak hours.

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 could include changes to bid cost recovery rules aimed at ensuring battery storage resources are properly incentivized to reflect 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.[12]

Bids for batteries used in local market power mitigation

In practice, most batteries are not subject to bid mitigation under the ISO's local market power mitigation procedures very frequently. And when subject to mitigation, the impact of mitigation on the dispatch of batteries has been very low. However, DMM recommends the ISO continue to enhance the methodology for calculating default energy bids for energy storage resources, create a standardized default energy bid for storage resources in the WEIM, and work towards extending mitigation to include hybrid resources.

The current default energy bids for energy storage resources include three types of costs: energy costs, variable operations costs—including cycling and cell degradation costs—and opportunity costs. DMM recommends that the ISO continue to enhance the proposed default energy bid for energy storage resources as follows:

- Allow the default energy bid value to vary throughout the day to capture opportunity or other costs that may differ based on resource operation over the day;
- More precisely clarify whether some components, such as sunk costs from intraday charging, are included for the purpose of increasing the default energy bid to approximate different costs that are not otherwise captured;
- Reconsider the use of day-ahead local market power mitigation run prices as an input to the day-ahead storage default energy bid; and
- Develop an enhanced framework that allows for estimation of opportunity costs outside of the market optimization horizon, and that accurately accounts for those opportunity costs by considering the ability of storage resources to discharge and recharge before reaching future intervals.

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12 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 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 charging bid range such that resources are unable to charge for later hours.

Allowing batteries to bid in excess or $1,000/MWh soft cap

Batteries are currently subject to a $1,000/MWh hard bid cap, even on days when some other resources can bid above $1,000/MWh. On days when real-time prices exceed the $1,000/MW soft cap, the $1,000/MWh bid cap on battery resources could prevent these resources from bidding potential intra-day opportunity costs in excess of $1,000/MWh. This could contribute to sub-optimal dispatch of the battery fleet by causing some battery capacity to be dispatched in hours prior to the highest priced peak net load hours. In practice, however, analysis by DMM shows that sub-optimal dispatch of batteries on days when real-time prices have exceeded the $1,000/MWh soft cap was not due to the $1,000/MWh bid cap on batteries, since most battery capacity was bid at prices below the $1,000/MWh on these days.[13]

DMM supports allowing batteries to bid up to opportunity costs in excess of $1,000 in the hours leading up the highest priced peak net load hours. However, DMM notes that during the peak net load hours, the opportunity cost for batteries to discharge should be much lower. The ISO has indicated it could not implement an approach with different opportunity costs for different hours, as suggested by DMM.

To ensure intra-day opportunity costs can be appropriately reflected in all hours, DMM recommends the ISO develop a bid cap that can vary hourly when exceeding $1,000/MWh. This approach would avoid overstating costs in many hours, as occurs under the ISO's recently approved real-time bid cap for storage resources on days with hours when bids may exceed $1,000/MWh.

Resource sufficiency tests

The resource sufficiency tests for capacity and flexible ramping capacity are key elements of the Western Energy Imbalance Market (WEIM) design, which are intended to ensure that enough resources are available to meet reliability needs and prevent one balancing area from leaning on other WEIM areas.

Energy assistance option

Currently, when a WEIM area fails either the capacity test or flexible ramping test, WEIM transfers into the balancing area are not allowed to increase beyond the level of supply being transferred into the area just prior to the test failure. DMM has recommended that both the California ISO and stakeholders consider other options, such as imposing a capacity charge or other financial charge.

A major change taking effect in 2023 was implementation of an energy assistance option that would allow WEIM areas to import additional energy through WEIM during intervals when they fail the resource sufficiency test. Areas importing additional energy under the emergency assistance option will be subject to a penalty cost based on the amount by which the area failed the test, the amount transferred into the area from WEIM, and the CAISO/WEIM penalty price in effect ($1,000 or $2,000/MWh). With this approach, the total cost of the penalty will be scaled closely with the degree to which areas may be relying on the WEIM when failing the test.

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13 *Comments on Management's proposed changes to rules for bidding over the soft-offer cap,* Department of Market Monitoring memorandum to the ISO Board of Governors and WEIM Governing Body, May 15, 2024: https://www.caiso.com/documents/departmentofmarketmonitoringcomments-softoffercap-memo-may2024.pdf

DMM supported the revised energy assistance option included in the proposal as a reasonable compromise that could be implemented in summer 2023 and would encourage a larger portion of WEIM balancing areas to participate in this option. DMM recommends that the ISO should continue to refine the consequences for areas that elect to not opt in to the energy assistance program, but then fail the resource sufficiency test. More specifically, DMM has recommended that both the California ISO and stakeholders consider other options, such as imposing a capacity charge or other financial charge.

Incorporating uncertainty into test requirements

Currently, a component for net load uncertainty is included in the flexible ramping test, but is not incorporated in the capacity test. The ISO is not proposing to add uncertainty back into the capacity test at this time. While incorporating some level of uncertainty into the test is reasonable, there is not an objectively correct answer to what this uncertainty adder should be.

In February 2023, the ISO implemented a new method of net load uncertainty calculation based on quantile regression for the flexible ramping product. DMM's review of the performance of this new methodology indicates that it is not a clear improvement over the prior method. Therefore, DMM continues to recommend that the ISO and stakeholders consider developing much simpler and more transparent uncertainty adders in the next phase of this initiative. DMM also recommends considering adoption of uncertainty calculations customized to the resource sufficiency evaluation, rather than using the uncertainty calculation that was developed for determining market requirements for the flexible ramping product.

Flexible ramping product

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. This product has the potential to help increase reliability and efficiency, while reducing the need for manual load adjustments by grid operators. Since 2016, DMM has recommended the following two key enhancements:

- **Implement locational procurement of flexible ramping capacity** to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. The ISO implemented changes to address this issue in 2023, as discussed in more detail below.

- **Increase 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 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.[14]

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

[14] *2021 Annual Report on Market Issues & Performance*, Department of Market Monitoring, July 11, 2023, pp 276-278: https://www.caiso.com/documents/2021-annual-report-on-market-issues-performance.pdf

very small portion of intervals, indicating that the product is not changing the commitment or 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 evening.

DMM continues to believe that 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.

- One approach could be extend the time frame of the flexible ramping product (e.g., 30, 60, and 120 minutes out from a given real-time interval).
- Another approach could be to develop a separate, simpler real-time uncertainty product that procures extra ramping and energy capacity (in excess of the load forecast) over a multi-hour time period (e.g., from 1 to 4 hours in the future).

Price formation enhancements

In 2022, the California ISO initiated a price formation enhancements working group, aimed at addressing multiple issues related to price formation in the ISO and WEIM markets. DMM suggests the ISO consider placing a priority on foundational market enhancements that will improve price formation, such as:

- Extending the time-horizon of the flexible ramping product (or creating a new real-time uncertainty product that serves this purpose),
- Re-optimizing ancillary services in the real-time market, and
- More accurately incorporating intraday opportunity costs into default energy bids and bid caps for battery resources.

DMM suggests the ISO place a priority on this type of foundational market enhancement before embarking on more complicated market design changes such as fast-start pricing and scarcity pricing.

Extended flexible ramping product time horizon

DMM continues to recommend the ISO extend the flexible ramping product or create separate ramping and energy capacity products for the same purpose. In addition to the operational benefits of improved management of available capacity, an extended product would also fix a current problem where the real-time prices are not always set equal to marginal cost.[15]

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 meet needs in an advisory interval.

With this multi-interval optimization, the marginal cost of meeting these needs is reflected in the advisory interval energy price and not the settled binding interval energy price. In the subsequent

15 *Comments on Price Formation Enhancements Issue Paper*, Department of Market Monitoring, August 11, 2022: https://www.caiso.com/Documents/DMM-Comments-Price-Formation-Enhancements-Issue-Paper-Aug-11-2022.pdf

market runs when this advisory interval becomes a binding interval, the actions taken to meet the need have already occurred, and there is no longer a cost to meet the need in the optimization run that creates the binding prices. Because the costs to meet the need have already occurred, i.e., are sunk, the energy price the resource is actually settled on does not include the marginal cost of meeting the need.

An uncertainty product with a multi-hour time horizon in the real-time market would move the marginal costs of the advisory interval into the binding interval prices of the optimization where the actions are taken to meet the advisory needs. Moving these costs into the binding interval prices would settle resources on real-time prices that include all the marginal costs.

Re-optimizing ancillary services in real-time

DMM recommends that the ISO re-optimize ancillary services with other products in the real-time, which could increase efficiency and allow real-time energy prices to better reflect real-time (ancillary service) conditions. The ISO placed ancillary service real-time re-optimization and locational procurement of ancillary services on their policy road map in 2023.[16]

Incorporating opportunity costs into bid caps

The ISO's current approach for determining default energy bids (DEBS) and allowing batteries to bid over $1,000/MWh is based on a relatively simple calculation of intra-day opportunity costs. These bid limits are currently based on day-ahead prices and are static values that do not vary on an hourly basis. As noted in the section on battery resources, DMM has recommended that the ISO continue to enhance the manner in which intra-day opportunity costs are calculated and to allow bid caps reflecting these costs vary by hour and be more dynamic in the real-time market. These enhancements could also be applicable to some hydro units that have intra-day energy limits.

Maximum import bid price calculation

The maximum import bid price (MIBP) calculation uses a shaping factor to convert bi-lateral hub index prices for multi-hour blocks of energy into hourly values. The hourly maximum import bid price calculation is an important component of the FERC Order 831 design, as this is used to determine when the $2,000/MW hard cap is in effect. In 2024, the ISO has expanded the use of the maximum import bid price so that it will be used to determine the level at which battery resources may bid on days when the $2,000/MW hard cap is triggered.

The shaping factor used to convert bi-lateral prices into hourly prices uses a ratio with historical hourly prices in the numerator from one day and daily average price from a different day in the denominator. DMM believes this is inconsistent with the tariff and was not the intended calculation during the stakeholder process.[17] DMM recommends that the ISO change the shaping factor calculation to use prices from the same day for both the denominator and numerator of the ratio. In practice, the effect of this change would tend to be an increase in the days when the maximum import bid price exceeds

16 *2023 Policy Initiatives Catalog*, California ISO, March 29, 2023: https://www.caiso.com/InitiativeDocuments/Final2023PolicyInitiativesCatalog.pdf

17 *Attachment 1: Maximum Import Bid Price Calculation*, Department of Market Monitoring, May 15, 2024. departmentofmarketmonitoringcomments-softoffercap-attachment1-may2024.pdf (caiso.com)

$1,000/MW and triggers a variety of changes that occur when bid cap is raised from $1,000/MW to $2,000/MW. The ISO is starting a stakeholder workshop to consider this change.[18]

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 flexible ramping product or other real-time uncertainty product with an extended time horizon would also serve a scarcity pricing purpose. Because there is a tradeoff between procuring flexible ramping 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 flexible 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.

Extending the flexible ramping time-horizon would allow capacity and energy prices to reflect upcoming scarcity in more distant advisory intervals. As previously noted, instead of extending the FRP time-horizon, the ISO could create a new uncertainty product that serves the same purpose. Either of these approaches would improve price formation by allowing prices for energy and flexible capacity to better reflect supply and demand conditions in the real-time market.

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.[19] However, DMM understands that in response to requests from some stakeholders, the ISO is examining the possibility of adopting some form of fast-start pricing in the CAISO and WEIM.

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.[20] The ISO's current analysis does not consider many complexities of the CAISO market. 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

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[18] Maximum Import Bid Price analysis workshop to discuss hourly shaping factor, call on 5/28/24: https://www.caiso.com/Documents/maximum-import-bid-price-analysis-workshop-to-discuss-hourly-shaping-factor-call-on-52824.html

[19] *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

[20] *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

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.

Transmission access for high priority wheeling schedules

The summer 2020 heat wave highlighted the need to review and clarify the California ISO's policies and procedures for curtailing load versus curtailing exports and wheeling schedules. During hours in August 2020, when the California ISO grid operators curtailed the CAISO balancing area load, operators did not curtail any non-high priority exports or wheeling schedules. DMM believes this was inconsistent with ISO tariff provisions and analogous provisions in the open access transmission tariffs (OATTs) of other balancing areas in the West. DMM recommended the ISO take steps to clarify priorities for curtailing native load vs. non-high priority exports, and make ISO rules and procedures similar to those of other balancing areas in the West.

In advance of summer 2021, the ISO established export prioritization rules and interim rules for high priority wheeling through transactions.[21] In 2022, the ISO completed the transmission service and market scheduling priorities initiative.[22]

In the second phase of this initiative, the ISO established a process for making excess transmission not needed to serve native CAISO load available to other entities to wheel power on a longer-term forward basis. This approach represents a significant improvement from the previously established interim rules for high priority wheeling access, and makes the ISO's rules more closely resemble the open access transmission tariff (OATT) framework used across the West in balancing areas without organized markets.

However, because the ISO's approach does not include a detailed analysis of the impact of wheeling schedules on flows within the CAISO, the proposal may make some additional wheeling capacity available, compared to DMM's understanding of how this OATT framework is typically applied. DMM continues to recommend that the ISO improve the modeling of the impact of high priority wheels on flows within the CAISO system.

DMM understands the ISO has committed to conduct an annual analysis of high priority wheeling impacts on Path 26, the major north to south transmission constraint within the CAISO footprint. As the ISO has begun to implement the new framework, DMM has learned that the ISO is only considering the flow impact from wheels importing to the CAISO at the Malin intertie. This intertie has been the import point of around 30 to 40 percent of high-priority wheel through transactions in recent years.[23] DMM believes the ISO also needs to study the impacts of high priority wheel though transactions importing at other interties.

21 Market Enhancements for Summer 2021 initiative page: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-Enhancements-for-Summer-2021-Readiness

22 California ISO Initiative, *Transmission service and market scheduling priorities:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

23 California ISO wheeling and resource adequacy imports aggregate data, *Priority Wheeling Through Transaction Data:* https://www.caiso.com/Documents/PriorityWheelingThroughTransactionsData.xlsx

Also, relying on historic wheel through patterns to determine which interties to include in the flow impact study and calculate the available transmission capacity (ATC) may not sufficiently mitigate the risk of reliability issues stemming from internal congestion caused by high-priority wheels. These patterns may change once reservations are restricted at historically used interties. In the first few months since ATC reservations became available for summer 2024, such changes in historical patterns have already occurred due to limited ATC at Malin in the summer months.

Some entities hold transmission ownership rights (TORs) in the northern part of the CAISO system, from Malin to the Round Mountain 230 scheduling point. Historically, the owners of many of these TORs converted them to CRRs, and did not use them for transmission scheduling. The ISO excludes these TORs from the ATC calculated for a given intertie. As the ISO limited ATC at Malin, some owners of these TORs are now using them to support schedules from Malin to the Round Mountain 230 scheduling point, where entities gain access to additional ATC to support high priority wheel through transactions. Although these reservations could impact Path 26 congestion similar to imports at Malin, the ISO did not consider the added ATC at Round Mountain 230 in the analysis of priority wheeling impacts on Path 26.

Resource adequacy

California relies on the state's long-term bilateral procurement 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 due to 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.[24]

The 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.[25]

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 indicates this approach has proven effective at ensuring delivery of resource adequacy imports since being implemented in 2020.

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

25 *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

DMM also recommends that the California ISO, CPUC, and stakeholders continue to 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.[26] 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 translate the current Planning Reserve Margin to the slice-of-day framework.[27] The CPUC will implement 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 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 Top 5 Day *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

The ISO's current mechanism for incentivizing the availability of resource adequacy capacity is the resource adequacy availability incentive mechanism (RAAIM). This mechanism deals solely with resource availability, not performance. 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 was $6.31/kW-month throughout 2023 and increased to $7.34/kW-month on June 1, 2024.[28]

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.

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26 *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 Rulemaking 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

27 *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

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

DMM recommends that the ISO and local regulatory authorities consider developing a resource adequacy incentive mechanism that is based on resource performance. Such a mechanism could result in potentially very high penalties that claw back a large portion of capacity payments when resources do not deliver on critical days. Incentivizing availability and performance of resource adequacy capacity could become increasingly important as resource adequacy payments increase compared to the magnitude of potential RAAIM charges. This type of mechanism could also 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 lesser 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.

Demand response resources

In the last four years, the California ISO has increasingly relied on demand response to curtail load during peak summer hours. Demand response resources are currently used to meet about 3 to 4 percent of total system resource adequacy capacity requirements in the peak summer months.

DMM's analysis of how demand response resources participated and performed in the CAISO market on high load days in summer 2020 through 2023 shows that a large portion of demand response resource adequacy capacity was not available for dispatch, or performed significantly below dispatched levels during key peak net load hours.[29] This results from a combination of how demand response resources are over counted toward resource adequacy requirements, as well as by the performance of some demand response programs after being dispatched.

Resource adequacy payments, or the value of reduced resource adequacy requirements, are the primary revenue sources for demand response resources. Even when demand response resources are frequently dispatched, the energy market revenues from actually performing (or charges for failing to perform) represent a relatively small portion of the overall compensation or value of these resources. This current market framework does not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions.

[29] *Demand response issues and performance 2023*, Department of Market Monitoring, March 6, 2024, pp 3-4: https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf

In prior reports, DMM has highlighted some recommendations that the ISO and CPUC could consider to enhance the availability and performance of demand response resources, especially before increasing reliance on demand response towards meeting resource adequacy requirements.[30] The CPUC has taken numerous steps to address DMM's recommendations, as described below:

- ***Re-examine demand response counting methodologies.*** For the last several years, DMM has recommended that counting methodologies should better capture the capacity contribution of demand response resources with load reduction capabilities that vary across the day and may have limited output in general. The new *slice-of-day* resource adequacy approach being adopted by the CPUC should help more properly count demand response resources. In addition, the CPUC and the California Energy Commission (CEC) are currently working together to develop an incentive-based qualifying capacity valuation for resource adequacy demand response resources that bid in as supply.[31]
- ***Remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction.*** The CPUC reduced the planning reserve margin adder applied to demand response capacity credits from 15 percent to 9 percent beginning in 2022. In 2023, the CPUC also approved eliminating this 9 percent reserve margin adder and the transmission loss factor (2.5 to 3 percent) beginning in 2024.[32] The adder for distribution loss factor (5 to 7 percent) will be maintained.
- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. In 2023, the CPUC adopted rules requiring that demand response resources be tested and that demand response capacity qualified to meet resource adequacy requirements be de-rated based on *ex post* analysis of performance. Beginning in 2024, participating demand response resources will be limited to a $500/MWh bid cap for July-September in the day-ahead and real-time markets. Although these steps represent significant improvements, DMM believes further financial penalties or disincentives for poor performance of demand response resources may be needed.
- ***Consider tariff changes to better define deadlines and penalties on data submission as well as continue outreach to demand response providers to ensure all necessary historical data is available for DMM to assess the validity of baseline submissions*.** Under many of the most frequently used baseline calculation methodologies, demand response data are required to submit historical data on their metered load and baselines. This historical data allows monitoring of the baselines submitted by providers. However, due to a lack of a clear timeline and penalties for failing to submit data, DMM has observed significant and ongoing problems with some providers submitting this data. DMM supports the ISO addressing this issue in the Penalty Enhancements initiative, which is focused in part on defining the penalty structure of demand response monitoring data.

30 *Demand response issues and performance*, Department of Market Monitoring, February 25, 2021, pp 3-4: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

31 *Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements* (D. 23-06-029), CPUC Docket No. R21-10-002, June 29, 2023, p 144: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

32 *Decision Adopting Local Capacity Obligations for 2022–2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, CPUC Docket No. R19-11-009, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.pdf

Organization of report

The remainder of this report is organized as follows:

- **Loads and resources.** Chapter 1 summarizes load and supply conditions that impact market performance. This chapter includes an analysis of net operating revenues earned by hypothetical new gas-fired generation from the CAISO markets.
- **Overall market performance.** Chapter 2 summarizes overall market performance.
- **Western Energy Imbalance Market.** Chapter 3 highlights the growth and performance of the Western Energy Imbalance Market.
- **Ancillary services.** Chapter 4 reviews performance of the ancillary services market.
- **Market competitiveness and mitigation.** Chapter 5 assesses the competitiveness of the energy market, along with impact and effectiveness of market power and exceptional dispatch mitigation provisions.
- **Congestion.** Chapter 6 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 7 reviews the various types of market adjustments made by the CAISO to the inputs and results of standard market models and processes.
- **Resource adequacy.** Chapter 8 assesses the short-term performance of California's resource adequacy program.
- **Recommendations.** Chapter 9 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis.

1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. In 2023, California ISO wholesale electricity prices were significantly lower due to large decreases in natural gas prices and continued reductions in average hourly load. Since June 2023, California ISO nameplate capacity has increased by 6,400 MW, with about 95% of that increase coming from battery and solar resource additions.

Specific trends highlighted in this chapter include the following:

- **California ISO instantaneous peak load was 44,534 MW** in 2023, which was the third lowest peak annual load recorded since 2010. The instantaneous peak load in 2023 was about 5 percent lower than the CAISO *1-in-2 year* load forecast (46,829 MW) and about 11 percent lower than the *1-in-10 year* forecast (49,919 MW).[33]
- **California ISO average hourly load continued to decrease in 2023**, due in part to increases in behind-the-meter solar generation and lower average temperatures.
- **Average gas prices decreased significantly in 2023 compared to 2022.** The large January premiums between western hubs and the Henry Hub decreased over the first quarter and storage inventories increased thereafter. Overall for 2023, average gas prices at NW Sumas, PG&E Citygate and SoCal Citygate decreased by 46 percent, 36 percent and 28 percent, respectively, compared to 2022.
- **Hydroelectric generation was about 68 percent higher in 2023 than in 2022.** California ISO hydroelectric generation increased to 12 percent of total supply, up from 7 percent in 2022.
- **Net imports accounted for 7 percent of generation, down from 14 percent in 2022**, as non-Western Energy Imbalance Market net imports fell from both the Southwest and Northwest by 93 percent and 60 percent, respectively. On an average hourly basis, net imports were about 2,027 MW lower across all hours than last year.
- **Non-hydro renewable generation accounted for about 34 percent of total supply in 2023**, slightly up from 32 percent in 2022.[34] Solar generation increased by about 5 percent and accounted for around 18 percent of total supply.
- **In the California ISO and WEIM areas, total downward dispatch in 2023 increased by 9 percent and 18 percent**, respectively, relative to 2022. In both these areas, the majority of downward dispatch is economic.
- **Since June 2023, solar capacity in the California ISO area grew by 2,300 MW**.
- **Capacity from active battery storage resources grew dramatically** from 4.2 GW in December 2022 to over 11.1 GW in June 2024. Of this growth, 2.2 GW occurred between December 2023 and June 2024. Of the 11.1 GW of battery capacity, about 4.7 GW is from stand-alone projects, 5.1 GW is from co-located projects, and 1.3 GW is from the storage components of hybrid resources and co-located hybrids.
- **Capacity from hybrid resources almost doubled.** Hybrid capacity grew from about 1 GW of capacity in June 2023 to over 1.9 GW in June 2024.

[33] For detailed information on the instantaneous peak load and average hourly peak load, please see the California ISO's Market Performance report: https://www.caiso.com/Documents/2023-Summer-Loads-and-Resources-Assessment.pdf

[34] In this analysis, non-hydro renewables include tie generators but do not include other imports or behind-the-meter generation such as rooftop solar. Thus, this analysis may differ from other reports of total renewable generation.

- **Third-party demand response resource capacity averaged 210 MW in 2023, down 14 percent** from 2022. The self-reported performance of third-party demand response increased from 40 percent to 65 percent during peak hours of summer 2023.
- **Utility demand response resource capacity averaged 1,175 MW in 2023, down 9 percent** from 2022. The self-reported performance of utility proxy demand response increased from 82 percent to 100 percent during peak hours of summer 2023.
- **The estimated net operating revenues for typical new gas-fired generation in 2023 were less than DMM's estimates of the going-forward fixed costs of gas capacity** and remained substantially below the annualized fixed cost of new generation.

1.1 Load conditions

1.1.1 System loads

The California ISO instantaneous peak load was 44,534 MW in 2023.[35] Over the last two decades, peak load has shifted to being later in both the day and the time of year. For example, peak load in 2002 occurred on July 10 just after 3 p.m., but occurred on August 16 at nearly 6 p.m. in 2023. Overall, the California ISO balancing area (CAISO) average load decreased in 2023, and was the lowest since 2003. Table 1.1 summarizes annual system peak loads and energy use since 2019. Average load has continued to decrease since 2019.

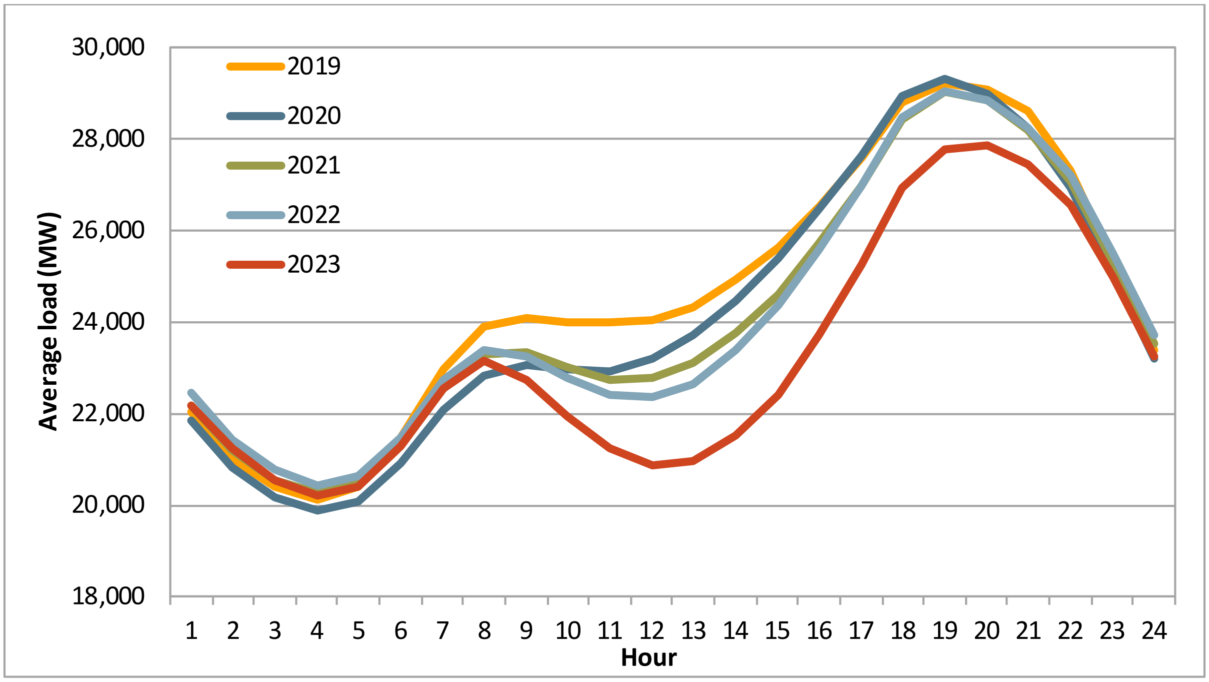
Table 1.1 Annual system load in CAISO: 2018 to 2023

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2019	214,955	24,541	-3.9%	44,301	-11.6%
2020	211,919	24,128	-1.7%	47,121	6.4%
2021	211,020	24,092	-0.1%	43,982	-6.7%
2022	210,879	24,059	-0.1%	52,061	6.4%
2023	203,268	23,207	-3.5%	44,534	-14.5%

Figure 1.1 shows average hourly load by year along with how the overall load shape has changed since 2019. Lower loads are due, in part, to the growth of behind-the-meter solar generation and storage resources, continued initiatives to improve energy efficiency, as well as variation in statewide temperatures. The decrease in load during the middle of the day in particular shows the effect of increased behind-the-meter solar generation on load in the California ISO.

35 For a historical view of the instantaneous peak load data, please see the California ISO peak load history: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

Figure 1.1 Average hourly load (2019–2023)



Seasonal load trends

Figure 1.2 and Figure 1.3 show the average load by quarter and month between 2019 and 2023, respectively. For most of 2023, the average load was lower than in the past four years. The most notable decrease in load occurred during the second and third quarters in 2023. This load tends to follow statewide temperatures on average.[36]

[36] For statewide temperature data, please see: National Oceanic and Atmospheric Administration (NOAA), *Climate at a Glance*: https://www.ncdc.noaa.gov/cag/

Figure 1.2 Average load by quarter (2019–2023)

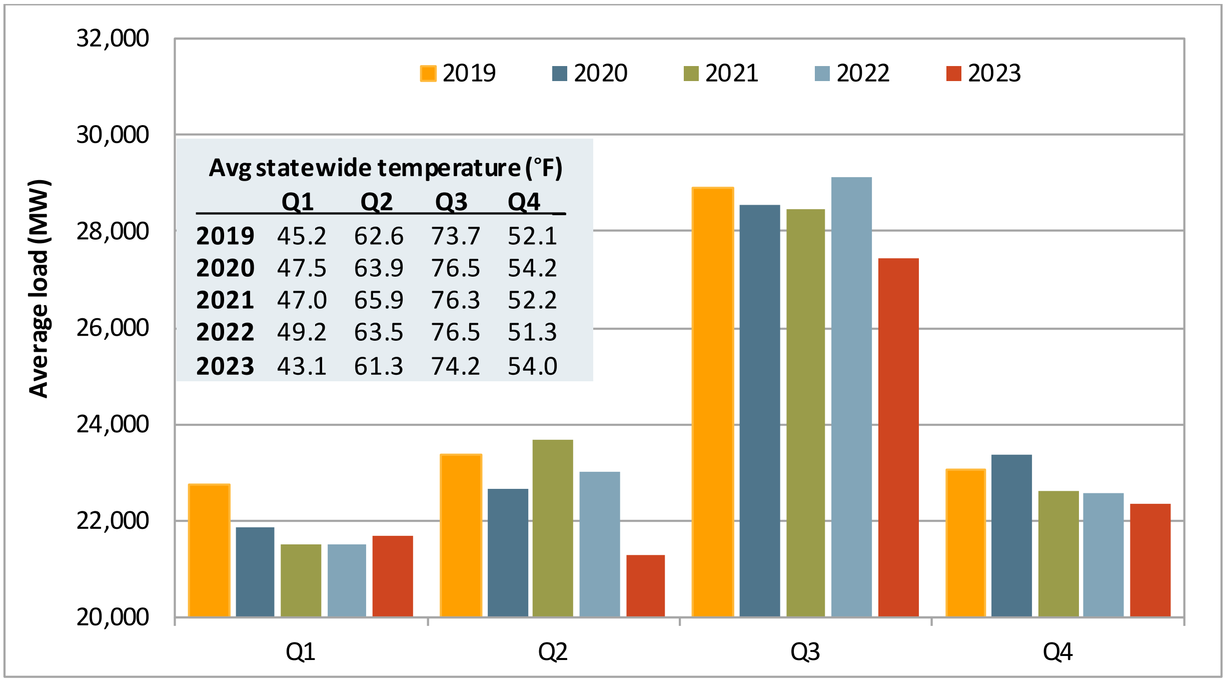
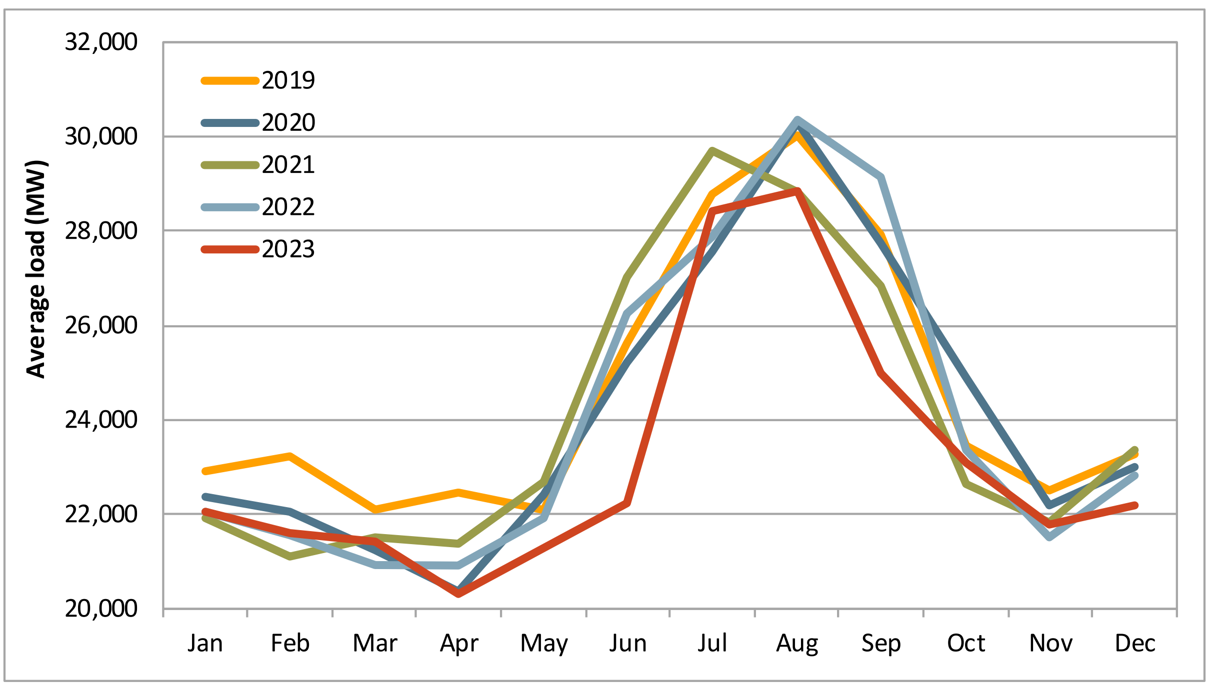


Figure 1.3 Average load by month (2019–2023)

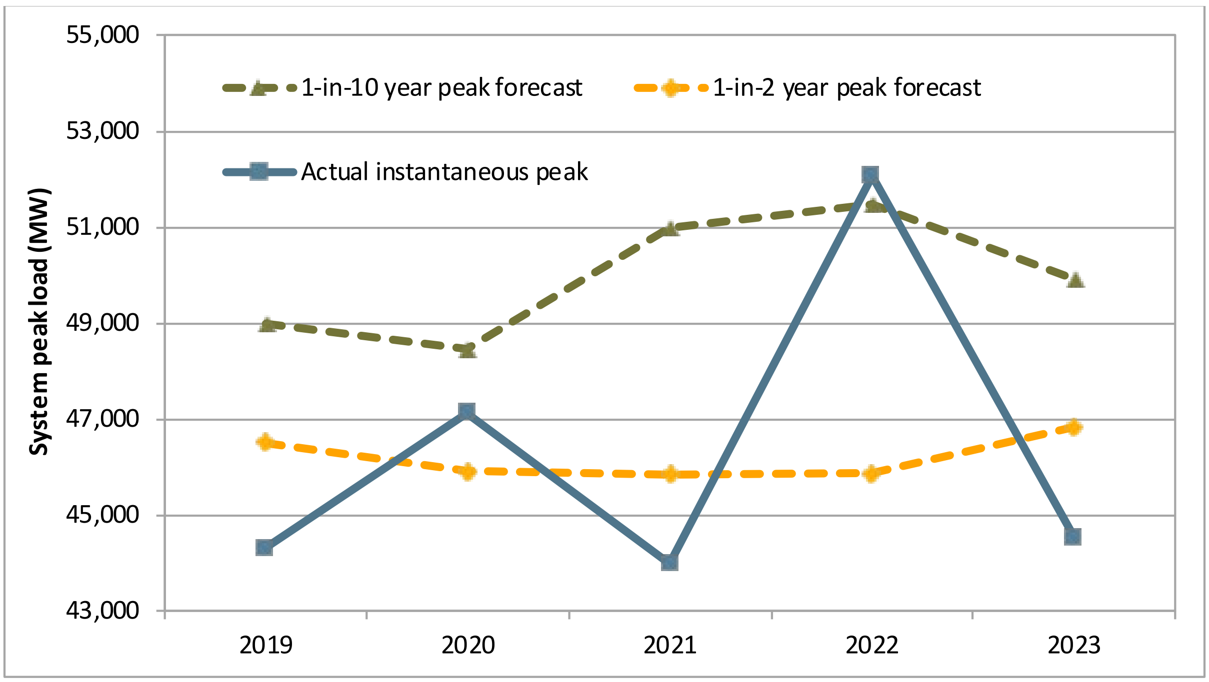


Peak load

Instantaneous summer loads peaked at 44,534 MW on August 16, about 7,500 MW lower than the 2022 peak. This peak represents the third lowest instantaneous load on record for the California ISO since 2010.[37] This instantaneous peak load fell below the 1-in-2 year forecast.

The instantaneous peak load in 2023 was about 5 percent lower than the CAISO *1-in-2 year* load forecast (46,829 MW) and about 11 percent lower than the *1-in-10 year* forecast (49,919 MW) as shown in Figure 1.4. 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. Resource adequacy requirements for local areas are based on the *1-in-10 year* (or 90th percentile year) peak forecast for each area.

Figure 1.4 Actual instantaneous load compared to planning forecasts



1.1.2 Local transmission constrained areas

The California ISO has defined ten local capacity areas 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 5 of this report assesses the structural competitiveness of the market for capacity in local areas, along with the frequency and impact of local energy market

[37] California ISO Instantaneous Peak Load History, 1998-2023: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

power mitigation procedures. This section provides a high-level perspective of supply and demand conditions in each local area.

Table 1.2 presents forecasted peak load, current dependable generation, and capacity requirements for these local capacity areas. Figure 1.5 shows the location of each local capacity area and the proportion of each area's load, relative to the total system peak load.[38] The local capacity requirement is defined as the resource capacity needed to serve load within a local capacity area reliably. Dependable generation is the net qualifying capacity of available resources within the locally constrained area.

Table 1.2 Load and supply within local capacity areas in 2023[39]

Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	11,136	23%	7,770	7,312	94%
Greater Fresno	PG&E	3,288	7%	3,411	1,870	55%
Sierra	PG&E	1,812	4%	1,909	1,150	60%
North Coast/North Bay	PG&E	1,494	3%	911	857	94%
Stockton	PG&E	1,090	2%	579	579	100%
Kern	PG&E	940	2%	439	439	100%
Humboldt	PG&E	175	0.4%	178	141	79%
LA Basin	SCE	19,537	40%	9,661	7,529	78%
Big Creek/Ventura	SCE	4,427	9%	5,475	2,240	41%
San Diego	SDG&E	4,768	10%	5,358	3,332	62%
Total		**48,667**		**35,691**	**25,449**	

*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.

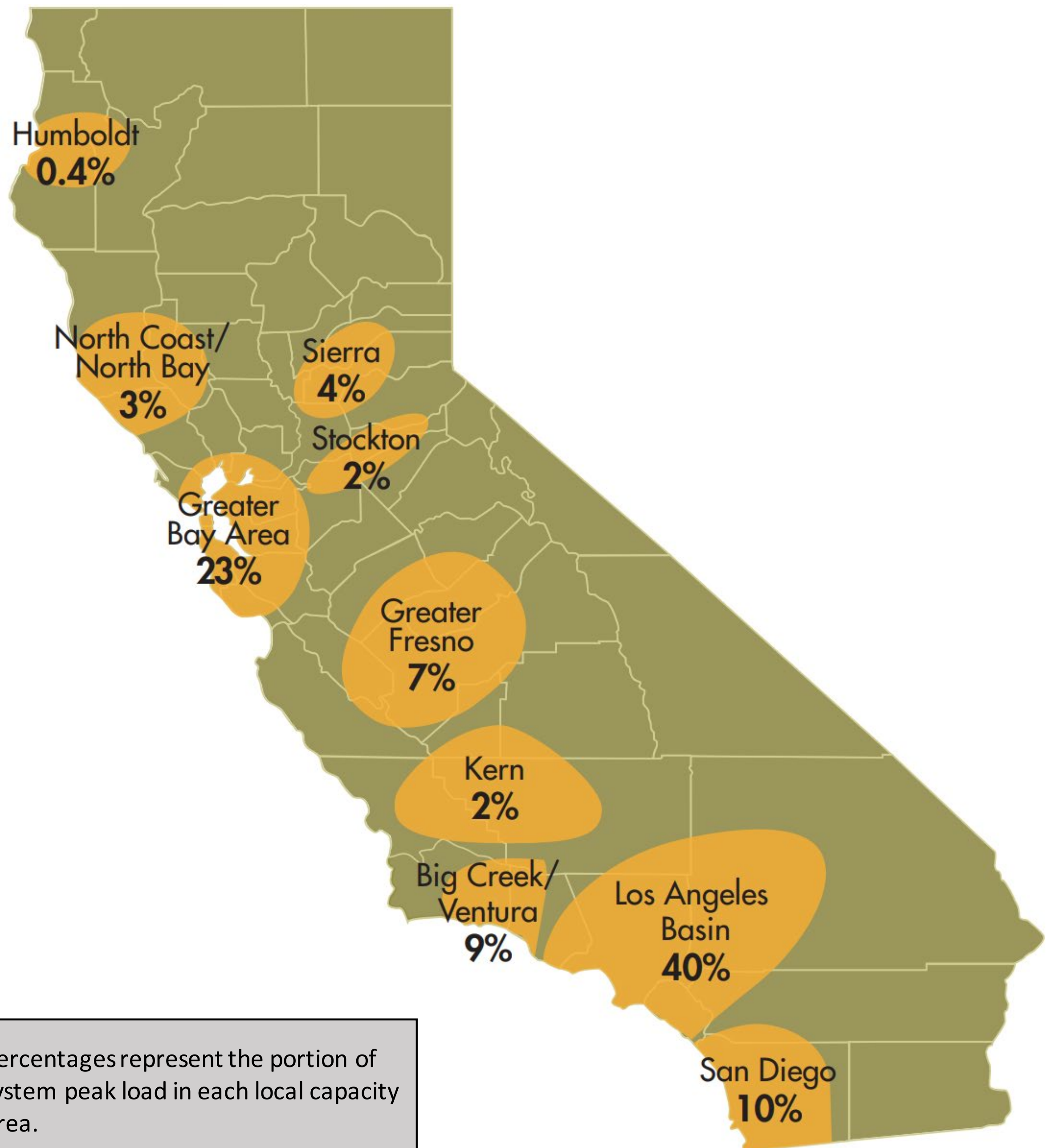
The California ISO performs annual studies to identify the minimum local resource capacity requirements in each local area to meet established reliability criteria. An updated criterion is used in the study to match the NERC transmission planning standards for resource adequacy in year 2023. As a result, local capacity requirements increased to 25,449 MW for 2023 compared to 25,113 MW in 2022. Dependable generation and peak load increased slightly overall in these areas. The final column in Table 1.2 shows the local reliability requirement as a percent of dependable generation 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. Of the local capacity areas, the Los Angeles Basin and the Greater Bay Area have the highest local capacity requirements, due in part to high *1-in-10 year* peak load forecasts. Requirements increased in the LA Basin (883 MW) and Greater Bay Area (81 MW), and decreased in Greater Fresno (117 MW), and San Diego (661 MW). In 2023, the peak load for

38 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.

39 *2023 Local Capacity Technical Analysis*, California ISO, April 28, 2022, p 27, Table 3.1-1: https://www.caiso.com/InitiativeDocuments/Final2023LocalCapacityTechnicalReport.pdf

most of the local areas increased, including a rise of 390 MW in the Greater Bay Area, 194 MW in the Sierra, 608 MW in the LA Basin, and 188 MW in San Diego.

Figure 1.5 Local capacity areas



Percentages represent the portion of system peak load in each local capacity area.

1.2 Supply conditions

1.2.1 Generation mix

Natural gas and non-hydro renewable generation were the largest sources of energy in the CAISO energy mix in 2023, together comprising 68 percent of total system energy. Battery generation increased during peak net load hours as new battery resources came on-line. Net imports decreased during all hours compared to 2022, continuing a trend over the last several years.

Monthly generation by fuel type

Figure 1.6 provides a profile of average hourly generation by month and fuel type. Figure 1.7 illustrates the same data on a percentage basis. These figures[40] show the following:

- Natural gas and non-hydro renewables were the largest sources of generation in 2023, together representing around 68 percent of total generation in the CAISO balancing area.
- Hydroelectric generation accounted for 12 percent of total generation, an increase from 7 percent in 2022. Hydroelectric resources generated 68 percent more in 2023 than in 2022.
- Net imports represented around 7 percent of total supply. On an average hourly basis, net imports were about 2,027 MW lower across all hours than last year. In April and July, hourly net imports were negative, on average. This is primarily driven by an increased amount of cleared intertie exports during these months.[41]
- In most months, hourly net WEIM transfers into the CAISO area were negative. Net WEIM transfers out of the CAISO area averaged around 387 MW across the year.
- Hourly net hybrid resources were positive for all months in 2023 and represented around 1 percent of the total supply. Most hybrid resources are not capable of charging from the grid and generally are not given charging schedules.[42]

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[40] In Figure 1.7, only months with positive hourly average net imports and net WEIM transfers are represented as a percentage of total positive generation. Months with negative net import and net WEIM transfers are not included in the total generation sum. Average hourly battery resource generation net of charging was negative during all months of 2023.

[41] See *Summer Market Performance Report July 2023,* California ISO, for more information on export scheduling during July events: https://www.caiso.com/Documents/Summer-Market-Performance-Report-for-July-2023.pdf

[42] For more information on storage resources, see *Special Report on Battery Storage,* Department of Market Monitoring, July 7, 2023: https://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

Figure 1.6 Average generation by month and fuel type in 2023

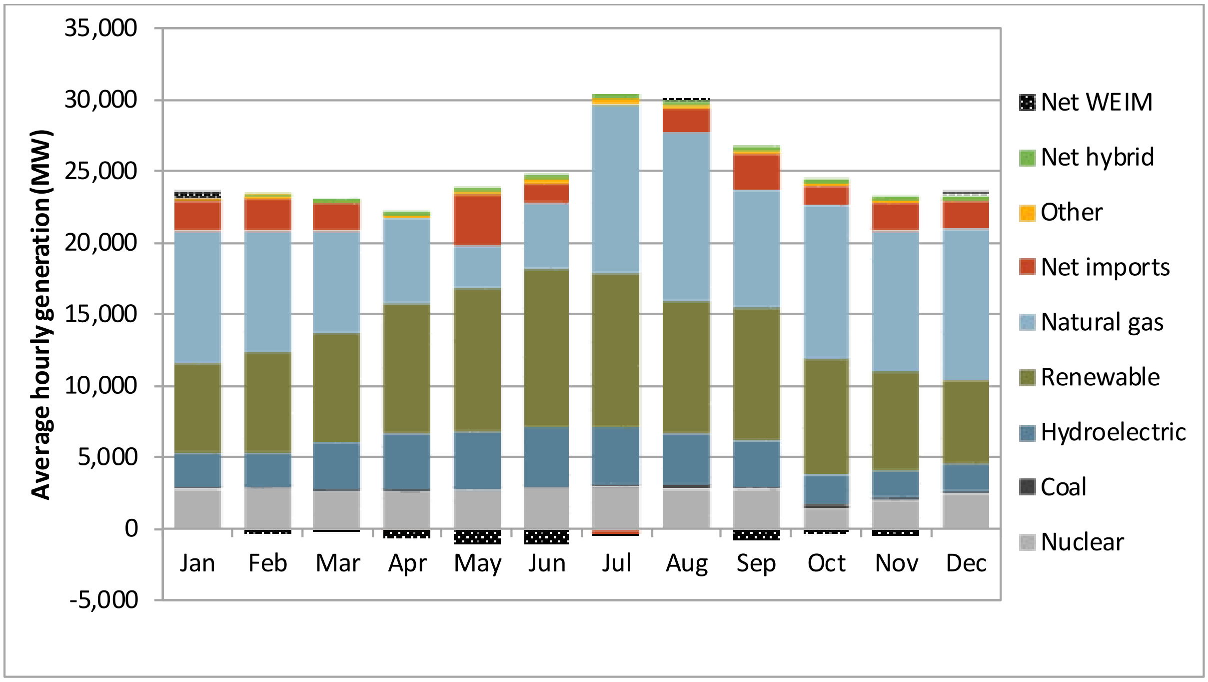
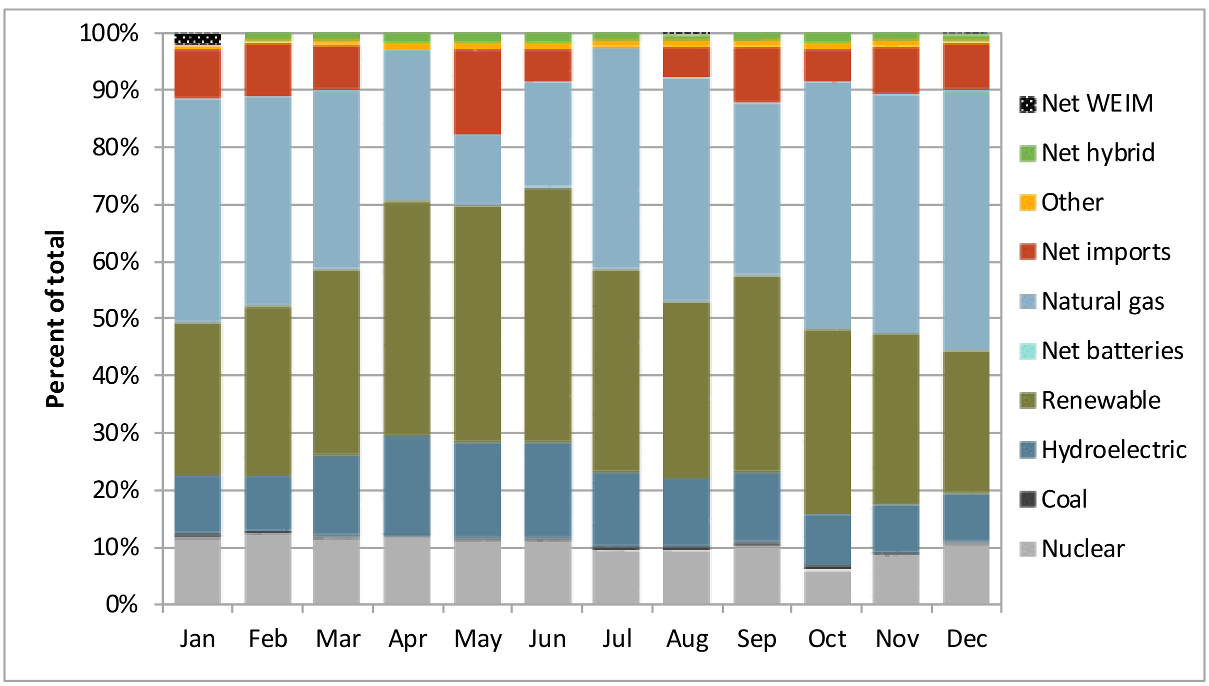


Figure 1.7 Average generation by month and fuel type in 2023 (percentage)



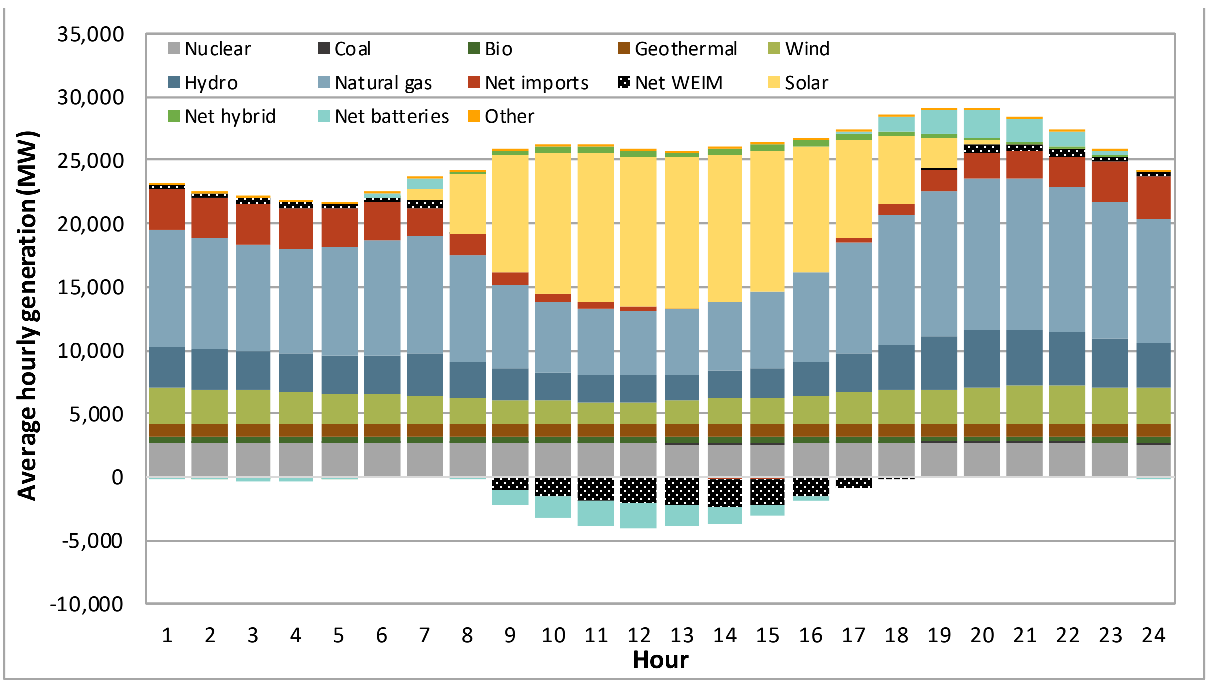
Hourly generation by fuel type

Figure 1.8 shows average hourly generation by fuel type over the year. Overall for 2023, hour-ending 19 averaged the highest amount of generation at about 29,003 MW, while hour-ending four averaged the lowest, at about 21,292 MW.[43] Generation from nuclear, coal, biogas, biomass, and geothermal resources averaged about 4,184 MW of inflexible base generation, or about 77 MW less than 2022. Generation from battery storage resources discharging averaged about 1,564 MW during the peak net load hours of 17-21, around 491 MW more than during the same hours of 2022.

Figure 1.9 shows the change in hourly generation by fuel type between 2022 and 2023. In the chart, positive values represent increased generation over the course of the year compared to 2022, while negative values represent a decrease in generation.

Net imports decreased in all hours, while net WEIM transfers into CAISO saw large decreases after the early morning hours. Natural gas generation was lower during the afternoon and evening hours.[44] Generation from battery storage resources increased during the peak net load hours of 17-21, helping to reduce the need for imports during these hours. This is accompanied by an increase in battery charging during the middle of the day. The net change largely represents a decrease in CAISO balancing area load for each hour on average.

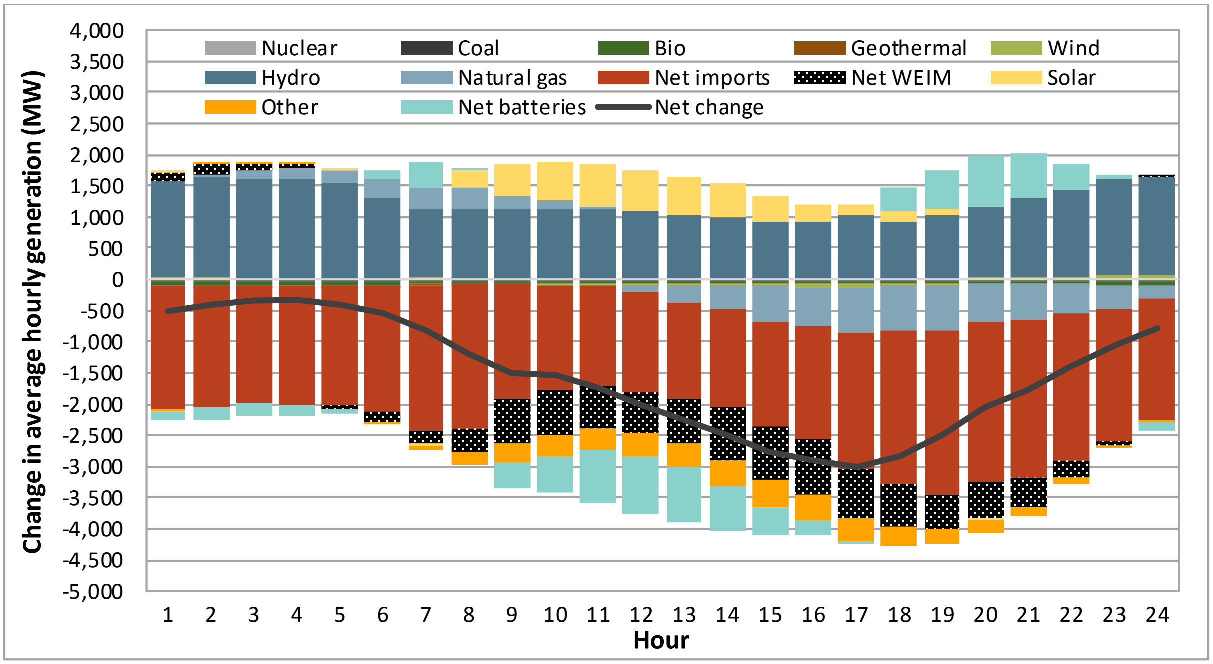
Figure 1.8 Average hourly generation by fuel type (2023)



43 These totals represent battery and hybrid resources generation net of their charging. The totals also account for net WEIM transfers, which was not included in prior versions of this report.

44 Hybrid generation was included in the "Other" category in 2022, but is identified as "Hybrid" in 2023, so it is excluded from this figure this year.

Figure 1.9 Change in average hourly generation by fuel type (2023 compared to 2022)



1.2.2 Renewable generation

In 2023, about 34 percent of CAISO generation was from non-hydro renewable resources, and about 12 percent was from hydroelectric generation. This section provides additional detail about trends in renewable generation and the factors influencing renewable resource availability.

Figure 1.10 provides a detailed breakdown of non-hydro renewable generation, including imports that are specifically identified as wind and solar resources.[45] Figure 1.10 also illustrates:

- In 2023, generation from solar resources increased by 5 percent while wind generation increased by less than 1 percent compared to 2022. Solar and wind resources contributed to 18 percent and 10 percent of total system energy, respectively.
- The overall output from geothermal generation decreased less than 1 percent from 2022, and continued to provide around 4 percent of system energy.
- Biogas, biomass, and waste generation decreased 8 percent from last year. Together, they accounted for around 2 percent of system energy.

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

Figure 1.10 Total renewable generation by type (2020–2023)

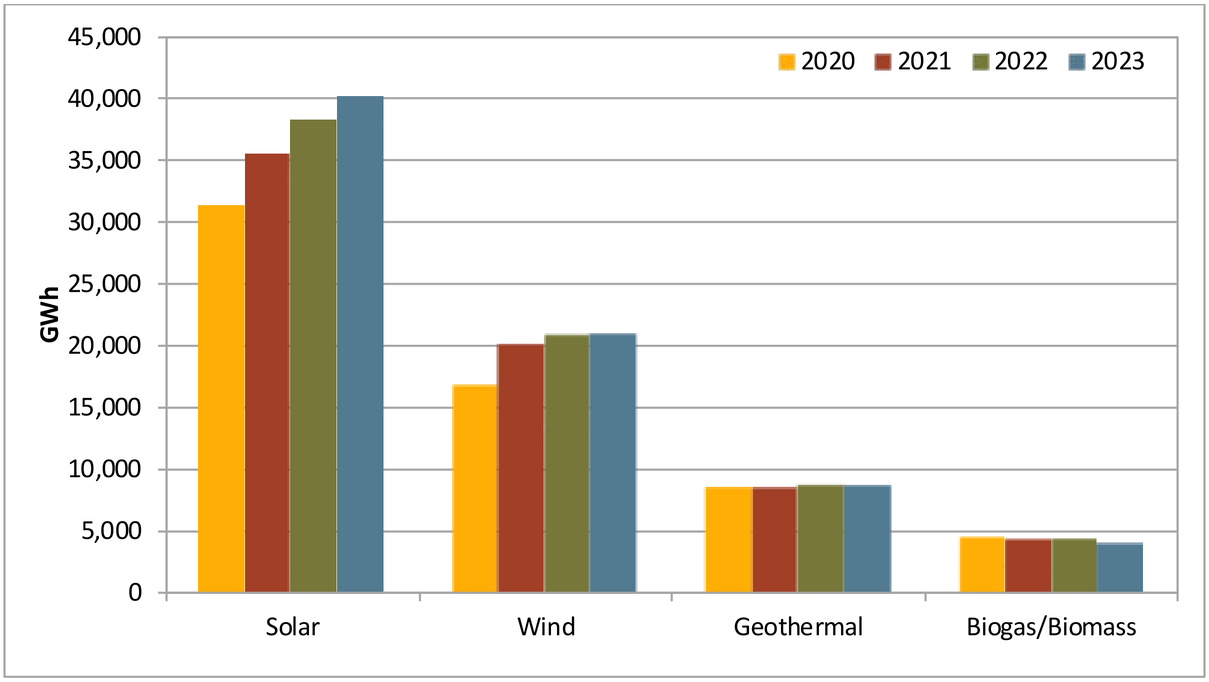
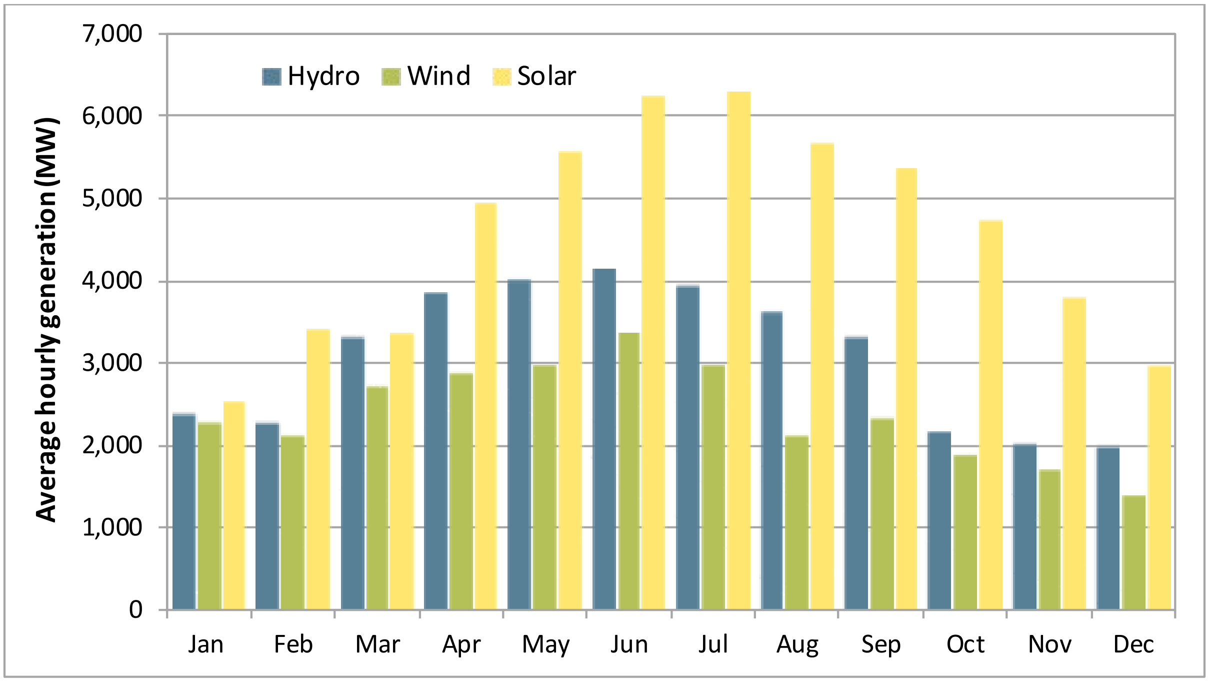


Figure 1.11 compares average monthly generation of hydro, wind, and solar resources. Due to high snowpack levels, the amount of energy produced by hydroelectric resources was higher than that of wind resources.

In 2023, average hourly solar generation peaked in July, while wind and hydroelectric generation both peaked in June. Non-hydro renewable generation made up its greatest portion of system generation during June, when it accounted for roughly 46 percent of total generation.

Figure 1.11 Monthly comparison of hydro, wind, and solar generation (2023)



Downward dispatch and curtailment of variable energy resources

In the California ISO and WEIM areas, total downward dispatch in 2023 increased by 9.5 percent and 18.2 percent, respectively, relative to 2022. In both of these areas, a majority of the downward dispatch is 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 1.12 shows the curtailment of wind and solar resources by month in the California ISO. Curtailments fall into six categories:

- **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; [46]

[46] 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 the market price is below a resource bid or the resource's upper limit is binding;
- **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. Most renewable generation dispatched down in the California ISO was from solar resources, as these resources typically bid more economic downward capacity than wind resources.

In the California ISO, total downward dispatch was 9.5 percent higher in 2023 than in 2022. Economic downward dispatch accounted for about 2,688 GWh (95.5 percent) of curtailment during the year, while self-scheduled curtailment accounted for about 53 GWh (2 percent). Exceptional dispatch curtailments for both self-scheduled and economic bid resources remained low and were together about 2.4 GWh (less than 1 percent). The roughly 70 GWh (2.5 percent) of remaining curtailment came from "other" economic and self-scheduled curtailment.

Figure 1.13 shows downward dispatch of WEIM wind and solar resources. As defined above, curtailments fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment. In the WEIM, total curtailment of wind and solar resources in 2023 rose to 755 GWh, 18 percent higher than 2022. Economic downward dispatch in the WEIM during 2022 accounted for roughly 580 GWh (77 percent) of total downward dispatch. February 2023 was the highest month of downward dispatch of 2023 at 147 GWh. This large increase in downward dispatch and curtailment was driven by congestion on internal transmission constraints between Wyoming wind generation and the surrounding system.

Figure 1.12 Reduction of wind and solar generation by month (CAISO)

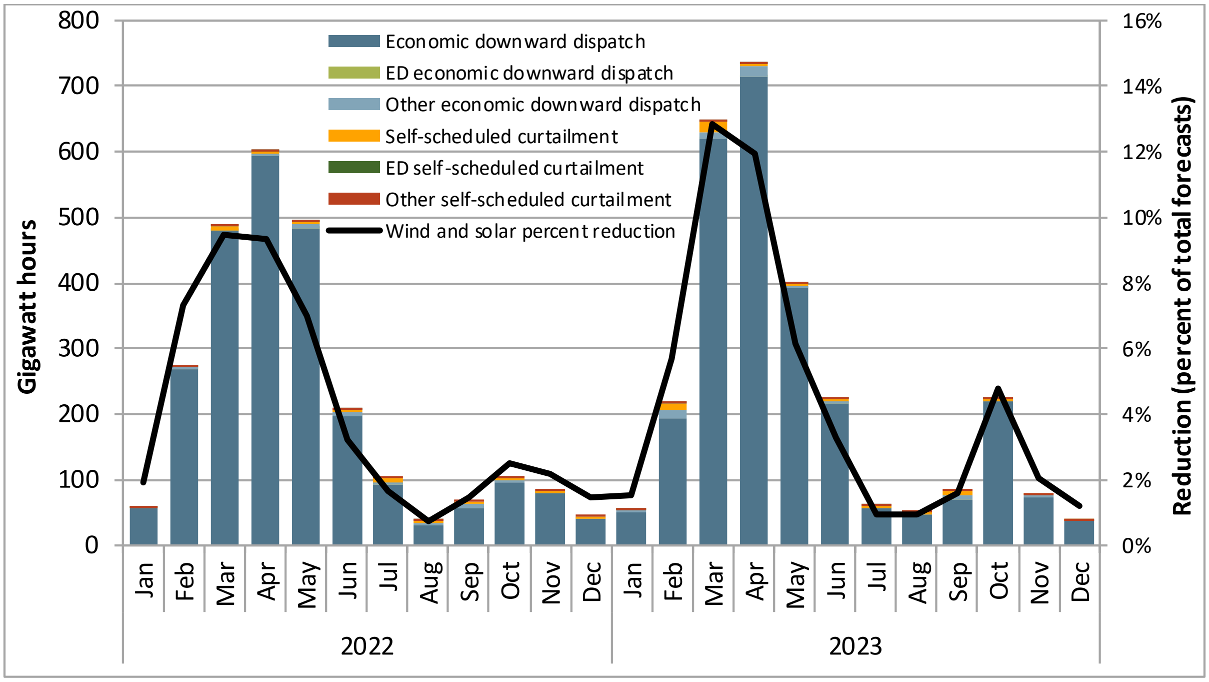
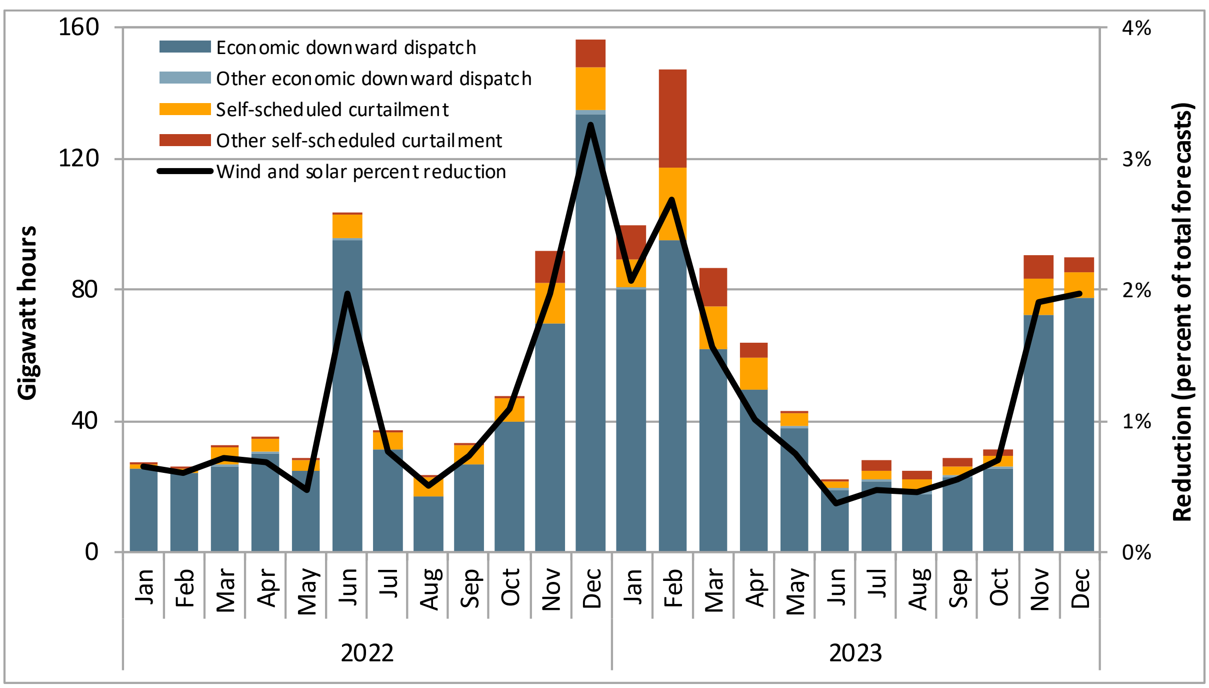


Figure 1.13 Reduction of wind and solar generation by month (WEIM)

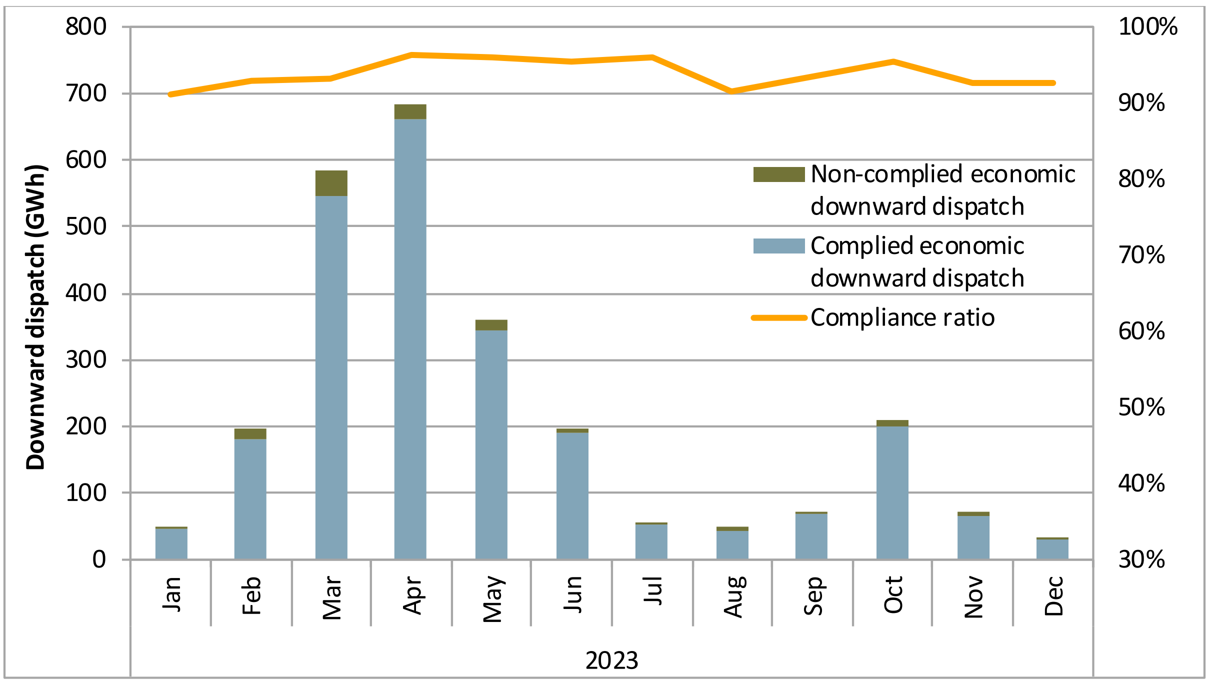


When the market dispatches a wind or solar resource below its forecasted value, scheduling coordinators receive a downward dispatch instruction indicating the need to adjust the resource output.

Figure 1.14 and Figure 1.15 show monthly solar and wind compliance with economic downward dispatch instructions during the year.[47] The blue bars represent the quantity of renewable generation that complied with economic downward dispatch, while the green bars represent the quantity that did not comply. The gold line represents the monthly rate of compliance.

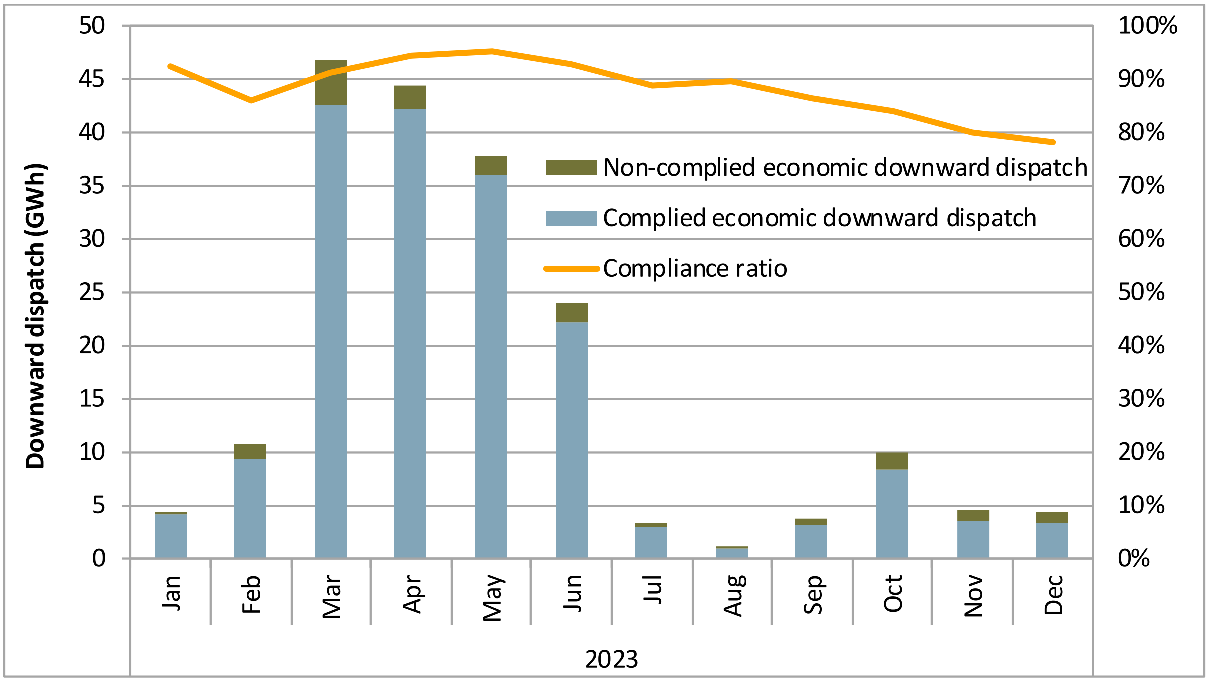
Solar resources were about 95 percent compliant with downward dispatch instructions in 2023, which was about the same as in 2022. Wind resources were 92 percent compliant with downward dispatch instructions, up from 84 percent the previous year. Under market rules, all market participants and resources are expected to follow dispatch instructions.

Figure 1.14 Compliance with dispatch instructions – solar generation



47 This analysis includes variable energy resources in the CAISO balancing area only.

Figure 1.15 Compliance with dispatch instructions – wind generation



Hydroelectric supplies

Total CAISO balancing area hydroelectric production in 2023 increased by around 69 percent from 2022.[48] Statewide snowpack, as measured on April 1, 2023, increased from last year to 245 percent of the long-term average.[49]

Year-to-year variation in hydroelectric power supply in California 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. Almost all hydroelectric resources in the California ISO area are owned by CPUC-jurisdictional investor-owned utilities.

Figure 1.16 shows total annual hydroelectric production in CAISO alongside the April 1 snowpack level in California from 2013 to 2023. Figure 1.17 compares monthly hydroelectric output from resources within the California ISO system for each month during the last five years. The hydroelectric generation pattern in 2023 is similar to 2019. Hydro generation followed a seasonal pattern with generation peaking in June. On average, monthly generation in 2023 was about 69 percent higher than in 2022.

48 Annual hydroelectric production includes all tie generators.

49 For snowpack information, please see: California Department of Water Resources, *California Data Exchange Center – Snow*, Snow Sensor Information/Course Measurements: https://cdec.water.ca.gov/snow/current/snow/index.html

Figure 1.16 Annual hydroelectric production (2013–2023)

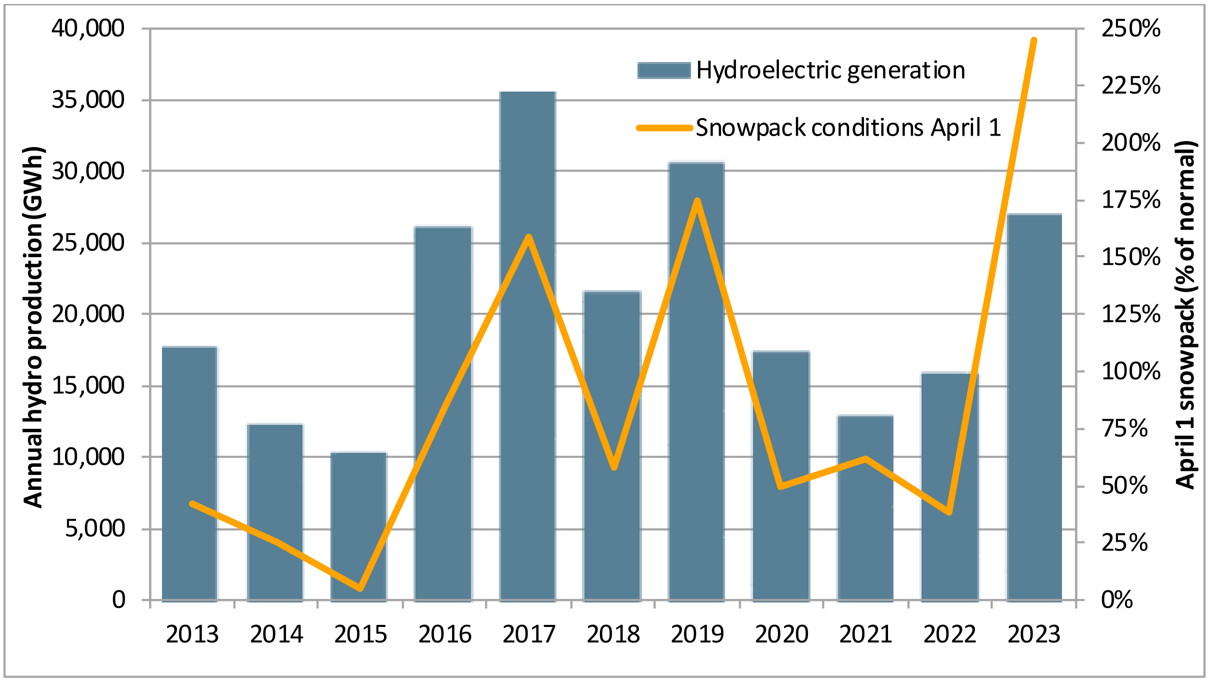
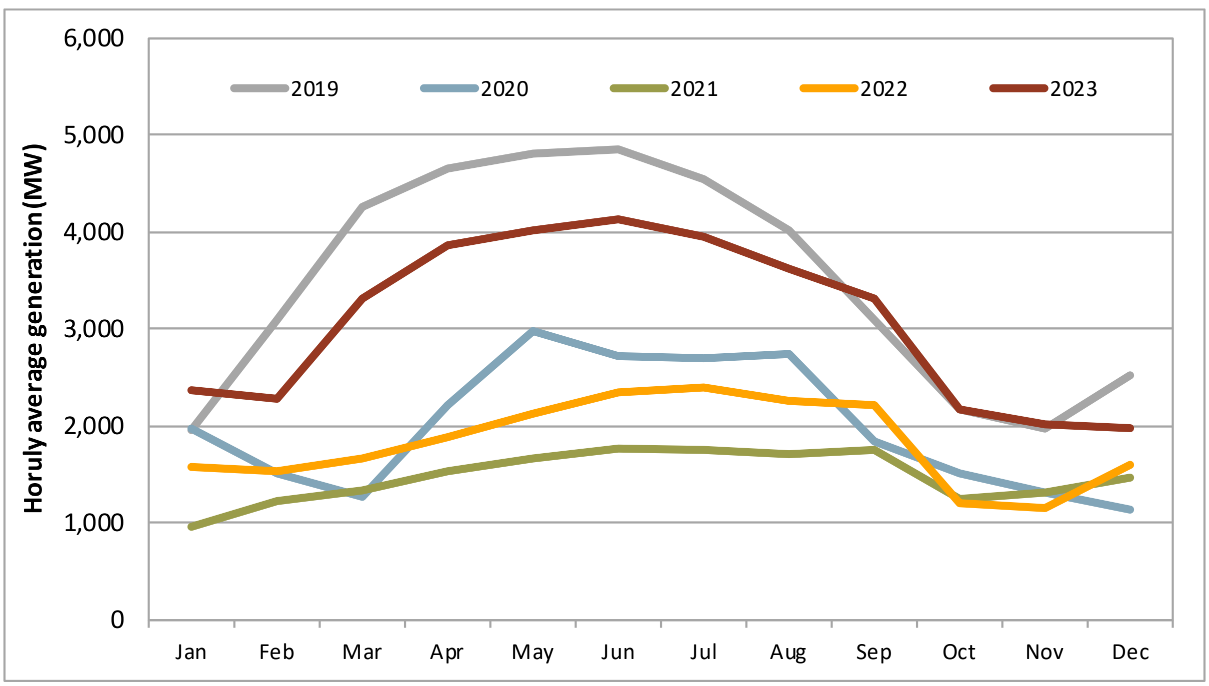


Figure 1.17 Average hydroelectric production by month (2019–2023)



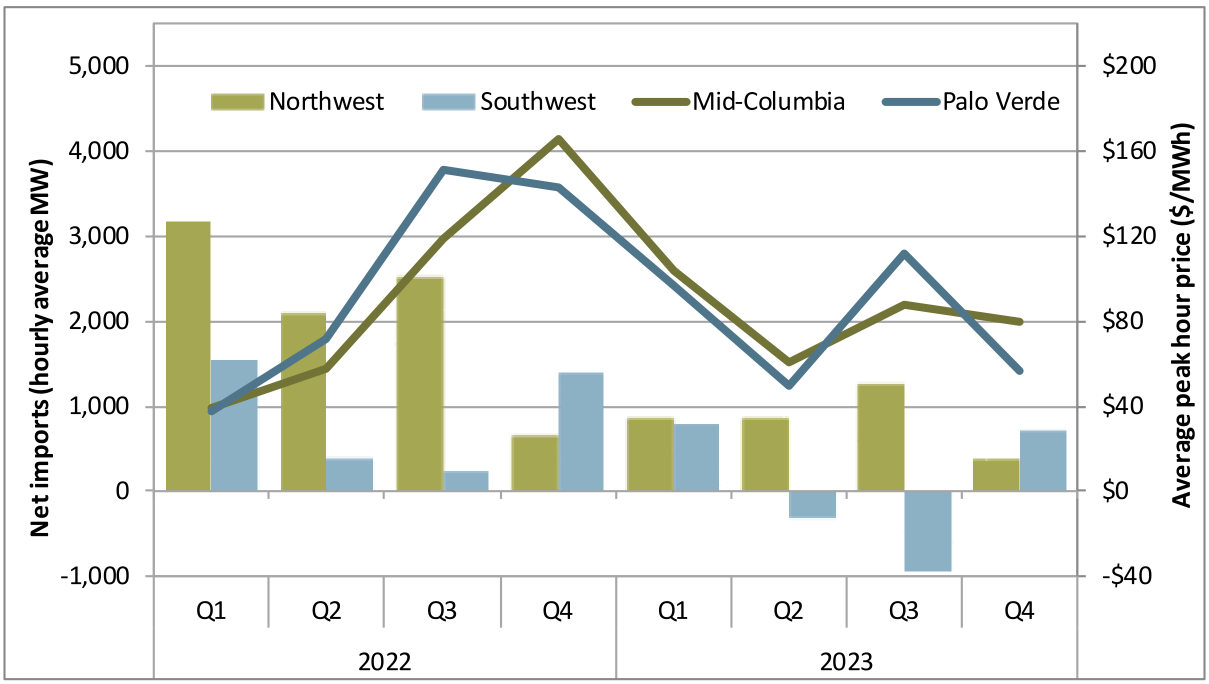
1.2.3 Net Imports

Peak hours and average prices

Total generation from net imports into the CAISO balancing area in 2023 during peak hours (hours-ending 7 through 22) decreased compared to 2022.[50] As shown in Figure 1.18, net imports from sources in the Northwest decreased by 60 percent, while net imports from the Southwest decreased by about 93 percent. Net imports from the Southwest were lower in all quarters with the second and third quarters resulting in negative net imports, i.e., exports. Net imports from the Northwest remained relatively consistent over the first three quarters, but decreased in the last quarter. In each quarter of 2023, net imports from the Northwest were less than the same quarter of the prior year.

Figure 1.18 also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. The bilateral prices that peaked in December 2022 due to persistent high gas prices in the Western U.S. tapered off in January 2023. The figure shows prices at Mid-Columbia and Palo Verde hubs spiked significantly in the third quarter.

Figure 1.18 Net imports and average day-ahead price (peak hours, 2022–2023)



Net interchange – CAISO imports and exports with WEIM transfers

The Western Energy Imbalance Market (WEIM) provides additional interchange between the CAISO and other balancing authority areas in both the import and export directions. The net quantity of imports *to* and exports *from* the CAISO, as well as WEIM transfers, is the CAISO system net interchange.

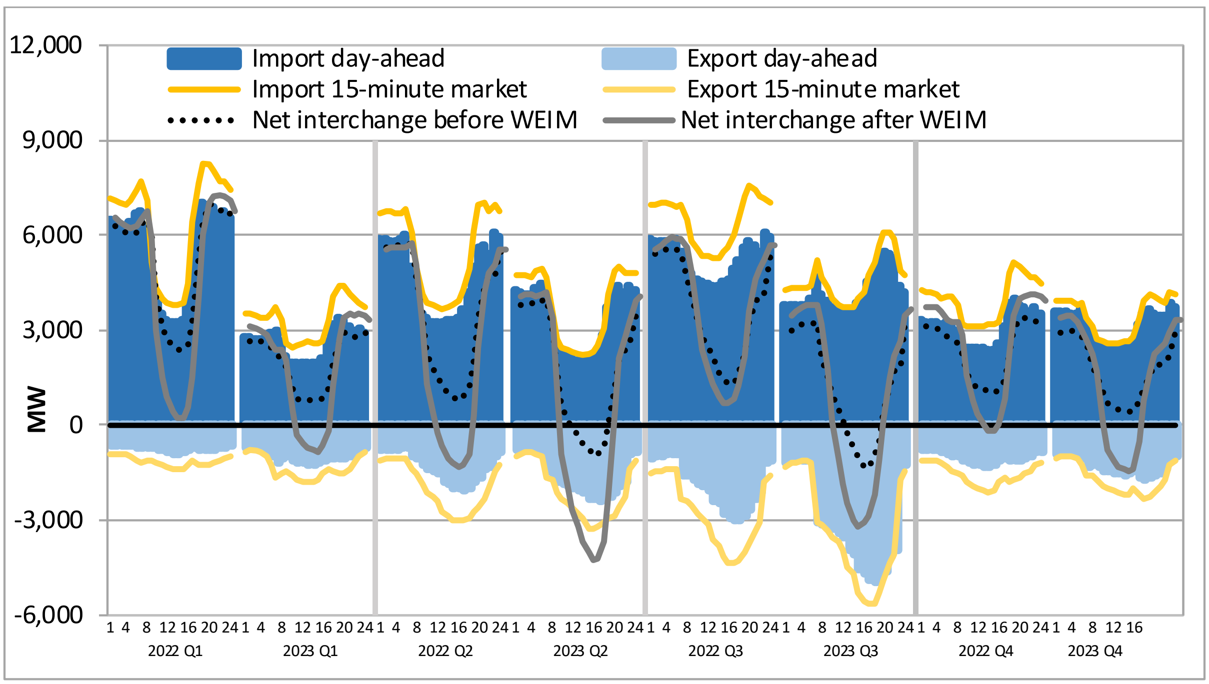
50 Net imports are equal to scheduled imports minus scheduled exports in any period. These net imports exclude any transfers associated with the Western Energy Imbalance Market.

As shown in Figure 1.19, average hourly net interchange into the CAISO balancing area continued to follow solar production patterns, falling in the mid-day hours as solar generation peaks, and rising in the peak net load hours. Cleared imports in both the day-ahead (dark blue columns) and the 15-minute market (dark yellow lines) peaked at lower volumes, but in similar hours to 2022.

Compared to 2022, exports increased in each quarter (shown as negative numbers below the horizontal axis). The pale blue columns represent day-ahead exports and the light yellow lines represent exports in the 15-minute market. The highest levels of exports were in the third quarter, peaking at about 5,600 MW in hour-ending 17.

Average net interchange into the CAISO area fell in 2023, on average, in each quarter. The average net interchange, excluding WEIM transfers (shown as the black dotted line), is based on meter data, and averaged by hour and quarter. The solid grey line adds incremental WEIM interchange; the lowest point occurred in the second quarter at about negative 4,200 MW in hour-ending 16.

Figure 1.19 Average hourly net interchange by quarter



1.2.4 Generation and interchange adjustments

Adjustments to market results from the day-ahead to the real-time markets can be attributed to changing system and market conditions, including over- or under-forecasted load, changes in expected renewable generation, exceptional dispatches, transmission outages, and generation availability during morning or evening net load ramp periods.

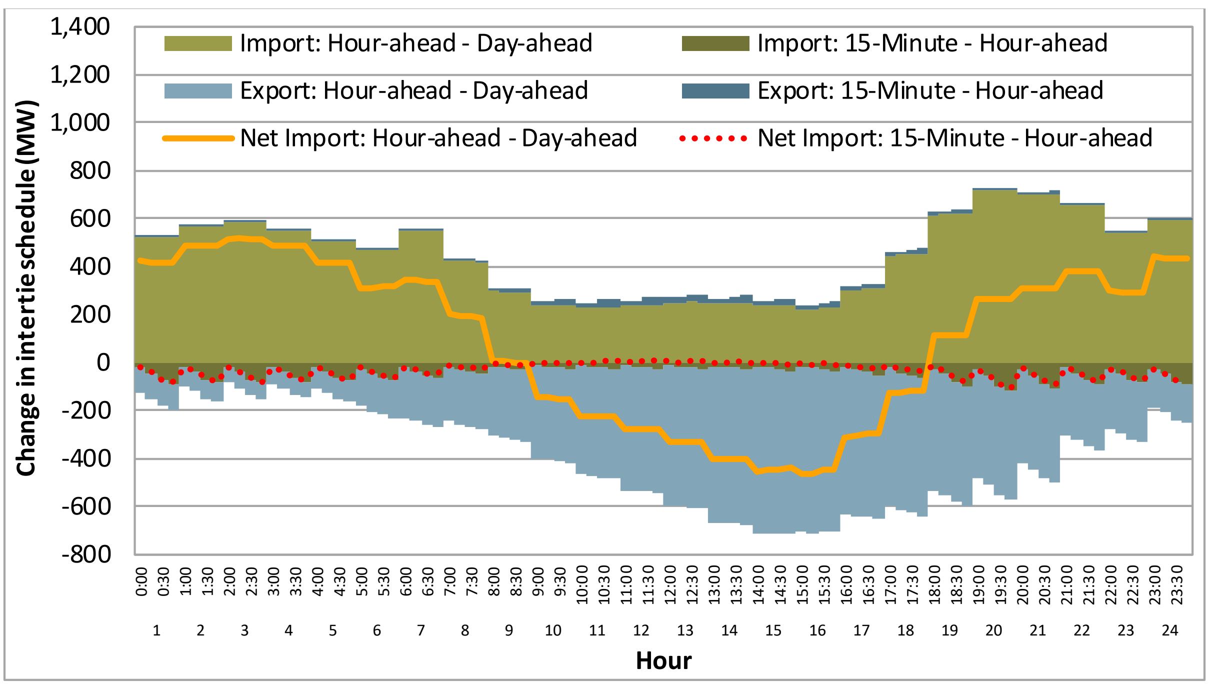
Figure 1.20 shows the incremental change in gross and net imports in the real-time market. The light green area shows the average incremental increase in imports from the day-ahead to the hour-ahead market. The light blue area shows the incremental change in exports from the day-ahead to the hour-ahead market, where an increased export is displayed as a negative value.

The yellow line in Figure 1.20 shows the change in net interchange, summing the effects of increased imports and exports. The red dotted line represents the change in net interchange from the hour-ahead to the 15-minute market, and is the sum of the changes in imports (dark green) and exports (dark blue). These are lower values relative to the changes observed between the day-ahead and the hour-ahead markets.

As shown in Figure 1.20, most incremental commitment of imports occurs in the hour-ahead market outside the mid-day hours in two periods, hours-ending 1 to 10 and hours-ending 17 to 24. During these hours in 2023, net interchange adjustments from the day-ahead to the hour-ahead market averaged about 250 MW, a decrease from an average of 500 MW during these hours in 2022. Unlike 2022, when the highest average net interchange adjustment was in hours-ending 19 to 22, and reaching a peak of 750 MW in hour-ending 22, 2023 instead peaked in hour-ending 3 at about 520 MW. The highest average for the evening peak was about 440 MW in hour-ending 24.

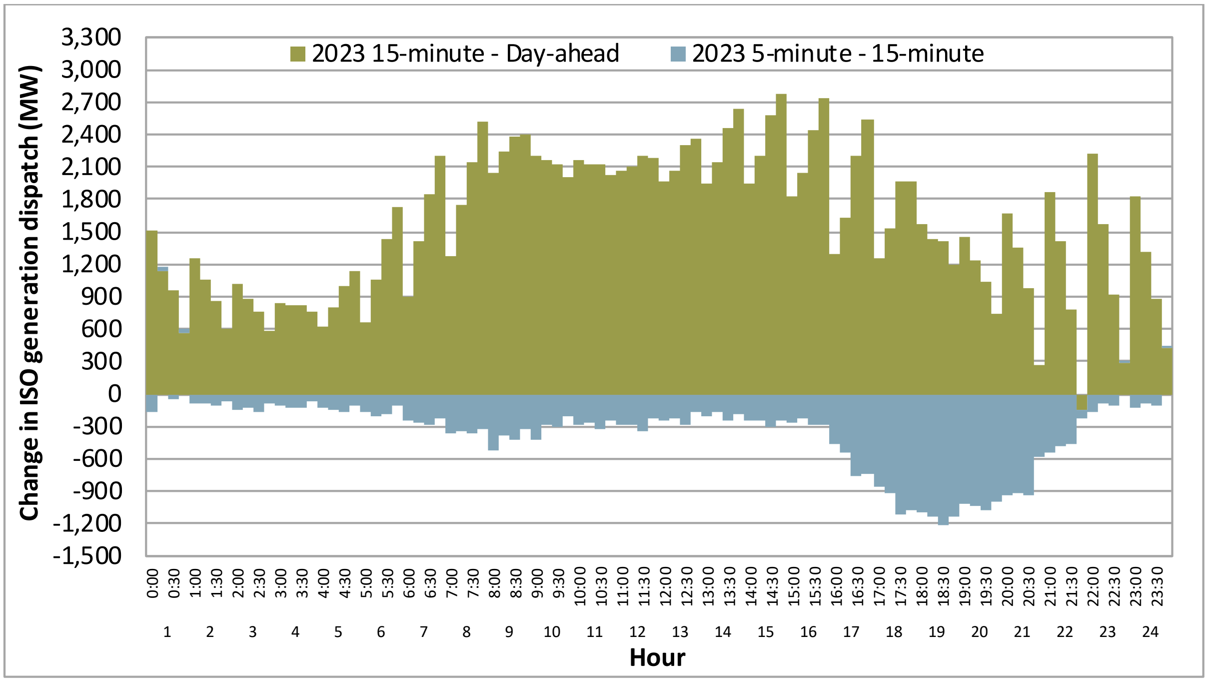
In 2023, as with the previous year, there was a noticeable increase in both imports and exports in the hour-ahead market from the day-ahead market during mid-day solar peak periods. Net imports fell between the day-ahead and hour-ahead markets in these hours, similar to prior years.

Figure 1.20 Net interchange dispatch volume



The incremental dispatch of internal generation between the day-ahead and 15-minute real-time markets tended to increase in the mid-day hours associated with solar schedules. Figure 1.21 shows the average incremental change for internal generation from the day-ahead market to the 15-minute market (green bars), and from the 15-minute to the 5-minute market (blue bars). During the evening hours of decreasing solar production—hours-ending 17 to 22—generation increases in the 15-minute market relative to the day-ahead market (green bars), but then decreases in the 5-minute market (blue bars). This reflects the much larger upward adjustment that CAISO area operators make to the 15-minute market load forecast than they make to the 5-minute market forecast.

Figure 1.21 Incremental generation dispatch volume



1.2.5 Energy storage and distributed energy resources

Batteries[51]

Capacity from battery storage resources has increased significantly in recent years. 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,

51 For more information see DMM's special report: *2023 Special Report on Battery Storage*, Department of Market Monitoring, July 16, 2024: https://www.caiso.com/documents/2023-special-report-on-battery-storage-jul-16-2024.pdf

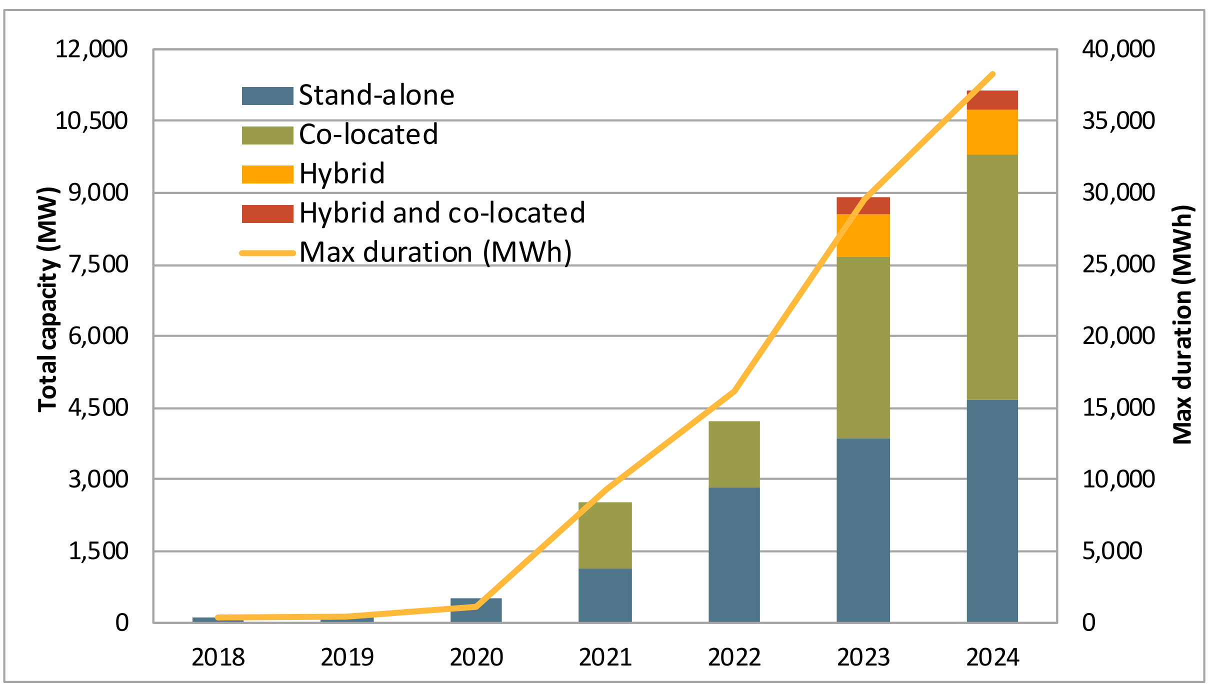
the ISO recently implemented an optional parameter that allows co-located batteries to restrict grid charging. This helps resources capture tax benefits meant to incentivize batteries to not charge beyond what their co-located solar component is producing.

As of June 1, 2024, there are 141 co-located resources across 65 points of interconnection. Around 37 percent of installed co-located capacity consists of batteries, and all but two of these 65 points of interconnection have at least one battery resource.

Figure 1.22 shows the total capacity of CAISO BAA-participating battery storage as of June 1, 2024, represented in terms of maximum output (MW) and maximum duration (MWh).[52] Stand-alone battery is defined as a resource with only battery storage components that does not share a point of interconnection with other resources. In June 2024, active battery capacity totaled 11,100 MW—4,700 MW from stand-alone projects, 5,100 MW from co-located projects, and about 1,300 MW from the storage components of hybrid resources and co-located hybrids. Most batteries in the CAISO market have a duration of four hours.

