California ISO

2022 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

July 11, 2023

ACKNOWLEDGEMENTS

The following members of
the Department of Market Monitoring
contributed to this report:

Eric Hildebrandt
Amelia Blanke
Ryan Kurlinski
Roger Avalos
Benjamin Dawson
Amol Deshmukh
Matt Gevercer
Aprille Girardot
Bokseong Jeong
Sai Koppolu
Patrick McLaughlin
Nicole Selling
Pearl O'Connor
Pat Prendergast
David Robinson
Adam Swadley
Kyle Westendorf

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

No table of figures entries found.

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 2022. Key highlights include the following:

- **The total estimated wholesale cost of serving California ISO area load in 2022 rose by about 70 percent, due to substantially higher natural gas prices**. Total costs for the CAISO footprint were about $21.6 billion, or about $95/MWh. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs per megawatt-hour increased by about 10 percent.
- **Natural gas prices increased across the West and in the California spot market**, averaging over $9/MMBtu at both California hubs. Nationally, natural gas demand growth exceeded supply growth, driving electricity prices up. Storage levels fell to historic lows in the West, limiting the use of storage inventories to moderate price spikes.
- **California ISO instantaneous load peaked at a record high during an extended regional heat wave,** while average load continued to decrease in 2022, due in part to increases in behind-the-meter solar generation. California ISO instantaneous loads peaked at 52,061 MW during this 1-in-25 year weather driven high load event, on September 6.
- **Expansion of the Western Energy Imbalance Market helped improve the overall structure and performance of the real-time market** in the CAISO and other participating balancing areas. In 2022, four new balancing areas (Avista Utilities, Tacoma Power, Bonneville Power Administration and Tucson Electric Power) joined the market. Load peaked at almost 130,000 MW, on September 6. Western Energy Imbalance Market transfers served some of this extremely high demand in some balancing areas, including the California ISO.
- **Summer supply margins were bolstered by the integration of additional capacity**. The California ISO added about 4.5 GW of capacity between June 2021 and June 2022, and 5.6 GW of additional capacity has been added since June 2022. Most of this new capacity was solar or battery.
- **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.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $118 million in 2022.** 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 $64 million per year from 2019 to 2022, compared to average losses of $114 million per year in the seven years before the reforms.

Several other factors contributed to increased wholesale energy costs in the California ISO in 2022:

- **Uplift costs rose to more than $700 million**, over 3 percent of wholesale costs, an historic high. Congestion offset costs of $257 million were largely generated by significant reductions in constraint limits between the day-ahead and 15-minute markets. Record high energy offset costs of $121 million were largely due to a structural inconsistency in the settlement of real-time market demand and generation. Bid cost recovery payments in the California ISO increased to the highest value since 2011, totaling $297 million.

- **Net imports into the California ISO fell on average,** as exports increased. Prices at major hubs outside of the California ISO were higher in peak months reflecting both demand growth and resource retirement outside of the California ISO.
- **Congestion increased in both frequency and impact** in both the day-ahead and real-time market, on interties, Western Energy Imbalance Market transfer constraints and internal constraints within the California ISO and other balancing areas**.** At $1.07 billion, total day-ahead congestion rents were about 5.3 percent of the day-ahead market energy costs.
- **Net profits paid to convergence bidders increased to about $106 million,** from $38 million in 2021 and $45 million in 2020. During the 2022 summer heat wave, market participants were paid over $36 million in net revenues from virtual demand, which represents nearly 93 percent of net revenues for virtual demand in all of 2022.
- **Imbalance conformance adjustments** averaged over 2,000 MW during the net load peak in the 15-minute market, about 800 MW over the average for the same time in 2021. This continued the increase in operator use of imbalance conformance that began in 2017. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributed to the price difference between these markets. Operator adjustments in the day-ahead residual unit commitment contributed an average of 584 MW per hour to requirements.
- **Drought conditions persisted across the West, decreasing available hydroelectric supply and increasing fire risk**. Although California snowpack was only 38 percent of the long-term average, hydro-electric generation increased to 7 percent of California ISO supply.

Some market costs grew at a lower rate than wholesale energy costs or mitigated cost increases:

- **There were significantly fewer structurally system level uncompetitive hours** in the 2022 day-ahead energy market, which accounts for most of the California ISO total wholesale energy market. This follows a decrease in uncompetitive hours from 2020 to 2021 as well. This downward trend in uncompetitive hours is due in part to the significant additions in battery capacity in recent years.
- **Ancillary service costs increased to $237 million from $165 million**, less than the rate of increase of wholesale energy costs, as the provision of ancillary services from limited energy storage resources continued to increase.
- **Energy subject to mitigation increased in both the day-ahead and real-time markets,** for both the California ISO and Western Energy Imbalance Market balancing areas. 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. Effective November 2021, battery energy storage resources were also subject to mitigation in the local market power mitigation process.
- **Flexible ramping product** system-level prices were zero for over 99 percent of intervals in the 15-minute market and 5-minute market for each of upward and downward flexible ramping capacity. The California ISO implemented nodal procurement for the flexible ramping product in February 2023, which was expected to resolve two issues lowering prices (1) stranded flexible ramping capacity and (2) the undesirable interplay between local and system requirements.

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

- Net market revenue significantly exceeded the estimated going forward fixed costs for both gas-fired combustion turbines and combined cycles in both Southern and Northern California.
- Although about 90 percent of resource adequacy capacity bid into the real-time market in critical hours, resource adequacy capacity requirements were significantly lower than the peak load observed during the 1-in-25 year weather event. Resource adequacy capacity met about three quarters of the system requirement in this peak hour, including both reserves and high priority exports.
- Gas capacity retiring from the market was largely replaced with solar and battery. 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 5,500 MW of discharge capacity by June 2023. 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.
- For more than a decade, California has relied 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. However, a number of structural changes, such as the increased reliance on energy-limited resources and the increase in load served by community choice aggregators (CCAs) are driving the need for significant changes in this resource adequacy framework.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2022 was about $21.6 billion, or about $95/MWh. This represents a 69 percent increase from about $56/MWh, or $12.6 billion in 2021. After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs increased by about 10 percent from about $41/MWh in 2021 to just over $45/MWh in 2022.

As highlighted elsewhere in this report, conditions that contributed to higher nominal wholesale costs include the following:

- **Higher energy prices due to the large increase in natural gas prices.** Spot market natural gas prices increased more than 50 percent from 2021 (Section 1.2.6).
- **Record high loads in early September were part of an extended regional heatwave**.
- **Higher costs for electricity outside of the California ISO**. Net imports decreased on average in each hour (Sections 1.2.1, 1.2.3, and 2.3.1).

Other factors moderated the increase, contributing to lower total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to lower prices include the following:

- **New generation capacity.** The CAISO added more than 4 GW of solar, battery, hybrid, and wind capacity between the summer of 2021 and 2022 (Section 1.2.8).
- **Higher hydroelectric production.** Hydroelectric production increased by about 24 percent from 2021 (Section 1.2.2).
- **A significant decrease in structurally uncompetitive hours** in the day-ahead energy market (Section 5.1.1).

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

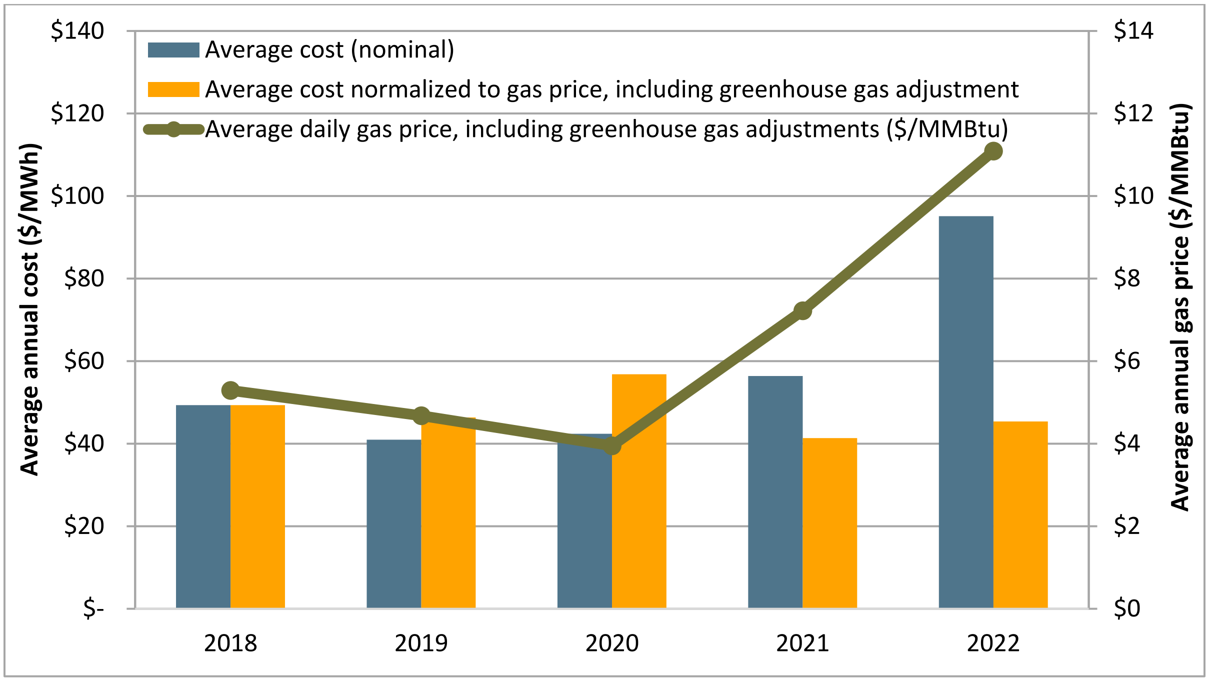


Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2018 to 2022. Wholesale costs are provided in nominal terms (blue bar), and after being normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual average daily natural gas price including greenhouse gas compliance, and is included to illustrate the correlation between natural gas prices and the total wholesale cost estimate.

Energy market prices

California ISO day-ahead and real-time market prices increased in 2022, driven primarily by an increase in natural gas prices despite lower average load, higher renewable and storage generation, and more competitive conditions. 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 and other resources 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 California ISO's day-ahead market were slightly higher than 15-minute real-time prices, but significantly higher than 5-minute prices. Day-ahead prices averaged $90/MWh, 15-minute prices were about $89/MWh, and 5-minute prices were about $81/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 the CAISO grid operators.
- 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.

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

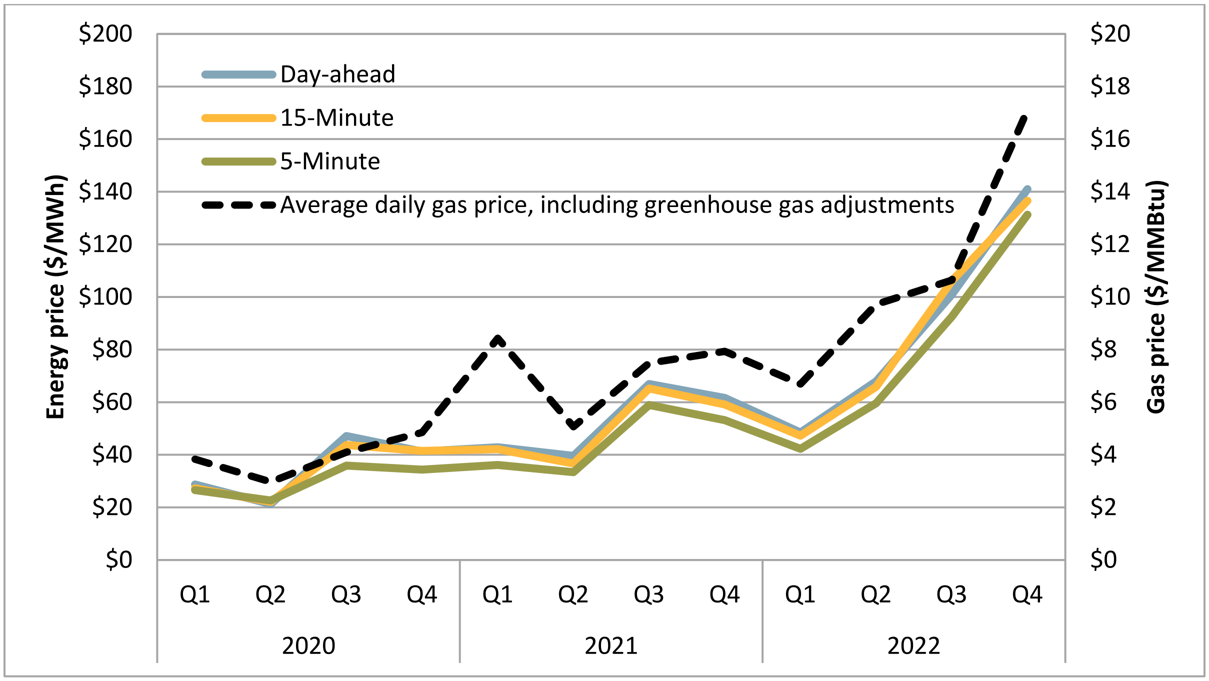
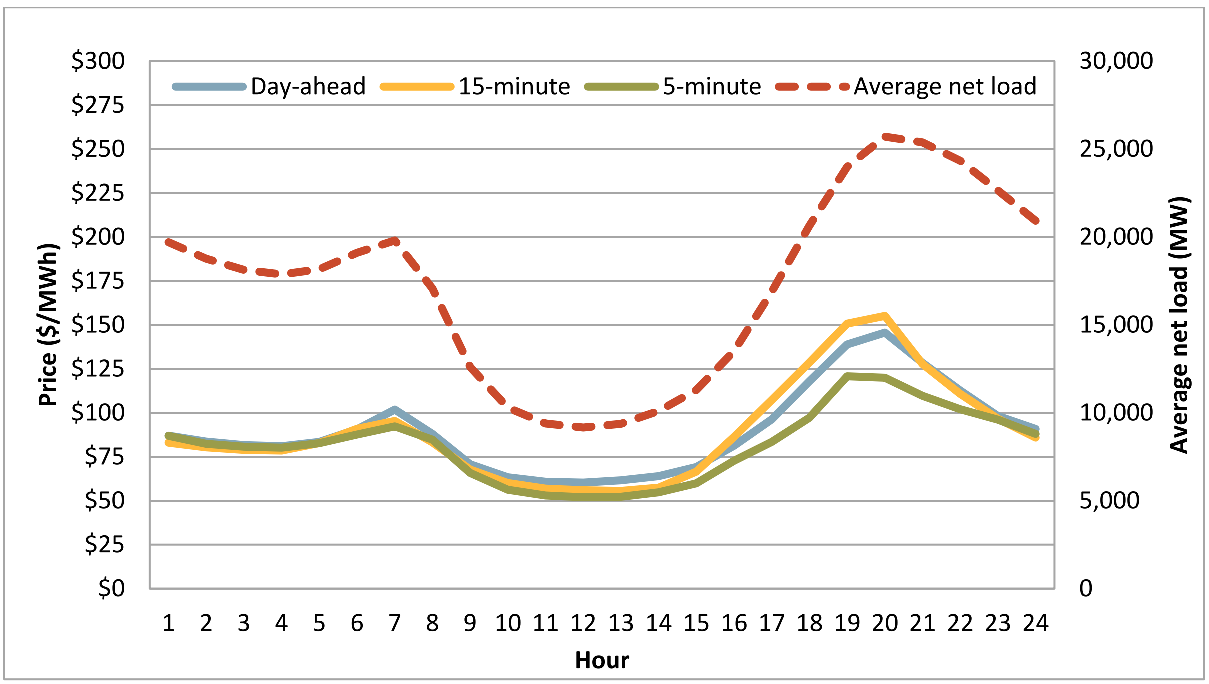


Figure E.3 Hourly system energy prices (2022)



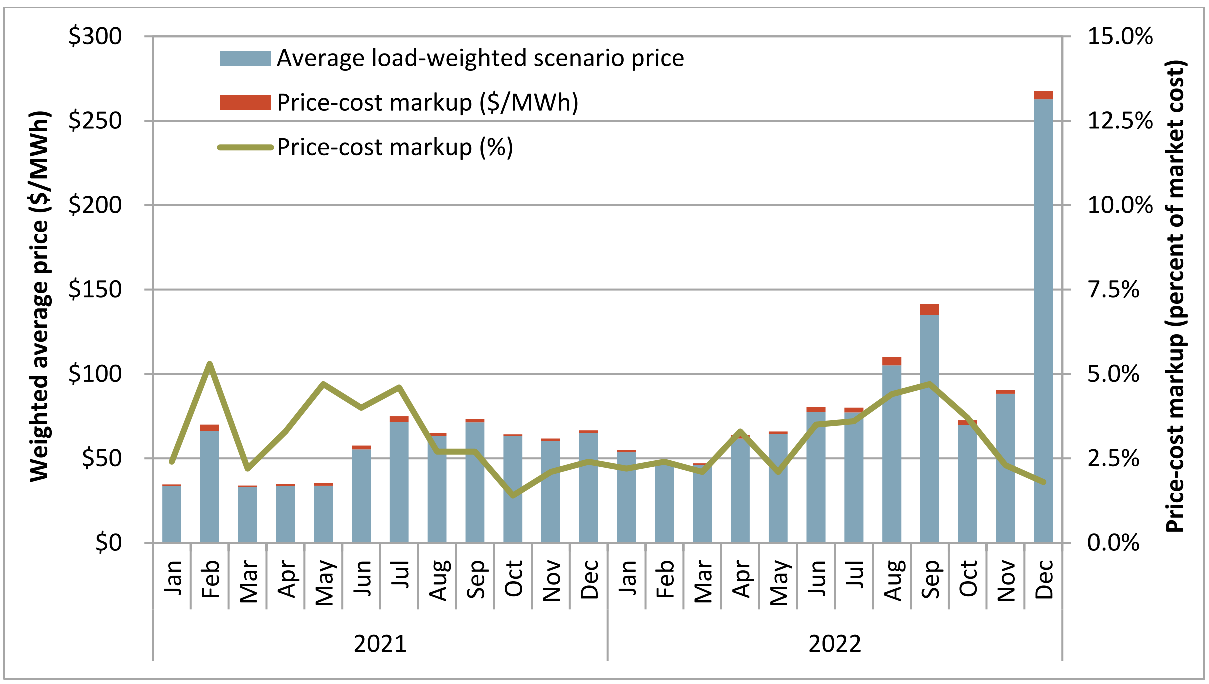
Market competitiveness

Prices in the California ISO energy markets were competitive in 2022. Overall, wholesale energy prices were about equal to competitive baseline prices 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 $3.04/MWh, or about 3.1 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.

Summer high demand event

Between August 31 and September 9, the combined California ISO and Western Energy Imbalance Market system experienced a prolonged heat event, resulting in demand for electricity well in excess of current resource planning targets over an extended period. Although several areas called the highest level of emergency alert, no area curtailed load to maintain reliability.

The CAISO published a comprehensive review of market results during the heat wave.[2] DMM concurs with many of the key findings and recommendations in the CAISO report. Additional analyses based on DMM's independent review are available in DMM's third quarter report.[3]

Market changes implemented following load curtailment in 2020 and stressed conditions in 2021, and the state of California's action to procure additional capacity, both allowed the market to meet the extraordinarily high peak load in the California ISO and the extended period of high demand across the Western Energy Imbalance Market. Other key findings include:

- **High bilateral market price indices** reflected regional market conditions. Traded volumes were relatively low over the Labor Day holiday weekend.
- **The maximum import bid cap allowed imports to bid up to the hard bid cap ($2,000/MWh)** in some hours when bilateral market price indices were high. Hours with the $2,000/MWh bid cap closely matched hours when the California ISO declared EEA2 and EEA3 alerts. The $2,000 bid cap attracted a limited quantity of additional imports into the market.
- **Penalty prices doubled, rising up to $2,000/MWh** on days with high bilateral market prices. During the heatwave, 15-minute and 5-minute prices in the CAISO rose above $1,000/MWh, exceeding day-ahead prices in many intervals. Real-time prices were often set by penalty prices in these intervals.
- **Balancing areas declaring emergencies were able to import supplemental energy**, both through emergency assistance from other balancing areas and Western Energy Imbalance Market imports. Most areas were net exporters in net peak hours during the heatwave, with the California ISO accounting for most imports.
- **California ISO supply was additionally supplemented** by out of market imports, non-market capacity procured through California's strategic reserve, and through voluntary demand reduction.
- **Congestion limited imports from the Northwest into California** in the real-time market but otherwise had little impact on market outcomes.
- **California ISO operators raised real-time imbalance conformance and residual unit commitment load forecasts to extraordinarily high levels**. Doing so helped ensure that lower priority exports not supported by physical supply would not be scheduled in the market.
- **Some low priority exports cleared the real-time market inappropriately because the prioritization applied in the scheduling run was not applied in the final pricing run.** This required the CAISO operators to take manual action and increased CAISO demand in the real-time market. The market optimization appropriately prioritized load over lower priority exports in the day-ahead market residual unit commitment process. The CAISO implemented a market enhancement in October 2022, following the heatwave, to resolve the market issue in the real-time market.

---

2 California ISO, *Summer Market Performance Report – Sept 2022,* November 2, 2022: http://www.caiso.com/Documents/Sept2022_summer_readiness_reportFinal.pdf#search=summer

3 Department of Market Monitoring, *Q3 2022 Report on Market Issues and Performance,* December 14, 2022, pp. 79-96: http://www.caiso.com/Documents/2022-Third-Quarter-Report-Market-Issues-Performance-2022-12-14.pdf

Ancillary services

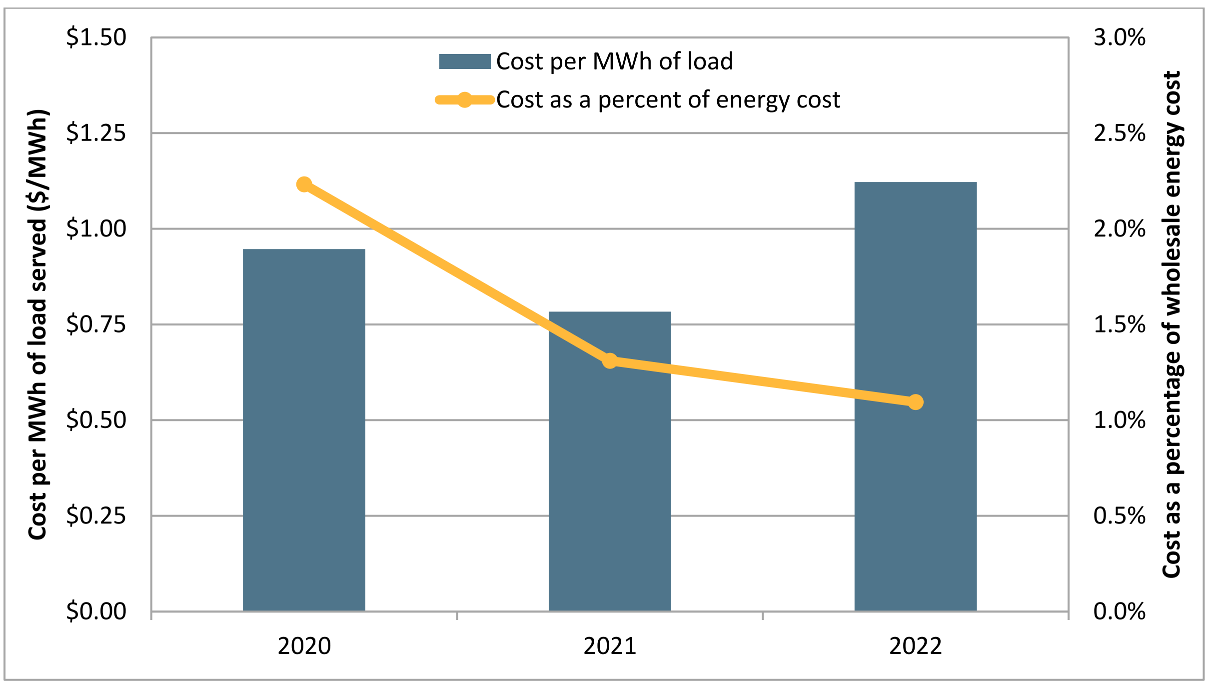
Ancillary service costs increased to $1.12/MWh from $0.78/MWh in 2021 and decreased from 1.3 to 1.1 as a percent of total wholesale energy cost, as shown in Figure E.5. Total ancillary service costs increased to $237 million, up from $165 million in 2021. Cost increases were highest among upward ancillary service products—regulation up, spinning reserve, and non-spinning reserve—which is consistent with the higher gas prices. Costs for regulation down increased as well, largely due to higher requirements during ramping hours and intervals with high solar generation.

Average regulation down requirements increased 18 percent to 807 MW and average regulation up requirements remained the same at around 400 MW. Average combined requirements for spinning and non-spinning operating reserves increased by 3 percent from the previous year to about 1,822 MW.

Twenty-two percent of resources failed ancillary service performance audits and unannounced compliance tests for spinning and non-spinning reserves, compared to 30 percent in 2021. The frequency of ancillary service scarcity intervals decreased significantly compared to previous years. There were six intervals in the 15-minute market with ancillary service scarcity, compared to 55 in 2021 and almost 129 in 2020.

Provision of ancillary services from limited energy storage resources continued to increase, replacing procurement from imports and natural gas. Battery storage resources now provide the majority of regulation requirements.

Figure E.5 Ancillary service cost as a percentage of wholesale energy cost



Load forecast adjustments

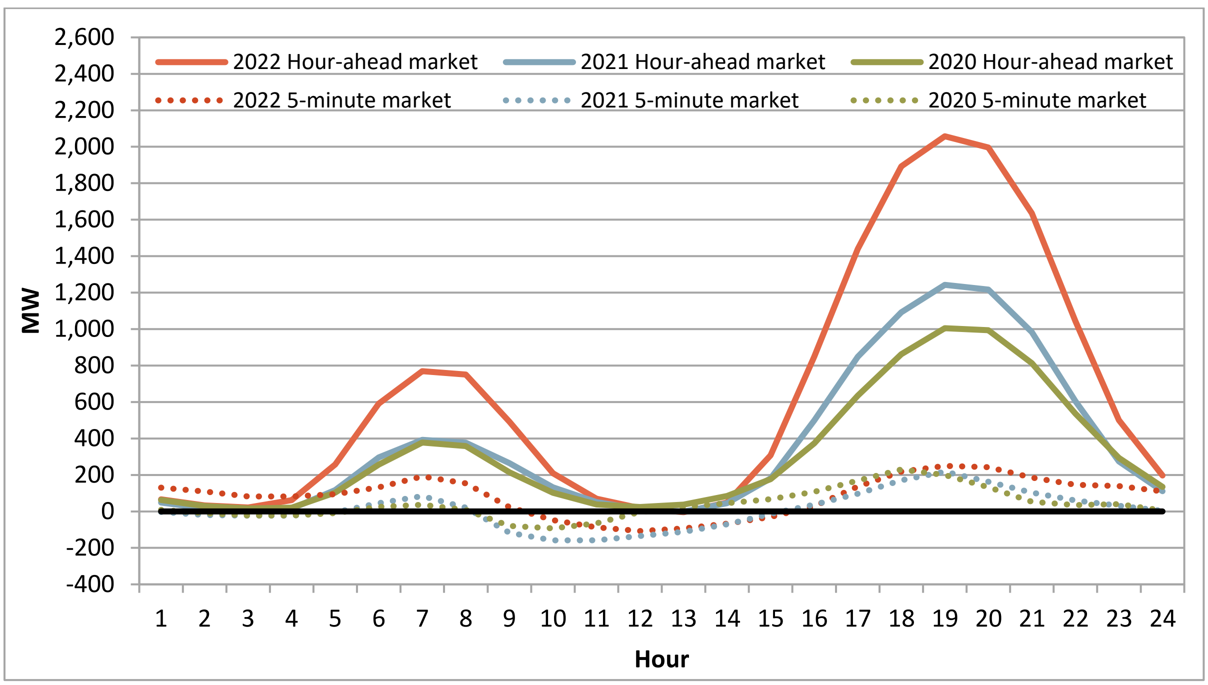
Operators in the California ISO and Western Energy Imbalance Market can manually modify load forecasts used in the market through load adjustments, sometimes referred to as load bias or load conformance. The CAISO uses the term imbalance conformance to describe the adjustments that are used to account 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.6, load forecast adjustments in the hour-ahead routinely mirror the pattern of net loads over the course of the day, averaging 800 MW to about 2,000 MW during the morning and evening ramping hours respectively; 15-minute market adjustments are very similar to hour-ahead and are not included in the figure. During these hours, imports made in the hour-ahead process often increase significantly, which allows additional generation within the CAISO to be available for dispatch in the 15-minute and 5-minute markets.

California ISO operator adjustments added an average of 584 MW per hour to residual unit commitment requirements, an increase from about 238 MW per hour in 2021.

Figure E.6 Average hourly load adjustment (2020 - 2022)



Real-time imbalance offset costs

The real-time imbalance offset cost is the difference between the total money paid by the CAISO and the total money collected by the CAISO 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.

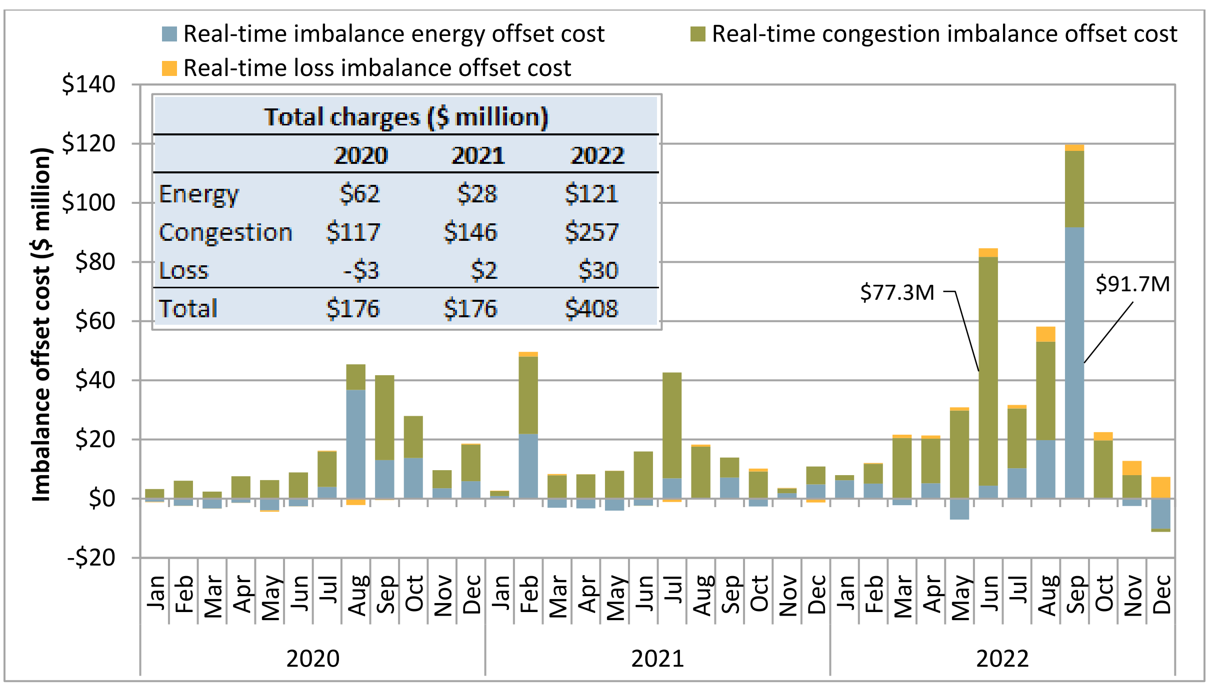
The real-time imbalance offset charge consists of three components. Any revenue imbalance made from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge*. Likewise, any revenue imbalance from the loss component of real-time 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 real-time imbalance offset costs within the CAISO were $408 million in 2022, a significant increase from around $176 million in both 2020 and 2021.

Real-time imbalance energy offset costs were $121 million in 2022, up from $38 million in 2021 and $62 million in 2020. Real-time imbalance energy offset charges reached almost $92 million in September alone. A significant portion of this revenue shortfall is created from a structural inconsistency in the settlement of real-time market demand and generation (Section 2.7).

The majority of the offset costs were from real-time congestion imbalance offsets ($257 million), up from $146 million in 2021 and $117 million in 2020. 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.

Figure E.7 Real-time imbalance offset costs



Total charges ($ million)	2020	2021	2022
Energy	$62	$28	$121
Congestion	$117	$146	$257
Loss	-$3	$2	$30
Total	$176	$176	$408

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 $297 million, the highest total since 2011 and a significant increase from $173 million in 2021.[4] About 80 percent of these payments, or $235 million, were to gas resources, followed by $30.3 million to battery energy storage resources, and about $18 million to hydro resources. Payments to fast start gas resources accounted for only 16 percent of payments to gas resources in the California ISO and about 3 percent of payments to gas resources in the Western Energy Imbalance Market.

Around $255 million of bid cost recovery payments in 2022 were for units in the California ISO (CAISO), and $42 million were for units in the Western Energy Imbalance Market (WEIM).[5] The CAISO portion of these payments represents about 1.2 percent of total CAISO wholesale energy costs, similar to 2021.

Bid cost recovery payments in 2022 were highest during the August and September heatwave period, as well as in December. These significantly high payments can be attributed to higher gas prices, particularly in December, and relatively high loads and gas prices in August and September.

Congestion

Locational price differences due to congestion in both the day-ahead and real-time markets increased in 2022, on interties, WEIM transfer constraints, and within the California ISO and other balancing areas. Key congestion trends during the year include the following:

- **Day-ahead market congestion increased.** Both the frequency and the price impact of day-ahead congestion were higher in 2022 than in 2021. In 2022, day-ahead congestion revenues totaled about 5.3 percent of the day-ahead market energy costs, about the same portion as in 2021.
- **Real-time market congestion increased**. 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.
- **The frequency and impact of WEIM transfer constraint congestion increased.** As in prior years, the frequency of congestion was highest for areas in the Pacific Northwest, where it decreased prices.
- **Intertie congestion increased**. Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $343 million, up from $164 million in 2021. This increase was largely driven by increased congestion on the two major interties linking the CAISO with the Pacific Northwest: the Malin 500 and the Nevada/Oregon Border (NOB).

[4] 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.

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

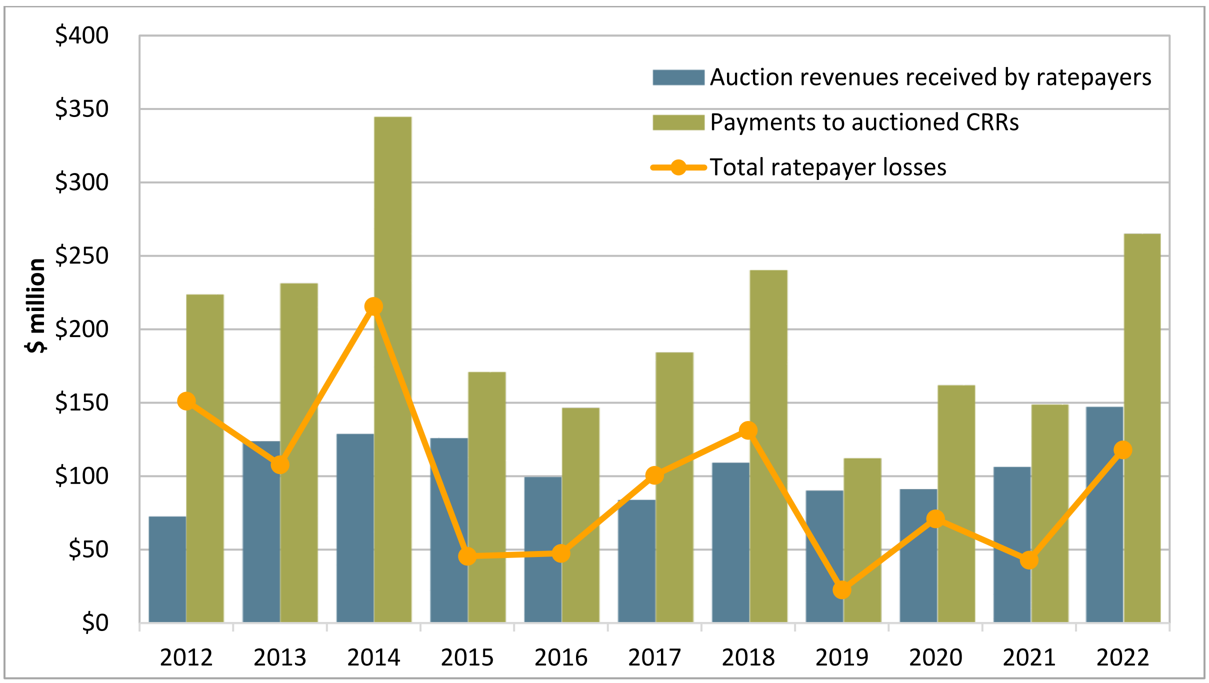
Congestion revenue rights

As shown in Figure E.8, in 2022, ratepayer losses from the auctions totaled $118 million, up from $43 million in 2021 and over $70 million in 2020. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC).

Transmission ratepayers received about 55 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2022, compared to 71 cents in 2021. Track 1B revenue deficiency offsets reduced payments to non-load serving entity auctioned CRRs by about $143 million. Losses from auctioned congestion revenue rights totaled about 11 percent of total day-ahead congestion rent in 2022, compared to 7 percent in 2021.

DMM believes the current auction is unnecessary and could be eliminated.[6,7] 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.8 Ratepayer losses from auctioned CRRs



6 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

7 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

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.

When the resource adequacy program began in 2006, requirements were typically met by traditional investor-owned utilities holding merchant gas-fired generation under long-term tolling contracts or bidding-in utility owned generation.[8] These investor-owned utilities bid this capacity into the market at cost, under least-cost bidding requirements set by the CPUC.

Over the last seven years, California's load has shifted from investor-owned utilities to community choice aggregators (CCAs). The percent of load served by CCAs grew from 2 percent in 2015 to 30 percent in 2021. Load served by investor-owned utilities fell from 89 to 61 percent over the same time.[9] This shift, together with uncertainty about future load migration, reduced demand for long-term tolling contracts. Resource adequacy requirements are now more typically met by short-term resource adequacy-only contracts.

For over 15 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 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, CPUC set an effective PRM between 20 and 22.5 percent.[10]

Analysis in this report shows that:

- **Most system resource adequacy capacity was procured by investor-owned utilities**. Investor-owned utilities accounted for about 61 percent of procurement (down from 66 percent in 2020), community choice aggregators procured 22 percent, municipal entities contributed 8 percent, and direct access providers accounted for 8 percent.
- **Over half of resource adequacy capacity was classified as use-limited** and thus exempt from CAISO bid insertion in all hours.

---

[8] CPUC Docket No. R.19-11-009, *Decision on Track 3B.2: Restructure of the Resource Adequacy Program (Decision 21-07-014),* July 16, 2021, pp. 5-6: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF

[9] Ibid. p. 6.

[10] The planning reserve margin reflects operating reserve requirements and additional capacity that may be needed to cover forced outages and potential load forecast error. 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 PRM 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

- **During system emergency hours, about 90 percent** of system resource adequacy capacity was bid or self-scheduled in the real-time market. In the day-ahead market, 91 percent was available during these hours.
- **Overall, total local resource adequacy capacity exceeded requirements in local capacity areas.** Significant amounts of energy, beyond requirements, were available in the day-ahead market for several local capacity areas, but procurement in other local capacity areas was significantly lower than the local area requirements.

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.

In December 2021, the CPUC approved measures to commission capacity in preparation of potential extreme weather events in summers 2022 and 2023, including a requirement for load serving entities to procure between 2,000 and 3,000 MW of capacity in total.[11] DMM believes this additional procurement will continue to help ensure additional capacity is available during peak net load hours when solar production drops off. However, DMM continues to support larger scale changes to the resource adequacy program discussed in the recommendations section below which could better capture the temporal contribution of different resource types towards meeting energy and capacity requirements.

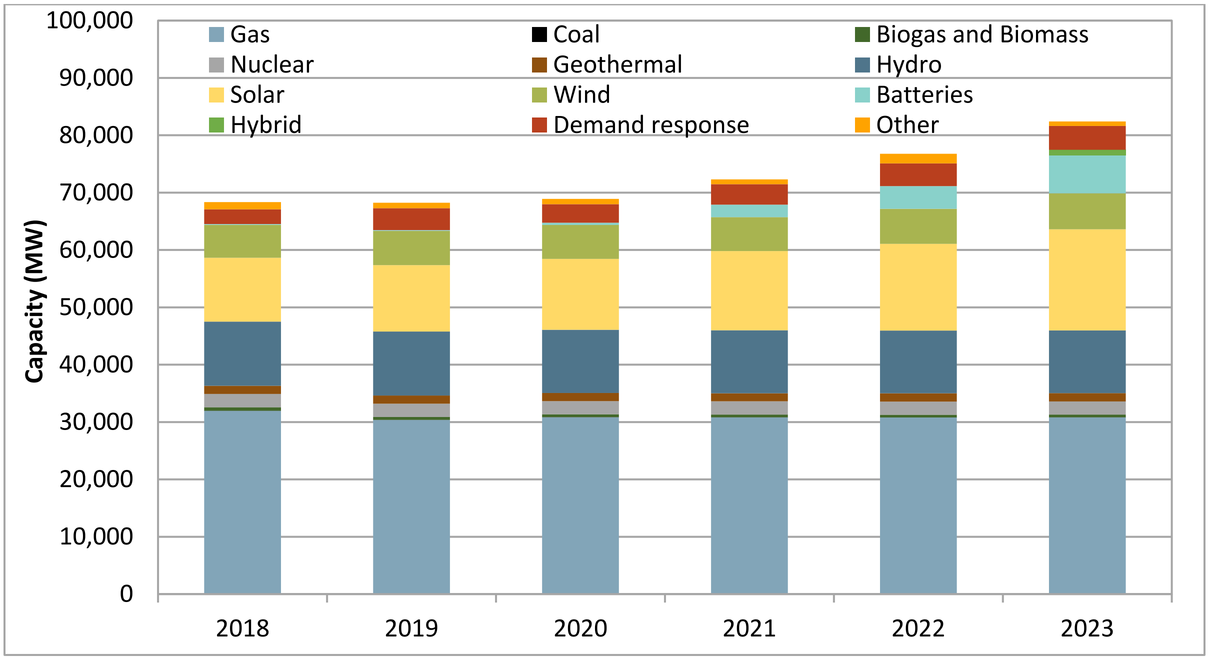
Figure E.9 summarizes the trends in available nameplate capacity from June of 2018 through 2023. At 30.8 GW, natural gas capacity saw almost no growth since June 2022. Solar and batteries grew the most out of any resource type in CAISO, adding 2.6 GW and 2.5 GW, respectively, since June 2022. The CAISO fleet currently has 1 GW of capacity from resources with multiple generation technologies participating under the hybrid model. While solar, wind, and demand response nameplate capacity additions have exceeded reductions in gas capacity, variable energy and demand response resources generally have limited energy and availability compared to gas capacity.[12]

---

11 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

12 In contrast to gas and nuclear capacity, the resource adequacy contribution or qualifying capacity (QC) of wind and solar resources in the California ISO is discounted compared to nameplate capacity, to reflect that these resource types have limited availability across peak net load hours. Additionally, compared to nuclear and most gas resources, demand response resources generally are limited to operating only a subset of hours each month.