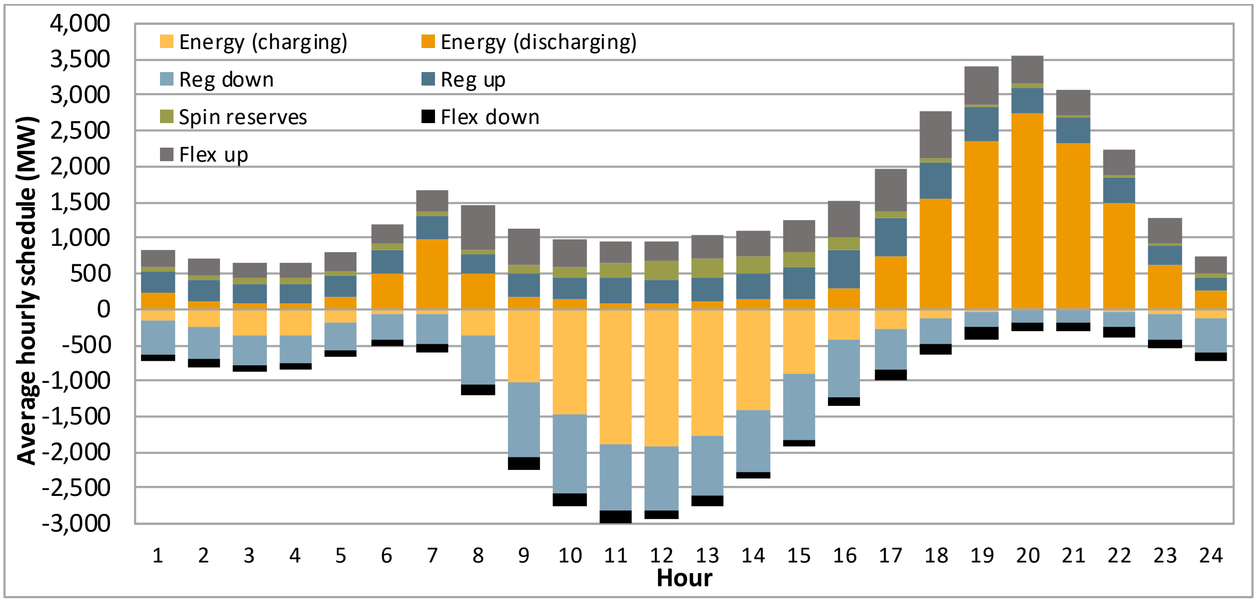
Figure 1.23 shows average hourly real-time (15-minute market) schedules of stand-alone battery resources. Historically, batteries have favored providing ancillary services—especially frequency regulation—over energy because it allows them to avoid deep charging and discharging cycles, which cause rapid cell degradation. Increasingly, batteries are scheduled to provide energy as well. Batteries tend to charge during the afternoon when solar energy is abundant, then discharge in the evening when power is in high demand, solar output is low, and prices are much higher. In peak demand hours, batteries contributed up to 77 percent of their scheduled output to discharging energy on average.

Figure 1.22 Battery capacity (2018–2024)



52 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 1.23 Average hourly real-time battery schedules in 2023



Demand response

Demand response programs are operated by load serving entities as well as third-party providers. Currently, demand response resources shown on monthly resource adequacy supply plans are scheduled by third-party (non-load-serving entity) demand response providers. Utility-operated demand response programs are not shown on monthly resource adequacy supply plans, and are instead credited against (used to reduce) load serving entity resource adequacy obligations under local regulatory authority provisions.

Utility demand response resource adequacy averaged 1,175 MW in 2023, and reported curtailing 90 percent of their real-time schedules on average in July, August, and September of 2023. Third party demand response resource adequacy capacity averaged about 210 MW this year, and their self-reported performance, including load curtailments in excess of individual resource schedules, averaged 65 percent of their real-time schedules. In general, demand response resources are primarily scheduled on days with high loads and tight conditions. DMM's report on demand response analyzes performance on these high load days in more detail.[53] Performance on high load days for utility demand response was similar to average performance, averaging 89 percent of their real-time schedules. Third party demand response, however, performed worse on high load days, averaging only 46 percent of their real-time schedules.

Figure 1.24 shows the total third-party demand response resource adequacy capacity shown on monthly supply plans in 2022 and 2023. Third-party demand response participating in the California ISO market decreased from 2022, averaging about 210 MW across 2023.

53 *Demand response issues and performance 2023,* Department of Market Monitoring, March 6, 2024: https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf

Figure 1.24 Third-party demand response shown on monthly resource adequacy supply plans

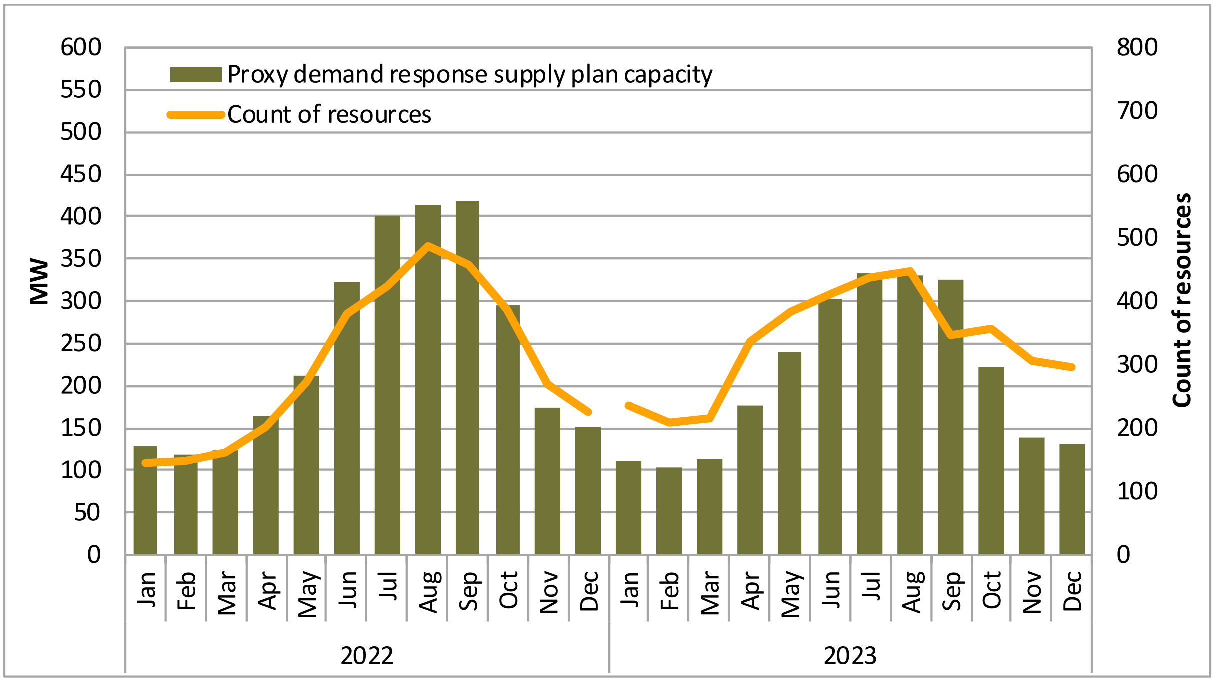
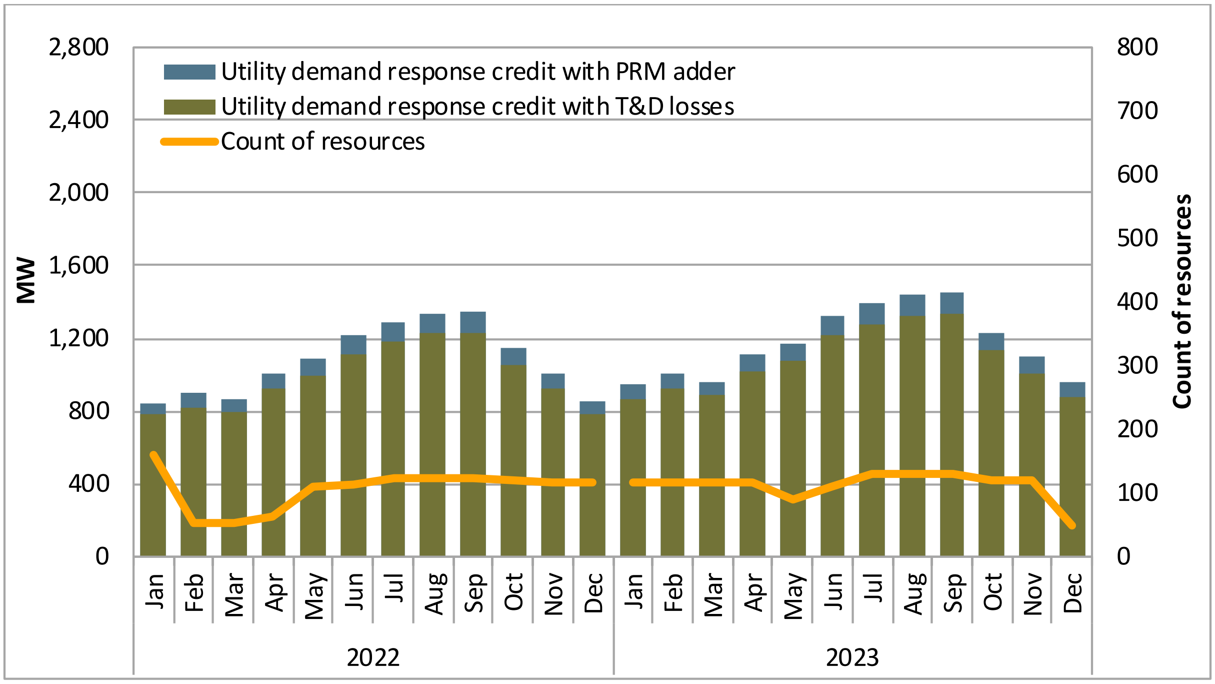


Figure 1.25 shows the total demand response resource adequacy capacity (proxy demand response and reliability demand response resources) associated with CPUC-jurisdictional utility demand response programs. Utility demand response capacity is credited against load serving entity resource adequacy obligations, which reduces the amount of resource adequacy capacity load serving entities are required to procure. Utility demand response capacity is grossed up for avoided transmission and distribution line losses. A 9 percent planning reserve margin adder is also applied to CPUC-jurisdictional utility demand response capacity, which further reduces load serving entities' resource adequacy obligations. Prior to 2022, this planning reserve margin adder was 15 percent, and starting in 2024, this adder will be removed entirely. 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 overwhelming majority of utility demand response resource adequacy capacity is comprised of reliability demand response resources. These resources are generally only dispatched under emergency conditions, although they are able to 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. This is a change to previous years, when the ISO had to be in an EEA 2 or higher to dispatch reliability demand response in the real-time. In 2023, reliability demand response was dispatched in the real-time only one day, July 20, when the California ISO was in an EEA 1.

Figure 1.25 CPUC-jurisdictional utility demand response resource adequacy credits



Dispatch and performance of demand response

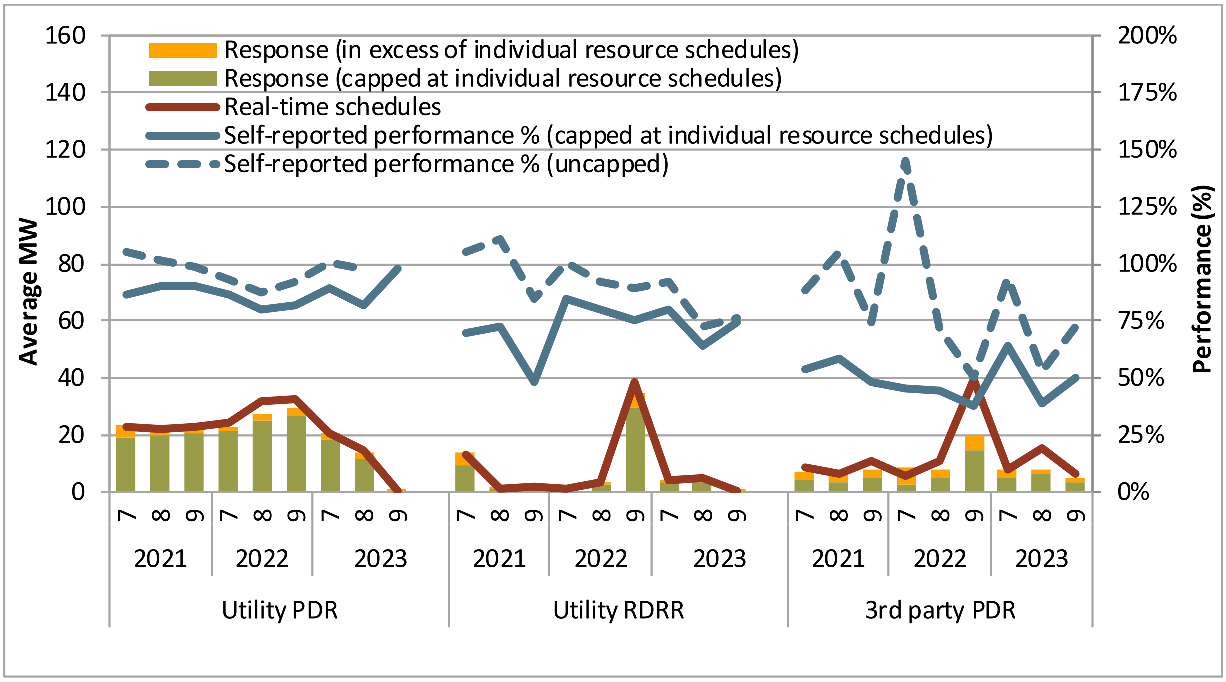
The CAISO relied on demand response resources, including reliability demand response, during high load days across July and August in 2023. The CAISO economically scheduled proxy demand response resources throughout the summer and issued manual dispatches to reliability demand response on July 20. More details on the performance of demand response resources on these specific high load days can be found in DMM's 2023 report on demand response issues and performance.[54]

Figure 1.26 shows the expected load curtailment (schedule) of demand response resource adequacy resources compared to reported performance from July to September in 2021, 2022, and 2023 in peak net load hours (4-9 p.m.). Self-reported performance has continually been higher for utility demand response resources compared to third-party demand response resources. In July through August 2023, uncapped performance of utility proxy demand response and reliability demand response averaged 100 percent and 80 percent, respectively, of their real-time schedule. Third-party demand response resources, however, averaged only 65 percent across July, August, and September 2023, and averaged only 46 percent of real-time schedules during high load days.[55]

54 *Demand response issues and performance 2023,* Department of Market Monitoring, March 6, 2024: https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf

55 *Demand response issues and performance 2023,* Department of Market Monitoring, March 6, 2024, pp 18-19: https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf

Figure 1.26 Demand response resource adequacy performance – July to September (4–9 p.m.)



1.2.6 Generation outages

The quantity of generation on outage in 2023 decreased by 1.5 percent from 2022. Generation outages typically follow a seasonal pattern, with the majority of outages taking place in the non-summer months. 2023 followed this trend. The steady increase in forced outages from 2019 to 2021 slowed in 2022 and 2023.

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.

Figure 1.27 and Figure 1.28 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.

Average total generation outages in the California ISO balancing area were about 13,700 MW, down from 13,925 MW in 2022.[56] Outages for planned maintenance averaged about 3,000 MW during peak hours, while all other types of planned outages averaged about 900 MW. Some common types of

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

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 4,100 MW, while all other types of forced outages averaged about 5,700 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 1.27 Quarterly average of maximum daily generation outages by type – peak hours

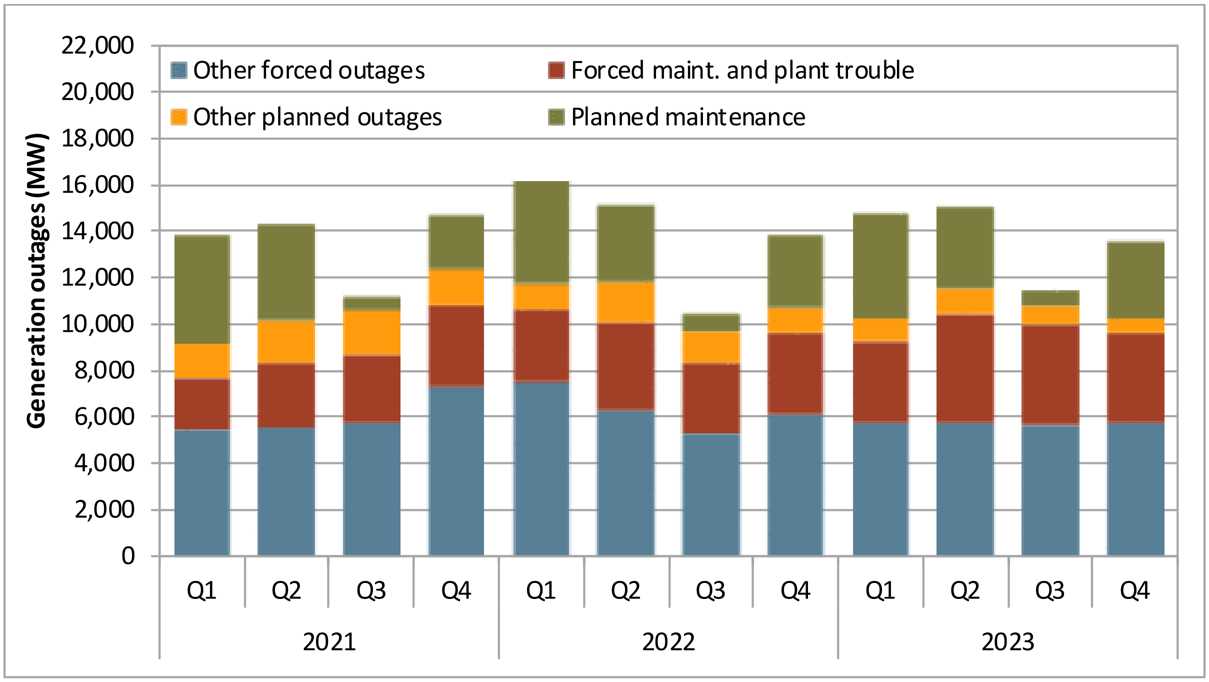
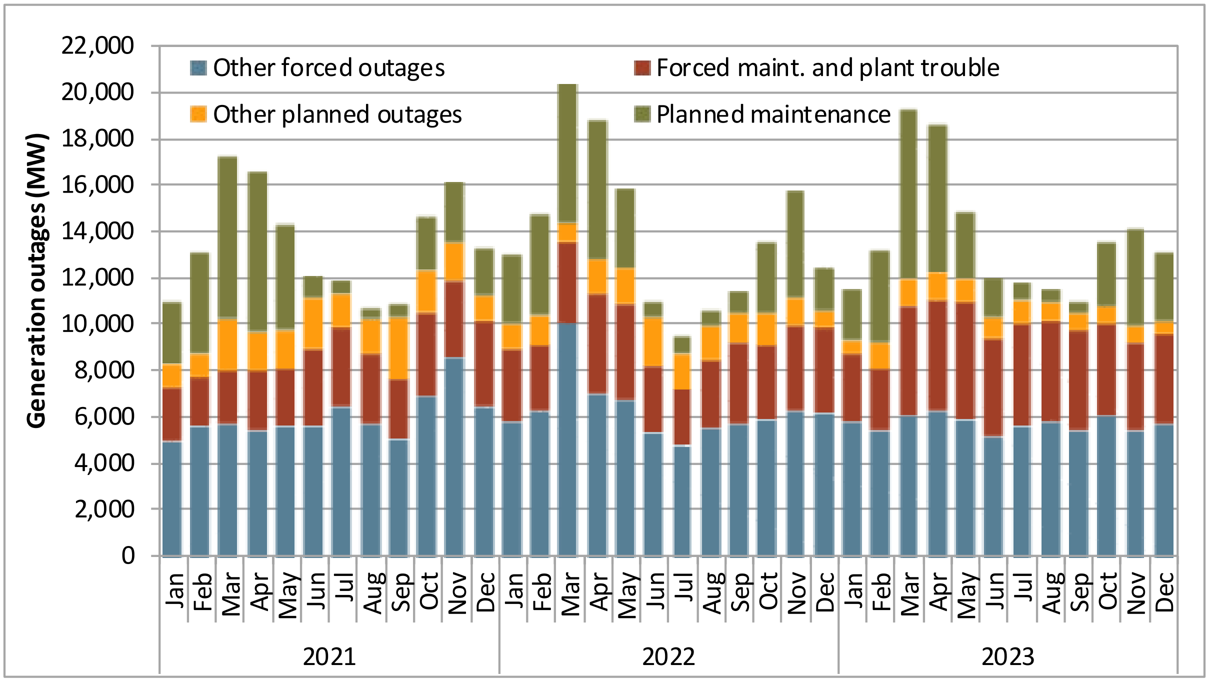


Figure 1.28 Monthly average of maximum daily generation outages by type – peak hours

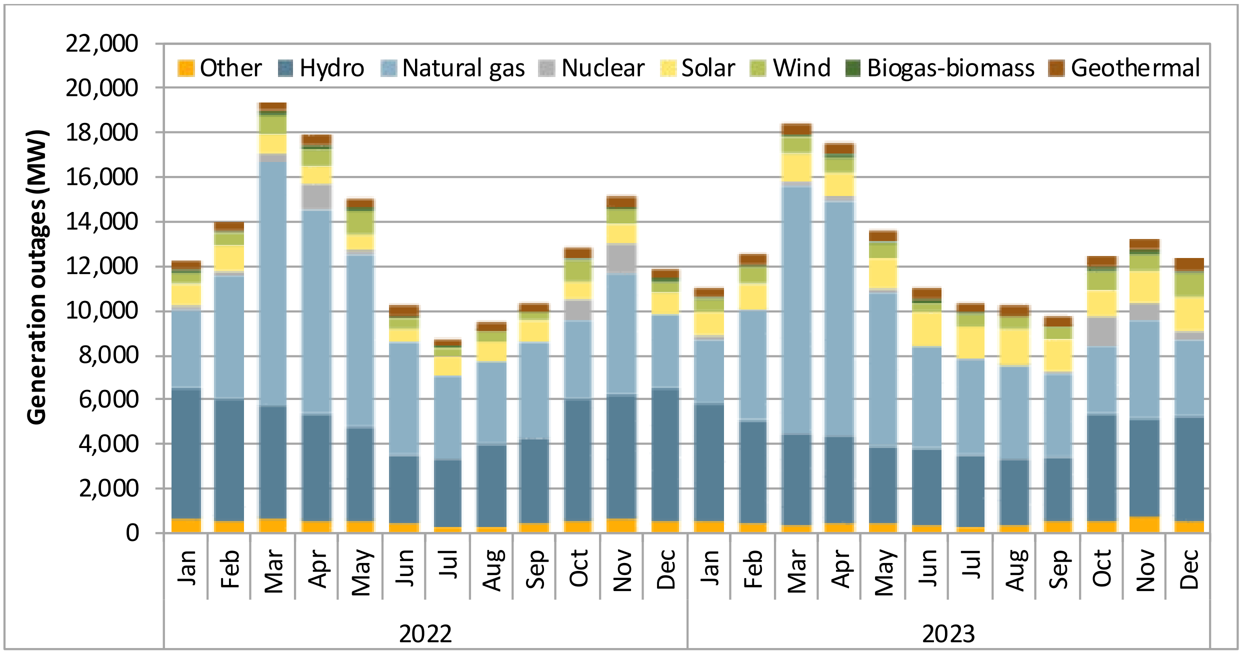


Generation outages by fuel type

Natural gas and hydroelectric generation averaged 5,500 MW and 4,700 MW on outage during 2023, respectively. Together, these two fuel types accounted for about 80 percent of the generation on outage for the year.

Figure 1.29 shows the monthly average generation on outage by fuel type during peak hours. Similar to last year, March experienced the highest monthly average generation on outage at 18,400 MW in total. This is in large part due to an increase in natural gas generation outages. These natural gas generation outages tapered down through the summer and remained fairly low in the winter.

Figure 1.29 Monthly average of maximum daily generation outages by fuel type – peak hours



1.2.7 Natural gas prices

Electricity prices in the western states typically follow natural gas price trends. This is because natural gas units are often the marginal source of generation in the California ISO area and other regional markets. During December 2022, gas prices at western gas hubs started to trend at a significant premium over Henry Hub. This continued into 2023. Within the CAISO balancing authority footprint the load-weighted average gas price increased to $30.60/MMBtu in December 2022 compared to $6.50/MMBtu in December 2021, and to $17.29 in January 2023 compared to $5.34 in January 2022.

Figure 1.30 shows monthly average natural gas prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

SoCal Citygate prices often impact overall system prices. First, there are large numbers of natural gas resources in the south. Second, these resources can set system prices in the absence of congestion.

As shown in Figure 1.30, gas prices at western gas hubs spiked in December of 2022. High gas prices continued into January 2023. Several days in January had prices over $20/MMBtu, with some as high as $50/MMBtu. There were several contributing factors to persistent high gas prices in January:[57]

[57] End-of-winter natural gas storage stocks in the Pacific region dip to record low, EIA Natural Gas Storage Dashboard, April 27, 2023: https://www.eia.gov/naturalgas/storage/dashboard/commentary/20230427

1. High natural gas consumption in the residential and electric power sector. Below normal temperatures leading to increased demand for natural gas;[58]
2. Reduced natural gas deliveries into the Pacific Northwest and California from supply regions. Pipeline constraints on the El Paso Natural Gas pipeline system restricted Permian Basin flows into Southern California; and
3. Low natural gas storage inventory levels in the Pacific region.[59,60] As of March 31, 2023, storage inventories were down by more than 50 percent from 2022 levels and the five-year average. After the 2022 summer heatwave, PG&E's injections to rebuild natural gas inventories did not keep pace with previous summers.[61]

By the end of the first quarter of 2023, natural gas prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) declined by 31 percent and 26 percent, respectively, compared to the fourth quarter of 2022. On March 18, 2022, the CPUC issued a proposed decision to extend SoCalGas's 8-stage winter operational flow order (OFO) penalty structure year-round, and made it applicable to the PG&E and SDG&E service territories. Compared to the previous year, prices generally continued to decline even when taking seasonal factors into account.

On August 31, 2023, the CPUC issued an order increasing the inventory limit for the Aliso Canyon storage facility from 41.16 Bcf to 68.6 Bcf, which builds on the storage level set in 2021 of about 34 Bcf.[62] This action contributed to increasing SoCalGas total authorized storage inventory capacity to 119.5 Bcf.[63] SoCalGas fourth quarter 2023 storage inventory steadily increased from about 91 Bcf on October 1, 2023 to about 106 Bcf on December 31, 2023. This is in contrast to the 2022 storage levels. From the beginning of October to mid-November 2022 SoCalGas storage levels were about 88 Bcf, and ended the year at roughly only 62 Bcf.[64]

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58 Daily regional average temperatures and departure from normal, EIA Natural Gas Storage Dashboard: https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20240118_natural_gas_storage_dashboard.pdf https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20240125_natural_gas_storage_dashboard.pdf

59 Pacific region weekly working gas in underground storage, EIA Natural Gas Storage Dashboard, p 3: https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20221229_natural_gas_storage_dashboard.pdf

60 Southern California daily energy report: https://www.eia.gov/special/disruptions/socal/archive/winter/2022-12-31_winter_socal_energy_report.pdf

61 California natural gas storage levels are much lower in the north than in the south: https://www.eia.gov/todayinenergy/detail.php?id=53259

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

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

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

Figure 1.30 Monthly average natural gas prices (2020–2023)

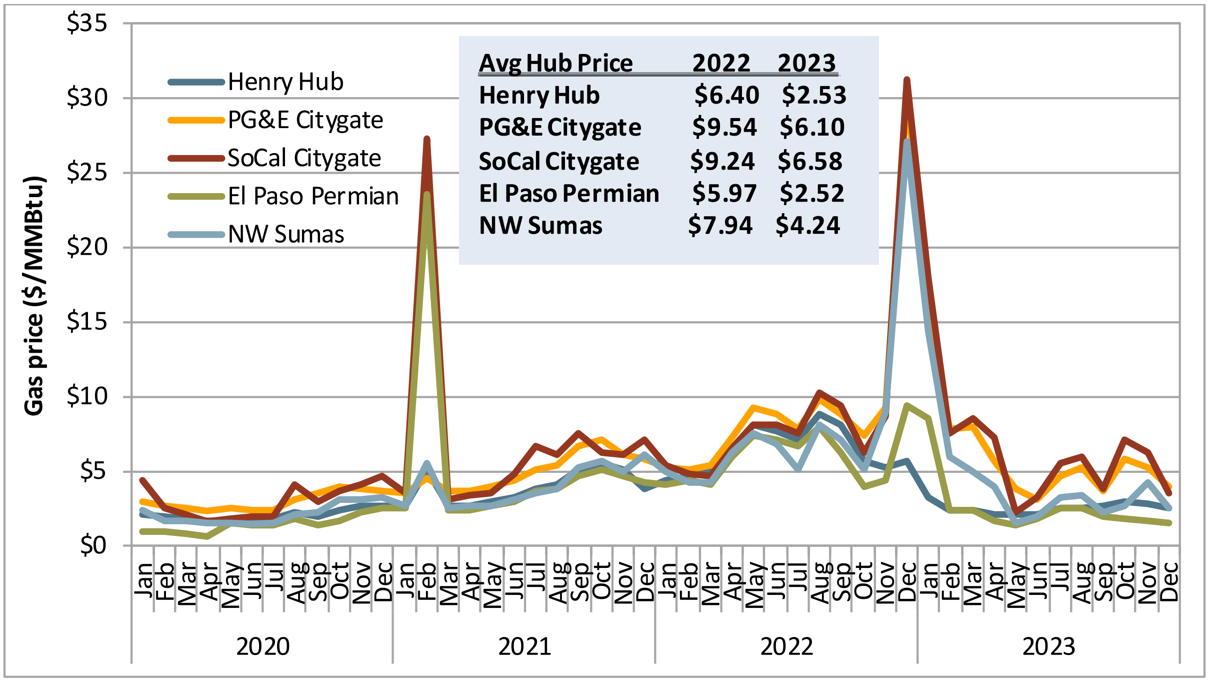
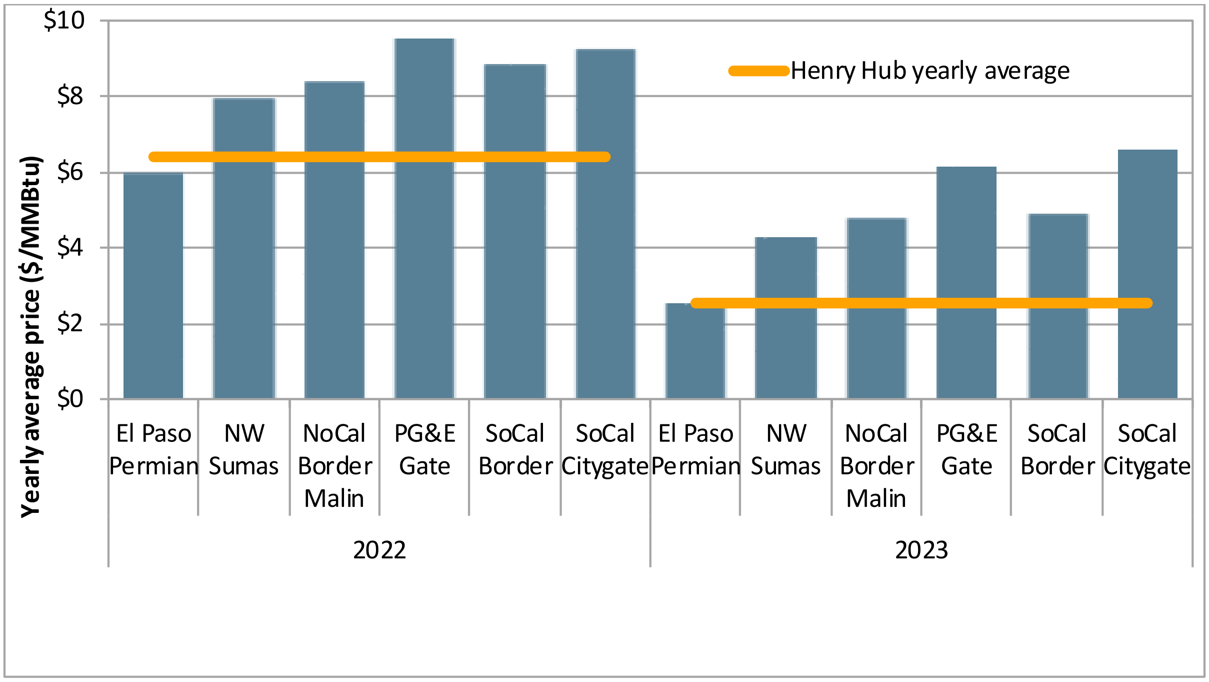


Figure 1.31 compares yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2022 and 2023. This hub acts as a point of reference for the national market for natural gas, and in 2023 prices decreased by 60 percent relative to 2022. This decrease was also evident in all trading hubs compared to the previous year, with El Paso Permian dropping 57 percent and NW Sumas, NorCal Border and SoCal Border declining between 43 percent and 46 percent, respectively. The PG&E Gate and SoCal Citygate hubs decreased the least compared to the previous year by 36 percent and 28 percent, respectively. These decreases in natural gas prices resulted in lower system marginal energy prices across the CAISO footprint in 2023.

Figure 1.31 Yearly average natural gas prices compared to the Henry Hub



1.2.8 California's greenhouse gas allowance market

This section provides background on California's greenhouse gas allowance market under the state's cap-and-trade program, which was applied to the wholesale electric market in 2013.[65] 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 the California ISO balancing area or other California balancing areas in the WEIM.

In addition, greenhouse gas compliance costs are attributed to resources that participate in the WEIM and serve load of the California ISO balancing area or other California balancing areas in the WEIM. 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 in Section 3.6 of this report.

Greenhouse gas allowance prices

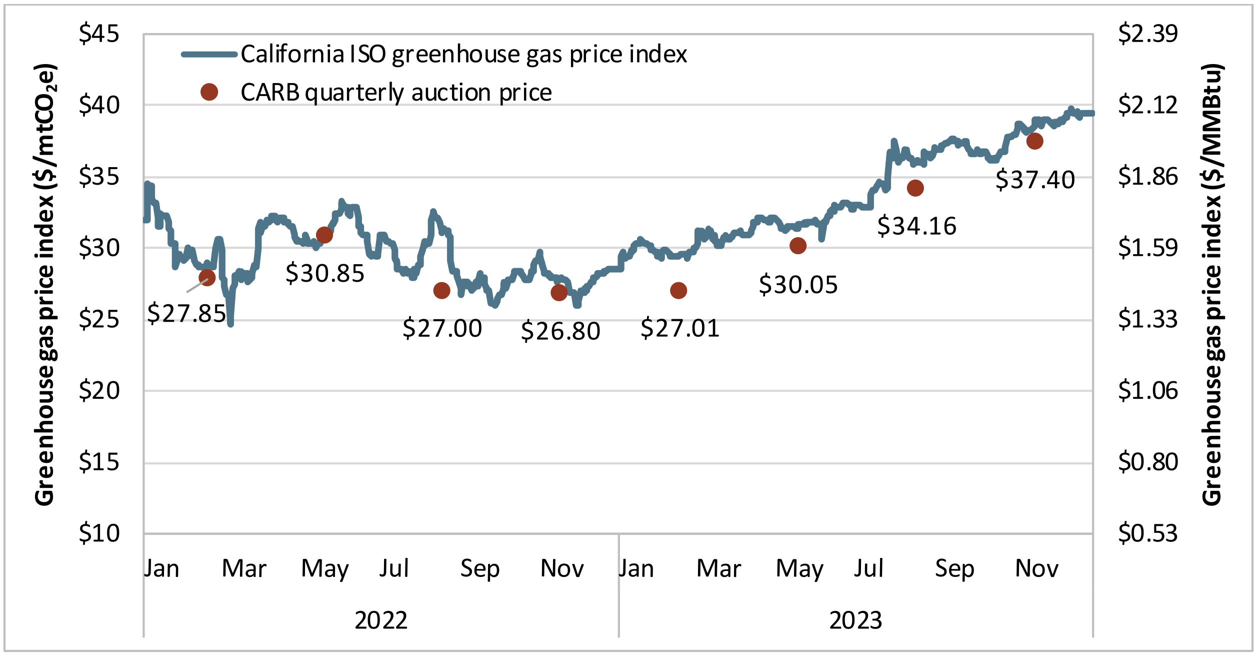
When calculating various cost-based bids used in the market software, a calculated greenhouse gas allowance index price is used as a daily measure for greenhouse gas allowance costs. The index price is

65 A more detailed description of the cap-and-trade program and its impact on wholesale electric 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

calculated as the average of two market-based indices.[66] Daily values of this greenhouse gas allowance index are plotted in Figure 1.32.

Figure 1.32 also shows market clearing prices in the California Air Resources Board's (CARB) quarterly auctions of emission allowances that can be used for the 2022 or 2023 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.[67]

Figure 1.32 California ISO greenhouse gas allowance price index



As shown in Figure 1.32, the average cost of greenhouse gas allowances in bilateral markets increased 15 percent from a load-weighted average of $29.47/mtCO$_2$e in 2022 to $34.06/mtCO$_2$e in 2023. In 2023, each of the California Air Resources Board's quarterly allowance auctions sold a fraction of allowances offered and thus cleared at an average auction reserve price of $32/mtCO$_2$e, compared to $28/mtCO$_2$e last year.

66 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

67 The emissions factor, 0.0531148 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_2O 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

Impact of greenhouse gas program

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.[68] The greenhouse gas compliance cost expressed in dollars per MMBtu in 2023 ranged from about $1.5/MMBtu to $2.1/MMBtu.

The $34.06/mt$CO_2$e average in 2023 would represent an additional cost of about $14.47/MWh for a relatively efficient gas unit.[69] This is an increase from 2022 when the average price was $29.47/mt$CO_2$e, or about $12.52/MWh for the same relatively efficient gas resource.

1.2.9 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. Trends in the amount of generation capacity each year provide important insight into the effectiveness of the market and California's regulatory structure in incentivizing new generation development. Since summer 2023, the primary trend in capacity changes have been increases in battery 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.

Graphs reflect nameplate capacity and changes between Junes of one year to the next to reflect changes to peak summer capacity.[70]

Total California ISO registered and participating capacity

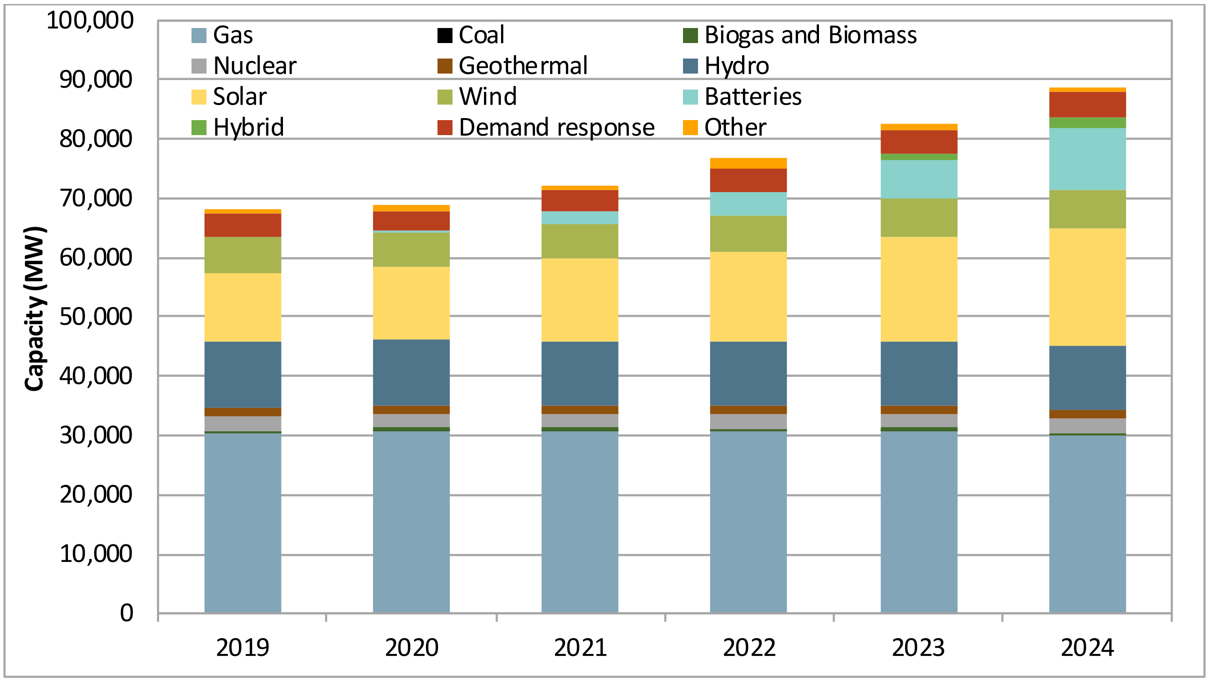
Figure 1.33 summarizes the trends in available nameplate capacity from June 2019 through June 2024 for the California ISO balancing area. At 30 GW, natural gas capacity has decreased around 770 MW since last year. Batteries and solar grew the most out of any resource type in CAISO, adding 3.8 GW and 2.3 GW, respectively, since June 2023. The CAISO fleet currently has 1.9 GW of capacity from resources with multiple generation technologies participating under the hybrid model, nearly double the amount from last year. Overall, nameplate capacity has increased by 6.4 GW since June 2023. In comparison, the CAISO added 5.6 GW of nameplate capacity from June 2022 to June 2023.

[68] *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

[69] 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: 0.0531148 mtCO_2e/MMBtu, derived in footnote 86.

[70] 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 1.33 Total California ISO participating capacity by fuel type and year (as of June 1)



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 December 2021, the CPUC approved measures meant to shore up capacity in preparation of potential extreme weather events in summers 2022 and 2023, including a requirement for LSEs to procure between 2,000 and 3,000 MW of capacity in total.[71] In October 2022, the ISO Board of Governors approved an extension for Reliability Must Run (RMR) contracts for three natural gas generators, keeping 159 MW of capacity available until at least December 31, 2023.[72] All three units have entered into resource adequacy contracts for the full amount of their available capacity, and have since been released from their RMR contracts. This leaves the ISO with no RMR contracts at the start of 2024.[73] Under the California ISO tariff, an RMR contract allows the ISO to call on the participating resource to generate energy, provide ancillary services, black start, voltage support, or similar services to maintain reliability on the grid. In addition, the State Water Resources Control Board adopted a

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71 CPUC Docket No. R.20-11-003, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, December 2, 2021, p 2: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M427/K639/427639152.PDF

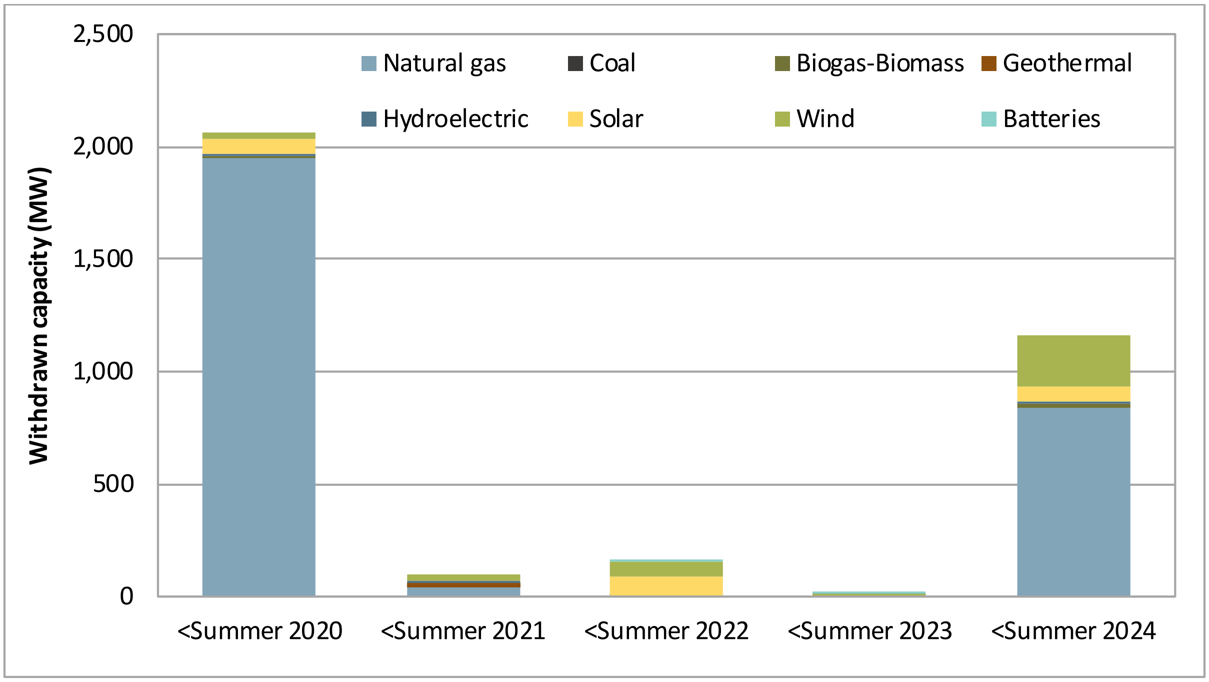
72 *Update on results of reliability must-run contract extensions for 2023*, California ISO, October 19, 2022: https://www.caiso.com/Documents/ReliabilityMust-RunContractsUpdate-Oct2022.pdf

73 *Update on results of reliability must-run contract extensions for 2024*, California ISO, November 1, 2023: https://www.caiso.com/Documents/UpdateonReliabilityMust-RunContractExtensionsfor2024-Nov2023.pdf

resolution amending its policy on once-through cooling to delay the retirement of six natural gas generating units, with nearly 3,000 MW of capacity, from December 2023 until 2026.[74]

Figure 1.34 shows the withdrawal and retirement of capacity from June 2019 through 2024. Withdrawal of natural gas plants to comply with the once-through cooling policy have driven a large amount of capacity retirement since June 2023. Around 1,200 MW of capacity, mostly located in the LA Basin, have withdrawn from the market since last summer. Between June 2020 and June 2023, only around 280 MW of capacity retired.

Figure 1.34 Withdrawals from California ISO market participation by fuel type



Additions to participating capacity

Figure 1.35 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.[75]

From June 2018 to June 2024, around 9.6 GW of solar, 1.6 GW of natural gas, 1.4 GW of wind, 1.9 GW of hybrid, and 10.3 GW of battery capacity were added or returned to the market.[76] The majority of the increase in battery capacity happened within the last two years, with around 6.5 GW of capacity added

74 State Water Resources Control Board, Resolution No. 2023-0025, August 15, 2023, p 3-4: https://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2023/rs2023-0025.pdf

75 These figures do not account for generation outages, despite being similar in nature.

76 Resource additions often transition into the market with various phases of testing, so the exact date of market entry reported can vary.

since June 2022. Over 91 percent of the natural gas capacity increases during the past six years occurred before June 2020.[77]

Figure 1.35 Additions to California ISO market participation by fuel type[78]

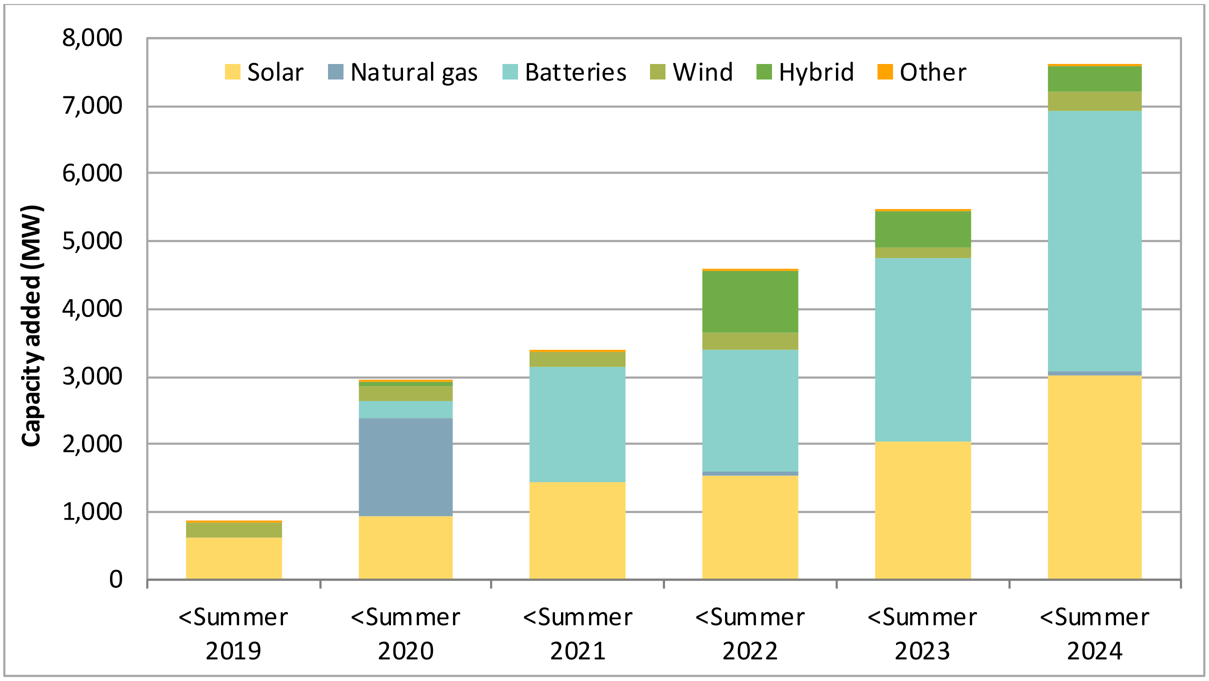


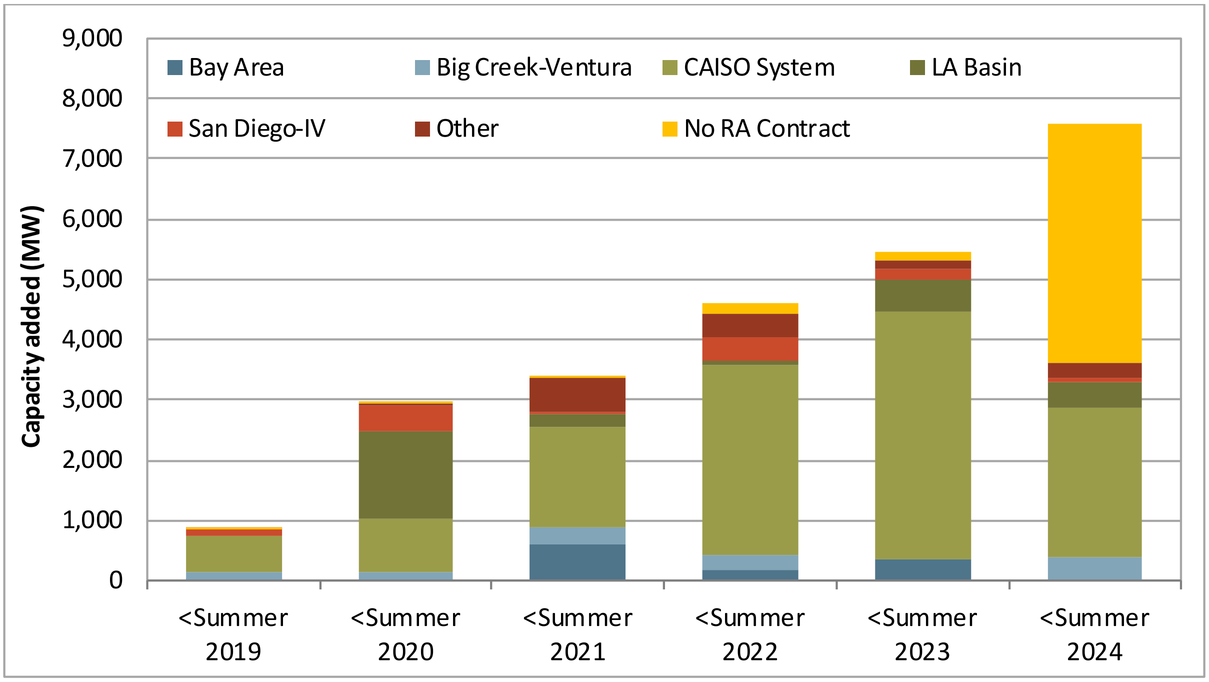
Figure 1.36 shows additions by local area according to local resource adequacy showings. Resources shown for system resource adequacy (RA) are labeled as CAISO System and are represented by the light green bars.[79] In the last couple of years, a significant amount of the new capacity came in as system RA, with around 4.1 GW added from June 2022 to June 2023, and 2.5 GW added from June 2023 to June 2024. The majority of added capacity from June 2023 to June 2024 has no RA contract as of this report's drafting, though this is subject to change.

[77] Between June 2023 and June 2024 about 620 MW solar converted to the hybrid participation model. The growth in hybrid in this figure does not include this converted solar capacity.

[78] 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.

[79] 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 1.36 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 nearly 126 GW of planned capacity, around 55 percent of which comes from mixed-fuel projects. All mixed-fuel projects currently in the interconnection queue contain a battery, with 97 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 48.4 GW and 58.2 GW of all planned capacity, respectively. Among non-battery projects, wind and solar projects are most common and make up 8 GW of all planned capacity.

Assuming all capacity in the interconnection queue comes on-line on schedule, the CAISO will have met its planning goal for total capacity additions by 2045, and most of its goals regarding the generation mix for this new capacity.[80] However, many projects drop out of the interconnection queue before their interconnection studies are finished. In 2023, 43 projects totaling 15 GW of planned capacity withdrew from the interconnection queue, down significantly from 109 projects in 2022. Projects that have dropped out of the ISO interconnection queue historically have waited an average of 564 days from their queue start date until dropping out. Historically, the average wait time for completed projects is 2,200 days. The average wait time for projects in the current queue is 3,059 days.

80 *20 Year Transmission Outlook*, California ISO, May 4, 2022, p 2: http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf

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 2023, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $25 to $37/kW-yr compared to total annualized fixed costs of about $137/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $20 to $28/kW-yr compared to total annualized fixed costs of about $168/kW-yr.

In addition, estimated net energy market revenues of gas units in 2023 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 $31 to $41/kW-yr, compared to net energy market revenues of $25 to $37/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues were about $20 to $28/kW-yr in 2023 compared to estimated annualized going-forward fixed costs of about $32 to $33/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 more than 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.[81] 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

81 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://www.cadc.uscourts.gov/internet/opinions.nsf/A7E4F1659200B2B4852587AE0054513A/$file/20-1388-1927124.pdf

and reasonable.[82] On May 23, 2022, the California ISO submitted a compliance filing excluding the 20 percent adder from the compensation methodology.[83] 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.[84]

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.[85] Incremental energy costs are calculated using default energy bids used in local market power mitigation.[86] Commitment costs are calculated using proxy start-up and minimum load cost methodology.[87]

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 1.5, respectively.

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82 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

83 *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

84 Capacity procurement mechanism enhancements initiative page: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Capacity-procurement-mechanism-enhancements

85 Net revenues due to ancillary services and flexible ramping capacity are not modeled in the optimization model. For a combined cycle unit in the California ISO area, 2023 total average annual net revenues for regulation (up and down), and spinning reserves were approximately $0.27/kW-yr, and payments for flexible ramping capacity were around $0.01/kW-yr. Similarly, for a combustion turbine unit, 2023 total average net revenues for spinning and non-spinning reserve were $4.56/kW-yr, while average flexible ramping payments were $0.03/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.

86 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

87 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

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*).[88] 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.[89] 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, DMM estimates that annual going-forward fixed costs range from $31 to $41/kW-yr for a typical combined cycle resource and $32 to $33/kW-yr for a typical combustion turbine.[90]

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

[88] 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

[89] *Answer and Motion for Leave to Answer, Comments on CPM Tariff Filing (ER20-1075)*, Department of Market Monitoring, Apr 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

[90] 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 CC and $8.7/kW for CT) 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 CC and $7.8/kW for CT) 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.

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 2023.

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 2023, for a unit located in NP15 with the above assumptions, net revenues were $25/kW-yr with a 19 percent capacity factor.[91] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $31/kW-yr with a 17 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.[92] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2023 for a hypothetical unit in the NP15 area were $32/kW-yr with a 25 percent capacity factor. In the SP15 area, net annual revenues were $37/kW-yr with a 22 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 market. Under this scenario, net revenues for a hypothetical unit located in the NP15 area were $27/kW-yr with a 24 percent capacity factor. In the SP15 area, net annual revenues were $32/kW-yr with a 19 percent capacity factor.

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

92 See Section 2.2 for further discussion on price-cost markup.

Table 1.3 Assumptions for typical new 2x1 combined cycle unit[93]

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 (2023)	$6,840	$13,680
Minimum load major maintenance cost adder (2023)	$342	$684
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	40 MW/minute	40 MW/minute
Financial Parameters (2023)		
Financing costs		$94 /kW-yr
Insurance		$8 /kW-yr
Ad Valorem		$10 /kW-yr
Fixed annual O&M		$14 /kW-yr
Taxes		$11 /kW-yr
Total Fixed Cost Revenue Requirement		**$137 /kW-yr**

93 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.

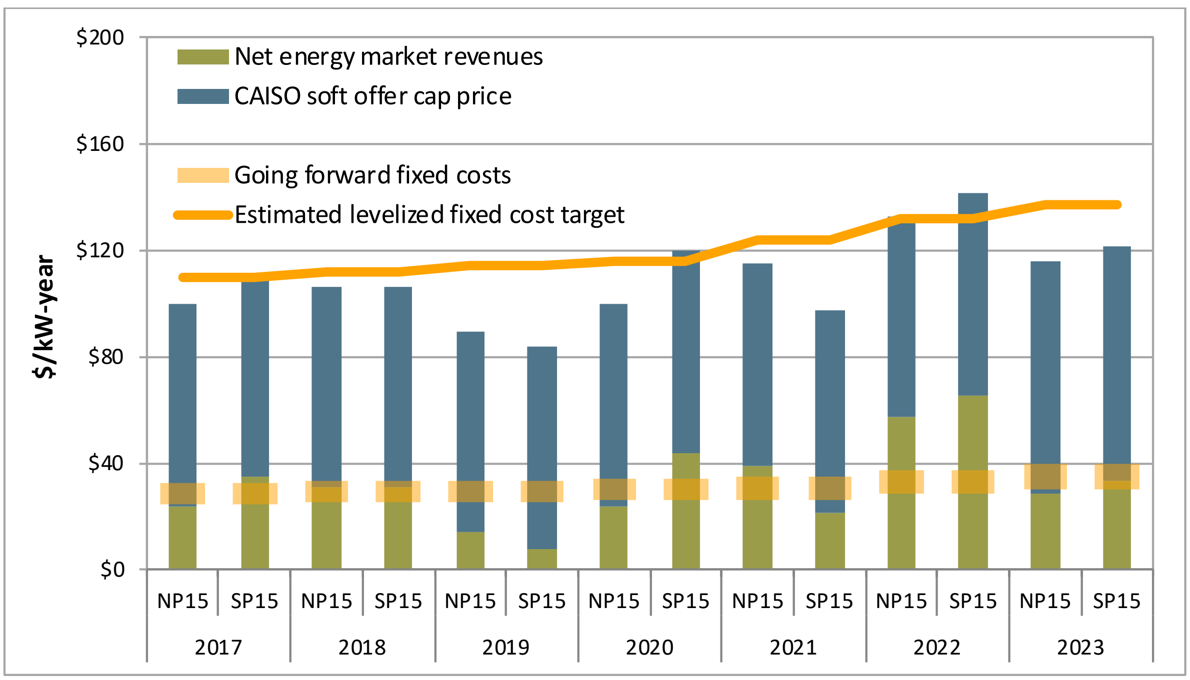
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

Table 1.4 Financial analysis of new combined cycle unit (2023)

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	19%	$175.65	$150.43	$25.22
	Day-ahead prices and default energy bids without adder	25%	$219.21	$187.52	$31.69
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	24%	$212.76	$185.52	$27.24
SP15	Day-ahead prices and default energy bids	17%	$168.99	$137.83	$31.15
	Day-ahead prices and default energy bids without adder	22%	$203.00	$165.87	$37.12
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	19%	$184.19	$151.93	$32.26

Figure 1.37 shows how net revenue results from the optimization model compare 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 1.37 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.37, compared to 2022, net revenues in 2023 for both NP15 and SP15 areas are significantly lower. This is primarily because of high gas prices resulting in relatively high day-ahead prices in 2022 compared to 2023. Lower prices in 2023 resulted in decreased unit commitment and dispatch, and hence decreased net energy market revenues.

Figure 1.37 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 ($75.68/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 2023 ranged between 0.7 and 80 percent with an average of 45 percent capacity factor. In the SP15 area, actual capacity factors ranged between 19 and 39 percent, with an average capacity factor of 28 percent. Our estimates ranged from 17 to 25 percent, and were relatively low compared to the actual results.

These differences in hypothetical capacity factors compared to existing resource capacity factors stem from several factors. 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 over six 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.[94]

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 2023.

94 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[95]

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 $mtCO_2e$/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 (2023)	$0
Minimum load major maintenance cost adder (2023)	$219
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters (2023)	
Financing costs	$124 /kW-yr
Insurance	$10 /kW-yr
Ad Valorem	$13 /kW-yr
Fixed annual O&M	$9 /kW-yr
Taxes	$12 /kW-yr
Total Fixed Cost Revenue Requirement	**$168 /kW-yr**

95 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. NERA Economic Consulting, *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator,* September 3, 2010: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B25745D07-C958-42EA-AC1A-A1BB0D80FF52%7D

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 technology type and resource operational characteristics of a typical peaking unit within the California ISO area.

Table 1.6 Financial analysis of new combustion turbine (2023)

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	3.8%	$57.71	$38.17	$19.54
	15-minute prices and default energy bids without adder	5.0%	$68.57	$47.20	$21.38
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	4.3%	$62.62	$42.18	$20.43
SP15	15-minute prices and default energy bids	3.6%	$61.34	$35.45	$25.89
	15-minute prices and default energy bids without adder	4.6%	$71.25	$43.68	$27.57
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	5.0%	$75.43	$47.39	$28.03

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 2023 prices, net annual revenues were approximately $20/kW-yr with a 3.8 percent capacity factor. Using SP15 prices for the same scenario, net revenues were approximately $26/kW-yr with a 3.6 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.[96] In this scenario, the hypothetical unit in NP15 earned net revenues of about $21/kW-yr with a 5 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $28/kW-yr with a capacity factor of 4.6 percent.

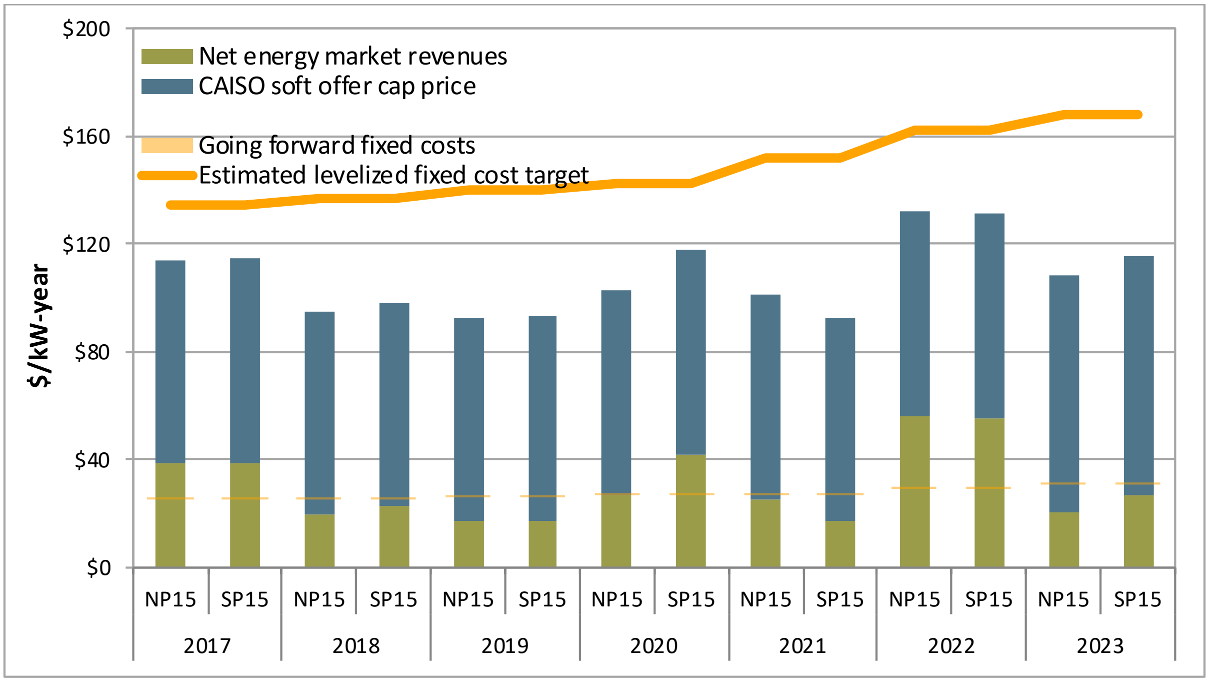
The third scenario includes all of the unit assumptions made in the first scenario, but also includes 5-minute prices for calculating unit revenues in addition to 15-minute prices. Specifically, this methodology commits the resource based on 15-minute market prices and then re-optimizes the dispatch 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 $20/kW-yr with a 4.3 percent capacity factor. In the SP15 area, net revenues were about $28/kW-yr with a 5 percent capacity factor.

Figure 1.38 shows how net revenue results from the optimization model compare to estimated annualized fixed costs of a hypothetical combustion turbine unit.[97] The green bars in this chart show estimated net revenues over the past seven years.

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

97 More information on the capacity procurement mechanism can be found in Section 43A of the California ISO tariff: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Sep28-2019.pdf

Figure 1.38 Estimated net revenues of new combustion turbine



As shown in Figure 1.38, net revenues for a hypothetical combustion turbine declined significantly in 2023. In both the NP15 and SP15 areas, simulated net market revenues were nearly half of what they were in 2022.

Figure 1.38 shows that, from 2017 through 2023, 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 1.5 with existing combustion turbines in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2023 ranged between 0.32 and 11 percent, with an average capacity factor of 4 percent. In the SP15 area, actual capacity factors ranged between 0.15 and 7.7 percent, with an average capacity factor of 2.7 percent. DMM's estimates ranged from 3.6 to 5 percent and were relatively close to average actual capacity factors.

2 Overview of market performance

The California ISO markets continued to perform efficiently and competitively in 2023.

- **Total wholesale costs decreased by about 32 percent** to $14.5 billion due to substantially lower natural gas prices. Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs decreased by about 10 percent.
- **Energy market prices were competitive, with prices usually reflecting resources' marginal costs**. DMM estimates the impact of bidding above reference levels, a conservative measure of average price-cost markup, was about $2.38/MWh, or 3.6 percent of cost-based prices, compared to 3.1 percent in 2022.
- **Energy market prices were about 31 percent lower in 2023 compared to 2022,** primarily due to lower gas prices and an increase in renewable generation. Prices in the 5-minute market were lower than prices in the day-ahead and 15-minute markets due to manual adjustments to the hour-ahead and 15-minute market load forecasts and operators limiting WEIM transfers into the CAISO balancing area in the hour-ahead and 15-minute markets during peak net load hours for most of the second half of 2023.
- **Residual unit commitment procurement increased by 81 percent in 2023 compared to 2022.** This was mainly due to large manual operator adjustments to the RUC requirement over the second half of 2023. Overall in 2023, manual adjustments increased by 154 percent relative to 2022.
- **Net revenues for convergence bidders**, before accounting for bid cost recovery charges, were about $95.4 million, a 30 percent decrease from 2022. After accounting for bid cost recovery charges, net revenues fell from $106 million in 2022 to about $32.4 million in 2023. Most of the bid cost recovery charges were due to increased RUC charges caused by large increases in manual operator RUC load adjustments over most of the second half of the year.
- **Bid cost recovery payments in the California ISO balancing area increased to the highest value since 2011,** totaling $289 million, up from $255 million in 2022. Most of this increase is from bid cost recovery attributable to the residual unit commitment process. RUC bid cost recovery in 2023 was around $60 million higher than in 2022.
- **Bid cost recovery payments for units in the Western Energy Imbalance Market totaled about $33 million,** down from $42 million in 2022. The cost of these payments is allocated back to the balancing area where the units receiving these payments are located.
- **CAISO real-time imbalance offset costs totaled $322 million in 2023.** This was less than the $401 million in 2022, but still significantly higher than the $176 million in offset costs in both 2021 and 2020. Congestion offset costs, $194 million, were largely generated by significant reductions in constraint limits between the day-ahead and 15-minute markets. Energy offset costs, $101 million, were largely caused by load settling on an average real-time price that can differ significantly from the real-time market prices that generating resources are settled on. The main impact of this difference is to shift payments by load serving entities from the price they pay for real-time energy to charges for imbalance offset costs.
- **A systematic error in real-time prices used to settle California ISO load during much of 2023 was identified and the ISO is working to correct settlements.** The error occurred from February 1, 2023 through February 5, 2024. While the pricing errors were large in some intervals, DMM estimates that the issue only shifted about $7.1 million in net costs between load serving entities, including around $0.8 million in load costs to exporters.

- **Nodal pricing for the flexible ramping product was implemented in February 2023.** Between February and December of 2023, the frequency of non-zero prices for system-level flexible ramping capacity was slightly higher compared to the same period of the previous year, prior to the enhancements. However, since the enhancements, 15-minute market system-level prices for upward flexible capacity were still non-zero in only around 0.8 percent of intervals for 2023. 77 percent of these intervals occurred during the peak net load hours (hours 18 through 21).
- **Mosaic quantile regression method for calculating uncertainty for flexible ramping product and resource sufficiency evaluation was also implemented in February 2023**. Over the year, the mosaic regression requirements covered between 96 and 97 percent of actual net load errors. Compared to the previous histogram method, the mosaic regression calculated lower average flexible ramping product uncertainty but a larger spread in results. The ceiling or floor designed to cap questionable results of the mosaic regression triggered in roughly 10 percent of 15-minute market intervals and 9 percent of 5-minute market intervals in 2023.

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2023 was about $14.5 billion, or about $65/MWh. This represents a 32 percent decrease from about $95/MWh or $21.6 billion in 2022. After normalizing for natural gas prices and greenhouse gas compliance costs, using 2019 as a reference year, DMM estimates that total normalized wholesale energy costs decreased by about 10 percent from about $40/MWh in 2022 to just over $36/MWh in 2023.

A variety of factors contributed to the decrease in total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to lower prices include the following:

- **Decreased natural gas prices.** Overall for 2023, average gas prices at NW Sumas, PG&E Citygate and SoCal Citygate decreased by 46 percent, 36 percent and 28 percent, respectively, compared to 2022 (Section 1.2.7);
- **Average hourly load continued to decrease in 2023**, due in part to increases in behind-the-meter solar generation and lower average temperatures (Section 1.1.1);
- **New generation capacity.** The CAISO added more than 6.4 GW of capacity between June 2023 and June 2024. This was mainly solar and battery capacity (Section 1.2.9); and
- **Higher hydroelectric production.** Hydroelectric production increased by about 69 percent from 2022 (Section 1.2.1).

Figure 2.1 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.[98]

Figure 2.1 Total annual wholesale costs per MWh of load (2019-2023)

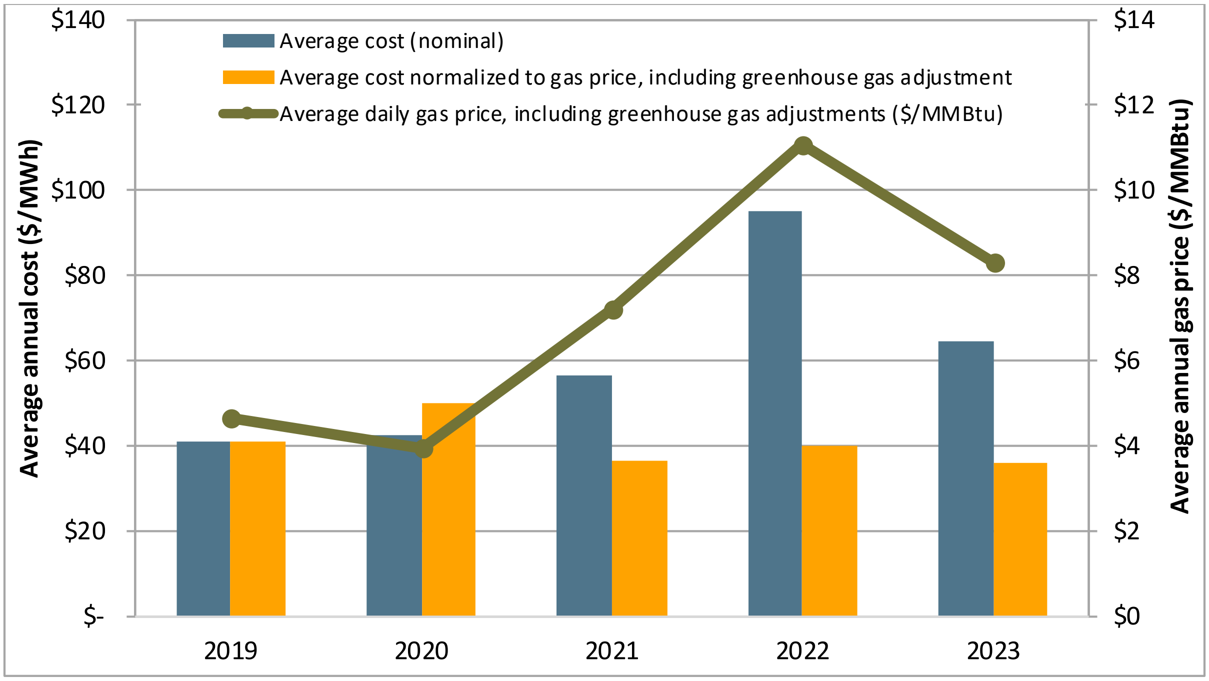


Table 2.1 provides annual summaries of nominal total wholesale costs by category for the previous five years.[99] The total wholesale energy cost also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping product, and grid management charges.[100]

As shown in Table 2.1, the 32 percent decrease in total nominal cost in 2023 was largely from changes in day-ahead energy costs, which decreased by over $29/MWh or roughly 33 percent. Real-time energy

98 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 tend 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. For the 2022 and 2023 reports, we have adjusted the 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.

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

100 A description of the basic methodology used to calculate the wholesale costs is provided in Appendix A of DMM's *2009 Annual Report on Market Issues & Performance.* This methodology was modified to include costs associated with the flexible ramping constraint and then the flexible ramping product when introduced in November of 2016. Flexible ramping costs are added to the real-time energy costs. This calculation was also updated to reflect the substantial market changes implemented on May 1, 2014. Following this period, both 15-minute and 5-minute real-time prices are used to calculate real-time energy costs. *2009 Annual Report on Market Issues & Performance,* Department of Market Monitoring, April 2010: http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf

costs also decreased about 31 percent, from $3.17/MWh down to $2.18/MWh, as discussed in more detail in Section 2.3. Reserve costs and backstop capacity costs decreased by 34 percent and 73 percent, respectively. Bid cost recovery saw a modest increase of about 15 percent to $1.26/MWh. Combined natural gas and greenhouse gas costs decreased about 25 percent.

Day-ahead energy costs remain the largest proportion of wholesale costs at about 93 percent, down slightly from 94 percent in 2022. The remaining components continue to represent a relatively small portion of the total. Real-time energy costs were about 3.4 percent of overall costs, similar to 3.3 percent in 2022. Overall reliability costs decreased in 2023 due to reduced costs for reliability must-run (RMR) contracts, decreasing as a percent of total cost to 0.1 percent from 0.2 percent in 2022.[101] Bid cost recovery totals increased as a percent of total cost, to nearly two percent in 2023 from 1.2 percent in 2022. Reserve costs decreased over 30 percent in 2023, reducing from 1.2 percent of total cost in 2022 down to just over 1.1 percent in 2023.[102]

Table 2.1 Estimated average wholesale energy costs per MWh (2019–2023)

	2019	2020	2021	2022	2023	Change '22-'23
Day-ahead energy costs	$ 38.13	$ 38.61	$ 53.09	$ 89.12	$ 59.83	$ (29.29)
Real-time energy costs (incl. flex ramp)	$ 1.02	$ 1.65	$ 1.21	$ 3.17	$ 2.18	$ (0.99)
Grid management charge	$ 0.46	$ 0.46	$ 0.43	$ 0.42	$ 0.45	$ 0.03
Bid cost recovery costs	$ 0.56	$ 0.60	$ 0.70	$ 1.10	$ 1.26	$ 0.16
Reliability costs (RMR and CPM)	$ 0.06	$ 0.07	$ 0.19	$ 0.22	$ 0.06	$ (0.16)
Average total energy costs	**$ 40.23**	**$ 41.40**	**$ 55.61**	**$ 94.03**	**$ 63.78**	**$ (30.25)**
Reserve costs (AS and RUC)	$ 0.75	$ 1.02	$ 0.79	$ 1.11	$ 0.74	$ (0.37)
Average total costs of energy and reserve	**$ 40.98**	**$ 42.42**	**$ 56.40**	**$ 95.14**	**$ 64.52**	**$ (30.62)**

2.2 Overall market competitiveness

The performance of California's wholesale energy markets remained competitive, with prices during most hours at or near the marginal cost of generation. DMM assesses the competitiveness of overall market prices based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs.

DMM calculates these estimated competitive baseline prices by re-simulating the day-ahead market after replacing bids or other market inputs using DMM's version of the day-ahead market software. Actual market prices were very close to these estimated competitive baseline prices, indicating that replacing high-priced energy bids with cost-based bids did not lower prices. Resources that may be subject to mitigation, such as gas-fired and other resources, were generally infra-marginal during high-priced hours. When performing day-ahead market re-runs using cost-based bids, high prices were

101 Costs for reliability must-run contracts decreased to about $11 million in 2023 from $49 million in 2022 (Section 8.6).

102 Additional information on bid cost recovery and ancillary service costs is included in Sections 2.6 and 4.1, respectively.

set by demand response and other resources not subject to mitigation. System-wide mitigation of imports and gas-fired resources during this period would not have lowered prices.

Competitive baseline prices were calculated by re-running day-ahead market simulations under several different scenarios.[103] Each market simulation run was preceded by a base case re-run, to screen for accuracy, where no changes were made to the inputs from the original day-ahead market run.[104] DMM calculates the day-ahead price-cost markup by comparing prices from the competitive baseline run to prices from this base case re-run, using load-weighted average prices for all energy transactions in the day-ahead market.[105]

As shown in Figure 2.2, monthly average prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices. This scenario shows competitive bidding for energy and commitment costs, as well as competitive import bids. The red bars show the difference between the competitive baseline scenario price and the base case price, indicating that average scenario prices were generally slightly below base case prices. The average price-cost markup was about $2.38/MWh or 3.6 percent, compared to $3.04/MWh or 3.1 percent the previous year. Very low price-cost markup values indicate that prices were competitive overall for the year.

103 Detailed descriptions 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

104 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 2023, a total of 34 trade dates were excluded, including a seven day period in late July where system conditions were especially challenging.

105 DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under the competitive baseline scenario. For example, if base case prices averaged $55/MWh and the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

Figure 2.2 Day-ahead market price-cost markup – competitive baseline scenario[106]

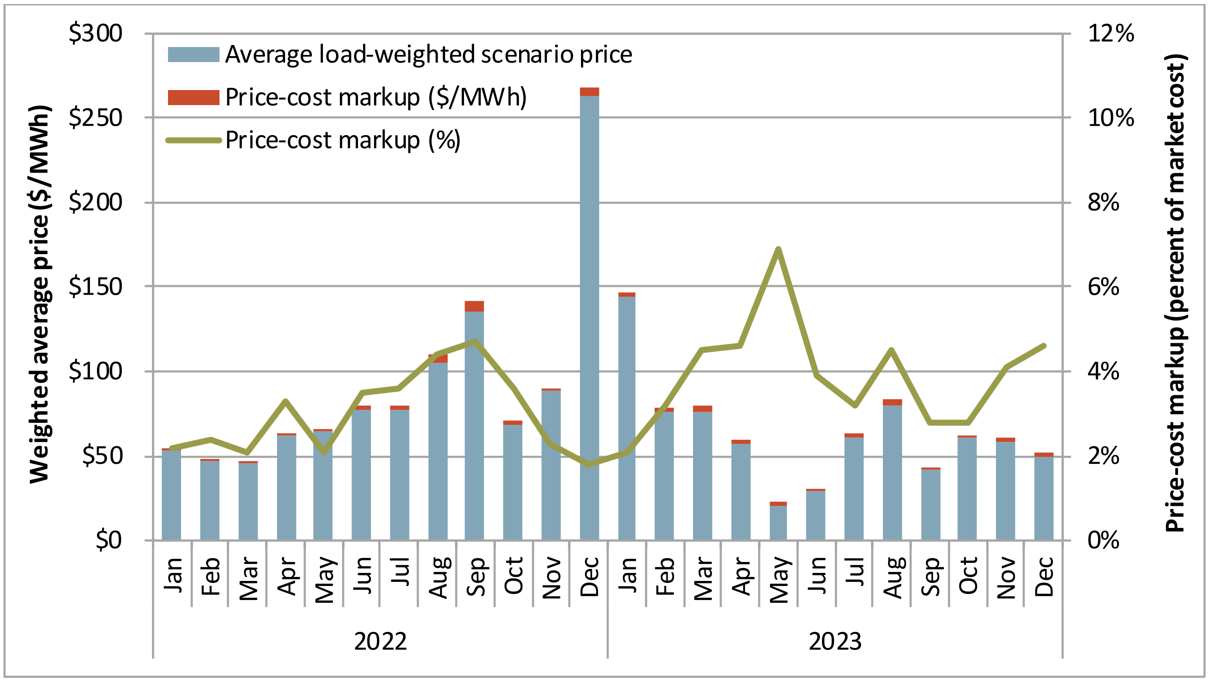


Figure 2.3 shows results for the scenario that caps energy bids for gas resources at the lower of their submitted bid or default energy bid. Price-cost markup values for this scenario were slightly lower in 2023, at about $1.03/MWh compared to $1.25/MWh in 2022. However, when comparing the markup as a percent of market cost, the value increased slightly to 1.6 percent in 2023 compared to 1.3 percent the previous year.

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.
- 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.

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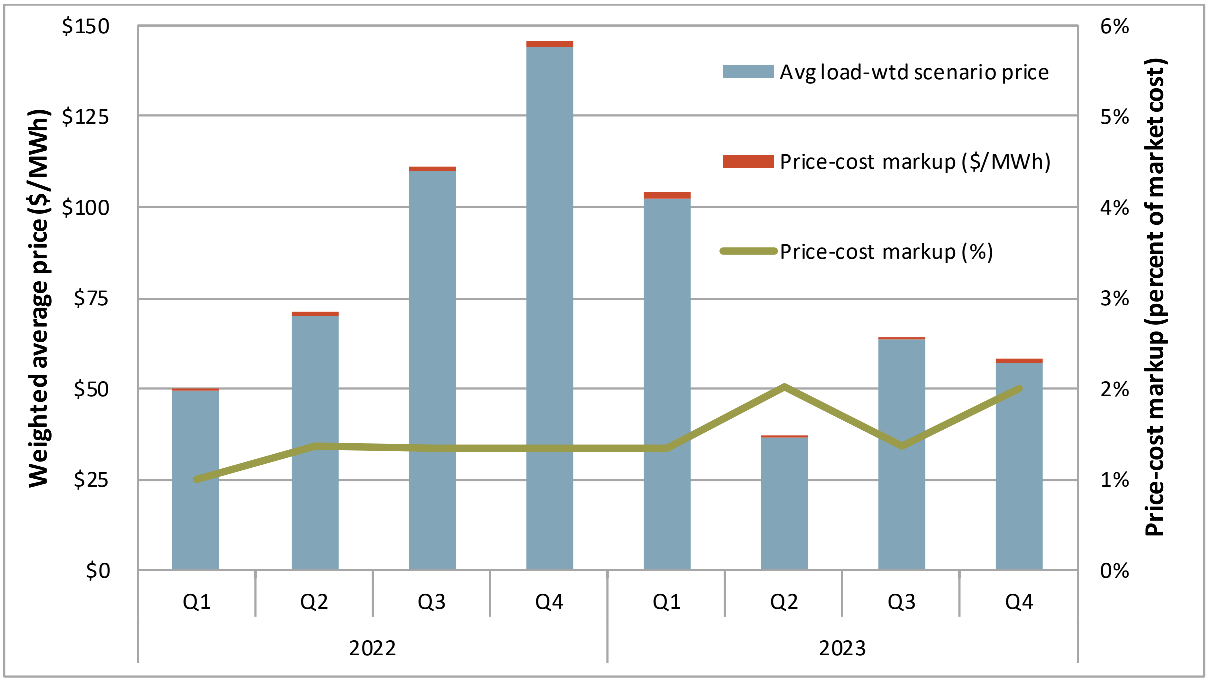
106 This figure shows results for a scenario where: 1) bids for resources subject to mitigation were set to the minimum of their submitted bid or default energy bid; (2) bids for commitment costs were set to the minimum of their bid or 110 percent of proxy price; and (3) import bids were set to the minimum of their bid or an estimated hydro default energy bid. In previous years, the competitive baseline scenario capped energy bids and commitment costs for gas-fired units only, and capped imports, as described above. The average price-cost markup for this scenario was $1.72/MWh or 2.6 percent, compared to $2.19/MWh or 2.3 percent in 2022.

Figure 2.3 Quarterly day-ahead market price-cost markup – default energy bid scenario



2.3 Energy market prices

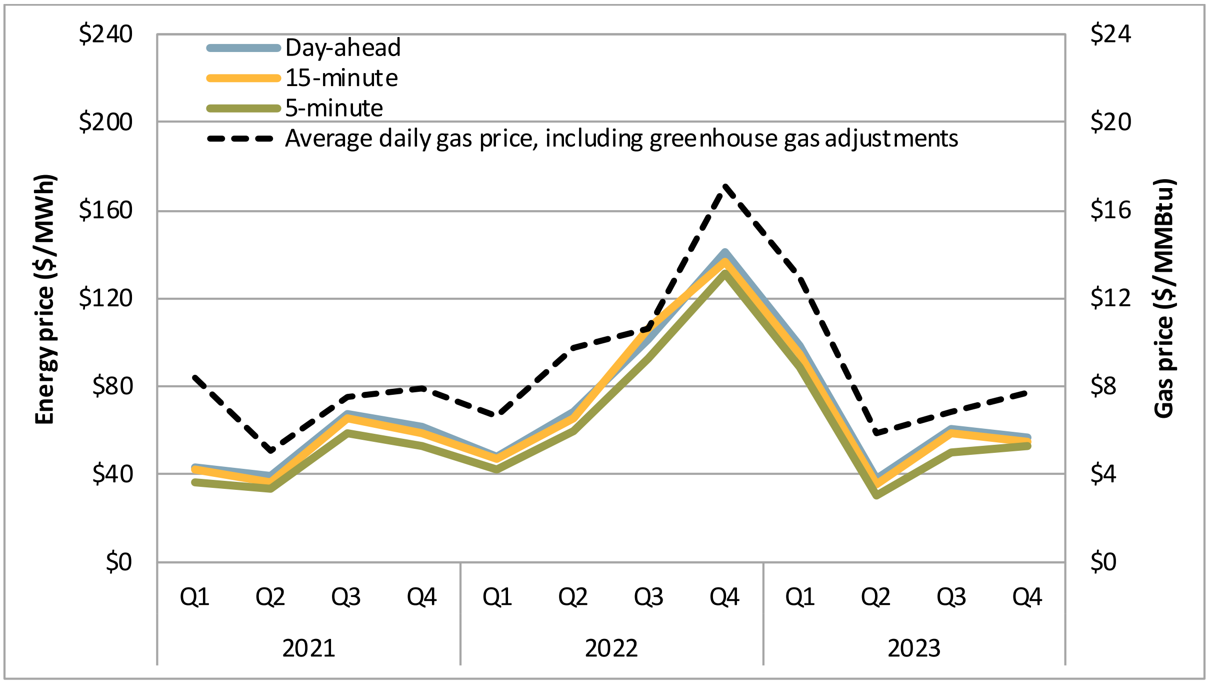
This section reviews energy market prices in the CAISO balancing area by focusing on price trends and comparison of prices in the day-ahead and real-time markets. Key points highlighted in this section include the following:

- Average energy market prices were about 31 percent lower than in 2022. The decline in prices can be attributed to changes in both supply and demand. On the demand side, the average load in the area continued to decrease in 2023. On the supply side, renewable generation increased and gas prices decreased significantly, leading to lower input costs for gas-fired plants that typically set prices during hours with positive prices.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets. Day-ahead prices averaged $63/MWh, 15-minute prices were about $61/MWh, and 5-minute prices were about $55/MWh. Convergence bidding provides incentives for financial arbitrage to converge day-ahead and 15-minute prices. Lower 5-minute prices reflect the difference between 15-minute and 5-minute load adjustments made by operators, as well as operators limiting WEIM transfers into the CAISO balancing area in the 15-minute market during peak hours for most of the second half of 2023.
- Average hourly prices generally moved in tandem with the average net load. The evening peak net load was 4 percent lower than in 2022. Peak prices in 2023 were 29 percent lower than those in 2022, and occurred during the highest net load hour, in hour-ending 20.

Figure 2.4 shows the load-weighted average energy prices across the three largest load aggregation points in the California ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as load-weighted average daily gas prices that include greenhouse gas adjustment. The figure displays the average energy and gas prices during all hours for the day-ahead and real-time markets. The figure illustrates that both energy and gas prices decreased sharply in 2023, and indicates a strong correlation between the two. Across all three markets, prices were roughly 31 percent lower in 2023 compared to 2022. These lower prices are due largely to lower gas prices.[107]

The day-ahead and 15-minute market energy prices averaged $63/MWh and $61/MWh, respectively. Prices in the 5-minute market averaged $55/MWh.

Figure 2.4 Average quarterly prices (all hours) – load-weighted average energy prices



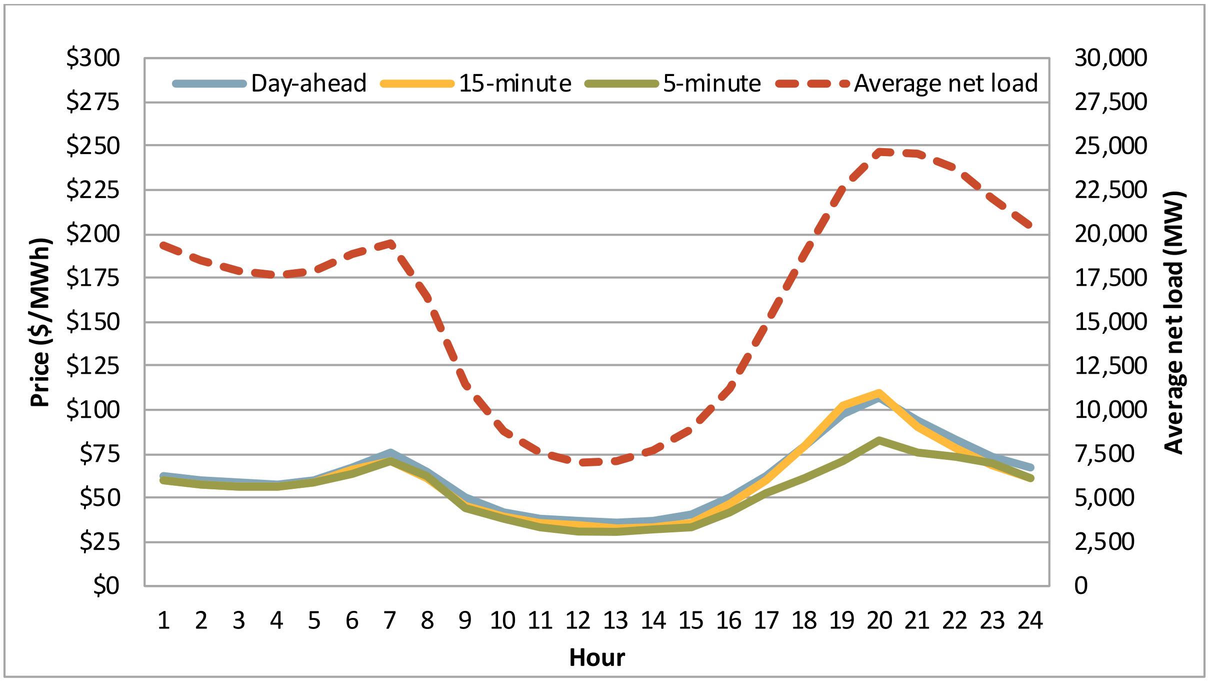
To analyze how prices vary throughout the day, Figure 2.5 illustrates hourly load-weighted average energy prices in CAISO in the day-ahead and real-time markets, as well as average hourly net load. As both utility scale and behind-the-meter solar generation have increased, energy prices have followed net load more closely. Net load and energy prices were lowest mid-day when low-priced solar generation was greatest.

Energy prices and net load both peak during the early evening when demand is still high but solar generation has substantially decreased. During the hours of high solar generation between 7 a.m. and 7 p.m., the energy prices in the three markets were 25 percent lower compared to the low solar generating hours in the remainder of the day.

During the hours with highest net load and highest energy prices, the divergence between the 5-minute market and the other two markets is the largest. In hours-ending 17-22, prices in the 5-minute market were about 25 percent lower than those in the day-ahead and 15-minute markets.

107 See Section 1.2.7 for additional discussion on natural gas price trends.

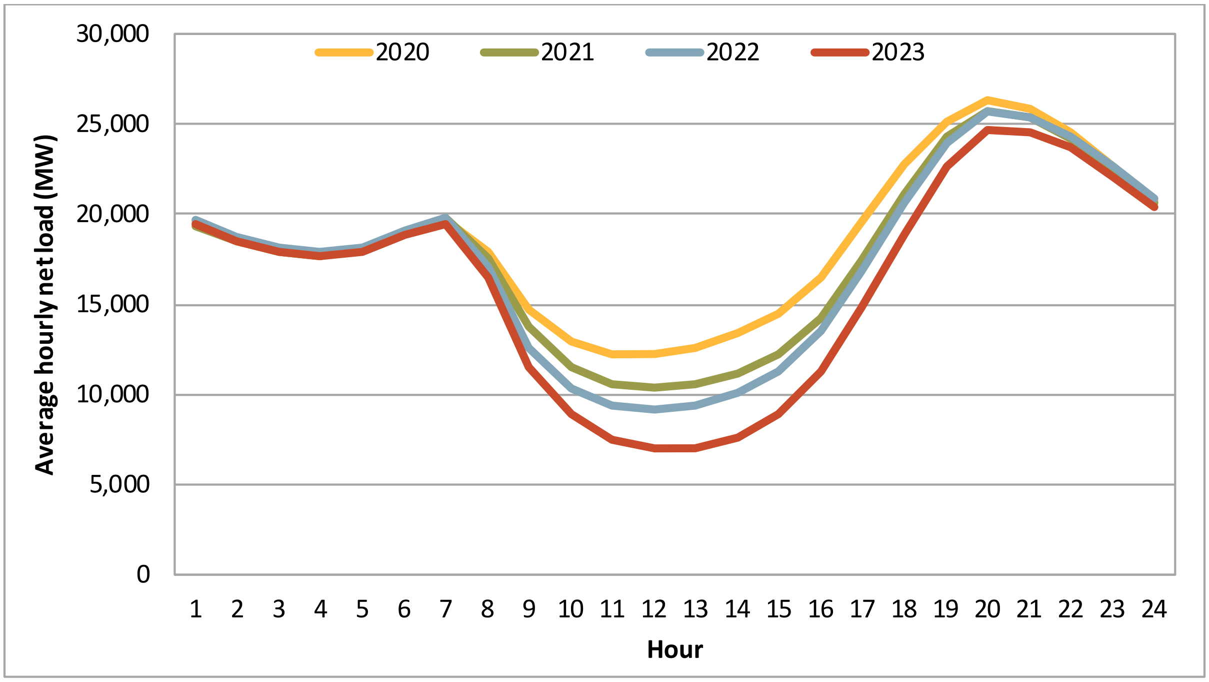
Figure 2.5 Hourly load-weighted average energy prices (2023)



Average net load peaked in hour-ending 20 at about 24,700 MW, which is lower than 25,700 MW for the same hour last year. Figure 2.6 shows the change in net load from 2020 to 2023. On average, net load was roughly nine percent lower in 2023 compared to 2022. The decrease in net load was most pronounced during the morning through afternoon (9 a.m. to 5 p.m.), when net load was 18 percent lower in 2023.

Prices in the day-ahead market were highest during the peak net load hour of hour-ending 20, averaging $107/MWh, which is 26 percent lower than the peak price last year. In this hour, the average 15-minute prices peaked at $109/MWh, and the average 5-minute market prices peaked at $82/MWh. These prices were 29 percent and 31 percent lower than in 2022, respectively.

Figure 2.6 Hourly average net load (2020–2023)

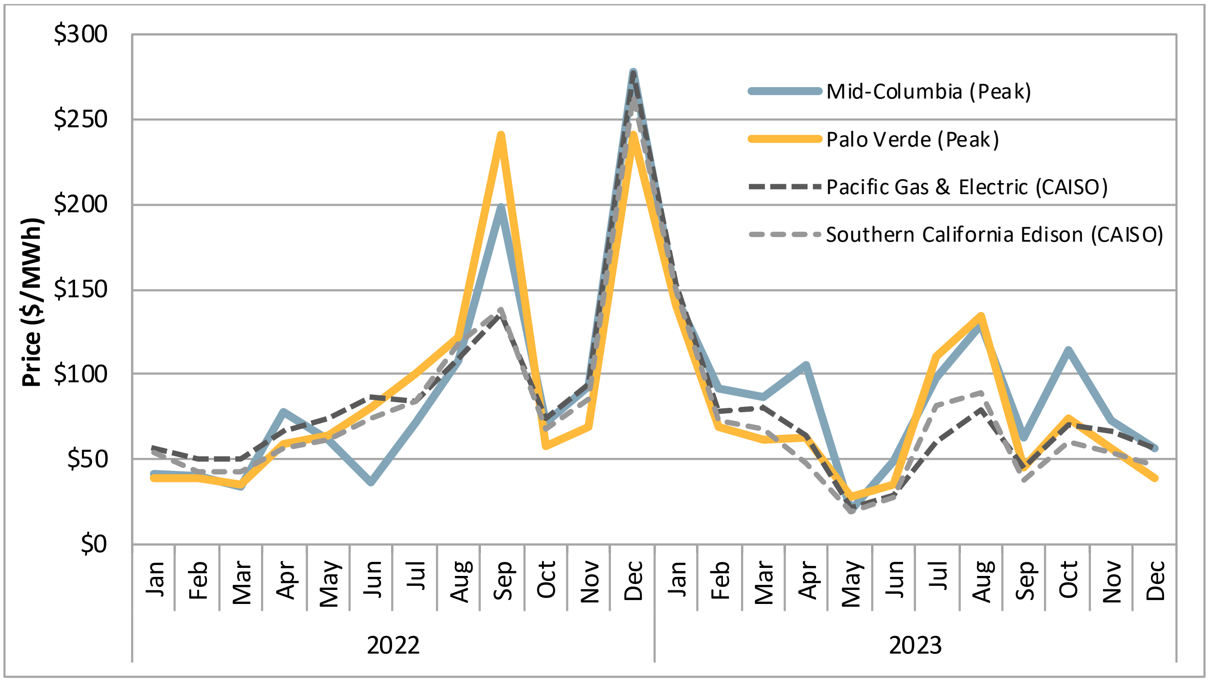


2.3.1 Comparison to bilateral prices

During the summer of 2023, day-ahead peak prices at Mid-Columbia and Palo Verde bilateral hubs exceeded the average day-ahead peak prices in the California ISO (CAISO). In addition, day-ahead prices at these bilateral hubs and CAISO areas were highest in January 2023 as they tapered off from the high gas prices in December 2022.

Figure 2.7 shows monthly average day-ahead peak prices in the CAISO balancing area compared to monthly average peak energy prices traded at the Palo Verde and Mid-Columbia hubs published by the Intercontinental Exchange (ICE). Prices in the CAISO balancing area are represented in the figure by prices at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Average bilateral prices for Mid-Columbia (Peak) significantly exceeded prices at the California ISO DLAPs in April, July, August, and October. Palo Verde (Peak) monthly average prices significantly exceeded prices at the California ISO DLAPs in July and August.

Figure 2.7 Monthly average day-ahead and bilateral market prices



Average day-ahead prices in the CAISO balancing area and bilateral hubs (from ICE) were also compared to real-time hourly energy prices traded at Mid-Columbia (Peak) and Palo Verde (Peak) hubs for all hours of 2023 using data published by Powerdex. On average by month across all hours of 2023, the Mid-Columbia (Peak) real-time prices were generally higher than the day-ahead hourly prices in both the Pacific Gas and Electric and Southern California Edison areas. The Palo Verde (Peak) real-time prices varied throughout the year; they were below the prices in the Pacific Gas and Electric and Southern California Edison areas in January through March, and again in November and December.

2.3.2 Price variability

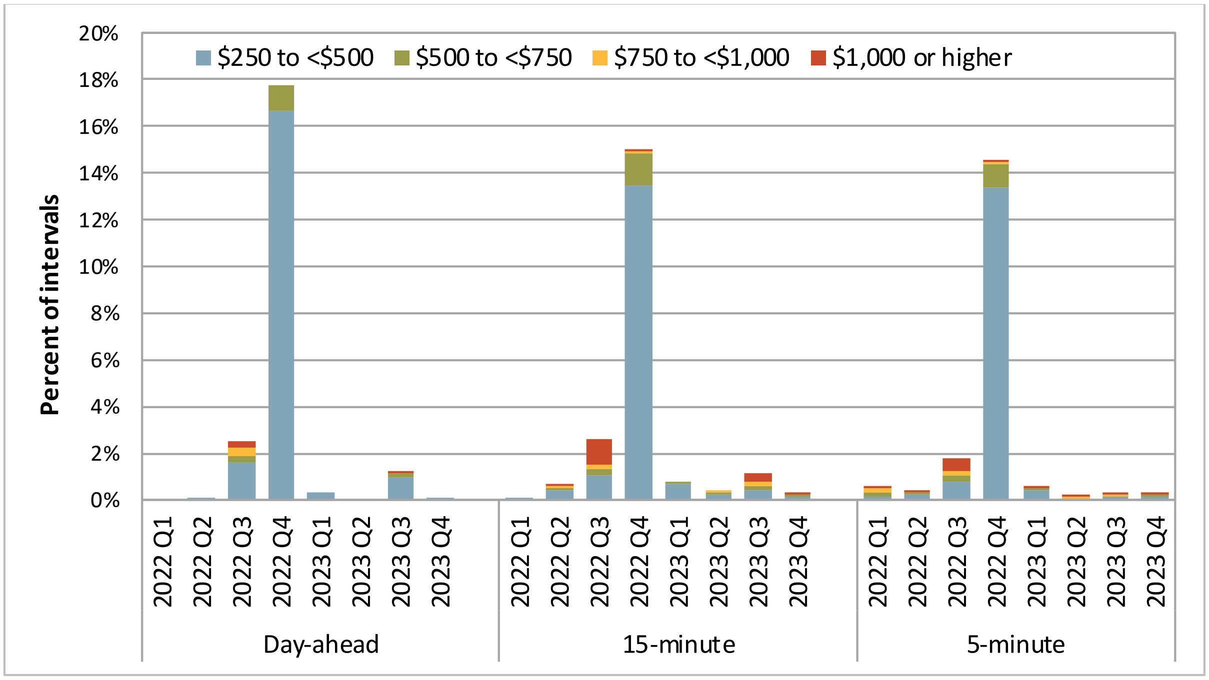
In 2023, compared to 2022, there was a significant increase in the frequency of negative prices across all three markets, while the frequency of positive prices notably decreased. From 2022 to 2023, across all three markets, the frequency of prices exceeding $250/MWh fell to 0.4 percent from 1.2 percent, and the frequency of negative prices rose to 4.6 percent from 2.7 percent.

High prices

Figure 2.8 shows the frequency of high prices in the day-ahead, 15-minute, and 5-minute markets in both 2022 and 2023. Positive price spikes were most common in the third quarter of 2023. However, the frequency of high prices in 2023 was lower than in 2022. CAISO experienced a major heatwave and extreme demand in the third quarter of 2022. Demand conditions in 2023 were not as extreme. The load distribution in 2023 was less skewed toward extreme highs. In 2022, there were more intervals with CAISO load exceeding 40,000 MW and the total WEIM load surpassing 100,000 MW.

Overall, in 2023, the frequency of prices exceeding $250/MWh was 0.4 percent across all markets. The day-ahead market recorded a frequency of 0.4 percent, the 15-minute market was at 0.6 percent, and the 5-minute market was at 0.3 percent.

Figure 2.8 Frequency of positive price spikes (California ISO areas)



FERC Order No. 831

In 2021, FERC Order No. 831 tariff amendment was implemented, which established a hard bid cap of $2,000/MWh along with a soft bid cap of $1,000/MWh. This allows resources to bid above the soft bid cap under certain circumstances, specifically when either the maximum import bid price (MIBP) or a cost-verified energy bid from a resource-specific resource is greater than the $1,000/MWh bid cap.[108] There were two days in 2023, August 15 and 16, with hours that had an MIBP over $1,000/MWh, which enabled the $2,000/MWh bid cap. This allowed non-resource adequacy imports to bid up to $2,000/MWh during those specific hours. There were no instances of a cost-verified energy bid over the bid cap, meaning internal resources were unable to bid above the $1,000/MWh soft bid cap.

Negative prices

Low or negative prices may occur during hours with an abundance of supply. The market arrives at a solution by matching supply with demand; when prices clear below a unit's bid, that resource may be dispatched down accordingly. During negatively priced intervals, the market continues to function

[108] The MIBP is a reference point for import bids that is based on the prices at Mid-Columbia and Palo Verde.

efficiently and the least expensive generation serves load, while generation that is more expensive is dispatched down.

In 2023, there was a notable increase in the frequency of negative prices compared to 2022. Figure 2.9 shows the frequency of prices near or below $0/MWh in the day-ahead, 15-minute, and 5-minute markets in 2022 and 2023. When averaging all three markets, the frequency of negative prices in 2023 was 4.6 percent, while in 2022, it was 2.7 percent. This indicates an overall increase of 73 percent in the frequency of negative prices. The most significant change occurred in the day-ahead market, where the frequency of negative prices increased from 0.5 percent to 2.6 percent, primarily due to a rise in the second quarter of 2023. Although the day-ahead market showed a substantial change, negative prices were more frequently observed in the real-time markets. The 5-minute and 15-minute markets had negative prices during 6.5 percent and 4.7 percent of intervals in 2023, respectively.

Figure 2.9 Frequency of negative price spikes California ISO areas

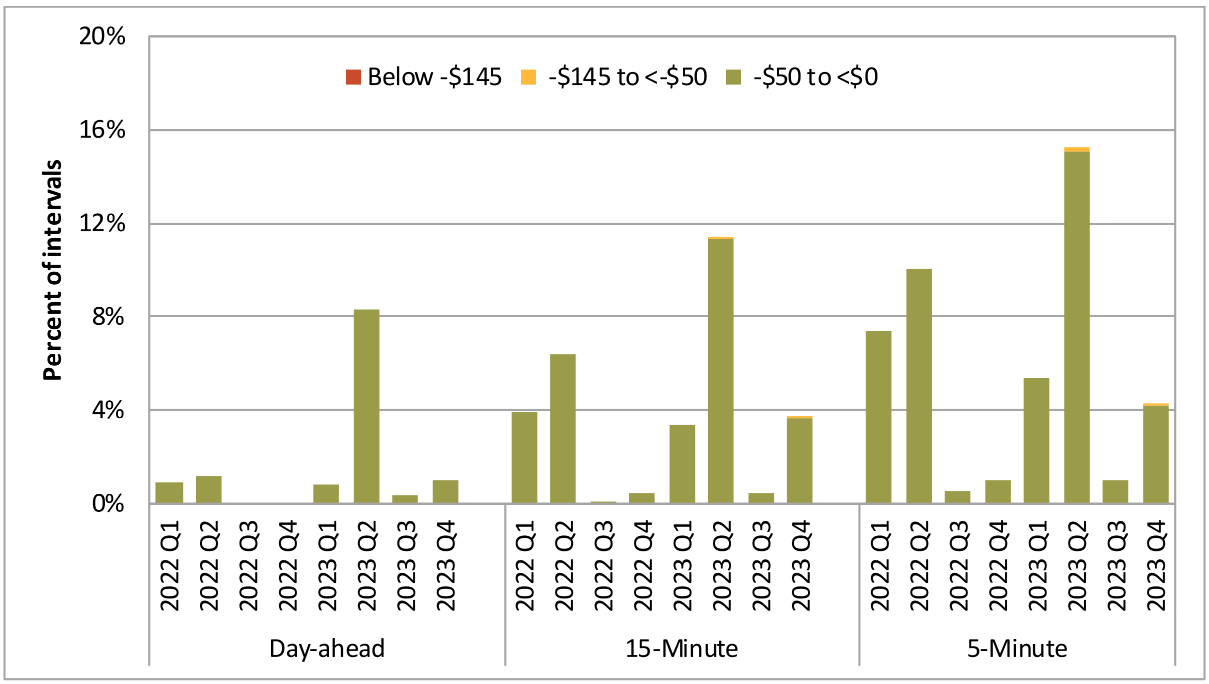


Figure 2.10 shows the annual frequency of negative prices in the 5-minute market since 2017. In 2023, roughly 6.5 percent of 5-minute intervals had negative prices, a considerable increase from 4.7 percent in 2022. The overall trend indicates that the frequency of negative price has been increasing since 2018. This correlates with a gradual rise in renewable generation. As explained in Section 1.2.2, combined solar and wind generation has been increasing over this time period. When this trend of increasing renewable generation is coupled with relative low load levels, negative prices occur more frequently.

Figure 2.11 shows the hourly frequency of negative 5-minute prices in the last four years. The figure illustrates a distinctive pattern in the frequency of negative priced hours in 2023 compared to previous years. Notably, there was a significant increase in the frequency observed between hour-ending 8 and 18. In hour-ending 12, the frequency of negative prices rose to 20 percent in 2023, nearly double in comparison to 2021 and 2020.

Figure 2.10 Frequency of negative 5-minute prices (CAISO LAP areas)

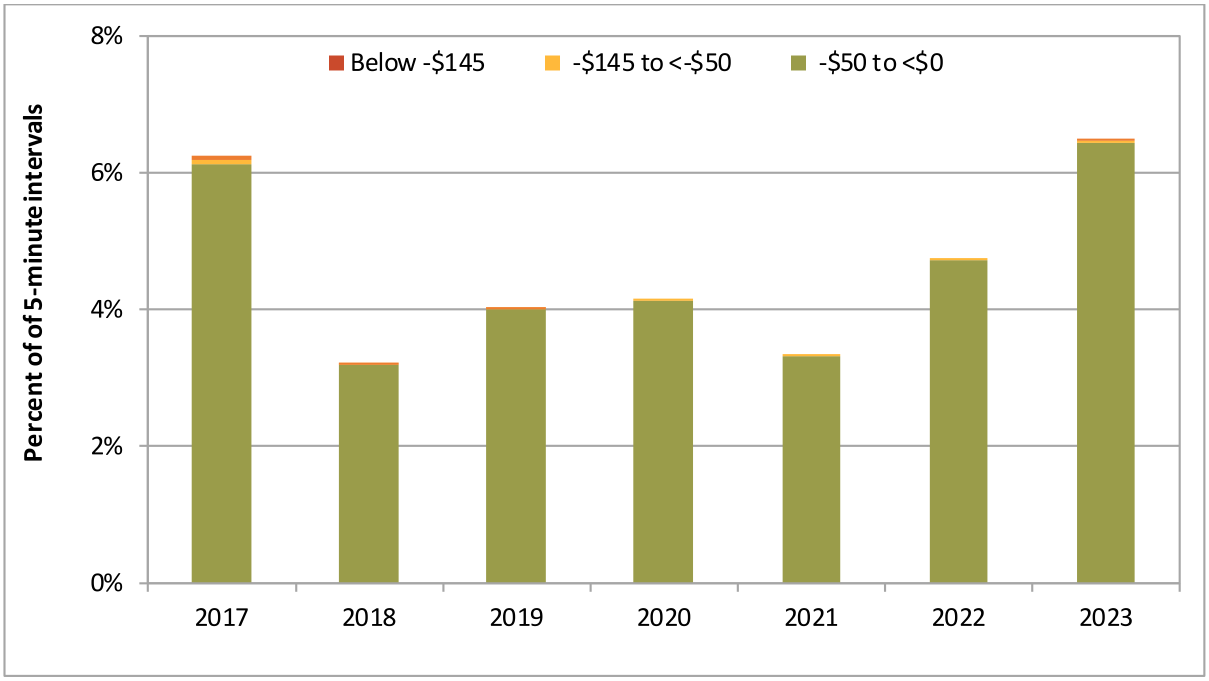
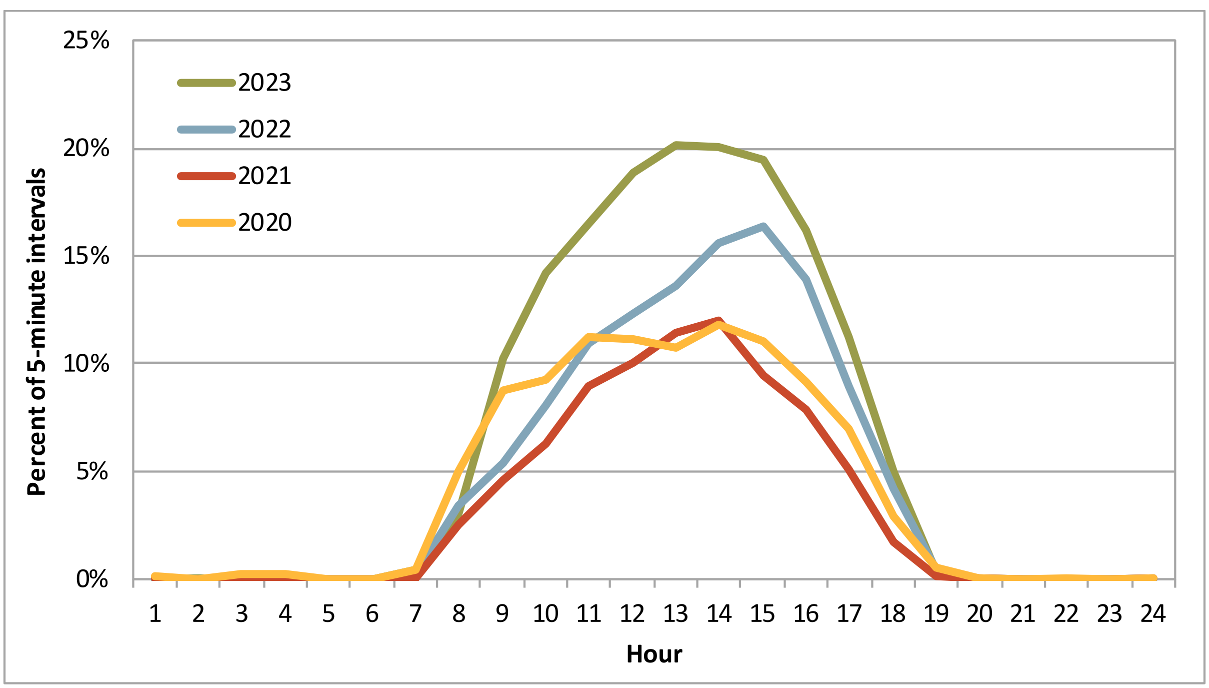


Figure 2.11 Hourly frequency of negative 5-minute prices by year (CAISO LAP areas)



2.3.3 Power balance constraint

The CAISO and Western Energy Imbalance Market areas can run out of ramping capability in either the upward or downward direction to solve the real-time market solution. This condition is known as a power balance constraint relaxation.[109] When this occurs, prices can be set at the $1,000/MWh penalty parameter while relaxing the constraint for shortages (undersupply infeasibility), or the -$155/MWh penalty parameter while relaxing the constraint for excess energy (oversupply infeasibility).[110]

The load conformance limiter reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. If the limiter is triggered, the size of the load adjustment is automatically reduced and the price is set by the last dispatched economic bid, rather than the penalty parameter for the relaxation.

System power balance constraint relaxations

The frequency of system power balance constraint relaxations, both set at the penalty price or resolved by the load conformance limiter, were relatively high in the third quarter of 2023, but low during other times of the year.

Figure 2.12 shows the quarterly frequency of undersupply and oversupply infeasibilities in the 15-minute and 5-minute markets. The frequency of undersupply infeasibilities in the 15-minute and 5-minute markets were highest during the third quarter. However, compared to 2022, the frequency in the third quarter was lower due to the absence of a major heatwave and the extremely high demand associated with such events.

There were very few instances during 2023 in which the system power balance constraint was relaxed because of insufficient downward flexibility, occurring in less than 0.01 percent of intervals. Bidding flexibility from renewable resources, in addition to increased transfer capability from the Western Energy Imbalance Market, continued to contribute to reduced oversupply conditions.

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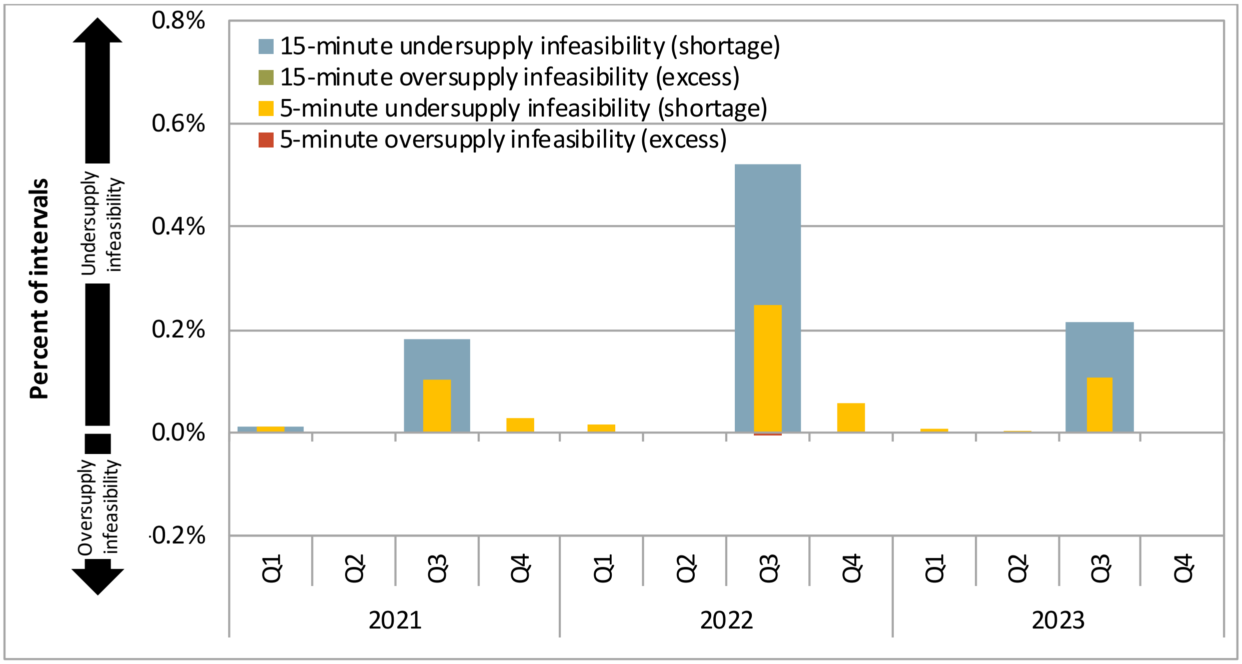
109 For a detailed description of the power balance constraint and load bias limiter, please refer to the *2016 Annual Report on Market Issues & Performance,* Department of Market Monitoring, May 2017, pp 101-103: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

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

Figure 2.12 Frequency of power balance constraint infeasibilities by market



2.4 Residual unit commitment

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 IFM run and the day-ahead forecast load. Capacity procured through residual unit commitment must be bid into the real-time market.

On average, the total volume of capacity procured through the residual unit commitment process in all quarters of 2023 was 81 percent higher than 2022 as shown in Figure 2.13. For comparison, the increase from 2021 to 2022 was about 14 percent.

California ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. In 2023, the California ISO changed the process for determining the adjustments to the RUC procurement target. Starting on June 30, the California ISO began using a regression-based method (similar to that used in the real-time market to determine flexible capacity requirements) to calculate the RUC adjustments. This significantly increased the operator adjustments in 2023, by 154 percent compared to 2022.[111]

Figure 2.13 also shows quarterly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to about 2,170 MW per hour in 2023 from an average of 1,200 MW in 2022. The

111 See Section 7.3 for further discussion on operator adjustments in the residual unit commitment process and the changes to the methodology.

figure shows that in 2023, the volume of residual unit commitment requirements was highest in the third quarter and remained high in the fourth.

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 receive capacity payments.[112] As shown by the small green segment of each bar in Figure 2.13, the non-resource adequacy volume averaged about 41 MW per hour in 2023, slightly up from about 23 MW procured in 2022. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in the same figure, increased to about $5.4 million in 2023, from a direct cost of about $1.4 million in 2022.

Figure 2.13 Residual unit commitment (RUC) costs and volume (2022–2023)

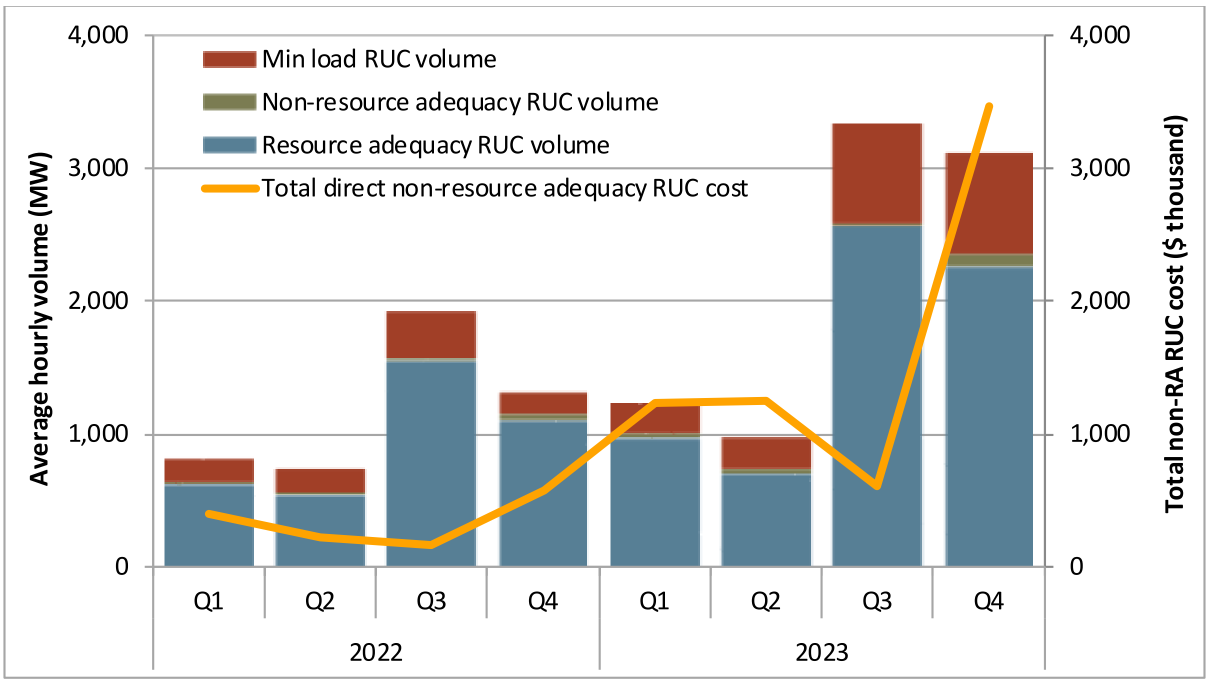
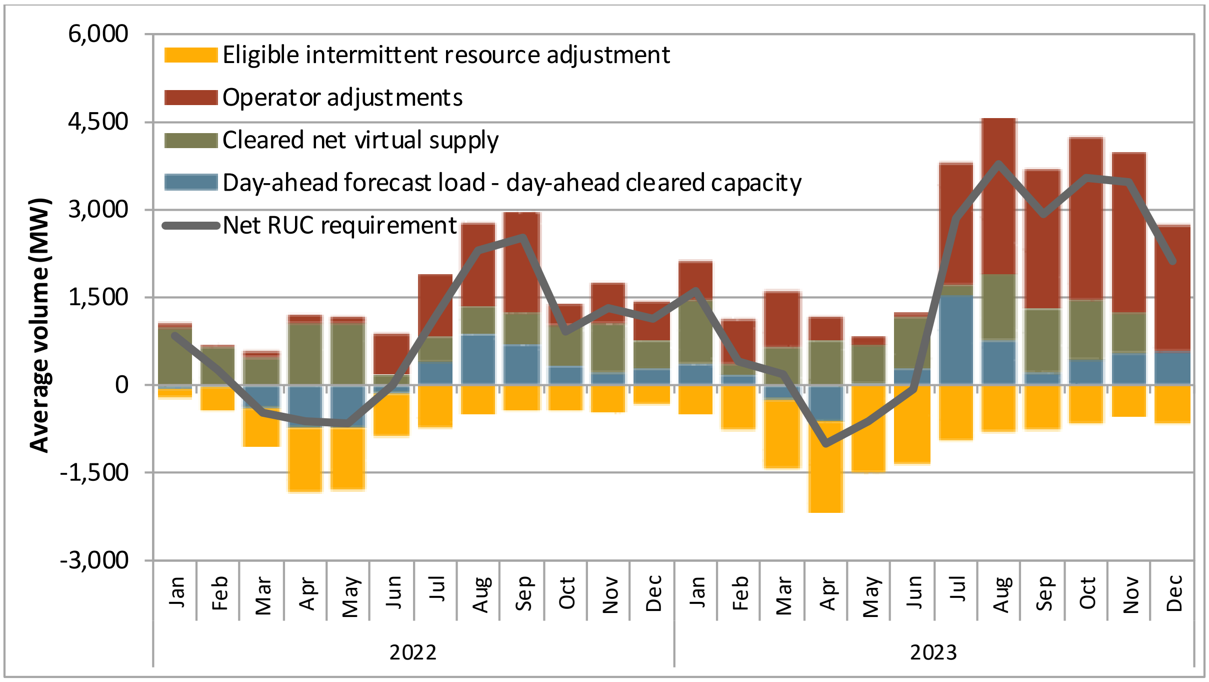


Figure 2.14 shows that the increase in RUC procurement in 2023 was primarily driven by large increases in manual operator adjustments over the second half of the year. Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market, illustrated by the yellow bars in Figure 2.14.

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

While residual unit commitment capacity must be bid into the real-time market, only a fraction of this capacity is committed to be on-line by the residual unit commitment process.[113] Most of the capacity procured is from units that are already scheduled to be on-line through the day-ahead market, or from short-start units that do not need to be started up unless they are actually needed in real-time. Residual unit commitment capacity committed to operate at minimum load averaged about 500 MW each hour, up from about 220 MW in 2022. In 2023, about 22 percent of this capacity was from long-start units, down from 14 percent in 2022.[114]

Figure 2.14 Determinants of residual unit commitment procurement



In September 2020, the California ISO revised the residual unit commitment (RUC) 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

113 Only the small portion of minimum load capacity from *long-start units*, units with start-up times greater than or equal to five hours, is committed to be on-line in real-time by the residual unit commitment process.

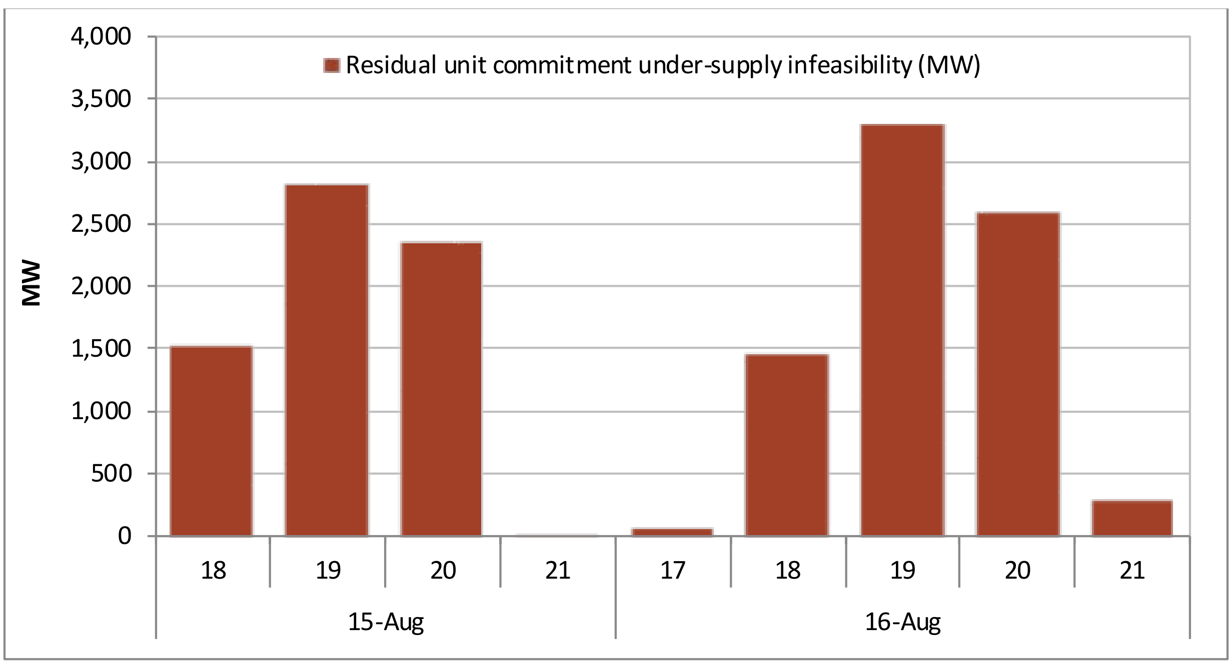
114 Long-start commitments are resources with a cycle time of more than 255 minutes (Start-Up Time plus Minimum Run Time is more than 255 minutes) and require between five and up to 18 hours to Start-Up and synchronize to the grid. The definition can be found in Appendix A of the ISO Fifth Replacement 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.

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.[115]

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.[116] 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.

In 2023, the *residual unit commitment undersupply power balance constraint* was infeasible on two days—August 15 and 16. Figure 2.15 shows the residual unit commitment power balance constraint hourly under-supply infeasibility quantities on these days. These infeasibilities resulted in prices being set around $250/MWh during those hours. In addition, significant volumes of economic exports and low-priority self-schedule exports were not procured in the residual unit process prior to relaxing the power balance constraint.[117]

Figure 2.15 Residual unit commitment under-supply infeasibilities (August 15 and 16, 2023)



[115] 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

[116] 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

[117] More information on residual unit commitment export schedule reductions can be found in: *Summer Market Performance Report* August 2023, California ISO, October 10, 2023, Section 5.3 and 6.1: https://www.caiso.com/Documents/SummerMarketPerformanceReportforAugust2023.pdf

2.5 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. Throughout 2023, 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.

- **Annual profits paid to convergence bidders totaled around $32.4 million**, a decrease of almost $74 million from 2022, after accounting for about $63 million in bid cost recovery charges allocated to virtual bids. Convergence bidders lost $7.4 million from virtual demand, and earned $102.8 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 700 MW per hour**, compared to 660 MW in 2022. The percent of bid-in virtual supply and demand clearing was around 41 percent, an increase from about 32 percent in 2022.
- **Financial entities and marketers continued to earn the most profits from virtual bidding**, receiving about 93 percent and 7 percent of positive net revenues, respectively. Physical generators and load serving entities both lost money from virtual positions in 2023.
- **Financial participants held the majority of cleared virtual positions (nearly 80 percent) throughout 2023**, continuing a multi-year trend. As with the previous years, financial participants bid more virtual supply than demand.

2.5.1 Convergence bidding revenues

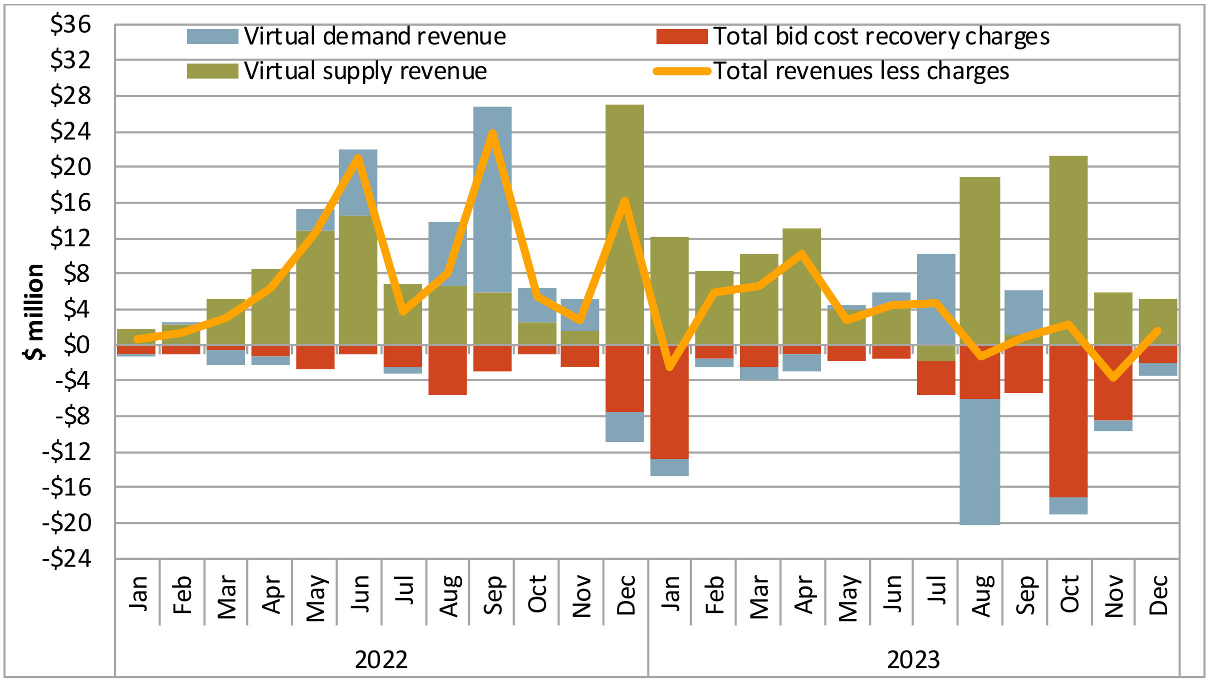
Historically, net convergence bidding revenues in a given month have been positive. However, in 2023, net convergence bidding revenues were negative for January, August, and November. In each of these months, there were large bid cost recovery settlements related to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC. When market revenues do not cover the commitment costs of resources committed in RUC, the resources receive bid cost recovery payments, and some of this bid cost recovery is allocated to virtual supply during periods with net virtual supply.[118]

Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $95.4 million, a 30 percent decrease from 2022. Net revenues for virtual supply and demand fell from $106 million in 2022 to about $32.4 million after accounting for bid cost recovery charges.

Figure 2.16 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 (gold line).

[118] 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 2.16 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 2.2 compares the distribution of convergence bidding cleared volumes and net revenues among different groups of convergence bidding participants.[119]

The quantity of virtual bids increased 27 percent from 2022, largely due to increased participation from marketers and financial entities. 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. After increased bid cost recovery and virtual demand losses from nearly all groups of convergence bidding participants, total virtual revenues decreased by around 70 percent from 2022.

[119] 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 2.2 Convergence bidding volumes and revenues by participant type – 2022 to 2023

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	
2023								
Financial	2,170	2,632	4,802	-$4.02	$83.10	-$40.53	$42.57	$38.55
Marketer	442	586	1,028	-$2.65	$18.06	-$12.53	$5.53	$2.88
Physical load	0	22	22	$0.00	$0.59	-$5.58	-$4.99	-$4.99
Physical generation	40	109	149	-$0.73	$1.08	-$4.43	-$3.35	-$4.08
Total	**2,652**	**3,349**	**6,001**	**-$7.40**	**$102.83**	**-$63.07**	**$39.76**	**$32.36**

Previous Year Annual Table

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	
2022								
Financial	1,521	1,956	3,477	$27.05	$76.79	-$18.68	$58.11	$85.16
Marketer	491	686	1,177	$10.34	$19.15	-$8.11	$11.04	$21.38
Physical load	0	27	28	$0.09	$0.32	-$2.68	-$2.36	-$2.27
Physical generation	13	13	26	$1.61	$0.25	-$0.14	$0.11	$1.72
Total	**2,025**	**2,682**	**4,708**	**$39.09**	**$96.51**	**-$29.61**	**$66.90**	**$105.99**

2.6 Bid cost recovery payments

Bid cost recovery payments totaled $320 million, the highest total since 2011 and a notable increase from 2022 when payments were $297 million.[120] Around $289 million of bid cost recovery payments in 2022 were for units in the California ISO (CAISO), and $33 million were for units in the Western Energy Imbalance Market (WEIM).[121] The CAISO portion of these payments represents about 2.2 percent of total CAISO wholesale energy costs, an increase from about 1.4 percent in 2022. Most of this increase is from bid cost recovery attributable to the residual unit commitment process. RUC bid cost recovery in 2023 was around $60 million higher than in 2022.

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. About 81 percent of these payments, or $260 million, went to gas resources, followed by roughly $32 million to battery energy storage resources, and about $14 million to hydro resources. In 2022, these figures were roughly $235 million, $30 million and $17 million, respectively.

On November 18, 2022, FERC issued an order to prevent battery energy storage resources from receiving real-time market bid cost recovery payments for market intervals in which the *Ancillary Service*

120 Bid cost recovery payments reported in earlier DMM reports did not include payments from flexible ramping product and greenhouse gas. Including these reduces the shortfall amount that is paid out as bid cost recovery.

121 All values reported in this section refer to DMM estimates for bid cost recovery totals.

State of Charge constraint requires such a resource to charge or discharge.[122] This was in response to DMM's observations in 2022, where under certain circumstances, battery storage resources with ancillary service awards and high energy bids received significant real-time bid cost recovery payments.

DMM estimates that about 59 percent of the CAISO's total bid cost recovery payments, approximately $169 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. This is an increase from about $145 million, or 57 percent, in 2022. Commitment cost bids are capped at 125 percent of reference proxy costs.[123] Similar to the percentage for 2022, about 93 percent of these payments in 2023 were for resources bidding at or near the 125 percent bid cap for proxy commitment cost.

Bidding flexibility for commitment costs, in addition to the 25 percent adder on reference proxy costs, is provided through reference level adjustment requests. This functionality was implemented as part of the commitment costs and default energy bids enhancements (CCDEBE) initiative processes. These requests, if accepted, are used in the market commitment process and can impact bid cost recovery by increasing the bid costs used in the calculation. In 2023, as well as the prior year, this feature had minimal impact to bid cost recovery payments.

Figure 2.17 provides a summary of total estimated bid cost recovery payments in 2022 and 2023 by month and market. The significantly higher payments in the second half of the year can be attributed to changes in the CAISO balancing area's method for determining operator adjustments to the RUC load forecast.[124]

Day-ahead bid cost recovery payments totaled roughly $28 million in 2023, a decrease from about $39 million in 2022. An estimated 32 percent of 2023 day-ahead bid cost recovery payments can be attributed to resources effective at meeting the minimum on-line constraints enforced in the day-ahead market, compared to 24 percent in 2022.[125]

Real-time bid cost recovery payments were $157 million in 2023, about $25 million lower than payments in 2022. Out of the $157 million in real-time payments, about 33 million was paid to resources (non-California ISO) participating in the WEIM. Bid cost recovery payments to WEIM resources was about $9 million lower than payments in 2022.

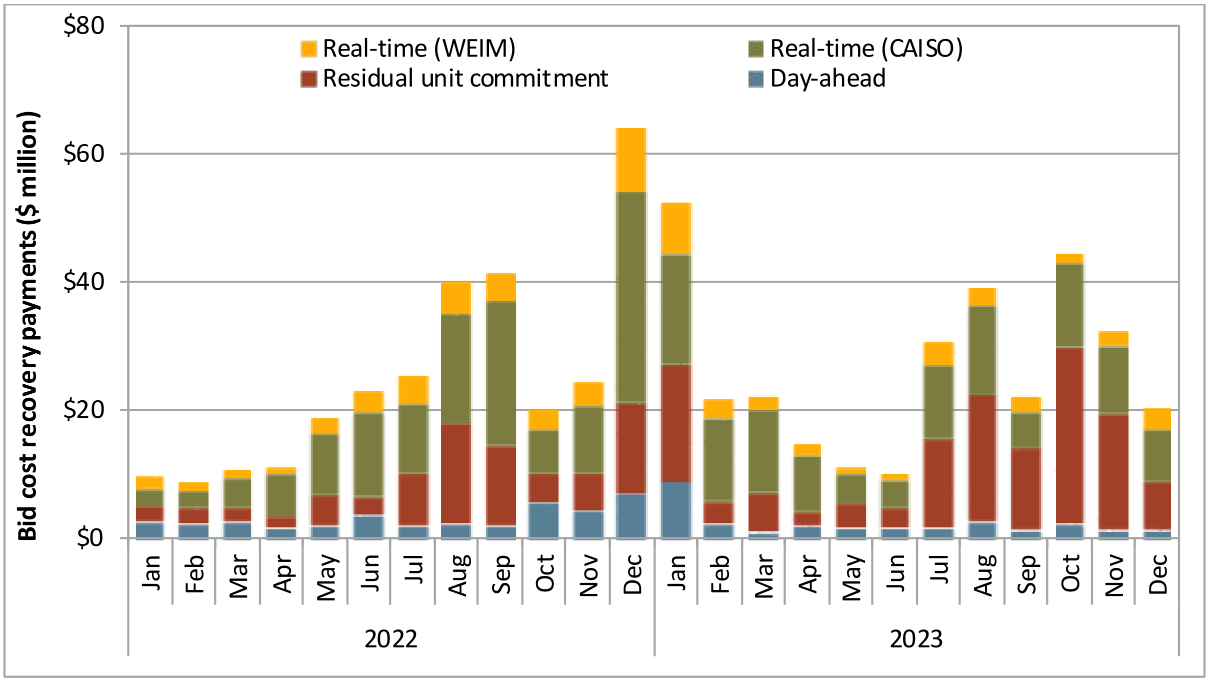
[122] *Order Accepting Tariff Revisions* (on energy storage bid cost recovery changes), California ISO, FERC Docket No. ER22-2881, November 18, 2022: https://www.caiso.com/Documents/Nov18-2022-OrderAccepting-EnergyStorageBidCostRecovery-ER22-2881.pdf

[123] See Section 6.3 for more information on commitment cost bid caps and bidding behavior.

[124] See Section 7.3 for more information about changes to the RUC calculation.

[125] Minimum on-line constraints (MOCs) are used to meet special reliability issues that require having units on-line to meet voltage requirements and for contingencies. These constraints are based on existing operating procedures that require a minimum quantity of on-line capacity from a specific group of resources in a defined area. These constraints ensure that the system has enough longer-start capacity on-line to (1) meet locational voltage requirements, and (2) respond to contingencies that cannot be directly modeled in the market.

Figure 2.17 Bid cost recovery payments



Units committed through exceptional dispatches are eligible to receive real-time bid cost recovery payments. Exceptional dispatches are made by real-time operators to help ensure reliability across the system. DMM estimates these payments for resources committed to operate through exceptional dispatches totaled about $5.5 million in 2023, significantly down from $9.5 million in 2022. Additional details regarding exceptional dispatches are covered in Section 7.1 of this report.

Bid cost recovery payments for units committed through the residual unit commitment process totaled about $135 million in 2023. This represents a $60 million increase in payments from 2022. Average procurement in the residual unit commitment process was considerably higher than the previous year, as described in Section 2.4. The majority of bid cost recovery payments for units committed through the residual unit commitment process are received by gas-fired resources. Higher levels of procurement resulted in higher total payments.

Table 2.3 and Table 2.4 show bid cost recovery payments in the CAISO and WEIM balancing areas by technology/status type.[126,127] As shown in Table 2.3, bid cost recovery paid to fast-start combustion turbines (excludes cogeneration and reciprocating engines) totaled about $19 million, $33 million, and $28 million for 2021, 2022, and 2023, respectively. These payments are only 12 percent of total bid cost recovery payments to gas resources in the CAISO footprint in 2023, a decrease from about 16 percent in

126 For this analysis, DMM classified combustion turbines as fast-start if the units' start-time and minimum operating time was within the definition of fast-start resources used by any of the five RTOs that have adopted fast-start pricing (ISO-NE, NYISO, MISO, PJM or SPP)

127 "QF/CHP/Must-take" category includes gas and hydro fuel types. "Reliability must-run" category includes gas resources. "Other" category includes Biogas, Biomass, Coal, Geothermal, Distillate oil, Demand response, Solar, Wind, and Nuclear technology types.

2022. Similarly, in the WEIM areas, bid cost recovery paid to fast-start combustion turbines totaled about $1 million in 2022 and about $1.3 million in 2023. These payments are about 3 percent and 6 percent of total bid cost recovery payments to gas resources in the WEIM areas in 2022 and 2023, respectively.

Table 2.3 Total bid cost recovery payments in the CAISO area by technology type (2021–2023)

System	Technology type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2021	2022	2023	2021	2022	2023
CISO	Batteries	$3,609,903	$24,184,805	$27,972,778	2%	10%	10%
CISO	Hybrid	-	-	$316,752	-	-	<1%
CISO	Once-through-cooling	$56,382,268	$63,076,246	$79,030,922	36%	25%	28%
CISO	Combined Cycle	$56,091,782	$78,790,711	$114,121,020	36%	32%	40%
CISO	Frame turbine: non-Fast start	$0	$159,200	$683,178	<1%	<1%	<1%
CISO	Gas turbine: non-Fast start	$3,619,185	$10,054,076	$5,042,993	2%	4%	2%
CISO	Gas turbine: Fast start cogeneration	$377,313	$489,399	$508,546	<1%	<1%	<1%
CISO	Gas turbine: Fast start (includes Frame CTs and Gas hybrids)	$18,959,940	$33,125,372	$27,661,951	12%	13%	10%
CISO	Reciprocating engines: Fast start (includes cogens)	$10,944	$6,709	$13,133	<1%	<1%	<1%
CISO	Reciprocating engines: non-Fast start	$4,531,553	$9,610,201	$6,380,190	3%	4%	2%
CISO	Hydro	$1,582,700	$1,866,697	$774,546	1%	1%	<1%
CISO	Other	$2,183,523	$6,346,392	$3,613,301	1%	3%	1%
CISO	QF/CHP/Must-take	$6,641,987	$19,632,249	$16,068,487	4%	8%	6%
CISO	Reliability must-run	$2,506,434	$2,740,654	$396,278	2%	1%	<1%

Table 2.4 Total bid cost recovery payments in the WEIM areas by technology type (2021–2023)

System	Technology type	Bid cost recovery payments ($)			Percent of total bid cost recovery payments (%)		
		2021	2022	2023	2021	2022	2023
WEIM	Batteries	$1,652	$18,763	$12,943	<1%	<1%	<1%
WEIM	Hybrid	-	-	$8,834	-	-	<1%
WEIM	Combined Cycle	$9,694,798	$30,352,158	$19,521,294	58%	72%	62%
WEIM	Frame turbine: non-Fast start	$0	$760,148	$675,618	<1%	2%	2%
WEIM	Gas turbine: non-Fast start	$3,032,158	$907,958	$409,917	18%	2%	1%
WEIM	Gas turbine: Fast start (includes Frame CTs)	$508,563	$987,783	$1,271,399	3%	2%	4%
WEIM	Reciprocating engines: Fast start	$25,928	$79,108	$163,240	<1%	<1%	1%
WEIM	Reciprocating engines: non-Fast start	$13,538	$55,108	$126,656	<1%	<1%	<1%
WEIM	Steam turbine	$20,092	$129,677	$74,276	<1%	<1%	<1%
WEIM	Hydro	$1,274,095	$1,009,581	$2,974,688	8%	2%	9%
WEIM	Other	$2,257,805	$7,599,921	$6,489,638	13%	18%	20%

2.7 Real-time imbalance offset costs

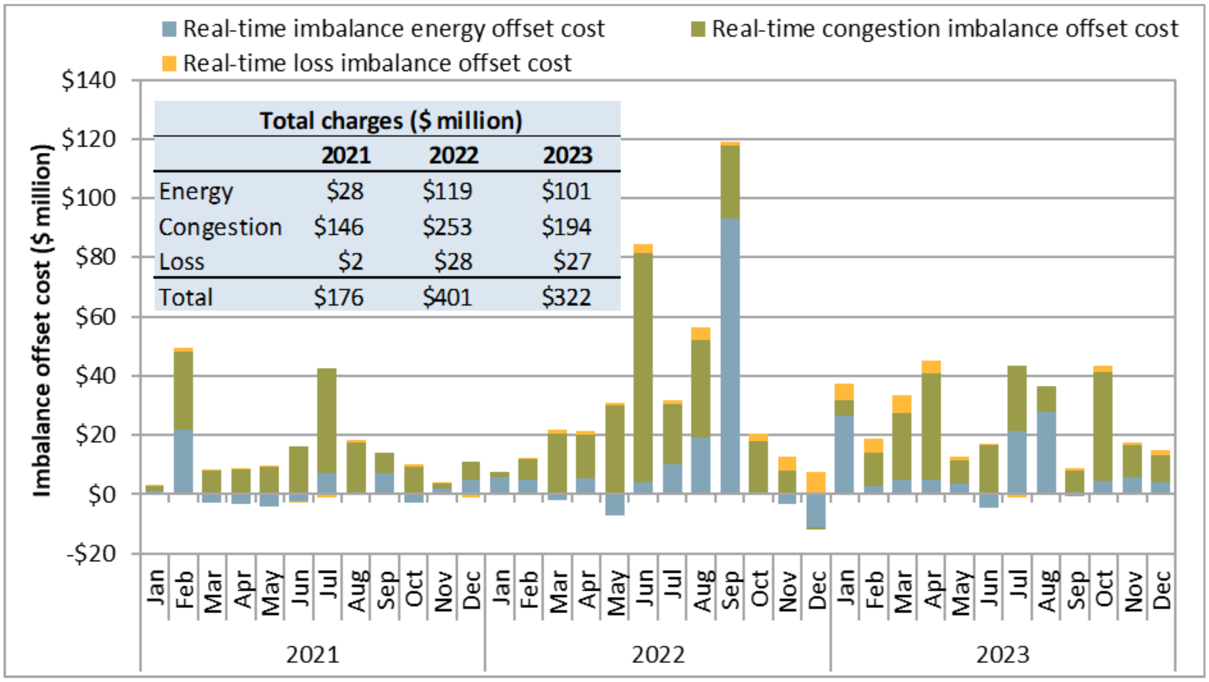
Total real-time imbalance offset costs decreased to around $322 million in 2023, down from around $401 million in 2022. The congestion portion of these imbalance offset costs were $194 million, compared to $253 million in 2022. The energy portion of the imbalance offset costs were $101 million in 2023, compared to $119 million in 2022.

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

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge (RTCIO)*. Similarly, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*, while any remaining revenue imbalance is recovered through the *real-time imbalance energy offset charge (RTIEO)*.

Figure 2.18 shows monthly imbalance offset costs since 2021. Overall, real-time imbalance offset costs for all three components in 2023 were lower compared to 2022, but were higher compared to 2021.

Figure 2.18 Real-time imbalance offset costs



Inconsistencies in settlement of real-time market demand and generation

Real-time revenue imbalances can be created by inconsistency between the real-time price generation is paid and the real-time price load pays. DMM has identified two significant sources of such inconsistency.

- Settling real-time load using an hourly price weighted by the absolute value of incremental load
- Settling real-time load using incorrect load schedules to weight prices

These two sources of real-time revenue load imbalances are described in more detail below.

Hourly price weighted by the absolute value of incremental load

Real-time *generation* is paid incrementally from one market to the next. The difference from the day-ahead to 15-minute market schedule is settled at the 15-minute market price, and the difference from the 15-minute to 5-minute market schedule (as well as from the 5-minute market to metered amount) is settled at the 5-minute market price. Real-time *load* is instead settled on the difference from the day-ahead schedules to metered load using a weighted average of the 15-minute and 5-minute market prices in each hour.

In some hours, the hourly real-time price paid by load is weighted by incremental load in the 15-minute and 5-minute markets. This price is calculated in a way that mathematically maintains revenue balance from day-ahead to 5-minute market schedules, but can be inappropriate in practice when applied to the difference between day-ahead scheduled load and *metered* load. Therefore, under some real-time conditions, real-time load is instead settled using an average hourly price that is weighted by the *absolute value* of incremental load in the 15-minute and 5-minute markets.[128] The *absolute value weighted average price* prevents extreme settlement outcomes under certain conditions, but also tends to cause the ISO to collect less money from real-time load than is paid to generators in the real-time market. This creates revenue shortfalls, which must be instead recovered through imbalance offset charges.[129] The imbalance offset costs are allocated to total metered load plus exports. DMM recommends that the ISO settle real-time load incrementally in each market directly using market prices.

Incorrect load schedules to weight prices

During most of 2023, incorrect load schedules for the CAISO balancing area load aggregation points (LAPs) were used to weight prices used for settling real-time load imbalance. Figure 2.19 shows 15-minute market load schedules by LAP between January 31 and February 2, 2023.[130] Due to an error with the implementation of flexible ramping product refinements on February 1, 2023, the distribution of the total CAISO load to the load aggregation points were incorrect. For example, load schedules on the Valley Electric Association (VEA) aggregate node are typically less than 100 MW, but were over 10,000 MW in many hours in the 15-minute market during the year. Schedules in the 5-minute market were also impacted, though to a lesser extent. This issue was corrected on February 5, 2024. The ISO is working on resettling real-time load for the impacted period.[131]

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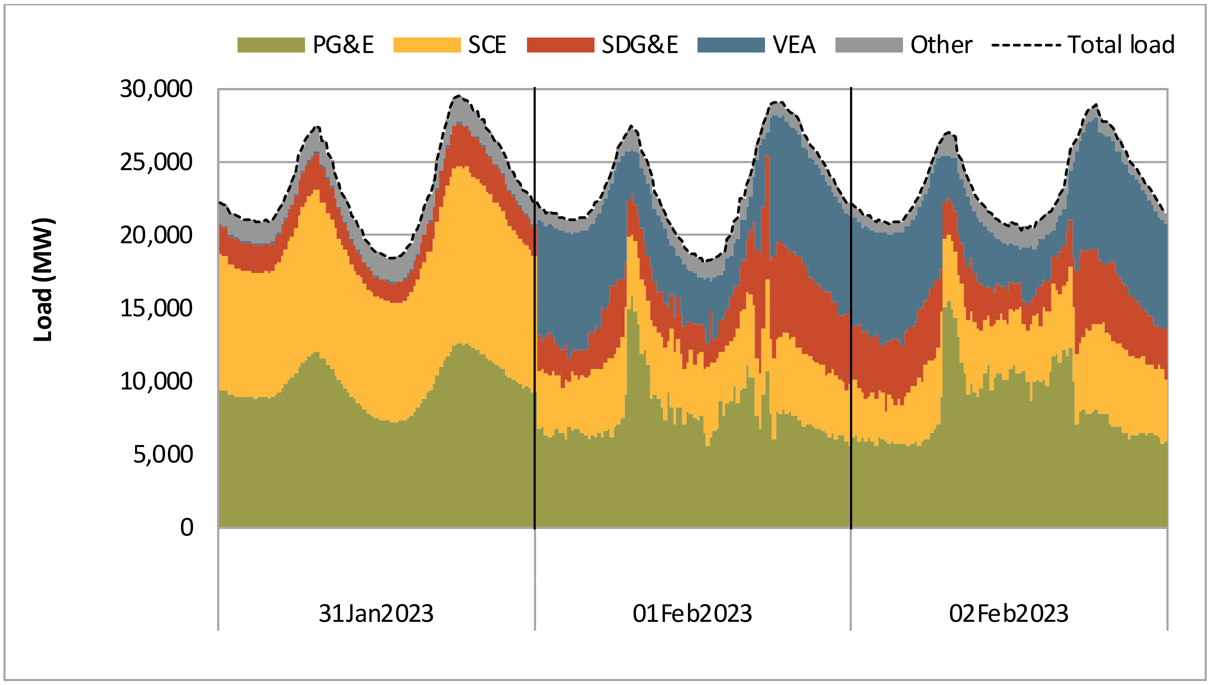
128 If the calculated weighted average price is outside the minimum or maximum of 15-minute and 5-minute market prices during the hour, then the ISO uses the absolute value weighted price. The absolute value weighted price is also used if these conditions exist for any individual price component (energy, congestion, losses, or GHG).

129 For more information, see DMM's special report: *Real-time load settlement price calculation causing revenue imbalances*, Department of Market Monitoring, August 30, 2023: http://www.caiso.com/Documents/Real-Time-Load-Settlements-and-Revenue-Imbalances-Aug-30-2023.pdf

130 Total load schedules on the metered subsystem load aggregation points (MLAP) and custom load aggregation points (CLAP) are grouped together in "Other".

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

Figure 2.19 15-minute market aggregate load schedules (January 31, 2023 to February 2, 2023)



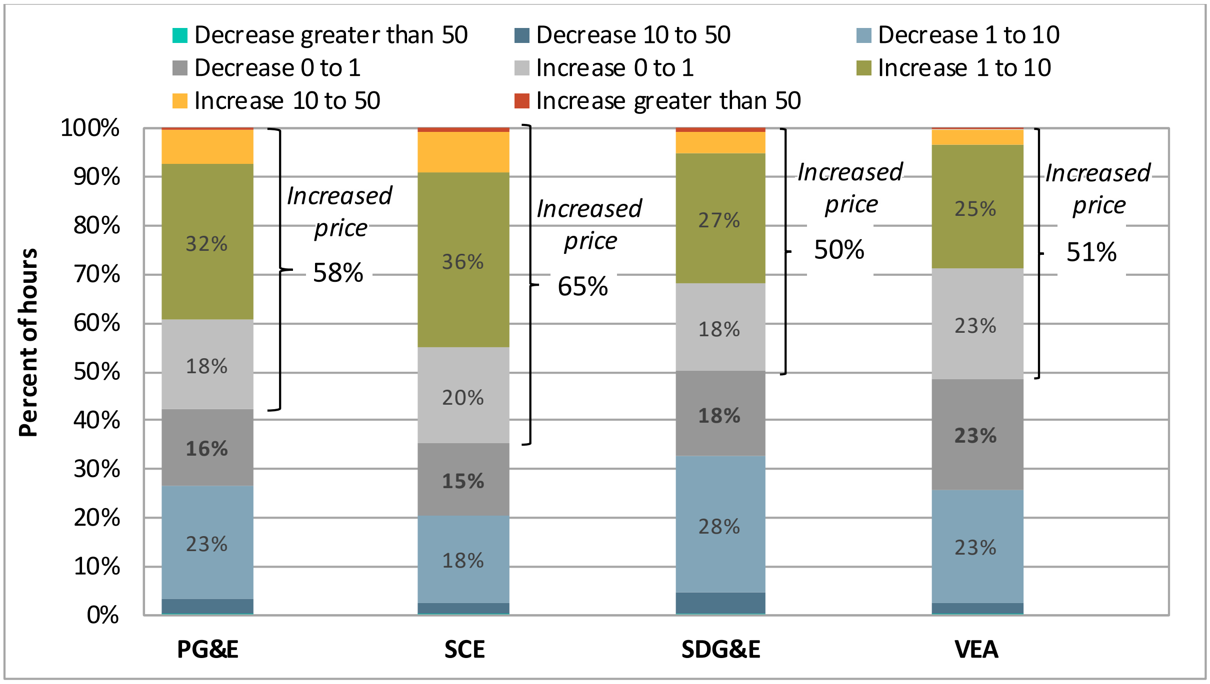
Non-participating real-time load is settled on the difference between the hourly day-ahead schedules and metered load, using an hourly weighted price calculated from the 15-minute and 5-minute market prices. Here, the incorrect aggregate load schedules do not impact the day-ahead or metered load, but do impact the weighting of prices in the calculation of the hourly real-time price.

Figure 2.20 summarizes the estimated impact of the error on the hourly real-time price used to settle load.[132] It shows the percent of hours in 2023 since February in which the calculated price was higher or lower for each default load aggregation point because of the error. Overall, there was not an extreme directionality in the way the error impacted the prices, though it tended to increase the price.

The use of incorrect load schedules increased the price for SCE real-time load imbalance in 65 percent of hours. For PG&E, SDG&E, and VEA the error increased the price in 58, 50, and 51 percent of hours, respectively. In most hours, the impact on the hourly real-time price was less than $10—though both these instances and the small percent of hours with more significant price differences can have a significant impact on total payments from load.

[132] DMM estimates the impact of the error by comparing to a counterfactual calculation of the hourly real-time price using corrected aggregate load schedules. These aggregate load schedules were determined by using the normal load distribution and load aggregation factors to distribute the total market load to the aggregate load schedules. In some cases, this information was not available such that it had to be estimated.

Figure 2.20 Impact of incorrect aggregate load schedules on hourly real-time price (February 1, 2023 to December 31, 2023)



When metered load exceeds day-ahead schedules, load serving entities will be charged for the incremental imbalance.[133] When metered load is less than day-ahead schedules, load serving entities will instead be paid for the decremental imbalance. Figure 2.21 summarizes the percent of hours in 2023 since February 1 in which the error was estimated to contribute to either revenue surplus or revenue shortfall. Overall, the error is estimated to more frequently contribute to *revenue shortfalls*, either from the ISO collecting less from load serving entities for incremental load imbalance or by paying load serving entities more for decremental load imbalance. Across the default load aggregation points, this issue caused a revenue shortfall between 57 and 64 percent of hours between February 1 and December 31.

- ***Increased* price and *incremental* total metered load imbalance:** Load serving entities were charged more overall for incremental load imbalance (increased net charge from load). The increased payment from load contributes to revenue surplus.
- ***Decreased* price and *decremental* total metered load imbalance:** Load serving entities were paid less overall for decremental load imbalance in real-time (increased net charge to load). The decreased payments to load contributes to revenue surplus.
- ***Decreased* price and *incremental* total day-ahead to metered load imbalance:** Load serving entities were charged less overall for incremental load imbalance (decreased net charge to load). The decreased payment from load contributes to revenue shortfall.

133 Assuming the hourly real-time price is positive.

- ***Increased* price and *decremental* total day-ahead to metered load imbalance:** Load serving entities were paid more overall for decremental load imbalance (decreased net charge to load). The increased payments to load contributes to revenue shortfall.

Figure 2.21 Impact of incorrect aggregate load schedules on net charge to load (February 1, 2023 to December 31, 2023)

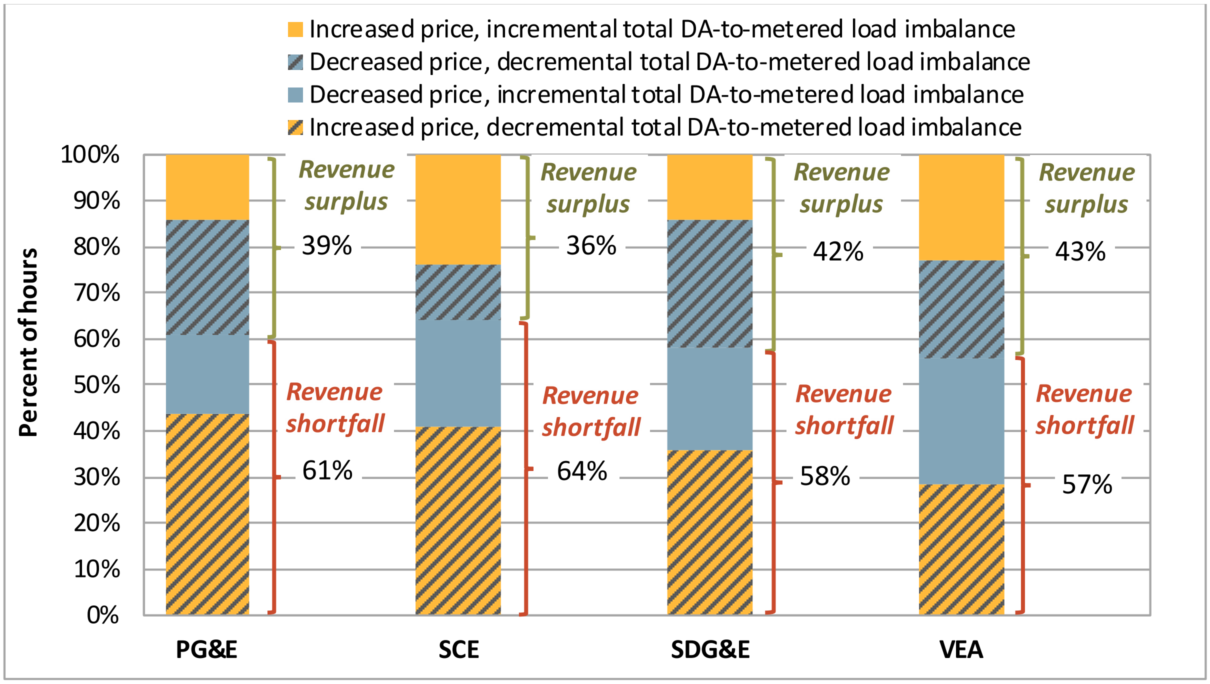


Figure 2.22 shows the monthly estimated impact of the error on settled, non-dispatchable real-time load between February 1 and December 31, 2023. Table 2.5 shows the same information instead by load aggregation point over the entire period.[134] Any estimated revenue imbalance because of the error was assessed for each hour by load serving entity and location, and shown summed as either contributing to shortfall or surplus. As shown in Figure 2.22, the effects contributing to either revenue surplus or revenue shortfall largely cancelled each other out in July and August, when prices were highest. Greater imbalance was instead accrued in the off-summer period. In net over this period, the error was estimated to decrease in-market payments from load (or increase the payments to load) by around $11.2 million. This effect would not have been balanced by generation and therefore would have contributed to revenue shortfall. The shortfall would have been recovered through the real-time imbalance offset charges, which shifts the allocation of these costs between load serving entities and exporters based on measured demand. Between February and December, DMM estimates that this would have ultimately shifted around $7.1 million in net costs between market participants, including around $0.8 million in load costs to exporters.

[134] "Other" category includes impact at Custom Load Aggregation Points (CLAP) and Metered Subsystem Load Aggregation Points (MLAP).

Figure 2.22 Estimated impact of incorrect aggregate load schedules by month

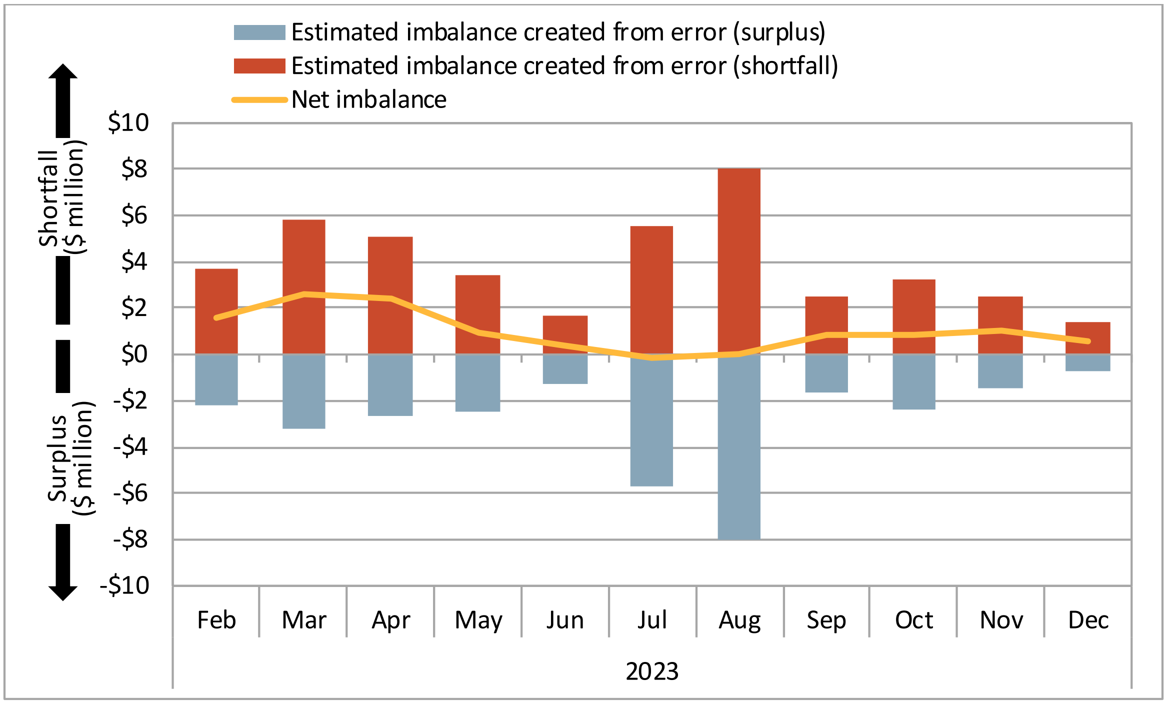


Table 2.5 Estimated impact of incorrect aggregate load schedules on net charge to load (February 1, 2023 to December 31, 2023)

LAP	Estimated impact of error (shortfall)	Estimated impact of error (surplus)	Estimated net shortfall
PG&E	$16,282,242	$12,474,293	$3,807,949
SCE	$18,793,455	$14,007,041	$4,786,415
SDG&E	$6,557,468	$4,661,010	$1,896,458
VEA	$180,919	$94,975	$85,944
Other	$1,099,241	$520,172	$579,069
Total	$42,913,325	$31,757,491	**$11,155,835**

2.8 Flexible ramping product and enhancements

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.[135] 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.

On February 1, 2023, the CAISO implemented two significant changes to the flexible ramping product. The first of these improves the deliverability by procuring and pricing flexible capacity at a nodal level to better ensure that sufficient transmission is available for this capacity to be utilized. The second significant change adjusted the calculation of the uncertainty requirement by incorporating current load, solar, and wind forecast information using a method called mosaic quantile regression.

2.8.1 Flexible ramping product requirement and deliverability enhancements

The end of the flexible ramping product demand curve is implemented in the California 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.[136] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation, which 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.

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

Flexible ramping product demand curves and implementation error

The prices on the demand curves should reflect the expected cost of a power balance constraint violation for the level of flexible ramping capacity procured. When the uncertainty requirement is met and flexible capacity is readily available, the price is zero. However, as this requirement is relaxed and less flexible capacity is procured (below the upper end of uncertainty that might materialize) the

135 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.

136 Based on a 95 percent confidence interval.

likelihood of a power balance constraint relaxation—and therefore the expected cost of this outcome—both increase.

The prices on the flexible ramping product demand curves were implemented incorrectly as part of the enhancements on February 1. The result was that the prices on the demand curve were too low relative to the expected cost of a power balance constraint relaxation for the level of flexible capacity procured. This effectively made it appear cheaper for the market optimization to forgo flexible ramping capacity. However, the frequency of forgone flexible capacity (relaxation of the uncertainty requirement) was low during this period, such that the error had a relatively small impact on system-wide flexible capacity procurement and prices. The ISO implemented a correction to the demand curves effective August 8, 2023.[137] For more information on the implementation error including the cause of the issue, see DMM's special report on the topic.[138]

Flexible ramping product prices

As part of flexible ramping product enhancements, flexible ramping product prices are now determined locationally at each node. This price can be made up of multiple components.[139] 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.[140] These components can create price differences across nodes in the WEIM based on the demand for flexibility in the system and the feasibility for flexible capacity at a node to meet that demand. For the transmission constraints, only base-case flow based constraints were modeled in the deployment scenarios at implementation of the enhancements on February 1, 2023. Nomogram constraints were later enforced for flexible ramping product procurement on September 7, 2023.[141] Contingency flowgate constraints were activated on June 4, 2024 and de-activated on June 12 due to performance issues with the solution run-times.[142] Using the same constraints for both the real-time market and flexible ramping product deployment

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137 A subsequent issue with this correction caused the price for each segment beyond the first to be incorrectly shifted by one segment. This was corrected on October 4, 2023.

138 *Flexible ramping product enhancements demand curve implementation error,* Department of Market Monitoring, July 20, 2023: http://www.caiso.com/Documents/Flexible-Ramping-Product-Enhancements-Demand-Curve-Implementation-Error-Jul-20-2023.pdf

139 For details on the new deployment scenario constraints and how the ISO derives flexible ramping prices from them, see *Flexible Ramping Product Refinements: Appendix B – Procurement and Deployment Scenarios Draft Technical Description*, CAISO, May 7, 2020, p 21: https://stakeholdercenter.caiso.com/InitiativeDocuments/DraftTechnicalDescription-FlexibleRampingProductRefinements-Procurement-DeploymentScenarios.pdf

140 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.

141 *Flexible Ramping Product Nomogram Activation*, California ISO Market Notice, September 7, 2023: https://www.caiso.com/Documents/flexible-ramping-product-nomogram-activation-on-9723.html

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

scenarios is important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore is not able to address materialized uncertainty.

The shadow price on the constraint for procuring flexible capacity in the pass-group has frequently been zero since the enhancements were implemented. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[143] A zero shadow price on the pass-group constraint indicates, in most scenarios, that the upper end of the total uncertainty requirement for all balancing areas that passed the resource sufficiency evaluation can be met by resources with zero opportunity cost for providing that flexibility.

Figure 2.23 shows the percent of intervals since implementation of the enhancements in which the 15-minute market price for flexible capacity was non-zero for the group of balancing areas that passed the resource sufficiency evaluation tests. This is the shadow price associated with meeting the pass-group uncertainty requirement and does not account for any congestion that may affect the price of flexible capacity at the nodal level.[144] This is compared against the frequency of non-zero prices on the constraint for *system-wide* flexible capacity that was in place prior to the enhancements. Between February and December of 2023, the frequency of non-zero prices was higher compared to the same period of the previous year (prior to the enhancements). Since the enhancements, 15-minute market prices for *upward* flexible capacity within the pass-group were non-zero in around 0.8 percent of intervals for 2023, and 77 percent of these intervals occurred during the peak net load hours (hours 18 through 21). The frequency of non-zero prices for *downward* flexible capacity in the 15-minute market was low, during less than 0.1 percent of intervals. In the 5-minute market, the frequency of non-zero prices in both directions was similarly low.

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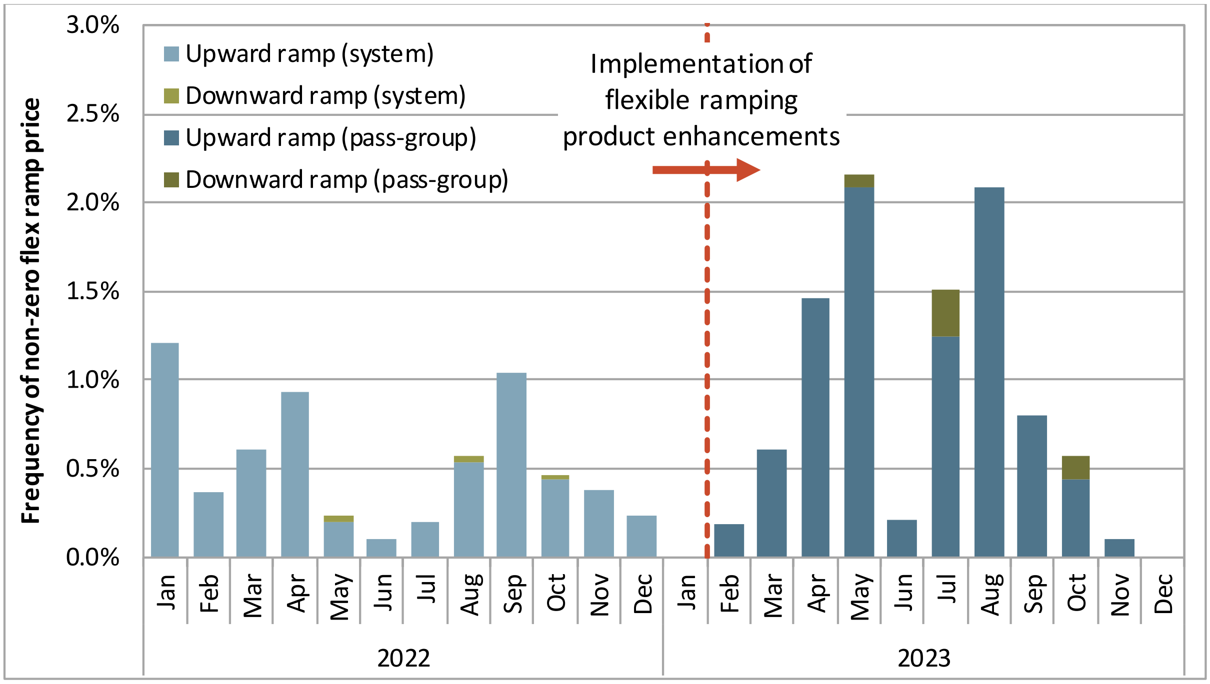
143 This pass-group constraint is intended to limit the sum of all flexible ramp capacity in the passing group. The limit is the group's total flexible ramp requirement. The formulation of the deployment scenario also includes an individual power balance constraint for each balancing area in the pass-group, 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 balance 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.

144 Congestion on WEIM transfer constraints between balancing areas in the pass-group should manifest as the balancing areas having different shadow prices on each of their new deployment scenario power balance constraint. Therefore, 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 2.23 Frequency of non-zero system or pass-group flexible ramping product shadow price (15-minute market)



The price of flexible capacity for a node in a balancing area that passed the resource sufficiency evaluation can still be positive even when the shadow price on the constraint for procuring pass-group-level flexible capacity is zero (e.g., not binding). This can occur because of congestion on WEIM transfer constraints that might separate a balancing area from the rest of the system. Here, outside flexible capacity may not be feasible to meet the isolated balancing area's share of pass-group uncertainty and this requirement may be relaxed, resulting in a localized price for flexible capacity.[145] Congestion on binding transmission constraints in the deployment scenario can also create a localized price for flexible capacity.

Figure 2.24 shows the percent of intervals in which there was a price for upward flexible capacity and a positive upward flexible capacity schedule at any node within the pass-group in the 15-minute market. These are the intervals in which resources were paid for providing flexible capacity. The prices are split out by whether the constraint for procuring flexible capacity in the pass-group was binding or not. The blue bars are identical to the information showed in Figure 2.23, showing the frequency of flex ramp prices for the group of balancing areas that passed the resource sufficiency evaluation. The gray bars instead show intervals when at least one resource node somewhere in the pass-group showed a positive price for flexible capacity, but without the pass-group level constraint binding.

[145] For the group of balancing areas that pass the resource sufficiency evaluation, the demand curves for flexible capacity are distributed out to surplus zones. These surplus zones are separate for each balancing area (or for each load aggregation point in the case of the CAISO area and BANC). The upper end of the demand curve for each surplus zone is equal to its share of the total pass-group uncertainty. This demand curve is used in the deployment scenario power balance constraint for each balancing area that passed the resource sufficiency evaluation.

Figure 2.25 shows the same information but further subdivides how many balancing areas had positive prices and schedules on their nodes in the intervals in which the shadow price on the constraint for procuring flexible capacity in the pass-group was zero. As shown in the figure, when there are positive prices on nodes for balancing areas that passed the test—but the pass-group constraint is *not* binding—this is typically within one balancing area, due to congestion on either WEIM transfer constraints or transmission constraints. More widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation may instead be better captured by the frequency in which the pass-group level constraint is binding (blue bars).

Figure 2.24 Frequency of nodal upward flexible ramping price in pass-group (15-minute market)

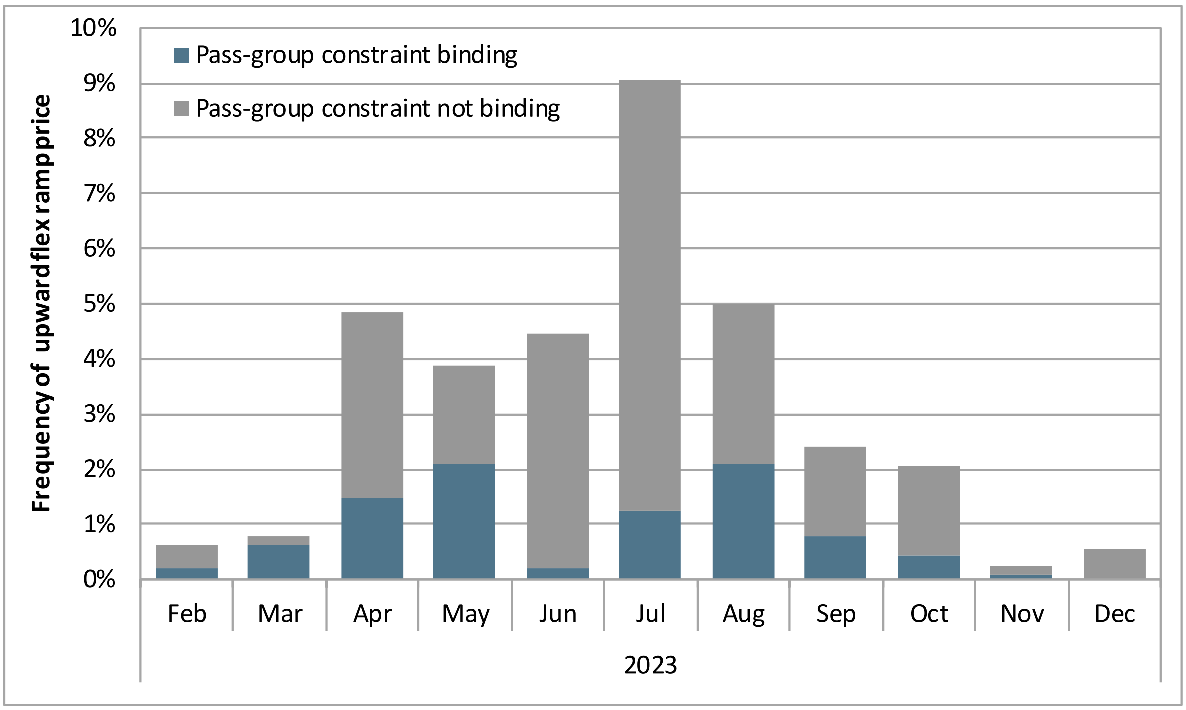
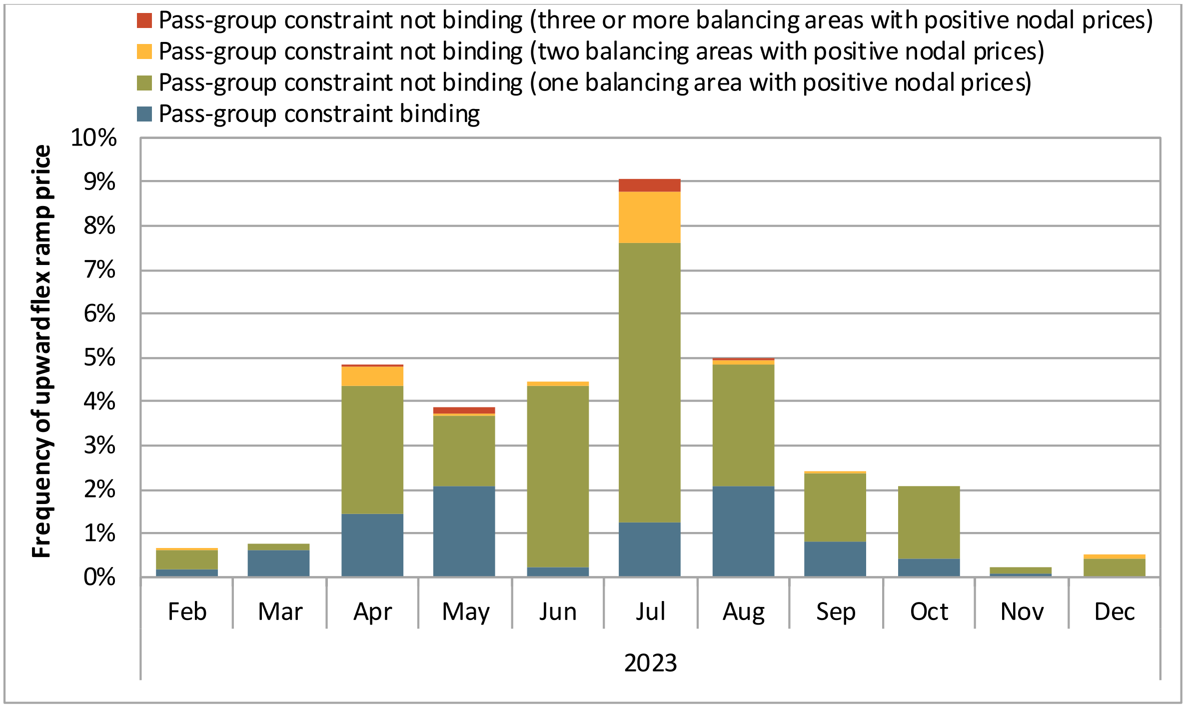


Figure 2.25 Frequency of nodal upward flexible ramping price in pass-group by number of balancing areas (15-minute market)



Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system during the quarter. Figure 2.26 and Figure 2.27 show the percent of upward or downward flexible capacity that was procured from various fuel types, both before and after the enhancements that were implemented at the start of February 2023. Prior to the enhancements, these amounts reflect the percent of *system-wide* uncertainty. After the enhancements, these amounts instead reflect the percent of *pass-group* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation.

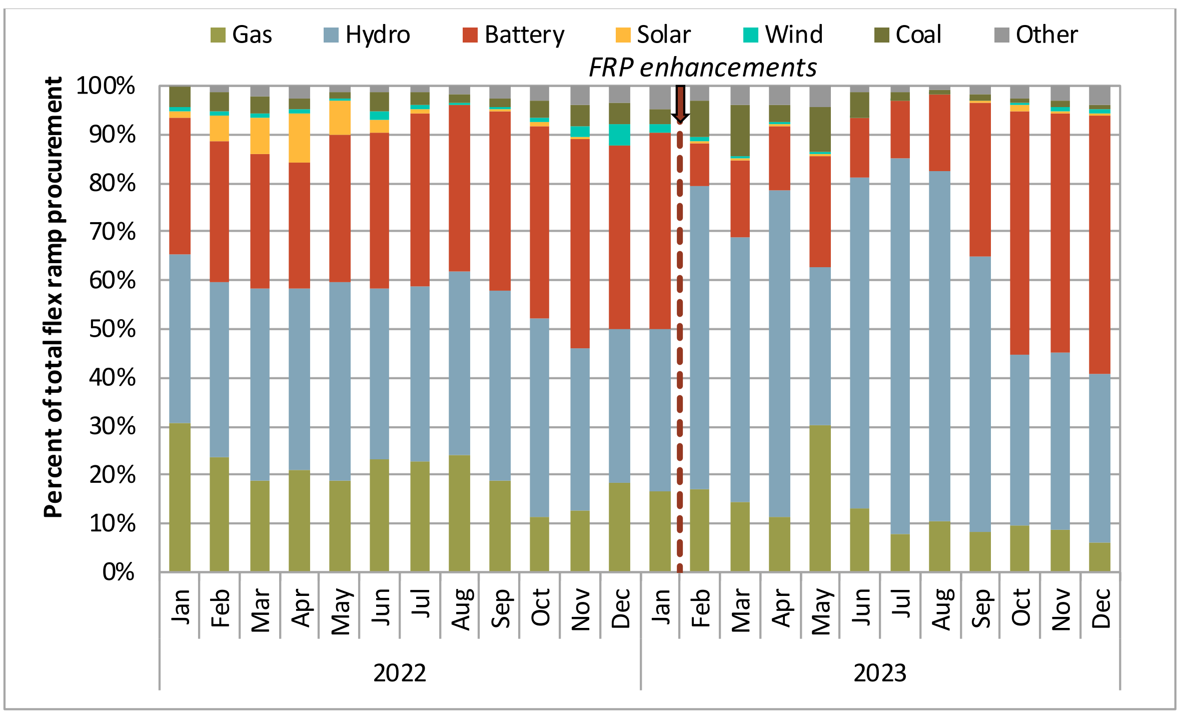
Following the enhancements, *upward* flexible capacity procured from hydro resources increased while upward capacity from gas and battery resources decreased. Between February and December, 2023, hydro resources made up 54 percent of upward flexible capacity, compared to 37 percent during the same period of the previous year. This was largely because of the elimination of the minimum requirement—a temporary measure which often required that a portion of system-wide flexible capacity be procured within the CAISO balancing area to help mitigate issues with stranded flexible capacity elsewhere in the system. Since nodal procurement can instead better ensure that flexible capacity is deliverable, the minimum requirement was removed and a greater share of flexible capacity can now be procured outside the CAISO balancing area.

For *downward* flexible capacity, battery resources made up a larger share of the procured capacity, while hydro resources made up a smaller share, compared to prior to the enhancements. Between February and December, 2023, battery resources made up 12 percent of downward flexible capacity, compared to less than 1 percent during the same period of the previous year. In 2023, gas resources made up the largest percent of procured downward flexible capacity (27 percent), followed by solar resources (23 percent) and then wind resources (20 percent).

Figure 2.28 and Figure 2.29 instead show the percent of upward or downward flexible capacity that was procured in various regions.[146] 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. As shown in Figure 2.28, the percent of *upward* capacity procured from balancing areas in the Pacific Northwest region increased significantly following the enhancements, to around 45 percent. In comparison, Pacific Northwest resources made up 30 percent of upward flexible capacity during the same period of the previous year.

Downward flexible capacity procured from balancing areas in the Desert Southwest region also increased significantly. Desert Southwest resources made up 28 percent of downward flexible capacity between February and December 2023, compared to only 4 percent for the same period of the previous year. Following the enhancements, most downward flexible capacity was still procured within the CAISO balancing area (42 percent), which was less than the previous year (49 percent).

Figure 2.26 Percent of upward system or pass-group flexible ramp procurement by fuel type



146 California (WEIM) includes BANC, LADWP, and Turlock Irrigation district. Desert Southwest includes Arizona Public Service, NV Energy, PNM, Salt River Project, El Paso Electric, Tucson Electric Power, and WAPA (DSW). Intermountain West includes Idaho Power, Northwestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power. These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas.

Figure 2.27 Percent of downward system or pass-group flexible ramp procurement by fuel type

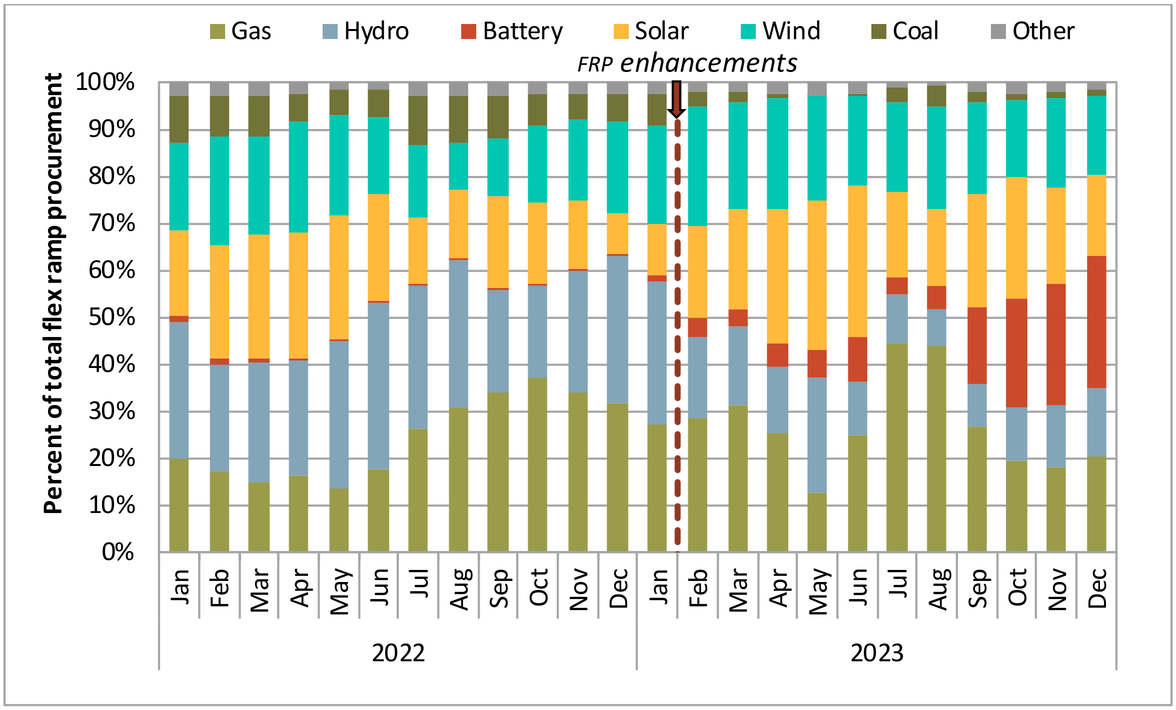


Figure 2.28 Percent of upward system or pass-group flexible ramp procurement by region

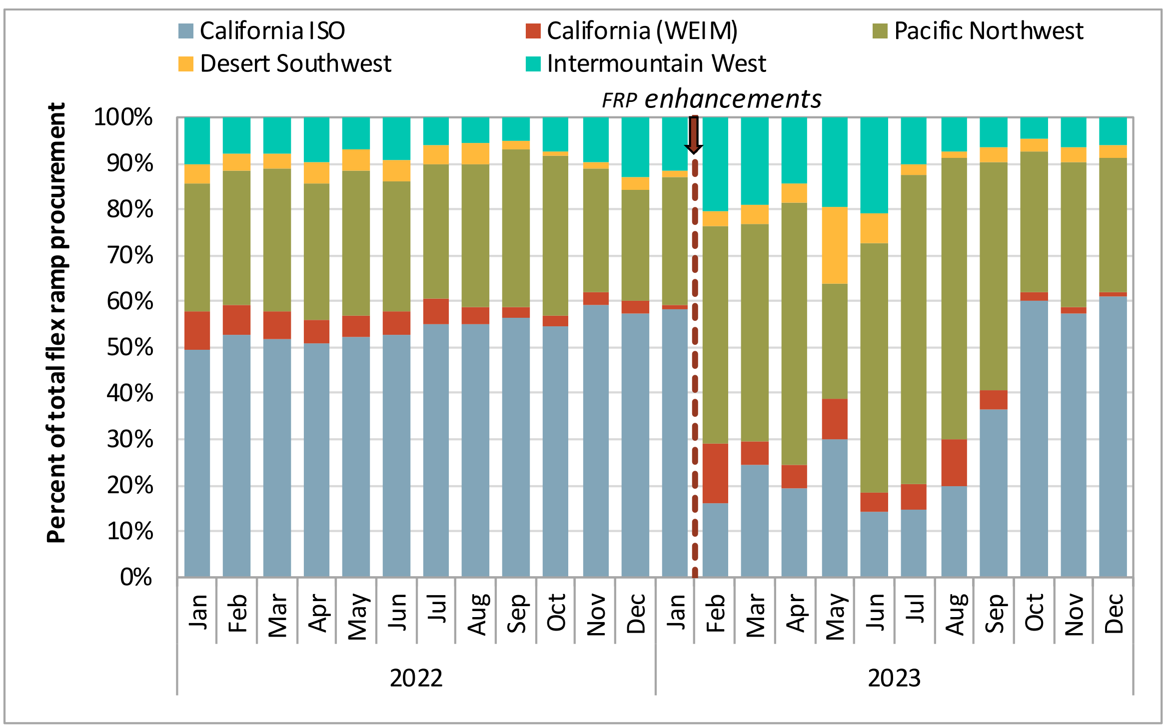
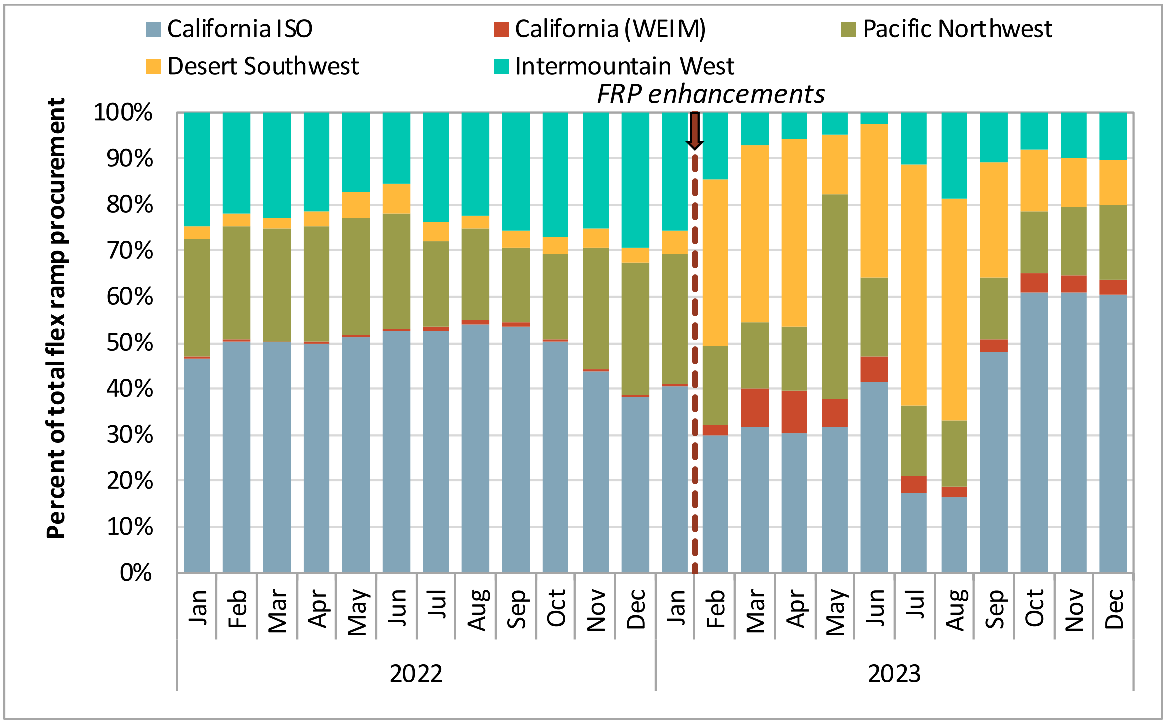


Figure 2.29 Percent of downward system or pass-group flexible ramp procurement by region



2.8.2 Net load uncertainty for the flexible ramping product

Uncertainty in the market is defined as forecasting error. The 15-minute and 5-minute markets utilize available forecasts for load, wind, and solar at the time when the market runs. If the target is hour-ending 18, both markets run for the same target hour, but calculations are made at different times. The 15-minute market runs earlier than the 5-minute markets, leading to differences in forecast data due to updates in weather and other variables in the interim period. This difference in forecast data is the uncertainty.

Uncertainty in the market can take many forms. General uncertainty is referred to as net load uncertainty, which is the net load forecasting error from different market runs. For flexible ramping product procured in the 15-minute market, net load uncertainty represents the difference between net load forecast data from the advisory 15-minute runs and the binding 5-minute market runs. In the 5-minute market, net load uncertainty is the difference between advisory 5-minute market runs and binding 5-minute runs.

Future uncertainty cannot be known in advance. For example, for the 15-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 15-minute forecast and the binding 5-minute forecasts.[147] While the advisory forecast is available for future periods, the 5-

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

minute forecast is not. Uncertainty calculation is to use historical data to forecast what the uncertainty might be. This allows for better preparation and adjustment in the market operations.

The calculation of uncertainty was adjusted on February 1 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).[148]

Calculating net load uncertainty

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[149] To understand this method, it is important to differentiate between regression and forecasting. Regression is about quantifying relationships in data. It identifies patterns in existing data sets. Forecasting, on the other hand, involves using these patterns to predict unknown future values.

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

Patterns in regression are essentially a formula. This formula shows the historical level of uncertainty for any given advisory forecast value. In simple terms, regression answers the question: if the advisory forecast was, for example, 10,000 MW, what was the level of uncertainty in the past? Expanding on this idea, plugging future advisory forecast values into the historical pattern can forecast uncertainty. This method assumes that the pattern between uncertainty and advisory forecasts that existed in the past will persist in the future.

The California ISO used quantile regression with input percentiles of 97.5 and 2.5. The regression method aims to find patterns at the extreme ends of samples. The forecast is then interpreted as a prediction interval, where future uncertainties are expected to fall within the upper and lower bounds with 95 percent probability.

The performance of this quantile regression is evaluated based on its accuracy and efficiency. The quantile regression method is designed to estimate the range of predictions. Therefore it is important to measure the coverage rate. The coverage rate indicates the percentage of realized uncertainty that falls within this range. The target coverage rate is 95 percent, meaning the expectation is that 95 percent of the realized uncertainty will be within the predicted range.

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148 For a detailed explanation of the mosaic quantile regression calculation and its performance, see the *Review of mosaic quantile regression for estimating net load uncertainty*, Department of Market Monitoring, Nov 20, 2023: https://www.caiso.com/Documents/Review-of-the-Mosaic-Quantile-Regression-Nov-20-2023.pdf

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

Additionally, an efficient model would produce a narrow prediction range while maintaining this 95 percent coverage rate. The efficiency is often measured by the average upward and downward requirement. These requirements represent the prediction range for uncertainty, with the upward requirement corresponding to the 97.5 percentile and the downward requirement corresponding to the 2.5 percentile uncertainty forecasts.

DMM has been testing and measuring the performance of this regression method. The first aspect examined the strengths of the patterns in historical data. DMM's technical report detailed the mosaic quantile regression, revealing that the pattern was inconsistent most of the time.[150] Other known issues in the mosaic quantile regression are outlined below.

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

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

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

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas in the pass-group for flexible ramping capacity procurement. This is based on the second run of the resource sufficiency evaluation (T-55) for interval 1 and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. Table 2.6 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

150 For detailed information about this report, please refer to the link below. The report tests the 15-minute uncertainty for the RSE pass-group only. DMM tested if the coefficient (representing the historical pattern, and used to predict uncertainty) is statistically different from zero. It was found that only 35 percent of the coefficients were statistically different from zero between February and September 2023. Link: https://www.caiso.com/Documents/Review-of-the-Mosaic-Quantile-Regression-Nov-20-2023.pdf

Table 2.6 Source of pass-group for calculating uncertainty and procuring flexible ramping capacity

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

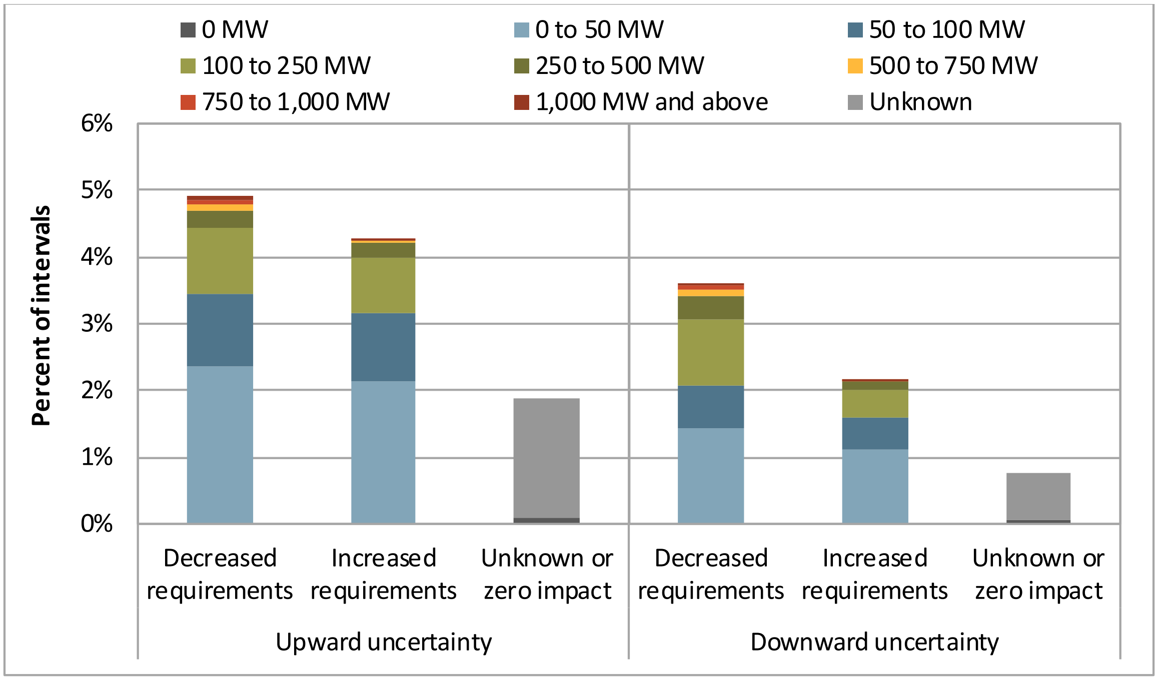
Using an inconsistent composition of balancing areas in the pass-group between the forecast and regression information can create significant swings in the calculated uncertainty for this group. For example, if you have a model to predict uncertainty based on forecast information of all but one balancing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

During about 16 percent of intervals between February and December, the composition of balancing areas in the pass-group used for regression information was inconsistent with the composition of balancing areas in the pass-group used for current forecast information. Figure 2.30 summarizes the impact of this inconsistency on pass-group uncertainty requirements in cases when the composition of balancing areas differed between the two sets of data. The figure shows the percent of intervals in which the market uncertainty requirements (with inconsistent balancing areas in the pass-group) were higher or lower than counterfactual uncertainty requirements with a consistent composition of balancing areas in the pass-group.[151] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

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

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

Figure 2.30 Impact of pass-group inconsistency on uncertainty requirements (February–December, 2023)



Results of quantile regression uncertainty calculation

Figure 2.31 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method, while the areas around the lines show the minimum and maximum amount over the month. The dashed red and yellow lines show the *average* histogram and mosaic thresholds, respectively, during the period.

Figure 2.32 shows the same information for 5-minute market uncertainty. Uncertainty in the 5-minute market reflects the error between the binding and advisory net load forecasts in the 5-minute market.

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

Figure 2.31 15-minute market pass-group uncertainty requirements (weekdays, February–December 2023)

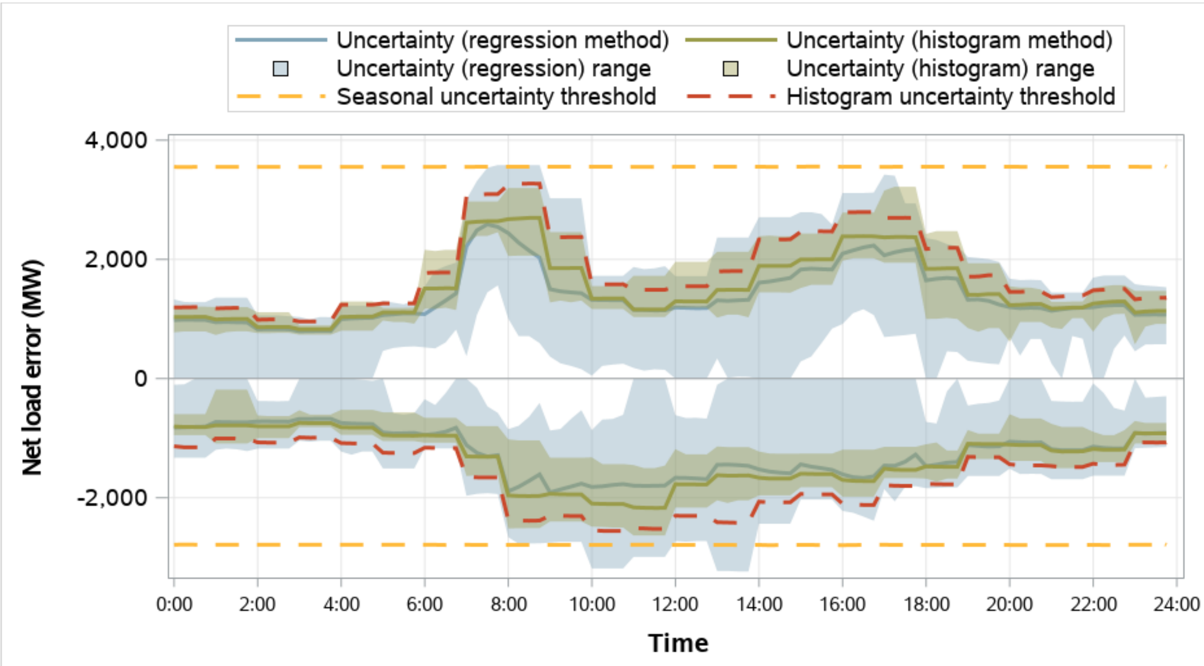


Figure 2.32 5-minute market pass-group uncertainty requirements (weekdays, February–December 2023)

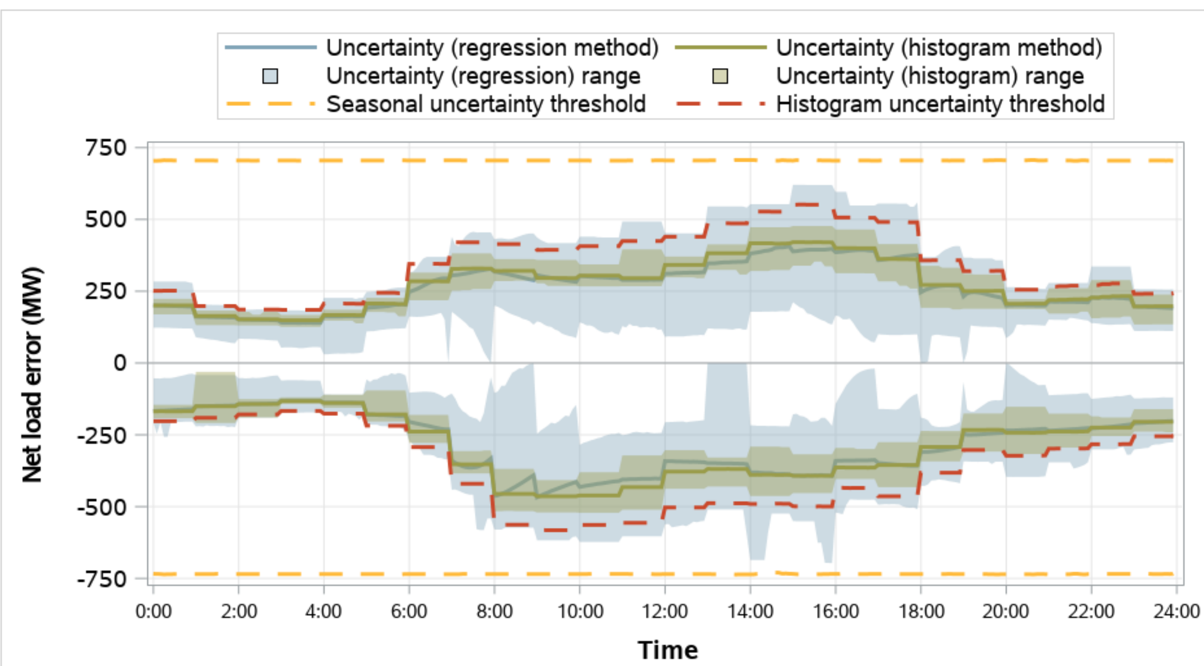


Table 2.7 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the 15-minute and 5-minute uncertainty calculated from the regression method was less than the histogram method for both directions.