Figure E.9 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 beyond 2021, 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. In 2022, estimated net revenues for both combined cycles and combustion turbines in both Southern and Northern California exceeded estimated going-forward fixed costs, but 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 summed with a capacity payment ($76/kW-yr, the CAISO backstop capacity soft offer cap) 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.10 Estimated net revenue of hypothetical combined cycle unit

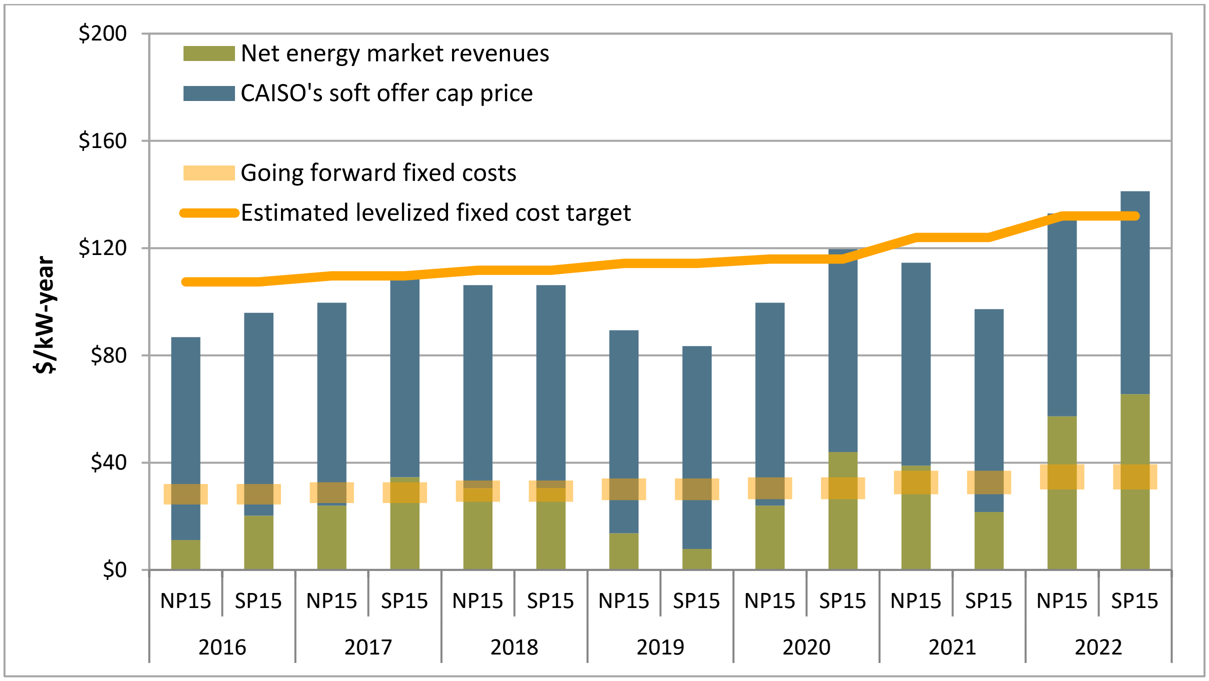
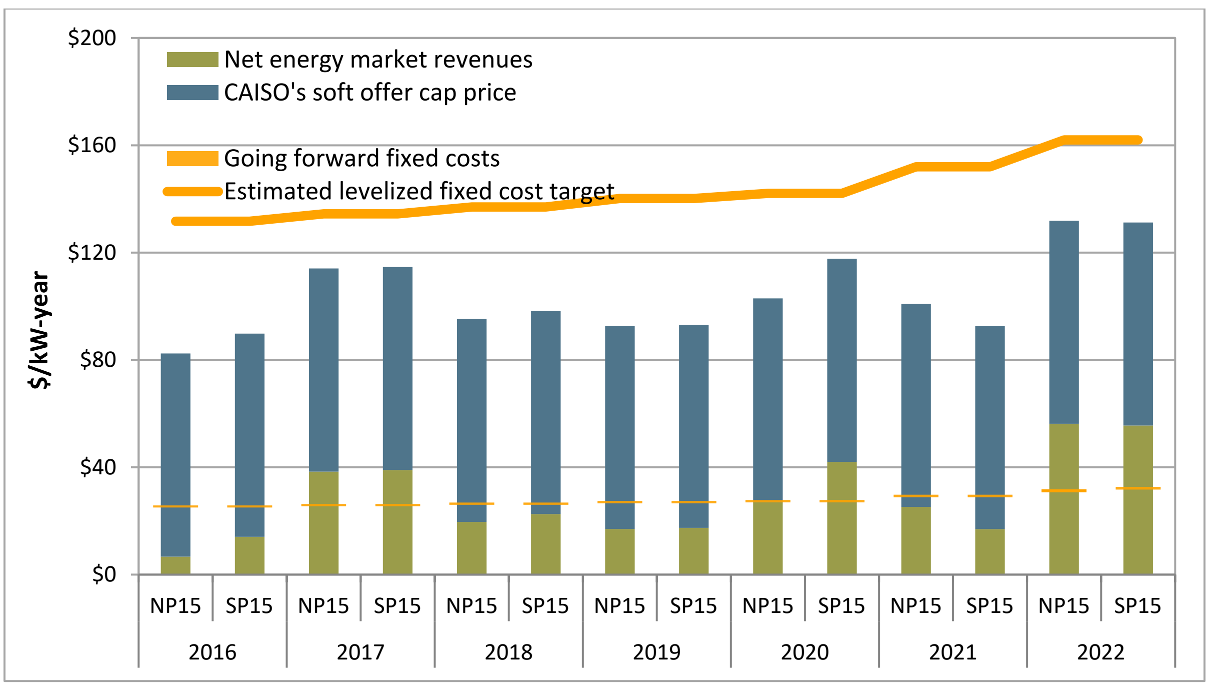


Figure E.11 Estimated net revenues of hypothetical combustion turbine



Recommendations

As the California ISO's independent market monitor, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives to the California ISO, the California ISO Governing Board, FERC staff, state regulators, market participants, and other interested entities.[13] DMM provides written comments and recommendations in the California ISO stakeholder process and in quarterly, annual, and other special reports.[14] DMM's current recommendations on key market design initiatives are summarized below and in Chapter 9.

Extended day-ahead market

In early 2023, the CAISO Board and WEIM Governing Body approved an extended day-ahead market (EDAM) proposal to be filed at FERC and implemented as soon as 2024.[15] DMM supports the CAISO's efforts to extend the day-ahead market to other balancing areas across the west. This has the potential to provide significant efficiency and greenhouse gas reduction benefits by facilitating trade between diverse areas and resource types.

The ISO has made significant progress toward developing a workable design that can provide near-term benefits to entities participating in EDAM. 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. 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 the CAISO proceeding with the final EDAM design passed by the CAISO Board and WEIM Governing Body in 2023, while the ISO continues working with stakeholders to resolve some crucial design elements.

Day-ahead market enhancements

In 2022, the California ISO also continued to develop a proposal for day-ahead market enhancements (DAME). This initiative is intended to feed into the initiative to develop an extended (regional) day-ahead market (EDAM). In May 2023, the CAISO Board and WEIM Governing Body approved a proposal for day-ahead market enhancements (DAME) to be filed at FERC in 2023 and implemented as soon as 2024.[16]

Given the large potential long-term benefits of a west-wide day-ahead market, DMM supported approval of the DAME proposal, while recommending that the ISO continue working with stakeholders on enhancements to the design that could be implemented before and after EDAM's initial

---

13 California ISO, *Tariff Appendix P, CAISO Department of Market Monitoring, Section 5.1*, April 1, 2017: http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

14 Department of Market Monitoring, Market Monitoring Reports and Presentations: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

15 *Extended Day-Ahead Market Enhancements Revised Draft Final Proposal*, California ISO, 2023.

16 Day-Ahead Market Enhancements Draft Revised Final Proposal, California ISO, April 6, 2023: http://www.caiso.com/InitiativeDocuments/DraftRevisedFinalProposal-Day-AheadMarketEnhancements.pdf

Day-Ahead Market Enhancements Addendum: Imbalance Reserve Demand Curve: http://www.caiso.com/InitiativeDocuments/Addendum-ImbalanceReserveDemandCurve-Day-AheadMarketEnhancements.pdf implementation. A more detailed summary of DMM's recommendations are provided in DMM's memo to the CAISO Board and WEIM Governing Body on the DAME proposal.[17]

A key element of the initial proposal 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.[18] DMM recommends that the ISO:

- Continue to refine the imbalance reserve product demand curve, considering potential reductions of the bid cap after implementation.
- More carefully consider whether it would ultimately be more efficient to procure imbalance reserves in the residual unit commitment market.
- Develop mechanisms to allow the real-time market to efficiently determine whether or not to preserve imbalance reserves procured in the day-ahead market.

Congestion revenue rights

Congestion revenue rights sold in the ISO auction consistently collect much less in total auction revenues than the total payments that are made to entities purchasing these revenue rights. 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. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC).

In response to these systematic losses from the congestion revenue right auction sales, the CAISO instituted significant changes to the auction starting in the 2019 settlement year. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. Ratepayer losses have averaged $64 million per year since 2019, compared to $114 million in the seven years before the reforms. Most of these losses have resulted from profits received by purely financial entities that purchase congestion revenue rights but do not schedule power or load in the California ISO.

DMM believes that under current rules it remains likely that the congestion revenue rights auction will continue to result in significant losses to transmission ratepayers. DMM continues to recommend that the CAISO take steps to discontinue auctioning congestion revenue rights and instead reallocate all congestion revenues back to ratepayers who pay for the cost of the transmission system through the transmission access charge. If the California ISO believes it is highly beneficial for them to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the CAISO replace the auction with a market for financial hedges based on clearing of bids from willing buyers and sellers.

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.

---

[17] Memorandum ISO Board of Governors and WEIM Governing Body, Department of Market Monitoring, May 9, 2023: http://www.caiso.com/Documents/DepartmentofMarketMonitoringReport-May2023.pdf

[18] Ibid.

Western Energy Imbalance Market resource sufficiency tests

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

The California ISO implemented a number of changes to the resource sufficiency evaluation in June 2022. These changes include the exclusion of some capacity that is unavailable because of various operating limitations. The ISO also suspended inclusion of intertie and net load uncertainty in the capacity test.[19] DMM supported these changes. As part of this ongoing initiative, DMM is providing additional information and analysis about resource sufficiency evaluation performance, accuracy, and impacts in regular monthly reports.[20]

Currently, when a WEIM area fails either the upward flexible ramping test or capacity 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.

In December 2022, the California ISO and WEIM Governing Body approved several additional changes that will take effect in 2023 as part of phase 2 of this initiative. One of these changes is 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. DMM believed the revised energy assistance option included in the proposal is 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 will allow 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 into 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, the ISO should continue to refine the failure consequences for areas that elect to not opt into the energy assistance program.

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 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

---

19 Department of Market Monitoring, *Comments on EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final Proposal*, January 11, 2022: http://www.caiso.com/Documents/DMM-Comments-EIM-Resource-Sufficiency-Evaluation-Enhancements-Phase-1-Revised-Draft-Final-Proposal-Jan-11-2022.pdf

20 Department of Market Monitoring, *2022 Western Energy Imbalance Market resource sufficiency evaluation reports*: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=1571AD84-67B2-4641-BA7D-4499082910E5

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 Western Energy Imbalance Market.

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.

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, and consider adopting uncertainty calculations customized to the resource sufficiency evaluation, rather than using the flexible ramping product uncertainty calculation.

Flexible ramping product enhancements

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the real-time market software. Although the CAISO has implemented numerous improvements to this product since its introduction in 2016, CAISO operators continue to rely primarily on significant manual interventions to ensure sufficient ramping capacity is available during the peak ramping hours.

These manual interventions include significant upward biasing of the load forecast used in the residual unit commitment and hour-ahead scheduling processes as well as manual commitments and upward dispatches of gas-fired generating units. These manual interventions have remained high, or even increased, since introduction of the flexible ramping product.

Since 2016, DMM has recommended the following two key enhancements in the flexible ramping product:

- **Implement locational procurement of flexible ramping capacity** to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. The CAISO implemented changes to address this issue in 2023. The effectiveness of these design changes is under review pending resolution of implementation issues.
- **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.[21] The ISO has not yet examined this change through the market design and stakeholder process.

Pricing under tight supply conditions

In 2021, the California ISO implemented numerous changes that feature steps to allow prices to rise and increase compensation for imports during tight supply conditions. DMM supported these changes and

[21] Department of Market Monitoring, *2021 Annual Report on Market Issues & Performance*: https://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

believes they will improve the functioning of the CAISO markets during tight system conditions.[22] The combined effect of these changes increases the frequency of very high prices at or near the $1,000/MWh bid cap under tight conditions when scarcity is most likely to occur. During the heat wave of summer 2022, prices in the CAISO markets rose to very high levels that appeared to be highly reflective of actual system and regional conditions.

DMM recommends the California ISO review and consider market performance, with these changes in effect, as it considers adding additional 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.

Export and wheeling schedules

The summer 2020 heat wave highlighted the need to review the California ISO 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 appeared inconsistent with ISO tariff provisions and analogous provisions in the OATTs of other balancing areas in the West. DMM recommended that the ISO take steps to clarify priorities for curtailing native load vs non-high priority exports, and make ISO rules and procedures more equivalent to those of other balancing areas in the West.

In 2021, the California ISO began the transmission service and market scheduling priorities initiative.[23] The first phase of this initiative developed and clarified interim rules that will be in effect until 2024. The second phase of this initiative was completed in 2022 and developed longer-term comprehensive rules for transmission scheduling priority to be effective by summer 2024.

DMM supports the market design changes developed in the second phase of the transmission service and market scheduling priorities initiative as an improvement over the existing interim rules.[24] These changes seem to strike a reasonable balance between the preferences of ISO load serving entities and external users of the ISO transmission system.

Going forward, the ISO and stakeholders could consider future refinements to address concerns of these different stakeholder groups. These changes could result in making less transmission capacity available, while increasing the firmness of these transmission rights to a level more analogous to the OATT framework.

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, numerous regulatory and structural market changes have occurred in recent years, which create the need for significant changes in the state's resource adequacy framework.

---

[22] Department of Market Monitoring, *Motion To Intervene and Comments (FERC Docket No.ER21-1536-000, EL10-56-000)*, April 16, 2021: http://www.caiso.com/Documents/DMM-Comments-on-ER21-1536-Summer-2021-Readiness-Apr-16-2021.pdf

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

[24] 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

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.[25] 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 Planning Reserve Margin to the slice-of-day framework.[26] 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 storage usage with capacity from other resources, as well as the counting rule methodology change from ELCC values to Top 5 Day exceedance values for wind and solar resources. Although the counting values are conservative, DMM believes that too much reliance on capacity that may not actually be available during peak net load hours is a reliability risk; especially with increased electrification and extreme weather patterns expected in California and the rest of the West.

Resource adequacy performance incentives

The current California ISO 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 CAISO capacity procurement mechanism (CPM) soft offer cap, which is currently $6.31/kW-month.[27]

As capacity becomes more limited and prices increase in the West, the difference between capacity payments and potential RAAIM penalties also increases. Additionally, starting in 2021, the CPUC's penalty costs for system resource adequacy showing deficiencies for summer months increased from $6.66/kW-month to $8.88/kW-month.[28] Starting in 2022, these penalties became much higher for load serving entities with repeated deficiencies.[29]

DMM is concerned that if the California ISO 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.

---

[25] CPUC Docket No. R.19-11-009, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program (D.21-07-014)*, July 15, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.pdf

[26] CPUC Docket No. R.21-10-002, *Decision on Phase 2 of the Resource Adequacy Reform Track (D.23-04-010)*, April 6, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF

[27] California ISO Tariff Section 40.9.6.1(c): http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-Jun1-2022.pdf

[28] CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program (D.20-06-031)*, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF

[29] CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

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 California ISO rules in effect during summer 2022 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 California 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.

Resource adequacy imports

DMM has longstanding concerns that existing rules 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.[30] The CPUC took steps to address this issue in 2020 by requiring that non-resource-specific import resource adequacy resources, procured by CPUC-jurisdictional participants, must be self-scheduled or bid into the CAISO markets at or below $0/MWh during the peak net load hours of 4-9 p.m., starting in 2021.[31]

DMM has suggested that the CAISO market rules could be modified so the resource adequacy imports would be subject to lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive capacity payments and can be subject to must-offer obligations. The California ISO contends that subjecting resource adequacy imports to any type of bid mitigation would be "ineffective and inappropriate."[32]

DMM has also suggested that the California ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. 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.[33] Over the longer term, DMM supports development of a more

---

30 Department of Market Monitoring, *2018 Annual Report on Market Issues & Performance*, May 2019, p. 269: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Department of Market Monitoring, *Import resource adequacy*, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

31 CPUC Docket No. R.17-09-020, *Decision adopting resource adequacy import requirements (D.20-06-028)*, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

32 California ISO, *System Market Power Mitigation Straw Proposal*, December 11, 2019, pp. 30-32: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

33 Department of Market Monitoring, *Reply comments on proposed decision adopting local capacity obligations for 2024-2026, flexible capacity obligations for 2024, and program refinements*, 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

source-specific framework for resource adequacy imports that ensures other balancing areas cannot recall import energy, particularly when they also face supply shortages.

Demand response

In the last three 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 2022 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.[34]

Resource adequacy payments, or the value of reduced resource adequacy requirements, are the primary revenue sources for demand response 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.

DMM has recommendations that the CAISO 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.[35] 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.[36]
- ***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 proposed eliminating this 9 percent planning reserve margin adder and the transmission loss factor (2.5 to 3 percent) beginning in 2024.[37] 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

---

34 Department of Market Monitoring, *Demand response issues and performance 2022*, February 14, 2023: http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

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

36 CPUC Rulemaking 21-10-002, Adopting Local Capacity Obligations for 2024–2026.

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

markets. Although these steps represent significant improvements, DMM believes further financial penalties or disincentives for poor performance of demand response resources may be needed.

Energy storage resources

The amount of energy storage resources 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.

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 help improve availability.[38]

Modeling energy storage costs

Energy storage resources face unique costs and operating parameters that may not align with current market mechanisms designed for traditional generators. DMM recommended that the California ISO and the energy storage community continue working together in the Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) stakeholder initiative to identify and develop modeling of unique energy storage resource costs in both market optimization and default energy bids used in local market power mitigation. A detailed discussion of this issue was included in DMM's 2019 annual report.[39]

The CAISO and DMM have made significant progress in understanding the costs of batteries through both the ESDER 4 and energy storage enhancements stakeholder processes. This information has led to the development of a default energy bid for energy storage resources, as well as proposals to model different operational limitations of these resources, and a proposal to develop a new energy storage model that reflects costs and bids based on state of charge.

DMM also recommends that the CAISO resume development of a new energy storage model based on state of charge as soon as practicable. This new model was initially proposed in the early phases of the energy storage enhancements initiative, but was later removed from that initiative and postponed to a later date.[40] This proposed model is likely to be a significant improvement in the ability of battery storage resources to accurately reflect costs applicable to a particular market interval.[41]

Exceptional dispatches

A key goal of enhancing how batteries are modeled and can be bid is to allow batteries to be used efficiently on a day-to-day basis through market bids and dispatches. However, experience during heat waves over the last few years has highlighted the need to take special steps to ensure that batteries are sufficiently charged and can provide their full capacity over the most critical net peak hours on days when system reliability is at stake. On these critical days, the ISO operators can help ensure batteries are available by issuing manual instructions (or exceptional dispatches) to batteries.

---

38 Department of Market Monitoring, *2018 Annual Report on Market Issues & Performance*, May 2019, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

39 Department of Market Monitoring, *2019 Annual Report on Market Issues & Performance*, June 2020, pp. 306-307: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

40 California ISO*, Energy Storage Enhancements – Second Revised Straw Proposal*, June 30, 2022: http://www.caiso.com/InitiativeDocuments/Second-Revised-Straw-Proposal-Energy-Storage-Enhancements.pdf

41 Department of Market Monitoring, *Comments on Energy Storage Enhancements Revised Straw Proposal*, April 7, 2022: http://www.caiso.com/Documents/DMM-Comments-on-Energy-Storage-Enhancements-Revised-Straw-Proposal-Apr-7-2022.pdf

In 2022, the CAISO Board of Governors approved new exceptional dispatch functionality for energy storage resources. This new functionality will allow exceptional dispatch to be issued as a state of charge value rather than only as a minimum, maximum, or specific level of charging or discharging. These market rule changes also allow for compensation of batteries based on the opportunity costs associated with holding state of charge due to exceptional dispatch.

Given the growing importance of batteries for maintaining system reliability on critical days, DMM supports continued development and use of enhanced tools for grid operators to help ensure the availability of batteries to meet system reliability needs on critical days.

Bid cost recovery rules for batteries

DMM has previously recommended new bid cost recovery (BCR) rules for energy storage resources. New BCR rules are needed to mitigate inefficiencies and potential gaming opportunities that may result from differences between day-ahead and real-time state of charge. Recent market outcomes and the growing capacity of energy storage resources on the CAISO system continue to underscore the need to address BCR for energy storage resources. In September 2022, the CAISO filed with FERC to eliminate one large driver of inefficient bid cost recovery payments to storage resources.[42] DMM supported this change.

However, DMM continues to recommend that the CAISO develop more general revisions to BCR rules for storage resources as soon as practicable. These new BCR rules are needed to mitigate potential gaming opportunities and improve the efficiency of market dispatch when day-ahead state of charge values deviate significantly from actual state of charge values in real-time. More generally, new BCR rules are also needed to address BCR payments deriving from a range of operator actions that can constrain state of charge or otherwise force uneconomic dispatch.

DMM is concerned that significant deviations between day-ahead and real-time state of charge values can create opportunities for potential gaming of bid cost recovery payments. Early in the ESDER stakeholder processes, DMM recommended the CAISO consider the implications of a day-ahead submitted state of charge as a new and unique intertemporal constraint between markets.[43] DMM recommended that the CAISO revisit this topic in future initiatives to address potential settlement implications.

DMM has recently observed market outcomes that continue to support the need to revise bid cost recovery rules for energy storage resources. Some change may be needed to address significant differences between day-ahead and real-time state of charge of batteries that inevitably occur. Changes are also 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.

---

[42] California Independent System Operator Corporation, FERC Docket No. ER22-2881, *Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resources*, September 19, 2022: http://www.caiso.com/Documents/Sep19-2022-TariffAmendment-EnergyStorageBidCostRecovery-ER22-2881.pdf

[43] Department of Market Monitoring, *Stakeholder Comments on Energy Storage and Distributed Energy Resources (ESDER), Revised Draft Final Proposal*, February 2, 2016: http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorageDistributedEnergyResources-RevisedDraftFinalProposal.pdf

Resource adequacy battery 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, DMM has observed that 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 for that state's resource adequacy program being developed by the CPUC addresses this issue from the perspective of capacity portfolio planning. On an operational level, additional software and rule enhancements are also needed to ensure that batteries are available when needed for reliability.[44]

DMM also recommends that the CAISO include specific storage parameters which limit a battery's availability when calculating the resource adequacy availability incentive mechanism (RAAIM). Although the current RAAIM may not provide a very strong financial incentive for resource availability, including the impact of additional storage parameters would improve the current RAAIM framework.

Market power mitigation

Local market power mitigation began to apply to storage resources in November 2021, except for those choosing to be modeled as hybrid resources. 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 CAISO 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 Western Energy Imbalance Market and work towards extending mitigation to include hybrid resources, such as combined solar and battery storage facilities.

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 CAISO calculates a static default energy bid value over the day for each battery resource.[45] DMM is supportive of this framework but has recommended several additional refinements.[46]

---

[44] Department of Market Monitoring, *Comments on Minimum State of Charge Extension Straw Proposal*, February 24, 2023: http://www.caiso.com/Documents/DMM-Comments-Minimum-State-of-Charge-Extension-Straw-Proposal-Feb24-2023.pdf

[45] California ISO, *Energy Storage and Distributed Energy Resources – Storage Default Energy Bid – Final Proposal*, October 22, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4-DefaultEnergyBid.pdf

[46] Department of Market Monitoring, *Comments on Energy Storage and Distributed Energy Resources – Storage Default Energy Bid Final Proposal*, November 12, 2020: http://www.caiso.com/Documents/DMMComments-EnergyStorageandDistributedEnergyResources-StorageDefaultEnergyBidFinalProposal-Nov122020.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 updated 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 system and flexible resource adequacy programs.
- **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 2022, California ISO wholesale electricity prices were significantly higher due to an increase in natural gas prices and record levels of load. Since June 2022, California ISO nameplate capacity has increased by 5,600 MW, primarily from solar and battery resource additions.

Specific trends highlighted in this chapter include the following:

- **California ISO instantaneous peak load hit a new high of 52,061 MW** in 2022, about 18 percent higher than the 2021 peak. During *1-in-25* year weather event in 2022, average hourly peak load was 51,479 MW, higher than both the *1-in-2* and *1-in-10 year* forecast.[47]
- **In contrast, California ISO average hourly load continued to decrease in 2022**, due in part to increases in behind-the-meter solar generation and continued initiatives to improve energy efficiency.
- **In December 2022, gas prices at western hubs traded at a significant premium over Henry hub. As of March 31, 2023, storage inventories were down by more than 50 percent from 2022 levels and the five-year average.** Overall for 2022, average gas price at PG&E Citygate and SoCal Citygate increased by 91 percent and 30 percent, respectively, compared to 2021.
- **Hydroelectric generation increased to 7 percent of supply in 2022 but still lower than the 11 percent average over the last five years.** California ISO hydroelectric generation in 2022 was about 24 percent higher than in 2021.
- **Net imports accounted for 14 percent of generation, down from 17 percent in 2021**, as non-Western Energy Imbalance Market imports fell from both the Southwest and Northwest by 22 percent and 15 percent, respectively.
- **Non-hydro renewable generation accounted for about 32 percent of total supply in 2022**, slightly up from 31 percent in 2021.[48] Solar generation increased by about 7 percent and accounted for around 17 percent of total supply.
- **In the California ISO and WEIM areas, total downward dispatch in 2022 increased significantly by 61 percent and 166 percent**, respectively, relative to 2021. In both these areas, the majority of downward dispatch is economic.
- **Since June 2022, solar and battery capacity grew by 2,600 MW and 2,500 MW**, respectively. The California ISO also has 1,000 MW of capacity participating under the hybrid model.
- **Third-party demand response resource capacity increased** by 30 percent from 2021 to 2022. The self-reported performance of third-party demand response decreased from 53 percent to 40 percent during peak hours of summer 2022.
- **Utility demand response resource capacity decreased** by 20 percent compared to 2021. The self-reported performance of utility proxy demand response decreased from 88 percent to 82 percent during peak hours of summer 2022.

---

47 For detailed information on the instantaneous peak load and average hourly peak load, please see the California ISO's Market Performance report: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

48 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.

- **Capacity from battery storage resources grew dramatically** from 2.5 GW in June 2021 to 5.5 GW as of June 2023. California ISO battery fleet now comprises over 2.8 GW of capacity from either co-located or hybrid resources, including storage resources prohibited from charging from the grid.
- **The estimated net operating revenues for typical new gas-fired generation in 2022 exceeded DMM's estimate of the going-forward fixed costs of gas capacity** and remained substantially below the annualized fixed cost of new generation.
- **The estimated net operating revenues for a typical new fast-ramping lithium-ion battery energy storage system** exceeded that of gas-fired generation in 2021 and 2022 once ancillary service payments were included, averaging about $114/kW-yr in 2022, similar to that of 2021. Net revenues are higher in the northern and central local capacity areas than southern areas.

1.1 Load conditions

1.1.1 System loads

California ISO's instantaneous peak load hit a new high of 52,061 MW in 2022.[49] 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 September 6 at nearly 5 p.m. in 2022. Overall, CAISO load decreased in 2022 and was the lowest since 2003. Table 1.1 summarizes annual system peak loads and energy use since 2018. Although total load decreased between 2021 and 2022, it fell at a slower rate than it had since 2018.

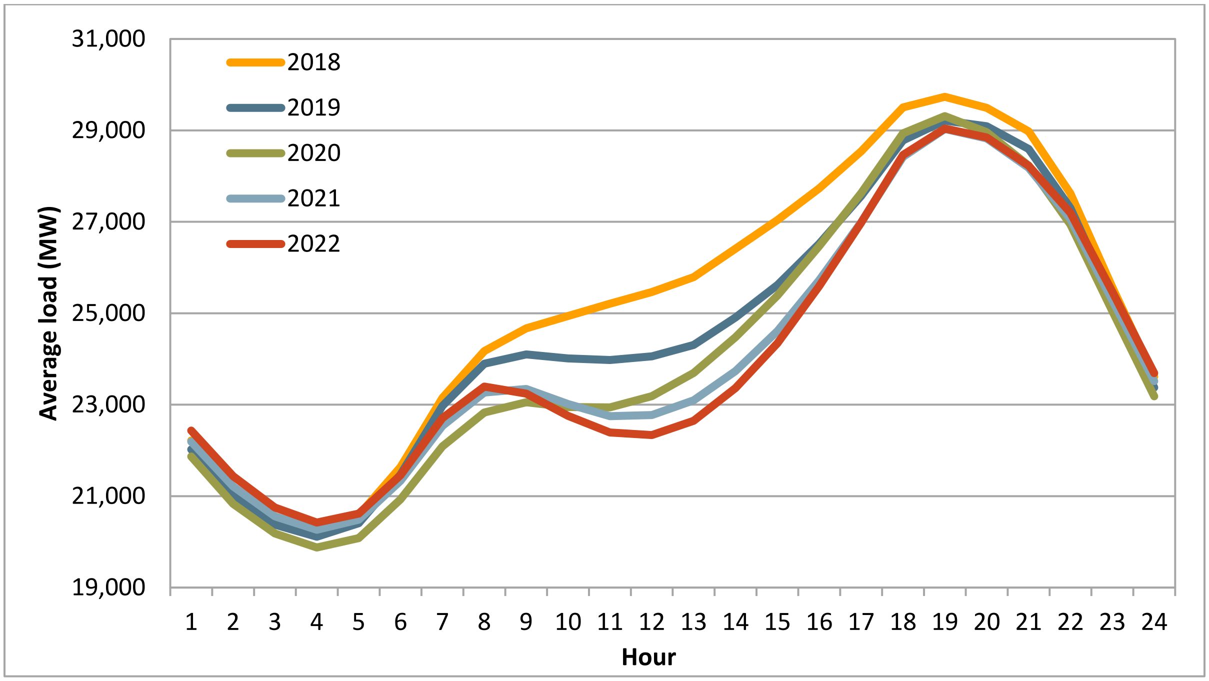
Table 1.1 Annual system load in CAISO: 2018 to 2022

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%
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	18.4%

Figure 1.1 shows average hourly load by year along with how the overall load shape has changed since 2018. 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 divergence in load across years through the middle of the day shows the effect of increased behind-the-meter solar generation on load in California.

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

Figure 1.1 Average hourly load (2018-2022)



Seasonal load trends

Figure 1.2 and Figure 1.3 show the average load by quarter and month between 2018 and 2022, respectively. Average load in 2022 was higher in the third quarter than in 2021, but lower in each of the other quarters. Higher third quarter load was a result of an extraordinary heat wave that affected the West from late August through early September. A number of factors influence load trends; however, load tends to follow statewide temperatures on average.[50]

50 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 (2018-2022)

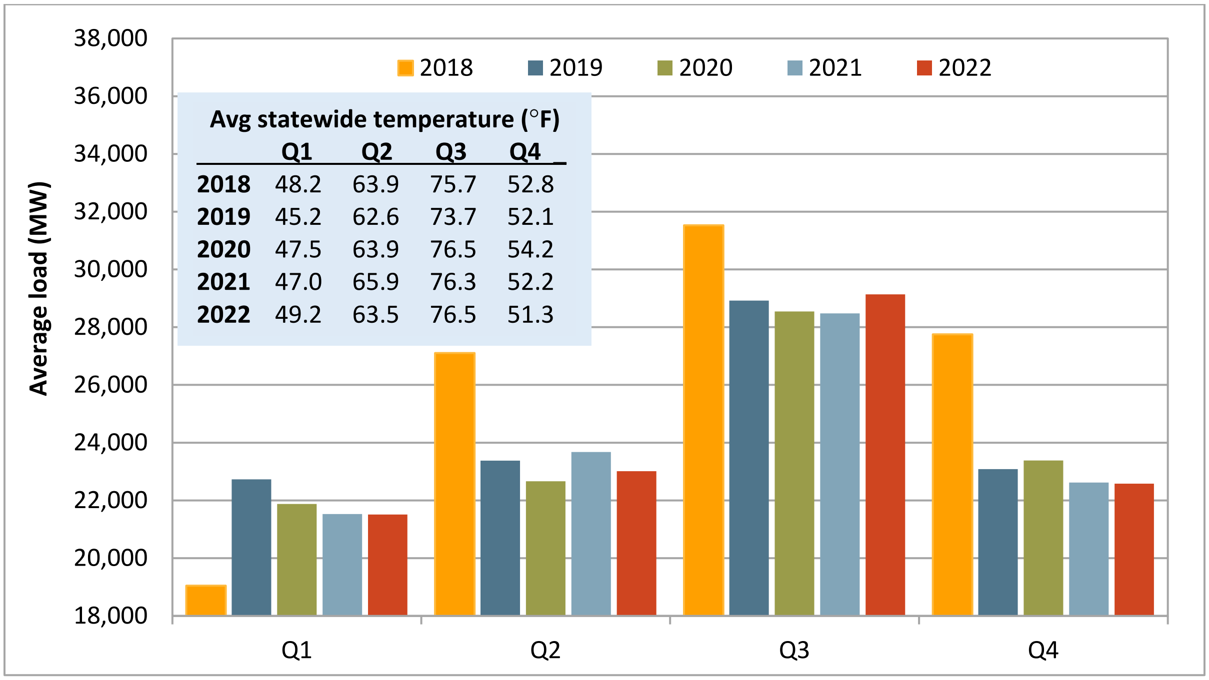
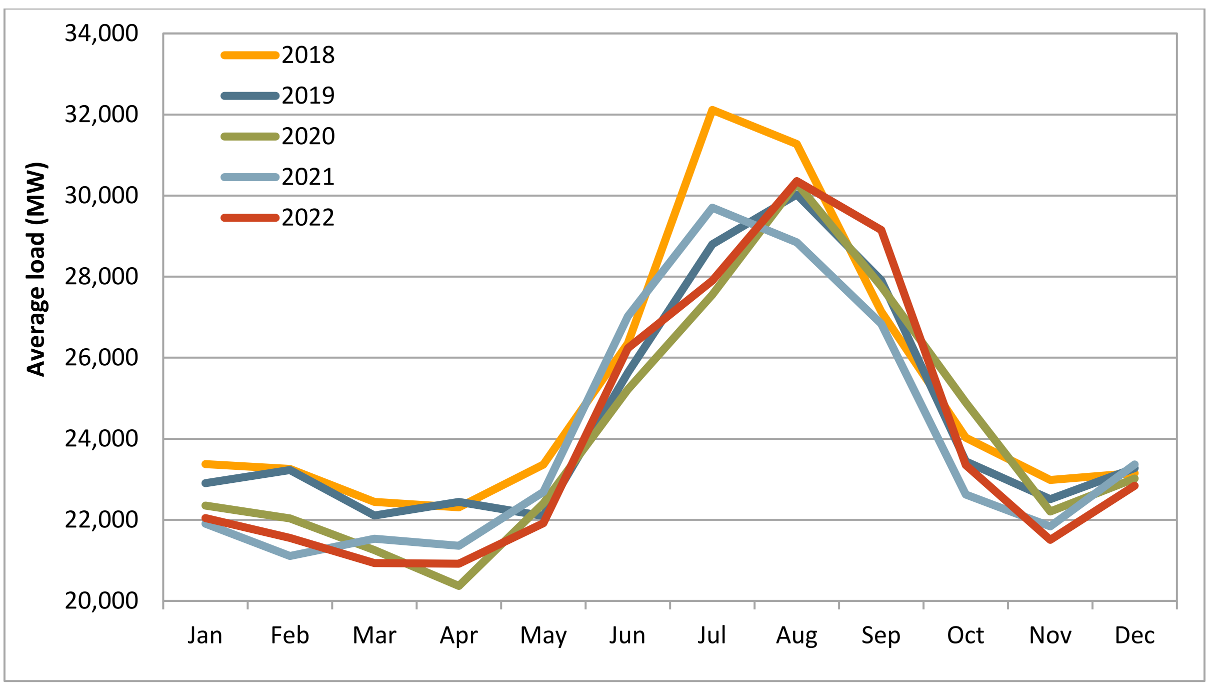


Figure 1.3 Average load by month (2018-2022)

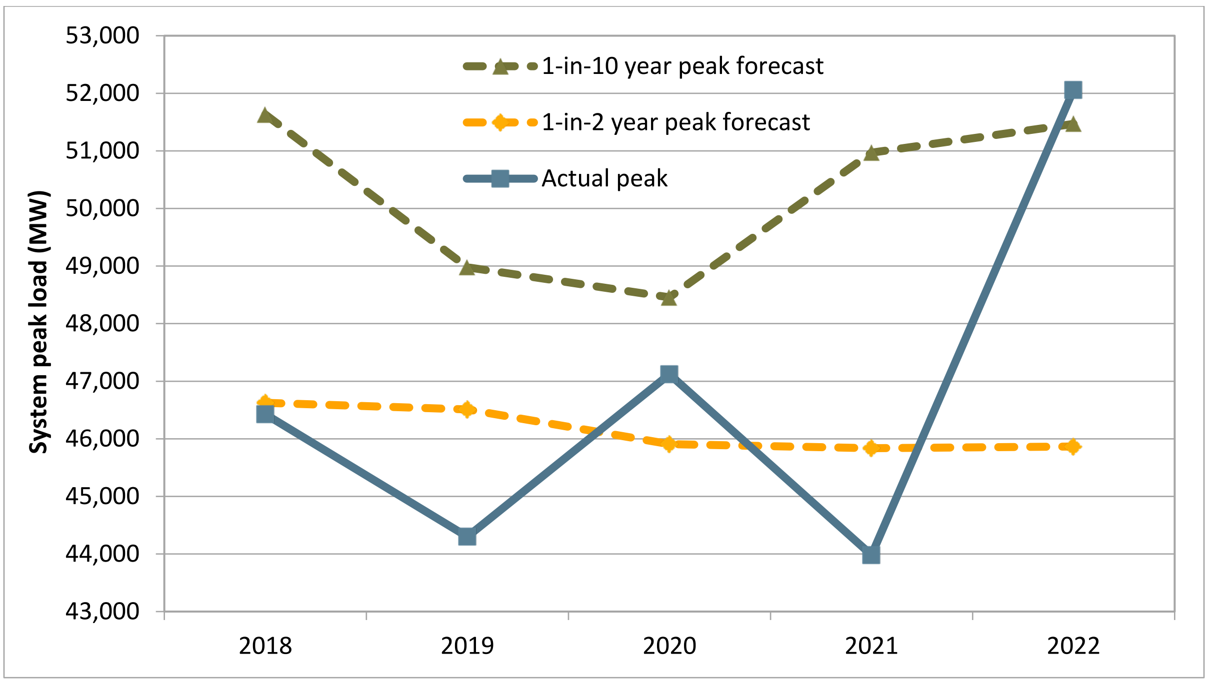


Peak load

Instantaneous summer loads peaked at 52,061 MW on September 6, about 18 percent higher than the 2021 peak. This peak represent the highest instantaneous load on record for the California ISO.[51] Average hourly peak load was 51,479 MW, higher than both the 1-in-2 and 1-in-10 year forecast. System demand during the single highest load hour often varies substantially year-to-year based on the weather conditions. The potential for extreme heat-related peak loads creates a continued threat to operational reliability and drives many of the California ISO reliability planning requirements.

The instantaneous peak load in 2022 was about 14 percent higher than the CAISO *1-in-2 year* load forecast (45,866 MW) and about 1 percent higher than the *1-in-10 year* forecast (51,469 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. Chapter 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

51 California ISO Instantaneous Peak Load History, 1998-2022: 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 peak load defined for all local areas.[52] 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 2022[53]

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	10,746	23%	7,748	7,231	93%
Greater Fresno	PG&E	3,435	7%	3,370	1,987	59%
Sierra	PG&E	1,618	3%	2,092	1,220	58%
North Coast/North Bay	PG&E	1,509	3%	834	834	100%
Stockton	PG&E	1,027	2%	586	562	96%
Kern	PG&E	1,029	2%	418	356	85%
Humboldt	PG&E	144	0.3%	181	111	61%
LA Basin	SCE	18,929	40%	8,774	6,646	76%
Big Creek/Ventura	SCE	4,394	9%	5,609	2,173	39%
San Diego	SDG&E	4,580	10%	4,362	3,993	92%
Total		**47,411**		**33,974**	**25,113**	

*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 year 2022. As a result, local capacity requirements increased to 25,113 MW for 2022 compared to 24,160 MW in 2021. Dependable generation and peak load decreased slightly overall in these areas. Table 1.2 shows the proportion of dependable generation capacity required to meet local reliability requirements established in the state resource adequacy program. In most areas, a high proportion of the available capacity is needed to meet peak reliability planning requirements.[54] 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

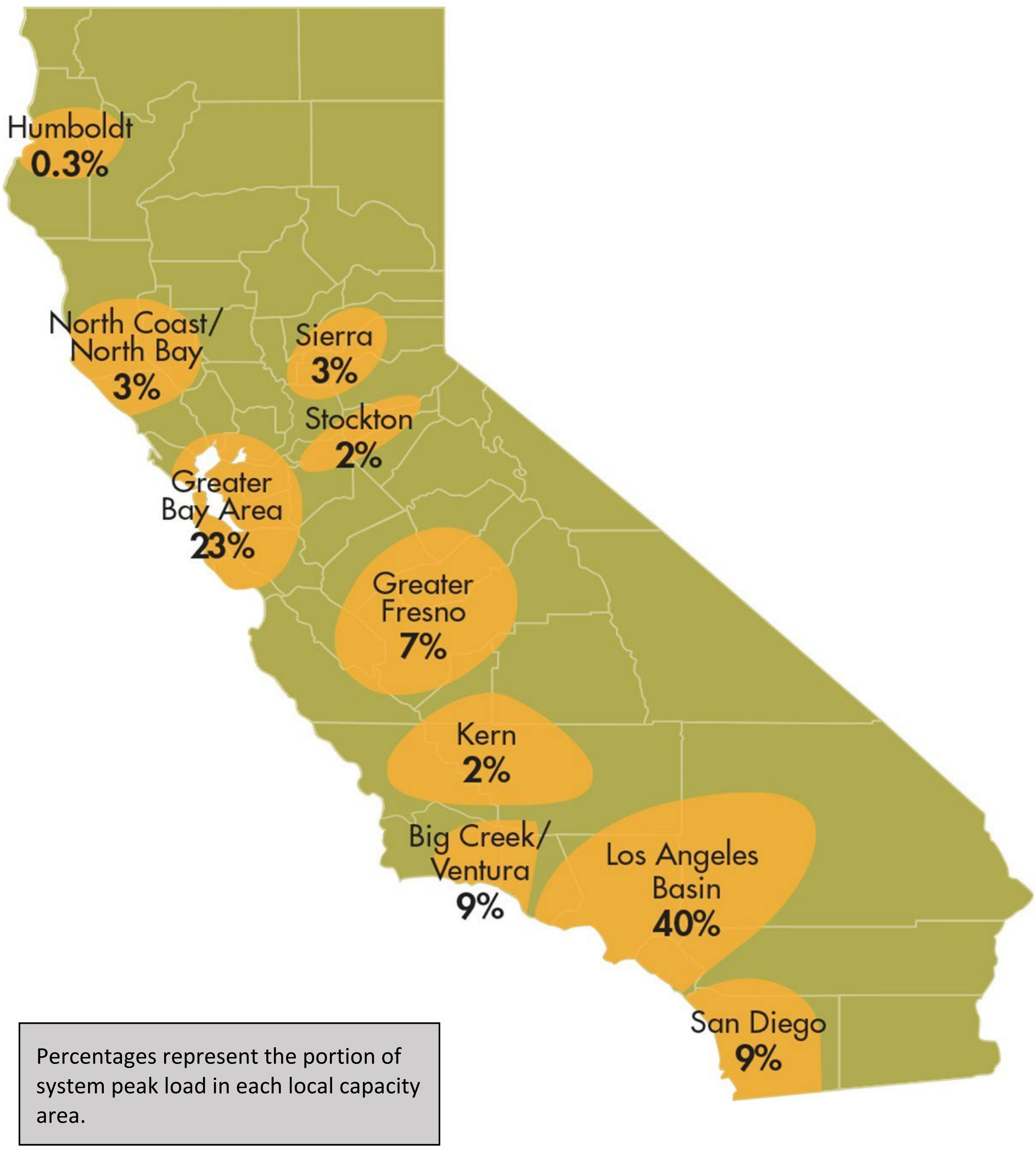
52 Note that the total local area peak load figure, as well as a proportion of each local capacity area's load of the total, is illustrative. Each local area's load will peak at a different time from one another and from the system-coincident peak load.