Table 2.8 summarizes the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[152] The left side of the table summarizes the closeness of the actual net load error to the pass-group uncertainty requirements when the actual net load error was within (or covered) by the upward or downward requirements. The mosaic regression requirements covered between 96 and 97 percent of actual net load errors across all markets and directions. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 2.9 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was slightly more than the mosaic regression method, but by less than one percent across both directions and markets. Overall, the use of the regression method for procuring system-level flexible capacity resulted in lower requirements on average, with similar coverage in comparison to the histogram method. However, uncertainty calculated from the regression approach fluctuates more significantly, including periods in which requirements for pass-group uncertainty are either very low or zero.

Table 2.7 Average pass-group uncertainty requirements (February–December 2023)

Market	Uncertainty type	Pass-group uncertainty: Histogram	Mosaic	*Difference*
15-minute market	Upward	1,543	1,381	-162
	Downward	1,323	1,229	-94
5-minute market	Upward	271	260	-11
	Downward	289	279	-10

Table 2.8 Actual net load error compared to mosaic regression pass-group uncertainty requirements (February–December 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*: Percent of intervals	Average distance to requirement (MW)	*Actual net load error exceeds requirement*: Percent of intervals	Average amount (MW)
15-minute market	Upward	96.1%	1,333	3.9%	327
	Downward	96.2%	1,413	3.8%	442
5-minute market	Upward	97.0%	279	3.0%	78
	Downward	96.7%	282	3.3%	85

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

Table 2.9 Actual net load error compared to histogram regression pass-group uncertainty requirements (February–December 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	97.2%	1,481	2.8%	324
	Downward	97.1%	1,493	2.9%	446
5-minute market	Upward	97.3%	290	2.7%	85
	Downward	97.1%	291	2.9%	89

Threshold for capping uncertainty

Uncertainty calculated from the quantile regressions is capped by a ceiling that is calculated as the lesser of two 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 the previous 180 days.[153] The *seasonal* threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days, including all hours. If the regression methodology produces a higher outcome than either the histogram or the seasonal ceiling, the ceiling is used to set the requirement instead of the forecasts from the regression.

The uncertainty calculated from the quantile regression is also limited by a 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.

It is important to note the implication of the frequency of hitting the ceiling. This means that the upper or lower uncertainty forecast from the regression was higher than the top 1 percent of historical observations of realized uncertainty from the last six months. Given that the forecasted uncertainty is higher than the top 1 percent of observed uncertainty from the last six months, it may not be expected to occur frequently. However, it is possible that available future data may indicate high uncertainty in the future. If this future uncertainty is indeed very high, it makes sense for the regression method to pick up this extreme event and adjust accordingly, resulting in the regression output hitting the ceiling.

Figure 2.33 shows how often the ceiling and floor were applied for the flexible ramping product pass-group uncertainty requirement by hour in 2023, covering both the 15-minute and 5-minute uncertainties. Blue bars indicate instances where the requirement from the regression method exceeds either the histogram or seasonal ceiling, and yellow bars represent cases where the requirement hits the floor cap.

Overall, ceilings and floors combined applied around 10 percent of the time in the 15-minute market, and 9 percent in the 5-minute market. As shown in Figure 2.33, the uncertainty requirement was capped

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

much more frequently by the ceiling threshold than by the floor. The high frequency of the ceiling threshold being applied indicates that the regression model's forecasted uncertainty was consistently higher than the top 1 percent of historically observed realizations of uncertainty. The graph shows that in the 15-minute market, the ceiling threshold was applied most frequently during the morning and evening ramping hours.

Figure 2.34 shows the average 15-minute flexible ramping product uncertainty requirement by interval during 2023 before applying either the ceiling or floor thresholds. Therefore, this figure shows the requirements calculated by the mosaic quantile regression. The chart illustrates that the average downward requirement around 2 a.m. for the pass-group was negative 70,000 MW. Additionally, the *average* upward requirement was occasionally negative for particular intervals, especially during the evening ramping hours. This was mainly due to the less than 1 percent of intervals in which the regression produced extreme forecasts.

Figure 2.33 Frequency of thresholds applied to flexible ramping product pass-group uncertainty requirement by hour (February–December 2023)

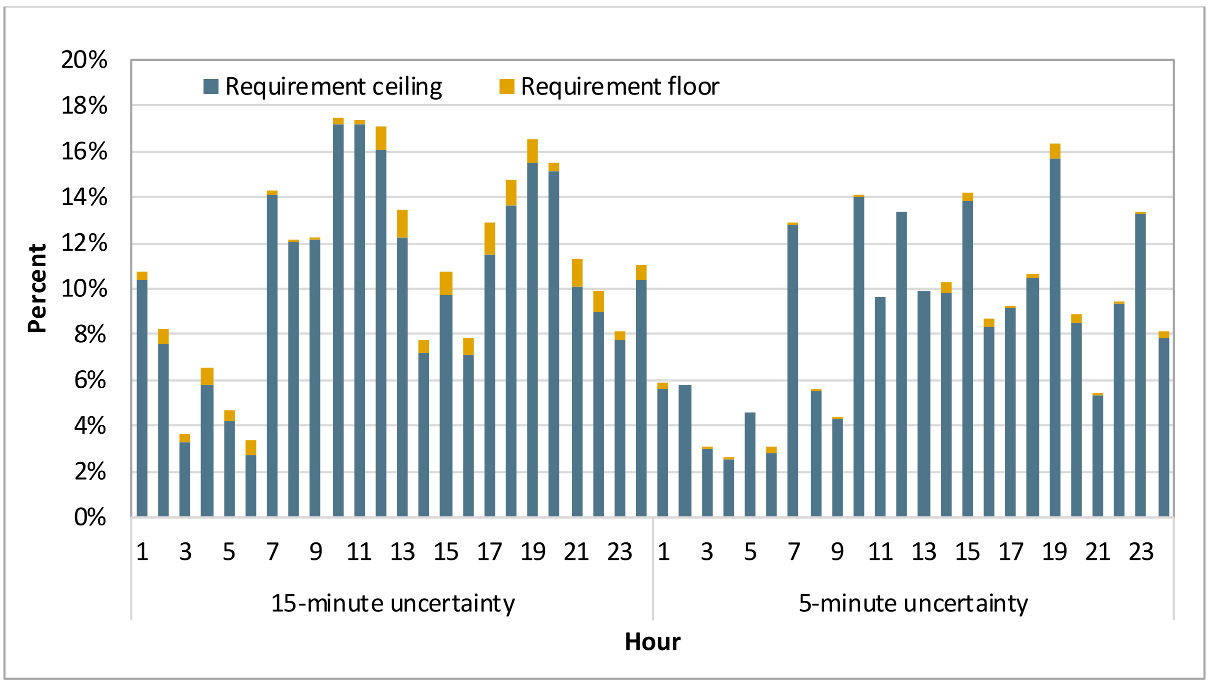
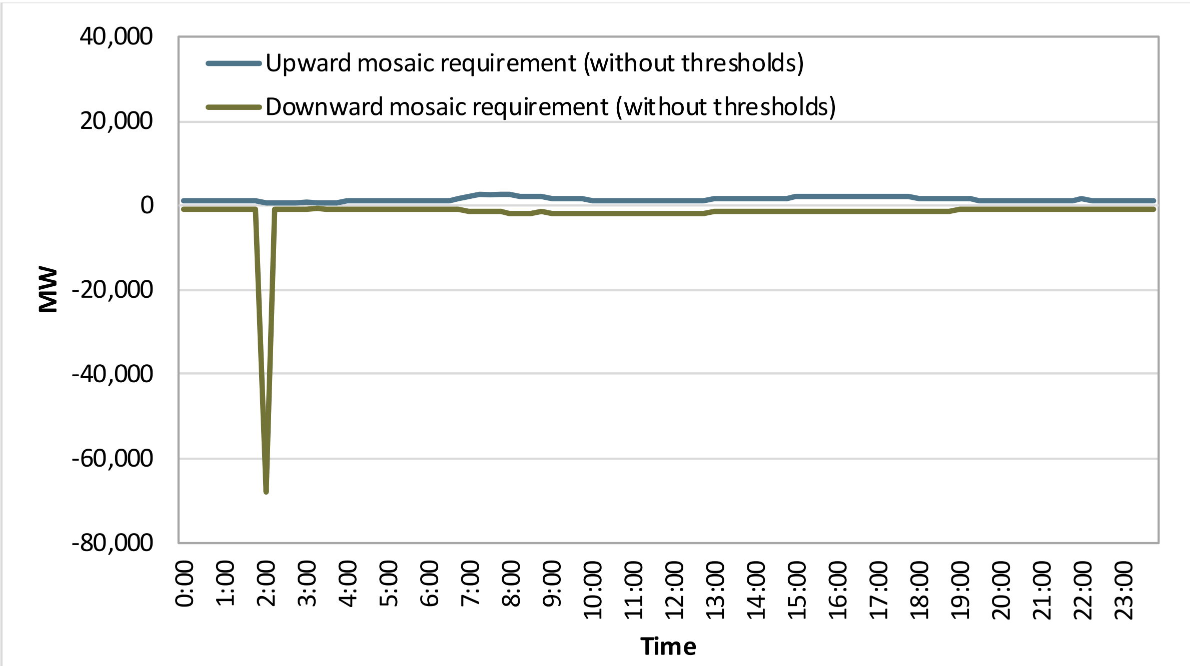


Figure 2.34 Average 15-minute flexible ramping product uncertainty requirement by interval (RSE pass-group, February–December 2023)

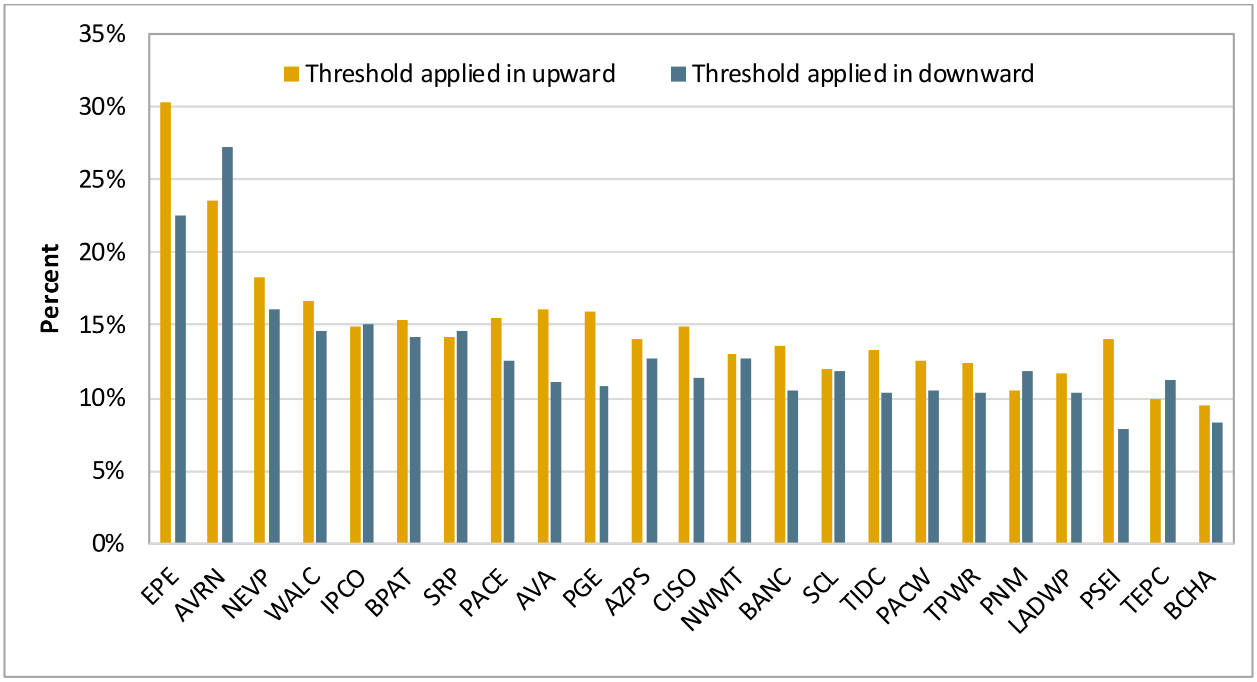


Beginning February 1, 2023, the ISO also began using the mosaic quantile regression method to calculate the uncertainty used in the resource sufficiency evaluation's flexible capacity test. Figure 2.35 shows the frequency of ceilings or floors applied for upward and downward uncertainty for individual BAAs during their resource sufficiency tests. Overall, an average of 13 percent of the uncapped regression outcomes either exceeded the ceiling or were below the floor. The majority of these incidences came from the requirement exceeding the ceiling. The percent of intervals in which the uncapped regression outcome was below the 0.1 MW floor was less than 1 percent on average over the balancing areas. The uncapped regression results for El Paso Electric and Avangrid had particularly high frequencies of exceeding the thresholds.

The implication of applying the ceiling threshold is that the uncertainty forecast from the mosaic regression method exceeded the top 1 percent of uncertainty observed in the last six months. As noted above, this occurred in roughly 13 percent of intervals for WEIM balancing areas' resource sufficiency evaluations. The top 1 percent of the previous 6 months represents the most extreme observations. New forecasts, even at the upper 95 prediction interval, are less likely to exceed this ceiling because such extreme events are rare and historical patterns tend to remain consistent. Therefore, unless there is a significant shift in underlying uncertainty conditions, the expected percentage that new forecasts would exceed the top 1 percent of the last six months is approximately 1 percent. An average of 13 percent, and even 30 percent for El Paso Electric, is extreme and may indicate that the regression is overestimating.

Some known issues of the mosaic quantile regression are detailed in DMM's special report.[154] The coefficients estimated with the quantile regression method were not statistically different from zero in most instances in DMM's replication. This indicates an inconsistent pattern between uncertainty and advisory forecasts, caused by the advisory forecasts lacking sufficient information to predict uncertainty. It could also result from a low sample size and seasonality effects. These factors likely contribute to the high frequency of the quantile regression producing an extremely high requirement, in excess of the ceiling threshold. The implication for the market was that the flexible ramping requirement and the uncertainty used in the resource sufficiency evaluations were frequently set at the ceiling, which represents the most extreme level of uncertainty over the previous six months.

Figure 2.35 Frequency of ceilings and floors applied for upward and downward uncertainty calculation in individual BAAs during resource sufficiency test (February–December 2023)



[154] *Review of mosaic quantile regression for estimating net load uncertainty*, Department of Market Monitoring, November 20, 2023: http://www.caiso.com/Documents/Review-of-the-Mosaic-Quantile-Regression-Nov-20-2023.pdf

3 Western Energy Imbalance Market

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO balancing area (CAISO) to participate in the California ISO real-time market. This chapter provides a summary of WEIM performance during 2023.

Key elements highlighted in this chapter include the following:

- **The Western Energy Imbalance Market continued to perform well**. The growth of the WEIM and increase in available transmission has increased economic transfers between balancing areas, displacing higher cost generation in favor of lower cost generation.
- **The Western Energy Imbalance Market continued to grow with the addition of four new participants in 2023.** Avangrid, El Paso Electric, and Western Area Power Administration – Desert Southwest joined the Western Energy Imbalance Market on April 5, 2023.
- **Total load across the Western Energy Imbalance Market footprint peaked on August 16, hour-ending 18 at over 130,000 MW** During this hour, 68 percent of load was from balancing areas outside the California ISO.
- **The California ISO balancing area restricted most WEIM transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 15.** CAISO area operators did not limit transfers in the 5-minute market. This modeling difference contributed to greater congestion and lower prices for many desert southwest balancing areas in the 15-minute market relative to the 5-minute market.
- **The transfer limitation had the intended effect of increasing hourly block imports into the CAISO area and decreasing hourly block exports out of the CAISO area to protect reliability during peak net load hours in late July through mid-August.** CAISO continued the transfer limitations through November 15, when it implemented software enhancements to better address hourly block export curtailments and to provide more accurate information on dispatchable capacity to operators. DMM has recommended that CAISO provide greater transparency on when and why it may implement these limitations in the future. DMM also recommends that CAISO work with stakeholders to consider other methods of achieving the intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and 5-minute markets.
- **Powerex and WAPA Desert Southwest also limited dynamic WEIM transfers to zero in at least one direction during a substantial number of 15-minute market intervals during 2023.** However, Powerex's 549 intervals and WAPA Desert Southwest's 487 intervals were significantly less than the CAISO area's 1,914 intervals. CAISO's average decrease in transfer capacity during each event was over 41,000 MW, but import transfers decreased by 751 MW on average in the interval following the transfer limitation. Powerex's and WAPA's average decreases in transfer capacity were around 50 MW and 5,200 MW, respectively, while their import transfers decreased by 47 MW and 165 MW, respectively, on average in the interval following a transfer limitation.
- **Powerex was very frequently import constrained relative to the CAISO balancing area because of WEIM transfer congestion—**during around 63 percent of 15-minute market intervals and 70 percent of 5-minute market intervals. This resulted in Powerex prices that were around $30/MWh higher because of WEIM transfer congestion.
- **The ISO implemented phase 2 (track 1) of resource sufficiency evaluation enhancements on July 1.** This included the implementation of Assistance Energy Transfers (AET), which give balancing areas that opt-in access to excess WEIM supply that may not have been available following a resource

sufficiency evaluation failure. Five balancing areas were opted into AET for some period of time during 2023.

- **Weighted 15-minute market greenhouse gas constraint prices averaged $10.99/MWh, while 5-minute market prices averaged $6.95/MWh.** Prices were similar to 2022, when they averaged $11.18/MWh and $5.84/MWh in the 15-minute and 5-minute markets, respectively. However, greenhouse gas constraint revenues decreased to $47.1 million in 2023 from $72 million in 2022. This was due largely due to the transfer limitations into the CAISO balancing area in the 15-minute market during peak hours of most of the second half of 2023.
- **About 70 percent of WEIM greenhouse gas compliance obligations were assigned to hydro resources**, similar to 2022.
- **Congestion revenues paid to non-CAISO WEIM balancing areas increased to $307 million in 2023**, up from $114 million in 2022.
- **Congestion rents and uplift from WEIM transfer constraints in the 5-minute market were misallocated between WEIM entities in some intervals between July 26 and December 11, 2023.** The ISO has corrected around $5 million of the incorrect allocation from trade date November 5. If this error had impacted all 5-minute market intervals, the maximum additional congestion rent that may have been impacted is about $19 million. However, it is not clear to DMM how many intervals were impacted by the error.

3.1 WEIM overview and continued expansion

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

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

The Western Energy Imbalance Market has expanded significantly since its implementation in November 2014. Table 3.1 shows the year that each current WEIM entity joined the market. On April 5, 2023, Avangrid, El Paso Electric, and Western Area Power Administration – Desert Southwest joined the Western Energy Imbalance Market, bringing the total number of participating WEIM entities (including the CAISO balancing area) up to 22.[155] Avangrid joined as the first generation-only entity with around 3,300 MW in participating capacity. WAPA Desert Southwest and El Paso Electric joined the WEIM with 2,300 MW and 2,000 MW of participating capacity, respectively.

Both the growth of the Western Energy Imbalance Market since 2015 and the increase in available transmission have increased economic transfers between balancing areas, displacing higher cost

155 PacifiCorp is counted as a single participating WEIM entity. PacifiCorp operates two balancing areas, PacifiCorp East and PacifiCorp West.

generation in favor of lower cost generation that can meet system-wide needs. Prices and transfers now highlight distinct daily and seasonal patterns that reflect regional supply conditions and transfer limitations.

Table 3.1 WEIM entities by implementation year

Year joined WEIM	WEIM entity	WEIM entity acronym
2014	PacifiCorp East/PacifiCorp West	PACE/PACW
2015	NV Energy	NEVP
2016	Arizona Public Service	AZPS
	Puget Sound Energy	PSEI
2017	Portland General Electric	PGE
2018	Idaho Power	IPCO
	Powerex	BCHA
2019	Balancing Authority of Northern California	BANC
2020	Salt River Project	SRP
	Seattle City Light	SCL
2021	Los Angeles Department of Water and Power	LADWP
	NorthWestern Energy	NWMT
	Public Service Company of New Mexico	PNM
	Turlock Irrigation District	TIDC
2022	Avista	AVA
	Bonneville Power Administration	BPA
	Tacoma Power	TPWR
	Tucson Electric Power	TEPC
2023	Avangrid	AVRN
	El Paso Electric	EPE
	Western Area Power Administration - Desert Southwest	WALC

3.2 Load and supply conditions in WEIM

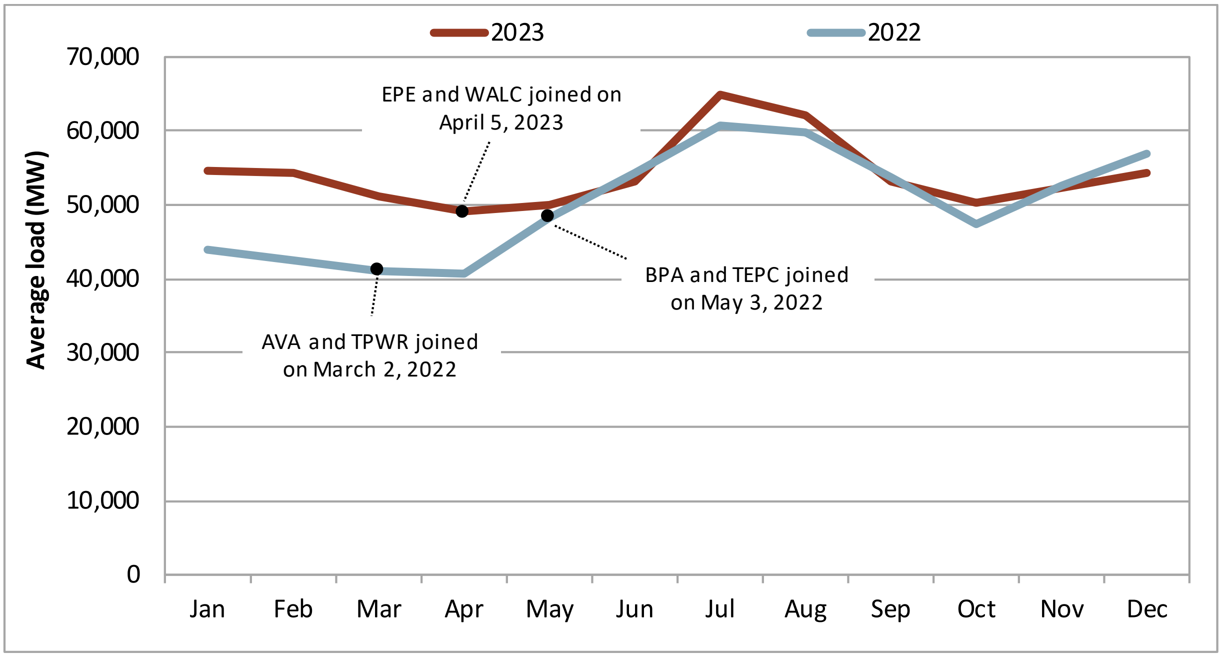
3.2.1 Load conditions

Total load served in the WEIM increased significantly in 2023 with the additions of new entities joining the market. During the year, average monthly load for non-CAISO WEIM areas peaked in July, at 64,906 MW.

Figure 3.1 shows the average load by month in the WEIM in 2023, compared to the previous year. This figure includes all non-CAISO WEIM areas. Peak average load in the WEIM generally occurs during the summer months of July and August, with a lower secondary peak in the winter from December to February. In 2023, average load reached 64,906 MW in July and 54,495 MW in January. This dual peak trend corresponds with the large WEIM footprint, as some areas see high loads in summer and others in winter.

Table 3.2 shows the load for each balancing area both during its individual peak during the year as well as during the WEIM system peak load hour.[156] The total hourly load across the WEIM footprint peaked on August 16, hour-ending 18, at 130,448 MW. During this hour, 68 percent of load was from non-CAISO WEIM areas. Generally, balancing areas in the Southwest peaked in mid-July and August, and balancing areas in the Pacific Northwest peaked in January and February.

Figure 3.1 Average WEIM load by month, excluding CAISO



[156] These are hourly metered amounts.

Table 3.2 System peak load by BAA

	Peak load		Load during WEIM system peak (16-Aug-23)	
BAA	Date	Load (MW)	Load (MW)	Percentage
AVA	15-Aug-23	2,093	2,061	1.6%
AZPS	15-Jul-23	8,081	7,192	5.5%
BANC	16-Aug-23	4,438	4,389	3.4%
BCHA	24-Feb-23	10,761	9,201	7.1%
BPAT	30-Jan-23	10,637	8,936	6.9%
CISO	16-Aug-23	41,730	41,730	32.0%
EPE	19-Jul-23	2,375	1,950	1.5%
IPCO	20-Jul-23	3,770	3,645	2.8%
LADWP	29-Aug-23	5,191	4,737	3.6%
NEVP	21-Jul-23	9,122	7,618	5.8%
NWMT	22-Feb-23	1,939	1,684	1.3%
PACE	17-Jul-23	9,343	8,877	6.8%
PACW	30-Jan-23	3,981	3,894	3.0%
PGE	16-Aug-23	4,524	4,453	3.4%
PNM	18-Jul-23	2,685	2,253	1.7%
PSEI	30-Jan-23	4,567	4,025	3.1%
SCL	30-Jan-23	1,693	1,400	1.1%
SRP	25-Jul-23	8,081	7,038	5.4%
TEPC	19-Jul-23	3,118	2,668	2.0%
TIDC	17-Aug-23	687	674	0.5%
TPWR	30-Jan-23	872	678	0.5%
WALC	26-Jul-23	1,621	1,345	1.0%
Total			**130,448**	

3.2.2 Participating capacity and generation

Figure 3.2 shows the total participating WEIM nameplate capacity from June 2019 through June 2024[157]. These amounts only reflect participating capacity and therefore do not include capacity from non-participating resources, which are neither bid nor optimized in the market. Since 2019, roughly 58 GW of capacity has been added to the Western Energy Imbalance Market, 23 percent of which was hydroelectric and about 38 percent natural gas. Since June 2023, WEIM nameplate capacity increased by around 7.6 GW, with around 87 percent of the additions coming from renewable and battery resources. Since June 2023, battery capacity has nearly tripled in the WEIM, adding around 2,000 MW. Among renewables, solar, wind, and hydroelectric capacity have increased 42 percent, 8 percent, and 5 percent, respectively, since June 2023.

Figure 3.2 Total WEIM participating capacity by fuel type and year (as of June 1, 2024)[158]

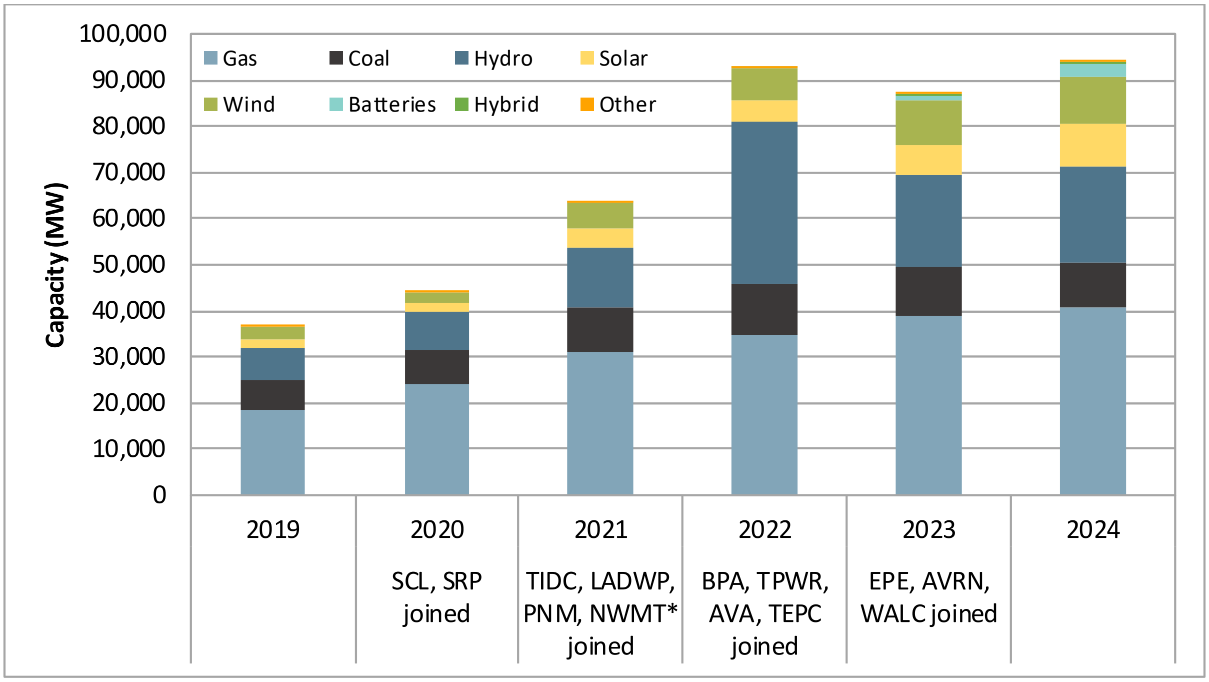


Figure 3.3 shows the fuel mix of participating capacity for each BAA in the WEIM as of June 1, 2024. PacifiCorp East (PACE) has the most nameplate capacity of the non-CAISO WEIM entities. Among the three newest entrants to WEIM, Avangrid Renewables (AVRN) has the most capacity, with a roughly 3,200 MW portfolio from mostly wind resources. WAPA Desert Southwest Region (WALC) and El Paso Electric (EPE) have around 2,300 MW and 2,000 MW of capacity, respectively.

158 BANC joined in two phases; the first was in April 2019 and the second was in 2021. NWMT joined shortly after June 1, 2021 but is included in the 2021 bar.

Figure 3.3 Fuel mix of WEIM participating capacity by BAA (as of June 1, 2024)

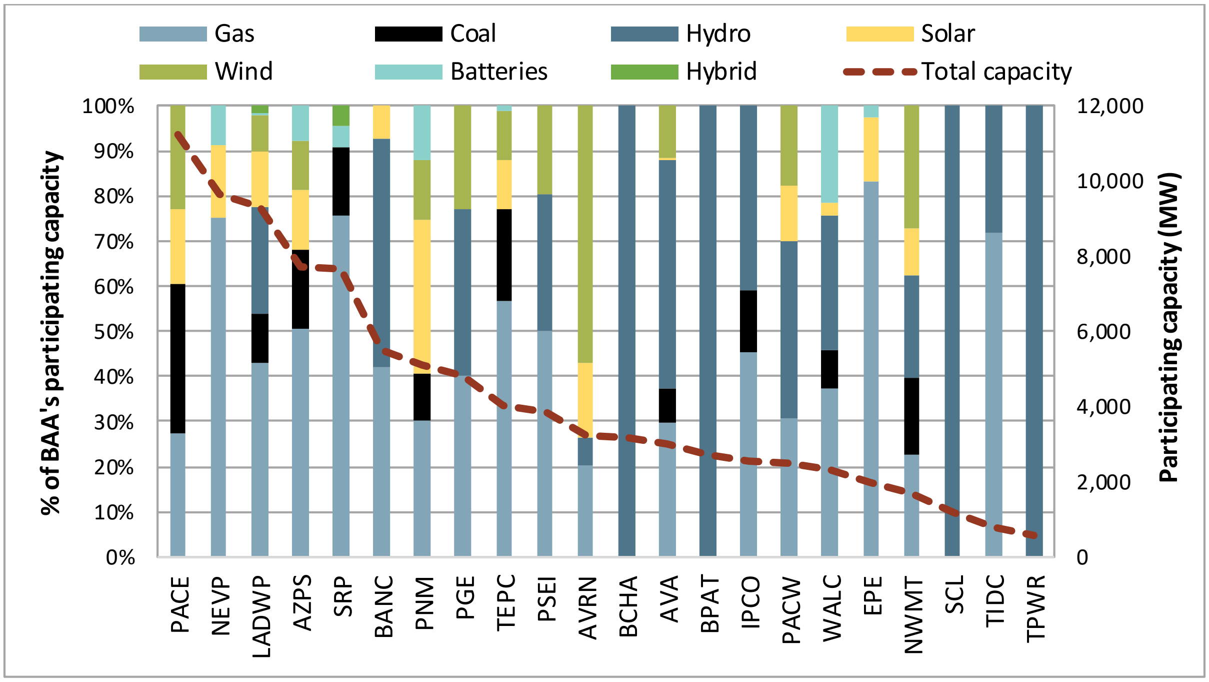


Figure 3.4 shows the change in capacity across WEIM BAAs by fuel type from June 2023 to June 2024. In the chart, positive values represent increased capacity, while negative values represent a decrease in capacity from last summer. Among the non-CAISO WEIM entities, Nevada Power Company (NEVP) and the Public Service Company of New Mexico (PNM) added the most capacity at around 2.4 GW and 1.4 GW, respectively, mostly consisting of batteries and solar. Most of the capacity additions in the WEIM BAAs are solar resources with 2.8 GW of new capacity. Natural gas and battery resource capacity increased by around 2 GW each. The majority of capacity decreases are from coal resources. Coal units co-owned by PacifiCorp East (PACE) and Idaho Power Company (IPCO), amounting to around 1.1 GW of capacity, underwent coal-to-natural gas conversion in 2024.

Figure 3.4 Capacity change of WEIM participating BAAs by fuel type

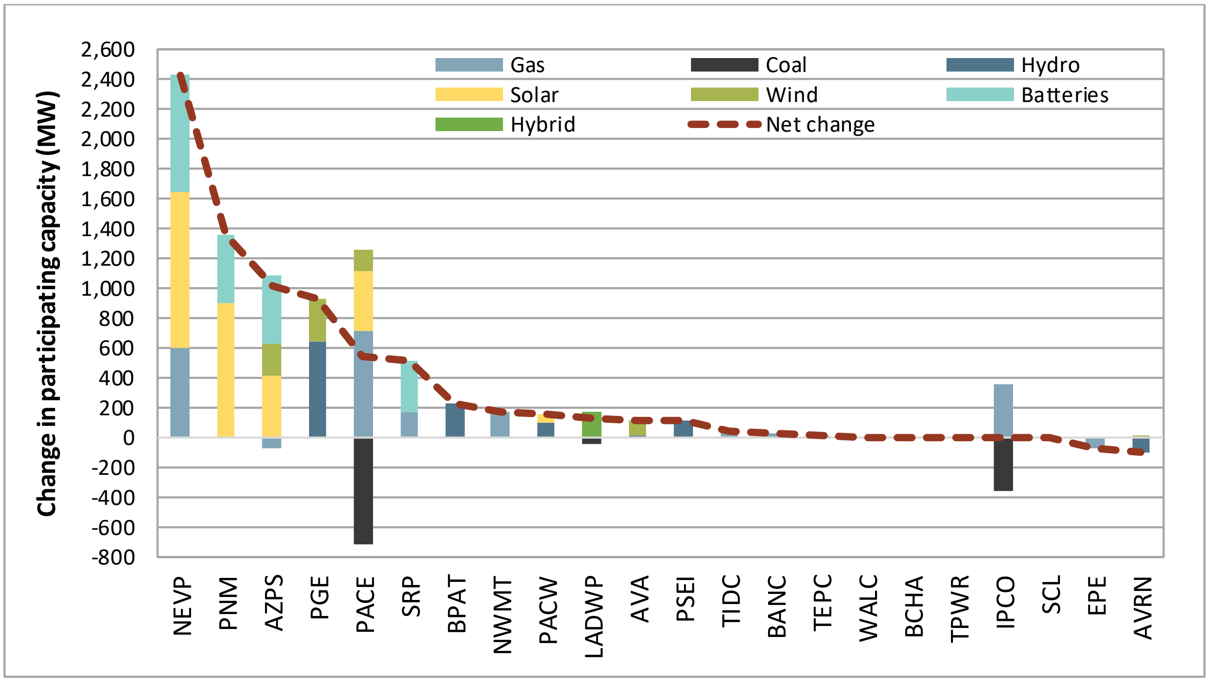


Figure 3.5 provides a profile of average monthly participating WEIM generation by fuel type. Figure 3.6 illustrates the same data on a percentage basis. These two figures show the following:

- Natural gas and coal were the largest sources of participating WEIM generation in 2023, representing 52 and 18 percent of total WEIM generation, respectively.
- The percent of total WEIM generation from renewables increased from around 14 percent in 2022 to 15 percent in 2023.[159]

Figure 3.7 shows average hourly participating WEIM generation by fuel type over the year.[160] In 2023, hour-ending 20 averaged the highest amount of WEIM generation at about 34,300 MW, while hour-ending 4 averaged the lowest at around 26,000 MW. Figure 3.8 shows the change in average hourly participating WEIM generation by fuel type from 2022 to 2023.[161] Generation from coal resources decreased by around 17 percent in 2023 compared to 2022. Natural gas generation saw significant increases in generation throughout all hours and increased 26 percent overall compared to last year. Wind and hydro-electric resources increased generation, on average, 21 percent and 13 percent respectively. Solar generation increased by an average of 26 percent across all hours, mainly coming from the middle of the day.

159 In this analysis, renewables are wind and solar generation, but do not include behind-the-meter generation such as rooftop solar.

160 Participating capacity includes resources that are bid-in and optimized in the real-time market. These charts therefore show lower values than total capacity, which also includes non-participating resources.

161 In this chart, positive values represent higher average hourly generation by a fuel type during the hour, while negative values represent a decrease in hourly generation.

Figure 3.5 Average monthly participating WEIM generation by fuel type in 2023

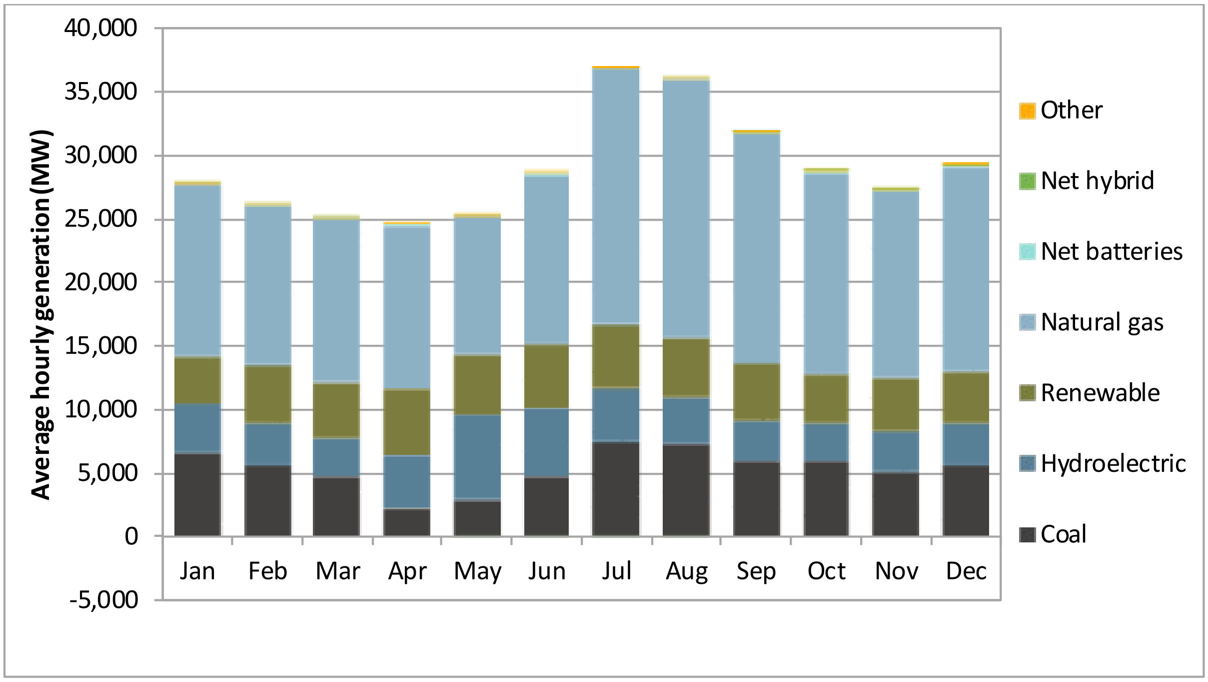


Figure 3.6 Average monthly participating WEIM generation by fuel type in 2023 (percentage)

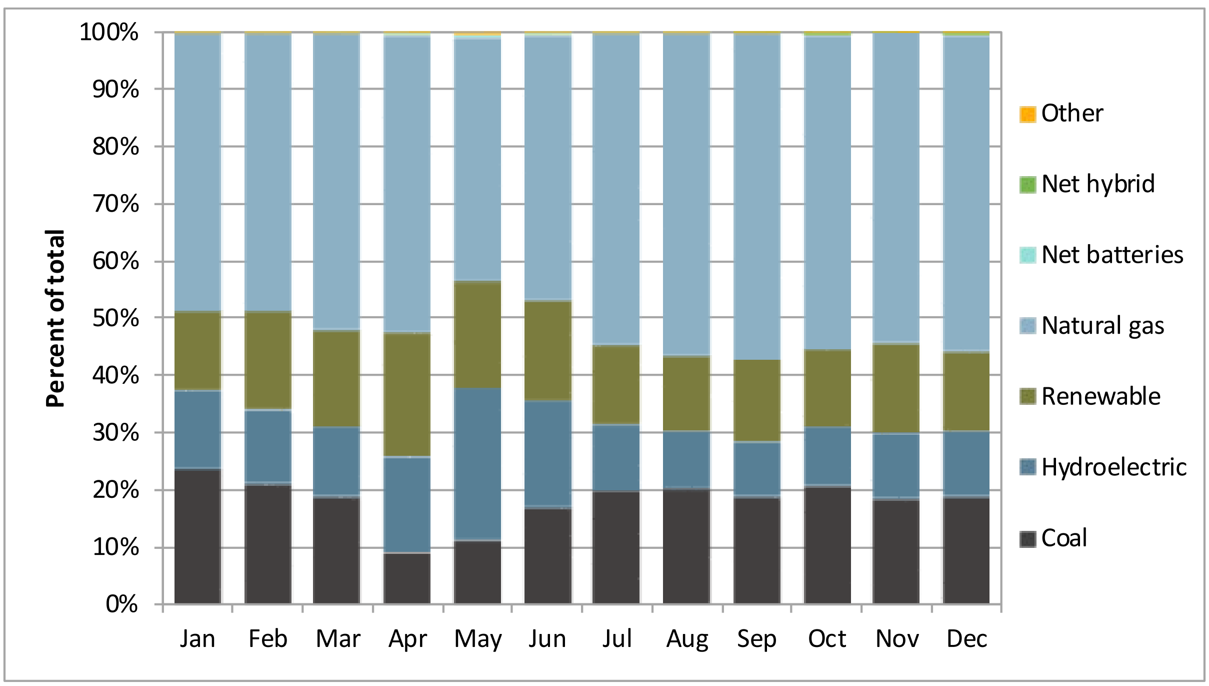


Figure 3.7 Average hourly participating WEIM generation by fuel type (2023)

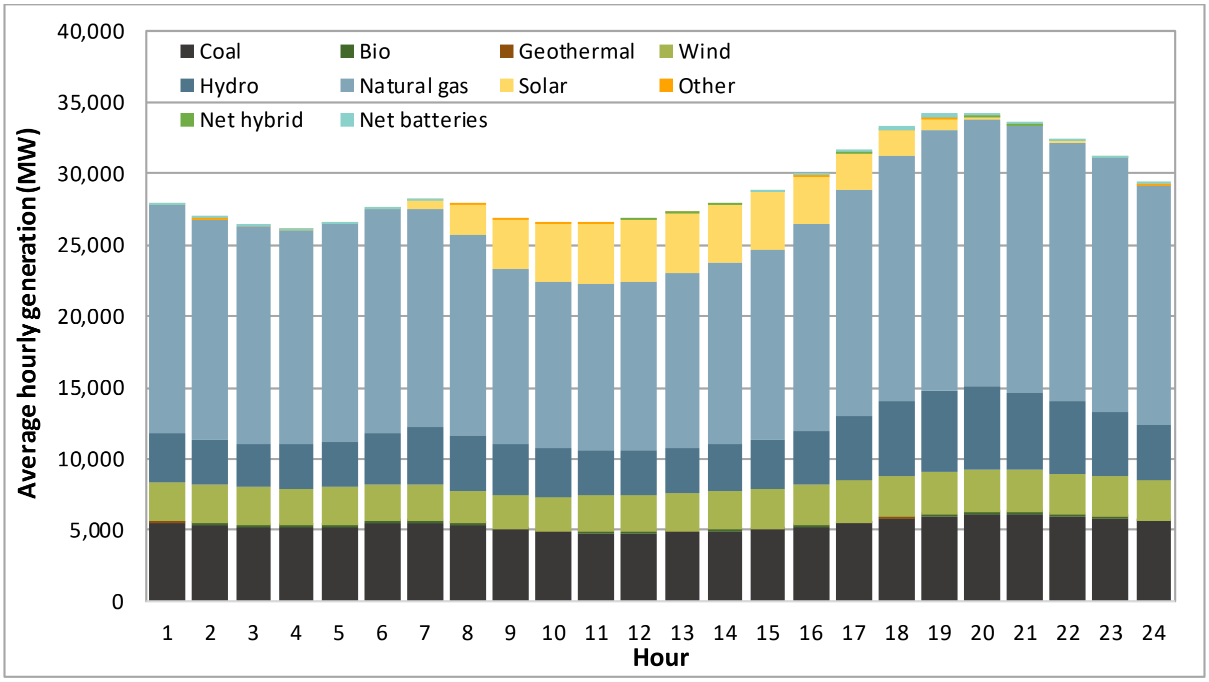
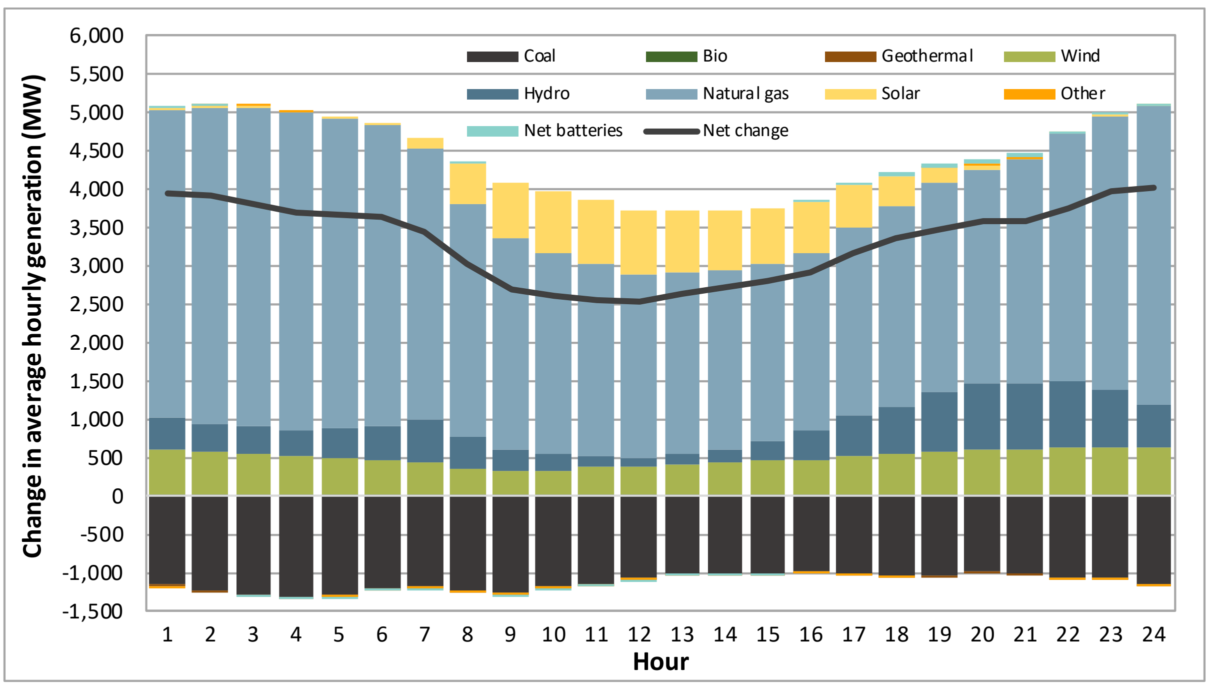


Figure 3.8 Change in average hourly participating WEIM generation by fuel type (2022–2023)



3.3 WEIM transfers, limits, and congestion

One of the key benefits of the Western Energy Imbalance Market is the ability to transfer energy between 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 also constrained by *transfer limits* that are made available by the WEIM entities to optimally transfer energy between areas.

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 subset of transfers (primarily between the Pacific Northwest areas and the CAISO area) that are only optimized in the 15-minute market.

3.3.1 Limitation of WEIM transfers to the CAISO balancing area

On July 26, CAISO balancing area operators began limiting WEIM import transfers into the CAISO balancing area each day during the peak net load hours. This limitation was put in place for the hour-ahead and 15-minute markets, to mitigate the risk during the critical hours that internal generation and hourly-block intertie schedules might be displaced by WEIM imports that may not materialize in real-time. This limitation typically lasted five hours each day and continued through November 15, 2023. Additional details on this action as well as its impact on the market are described in this section.

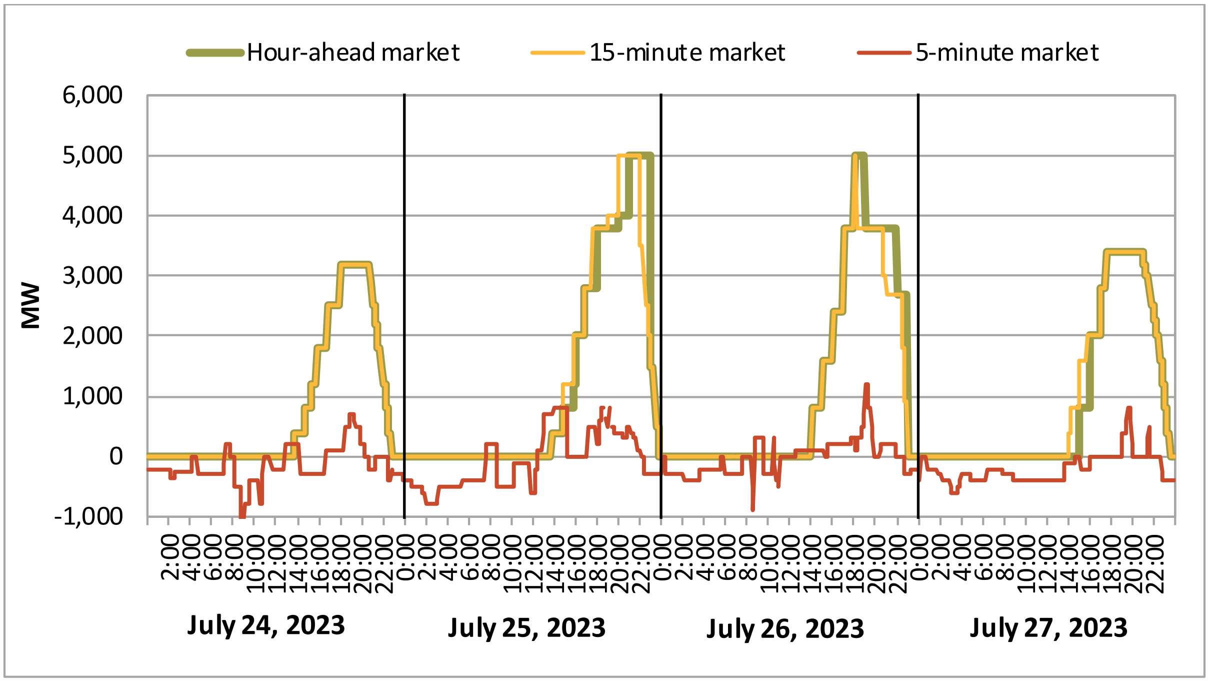
Beginning of WEIM transfer limitation and impact during the summer

The hour-ahead scheduling process (HASP) produces an optimized solution for four 15-minute intervals in the upcoming hour. It is included as part of a special run of the real-time unit commitment process that starts approximately 71.5 minutes prior to the hour. The majority of CAISO balancing area intertie schedules must be scheduled in hourly blocks, and HASP is the final opportunity for these to be optimized in the market. These schedules are optimized against the forecasted load used as an input in the hour-ahead market, as well as the generation dispatches and WEIM transfers produced in the hour-ahead market run across the WEIM footprint. While the hourly block intertie schedules produced by the hour-ahead market are binding schedules, the generation dispatches and WEIM transfers are only advisory schedules.

Operators can modify the load forecast used in the market through load conformance adjustments. In the CAISO balancing area, these adjustments are routinely used in the hour-ahead and 15-minute scheduling processes to increase capacity to address uncertainty that can materialize around net load ramping periods. Load conformance in the 5-minute market is then typically much lower.

Figure 3.9 shows CAISO area load conformance adjustments between July 24 and July 27. When operators increase the load conformance in HASP, this can be met by a combination of factors including increased commitment or dispatch of internal resources, increased hourly imports, decreased hourly exports, and changes to advisory WEIM transfers. To the extent that the increased load conformance is met by advisory WEIM imports, these transfers may not materialize in the 5-minute market due to either lower levels of load conformance or changes to projected supply conditions in the surrounding WEIM system.

Figure 3.9 ISO area load conformance adjustments (July 24–27)



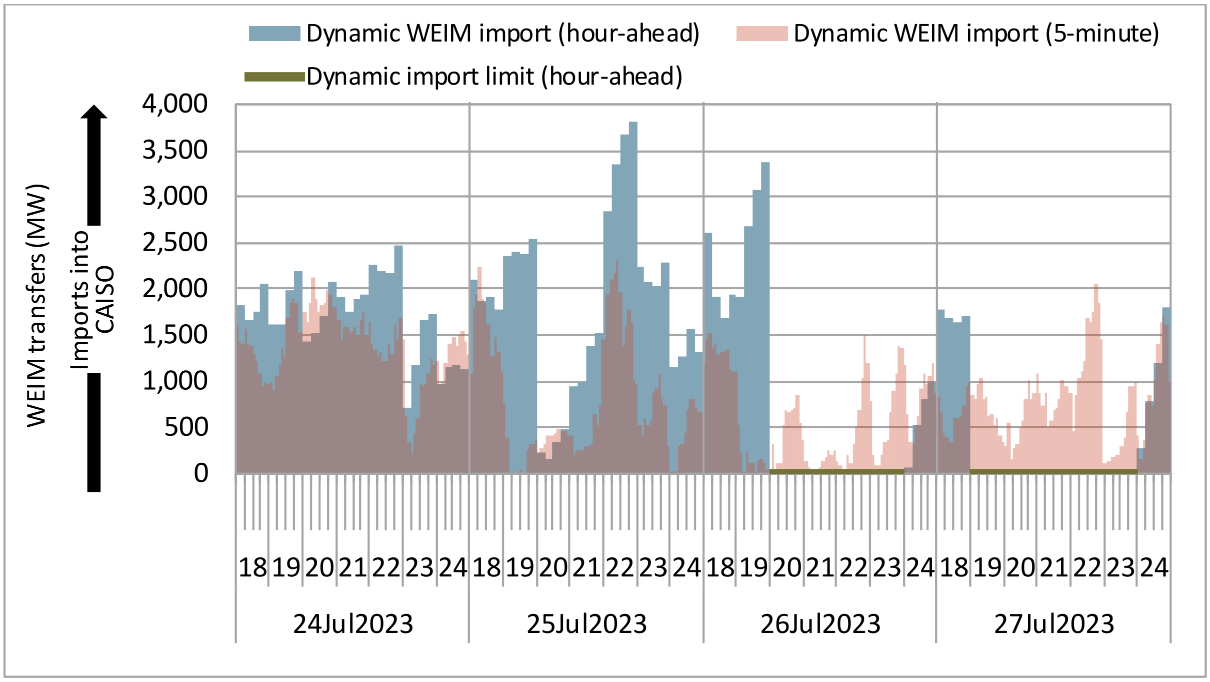
Starting on July 26, during peak hours each day, CAISO balancing area operators limited dynamic WEIM import transfers into the CAISO balancing area in the hour-ahead and 15-minute markets to zero.[162] The intent of this action was to limit advisory WEIM imports that might offset a significant portion of the demand forecast or load conformance. This would instead allow increased load conformance to be served by internal generation and intertie schedules. As a result, the CAISO balancing area would have a reduced reliance on imports from the WEIM to meet internal demand, and its system would be better positioned to address uncertainty that may materialize. In the 5-minute market, the limit on WEIM transfers was lifted, allowing transfers to freely and optimally flow between the CAISO balancing area and neighboring balancing areas.[163]

Figure 3.10 shows dynamic WEIM imports into the CAISO balancing area in the evening hours between July 24 and July 27. The blue bars show advisory WEIM imports in the hour-ahead market. The red bars show WEIM imports in the 5-minute market. The green line shows the transfer lock periods in which imports were limited to zero in the hour-ahead market. Outside the lock periods, WEIM transfers into the CAISO balancing area in the hour-ahead market significantly exceeded what was realized in the 5-minute market in most intervals. During the lock periods, hour-ahead (and 15-minute market) transfers into the CAISO balancing area were limited to zero, but substantial 5-minute market imports were still able to flow in those peak evening hours.

[162] Static WEIM transfers were not impacted by the limit put in place in the peak hours starting July 26. Dynamic export transfers were also not impacted.

[163] Subject to normal WEIM transmission limitations.

Figure 3.10 Dynamic WEIM imports into ISO area (evening hours, July 24–July 27)



Impact on California ISO balancing area supply and demand during the summer

When the WEIM imports into the California ISO balancing area are limited to zero in the hour-ahead market, the optimization generally balances the total load (including any load conformance) mostly from a combination of (1) increased internal generation, (2) increased hourly-block imports, (3) decreased WEIM exports, and (4) decreased hourly-block exports. This section summarizes supply and demand differences before and after the limitation on WEIM imports into the CAISO balancing area.

Figure 3.11 shows hour-ahead supply (S) and demand (D) during the peak hours of July 26. On this day, WEIM imports (dashed gray bars) decreased by over 3,000 MW following the WEIM import lock.[164] This was mostly answered with a reduction of around 2,900 MW from hourly block exports (blue bars).

Figure 3.12 summarizes supply and demand components during the highest load days in the interval immediately before and after the WEIM transfer lock.[165] On average over these peak summer days, WEIM imports decreased by over 1,600 MW in the interval immediately following the WEIM transfer limitation. This loss was absorbed in the market through changes to other components. Hourly-block exports decreased by over 1,100 MW. Hourly-block imports increased by around 420 MW.

164 WEIM transfers in these figures include both dynamic and static WEIM transfers. Static WEIM transfers were not impacted by the limit put in place in the peak hours starting July 26. WEIM imports are therefore shown above zero following the transfer lock in these figures.

165 This figure is an average over the nine days during the summer of 2023 in which the ISO load forecast reached 40,000 MW or more and the dynamic WEIM imports were limited: July 26, July 27, August 14, August 15, August 16, August 17, August 28, August 29, and August 30.

Figure 3.11 CAISO area hour-ahead supply and demand (peak net load hours, July 26, 2023)

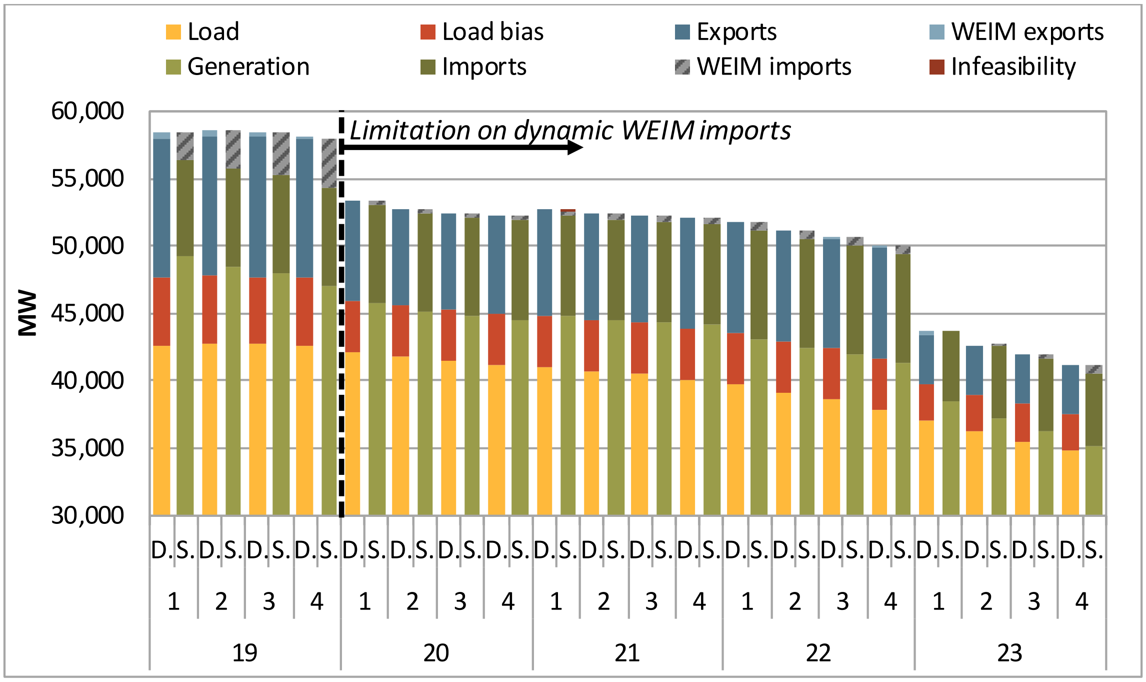
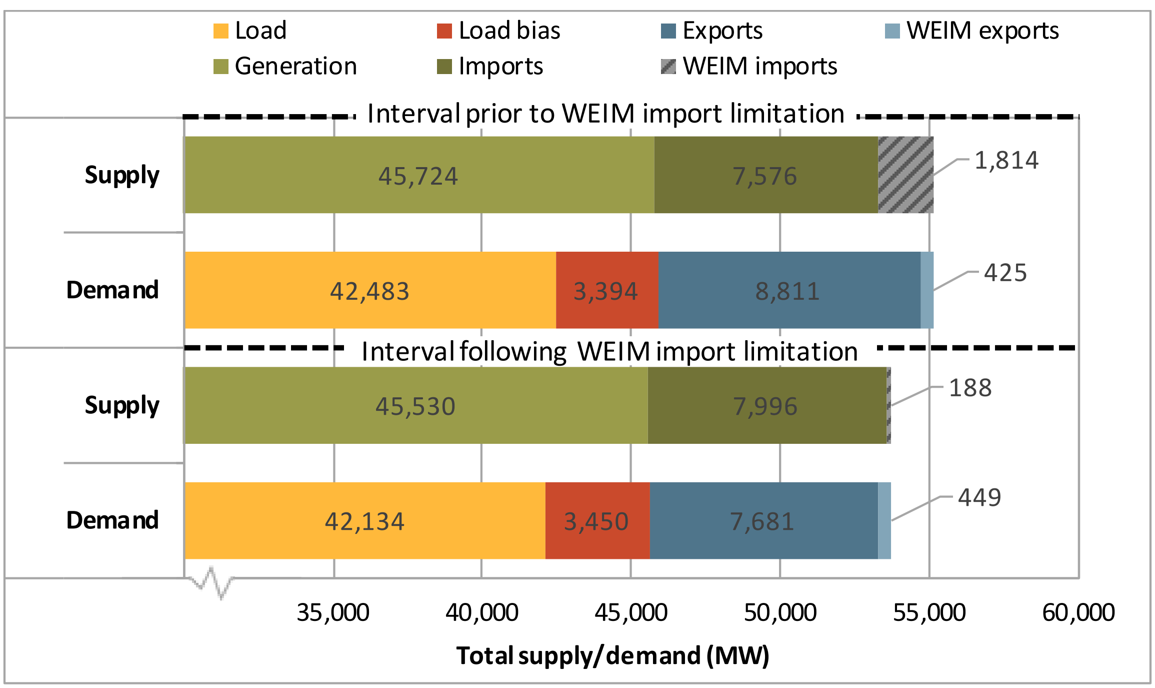


Figure 3.12 Average hour-ahead CAISO balancing area supply and demand in interval before and after WEIM import limitation (summer 2023 peak days)



Impact on WEIM transfer flows during the summer

The limitation on WEIM imports into the CAISO balancing area impacted transfer patterns throughout the WEIM footprint. Figure 3.13 shows average hour-ahead WEIM exports out of each area in the interval immediately prior to the WEIM import lock during the same highest summer load days.[166] Figure 3.14 instead shows average exports in the interval immediately following the WEIM import lock.[167] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area. Each small tick is 100 MW and each large tick is 500 MW.

As shown in these figures:

- **The amount of exports from the Desert Southwest region decreased, while transfers in the Intermountain West region increased significantly.** With the CAISO balancing area no longer able to import cheaper excess energy from the Desert Southwest region, excess energy from these balancing areas instead generally flowed north to PacifiCorp East and Idaho Power. Some of this energy was moved onward to balancing areas in the PacifiCorp Northwest region.

- **As expected, CAISO balancing area imports through the WEIM decreased significantly, by over 1,600 MW on average.** The CAISO balancing area continued to transfer out around 400 MW on average to Powerex and BANC on these peak days.

166 These figures exclude the fixed bilateral transfers between WEIM entities (base WEIM transfer schedules) and therefore reflect optimized flows in the market. Optimized dynamic and static WEIM transfers are included here. Average WEIM transfer paths less than 50 MW are excluded for readability.

167 Static WEIM imports into the CAISO balancing area (mostly from Portland General Electric and PacifiCorp West) were not impacted.

Figure 3.13 Average hour-ahead WEIM exports in interval prior to WEIM import limitation (summer 2023 peak days)

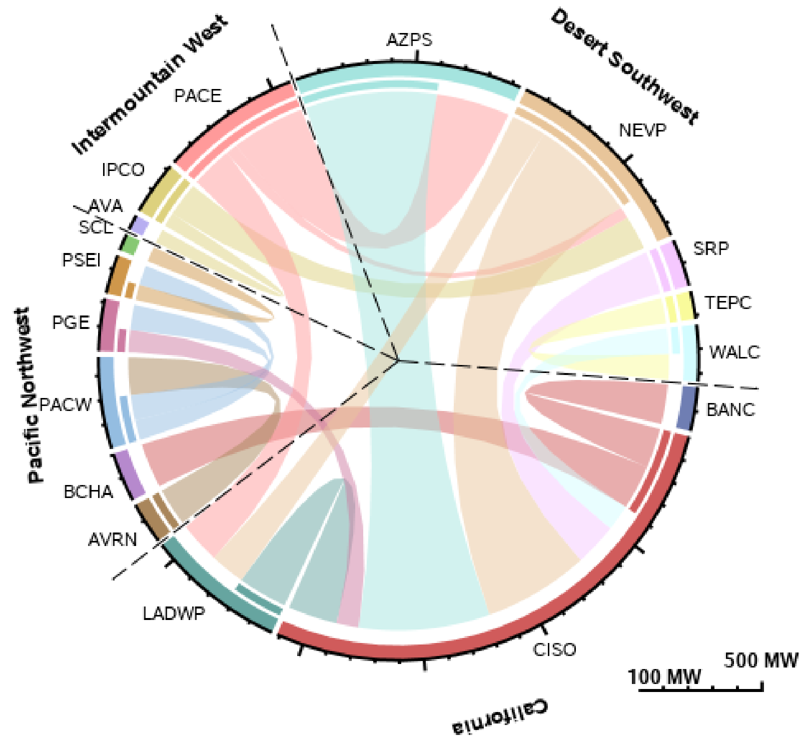
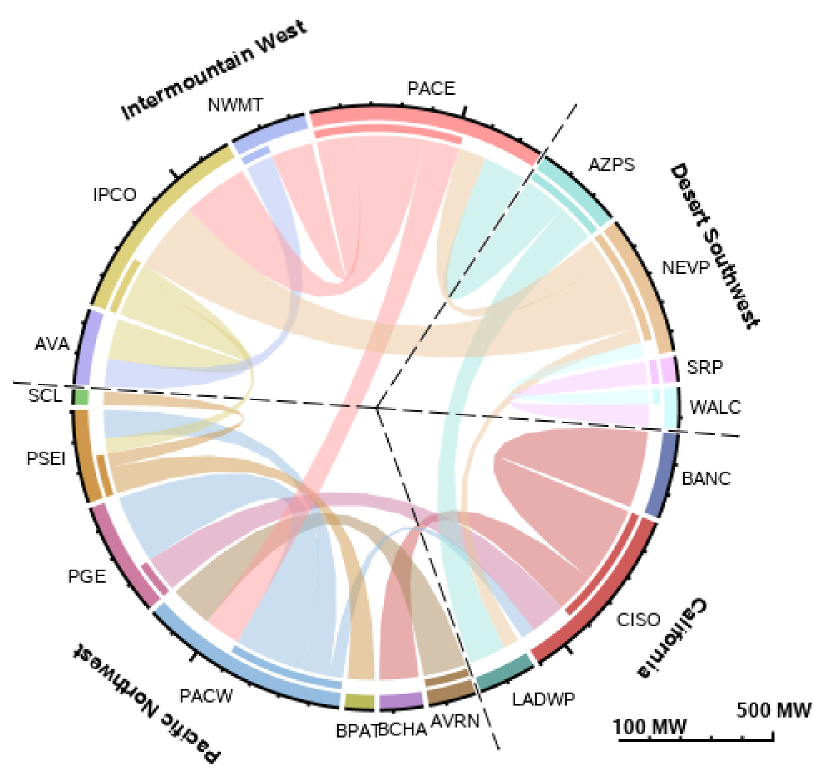


Figure 3.14 Average hour-ahead WEIM exports in interval following WEIM import limitation (summer 2023 peak days)



Impact of WEIM transfer limitation following the summer

The limitation of WEIM imports into the CAISO area continued through November 15, 2023. DMM understands that the transfer limitations were needed in July and August for reliability reasons. CAISO has explained that it continued the transfer limitations through November 15 because that is when it implemented software enhancements to better address hourly block export curtailments and to provide more accurate information on dispatchable capacity to operators.[168] DMM has recommended that CAISO provide greater transparency on when and why it may implement these limitations in the future. DMM also recommends that CAISO work with stakeholders to consider other methods of achieving the intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and 5-minute markets.

Following the summer, the WEIM import limitation typically occurred between hours 18 and 22 during October and between hours 16 and 20 during November (until its conclusion on November 15).[169] Figure 3.15 compares CAISO area supply and demand components during the WEIM import limitation intervals that occurred in the first half of November with the same hours in the second half of November (without the WEIM import limitation in place).[170] Both overall supply and overall demand in the absence of WEIM transfers were very similar in these two periods. Therefore, the primary outcome of limiting transfers in the hour-ahead market was reducing WEIM transfers flowing through the CAISO balancing area.

Figure 3.16 summarizes the hour-ahead supply and demand components on November 15 and November 16—at the end of the practice of limiting WEIM imports into the California ISO area during the peak hours. On November 15, with the import limitation in place, the following outcomes occurred on average, relative to the same hours on November 16:

- WEIM imports were 550 MW less while combined load and load bias were 140 MW lower.
- Internal generation was around 180 MW higher.
- Hourly-block exports were around 400 MW lower while hourly-block imports were also around 440 MW *lower*.
- WEIM exports were 270 MW lower.

In comparing these days, the limitation on WEIM imports on November 15 does not appear to have resulted in a substantial increase in internal generation or net hourly block imports into the CAISO balancing area. The ISO has explained that it stopped the transfer limitations after implementing enhancements to system software to better address export self-schedules that declined hour-ahead market curtailments. However, system conditions that may have necessitated curtailing hourly block exports in the hour-ahead market did not arise during October and the first half of November.

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168 *Market Performance and Planning Forum – Q2*, CAISO, June 27, 2024, p. 111: https://www.caiso.com/documents/presentation-market-performance-planning-forum-jun-27-2024.pdf

169 On the day of the solar eclipse, October 14, 2023, the WEIM import limitation was also put in place between hours 9 and 13.

170 WEIM imports in these figures include both dynamic and static WEIM transfers. Static WEIM transfers were not impacted by the limit put in place in the peak hours. WEIM imports are therefore shown above zero during the WEIM transfer lock intervals.

Figure 3.15 Average hour-ahead CAISO balancing area supply and demand with and without WEIM import limitations (November, hours 16 to 20)

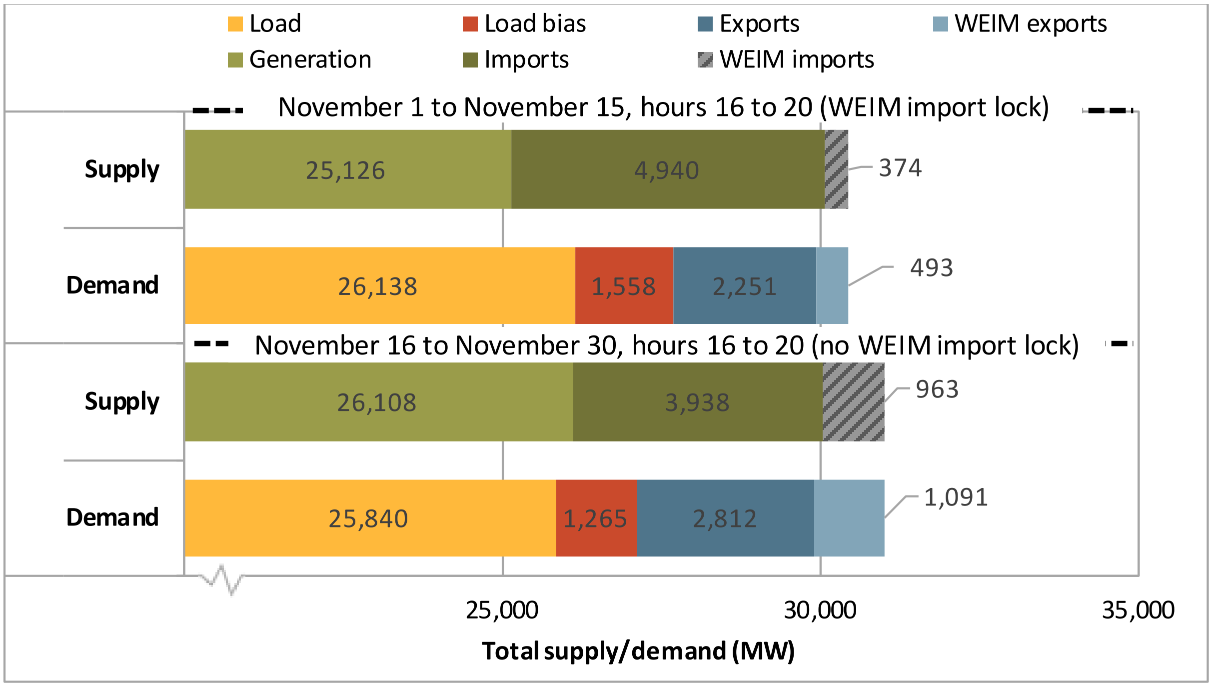
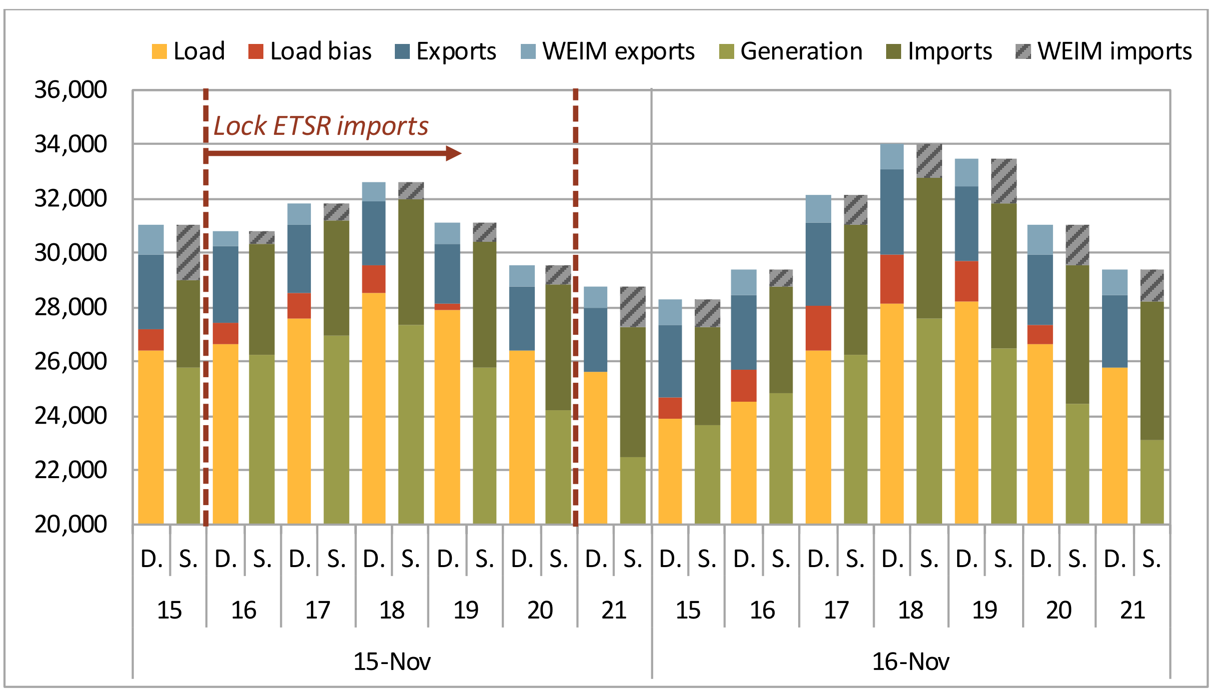


Figure 3.16 CAISO area hour-ahead supply and demand (peak hours, November 15–16, 2023)



Use of transfer limitation throughout the WEIM

All WEIM entities have the ability to limit transfers to manage reliability in their system. This section summarizes events in which a balancing area has decreased participation in the WEIM by reducing total transfer limits for either imports or exports to zero. As discussed in the sections above, the CAISO balancing area limited WEIM imports to zero in the peak hours between July 26 and November 15. Here, the limit on all dynamic import WEIM transfers were simultaneously set to zero in only the hour-ahead and 15-minute markets. WEIM entities also have the ability to manage individual WEIM transfer limits. They can also manage a reliability situation internally by initiating a Market Isolation. This process will lock the WEIM transfers to zero (or to base schedules) while allowing the market to still produce optimized dispatch of internal resources.

Table 3.3 summarizes all 15-minute intervals in 2023 in which total dynamic WEIM transfers were limited to zero in at least one direction.[171] A single event is defined as one or more consecutive intervals with these conditions. The table shows the average length of each of these events, as well as the average change in the WEIM transfer limits and flows in each event (from the interval immediately before transfers were limited to zero, to the next interval).

Table 3.4 provides additional data for the same 15-minute intervals. First, the table shows the percent of these limitation intervals in which either only imports, only exports, or both directions were set to zero. Next, the table shows the percent of corresponding intervals in the 5-minute market that were also limited. Of note, there can be a timing delay between initiating and ending a transfer limitation, such that a transfer limitation intended for both markets will not always align in the corresponding intervals of both markets. In other cases, the underlying conditions that necessitated the transfer limitation were resolved prior to the 5-minute market.

The CAISO balancing area limited dynamic WEIM transfers to zero (in at least one direction) more frequently than other WEIM entities in 2023—during over 1,900 intervals (or 475 hours) in 113 days. The magnitude of transfer capacity that was limited in the CAISO balancing area was also significantly greater than other WEIM entities, at around 41,700 MW on average in the import direction. The CAISO balancing area also only limited dynamic WEIM *imports* to zero and only in the hour-ahead and 15-minute markets, whereas other WEIM entities generally tended to limit transfers in both directions and all markets during a reliability event. On average, WEIM imports into the CAISO balancing area decreased by 751 MW in the interval following the transfer limitation.

Powerex had almost 550 intervals in which dynamic WEIM import limits were set to zero. Powerex typically has very limited *dynamic* WEIM import capacity into the balancing area (typically 50 MW from Puget Sound Energy). In some intervals, the limit on this WEIM transfer is reduced to zero such that the interval is flagged accordingly for this summary. WAPA Desert Southwest had almost 490 15-minute intervals (or around 122 hours) in which WEIM transfers were limited to zero in both directions.

[171] This summary captures intervals in which the sum of transfer limits on individual dynamic WEIM transfer resources for a balancing area is zero in at least one direction. This summary is not impacted by any resource sufficiency evaluation failure that may impact total transfer capacity.

Table 3.3 Summary of dynamic WEIM transfer limitation to zero in at least one direction (2023)

Balancing area	Total intervals (15 min. intervals)	Total events	Average length of event (15 min. intervals)	Event start average decrease in … Transfer limits Imports	Event start average decrease in … Transfer limits Exports	Event start average decrease in … Transfer flows Imports	Event start average decrease in … Transfer flows Exports
California ISO	1,914	113	16.9	41,735	N/A	751	N/A
Powerex	549	44	12.0	50	48	47	4
WAPA DSW	487	9	54.1	5,227	5,368	165	135
BPA	96	18	5.3	552	809	113	48
NV Energy	47	2	23.5	5,479	5,028	36	133
Seattle City Light	27	3	6.3	70	80	27	8
Avista	27	7	3.9	436	647	69	26
Tacoma Power	21	5	3.8	256	149	88	29
PacifiCorp East	18	2	1.0	3,514	1,400	0	222
El Paso Electric	15	2	7.5	90	88	0	54
Portland Gen. Elec.	14	2	7.0	322	595	115	4
Puget Sound En.	4	1	4.0	707	767	118	145
PSC of New Mexico	4	1	4.0	826	942	95	168
PacifiCorp West	2	1	2.0	1,006	1,601	0	171
Arizona Publ. Serv.	1	1	1.0	6,729	7,603	526	792
Tucson Elec. Pow.	1	1	1.0	2,801	3,146	0	2
Avangrid	1	1	1.0	641	508	0	152

Table 3.4 Summary of dynamic WEIM transfer limitation to zero in at least one direction (2023)

Balancing area	Total intervals (15 min. intervals)	Percent of limitation intervals by direction: Both directions	Imports only	Exports only	Percent of corresponding intervals also limited in the 5-minute
California ISO	1,914	0%	100%	0%	0%
Powerex	549	1%	95%	4%	52%
WAPA DSW	487	100%	0%	0%	96%
BPA	96	100%	0%	0%	63%
NV Energy	47	100%	0%	0%	91%
Seattle City Light	27	41%	30%	30%	93%
Avista	27	85%	15%	0%	72%
Tacoma Power	21	90%	0%	10%	48%
PacifiCorp East	18	11%	0%	89%	81%
El Paso Electric	15	100%	0%	0%	64%
Portland Gen. Elec.	14	100%	0%	0%	71%
Puget Sound En.	4	100%	0%	0%	33%
PSC of New Mexico	4	100%	0%	0%	100%
PacifiCorp West	2	100%	0%	0%	50%
Arizona Publ. Serv.	1	100%	0%	0%	0%
Tucson Elec. Pow.	1	100%	0%	0%	0%
Avangrid	1	100%	0%	0%	0%

3.3.2 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. Table 3.5 shows average 5-minute market import and export limits for each balancing area. These amounts exclude base WEIM transfer schedules and therefore reflect transfer capability, which is made available by WEIM entities to optimally transfer energy between areas. Of note, WEIM transfer limits shown here in the 5-minute market were not impacted by the CAISO transfer limitation discussed in the previous section.

On April 5, 2023 Avangrid, El Paso Electric, and Western Area Power Administration (WAPA) – Desert Southwest joined the Western Energy Imbalance Market. WAPA Desert Southwest added significant import and export capacity at around 5,870 MW (average for 2023). Avangrid joined with around 680 MW on average in dynamic transfer capacity to neighboring areas. Dynamic import and export transfer capacity for El Paso Electric during the year was relatively low, at around 420 MW.

The balancing areas in Table 3.5 are grouped in one of four regions: California, Desert Southwest, Intermountain West, and Pacific Northwest. These regions reflect a combination of general geographic location, as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. The last two columns in Table 3.5 show WEIM transfer limits between these regions (out-of-region import and export limits).

In the 5-minute market, import and export transfer capacity into or out of the Desert Southwest region was 30,171 MW and 27,556 MW, respectively. For the Pacific Northwest region, there was an average of 1,755 MW of import and 715 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Table 3.5 Average 5-minute market WEIM limits (2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**26,324**	**29,515**
California ISO	35,303	33,572	23,193	25,277
BANC	4,032	3,855	0	0
LADWP	7,279	12,236	3,131	4,238
Turlock Irrig. District	1,416	1,558	0	0
Desert Southwest			**30,171**	**27,556**
Arizona Public Service	30,945	26,713	21,315	18,383
El Paso Electric*	436	406	0	0
NV Energy	5,387	5,079	4,300	3,796
PSC New Mexico	951	1,131	0	0
Salt River Project	7,848	8,711	1,863	2,413
Tucson Electric	4,279	5,168	652	803
WAPA - Desert SW*	5,859	5,881	2,041	2,162
Intermountain West			**2,264**	**2,727**
Avista Utilities	708	1,020	114	111
Idaho Power	2,102	2,908	599	846
NorthWestern Energy	734	790	35	22
PacifiCorp East	3,317	2,607	1,515	1,747
Pacific Northwest			**1,755**	**715**
Avangrid*	690	672	11	16
Powerex	598	50	549	0
BPA	734	885	181	180
PacifiCorp West	1,650	1,522	650	431
Portland General Electric	822	636	215	30
Puget Sound Energy	1,150	954	120	29
Seattle City Light	439	436	29	30
Tacoma Power	356	247	0	0

*Since joining the WEIM

3.3.3 Congestion on WEIM transfer constraints

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Table 3.6 shows the percent of intervals and price impact of 15-minute and 5-minute market transfer constraint congestion in each WEIM area over the year.[172] The congestion on the WEIM transfer constraints are measured relative to a reference price in the CAISO balancing area. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or

[172] This accounts for any constraint that can limit WEIM transfers between balancing areas including (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraint and intertie scheduling limits.

region, relative to the CAISO (and connected WEIM system). *Congestion into area* reflects that prices are higher within an area, because of limited import capability into the area or region.[173]

The WEIM allows the market to increase efficiency by optimizing energy transfers economically in real-time between WEIM areas, balancing supply and demand across the footprint with lower-cost generation. When the CAISO balancing area limited dynamic WEIM imports to zero in the peak hours of the hour-ahead and 15-minute markets, this reduced the ability for the market to displace higher cost energy in the California ISO with cheaper excess energy in the surrounding WEIM system. The result was that most of the WEIM footprint was collectively export constrained at a lower price relative to the CAISO area during these intervals. This WEIM price was based on regional supply conditions in the surrounding WEIM system. As shown in Table 3.6, most WEIM balancing areas were congested towards the CAISO area (congested from area) in at least 5 percent of intervals in the 15-minute market. In the 5-minute market, WEIM imports into the CAISO balancing area were not limited this way, and the congestion frequency and price impact were both smaller on average for the year.

Powerex was frequently import constrained relative to the CAISO balancing area because of WEIM transfer congestion. Powerex was congested into the area during around 63 and 70 percent of intervals in the 15-minute and 5-minute markets, respectively. On average for the year, prices in Powerex were around $30/MWh higher because of WEIM transfer congestion. 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.[174]

El Paso Electric was frequently export constrained, during 35 percent of 15-minute market intervals and 27 percent of 5-minute market intervals. This was largely because of limited dynamic export capacity out of the balancing area.

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

174 If bid in supply after removing the three largest suppliers is less than the generation dispatched in the area in the market power mitigation run, bids in excess of the higher of default energy bids and the competitive LMP will be replaced by the higher of default energy bids and the competitive LMP. The California ISO balancing area is not subject to market power mitigation when WEIM transfer limits into the CAISO area are constrained.

Table 3.6 Frequency and impact of transfer congestion in the WEIM (2023)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$1.66	0.0%	$0.05	0.0%	$0.00	0.0%	$0.11
Turlock Irrigation District	2%	-$1.95	0.2%	$0.03	0.6%	-$0.14	0.4%	$0.05
NV Energy	5%	-$3.51	0.0%	$0.16	0.3%	-$0.24	0.1%	$0.58
L.A. Dept. of Water and Power	5%	-$3.44	0.2%	$0.21	0.2%	-$0.06	0.2%	$0.49
Arizona Public Service	5%	-$3.84	0.3%	$1.62	0.6%	-$0.59	0.4%	$2.59
WAPA – Desert Southwest*	8%	-$5.22	3%	$2.51	2%	-$0.75	2%	$2.29
Public Service Company of NM	6%	-$3.98	0.6%	$2.93	0.8%	-$0.46	0.5%	$2.71
PacifiCorp East	5%	-$3.37	5%	$0.60	0.4%	-$0.09	4%	$0.85
Tucson Electric Power	12%	-$4.48	4%	$0.99	6%	-$0.92	5%	$1.81
Idaho Power	6%	-$3.49	11%	$2.48	1%	-$0.31	9%	$2.57
NorthWestern Energy	7%	-$3.61	12%	$3.56	2%	-$0.43	10%	$4.01
Avista Utilities	6%	-$3.57	12%	$3.24	2%	-$0.42	10%	$3.46
PacifiCorp West	13%	-$4.74	14%	$3.44	7%	-$1.47	11%	$3.44
Portland General Electric	12%	-$4.18	16%	$4.18	7%	-$1.41	11%	$3.98
Avangrid Renewables*	15%	-$5.81	15%	$3.57	8%	-$1.74	11%	$3.68
Tacoma Power	14%	-$4.65	18%	$4.49	10%	-$2.15	15%	$4.68
Seattle City Light	14%	-$4.89	18%	$4.57	10%	-$2.36	16%	$4.77
Salt River Project	18%	-$8.15	6%	$4.38	13%	-$5.18	6%	$5.34
Puget Sound Energy	14%	-$4.59	18%	$6.27	10%	-$2.13	16%	$6.52
Bonneville Power Admin.	13%	-$4.69	20%	$5.66	9%	-$2.10	17%	$5.28
El Paso Electric Company*	35%	-$12.34	8%	$1.21	27%	-$7.70	8%	$1.42
Powerex	8%	-$3.45	63%	$28.62	13%	-$3.22	70%	$30.02

*Since joining the WEIM

3.4 WEIM prices and market performance

This section describes prices in the Western Energy Imbalance Market and some of the factors that contribute to price separation between participating areas. The WEIM lowers costs by committing and ramping less expensive generation across all areas to meet system-wide load. When transfer constraints do not limit the ability for energy to move between areas, prices within each balancing authority area often converge. In contrast, prices can diverge on each side of a transfer constraint when energy flow is limited from the lower-priced region to the higher priced region. When transfer constraints become binding and an area runs out of upward or downward ramping capability to balance internal supply and demand, the market can relax the power balance constraint, setting prices at penalty parameters. A failed resource sufficiency evaluation can also lead to this outcome and have a significant impact on prices by limiting an area's transfer capability, and consequently its ability to balance load.

Greenhouse gas compliance costs, enforced for imports into California, can also contribute to price separation between WEIM areas. These costs are discussed in Section 3.6. Congestion on internal constraints, as discussed in Section 3.3.3, can also impact WEIM prices.

3.4.1 Energy market prices

Figure 3.17 and Figure 3.18 show average 15-minute and 5-minute market prices by month. Figure 3.19 and Figure 3.20 show instead average hourly prices in the 15-minute and 5-minute markets during the year. The color gradient highlights deviation from the average system marginal energy cost (SMEC), shown in the top row. Here, blue indicates prices below the average system price for that month (or hour) and orange indicates prices above. The CAISO prices in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) areas are included as points of comparison.

Figure 3.17 Average monthly 15-minute market prices ($/MWh)

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

Figure 3.18 Average monthly 5-minute market prices ($/MWh)

	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	2022 Nov	2022 Dec	2023 Jan	2023 Feb	2023 Mar	2023 Apr	2023 May	2023 Jun	2023 Jul	2023 Aug	2023 Sep	2023 Oct	2023 Nov	2023 Dec
SMEC	$43	$38	$38	$50	$51	$45	$62	$88	$97	$66	$86	$241	$135	$68	$66	$47	$16	$27	$58	$53	$39	$53	$57	$49
PG&E (CAISO)	$45	$42	$48	$54	$63	$80	$73	$95	$110	$73	$92	$254	$136	$70	$68	$49	$16	$28	$52	$52	$42	$58	$62	$53
SCE (CAISO)	$43	$36	$39	$45	$54	$63	$72	$98	$107	$60	$77	$234	$133	$63	$58	$41	$16	$26	$62	$53	$35	$48	$52	$44
BANC	$45	$42	$49	$56	$65	$72	$70	$97	$107	$74	$92	$249	$138	$71	$68	$49	$16	$29	$54	$53	$42	$57	$62	$53
Turlock ID	$46	$43	$49	$60	$73	$72	$71	$94	$113	$77	$94	$263	$139	$72	$69	$52	$16	$30	$54	$53	$42	$58	$63	$54
LADWP	$42	$35	$38	$45	$51	$55	$70	$98	$106	$61	$81	$244	$134	$67	$59	$42	$16	$26	$62	$55	$37	$51	$53	$45
NV Energy	$35	$31	$33	$42	$49	$51	$67	$90	$90	$57	$76	$235	$126	$62	$60	$42	$14	$22	$56	$45	$34	$44	$50	$43
Arizona PS	$33	$29	$31	$37	$47	$59	$67	$89	$96	$54	$77	$240	$123	$66	$61	$42	$15	$24	$59	$45	$32	$40	$46	$40
Tucson Electric					$50	$58	$67	$89	$90	$54	$73	$215	$123	$60	$54	$40	$20	$26	$58	$44	$31	$38	$46	$40
Salt River Project	$35	$29	$33	$41	$54	$68	$68	$83	$75	$51	$72	$149	$109	$49	$54	$45	$23	$26	$61	$48	$27	$38	$49	$39
PSC New Mexico	$32	$31	$28	$35	$42	$45	$64	$78	$80	$57	$63	$123	$122	$60	$58	$53	$14	$24	$56	$44	$33	$46	$51	$42
WAPA - Desert SW																$40	$19	$26	$58	$44	$33	$38	$47	$40
El Paso Electric																$28	$16	$23	$47	$40	$30	$33	$23	$23
PacifiCorp East	$32	$30	$28	$39	$39	$29	$59	$74	$76	$57	$70	$192	$116	$59	$62	$45	$14	$25	$52	$43	$34	$44	$47	$40
Idaho Power	$38	$36	$30	$53	$43	$18	$60	$75	$76	$61	$80	$233	$127	$66	$68	$51	$13	$26	$52	$44	$35	$61	$54	$46
NorthWestern	$37	$34	$29	$53	$37	$4	$37	$64	$66	$64	$86	$241	$128	$67	$69	$56	$9	$27	$55	$46	$37	$67	$55	$48
Avista Utilities			$29	$54	$37	-$2	$31	$63	$65	$64	$83	$242	$129	$67	$69	$56	$10	$27	$51	$44	$37	$68	$55	$48
Avangrid																$56	$6	$27	$51	$44	$38	$68	$55	$48
BPA					$37	$2	$34	$68	$78	$63	$83	$247	$130	$68	$68	$57	$4	$28	$53	$48	$37	$69	$56	$47
Tacoma Power			$27	$57	$41	$7	$33	$67	$71	$62	$82	$246	$130	$67	$69	$56	$5	$28	$50	$45	$37	$69	$54	$47
PacifiCorp West	$35	$32	$28	$57	$39	-$2	$37	$68	$69	$63	$83	$239	$129	$66	$68	$56	$6	$26	$50	$42	$37	$68	$54	$47
Portland GE	$36	$32	$26	$57	$38	$0	$37	$68	$72	$63	$84	$239	$129	$66	$68	$56	$9	$27	$50	$45	$37	$69	$54	$47
Puget Sound Energy	$34	$32	$28	$57	$41	$7	$34	$66	$71	$62	$83	$247	$131	$68	$69	$56	$7	$28	$61	$47	$38	$74	$56	$47
Seattle City Light	$34	$32	$28	$58	$41	$5	$33	$67	$70	$62	$82	$247	$130	$69	$68	$56	$5	$27	$50	$46	$37	$68	$55	$47
Powerex	$34	$32	$31	$50	$44	$10	$32	$57	$67	$65	$80	$209	$127	$77	$83	$77	$14	$52	$87	$94	$77	$102	$101	$61

In 2023, higher prices were observed in Pacific Northwest and Intermountain West during April and October, while in 2022, high prices were frequently seen across California entities throughout the year.

Figure 3.19 Average hourly 15-minute market prices ($/MWh)

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	$59	$57	$56	$56	$59	$66	$71	$61	$47	$42	$40	$38	$36	$37	$39	$49	$61	$80	$101	$108	$90	$77	$68	$61
PG&E (CAISO)	$59	$57	$56	$56	$59	$65	$70	$64	$53	$48	$45	$43	$41	$41	$43	$52	$63	$79	$98	$102	$86	$74	$67	$60
SCE (CAISO)	$60	$57	$56	$56	$59	$66	$71	$58	$38	$32	$29	$26	$26	$27	$30	$43	$57	$79	$104	$115	$94	$81	$70	$62
BANC	$59	$56	$55	$55	$58	$65	$70	$63	$53	$50	$47	$45	$44	$43	$45	$53	$63	$74	$82	$90	$83	$74	$67	$60
Turlock ID	$59	$56	$55	$55	$58	$64	$69	$63	$55	$53	$50	$48	$46	$46	$48	$54	$64	$75	$81	$88	$82	$73	$67	$60
LADWP	$62	$58	$57	$57	$60	$67	$72	$60	$41	$33	$30	$28	$27	$28	$32	$45	$57	$69	$80	$92	$82	$77	$71	$64
NV Energy	$52	$49	$48	$49	$53	$60	$63	$52	$39	$36	$34	$32	$31	$31	$33	$44	$53	$64	$70	$80	$73	$65	$61	$54
Arizona PS	$54	$48	$48	$49	$54	$67	$66	$56	$40	$33	$25	$23	$24	$25	$28	$43	$52	$60	$71	$82	$75	$66	$63	$58
Tucson Electric	$50	$47	$47	$47	$51	$58	$61	$50	$34	$30	$28	$27	$26	$27	$31	$43	$54	$62	$70	$81	$74	$65	$61	$52
Salt River Project	$48	$45	$43	$43	$48	$58	$61	$50	$37	$29	$28	$29	$28	$29	$31	$39	$52	$61	$74	$78	$71	$63	$66	$51
PSC New Mexico	$54	$56	$50	$53	$52	$68	$68	$63	$39	$32	$28	$26	$26	$27	$29	$41	$52	$64	$75	$83	$77	$66	$61	$59
WAPA - Desert SW*	$45	$40	$39	$37	$39	$45	$47	$33	$20	$17	$18	$19	$23	$24	$25	$34	$41	$48	$58	$71	$61	$54	$53	$44
El Paso Electric*	$27	$24	$24	$23	$26	$30	$26	$21	$19	$18	$20	$22	$21	$23	$25	$31	$34	$37	$46	$54	$43	$32	$35	$28
PacifiCorp East	$50	$47	$46	$46	$50	$57	$59	$52	$41	$38	$36	$35	$34	$34	$36	$44	$52	$58	$65	$73	$67	$60	$58	$51
Idaho Power	$53	$50	$49	$50	$54	$61	$65	$58	$50	$47	$45	$44	$43	$43	$44	$50	$57	$63	$68	$74	$70	$63	$62	$54
NorthWestern	$52	$50	$49	$50	$54	$63	$64	$59	$54	$50	$47	$47	$46	$45	$46	$53	$62	$63	$67	$72	$69	$62	$62	$54
Avista Utilities	$53	$50	$49	$50	$54	$62	$63	$59	$53	$51	$49	$48	$48	$47	$47	$52	$59	$63	$66	$70	$68	$62	$62	$55
Avangrid*	$40	$37	$36	$37	$39	$45	$44	$39	$39	$40	$40	$40	$41	$42	$41	$44	$47	$49	$49	$53	$52	$47	$49	$42
BPA	$54	$50	$49	$49	$53	$61	$61	$57	$55	$54	$53	$51	$51	$51	$50	$56	$61	$65	$69	$73	$70	$63	$64	$54
Tacoma Power	$53	$50	$49	$50	$53	$59	$60	$56	$53	$53	$52	$51	$50	$50	$49	$53	$58	$62	$67	$71	$66	$60	$63	$54
PacifiCorp West	$52	$49	$48	$49	$53	$60	$60	$56	$52	$51	$50	$49	$49	$47	$47	$52	$58	$63	$64	$67	$65	$60	$61	$54
Portland GE	$53	$50	$49	$50	$53	$59	$61	$57	$53	$52	$51	$50	$50	$48	$49	$55	$59	$66	$70	$72	$68	$61	$61	$54
Puget Sound Energy	$54	$49	$48	$50	$54	$59	$60	$56	$55	$56	$53	$51	$51	$53	$49	$56	$63	$71	$73	$79	$69	$63	$63	$54
Seattle City Light	$56	$50	$49	$50	$53	$59	$59	$56	$53	$53	$51	$51	$51	$51	$50	$54	$58	$62	$67	$71	$67	$62	$61	$54
Powerex	$72	$67	$66	$67	$69	$75	$83	$87	$86	$83	$84	$82	$82	$81	$82	$86	$91	$93	$93	$94	$92	$87	$83	$74

*Since joining the WEIM

During solar production hours, prices were high in Northern California, the Pacific Northwest, and in the Intermountain West, but were lower in the Desert Southwest and Southern California. This price separation can be attributed to congestion from excess solar power flowing from southern to northern regions. The congestion results in higher cost resources setting the price in northern regions than in southern regions during solar production hours.

During evening peak hours between hour-ending 17 and 22, prices in California entities were generally higher than in the rest of WEIM entities. This was caused by a combination of congestion and GHG costs raising prices in California relative to much of the rest of the WEIM during peak net load hours.