53 California ISO, *2022 Local Capacity Technical Analysis*, April 30, 2021, p. 26, Table 3.1-1: http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf

54 California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet requirements in four areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura, and San Diego.

the highest local capacity requirements, due in part to high *1-in-10 year* peak load forecasts. Requirements increased in the Greater Bay Area (878 MW), Greater Fresno (293 MW), LA Basin (519 MW), and San Diego (105 MW). The local requirement for Sierra decreased substantially by 601 MW. In 2022, the peak load for most of the local areas decreased, including a drop of 256 MW in Kern and 247 MW in Sierra.

Figure 1.5 Local capacity areas



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 2022, together comprising 65 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 2021.

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 show the following:

- Natural gas and non-hydro renewables were the largest sources of generation in 2022, together representing 65 percent of total generation in the CAISO.
- Natural gas generation accounted for 33 percent of total supply, a decrease from 34 percent in 2021. This was driven primarily by increased hydroelectric generation, which increased to 7 percent of supply.
- Net imports represented 14 percent of total supply, a decrease from 17 percent in 2021. On an average hourly basis, net imports were about 475 MW lower across all hours than last year.
- Nuclear generation provided 10 percent of supply, roughly the same as previous years.

Figure 1.6 Average generation by month and fuel type in 2022

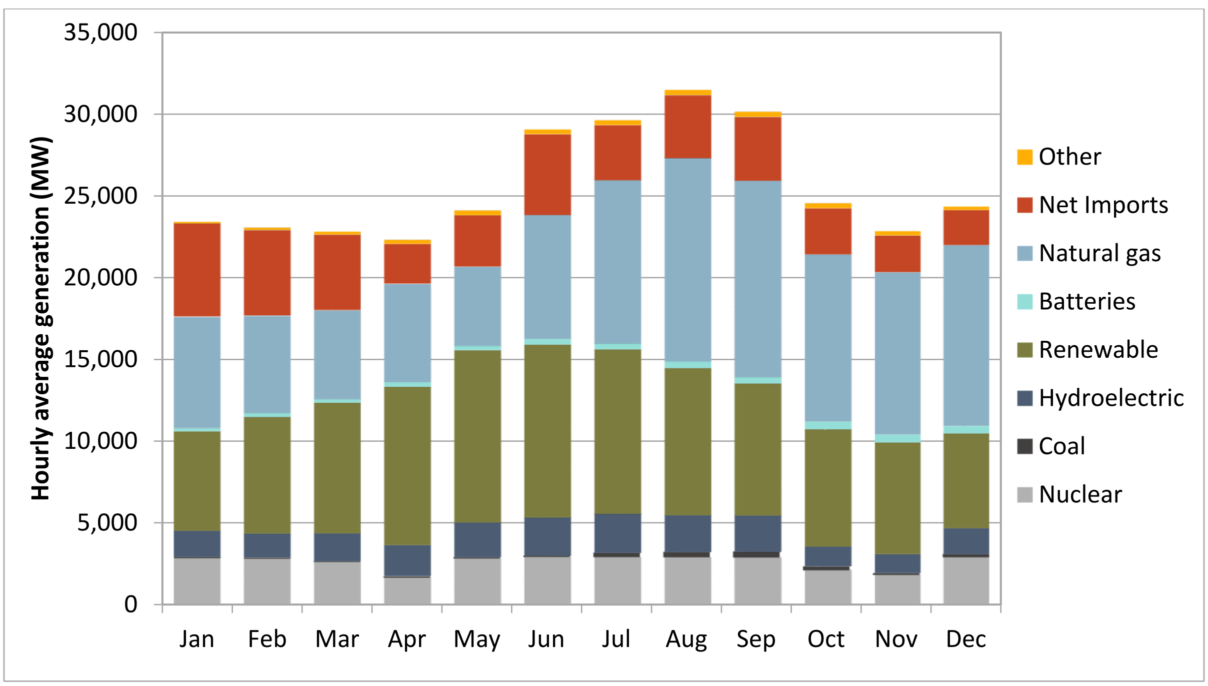
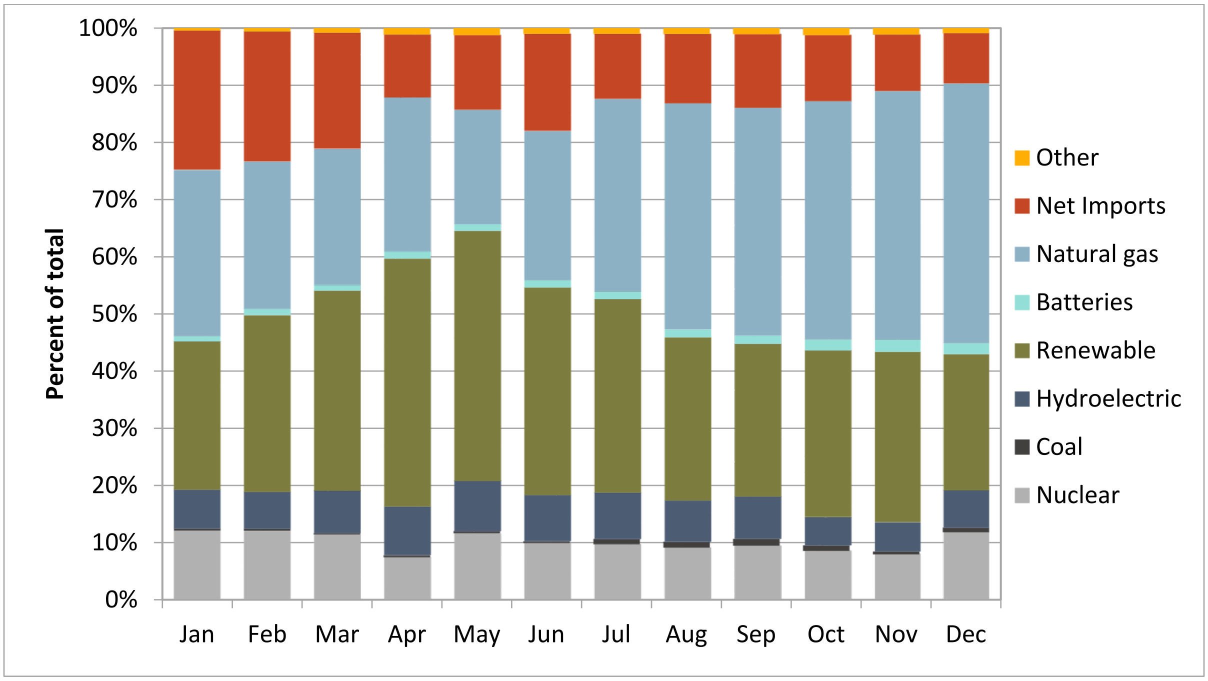


Figure 1.7 Average generation by month and fuel type in 2022 (percentage)



Hourly generation by fuel type

Figure 1.8 shows average hourly generation by fuel type over the year.[55] Overall for 2022, hour ending 19 averaged the highest amount of generation at about 30,025 MW, while hour ending 4 averaged the lowest at about 21,475 MW. Generation from nuclear, coal, biogas, biomass, and geothermal resources comprised about 4,250 MW of inflexible base generation, or about 75 MW more than 2021. Generation from battery storage resources averaged about 950 MW during the peak net load hours of 17-21, more than double the same hours of 2021.

Figure 1.9 shows the change in hourly generation by fuel type between 2021 and 2022. In the chart, positive values represent increased generation over the course of the year compared to 2021, while negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation throughout the day, with the larger increases happening during off-peak hours. Net imports were lower than 2021 during all hours, while natural gas generation was lower during the middle of the day. These reductions were matched by increased hydroelectric, battery, and natural gas generation in off-peak hours and renewables in the middle of the day. 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.

55 Batteries and Coal were previously included in the "Other" category.

Figure 1.8 Average hourly generation by fuel type (2022)

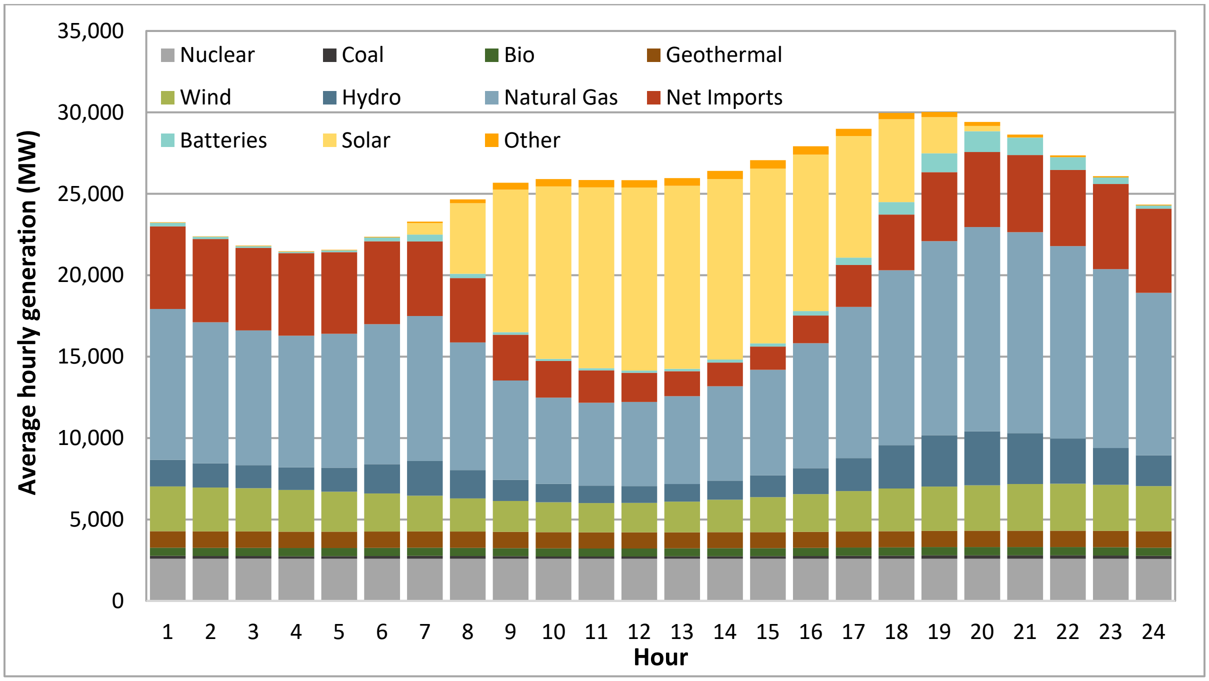
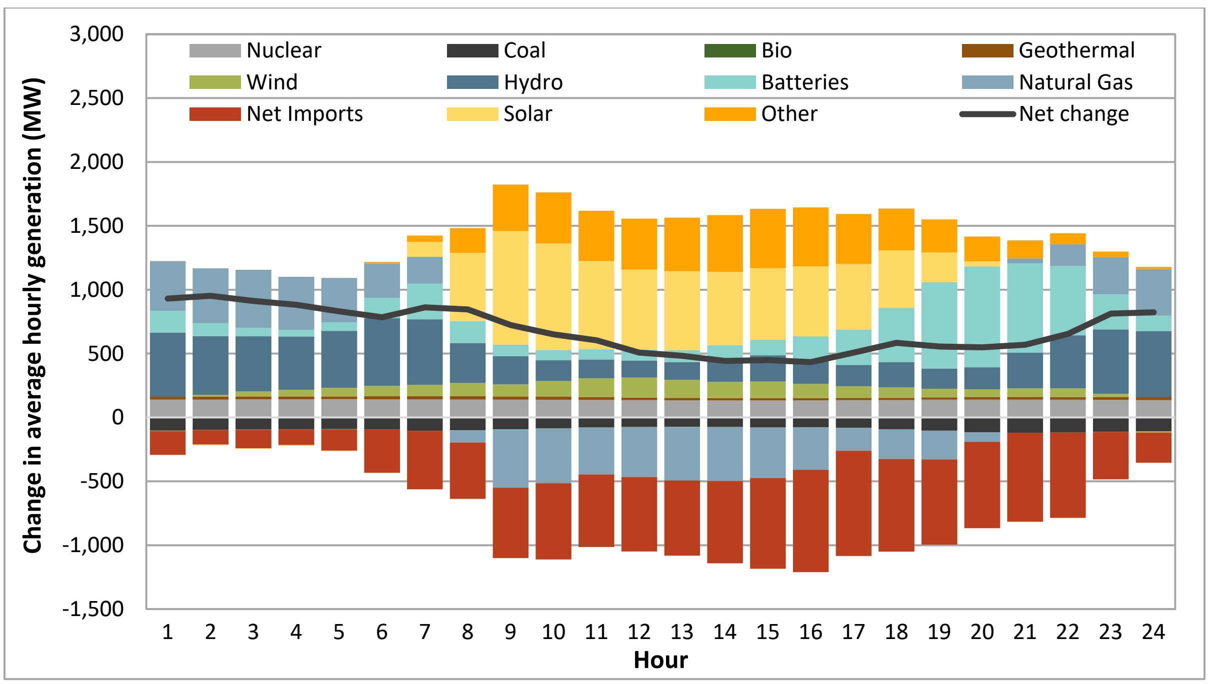


Figure 1.9 Change in average hourly generation by fuel type (2022 compared to 2021)



1.2.2 Renewable generation

In 2022, about 32 percent of CAISO generation was from non-hydro renewable resources and about 7 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.[56] Figure 1.10 also illustrates:

- Generation from solar and wind resources increased by 7 percent and 3 percent, and contributed to 17 percent and 9 percent of total system energy, respectively.
- The overall output from geothermal generation increased 2 percent compared to 2021, and continued to provide 4 percent of system energy.
- Biogas, biomass, and waste generation remained the same as last year. Together they accounted for 2 percent of system energy.

Figure 1.10 Total renewable generation by type (2019–2022)

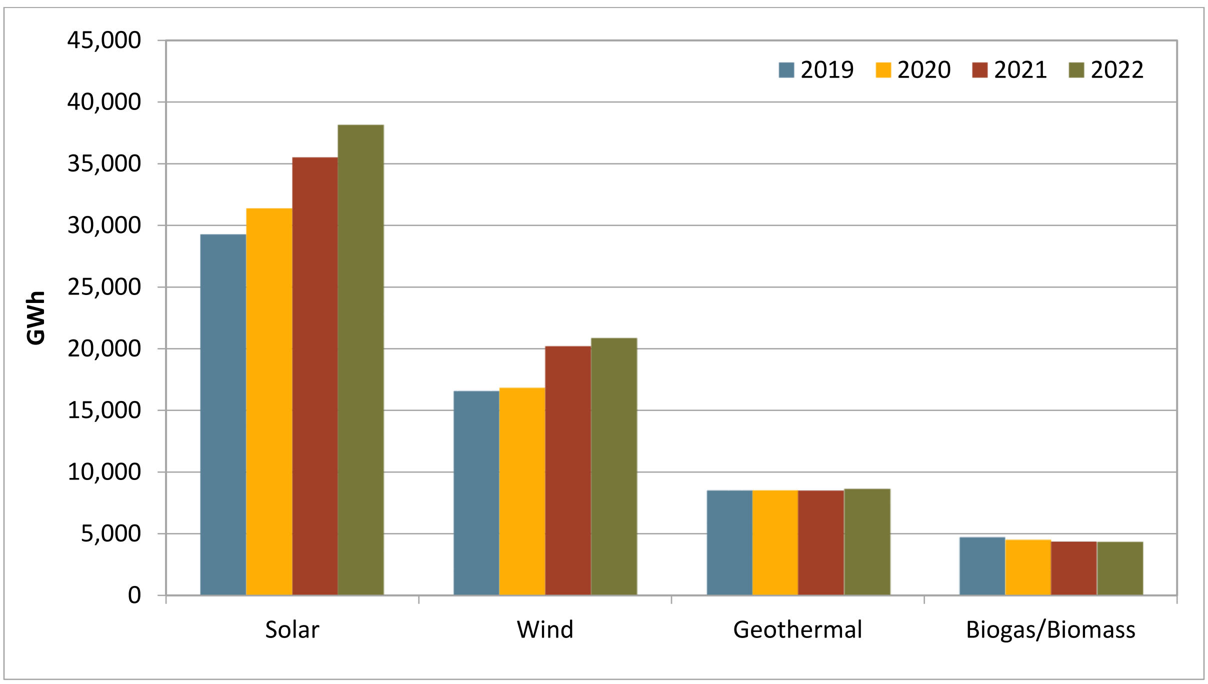


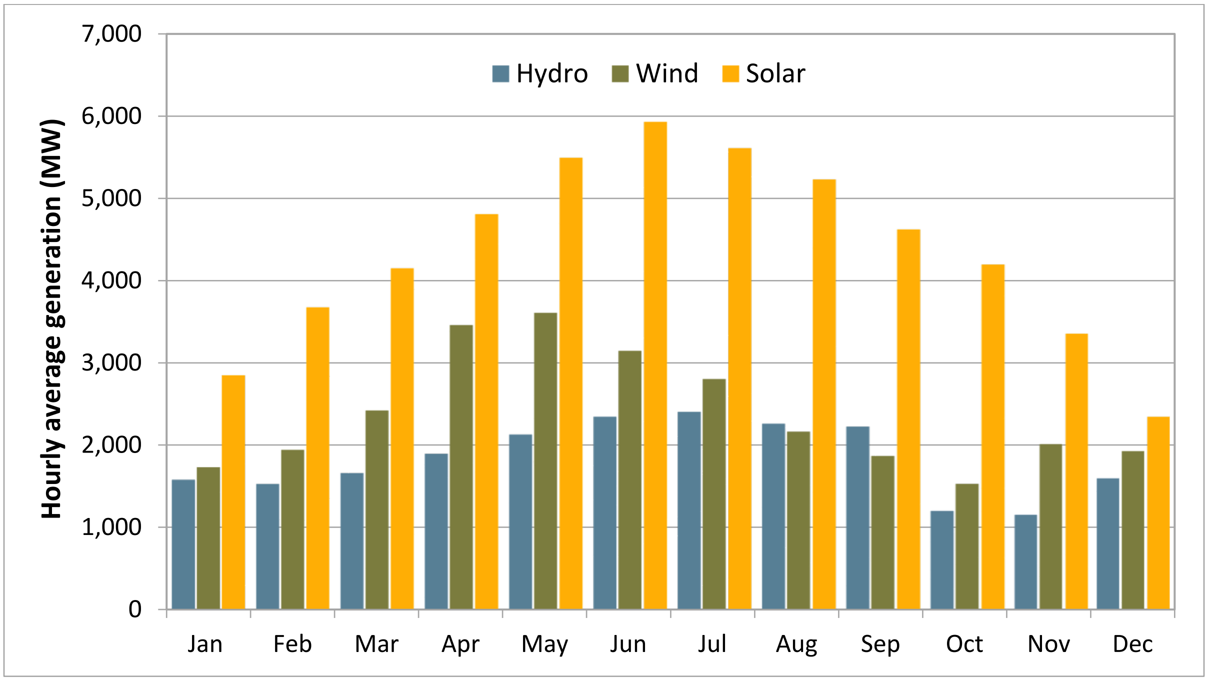
Figure 1.11 compares average monthly generation of hydro, wind, and solar resources. Due to low snowpack levels, the amount of energy produced by hydroelectric resources was generally below that of wind resources.

In 2022, average hourly solar generation peaked in June, wind generation peaked in May, and hydroelectric generation peaked in July. Non-hydro renewable generation made up the greatest portion of system generation during May when it accounted for 44 percent of total generation. During the spring, renewable generation's share of total system generation tends to peak as there is low load and high solar and wind generation.

---

56 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 1.11 Monthly comparison of hydro, wind, and solar generation (2022)



Downward dispatch and curtailment of variable energy resources

In the California ISO and WEIM areas, total downward dispatch in 2022 increased significantly by 61 percent and 166 percent, respectively, relative to 2021. In both these areas, 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; [57]
- **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;

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

- **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 61 percent higher in 2022 than in 2021. Economic downward dispatch accounted for about 2,475 GWh (96 percent) of curtailment during the year, while self-scheduled curtailment accounted for about 38 GWh (1.5 percent). Exceptional dispatch curtailments for both self-scheduled and economic bid resources remained low and were about 2 GWh (less than 1 percent). The roughly 54 GWh (2 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 2022 rose to 638 GWh, more than 2.5 times higher than 2021. Economic downward dispatch in the WEIM during 2022 accounted for roughly 544 GWh (85 percent) of total downward dispatch. December 2022 was the highest month of downward dispatch to date at 156 GWh. This large increase in downward dispatch and curtailment was driven by congestion in the Four Corners area and on the Wyoming Export constraint.[58]

[58] The effects of the Four Corners area (*Line_FC-CH2_345KV* & *Line_FC-CH1_345KV*) and Wyoming Export constraint (*Total_Wyoming_Export*) congestion during the fourth quarter of 2022 are discussed in Section 6.1.2.

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

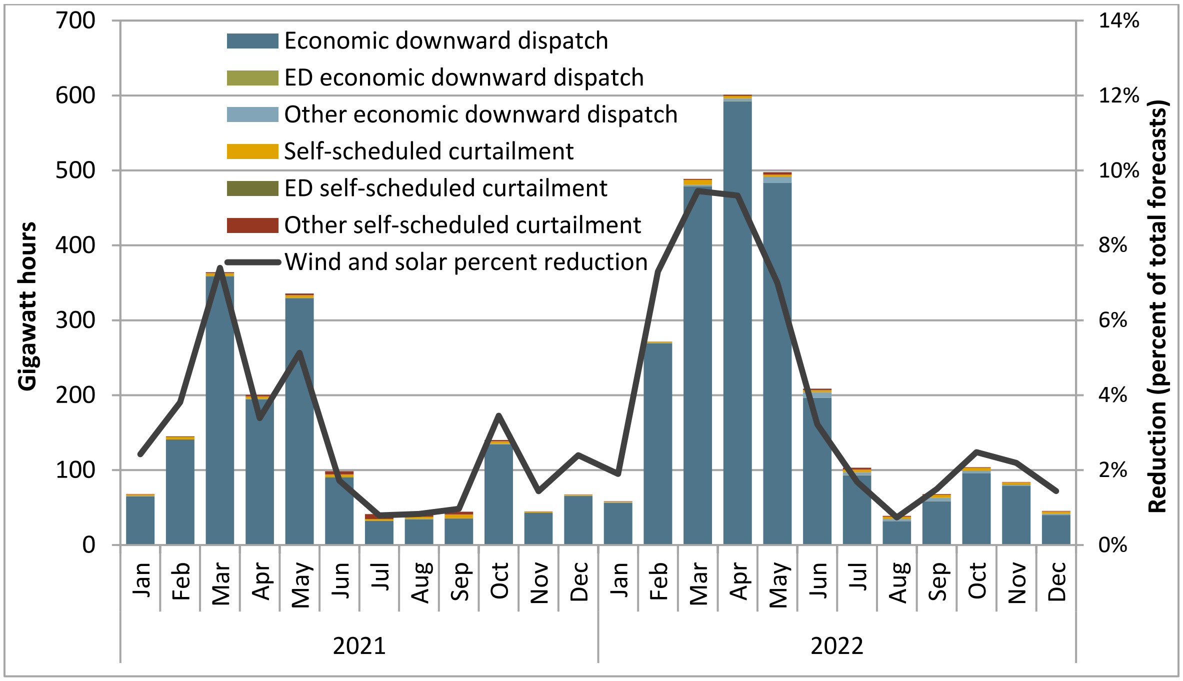
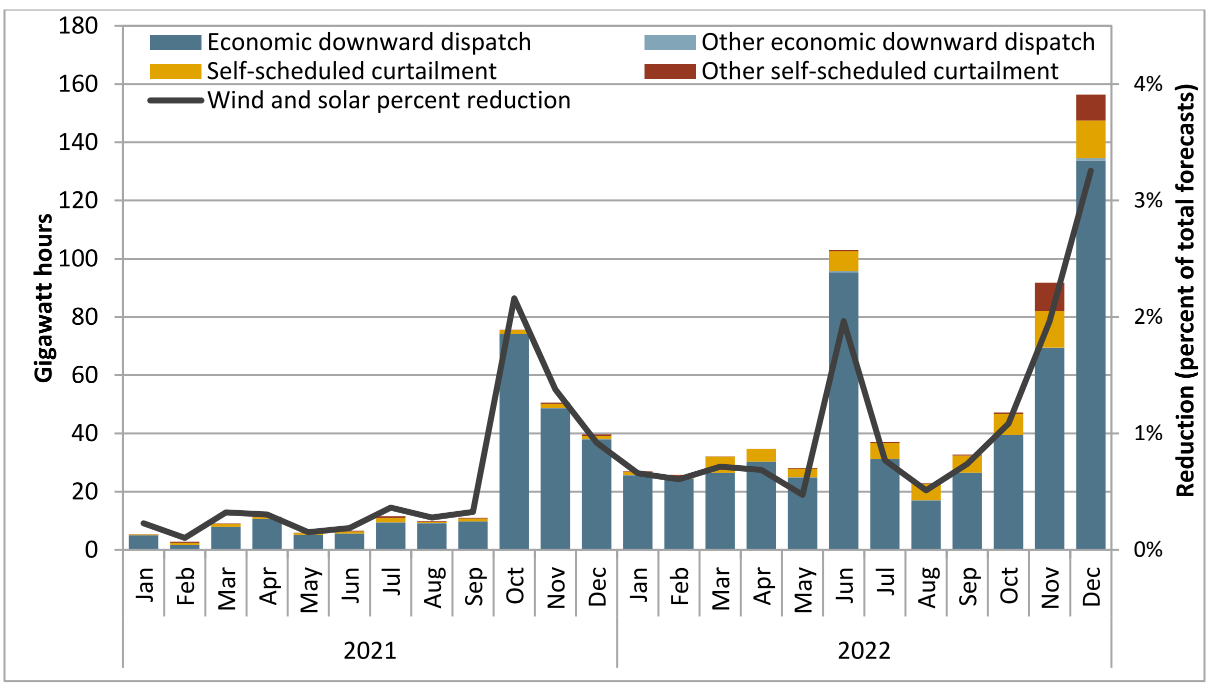


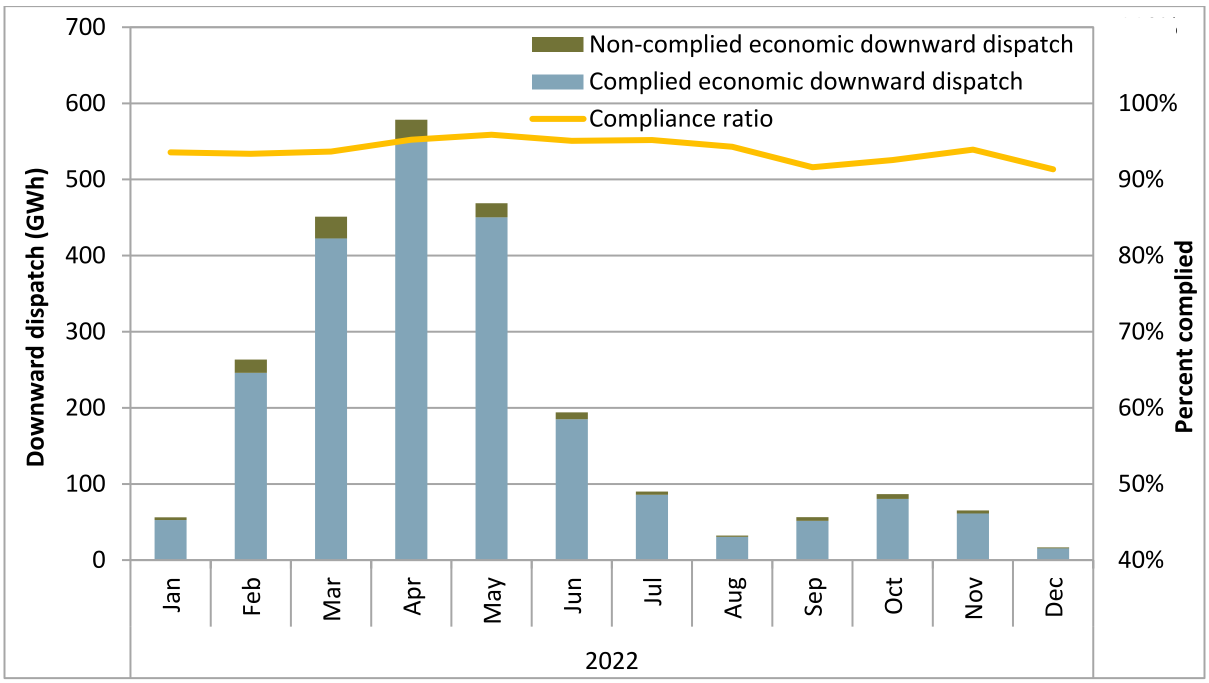
Figure 1.13 Reduction of wind and solar generation by month (WEIM)



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.[59] 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.

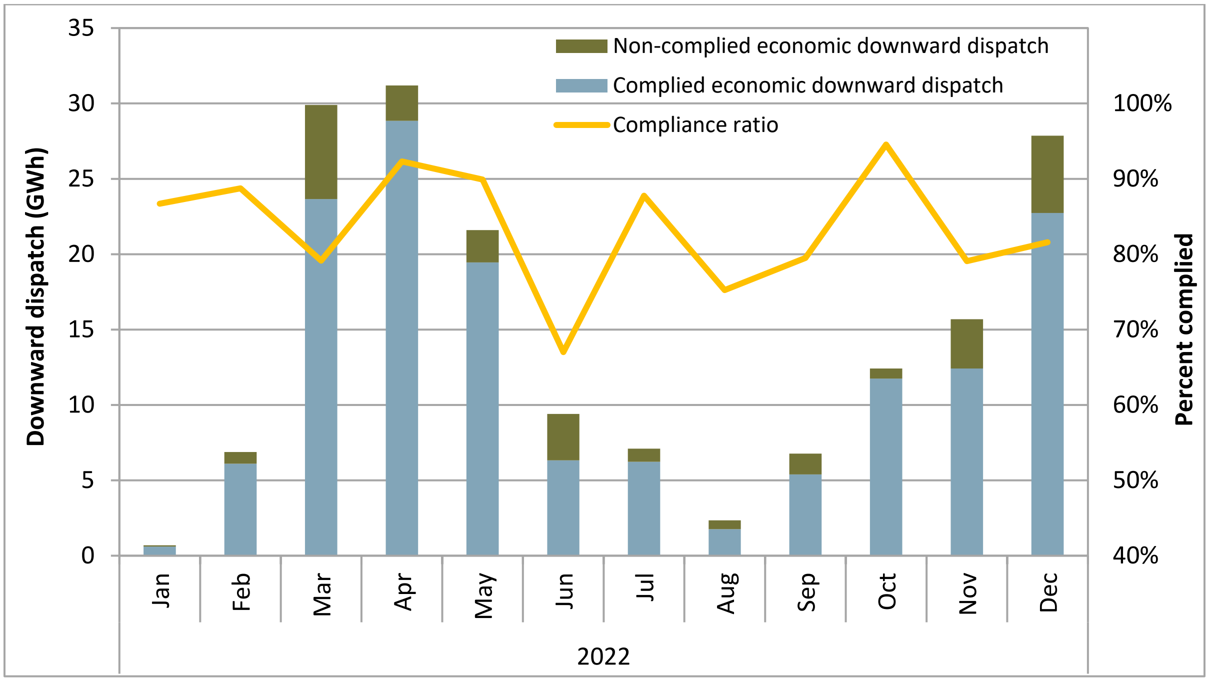
The quantity and performance of solar and wind resources that complied with economic downward dispatch was about the same as last year. Solar resources were about 95 percent compliant, while wind resources were 84 percent compliant with downward dispatch instructions. Under market rules, all market participants and resources are expected to follow dispatch instructions.

Figure 1.14 Compliance with dispatch instructions – solar generation



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

Figure 1.15 Compliance with dispatch instructions – wind generation



Hydroelectric supplies

Total hydroelectric production in 2022 increased 24 percent from 2021.[60] Statewide snowpack, as measured on April 1, 2022, was 38 percent of the long-term average.[61]

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 2012 to 2022. Figure 1.17 compares monthly hydroelectric output from resources within the California ISO system for each month during the last four years. The hydroelectric generation pattern in 2022 is similar to 2020 and 2021. Hydro generation followed a seasonal pattern, but remained relatively flat over the year. On average, monthly generation in 2022 was about 24 percent higher than in 2021.

60 Annual hydroelectric production includes all tie generators.

61 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/cgi-progs/prevsnow/COURSES

Figure 1.16 Annual hydroelectric production (2012–2022)

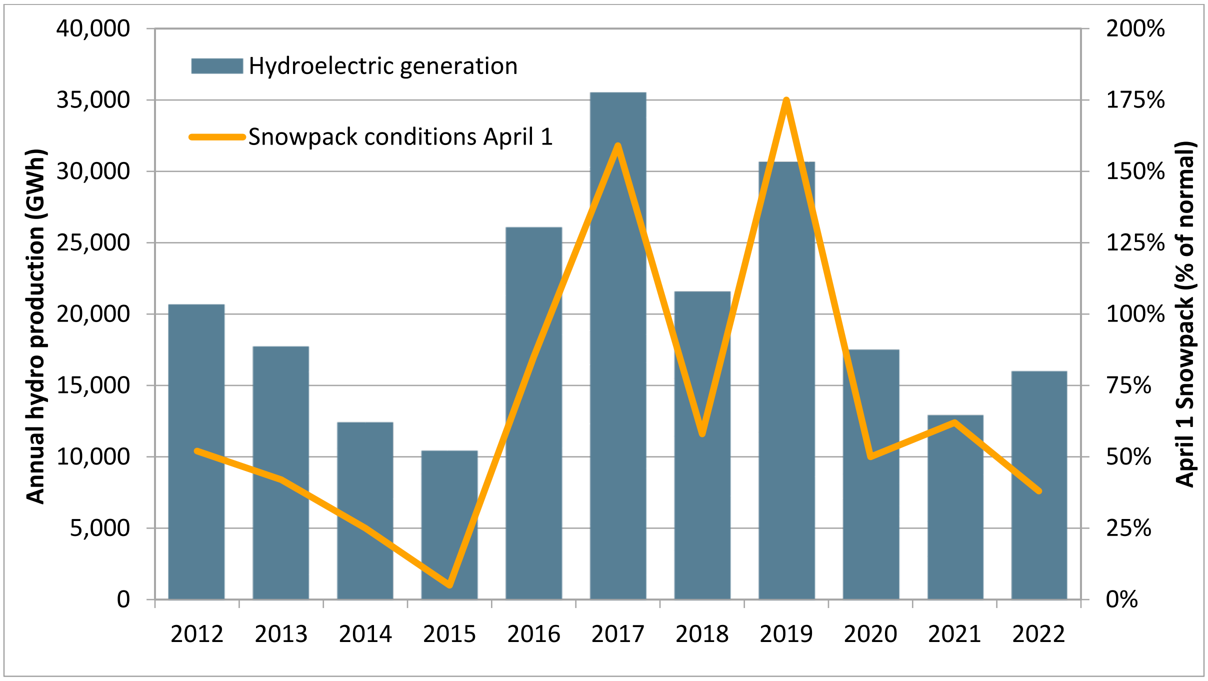
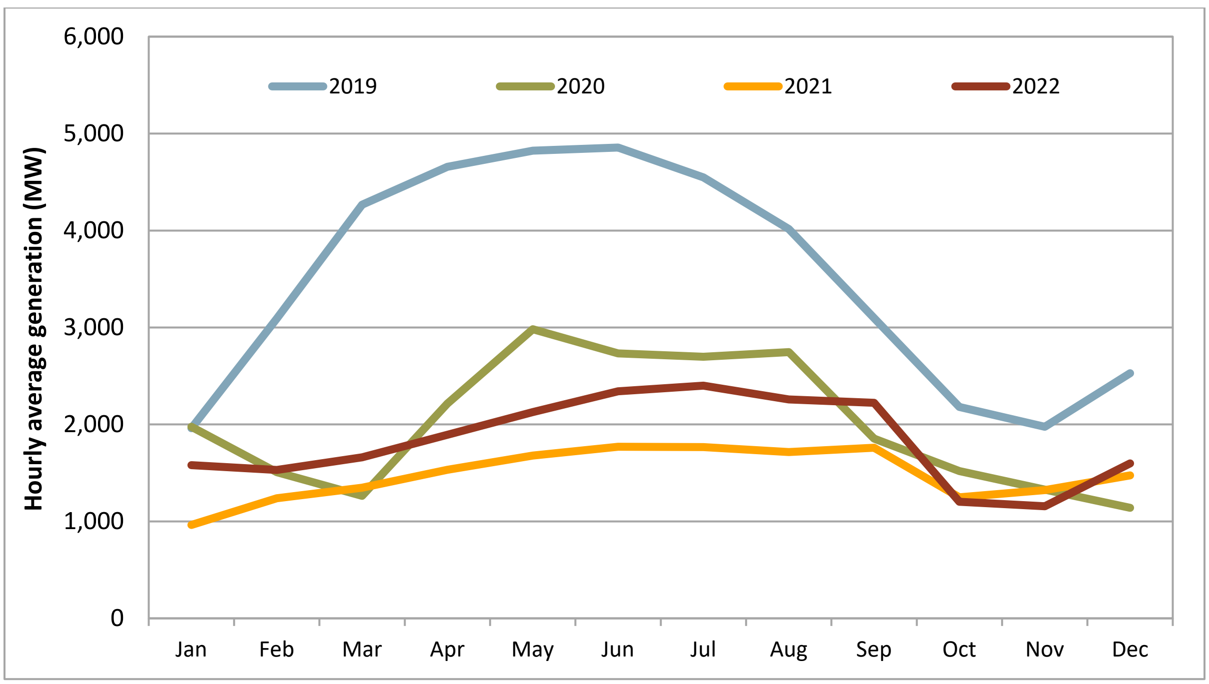


Figure 1.17 Average hydroelectric production by month (2019–2022)



1.2.3 Net imports

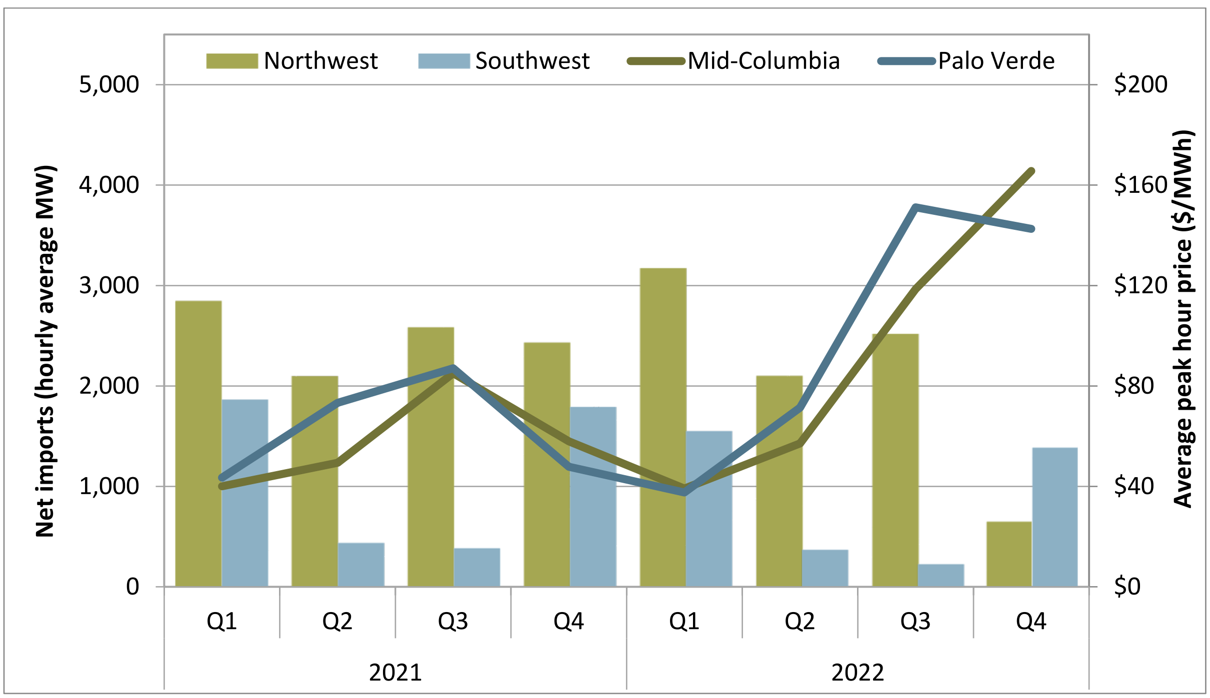
Peak hours and average prices

Total generation from net imports in 2022 decreased compared to 2021.[62] As shown in Figure 1.18, net imports from sources in the Northwest decreased by 15 percent, while net imports from the Southwest decreased by about 22 percent.

Figure 1.18 also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. During the late August and early September heatwave of 2022, prices at Palo Verde and Mid-Columbia were substantially higher than historical levels, clearing above the $1,000/MWh WECC soft offer cap.[63] Bilateral prices peaked in December 2022 due to persistent high gas prices in the Western U.S. As a result, imports into California ISO decreased substantially and were replaced by natural gas generation.[64]

As shown in the figure, net imports from the Northwest increased in the first quarter, remained the same in the second quarter, but decreased in the last two quarters over the previous year. Net imports from the Southwest were lower in all quarters.

Figure 1.18 Net imports and average day-ahead price (peak hours, 2021-2022)



62 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.

63 Further coverage of bilateral prices relative to prices within the California ISO balancing area is available in Section 2.3.1 of this report.

64 Presentation on Gas-Electric prices at CPUC En Banc proceeding, slide 7, February 7, 2023: http://www.caiso.com/Documents/Presentation-Gas-Electric-Prices-En-Banc-Proceeding-Feb-7-2023.pdf

Net interchange – CAISO imports and exports with WEIM transfers

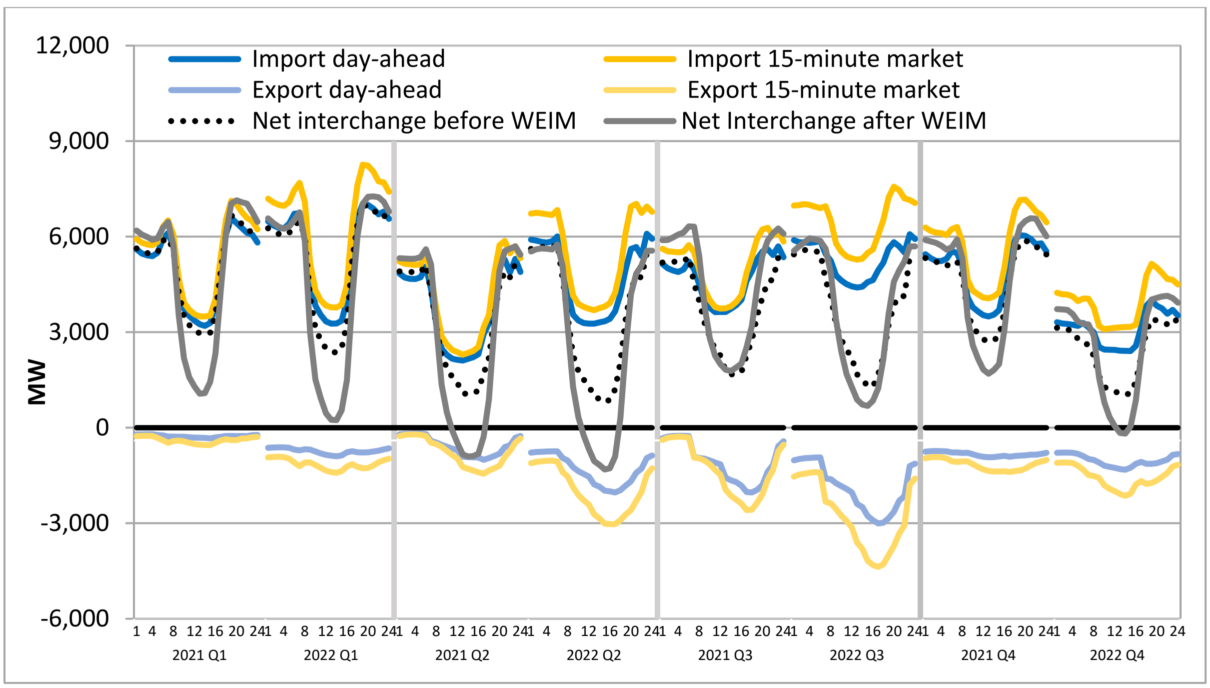
The Western Energy Imbalance Market (WEIM) provides additional interchange between the CAISO and other balancing authority areas in both the import and export directions. The net quantity of imports *to* and exports *from* the CAISO, as well as WEIM transfers, is the CAISO system net interchange.

As shown in Figure 1.19, average hourly net interchange continued to follow CAISO net load and average prices, falling in the mid-day hours as solar generation peaks, and rising in the peak net load hours. Cleared imports (shown in dark blue and dark yellow) peaked at lower volumes but in similar hours as in 2021.

Compared to 2021, exports increased in each quarter (shown as negative numbers below the horizontal axis in pale blue and yellow) and were the highest in the third quarter, peaking at about 4,400 MW in hour ending 17.

Average net interchange fell in 2022, on average, in each quarter. The average net interchange, excluding WEIM transfers (shown in dashes), 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 1,300 MW in hour ending 15.

Figure 1.19 Average hourly net interchange by quarter



1.2.4 Energy storage and distributed energy resources

Batteries[65]

Capacity from battery storage resources has increased significantly in recent years. Storage resources typically participate under the non-generator resource (NGR) model. NGRs 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 CAISO 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 CAISO. 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. Despite these separate arrangements, there are several existing and planned features that would link co-located sets of resources together in the market. For example, the aggregate capability constraint ensures that dispatch instructions to co-located resources behind a common point of interconnection do not exceed interconnection limits.[66] As of June 1, 2023, there are 76 co-located resources across different 23 points of interconnection. Only one out of these 23 points of interconnection does not include a battery resource.

Figure 1.20 shows the total capacity of CAISO-participating battery storage as of June 1, 2023, represented in terms of maximum output (MW) and maximum duration (MWh).[67] 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 2023, active battery capacity totaled 5,500 MW—2,600 MW from stand-alone projects, 2,000 MW from co-located projects, 800 MW from the storage components of hybrid resources, and 100 MW from the storage components of co-located hybrids. Most batteries in the CAISO market have a duration of four hours.

---

65 For more information see DMM's special report:
Department of Market Monitoring, *2022 Special Report on Battery Storage*, July 7, 2023:
http://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

66 Policy changes approved in 2022 will introduce electable functionality that will prevent storage resources from receiving instructions to charge that exceed the dispatch operating target of a renewable resource at the same point of interconnection to help capture Investment Tax Credit incentives.

67 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 1.20 Battery capacity (2017–2023)

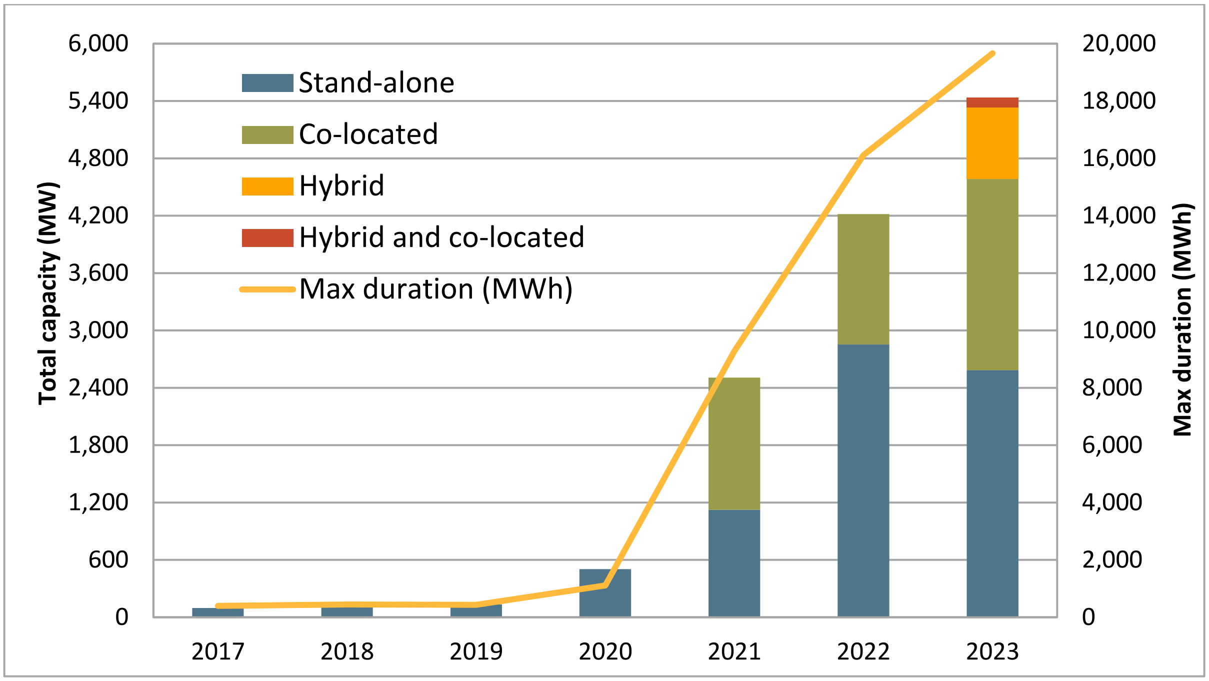


Figure 1.21 Average hourly real-time battery schedules (2021–2022)

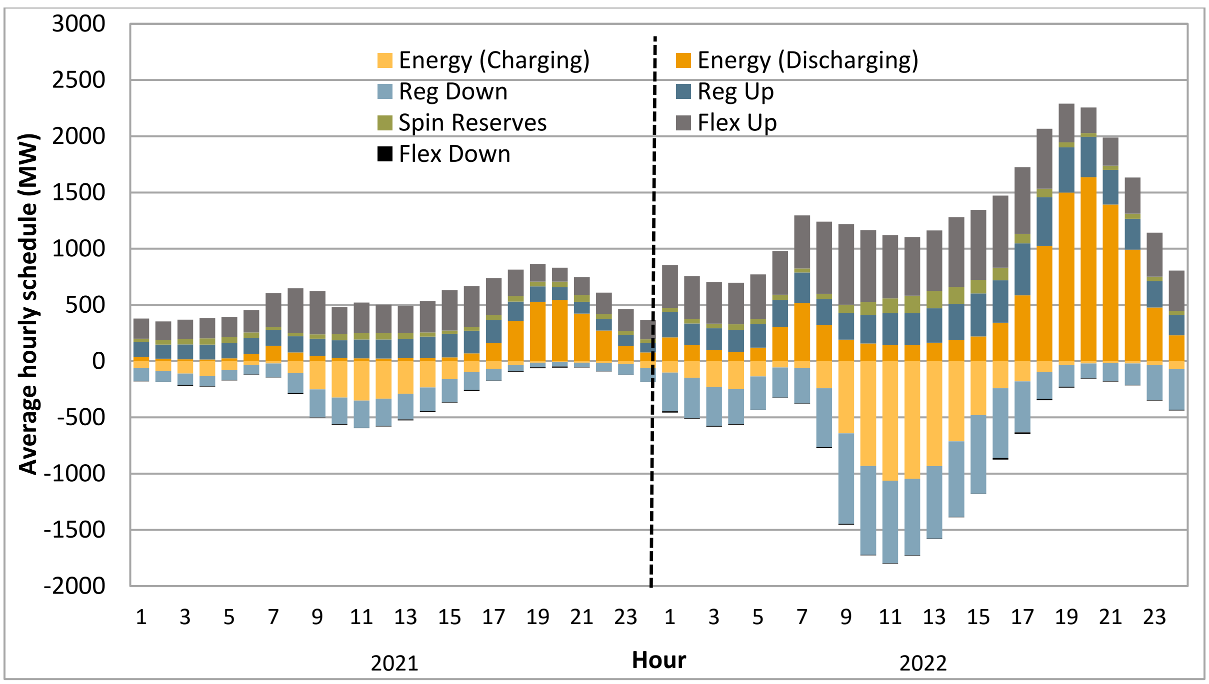


Figure 1.21 shows average hourly real-time (15-minute market) schedules of standalone battery resources. Historically, batteries have favored providing ancillary services, especially frequency regulation, over energy because it allows them to avoid deep charging and discharging cycles which cause rapid 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 73 percent of their scheduled output to discharging energy on average.

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.

Third party demand response resource adequacy capacity increased about 30 percent from 2021 to 2022. Utility demand response resource adequacy, on the other hand, decreased 20 percent. The decline in credited utility demand response is due in part to fewer demand response resources and the drop in the multiplier added to utility's demand response value.[68]

Self-reported performance of utility proxy demand response and third party supply demand response averaged 82 percent and 40 percent, respectfully, throughout July, August, and September 2022.[69] This is a decrease in performance compared to the same months in 2021. This decline in performance is due in part to tighter grid conditions in summer of 2022 compared to 2021. Demand response resources are primarily scheduled on days with high loads and tight conditions. DMM's report on demand response analyzes performances on these high load days in more detail.[70]

In addition to these demand response participating models, the California ISO issues Flex Alerts when system conditions are expected to be particularly stressed. Flex Alerts urge consumers to voluntarily reduce demand, and are communicated through press releases, text messages, and other means. In 2022, the California ISO declared Flex Alerts on August 17 and August 31 through September 9 in response to reliability concerns related to high temperatures and high system demand in California. On September 6, when the California ISO experienced an EEA 3, there were additional calls for reduced electricity consumption including an emergency alert from the Governor's Offices sent to all California residents.[71]

Figure 1.22 shows the total third-party demand response resource adequacy capacity shown on monthly supply plans in 2021 and 2022. Third-party demand response participating in the California ISO market increased 30 percent from 2021, averaging about 244 MW across 2022.

---

[68] The CPUC calculates credited demand response by multiplying the reported capacity by a number of adders. One adder is the planning reserve margin (PRM), which decreased from 15 percent to 9 percent in 2022.

[69] Performance here is measured by the comparison of resources' responses (capped at each individual resource's schedule) compared to their real-time schedules.

[70] Department of Market Monitoring, *Demand Response Issues and Performance 2022,* February 14, 2023: http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

[71] Summer Market Performance Report for September 2022: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

Figure 1.22 Third-party demand response shown on monthly resource adequacy supply plans

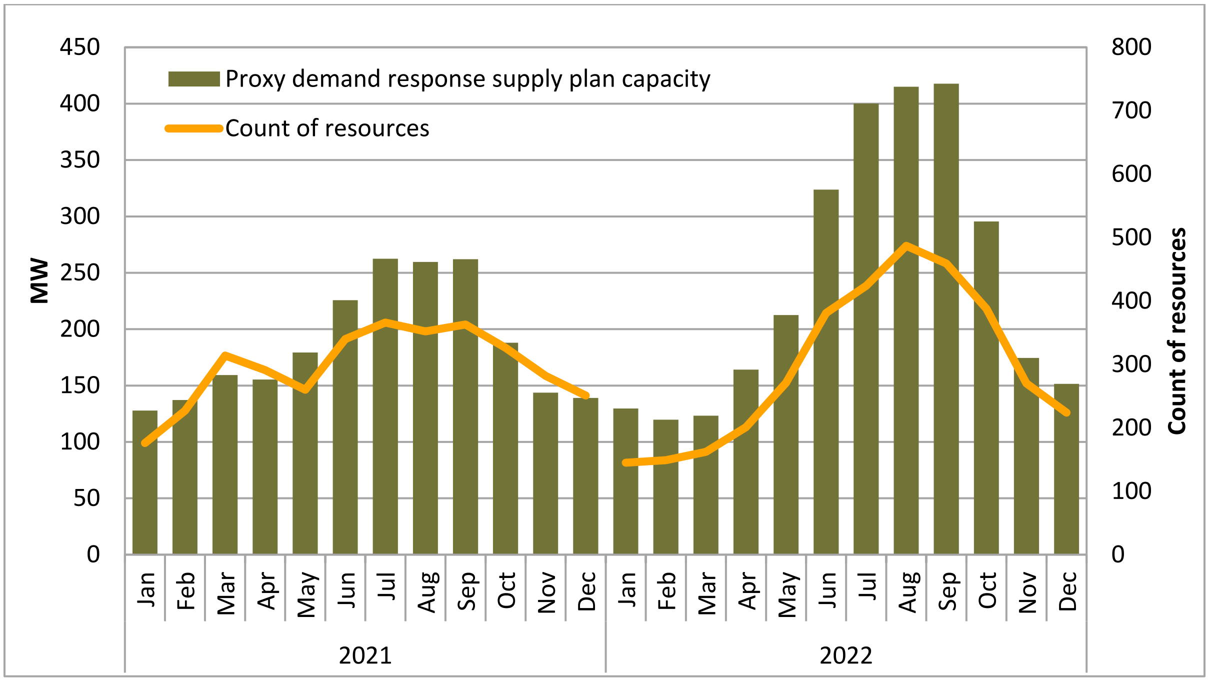


Figure 1.23 CPUC-jurisdictional utility demand response resource adequacy credits

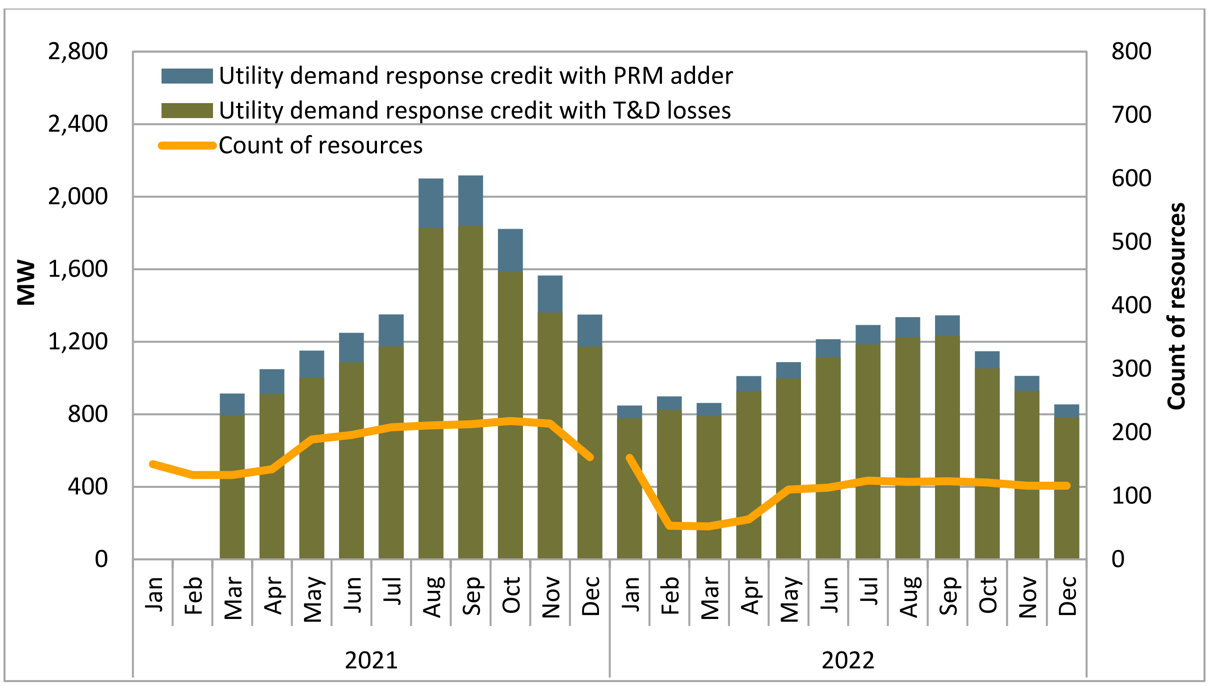


Figure 1.23 shows the total demand response resource adequacy capacity (proxy demand response and reliability demand response resources) associated with CPUC-jurisdictional utility demand response

programs.[72] 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. 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.

Dispatch and performance of demand response

The CAISO relied on demand response resources, including reliability demand response, during high load days in September 2022. The CAISO economically scheduled proxy demand response resources throughout the summer and issued manual dispatches to reliability demand response between September 5 and 7.

DMM reported on demand response availability and performance during the September heatwave and found that aggregate demand response performance was similar to the August heatwave in 2020, with roughly 65 percent of resource adequacy demand response bidding into the market and an average uncapped performance of about 70 percent.[73]

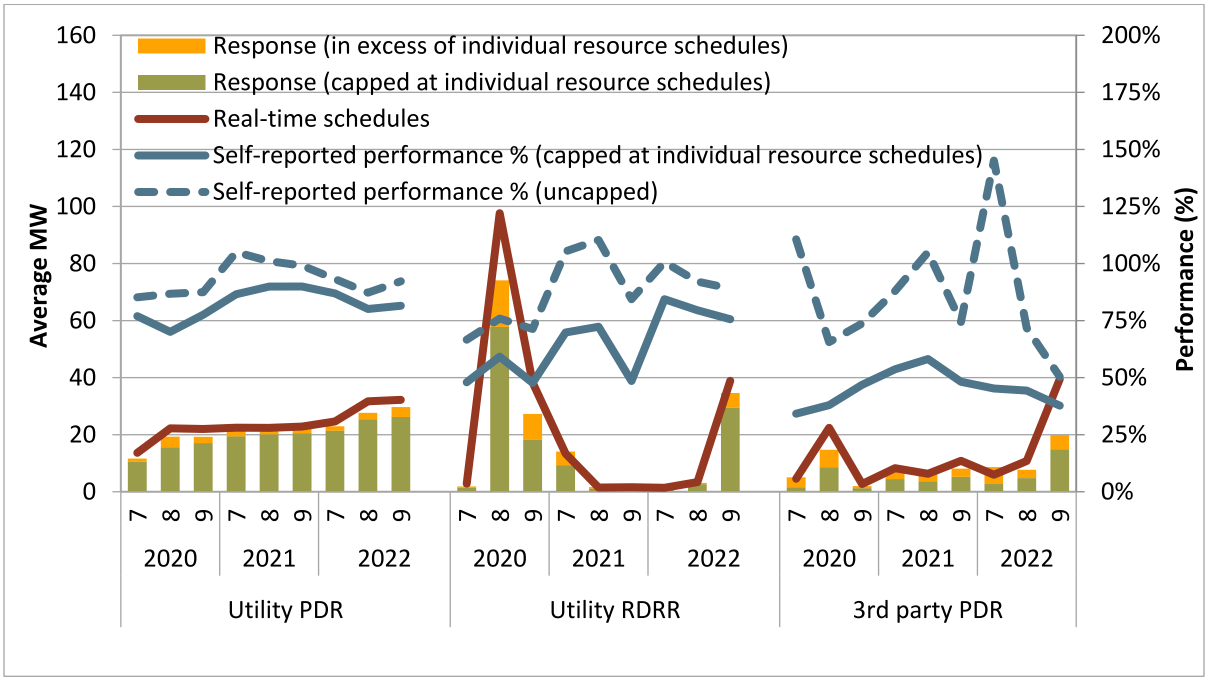
Figure 1.24 shows the expected load curtailment (schedule) of demand response resource adequacy resources compared to reported performance from July to September in 2020, 2021, and 2022 in peak net load hours (4-9 p.m.). Self-reported performance has continually been higher for utility demand response resources compared to third party demand response resources. In summer 2022, uncapped performance of proxy demand response and reliability demand response resources both averaged about 90 percent of their real-time schedule, compared to third party resources which averaged only 65 percent.

---

[72] There were no demand response (or other local regulatory authority) credits for January and February 2021 due to a business practice manual change that eventually was withdrawn by the California ISO.
California ISO, *Brief – PRR 1280 Appeal,* August 27, 2020:
http://www.caiso.com/Documents/ISOAnsweringBrief-PRR1280-Nov23-2020.pdf
California ISO, *Staff Statement on Withdrawing PRR 1280*:
http://www.caiso.com/Documents/ISOStaffStatement-WithdrawingPRR1280.pdf

[73] Department of Market Monitoring, *Demand Response Issues and Performance 2022,* February 14, 2023, p. 18:
http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

Figure 1.24 Demand response resource adequacy performance - July to September (4–9 p.m.)



1.2.5 Generation outages

The quantity of generation on outage increased by 3 percent from 2021 and by 16 percent from 2020. Generation outages typically follow a seasonal pattern with the majority of outages taking place in the non-summer months; 2022 followed this trend. The steady increase in forced outages from 2019 to 2021 slowed and the amount of forced outages was relatively consistent in 2022.

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 1.25 and Figure 1.26 show the quarterly and monthly averages of maximum daily outages by type during peak hours, respectively. 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 13,925 MW, up from 13,500 MW in 2021.[74] Outages for planned maintenance averaged about 2,925 MW during peak hours, while all other types of planned outages averaged about 1,325 MW. Some common types of outages in this category are ambient de-rates (both due to temperature and not due to temperature) and transmission related outages.

Forced outages for plant maintenance or trouble averaged about 3,375 MW, while all other types of forced outages averaged about 6,300 MW. Included in the other category of forced outages are ambient

[74] 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.

due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

Figure 1.25 Quarterly average of maximum daily generation outages by type – peak hours

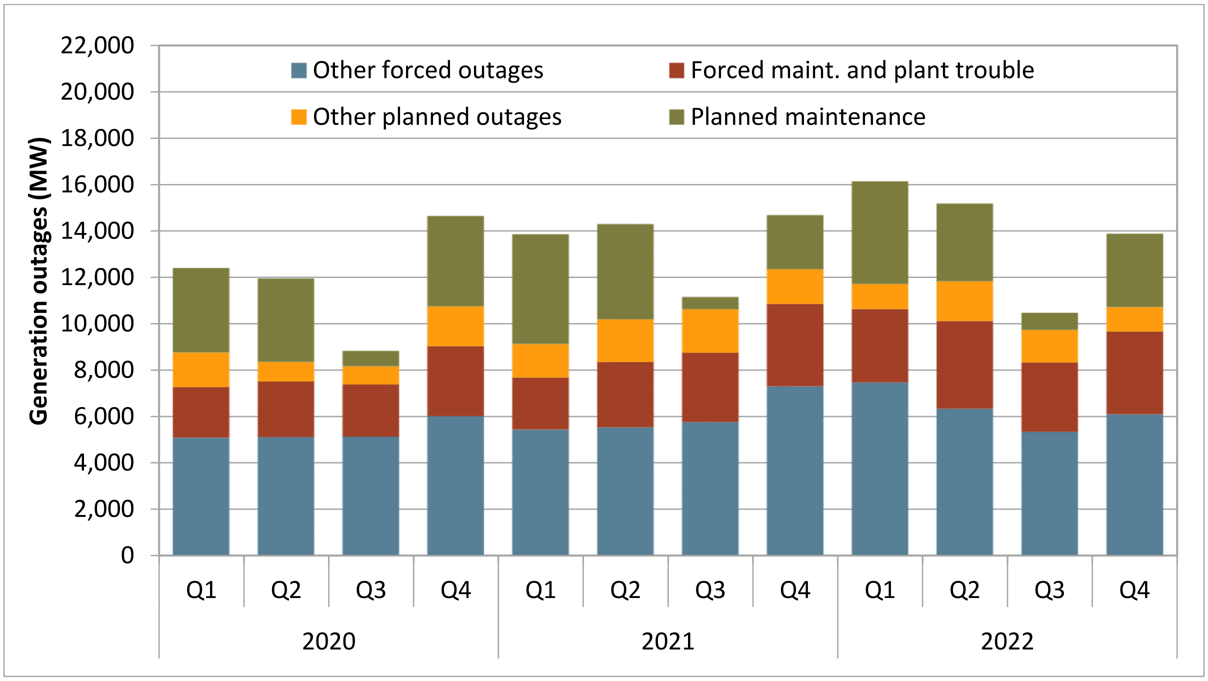
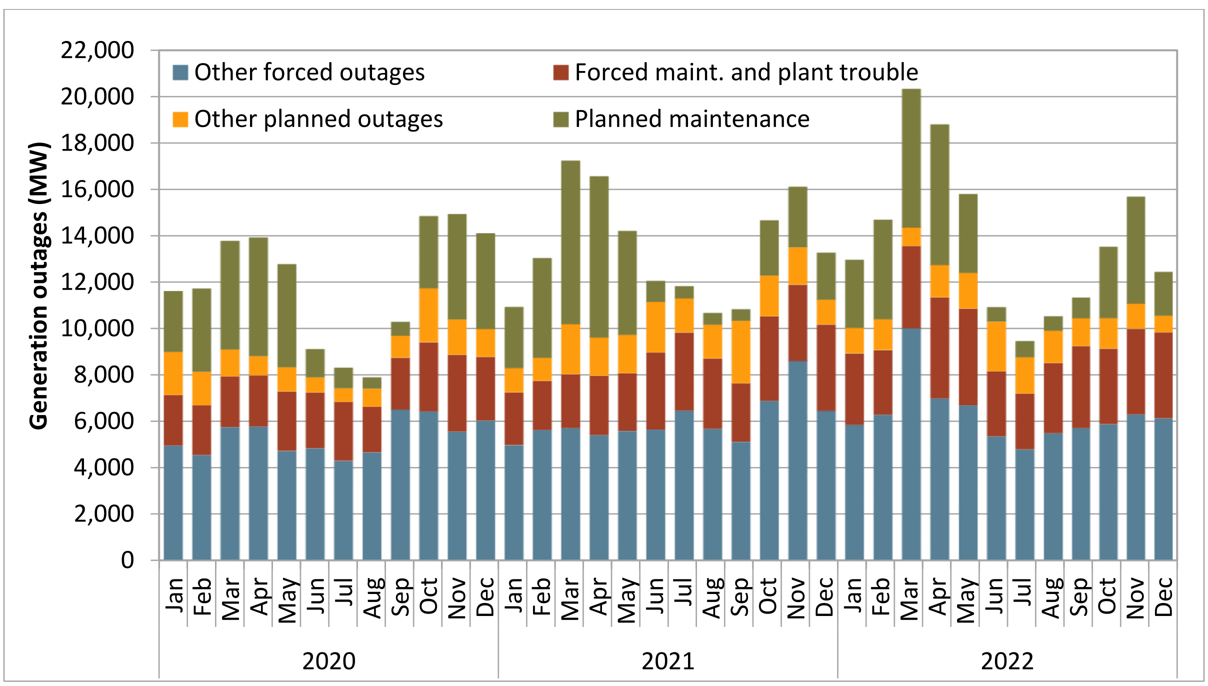


Figure 1.26 Monthly average of maximum daily generation outages by type – peak hours

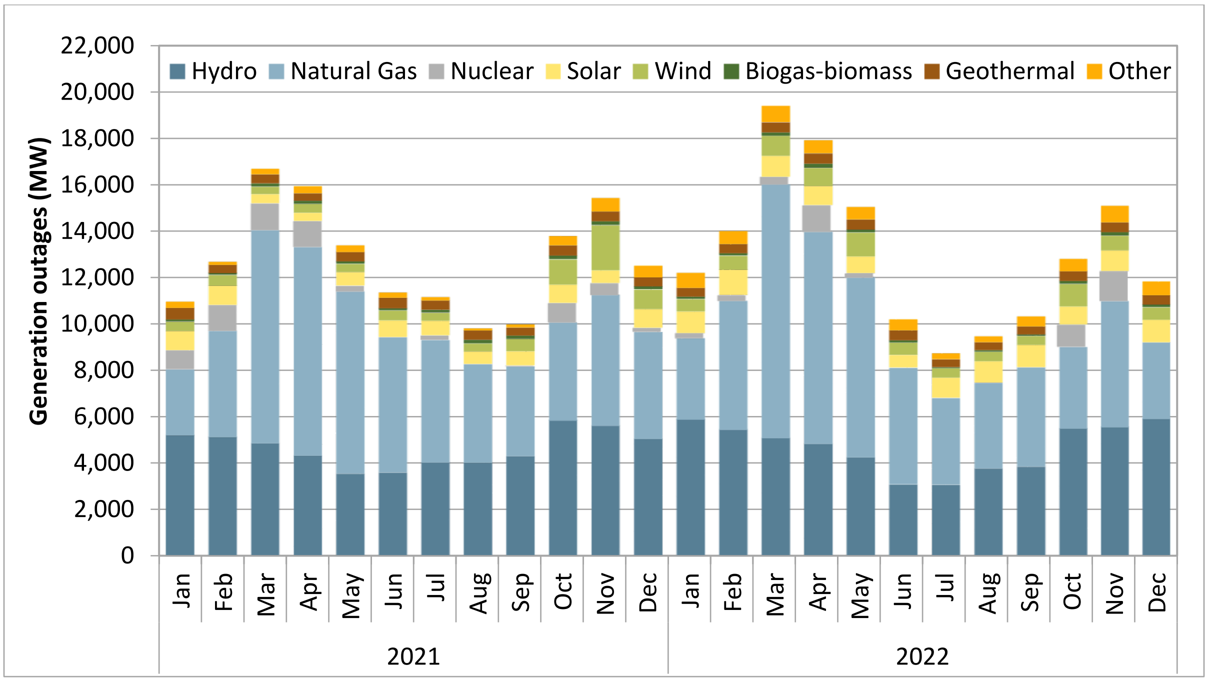


Generation outages by fuel type

Natural gas and hydroelectric generation averaged 5,600 MW and 4,625 MW on outage during 2022, respectively. Together, these two fuel types accounted for 80 percent of the generation on outage for the year.

Figure 1.27 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 19,375 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 1.27 Monthly average of maximum daily generation outages by fuel type – peak hours



1.2.6 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 and other regional markets. During December 2022, gas prices at western gas hubs started to trend at a significant premium over Henry Hub. In the CAISO footprint, load-weighted average gas price increased to $30.60/MMBtu in December 2022 compared to $6.50/MMBtu in December 2021.

Overall for 2022, average natural gas price at PG&E Citygate and Northwest Sumas increased significantly by 91 percent and 97 percent, respectively, compared to 2021. Average price at SoCal Citygate and El Paso Permian gas hubs increased moderately by 30 percent and 15 percent, respectively, compared to 2021. By comparison, average price at Henry Hub, which acts as a point of reference for the national market for natural gas, increased by 65 percent relative to 2021. This increase in natural gas prices resulted in higher system marginal energy prices across the CAISO footprint in 2022.

Figure 1.28 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 1.28, gas prices at western gas hubs spiked in December and on some days settled as high as $50/MMBtu. There were several contributing factors to persistent high gas prices in December[75]:

1. High natural gas consumption in the residential and electric power sector. Below normal temperatures leading to increased demand for natural gas;[76]
2. Reduced natural gas deliveries into the Pacific Northwest and California from supply regions. Pipeline constraints on the El Paso Natural Gas pipeline system restricting Permian Basin flows into Southern California; and
3. Low natural gas storage inventory levels in the Pacific region.[77,78] 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 have not kept pace with previous summers.[79]

The Aliso Canyon protocol remained in effect in 2022 making the facility available for withdrawals for Stage 2 or above low operational flow orders (OFO). These protocols exist to mitigate gas price spikes and maintain system reliability.[80] On November 4, 2021, the California Public Utilities Commission (CPUC) issued a temporary order increasing the inventory limit for the Aliso Canyon Storage Field from 34 Bcf to 41.16 Bcf.[81] In 2022, SoCalGas withdrew gas from the Aliso Storage facility on 60 gas days compared to 73 gas days in 2021.

In addition, on March 18, 2022, the CPUC issued a proposed decision to extend SoCalGas' 8-stage winter operational flow order (OFO) penalty structure year-round and made it applicable to the PG&E and SDG&E service territories.[82] Until November 2022, SoCalGas declared 11 low OFOs, primarily stage 1. In

---

75 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

76 Daily regional average temperatures and departure from normal, EIA Natural Gas Storage Dashboard, p. 4: https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20221215_natural_gas_storage_dashboard.pdf https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20221229_natural_gas_storage_dashboard.pdf

77 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

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

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

80 CPUC Docket No. I.17-0-002, A.18-07-024, A.17-10-007, *Aliso Canyon Withdrawal Protocol*, July 23, 2019: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf

81 CPUC Docket No. I.17-02-002, *Decision setting the interim range of Aliso Canyon Storage Capacity at 0 to 41.16 Bcf (D.21-11-008)*, November 4, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

82 Proposed Decision for CPUC Docket No. R.20-01-007, *Decision Implementing Southern California Gas Company Rule 30 Operational Flow Order Winter Noncompliance Penalty Structure Year-Round for Southern California Gas Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company,* March 18, 2022: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M460/K301/460301154.PDF

December 2022, SoCalGas declared 10 low OFOs, primarily Stage 3.3 and above, with a starting non-compliance charge of $20/dth. In the PG&E service area, there were 25 low OFOs, primarily Stage 1 declared until November 2022. In December 2022, there were 8 Stage 3 and above low OFOs declared.

Figure 1.28 Monthly average natural gas prices (2019–2022)

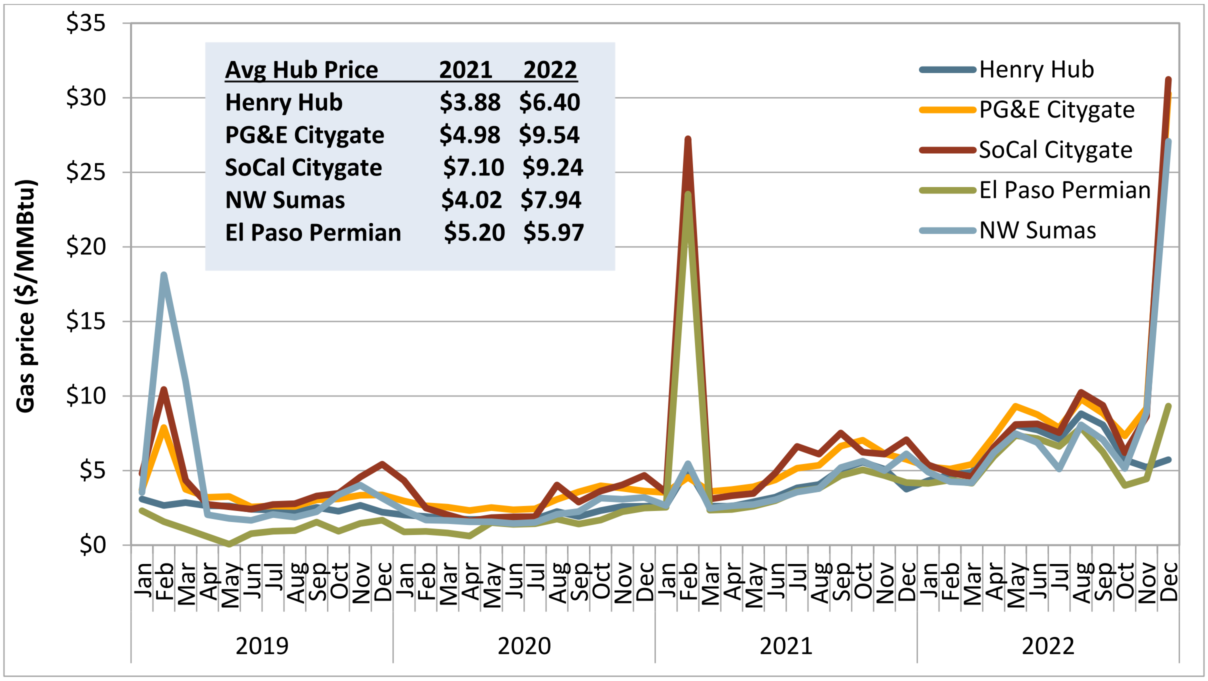


Figure 1.29 Yearly average natural gas prices compared to the Henry Hub

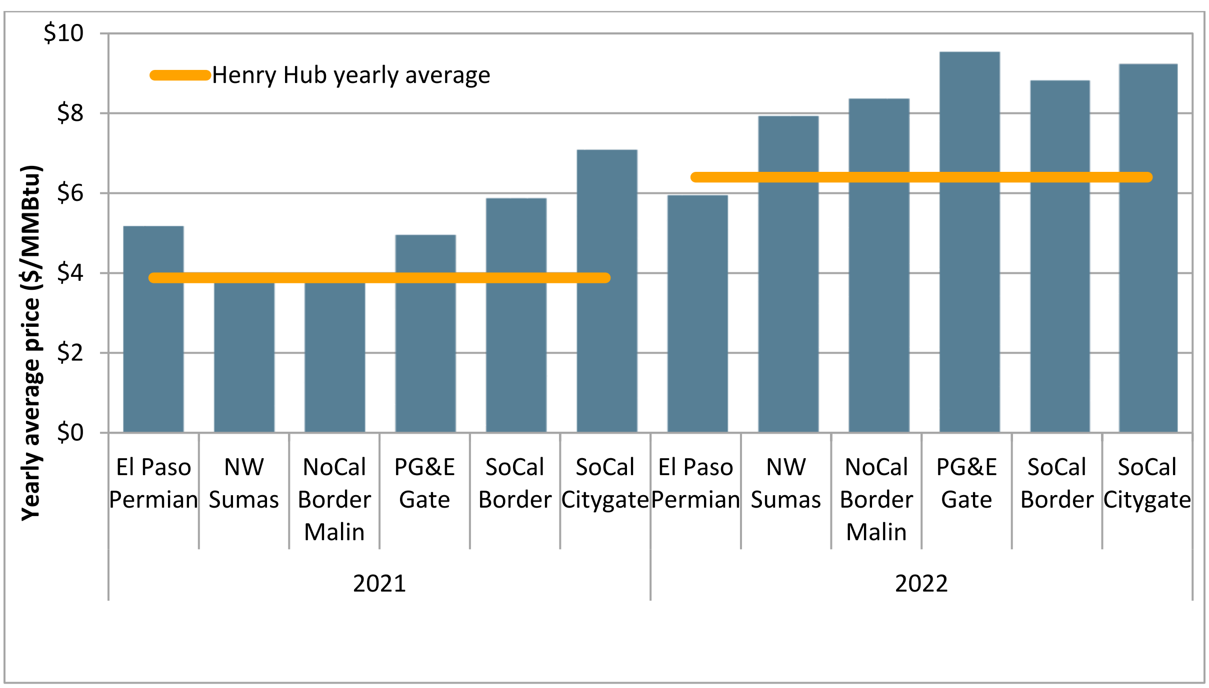


Figure 1.29 compares yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2021 and 2022. The yearly average prices in 2022 exceeded the Henry Hub reference price at all the trading hubs except El Paso Permian. On average, the yearly price at SoCal Citygate exceeded the Henry Hub average by 44 percent. Similarly, PG&E Citygate and Northwest Sumas exceeded the Henry Hub average by 49 percent and 24 percent, respectively. The average Permian price was below the Henry Hub average by 6 percent.

1.2.7 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.[83] 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 who participate in the WEIM and serve California load, which is defined as load within the California ISO such as Turlock Irrigation District, the Balancing Area of Northern California, or Los Angeles Department of Water and Power. 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 calculated as the average of two market-based indices.[84] Daily values of this greenhouse gas allowance index are plotted in Figure 1.30.

83 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. Department of Market Monitoring, *2015 Annual Report on Market Issues & Performance*, May 2016, pp. 45-48: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

84 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

Figure 1.30 California ISO greenhouse gas allowance price index

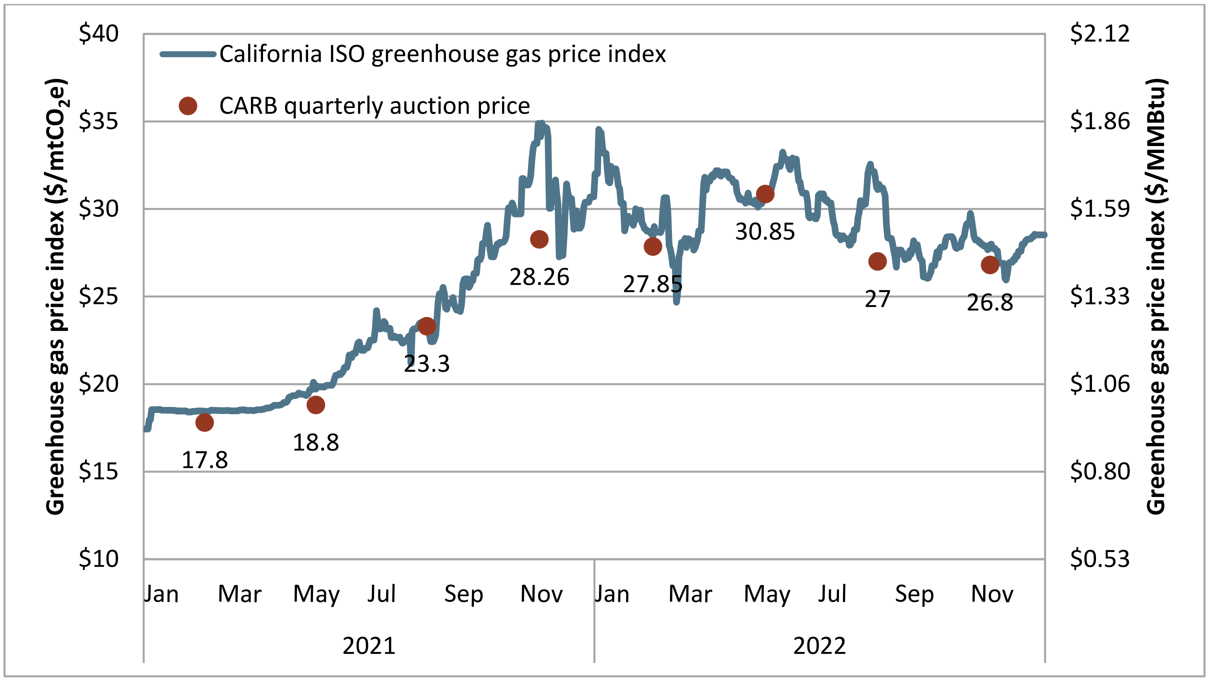


Figure 1.30 also shows market clearing prices in the California Air Resources Board's (CARB) quarterly auctions of emission allowances that can be used for the 2021 or 2022 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price 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.[85]

As shown in Figure 1.30, the average cost of greenhouse gas allowances in bilateral markets increased 27 percent from a load-weighted average of $23.14/mtCO_2e in 2021 to $29.47/mtCO_2e in 2022. In 2022, 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 $28/mtCO_2e, compared to $22/mtCO_2e last year.

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.[86] The greenhouse gas compliance cost expressed in dollars per MMBtu in 2022 ranged from about $1.3/MMBtu to $1.8/MMBtu.

---

85 The emissions factor, 0.0531148 mtCO_2e/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

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

The \$29.47/mtCO_2e average in 2022 would represent an additional cost of about \$12.52/MWh for a relatively efficient gas unit.[87] This is an increase from 2021 when the average price was \$23.14/mtCO_2e, or about \$9.83/MWh for the same relatively efficient gas resource.

1.2.8 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 incenting new generation development.

Since the record loads and stressed supply conditions in summer 2022, the primary trends in capacity changes have been the continued delay in retirement of natural gas facilities and 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 (CAISO) 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.[88]

Total California ISO registered and participating capacity

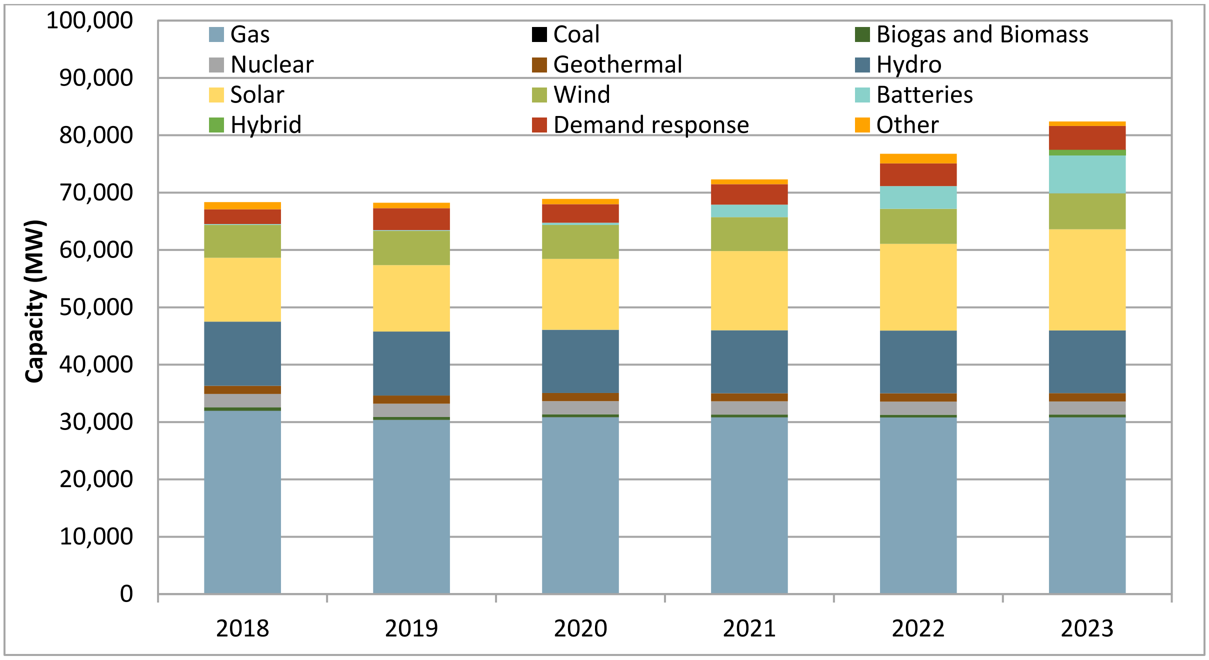
Figure 1.31 summarizes the trends in available nameplate capacity from June 2018 through June 2023. At 30.8 GW, natural gas capacity saw almost no growth since June 2020. Solar and batteries grew the most out of any resource type in CAISO, adding 2.6 GW and 2.5 GW, respectively, since June 2022. The CAISO fleet currently has 1 GW of capacity from resources with multiple generation technologies participating under the hybrid model. Overall, nameplate capacity has increased by 5.6 GW since June 2022. In comparison, the CAISO added 4.5 GW of nameplate capacity from June 2021 to June 2022.