Figure 3.20 Average hourly 5-minute market prices ($/MWh)

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	$60	$57	$56	$56	$58	$64	$70	$62	$45	$41	$38	$35	$35	$35	$37	$44	$53	$61	$70	$81	$75	$73	$69	$60
PG&E (CAISO)	$60	$57	$56	$56	$58	$64	$70	$65	$51	$48	$43	$41	$40	$40	$41	$47	$55	$61	$68	$78	$72	$71	$68	$60
SCE (CAISO)	$60	$57	$56	$56	$58	$64	$71	$59	$36	$29	$26	$23	$23	$24	$27	$38	$50	$62	$73	$86	$79	$75	$70	$61
BANC	$60	$57	$55	$55	$58	$63	$71	$65	$52	$50	$45	$44	$43	$42	$43	$48	$55	$61	$68	$79	$73	$71	$68	$60
Turlock ID	$60	$57	$55	$55	$58	$63	$70	$64	$54	$53	$48	$46	$45	$45	$46	$50	$56	$62	$68	$78	$72	$71	$68	$60
LADWP	$63	$58	$56	$56	$59	$65	$72	$61	$39	$30	$27	$24	$25	$25	$29	$39	$54	$64	$73	$85	$79	$75	$72	$64
NV Energy	$52	$49	$48	$49	$53	$59	$63	$55	$37	$33	$31	$29	$29	$30	$31	$40	$52	$59	$67	$78	$69	$63	$63	$54
Arizona PS	$53	$48	$48	$50	$55	$63	$64	$62	$43	$29	$25	$20	$21	$23	$28	$42	$48	$58	$68	$79	$73	$69	$63	$56
Tucson Electric	$52	$48	$47	$48	$51	$58	$61	$52	$32	$28	$25	$24	$26	$27	$32	$42	$51	$62	$68	$77	$70	$63	$63	$52
Salt River Project	$48	$44	$42	$42	$47	$57	$58	$48	$33	$27	$30	$35	$33	$28	$30	$41	$50	$56	$71	$75	$67	$59	$67	$50
PSC New Mexico	$54	$52	$49	$53	$53	$62	$65	$63	$35	$29	$26	$24	$24	$25	$28	$37	$53	$64	$74	$82	$71	$66	$63	$57
WAPA - Desert SW*	$45	$39	$37	$38	$39	$46	$50	$34	$18	$17	$16	$17	$21	$23	$24	$34	$40	$49	$56	$70	$59	$52	$54	$44
El Paso Electric*	$28	$25	$24	$24	$26	$33	$29	$24	$18	$17	$18	$21	$21	$23	$25	$31	$35	$39	$46	$53	$44	$34	$35	$28
PacifiCorp East	$50	$47	$45	$46	$49	$57	$61	$52	$39	$36	$34	$33	$32	$32	$34	$40	$48	$55	$62	$71	$64	$59	$59	$52
Idaho Power	$53	$50	$49	$50	$53	$60	$65	$59	$48	$46	$43	$42	$41	$41	$42	$46	$53	$60	$66	$74	$68	$63	$62	$54
NorthWestern	$57	$50	$49	$50	$54	$62	$64	$60	$53	$48	$46	$45	$45	$44	$45	$51	$56	$60	$66	$74	$67	$62	$63	$57
Avista Utilities	$55	$50	$49	$50	$54	$61	$64	$60	$52	$50	$48	$47	$46	$45	$46	$50	$56	$59	$64	$71	$66	$62	$63	$55
Avangrid*	$40	$37	$36	$37	$40	$45	$46	$41	$39	$40	$39	$39	$40	$41	$41	$43	$47	$49	$52	$58	$53	$49	$50	$42
BPA	$53	$51	$49	$49	$53	$59	$62	$58	$53	$52	$51	$49	$49	$49	$49	$54	$55	$60	$65	$70	$66	$61	$62	$54
Tacoma Power	$53	$49	$48	$50	$53	$59	$61	$57	$52	$51	$50	$48	$49	$48	$48	$50	$54	$58	$65	$69	$63	$60	$63	$54
PacifiCorp West	$53	$50	$49	$50	$53	$59	$62	$57	$52	$50	$48	$47	$46	$46	$46	$49	$54	$59	$63	$69	$64	$61	$61	$53
Portland GE	$53	$50	$49	$50	$53	$59	$62	$57	$52	$50	$49	$47	$47	$46	$47	$50	$55	$62	$68	$72	$65	$61	$61	$53
Puget Sound Energy	$53	$49	$48	$50	$53	$59	$61	$57	$55	$55	$51	$48	$49	$52	$48	$51	$57	$68	$73	$77	$68	$61	$63	$55
Seattle City Light	$54	$50	$48	$50	$52	$59	$62	$57	$52	$51	$50	$48	$50	$50	$49	$51	$54	$58	$64	$69	$64	$61	$60	$52
Powerex	$71	$66	$65	$66	$70	$73	$81	$80	$81	$81	$81	$80	$81	$80	$80	$82	$85	$87	$90	$93	$90	$86	$81	$73

*Since joining the WEIM

Figure 3.21 and Figure 3.22 show the average 15-minute and 5-minute market price by component for each balancing authority area in 2023. 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 in the California ISO balancing area. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.

- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limits WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraints (ITC) and intertie scheduling limits (ISL).

The three WEIM entities that joined in the second quarter of 2023 have lower system marginal energy prices than the other WEIM areas. This was due to Q1 prices being higher on average than system prices in the rest of the year due to higher gas prices in the first quarter.

Significant factors impacting the LMP include congestion on WEIM transfer constraints and internal congestion from flow-based constraints. GHG costs also contributed to lowering prices in non-California balancing areas relative to California area. This indicates resources with non-zero GHG costs were often sending the last increment of power to California in the real-time markets.

In the 15-minute market, WEIM transfer constraints increased prices for BCHA, BPA, and PSE, while most of the Desert Southwest and newly joined entities experienced a negative impact on price from WEIM transfers and congestion. In the 5-minute market, congestion from transfer constraints contributed to increasing prices in most BAAs. This indicates a different congestion dynamic between the 15-minute and 5-minute markets.

The different impact that transfer congestion had on most balancing areas in the 15-minute market than in the 5-minute market was largely due to the WEIM transfer limitation imposed by the CAISO balancing area from July 26 to November 15, as detailed in Section 3.3.1. This limitation typically lasted five hours each day in the 15-minute market, but it was not enforced in the 5-minute market. This transfer limitation caused congestion into the CAISO balancing area in the 15-minute market, reducing prices in much of the rest of the WEIM. This limitation was not implemented in the 5-minute market, resulting in a pattern of lower congestion from WEIM areas into CAISO in the 5-minute market than in the 15-minute market.

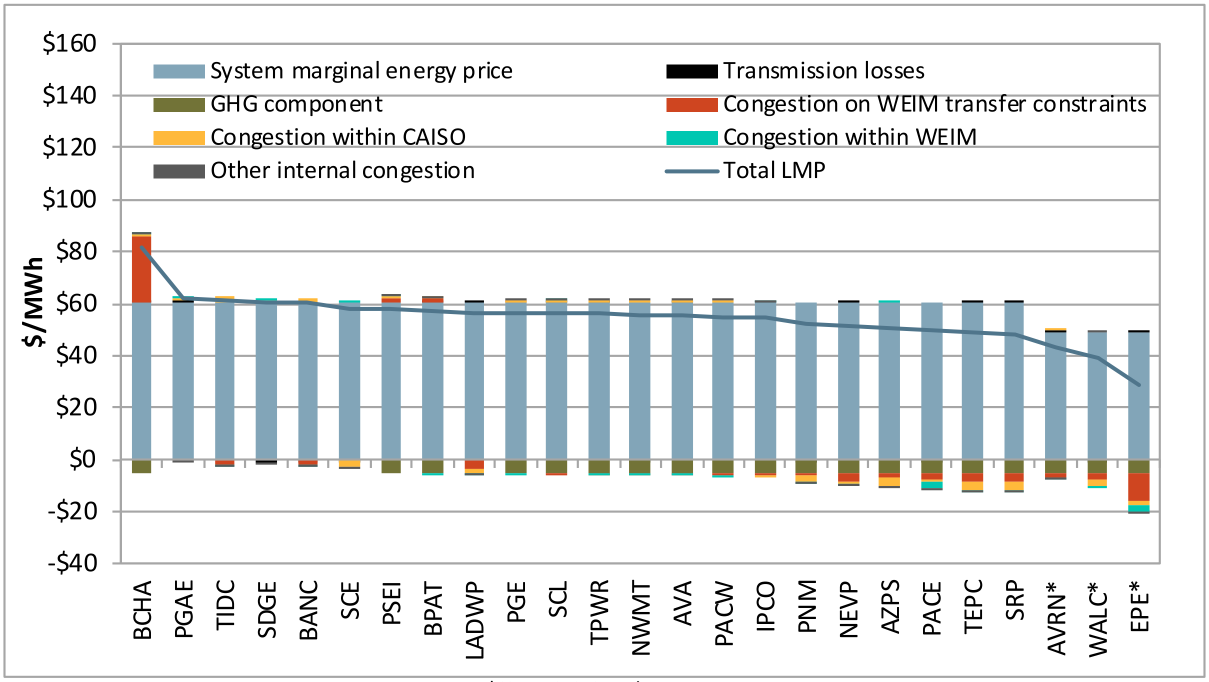
The impact of internal constraints on prices can be driven by two major patterns: (1) During solar hours, most congestion occurs from flows traveling south to north, increasing prices in Northern California, Intermountain West, and Pacific Northwest areas, and decreasing prices in Southern California and Desert Southwest areas.[175] This pattern is driven by high solar production in the south serving northern

175 More details on the impact of internal congestion pattern can be found in Section 6.

WEIM load. (2) During non-solar production hours, the pattern of flows typically shifts to north to south, decreasing prices in the north relative to prices southern areas.

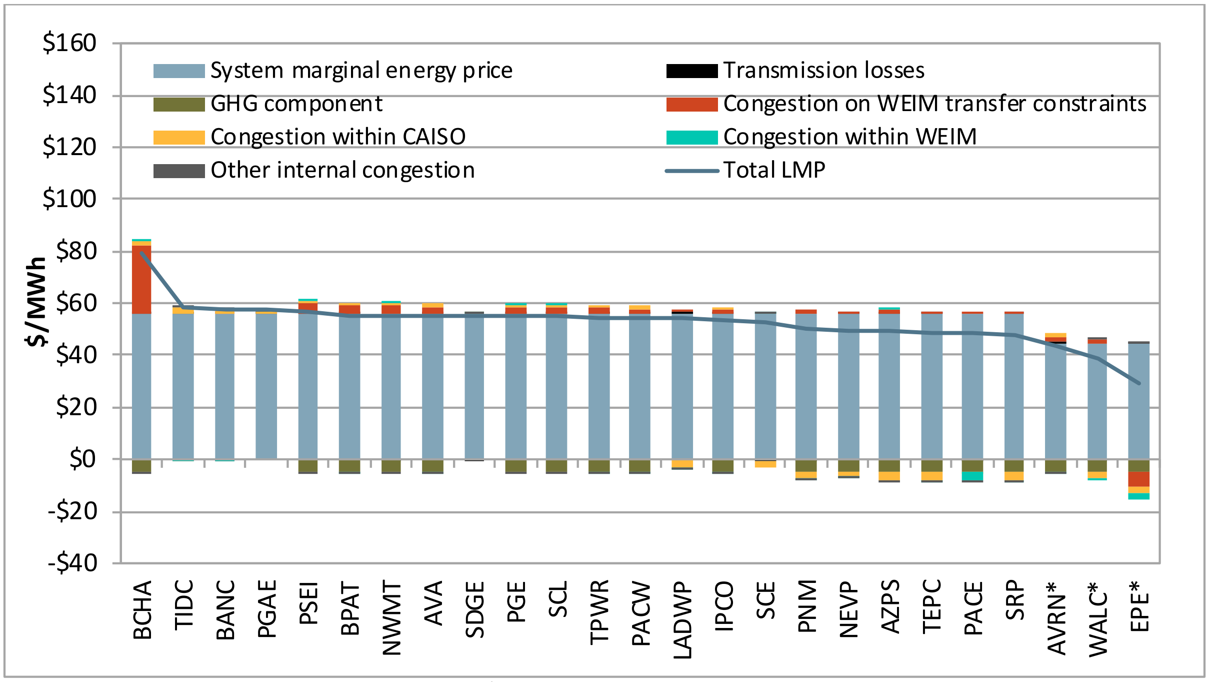
The overall impact of internal congestion on price differences between areas was greater in the south to north direction. For the year, the internal congestion impact was more positive in the northern WEIM entities and more negative in the southern entities.

Figure 3.21 Annual average 15-minute price by component (2023)



*Since joining the WEIM

Figure 3.22 Annual average 5-minute price by component (2023)



*Since joining the WEIM

3.4.2 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*. 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.[176] 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 3.7 shows the frequency of power balance constraint relaxations in the 15-minute and 5-minute markets by balancing areas for undersupply (shortage) and oversupply (excess) conditions throughout 2023. 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 Southwest region, including Salt River Project, Arizona Public Service, Public Service Company of New Mexico, and El Paso Electric had a relatively high frequency of PBC relaxations. Salt River and Arizona Public Service had relatively high frequencies of both oversupply and undersupply infeasibilities. New Mexico, El Paso, WAPA and Puget Sound had relatively high frequencies of undersupply infeasibilities.

[176] 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.

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.

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.

Table 3.7 Frequency of power balance constraint relaxations by market

Balancing area	Oversupply infeasibility		Undersupply infeasibility	
	15-minute	5-minute	15-minute	5-minute
Salt River Project	0.17%	0.42%	0.30%	0.46%
Arizona PS	0.13%	0.21%	0.15%	0.28%
PSC New Mexico	0.07%	0.07%	0.31%	0.32%
El Paso Electric*	0.07%	0.09%	0.17%	0.31%
WAPA - Desert SW*	0.04%	0.04%	0.27%	0.18%
Puget Sound Energy	0.00%	0.02%	0.16%	0.20%
Seattle City Light	0.13%	0.14%	0.02%	0.02%
Tucson Electric	0.01%	0.00%	0.01%	0.12%
NV Energy	0.01%	0.04%	0.01%	0.06%
NorthWestern	0.00%	0.00%	0.05%	0.09%
Portland GE	0.00%	0.00%	0.02%	0.04%
LADWP	0.01%	0.00%	0.01%	0.04%
Idaho Power	0.00%	0.02%	0.01%	0.02%
CAISO	0.00%	0.00%	0.05%	0.03%
Tacoma Power	0.01%	0.02%	0.02%	0.02%
Powerex	0.00%	0.01%	0.00%	0.01%
BPA	0.01%	0.00%	0.02%	0.02%
Avista Utilities	0.00%	0.00%	0.01%	0.02%
PacifiCorp East	0.00%	0.00%	0.00%	0.02%
PacifiCorp West	0.01%	0.00%	0.01%	0.01%
Turlock ID	0.02%	0.01%	0.00%	0.00%
BANC	0.00%	0.00%	0.01%	0.01%
Avangrid*	0.00%	0.00%	0.00%	0.00%

*Since joining the WEIM

3.4.3 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 CAISO system software to deploy such capacity through the market, and prevents market infeasibilities that may arise without the availability of this capacity.[177]

Table 3.8 and Table 3.9 summarize the annual frequency of upward and downward available balancing capacity, both offered and scheduled, in each area during 2023.[178] Most 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, LADWP, PacifiCorp West, PSC New Mexico, Puget Sound Energy, Seattle City Light, and Portland General Electric 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 1,158 and 591 MW of upward and downward available balancing capacity, respectively, during 2023.

Overall, available balancing capacity was dispatched very infrequently for scarcity conditions during 2023. However, upward available balancing capacity offered by Salt River Project was dispatched during around 1 percent of 15-minute and 5-minute market intervals.

[177] 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

[178] 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 3.8 Frequency of upward available balancing capacity offered and scheduled (2023)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
BANC	100%	90	0.0%	0.0%
Bonneville Power Admin.	100%	310	0.2%	0.2%
Turlock Irrigation District	100%	14	0.0%	0.0%
Avista Utilities	100%	20	0.0%	0.0%
Powerex	100%	1,158	0.0%	0.0%
Tucson Electric	100%	34	0.1%	0.2%
Salt River Project	100%	97	1.0%	1.1%
WAPA - Desert Southwest*	99%	35	0.7%	0.6%
NV Energy	99%	53	0.0%	0.1%
Portland General Electric	99%	30	0.1%	0.1%
Tacoma Power	99%	2	0.0%	0.0%
NorthWestern Energy	97%	5	0.0%	0.1%
Arizona Public Service	95%	20	0.1%	0.2%
LADWP	71%	52	0.0%	0.1%
PacifiCorp East	23%	49	0.0%	0.0%
Seattle City Light	6%	43	0.0%	0.0%
PacifiCorp West	5%	39	0.0%	0.0%
PSC New Mexico	0.8%	44	0.0%	0.0%
El Paso Electric*	0.2%	27	0.0%	0.0%
Puget Sound Energy	0.2%	3	0.0%	0.0%
Avangrid*	0%	N/A	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%

*Since joining the WEIM

Table 3.9 Frequency of downward available balancing capacity offered and scheduled (2023)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
BANC	100%	116	0.0%	0.0%
Powerex	100%	591	0.0%	1.1%
Bonneville Power Admin.	100%	328	0.1%	0.0%
Turlock Irrigation District	100%	5	0.0%	0.0%
Avista Utilities	100%	20	0.0%	0.0%
Tucson Electric	100%	36	0.0%	0.0%
WAPA - Desert Southwest*	100%	33	0.1%	0.2%
NorthWestern Energy	99%	5	0.0%	0.0%
Salt River Project	98%	49	0.3%	0.6%
Tacoma Power	98%	6	0.0%	0.0%
Arizona Public Service	95%	20	0.1%	0.1%
NV Energy	85%	52	0.0%	0.0%
PSC New Mexico	80%	72	0.0%	0.0%
PacifiCorp East	41%	161	0.0%	0.0%
PacifiCorp West	8%	48	0.0%	0.0%
Seattle City Light	4%	37	0.0%	0.0%
LADWP	0.7%	72	0.0%	0.0%
Puget Sound Energy	0.2%	31	0.0%	0.0%
Avangrid*	0.0%	13	0.0%	0.0%
El Paso Electric*	0%	N/A	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%
Portland General Electric	0%	N/A	0.0%	0.0%

*Since joining the WEIM

3.5 Resource sufficiency evaluation

As part of the Western Energy Imbalance Market (WEIM), each area, including the California ISO, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while incentivizing each area to provide sufficient supply to meet its own load. 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. Failing two of these tests will 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 have enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction, transfers into that area cannot be increased.[179] Similarly, if an area fails either test in the downward direction, transfers out of that area cannot be increased.

Net load uncertainty—which is added to the flexibility test requirement—was adjusted on February 1, 2023 as part of flexible ramping enhancements. The uncertainty was adjusted to incorporate current load, solar, and wind forecast information using a technique called *mosaic quantile regression*. This method combined historical and current forecast information to estimate the lower and upper extremes of uncertainty that might materialize. The capacity test currently does not include any load uncertainty adder in the requirement. For more information on net load uncertainty in the resource sufficiency evaluation, see Section 3.5.2.

Phase 2 (track 1) of resource sufficiency evaluation enhancements was implemented on July 1, 2023. This included the implementation of Assistance Energy Transfers (AET) and an adjustment for real-time low-priority and economic exports in the CAISO balancing area resource sufficiency evaluation. AET gives balancing areas access to excess WEIM supply that may not have been available otherwise following a resource sufficiency evaluation failure. However, balancing areas are subject to an ex-post surcharge for this energy. For more information on these enhancements, see Section 3.5.3.

3.5.1 Resource sufficiency evaluation results

Figure 3.23 and Figure 3.24 show the percent of intervals in which each WEIM area failed the upward capacity or flexibility tests, while Figure 3.25 and Figure 3.26 provide the same information for the downward direction.[180] The dash indicates the area did not fail the test during the month.

Overall, WEIM areas failed the resource sufficiency evaluation infrequently during the year. Of note in 2023:

- Salt River Project failed the upward flexibility test in around 1.3 percent of intervals.
- Public Service Company of New Mexico failed the upward flexibility test in 1.1 percent of intervals.
- Puget Sound Energy failed the upward flexibility test in 0.9 percent of intervals.

[179] If an area fails either test in the upward direction, WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval prior to the hour.

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

Figure 3.23 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.	0.4	0.5	0.7	0.2	0.0	0.1	—	—	—	0.0	—	0.1
Avangrid				0.0	—	—	—	—	0.8	—	—	—
Avista	—	—	—	0.1	0.0	—	—	—	—	0.0	0.1	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	0.2	—	0.3	0.4	—	0.1	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric				0.0	0.1	0.3	0.8	0.0	0.1	0.1	—	—
Idaho Power	—	—	—	0.0	0.1	—	—	—	—	—	0.1	—
LADWP	0.1	—	—	—	—	—	0.1	0.0	—	—	—	0.0
NorthWestern En.	0.3	0.1	—	—	—	—	0.3	—	—	—	—	—
NV Energy	—	—	—	—	0.0	—	0.0	0.0	—	0.0	—	—
PacifiCorp East	—	—	—	—	—	—	0.0	—	—	—	—	—
PacifiCorp West	0.1	0.1	—	—	—	—	—	0.1	—	—	—	—
Portland Gen. Elec.	—	0.0	0.0	0.1	0.4	0.1	0.0	—	0.0	0.0	0.6	—
Powerex	—	—	—	—	0.1	—	—	—	0.1	0.0	0.0	—
PSC of New Mexico	—	—	0.7	0.3	0.2	0.0	—	0.0	0.1	0.1	—	0.1
Puget Sound En.	—	0.0	0.2	—	0.1	0.5	1.5	0.5	0.2	0.7	1.0	0.2
Salt River Proj.	1.0	0.4	1.1	0.9	0.2	0.0	2.8	1.2	0.0	0.8	0.2	0.1
Seattle City Light	0.0	0.1	—	—	—	—	0.1	0.9	—	0.1	0.6	—
Tacoma Power	0.0	0.1	0.1	—	0.1	—	—	0.1	—	0.1	0.0	—
Tucson Elec. Pow.	0.1	0.0	—	—	—	—	0.3	—	—	0.2	—	—
Turlock Irrig. Dist.	—	—	—	0.0	—	—	0.1	—	—	—	—	—
WAPA DSW				2.3	0.8	0.7	1.1	0.6	0.1	0.3	0.4	0.1

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Figure 3.24 Frequency of upward flexibility test failures by month and area (15-minute intervals)

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

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Figure 3.25 Frequency of downward capacity test failures by month and area (15-minute intervals)

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

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Figure 3.26 Frequency of downward flexibility test failures by month and area (15-minute intervals)

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

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3.5.2 Net load uncertainty in the resource sufficiency evaluation

Net load uncertainty is included in the requirement of the flexible ramp sufficiency test (flexibility test) to capture additional flexibility needs that may be required in the evaluation hour due to variation in either load, solar, or wind forecasts.[181] This calculation was adjusted on February 1, 2023 using a method called *mosaic quantile regression*. This calculation is similar to that used in the 15-minute market flexible ramping product—based on the difference between binding 5-minute market forecasts and corresponding advisory 15-minute market forecasts. The quantile regression uses the historical sample of 5-minute and 15-minute market forecast observations to create hourly coefficients that define the relationship between the forecasts and uncertainty.[182] The regression coefficients are then combined with current forecast information to calculate the uncertainty. The resource sufficiency evaluation and flexible ramping product uncertainty calculations for a single balancing area use the same hourly coefficients, but are combined with their respective current forecast information based on the timing of each market process.[183]

Figure 3.27 and Figure 3.28 summarize the average upward or downward uncertainty calculated from the mosaic quantile regression method for each balancing area in the WEIM.[184] The final column shows the average regression-based uncertainty between February and December. Figure 3.29 and Figure 3.30 instead show the average increase (or decrease) in the calculated uncertainty relative to the histogram method. The histogram method was the simpler approach that was in place prior to February 1, 2023, based on the 2.5th or 97.5th percentile of observations in the historical distribution of net load forecast uncertainty.[185] On average for the year, the regression method produced lower uncertainty relative to the histogram method for all balancing areas.

181 The flexibility test also includes a credit for *diversity benefit*, which reflects that system-level flexibility needs are typically smaller than the sum of individual balancing area needs, because of reduced uncertainty across a larger footprint.

182 For more information on the mosaic quantile regression calculation, see Section 2.8.2.

183 An individual balancing area flexible ramping product uncertainty requirement will be enforced for any balancing area that failed the resource sufficiency evaluation.

184 These amounts account for the *thresholds* that can cap the calculated uncertainty. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty.

185 The downward and upward histogram uncertainty was calculated by selecting the 2.5th and 97.5th percentile of historical net load forecast uncertainty. Weekday distributions used data for the same hour from the previous 40 weekdays, while weekend distributions instead used same-hour observations from the previous 20 weekend days.

Figure 3.27 Average upward uncertainty from mosaic quantile regression method

	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	*Avg.* 2023
Arizona Publ. Serv.	137	142	155	161	170	171	183	188	175	178	188	168
Avangrid			108	119	161	183	171	160	130	106	103	138
Avista	48	45	43	38	35	36	37	39	35	36	37	39
BANC	37	43	37	41	38	40	47	37	36	33	34	38
BPA	185	206	197	193	217	219	206	178	153	135	138	184
California ISO	983	1,064	941	1,052	1,079	1,023	1,060	1,115	1,058	1,008	950	1,030
El Paso Electric			23	28	36	46	46	42	35	28	28	35
Idaho Power	100	99	96	92	98	105	106	98	95	92	95	98
LADWP	143	155	139	142	150	149	157	156	145	135	129	145
NorthWestern En.	72	61	72	64	62	66	64	60	55	67	68	65
NV Energy	145	156	136	167	173	175	195	257	244	205	167	184
PacifiCorp East	269	266	271	262	260	301	309	314	324	374	356	301
PacifiCorp West	91	96	96	80	80	78	80	75	68	66	67	80
Portland Gen. Elec.	102	106	109	105	115	112	104	90	73	84	99	100
Powerex	160	152	157	131	138	133	141	139	129	133	153	142
PSC of New Mexico	98	102	98	99	103	104	104	102	101	102	101	101
Puget Sound En.	146	134	132	114	107	112	114	121	133	141	141	127
Salt River Proj.	96	98	89	94	97	110	118	100	85	85	89	97
Seattle City Light	23	21	21	17	14	16	17	14	14	14	16	17
Tacoma Power	12	12	12	10	9	10	10	9	9	9	11	10
Tucson Elec. Pow.	107	109	111	102	93	99	103	92	78	74	83	96
Turlock Irrig. Dist.	8	8	8	7	7	6	7	7	7	7	7	7
WAPA DSW			9	11	12	15	19	17	17	19	20	16

Figure 3.28 Average downward uncertainty from mosaic quantile regression method

	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	*Avg.* 2023
Arizona Publ. Serv.	100	93	96	126	133	151	173	177	180	169	187	144
Avangrid			115	124	171	186	152	159	145	118	102	142
Avista	48	46	47	46	50	55	56	57	54	51	52	51
BANC	36	39	36	43	46	47	54	47	43	37	36	42
BPA	263	291	288	283	311	323	288	266	231	197	186	266
California ISO	723	779	783	838	828	819	888	817	712	687	734	783
El Paso Electric			23	29	31	38	42	38	30	28	25	32
Idaho Power	120	121	116	121	125	134	137	125	117	107	110	121
LADWP	134	135	132	150	153	165	184	167	157	153	151	153
NorthWestern En.	60	64	68	72	72	68	74	79	77	72	79	71
NV Energy	125	132	118	152	167	154	194	263	216	167	153	168
PacifiCorp East	324	326	302	303	320	367	410	412	410	421	395	363
PacifiCorp West	87	98	102	98	101	101	99	100	86	89	90	95
Portland Gen. Elec.	96	109	110	106	119	128	114	99	99	105	114	109
Powerex	173	156	152	135	147	145	147	131	132	144	159	147
PSC of New Mexico	91	94	95	103	117	125	135	130	116	115	111	112
Puget Sound En.	128	133	131	145	156	157	152	147	152	137	139	144
Salt River Proj.	78	77	70	86	94	103	114	101	92	87	89	90
Seattle City Light	21	20	18	14	14	16	17	14	15	17	20	17
Tacoma Power	13	13	11	9	8	9	10	9	9	10	12	10
Tucson Elec. Pow.	70	66	71	79	77	79	86	77	66	60	57	72
Turlock Irrig. Dist.	7	7	7	8	8	8	8	8	8	6	6	7
WAPA DSW			10	12	13	14	19	19	16	20	20	16

Figure 3.29 Average increase (decrease) in upward uncertainty using the regression method relative to histogram method

	2023											2023
	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
Arizona Publ. Serv.	(6)	(4)	4	(5)	(6)	(24)	(25)	(23)	(39)	(33)	(50)	(19)
Avangrid			(37)	(35)	(21)	(24)	(42)	(56)	(81)	(96)	(87)	(53)
Avista	(0)	(3)	(5)	(10)	(12)	(11)	(10)	(8)	(11)	(9)	(7)	(8)
BANC	(6)	0	(7)	(3)	(5)	(3)	2	(4)	(3)	(5)	(6)	(4)
BPA	(15)	2	(19)	(23)	(6)	(7)	(18)	(36)	(57)	(62)	(50)	(26)
California ISO	(114)	(26)	(191)	(115)	(99)	(125)	(79)	(41)	(119)	(181)	(274)	(124)
El Paso Electric			(0)	2	3	3	(1)	(6)	(14)	(22)	(19)	(6)
Idaho Power	2	4	(1)	(8)	(8)	(5)	(6)	(15)	(16)	(16)	(9)	(7)
LADWP	(18)	(5)	(25)	(21)	(15)	(12)	(9)	(8)	(16)	(19)	(15)	(15)
NorthWestern En.	(3)	(15)	(6)	(15)	(13)	(7)	(7)	(9)	(12)	(3)	(4)	(9)
NV Energy	(36)	(25)	(55)	(31)	(35)	(35)	(27)	(5)	(25)	(60)	(82)	(38)
PacifiCorp East	(6)	(3)	(6)	(26)	(36)	(14)	(26)	(32)	(32)	8	(14)	(17)
PacifiCorp West	(3)	(0)	(4)	(13)	(10)	(10)	(8)	(8)	(12)	(14)	(14)	(9)
Portland Gen. Elec.	(9)	(8)	(8)	(15)	(6)	(7)	(15)	(22)	(65)	(45)	(26)	(21)
Powerex	4	(12)	(8)	(29)	(17)	(18)	(6)	1	(6)	(5)	8	(8)
PSC of New Mexico	2	3	(2)	(4)	(3)	(7)	(9)	(10)	(12)	(12)	(8)	(6)
Puget Sound En.	13	(5)	(11)	(33)	(38)	(20)	(20)	(12)	(6)	3	2	(12)
Salt River Proj.	(10)	(4)	(10)	(3)	(2)	11	9	(14)	(30)	(32)	(30)	(10)
Seattle City Light	1	(2)	(4)	(7)	(9)	(5)	(3)	(3)	(0)	(0)	1	(3)
Tacoma Power	1	(0)	(1)	(3)	(3)	(2)	(1)	(1)	(1)	(1)	1	(1)
Tucson Elec. Pow.	(3)	(6)	(6)	(15)	(20)	(9)	(4)	(11)	(22)	(22)	(11)	(12)
Turlock Irrig. Dist.	(0)	0	(1)	(1)	(1)	(2)	(1)	(0)	(0)	(0)	(0)	(1)
WAPA DSW			(0)	0	0	1	1	(2)	(4)	(3)	(2)	(1)

Figure 3.30 Average increase (decrease) in downward uncertainty using the regression method relative to histogram method

	2023											2023
	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
Arizona Publ. Serv.	(18)	(18)	(16)	(4)	(12)	(12)	(1)	(7)	(13)	(22)	(23)	(13)
Avangrid			(26)	(18)	(9)	(10)	(38)	(36)	(49)	(71)	(81)	(38)
Avista	(3)	(3)	(3)	(8)	(8)	(6)	(7)	(8)	(11)	(10)	(8)	(7)
BANC	(9)	(6)	(10)	(5)	(4)	(4)	1	(2)	(4)	(10)	(8)	(6)
BPA	(65)	(47)	(61)	(74)	(51)	(38)	(60)	(65)	(83)	(92)	(89)	(66)
California ISO	(12)	(34)	(98)	(81)	(125)	(122)	(37)	(8)	(31)	(9)	(27)	(53)
El Paso Electric			1	0	(3)	2	3	(3)	(11)	(11)	(12)	(4)
Idaho Power	2	(3)	(14)	(18)	(20)	(13)	(8)	(18)	(19)	(21)	(10)	(13)
LADWP	(16)	(19)	(32)	(19)	(19)	(8)	9	(3)	(8)	(7)	(4)	(11)
NorthWestern En.	(17)	(10)	(6)	(4)	(7)	(11)	(7)	(5)	(5)	(11)	(3)	(8)
NV Energy	(35)	(32)	(59)	(32)	(27)	(47)	(18)	22	(21)	(57)	(56)	(33)
PacifiCorp East	(13)	(8)	(30)	(35)	(37)	(26)	(15)	(32)	(47)	(33)	(40)	(29)
PacifiCorp West	(11)	(2)	(7)	(16)	(16)	(20)	(27)	(31)	(44)	(46)	(48)	(24)
Portland Gen. Elec.	(14)	(5)	(10)	(18)	(8)	1	(9)	(22)	(49)	(25)	(9)	(15)
Powerex	10	(10)	(16)	(30)	(15)	(13)	(6)	(16)	(7)	4	15	(8)
PSC of New Mexico	(7)	(5)	(6)	(3)	1	(2)	3	(2)	(14)	(10)	(7)	(5)
Puget Sound En.	(7)	(7)	(17)	(11)	(9)	(8)	(7)	(11)	(5)	(12)	(2)	(9)
Salt River Proj.	(21)	(19)	(21)	(6)	1	8	12	(10)	(24)	(29)	(27)	(12)
Seattle City Light	2	(1)	(4)	(8)	(7)	(5)	(2)	(3)	(1)	1	2	(2)
Tacoma Power	1	(0)	(2)	(4)	(4)	(3)	(1)	(2)	(0)	(0)	1	(1)
Tucson Elec. Pow.	(11)	(16)	(13)	(4)	(4)	(1)	5	(2)	(11)	(13)	(16)	(8)
Turlock Irrig. Dist.	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(1)	(2)	(2)	(1)
WAPA DSW			1	1	(1)	(0)	1	(1)	(4)	(1)	(2)	(1)

3.5.3 Resource sufficiency evaluation enhancements phase 2

The ISO implemented a few changes to the resource sufficiency evaluation on July 1, 2023 as part of Phase 2 (track 1) of resource sufficiency evaluation enhancements. This included the following enhancements:

- **Adjustment for real-time low-priority and economic exports in the California ISO balancing area's resource sufficiency evaluation.** These exports are no longer strictly counted as part of the California ISO balancing area's demand obligation.

- **Implementation of assistance energy transfers (AET). This option gives balancing areas access to excess WEIM supply that may not have been available otherwise following a resource sufficiency evaluation failure.** Balancing areas can opt into AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge.

More detailed information on each of these enhancements is discussed in the following sections.

Adjustment for lower priority exports in CAISO's resource sufficiency evaluation

Export schedules in the market can be based on economic bids or self-scheduled (price-taking). The market defines different levels of prioritization for self-scheduled exports. The highest priority is given to existing transmission contract and transmission ownership right export schedules. Next, exports that are supported by capacity that is not resource adequacy capacity are given high-priority. Low-priority exports are those supported by resource adequacy capacity. Within this category, export schedules that clear the residual unit commitment process can be self-scheduled in the real-time market with day-ahead priority (DA-LPT). Real-time low-priority price-taking (RT-LPT) exports are instead self-scheduled directly in real-time.

RT-LPT and economic exports that clear the hour-ahead scheduling process (HASP) are effectively no longer counted against CAISO obligation in the resource sufficiency evaluation. During phase 1 of the initiative, analysis by the ISO showed the potential for advisory WEIM imports to support additional exports in HASP.[186] These hourly exports would then be counted against CAISO in the resource sufficiency evaluation but may not have existed without WEIM imports to balance these. Further, it was identified that these real-time low-priority and economic exports could be curtailed by CAISO operators during tight system conditions subject to operator judgement and consistent with good utility practices.[187] As a result, these export schedules were adjusted in CAISO capacity and flexibility tests on July 1, 2023. In effect, only higher-priority exports, as well as exports that were scheduled through the ISO residual unit commitment process, are counted in the CAISO demand obligation.[188]

186 California ISO, *Interaction of Hourly Intertie Schedules and WEIM Transfers*, April 26, 2022: https://www.caiso.com/InitiativeDocuments/AnalysisReport-InteractionofHourlyIntertieSchedulesandTransfers-WEIMResourceSufficiencyEvaluationEnhancements.pdf

187 California ISO, *WEIM RSE Enhancements Phase 2 Second Revised Final Proposal*, December 6, 2022: https://www.caiso.com/InitiativeDocuments/SecondRevisedFinalProposal-WEIMResourceSufficiencyEvaluationEnhancementsPhase2.pdf

188 Including existing transmission contract (ETC) and transmission ownership right (TOR) export schedules.

The change in the treatment of exports prevented the CAISO balancing area from failing the flexibility test during four 15-minute intervals in August. The CAISO balancing area did not fail the flexibility or capacity test during 2023.

Assistance energy transfers

Assistance energy transfers (AET) give balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[189]

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 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 3.10 shows the days in which a balancing area was opted in to assistance energy transfers during the year since its implementation on July 1. Five balancing areas were opted in to the program in at least one day during this period: Avangrid, CAISO, NorthWestern Energy, NV Energy, and the Public Service Company of New Mexico. Avangrid was opted in to AET during all days since implementation.

Table 3.11 summarizes all balancing areas that were opted in to assistance energy transfers in at least one day during the year, 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 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. Table 3.11 also shows the percent of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. The table also shows the average and maximum WEIM imports added in the 5-minute market because of AET.[190] The CAISO balancing area did not fail the resource sufficiency evaluation during 2023, therefore opting in to

[189] 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/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

[190] The average WEIM imports added summarizes the average additional WEIM imports achieved in the 5-minute market due to AET during all intervals in which the balancing area both failed the resource sufficiency evaluation and opted in to the program (including intervals when the additional WEIM imports achieved was zero).

AET had no effect (and no surcharge).[191] All other balancing areas who opted in to the program failed the resource sufficiency evaluation and achieved additional WEIM imports during some intervals.

Table 3.10 Assistance energy transfer opt-in designations by balancing area (2023)

Balancing area	Period opted in to Assitance Energy Transfers	Days opted in to AET
Avangrid	Jul. 1 - Dec. 31	184
California ISO	Aug. 15 - Aug. 17, Aug. 22 - Aug. 23, Aug. 28 - Aug. 30, Oct. 14, Nov. 8 - Nov. 9, Nov. 28 - Nov. 30	14
NorthWestern Energy	Aug. 23 - Dec. 31	131
NV Energy	Jul. 7 - Sep. 15, Sep. 25 - Oct. 15, Oct. 25 - Oct. 31, Dec. 1 - Dec. 31	130
Public Service Company of New Mexico	Jul. 8 - Jul. 29, Aug. 5 - Aug. 31	49

Table 3.11 Resource sufficiency evaluation failures during assistance energy transfer opt-in (2023)

Balancing area	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)
Avangrid	56	9%	2	61
California ISO	0	N/A	N/A	N/A
NorthWestern Energy	16	46%	20	81
NV Energy	12	28%	26	177
Public Service Company of New Mexico	30	46%	32	210

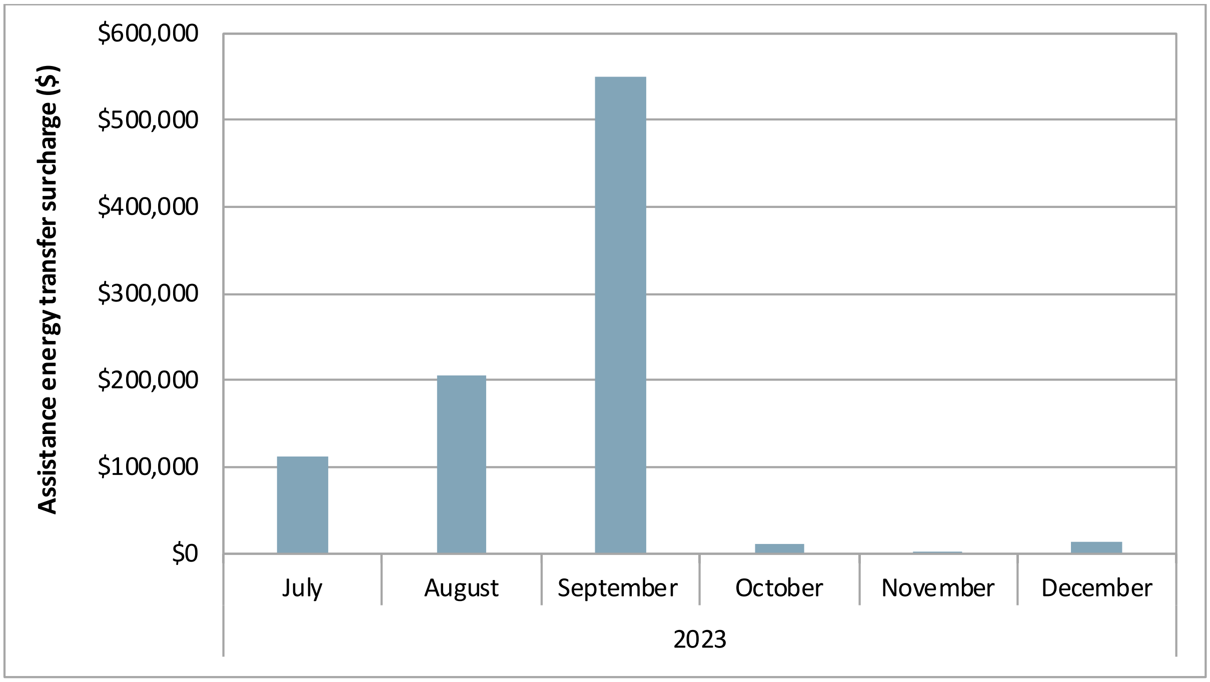
The assistance energy transfer surcharge is applied during any interval in which an opt-in balancing area fails the upward flexibility or capacity test. The surcharge is calculated as the *applicable real-time assistance energy transfer* times the real-time bid cap.[192] The applicable AET quantity is based on the lesser of either (1) the tagged dynamic WEIM transfers or (2) the amount by which the balancing area failed the resource sufficiency evaluation. If the tagged dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the CAISO balancing area.

Figure 3.31 shows the monthly assistance energy transfer surcharge for opted-in balancing areas since implementation of the program on July 1. Between July and December, the total surcharge for assistance energy transfers was around $893,000.

191 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

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

Figure 3.31 Monthly assistance energy transfer surcharge (2023)



3.6 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.[193] 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.

193 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 ARB's website here: https://ww2.arb.ca.gov/mrr-data

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.[194] If all bids have been exhausted, the price may be set higher than the greenhouse gas bid of a marginal resource.

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.

Greenhouse gas prices

Figure 3.32 shows monthly average cleared WEIM greenhouse gas prices and hourly average quantities for energy delivered to California from 2021 to 2023.[195] Average 15-minute market 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 2023, weighted 15-minute greenhouse gas prices averaged $10.99/MWh, while 5-minute prices averaged $6.95/MWh. Prices were similar to 2022, when they averaged $11.18/MWh and $5.84/MWh in the 15-minute and 5-minute market, respectively. Overall, prices over the last two years have been high due to an increase in the cost of greenhouse gas allowances. In 2023, the average cost of greenhouse gas allowances in bilateral markets averaged $34.06/ mt$CO_2$e, a 15 percent increase from 2022. Allowance costs in 2022 were 27 percent higher than they were in 2021, highlighting the recent upward trend. The $34.06/ mt$CO_2$e cost of allowances translates to about $14.47/MWh for a relatively efficient gas unit.[196]

Weighted average greenhouse gas prices in the 5-minute market averaged almost 40 percent lower than 15-minute prices throughout 2023. In comparison, average 5-minute market greenhouse gas prices were 48 percent lower than 15-minute prices in 2022. Price differences between markets may occur if resources are procured in the 15-minute market and then subsequently decrementally dispatched in the 5-minute market. This price separation is often correlated with operator imbalance conformance adjustments, described in Section 7.4, which are consistently higher in the 15-minute market than the 5-minute market during peak net load hours.

194 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

195 An issue with the ISO greenhouse gas obligation calculation may have affected prices and quantities in 2021. After Los Angeles Department of Water and Power (LADWP) joined the WEIM in April 2021, the market was incorrectly including LADWP's base schedule transfers as market transfers. The ISO fixed this issue on January 27, 2022.

196 Discussed further in Section 1.2.8.

Figure 3.32 WEIM greenhouse gas price and cleared quantity

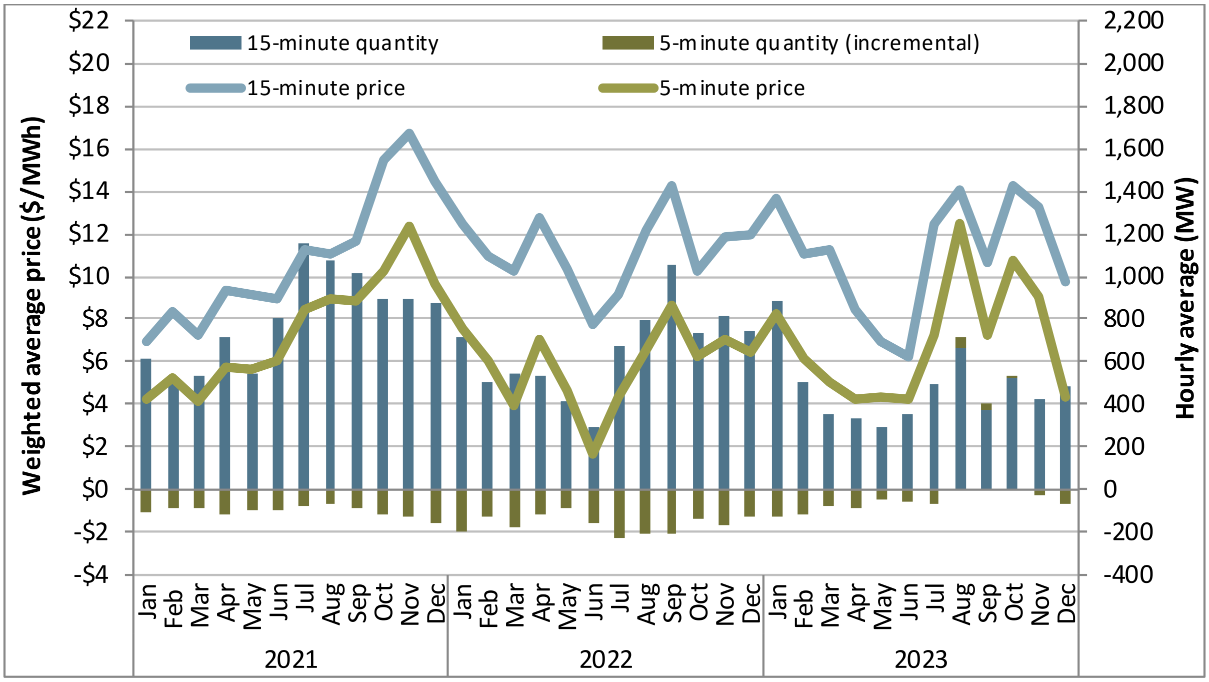


Figure 3.33 and Figure 3.34 illustrate the frequency of high prices for each market and quarter of the last two years, as well as the maximum price by quarter. In Figure 3.33, we see a drastic increase in WEIM greenhouse gas compliance prices in the second half of 2021, when prices in the 15-minute market were over $16/MWh in almost 20 percent of intervals in the fourth quarter. There were fewer price spikes in 2022, when less than 5 percent of intervals had prices over $16/MWh. In 2023, there were high price spikes again in the fourth quarter, with more than 15 percent of intervals exhibiting prices over $16/MWh. This trend was similar for greenhouse gas prices in the 5-minute market as well, as seen in Figure 3.34.

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 2023 were $53/MWh and $107/MWh, respectively.

Figure 3.33 High 15-minute WEIM greenhouse gas prices

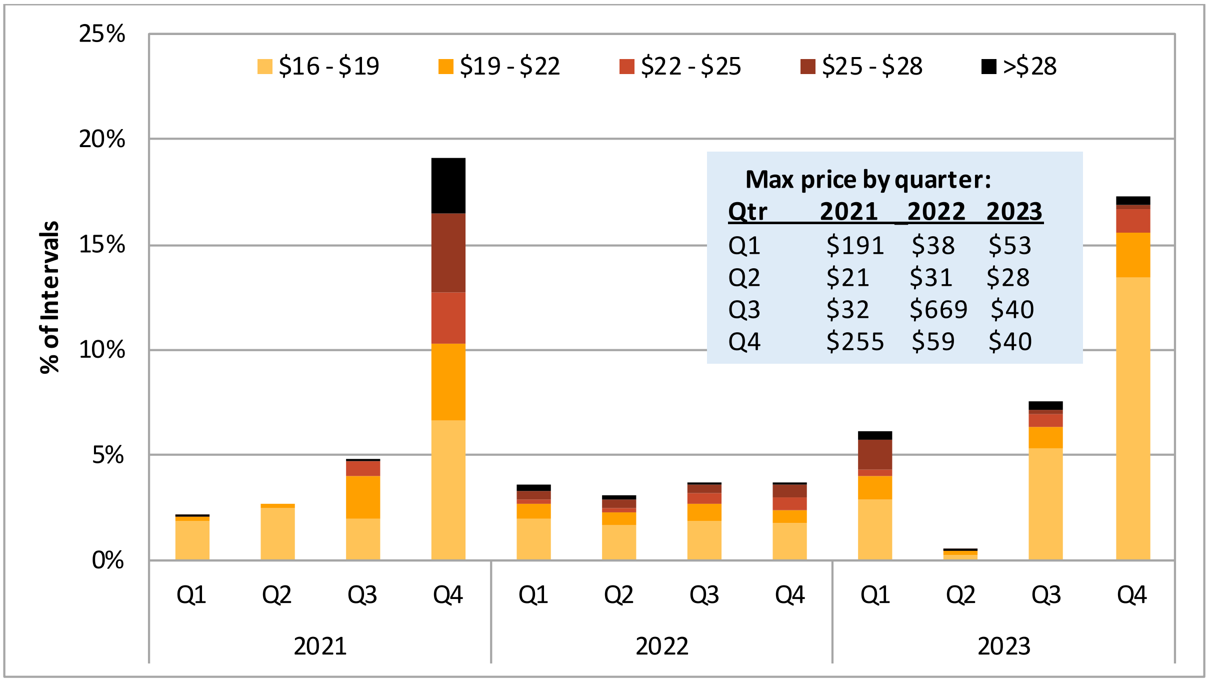
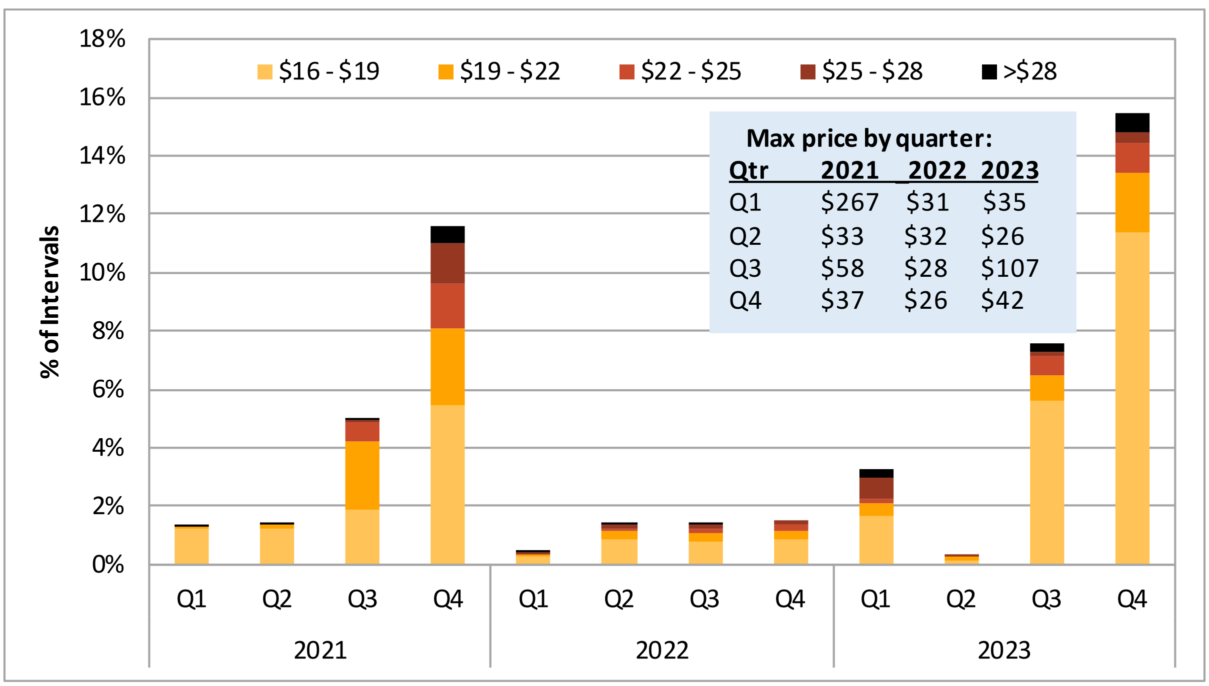


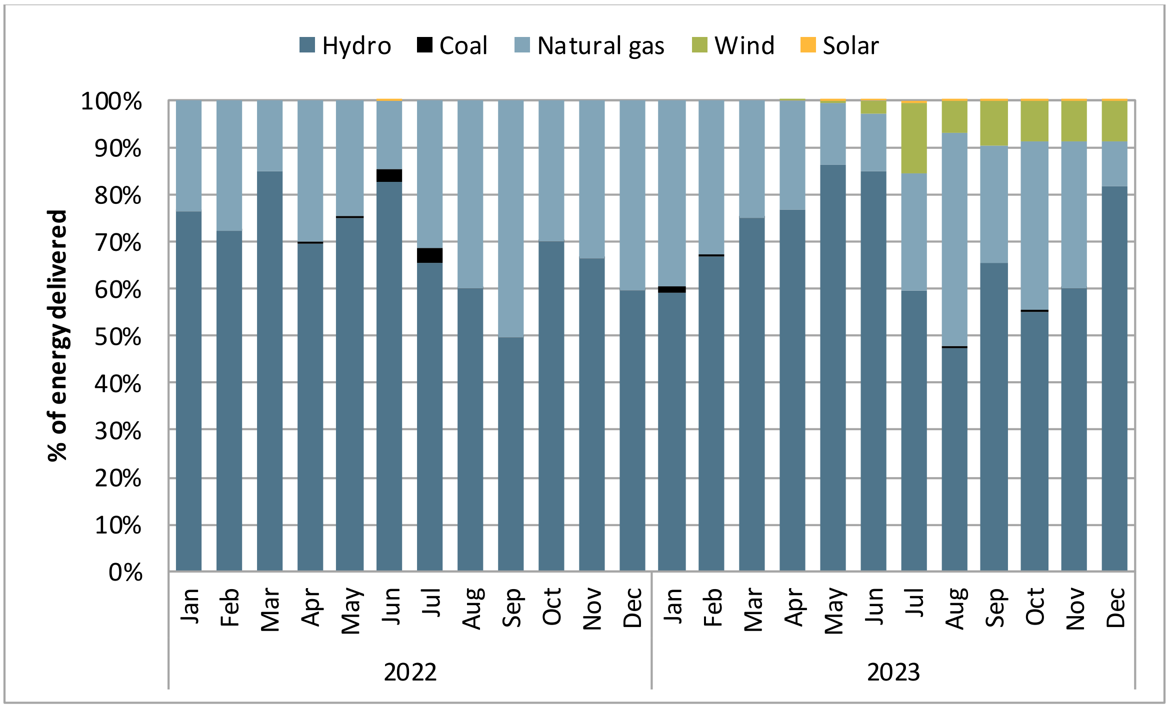
Figure 3.34 High 5-minute WEIM greenhouse gas prices



Energy delivered to California by fuel type and balancing area

Figure 3.35 shows hourly average greenhouse gas energy by fuel type. In 2023, about 70 percent of WEIM greenhouse gas compliance obligations were assigned to hydro resources, similar to 2022. Greenhouse gas attribution to wind resources increased in 2023, due in part to Avangrid joining the WEIM in April.[197] Figure 3.36 shows the percentage of total greenhouse gas energy cleared by region. In 2023, 75 percent of greenhouse gas energy came from entities in the Northwest areas with large fleets of hydroelectric resources, similar to 2022. Table 3.12 provides details on the percentage of total greenhouse gas energy cleared by WEIM balancing area. In 2023, Puget Sound and Idaho Power each accounted for almost 20 percent of the total greenhouse gas energy deemed delivered.

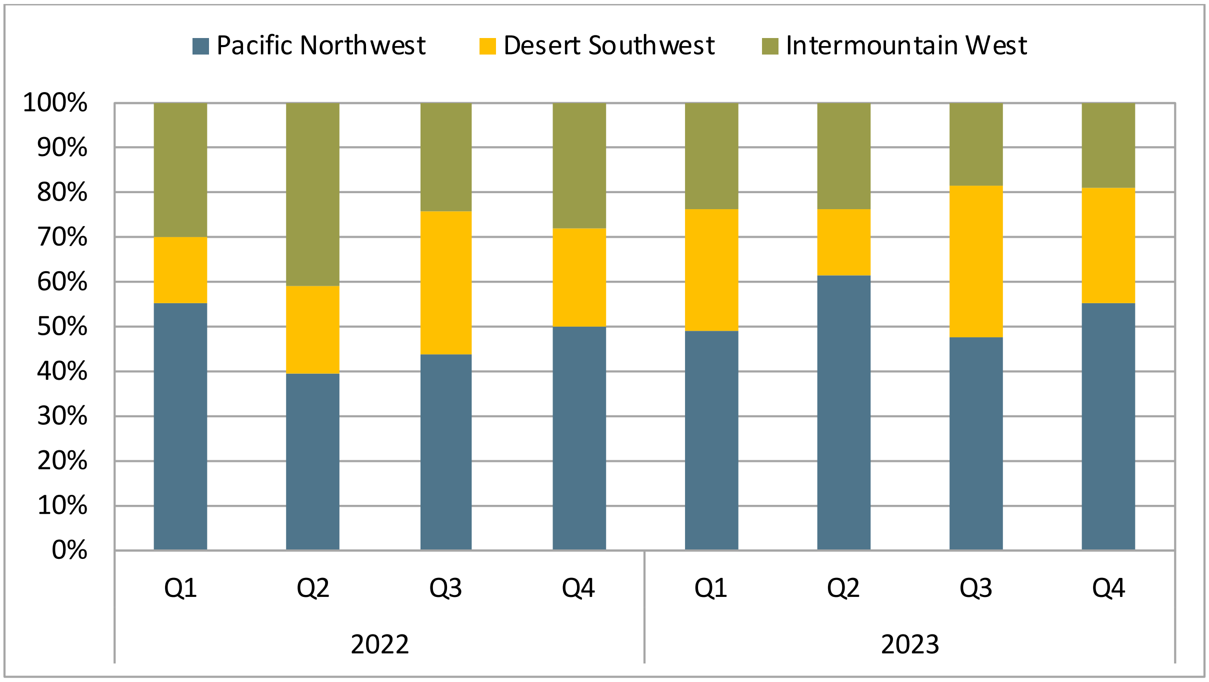
Figure 3.35 Percentage of greenhouse gas energy delivered to California by fuel type[198]



197 See Figure 3.3.

198 In 2021 and 2022, there were a couple negligible instances of energy from oil and solar delivered to California.

Figure 3.36 Percentage of greenhouse gas energy delivered to California by region[199]



[199] Desert Southwest includes Arizona Public Service, NV Energy, PNM, Salt River Project, El Paso Electric, Tucson Electric Power, and WAPA (DSW). Intermountain West includes Idaho Power, Northwestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power. These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas.

Table 3.12 Percentage of greenhouse gas energy delivered to California by area[200]

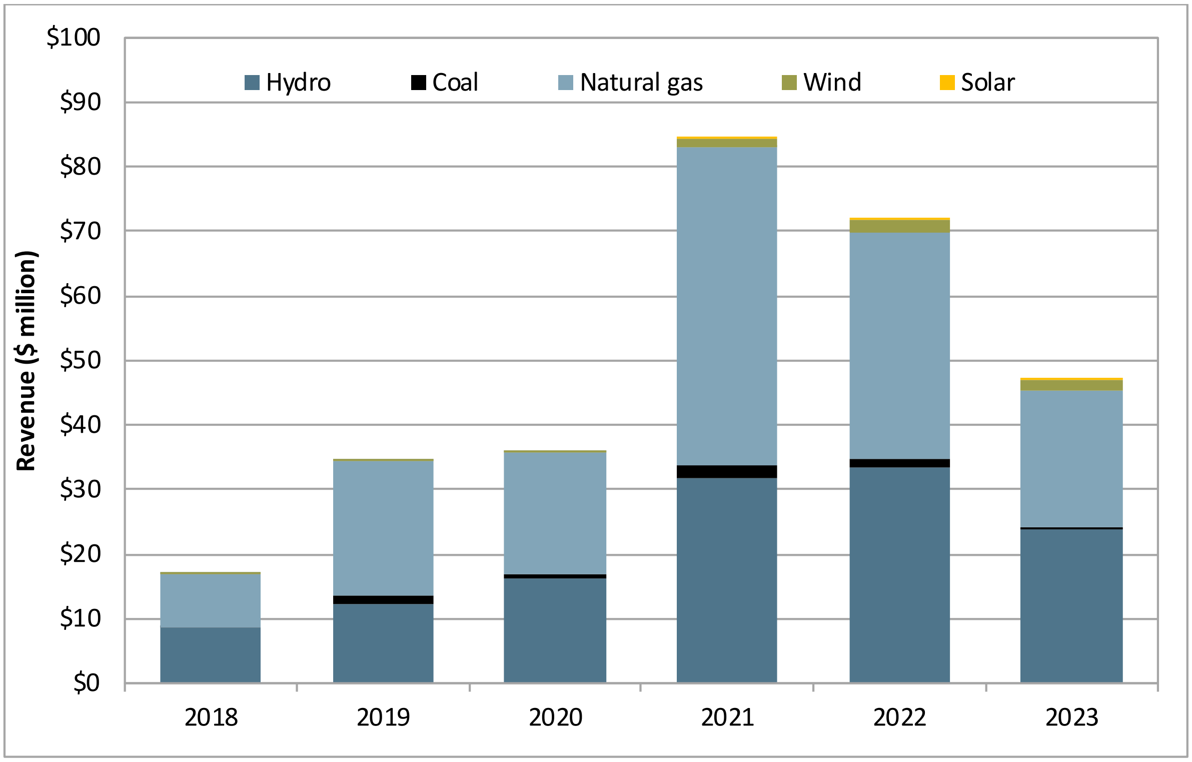
	2022				2023			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Pacific Northwest								
Avangrid	0%	0%	0%	0%	0%	1%	8%	3%
Bonneville Power Administration	0%	4%	3%	3%	3%	8%	1%	1%
PacifiCorp West	16%	12%	16%	18%	16%	16%	1%	1%
Portland General Electric	13%	7%	8%	8%	9%	9%	8%	10%
Puget Sound Energy	5%	5%	6%	6%	7%	16%	21%	26%
Seattle City Light	22%	9%	8%	9%	9%	6%	5%	7%
Tacoma Power	0%	1%	4%	6%	6%	6%	4%	7%
Desert Southwest								
Arizona Public Service	3%	4%	7%	6%	8%	2%	11%	8%
NV Energy	2%	6%	5%	5%	9%	2%	6%	6%
Public Service New Mexico	0%	0%	2%	1%	1%	1%	4%	3%
Salt River Project	8%	6%	11%	8%	8%	9%	12%	7%
Tucson Electric Power	0%	4%	7%	3%	2%	0%	1%	2%
WAPA Desert Southwest	0%	0%	0%	0%	0%	0%	0%	0%
Intermountain West								
Avista	6%	16%	8%	9%	0%	0%	0%	0%
Idaho Power	23%	22%	13%	14%	18%	22%	18%	17%
PacifiCorp East	1%	3%	3%	5%	6%	2%	1%	2%

WEIM greenhouse gas revenues

Figure 3.37 shows revenues accruing to WEIM resources for energy delivered to California by fuel type. In 2023, revenues totaled roughly $47.1 million, a 35 percent decrease from last year when revenues were almost $72 million. In 2023, natural gas revenues comprised 45 percent of revenues, while hydroelectric revenues comprised 50 percent. Coal and wind revenues comprised 1 and 4 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.

200 Some balancing areas are not included due to little to no GHG attribution in 2022 or 2023.

Figure 3.37 Annual greenhouse gas revenues



3.7 WEIM imbalance offset costs

Real-time imbalance offset costs in the WEIM are calculated for each balancing area from the difference between the total money *paid out* and the total money *collected* for energy settled in the real-time markets. Any revenue shortfall or revenue surplus is allocated to the WEIM entity scheduling coordinator. This charge consists of three components. Any revenue imbalance from the congestion component of price in the real-time energy settlement is collected through the *real-time congestion imbalance offset charge* (RTCIO).[201] Any revenue imbalance from the loss component is collected through the *real-time loss imbalance offset charge*, while any remaining revenue imbalance is accounted for through the *real-time imbalance energy offset charge* (RTIEO).

Figure 3.38 shows monthly imbalance offset costs for WEIM balancing areas, excluding the CAISO area. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus). Monthly *congestion* imbalance offsets for revenue surplus (dark green bars) were significantly higher in 2023 at around $307 million, compared to $114 million in 2022. More than half of the congestion imbalance offsets paid out for revenue surplus in 2023

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

were to Powerex ($167 million). Overall, *energy* imbalance offsets for WEIM balancing areas were lower in 2023 compared to 2022.

Figure 3.38 Monthly WEIM real-time imbalance offset costs

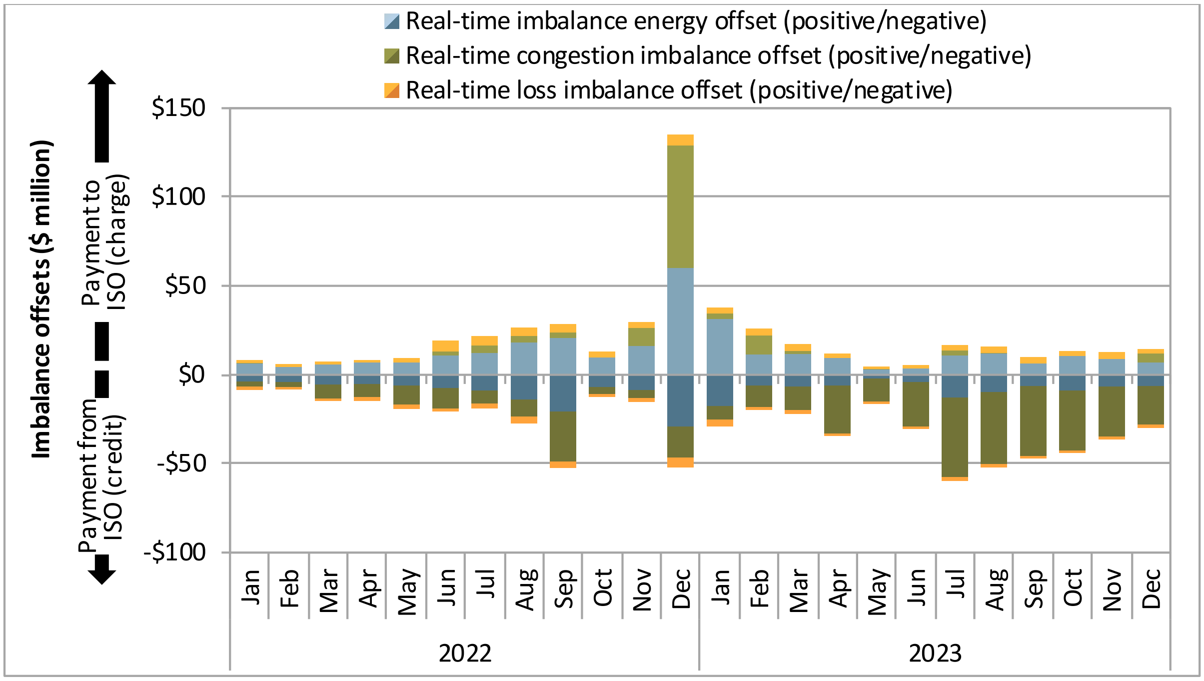


Figure 3.39 through Figure 3.41 show the monthly real-time energy, congestion, or loss imbalance offset charges for each balancing area in the WEIM. Negative amounts (or credits for revenue surplus) are shown in parentheses. Figure 3.42 shows the *total* real-time imbalance offset charges for each month and balancing area. The final column in each of these figures shows the total amount for each balancing area in 2023.

Figure 3.39 Real-time imbalance energy offset charges (credits) by month and balancing area ($ millions)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	*Total*
Arizona Publ. Serv.	8.2	2.4	2.4	1.1	0.2	0.9	2.0	2.0	0.9	1.5	1.4	1.2	24.3
Avangrid				(0.1)	0.0	(0.0)	1.1	1.6	0.2	0.2	(0.2)	0.2	2.9
Avista	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	(0.1)	0.0	0.0	(0.0)	0.6
BANC	0.1	(0.0)	(0.0)	(0.0)	0.1	(0.1)	0.1	0.1	(0.2)	(0.3)	0.1	(0.1)	(0.4)
BPA	0.5	0.0	0.7	(0.1)	(0.0)	0.1	0.4	0.3	0.0	0.1	0.2	(0.1)	2.1
El Paso Electric				(0.4)	(0.1)	(0.2)	(0.4)	(0.0)	(0.2)	(0.2)	(0.0)	(0.1)	(1.6)
Idaho Power	1.5	0.5	0.4	0.3	1.4	(0.1)	(0.9)	(0.1)	(0.1)	0.9	0.2	(0.5)	3.4
LADWP	(0.5)	0.0	0.0	(0.1)	(0.1)	(0.3)	(1.0)	0.1	0.0	(0.4)	0.0	0.0	(2.0)
NorthWestern En.	6.3	3.4	2.3	2.3	0.4	0.4	1.8	1.4	0.9	1.6	2.3	2.4	25.5
NV Energy	0.6	0.5	0.6	0.3	0.1	0.1	0.2	0.1	0.1	0.6	0.5	0.7	4.4
PacifiCorp East	7.7	2.1	1.7	1.2	0.3	1.3	2.6	3.4	3.0	4.2	2.1	1.0	30.6
PacifiCorp West	(7.1)	(2.2)	(1.7)	(1.5)	(0.2)	(1.5)	(4.0)	(5.6)	(3.3)	(4.3)	(2.3)	(1.3)	(35.0)
Portland Gen. Elec.	0.1	0.0	(0.0)	0.1	0.1	0.0	0.4	0.2	0.0	0.1	0.1	0.0	1.2
Powerex	0.7	(0.0)	(0.4)	(0.6)	(0.4)	(0.0)	(0.0)	0.5	0.2	(0.2)	(0.3)	(0.2)	(0.8)
PSC of New Mexico	4.1	2.0	2.9	2.8	0.4	0.6	1.2	1.3	0.7	1.0	1.6	1.0	19.6
Puget Sound En.	(6.2)	(2.9)	(3.0)	(2.0)	(0.6)	(0.9)	(2.2)	(2.3)	(1.2)	(1.8)	(2.2)	(2.0)	(27.2)
Salt River Proj.	(3.9)	(0.9)	(1.5)	(1.3)	(0.8)	(0.8)	(4.4)	(1.7)	(1.1)	(1.2)	(1.4)	(2.0)	(21.0)
Seattle City Light	0.1	0.0	0.2	0.1	(0.0)	(0.1)	(0.1)	0.1	0.0	0.0	0.1	0.1	0.4
Tacoma Power	0.0	(0.0)	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Tucson Elec. Pow.	0.6	0.4	0.1	0.4	0.1	0.1	0.1	0.2	(0.0)	0.2	0.2	0.3	2.8
Turlock Irrig. Dist.	0.6	0.2	0.3	0.3	0.1	0.2	0.6	0.7	0.2	0.2	0.1	0.1	3.7
WAPA DSW				0.4	(0.1)	0.0	0.2	0.1	0.1	(0.5)	(0.0)	(0.0)	0.3
	2023												2023

Figure 3.40 Real-time congestion imbalance offset charges (credits) by month and balance area ($ millions)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	*Total*
Arizona Publ. Serv.	(0.1)	(0.5)	(1.0)	(0.7)	(0.3)	(1.4)	0.4	0.0	(0.1)	0.0	(0.2)	(0.2)	(4.0)
Avangrid				(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.0)	(0.0)	(0.1)	(0.0)	(0.7)
Avista	(0.0)	(0.1)	(0.1)	(0.2)	(0.2)	(0.0)	(0.1)	(0.0)	(0.1)	(0.3)	(0.1)	0.0	(1.1)
BANC	(0.0)	0.0	(0.0)	0.1	0.2	0.0	(0.0)	(0.0)	0.0	0.0	0.0	(0.1)	0.2
BPA	(0.4)	0.1	(0.4)	(0.4)	(0.9)	(0.1)	(0.5)	(0.4)	(0.4)	(0.6)	(0.2)	(0.1)	(4.5)
El Paso Electric				(0.1)	(0.4)	(0.3)	(1.1)	(0.3)	(0.2)	(0.9)	(0.0)	(0.0)	(3.3)
Idaho Power	(0.2)	(0.3)	(0.4)	(1.1)	(0.9)	(0.3)	(0.4)	(0.3)	(0.3)	(1.0)	(0.5)	(0.1)	(5.8)
LADWP	(0.2)	(0.1)	(0.4)	(0.4)	(0.4)	(0.4)	(1.9)	(1.2)	(0.8)	(0.5)	(0.3)	(0.3)	(7.0)
NorthWestern En.	(0.2)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	0.1	(0.1)	(0.1)	(0.2)	(0.1)	(0.0)	(0.9)
NV Energy	(0.2)	(0.3)	(0.7)	(0.8)	(0.4)	(0.5)	(0.1)	(0.0)	(0.1)	(0.7)	(0.3)	(0.0)	(4.3)
PacifiCorp East	3.2	10.4	1.9	(5.3)	(1.0)	(1.1)	(2.9)	(2.9)	(3.4)	(3.6)	(8.8)	(10.9)	(24.4)
PacifiCorp West	(0.6)	(0.5)	(0.6)	(1.1)	(1.3)	(0.5)	(1.3)	(1.2)	(0.6)	(1.5)	(0.7)	(0.2)	(9.9)
Portland Gen. Elec.	(0.6)	(0.9)	(0.5)	(0.8)	(0.5)	(0.5)	(0.9)	(3.6)	(0.3)	(2.3)	(0.5)	(0.2)	(11.4)
Powerex	(1.5)	(7.3)	(7.1)	(11.6)	(2.0)	(15.7)	(29.0)	(25.7)	(29.9)	(16.8)	(13.0)	(7.8)	(167.4)
PSC of New Mexico	(0.1)	(0.0)	(0.2)	(1.0)	(0.3)	(0.0)	2.3	(0.1)	(0.2)	(0.1)	(0.7)	5.3	4.9
Puget Sound En.	(0.3)	(0.3)	(0.5)	(0.6)	(0.5)	(0.9)	(2.2)	(1.7)	(0.8)	(2.4)	(0.0)	(0.4)	(10.7)
Salt River Proj.	(2.6)	(1.5)	(0.7)	(1.8)	(2.2)	(1.9)	(2.5)	(1.1)	(1.3)	(1.5)	(2.4)	(1.0)	(20.5)
Seattle City Light	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(0.0)	(1.0)
Tacoma Power	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.4)
Tucson Elec. Pow.	(0.4)	(0.3)	(0.3)	(0.8)	(1.4)	(1.3)	(1.4)	(1.1)	(1.0)	(1.3)	(0.1)	(0.2)	(9.6)
Turlock Irrig. Dist.	(0.0)	(0.0)	(0.1)	(0.0)	0.0	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.2)
WAPA DSW				(0.0)	(0.1)	0.0	(0.0)	(0.2)	(0.0)	(0.0)	(0.0)	(0.0)	(0.5)
	2023												2023

Figure 3.41 Real-time loss imbalance offset charges (credits) by month and balancing area ($ millions)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	*Total*
	2023												2023
Arizona Publ. Serv.	(1.3)	(0.7)	(0.8)	(0.3)	(0.1)	(0.1)	(0.7)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(4.7)
Avangrid				(0.0)	(0.0)	(0.0)	0.0	0.1	0.0	(0.0)	(0.0)	(0.0)	0.0
Avista	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)
BANC	0.2	0.1	(0.1)	0.0	(0.1)	(0.0)	0.0	0.1	0.0	0.0	0.0	0.0	0.3
BPA	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	0.1	(0.0)	0.0	(0.9)
El Paso Electric				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.2)
Idaho Power	0.3	0.4	(0.1)	0.1	(0.0)	0.2	0.0	0.7	0.6	0.1	0.3	0.4	2.9
LADWP	(0.0)	0.1	(0.1)	(0.1)	0.0	0.0	(0.1)	(0.0)	0.0	0.1	(0.1)	0.1	(0.2)
NorthWestern En.	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.1	(0.0)
NV Energy	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(1.2)
PacifiCorp East	(0.5)	0.4	0.8	0.1	0.2	0.0	(0.4)	(0.9)	(0.6)	(0.6)	(0.5)	(1.0)	(3.0)
PacifiCorp West	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.2)	(0.2)	(1.3)
Portland Gen. Elec.	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.1	(0.0)	0.9
Powerex	1.1	1.7	1.7	1.5	0.0	0.9	2.4	2.6	2.7	2.0	3.1	1.7	21.4
PSC of New Mexico	1.1	0.6	1.0	0.3	0.1	0.4	0.3	0.0	0.0	0.1	0.1	(0.0)	4.0
Puget Sound En.	0.1	0.0	(0.1)	(0.0)	(0.0)	0.0	0.1	0.0	0.0	0.1	(0.0)	0.1	0.3
Salt River Proj.	(0.5)	(0.4)	(0.4)	(0.3)	(0.0)	(0.1)	(0.3)	(0.2)	(0.2)	(0.1)	(0.2)	(0.3)	(3.1)
Seattle City Light	0.2	0.1	0.1	0.2	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.0	1.0
Tacoma Power	(0.2)	(0.0)	(0.0)	0.0	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.2)
Tucson Elec. Pow.	(0.2)	(0.0)	(0.1)	(0.1)	0.0	0.1	(0.3)	(0.2)	(0.0)	(0.1)	(0.2)	(0.1)	(1.4)
Turlock Irrig. Dist.	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.2)
WAPA DSW				0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)

Figure 3.42 Total real-time imbalance offset charges (credits) by month and balancing area ($ millions)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	*Total*
	2023												2023
Arizona Publ. Serv.	6.8	1.2	0.7	0.2	(0.2)	(0.6)	1.7	1.9	0.6	1.4	1.1	0.9	15.5
Avangrid				(0.3)	(0.1)	(0.1)	1.1	1.5	0.2	0.1	(0.3)	0.2	2.2
Avista	0.0	(0.0)	(0.0)	(0.2)	(0.2)	(0.0)	0.0	0.1	(0.2)	(0.2)	(0.0)	0.0	(0.6)
BANC	0.2	0.1	(0.1)	0.0	0.2	(0.1)	0.1	0.1	(0.2)	(0.2)	0.1	(0.1)	0.1
BPA	(0.1)	(0.1)	0.1	(0.6)	(1.0)	(0.1)	(0.2)	(0.2)	(0.4)	(0.3)	(0.1)	(0.2)	(3.3)
El Paso Electric				(0.5)	(0.5)	(0.5)	(1.5)	(0.4)	(0.4)	(1.1)	(0.0)	(0.1)	(5.0)
Idaho Power	1.6	0.7	(0.2)	(0.7)	0.4	(0.1)	(1.2)	0.2	0.1	0.0	(0.0)	(0.2)	0.5
LADWP	(0.7)	0.1	(0.5)	(0.5)	(0.5)	(0.7)	(2.9)	(1.2)	(0.8)	(0.9)	(0.4)	(0.3)	(9.2)
NorthWestern En.	6.1	3.3	2.2	2.2	0.3	0.3	1.9	1.3	0.8	1.4	2.3	2.4	24.5
NV Energy	0.1	0.2	(0.3)	(0.5)	(0.4)	(0.5)	(0.0)	(0.1)	(0.0)	(0.2)	0.2	0.5	(1.1)
PacifiCorp East	10.5	13.0	4.4	(4.0)	(0.5)	0.2	(0.8)	(0.4)	(1.0)	(0.0)	(7.3)	(10.9)	3.2
PacifiCorp West	(8.0)	(2.8)	(2.4)	(2.7)	(1.5)	(2.0)	(5.4)	(6.9)	(3.9)	(5.8)	(3.2)	(1.7)	(46.3)
Portland Gen. Elec.	(0.3)	(0.7)	(0.4)	(0.6)	(0.4)	(0.4)	(0.4)	(3.3)	(0.2)	(2.1)	(0.4)	(0.2)	(9.3)
Powerex	0.2	(5.6)	(5.8)	(10.7)	(2.3)	(14.8)	(26.7)	(22.6)	(27.0)	(15.0)	(10.2)	(6.3)	(146.8)
PSC of New Mexico	5.2	2.6	3.7	2.0	0.2	0.9	3.8	1.2	0.5	0.9	1.0	6.3	28.4
Puget Sound En.	(6.4)	(3.2)	(3.6)	(2.6)	(1.1)	(1.7)	(4.4)	(4.0)	(1.9)	(4.1)	(2.2)	(2.3)	(37.6)
Salt River Proj.	(7.0)	(2.7)	(2.6)	(3.4)	(3.0)	(2.8)	(7.1)	(2.9)	(2.7)	(2.9)	(4.0)	(3.3)	(44.6)
Seattle City Light	0.3	0.1	0.2	0.2	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	0.1	0.4
Tacoma Power	(0.2)	(0.1)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.5)
Tucson Elec. Pow.	0.1	0.1	(0.3)	(0.5)	(1.3)	(1.1)	(1.6)	(1.1)	(1.1)	(1.1)	(0.1)	(0.1)	(8.2)
Turlock Irrig. Dist.	0.5	0.2	0.2	0.3	0.1	0.2	0.5	0.7	0.2	0.2	0.1	0.1	3.3
WAPA DSW				0.4	(0.2)	0.0	0.2	(0.1)	0.0	(0.5)	(0.1)	(0.0)	(0.2)

Issue in allocation of 5-minute market component of real-time congestion imbalance offset costs

Real-time congestion imbalance offset costs occur when the congestion payments the ISO pays out do not equal the congestion payments collected by the ISO (i.e., the payments and collections do not balance). This calculation considers the net congestion revenue from a number of components including 15-minute market instructed imbalance energy, 5-minute market instructed imbalance energy, uninstructed imbalance energy, and unaccounted for energy. Starting June 26, 2023, a software defect affected the allocation of the *5-minute market* component of the congestion offset calculation. The issue was fixed on December 12, 2023.

Figure 3.43 shows the daily 5-minute market congestion revenue during 2023 across all WEIM entities where payments to the ISO (charge) are shown positive in red and payments from the ISO (credit) are shown negative in blue.[202] The *total* positive or negative congestion offset for each day is also shown for comparison in the lighter shades.

Figure 3.44 shows the same information, except with only the 5-minute market component during the period impacted by the issue. Figure 3.45 shows these congestion offsets split out by different types of congestion. The allocation of congestion revenue associated with internal transmission constraints (yellow bars) and the total WEIM transfer scheduling limit constraints (green bars) were not impacted by the software defect.[203] The remainder is primarily from congestion revenue associated with the congestion on individual WEIM transfers for each balancing area and intertie. This category was impacted by the defect.

On November 5, an extreme event resulted in around $5 million in congestion imbalance in the Pacific Northwest region during 14 five-minute market intervals. This amount was then incorrectly allocated across a number of WEIM balancing areas in a way that was inconsistent with each area's expected share of the congestion component of the price. The ISO has manually corrected and resettled the congestion allocation for the 14 five-minute market intervals on November 5. Due to the manual nature and complexity of this correction, the extreme outcome on November 5 was targeted for correction, while additional hours and days during the 169-day period that was impacted by the issue were not adjusted. After accounting for the internal transmission constraint and scheduling limit constraint congestion that were not impacted by the issue, the remaining 5-minute market component of congestion offsets paid to WEIM entities during the affected period was around $12 million, while the amount charged to WEIM entities was around $7 million.[204] DMM understands that some of this amount was misallocated to WEIM entities.

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202 These amounts exclude congestion offset allocations to the CAISO balancing area. Most of the congestion offset allocation to the CAISO balancing area is expected to occur from internal transmission constraint congestion that was not impacted by the underlying issue.

203 Congestion revenue on internal transmission constraints are allocated 100 percent to the balancing area the constraint resides in. WEIM transfer scheduling limit constraints are the constraints on *total* WEIM transfers into or out of a balancing area—typically when a balancing area fails the resource sufficiency evaluation. Congestion revenue on this constraint is allocated 100 percent to the balancing area for which the constraint is formulated.

204 These amounts exclude November 5, which had around $5 million in WEIM transfer constraint congestion manually corrected and resettled.

Figure 3.43 WEIM daily congestion offsets (January–December 2023)

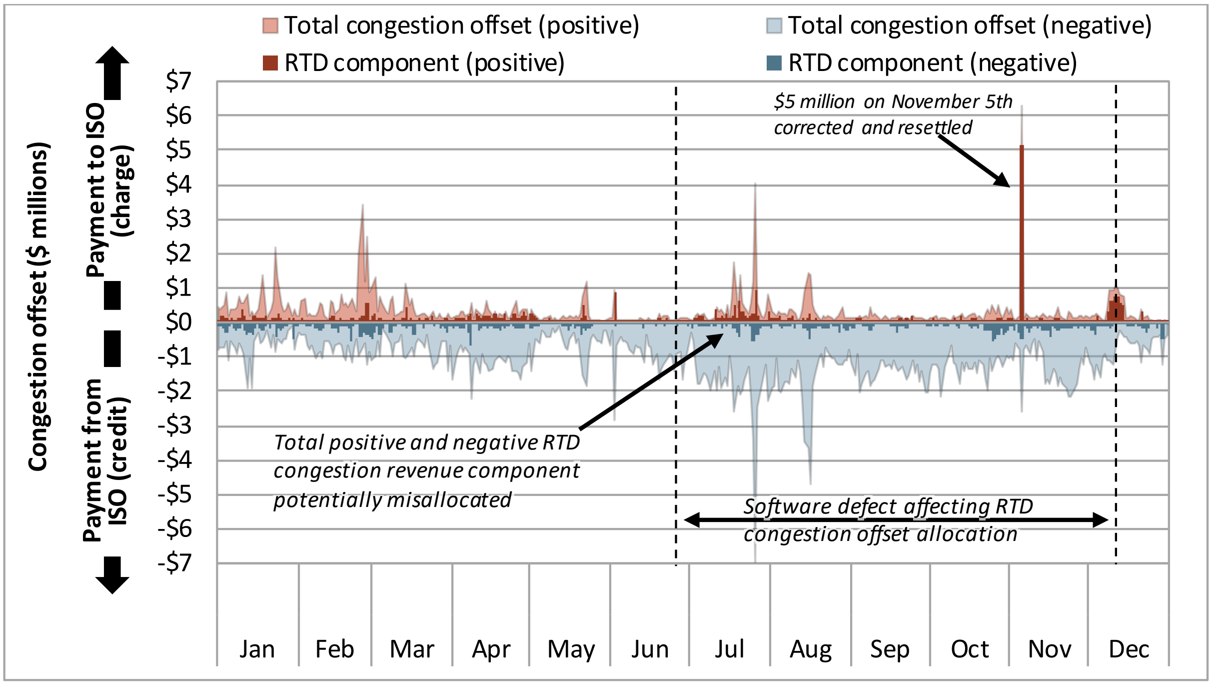


Figure 3.44 WEIM daily 5-minute market component of congestion offset calculation (Issue period, June 26–December 11, 2023)

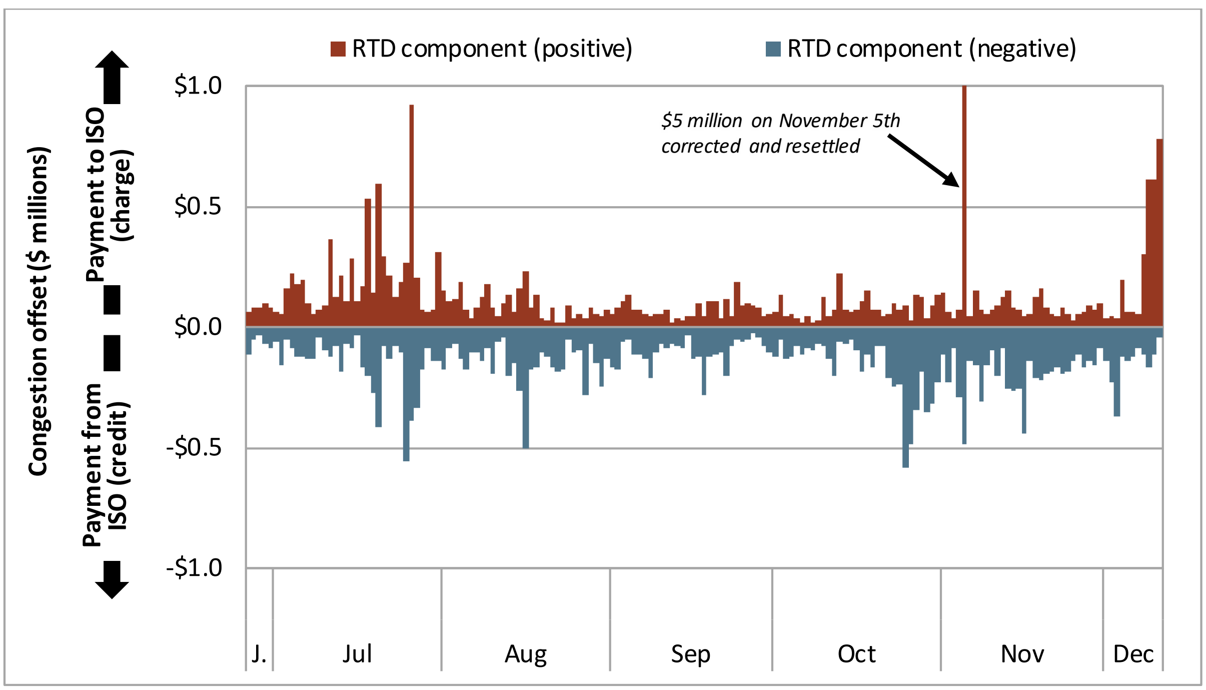
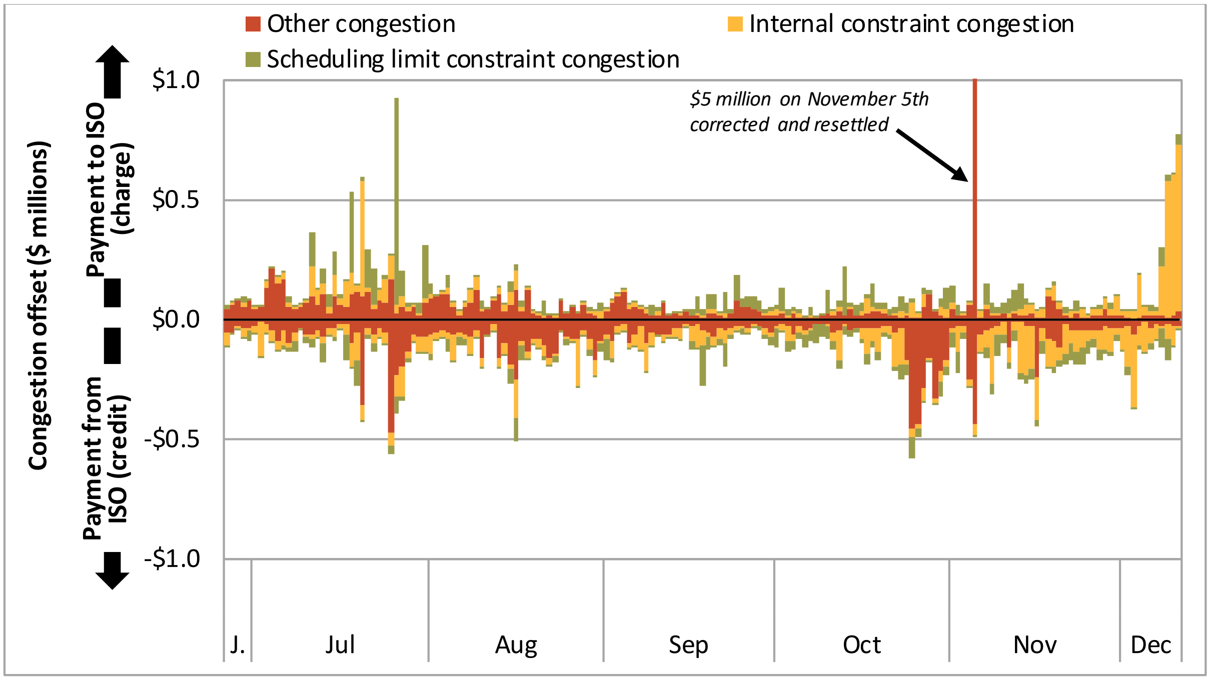


Figure 3.45 WEIM daily 5-minute market component of congestion offset calculation by congestion type (Issue period, June 26–December 11, 2023)



4 Ancillary services

This chapter provides a summary of the ancillary service market in 2023. Key trends highlighted in this chapter include the following:

- **Ancillary service costs decreased to $151 million,** down from $237 million in 2022.
- **On March 1, 2023, CAISO operators began procuring 20 percent of operating reserves as spinning reserves and the rest as non-spinning reserves** following changes in WECC and NERC reliability standards. Historically, operating reserve requirements were split equally between spinning and non-spinning reserves.
- **Operating reserve requirements decreased, and regulation down requirements increased while regulation up requirements remained similar to those in 2022**. Regulation down requirements increased 12 percent to 901 MW. Average combined requirements for spinning and non-spinning operating reserves decreased by 10 percent from the previous year to 1,618 MW.
- **Provision of ancillary services from battery resources continued to increase, replacing procurement from hydroelectric and natural gas resources.** Average hourly procurement of ancillary services from battery resources increased by 29 percent compared to 2022, and batteries now provide 69 percent of CAISO regulation requirements.
- **The frequency of ancillary service scarcity intervals continued to decrease.** There were two intervals with ancillary service scarcities in 2023, compared to 6 in 2022, and 55 in 2021.
- **Fifteen percent of resources failed** unannounced ancillary service performance audits and compliance tests, compared to 22 percent in 2022 and 30 percent in 2021.
- **The CAISO began modeling the impact of providing regulation on batteries' state-of-charge.** Since implementation, the share of regulation provided by batteries has not changed significantly.

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.[205]

4.1 Ancillary service costs

Costs for ancillary services totaled about $151 million in 2023, a significant decrease from $237 million in 2022.

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 CAISO rescinded about 6 percent of ancillary service payments in 2023.

[205] *2010 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2011, pp 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf

Figure 4.1 shows ancillary service costs both as percentage of wholesale energy costs and per megawatt-hour of load from 2021 to 2023. Following an increase in ancillary service costs in 2022, the cost per megawatt-hour decreased from $1.12 to $0.75 in 2023. As a percent of energy costs, ancillary service costs decreased to 1 percent from 1.1 percent in 2022, and 1.3 percent in 2021.

Figure 4.2 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. Similar to previous years, ancillary service costs were highest in the third quarter, corresponding with high loads during the summer months.

In 2023, payments for regulation down, regulation up, spinning reserves, and non-spinning reserves decreased by 24 percent, 31 percent, 63 percent, and 7 percent, respectively. Of all ancillary service products, spinning reserves had the largest decrease in percentage and absolute terms, at around $47.4 million less than what was paid in 2022. This was largely the result of new operating reserve procurement targets, where the CAISO procured spinning reserves at a lower percentage compared to total operating reserve requirements.

Figure 4.1 Ancillary service cost as a percentage of wholesale energy costs (2021–2023)

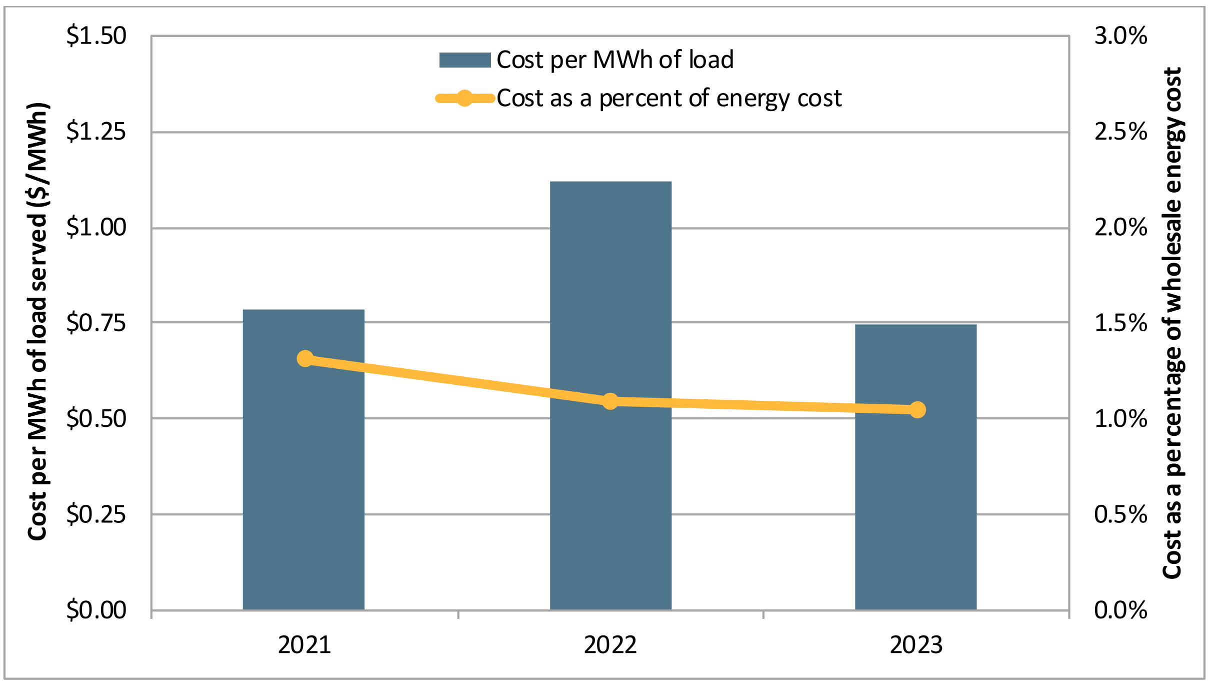
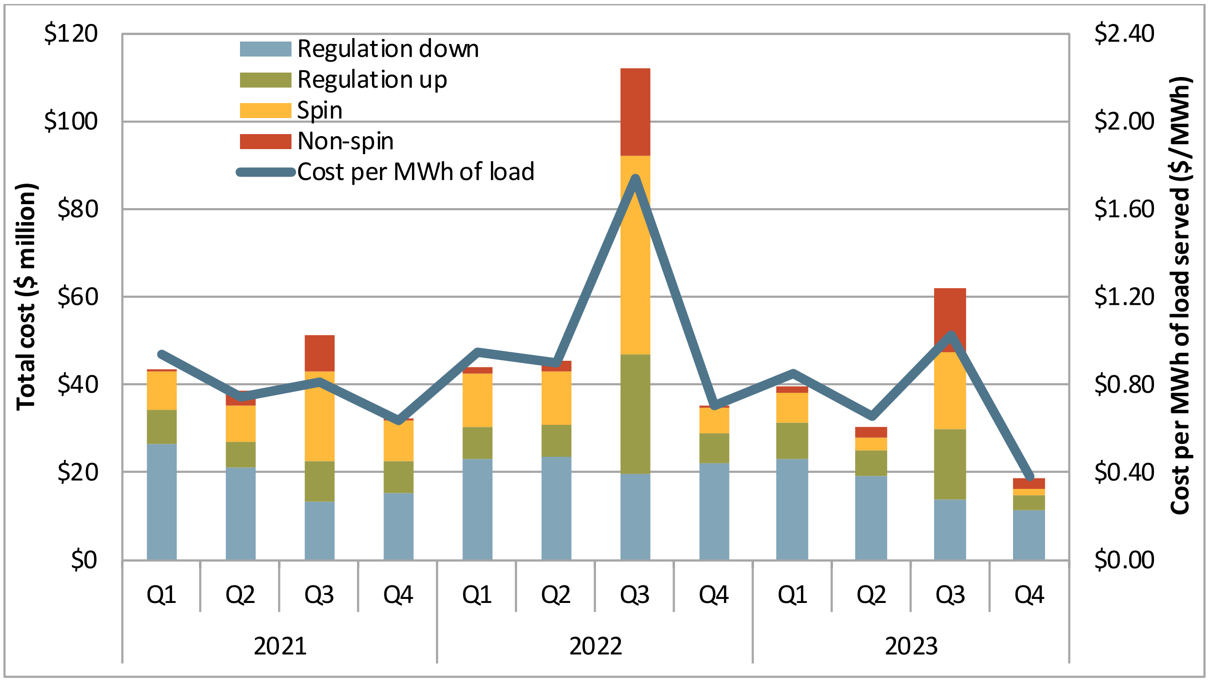


Figure 4.2 Total ancillary service cost by quarter and type



The value of self-provided ancillary services was around 0.1 percent of the total cost of ancillary services, a decrease from 1 percent in 2022. 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 $207,000 in 2023.

4.2 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.[206] 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 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

206 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.

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.

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.[207] 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.[208] 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.

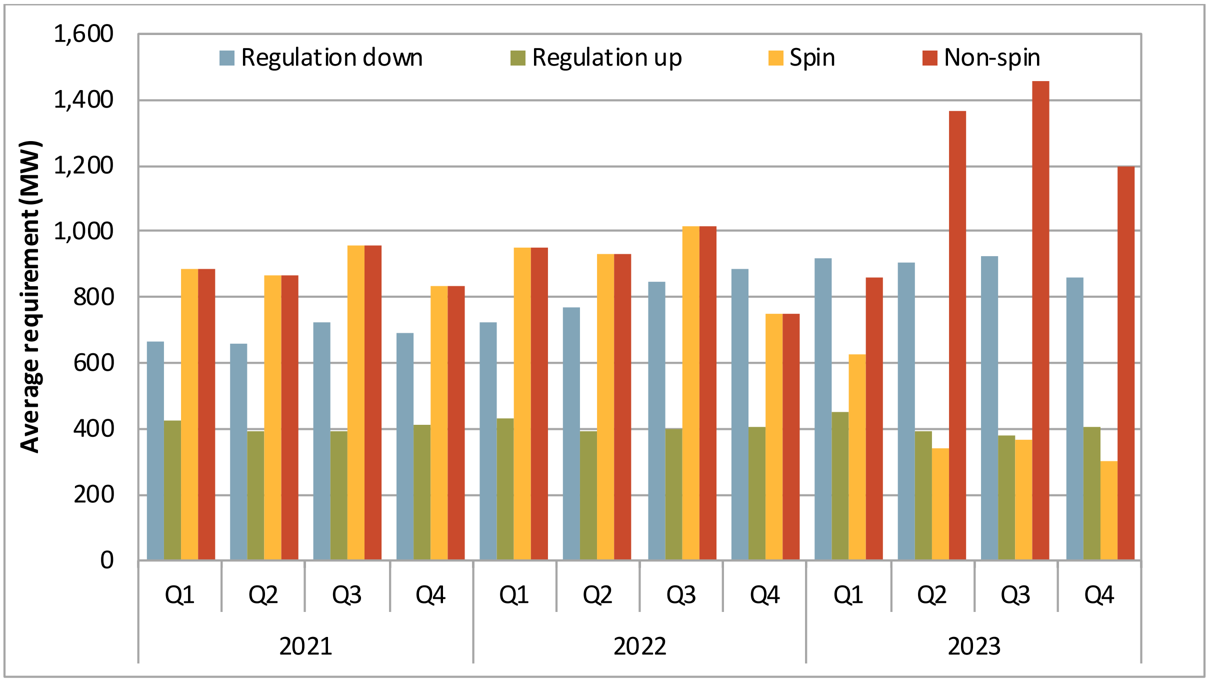
Historically, operating reserve requirements were split equally between spinning and non-spinning reserves. However, starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. In all months after the procurement target changed, CAISO operators procured 20 percent of operating reserves as spinning reserves, and the rest as non-spinning reserves.