---

87 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 85.

88 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 1.31 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 (CAISO) 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.[89] In August 2022, the CAISO Board of Governors approved an extension for Reliability Must Run (RMR) contracts for five natural gas generators, keeping 435 MW of capacity available until at least December 31, 2023.[90] Under the CAISO Tariff, an RMR contract allows the CAISO 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 proposed 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.[91]

89 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

90 California ISO, *Decision on conditional approval to extend existing reliability must-run contracts for 2023*, August 24, 2022: http://www.caiso.com/Documents/DecisiononConditionalApprovaltoExtendReliabilityMust-RunContracts-Memo-Aug2022.pdf

91 State Water Resources Control Board, *Draft Staff Report for the Amendment to the Water Quality Control Policy on the Use of Costal and Estuarine Waters for Power Plant Cooling*, January 31, 2023, p. 8: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/2023/draft-staff-report.pdf

Retirements of CAISO capacity have slowed down significantly in the past three years. From June 2016 to June 2020, there was substantial retirement of natural gas plants, averaging about 2,000 MW each year. Since June 2020, only 350 MW of capacity withdrew from market participation. Most of the retired capacity supported either system resource adequacy or local resource adequacy for the LA Basin area.

Additions to participating capacity

Figure 1.32 shows additions to California ISO (CAISO) 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.[92]

From June 2017 to June 2023, 8,000 MW of solar, 2,000 MW of gas capacity, 1,500 MW of wind, 1,000 MW of hybrid, and 6,500 MW of battery capacity were added or returned to the market.[93] The majority of the increase in battery capacity happened within the last two years, with 4,600 MW of capacity added since June 2021.

Figure 1.32 Additions to California ISO market participation by fuel type[94]

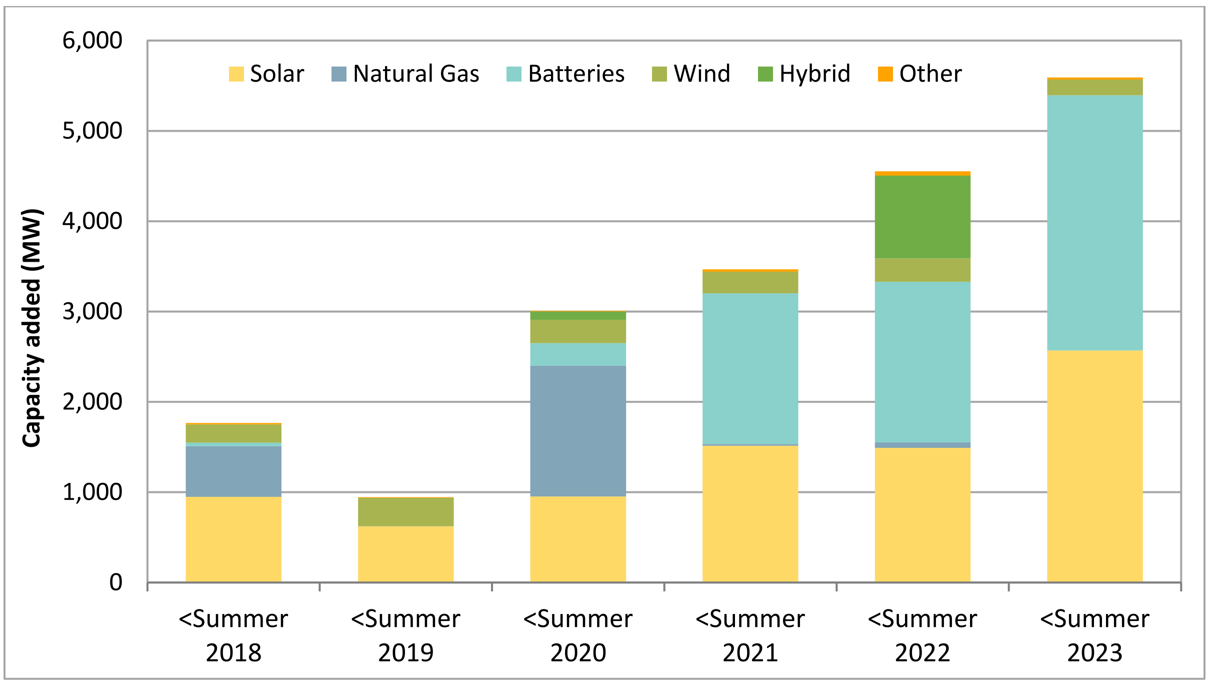


Figure 1.33 shows additions by local area according to local resource adequacy showings. Resources shown for system resource adequacy (RA) are labeled as CAISO System.[95] In the last couple of years, a

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

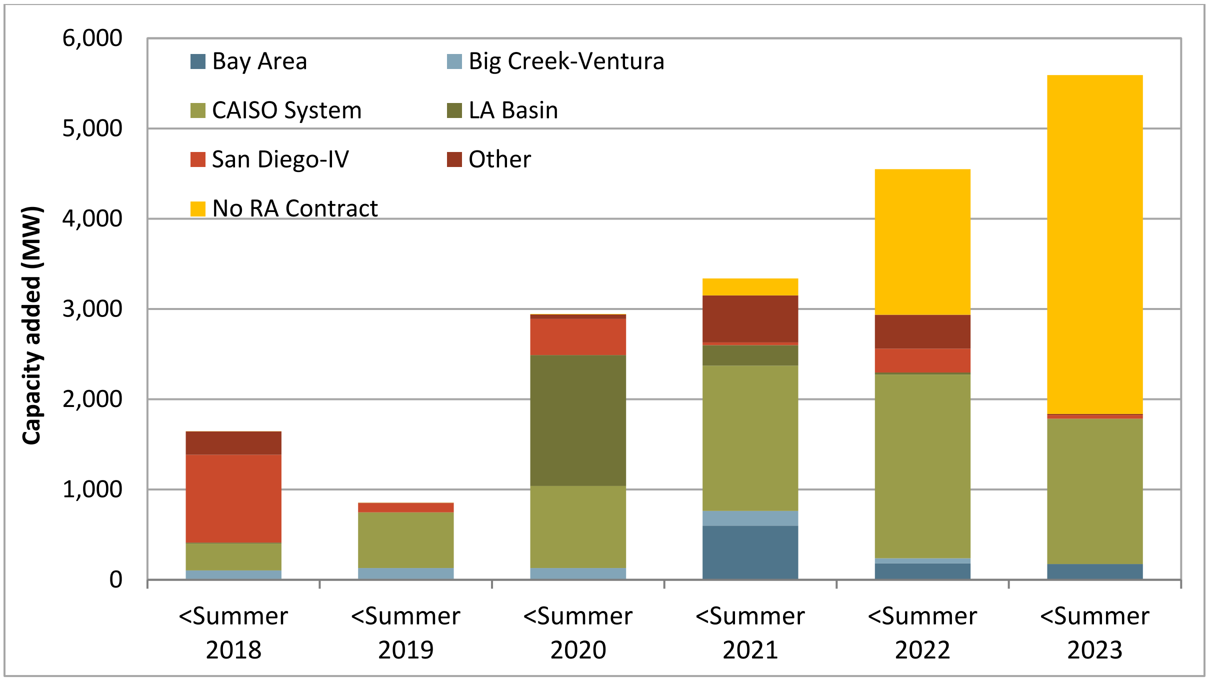
93 Resource additions often transition into the market with various phases of testing, so the exact date of market entry reported can vary.

94 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.

95 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.

significant amount of the new capacity came in as system RA, with around 2,000 MW added from June 2021 to June 2022, and 1,600 MW added from June 2022 to June 2023. The majority of added capacity from June 2022 to June 2023 has no RA contract as of this report's publication, though this is subject to change.

Figure 1.33 Additions to California ISO market participation by local area



The CAISO 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, 55 percent of which comes from mixed-fuel projects. Mixed-fuel projects most commonly have a renewable component paired with a battery.

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.[96] However, many projects drop out of the interconnection queue before their interconnection studies are finished. Projects that have dropped out of the CAISO's interconnection queue historically have waited an average of 554 days from their queue start date until dropping out. Historically, the average wait time for completed projects is 2,078 days. The average wait time for projects in the current queue is 2,366 days.

96 California ISO, *20 Year Transmission Outlook*, 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. Starting in 2020, this analysis has been expanded to include net market revenues for a new battery energy storage system (BESS). Results from the analysis show that net market revenues for a battery unit participating in both energy and regulation markets is significantly higher than just participating in energy price arbitrage. In addition, net revenues in 2022 are higher in northern and central local capacity areas than southern areas under these scenarios.

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 2022, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $53 to $72/kW-yr compared to total annualized fixed costs of about $132/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $53 to $60/kW-yr compared to total annualized fixed costs of about $162/kW-yr.

In addition, estimated net energy market revenues of gas units in 2022 were, on average, higher 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 $30 to $39/kW-yr, compared to net energy market revenues of $53 to $72/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $53 to $60/kW-yr in 2022 compared to estimated annualized going-forward fixed costs of about $31 to $32/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 is currently set at $76/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 justify its decision adequately to allow a 20 percent adder for bids above the CPM soft offer cap.[97] On

[97] U.S. Court of Appeals, Order No. 20-1388 on *Petition for Review of Order Regarding Bids Above CPM Soft Offer Cap*, December 17, 2021: https://www.cadc.uscourts.gov/internet/opinions.nsf/A7E4F1659200B2B4852587AE0054513A/$file/20-1388-1927124.pdf

April 22, 2022, FERC issued an order reversing its original determination and finding that the California ISO has not demonstrated that the proposed 20 percent adder is just and reasonable.[98] On May 23, 2022, the California ISO submitted a compliance filing excluding the 20 percent adder from the compensation methodology.[99] The California ISO is currently working on a stakeholder initiative to examine the CPM soft offer cap and consider whether it needs to be changed.[100]

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.[101] Incremental energy costs are calculated using default energy bids used in local market power mitigation.[102] Commitment costs are calculated using proxy start-up and minimum load cost methodology.[103]

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.

---

98 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

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

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

101 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, 2022 total average annual net revenues for regulation (up and down), and spinning reserves were approximately $0.70/kW-yr, and payments for flexible ramping capacity were around $0.05/kW-yr. Similarly, for a combustion turbine unit, 2022 total average net revenues for spinning and non-spinning reserve were $7/kW-yr, while average flexible ramping payments were $0.14/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.

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

103 Start-up and minimum load costs are calculated using the proxy cost option as described in: California ISO, *Business Practice Manual Change Management, Market Instruments, Appendix G.2, Proxy Cost Option*: 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: California ISO, *Business Practice Manual Change Management, Market Instruments, Appendix M.2, Retail Region Price*: 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*).[104] However, instead of fixed annual O&M costs from the CEC report, DMM now uses estimates derived from DMM's review of California-specific and nationwide sources.[105] 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 O&M costs of combined cycle gas units. In this report, DMM estimates that annual going-forward fixed costs range from $30 to $39/kW-yr for a typical combined cycle resource and $32 to $33/kW-yr for a typical combustion turbine.[106]

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 that were used in the optimization model. The table also provides a breakdown of financial parameters that contribute to the estimate of total annualized fixed costs for a new 2x1 combined cycle unit.

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

Table 1.4 shows the optimization model results using the parameters specified in Table 1.3. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or

---

[104] 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

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

[106] 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.

Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2022.

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 2022, for a unit located in NP15 with the above assumptions, net revenues were $53/kW-yr with an 18 percent capacity factor.[107] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $60/kW-yr with a 26 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.[108] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2022 for a hypothetical unit in the NP15 area were $62/kW-yr with a 23 percent capacity factor. In the SP15 area, net annual revenues were $72/kW-yr with a 34 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 $57/kW-yr with a 28 percent capacity factor. In the SP15 area, net annual revenues were $65/kW-yr with a 30 percent capacity factor.

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

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

Table 1.3 Assumptions for typical new 2x1 combined cycle unit[109]

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 (2022)	$6,665	$13,330
Minimum load major maintenance cost adder (2022)	$333	$666
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	40 MW/minute	40 MW/minute
Financial Parameters (2022)		
Financing costs		$91 /kW-yr
Insurance		$7 /kW-yr
Ad Valorem		$9 /kW-yr
Fixed annual O&M		$13.5 /kW-yr
Taxes		$11 /kW-yr
Total Fixed Cost Revenue Requirement		**$132 /kW-yr**

109 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 manufacturer spec sheet and resource operational characteristics of a typical combined cycle unit within the California ISO balancing area: https://assets.siemens-energy.com/siemens/assets/api/uuid:2ead6ba9-ceea-4053-a079-a0496124af45/gas-portfolio-brochure.pdf

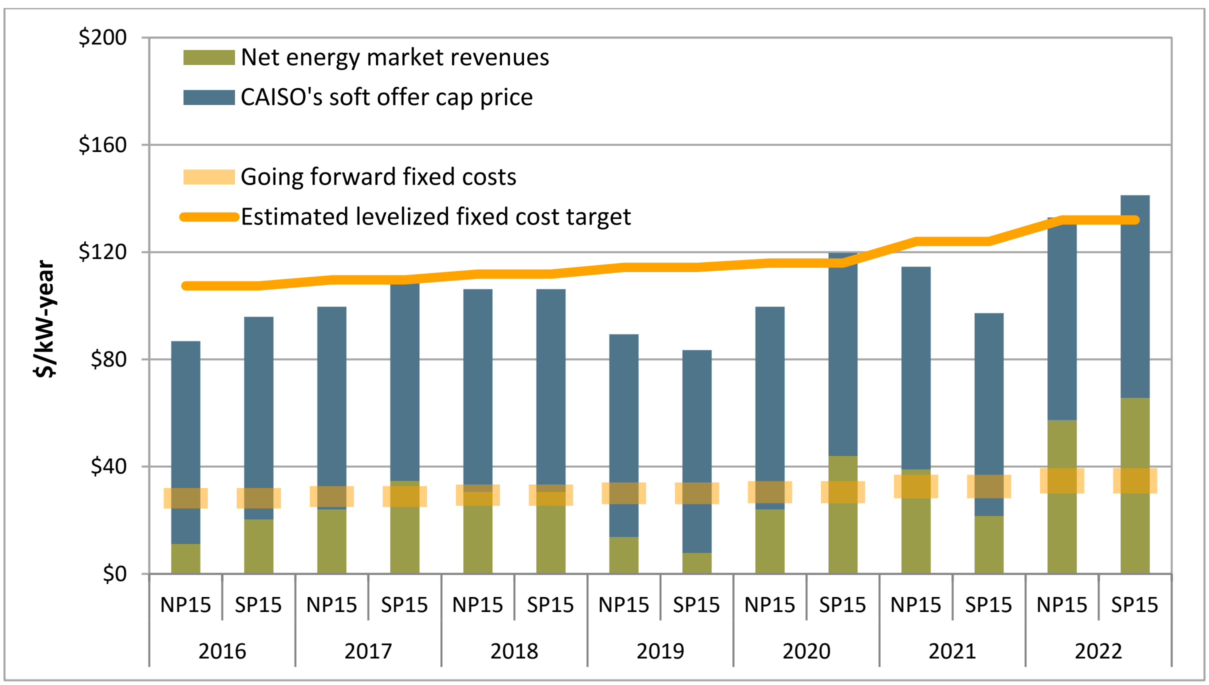
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

Table 1.4 Financial analysis of new combined cycle unit (2022)

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	18%	$273.88	$221.31	$52.57
	Day-ahead prices and default energy bids without adder	23%	$332.58	$270.35	$62.23
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	28%	$358.00	$300.97	$57.04
SP15	Day-ahead prices and default energy bids	26%	$329.57	$269.82	$59.75
	Day-ahead prices and default energy bids without adder	34%	$404.53	$332.76	$71.76
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	30%	$358.65	$293.44	$65.21

Figure 1.34 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 ($75.68/kW-yr).

Figure 1.34 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.34, compared to 2021, net revenues in 2022 for both NP15 and SP15 areas are significantly higher. This is primarily because of high gas prices resulting in relatively high day-ahead prices in 2022 compared to 2021. This in turn led to increased unit commitment and dispatch, and hence increased net energy market revenues.

Figure 1.34 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.

For 2022, the average net revenues, on average, exceeded the going-forward fixed cost estimate range, shown by transparent yellow bars in Figure 1.34. As shown in this chart, DMM estimates that annual going-forward fixed costs range from $30 to $39/kW-yr for combined cycle resources.

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 2022 ranged between 6 and 80 percent with an average of 47 percent capacity factor. In the SP15 area, actual capacity factors ranged between 35 and 49 percent, with an average capacity factor of 42 percent. Our estimates ranged from 18 to 34 percent and were relatively low, compared to 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.

Additionally, software limitations make shutdown instructions less frequent for these resources during the middle of the day because of the limited dispatch horizon used.[110] This can result in a resource staying on in the mid-day hours even when it is uneconomic to do so. This in turn might lead to out-of-market uplift payments. 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.[111]

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 2022.

110 The real-time market only sees a couple hours ahead of the current dispatch interval. This can be an issue for resources that have to honor minimum downtime constraints. DMM has observed cases where resources could turn off and honor their minimum downtime if they received the signal to shut down early enough. However, the market does not always look out far enough to give enough time for a resource to shut down and honor its minimum downtime. Our optimization model does not have this limitation.

111 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[112]

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 (2022)	$0
Minimum load major maintenance cost adder (2022)	$214
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters (2022)	
Financing costs	$120 /kW-yr
Insurance	$10 /kW-yr
Ad Valorem	$12 /kW-yr
Fixed annual O&M	$9 /kW-yr
Taxes	$12 /kW-yr
Total Fixed Cost Revenue Requirement	**$162 /kW-yr**

112 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 manufacturer spec sheet based on the technology type and resource operational characteristics of a typical peaking unit within the California ISO area: https://www.ge.com/content/dam/gepower/global/en_US/documents/gas/gas-turbines/aero-products-specs/lm6000-fact-sheet-product-specifications.pdf

Table 1.6 Financial analysis of new combustion turbine (2022)

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	4.1%	$118.43	$65.66	$52.76
	15-minute prices and default energy bids without adder	5.4%	$144.44	$88.40	$56.04
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	5.4%	$142.79	$82.96	$59.83
SP15	15-minute prices and default energy bids	5.6%	$135.14	$82.12	$53.01
	15-minute prices and default energy bids without adder	7.5%	$160.76	$103.68	$57.08
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	6.1%	$145.14	$88.62	$56.52

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 2022 prices, net annual revenues were approximately $53/kW-yr with a 4 percent capacity factor. Similarly, in the SP15 area, net revenues were approximately $53/kW-yr with a 5.6 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.[113] Using this scenario, the hypothetical unit in NP15 earned net revenues of about $56/kW-yr with a 5.4 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $57/kW-yr with a capacity factor of 7.5 percent.

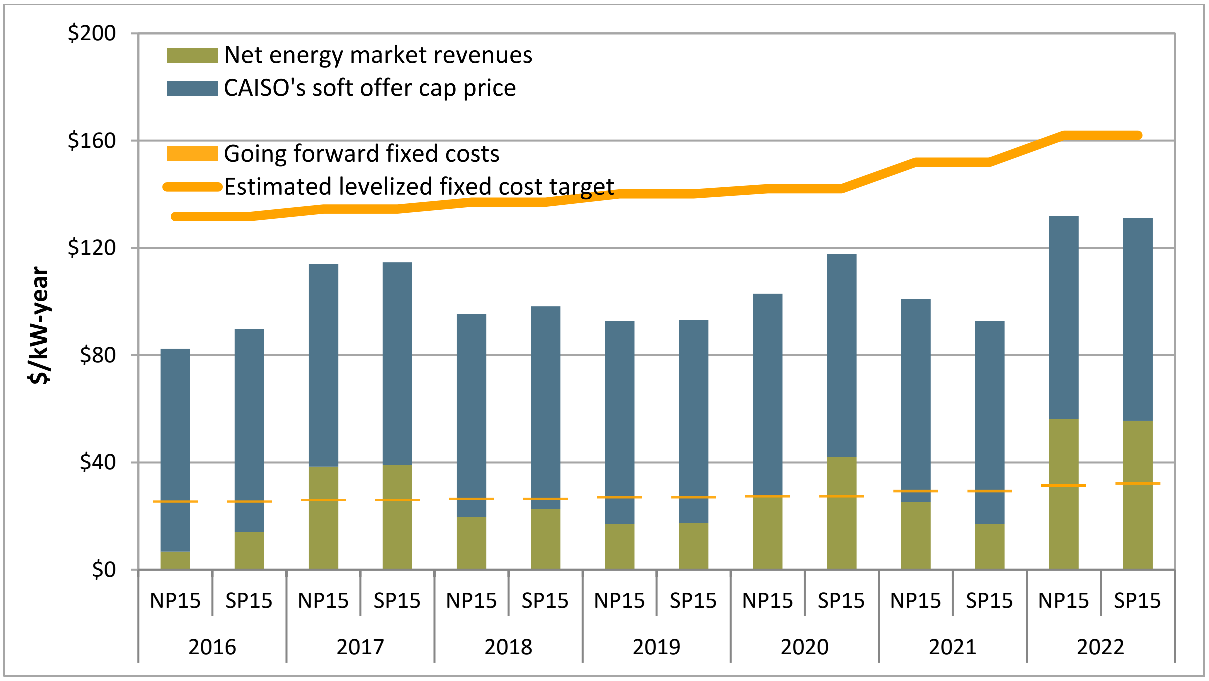
The third scenario includes all of the unit assumptions made in the first scenario, but also includes 5-minute prices for calculating unit revenues in addition to 15-minute prices. Specifically, this methodology commits the resource based on 15-minute market prices and then re-optimizes the dispatch 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 $60/kW-yr with a 5.4 percent capacity factor. In the SP15 area, net revenues were about $57/kW-yr with a 6 percent capacity factor.

Figure 1.35 shows how net revenue results from the optimization model compare to estimated annualized fixed costs of a hypothetical combustion turbine unit.[114] The green bars in this chart show estimated net revenues over the past seven years.

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

114 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 1.35 Estimated net revenues of new combustion turbine



As shown in Figure 1.35, net revenues for a hypothetical combustion turbine rose significantly in 2022 when compared to 2021. In NP15 area, the net revenues were more than twice than they were in 2021. In the SP15 area, the net revenues were more than three times the revenues in 2021. The increase in net revenues can be attributed to high real-time energy prices resulting from overall high gas prices in 2022.

Figure 1.35 shows that, from 2016 through 2022, 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 2022 ranged between 0.45 and 16 percent, with an average capacity factor of 5 percent. In the SP15 area, actual capacity factors ranged between 0.17 and 7 percent, with an average capacity factor of 3.4 percent. DMM's estimates ranged from 4 to 7.5 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 2022.

- **Total wholesale costs increased by about 69 percent** to $21.6 billion due to substantially higher natural gas prices. Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs increased 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 $3.04/MWh or 3.13 percent, compared to 3.2 percent in 2021.
- **Energy market prices were about 74 percent higher in 2022 compared to 2021,** primarily due to higher natural gas prices. 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 load forecast and additional energy from out-of-market commitments and dispatches issued after the day-ahead market.[115]
- **Total CAISO real-time imbalance offset costs totaled $408 million this year,** by far the highest value since 2009, compared to $176 million in both 2021 and 2020. Congestion offset costs, $257 million, were largely generated by significant reductions in constraint limits between the day-ahead and 15-minute markets. Record high energy offset costs, $121 million, were largely due to a structural inconsistency in the settlement of real-time market demand and generation.
- **Bid cost recovery payments in the California ISO increased to the highest value since 2011,** totaling $297 million, up from $158 million in 2021, or about 1.2 percent of total energy costs. This increase was similar to the increase in wholesale costs. Payments to non-fast start gas resources accounted for more than half of payments in both 2021 and 2022.
- **Bid cost recovery payments for units in the Western Energy Imbalance Market totaled about $42 million** up from $22 million in 2021. The cost of these payments is allocated back to the balancing area where the units receiving these payments are located.
- **Net profits paid to convergence bidders increased to about $106 million** from $38 million in 2021 from $45 million in 2020. During the 2022 summer heat wave, market participants earned $36.25 million in net revenues from virtual demand, which represents nearly 93 percent of net revenues for virtual demand in all of 2022.
- **Recent changes to the residual unit commitment (RUC) process** allow exports to be curtailed when procurement alone fails to bridge the gap between physical supply cleared in the day-ahead and the day-ahead forecast load. Significant volumes of exports clearing the day-ahead market were curtailed through the residual unit commitment process on the highest load days.
- **Flexible ramping product** system-level prices were zero for over 99 percent of intervals in the 15-minute market and 5-minute market for each of upward and downward flexible ramping capacity. The California ISO implemented nodal procurement for the flexible ramping product in February 2023, which was expected to resolve two issues lowering prices (1) stranded flexible ramping capacity and (2) the undesirable interplay between local and system requirements.

[115] The California ISO is investigating factors contributing to a day-ahead price premium in an ongoing stakeholder process, Price Formation Enhancements: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2022 was about $21.6 billion, or about $95/MWh. This represents a 69 percent increase from about $56/MWh or $12.6 billion in 2021. After normalizing for natural gas prices and greenhouse gas compliance costs, using 2018 as a reference year, DMM estimates that total normalized wholesale energy costs increased by about 10 percent from about $41/MWh in 2021 to just over $45/MWh in 2022.

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

- **A large increase in natural gas prices.** Spot market natural gas prices increased more than 50 percent from 2021 (Section 1.2.6);
- **Record high loads in early September were part of an extended regional heatwave**; and
- **Higher costs for electricity outside of the California ISO**; net imports decreased on average in each hour (Sections 1.2.1, 1.2.3 and 2.3.1)

Other factors moderated the increase, contributing to lower total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to lower prices include the following:

- **New generation capacity.** The CAISO added more than 4 GW of solar, battery, hybrid, and wind capacity between the summer of 2021 and 2022 (Section 1.2.8)**;**
- **Higher hydroelectric production.** Hydroelectric production increased by about 24 percent from 2021 (Section 1.2.2); and
- **A significant decrease in structurally uncompetitive hours** in the day-ahead energy market (Section 5.1.1).

Figure 2.1 Total annual wholesale costs per MWh of load (2018–2022)

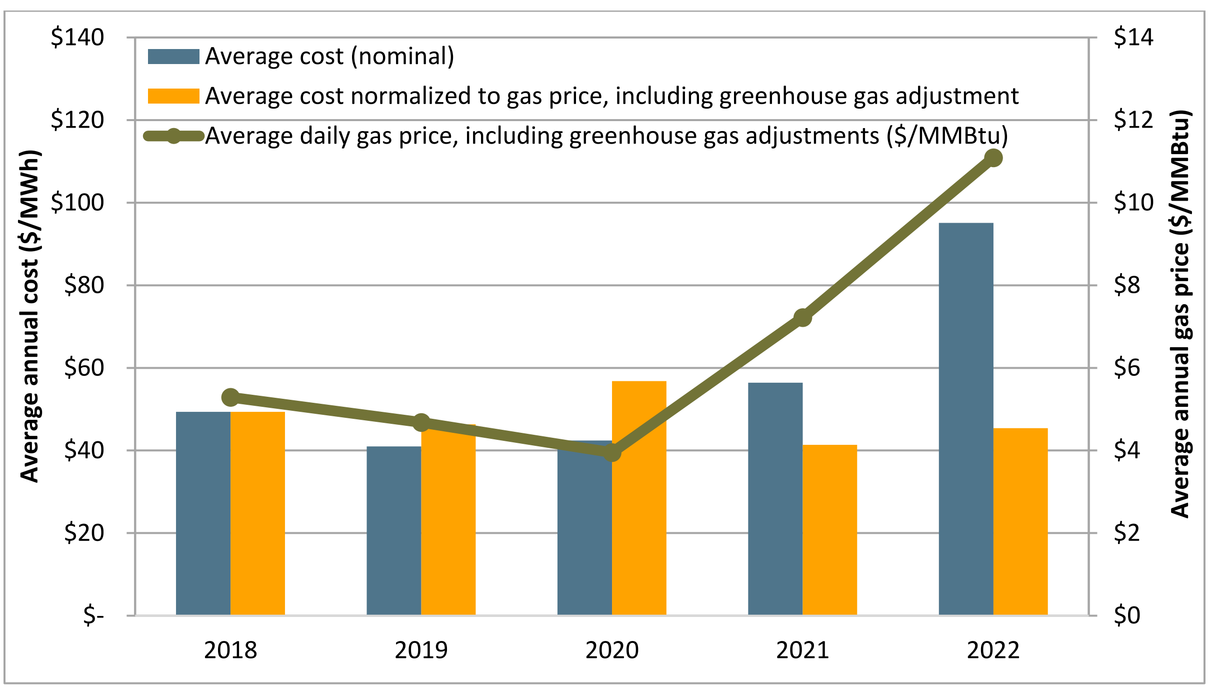


Figure 2.1 shows total estimated wholesale costs per megawatt-hour of system load for the previous five years. Wholesale costs are provided in nominal terms (blue bar), and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost 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.[116]

Table 2.1 provides annual summaries of nominal total wholesale costs by category for the previous five years.[117] 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 constraint and product, and grid management charges.[118]

As shown in Table 2.1, the 69 percent increase in total nominal cost in 2022 was largely from changes in day-ahead energy costs, which increased by over $36/MWh or roughly 68 percent. Real-time energy costs more than doubled from $1.21/MWh to $3.13/MWh, as discussed in more detail in Section 2.3. Bid cost recovery and reserve costs also increased, by over 60 percent and 40 percent, respectively. Combined natural gas and greenhouse gas costs increased about 54 percent.

Day-ahead energy costs remain the largest proportion of wholesale costs at about 94 percent. The remaining components continue to represent a relatively small portion of the total. Real-time energy costs increased to 3 percent of overall costs, compared to 2 percent in 2021, and remaining cost categories saw modest proportional decreases. Overall reliability costs continued to increase due to additional costs for reliability must-run (RMR) contracts, while decreasing as a percent of total cost to 0.23 percent from 0.33 percent in 2021.[119] Bid cost recovery totals increased significantly, partly due to the rise in gas prices at major trading hubs in the West during December 2022, but decreased slightly as a percent of total cost. Reserve costs increased over 40 percent in 2022, partly as a result of record high

---

[116] 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 this report, we have adjusted the factor to 1, to account for the linear relationship between the changes in gas costs from year to year and the corresponding changes in electricity costs. We also performed sensitivity analyses using different gas cost normalization factors for each year, as described in the 2021 annual report. With this method, the gas normalized wholesale electricity cost, in dollars per megawatt-hour, increased by 11 percent with a factor of 0.85 between 2021 and 2022. Additional sensitivities were performed for different gas cost factors, where a factor of 0.8 resulted in a 20 percent increase in 2022, 0.9 resulted in a 17 percent increase, and 0.7 resulted in a 31 percent increase. Detailed sensitivity results are available upon request.

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

[118] 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. Department of Market Monitoring, *2009 Annual Report on Market Issues & Performance,* April 2010: http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf

[119] Costs for reliability must-run contracts increased to about $48 million in 2022 from $38 million in 2021 (Section 9.7).

loads during the extended heat wave in early September, while decreasing from 1.4 percent of total cost in 2021 down to 1.2 percent in 2022.[120]

Table 2.1 Estimated average wholesale energy costs per MWh (2018–2022)

	2018	2019	2020	2021	2022	Change '21-'22
Day-ahead energy costs	$ 46.05	$ 38.13	$ 38.61	$ 53.09	$ 89.12	$ 36.03
Real-time energy costs (incl. flex ramp)	$ 0.59	$ 1.02	$ 1.65	$ 1.21	$ 3.13	$ 1.92
Grid management charge	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ 0.42	$ (0.01)
Bid cost recovery costs	$ 0.68	$ 0.56	$ 0.60	$ 0.70	$ 1.12	$ 0.42
Reliability costs (RMR and CPM)	$ 0.68	$ 0.06	$ 0.07	$ 0.19	$ 0.22	$ 0.03
Average total energy costs	**$ 48.47**	**$ 40.23**	**$ 41.40**	**$ 55.61**	**$ 94.01**	**$ 38.40**
Reserve costs (AS and RUC)	$ 0.87	$ 0.75	$ 1.02	$ 0.79	$ 1.11	$ 0.32
Average total costs of energy and reserve	**$ 49.34**	**$ 40.98**	**$ 42.42**	**$ 56.40**	**$ 95.12**	**$ 38.72**

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 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.[121] 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. 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.[122]

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

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

122 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.

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 $3.04/MWh or 3.13 percent, compared to $1.83/MWh or 3.2 percent the previous year. Very low price-cost markup values indicate that prices were competitive overall for the year.

Figure 2.2 Day-ahead market price-cost markup – competitive baseline scenario[123]

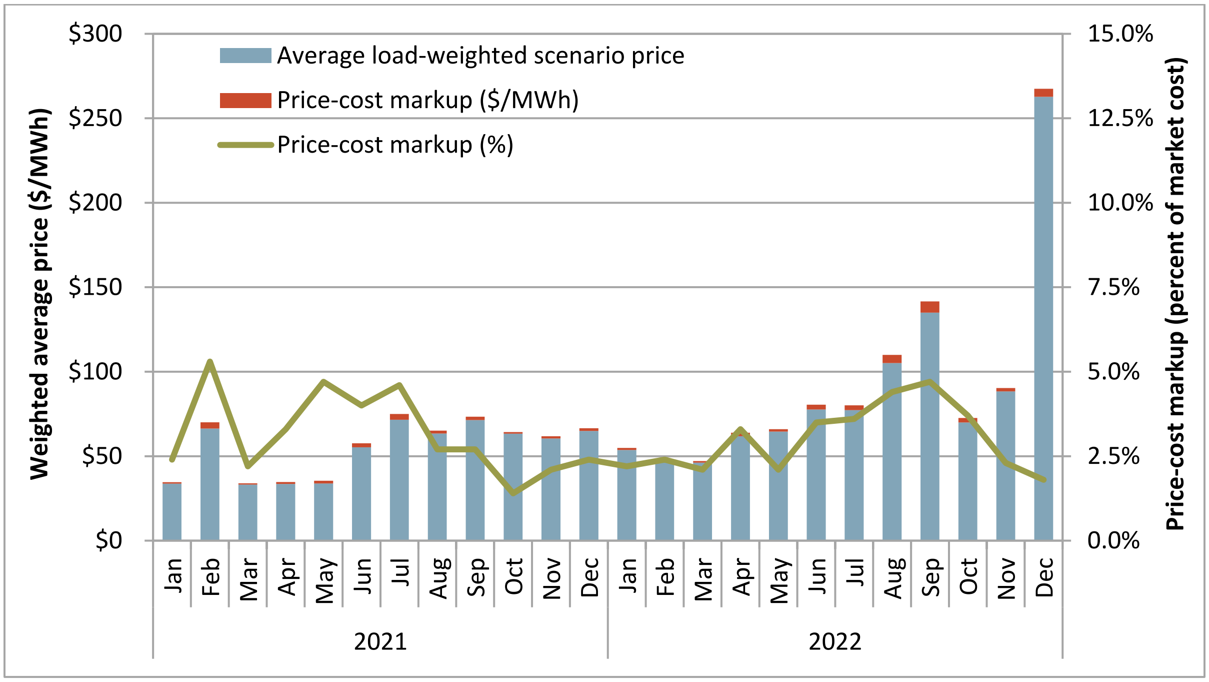


Figure 2.3 shows daily average price-cost markup values for the intense heat wave period in early September 2022. Extended high temperatures during this period led to high prices and record demand. The competitive baseline price was more frequently lower than the day-ahead market price on these days, with the average daily price-cost markup value rising to just over 9 percent on September 6 when peak demand exceeded 52 GW.

123 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 $2.19/MWh or 2.25 percent in 2022, compared to $1.41 or almost 2.5 percent in 2021.

Figure 2.3 Daily average price-cost markup values during September heat wave period – competitive baseline scenario

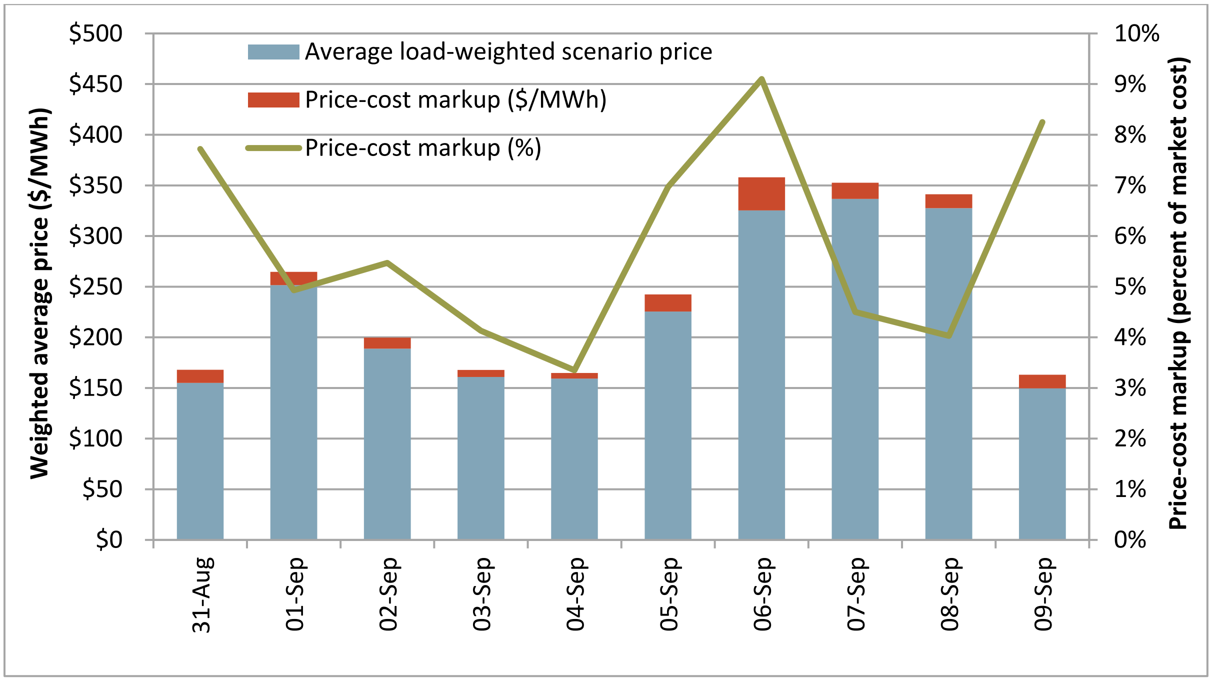
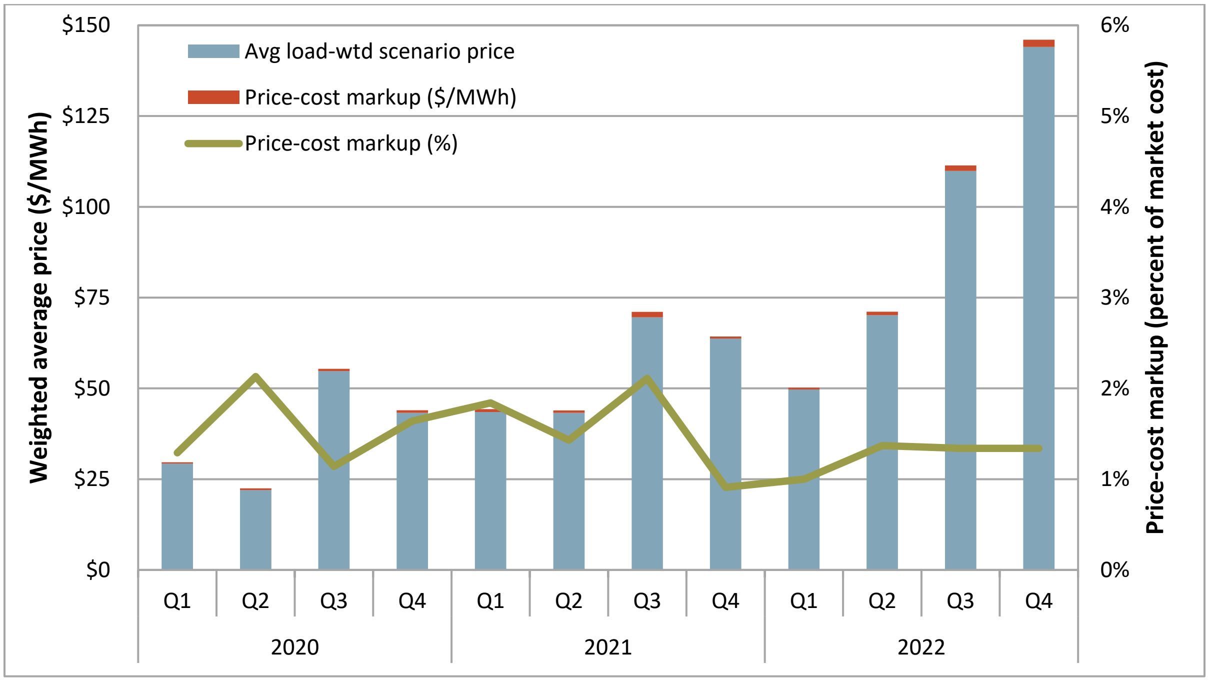


Figure 2.4 shows results for the scenario that caps energy bids for gas resources at the lower of their submitted bid or default energy bid. Price-cost markup values for this scenario were slightly higher in 2022 at about $1.26/MWh compared to $0.94/MWh in 2021, because of higher average energy prices in 2022. However, when comparing the markup as a percent of market cost, the value dropped slightly to 1.3 percent in 2022 compared to 1.6 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 capping 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. In addition, this analysis did not change commitment cost bids for gas-fired resources, which are capped at 125 percent of each resource's estimated start-up and minimum load bids.