Figure 4.3 includes quarterly average day-ahead operating reserve requirements since 2021. Total operating reserve requirements in the day-ahead market averaged 1,618 MW in 2023, a 10 percent decrease from 2022.

[207] 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.

[208] 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 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-002-2 reliability standard is available here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf

Figure 4.3 Quarterly average day-ahead ancillary service requirements



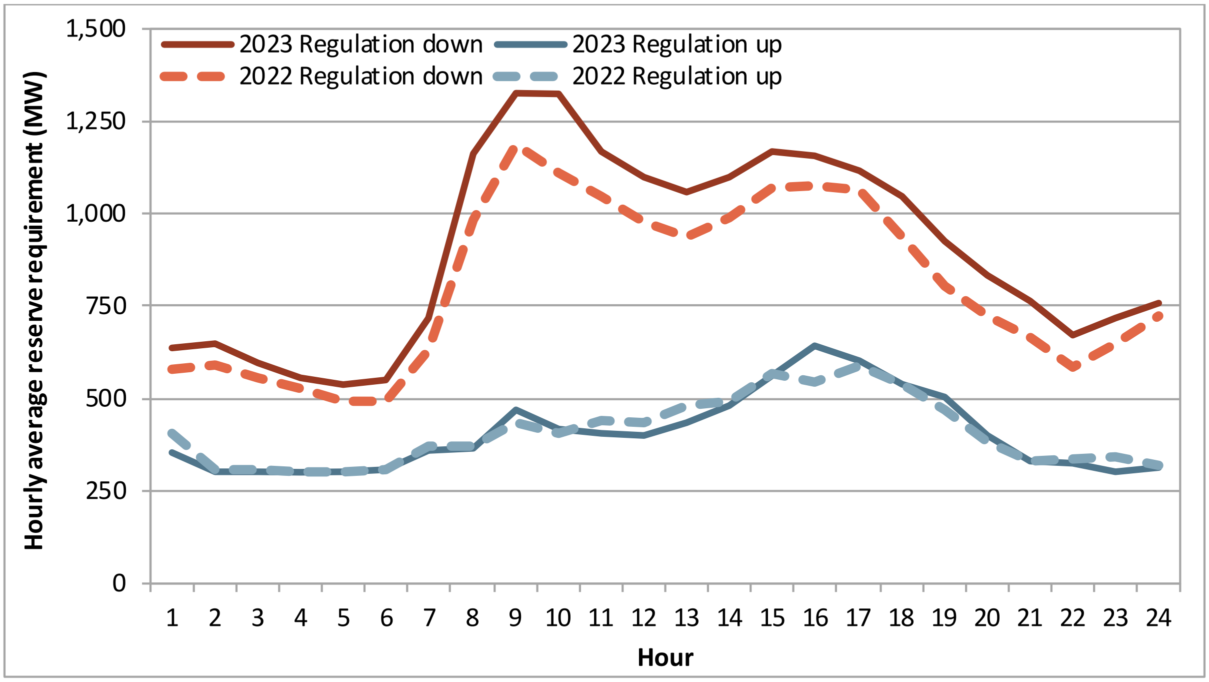
Regulation requirements

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.

Figure 4.3 shows average regulation requirements by quarter. During 2023, day-ahead requirements for regulation down increased substantially, especially during the morning ramp. Regulation down requirements averaged 901 MW, a 10 percent increase from 2022. At 407 MW, average day-ahead regulation up requirements did not change substantially from 2022.

Figure 4.4 summarizes the average hourly profile of the day-ahead regulation requirements in 2022 and 2023. Average hourly requirements for regulation up and down both peaked during ramping hours.

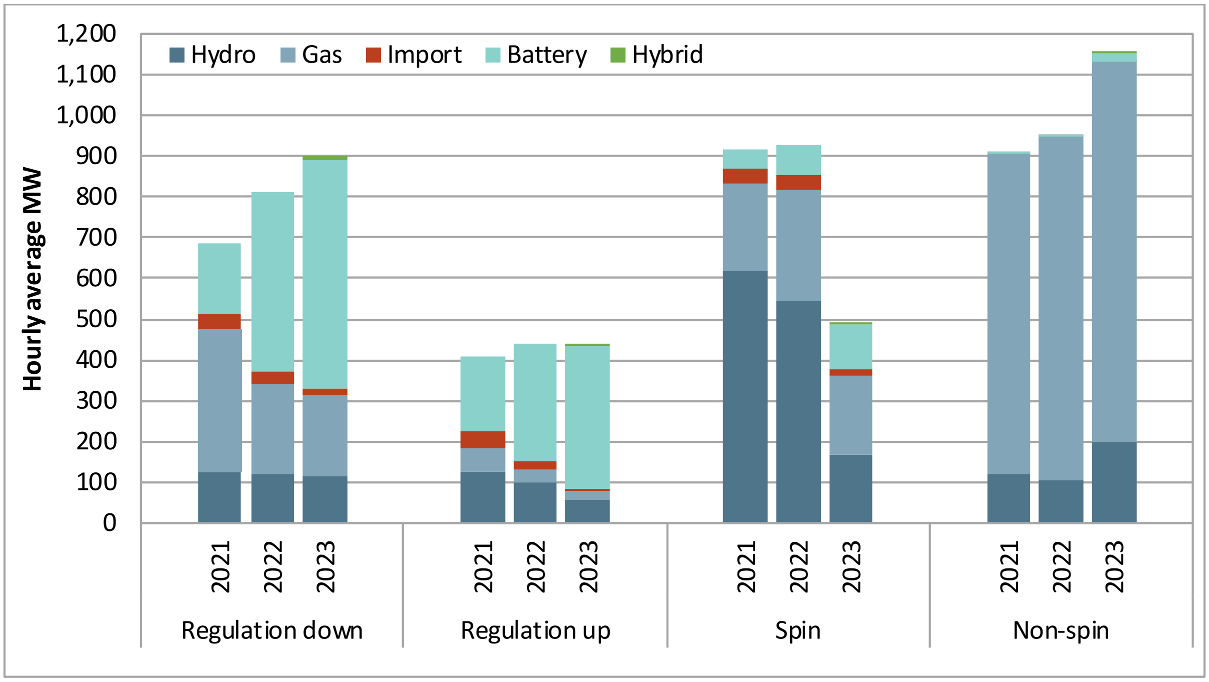
Figure 4.4 Hourly average day-ahead regulation requirements



Ancillary service procurement by fuel

Figure 4.5 shows the portion of ancillary services procured by fuel type from 2021 through 2023. 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 the California ISO resources.

Figure 4.5 Procurement by internal resources and imports



As in previous years, the vast majority of required ancillary service capacity came from a mix of CAISO gas, hydroelectric, and battery resources. Average ancillary service hourly procurement served by battery resources has been steadily increasing in recent years, growing from 400 MW in 2021 to 1,040 MW in 2023. In 2023, battery resources provided around 69 percent of the CAISO's regulation requirements. Average ancillary service procurement from gas and hydroelectric resources dropped 1 percent and 38 percent, respectively, in 2023, though these resource types still provide the majority of required operating reserves. Hourly average ancillary service procurement served by imports was 35 MW, a 59 percent decrease from 2022.

4.3 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 4.6 and Figure 4.7 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2022 and 2023, weighted by the quantity settled.

As shown in Figure 4.6, weighted average day-ahead prices for all upward ancillary service products (spinning reserve, non-spinning reserve, and regulation up) tended to decrease compared to 2022. The biggest year-over-year decrease in prices was in the third quarter. In the third quarter of 2022, energy scarcity during the prolonged heatwave event from August 31 to September 9 resulted in especially high prices for upward ancillary service products. Regulation down prices decreased in 2023 despite increases in requirements, largely due to more participation from battery storage resources.

Figure 4.6 Day-ahead ancillary service market clearing prices

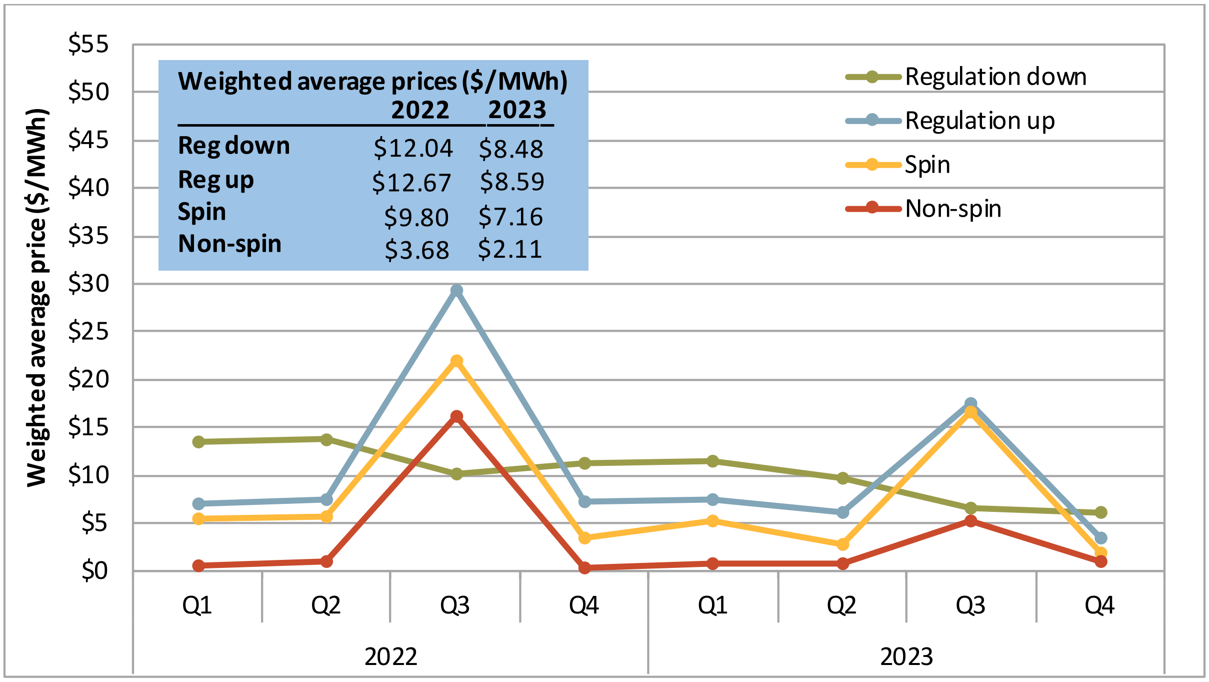
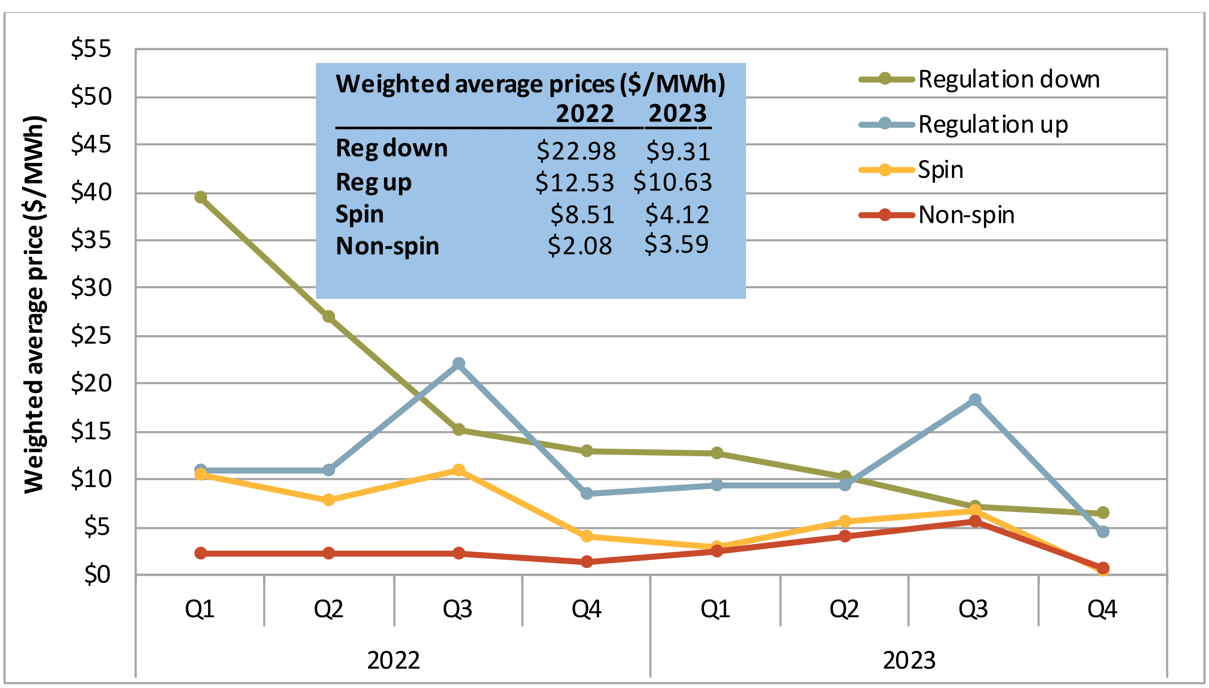


Figure 4.7 shows that the weighted average prices for ancillary services decreased for the most part in the real-time market. In general, ancillary service costs are largely determined by day-ahead market prices since most ancillary services are procured in the day-ahead market, with only 8 percent of ancillary service costs incurred in the real-time market in 2023.

Figure 4.7 Real-time ancillary service market clearing prices



4.4 Special issues

4.4.1 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 was only one scarcity event in 2023, compared to six in 2022, and 55 in 2021. The CAISO's only ancillary service scarcity event in 2023 resulted from a 5 percent shortfall of non-spinning reserves in the fifteen-minute market, which lasted for two intervals on July 25.

This lack of scarcity events can be attributed in part to the rapidly increasing participation of battery storage resources, which now provide a majority of CAISO regulation.

4.4.2 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 concerned ancillary service. In addition, payments that were made to the resource for the impacted ancillary service will be rescinded.[209]

During 2023, the California ISO performed a combined total of 335 performance audits and unannounced compliance tests for resources holding ancillary services, which was an increase from the 241 tests performed in 2022. The failure rate was 15 percent for unannounced tests, an improvement over 22 percent in 2022. The failure rate for performance tests was 2 percent in 2023.

4.4.3 State-of-charge attenuation factors

In November 2023, the California ISO implemented a new initiative to model the impact of batteries providing ancillary services on their state-of-charge. The CAISO underwent this policy change in order to model state-of-charge more accurately for the growing battery fleet, as well as address an operational concern where batteries were becoming unable to respond to automatic generator control instructions when receiving regulation awards for multiple consecutive hours.

[209] 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

To implement the new initiative, the CAISO kept the original calculation for battery state-of-charge the same—in that it only accounts for the impact of energy schedules—and introduced a new market constraint for batteries, which accounts for the impact of regulation and energy schedules.

Originally, the CAISO planned to model the impact of regulation under a single state-of-charge constraint. However, in market simulations with a single state-of-charge constraint, the market produced solutions with negative regulation down prices. These solutions with negative prices reflect how the market's multi-interval optimization processed the connection between regulation down and energy. Since regulation down increases a battery's state-of-charge, which they can discharge later at high energy prices, the optimization found that charging a cost to batteries for providing regulation down resulted in the lowest cost to the market overall. The CAISO tariff currently prohibits negative ancillary service prices.

The new attenuated state-of-charge constraint works by using multipliers for regulation up and regulation down, which model the state-of-charge as being depleted or increased by a certain percentage of the regulation schedule. The CAISO chooses multipliers based on historical usage of regulation, and updates the multipliers on a quarterly basis to account for seasonality of regulation usage.

The CAISO has reported that there has been no material changes for awards held by batteries since the new constraint's implementation.[210] In addition, there were no negative regulation down prices since implementation.[211]

210 California ISO, Market Performance and Planning Forum, March 11, 2024, slides 26-32: https://www.caiso.com/Documents/Presentation-Market-Performance-Planning-Forum-Mar-11-2024.pdf

211 Ibid, slides 33-34.

5 Market competitiveness and mitigation

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

- **Overall prices in the California ISO 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.[212]
- **The number of structurally uncompetitive hours in the day-ahead market in 2023 was similar to 2022.** Uncompetitive hours decreased significantly from 2020 to 2022.
- **The market for capacity needed to meet local resource adequacy requirements was structurally uncompetitive in 5 of the 10 local areas.** In both the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures.
- **Energy subject to mitigation in the CAISO balancing area increased in the day-ahead and 15-minute markets,** but decreased in the 5-minute market, resulting in bids subject to mitigation being similar across the real-time markets.
- **Energy subject to mitigation in other WEIM balancing areas increased in both the 15-minute and 5-minute markets.** Tighter conditions outside of CAISO over the summer and through October, particularly in the Pacific Northwest, caused more congestion into WEIM areas with limited supply competition. Some of the increase was also due to the WEIM adding three new balancing areas in 2023.
- **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 20 percent of the day-ahead bids that were subject to mitigation were changed.
- **Capacity with bids lowered by mitigation in the 15-minute market remained low**, averaging 282 MW per hour in the California ISO and 349 MW per hour in the Western Energy Imbalance Market. In the 5-minute market, capacity with bids lowered by mitigation averaged 234 MW per hour in the California ISO and 246 MW in the Western Energy Imbalance Market.

5.1 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 of these 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.

[212] Further information on DMM's estimation of overall market competitiveness is available in Section 2.2.

- **Residual supply index:** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[213] 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.

5.1.1 Day-ahead system energy

The residual supply index analysis includes the following elements to account for supply and demand:

- Day-ahead input bids for physical generating resources (adjusted for outages and de-rates).
- Transmission losses are not explicitly added to demand. The day-ahead load forecast already factors in losses.
- Non-dispatchable pump load is used for additional demand.
- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements).
- Ancillary services bids are included in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market.
- CPUC jurisdictional investor-owned utilities are excluded as potentially pivotal suppliers.
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids are excluded.

During 2023, the number of hours with a residual supply index less than one was similar to the previous year. Table 5.1 shows the annual number of hours with a residual supply index ratio less than one since 2020, based on the assumptions listed above. Figure 5.1 shows the same information graphically by quarter. For 2023, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 132 hours, and the index was less than one during 75 hours with the two largest suppliers removed (RSI_2). With the largest single supplier removed (RSI_1), there were 26 hours in 2023 with the index less than one, compared to 44 hours in 2022.

Figure 5.2 shows the lowest 500 RSI_3 values for each year. During these hours, structural competitiveness in 2023 was very similar to that of 2022. However, in comparison to 2021 and 2020, structural competitiveness was greater in 2023. During 2023, with the three largest suppliers removed, the RSI_3 was less than 0.9 in 45 hours, and less than 0.8 in five hours. At its lowest, the RSI_3 was around 0.75 in 2023, similar to the previous year.

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213 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.

Figure 5.3 summarizes non-pivotal supply with the three largest suppliers excluded in the same 500 hours with the lowest RSI_3 values. In particular, continued additions of battery (and hybrid) capacity in recent years helped reduce the number of potentially non-competitive hours.

Table 5.1 Hours with residual supply index less than one by year

Year	RSI_1	RSI_2	RSI_3
2020	129	333	524
2021	84	189	316
2022	44	79	130
2023	26	75	132

Figure 5.1 Hours with residual supply index less than one by quarter

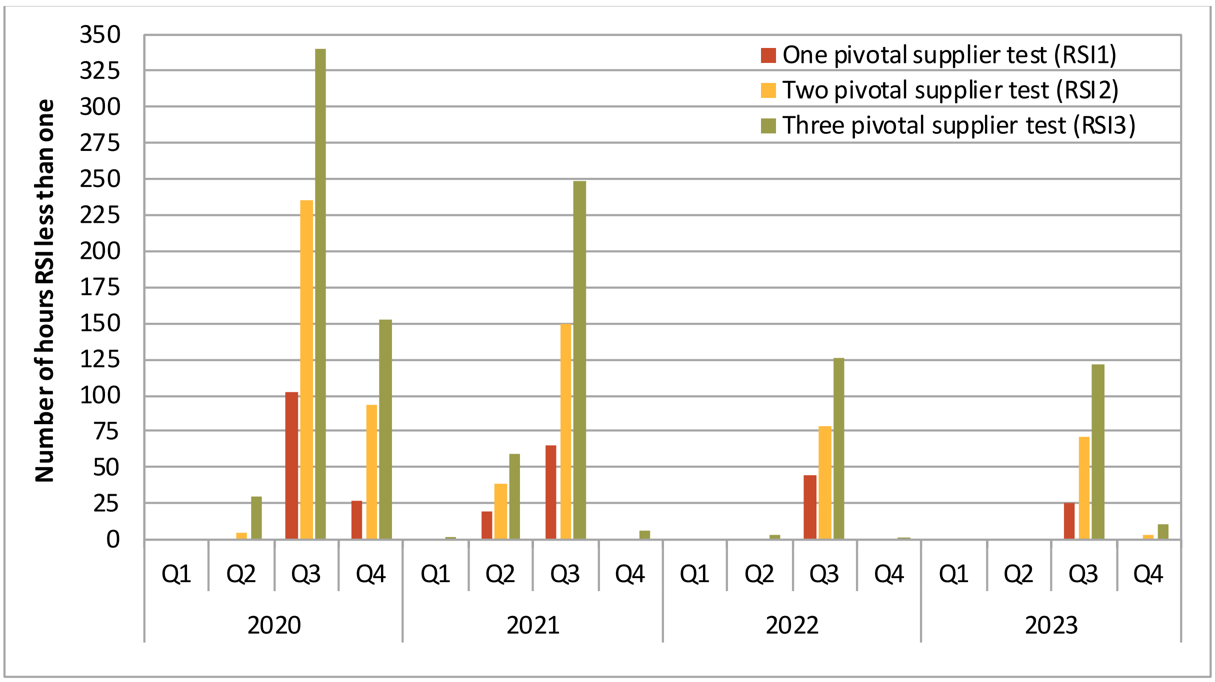


Figure 5.2 Residual supply index with largest three suppliers excluded (RSI_3) – lowest 500 hours

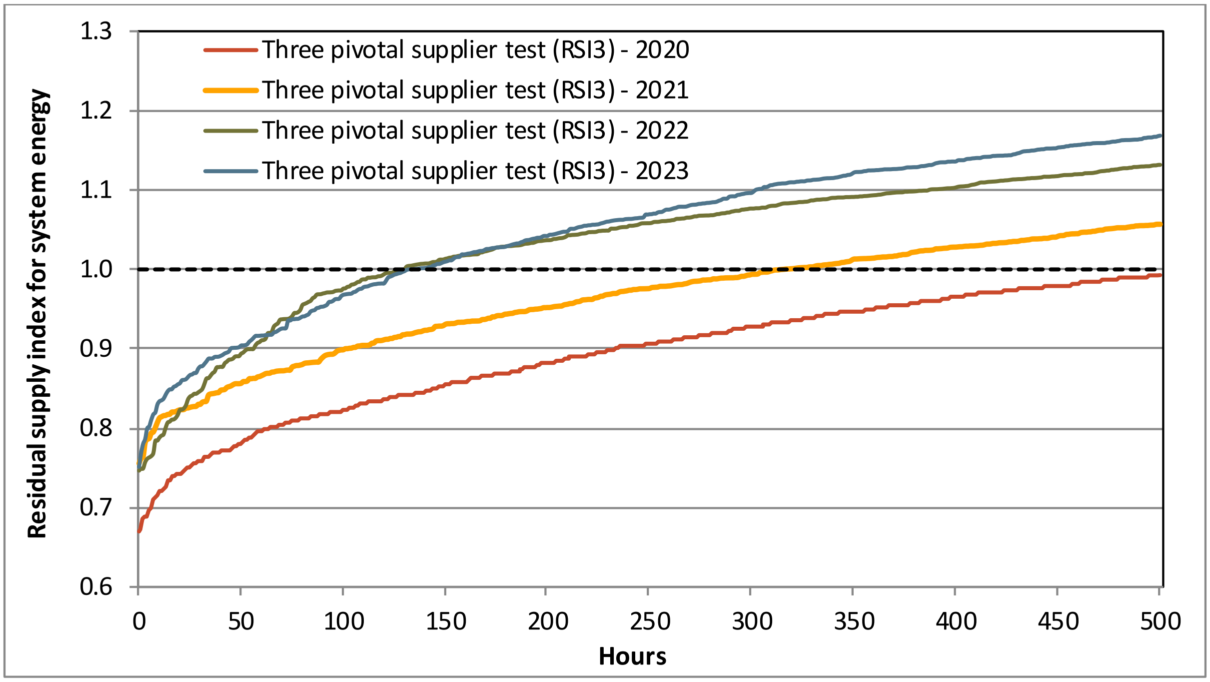
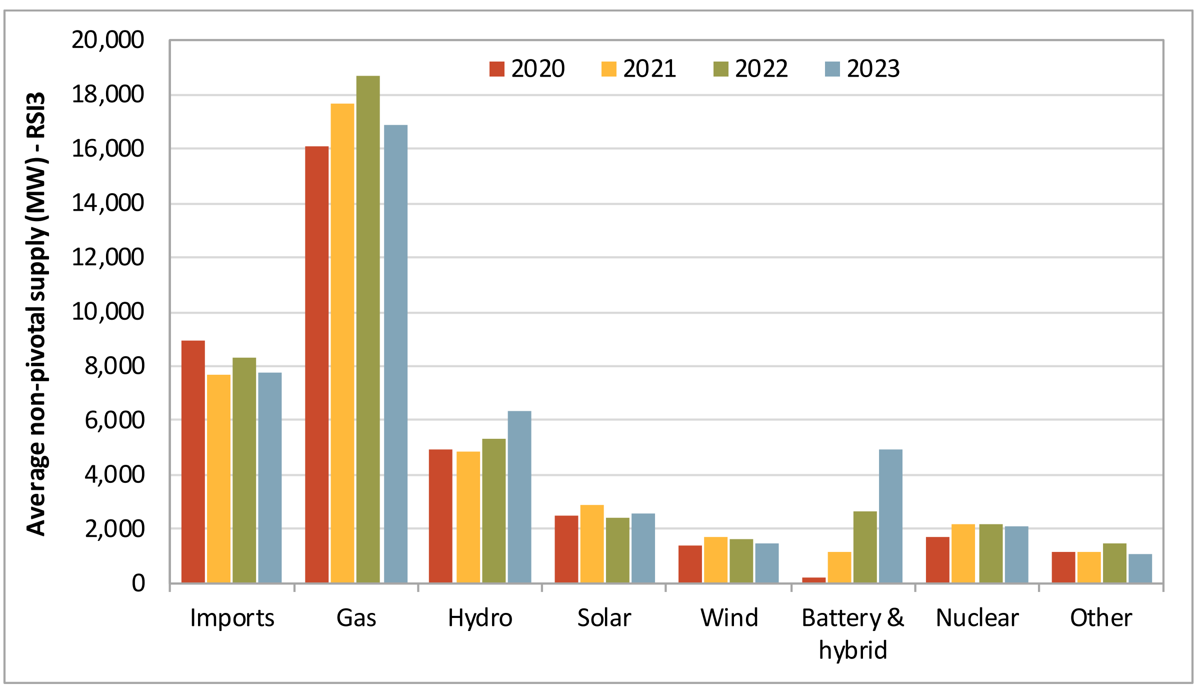


Figure 5.3 Non-pivotal supply with the largest three suppliers excluded (RSI_3) – lowest 500 hours



5.1.2 Local capacity requirements

In 2023, half 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 5.2 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 though 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.[214]

Table 5.2 shows that the total amount of supply owned by non-load-serving entities meets or exceeds the additional capacity needed by load serving entities to meet these requirements in all local capacity areas with a net non-load-serving entity local capacity requirement, other than Kern. In Kern and 4 other areas, 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.

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 year 2023.[215] As a result, the total local capacity requirement increased by around 1.3 percent between 2022 and 2023, with a considerable increase to the Big Creek/Ventura and LA Basin local capacity area requirements.

Key findings of this analysis include the following:

- The Greater Bay, Kern, North Coast/North Bay, Stockton, and LA Basin 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.
- In 2023, the LA Basin local area capacity requirement increased from 2022 due to load forecast increase and new constraints; Kern's requirement increased due to new limiting contingency and element.

[214] 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.

[215] *2023 Local Capacity Technical Study*, California ISO, April 28, 2022: https://www.caiso.com/InitiativeDocuments/Final2023LocalCapacityTechnicalReport.pdf

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.[216]

Table 5.2 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	4,732	5,156	1.09	0.44	0.11	0.07	2
Kern	327	304	0.93	0.00	0.00	0.00	3
North Coast/North Bay	708	826	1.17	0.00	0.00	0.00	1
Stockton	358	369	1.03	0.09	0.04	0.00	3
SCE TAC area							
LA Basin	1,828	3,553	1.94	0.74	0.27	0.18	1
San Diego/Imperial Valley	744	1,705	2.29	1.48	0.68	0.25	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 5.2.1 examines the frequency and impact of these automated bid mitigation procedures.

5.2 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures in the California ISO (CAISO) and Western Energy Imbalance Market (WEIM) balancing authority areas. This section also provides a summary of the volume of non-automated mitigation procedures that are applied for exceptional dispatches.

216 For further information on the capacity procurement mechanism, see Section 8.5.

5.2.1 Frequency and impact of automated bid mitigation

In the CAISO and WEIM balancing areas, average incremental energy subject to mitigation has increased in 2023, relative to 2022. However, average incremental energy with bids lowered and potential increase in dispatch because of mitigation continues to be very low. For the CAISO balancing authority area, incremental energy subject to mitigation has increased relative to prior years, due in part to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers. For the WEIM, tighter conditions over the summer and through October, particularly in the Pacific Northwest, caused more congestion into WEIM areas with limited supply competition. Part of the increase in average incremental energy subject to mitigation was also due to the increased capacity participating in the WEIM with El Paso Electric, Avangrid, and WAPA Desert Southwest Region joining in 2023.

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 price changes.[217]

The following sections provide analysis on the frequency and impact of bid mitigation in the day-ahead and real-time markets, for the CAISO and other WEIM balancing authority areas.

Day-ahead market

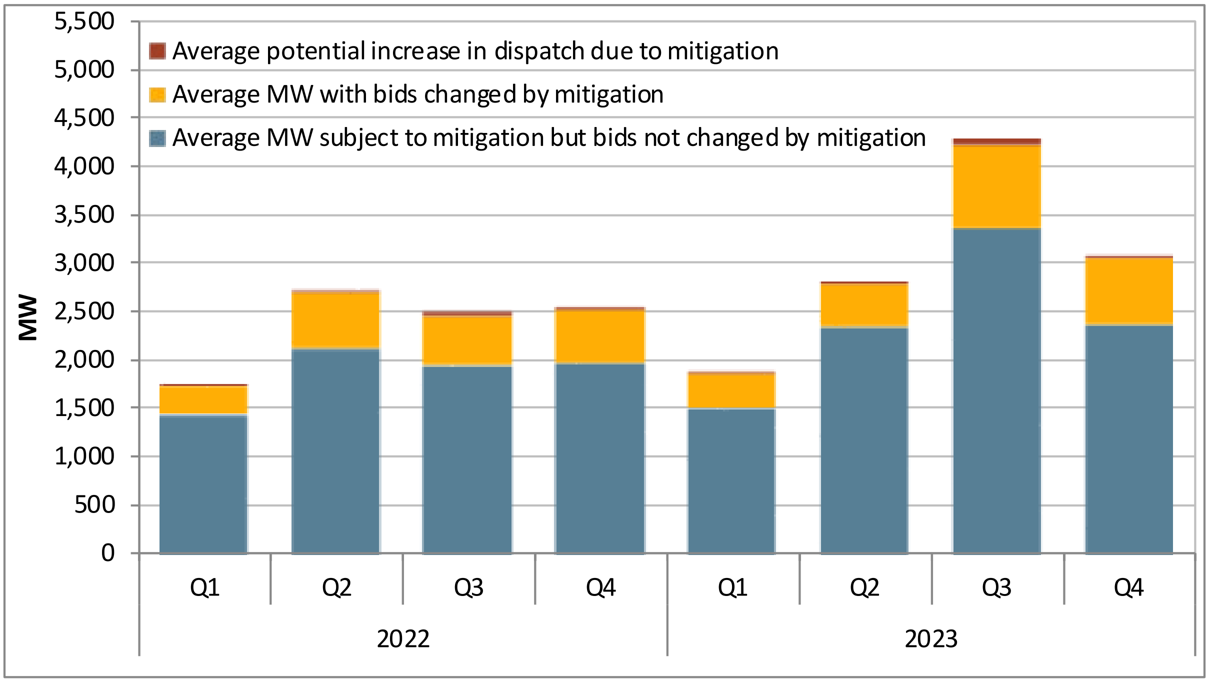
As shown in Figure 5.4, in 2023, the average incremental energy subject to mitigation increased by 27 percent relative to 2022.

- Bids for an average of 2,979 MW per hour were subject to mitigation 2023, an increase from 2,354 MW in 2022. Out of these bids subject to mitigation, 44 percent were gas resources, 17 percent were battery resources, and 18 percent were hydro resources.

[217] 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.

- The amount of bids actually lowered due to mitigation averaged 580 MW in 2023, compared to 477 MW in 2022. About 20 percent of bids subject to mitigation had their bids lowered in 2023, similar to the percentage in 2022.
- Potential increase in dispatch from bid mitigation averaged about 29 MW per hour in 2023, compared to 21 MW per hour in 2022.
- On average, about 500 MW of bids from battery resources were subject to mitigation per hour in 2023, while only about 200 MW were lowered.[218]

Figure 5.4 Average incremental energy mitigated in day-ahead market



Real-time market

Figure 5.5 and Figure 5.6 highlight the frequency and volume of 15-minute and 5-minute market mitigation in the CAISO balancing area. As shown in these figures, average incremental energy subject to mitigation in 2023 increased by 17 percent in the 15-minute market but decreased 16 percent in the 5-minute market. This resulted in incremental energy subject to mitigation in the two markets being very similar in 2023.

- In the 15-minute market, an average of 1,687 MW of incremental energy bids in the CAISO balancing area was subject to mitigation, which is an increase from 1,448 MW in 2022. About 282 MW of these bids were lowered due to mitigation. Bids that were lowered came primarily from battery energy storage resources (160 MW), gas resources (89 MW), and hydro (22 MW).

218 For battery energy storage units, both charge and discharge bid curves are subject to mitigation if local market power mitigation measures are triggered. This calculation accounts for incremental energy under discharge portion only.

- In the 5-minute market, an average of 1,793 MW of bids were subject to mitigation, compared to 2,136 MW in 2022. Out of these bids, only 234 MW on average were lowered in 2023, compared to 250 MW of bids lowered due to mitigation in 2022.
- On average, the potential increase in 15-minute dispatch due to bid mitigation increased to 30 MW in 2023 compared to 23 MW in 2022. Potential increase in 5-minute dispatch from bid mitigation averaged 33 MW per hour in 2023, similar to 2022.

Figure 5.5 Average incremental energy mitigated in 15-minute real-time market (CAISO)

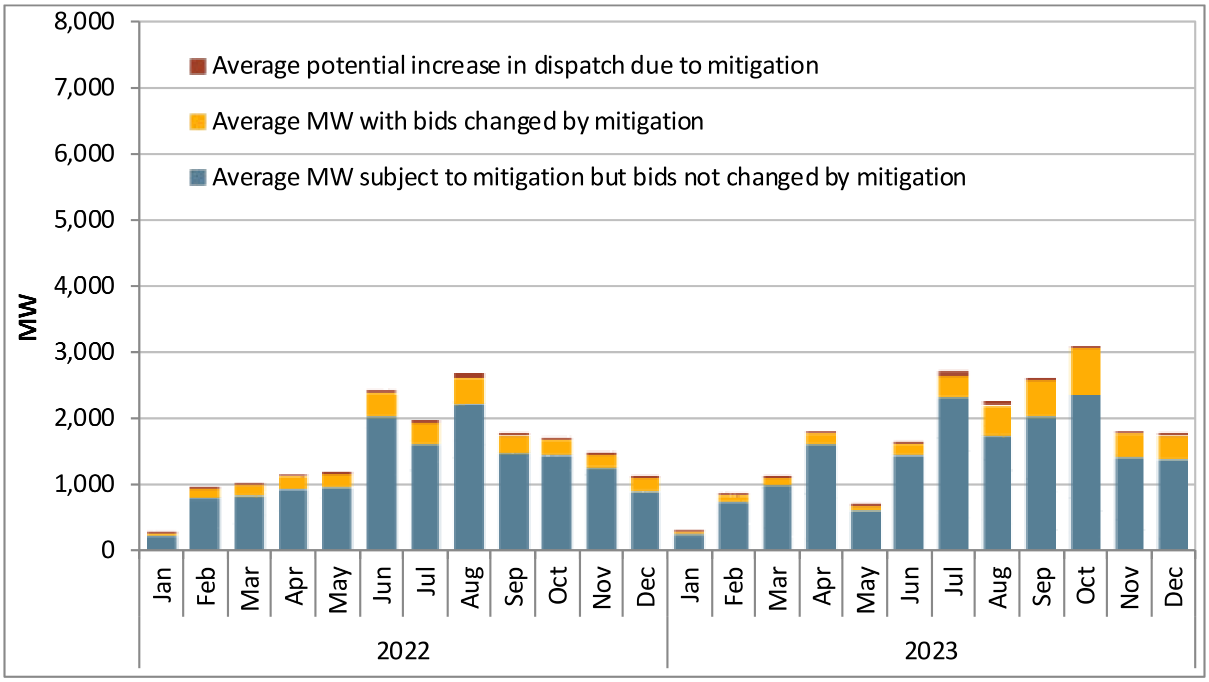


Figure 5.6 Average incremental energy mitigated in 5-minute real-time market (CAISO)

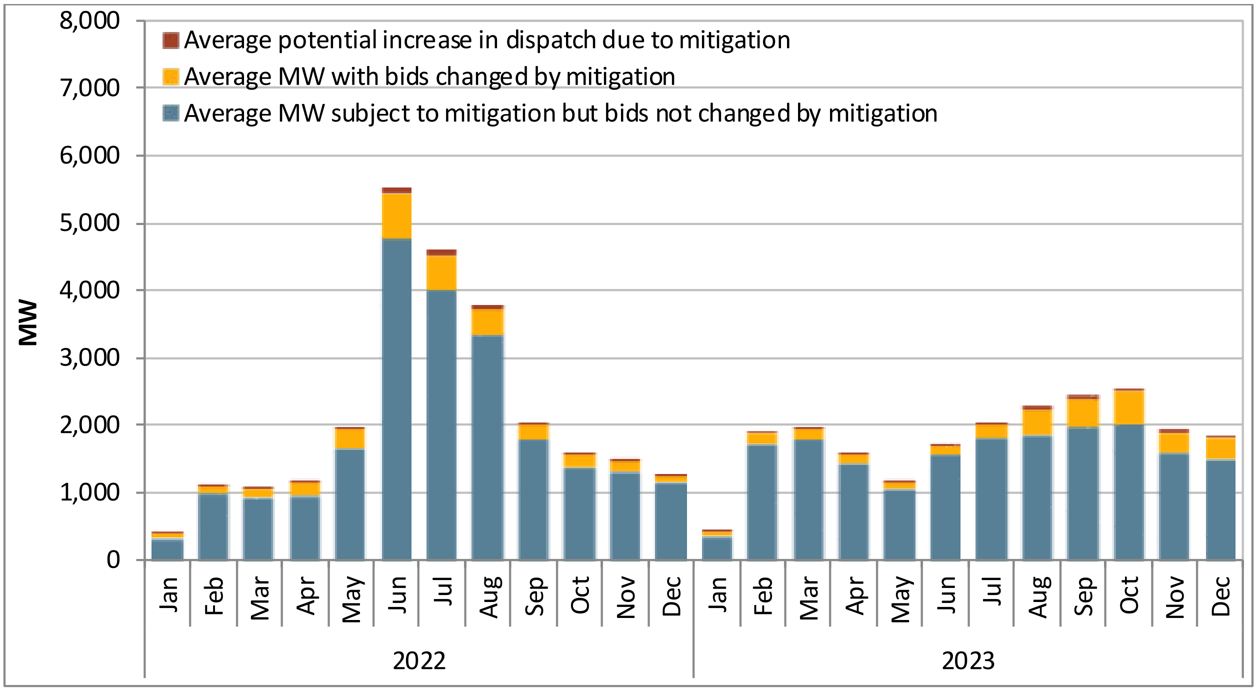


Figure 5.7 and Figure 5.8 highlight the frequency and volume of 15-minute and 5-minute market mitigation in all of the WEIM balancing areas outside the California ISO. Average MW subject to mitigation increased substantially in both the 15-minute and 5-minute markets compared to 2022. Tighter conditions outside of CAISO over the summer and through October, particularly in the Pacific Northwest, caused more congestion into WEIM areas with limited supply competition. Part of the increase can also be attributed to three new balancing areas joining WEIM in 2023.

Figure 5.7 Average incremental energy mitigated in 15-minute real-time market (WEIM)

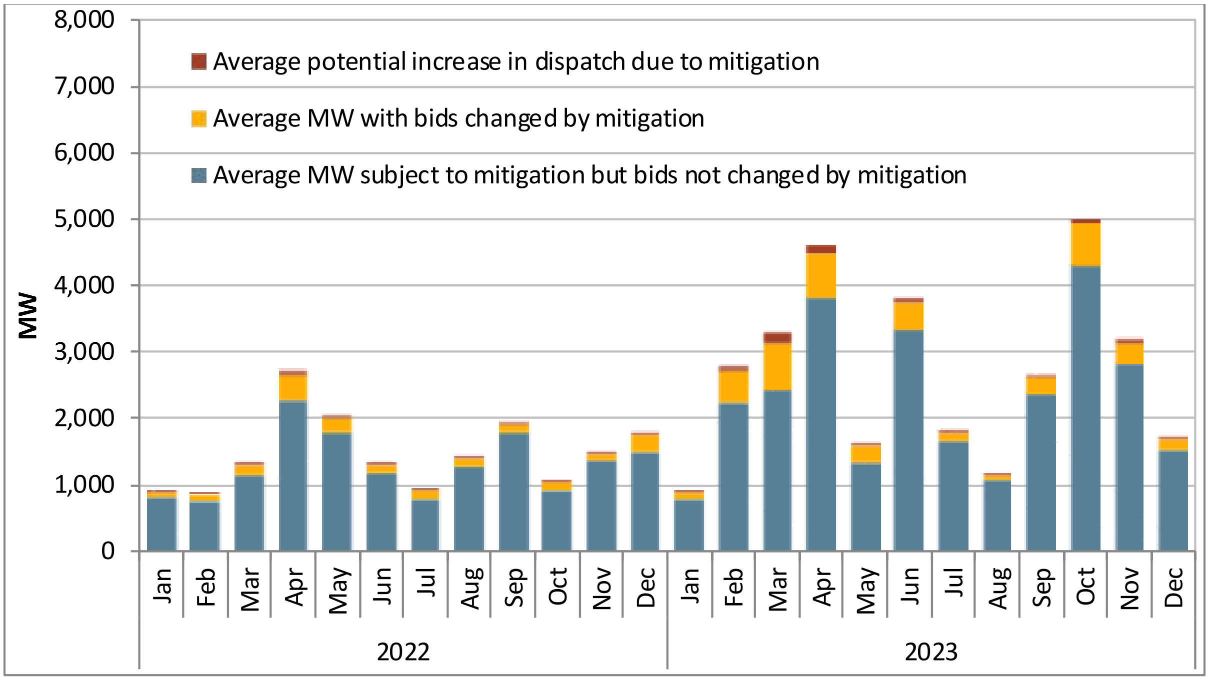
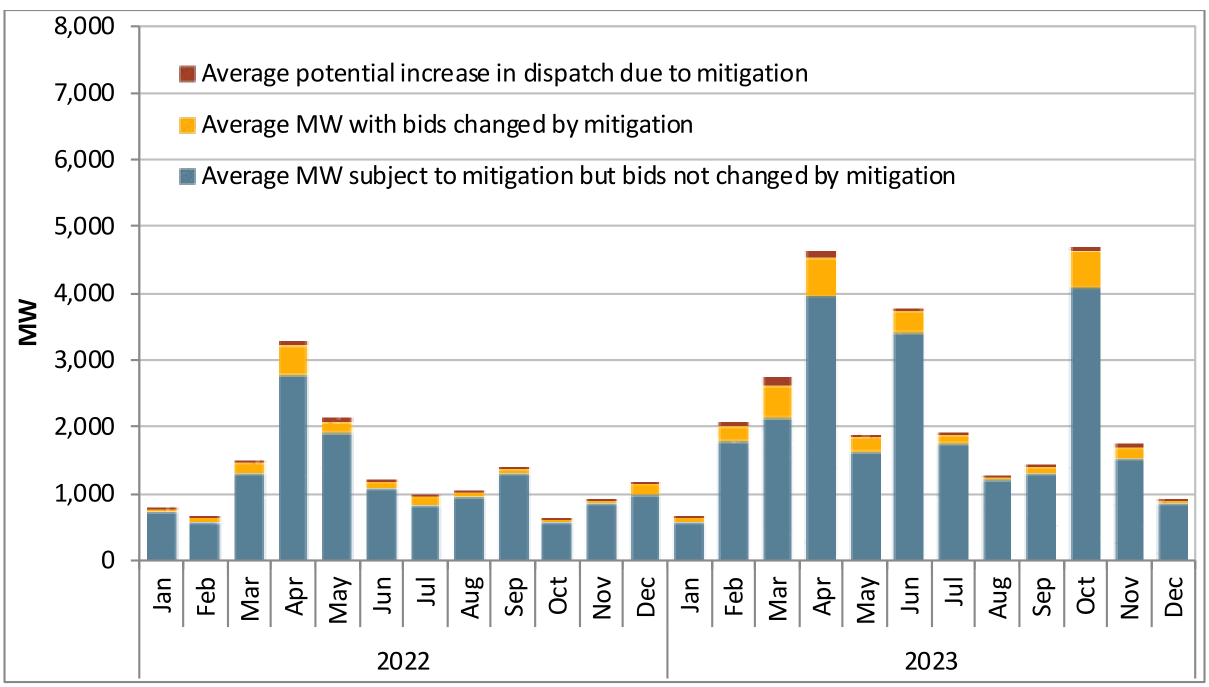


Figure 5.8 Average incremental energy mitigated in 5-minute real-time market (WEIM)



- In the 15-minute market, an average of 2,653 MW of incremental energy bids in WEIM balancing areas were subject to mitigation, which is an increase from 1,456 MW in 2022. About 349 MW of these bids were lowered due to mitigation compared to 156 MW in 2022.
- In the 5-minute market, an average of 2,264 MW of bids were subject to mitigation, up from 1,278 MW in 2022. Out of these bids, only 246 MW on average were lowered in 2023, compared to 120 MW of bids lowered due to mitigation in 2022.
- The potential increase in dispatch due to mitigation continues to be very low in 2023, as seen by the red bars in the figures above.

5.2.2 Mitigation of exceptional dispatches

Overview

Exceptional dispatches are instructions issued by grid operators when the market optimization is not able to address a particular reliability requirement or constraint.[219] Total energy from exceptional dispatches in 2023 increased about 2.43 percent from the previous year. The above-market costs for exceptional dispatches decreased by 33 percent to $9.3 million in 2023, down from $13.9 million in 2022. A majority of this cost was associated with exceptional dispatch commitments to minimum load rather than out-of-market costs for exceptional dispatch of incremental energy.

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:

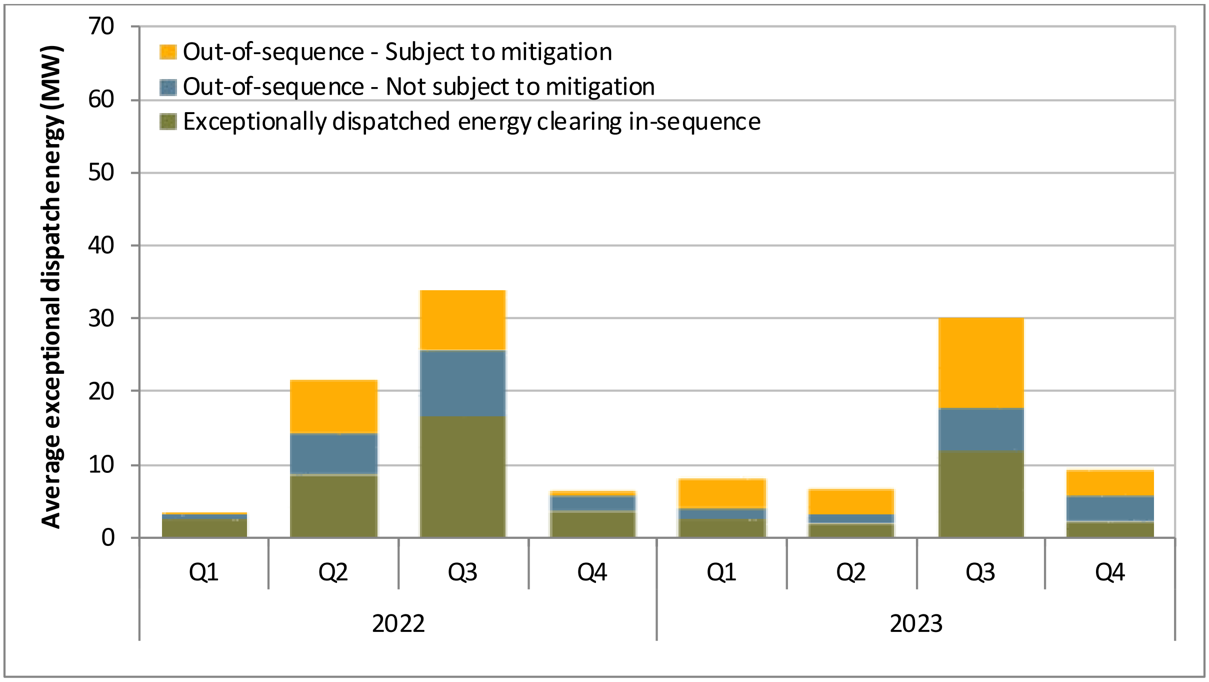
- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real-time;
- Ramp resources to their minimum dispatch level in real-time, 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 5.9, the overall volume of exceptional dispatch energy above minimum load declined by about 17 percent in 2023 when compared to 2022. As discussed in Section 7, 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 32 percent in 2023 compared to 2022. Out-of-sequence exceptional dispatches subject to mitigation increased by about 46 percent in 2023 compared to 2022.

219 A more detailed discussion of exceptional dispatches is provided in Section 7.1.

Figure 5.9 Exceptional dispatches subject to bid mitigation



5.3 Start-up and minimum load bids

This section analyzes commitment cost bid behavior for the California ISO balancing area (CAISO) gas capacity—excluding use-limited resources—under the proxy cost option.[220] For 2023, DMM estimates that about 59 percent of the total CAISO bid cost recovery payments, approximately $171 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. In comparison, 57 percent of the CAISO's total bid cost recovery payments were allocated to resources that bid their commitment costs above 110 percent of their reference levels in 2022. Commitment cost bids are capped at 125 percent of reference proxy costs. About 92 percent of the $171 million is for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure 5.10 and Figure 5.11 highlight how proxy commitment costs were bid into the day-ahead and real-time markets in 2023 compared to 2022.[221,222]

As shown in Figure 5.10, about 41 percent of the capacity in the day-ahead market submitted start-up bids at or near the proxy cost cap in 2023, slightly higher than in both 2022 and 2021. About 37 percent

[220] 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, p 195: http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

[221] 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.

[222] 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.

of capacity submitted start-up bids at or below the proxy cost in the day-ahead market in 2023, compared to 34 percent in 2022. The real-time market can only make start-up and shutdown decisions for short start units. About 44 percent of this capacity submitted bids at or near the proxy cost cap in the real-time market in 2023, up from 39 percent in 2022.

Startup proxy costs are a function of gas price indices, and therefore declined steeply as natural gas supply constraints eased throughout the west in the first and second quarters of 2023. Bid-in startup costs tended to decline as well, though not as drastically as the CAISO's calculated proxy costs. This disconnect between bid-in startup costs and proxy costs caused the CAISO to cap start-up bids more frequently in the second quarter.

As shown in Figure 5.11, about 32 percent of the capacity in the day-ahead market submitted minimum load bids at or near the proxy cost cap in 2023, compared to 34 percent in 2022 and 33 percent in 2021. About 37 percent of capacity submitted minimum bids at or below the proxy cost in the day-ahead market in 2023, compared to 34 percent in 2022. About 33 percent of real-time minimum load bids were submitted at or near the proxy cost cap in 2023, compared to 34 percent in 2022.

Figure 5.10 Day-ahead and real-time gas-fired capacity under the proxy cost option for start-up cost bids (percentage)

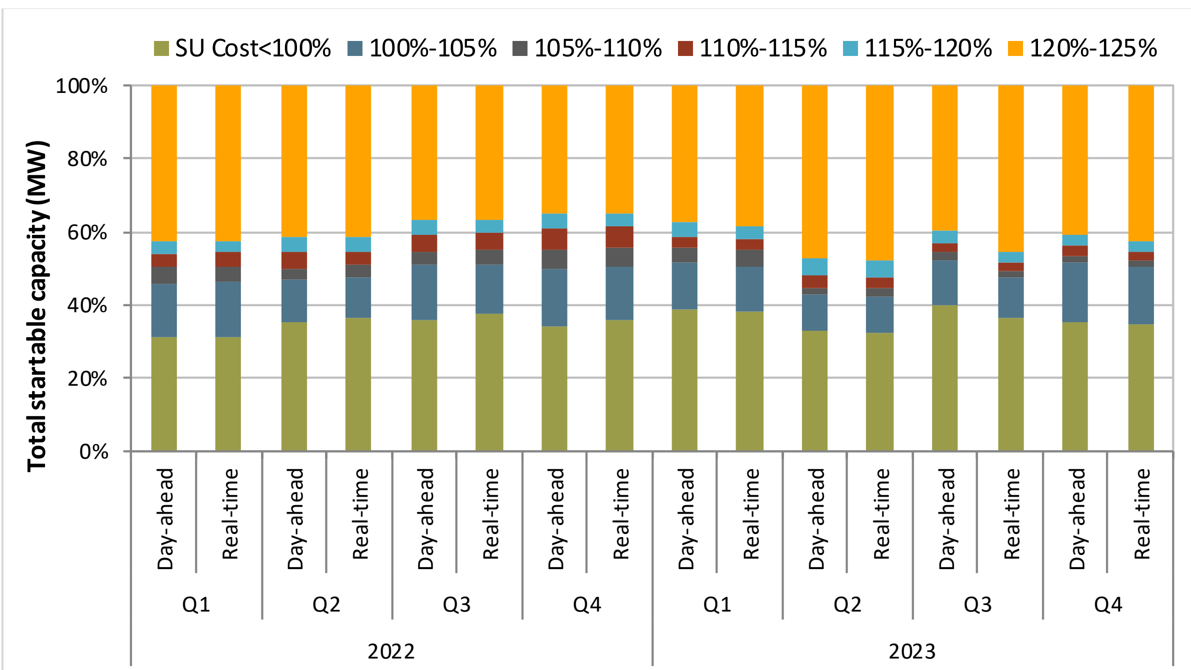
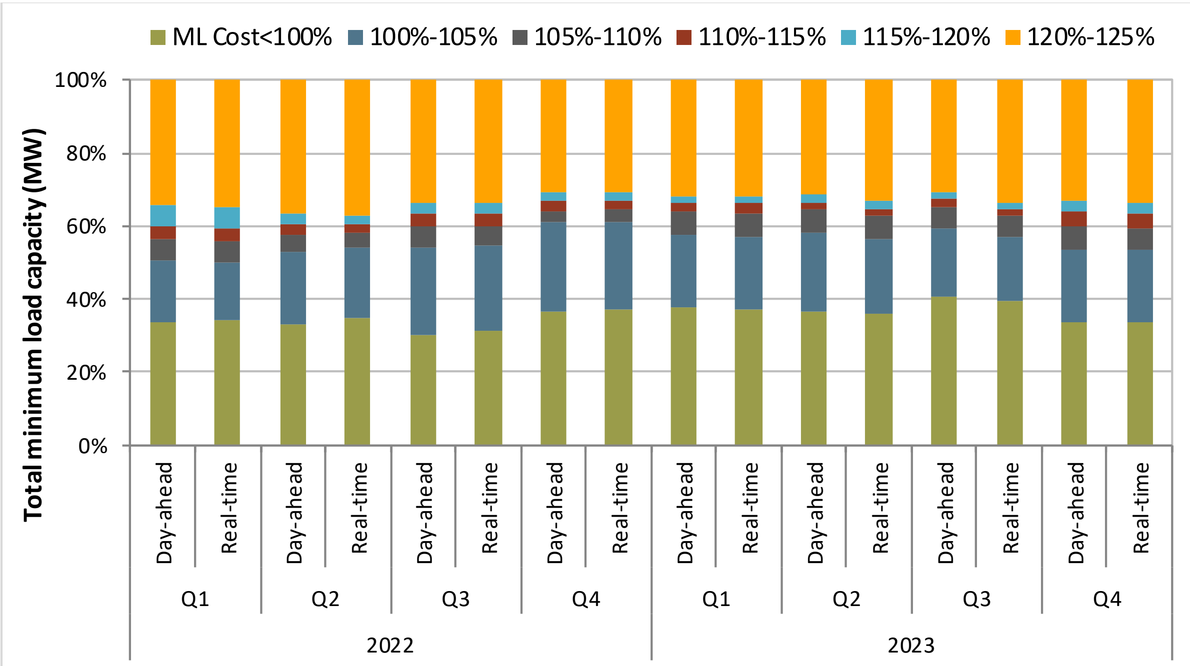


Figure 5.11 Day-ahead and real-time gas-fired capacity under the proxy cost option for minimum load cost bids (percentage)



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 submit a start-up or minimum-load bid above this cap.[223,224] 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.[225] 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.

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223 *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

224 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

225 *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

In 2023, the first quarter saw the highest level of automated reference level change requests from gas, when Western gas prices spiked. There were only a few manual requests for higher gas prices not covered by automated requests that were approved for the November 13 trading day. When the policy was first implemented in February 2021, there were a number of manual requests that were denied for a variety of reasons, such as requests incorporating Operational Flow Order (OFO) penalties, inability to determine the specific price requested, and inadequate supporting documentation.

6 Congestion

This chapter provides a review of congestion and the congestion revenue rights auction in 2023. Findings from this chapter include the following:

- **Day-ahead market congestion decreased.** Total day-ahead congestion rents and loss surpluses amounted to $1.1 billion, a decrease from $1.4 billion in 2022. 2023 congestion rent was $866 million, about 19 percent lower than the $1.07 billion from 2022. This decrease was driven by a $135 million reduction in intertie congestion and lower congestion prices on key internal constraints.
- **Real-time market congestion shifted to a predominantly south-to-north flow pattern.** This was a change from 2022 when the flow pattern was more predominantly from northern areas to southern areas. The 2023 congestion pattern resulted in increased prices in the Pacific Northwest, Intermountain West, and Northern California relative to prices in the Desert Southwest and Southern California. This pattern was consistent in both the 15-minute and 5-minute markets, with the 5-minute market showing a greater overall impact on price differences between the regions.
- **Total day-ahead California ISO intertie congestion decreased, but export congestion increased**. The total congestion charges on interties in the day-ahead market amounted to $46.5 million, a decrease from $181 million in 2022. There was an increase in export congestion on interties, particularly on interties connecting CAISO to the Pacific Northwest. The frequency of export congestion on major interties nearly doubled in 2023 compared to 2022, and the associated export congestion charges in the day-ahead market rose from $7 million in 2022 to $13 million in 2023.

This chapter includes an analysis of the performance of the **congestion revenue rights auction** from the perspective of the ratepayers of load serving entities. Key findings of this analysis include the following:

- **In 2019, the California ISO implemented two sets of changes to the congestion revenue rights auction process**. The first (Track 1A) reduced the number and pairs of nodes at which congestion revenue rights can be purchased in the auction. The second (Track 1B) reduced the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis. DMM supports both initiatives as incremental improvements that should help reduce the losses incurred by transmission ratepayers due to the CAISO auction of congestion revenue rights.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $59 million, down from $117 million in 2022, but still significantly higher than the $43 million in 2021**. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Losses from congestion revenue rights sold in the auction totaled about $100 million in 2017, $131 million in 2018, and fell to $22 million in 2019 before rising to $71 million in 2020.
- **Transmission ratepayers received about 76 cents in auction revenue per dollar paid out to these rights purchased in the auction, up from 57 cents in 2022.** Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $97 million. Losses from auctioned congestion revenue rights totaled about 7 percent of total day-ahead congestion rent in 2023, compared to about 11 percent in 2022, 7 percent in 2021, 14 percent in 2020, 6 percent in 2019, and 21 percent in 2018.
- **DMM believes the current auction is unnecessary and could be eliminated**. If the CAISO believes it is beneficial to the market to facilitate hedging, DMM believes 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.

6.1 Congestion impacts on locational prices

This section provides an assessment of the frequency and impact of internal congestion on locational price differences in the day-ahead and real-time markets.[226] It focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas.[227] The impact from transfer constraints are discussed in greater depth in Sections 3.3.3 and 3.4.1. Highlights of 2023 include:

- In the day-ahead market, internal congestion increased prices in the PG&E and SDG&E areas relative to prices in the SCE area. The frequency of congestion increased compared to 2022. However, in 2023, frequently binding constraints typically had smaller capacities and lower shadow prices compared to 2022, leading to a decrease in day-ahead congestion rent.
- In the real-time market, the overall internal congestion pattern was south-to-north during solar production hours, resulting in increased prices in Northern California, the Intermountain West, and the Pacific Northwest relative to prices in the Desert Southwest and Southern California. In the evening hours, the flow pattern reversed to predominantly north-to-south.

6.1.1 Day-ahead congestion

Congestion rent and loss surplus

Total congestion rents and loss surpluses amounted to $1.1 billion, down from $1.4 billion in 2022. As shown in Figure 6.1, total day-ahead congestion rent for 2023 was $866 million, about 19 percent less than the $1.07 billion in 2022. This decrease was driven by a $135 million reduction in intertie congestion and lower congestion prices on key internal constraints.

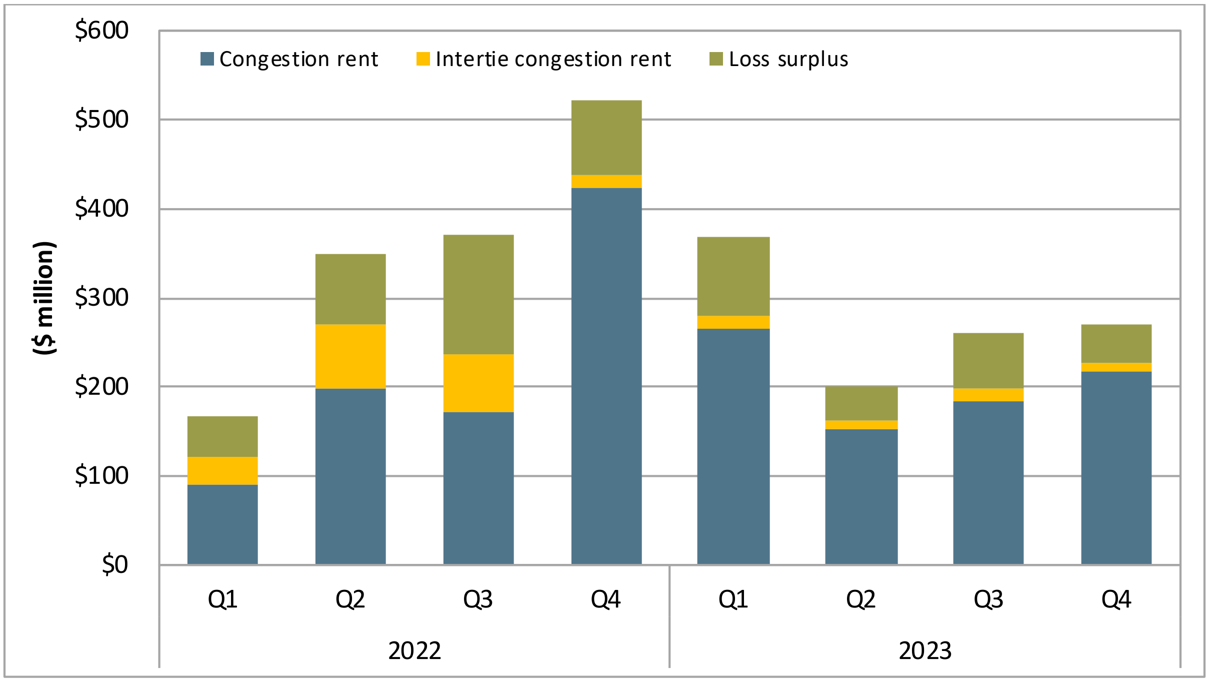
In the day-ahead market, *hourly congestion rent* collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The *daily congestion rent* is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. *The daily marginal loss surplus* is computed as the difference between daily net energy charge and daily congestion rent. The *loss surplus* is allocated to measured demand.[228]

[226] For a detailed background on congestion, from how it is calculated to how it interacts with other market elements, see Section 8.1 and the *2019 Annual Report on Market Issues & Performance*, Department of Market Monitoring, June 2020: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

[227] 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.

[228] For more information on marginal loss surplus allocation, refer to *Settlements and Billing, CG CC 6947 IFM Marginal Losses Surplus Credit Allocation*, California ISO Business Practice Manual Change Management: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

Figure 6.1 Congestion rent and loss surplus by quarter (2022–2023)



Congestion impact in the day-ahead market from internal, flow-based constraints

The frequency of internal congestion continued to increase from 2022 to 2023. On average over the year, day-ahead market internal congestion increased prices in the PG&E and SDG&E areas and decreased prices in the SCE area in 2023.[229]

Figure 6.2 shows the overall impact of congestion on price separation in the day-ahead market, incorporating averages from all hours, including non-congested hours. Figure 6.3 shows the percentage of hours during which congestion affected prices in 2022 and 2023.

- Congestion increased Pacific Gas & Electric prices by $1.43/MWh, less than the $1.79/MWh in 2022.
- Congestion decreased prices in Southern California Edison by $0.80/MWh. This was a lower impact than the ($1.07)/MWh in 2022.

229 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.

- For San Diego Gas & Electric, congestion increased average prices by about $0.43/MWh in 2023. In 2022, congestion contributed to decreasing prices by $0.60/MWh.
- The percentage of hours with congestion affecting day-ahead prices increased to an average of 51 percent in 2023, up from 36 percent in 2022.
- Despite this, the total internal congestion rent decreased by $66 million compared to 2022, due to lower shadow prices and key internal constraints having lower binding limits in 2023.

Figure 6.2 Overall impact of congestion on price separation in the day-ahead market

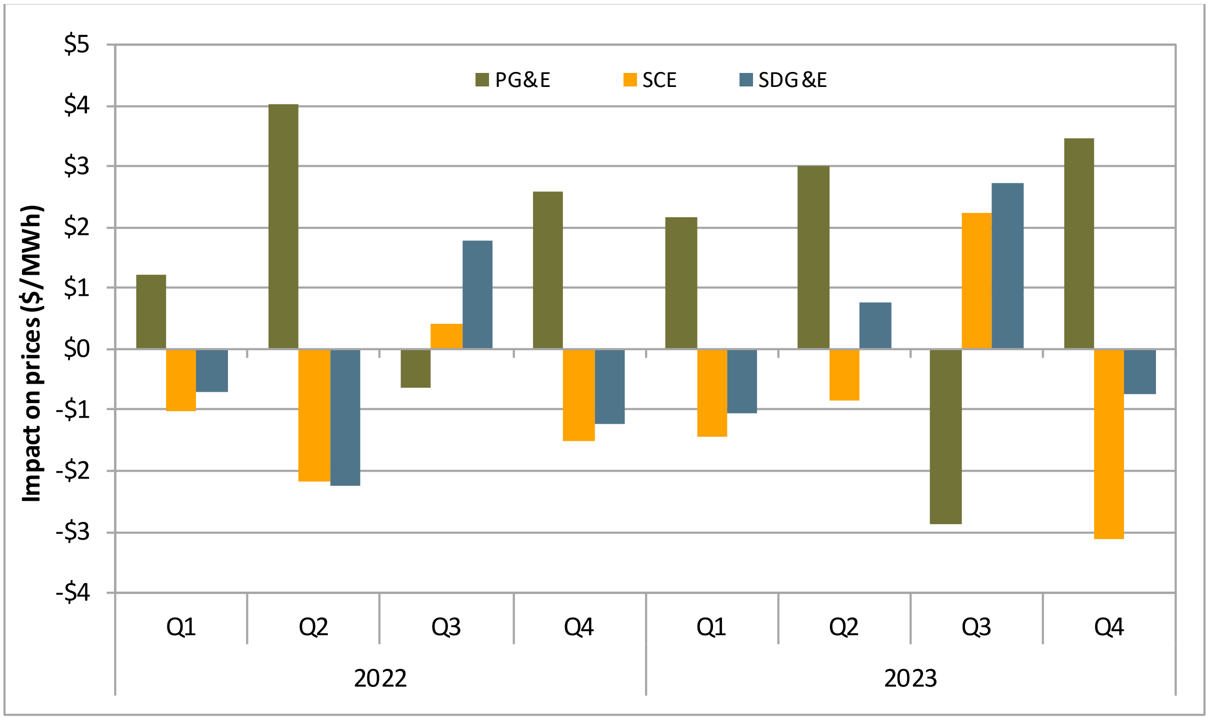


Figure 6.3 Percent of hours with congestion impacting prices by load area

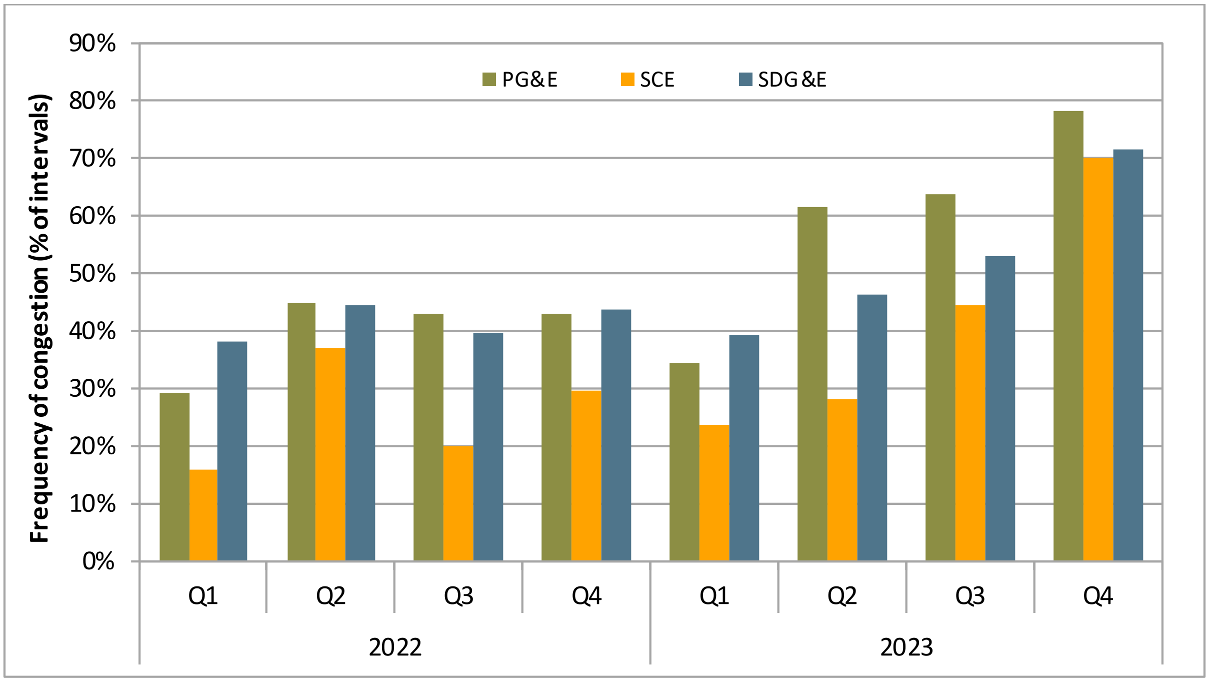


Table 6.1 shows the annualized frequency and impact of congestion from individual constraints on prices in each load aggregation area.[230] The three constraints that had the greatest impact on price separation over the year were the Midway-Vincent #2 500 kV line, the Moss Landing-Las Aguilas 230kV line, and the Gates-Midway #1 500kV line.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) typically limited north-to-south flows. This resulted in higher prices in SCE and SDG&E, and lower prices in PG&E. This line had an average binding limit of around 2,100 MW. Approximately 50 percent of congested hours were between 5 p.m. and 8 p.m. Over 90 percent of congestion occurred between June and August in 2023.

Moss Landing-Las Aguilas 230 kV line

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) typically limited south-to-north flows. This resulted in higher prices in the PG&E area and lower prices in SCE and SDG&E. This line had an average binding limit of 340 MW. In terms of hourly distribution, over 70 percent of congestion occurred between 9 a.m. and 3 p.m. The majority of congestion took place from April to October in 2023.

230 For a breakdown of each individual constraint's impact on prices during the respective quarter, see DMM quarterly reports: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) typically limited south-to-north flows, raising prices in PG&E and lowering them in SCE and SDG&E. This line had an average binding limit of 2,500 MW. Over 80 percent of congestion occurred between 8 a.m. and 3 p.m. 90 percent of congestion took place from September to December in 2023.

SCE and SDG&E had some constraints that impacted their prices in the same direction, but there were constraints that specifically increased prices only in SDG&E. These constraints were located between the metropolitan area of San Diego and the Imperial Valley, a region known for solar generation. This congestion typically occurred around the Imperial Valley, Suncrest, and Miguel substations and increased prices in the SDG&E area.

Table 6.1 Impact of internal transmission constraint congestion on day-ahead market prices during all hours – top 25 primary constraints (2023)

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	4.0%	-0.65	0.49	0.46
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	18.9%	0.78	-0.23	-0.17
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	5.2%	0.41	-0.35	-0.32
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	4.0%	0.40	-0.33	-0.30
30790_PANOCHE_230_30900_GATES_230_BR_2_1	6.9%	0.42	-0.29	-0.26
6410_CP1_NG	3.0%	-0.35	0.26	0.26
30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_1	0.6%	-0.18	0.13	0.12
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	2.3%	0.13	-0.10	-0.09
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	1.3%	0.09	-0.07	-0.06
35621_IBM-HRJ_115_35642_METCALF_115_BR_1_1	3.8%	0.09	-0.07	-0.06
MIGUEL_BKs_MXFLW_NG	1.1%	-0.01	0.00	0.20
7440_MetcalfImport_Tes-Metcalf	0.8%	0.07	-0.05	-0.05
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	1.6%	-0.02	0.00	0.14
30735_METCALF_230_30042_METCALF_500_XF_13	0.9%	0.06	-0.04	-0.04
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	4.5%	0.00	0.00	-0.11
33020_MORAGA_115_30550_MORAGA_230_XF_1_P	0.8%	0.04	-0.03	-0.03
OMS_14369435_Miguel_BK80	0.6%	-0.01	0.00	0.08
7820_TL23040_IV_SPS_NG	1.1%	-0.01	0.00	0.07
6410_CP5_NG	0.2%	-0.03	0.03	0.02
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	2.3%	0.00	0.00	0.07
30797_LASAGUIL_230_30790_PANOCHE_230_BR_2_1	0.6%	0.03	-0.02	-0.02
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1_1	0.5%	0.00	0.00	0.06
30790_PANOCHE_230_30900_GATES_230_BR_1_1	1.0%	0.04	-0.01	-0.01
SYLMAR-AC_BG_NG	0.7%	-0.01	0.01	-0.03
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	1.5%	0.02	-0.02	-0.02
Other	0.5%	0.13	-0.11	0.51
Total		1.43	-0.79	0.43

6.1.2 Real-time congestion

This section presents analysis of the effect of internal congestion on real-time markets across WEIM.[231] This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The impact from transfer constraints are discussed in greater depth in Sections 3.3.3 and 3.4.1.

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

Figure 6.4 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAP) and EIM load aggregation points (ELAP) in 2023. The blue bars represent the 15-minute price impact, and the yellow bars indicate the 5-minute price impact from internal constraints.

The average impact of congestion in the real-time markets over 2023 was in the south-to-north direction. The congestion pattern was closely correlated with solar production; during the day, congestion was created by low priced solar generation in the south flowing north to displace more expensive dispatchable generation. This resulted in increased prices in the Intermountain West, Pacific Northwest, and Northern California, and decreased prices in Southern California and the Desert Southwest.

The impacts of congestion on areas' prices were consistent in both the 15-minute and 5-minute markets. However, price impacts from congestion were greater in the 5-minute market.

231 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.

Figure 6.4 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets

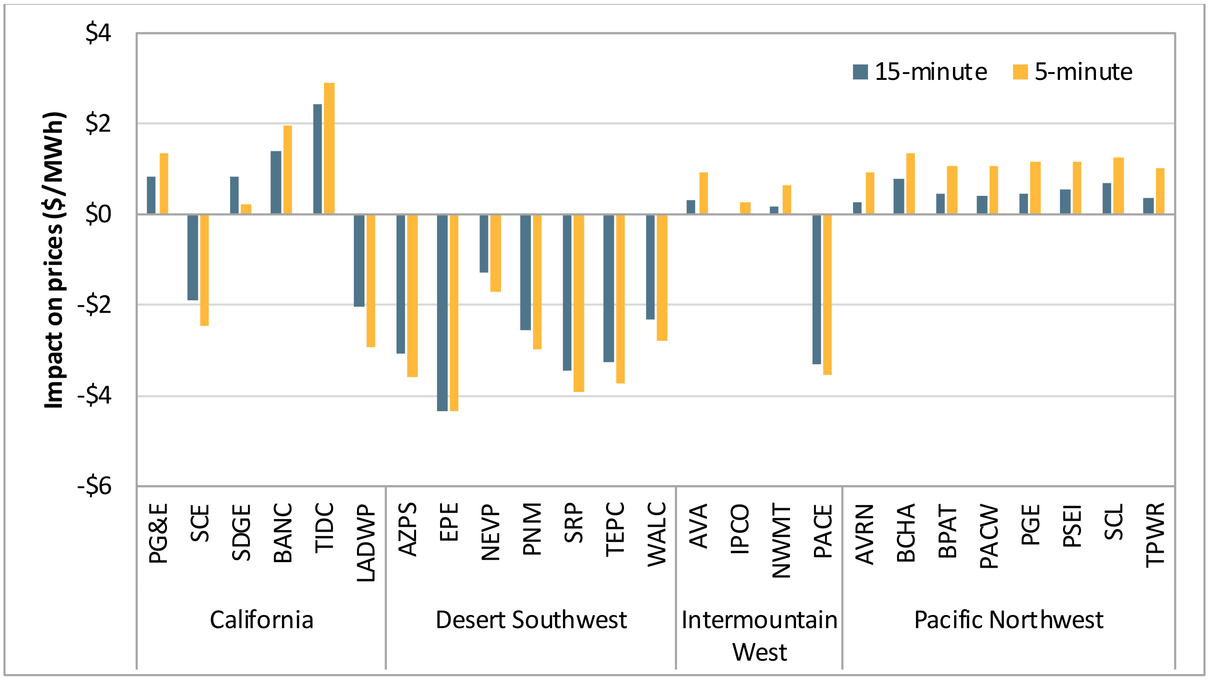


Figure 6.5 displays the average impact of internal congestion on prices in 2022 and 2023. The blue bar represents the impact for 2022, and the red bar shows the impact for 2023. This impact was calculated as the average of the 15-minute and 5-minute price impacts of internal constraints for all intervals.

The overall congestion pattern changed from 2022 to 2023. In 2022, average congestion was into California areas from the rest of the WEIM. However, in 2023 the overall pattern shifted to congestion going from the Desert Southwest and Southern California into the Pacific Northwest, Northern California and the Intermountain West. Congestion on internal transmission constraints had an overall lower impact on price separation in 2023 compared to 2022.

Figure 6.5 Average impact of internal congestion on real-time market price (2022–2023)[232]

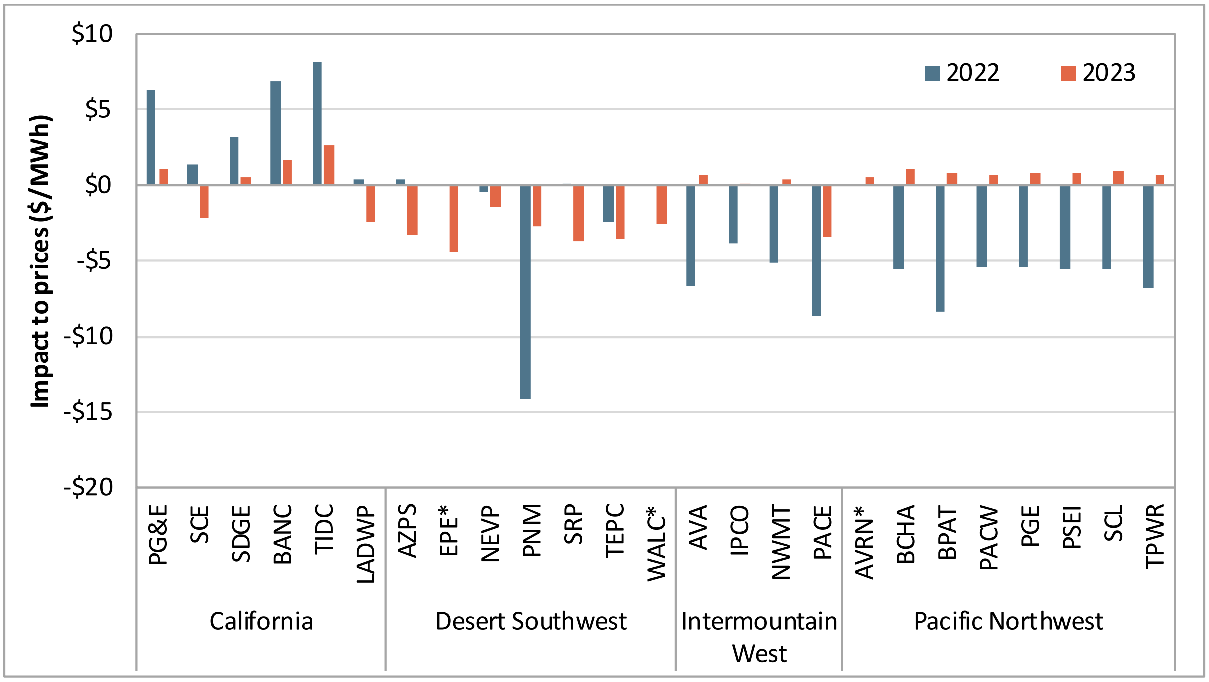


Figure 6.6 and Figure 6.7 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for 2022 and 2023. In 2023, the internal congestion pattern was south-to-north during solar production hours, shifting to north-to-south in the evening as solar generation decreased. El Paso Electric and PacifiCorp East ELAPs were outliers. These areas experienced average negative impact from internal congestion during most hours. Specific transmission elements that limited flows out of these areas did not have a significant impact on prices in other WEIM areas.

Congestion patterns during hours-ending 1 to 6 shifted between 2022 and 2023. The significant congestion from the Intermountain West and Pacific Northwest to California and the Desert Southwest during these hours in 2022 did not materialize on average in 2023. These figures also show that the impact of internal congestion on prices in 2023 was significantly lower than in 2022.

232 BAAs marked with an asterisk (*) joined WEIM in 2023. No data is available for those entities in 2022.

Figure 6.6 Overall impact of internal congestion on price separation in the 15-minute market by hour (2023)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	-0.2	-0.3	-0.3	-0.3	-0.3	-0.4	-0.8	2.2	4.8	5.2	4.8	5.1	4.5	4.1	3.6	2.0	1.7	-0.5	-2.2	-5.2	-3.4	-2.6	-0.8	-0.4
BANC	-0.6	-0.6	-0.6	-0.7	-0.6	-0.9	-1.0	2.0	6.1	7.4	7.2	7.5	7.1	6.6	6.1	3.6	2.1	-0.4	-2.3	-5.7	-3.8	-2.8	-1.2	-0.7
Turlock ID	-0.5	-0.5	-0.5	-0.4	-0.5	-0.8	-1.0	2.6	7.8	10.3	10.2	10.5	9.7	9.2	8.6	5.8	3.8	0.6	-2.3	-5.8	-3.8	-2.8	-1.2	-0.7
SCE	0.7	0.7	0.7	0.7	0.7	1.1	1.3	-2.0	-7.3	-9.7	-9.9	-10.3	-10.0	-9.1	-8.2	-5.1	-2.6	0.6	3.8	7.7	4.7	3.4	1.7	1.0
SDG&E	2.5	2.5	2.4	2.2	2.4	3.0	3.2	1.3	-2.3	-5.6	-5.5	-6.3	-7.1	-6.7	-5.2	-2.0	0.3	3.2	6.1	10.0	7.5	6.0	4.5	3.2
LADWP	0.4	0.4	0.3	0.1	0.2	0.8	1.1	-2.2	-7.2	-9.8	-9.9	-10.3	-10.0	-8.4	-7.8	-4.7	-2.5	0.4	3.4	7.0	4.4	2.9	1.1	0.7
NV Energy	-0.2	-0.3	-0.2	-0.1	0.1	0.2	0.4	-2.7	-4.9	-5.1	-4.9	-4.9	-4.8	-4.6	-4.0	-2.0	-1.1	0.4	2.1	3.7	2.1	1.1	-0.5	-0.4
Arizona PS	-0.1	-0.1	-0.2	-0.1	0.0	0.2	0.4	-3.7	-9.7	-11.8	-11.8	-12.1	-11.5	-10.4	-8.5	-4.5	-2.6	-0.2	2.3	5.2	3.0	1.8	0.3	0.0
Tucson Electric	-0.1	-0.1	-0.2	-0.1	0.0	0.3	0.4	-3.5	-9.4	-11.3	-11.3	-11.6	-11.4	-10.8	-9.9	-6.2	-3.8	-0.9	2.0	4.8	2.8	1.6	0.2	-0.1
Salt River Project	-0.1	-0.1	-0.1	-0.1	0.0	0.3	0.4	-3.8	-9.9	-11.9	-11.9	-12.3	-12.0	-11.5	-10.6	-6.7	-4.1	-1.1	2.1	5.1	3.0	1.8	0.3	0.0
PSC New Mexico	-0.1	-0.2	-0.1	0.0	0.1	0.3	0.4	-2.9	-7.4	-8.8	-9.1	-9.4	-9.3	-8.6	-7.9	-4.9	-2.9	-0.4	2.1	4.3	2.5	1.4	-0.1	-0.5
WAPA - Desert SW	0.0	0.0	-0.1	-0.1	-0.1	-0.2	-0.5	-3.7	-9.1	-10.3	-9.6	-9.5	-8.8	-8.2	-7.1	-3.9	-2.8	0.0	3.6	7.1	4.0	2.3	0.6	0.1
El Paso Electric	-4.1	-4.0	-3.9	-4.0	-3.8	-3.3	-3.9	-5.6	-9.3	-9.8	-9.1	-8.8	-7.8	-7.2	-6.5	-4.4	-4.2	-2.3	0.9	3.7	0.8	-1.0	-3.0	-3.9
PacifiCorp East	-2.9	-2.9	-2.8	-3.0	-3.1	-3.2	-3.5	-3.5	-3.5	-3.5	-3.4	-3.3	-3.4	-3.5	-3.4	-3.4	-3.3	-3.3	-3.6	-4.0	-3.7	-3.3	-3.3	-3.0
Idaho Power	0.0	0.0	0.0	0.0	0.0	0.1	-0.2	0.5	1.6	1.8	1.8	1.8	1.6	1.3	1.1	0.5	0.4	-0.5	-2.2	-4.2	-2.5	-1.6	-0.6	-0.2
NorthWestern	-0.3	-0.3	-0.2	-0.2	-0.2	-0.4	-0.5	0.8	2.8	3.3	3.1	3.2	3.1	2.7	2.3	1.3	0.6	-0.9	-3.2	-5.8	-3.4	-2.1	-0.8	-0.4
Avista Utilities	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.6	1.0	3.6	4.3	4.1	4.3	4.3	3.9	3.2	1.7	0.8	-1.1	-3.8	-6.9	-4.1	-2.5	-1.0	-0.6
Avangrid	-0.7	-0.6	-0.6	-0.5	-0.6	-0.7	-0.2	1.6	5.4	6.0	5.5	5.5	5.1	4.7	3.7	1.8	1.0	-1.7	-5.6	-10.3	-6.1	-3.7	-1.5	-0.8
BPA	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.1	3.9	4.7	4.6	4.8	4.7	4.2	3.7	1.9	1.0	-1.1	-3.7	-6.7	-4.0	-2.6	-1.1	-0.6
Tacoma Power	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.1	3.8	4.6	4.4	4.6	4.5	4.0	3.5	1.8	0.9	-1.2	-3.9	-7.2	-4.3	-2.7	-1.1	-0.6
PacifiCorp West	-0.5	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.1	4.1	4.9	4.7	4.9	4.6	4.1	3.5	1.8	1.0	-1.2	-4.0	-7.4	-4.5	-2.8	-1.1	-0.6
Portland GE	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.1	4.1	4.7	4.6	4.8	5.1	3.9	3.9	2.3	1.4	-0.8	-3.9	-7.3	-4.5	-2.8	-1.1	-0.6
Puget Sound Energy	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.2	4.0	4.8	4.7	4.9	5.2	4.9	4.3	2.5	1.0	-1.1	-3.9	-7.1	-4.3	-2.6	-1.1	-0.6
Seattle City Light	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.2	4.0	4.9	4.8	5.0	5.7	5.6	4.9	2.9	1.1	-1.0	-3.9	-7.1	-4.3	-2.6	-1.1	-0.6
Powerex	-0.4	-0.4	-0.3	-0.3	-0.4	-0.7	-0.7	1.3	4.0	5.1	4.9	5.1	6.1	6.1	5.2	3.3	1.2	-0.9	-3.8	-7.0	-4.2	-2.5	-1.1	-0.6

Hour

Figure 6.7 Overall impact of internal congestion on price separation in the 15-minute market by hour (2022)

	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	4.2	4.5	4.6	4.5	4.6	4.2	3.3	4.5	4.1	5.0	4.9	4.9	5.1	5.3	6.7	6.8	6.7	5.6	4.5	6.1	8.3	6.3	3.5	3.4
BANC	2.9	3.3	3.2	2.9	3.1	2.8	2.5	3.4	5.6	7.2	7.8	8.3	8.5	8.1	9.3	8.4	9.0	5.1	5.3	3.4	4.4	4.9	2.6	2.0
Turlock ID	3.5	4.0	3.9	3.8	3.6	3.1	2.3	3.6	8.0	10.3	11.7	11.8	12.3	12.5	14.0	11.7	8.0	3.3	2.2	3.1	4.3	4.3	2.4	2.6
SCE	3.2	3.5	3.3	3.6	3.3	3.0	2.3	0.7	-2.9	-6.2	-7.0	-7.1	-6.6	-5.8	-4.4	0.1	3.2	6.1	11.7	12.0	8.3	5.7	4.4	3.5
SDG&E	3.4	4.0	3.6	3.8	3.5	3.5	2.8	3.1	1.8	-0.7	-1.8	-4.3	-4.5	-2.9	-0.8	4.1	7.4	9.9	12.4	12.7	9.2	6.2	5.2	4.1
LADWP	2.3	2.3	2.1	2.4	2.1	1.9	1.5	0.0	-3.0	-5.9	-6.9	-6.8	-6.3	-5.5	-4.3	-0.6	2.4	5.8	10.1	9.6	6.8	4.3	3.4	2.5
NV Energy	0.7	0.6	0.9	1.4	1.1	1.3	0.1	-3.0	-3.2	-3.8	-3.6	-3.4	-3.1	-2.8	-2.4	-1.1	0.2	2.1	4.3	4.5	2.2	0.3	0.3	0.1
Arizona PS	3.5	3.5	3.4	3.6	3.5	3.3	2.6	0.0	-4.3	-7.4	-8.2	-8.4	-7.6	-6.8	-5.6	-2.5	0.1	4.0	9.3	9.4	6.8	5.2	4.8	3.4
Tucson Electric	-0.8	-0.5	-0.4	-0.3	0.3	0.2	-0.4	-2.8	-6.0	-8.6	-9.7	-9.8	-9.4	-8.7	-8.0	-4.3	-3.1	0.7	7.3	6.4	2.9	-0.5	-1.6	-1.1
Salt River Project	3.5	3.4	3.2	3.5	3.5	3.2	2.5	-0.1	-4.5	-7.6	-8.3	-8.4	-7.6	-7.0	-6.6	-3.4	-0.9	3.7	9.2	9.3	6.7	5.1	4.7	3.4
PSC New Mexico	-16.8	-15.0	-14.2	-14.9	-13.4	-12.6	-12.7	-13.5	-14.2	-14.5	-16.4	-14.7	-14.4	-12.8	-12.0	-10.8	-15.0	-16.1	-12.5	-13.8	-17.1	-21.8	-24.3	-17.7
WAPA - Desert SW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
El Paso Electric	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PacifiCorp East	-8.8	-8.5	-8.1	-8.6	-8.2	-8.2	-8.2	-7.7	-6.5	-6.2	-6.4	-5.9	-5.6	-5.0	-5.9	-6.9	-9.3	-11.7	-13.5	-12.8	-12.6	-11.9	-11.1	-8.7
Idaho Power	-3.8	-3.8	-3.5	-3.4	-3.5	-3.2	-2.6	-1.7	-0.5	0.0	0.7	0.7	0.7	1.0	-0.4	-2.5	-3.8	-6.8	-10.7	-8.9	-8.7	-6.9	-5.2	-3.7
NorthWestern	-4.1	-4.4	-4.1	-4.2	-4.1	-3.8	-2.6	-1.8	0.3	1.4	1.5	1.4	0.8	0.0	-1.4	-4.2	-6.6	-9.0	-15.5	-15.9	-12.1	-8.3	-5.1	-3.9
Avista Utilities	-4.9	-5.6	-5.2	-5.3	-5.4	-5.0	-3.4	-2.3	0.8	2.3	2.4	2.4	1.5	0.2	-1.7	-5.6	-9.1	-12.8	-21.9	-22.2	-16.5	-10.8	-5.5	-4.6
Avangrid	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA	-6.1	-6.9	-6.5	-6.7	-6.8	-6.2	-4.2	-2.9	0.2	1.9	2.4	2.2	1.2	-0.3	-3.0	-8.1	-12.8	-16.6	-27.0	-27.7	-21.0	-13.6	-6.9	-5.6
Tacoma Power	-5.0	-5.6	-5.3	-5.4	-5.4	-5.0	-3.5	-2.2	1.0	2.7	2.9	2.8	1.9	0.4	-1.5	-5.8	-9.6	-13.4	-22.9	-23.3	-17.2	-11.0	-5.6	-4.7
PacifiCorp West	-4.1	-4.7	-4.4	-4.5	-4.5	-4.2	-2.8	-1.7	1.3	2.9	3.5	3.2	2.4	1.2	-0.6	-4.5	-7.7	-11.0	-19.0	-19.7	-14.5	-9.2	-4.7	-3.9
Portland GE	-4.2	-4.7	-4.5	-4.5	-4.6	-4.2	-2.8	-1.7	1.3	3.0	3.8	3.3	2.6	1.2	-0.6	-4.7	-7.8	-11.0	-19.0	-19.8	-14.6	-9.2	-4.7	-3.9
Puget Sound Energy	-4.2	-4.7	-4.4	-4.5	-4.5	-4.2	-2.9	-1.8	1.1	2.6	2.9	2.8	2.0	0.8	-0.8	-4.6	-7.9	-11.1	-19.0	-19.4	-14.3	-9.2	-4.7	-3.9
Seattle City Light	-4.2	-4.7	-4.4	-4.5	-4.5	-4.2	-3.0	-1.8	1.0	2.4	2.6	2.6	1.8	0.6	-1.0	-4.6	-7.9	-11.3	-19.1	-19.4	-14.3	-9.2	-4.7	-3.9
Powerex	-4.1	-4.7	-4.4	-4.5	-4.5	-4.2	-3.0	-1.8	1.0	2.4	2.5	2.6	1.8	0.6	-1.0	-4.6	-7.7	-11.2	-19.0	-19.2	-14.2	-9.1	-4.7	-3.9

Hour

Impact of individual internal constraints on 15-minute market prices

Table 6.2 and Table 6.3 show the annual impact of congestion from individual constraints on prices in the CAISO and WEIM areas for the 15-minute market. The three constraints that had the greatest impact on price separation in the 15-minute market were Path 26 Control Point 1 nomogram, the Tesla-Los Banos #1 500kV line, and the Panoche-Gates #2 230kV line.

Path 26 Control Point 1 nomogram

The Path 26 Control Point 1 nomogram (6410_CP1_NG) was a major constraint on north-to-south flows, leading to increased prices in Southern California and the Desert Southwest, and lower prices in Northern California, the Intermountain West, and the Pacific Northwest. This nomogram is used to mitigate the Midway-Whirlwind line for the contingency of the Midway-Vincent #1 and #2 lines.

This line typically experienced congestion after 6 p.m., with an overall binding limit of 1,600 MW. It often bound during the summer months, from July to September in 2023.

Tesla-Los Banos #1 500kV line

The Tesla-Los Banos #1 500kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) increased prices in Northern California, the Intermountain West, and the Pacific Northwest, while it decreased prices in Southern California and the Desert Southwest. This line had an overall binding limit of 1,600 MW and typically experienced congestion during solar hours. In 2023, it was mainly congested between October and December.

Panoche-Gates #2 230kV line

Panoche-Gates #2 230kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) increased prices in Northern California, the Intermountain West, and the Pacific Northwest, while it decreased prices in Southern California and the Desert Southwest. This line had an overall binding limit of 200 MW and was typically congested between 9 a.m. and 4 p.m. during the first quarter in 2023.

Another notable constraint was the 115kvLK line in the Public Service Company of New Mexico (PNM), which reduced the El Paso Electric price by an average of $2.7/MWh. This line had an overall binding limit of 40 MW and had high shadow prices, especially during November and December of 2023.

TOTAL_WYOMING_EXPORT and WINDSTAREXPORTTCOR were major constraints affecting PACE, with binding limits of 1,900 MW and 700 MW, respectively. These lines were congested during most hours. They primarily constrained the transfer of wind generation from PACE to the rest of the WEIM area.