Figure 2.4 Quarterly day-ahead market price-cost markup – default energy bid scenario



2.3 Energy market prices

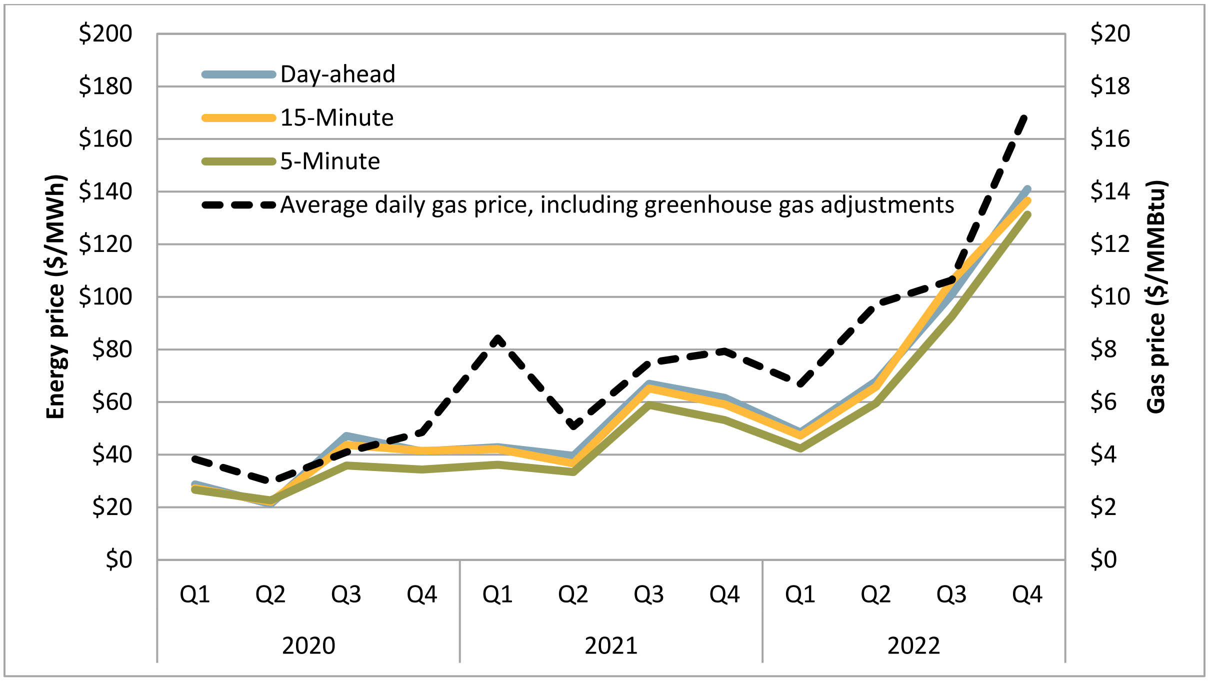
This section reviews energy market prices in the CAISO balancing area by focusing on price trends and comparison of prices in the day-ahead and real-time markets. Key points highlighted in this section include the following:

- Average energy market prices were about 74 percent higher than in 2021. The considerable increase in energy prices resulted from the significant increase in natural gas prices. In 2022, the natural gas price, including greenhouse gas adjustment, grew by 54 percent. Since natural gas units are typically the marginal source of generation in the California ISO and other regional markets, this increase was a major factor driving the high energy prices in 2022.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets. Day-ahead prices averaged $90/MWh, 15-minute prices were about $89/MWh, and 5-minute prices were about $81/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 the CAISO operators.
- Average hourly prices generally moved in tandem with the average net load. The evening peak net load was 4 percent lower than in 2021. Peak prices in 2022 were 66 percent higher than those in 2021, and occurred during the highest net load hour in the day-ahead market, but an hour earlier (during ramping period) in the real-time markets.

Figure 2.5 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 increased sharply in 2022, and indicates a strong correlation between the two. Across all three markets, prices were roughly 74 percent higher in 2022 compared to 2021. These higher prices are due in part to higher gas prices.[124]

The day-ahead and 15-minute market energy prices averaged $90/MWh and $89/MWh, respectively. Prices in the 5-minute market averaged $81/MWh.

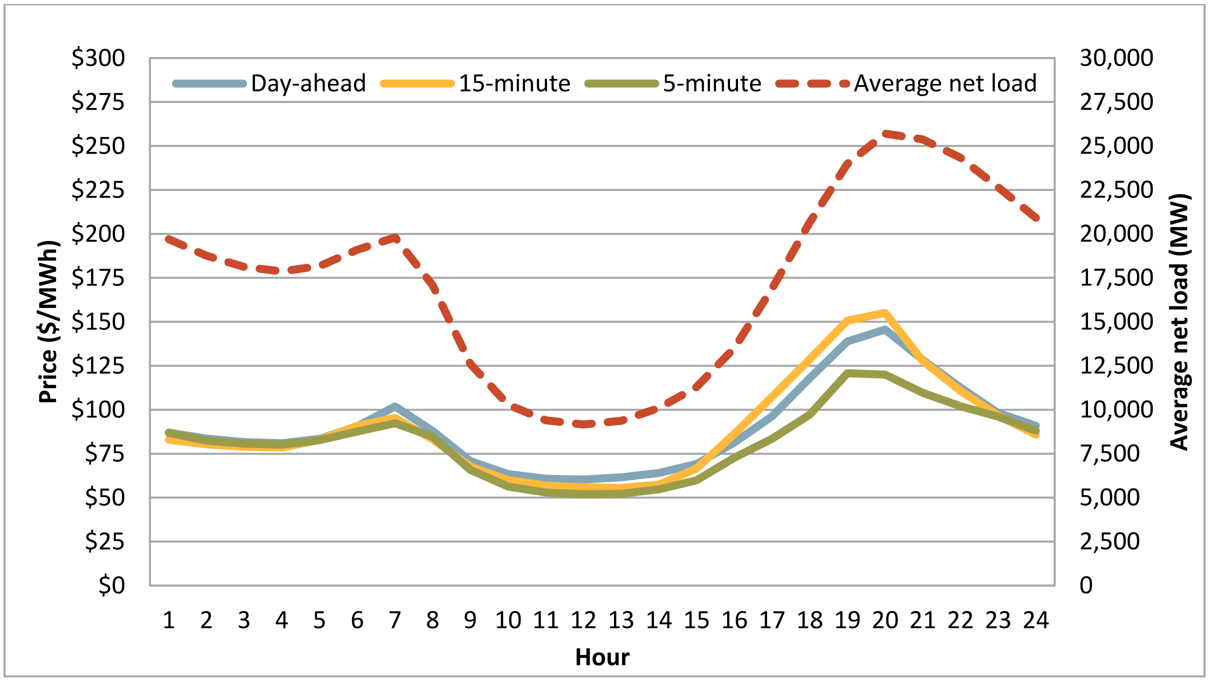
Figure 2.5 Average quarterly prices (all hours) – load-weighted average energy prices



To analyze how prices vary throughout the day, Figure 2.6 illustrates hourly load-weighted average energy prices in the California ISO 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 20 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 20 percent lower than those in the day-ahead and 15-minute markets.

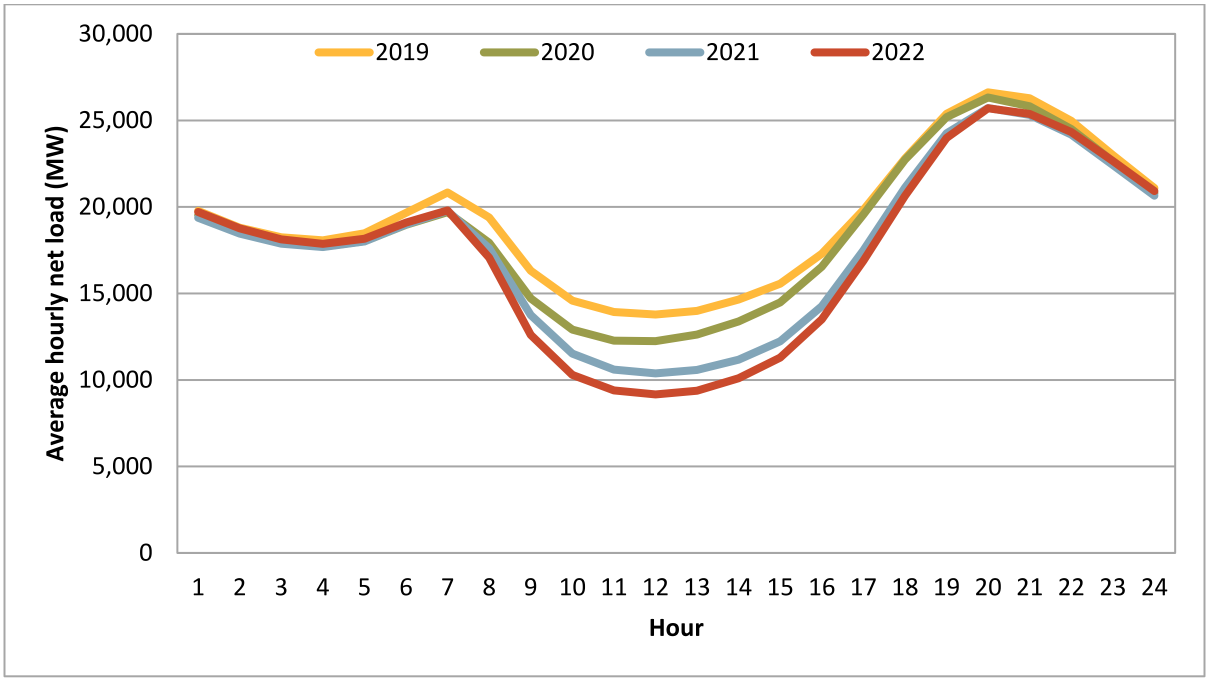
124 See Section 1.2.6 for additional discussion on natural gas price trends.

Figure 2.6 Hourly load-weighted average energy prices (2022)



Average net load peaked in hour ending 20 was about 25,700 MW, which is similar to 25,800 MW for the same hour last year. Figure 2.7 shows the change in net load from 2019 to 2022. On average, net load was roughly 2 percent lower in 2022, compared to 2021. The decrease in net load was most pronounced during the morning through afternoon (9 a.m. to 5 p.m.), when net load was 9 percent lower in 2022. Prices in the day-ahead market were highest during the peak net load hour, averaging $145/MWh, which is 53 percent higher than the peak price last year. Prices in the real-time market spiked during the ramp up period with the highest prices in both the 15-minute and 5-minute markets during hour ending 19. In this hour, 15-minute prices averaged $93/MWh, and 5-minute market prices averaged $68/MWh.

Figure 2.7 Hourly average net load (2019–2022)

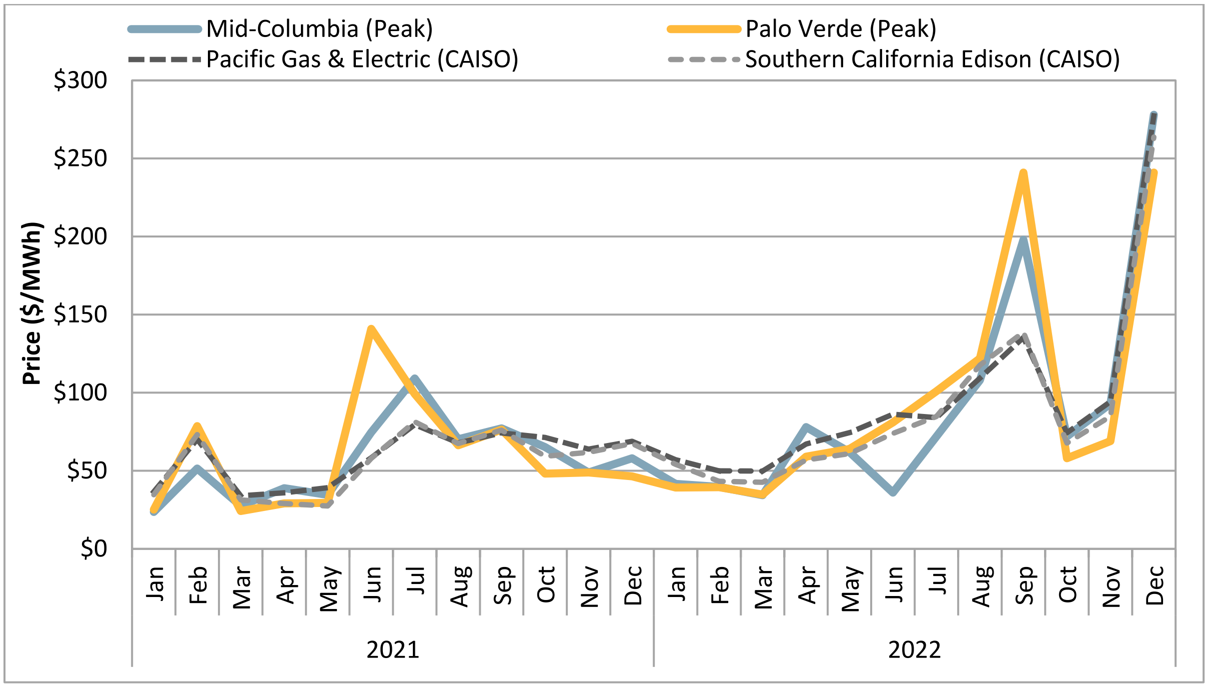


2.3.1 Comparison to bilateral prices

During the summer of 2022, 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 spiked in December 2022 due to persistent high gas prices. Figure 2.8 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 also represented in the figure by prices at the Southern California Edison and Pacific Gas and Electric load aggregation points.

During the heat wave conditions that existed across the west from September 1 through September 10, bilateral index prices at Mid-Columbia exceeded the $1,000/MWh WECC soft offer cap while index prices at Palo Verde were at or below the cap on some days. Consequently, CAISO raised its energy bid cap and penalty prices to $2,000/MWh during this period. On average, day-ahead market prices in July and August were higher in the CAISO and the Palo Verde hub than at the Mid-Columbia hub across peak hours. In September, average bilateral prices across peak hours exceeded CAISO prices.

Figure 2.8 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 and Palo Verde hubs for all hours of 2021 using data published by Powerdex. Day-ahead hourly prices in the Pacific Gas and Electric and Southern California Edison areas, across all hours in 2021, were higher on average than prices at Mid-Columbia and Palo Verde by about $20/MWh and $10/MWh, respectively. Average day-ahead prices at Mid-Columbia (from ICE) were greater than the average real-time prices at Mid-Columbia (from Powerdex) by $10/MWh. At Palo Verde, the average day-ahead price (from ICE) was higher than the real-time price (from Powerdex) by $11/MWh.

Beginning on April 8, 2022, FERC started issuing orders in response to cost justification filings from sellers who made sales above the WECC soft offer cap during the August 2020 heat wave event. In particular, FERC has ordered some sellers to refund the premium they charged above the index price, for sellers whose sales were above the prevailing index price.[125] DMM estimates the refunds to be about $5.1 million out of $90 million in bilateral sales exceeding the WECC soft offer cap during August 2020.[126] Based on FERC rulings on the cost justification filings for June 2021, DMM estimates the refunds to be about $1.6 million out of $34 million in bilateral sales exceeding the WECC soft offer cap. FERC has yet to rule on some of the cost justification filings for June 2021, and has not begun to issue orders

125 FERC issued orders on a number of sellers and directing them to refunds for sales during August 2020. Following order directing refunds re Mercuria Energy America, LLC under ER21-46: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220422-3059&optimized=false

126 DMM estimates are based on public FERC cost justification filings and FERC electric quarterly report (EQR) data.

related to the August and September 2022 filings. A motion is pending at FERC to raise the soft offer cap from $1,000/MWh to $2,000/MWh for spot sales in WECC's bilateral markets.[127]

2.3.2 Price variability

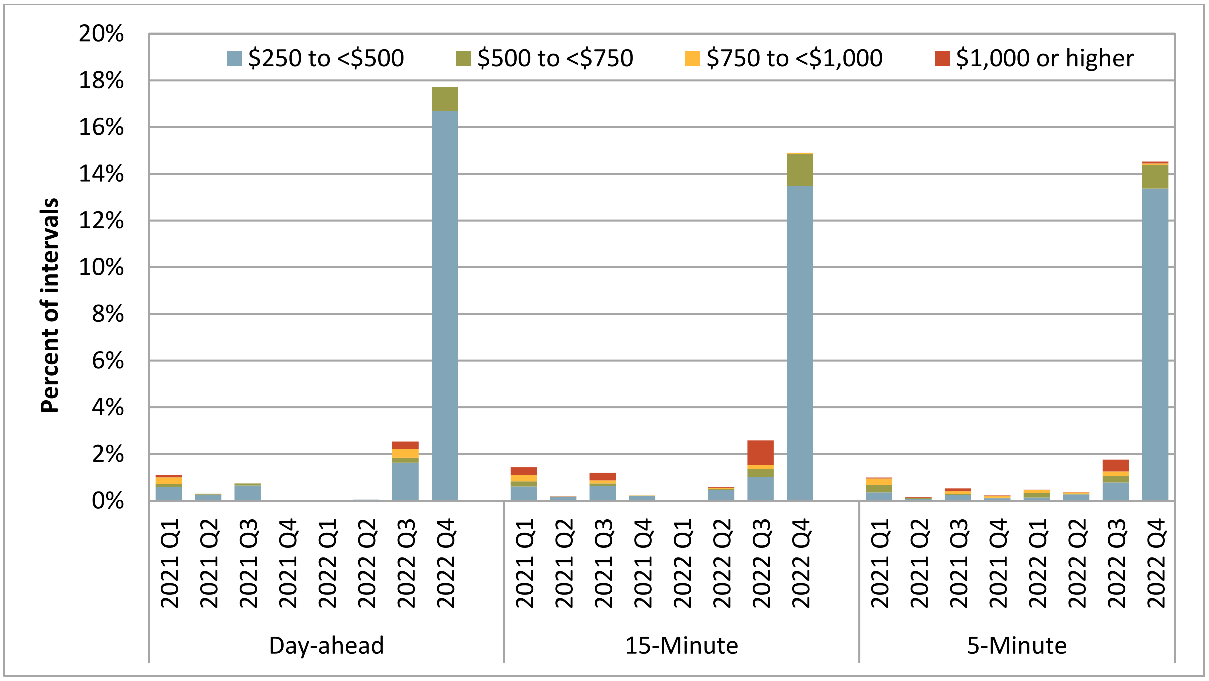
In 2022, there was a significant increase in the volatility of energy prices, with a large increase in the frequency of high prices across all three markets. In 2021, the frequency of energy prices exceeding $250/MWh was 0.2 percent, but in 2022, this figure increased to 1.2 percent, a 680 percent rise in the likelihood of these high prices.

High prices

Figure 2.9 shows the frequency of high prices in the day-ahead, 15-minute, and 5-minute markets in both 2021 and 2022. Positive price spikes were most common in the third and fourth quarters in 2022. During the third quarter, the California ISO balancing area faced an intense heat wave in late August and early September, which led to a significant increase in demand and a subsequent surge in prices. The frequency of prices reaching $1,000/MWh or higher was particularly prominent during this period. In the fourth quarter, high gas prices in December contributed to the positive price spikes. The average market price in December was $250/MWh on average. About 46 percent of market intervals in December had prices exceeding $250/MWh.

[127] FERC Docket No. ER21-64*, Macquarie Energy, LLC submits Explanation for Bilateral Spot Sales in Western Electricity Coordinating Council:* eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. ER21-46, *Mercuria Energy America, LLC submits tariff filing per 35: Explanation for Bilateral Spot Sales in the West:* eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. EL10-56*, Macquarie Energy and Mercuria Energy filings, July 19, 2021:* eLibrary | Docket Search Results (ferc.gov)

Figure 2.9 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.[128] There were seven days over the September heatwave with hours that had an MIBP over the $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.[129]

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

In 2022, there was a gradual increase in the frequency of negative prices compared to 2021. Figure 2.10 shows the frequency of prices near or below $0/MWh in the day-ahead, 15-minute, and 5-minute markets in 2021 and 2022. When averaging all three markets, the frequency of negative prices in 2022 was 0.9 percent, while in 2021, it was 0.7 percent. This indicates an overall increase of 36 percent in the

---

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

129 Please refer to DMM's *2022 Q3 Report* for additional information regarding the instances of $2,000/MWh bid caps during the September heatwave, pp. 80-82: http://www.caiso.com/Documents/2022-Third-Quarter-Report-Market-Issues-Performance-2022-12-14.pdf

frequency of negative prices. Negative prices are more frequent in the 15-minute and 5-market markets, compared to the day-ahead market. On average, about 1.6 percent of 15-minute and 5-minute prices were below zero, whereas only 0.2 percent of prices in the day-ahead market fell below zero. Furthermore, there was a consistent pattern of negative price spike occurring mostly in the first and second quarters across 2021 and 2022. On average, 96 percent of negative pricing hours were observed during the first and second quarter.

Figure 2.10 Frequency of negative price spikes California ISO areas

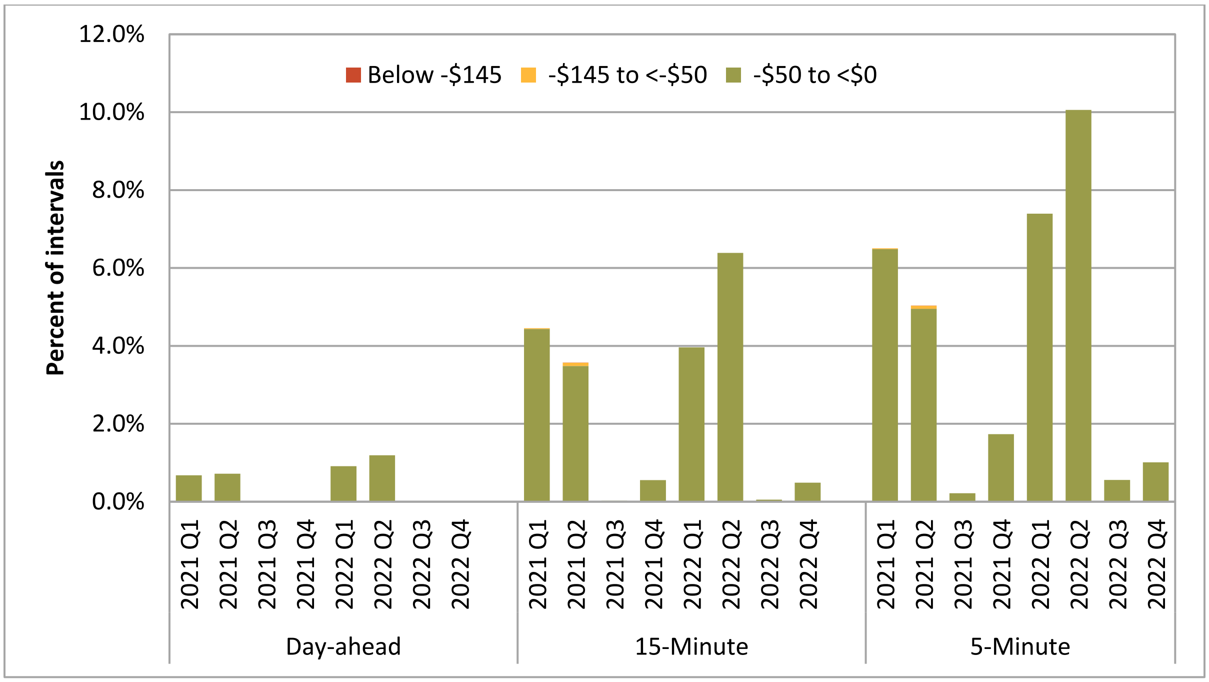


Figure 2.11 shows the annual frequency of negative prices in the 5-minute market since 2016. In 2022, roughly 4.7 percent of 5-minute intervals had negative prices, a considerable increase from 2021. Figure 2.12 shows the hourly frequency of negative 5-minute prices in the last four years. The figure illustrates a distinctive pattern in the frequency of negative pricing hours in 2022 compared to previous years. Notably, there was a significant increase in the frequency observed between 12 p.m. and 5 p.m. While the highest average percentage of intervals with negative pricing was around 12 percent in the last four years, in 2022, the highest frequency was 16 percent around 3 p.m.

Figure 2.11 Frequency of negative 5-minute prices (CAISO LAP areas)

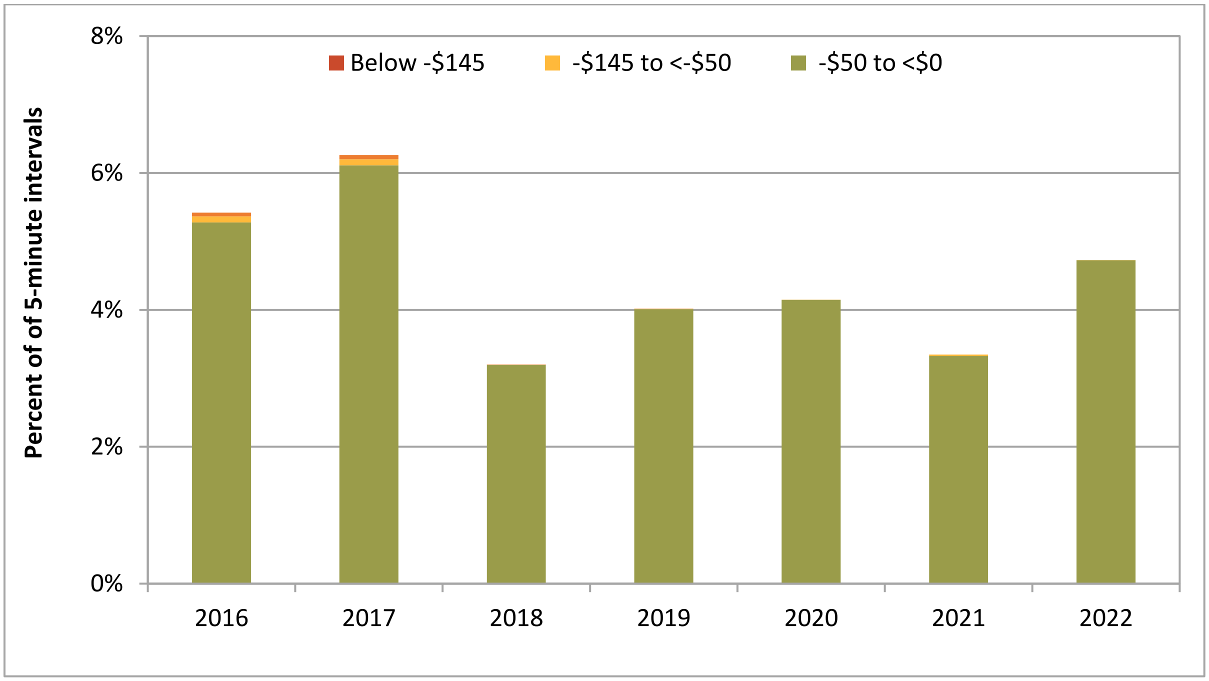
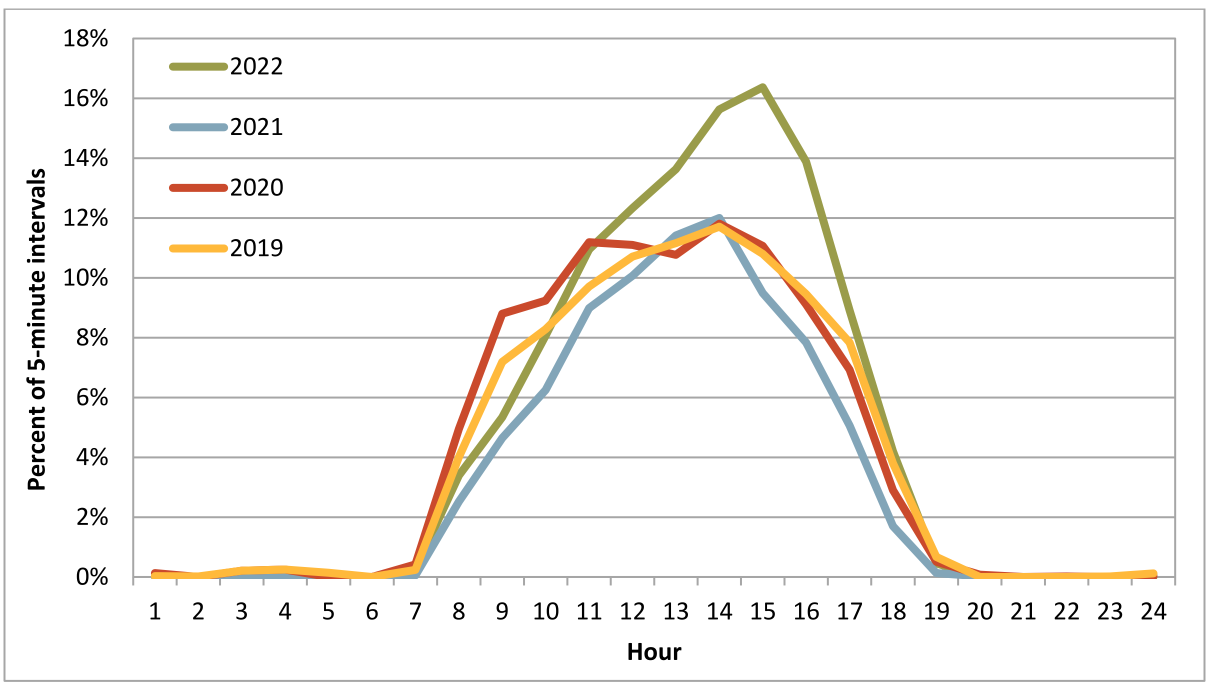


Figure 2.12 Hourly frequency of negative 5-minute prices by year (CAISO LAP areas)



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.[130] 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).[131]

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 2022, but low during other times of the year.

Figure 2.13 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 due to the summer heat event, becoming more frequent than the third quarter of 2020.

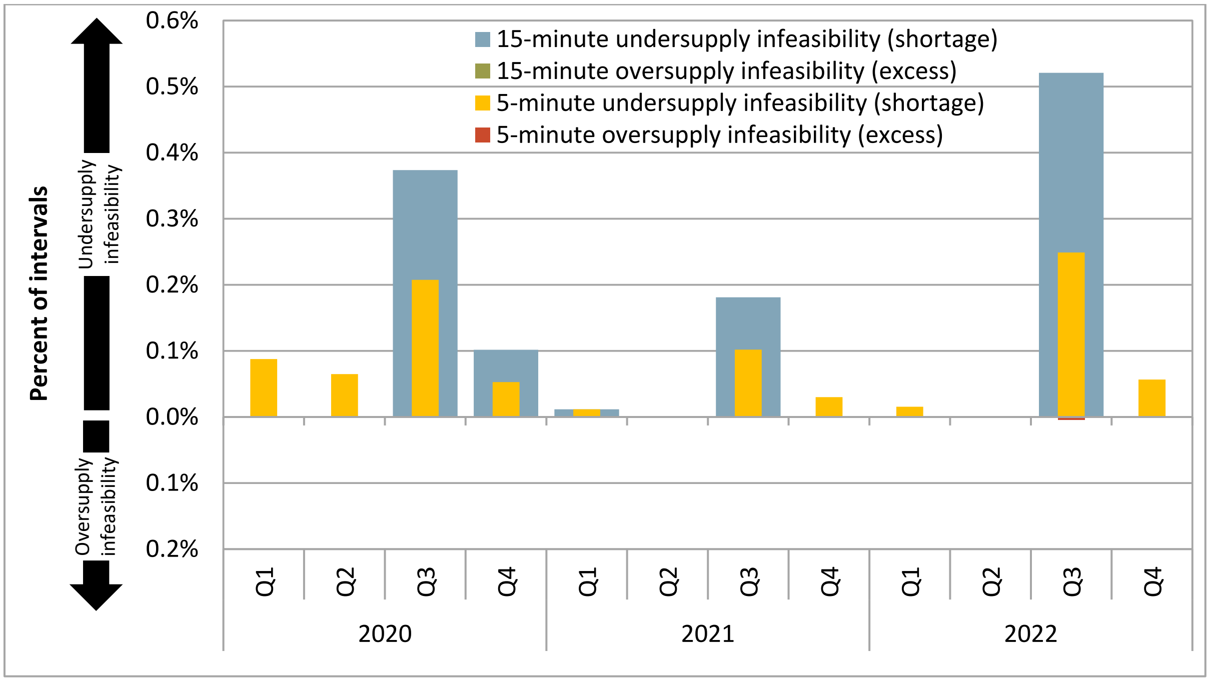
There were very few instances during 2022 in which the system power balance constraint was relaxed because of insufficient downward flexibility, occurring in less than 0.01 percent of intervals. Bidding flexibility from renewable resources, in addition to increased transfer capability from the energy imbalance market, continued to contribute to reduced oversupply conditions.

---

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

131 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 2.13 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 2022 was 14 percent higher than 2021, as shown in Figure 2.14. California ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. In 2022, these operator adjustments increased significantly by 147 percent compared to 2021.[132]

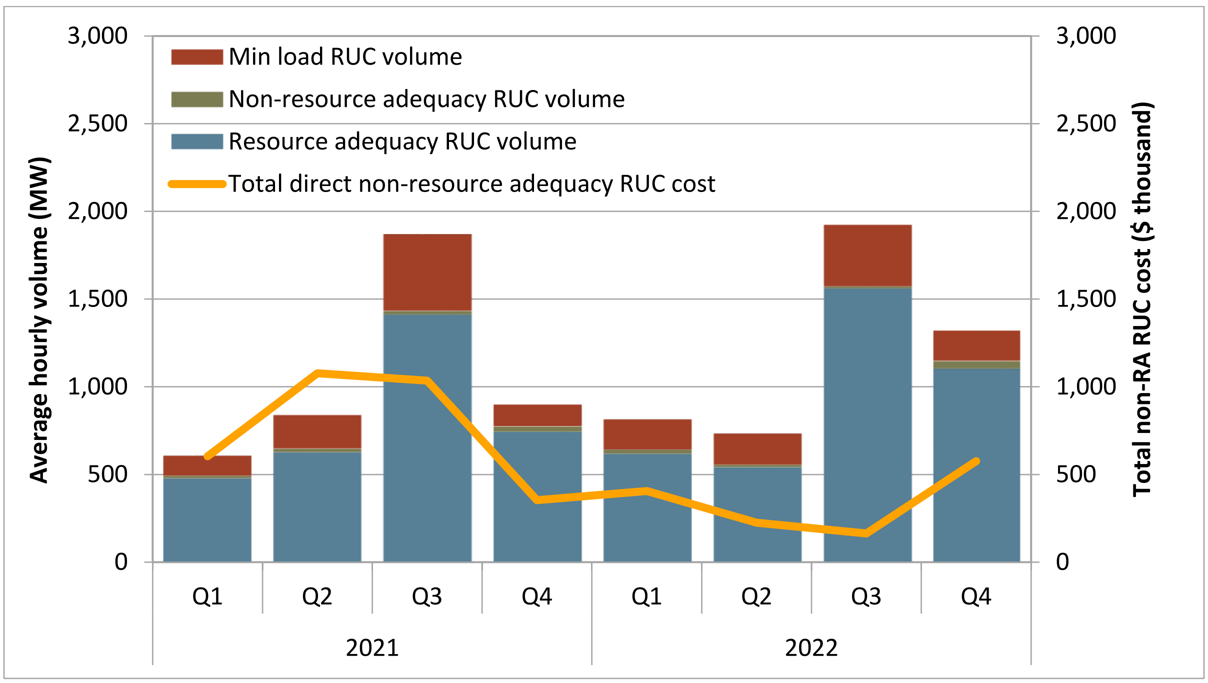
Figure 2.14 also shows quarterly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to 1,198 MW per hour in 2022 from an average of 1,054 MW in 2021. The figure shows that in 2022, the volume of residual unit commitment requirements was highest in the third quarter. High third quarter volume was primarily driven by relatively high operator adjustments, and larger gaps between day-ahead load forecast and cleared supply.

[132] See Section 8.3 for further discussion on operator adjustments in the residual unit commitment process.

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.[133] 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 218 MW each hour, slightly up from 216 MW in 2021. In 2022, about 14 percent of this capacity was from long-start units, down from 17 percent in 2021.[134]

Most of the capacity procured in the residual unit commitment market does not incur any direct costs because only non-resource adequacy units committed in the process receive capacity payments.[135] As shown by the small green segment of each bar in Figure 2.14, the non-resource adequacy volume averaged about 23 MW per hour in 2022, slightly up from about 21 MW procured in 2021. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in the same figure, decreased to about $1.4 million in 2022, from a direct cost of about $3 million in 2021.

Figure 2.14 Residual unit commitment (RUC) costs and volume (2021–2022)



[133] 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.

[134] Long-start commitments are resources that require 300 or more minutes to start up. 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.

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

In September 2020, the California ISO revised the residual commitment 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 curtail economic and lower priority self-scheduled exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds the California ISO real-time load, and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[136]

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.[137] All low-priority exports that clear the residual unit commitment process will be prioritized below internal load. In addition, the California ISO will prioritize exports that bid into the day-ahead market and clear the residual unit commitment process over new exports that self-schedule into the real-time market.

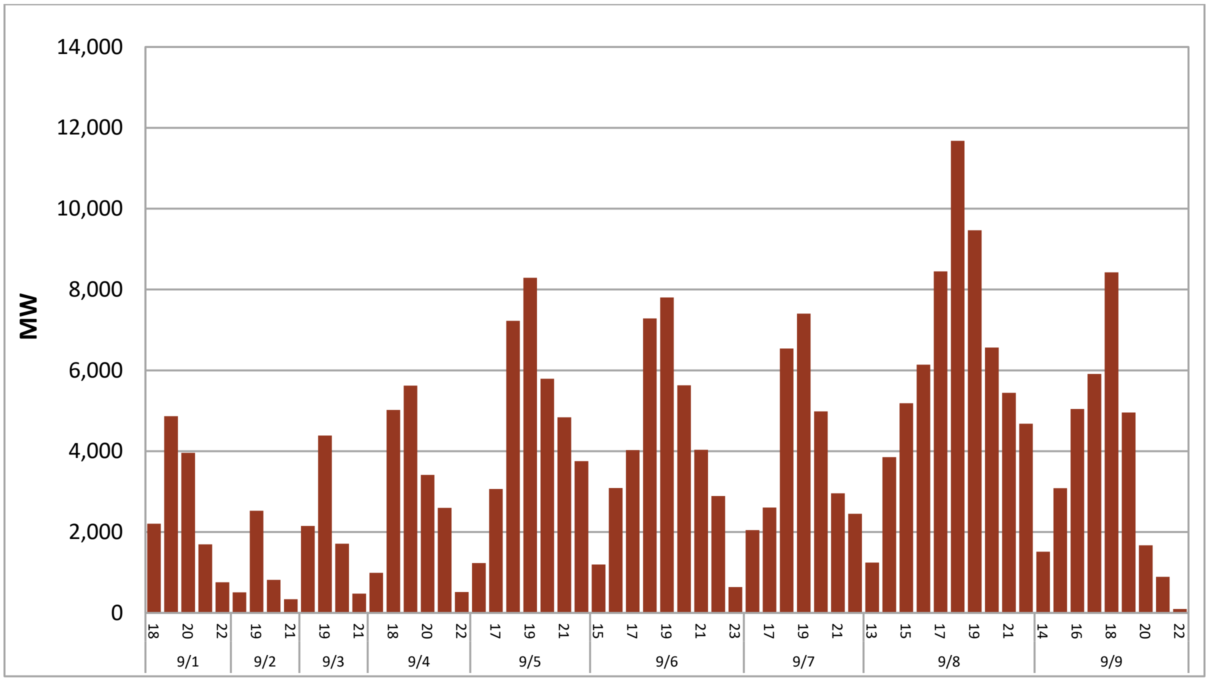
In 2022, the *residual unit commitment undersupply power balance constraint* was infeasible on twelve days, August 16-17, September 1-9, and September 26. Figure 2.15 shows the residual unit commitment power balance constraint hourly under-supply infeasibility quantities that resulted during the heat wave conditions from September 1 through 9. 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 cut in the residual unit commitment process prior to relaxing the power balance constraint.[138]

136 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

137 Additional information and analysis on market changes implemented in August 2021 is provided in: Department of Market Monitoring, *Q3 2021 Market Issues and Performance,* December 9, 2021, pp. 94-102: http://www.caiso.com/Documents/2021-Third-Quarter-Report-on-Market-Issues-and-Performance-Dec-9-2021.pdf

138 More information on residual unit commitment export schedule cuts can be found in: California ISO, Summer Market Performance Report Sept 2022, November 2, 2022, Section 5.1: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

Figure 2.15 Residual unit commitment under-supply infeasibilities (Sep 1–9, 2022)



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 2022, 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.

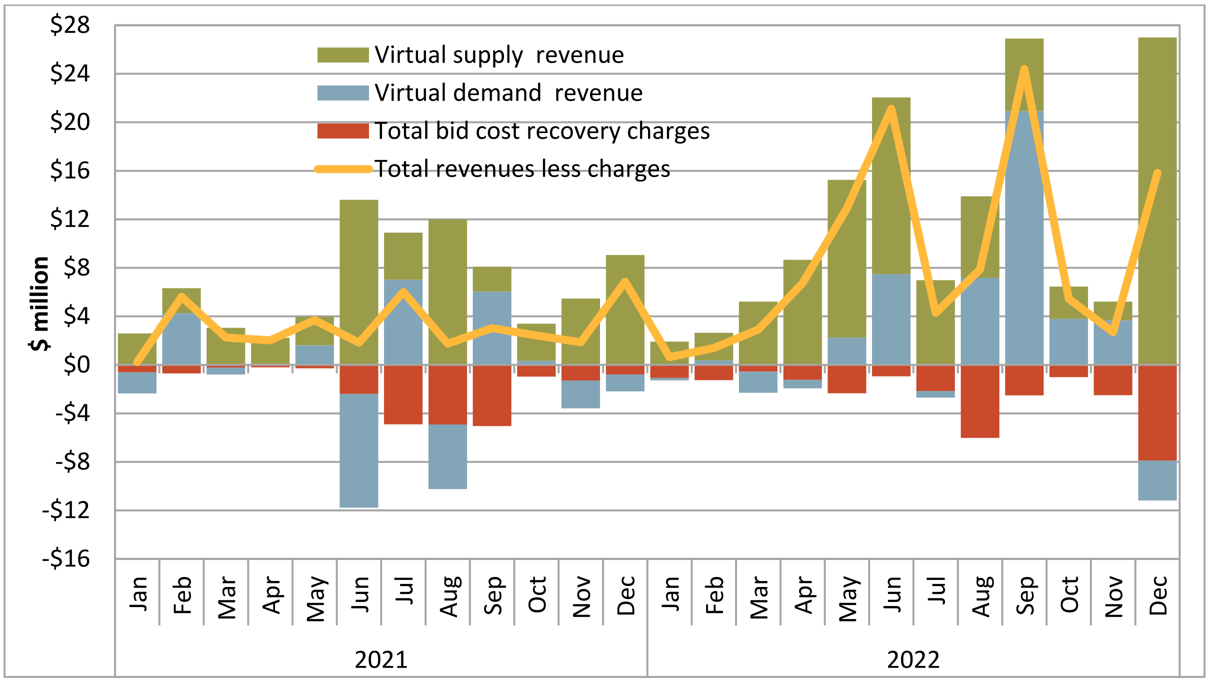
- **Annual profits paid to convergence bidders totaled around $106 million**, an increase of almost $70 million from 2021, after accounting for about $30 million in bid cost recovery charges allocated to virtual bids. Virtual demand generated net revenues of about $39.1 million for the year, while virtual supply generated about $96.5 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 660 MW per hour**, compared to 872 MW in 2021. The percent of bid-in virtual supply and demand clearing was around 32 percent, a slight decrease from about 34 percent in 2021.
- **Financial entities and marketers continued to earn most profits from virtual bidding**, receiving about 79 percent and 20 percent of positive net revenues, respectively. Physical generators received less than 2 percent of positive net revenues, and load serving entities lost money from virtual positions for the third year in a row.
- **Financial participants held nearly 74 percent of cleared virtual positions throughout 2022**, continuing a multi-year trend. As with the previous years, financial participants bid more virtual supply than demand.
- **During the 2022 summer heat wave, market participants earned $36.25 million in net revenues from virtual demand**, which represents nearly 93 percent of net revenues for virtual demand in all of 2022. Market participants lost nearly $8.9 million through virtual supply bids in the heat wave.

2.5.1 Convergence bidding revenues

Net convergence bidding revenue was positive in every month and quarter of 2022. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $135.6 million, a 127 percent increase from 2021. Net revenues for virtual supply and demand fell to about $106 million after accounting for bid cost recovery charges associated with virtual supply.[139]

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).

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.[140]

The quantity of virtual bids increased 20 percent from 2021, 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.

139 For more information on how bid cost recovery charges are allocated, please refer to: Department of Market Monitoring, *Q3 2017 Report on Market Issues and Performance*, December 8, 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf

140 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.

Revenues from virtual supply and virtual demand bids both increased since 2021, resulting in a nearly three-fold year-over-year increase in total virtual revenues after accounting for bid cost recovery. The largest percentage increase for any revenue category was virtual demand for financial entities, which increased eight-fold over its 2021 value.

Table 2.2 Convergence bidding volumes and revenues by participant type – 2021 to 2022

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**	**$105.99**
Trading entities	**Average hourly megawatts**			**Revenues\Losses ($ million)**				**Total revenue after BCR**
	Virtual demand	**Virtual supply**	**Total**	**Virtual demand**	**Virtual supply before BCR**	**Virtual bid cost recovery**	**Virtual supply after BCR**	
2021								
Financial	1,172	1,823	2,995	$3.37	$47.31	-$16.75	$30.56	$33.93
Marketer	342	500	842	-$4.08	$12.89	-$4.81	$8.08	$4.00
Physical load	0	27	27	$0.00	$0.21	-$0.81	-$0.60	-$0.60
Physical generation	17	53	70	-$0.98	$0.92	-$0.98	-$0.06	-$1.04
Total	**1,531**	**2,403**	**3,934**	**-$1.69**	**$61.33**	**-$23.35**	**$37.98**	**$36.29**

Virtual bids during heat wave

During the prolonged heat event from August 31 to September 9, 2022, virtual bidding participants made over $36 million in net revenue from virtual load bids. In comparison, total net revenue for all virtual bids in the third quarter of 2022, after accounting for bid cost recovery, was around $36 million. Virtual supply had a nearly $9 million net loss during this 10-day period. Figure 2.17 shows hourly net virtual revenue during the heat wave.

Figure 2.18 shows hourly virtual capacity offered and cleared throughout the heat wave. Cleared virtual load bids surpassed cleared virtual supply bids for much of this period, especially during evening hours. Average hourly capacity cleared for virtual supply and load was 1,666 MW and 2,113 MW, respectively.

Figure 2.17 Hourly virtual revenues during 2022 heat wave

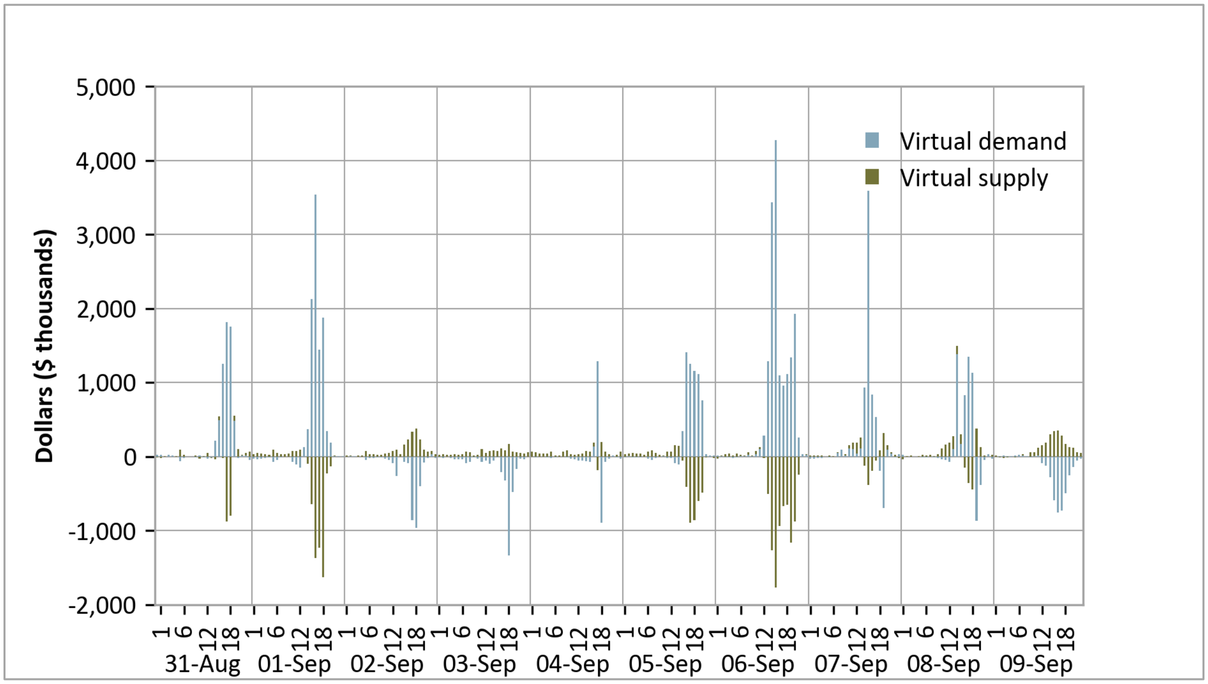
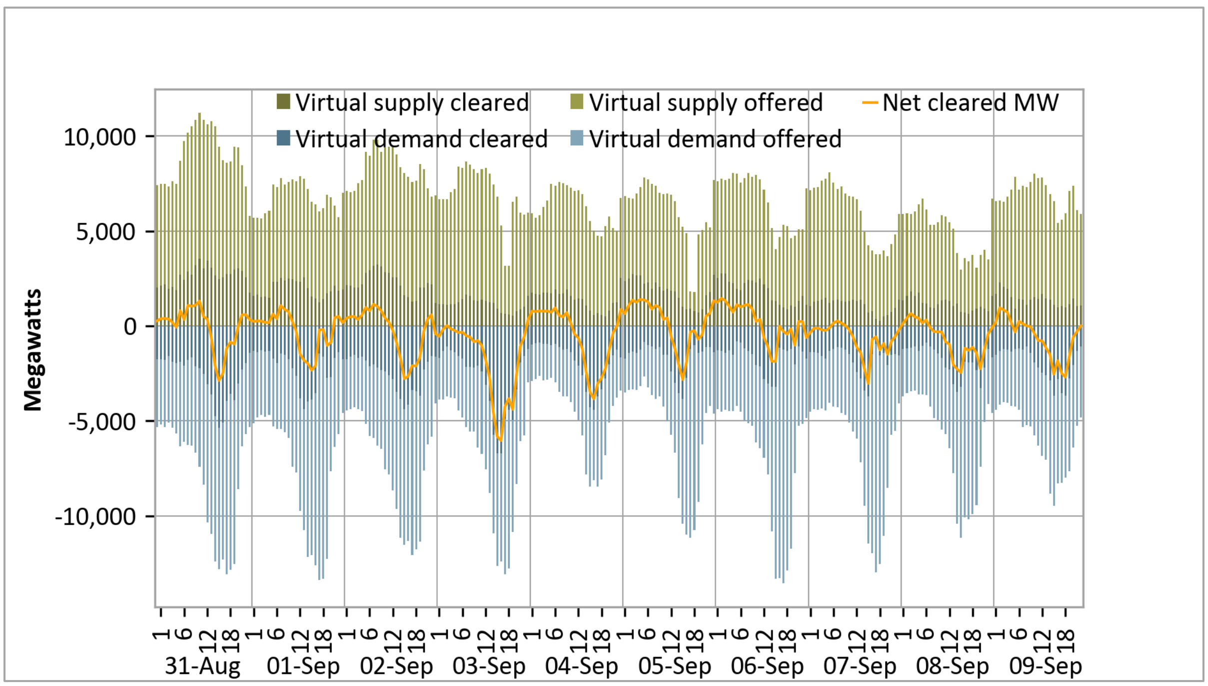


Figure 2.18 Hourly virtual activity during 2022 heat wave



2.6 Bid cost recovery payments

Bid cost recovery payments totaled $297 million, the highest total since 2011 and a significant increase from 2021 when payments were $173 million.[141] Around $255 million of bid cost recovery payments in 2022 were for units in the California ISO (CAISO), and $42 million were for units in the Western Energy Imbalance Market (WEIM).[142] The CAISO portion of these payments represents about 1.2 percent of total CAISO wholesale energy costs, similar to 2021.

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 79 percent of these payments, or $235 million, were to gas resources, followed by $30.3 million to battery energy storage resources, and about $18 million to hydro resources.

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 State of Charge* constraint requires such a resource to charge or discharge.[143] This is in response to DMM's observations in 2022; where under certain circumstances, battery storage resources with ancillary service awards and high energy bids receive significant real-time bid cost recovery payments.

The increase in bid cost recovery payments can be attributed to the significant increase in gas prices, especially in December 2022. In the CAISO footprint, load-weighted average gas price increased to $30.60/MMBtu in December 2022 compared to $6.50/MMBtu in December 2021.

DMM estimates that about 57 percent of the CAISO's total bid cost recovery payments, approximately $145 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. Commitment cost bids are capped at 125 percent of reference proxy costs. About 94 percent of these payments are for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Commitment cost bids are capped at 125 percent of reference proxy costs.[144] Additional bidding flexibility for commitment costs is provided through reference level adjustment requests. This functionality was implemented as part of 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 2022, this feature had minimal impact to bid cost recovery payments.

---

[141] 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.

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

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

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

Figure 2.19 Bid cost recovery payments

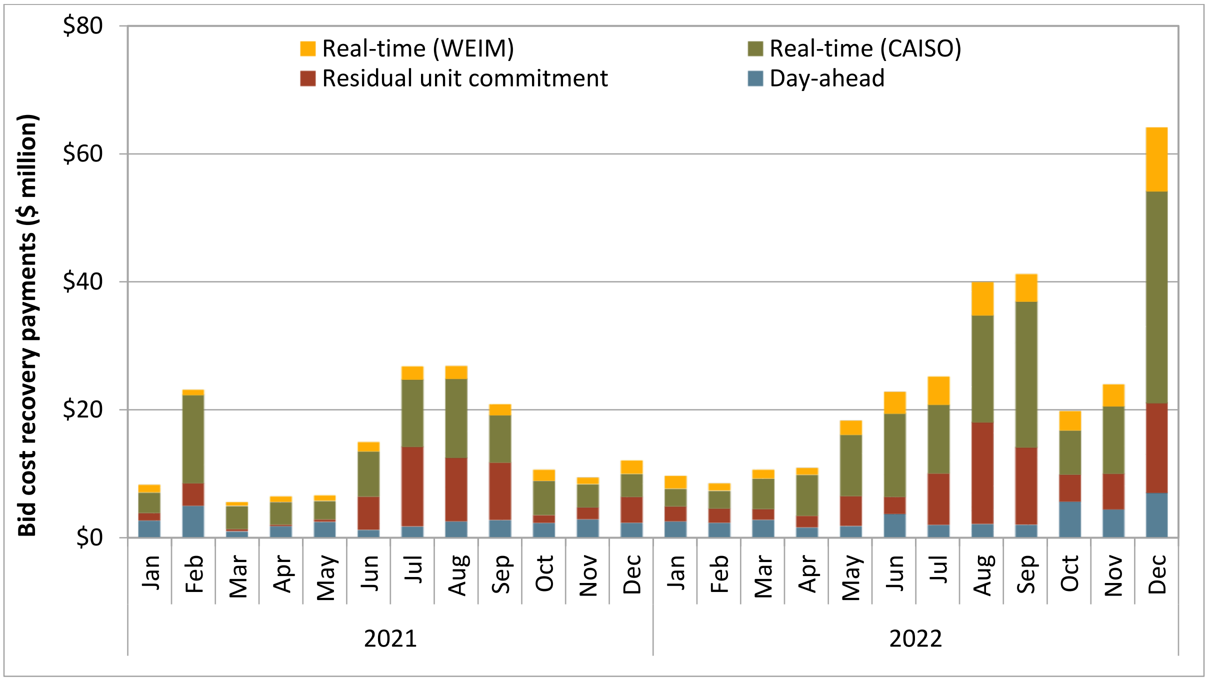


Figure 2.19 provides a summary of total estimated bid cost recovery payments in 2021 and 2022 by month and market. As shown in the figure, bid cost recovery payments in 2022 were highest during the August and September heatwave period as well as December 2022. These significantly high payments can be attributed to higher gas prices, particularly in December, and relatively high loads and gas prices in August and September.

Day-ahead bid cost recovery payments totaled $38.5 million in 2022, an increase from $29 million in 2021. An estimated 24 percent of these payments can be attributed to resources effective at meeting the minimum on-line constraints enforced in the day-ahead market, compared to 35 percent in 2021.[145]

Real-time bid cost recovery payments were $183 million in 2022, about $89 million higher than payments in 2021. Out of the $183 million in real-time payments, about 42 million was allocated to resources (non-California ISO) participating in the WEIM, which is $25 million higher than payments in 2020. About $4.25 million of these payments were to units in balancing areas that joined the WEIM in 2022.

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 $9.5 million in 2022, significantly down from $24 million in 2021. Additional details regarding exceptional dispatches are covered in Section 7.1 of this report.

145 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 meet locational voltage requirements and respond to contingencies that cannot be directly modeled in the market. Bid cost recovery payments attributed to resources committed to meet minimum on-line constraints in 2018 have been re-calculated based on an updated methodology.

Bid cost recovery payments for units committed through the residual unit commitment process totaled about $76 million in 2022. This represents a $26 million increase in payments from 2021. Average procurement in the residual unit commitment process was 14 percent higher than the previous year, as stated in Section 2.4. In addition, gas prices were substantially higher this year, and the majority of bid cost recovery payments for units committed through the residual unit commitment process are received by gas-fired resources.

Table 2.3 and Table 2.4 show bid cost recovery payments in the CAISO and WEIM balancing areas by technology/status type.[146,147] As shown in Table 2.3, bid cost recovery paid to fast-start combustion turbines (excludes cogeneration and reciprocating engines) totaled about $18 million and $32 million in 2021 and 2022, respectively. These payments are only 12 percent and 16 percent of total bid cost recovery payments to gas resources in the CAISO footprint in 2021 and 2022, respectively. Similarly, in the WEIM areas, bid cost recovery paid to fast-start combustion turbines totaled $0.6 million and $1 million in 2021 and 2022, respectively. These payments are about 5 percent and 3 percent of total bid cost recovery payments to gas resources in the WEIM areas in 2021 and 2022, respectively.

Table 2.3 Total bid cost recovery payments in the CAISO area by technology type (2021–2022)

System	Technology type	Bid cost recovery payments ($)		Percent of total bid cost recovery payments (%)	
		2021	2022	2021	2022
CISO	Batteries	$3,612,062	$30,330,699	2%	12%
CISO	Once-through-cooling	$56,382,130	$63,073,832	36%	25%
CISO	Combined Cycle	$56,073,876	$77,554,525	36%	30%
CISO	Frame turbine: non-Fast start	$0	$159,200	0%	<1%
CISO	Gas turbine: non-Fast start	$4,599,725	$11,615,876	3%	5%
CISO	Gas turbine: Fast start cogeneration	$377,313	$489,399	<1%	<1%
CISO	Gas turbine: Fast start (includes Frame CTs and Gas	$17,976,008	$32,019,625	11%	13%
CISO	Reciprocating engines: Fast start (includes cogens)	$10,944	$6,709	<1%	<1%
CISO	Reciprocating engines: non-Fast start	$4,531,553	$9,606,152	3%	4%
CISO	Hydro	$1,582,710	$1,866,557	1%	1%
CISO	Other	$2,183,520	$6,346,394	1%	2%
CISO	QF/CHP/Must-take	$6,641,987	$19,630,826	4%	8%
CISO	Reliability must-run	$2,506,434	$2,284,017	2%	1%

Table 2.4 Total bid cost recovery payments in the WEIM areas by technology type (2021–2022)

System	Technology type	Bid cost recovery payments ($)		Percent of total bid cost recovery payments (%)	
		2021	2022	2021	2022
WEIM	Batteries	$1,651	$11,425	<1%	<1%
WEIM	Combined Cycle	$9,694,798	$30,411,722	58%	73%
WEIM	Frame turbine: non-Fast start	$0	$760,148	<1%	2%
WEIM	Gas turbine: non-Fast start	$2,892,875	$906,748	17%	2%
WEIM	Gas turbine: Fast start (includes Frame CTs)	$647,846	$987,205	4%	2%
WEIM	Reciprocating engines: Fast start	$25,928	$79,067	<1%	<1%
WEIM	Reciprocating engines: non-Fast start	$13,538	$51,609	<1%	<1%
WEIM	Steam turbine	$20,092	$126,072	<1%	<1%
WEIM	Hydro	$1,274,095	$1,009,581	8%	2%
WEIM	Other	$2,257,805	$7,600,212	13%	18%

146 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)

147 "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, Nuclear technology types.

2.7 Real-time imbalance offset costs

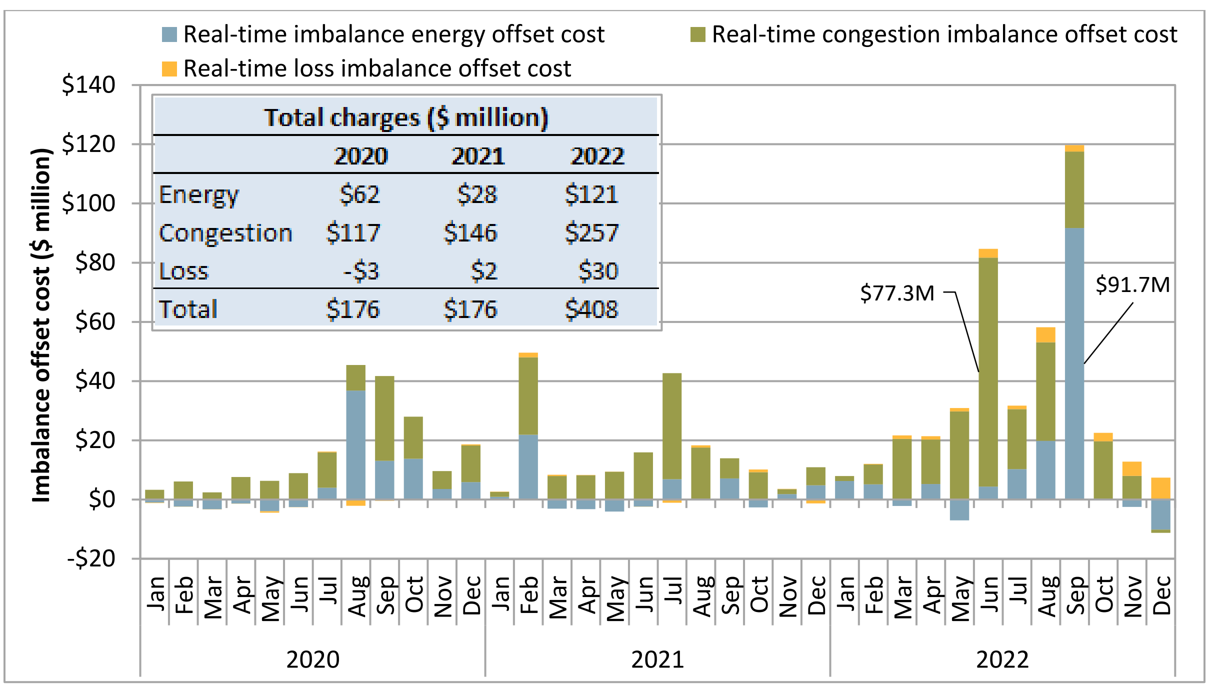
Total real-time imbalance offset costs increased significantly to around $408 million in 2022, up from around $176 million in both 2020 and 2021. Real-time congestion imbalance offset costs were $257 million, up from $146 million in 2021 and $117 million in 2020. Real-time imbalance energy offset costs were $121 million in 2022, up from $28 million in 2021 and $62 million in 2020.

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 2.20 shows monthly imbalance offset costs since 2020. In June, real-time congestion offset costs reached $77 million. In September, real-time energy offset costs were around $92 million. Each of these amounts were the highest monthly totals recorded for their respective imbalance offset cost type since locational marginal pricing was introduced in 2009. The following sections provide more context into each of these outcomes.

Figure 2.20 Real-time imbalance offset costs



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 can occur because of either a change from the day-ahead market to the 15-minute market (15-minute imbalance) or a change from the 15-minute market to the 5-minute market (5-minute imbalance). When a change to a real-time energy schedule reduces flows on a constraint, that schedule is paid the real-time constraint congestion price for making space available on the constraint. Generally, if the constraint is still binding with a non-zero price, another schedule has increased flows on the constraint. The schedule that increased flows would then pay the ISO enough to cover the ISO's payments to the schedule that reduced flows—and the ISO congestion accounts would remain balanced.

There are several reasons the congestion payments will not balance. One reason is that flows increase causing a constraint to bind, generating additional congestion rent. Another is that the real-time constraint limits are lower than the day-ahead market limits. With a lower limit, schedules may be forced to reduce flows over the binding constraint without a corresponding flow increase. The ISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the ISO charges an uplift to measured demand to offset the imbalance. Congestion imbalances can also occur from differences in transmission modeling and the modeling of non-settled flows.

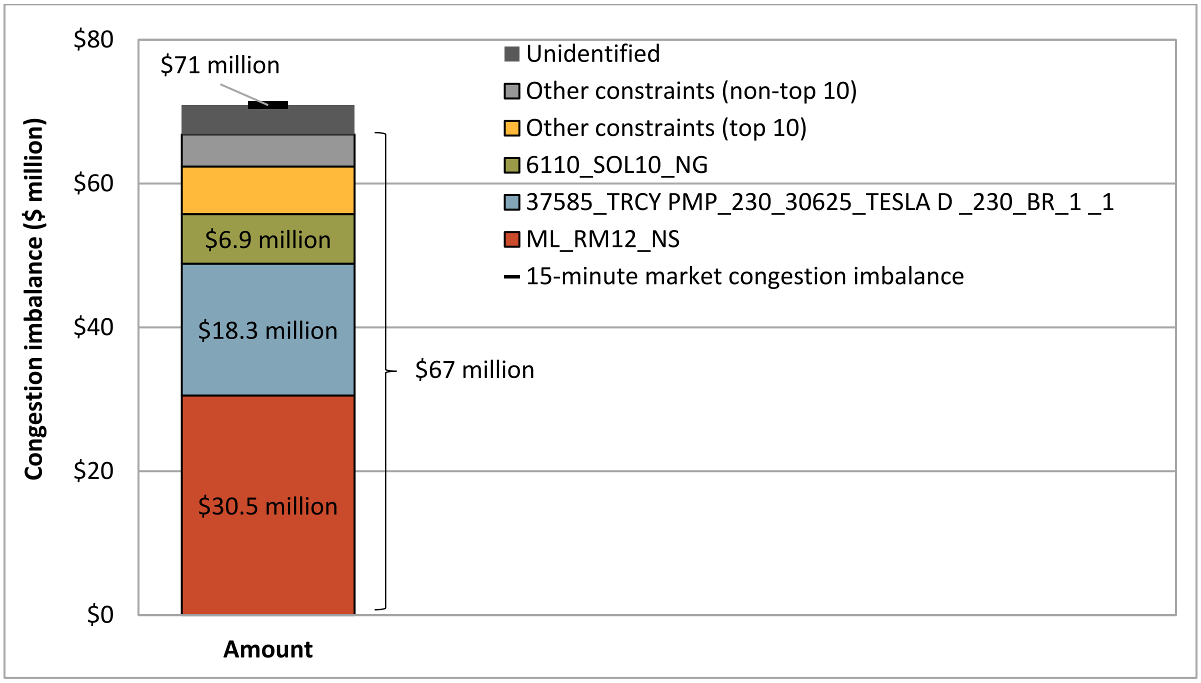
Around $71 million of the total congestion offset costs in June were associated with 15-minute market imbalances. Figure 2.21 shows the 15-minute market congestion offset costs split out by individual constraints.[148] The three largest constraints associated with real-time congestion offset costs during June are listed below. These three constraints accounted for about $56 million of the 15-minute market congestion imbalances, or around 79 percent.[149]

1. **ML_RM12_NS ($30.5 million):** This constraint was one of the most frequently binding constraints in the 15-minute market and was heavily impacted by unscheduled flows over Path 66 (COI) which were exacerbated by the loss of the Tesla-Tracy 500 kV line and Captain Jack CB 4977.
2. **37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1 ($18.3 million):** This line was impacted by maintenance on the Tesla-Tracy 230 kV line as well as mitigation for the contingency of the Malin 500 intertie.
3. **6110_SOL10_NG ($6.9 million):** Path 66 control point #10 is used to limit thermal loading on Round Mountain-Cottonwood 230 kV #3 line. This constraint is used to manage conditions similar to the 6110_COI_N-S constraint used only in the 5-minute market. As noted above, the 5-minute market only 6110_COI_N-S would generate additional congestion offset when binding.

148 Individual constraints were identified by replicating the nodal congestion component of the price (that was used in the RTCIO calculation) from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the marginal congestion component such that the entire congestion offset cost was instead flagged as unidentified.

149 This does not account for congestion revenue imbalances associated with the impact of load on particular constraints. This would be included in the total congestion offset calculation as part of uninstructed imbalance energy component.

Figure 2.21 15-minute market congestion imbalance by constraint (June 2022)

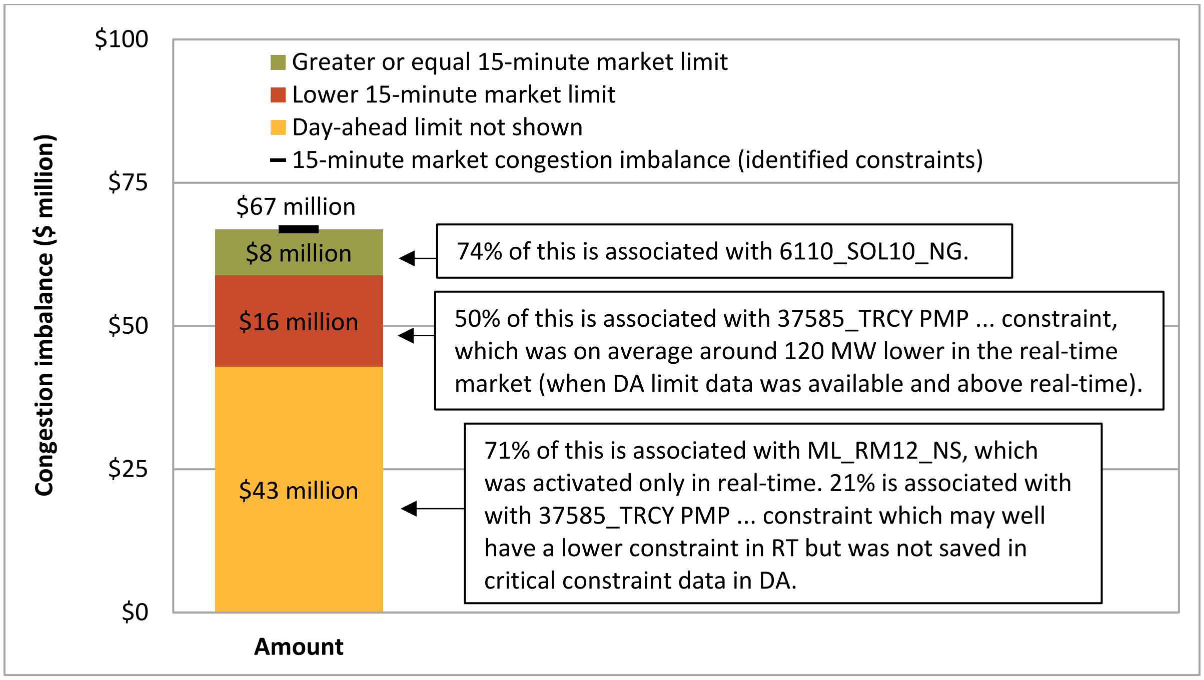


Much of the congestion imbalances observed in June occurred when the constraint limits in the 15-minute market were lower than the day-ahead limits, or with the activation of the ML_RM12_NS nomogram which was not enforced in the day-ahead market. Figure 2.22 summarizes the 15-minute congestion imbalance costs broken into three groups where the 15-minute market limit on the corresponding constraint was: (1) above the day-head limit; (2) below the day-ahead limit; or (3) there was no day-ahead limit available in the trade hour for comparison.

Around $16 million were associated with constraints in which the transmission limit was lower in the 15-minute market than in the day-ahead market. In particular, around half of this was associated with the binding 37585_TRCY PMP_230_30625_TESLA D_230_BR_1_1 constraint.

Around $43 million were associated with constraints in which the limits were not shown in the day-ahead data. This does not necessarily mean the constraint was not enforced in the day-ahead market. The constraint data may not have been saved in the critical constraint data as the constraint was not close enough to binding to be placed in the market run. However, around 71 percent of this was associated with the ML_RM12_NS nomogram, which was only activated in the real-time market.

Figure 2.22 15-minute market congestion imbalance by status, 15-minute market limit relative to day-ahead market (June 2022)



Last, Table 2.5 summarizes total 15-minute market congestion offset costs during June both individually for the top ten constraints (by imbalance) and grouped for all other constraints. The table highlights the percent of congestion imbalances which were associated with either a lower or higher limit in the 15-minute market relative to the day-ahead market. The table also shows the total intervals that each constraint was binding in the 15-minute market.[150] Outside the top three which were already discussed, the other constraints within the top ten were associated with around $6.6 million in congestion imbalances. Here, 57 percent of this deficit was associated with a lower 15-minute market limit and 25 percent had no day-ahead limit shown. Outside the top ten constraints (around $4.5 million), 80 percent was associated with a lower limit in the 15-minute market.

150 15-minute intervals are counted by unique constraint element and contingency. In some cases, the same constraint was binding for multiple contingencies in the same interval, which were counted separately.

Table 2.5 15-minute market congestion imbalance by constraint (June 2022)

Constraint	Binding in 15-minute market (constraint/case intervals)	15-minute congestion imbalance ($ million)	Percent of congestion imbalance by 15-minute market limit relative to day-ahead		
			Lower FMM limit	Day-ahead limit not shown	Greater or equal FMM limit
ML_RM12_NS	1,209	$30.5	0%	100%	0%
37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	547	$18.3	43%	50%	7%
6110_SOL10_NG	328	$6.9	10%	4%	86%
31336_HPLND JT_60.0_31370_CLVRDLJT_60.0_BR_1 _1	889	$1.4	59%	7%	34%
30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	228	$1.3	61%	3%	36%
SUMMIT_BG	105	$0.9	0%	100%	0%
30055_GATES1 _500_30900_GATES _230_XF_12_P	324	$0.8	91%	9%	0%
30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	200	$0.8	100%	0%	0%
30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	92	$0.7	23%	51%	26%
32214_RIO OSO _115_30330_RIO OSO _230_XF_2A	172	$0.6	62%	38%	0%
Other identified constraints	8,496	$4.5	80%	27%	-7%
Totals		$67	24%	12%	64%

Real-time energy imbalance offset costs

Real-time imbalance energy offset charges reached almost $92 million in September, or around $121 for all of 2022. A significant portion of this revenue shortfall is created from a structural inconsistency in the settlement of real-time market demand and generation.

Real-time *generation* is paid incrementally from one market to the next — the difference from the day-ahead to 15-minute market schedule at the 15-minute market price and the difference from the 15-minute to 5-minute market schedule at the 5-minute market price.

Real-time non-dispatchable *load* is instead settled on the difference from 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, this average hourly price 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 result in nonsensical settlement outcomes 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.[151] 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. The imbalance offset costs are allocated to total metered load plus exports.

The majority of 2022 energy offset charges occurred in September. Almost all the September costs occurred during the heatwave period between September 1 and September 8. Figure 2.23 compares the energy offset costs during this period with the estimated energy account shortfall created from the current settlement of real-time load using prices weighted by the absolute value of imbalance. During September, the revenue deficit created from this settlement approach made up around 79 percent of real-time energy imbalance offset costs.

151 If the calculated weighted average price is greater than the maximum of the 15-minute and 5-minute market prices, or less than the minimum of the 15-minute and 5-minute market prices, 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).

In total for 2022, the use of the absolute value weighted price created $143 million in CAISO real-time revenue imbalances. Figure 2.24 shows these revenue shortfalls by month. During the year, revenue shortfalls created by settling the *energy component* of real-time load with the absolute value weighted price were $140 million, compared to almost $121 million in real-time imbalance energy offset costs.

Figure 2.23 CAISO real-time imbalance energy offsets costs and energy account shortfall from settlement using absolute value weighted price (September 1–8, 2022)

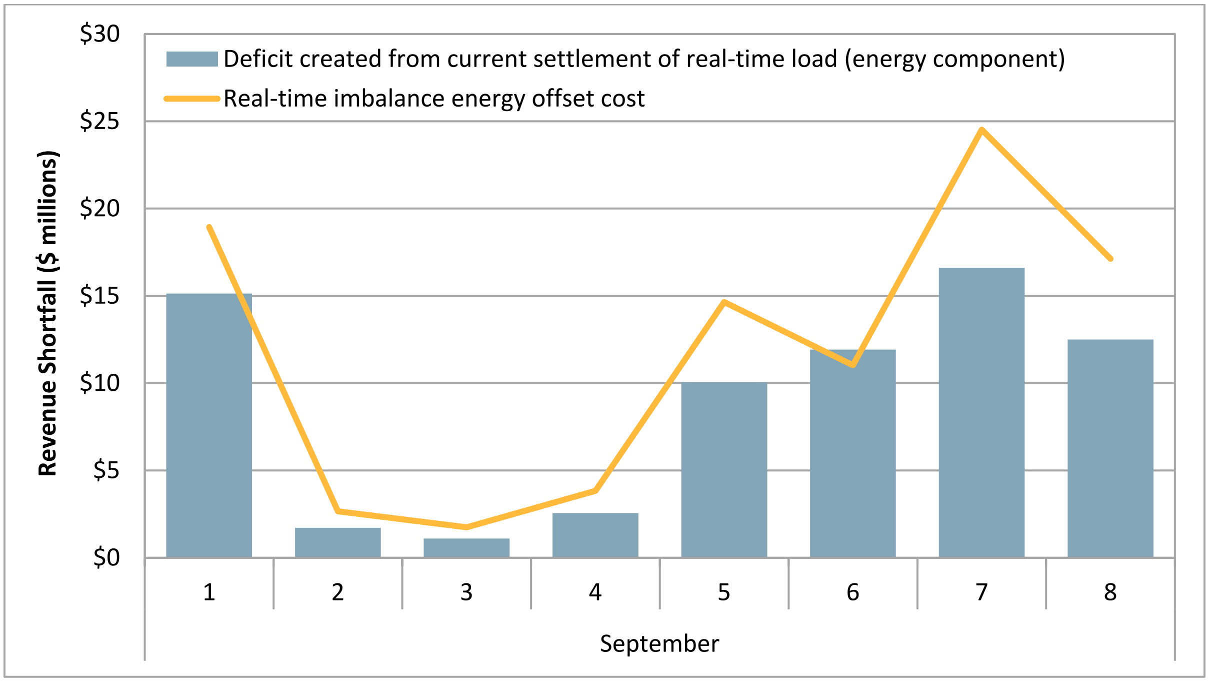
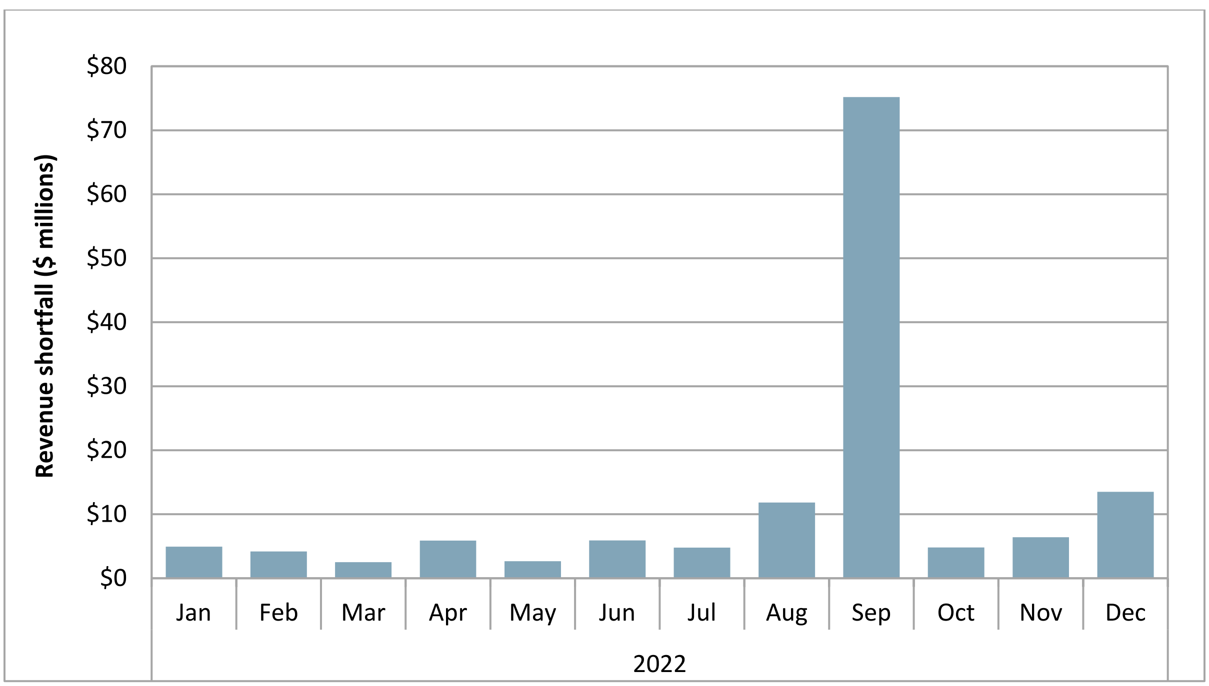


Figure 2.24 Total shortfall created from settling real-time load with absolute value weighted price



2.8 Flexible ramping product

Background

The flexible ramping product is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage volatility and uncertainty of real-time imbalance demand. 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.

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

Flexible ramping product requirement

The end of the 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 that might materialize.[152] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

Uncertainty requirements prior to February 1, 2023

During 2022, there was a separate demand calculated for each WEIM area, in addition to a system-level demand curve. The system uncertainty requirement for the entire footprint was always enforced in the market, while the uncertainty requirements for the individual balancing areas were reduced in every interval by their transfer capability — with a floor of zero or any minimum requirement that was active.[153] The minimum requirement helped procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty.[154] This was typically only the CAISO area, which had a minimum upward and downward uncertainty requirement enforced in most intervals.

Uncertainty requirements for the flexible ramping product were 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. The historical net load error observations in the distribution were the difference between binding 5-minute market net load forecasts and corresponding advisory 15-minute market net load forecasts. Here, the 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

[152] Based on a 95 percent confidence interval.

[153] In each interval, the upward uncertainty requirement for each area was reduced by net import capability while the downward uncertainty requirement was reduced by net export capability. If the area fails the sufficiency test in the corresponding direction, the uncertainty requirement would not include this reduction.

[154] If a balancing area requirement was greater than 60 percent of the system requirement, then a minimum would be enforced equal to the balancing area's share of the diversity benefit.

weekend days. The histogram method did not factor in any current load, solar, or wind forecast information.

Uncertainty requirements after February 1, 2023

Flexible ramping product refinements implemented on February 1, 2023 introduced two significant changes.[155] The first of these addressed the deliverability of flexible ramping capacity. As part of these enhancements, the real-time market enforces an area-specific uncertainty target for balancing areas that fail the resource sufficiency evaluation which can only be met by flexible capacity within that area. In contrast, flexible capacity for the group of balancing areas that pass the resource sufficiency evaluation are pooled together to meet the uncertainty target for the rest of the system. Deliverable flexible capacity awards are produced through two deployment scenarios that adjust the expected net load forecast in the following interval by the lower and upper ends of uncertainty that might materialize. This 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.

The second significant change impacted how uncertainty is calculated. Here, uncertainty was adjusted to incorporate current load, solar, and wind forecast information using a method called *mosaic quantile regression*.[156]

Flexible ramping product prices

Flexible ramping product procurement and shadow prices are determined from demand curves. When the shadow price is $0/MWh, the maximum value of capacity on the demand curve is procured. This reflects that flexible ramping capacity is readily available relative to the need for it, such that there is no cost associated with the level of procurement.

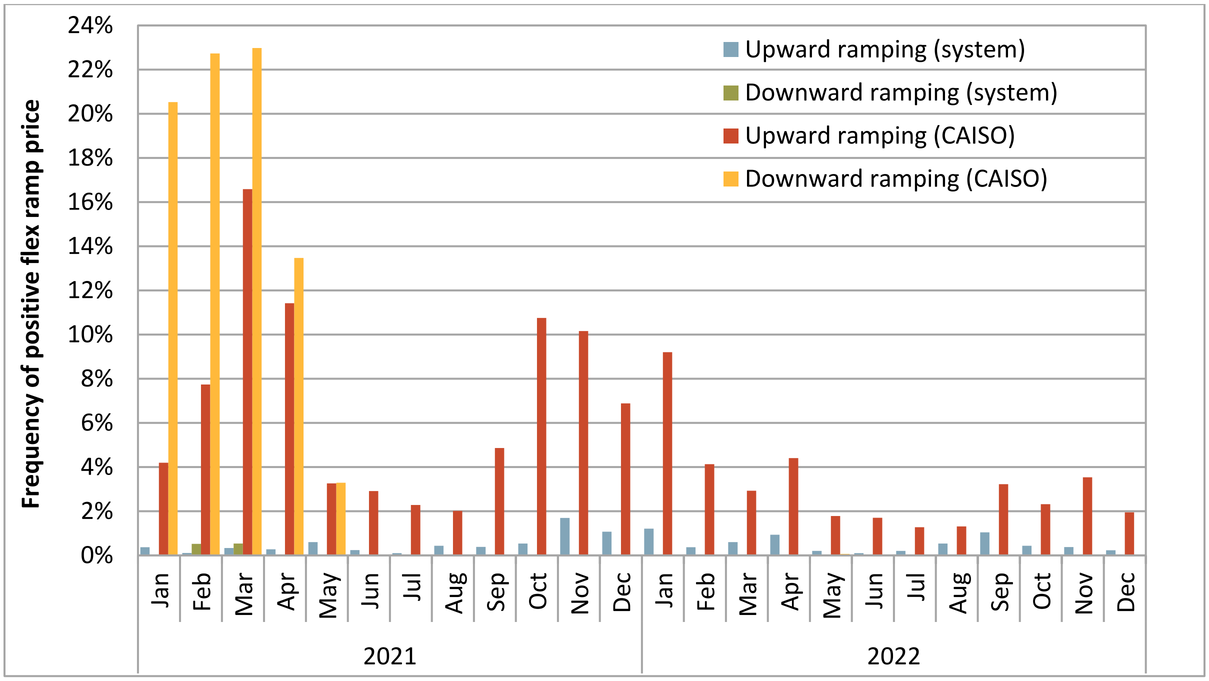
Figure 2.25 shows the percent of intervals that the system-level flexible ramping demand curve was binding at a positive shadow price in the 15-minute market. The percent of intervals in which the CAISO demand curve was binding is also shown. This was frequent during 2022 because of the minimum requirement, which typically necessitated a portion of flexible ramping capacity be procured within CAISO.

The frequency of positive shadow prices for the *system* continued to be low. During the year, the 15-minute market system-level demand curve for upward and downward ramping capacity bound in less than 1 percent of intervals. 15-minute market shadow prices for upward flexible capacity in the CAISO area bound slightly more frequently (during around 3 percent of intervals) due to the minimum requirements that were in place. In the 5-minute market, the system-level and California ISO-specific demand curves for upward and downward ramping capacity were binding in less than 0.2 percent of intervals.

155 California ISO, *Flexible Ramping Product Refinements Final Proposal,* August 31, 2020. http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

156 For more information on the calculation of the mosaic quantile regression uncertainty, see: Department of Market Monitoring, *Western Energy Imbalance Market Resource Sufficiency Evaluation Report covering February 2023*, May 3, 2023: http://www.caiso.com/Documents/Feb-2023-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-May-3-2023.pdf

Figure 2.25 Frequency of positive system or CAISO flexible ramping shadow price (15-minute market)



System-level flexible ramping product prices were often zero during 2022 because of procured flexible ramping capacity that was stranded behind WEIM transfer constraints.[157] In particular, limited export capability out of the Northwest region often resulted in flexible ramping capacity that was procured in these areas as the opportunity cost of providing ramping capacity in lieu of energy was then lower. This resulted in lower deliverability of flexibility capacity that also suppressed the opportunity cost of providing such capacity instead of energy at the system-level.

The California ISO implemented nodal procurement for the flexible ramping product on February 1, 2023 as part of the flexible ramping product refinements stakeholder initiative.[158] This change was intended to address the issues associated with stranded flexible ramping capacity by procuring such capacity at a nodal level, using deployment scenarios to ensure that flexible capacity awards are feasible to deliver.

[157] For more information including other contributors to zero system-level prices, see *2021 Annual Report on Market Issues & Performance,* Department of Market Monitoring, July 27, 2022, pp. 121-127: http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

[158] California ISO, *Flexible Ramping Product Refinements Final Proposal,* August 31, 2020. http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

3 Western Energy Imbalance Market

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO balancing area to participate in the California ISO real-time market. This chapter provides a summary of WEIM performance during 2022.