Table 6.2 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 25 primary congestion constraints (CAISO, 2023)

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
6410_CP1_NG	4.5%	-0.68	0.59	0.59
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	3.0%	0.22	-0.68	-0.65
30790_PANOCHE_230_30900_GATES_230_BR_2_1	4.3%	0.24	-0.61	-0.56
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	4.2%	0.31	-0.50	-0.47
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	5.0%	0.33	-0.48	-0.46
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	7.7%	0.11	-0.52	-0.49
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	1.4%	-0.25	0.22	0.21
7820_TL50002_IV-NG-OUT_TDM	0.9%	0.00	0.03	0.63
30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_1	1.2%	-0.18	0.16	0.15
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.9%	0.01	0.04	0.30
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	0.7%	0.07	-0.13	-0.12
7440_MetcalfImport_Tes-Metcalf	0.5%	0.11	-0.10	-0.10
OMS_13175637_SUNCRESTBK80_NG	0.3%	.	0.02	0.28
7820_TL230S_OVERLOAD_NG	2.1%	0.00	0.02	0.26
6410_CP5_NG	0.4%	-0.08	0.10	0.09
MIGUEL_BKs_MXFLW_NG	0.4%	0.00	0.01	0.24
OMS13368679_50001_OOS_NG	0.5%	.	0.01	0.22
ML_RM12_NS	0.4%	0.11	0.07	0.06
INTNEL	0.3%	-0.07	-0.07	-0.07
30042_METCALF_500_30045_MOSSLAND_500_BR_1_1	0.3%	0.03	-0.09	-0.08
OMS_14369435_Miguel_BK80	0.5%	0.01	0.02	0.17
ML_RM12_SN	0.3%	-0.08	-0.06	-0.05
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	4.0%	0.12	0.02	0.04
30055_GATES1_500_30057_DIABLO_500_BR_1_1	0.3%	0.03	-0.06	-0.06
24086_LUGO_500_26105_VICTORVL_500_BR_1_1	0.8%	0.04	0.05	0.06
Other	0.9%	0.43	0.07	0.63
Total		0.84	-1.88	0.82

Table 6.3 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary congestion constraints (WEIM, 2023)

		Average quarter impact ($/MWh)																					
Constraint		California			Desert Southwest							Intermountain West				Pacific Northwest							
location	Constraint	BANC	TIDC	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	CCXFMR8A69KV	—	—	—	0.24	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	XFMR1500.TRY	0.02	0.03	0.01	0.01	0.01	—	—	0.01	0.01	0.01	-0.02	-0.02	-0.02	-0.01	-0.04	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
	XFMR2500.TRY	0.01	0.01	0.01	0.00	0.00	—	—	0.00	0.00	0.01	-0.01	-0.01	-0.01	0.00	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
BPAT	INTNEL	-0.07	-0.07	-0.07	-0.07	-0.03	-0.07	-0.06	-0.07	-0.07	-0.03	0.00	-0.06	0.01	-0.06	-0.03	0.39	0.00	-0.08	-0.09	0.15	0.27	-0.04
CISO	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	0.56	0.56	-0.67	-0.58	-0.68	-0.35	-0.50	-0.58	-0.56	-0.76	0.40	0.20	0.32	-0.05	0.65	0.42	0.43	0.45	0.45	0.43	0.43	0.43
	6410_CP1_NG	-0.65	-0.67	0.62	0.52	0.52	0.36	0.43	0.52	0.50	0.58	-0.44	-0.26	-0.36	0.00	-0.61	-0.46	-0.45	-0.48	-0.48	-0.46	-0.46	-0.46
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.48	0.50	-0.49	-0.42	-0.51	-0.27	-0.36	-0.42	-0.41	-0.56	0.36	0.19	0.30	-0.02	0.56	0.37	0.38	0.39	0.39	0.38	0.37	0.38
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	0.39	0.40	-0.47	-0.42	-0.51	-0.25	-0.37	-0.42	-0.41	-0.56	0.25	0.09	0.19	-0.08	0.37	0.26	0.28	0.28	0.28	0.27	0.26	0.27
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	0.48	0.59	-0.59	-0.46	-0.07	-0.17	-0.33	-0.46	-0.43	-0.08	0.14	—	0.03	—	0.08	0.15	0.16	0.19	0.17	0.15	0.15	0.15
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-0.24	-0.25	0.22	0.19	0.22	0.13	0.16	0.19	0.18	0.25	-0.16	-0.09	-0.13	0.01	-0.26	-0.17	-0.16	-0.18	-0.18	-0.17	-0.17	-0.17
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_1	-0.17	-0.18	0.16	0.14	0.17	0.09	0.11	0.13	0.13	0.19	-0.12	-0.07	-0.10	0.00	-0.19	-0.12	-0.12	-0.13	-0.13	-0.12	-0.12	-0.12
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	0.10	0.11	0.13	-0.51	-0.09	-0.11	-0.41	-0.55	-0.48	-0.09	—	—	—	-0.11	—	—	—	—	—	—	—	—
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	0.07	0.52	-0.48	-0.36	-0.06	—	-0.05	-0.35	-0.29	-0.30	0.00	—	—	—	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ML_RM12_NS	0.11	0.11	0.06	0.05	0.04	0.03	0.03	0.04	0.04	0.05	-0.15	-0.11	-0.13	-0.06	-0.21	-0.16	-0.15	-0.16	-0.16	-0.16	-0.16	-0.16
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	0.09	0.10	-0.13	-0.11	-0.04	-0.07	-0.09	-0.11	-0.11	-0.05	0.06	0.03	0.05	-0.01	0.04	0.06	0.06	0.07	0.07	0.06	0.06	0.06
	6410_CP5_NG	-0.08	-0.08	0.09	0.08	0.00	0.05	0.07	0.08	0.07	0.00	-0.05	-0.02	-0.04	0.01	0.00	-0.05	-0.05	-0.06	-0.06	-0.05	-0.05	-0.05
	ML_RM12_SN	-0.08	-0.08	-0.05	-0.04	-0.01	-0.02	-0.03	-0.04	-0.04	-0.01	0.06	0.04	0.05	0.02	0.02	0.06	0.07	0.07	0.07	0.07	0.07	0.07
	7440_MetcalfImport_Tes-Metcalf	0.07	0.15	-0.10	-0.09	-0.01	-0.06	-0.07	-0.09	-0.08	-0.01	0.01	—	0.00	-0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03
	30042_METCALF_500_30045_MOSSLAND_500_BR_1_1	0.06	0.08	-0.09	-0.07	—	-0.04	-0.06	-0.07	-0.07	—	0.04	0.02	0.03	0.00	—	0.04	0.04	0.04	0.04	0.04	0.04	0.04
	24086_LUGO_500_26105_VICTORVL_500_BR_1_1	0.03	0.04	-0.11	-0.09	—	-0.07	-0.08	-0.09	-0.09	—	0.01	0.00	0.00	-0.04	—	0.01	0.01	0.02	0.02	0.01	0.01	0.01
	7820_TL50002_IV-NG-OUT_TDM	—	—	—	-0.14	-0.12	—	-0.01	-0.11	-0.11	-0.20	—	—	—	—	—	—	—	—	—	—	—	—
	30055_GATES1_500_30057_DIABLO_500_BR_1_1	0.04	0.04	-0.06	-0.05	—	-0.03	-0.04	-0.05	-0.05	—	0.03	0.01	0.02	-0.01	—	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	—	—	—	-0.09	-0.11	-0.01	-0.07	-0.09	-0.09	-0.12	—	—	—	-0.01	—	—	—	—	—	—	—	—
	OMS_13175637_SUNCRESTBK80_NG	—	—	—	-0.10	—	-0.01	-0.08	-0.10	-0.10	—	—	—	—	-0.01	—	—	—	—	—	—	—	—
	7820_TL230S_OVERLOAD_NG	0.00	0.00	0.00	-0.05	-0.07	-0.02	-0.05	-0.06	-0.06	-0.07	—	0.00	—	-0.02	0.00	—	—	—	—	—	—	—
	MIGUEL_BKs_MXFLW_NG	—	—	—	-0.07	-0.05	—	-0.06	-0.07	-0.07	-0.06	—	—	—	—	—	—	—	—	—	—	—	—
	24801_DEVERS_500_24804_DEVERS_230_XF_2_P	0.01	0.01	0.01	-0.05	-0.04	-0.01	-0.04	-0.05	-0.05	-0.04	—	—	—	-0.02	0.01	—	—	0.00	0.00	—	—	—
	OMS_14369435_Miguel_BK80	—	—	—	-0.05	-0.06	—	-0.04	-0.05	-0.05	-0.07	—	—	—	0.00	—	—	—	—	—	—	—	—
	99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	0.01	0.01	0.02	-0.05	-0.01	0.01	-0.07	-0.05	-0.06	0.00	—	—	—	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1_1	-0.02	-0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	-0.01	-0.01	-0.01	—	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	OMS13938629_CP1_NG	-0.02	-0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.01	-0.01	-0.01	—	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	6410_CP7_NG	0.02	0.02	-0.02	-0.02	0.00	-0.01	-0.02	-0.02	-0.02	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	30790_PANOCHE_230_30900_GATES_230_BR_1_1	0.02	0.03	-0.03	-0.02	0.00	-0.01	-0.01	-0.02	-0.02	-0.01	0.00	—	—	—	—	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	30060_MIDWAY_500_24156_VINCENT_500_BR_1_3	-0.01	-0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.01	-0.01	-0.01	—	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	OMS13368679_50001_OOS_NG	—	—	—	-0.03	-0.04	-0.01	-0.02	-0.03	-0.03	-0.04	—	—	—	-0.01	—	—	—	—	—	—	—	—
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	0.06	0.13	-0.02	—	—	—	—	—	—	—	—	—	—	—	0.00	—	—	—	—	—	—	—
	OMS_14330422_Miguel_BK81	—	—	—	-0.03	-0.04	—	-0.03	-0.03	-0.03	-0.04	—	—	—	—	—	—	—	—	—	—	—	—
	30050_LOSBANOS_500_30055_GATES1_500_BR_3_1	0.01	0.01	-0.02	-0.01	0.00	-0.01	-0.01	-0.01	-0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	6110_COI_N-S	0.01	0.01	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.01	-0.01	-0.01	-0.01	0.00	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	30763_Q0577SS_230_30765_LOSBANOS_230_BR_1_1	0.02	0.03	-0.01	-0.01	—	-0.01	-0.01	-0.01	-0.01	—	0.01	0.00	0.01	—	—	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	OMS14384679_50001_OOS_NG	—	—	—	-0.03	-0.03	-0.01	-0.02	-0.03	-0.03	-0.04	—	—	—	0.00	—	—	—	—	—	—	—	—
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1_1	—	—	—	-0.04	-0.01	—	-0.03	-0.05	-0.04	-0.01	—	—	—	—	—	—	—	—	—	—	—	—
	30005_ROUNDMT_500_30015_TABLEMT_500_BR_2_2	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.01	-0.01	-0.01	-0.01	0.00	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3_1	0.01	0.01	0.01	-0.03	0.00	0.00	-0.02	-0.03	-0.03	0.00	0.00	0.00	0.00	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	32218_DRUM_115_32244_BRNSWKT2_115_BR_2_1	0.00	—	—	—	—	-0.17	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	6110_COI_S-N	-0.01	-0.01	-0.01	0.00	-0.01	0.00	0.00	0.00	0.00	-0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
IPCO	PATH_14	-0.01	-0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.02	0.06	0.00	0.03	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
PACE	WINDSTAREXPORTTCOR	—	—	—	—	—	—	—	—	—	—	—	—	—	-1.44	—	—	—	—	—	—	—	—
	TOTAL_WYOMING_EXPORT	—	—	—	—	—	—	—	—	—	—	—	—	—	-1.27	—	—	—	—	—	—	—	—
PNM	115kvLK	—	—	—	—	-2.76	—	-0.05	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	Other	0.07	0.32	-0.05	-0.24	0.00	-0.19	-0.30	-0.34	-0.37	-0.33	-0.03	0.02	-0.01	-0.14	-0.03	-0.02	-0.02	-0.03	0.09	-0.02	-0.02	-0.02
Total	Total	1.41	2.43	-2.06	-3.09	-4.35	-1.27	-2.57	-3.46	-3.27	-2.34	0.33	0.00	0.17	-3.33	0.27	0.78	0.47	0.40	0.48	0.56	0.68	0.37

6.2 Congestion on interties

Overall, the frequency and financial impact of congestion on most interties connecting the CAISO with other balancing authority areas decreased relative to 2022, particularly on interties connecting the CAISO to the Pacific Northwest.

The total day-ahead congestion charges on interties amounted to $46.5 million, a decrease from $181 million in 2022 and $105 million in 2021.

Another significant change in 2023, compared to 2022, was the increase in export congestion on interties. The frequency of day-ahead export congestion on major interties nearly doubled in 2023, and the associated day-ahead export congestion charges rose from $7 million in 2022 to $13 million in 2023.

Congestion on interties between the CAISO and other balancing areas impact the price of imports and exports and affect payments for congestion revenue rights. However, intertie congestion has generally had a minimal impact on prices for load and generation within the CAISO system. This is because when congestion limits additional imports on one or more interties, there is usually additional supply available from other interties or from within the CAISO at a relatively small increase in price.

Table 6.4 provides a summary of import congestion frequency on interties, including average day-ahead congestion charges and the total day-ahead congestion charges. Table 6.5 provides the same category of information for export congestion.

The congestion prices reported in Table 6.4 and Table 6.5 are the megawatt weighted average shadow prices for the binding intertie constraints. For a supplier or load serving entity trying to import power over a congested intertie, assuming a radial line, the congestion price represents the difference between the higher price of power on the CAISO side of the intertie and the lower price offered by importers outside of the CAISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the CAISO at points corresponding to these interties.

Figure 6.8 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years, categorized by import and export congestion. Figure 6.9 shows the total day-ahead congestion charges on major interties between 2020 and 2023. Additionally, this figure categorizes the total day-ahead congestion charges by interties and direction, distinguishing between import and export.

Table 6.4 Summary of day-ahead import congestion (2021–2023)

Import region	Intertie	Day-ahead frequency of import congestion			Day-ahead average congestion charge ($/MW)			Total day-ahead import congestion charges (thousands)		
		2021	2022	2023	2021	2022	2023	2021	2022	2023
Northwest	Malin	23.0%	17.4%	2.4%	$13.41	$24.88	$17.89	$54,927	$90,385	$6,367
	NOB	10.7%	18.4%	2.9%	$13.91	$22.34	$28.72	$20,429	$58,510	$11,832
	COTPISO	0.5%	5.0%	1.7%	$12.59	$19.57	$16.48	$31	$813	$232
	Cascade		0.7%			$15.44			$72	
	Summit		0.4%	0.5%		$35.19	$79.74		$20	$57
Southwest	Palo Verde	6.6%	4.9%	3.3%	$37.37	$34.74	$31.98	$24,128	$18,000	$10,582
	IPP Utah	5.8%	6.4%	1.2%	$17.25	$53.62	$14.48	$1,625	$5,636	$264
	IPP DC Adelanto	0.2%	1.6%	1.7%	$4.91	$34.87	$48.42	$40	$685	$2,996
	Mona									
	Mead	0.1%	0.2%	0.1%	$8.44	$10.55	$9.82	$84	$182	$75
	Merchant	0.1%	0.0%		$19.65	$79.24		$150	$101	
	Silver Peak									
	Mercury		0.0%			$192.86			$10	
	Other							$1,511	$10	$1,357
Total								***$102,925***	***$174,414***	***$33,762***

Table 6.5 Summary of day-ahead export congestion (2021-2023)

Export region	Intertie	Day-ahead frequency of export congestion			Day-ahead average congestion charge ($/MW)			Total day-ahead export congestion charges (thousands)		
		2021	2022	2023	2021	2022	2023	2021	2022	2023
Northwest	Malin		0.8%	3.8%		$118.68	$34.75		$4,826	$8,658
	NOB	0.3%	2.0%	1.5%	$19.87	$22.70	$17.11	$267	$1,398	$1,170
	COTPISO		0.1%	0.8%		$13.74	$16.57		$1	$89
	Cascade			0.0%			$0.21			$0
	Summit		0.0%			$0.39			$0	
Southwest	Palo Verde			0.0%			$69.78			$243
	IPP Utah		0.2%			$6.22			$20	
	IPP DC Adelanto									
	Mona	0.1%	0.1%	0.3%	$186.66	$20.46	$44.83	$1,060	$83	$220
	Mead	0.1%	0.1%	0.4%	$79.26	$32.11	$58.13	$665	$308	$2,370
	Merchant									
	Silver Peak		0.6%	0.7%		$47.86	$20.58		$34	$16
	Mercury									
	Other							$72	$0	$0
Total								***$2,065***	***$6,669***	***$12,765***

Figure 6.8 Percent of hours with day-ahead congestion on major interties (2021–2023)

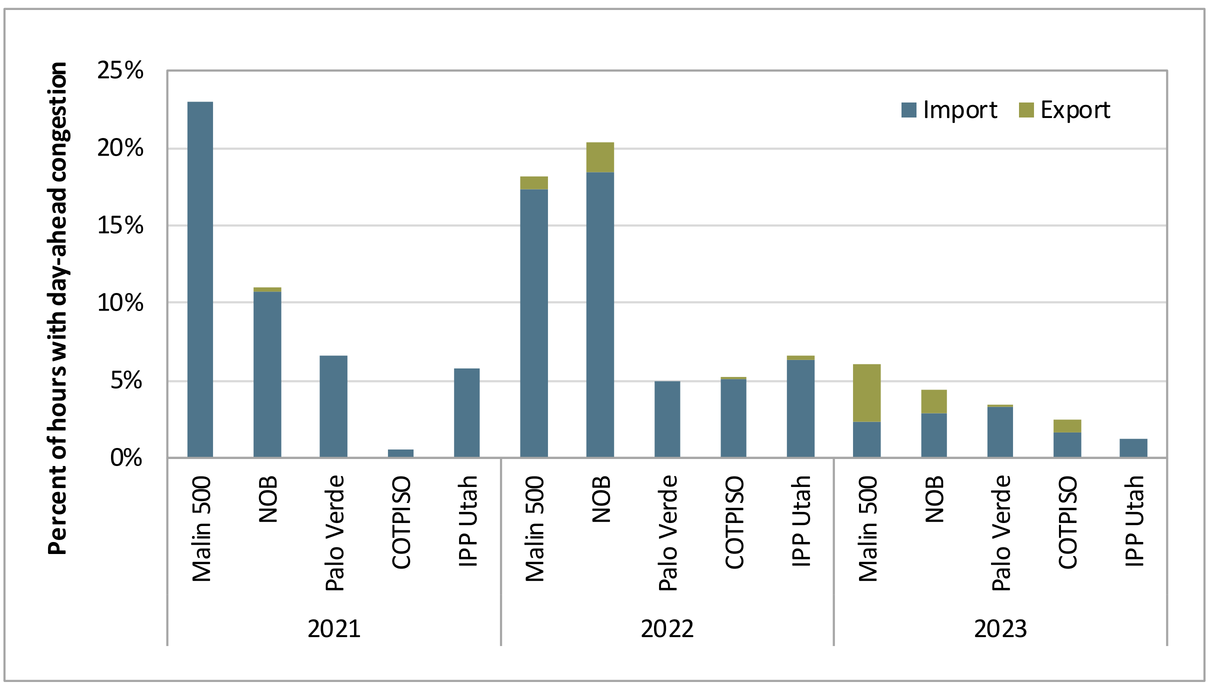
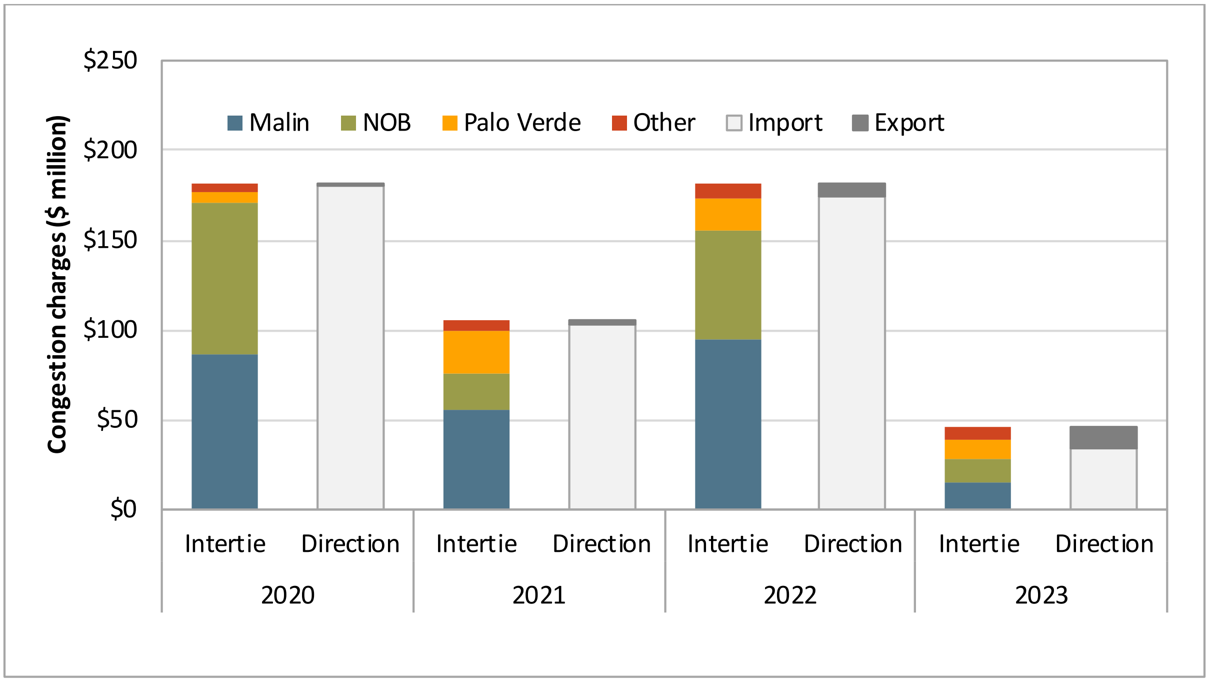


Figure 6.9 Day-ahead congestion charges on major interties (2020–2023)



Trends in impact of congestion on interties

Day-ahead import congestion on interties totaled about $34 million, significantly lower than $174 million in 2022 and $103 million in 2021. The significant reduction in congestion charges was mainly due to the decreased frequency of intertie congestion in the import direction. Malin and NOB, the most congested interties in recent years, experienced import congestion frequencies of only 2.4 percent and 2.9 percent of hours, respectively, which are considerably lower than the 17.4 percent and 18.4 percent observed in 2022. Furthermore, the binding interties in 2023 tended to have smaller capacities and lower shadow prices compared to those in 2022 and 2021.

Day-ahead export congestion on interties increased significantly compared to 2022 and 2021. This increase was particularly notable on Malin, which connects CAISO to the Pacific Northwest. Total congestion charges in the day-ahead market across all export constraints amounted to $13 million, an 85 percent increase from $7 million in 2022. The export congestion charge on Malin amounted to $8.6 million in 2023.

This substantial rise can largely be attributed to a higher frequency of export congestion during April and October in 2023 compared to 2022. Export congestion over Malin was lower in December 2023 than December 2022. However, the rest of the months in 2023 saw consistently higher export shadow prices on this intertie.

6.3 Congestion revenue rights

Congestion revenue rights sold in the auction consistently pay more to purchasers than they cost at auction. If these congestion revenue rights were not sold in the auction, all of these congestion revenues would be allocated back to load serving entities based on their share of total load. From 2009 through 2018, transmission ratepayers received about 50 percent of the value of their congestion revenue rights sold at auction, with a total shortfall of more than $860 million.

In response to these systematic losses from congestion revenue right auction sales, the California ISO instituted significant changes to the congestion revenue right auction starting in the 2019 settlement year. 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.[233]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[234]
- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[235]

In 2023, transmission ratepayer losses from congestion revenue right auctions totaled about $59 million, down from $117 million in 2022, but still significantly up from $43 million in 2021. Transmission ratepayers received about 76 cents in auction revenue per dollar paid out to these rights purchased in the 2023 auctions.

Section 6.3.1 provides an overview of allocated and auctioned congestion revenue rights holdings. Section 6.3.2 provides more details on the performance of the congestion revenue rights auction.

6.3.1 Allocated and auctioned congestion revenue rights

Background

Congestion revenue rights 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.

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233 *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, California ISO, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

234 *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

235 *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

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]

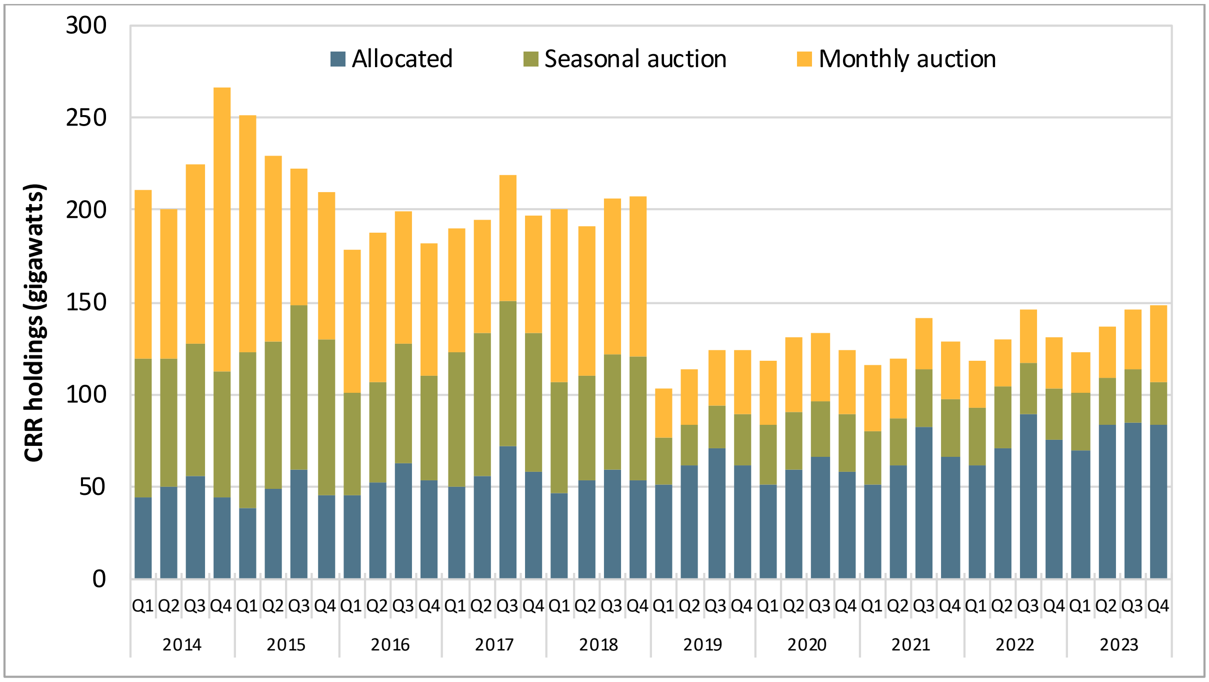
Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. Allocating congestion revenue rights, also known as congestion rent, is a means of distributing the revenue from these rights to entities serving load, to then be passed on to ratepayers. Any revenues 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 6.10 shows the congestion revenue right megawatts held by allocated, seasonally auctioned, and monthly auctioned rights; this figure includes all peak and off-peak rights. In 2023, the share of allocated congestion revenue rights was about 58 percent of the total megawatts held. Auctioned rights were about 42 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.

[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 6.10 Congestion revenue rights held by procurement type (2014–2023)[237]



6.3.2 Congestion revenue right auction returns

The CRR auction returns compare the auction revenues that ratepayers receive for rights sold in the California ISO auction to the payments made to these auctioned rights based on day-ahead market prices. 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.[238] 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.[239]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[240]

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237 Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs).

238 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.

239 *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, California ISO, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

240 *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.[241]

DMM believes the current auction is unnecessary and could be eliminated.[242] If the California ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should 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.

Congestion revenue right auction returns

As described above, 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 6.11 compares the following for each of the last several years:

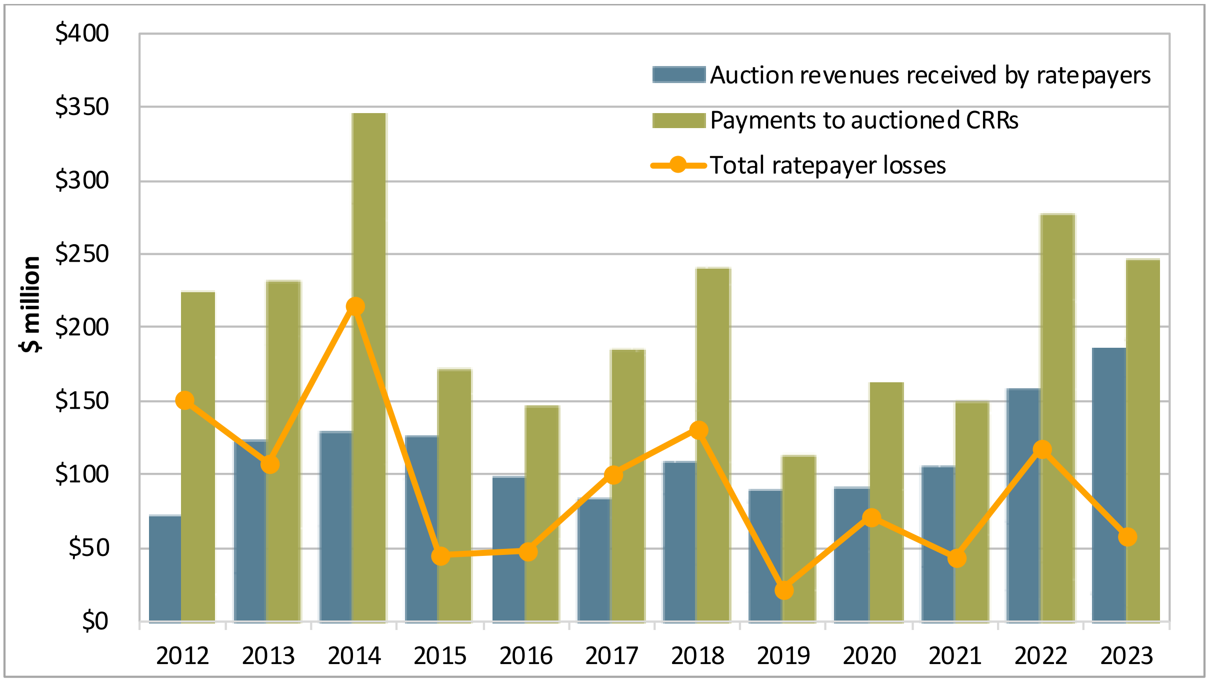
- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars).[243]
- Net payments made to the non-load-serving entities purchasing congestion revenue rights in auction (green bars).
- Total ratepayers losses are the difference between auction revenues received and payments made to non-load-serving entities (yellow line).

241 *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

242 *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

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

Figure 6.11 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Between 2012 and 2018, prior to the auction modifications, ratepayers received on average about $114 million less per year from auction revenues than entities purchasing these rights in the auction received from day-ahead congestion revenues. Over this seven year period, ratepayers received an average of 48 cents in auction revenues for every dollar paid to congestion revenue rights holders, summing to a total shortfall of $800 million, or about 28 percent of day-ahead congestion rent.

In 2023, ratepayer auction losses were around $59 million, or about 7 percent of day-ahead market congestion rent. Ratepayers received an average of 76 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 $97 million.

In 2022, losses were around $117 million, or about 11 percent of day-ahead market congestion rent. Ratepayers received an average of 57 cents in auction revenue per dollar paid out. Track 1B revenue deficiency offsets reduced payments to auctioned rights by about $150 million.

With the implementation of the constraint specific allocation of revenue inadequacy offsets to congestion revenue right 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 created 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 6.12 shows the estimated breakout of ratepayer auction losses by CAISO sales (the blue bars) and load serving entity trades (the green bars). The losses are mostly from CAISO sales. On net, we estimate that trades made by load serving entities (LSE) increased ratepayer losses by $13 million in 2023 compared to decreasing losses by almost $11 million in 2022.

Figure 6.12 Estimated CRR auction loss breakout by CAISO and load serving entity

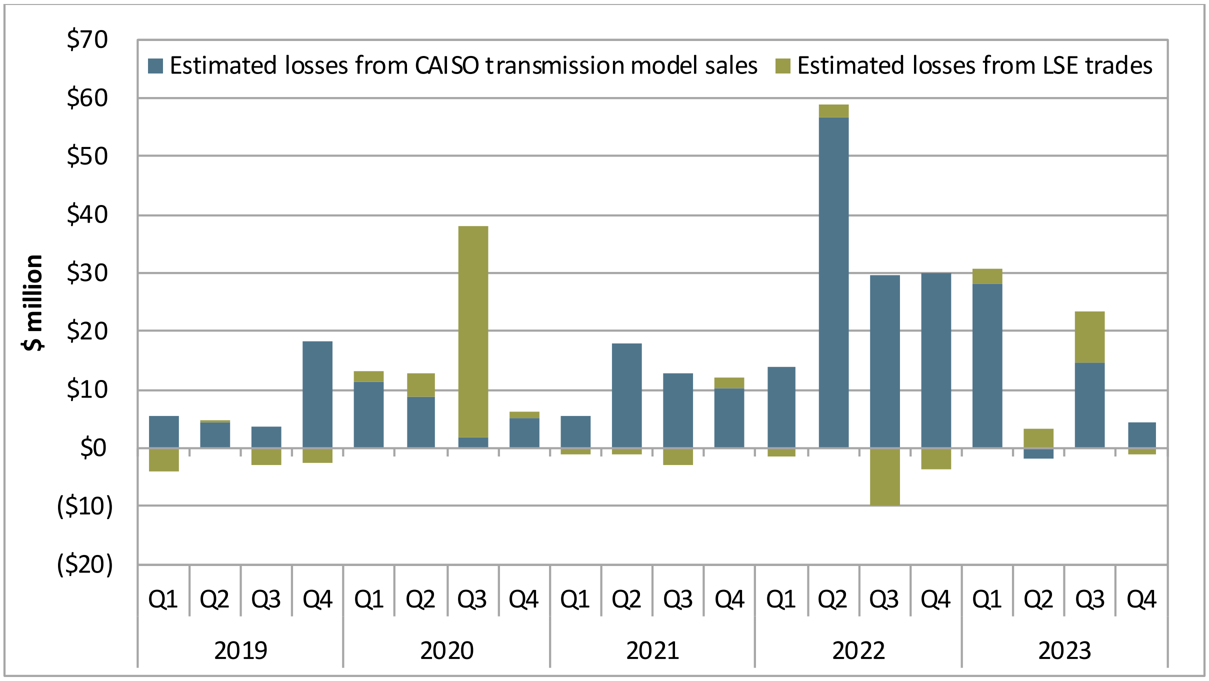


Figure 6.13 through Figure 6.15 compare the auction revenues paid for and payments received from congestion revenue rights traded in the auction by market participant type.[244] The difference between auction revenues and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities received net revenue of about $43 million in 2023, down from nearly $71 million in 2022. Total revenue deficit offsets were about $66 million.
- Marketers received net revenues of nearly $11 million from auctioned rights in 2023, down significantly from $34 million in 2022. Total revenue deficit offsets were nearly $23 million.
- Physical generation entities received about $2 million in net revenue from auctioned rights in 2023 down from about $12 million in 2023. Total revenue deficit offsets were about $7 million.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2023 physical generators as a group continued to account for a

244 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.

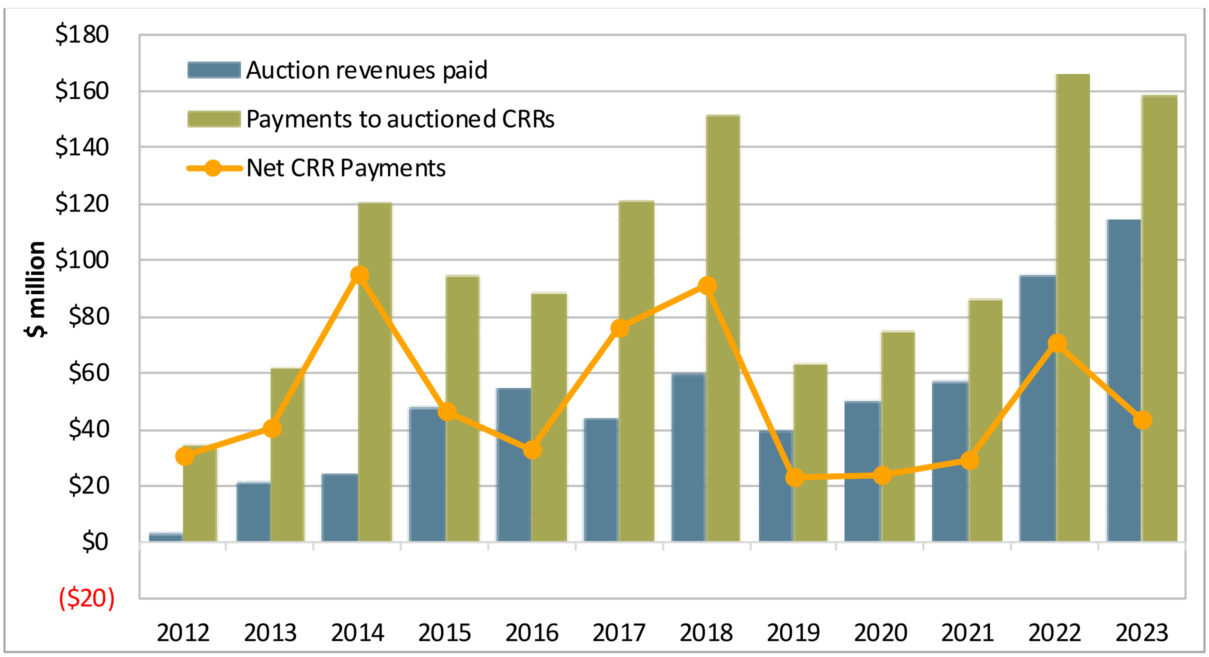
relatively small portion of congestion revenue rights held. As a group, generators received the lowest overall payments from congestion revenue rights.

The losses to ratepayers from the congestion revenue rights auction could, in theory, be avoided if load serving entities purchased the congestion revenue rights at the auction from themselves. However, load serving entities face significant technical and regulatory hurdles to purchasing these rights. Moreover, DMM does not believe it is appropriate to design an auction so that load serving entities would have to purchase rights in order to avoid obligations to pay other congestion revenue rights holders.

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 participants. 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, financial, or other entities.

DMM believes the current auction is unnecessary and could be eliminated.[245,246] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes 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.

Figure 6.13 Auction revenues and payments (financial entities)



245 *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

246 *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 6.14 Auction revenues and payments (marketers)

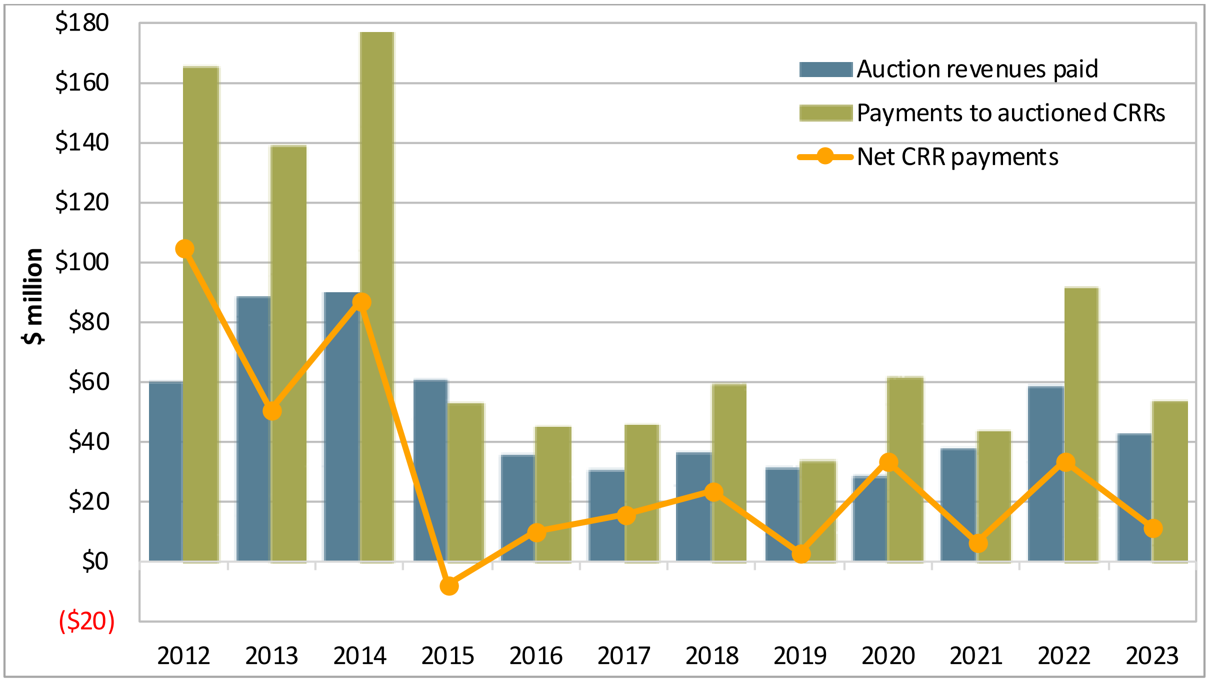
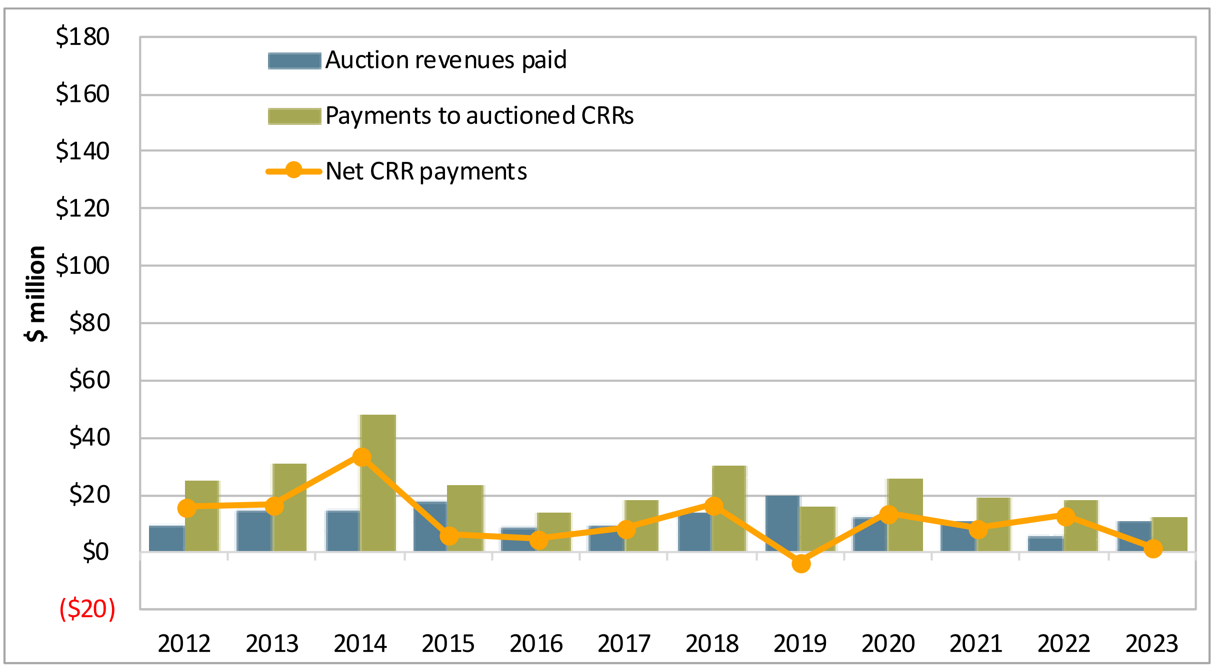


Figure 6.15 Auction revenues and payments (generators)



7 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, transmission limits may be modified to account for potential differences between modeled power flows and actual real-time power flows. 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 residual unit commitment requirements, 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:

- **Total energy resulting from all types of exceptional dispatch increased by 2.4 percent in 2023.** It continued to account for a relatively low portion of total system load at 0.26 percent in 2023, similar to the 0.24 percent in 2022. Exceptional dispatch energy above minimum load decreased by approximately 17 percent in 2023 from 2022, while minimum load energy from unit commitments increased by 9.8 percent.
- **Total above-market costs from exceptional dispatch decreased** by about 33 percent to $9.3 million in 2023, down from $13.9 million in 2022.
- **Out-of-market dispatches of both imports and emergency assistance decreased significantly**. In 2023, the California ISO did not procure any imports via out-of-market manual dispatches. This was a substantial decrease from the 2,450 MWh of emergency assistance and 17,400 MWh of non-emergency assistance imports that the CAISO balancing area manually dispatched in 2022.
- **California ISO operator adjustments to residual unit commitment requirements increased by 154 percent**. This followed an increase of 147 percent in 2022 compared to average 2021 RUC adjustments. In the third quarter, the average RUC adjustment was about 2,360 MW per hour compared to 1,384 MW in the same quarter in 2022. These large increases were caused by the CAISO area changing its method for determining the uncertainty portion of the RUC load adjustment in the summer of 2023.
- **High levels of real-time market load adjustments by the California ISO continued in solar ramping periods.** Imbalance conformance adjustments in the 15-minute market averaged about 1,820 MW during the peak hour, hour-ending 19, about 200 MW less than the average hourly adjustment for the same hour of 2022. This continued the operator use of imbalance conformance that began in 2017. Maximum load adjustments during the morning ramping hours were around 2,000 MW, while the maximum load adjustment during the evening ramp reached 5,000 MW in hours-ending 19 to 22 during the late summer heat wave period.

7.1 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatch used to instruct a generating unit to start up, continue operating at minimum operating levels, or 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 dispatch issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have 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** — Occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. When the bid price of the unit being exceptionally dispatched is subject to 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.

Summary of exceptional dispatch

Energy from exceptional dispatch continued to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 0.26 percent of system loads in 2023, similar to the 0.24 percent in 2022.

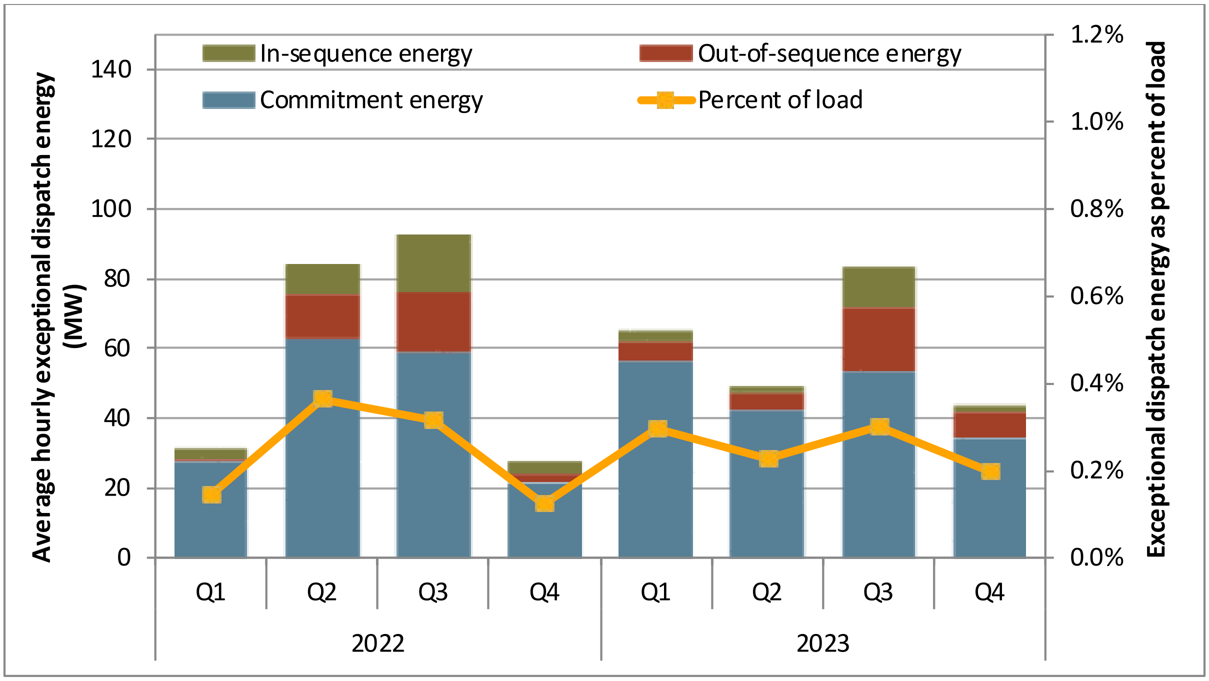
Exceptional dispatch energy above minimum load decreased by approximately 17 percent in 2023 from 2022, while minimum load energy from unit commitments increased by 9.8 percent. As shown in Figure 7.1, minimum load energy from units committed via exceptional dispatch (blue) accounted for 77 percent of all exceptional dispatch energy in 2023. About 15 percent of energy from exceptional dispatches was from out-of-sequence energy above minimum load (red), and the remaining 8 percent was from in-sequence energy above minimum load (green).

The In-sequence energy portion of exceptional dispatches above minimum load decreased by 40 percent in 2023 compared to 2022. Out-of-sequence energy from exceptional dispatch increased 6 percent year over year between 2022 and 2023.

In formulating the market clearing prices for energy, the market software does not utilize the submitted bid prices from most resources receiving exceptional dispatches. However, exceptional dispatches can affect these market clearing prices. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by other supply. This can reduce market prices relative to a case where no exceptional dispatch was made.

However, as discussed later in this section, the bulk of energy from exceptional dispatches is minimum load energy from unit commitments. Minimum load energy cannot set market prices. Therefore, the energy from unit commitment exceptional dispatches would not set market prices even if the reliability issue creating the need for the exceptional dispatch was incorporated into the market model. So, if the modeling was improved and these commitment exceptional dispatches were instead commitment instructions from the market optimization, real-time market prices would not increase. Furthermore, most exceptional dispatches occur after the day-ahead market. If the constraints were modeled in the day-ahead market, causing the day-ahead market to issue the commitment instructions, prices in the day-ahead market would likely decrease.

Figure 7.1 Average hourly energy from exceptional dispatch

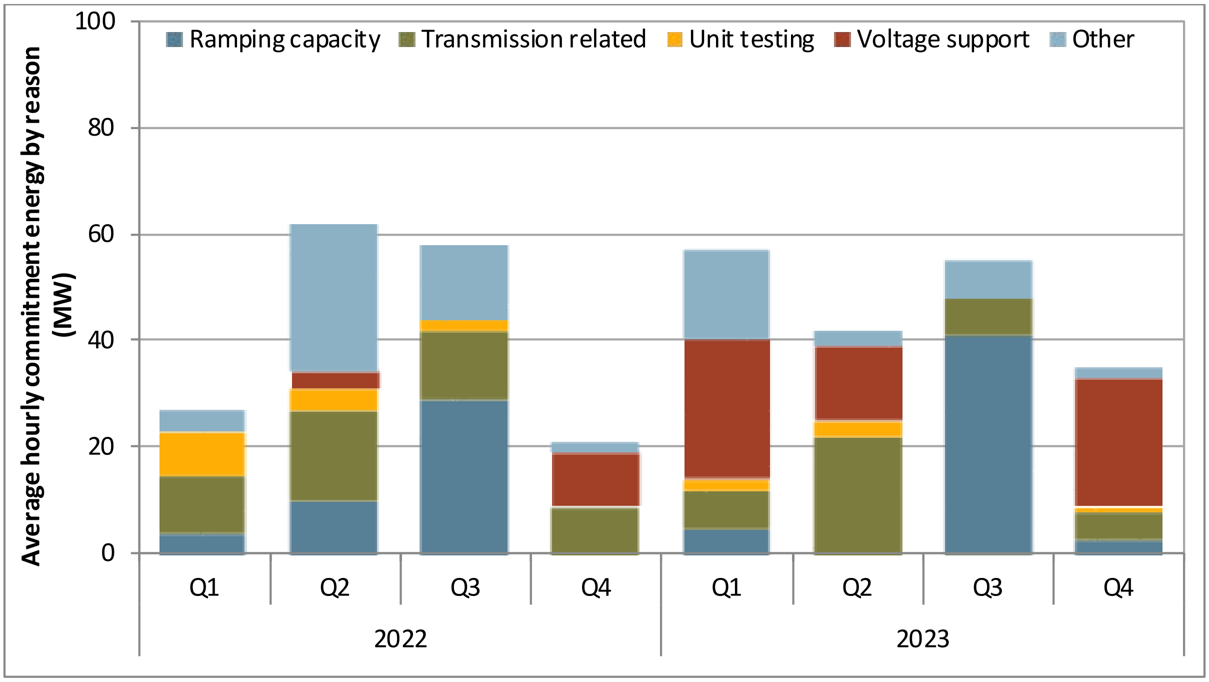


Exceptional dispatches for unit commitment

California ISO operators sometimes 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 other cases, a scheduling coordinator may request to operate a resource out-of-market for purposes of unit testing. 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 7.2 shows the reasons for minimum load energy exceptional dispatches—ramping capacity (blue), transmission related (green), unit testing (yellow), and voltage support (red). Minimum load energy from exceptional dispatch unit commitments increased in 2023 compared to 2022, with most occurring in the first and third quarters of 2023. Exceptional dispatch unit commitments in the third quarter of 2023 were predominately issued to provide additional ramping capacity to the grid. These exceptional dispatches are issued to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real-time. Exceptional dispatch unit commitments for voltage support increased in the first, second, and fourth quarters of 2023 compared to their respective quarters in 2022. 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 7.2 Average minimum load energy from exceptional dispatch unit commitments



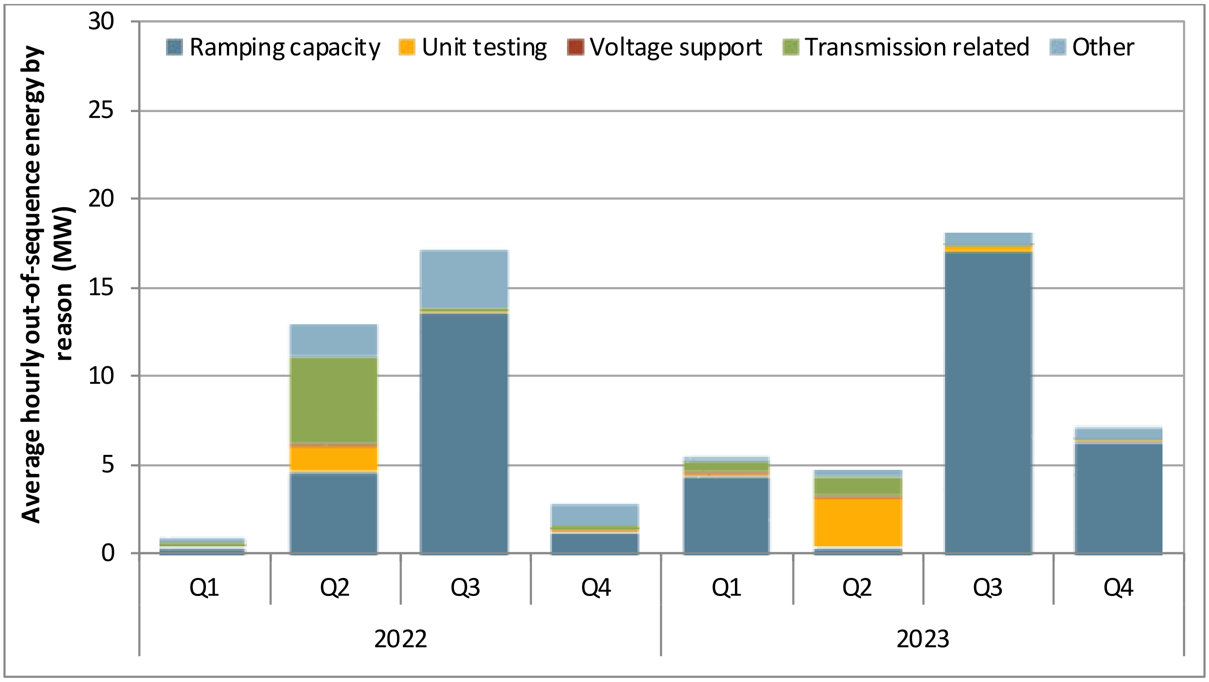
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to operate units above minimum load—or to ensure they do not operate below their regular market dispatch—decreased by 17 percent in 2023. As illustrated earlier in Figure 7.1, about 15 percent of this type of exceptional dispatch energy was out-of-sequence, meaning the bid price was greater than the locational market clearing price.[247] Out-of-sequence exceptional dispatch energy increased by 6 percent in 2023 when compared to 2022.

Figure 7.3 shows the out-of-sequence exceptional dispatch energy by quarter for 2022 and 2023. Out-of-sequence exceptional dispatch energy followed a similar trend to the previous year, with most occurring in the third quarter, but overall there was an increase in 2023 from 2022. The primary reason logged for out-of-sequence energy exceptional dispatches was for ramping capacity. Many of these exceptional dispatches were used to ramp thermal resources to their minimum dispatchable level—a higher operating level with a faster ramp rate, which allows these units to be more available to meet reliability requirements and other uncertainties in real-time.

[247] The unit's bid price can equal the resource's default energy bid if subject to energy bid mitigation, or if the resource did not submit a bid.

Figure 7.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

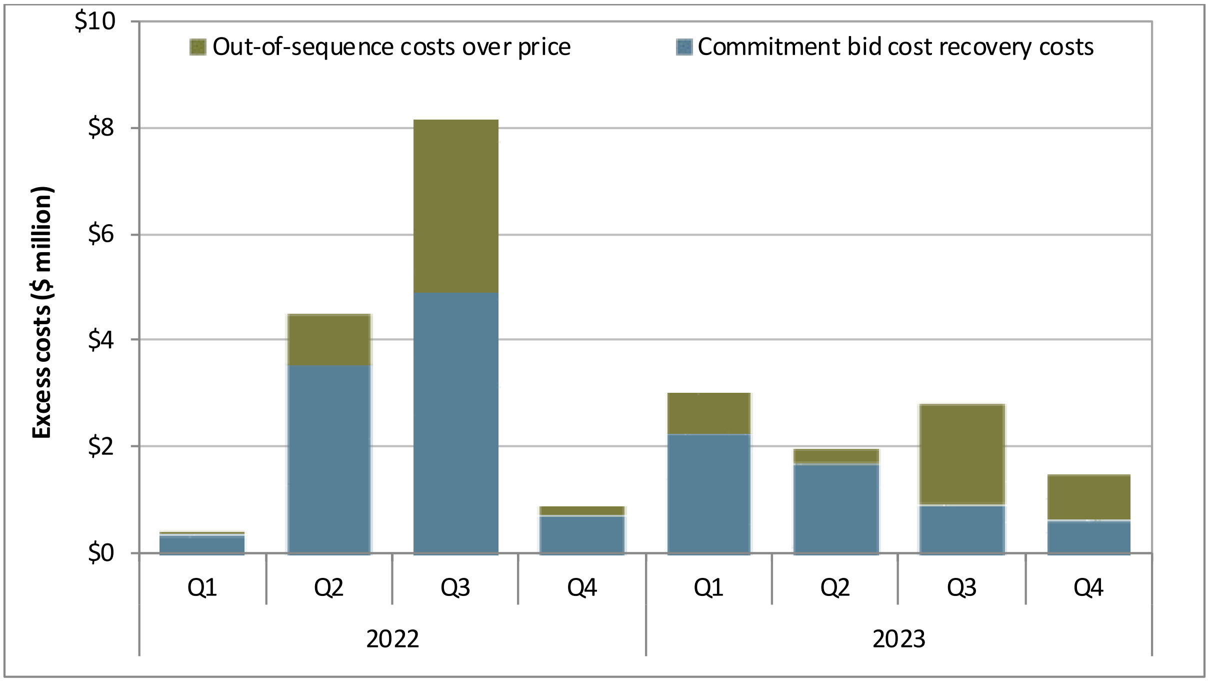
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy:

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

Figure 7.4 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market clearing price for this energy. Commitment and additional energy costs for exceptional dispatch paid through bid cost recovery decreased from $9.5 million in 2022 to $5.5 million in 2023, and out-of-sequence energy costs decreased from $4.4 million in 2022 to $3.8 million in 2023.[248] Total excess costs for exceptional dispatches decreased by about 33 percent to about $9.3 million in 2023 from $13.9 million in 2022.

[248] The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid, if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

Figure 7.4 Excess exceptional dispatch cost by type



7.2 Manual dispatches

Manual dispatch on the interties

Exceptional dispatches on the interties are instructions issued by California ISO operators when the market optimization is not able to address a particular reliability requirement or constraint. Energy dispatches issued by the California ISO operators are sometimes referred to as manual or out-of-market dispatches. During periods of extreme temperature and energy demand, the California ISO may call upon neighboring balancing authority areas to provide emergency assistance on the interties in the real-time markets.[249]

In 2023, no such manual dispatches were used to import energy into the California ISO area. This contrasts with 2020, 2021, and 2022, when manual dispatches were used to import energy into the California ISO area. The reduction in out-of-market dispatches for imports in 2023 was largely due to the relatively milder summer temperatures and resultant lower energy demand.

249 For additional details on manual dispatch types and prices paid for out-of-market imports, see the *2019 Annual Report on Market Issues &* Performance, Department of Market Monitoring, June 2020, pp 206-207: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

Western Energy Imbalance Market

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 system, 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. 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 7.5 through Figure 7.10 summarize monthly manual dispatch activity of participating and non-participating resources for WEIM areas with incremental or decremental volume above 10 MW in any month. The volume of manual dispatches in WEIM areas can peak in the first few months that a new market participant is active in the market.

Figure 7.5 WEIM manual dispatches – Arizona Public Service area

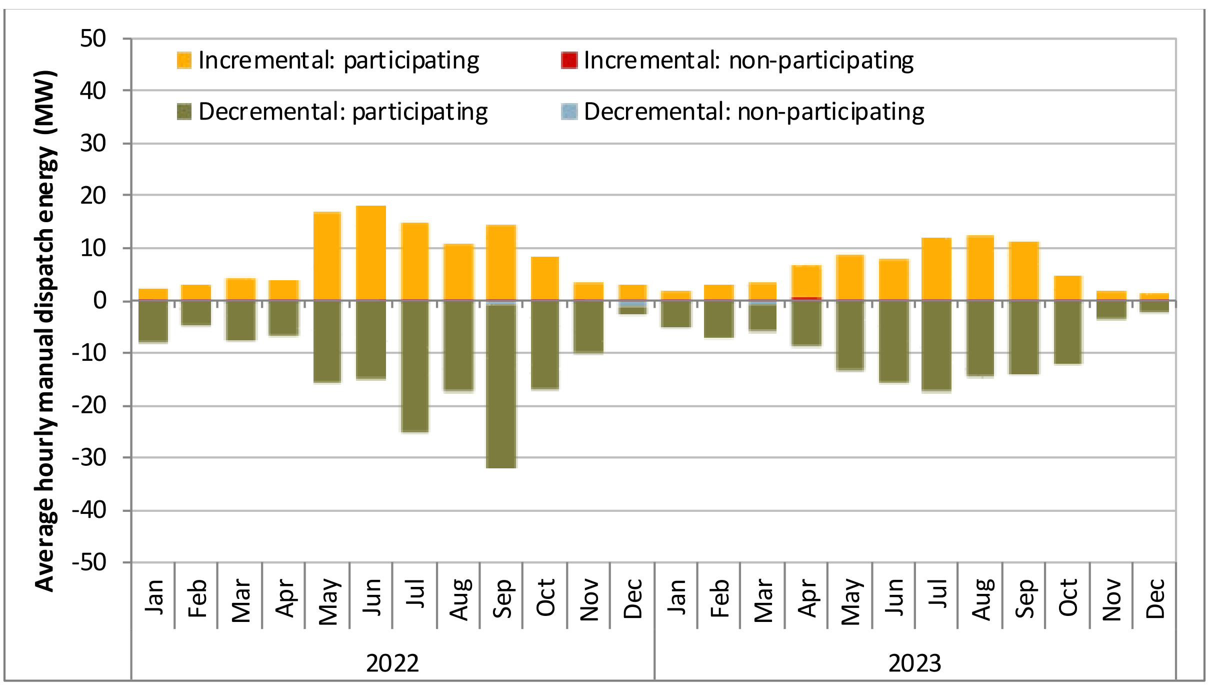


Figure 7.6 WEIM manual dispatches – Salt River Project area

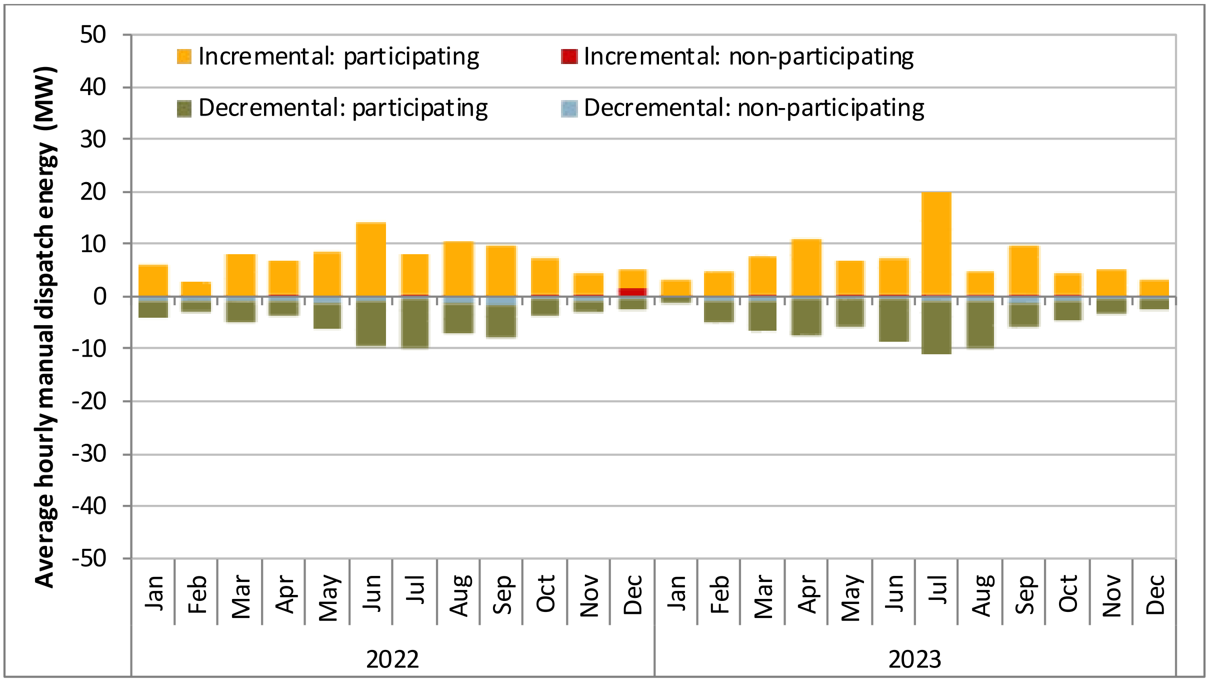


Figure 7.7 WEIM manual dispatches – Nevada Energy area

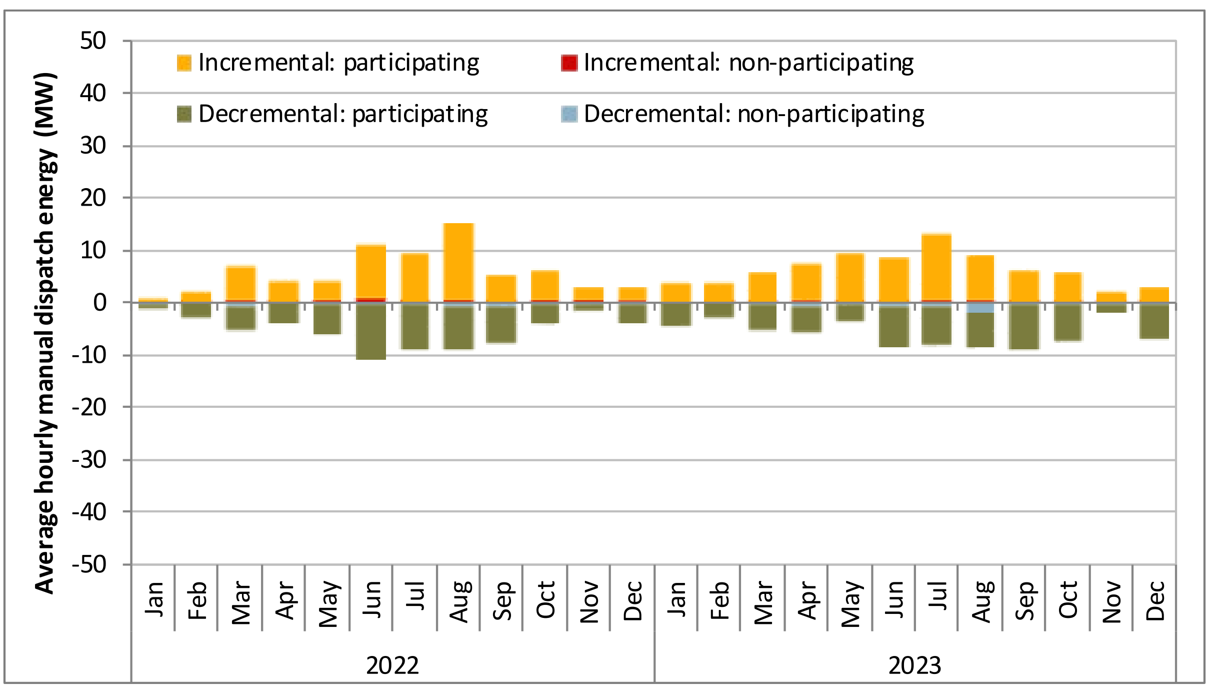


Figure 7.8 WEIM manual dispatches – Tucson Electric Power area

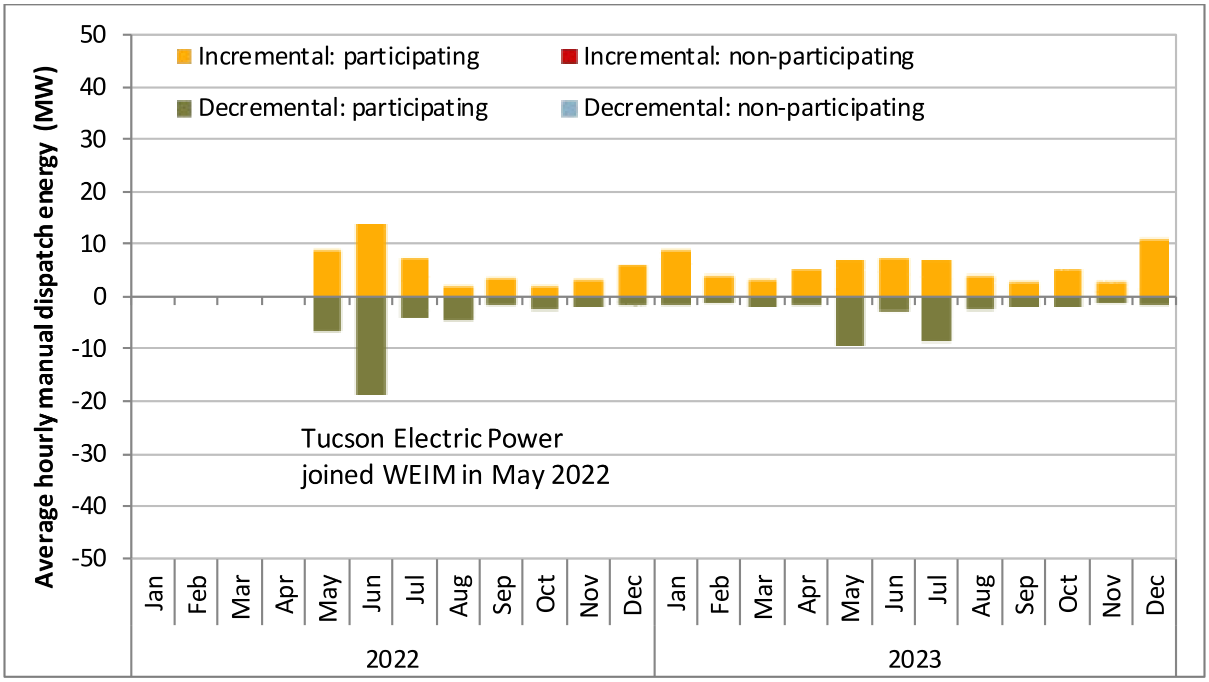


Figure 7.9 WEIM manual dispatches – Idaho Power area

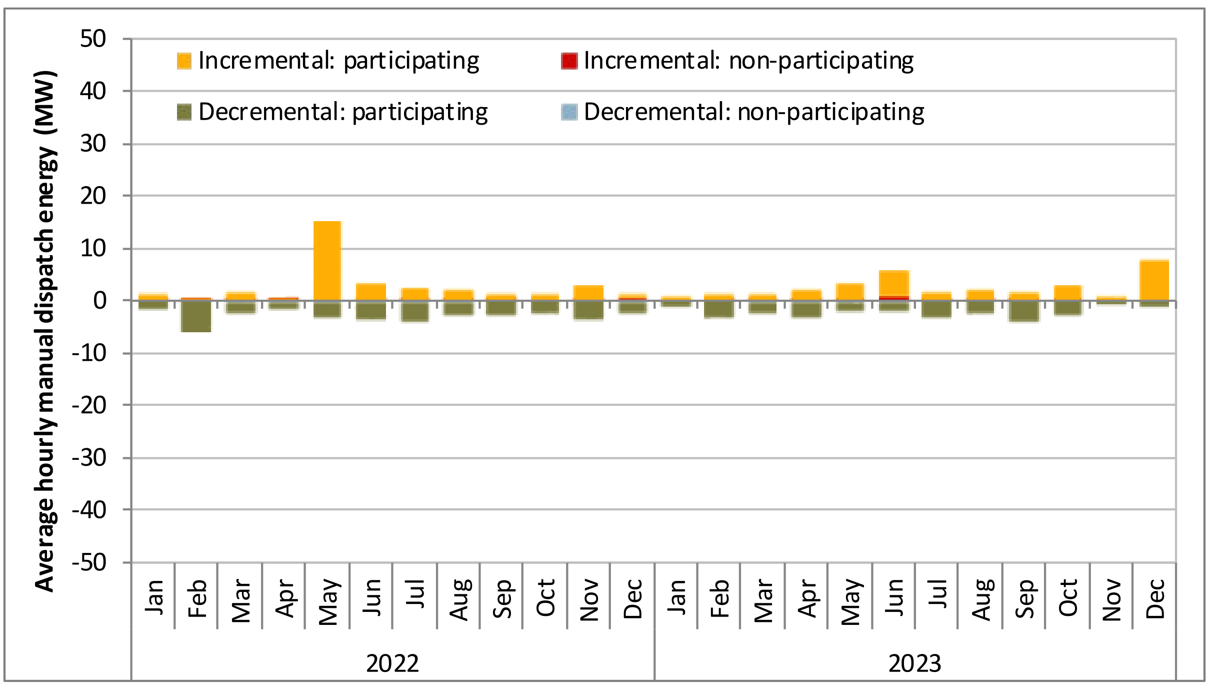
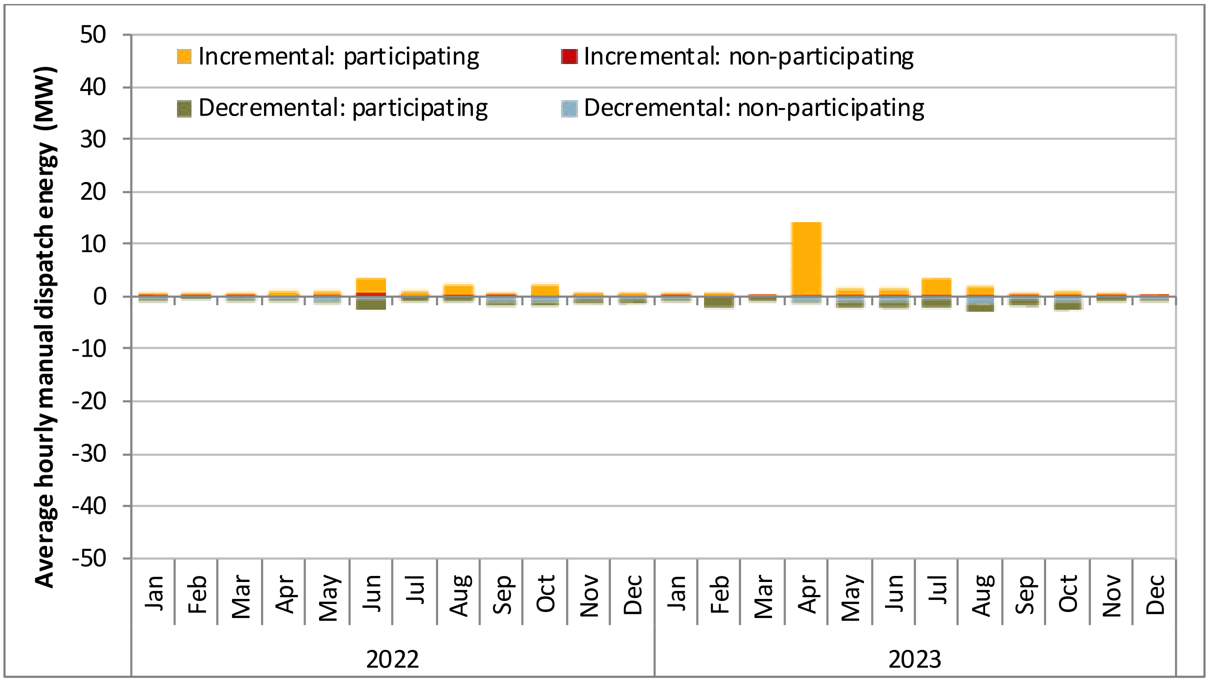


Figure 7.10 WEIM manual dispatches – Puget Sound Energy area



7.3 Residual unit commitment adjustments

The quantity of residual unit commitment (RUC) procured is determined by several automatically calculated components, as well as any adjustments that operators make to increase residual unit commitment requirements for reliability purposes. In 2023, these operator adjustments increased significantly by 154 percent compared to 2022, in large part because of a change in the methodology in the way the adjustments are determined.

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment process is run immediately after the integrated forward market (IFM) has run for the day-ahead market, and procures capacity to bridge the gap between the amount of load cleared in the IFM run and the day-ahead forecast load.

Operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. During 2023, there were significant changes to how these amounts were determined, as summarized in Figure 7.11. This figure shows the average RUC adjustment on each day of 2022 (red) and 2023 (blue). The arrows in Figure 7.11 highlight three key changes that occurred in 2023:

1. During most of May and June, the ISO decreased residual unit commitment adjustments to zero each day as part of a pilot program for the ISO to assess the use of these adjustments, as well as

imbalance conformance adjustments. Under the pilot program, no adjustments were used when demand was projected to be under 35,000 MW.[250]

2. Starting on June 30, the ISO began using the *mosaic quantile regression* method to calculate the RUC adjustments. This calculation is similar to that used to measure flexible ramping product uncertainty, except that it is based on the historical difference between the *day-ahead* and real-time market forecasts for load, solar, and wind. This calculation was based on the 97.5th percentile of net load uncertainty that might materialize in real-time.[251]

3. Starting on December 21, the ISO implemented a new operating procedure that changed the methodology for calculating the RUC adjustments, effectively lowering the amount. Under *normal conditions*, the RUC adjustments are now calculated based on the 50th percentile of upward net load uncertainty. Operators can adjust the calculation any day to instead be based on the 75th or 97.5th percentile during periods of higher forecast uncertainty or extreme conditions.

On May 7, 2024, the ISO adjusted the operating procedure again for calculating the adjustments used in the residual unit commitment process.[252] The changes limited the adjustments to only the peak morning and peak evening hours as well as added percentile options below the 50th percentile. Under periods with moderate operational uncertainty, the procedure calls for using a RUC adjustment that will only procure enough capacity to cover uncertainty 50 percent of the time (i.e., the 50th percentile of upward uncertainty). During periods with low or very low operational uncertainty, the procedure instead specifies either use of the 25th percentile or no adjustment, respectively. This indicates that there is still a substantial degree of judgment and discretion used in setting the RUC adjustment, even when using the mosaic quantile regression method to calculate the uncertainty component.

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

250 *Summer Market Performance Report for June 2023*, California ISO, July 28, 2023, p 42: https://www.caiso.com/Documents/SummerMarketPerformanceReportforJune2023.pdf

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

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

Figure 7.11 Average residual unit commitment adjustment by day (2022 versus 2023)

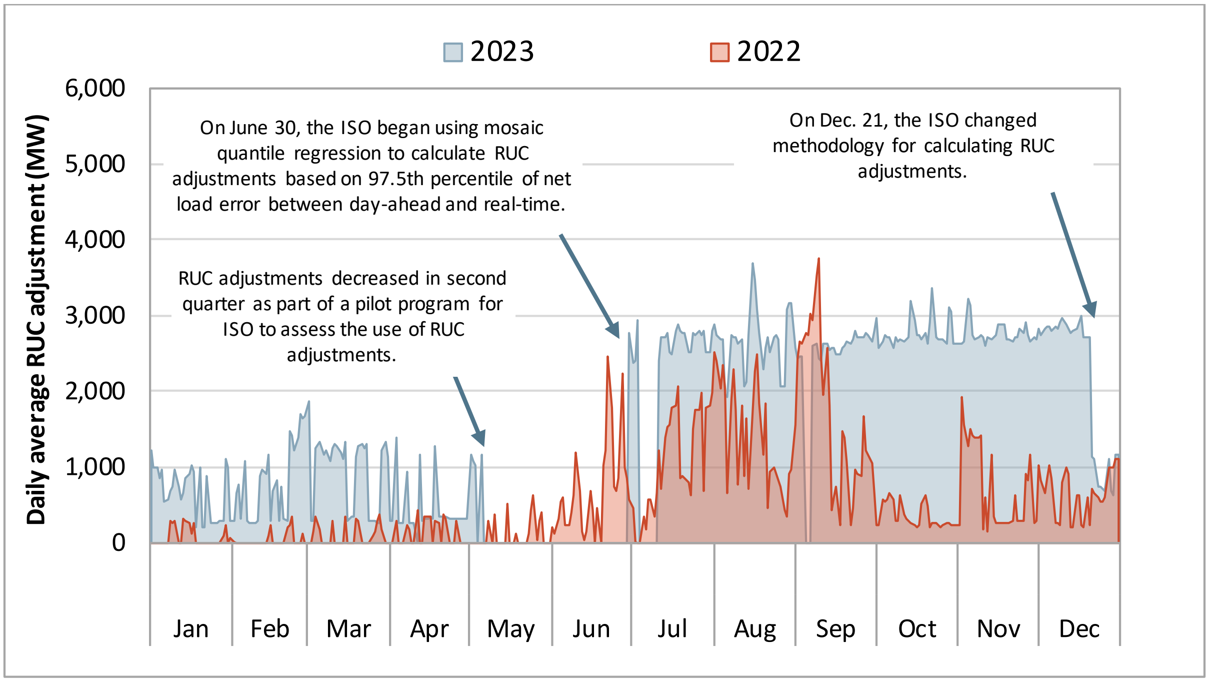


Figure 7.12 shows the average hourly determinants of capacity requirements used in residual unit commitment process by quarter in 2022 and 2023.

The residual unit commitment process includes an automated adjustment to account for the need to replace net virtual supply clearing in the IFM run of the day-ahead market, which can offset physical supply in that run. In 2022, this automated adjustment, shown in the green bars in Figure 7.12, was the primary driver of positive residual unit commitment requirement. The average increase in residual unit commitment requirements due to net virtual supply increased slightly to 696 MW in 2023 from 658 MW in 2022.

As shown earlier, California ISO operators can also make adjustments to increase the amount of residual unit commitment requirements above the day-ahead load forecast. These adjustments, shown in the red bars in Figure 7.12, contributed an average of 1,485 MW per hour to requirements in 2023, an increase of 154 percent from about 584 MW per hour in 2022. These adjustments were largest during the third and fourth quarters, consistent with the change to the methodology discussed above.

The blue bars in Figure 7.12 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 integrated forward market (IFM). This difference increased residual unit commitment requirements by about 340 MW on a yearly average basis in 2023, up from about 60 MW in 2022.

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 7.12.

Figure 7.12 Determinants of residual unit commitment procurement

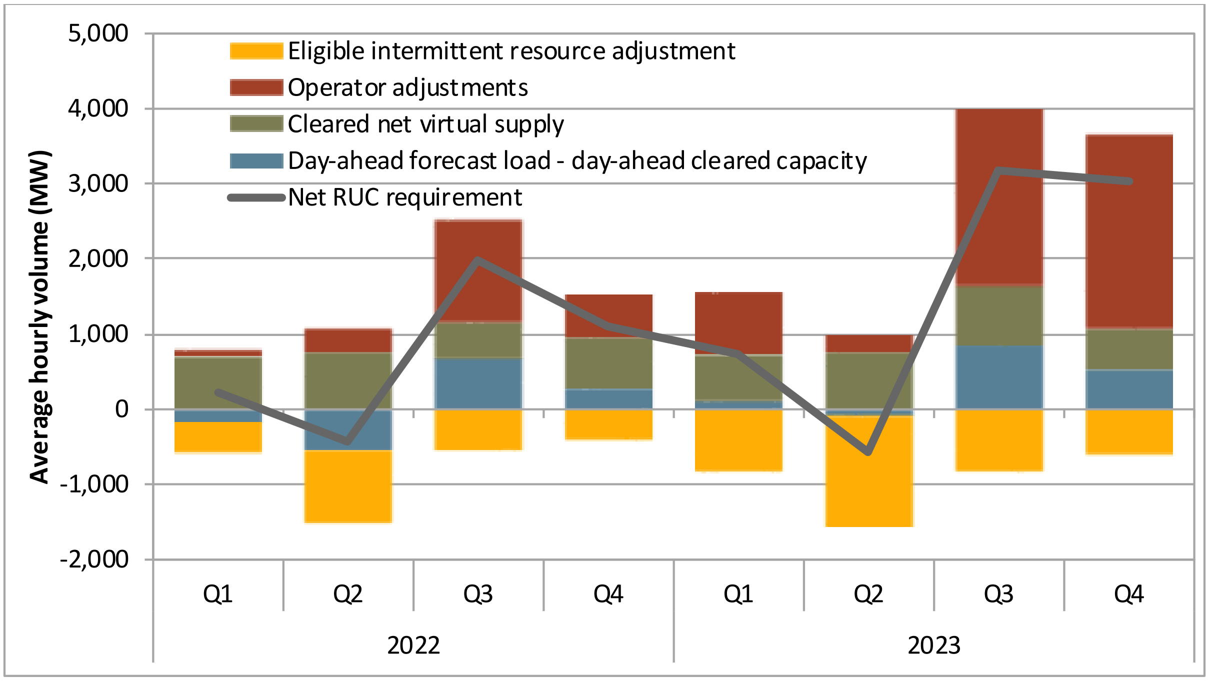


Figure 7.13 shows these same four determinants of the residual unit commitment requirements for 2023 by hour. As shown by the red bars, adjustments to the requirement by grid operators generally occur throughout the day, but tend to be greatest in the morning and evening solar ramp periods. During the third and fourth quarters of 2023, operators increased the residual unit commitment requirement on average for all hours by about 2,560 MW and 2,359 MW, respectively.

While operator adjustments were generally lower in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. On average, day-ahead load forecast was greater than day-ahead cleared capacity (i.e., cleared IFM load) during all hours except 9 through 15 in 2023. Similar to 2022, the bulk of the intermittent resource adjustments occurred in hours-ending 9 to 18.

Figure 7.14 shows the hourly distribution of operator adjustments during the third quarter of 2023. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour. The operators used this tool on all days of the first and fourth quarters, 82 days out of 92 in the third quarter, and least of all in the second quarter, when operators adjusted the requirement on 57 out of the 91 days in the quarter. Over all of 2023, operators adjusted the RUC requirement on 298 days. The average adjustment in the third quarter was about 2,360 MW per hour, compared to about 1,384 MW in the same quarter of 2022. These adjustments were primarily used to address reliability concerns and to account for net load forecast errors.

Figure 7.13 Average hourly determinants of residual unit commitment procurement (2023)

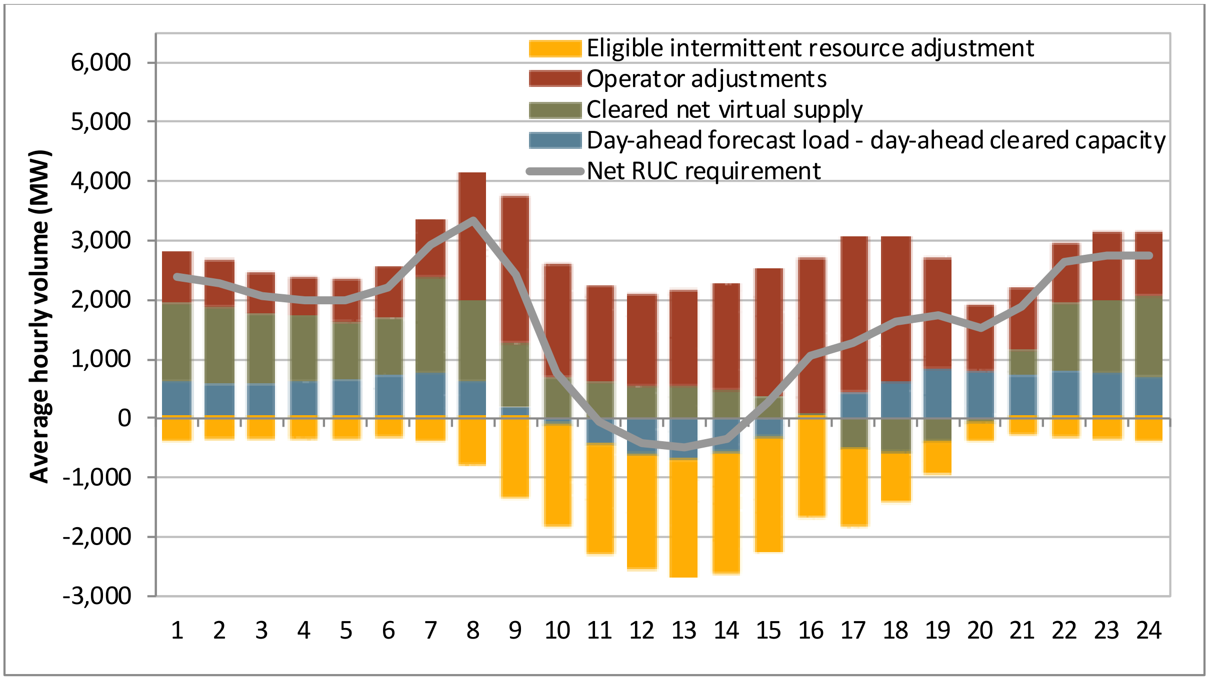
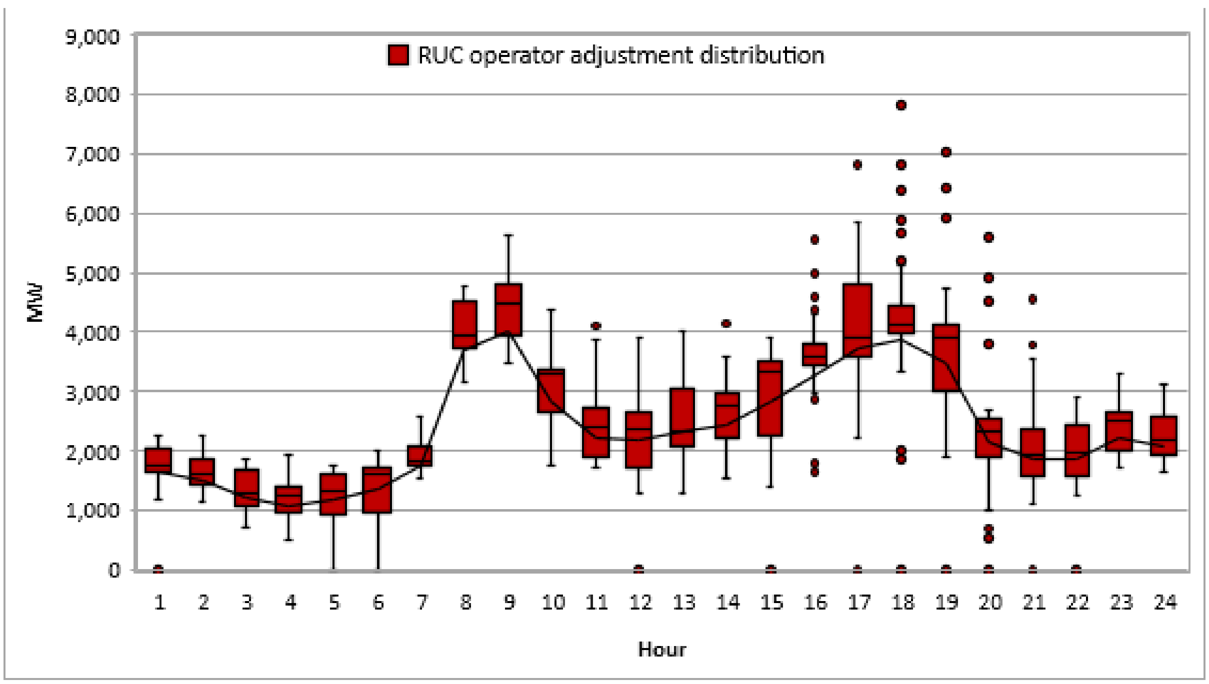


Figure 7.14 Hourly distribution of residual unit commitment operator adjustments (July–September)



7.4 Real-time imbalance conformance

Load forecast adjustments

Operators in the California ISO and Western Energy Imbalance Market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. The ISO uses the term *imbalance conformance* to describe these adjustments. Load forecast adjustments can be used to account for potential modeling inconsistencies and inaccuracies, including uncertainty that may exist between the net load forecast used in the market run and the net load that might actually materialize.

In the CAISO, load adjustments are routinely used in the hour-ahead and 15-minute scheduling processes to increase the supply of ramping capacity within the CAISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the CAISO by increasing hourly imports and committing additional units. The California ISO performed a counterfactual analysis showing that load adjustments led to additional hour-ahead imports, WEIM transfers, and additional internal generation.[253]

Real-time market load adjustments by the California ISO

Beginning in 2017, there was a large increase in load forecast adjustments in the steep morning and evening net load ramp periods in the California ISO hour-ahead and 15-minute markets. This trend continued in 2023, with average hourly load adjustments in the hour-ahead and 15-minute markets peaking at roughly 1,820 MW during hour-ending 19. This was a decrease from 2022, when the highest average hourly load adjustment was around 2,050 MW. However, 2023's highest average hourly load adjustment was about 290 percent higher than 2016's largest average hourly value of 460 MW.

Figure 7.15 shows the average hourly load adjustment profile for the hour-ahead and 5-minute markets for 2021 to 2023.[254] As in prior years, the general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments. During the morning ramp hours, the largest average adjustment in the hour-ahead market for 2023 was about 330 MW. This was significantly lower than the largest average morning adjustment for 2022 of 770 MW. The largest evening ramping hour adjustments also decreased to about 1,820 MW in 2023 from 2,050 the prior year. The average hour-ahead load forecast adjustments in 2023 mirror the pattern of net loads over the course of the day, averaging nearly 415 MW over the entire day.

The load adjustments in the 5-minute market have a similar shape as the hour-ahead market adjustments, but 5-minute market load adjustments are significantly lower than hour-ahead market load adjustments during the morning and evening ramping hours. During hours-ending 19-21, 2023 hour-ahead market load adjustments exceeded the 5-minute market adjustments by around 1,450 MW.

Figure 7.16 shows the hourly distribution of 15-minute market load adjustments for 2023. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the

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253 *WEIM Transfers, Hourly Interties and Load Conformance*, California ISO, Market Analysis and Forecasting, June 21, 2022: http://www.caiso.com/InitiativeDocuments/FinalAnalysisReport-WEIMTransfers-HourlyInterties-Load.pdf

254 Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. The 15-minute market data has been removed from the figure for clarity.

filled 'dots'—the outside whiskers do not include these outliers. For the year, there were outliers of 4,500 and 5,000 MW in hours-ending 19 to 22, which occurred during the July 22-26 heat wave period. The maximum load adjustments—excluding the extreme outliers—in the morning ramp were between 1,200 MW and 1,600 MW in hours-ending 6 through 8. Maximum load adjustments—with extreme outliers excluded—during evening ramp hours were between 1,800 MW and 4,000 MW in hours-ending 17 through 22.

Figure 7.15 Average hourly load adjustment (2021–2023)

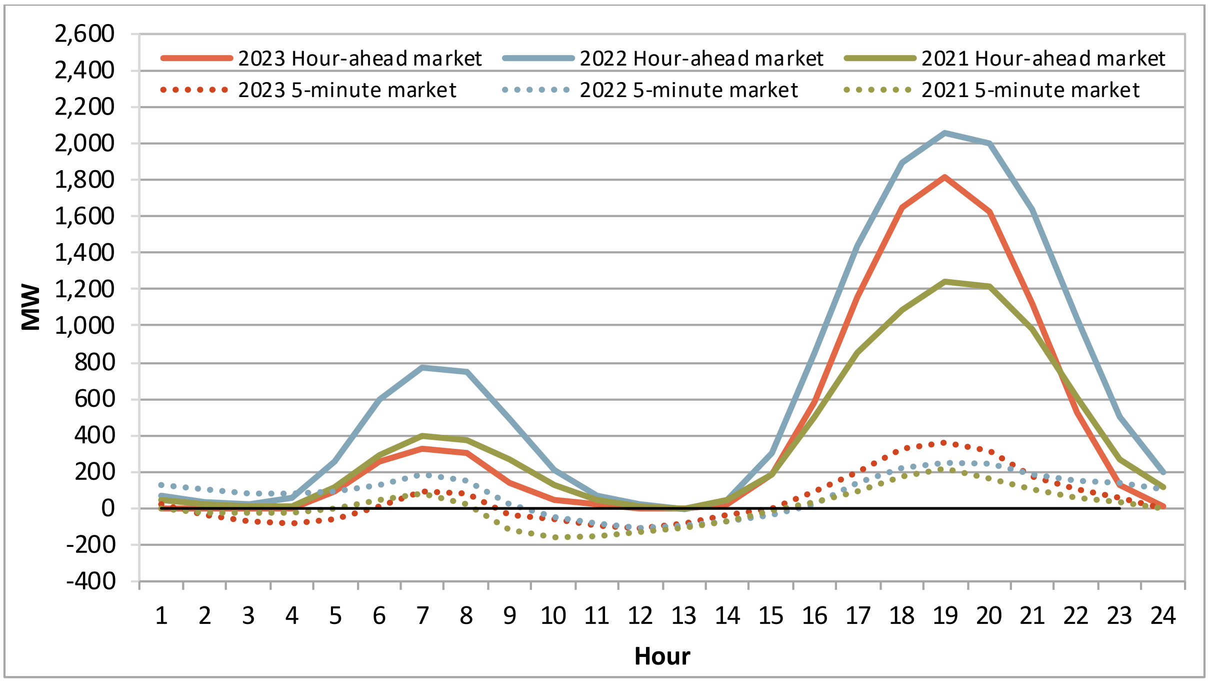
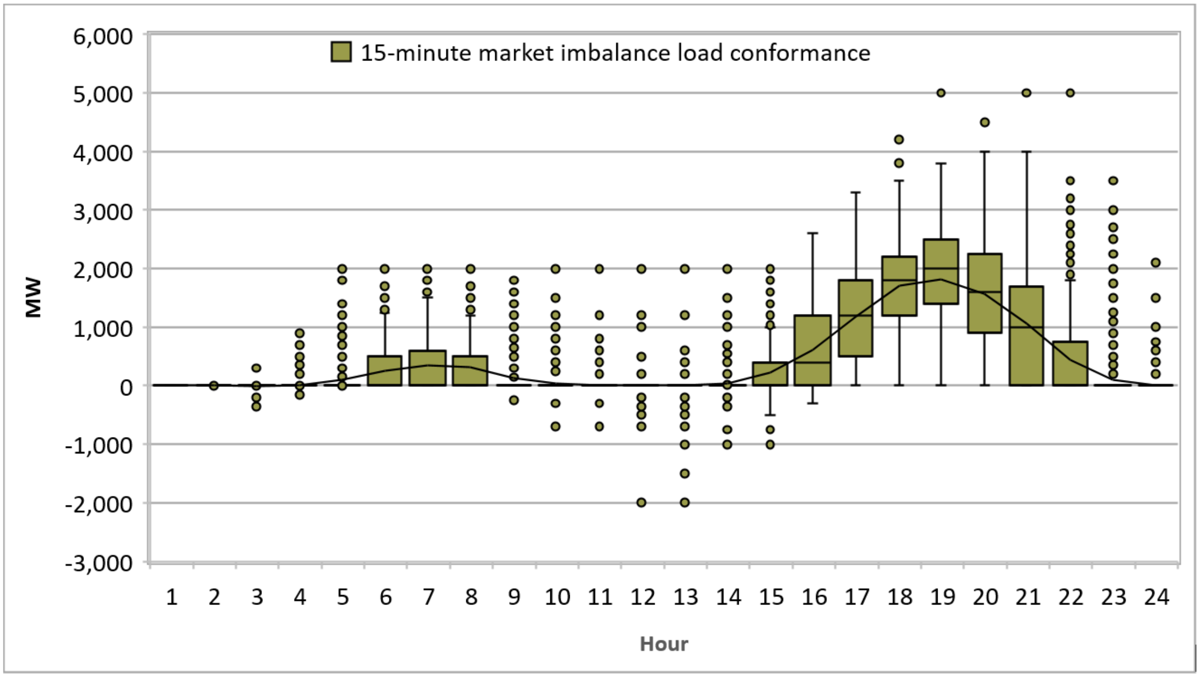


Figure 7.16 15-minute market hourly distribution of operator load adjustments (2023)



Load adjustments in the Western Energy Imbalance Market

Western Energy Imbalance Market (WEIM) operators can also make load adjustments in their respective balancing areas. The frequency of positive and negative load forecast adjustments for the 15-minute and 5-minute markets are shown in Figure 7.17 through Figure 7.20.

For much of the year, in the 15-minute market, positive and negative load adjustments were most frequent in Bonneville Power Administration, El Paso Electric, NorthWestern Energy, Salt River Project, Seattle City Light, and Avista Utilities. Overall, load adjustments in the 5-minute market were more frequent than load adjustments in the 15-minute market for most balancing areas and quarters during the year.

Figure 7.17 Average frequency of positive and negative load adjustments: 2023 WEIM – North (15-minute market)

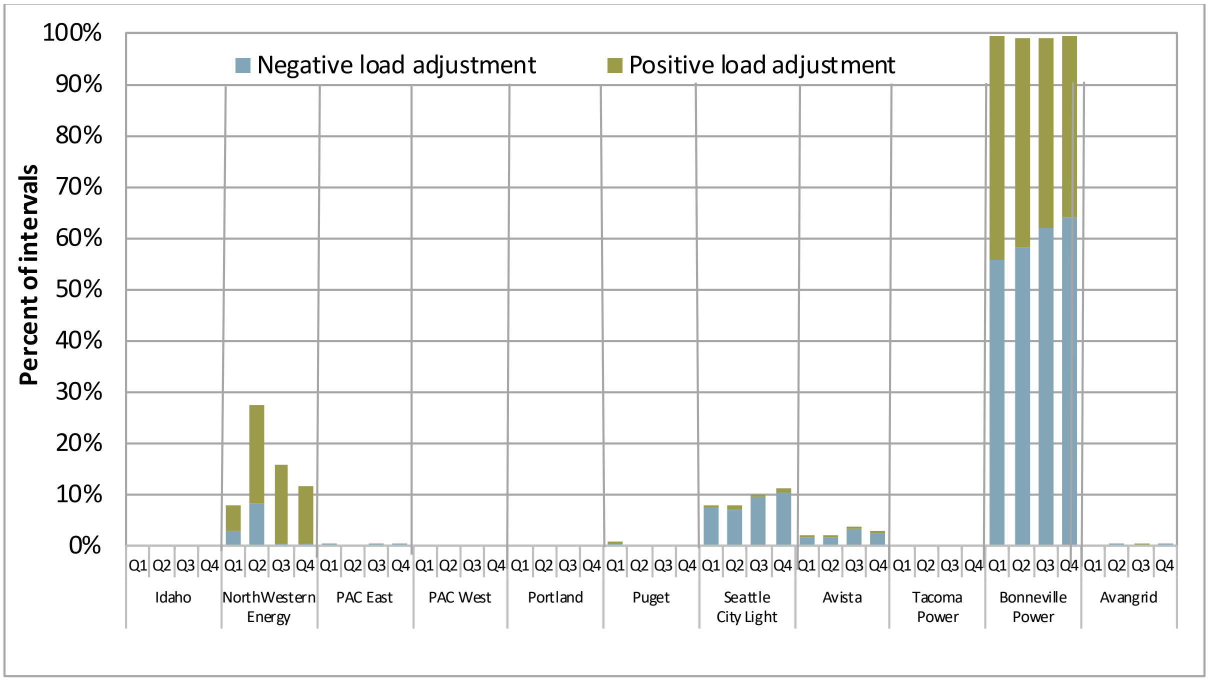


Figure 7.18 Average frequency of positive and negative load adjustments: 2023 WEIM – East and within California (15-minute market)

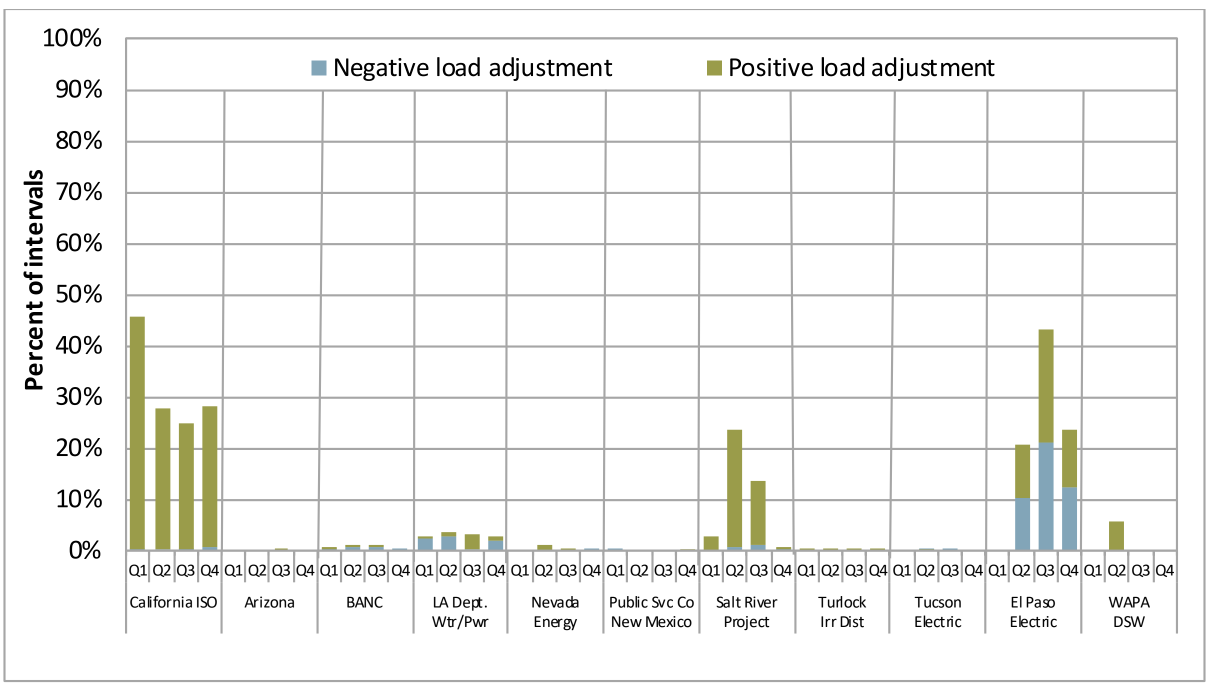


Figure 7.19 Average frequency of positive and negative load adjustments: 2023 WEIM – North (5-minute market)

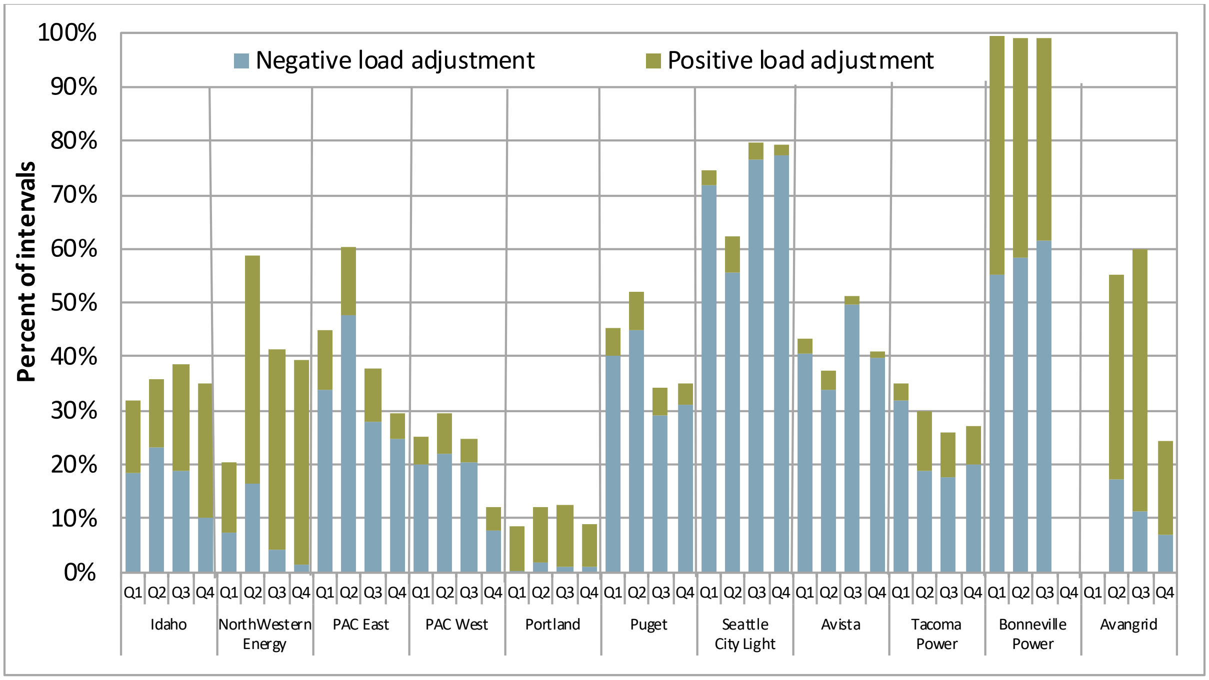
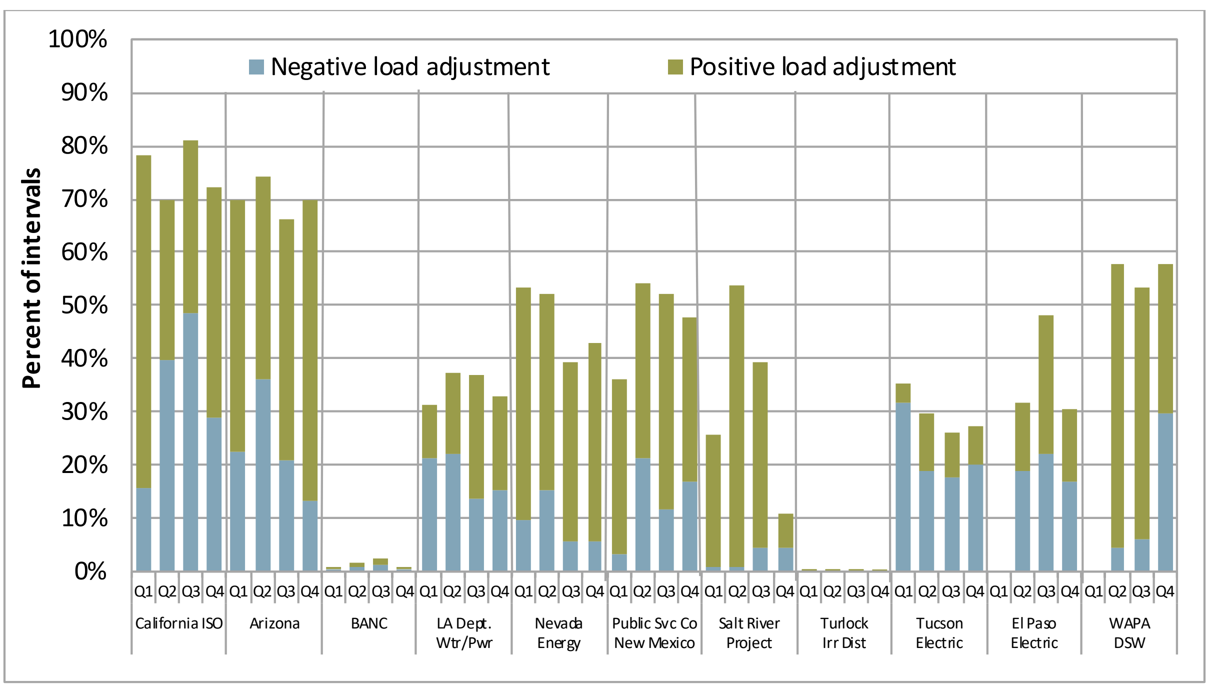


Figure 7.20 Average frequency of positive and negative load adjustments: 2023 WEIM – East and within California (5-minute market)



7.5 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.[255] 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 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 7.21 shows the frequency of blocked real-time commitment instructions for both the CAISO balancing area (blue, green, and gold bars) and other WEIM balancing areas (red bars).

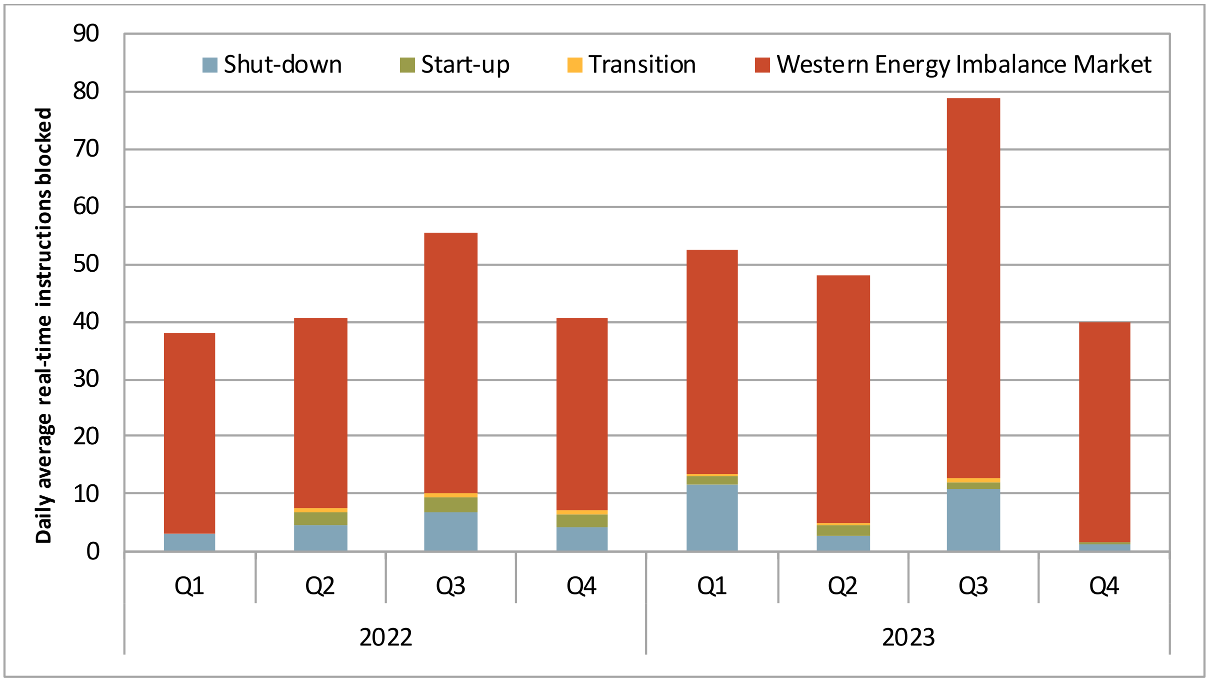
Within the CAISO area, blocked commitment instructions increased from a daily average of seven in 2022 to eight in 2023. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 82 percent in 2023. This was an increase from about 67 percent of all blocked commitment instructions in 2022.

Blocked start-up instructions accounted for about 14 percent of blocked instructions within the CAISO in 2023, down from 25 percent in 2022. Blocked transition instructions to multi-stage generating units decreased from about 8 percent in 2022 to about 4 percent of all blocked instructions in 2023.

The average number of instructions blocked by Western Energy Imbalance Market operators (red bars in Figure 7.21) was 47 per day in 2023, an increase from 37 per day in 2022.

255 *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

Figure 7.21 Frequency of blocked real-time commitment instructions



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.

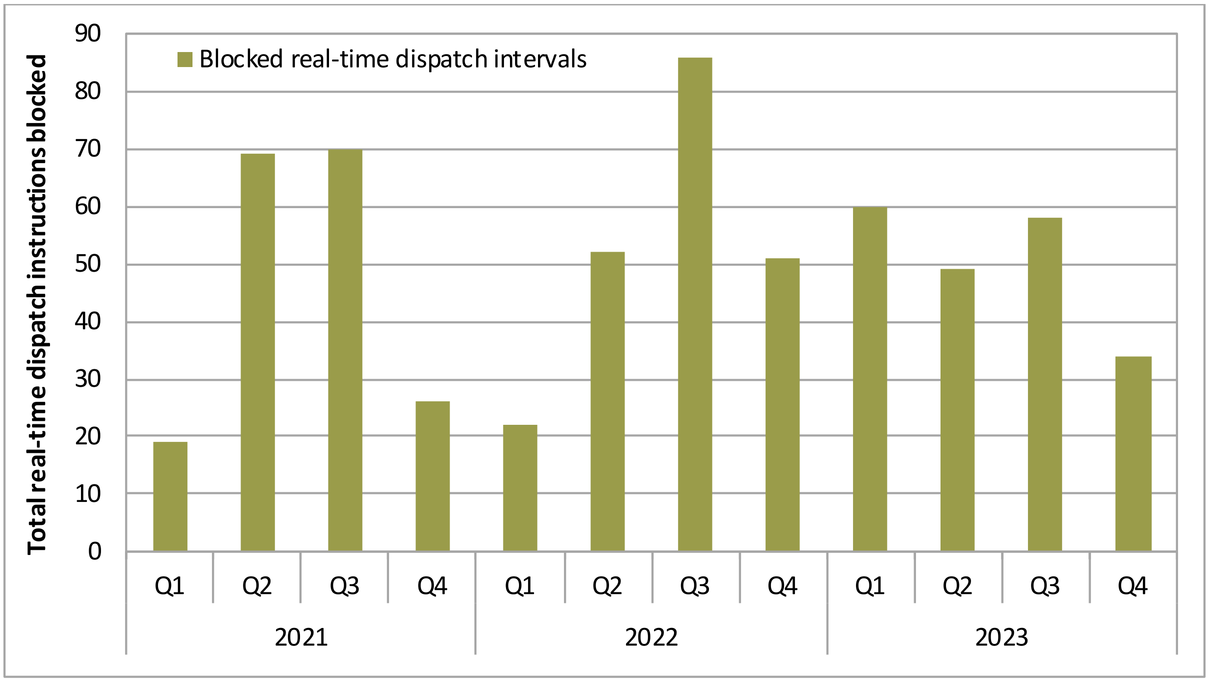
The California ISO began blocking dispatches in 2011, as both market participants and California ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often have caused participants to 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.[256]

Figure 7.22 shows the frequency that operators blocked price results in the real-time dispatch from the first quarter in 2021 through 2023. The total number of blocked intervals in 2023 decreased by about 5 percent from the previous year.

[256] For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

Figure 7.22 Frequency of blocked real-time dispatch intervals



8 Resource adequacy

The purpose of the resource adequacy program is to ensure the California ISO system has enough resources to operate the grid safely and reliably in real-time. Key findings in this chapter include:

- **Resource adequacy capacity provided sufficient coverage of annual instantaneous peak load.** The annual instantaneous peak load in 2023 reached 44,534 MW on August 16 during hour-ending 18. The total CAISO balancing area load requirement including operating reserve (2,760) and regulation up (650 MW) requirements was 47,944. Schedules from resource adequacy resources in the real-time market were over 53,000 MW. This included solar, wind and other schedules in excess of a resource's resource adequacy capacity.
- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2023.** There were 72 total hours with RMO+ emergency notifications, and 12 EEA Watch+ hours in 2023, all occurring in July or August 2023. Average hourly load was about 38-39 GW during these hours, while average resource adequacy capacity was 51-52 GW.
- **In the real-time market, 94 percent of system resource adequacy capacity was available after outages during EEA Watch+ hours in 2023.** Eighty-nine percent of this capacity was bid or self-scheduled into the real-time market. In the day-ahead market, 96 percent of system resource adequacy capacity was available after outages, with 94 percent offered. This analysis caps offered bids at each resource's individual resource adequacy values.
- **Investor-owned utilities procured most of the system resource adequacy capacity.** Investor-owned utilities accounted for about 27,200 MW (or 52 percent) of resource adequacy procurement, community choice aggregators contributed 25 percent, municipal utilities contributed 9 percent, and direct access services contributed 7 percent. The remaining 6 percent is a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Use-limited resources comprised over 60 percent of resource adequacy capacity.** This capacity is exempt from California ISO bid insertion in all hours.
- **The amount of resource adequacy procured from storage resources increased significantly in 2023.** In 2022, storage resources accounted for 6 percent of total resource adequacy capacity. However, in 2023, procured storage megawatts increased by around 170 percent, causing storage resources to comprise 9 percent of the total capacity.
- **Both year-ahead and actual flexible resource adequacy requirements were sufficient to meet the actual maximum three-hour net load ramp for all months in 2023.** 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 2023 requirements and must-offer hours were sufficient in reflecting actual ramping needs in all cases.
- **In 2023, the first monthly capacity procurement mechanism designations occurred since the program was implemented in 2016.** The monthly August procurement totaled 186 MW at an estimated cost of $1.25 million. An additional 70 MW of capacity was procured through the intra-monthly capacity procurement mechanism designation at an estimated cost of $1.06 million.
- **Bids from CPUC jurisdictional import resource adequacy resources exceeded $0/MWh only during a limited number of hours within the Availability Assessment Hours period**. This is a result of CPUC Decision D.20-06-028, which requires non-resource-specific resource adequacy imports to self-

schedule, or bid at or below $0/MWh, during availability assessment hours beginning in 2022. Procurement of import capacity also declined compared to previous years.

- **Resource adequacy imports bid similarly into the day-ahead market as the previous year.** Imports bid in an average of about 2,500 MW during peak hours in August 2023. This is up from an average of about 2,200 MW in the same month of 2022 and down from 3,300 MW in 2021.

8.1 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 to 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.

8.2 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 issued energy emergency alerts to operate the grid safely and reliably.[257]

Regulatory requirements

The California ISO 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 PRM for 2023 was set at 16 percent,

[257] Previous annual reports analyzed resource adequacy availability during the top 210 load hours of the year.

with an "effective" PRM between 20 and 22.5.[258,259] 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 coming compliance year.[260] For monthly supply plan showings, CPUC-jurisdictional entities must demonstrate they have procured 100 percent of their monthly system obligation. Table 8.1 shows recent CPUC decisions that affected the procurement, availability, or performance of resource adequacy resources in 2023:

[258] The planning reserve margin reflects operating reserve requirements and additional capacity to cover potential forced outages and load forecast error.

[259] For the summers of 2022 and 2023, CPUC decision D.21-12-015 established an "effective" PRM between 20 and 22.5 percent by requiring extra procurement from the three IOUs. See Table 8.1 for more details.

[260] 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 8.1 Recent CPUC decisions relevant to 2023 resource adequacy year[261]

Decision	Title	Description
D.21-03-056	Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022	Emergency Load Reduction Program (ELRP): PG&E, SCE, and SDG&E were directed to each develop a 5-year ELRP pilot program in accordance with guidelines that define eligible capacity, availability requirements, event triggers, and compensation. Planning Reserve Margin (PRM): an effective PRM of 17.5% was established (higher than the CPUC 15% PRM) starting in the summer of 2021. The 2.5% in excess of the 15% PRM was assigned to the three IOUs and will be active until a new PRM is decided on through the RA reform proceeding.
D.21-06-029	Decision Adopting Local Capacity Obligations for 2022-2024, Adopting Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program	Starting in the 2022 compliance year, the Maximum Cumulative Capacity Buckets were adjusted to require availability Monday through Saturday and the availability of Category 1 resources increased to 100 hours per month. For demand response resources, the 6% component of the planning reserve margin (PRM) adder associated with ancillary services and operating resources is removed for demand response resources and the distribution loss factor (DLF) adder is incorporated into DR qualifying capacity values starting in the 2022 compliance year. A points-based penalty structure for RA deficiencies is added to the current penalty structure where LSEs are charged a multiple of the system RA penalty price based on how many points they accrue in a 24-month period for having month-ahead deficiencies.
D.21-12-015	Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022	The Commission adopted an “effective PRM” of 20 to 22.5 percent for summers 2022 and 2023.
D.22-06-050	Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework	The comissions modified Resource Adequacy (RA) measurement hours to 5:00-10:00 PM for March and April, and 4:00–9:00 PM for all other months. The modified RA hours shall be effective beginning in the 2023 RA compliance year. A 16% PRM is adopted for 2023, and a minimum of a 17% PRM for 2024. ELCC values for solar and wind were updated, and the quarterly demand response testing must be for 4 hours. Slice-of-day is adopted with a test year in 2024 and program implementation in 2025. An exceedance methodology is adopted to calculate solar and wind profiles for RA accounting. Storage resource accounting must be accompanied by excess energy generation.
D.23-06-029	Decision on Phase 3 of the Resource Adequacy Implementation Track	Adopts the local and flexible RA requirements. Adopts a 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). Reliablity 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.

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.[262] 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.[263] 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 secured during the planning timeframe. The analysis also caps bids and schedules according to individual resource outages and de-rates.

Availability and performance during Energy Emergency Alert 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. For example, the CPUC uses a maximum cumulative capacity bucket to require most resource adequacy capacity to be available at least 100 hours per month all year round, excluding March and April.[264]

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 is 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 the 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.[265] Table 8.2 provides descriptions of the EEA systems, and how hours with these notifications are included in the analysis of this section.

261 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

262 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.

263 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.

264 100 hours comes from the CPUC's maximum cumulative capacity (MCC) buckets. Under this construct, all resources counted toward resource adequacy requirements (except for demand response) must be available for at least 100 hours across summer months. CPUC decision D.22-06-050 changed this requirement from 200 hours over the summer months (May through September) to the 100 hours per month. February has a 96 hour requirement.

265 This series of notifications matches the North America 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 8.2 Energy Emergency Alert (EEA) categories and analysis groups (effective on 4/1/2022)[266]

Notification category	Description	Analysis category			
		Flex Alert	RMO+	EEA Watch+	EEA2+
Flex Alerts	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.	X			
RMO (Restricted Maintenance Operations)	Requires generators and transmission operators to postpone any planned outages for routine equipment maintenance, ensuring all grid assets are available for use.		X		
EEA Watch	When the Day-Ahead analysis is forecasting that one or more hours may be energy deficient.		X	X	
Energy Emergency Alert 1 (EEA 1)	When real-time analysis is forecasting that one or more hours may be energy deficient.		X	X	
Energy Emergency Alert 2 (EEA 2)	When all resources are in use and emergency load management programs are needed.		X	X	X
Energy Emergency Alert 3 (EEA3)	When all actions listed above have been taken, yet expected energy and contingency reserve requirements cannot be met. Notice issued to utilities of potential electricity interruptions through firm load shedding.		X	X	X
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.				

The following analysis groups emergency notification hours to show availability and performance during a variety of stressed system conditions. The California ISO may request reliability coordinators to issue an EEA 1, EEA 2, or EEA 3, depending upon the circumstance.[267] Basing the analysis on the notification category alone may omit more severe system conditions, as well as limit the analysis to a small sample size where a single event may affect availability and performance. This is a bigger concern amid the more severe notifications that occur less often.

There are three categories of analysis for each year: the *Flex Alert*, *RMO+*, and *EEA Watch+.* The *Flex Alert* category includes hours throughout the year where the California ISO issued a Flex Alert notification, regardless of the issuance of more severe notifications. The choice to look at Flex Alert hours is due to the role they play in the California ISO summer readiness program.[268] Flex Alerts typically

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266 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

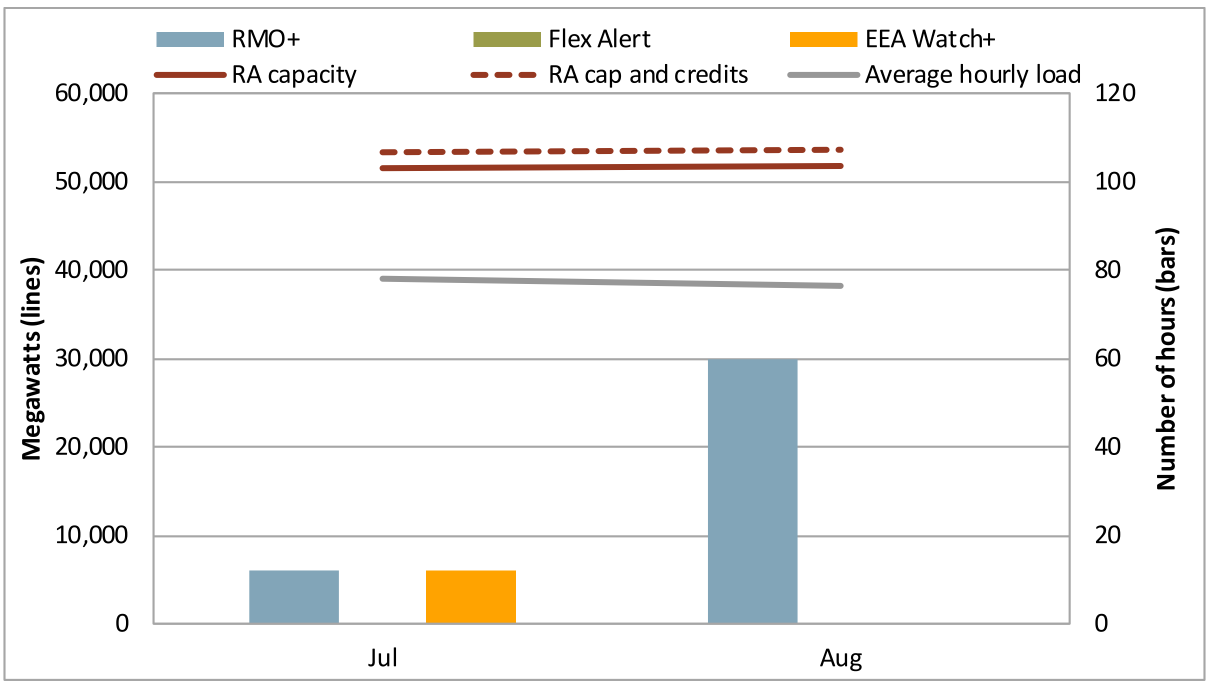
267 An EEA Watch can be issued in the day-ahead timeframe. A Flex Alert should always be issued in conjunction with an EEA Watch. When real-time analysis predicts energy shortages for one or more hours, EEA levels 1, 2, and 3 can be issued in any order. Each EEA level enables the California ISO to trigger different emergency demand response programs and other out-of-market programs. For additional details, please see:
http://www.caiso.com/Documents/4100.pdf
https://www.caiso.com/Documents/4420.pdf

268 *Summer readiness 2023*, California ISO: https://www.caiso.com/library/summer-readiness-2023

include evening peak hours; however, they can also include hours that span over a few days. The *RMO+* category includes hours where the California ISO issued a notification at least as severe as a Restricted Maintenance Operations notification, which often last over multiple days. This analysis includes many off-peak hours. The *EEA Watch+* category includes hours in 2023 in which the California ISO issued a notification that was at least as severe as an Energy Emergency Alert Watch (EEA Watch). Most of the analysis in this section focuses on the *EEA Watch+* category.

Figure 8.1 provides an overview of resource adequacy capacity during system emergency notification hours in 2023. The green, blue, and yellow bars show the number of hours, by month, that are in the *RMO+, Flex Alert*, and *EEA Watch+* categories, respectively. Note, there were no Flex Alerts in 2023, but for comparison to previous years, Flex Alerts were included. These categories are clustered bars, as opposed to stacked bars, because the hours are not mutually exclusive. The solid grey line shows average hourly load during these hours. The solid red line shows monthly average procured resource adequacy supply.[269] The dashed red line adds the additional capacity the CPUC credits towards load serving entity obligations, as well as legacy reliability must-run capacity.[270]

Figure 8.1 Average hourly resource adequacy capacity and load (2023 emergency notification hours)



[269] Monthly average load and procured resource adequacy capacity is weighted by the number of RMO+, Flex Alert, and EEA Watch+ hours.

[270] These credits include capacity from utility demand response programs with a PRM adder, as well as liquidated damage credits.

Key findings of this analysis include:

- **Hours with stressed system conditions were constrained to the summer months in 2023.** There were 72 total hours with RMO+ emergency notifications, and 12 EEA Watch+ hours. These emergency hours were exclusively confined to July and August in 2023.
- **The most severe emergency notifications in 2023 occurred between July 20 and 26.** There were 12 RMO+ hours, 0 Flex Alert hours, and 12 EEA Watch+ hours in these seven days. The EEA Watch+ hours include three hours on July 20 when the California ISO issued an Energy Emergency Alert 1 (EEA 1). During these hours, the California ISO faced rapidly evolving real-time operations. After adding onto CAISO's obligations the roughly 8,000 MW of export schedules that cleared the hour ahead market during some of these hours, CAISO faced potential supply infeasibilities.
- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2023**. Average hourly load was about 38-39 GW during these hours, while average resource adequacy capacity was 51-52 GW.

Table 8.3 shows capacity procurement, de-rates, availability, and performance of system resource adequacy resources during emergency notification hours from 2020 to 2023. Bids and self-schedules, cleared schedules, and meter amounts are capped by resource adequacy capacity at the resource level, unless otherwise indicated.[271,272]

Table 8.3 Average total system resource adequacy capacity, availability, and performance by system emergency notification category

Year	Alert category	Number of hours	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
				Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
2020	RMO+	390	47,723	94%	87%	61%	93%	86%	58%	68%	55%	64%
	Flex Alert+	154	48,602	95%	87%	67%	93%	85%	63%	73%	61%	68%
	Alert+	97	45,404	95%	89%	72%	94%	88%	68%	79%	65%	73%
2021	RMO+	359	41,480	93%	88%	57%	92%	87%	52%	66%	50%	63%
	Flex Alert+	38	48,878	94%	88%	81%	92%	87%	77%	87%	73%	81%
	Alert+	14	49,359	93%	85%	80%	92%	85%	77%	85%	73%	80%
2022	RMO+	151	49,799	95%	90%	75%	94%	89%	69%	83%	64%	77%
	Flex Alert+	56	49,509	95%	91%	85%	93%	89%	77%	88%	72%	81%
	EEA Watch+	35	49,390	95%	90%	87%	93%	89%	79%	89%	74%	81%
	EEA 2+	17	49,490	95%	91%	89%	93%	90%	82%	92%	78%	85%
2023	RMO+	72	51,688	94%	90%	73%	93%	89%	67%	82%	62%	75%
	EEA Watch+	12	51,772	96%	94%	68%	94%	92%	58%	80%	54%	75%

Key findings of this analysis include:

- **A small percentage of procured capacity was on outage during stressed hours from 2020 to 2023.** The day-ahead and real-time markets could access between 93 and 96 percent of procured capacity during these hours. Gas-fired generators, hydro, and storage generators de-rated their capacity

271 The current metrics for schedules and bids only consider the discharge MW for all storage and hydro resources. In contrast, reports from previous years included both discharge and charge MW in bids and schedules for these resources.

272 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 where 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.

more than other fuel categories, although there was variability across the years and alert category groups.

- **Resource availability, as measured by capped bids and self-schedules, was moderately high.** On average, between 85 and 94 percent of procured capacity bid or self-scheduled into the day-ahead and real-time markets. Over the course of three years, there was a gradual improvement in resource availability during the hours with stressed system conditions. In 2023, 90-94 percent of the procured capacity was bid or self-scheduled into the day-ahead market, and 89-92 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 and wind resources drive this increase in performance since their production can surpass net qualifying capacity values, particularly during hours before the net load peak.
- **During the most critical hours with EEA Watch+, the majority of resource adequacy was available to the market.** The California ISO declared EEA Watch alerts for a total of 12 hours during 2023. Despite the rapidly evolving real-time operations and over 8,000 MW of exports scheduled in the hour-ahead market leaving the system facing supply infeasibilities, the percentage of outages was low, with 94-96 percent of resource adequacy available. Furthermore, 94 and 92 percent of capacity bid into the day-ahead and real-time markets, respectively. Only 58 percent of generation was scheduled, but this was because peak demand was far below RA capacity accounting for uncapped schedules.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 8.4 shows capacity procurement by resource type, capacity de-rates, availability, and performance of system resource adequacy resources during RMO+ hours in 2023.[273] Separate sub-totals are provided for the resources that the California ISO creates bids for if 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).

[273] Bids and self-schedules in the day-ahead and real-time markets are reported as the proportion of total resource adequacy capacity.

Table 8.4 Average system resource adequacy capacity, availability, and performance by fuel type (RMO+ hours)

Resource type	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter
		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	19,130	94%	94%	75%	93%	93%	72%	74%	76%	76%	69%
Other generators	1,340	92%	92%	89%	91%	90%	86%	92%	92%	84%	88%
Subtotal	20,470	94%	94%	76%	93%	92%	73%	75%	77%	77%	70%
Other:											
Imports	2,323	97%	94%	84%	100%	86%	84%	84%	84%	83%	83%
Imports-MSS	326	100%	67%	67%	100%	68%	67%	76%	76%	67%	67%
Use-limited gas units	9,589	92%	92%	72%	91%	91%	60%	61%	68%	54%	54%
Hydro generators	6,456	94%	91%	79%	93%	87%	62%	73%	89%	60%	60%
Nuclear generators	2,887	100%	99%	99%	100%	99%	99%	99%	99%	98%	98%
Solar generators	1,848	99%	58%	58%	98%	63%	61%	329%	329%	59%	59%
Wind generators	1,126	99%	57%	56%	99%	80%	80%	180%	180%	65%	65%
Qualifying facilities	878	99%	94%	87%	98%	94%	84%	95%	95%	82%	82%
Demand response (PDR)	332	100%	49%	9%	95%	36%	9%	10%	10%	4%	4%
Storage	4,605	91%	90%	44%	90%	90%	32%	33%	51%	18%	18%
Other non-dispatchable	848	98%	90%	59%	97%	89%	85%	107%	111%	75%	75%
Subtotal	31,218	95%	88%	71%	94%	87%	63%	87%	95%	58%	78%
Total	**51,688**	**94%**	**90%**	**73%**	**93%**	**89%**	**67%**	**82%**	**88%**	**62%**	**75%**

Key findings of this analysis include:

- **Gas-fired generators accounted for about 56 percent of capacity procurement.** Gas-fired resources (gas-fired must-offer generators and use-limited gas units) supplied about 28,719 MW of resource adequacy capacity during the RMO+ hours of 2023.
- **Resources that are not availability-limited accounted for just 40 percent of system capacity.** About 20,500 MW of system capacity was subject to California ISO bid insertion 24x7.[274] Gas-fired generation in this category made up about 19,100 MW (37 percent) of total resource adequacy capacity. Other generators accounted for 3 percent.
- **Use-limited gas units made up the largest portion of resource adequacy capacity with limited availability not subject to California ISO bid insertion.** These resources contributed about 9,600 MW of total capacity (18 percent). Hydro generators contributed 12 percent, storage contributed 9 percent, imports (including metered subsystems) contributed 5 percent, nuclear resources contributed 6 percent, solar resources contributed 4 percent, wind resources contributed 2 percent, qualifying facility resources contributed 2 percent, demand response contributed less than one percent, and other non-dispatchable resources contributed less than one percent of system capacity.
- **The amount of resource adequacy procured from storage resources increased significantly in 2023.** In 2022, storage resources accounted for 6 percent of total resource adequacy capacity. However, in 2023, procured storage megawatts increased by around 170 percent, causing storage resources to comprise 9 percent of the total capacity.

274 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.

- **Storage and hydro resources contributed to the provision of ancillary services during the RMO+ hours.** The "uncapped schedules + AS" column presents real-time scheduling for RA and partial RA resources with their 15-minute ancillary service schedules. Storage resources energy schedules were only 33 percent of their RA capacity. However, upon inclusion of ancillary service schedules, the percentage of scheduled capacity rose to 51 percent. Hydro units were scheduled for 89 percent of their RA capacity, incorporating RA and partial RA energy and ancillary service schedules.
- **Capacity available after reported outages and de-rates was similar in 2023 to 2022**. Average resource adequacy capacity was around 51,688 MW during the RMO+ hours in 2023, above the 49,390 MW in 2022 for EEA Watch+ hours. After adjusting for outages and de-rates, the remaining capacity in the day-ahead market was about 94 percent of the overall resource adequacy capacity, which was only about 1 percent lower than in 2022.
- **The day-ahead market showed similar capacity availability in 2023 compared to the previous year.** 94 percent of must-offer and 88 percent of non-must-offer resources were available in the day-ahead market. Must-offer resources bid in about 100 percent of day-ahead de-rated capacity. Non-must-offer resources bid in about 93 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, most of the RMO+ 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 92 percent of must-offer and 87 percent of non-must-offer capacity bid or self-scheduled in the real-time market. These totals are capped by individual resource adequacy values. 49 percent of proxy demand response bid in the day-ahead market, and only 36 percent bid into the real-time market. Demand response resources typically exhibit low bid availability as a percentage of procured capacity.
- **A higher percentage of procured must-offer resources cleared and generated in the real-time market compared to non-must-offer resources.** About 92 percent bid into the real-time, and 73 percent of procured must-offer capacity cleared the real-time market. These percentages are capped by individual resource adequacy values.

Table 8.5 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.[275] 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.

[275] 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 8.5 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
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
Community choice aggregator	12,784	97%	93%	66%	93%	88%	65%	80%	60%	72%
Direct access	3,721	96%	95%	65%	94%	90%	63%	88%	59%	81%
Investor-owned utility	27,210	95%	94%	76%	93%	91%	69%	84%	64%	77%
Municipal/government	4,752	96%	95%	72%	95%	81%	63%	79%	61%	76%
Not on a plan	3,223	102%	97%	78%	96%	95%	66%	67%	61%	62%
Total	**51,690**	**96%**	**94%**	**73%**	**93%**	**89%**	**67%**	**82%**	**62%**	**75%**

Key findings of this analysis include:

- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 27,200 MW (or 52 percent) of system resource adequacy procurement, community choice aggregators contributed 25 percent, municipal utilities contributed 9 percent, and direct access services contributed 7 percent. The remaining 6 percent is a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Capacity availability for all load types was lower in the real-time than in the day-ahead.** Resources bid on average 89-96 percent of procured capacity from the four load types in these markets. These bids are capped by individual resource adequacy values. The bidding was on average higher for the 'not on a plan' resources, because they are largely local resources and have local must-offer obligation.
- **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 87 percent of their resource adequacy capacity from these resources, while municipal utilities procured 67 percent, community choice aggregators procured 38 percent, and direct access services procured 29 percent.
- **All local regulatory authorities 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 6 percent, direct access services procured 1 percent, and investor-owned utilities procured 4 percent.

Table 8.6 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. This analysis uses settlements data to identify resources exempt from RAAIM charges if they were unavailable during the availability assessment hours.[276]

Table 8.6 Average system resource adequacy capacity and availability by RAAIM category (RMO+ hours)

RAAIM category	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
Non-RAAIM exempt	43,656	94%	92%	73%	93%	91%	67%	70%	62%	65%
RAAIM exempt	8,034	98%	80%	70%	96%	81%	68%	149%	62%	133%
Total	**51,690**	**94%**	**90%**	**73%**	**93%**	**89%**	**67%**	**82%**	**62%**	**75%**

Key findings of this analysis include:

- **RAAIM exempt resources accounted for about 16 percent of overall resource adequacy capacity during the RMO+ hours of 2023.** This was mostly solar, gas, and wind resources.
- **RAAIM exempt resources bid and performed at a lower percentage in the markets**. In the day-ahead market and real-time markets, RAAIM exempt capacity bid about 80 to 81 percent of their capacity, while non-RAAIM exempt bid 91 to 92 percent of their capacity into the markets during restricted maintenance operation hours. This considers bids capped at individual resource adequacy values. Including the remaining capacity from partial resource adequacy resources, nearly 150 percent of the procured capacity from RAAIM exempt resources bid into the real-time market. This is due to wind and solar resources that bid significantly above their 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.[277]

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

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276 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

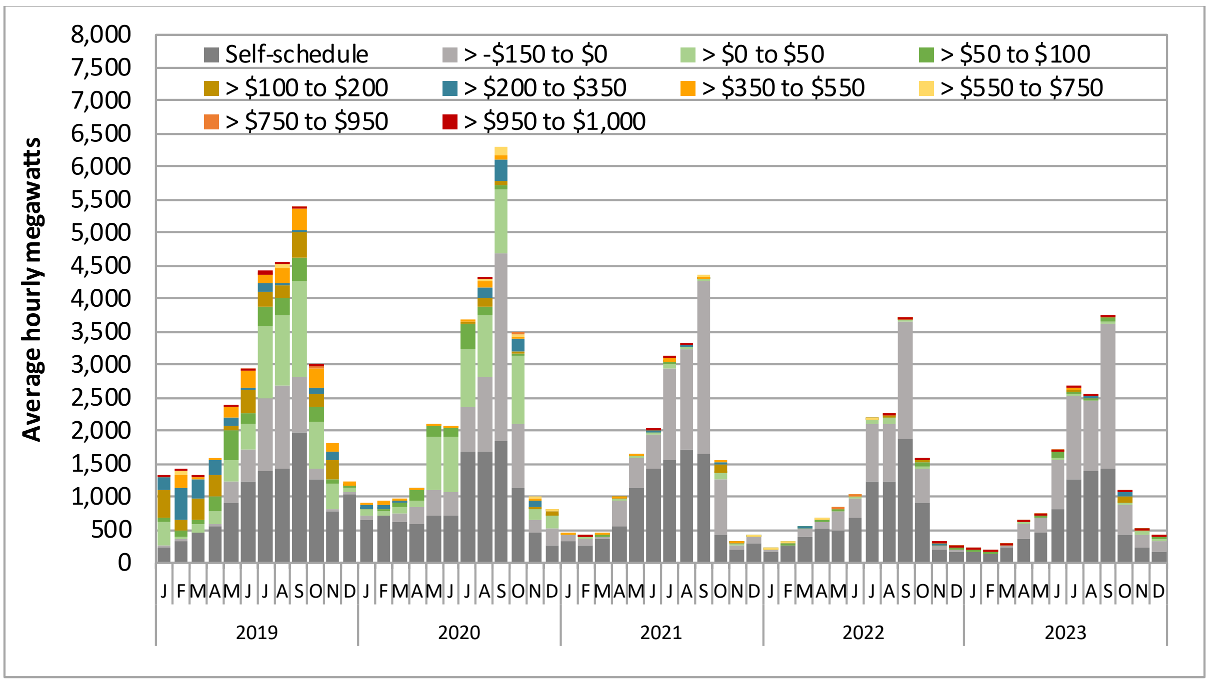
277 In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh, or when the California ISO has 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.

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.

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.[278] 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 were at similar levels in 2023 to 2022. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports. In 2023, CPUC-jurisdictional entities submitted import bids exceeding $0/MWh during only a limited number of hours within the Availability Assessment Hours period.

Figure 8.2 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market during peak hours.[279] 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 8.2 Average hourly resource adequacy imports by price bin



8.3 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

[278] *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

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

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.[280]

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.[281,282] 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.[283]

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.

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.

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280 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

281 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.

282 Net load is total load less wind and solar production.

283 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.

- **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 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

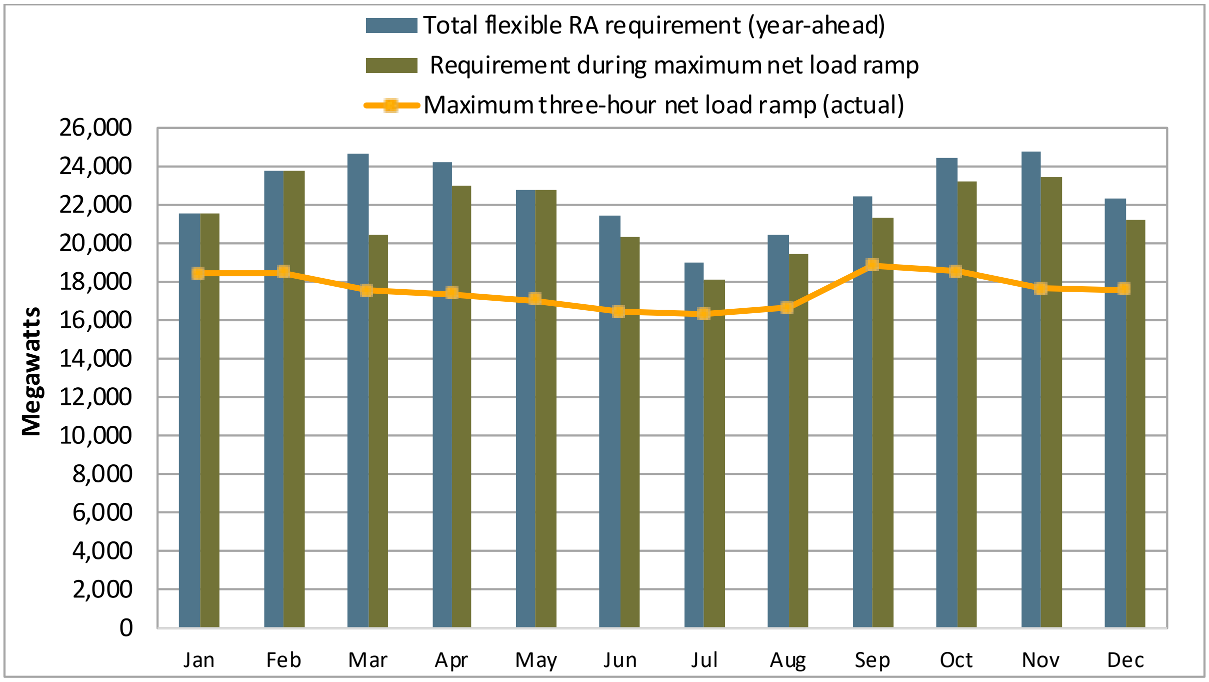
Figure 8.3 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2023 by comparing the requirements and the actual maximum three-hour net load ramp on a monthly basis.[284] The blue bars represent total three-hour requirements for the month and the gold 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 capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.[285] Therefore, this analysis first 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.

[284] 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.

[285] 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.

Figure 8.3 Flexible resource adequacy requirements during the actual maximum net load ramp



Key findings of this analysis include:

- **Year-ahead flexible resource adequacy requirements were sufficient to meet the actual maximum three-hour net load ramp for all months in 2023.** This is where the blue bars are higher than the gold line.
- **Actual flexible resource adequacy requirements set at the time of the peak ramp were sufficient to meet actual maximum three-hour net load ramps for all months.** This is when the green bars are higher 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 2023 requirements and must-offer hours were sufficient in reflecting actual ramping needs in all cases.

Table 8.7 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 8.7 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)
Jan	18,426	21,506	21,506	1/23/2023	14:30	Y
Feb	18,500	23,815	23,815	2/15/2023	15:00	Y
Mar	17,531	24,625	20,454	3/2/2023	15:10	Y
Apr	17,392	24,250	23,038	4/9/2023	16:50	Y
May	17,025	22,756	22,756	5/8/2023	16:15	Y
Jun	16,424	21,402	20,332	6/25/2023	16:55	Y
Jul	16,325	19,032	18,082	7/9/2023	16:45	Y
Aug	16,658	20,452	19,432	8/27/2023	15:55	Y
Sep	18,839	22,434	21,313	9/24/2023	15:40	Y
Oct	18,519	24,443	23,219	10/15/2023	14:55	Y
Nov	17,653	24,733	23,495	11/25/2023	14:00	Y
Dec	17,604	22,321	21,207	12/9/2023	14:00	Y

Key results of this analysis include:

- **The average requirement during the maximum net load ramp was sufficient to meet the actual maximum three-hour net load ramps in all months.** The average requirement was at least 1,757 MW greater than the maximum 3-hour net load ramp in most months.
- **The average maximum three-hour net load ramp across all months in 2023 is about 1,632 MW higher than in 2022, while the average requirement during the net load ramp is 3,991 MW higher.**

Procurement

Table 8.8 shows what types of resources provided flexible resource adequacy, and details the average monthly flexible capacity procurement in 2023 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, the majority of flexible ramping procurement continued to be composed of natural gas-fired generation in 2023.

Table 8.8 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	11,454	52%	19	1%	0	0%
Use-limited gas units	4,997	23%	670	34%	45	12%
Use-limited hydro generators	757	3%	47	2%	0	0%
Other hydro generators	153	1%	0	0%	0	0%
Geothermal	353	2%	0	0%	0	0%
Energy storage	4,113	19%	1,255	63%	332	88%
Total	**21,827**	**100%**	**1,991**	**100%**	**377**	**100%**

Key findings of this analysis include:

- **Gas-fired resources accounted for most flexible resource adequacy capacity procurement.** About 11,473 MW (or 47 percent) of total flexible capacity came from these resources. Almost all (99 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2023.
- **Use-limited gas units made up the second largest volume of flexible resource adequacy capacity.** These generators made up 23 percent of Category 1 capacity and about 24 percent of overall flexible capacity.
- **Energy storage resources made up the third largest volume of Category 1 flexible resource adequacy capacity.** These generators accounted for about 4,113 MW (19 percent) of Category 1 capacity in 2023, an increase from about 1,675 MW (8 percent) in 2022.
- **Load serving entities procured more flexible capacity across Category 1 and Category 2 compared to the previous year, while procuring less of Category 3.** Load serving entities procured 2,110 MW more capacity in category 1, 964 MW more in category 2, and 194 MW less in category 3.

Table 8.9 shows flexible resource adequacy procurement by load serving entity type in 2023, 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 8.9 Average monthly flexible resource adequacy procurement by load type and flex category

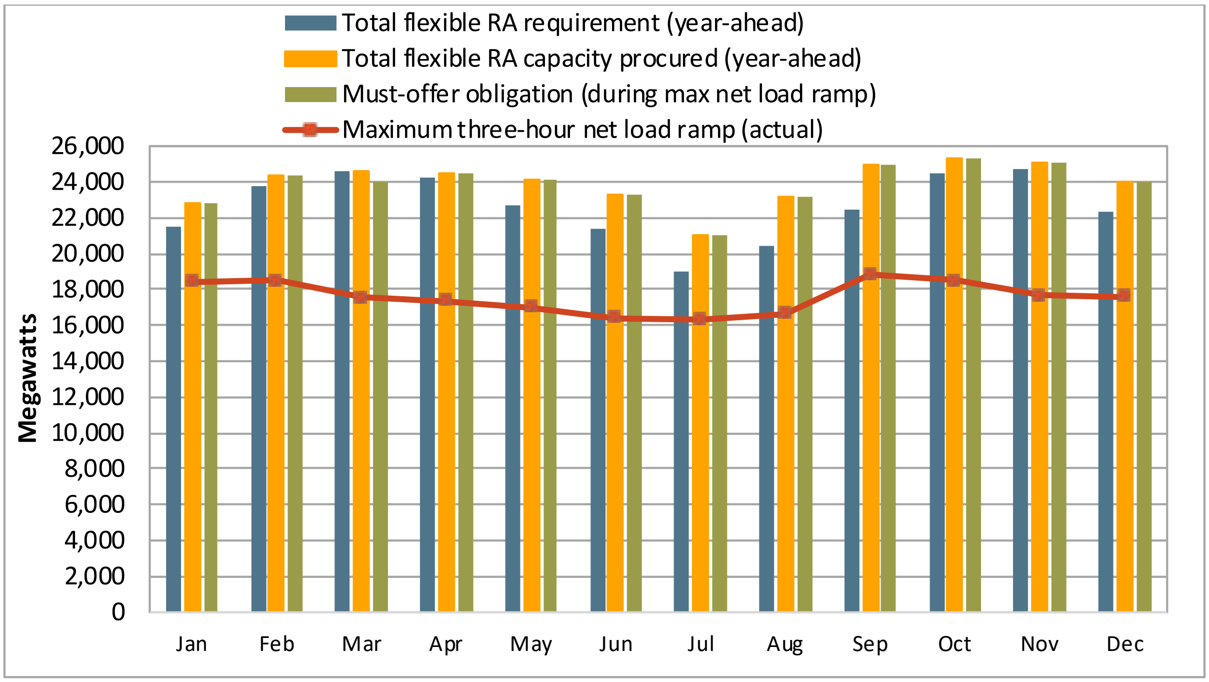
Load Type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
CCA	5,184	24%	588	28%	79	21%
DA	1,411	6%	272	13%	16	4%
IOU	14,457	66%	1,113	52%	287	75%
Muni	810	4%	153	7%	0	0%
Total	**21,862**	**100%**	**2,126**	**100%**	**382**	**100%**

Key findings of this analysis include:

- **Investor-owned utilities procured the highest proportion of each flexible resource adequacy category**. Investor-owned utilities procured 65 percent of total flexible capacity, community choice aggregators procured 24 percent, direct access services procured seven percent, and municipal utilities procured four percent. Investor-owned utilities procured at least 52 percent of the capacity of each category, but their share of procurement in each category has decreased from last year.
- **Most load types procured resources for multiple flexible resource adequacy categories.** Investor-owned utilities, community choice aggregators, and direct access services procured Category 1, 2, and 3 flexible resource adequacy resources. Municipal utilities did not procure any Category 3 capacity.
- **Community choice aggregators procured the second highest proportion of all flexible resource adequacy capacity**. CCAs procured 24 percent of Category 1, 28 percent of Category 2, and 21 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 2023. Figure 8.4 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.[286] 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 8.4 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) is the same as total procurement (gold bars) for all months except for March. For March, the must-offer obligation is about 600 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 2023.

[286] 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.

Availability

Table 8.10 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 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 2023. This analysis is not intended to replicate the method by which the resource adequacy availability incentive mechanism measures availability.

Table 8.10 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	21,114	18,122	86%	15,270	13,251	87%
February	22,518	18,616	83%	16,675	14,004	84%
March	22,713	15,549	68%	18,278	14,822	81%
April	23,029	16,500	72%	18,450	14,962	81%
May	22,611	17,638	78%	16,920	14,552	86%
June	21,914	18,114	83%	15,900	13,803	87%
July	19,476	15,962	82%	14,763	12,319	83%
August	21,581	17,337	80%	16,860	14,176	84%
September	23,281	18,867	81%	17,116	15,255	89%
October	23,710	19,152	81%	17,815	15,182	85%
November	23,333	18,510	79%	16,945	14,858	88%
December	22,039	17,759	81%	16,206	14,592	90%
Total	**22,277**	**17,677**	**79%**	**16,767**	**14,315**	**85%**

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 2023**. Average availability in the day-ahead market was 79 percent and ranged from 68 percent to 86 percent. This is lower than 2022, when average availability in the day-ahead market was about 84 percent, with a range from 72 percent to 91 percent. Average availability in the real-time market was 85 percent, and ranged from 81 percent to 90 percent. This is similar to 2022, when average real-time availability was 85 percent, and ranged from 77 percent to 90 percent.

- **The real-time average must-offer obligation is much lower than the day-ahead obligation**. Flexible capacity must-offer requirements were about 17,700 MW in the day-ahead market and only about 14,300 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 8.11 includes the same data summarized in Table 8.10, 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 is a community choice aggregator (CCA), direct access service (DA), investor-owned utility (IOU), or a municipal/government entity (Muni).

Table 8.11 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	5,358	4,303	80%	3,642	3,151	87%
DA	1,495	1,257	84%	1,113	928	83%
IOU	14,575	11,318	78%	11,223	9,543	85%
Muni	848	799	94%	789	692	88%
Total	**22,277**	**17,677**	**79%**	**16,767**	**14,315**	**85%**

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**. Resources that contracted with community choice aggregators had about 80 percent availability in the day-ahead market, those that contracted with direct access services had about 84 percent availability, and those that contracted with investor-owned utilities and municipalities had 78 and 94 percent availability, respectively. In the real-time market, these resources were available between 83 and 87 percent of the time, depending on load type.

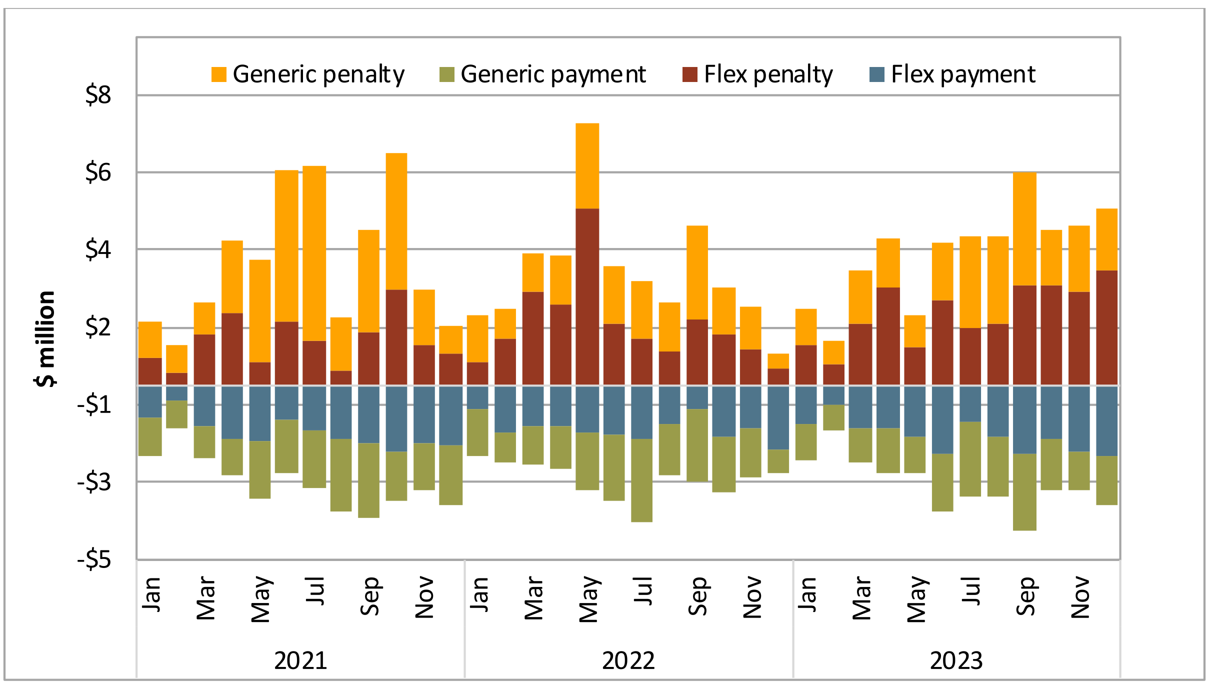
8.4 Incentive mechanism payments

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 2023 availability assessment hours for *system and local resource adequacy resources* were hours-ending 18 to 22 in March and April, and hours-ending 17 to 21 in May through February. *Flexible resource adequacy resources* were assessed for hours-ending 6 to 22 for base ramping resources. Both peak ramping and super-peak ramping resources were assessed for hours-ending 15 to 19 in January, February, November, and December; hours-ending 17 to 21 in March through August; and hours-ending 16 to 20 in September and October.

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 *less* than the availability standard of 94.5 percent are *charged* a non-availability charge for the month. Resources whose average capacity availability is *greater* than the availability standard of 98.5 percent 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 $3.79/kW-month.[287]

Figure 8.5 summarizes monthly RAAIM charges and payments to resource adequacy resources from January 2021 to December 2023. 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.

Figure 8.5 Monthly RAAIM penalties and payments



[287] 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.

Key findings from this analysis include:

- **In 2023, RAAIM penalties and payments were fairly evenly distributed between generic and flexible resource adequacy resources.** In 2023, RAAIM charges were about $41 million and incentive payments were about $31 million. RAAIM charges and payments increased from $35 million and $25 million, respectively, in 2022.
- **In 2023, most RAAIM charges occurred in the third quarter.** In the third quarter, the RAAIM charges averaged $4.4 million per month. The first quarter had the lowest average RAAIM charges at $2.0 million per month, with the second and fourth quarters having average charges at $3.1 and $4.3 million, respectively.

8.5 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. Bids may range up to a soft offer cap set at $6.31/kW-month ($75.68/kW-year).

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 2023. Since the implementation of the current capacity procurement mechanism framework in 2016, the only annual designations were made in 2018.

Monthly designations

2023 had the first monthly capacity procurement mechanism designation since the program was implemented in 2016. There were four resources procured through the CPM to meet a system deficiency. Table 8.12 shows the monthly capacity procurement mechanism designations that occurred in 2023. The table shows the designated resources, amount of megawatts procured, the date range of the designations, the price, estimated cost of the procurement, the area that had insufficient capacity, and the CPM designation details.

Table 8.12 Monthly capacity procurement mechanism costs

Resource	Designated MW	CPM start date	CPM end date	CPM type	Price ($/kW-mon)	Estimated cost ($ mil)	Local capacity area	CPM designation details
CHINO_2_PESBT1	10	8/1/2023	8/31/2023	CADEF	$6.31	$0.07	SYS	CPM designation for August 2023 month-ahead system resource adequacy deficiency
MARVEL_2_MARBT3	46	8/1/2023	8/31/2023	CADEF	$6.31	$0.31	SYS	CPM designation for August 2023 month-ahead system resource adequacy deficiency
MRCHNT_2_PL1X3	82	8/1/2023	8/31/2023	CADEF	$6.31	$0.55	SYS	CPM designation for August 2023 month-ahead system resource adequacy deficiency
ELCAJN_6_LM6K	48	8/1/2023	8/31/2023	CADEF	$6.31	$0.32	SYS	CPM designation for August 2023 month-ahead system resource adequacy deficiency
Total	186					$1.25		

Intra-monthly designations

Table 8.13, similar to Table 8.12, shows the intra-monthly capacity procurement mechanism designation that occurred in 2023.

Table 8.13 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM start date	CPM end date	CPM type	Price ($/kW-mon)	Estimated cost ($ mil)	Local capacity area	CPM designation details
SYCAMR_2_UNIT 3	70	11/2/2023	1/1/2024	ED	$7.31	$1.06	SCE	Initial CPM Designation
Total	70					$1.06		

Key findings of the monthly and intra-monthly analysis include:

- **In 2023, about 256 MW of capacity was procured through the competitive solicitation process at an estimated cost of $2.31 million.** There were 186 MW of procurements for an August resource adequacy deficiency, and to address an overload on the transmission system. The remaining 70 MW were procured as an exceptional dispatch for a transmission need through November and December.
- **The monthly August procurement totaled 186 MW at an estimated cost of $1.25 million.** Due to tight resource adequacy supply conditions, multiple scheduling coordinators failed to show sufficient resource adequacy capacity on the August 2023 monthly Resource Adequacy Plans. The deficiency was for 186 MW, which was then procured through the capacity procurement competitive solicitation process.
- **The intra-monthly procurement totaled 70 MW at an estimated cost of $1.06 million, and spanned 62 days from November 2 through December.** The procurement was an exceptional dispatch CPM type to address a non-system reliability need. The exceptional dispatch was issued to address a potential thermal overload in the Southern California Edison Local Area. Specifically, the CPM was to relieve a thermal overload on a 230 kV transformer and maintain reliability.
- **In 2023, intra-monthly capacity procurement dropped compared to 2022.** A total of 120 MW of capacity was procured through CPM in 2022, at a cost of $0.9 million. In 2023, the California ISO procured 60 percent of the 2022 CPM capacity, but cumulatively it was more capacity over a longer time, leading to an increased cost of $1.06 million.
- **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.

8.6 Reliability must-run contracts

As of December 2023, capacity designated as reliability must-run (RMR) totaled about 159 MW. Total settlement for reliability must-run capacity was about $13.5 million, which is $34 million lower than in 2022. 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.

Table 8.14 shows designated reliability must-run resources from 2016 through 2023. In 2017, the California ISO designated three new efficient gas units that represented almost 700 MW to provide reliability must-run service beginning in 2018.[288] The California ISO did not designate about 600 MW of this 700 MW of gas-fired generation for reliability must-run service in 2019. Metcalf Energy Center's designation as a resource adequacy unit in 2019, and transmission upgrades completed in December 2018 and January 2019, eliminated the need to designate the resource as a reliability must-run unit. The California ISO did not re-designate the remaining 100 MW of gas-fired generation for reliability must-run service in 2020. Yuba City Energy Center and Feather River Energy Center returned as resource adequacy units in 2020. No new resources were designated for reliability must-run in 2023.

Table 8.14 Designated reliability must-run resource capacity (2016–2023)

RMR Start Date	RMR End Date	RMR resource name	MW
5-Dec-2016	N/A	Oakland Station Unit 1	55.00
5-Dec-2016	31-Dec-2020	Oakland Station Unit 2	55.00
5-Dec-2016	N/A	Oakland Station Unit 3	55.00
1-Jan-2018	31-Dec-2018	Metcalf Energy Center	593.16
1-Jan-2018	31-Dec-2019	Feather River Energy Center	47.60
1-Jan-2018	31-Dec-2019	Yuba City Energy Center	47.60
1-May-2020	31-Dec-2022	Channel Islands Power	27.50
1-Jun-2020	31-Dec-2020	E.F. Oxnard	47.70
1-Jun-2020	N/A	Greenleaf II Cogen	49.20
1-Feb-2021	31-Dec-2022	Midway Sunset Cogeneration Plant	248.00
1-May-2021	31-Dec-2022	Kingsburg Cogen	34.50

In 2018, the California ISO designated one unit at the Ormond Beach Generating Station and Ellwood Energy Support Facility as reliability must-run units aggregating 800 MW. This extended the life of the units to the retirement dates originally considered in system planning. In 2019, these units entered the resource adequacy program after not entering into reliability must-run contracts with the California ISO.

In 2020, the California ISO designated E.F. Oxnard, Greenleaf II, and Channel Islands Power (aggregating 124.4 MW of capacity) for service as reliability must-run units. The ISO filed contracts for these three units at FERC in the May-June timeframe. About 47.7 MW of capacity from E.F. Oxnard returned as a resource adequacy unit in 2021.

In 2021, the California ISO designated about 282.5 MW of new capacity from Midway Sunset Cogeneration Plant and Kingsburg Cogen as reliability must-run. In 2021, the California ISO could have entered a reliability must-run contract for about 28.56 MW with Agnews Power Plant.[289] Ultimately, this did not happen because it received a resource adequacy contract in 2022. On January 20, 2022, this resource notified the California ISO of its intention to retire on January 1, 2023, and repower the site.

[288] These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

[289] *Potential reliability must-run designation – Agnews Power Plant,* California ISO, presented by Catalin Micsa, May 18, 2021: http://www.caiso.com/Documents/PresentationPotentialReliabilityMustRunDesignationAgnewsPowerPlant-May182021.pdf

Since this resource is required to meet local reliability needs in San Jose sub-area, the California ISO recommended designating it for reliability must-run services for year 2023, but that never occurred.[290]

In 2022, the Kingsburg Cogen unit secured a multi-year resource adequacy capacity contract, and as a result, did not receive an extension for its reliability must-run contract for 2023. The Midway Sunset Cogeneration Plant also entered into resource adequacy contracts for the full amount of their available capacity through 2026. Furthermore, the Channel Islands Power unit signed a contract with the California Department of Water Resources, making the unit accessible to the ISO as the California Strategic Reliability Reserve Program. All of these resources terminated their RMR contract effective midnight on December 31, 2022.[291] In summary, 310 MW of reliability must-run resources had their contracts terminated by the end of 2022. For 2023, the overall capacity of reliability must-run units amounted to 159 MW.

The California ISO completed a stakeholder initiative to clarify the reliability must-run designation type (local or system) when more than one reliability need exists.[292] The type of *reliability need* triggers cost allocation as well as the *resource adequacy credits allocation* of the reliability must-run contract. The final proposal considers "local" to be *primary reliability need*, as it is consistent with both cost causation and *resource adequacy credits allocation principles*, while also providing other incentives and benefits.

290 *Potential Reliability Must-Run Designation: Agnews Power Plant*, California ISO Market Notice, May 19, 2022: http://www.caiso.com/Documents/Potential-Reliability-Must-Run-Designation-Agnews-Power-Plant-Call-051922.html

291 *Update on results of reliability must-run contract extensions for 2023*, California ISO Memorandum, October 19, 2022: http://www.caiso.com/Documents/ReliabilityMust-RunContractsUpdate-Oct2022.pdf

292 California ISO initiative: *Clarifications to reliability must-run designation process,* August 9, 2021*:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Clarifications-to-reliability-must-run-designation-process

9 Recommendations

As the independent market monitor for the California ISO and the Western Energy Imbalance Market, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives.[293] 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.[294] A summary of key recommendations is provided in the executive summary of this report.

9.1 Extended day-ahead energy market

In 2023, the ISO Board and WEIM Governing Body approved proposed designs for an extended day-ahead market (EDAM) and day-ahead market enhancements (DAME). These proposals were approved by FERC and are scheduled for implementation in 2026.

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. A more detailed summary of DMM's recommendations are provided in DMM's memo to the ISO Board and WEIM Governing Body on the EDAM proposal.[295]

The ISO has made significant progress toward developing a workable design for a regional day-ahead market that can provide near-term benefits to entities participating in EDAM. Given the large potential long-term benefits of a West-wide day-ahead market and the enormous challenges in initiating such a market, DMM supports proceeding with the final EDAM design passed by the ISO Board and WEIM Governing Body in 2023, while the ISO continues working with stakeholders to resolve some crucial design elements.

Some important unresolved issues remain in the design that, if not adequately addressed, could have reliability or efficiency costs that could significantly limit the net benefits of EDAM for participating entities during this initial implementation phase. However, DMM believes the most significant unresolved issues can be addressed through a combination of (1) stakeholder processes in each participating EDAM balancing area, (2) clarifications of details during development of the tariff supporting the EDAM design, and (3) design enhancements within the first few years of implementation.

The ISO's final proposal recognizes that further details of both EDAM and DAME design will need to be developed and adapted based on testing the full software model prior to implementation, and on

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

294 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

295 Memorandum to ISO Board of Governors and WEIM Governing Body, Department of Market Monitoring, January 25, 2023: http://www.caiso.com/Documents/DepartmentofMarketMonitoringReport-Feb2023.pdf

operational experience after implementation. The final proposal also includes a set of specific configurable software parameters, which can be adjusted before and after implementation in consultation with stakeholders. This approach reflects a conservative and prudent approach for dealing with the uncertainty and complexity of initiating the type of regional day-ahead market being proposed.

DMM supports this approach and looks forward to continuing to collaborate with the ISO and stakeholders on the remaining steps towards developing and implementing a regional day-ahead market.

9.2 Day-ahead imbalance reserve product

A key element of the EDAM and DAME proposals 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 such a product, but has provided several key recommendations regarding potential changes to the initial proposal, as summarized below.[296]

Demand curve for day-ahead reserve capacity

DMM recommends that the ISO continue to work on developing more accurate methods for determining demand curve values, and prepare to potentially reduce the $55/MWh cap during enhancements after the initial EDAM implementation.

Procuring imbalance reserves in the energy market with virtual bidding

Procuring imbalance reserves in the integrated forward market (IFM) rather than the residual unit commitment market has the potential advantage of allowing the market to co-optimize energy and reserve awards. However, virtual supply clearing the IFM may undo much of this potential benefit by displacing the more expensive and slower ramping physical supply. This would require the residual unit commitment process to continue serving its current role of procuring excess capacity to address net load uncertainty after the IFM has issued energy awards. In the event that significant procurement of extra capacity occurs in the residual unit commitment process, DMM recommends that the ISO and stakeholders more carefully consider whether it would ultimately be more efficient to procure imbalance reserves in the residual unit commitment market.

Utilizing reserves procured in day-ahead market in real-time

DMM continues to recommend that the ISO develop mechanisms to allow the real-time market to efficiently determine whether or not to preserve imbalance reserves procured in the day-ahead market. If the real-time market does not have a mechanism to maintain these reserves, the value of procuring imbalance energy reserves in the day-ahead market could be significantly reduced.

Extending the real-time flexible ramping product and real-time market lookout horizons would help the real-time market manage this capacity. DMM continues to recommend that the ISO consider extending the uncertainty horizon of the real-time flexible ramping product so the markets can procure and compensate the capacity required to address net load uncertainty over a longer time horizon in the real-time.

[296] Ibid.

As an alternative to this, the ISO should consider adding one or more simpler products to the real-time markets in order to procure and compensate the ramping capacity and energy required to meet expected net load uncertainty over a multi-hour horizon (e.g., 1 to 4 hours from the current market run). These new uncertainty products could resemble more traditional reserve products. Therefore, they may be much easier to implement in the near-term than a more complicated approach that incorporates net load uncertainty directly into advisory intervals of the multi-interval optimization.

9.3 Market power in transmission access

The EDAM design requires generation in a *source* balancing area to have firm transmission to the *sink* balancing area before each day's EDAM run. This can limit the pool of resources within EDAM balancing areas that can compete to meet a sink balancing area's resource sufficiency evaluation requirements.

Under this requirement, if all the transmission rights on a path to a sink balancing area have been purchased in advance of the day-ahead time frame, a generator in an EDAM area that has not purchased the transmission rights will not be able to offer its capacity to load serving entities seeking capacity to meet their EDAM balancing area's resource sufficiency evaluation (RSE) requirements. These load serving entities would have to buy the transmission rights from the transmission rights holders, or be limited to negotiating with the resources in EDAM balancing areas that procured the transmission rights in advance.

If one company controls enough transmission rights on a path to prevent the sink balancing area from acquiring the total capacity it needs without buying some of that company's transmission rights, the company holding the rights could force load serving entities in the sink balancing area to buy supply from its affiliated resources in order to pass the EDAM resource sufficiency evaluation. The resources affiliated with the large transmission rights holder could exercise market power in the resource sufficiency evaluation supply market, charging excessively high prices for the capacity that the sink balancing area needs to pass the evaluation.

The potential for holders of large quantities of transmission rights on key paths to exercise market power in this way is likely to be mitigated during the initial EDAM implementation due to a limited number of balancing areas initially participating in EDAM. However, before a substantial number of balancing areas join EDAM, DMM recommends the ISO prioritize assessing the extent to which this market power can exist on specific transmission paths, and develop market design enhancements to mitigate this market power where it has the potential to be exercised.

9.4 Counting non-source specific supply in resource sufficiency evaluation

The EDAM design allows contracts for non-source specific energy to count toward an EDAM balancing area's resource sufficiency evaluation. This creates the potential to double-count resources and capacity. This can occur if an entity has not procured the capacity or energy it schedules into EDAM to meet resource sufficiency evaluation requirements by the time the day-ahead market closes at 10 a.m. In this scenario, the entity could be relying in part on existing excess capacity in non-EDAM balancing areas. However, the entity may also be relying on capacity in an EDAM balancing area that had been counted towards the area's EDAM resource sufficiency evaluation requirements.

DMM recommends that as part of the process of enhancing the initial EDAM design, the ISO and stakeholders consider more nuanced rule 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.

9.5 Congestion revenue rights

Over the 10-year period 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 CRRs, these congestion revenues would be credited back to transmission ratepayers who pay for the cost of the transmission system through the transmission access charge. Thus, this $860 million represents profits to the entities purchasing these financial rights in the auction, but represents revenue losses to transmission ratepayers. 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.[297] Although changes implemented in 2019 reduced ratepayer auction losses, these losses have continued to be very significant.

- In the five years since the ISO implemented CRR reforms aimed at reducing these losses in 2019, ratepayers have lost $312 million (or an average of $62 million per year) and have received only 67 cents in auction revenues per dollar paid out.
- In 2023, ratepayer losses from CRRs auctioned off by the ISO totaled $58 million and have received only 76 cents in auction revenues per dollar paid out.[298]

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 losses from CRRs in November 2023. Analysis presented by the ISO to the MSC also shows that auction revenues have equaled only about 65 percent of congestion revenue payouts since 2019, compared to about 49 percent in the years prior to the 2019 changes.[299]

The MSC has noted that "the ratio of day-ahead market payments to auction net revenues is still far too high to be accounted for by plausible values of the time value of money for congestion revenue rights purchased by hedgers" and has posed a series of questions and potential further analyses for consideration.[300] However, no further action has been taken on this issue as of June 2024.

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297 *2019 Annual Report on Market Issues & Performance,* Department of Market Monitoring, June 2020, pp 230-234: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

298 *2022 Annual Report on Market Issues and Performance*, Department of Market Monitoring, July 11, 2023, pp 18, 183-190: https://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf

299 *Congestion Revenue Rights discussion*, Market Surveillance Committee Meeting, November 29, 2023, slide 33: https://www.caiso.com/Documents/CongestionRevenueRights-Presentation-Nov29-2023.pdf

300 *CRR Pricing, Track 0, 1A and 1B Changes*, Market Surveillance Committee Meeting, November 29, 2023: https://www.caiso.com/Documents/CongestionRevenueRightsMSC-Presentation-Nov29_2023.pdf

Recommendations

The ISO has deemed any further revisions to the congestion revenue rights auction a potential discretionary initiative that must be considered along with all other potential discretionary initiatives under consideration. DMM believes that the ISO should proceed to initiate a process to develop changes, given the magnitude of continued losses from the auction and the commitment made by the ISO to take additional actions if significant losses continued after the 2019 changes.

Building on the existing reforms might further reduce ratepayer losses. Auction losses could be further decreased by reducing the amount of auctioned rights, either generally or from specific locations with significant underpricing. Reducing the amount of rights could be achieved by lowering auction constraint limits.

Some load serving entities have pointed out that ratepayer losses could also be reduced by raising (rather than lowering) constraint limits in the allocation process. This could reduce the amount of rights that could be sold in the auction without reducing rights allocated to load serving entities, as could occur if constraints were de-rated in the allocation and auction.

However, DMM continues to believe that the current auction is unnecessary and could be eliminated, with all congestion rents being returned to transmission ratepayers. If the ISO and stakeholders believe it is beneficial to the market to facilitate hedging, then the current auction format should be changed to a market for congestion revenue rights or locational price swaps based only on bids submitted by entities willing to buy or sell CRRs.

This approach—based on willing sellers and buyers—would replace the current auction with the same type of market through which all other financial derivatives are bought and sold. This approach would provide a market in which load serving entities could continue to voluntarily sell back any CRRs acquired in the allocation process. This 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 CRRs sold in the auction by the ISO.

9.6 Battery resources

The amount of energy storage resources (batteries) on the CAISO system has increased significantly in recent years, and is projected to continue increasing in coming years. While battery resources are generally very fast responding and flexible, the availability of these resources depends on their state of charge levels. For example, battery resources providing resource adequacy often do not have sufficient charge to provide their full resource adequacy capacity values for four consecutive hours across peak net load periods.

DMM has played an active role in efforts to develop new market rules and software enhancements to facilitate efficient and reliable use of energy storage resources. Beginning in 2018, DMM has suggested potential changes to CPUC and CAISO rules that could improve modeling and help mitigate availability concerns related to battery resources.[301]

[301] *2018 Annual Report on Market Issues & Performance*, Department of Market Monitoring, May 2019, p 24: https://www.caiso.com/documents/2018annualreportonmarketissuesandperformance.pdf

9.6.1 Bid cost recovery rules for batteries

The main purpose of bid cost recovery (BCR) for traditional generators is to alleviate 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 startup, shutdown, minimum load, or transition costs—and thus lack the traditional drivers of BCR. However, in 2023, batteries received nearly $28 million of bid cost recovery (primarily from the real-time market), which was 10 percent of all BCR awarded that year.

The main limitations on battery dispatch that lead to BCR payments derive from state-of-charge limitations. These state-of-charge limitations can result in uneconomic market dispatches that are eligible for BCR. Early in the energy storage and distributed energy resources (ESDER) stakeholder process in 2016, DMM recommended the ISO consider the implications of a day-ahead submitted state of charge as a new and unique intertemporal constraint between markets. DMM recommended that the ISO revisit this topic in future initiatives to address potential settlement implications.[302]

In September 2022, the ISO filed with FERC to eliminate one large driver of inefficient BCR payments to storage resources that was identified by DMM.[303] However, the need to further modify BCR rules for batteries continues to be underscored by recent market outcomes and the growing capacity of energy storage resources on the CAISO system. Further changes are needed to address a number of ways in which storage resource operators can take actions to force uneconomic dispatch that drives bid cost recovery payments.

DMM continues to recommend that the ISO place a high priority on developing more general revisions to BCR rules for batteries as soon as practicable. New BCR rules are specifically needed to address BCR payments stemming from a range of actions by battery operators that can constrain a battery's state of charge or otherwise force uneconomic dispatch by the market software. When a battery's day-ahead state of charge value deviates significantly from actual state of charge value in real-time, this creates inefficient dispatch, reduces reliability, and creates opportunities for gaming of BCR payments.

9.6.2 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 new slice-of-day framework of California's resource adequacy program that is being developed by the California Public Utilities Commission (CPUC) addresses this issue from the perspective of capacity portfolio planning. Under this slice-of-day approach, resource adequacy portfolios of load serving

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302 *Stakeholder Comments: Energy Storage and Distributed Energy Resources (ESDER) Revised Draft Final Proposal*, Department of Market Monitoring, February 2, 2016: http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorageDistributedEnergyResources-RevisedDraftFinalProposal.pdf

303 *Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resources*, California Independent System Operator Corporation, FERC Docket No. ER22-2881 September 19, 2022: http://www.caiso.com/Documents/Sep19-2022-TariffAmendment-EnergyStorageBidCostRecovery-ER22-2881.pdf

entities will need to include sufficient surplus energy to ensure that batteries can be fully charged over the four most critical net peak hours.

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 will rely on storage capacity the most. This could include bid cost recovery enhancements aimed at ensuring battery storage resources are properly incentivized to reflect real-time intra-day opportunity costs in energy bids during the hours preceding the highest net load hours of the day.

Additionally, 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.[304]

9.6.3 Bids for batteries used in market power mitigation

Starting in November 2021, storage resources (except for those choosing to be modeled as hybrid resources) became subject to local market power mitigation. In practice, most batteries are not subject to bid mitigation very frequently. And when subject to mitigation, the impact of mitigation on the dispatch of batteries has been very low. However, DMM recommends the ISO continue to enhance the methodology for calculating default energy bids for energy storage resources, create a standardized default energy bid for storage resources in the WEIM, and work towards extending mitigation to include hybrid resources.

The current default energy bids for energy storage resources include three types of costs: energy costs, variable operations costs—including cycling and cell degradation costs—and opportunity costs. The ISO calculates a static default energy bid value over the day for each battery resource. DMM is supportive of this framework, but has recommended several additional refinements.[305] DMM recommends that the ISO continue to enhance the proposed default energy bid for energy storage resources to:

- Allow the default energy bid value to vary throughout the day to capture opportunity or other costs that may differ based on resource operation over the day;
- More precisely clarify whether some components, such as sunk costs from intra-day charging, are included for the purpose of increasing the default energy bid to approximate different costs that are not otherwise captured;
- Reconsider the use of day-ahead local market power mitigation run prices as an input to the day-ahead storage default energy bid; and

[304] 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 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 charging bid range such that resources are unable to charge for later hours.

[305] *Comments on Energy Storage and Distributed Energy Resources – Storage Default Energy Bid Final Proposal*, Department of Market Monitoring, November 12, 2020: http://www.caiso.com/Documents/DMMComments-EnergyStorageandDistributedEnergyResources-StorageDefaultEnergyBidFinalProposal-Nov122020.pdf

- Develop an enhanced framework that allows for estimation of opportunity costs outside of the market optimization horizon, and that accurately accounts for those opportunity costs by considering the ability of storage resources to discharge and recharge before reaching future intervals.

9.6.4 Allowing batteries to bid in excess or $1,000/MWh soft cap

Batteries are currently subject to a $1,000/MWh hard bid cap, even on days when some other resources can bid above $1,000/MWh. On days when real-time prices exceed the $1,000/MWh soft cap, the $1,000/MWh bid cap on battery resources could prevent these resources from bidding potential intra-day opportunity costs in excess of $1,000/MWh. This could contribute to sub-optimal dispatch of the battery fleet by causing some battery capacity to be dispatched in hours prior to the highest priced peak net load hours. In practice, however, analysis by DMM shows that sub-optimal dispatch of batteries on days when real-time prices have exceeded the $1,000/MWh soft cap was not due to the $1,000/MWh bid cap on batteries, since most battery capacity was bid at prices below the $1,000/MWh on these days.[306]

To address this potential scenario, the ISO is changing rules to allow batteries to bid in excess of the $1,000/MWh on days when the $2,000/MWh hard cap is triggered. Under these new rules, the ISO will allow batteries to bid up to a static bid cap over $1,000/MWh during all hours on days when any other resources are allowed to bid over the $1,000/MWh soft cap.

DMM supports allowing batteries to bid up to opportunity costs in excess of $1,000/MWh in the hours leading up the highest priced peak net load hours. However, DMM notes that during the peak net load hours, the opportunity cost for batteries to discharge should be much lower. The ISO has indicated it could not implement an approach with different opportunity costs for different hours, as suggested by DMM.

To ensure intra-day opportunity costs can be appropriately reflected in all hours, DMM recommends the ISO develop a bid cap that can vary hourly when exceeding $1,000/MWh. This approach would avoid overstating costs in many hours, as occurs under the ISO’s recently approved real-time bid cap for storage resources on days with hours where bids may exceed $1,000/MWh.[307] This recommended approach is discussed further in Section 2.3.2.

9.7 Resource sufficiency tests

The resource sufficiency tests for capacity and flexible ramping capacity are key elements of the Western Energy Imbalance Market (WEIM) design, and are intended to ensure that enough resources are available to meet reliability needs and prevent one balancing area from leaning on other WEIM areas.

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306 *Comments on Management’s proposed changes to rules for bidding over the soft-offer cap,* Department of Market Monitoring memorandum to the ISO Board of Governors and WEIM Governing Body, May 15, 2024: https://www.caiso.com/documents/departmentofmarketmonitoringcomments-softoffercap-memo-may2024.pdf

307 Ibid.

The California ISO implemented a number of changes to the resource sufficiency evaluation in June 2022 as part of the resource sufficiency evaluation enhancements phase 1.[308] In December 2022, the ISO Board and WEIM Governing Body approved several additional changes that took effect in 2023 as part of phase 2 of this initiative. These include a new *energy assistance option* described below.

Energy assistance option

Currently, when a WEIM area fails either the capacity test or flexible ramping test, WEIM transfers into the balancing area are not allowed to increase beyond the level of supply being transferred into the area just prior to the test failure. DMM has recommended that both the ISO and stakeholders consider other options, such as imposing a capacity charge or other financial charge.

A major change taking effect in 2023 under phase 2 of the resource sufficiency evaluation enhancements initiative was implementation of an energy assistance option that would allow WEIM areas to import additional energy through WEIM during intervals when they fail the resource sufficiency test. Areas importing additional energy under the emergency assistance option will be subject to a penalty cost which will be set at the CAISO/WEIM penalty price ($1,000 or $2,000/MWh). The amount of energy subject to the penalty would be based on the lower of (1) the amount by which the area failed the capacity or flexibility test, or (2) dynamic WEIM transfers made into the area. With this approach, the total cost of the penalty will be scaled closely with the degree to which areas may be relying on the WEIM when failing the test.

DMM supported the revised energy assistance option included in the proposal as a reasonable compromise that could encourage a larger portion of WEIM balancing areas to participate in this option. While further refinements to this approach should be considered, the relative simplicity of the proposal allowed implementation of this option by summer 2023.

The ISO is not proposing to change existing sufficiency test failure consequences for balancing areas that do not elect energy assistance eligibility. For balancing areas that elect to not opt in to the energy assistance program, the consequence of only limiting WEIM import transfers at the last interval's transfer level can be too lenient. In the next phase of this initiative, DMM recommends that the ISO should continue to refine the consequences for areas that elect to not opt in to the energy assistance program, but then fail the resource sufficiency test. More specifically, DMM has recommended that both the ISO and stakeholders consider other options, such as imposing a capacity charge or other financial charge.

Incorporating uncertainty into test requirements

Currently, a component for net load uncertainty is included in the flexible ramping test, but is not incorporated in the capacity test. The ISO is not proposing to add uncertainty back into the capacity test at this time. While incorporating some level of uncertainty into the test is reasonable, there is not an objectively correct answer to what this uncertainty adder should be.

On the one hand, increasing the test requirements by adding uncertainty adders will create more incentives for WEIM areas to procure more capacity in advance of the real-time market, and will reduce the potential for one area to rely on WEIM to meet its load. On the other hand, it would be prohibitively

[308] CAISO stakeholder initiative: *WEIM resource sufficiency evaluation enhancements*: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements

expensive to adopt test requirements designed to ensure that each balancing area can meet its full imbalance requirements 100 percent of the time with just the resources made available to the real-time market in that area. Therefore, the question of how to set an uncertainty adder is a policy question that can only be answered through debate and consensus among the balancing areas participating in the WEIM.

In February 2023, the ISO implemented a new method of net load uncertainty calculation based on quantile regression for the flexible ramping product. DMM's review of the performance of this new methodology indicates that it is not a clear improvement over the prior method. Although uncertainty values calculated with this method are generally lower while covering uncertainty (an improvement), they fluctuate more significantly and are likely to be more difficult for balancing areas to reproduce or predict in advance.[309]

Therefore, DMM continues to recommend that the ISO and stakeholders consider developing much simpler and more transparent uncertainty adders in the next phase of this initiative. DMM recommends considering adoption of uncertainty calculations customized to the resource sufficiency evaluation, rather than using the uncertainty calculation that was developed for determining market requirements for the flexible ramping product.

9.8 Flexible ramping product

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. This product has the potential to help increase reliability and efficiency, while reducing the need for manual load adjustments by grid operators. Since 2016, DMM has recommended the following two key enhancements:

- **Implement locational procurement of flexible ramping capacity** to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. The ISO implemented changes to address this issue in 2023, as discussed in more detail in the following section.

- **Increase 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 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.[310]

In February 2023, the California ISO implemented nodal procurement as part of the flexible ramping product refinements stakeholder initiative. DMM identified an error in the implemented calculation of the demand curves for procurement of flexible ramping product enforced in the market software. This error lowered the value of flexible capacity in the market optimization, effectively making that capacity appear cheaper relative to the expected cost of a shortage. The ISO implemented changes to correct this issue in August 2023. This error and its resolution are discussed in greater detail in Section 2 of this report.

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[309] *Review of the Mosaic Quantile Regression,* Department of Market Monitoring, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

[310] *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

Even after locational procurement was correctly implemented, the flexible ramping product does not seem to have effectively addressed 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 commitment or 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 evening.

DMM continues to believes that 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.

- One approach could be to extend the time frame of the flexible ramping product (e.g., 30, 60, and 120 minutes out from a given real-time interval).
- Another approach could be to develop a separate, simpler real-time uncertainty product that procures extra ramping and energy capacity (in excess of the load forecast) over a multi-hour time period (e.g., from 1 to 4 hours in the future).

9.9 Price formation enhancements

In 2022, the California ISO initiated a price formation enhancements working group.[311] This working group is ongoing and aims to address multiple issues related to price formation in the ISO and WEIM markets. DMM has offered several recommendations related to the different topics addressed in this working group. DMM suggests the ISO consider placing a priority on foundational market enhancements that will improve price formation before embarking on more complicated market design changes such as fast-start and scarcity pricing. Foundational enhancements that should be given top priority include:

- Extending the time-horizon of the flexible ramping product (or creating a new product/constraint that serves this purpose);
- Accurately incorporating intra-day opportunity costs into default energy bids for storage resources; and
- Re-optimizing ancillary services in the real-time market.

The sections below explain how each of these three enhancements would address existing issues with price formation and provide other market and reliability benefits.

Extended flexible ramping product time horizon

As explained in Section 2.8, DMM continues to recommend the ISO extend the flexible ramping product, or create separate ramping and energy capacity products for the same purpose. In addition to the

[311] CAISO stakeholder initiative: Price formation enhancements: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements

operational benefits of improved management of available capacity, an extended product would also fix a current problem where the real-time prices are not always set equal to marginal cost.[312]

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 meet needs in an advisory interval.

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

An extended product would move the marginal costs from the advisory interval into the binding interval prices of the optimization where the actions are taken to meet the advisory needs. Moving the costs into the binding interval prices would settle resources on prices that include all the marginal costs.

Rules for bidding over the $1,000/MWh soft offer cap

In a 2024 policy initiative, the ISO sought to improve the ability for limited energy resources, such as hydro and storage resources, to submit bids over the $1,000/MWh soft offer cap to reflect high intra-day opportunity costs on days when the $2,000/MWh hard cap is in effect. These policy changes raise the cap on default energy bids (DEBs) to $2,000/MWh, and establish a real-time bid cap for storage resources that can exceed $1,000/MWh where an approximation of intra-day opportunity costs for storage resources exceeds $1,000/MWh.

DMM believes that resources with daily energy limitations should be able to reflect intra-day opportunity costs in energy bids and default energy bids. DMM supported a short-term solution for summer 2024 that would allow storage and select hydro resources to reflect intra-day opportunity costs exceeding $1,000/MWh in a limited number hours in which these costs may be applicable.[313] The ISO determined that this type of targeted hourly solution was not feasible by summer 2024. Instead, the ISO adopted an approach that would raise the cap on DEBs to $2,000/MWh for all resources. For battery resources, the new rules would establish a static daily real-time energy bid cap that can exceed $1,000/MWh on days when the $2,000/MWh hard offer cap is in effect.

DMM supports an increased bid cap on DEBs to $2,000/MWh, and does not oppose increasing the real-time energy bid cap for storage resources on days when the $2,000/MWh hard offer cap is in effect. However, DMM recommends the ISO add a policy initiative in the near future focused on designing

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312 *Comments on Price Formation Enhancements Issue Paper*, Department of Market Monitoring, August 11, 2022: https://www.caiso.com/Documents/DMM-Comments-Price-Formation-Enhancements-Issue-Paper-Aug-11-2022.pdf

313 *Comments on Price Formation Enhancements: Rules for Bidding above the Soft Offer Cap*, Department of Market Monitoring, April 30, 2024: https://www.caiso.com/Documents/DMM-Comments-on-PFE-Rules-for-Bidding-Above-the-Soft-Offer-Cap-Straw-Proposal-Apr-30-2024.pdf

hourly DEBs for resources that face intra-day opportunity costs—including when opportunity costs are above $1,000/MWh on days when the bid cap is raised above $1,000/MWh for some hours.[314]

Maximum import bid price calculation

The maximum import bid price (MIBP) calculation uses a shaping factor to convert bi-lateral hub index prices for multi-hour blocks of energy into hourly values. The hourly maximum import bid price calculation is an important component of the FERC Order 831 design, as this is used to determine when the $2,000/MWh hard cap is in effect. In 2024, the ISO has expanded the use of the maximum import bid price so that it will be used as one input to determine the level at which battery resources may bid on days when the $2,000/MWh hard cap is triggered in some hours.

The shaping factor used to convert bi-lateral prices into hourly prices uses a ratio with historical hourly prices in the numerator from one day, and a daily average price that can be from a different day in the denominator. DMM believes this is not consistent with the tariff, and not the calculation that was intended by the stakeholder process.[315] DMM recommends that the ISO change the shaping factor calculation to use prices from the same day for both the denominator and numerator of the ratio. The ISO is starting a stakeholder workshop to consider this change.[316]

Re-optimizing ancillary services in real-time

DMM recommends that the ISO re-optimize ancillary services with other products in the real-time, which could increase efficiency and allow real-time energy prices to better reflect real-time (ancillary service) conditions. The ISO placed ancillary service real-time re-optimization and locational procurement of ancillary services on their policy road map in 2023.[317]

Scarcity pricing

The ISO is beginning to consider changes to its scarcity pricing provisions under the broader price formation enhancements initiative, which began in 2022. 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. It is worth noting that an extended flexible ramping product (FRP), as described in Section 2.8, would also serve a scarcity pricing purpose. Because there is a tradeoff between procuring flexible ramping capacity or energy, when the amount of available capacity declines the prices for both capacity and energy start to rise. This allows prices to increase as available flexible capacity falls, even before there is insufficient energy supply to meet load in the market. However, because FRP currently only looks out to one advisory interval, the

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[314] Memorandum to ISO Board of Governors and WEIM Governing Body, *Comments on Management's proposed changes to rules for bidding over the soft-offer cap,* Department of Market Monitoring, May 15, 2024. https://www.caiso.com/documents/departmentofmarketmonitoringcomments-softoffercap-memo-may2024.pdf

[315] *Attachment 1: Maximum Import Bid Price Calculation*, Department of Market Monitoring, May 15, 2024: https://www.caiso.com/documents/departmentofmarketmonitoringcomments-softoffercap-attachment1-may2024.pdf

[316] Maximum Import Bid Price analysis workshop to discuss hourly shaping factor, call on 5/28/24: https://www.caiso.com/Documents/maximum-import-bid-price-analysis-workshop-to-discuss-hourly-shaping-factor-call-on-52824.html

[317] *2023 Policy Initiatives Catalog*, California ISO, March 29, 2023: https://www.caiso.com/InitiativeDocuments/Final2023PolicyInitiativesCatalog.pdf

FRP and energy prices will not reflect the potential scarcity of available capacity over a longer and more relevant timeframe.

Extending the flexible ramping time-horizon would allow capacity and energy prices to reflect upcoming scarcity in more distant advisory intervals. As DMM has previously noted, instead of extending the time-horizon of FRP, the ISO could create a new product that serves the same purpose. Either of these approaches would improve price formation by allowing prices for energy and flexible capacity to better reflect supply and demand conditions in the real-time market.

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. However, DMM understands that in response to requests from some stakeholders, the ISO is examining the possibility of adopting some form of fast-start pricing in the CAISO and WEIM.

The ISO provided analysis which suggests the impacts of fast-start pricing are small on average, but can be large in a limited number of intervals.[318] DMM believes further analysis is needed for the ISO to assess whether the pattern of estimated price impacts could lead to meaningful increases of import bids into the WEIM (which is the purported potential efficiency benefit). The current analysis, in the interest of getting a reasonable estimate in a timely manner, does not consider many complexities of the CAISO market. If stakeholders and the ISO decide to move forward with fast-start pricing, additional testing in the actual market software will be needed.

9.10 Transmission access for high priority wheeling schedules

The summer 2020 heat wave highlighted the need to review the ISO policies and procedures for curtailing load versus curtailing exports and wheeling schedules. During hours in August 2020, when the ISO grid operators curtailed the CAISO balancing area load, operators did not curtail any non-high priority exports or wheeling schedules. DMM believes this was inconsistent with ISO tariff provisions and analogous provisions in the open access transmission tariffs (OATTs) of other balancing areas in the West. DMM recommended the ISO take steps to clarify priorities for curtailing native load vs. non-high priority exports, and make ISO rules and procedures similar to those of other balancing areas in the West.

Through the market enhancements for summer 2021 readiness initiative, the ISO established export prioritization rules and interim rules for high priority wheeling through transactions.[319] In 2022, the ISO completed the transmission service and market scheduling priorities initiative.[320] This initiative

318 *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

319 Market Enhancements for summer 2021 readiness initiative page: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-Enhancements-for-Summer-2021-Readiness

320 California ISO Initiative, *Transmission service and market scheduling priorities:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

developed longer-term, comprehensive rules for transmission scheduling priority for wheel-through transactions to be effective by summer 2024.

DMM supports the market design changes developed in the transmission service and market scheduling priorities initiative as an improvement over the earlier established interim rules. The next section provides a recommendation to enhance the framework established for high priority wheeling access further.[321]

Transmission service and market scheduling priorities

In the second phase of the transmission service and market scheduling priorities initiative, the ISO established a process for making excess transmission not needed to serve native CAISO load available to other entities to wheel power on a longer-term forward basis. This approach represents a significant improvement from the previously established interim rules for high-priority wheeling access, and makes the ISO's rules more closely resemble the open access transmission tariff (OATT) framework used across the West in balancing areas without organized markets.

DMM noted throughout the policy development that because the developed approach does not include a detailed analysis of the impact of wheeling schedules on flows within the CAISO, the proposal may make some additional wheeling capacity available, compared to DMM's understanding of how this OATT framework is typically applied.

DMM recommends the ISO significantly improve the modeling of CAISO internal flow impacts of high-priority wheels. DMM understands the ISO has committed to conduct an annual analysis of high-priority wheeling impacts on Path 26, the major north-to-south transmission constraint within the CAISO footprint. However, as the ISO has begun to implement the new framework for high-priority wheels, DMM has learned that the ISO is only considering the flow impact from wheels importing to the CAISO at the Malin intertie.

The Malin intertie has been the import point of around 30 to 40 percent of high-priority wheel through transactions in recent years.[322] While the ISO does need to consider the CAISO internal flow impacts of wheel through transactions that import at Malin, DMM believes the ISO also needs to study the impacts of high-priority wheel through transactions importing at other interties. Relying on historic wheel through patterns--to determine which interties to include in the flow impact study and calculate *available transfer capacity* (ATC) for--may not sufficiently mitigate the risk of reliability issues stemming from internal congestion caused by high-priority wheels, because these patterns may change once reservations are restricted at historically used interties.

In the first few months since ATC reservations became available for summer 2024, such changes in historical patterns have already occurred due to limited ATC at Malin in the summer months. Some entities hold transmission ownership rights (TORs) in the northern part of the CAISO system, from Malin to the Round Mountain 230 scheduling point. Historically, the owners of many of these TORs converted them to congestion revenue rights, and did not use them for transmission scheduling. The ISO excludes these TORs from the ATC calculated for a given intertie.

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321 Memorandum to ISO Board of Governors and WEIM Governing Body, Department of Market Monitoring, January 25, 2023: http://www.caiso.com/Documents/DepartmentofMarketMonitoringReport-Feb2023.pdf

322 California ISO wheeling and resource adequacy imports aggregate data, *Priority Wheeling Through Transaction Data:* https://www.caiso.com/Documents/PriorityWheelingThroughTransactionsData.xlsx

In response to the limits on ATC at Malin set by the ISO, some owners of these TORs are now using them to support schedules from Malin to the Round Mountain 230 scheduling point, where entities gain access to additional ATC to support high-priority wheel through transactions. These reservations importing at Round Mountain 230 could impact Path 26 congestion similar to imports at Malin. However, the ISO does not consider the added ATC at Round Mountain 230 in the analysis of priority wheeling impacts on Path 26.

9.11 Resource adequacy

California relies on the state's long-term bilateral procurement 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 due to numerous regulatory and structural market changes in recent years.

Resource adequacy imports

DMM has warned that existing 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.[323]

The 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.[324]

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 indicates this approach has proven effective at ensuring delivery of resource adequacy imports since being implemented in 2020.

DMM also recommends that the ISO, CPUC, and stakeholders continue to 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.[325] Over the longer term, DMM supports development of a more source-specific framework

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323 *Import resource adequacy*, Department of Market Monitoring Special Report, September 10, 2018, pp 1-2: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

324 *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

325 *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 Rulemaking 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

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 July 2021, the CPUC issued a decision directing further development of a reformed resource adequacy framework that considers both capacity and energy needs across all hours of the year.[326] DMM supported the CPUC's decision that could result in significant, but important, changes to the CPUC resource adequacy program. This includes ensuring the resource adequacy fleet can meet demand across all hours of the day, as well as energy required to charge storage resources.

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 translate the current Planning Reserve Margin to the slice-of-day framework.[327] The CPUC will implement 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 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 Top 5 Day 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

The ISO's current mechanism for incentivizing the availability of resource adequacy capacity is the resource adequacy availability incentive mechanism (RAAIM). This mechanism deals solely with resource availability, not performance. 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 was $6.31/kW-month throughout 2023 and increased to $7.34/kW-month on June 1, 2024.

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.

During the heat waves of 2020 and 2021, resources that were scheduled to operate, but did not perform in real-time, generally faced little financial consequences. This was because real-time energy market prices were often lower than day-ahead prices. Changes in ISO rules in effect during summer 2022

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326 *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program (D.21-07-014),* CPUC Docket No. R.19-11-009 July 15, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.pdf

327 *Decision on Phase 2 of the Resource Adequacy Reform Track (D.23-04-010)*, CPUC Docket No. R.21-10-002, April 6, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF

appear to have enhanced real-time pricing during tight system conditions, which may create somewhat stronger financial incentives for resources to deliver expected energy. However, DMM is still concerned that if capacity payments are very high, there could also be limited incentives for resources receiving these payments to actually perform when needed.

DMM recommends that the ISO and local regulatory authorities consider developing a resource adequacy incentive mechanism that is based on resource performance. Such a mechanism could result in potentially very high penalties that claw back a large portion of capacity payments when resources do not deliver on critical days. Incentivizing availability and performance of resource adequacy capacity could become increasingly important as resource adequacy payments increase compared to the magnitude of potential RAAIM charges. This type of mechanism could also 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 lesser scrutiny and will be automatically be approved, DMM is concerned a discretionary outage transferred into the forced timeframe may compromise reliability during tight grid conditions.

As a result of 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.

9.12 Demand response resources

In the last four years, the California ISO has increasingly relied on demand response to curtail load during peak summer hours. Demand response resources are currently used to meet about 3 to 4 percent of total system resource adequacy capacity requirements in the peak summer months.

DMM's analysis of how demand response resources participated and performed in the CAISO market on high load days in summer 2020 through 2023 shows that a large portion of demand response resource adequacy capacity was not available for dispatch, or performed significantly below dispatched levels during key peak net load hours.[328] This results from a combination of how demand response resources are overcounted toward resource adequacy requirements, as well as by the performance of some demand response programs after being dispatched.

Resource adequacy payments, or the value of reduced resource adequacy requirements, are the primary revenue sources for demand response resources. Even when demand response resources are frequently dispatched, the energy market revenues from actually performing (or charges for failing to perform) represent a relatively small portion of the overall compensation or value of these resources.

[328] *Demand response issues and performance 2023*, Department of Market Monitoring, March 6, 2024, pp 3-4: https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf

This current market framework does not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions.

In prior reports, DMM has highlighted some recommendations that the ISO and CPUC could consider to enhance the availability and performance of demand response resources, especially before increasing reliance on demand response towards meeting resource adequacy requirements.[329] The CPUC has taken numerous steps to address DMM's recommendations, as described below:

- ***Re-examine demand response counting methodologies.*** For the last several years, DMM has recommended that counting methodologies should better capture the capacity contribution of demand response resources with load reduction capabilities that vary across the day and may have limited output in general. The new *slice-of-day* resource adequacy approach being adopted by the CPUC should help more properly count demand response resources. In addition, the CPUC and the California Energy Commission (CEC) are currently working together to develop an incentive-based qualifying capacity valuation for resource adequacy demand response resources that bid in as supply.[330]
- ***Remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction.*** The CPUC reduced the planning reserve margin adder applied to demand response capacity credits from 15 percent to 9 percent beginning in 2022. In 2023, the CPUC also approved eliminating this 9 percent reserve margin adder and the transmission loss factor (2.5 to 3 percent) beginning in 2024.[331] The adder for distribution loss factor (5 to 7 percent) will be maintained.
- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. In 2023, the CPUC adopted rules requiring that demand response resources be tested and that demand response capacity qualified to meet resource adequacy requirements be de-rated based on ex post analysis of performance. Beginning in 2024, participating demand response resources will be limited to a $500/MWh bid cap for July-September in the day-ahead and real-time markets. Although these steps represent significant improvements, DMM believes further financial penalties or disincentives for poor performance of demand response resources may be needed.
- ***Consider tariff changes to better define deadlines and penalties on data submission as well as continue outreach to demand response providers to ensure all necessary historical data is available for DMM to assess the validity of baseline submissions.*** Under many of the most frequently used baseline calculation methodologies, demand response data are required to submit historical data on their metered load and baselines. This historical data allows monitoring of the baselines submitted by providers. However, due to lack of a clear timeline and penalties for failing to submit data, DMM has observed significant and ongoing problems with some providers submitting this data. DMM supports the ISO addressing this issue in the penalty enhancements

329 *Demand response issues and performance*, Department of Market Monitoring, February 25, 2021, pp 3-4: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

330 *Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements* (D. 23-06-029), CPUC Docket No. R21-10-002, June 29, 2003, p 144: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

331 *Decision Adopting Local Capacity Obligations for 2022–2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, CPUC Docket No. R19-11-009, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.pdf

initiative, which is focused in part on defining the penalty structure of demand response monitoring data.[332]

[332] CAISO stakeholder initiative: Penalty enhancements - demand response, investigation, and tolling: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Penalty-enhancements-demand-response-investigation-tolling