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 2022.** Avista Utilities (AVA) and Tacoma Power (TPWR) joined on March 2, while Bonneville Power Administration (BPA) and Tucson Electric Power (TEPC) joined on May 3, bringing the total number of participants up to 19.
- **Total hourly load across the Western Energy Imbalance Market footprint peaked on September 6 at almost 130,000 MW.** During this hour, 62 percent of load was from balancing areas outside the California ISO.
- **The California ISO exports significant energy to other balancing areas in the Western Energy Imbalance Market in periods of relatively high solar production.** These transfers reduced the need to curtail solar and other low cost renewable production.
- **During peak evening hours in the summer, the California ISO tends to import significantly from other balancing areas.** This reflects regional supply conditions and transfer capacity across the market footprint that can best meet system-wide demand during this period.
- **Western Energy Imbalance Market participants in the Pacific Northwest continued to be in the most frequently congested region**, resulting in price separation relative to the greater market footprint.
- **The California ISO implemented phase 1 of resource sufficiency evaluation enhancements in June.** Phase 1 included enhancements to omit offline long-start capacity from the bid-range capacity test.

3.1 WEIM overview and continued expansion

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO (CAISO) balancing area to voluntarily take part in the CAISO 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 helps 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, when it only optimized the California ISO and PacifiCorp balancing authority areas (PACE and PACW). Since then, NV Energy (NEVP) was integrated in the market in December 2015, Puget Sounded Energy (PSEI) and Arizona Public Service (AZPS) joined in October 2016, Portland General

Electric (PGE) began participation in 2017, Idaho Power (IPCO) and Powerex (BCHA) joined in 2018, and the Balancing Authority of Northern California (BANC) joined in 2019.[159] Next, Seattle City Light (SCL) and Salt River Project (SRP) joined in 2020. Turlock Irrigation District (TIDC), Los Angeles Department of Water and Power (LADWP), Public Service Company of New Mexico (PNM), and NorthWestern Energy (NWMT) joined the market in 2021.

In 2022, the Western Energy Imbalance Market continued to expand with four new participants. Avista Utilities (AVA) and Tacoma Power (TPWR) joined on March 2, while Bonneville Power Administration (BPA) and Tucson Electric Power (TEPC) joined on May 3, bringing the total number of participants up to 19, including CAISO.[160]

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 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.

3.2 Load and supply conditions in WEIM

3.2.1 Load conditions

Total load served in the WEIM increased significantly in 2022 with the additions of new entities joining the market. During the year, hourly load for non-CAISO WEIM areas peaked in July, at 60,725 MW.

Figure 3.1 shows the average load by month in the WEIM in 2022, 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 December. In 2022, average load reached 60,725 MW in July and 57,050 MW in December. This dual peak trend corresponds with the large WEIM footprint as some areas see high loads in summer and others in winter.

Table 3.1 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.[161] The total hourly load across the WEIM footprint peaked on September 6 at 129,872 MW. During this hour, 62 percent of load was from non-CAISO WEIM areas. Generally, load peaked in balancing areas in the Southwest in mid-July and in the Pacific Northwest in late-December.

---

159 The Balancing Authority of Northern California initially began participation in 2019 with only the Sacramento Municipal Utility District participating as a member within the balancing authority area (phase 1). On March 25, 2021, three other members including Modesto Irrigation District, City of Redding, and City of Roseville began participation (phase 2).

160 PacifiCorp includes two balancing areas, PacifiCorp East and PacifiCorp West. Total balancing areas including CAISO is 20.

161 These are hourly metered amounts.

Figure 3.1 Average WEIM load by month, excluding CAISO

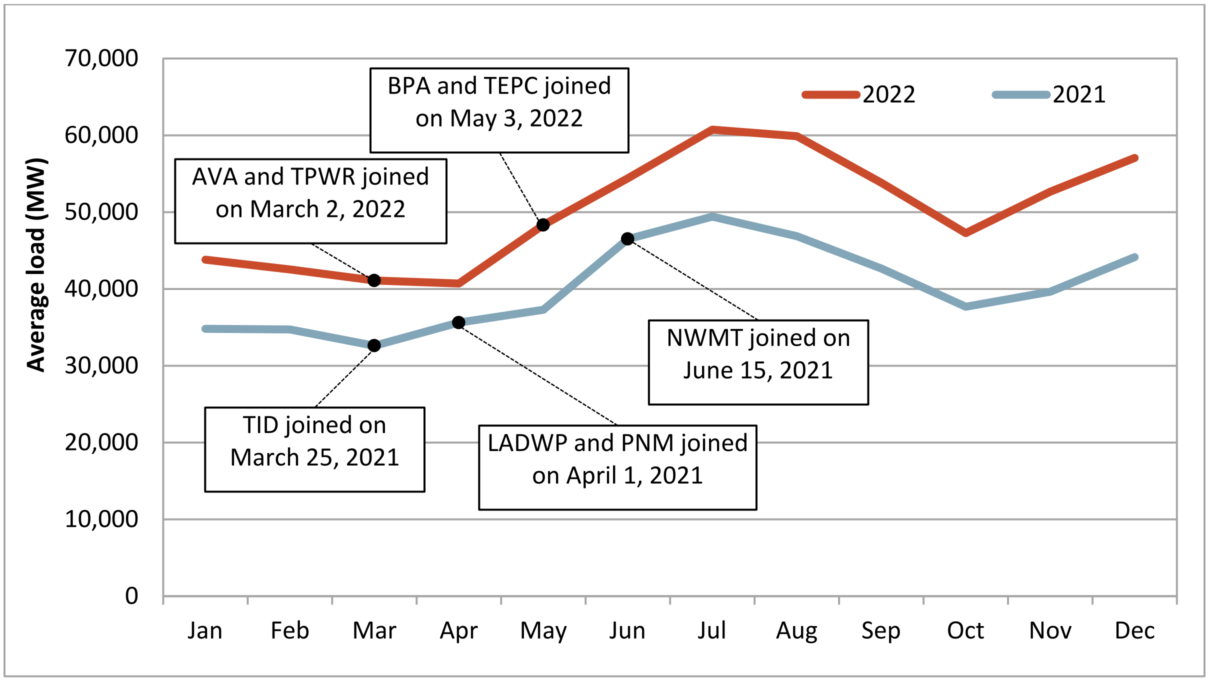


Table 3.1 System peak load by BAA

	Peak load		Load during WEIM system peak (06-Sep-22)	
BAA	Date	Load (MW)	Load (MW)	Percentage
CISO	6-Sep-22	49,312	49,269	37.9%
PACE	6-Sep-22	9,408	9,408	7.2%
NEVP	12-Jul-22	8,867	8,682	6.7%
BCHA	19-Dec-22	11,899	7,800	6.0%
BPAT	22-Dec-22	10,941	7,305	5.6%
SRP	11-Jul-22	7,512	6,850	5.3%
AZPS	11-Jul-22	7,373	6,720	5.2%
LADWP	6-Sep-22	6,041	5,941	4.6%
BANC	6-Sep-22	4,744	4,710	3.6%
PGE	2-Jun-22	4,354	3,481	2.7%
IPCO	3-Aug-22	3,793	3,413	2.6%
PACW	23-Feb-22	3,976	3,234	2.5%
PSEI	22-Dec-22	5,017	2,950	2.3%
TEPC	11-Jul-22	2,890	2,462	1.9%
PNM	19-Jul-22	2,617	2,163	1.7%
NWMT	22-Dec-22	2,016	1,586	1.2%
AVA	22-Dec-22	2,206	1,562	1.2%
SCL	22-Dec-22	1,863	1,109	0.9%
TIDC	6-Sep-22	728	722	0.6%
TPWR	24-Mar-22	1,310	505	0.4%
Total			**129,872**	

3.2.2 Participating capacity and generation

Figure 3.2 shows the total participating WEIM nameplate capacity from June 2018 through June 2023. 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 2018, roughly 54,000 MW of capacity has been added to the Western Energy Imbalance Market, 24 percent of which was hydroelectric and about 41 percent natural gas. WEIM nameplate capacity decreased from June 2022, despite the addition of new entities, due to operational downgrades to several large hydro resources in Bonneville Power Administration.

Figure 3.2 Total WEIM participating capacity by fuel type and year (as of June 1, 2023)[162]

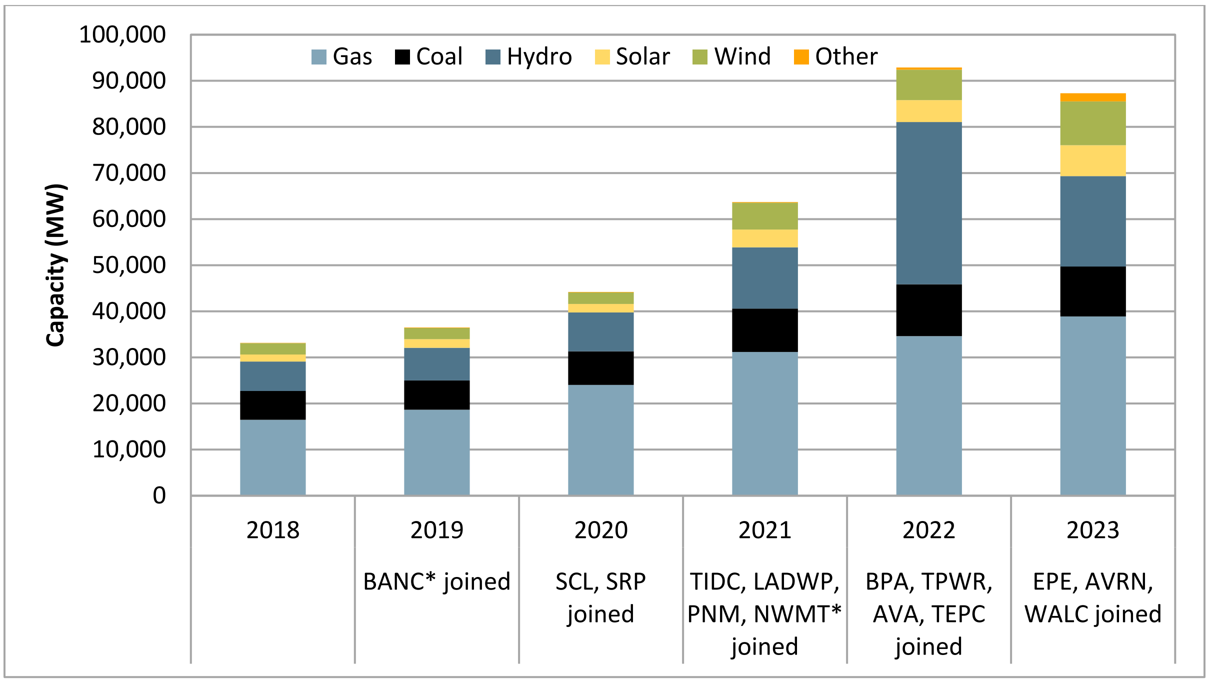


Figure 3.3 shows the fuel mix of participating capacity for each BAA in the WEIM as of June 1, 2023. Avangrid has the most nameplate capacity of new WEIM entrants, with a 3,300 MW portfolio from mostly wind resources. WAPA Desert Southwest Region (WALC) and El Paso Electric (EPE) added 2,300 MW and 2,000 MW of capacity, respectively, to the WEIM.

162 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, 2023)

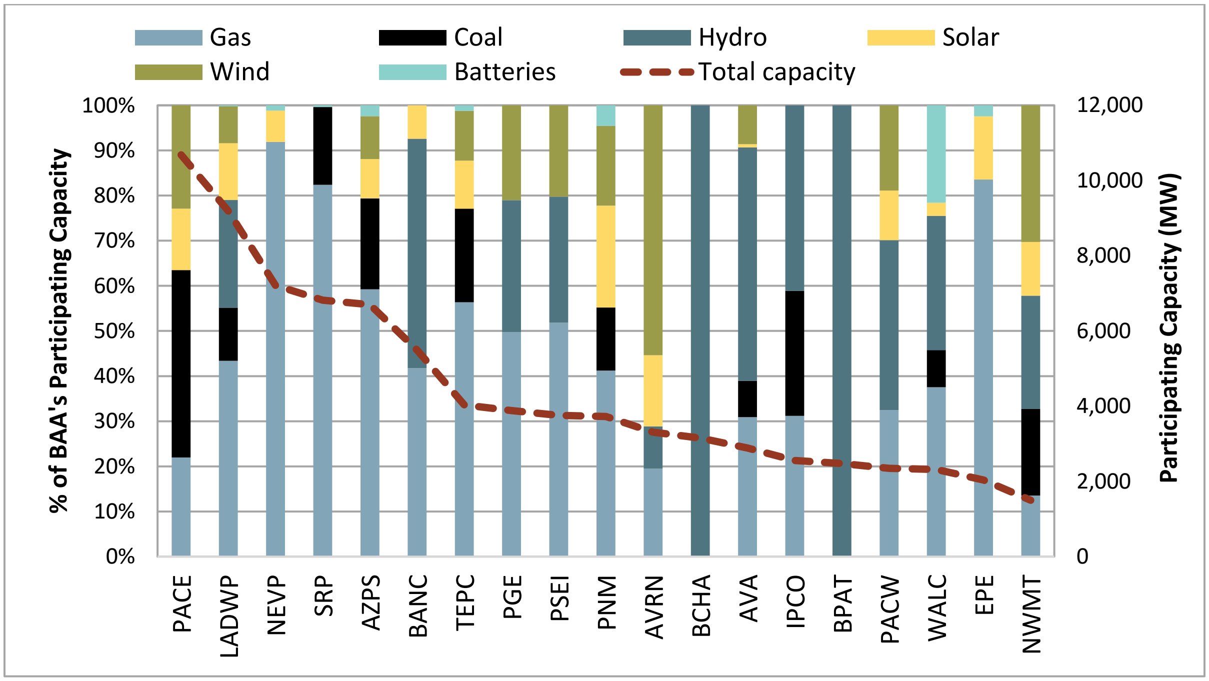


Figure 3.4 provides a profile of average monthly participating WEIM generation by fuel type.[163] Figure 3.5 illustrates the same data on a percentage basis. These two figures show the following:

- Natural gas and coal were the largest sources of participating WEIM generation in 2022, representing 47 and 25 percent of total WEIM generation, respectively.
- The percent of total WEIM generation from renewables increased from around 13.2 percent in 2021 to 14.3 percent in 2022.[164]

Figure 3.6 shows average hourly participating WEIM generation by fuel type over the year.[165] In 2022, hour ending 20 averaged the highest amount of WEIM generation at about 30,625 MW, while hour ending 4 averaged the lowest at about 22,475 MW. Figure 3.7 shows the change in average hourly participating WEIM generation by fuel type from 2021 to 2022.[166] Generation from hydroelectric and wind resources increased by 41 percent and 24 percent, respectively, in 2022 compared to 2021. Natural gas generation saw significant declines in generation in the middle of the day and decreased 2 percent overall compared to last year. Changes to average hourly generation and the overall increase in generation is influenced by new entities joining the WEIM.

---

163 Changes in monthly generation are due in part to new WEIM entities joining the market.

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

165 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.

166 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 3.4 Average monthly participating WEIM generation by fuel type in 2022

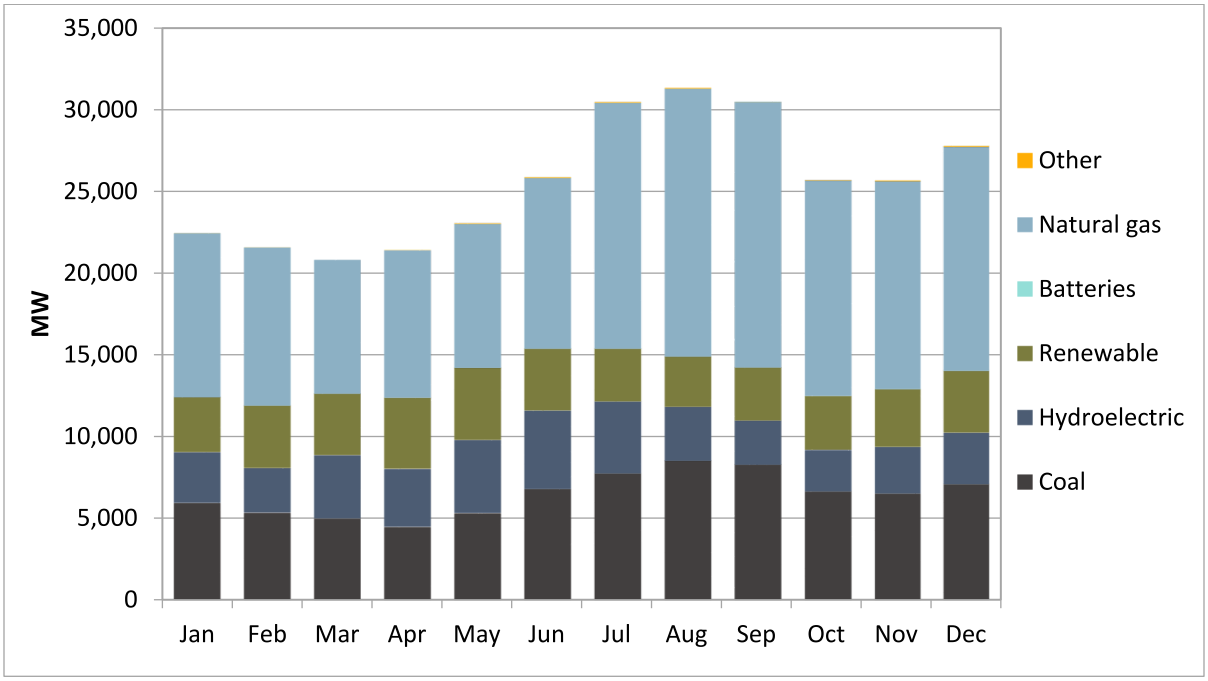


Figure 3.5 Average monthly participating WEIM generation by fuel type in 2022 (percentage)

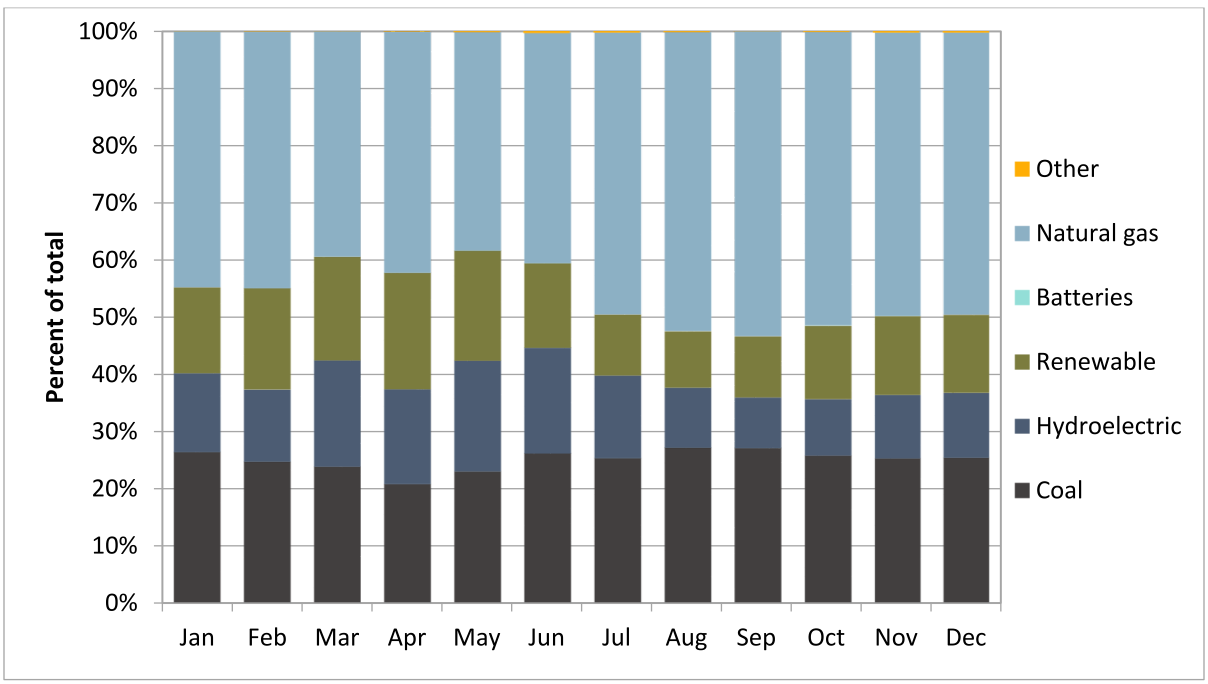


Figure 3.6 Average hourly participating WEIM generation by fuel type (2022)

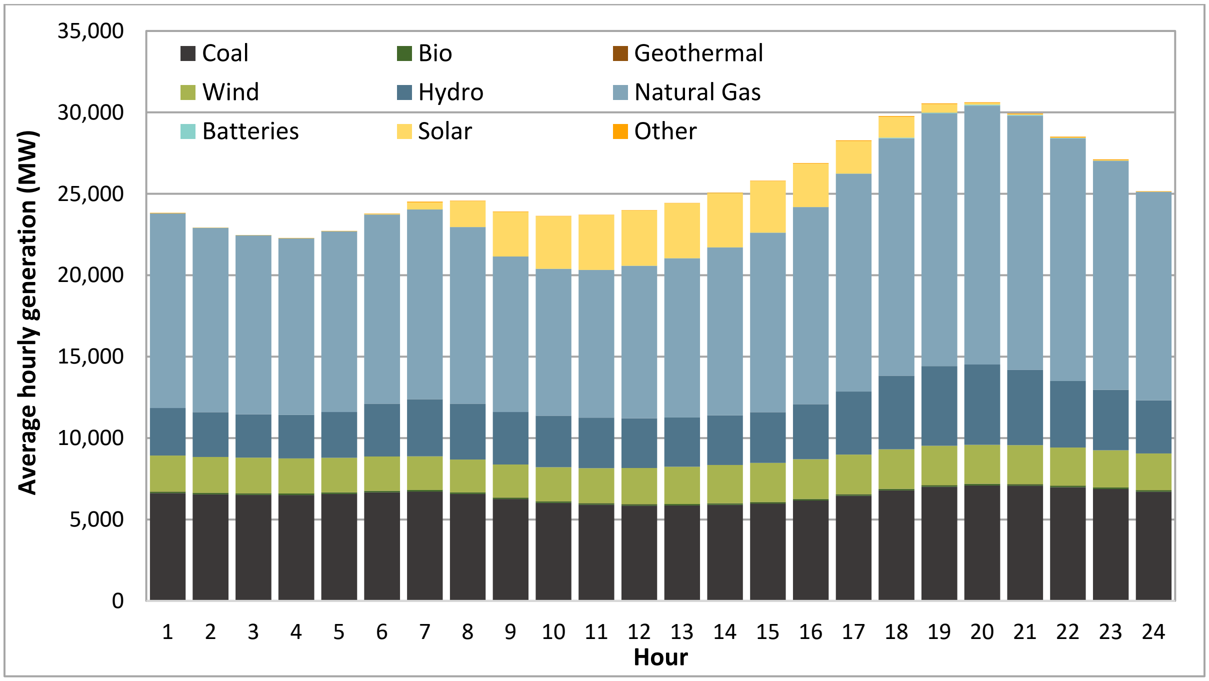
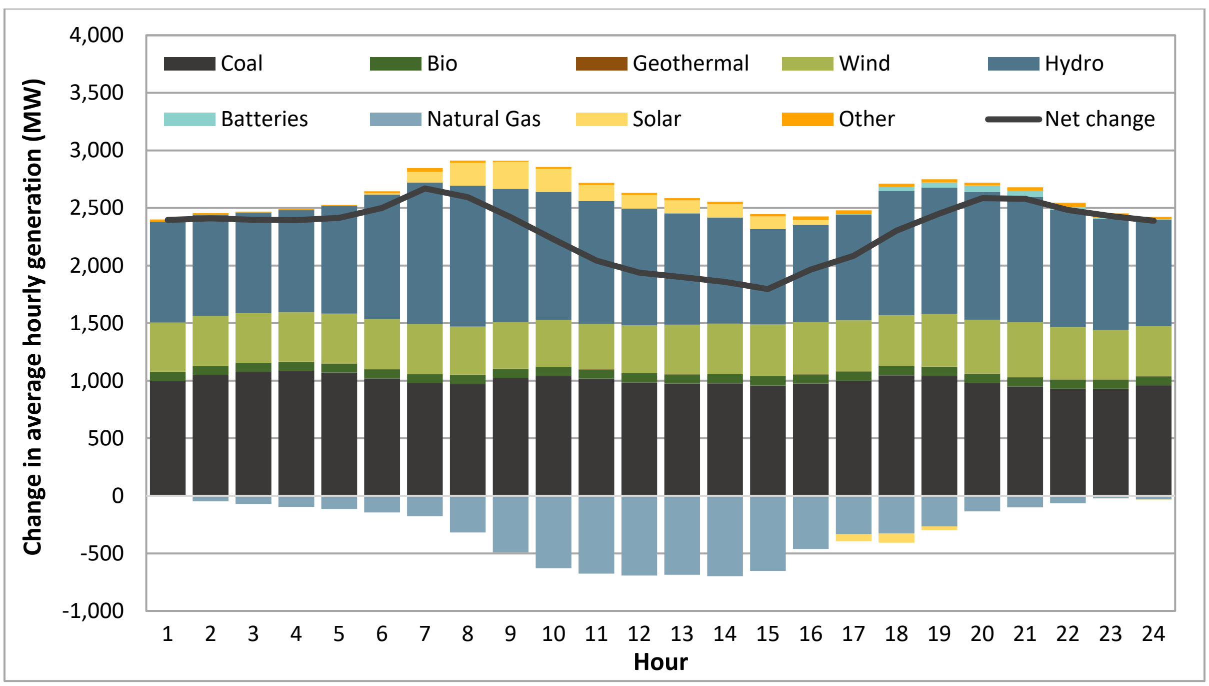


Figure 3.7 Change in average hourly participating WEIM generation by fuel type (2021–2022)



3.3 Transfers, limits, and congestion

Transfers

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* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 3.8 and Figure 3.9 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[167] First, Figure 3.8 shows average dynamic 15-minute market exports out of each area during mid-day spring hours between March and May 2022.[168] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area. Each small tick is 50 MW and each large tick is 250 MW.

Figure 3.8 shows that the CAISO exported almost 2,000 MW, on average during these mid-day spring hours, out to neighboring areas including BANC, LADWP, Portland General Electric, Powerex, NV Energy, Salt River Project, and Arizona Public Service. These areas each remained a net importer on average, despite having some exports out to other connecting areas in the WEIM footprint (which can be followed around in the chart). These mid-day spring hours typically contain the highest levels of exports out of the CAISO area because of significant renewable production (particularly solar), as well as modest loads. PacifiCorp East was also a net exporter during these hours, with around 260 MW on average out to neighboring areas.

Figure 3.9 shows average dynamic transfers during peak load hours between the months of July and September 2022. During these hours, when supply conditions across the footprint are typically tightest, imports into the CAISO are often high. The figure shows, on average, almost 1,600 MW of exports – out of LADWP, Turlock Irrigation District, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power — going into the CAISO during these hours (CAISO import). PacifiCorp East was also a significant net exporter during these hours, with around 550 MW on average out to neighboring areas.

---

167 WEIM transfer paths less than 25 MW, on average, are excluded from the figures.

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

Figure 3.8 Average 15-minute market WEIM exports (mid-day hours, March–May, 2022)

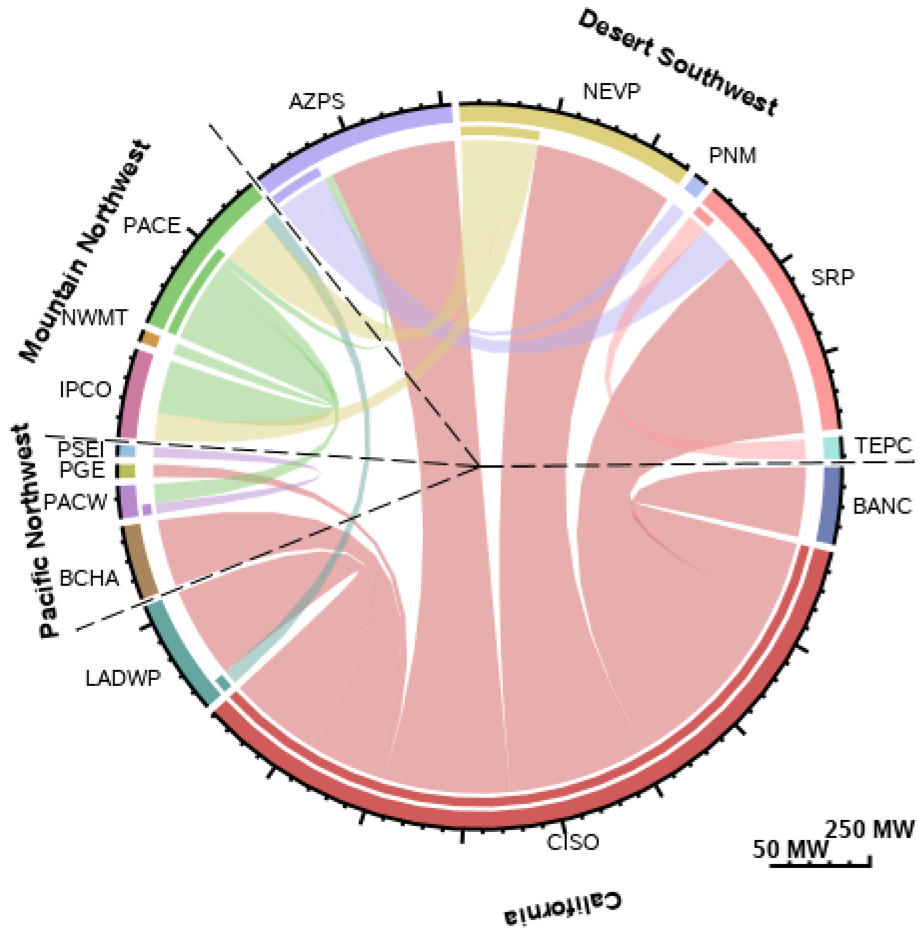
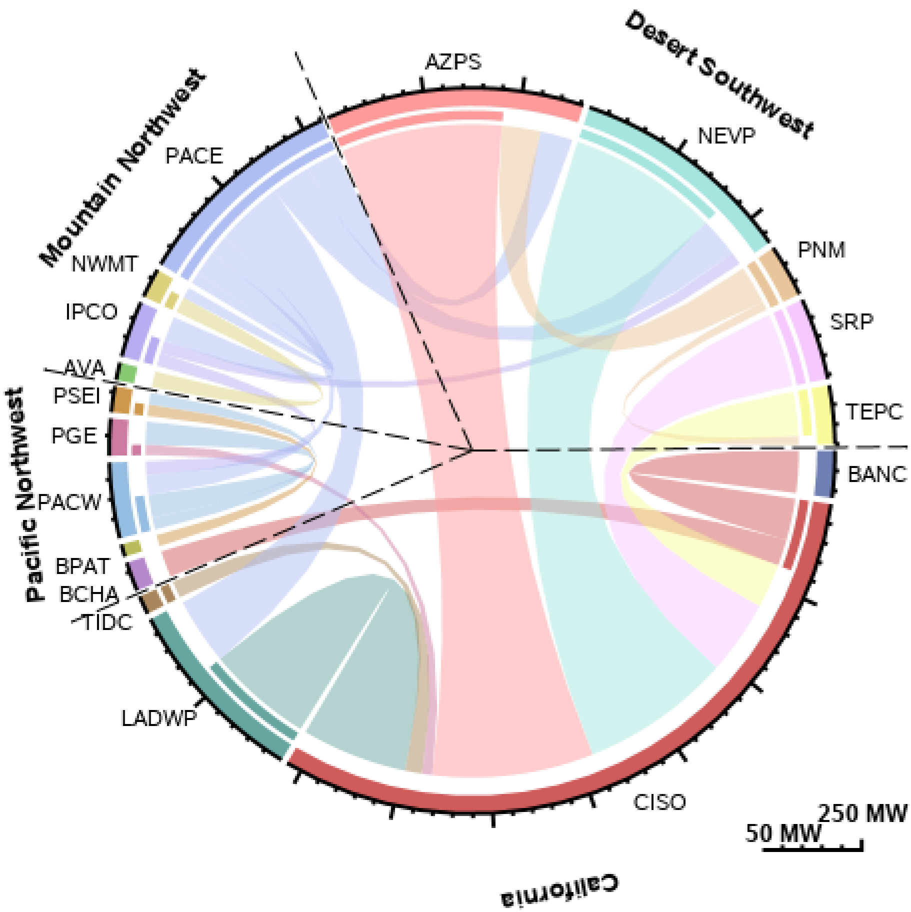


Figure 3.9 Average 15-minute market WEIM exports (peak load hours, July–September, 2022)



Transfer limits

WEIM transfers between areas are constrained by *transfer limits*. These largely reflect transmission and interchange rights made available to the market by participating WEIM entities.[169] Table 3.2 shows average 15-minute market limits between each of the areas over the year.[170] These amounts exclude base transfer schedules and therefore reflect only the transfer capability made available by WEIM entities to optimally transfer energy between areas. The sum of each column reflects the average total import limit into each balancing area, while the sum of each row reflects the average total export limit from each area.

Transfer capacity into or out of the Pacific Northwest (including Bonneville Power Administration, Tacoma Power, PacifiCorp West, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light) was around 590 MW of exports and 1,080 MW of imports on average during the year.

[169] The exception to this is PacifiCorp West and Portland General Electric 5-minute market transfer limits with CAISO, which are based on the allocated dynamic transfer capacity driven by system operating conditions.

[170] The blank cells indicate that the pair of areas have no energy transfer system resource (ETSR) defined between them. A cell with zero MW indicates that there is an ETSR defined between the pair of areas, but the limit was zero on average during the year.

Significant transfer capability between balancing areas in the rest of the WEIM system typically allowed energy to flow between these areas with relatively little congestion.

Table 3.2 Average 15-minute market WEIM transfer limits (2022)

From Balancing Authority Area	To Balancing Authority Area: CAISO	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	SCL	*Total export limit*
California ISO		3,500	1,180	4,460	3,610	1,410	220	1,650					0	50		50	70		310		16,510
BANC	3,500		530																		4,030
Turlock Irrig. District	1,180	760																			1,940
LADWP	7,910				1,670	320	280			180											10,360
NV Energy	4,020			1,020		320				770	410										6,540
Arizona Public Service	2,520			230	240		1,460	3,530	600	620											9,200
Tucson Electric*	460			150		1,750		1,610	210	240											4,420
Salt River Project	3,090					2,900	1,070		70												7,130
PSC New Mexico						470	280	150													900
PacifiCorp East				210	380	450	160				750	220				170					2,340
Idaho Power					330					1,570		220	310	0		310				30	2,770
NorthWestern Energy										120	170		310	20	0						620
Avista Utilities*	0										360	330		40	0	30					760
BPA*	60										0	40	50		120	40	160	80	0	40	590
Tacoma Power*												0	0	60			10	210			280
PacifiCorp West	120									0	140		30	20			320	100		10	740
Portland GE	130													150	10	350				10	650
Puget Sound Energy														110	220	90			50	350	820
Powerex	0													0				50			50
Seattle City Light											20			20		10	10	350			410
Total import limit	22,990	4,260	1,710	6,070	6,230	7,620	3,470	6,940	880	3,500	1,850	810	700	470	350	1,050	570	790	360	440	

*Since joining the WEIM

Congestion on transfer constraints

WEIM participants in the Pacific Northwest continued to be the most frequently congested region relative to the greater market footprint.[171] WEIM areas in the remaining footprint experienced lower frequencies of congestion, with BANC and LADWP experiencing less than 1 percent in both the 15-minute and 5-minute markets.

Table 3.3 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of a WEIM area. This is calculated as the percent of intervals when the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices.[172] When prices are lower relative to the system, this indicates congestion out of an area (or region) and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for outside energy to serve that area's load. The results of this section are the same as those found in Section 6.1.3 of this report on congestion. Section 6.1.3 focuses on the impact of congestion on prices, whereas this section describes the same information in terms of the impact to WEIM import or export capability.

The highest frequency of congestion occurred with areas located in the Pacific Northwest. WEIM *exports* were congested from this region during around 25 percent of the 15-minute market intervals and 20 percent of the 5-minute market intervals. WEIM *imports* into the Pacific Northwest region were also frequently congested, typically during mid-day hours. These areas were import congested during around 17 percent and 19 percent of the 15-minute and 5-minute market intervals.

171 Pacific Northwest areas include Powerex, Puget Sound Energy, Seattle City Light, Portland General Electric, PacifiCorp West, Tacoma Power, and Bonneville Power Administration.

172 Greenhouse gas prices can contribute to lower prices relative to those inside the CAISO. This calculation uses the WEIM greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

Congestion in either direction for BANC, LADWP, Arizona Public Service, NV Energy, PNM, and Turlock Irrigation District was relatively infrequent during the year. Congestion that did occur between these areas and the larger WEIM system was often the result of a failed upward or downward resource sufficiency evaluation, which limited transfer capability.

Table 3.3 Frequency of congestion on WEIM area transfer constraints (2022)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
L.A. Dept. of Water and Power	0%	0%	0%	0%
Arizona Public Service	1%	0%	1%	1%
NV Energy	1%	0%	1%	1%
Public Service Company of NM	1%	0%	1%	1%
Turlock Irrigation District	0%	2%	0%	2%
PacifiCorp East	6%	1%	4%	1%
Tucson Electric Power*	2%	4%	1%	6%
Idaho Power	6%	7%	4%	7%
Salt River Project	13%	3%	12%	4%
NorthWestern Energy	12%	8%	8%	8%
Avista Utilities*	13%	7%	8%	8%
PacifiCorp West	22%	9%	12%	7%
Portland General Electric	22%	12%	13%	9%
Bonneville Power Admin.*	21%	21%	16%	20%
Tacoma Power*	25%	21%	19%	23%
Puget Sound Energy	27%	19%	21%	21%
Seattle City Light	27%	19%	21%	21%
Powerex	34%	17%	36%	32%

*Since joining the WEIM

3.4 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 preventing leaning by one area on another. The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two of the tests 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.[173] Similarly, if an area fails either test in the downward direction, transfers out of that area cannot be increased.

Resource sufficiency evaluation enhancements phase 1

The CAISO implemented a number of changes to the resource sufficiency evaluation on June 1, 2022 as part of Phase 1 of resource sufficiency evaluation enhancements. This included the following enhancements:

- **Consideration of offline resources in the capacity test.** The capacity test will now omit offline long-start capacity from the bid-range capacity test.[174] Short-start units which failed-to-start per the unit's telemetry will also be excluded.
- **Accounting for CAISO interchange awards that have not submitted Transmission Profile e-Tag.** CAISO hour-ahead import and export schedules are expected to be reduced based on the transmission profile e-Tag at T-40. This is intended to help align the interchange schedules used in the resource sufficiency evaluation with what is reasonably expected to be delivered. DMM analysis indicates that this change was not implemented correctly. In some cases, CAISO import and export schedules were not correctly capped by the transmission profile e-Tag at 40 minutes prior to the test hour. The outcome here was effectively no adjustment. DMM's understanding is that this issue is persistent and ongoing.
- **Adjustment to initial reference point used in the flexibility test.** The flexibility test requirement will now consider any power balance constraint shortage that is present in the interval immediately prior to the test hour.
- **Accounting for storage resource's state of charge in the resource sufficiency evaluation.** The capacity and flexibility test should consider the state-of-charge of batteries from the market run immediately prior to the test hour. DMM analysis indicates this change was not implemented correctly. Following implementation, battery capacity counted in the test has often exceeded actual availability. Some of the issues associated with over-counting battery capacity were fixed in mid-October 2022.[175]
- **Submission of load forecast adjustments to reflect non-participating demand response schedules.** Demand response programs, which cannot be accounted for otherwise in the real-time market, can be submitted as a load forecast adjustment to be accounted for in the resource sufficiency evaluation.
- **Suspension of uncertainty in the capacity test.** Intertie uncertainty was removed from the capacity test on June 1, 2022. Net load uncertainty was removed from the capacity test on February 15, 2022.

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

174 Capacity for a unit that is offline in the last 15-minute interval prior to the test hour will only be considered for short-start units (start-up time plus minimum up time at or below 255 minutes).

175 For more information including the impact on test failures, see: Department of Market Monitoring, *Western Energy Imbalance Market Resource Sufficiency Evaluation Metrics Report covering October 2022*, November 30, 2022: http://www.caiso.com/Documents/2022-10-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-2022-11-30.pdf

- **Exclusion of CAISO from allocation of funds associated with balancing test failure.** CAISO is now excluded from potential revenues from failures of the balancing test. The CAISO is not subject to the balancing test as it does make supply available through the base scheduling process.

Bid range capacity and flexible ramping sufficiency test results

Figure 3.10 and Figure 3.11 show the percent of intervals in which each WEIM area failed the upward capacity or flexibility tests, while Figure 3.12 and Figure 3.13 provide the same information for the downward direction.[176] 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 2022:

- NV Energy failed the downward flexibility test in around 1.3 percent of intervals.
- Salt River Project failed the upward and downward flexibility tests in around 0.5 percent of intervals.
- Public Service Company of New Mexico and Arizona Public Service each failed the downward flexibility test in around 0.4 percent of intervals.

The California ISO failed the bid range capacity test during only three 15-minute market intervals during 2022. This was due in part to an issue with the implementation of new logic to consider the initial state-of-charge for battery units in the tests. Due to errors in how these changes were implemented, battery storage capacity counted in the capacity test significantly exceeded the actual available capacity from batteries during the September heatwave. The California ISO would have failed the capacity test in 14 additional intervals after adjusting for unavailable battery capacity. For more information on the performance of the resource sufficiency evaluation during the September heatwave, see DMM's October 2022 resource sufficiency evaluation report.[177] This report also includes the following topics for the heatwave period:

(1) Impact of excluding lower priority exports from CAISO's tests

(2) Overview of reliability demand response resources in the capacity test

(3) Overview of variable energy resources in the capacity test

(4) Demand-response-based load adjustments in the resource sufficiency evaluation

---

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

177 Department of Market Monitoring, *Western Energy Imbalance Market Resource Sufficiency Evaluation Metrics Report covering October 2022*, November 30, 2022: http://www.caiso.com/Documents/2022-10-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-2022-11-30.pdf

Figure 3.10 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
	2022											
Arizona PS	—	—	0.0	0.0	—	—	—	—	—	—	—	0.1
Avista			—	0.0	—	0.2	0.2	0.0	—	—	—	0.1
BANC	—	—	—	—	—	—	—	0.0	0.3	—	—	—
BPA					—	0.1	—	0.0	0.5	—	—	0.4
California ISO	—	—	—	—	—	—	—	—	0.1	—	—	—
Idaho Power	—	0.1	—	—	—	—	—	0.2	0.2	—	—	—
LADWP	—	—	—	—	—	—	0.0	—	—	—	—	—
NorthWestern	0.3	0.1	—	0.0	—	—	—	0.1	0.1	—	0.2	0.1
NV Energy	—	—	—	0.2	0.1	0.0	0.1	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	0.1	—	—	0.3
PacifiCorp West	0.3	0.1	0.3	0.0	0.2	0.0	1.0	0.2	0.0	—	0.0	0.0
Portland GE	0.1	—	—	—	—	—	—	0.1	—	—	0.3	—
Powerex	0.2	—	—	0.1	—	—	—	0.2	—	—	0.0	—
PSC New Mexico	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound En	—	—	—	0.0	0.0	0.2	—	—	0.2	0.1	0.0	—
Salt River Proj.	—	—	0.2	1.5	1.0	0.2	0.2	0.4	0.4	0.2	0.0	0.0
Seattle City Light	—	—	0.1	—	—	—	0.2	0.1	0.2	0.0	0.0	0.2
Tacoma Power			—	0.6	0.1	0.0	0.0	0.2	0.0	—	—	—
Tucson Elec.					—	—	—	0.1	—	—	—	—
Turlock ID	—	—	—	—	—	0.1	—	—	—	—	—	0.2

Figure 3.11 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
	2022											
Arizona PS	0.0	0.2	0.1	—	—	—	0.0	0.1	—	—	0.1	0.4
Avista			—	0.2	0.5	1.0	0.5	0.1	—	0.1	—	0.1
BANC	—	—	—	—	—	—	—	—	0.3	—	—	—
BPA					0.9	3.1	3.3	1.0	1.1	0.2	0.1	0.4
California ISO	—	—	—	—	—	—	—	0.1	0.5	0.0	—	—
Idaho Power	—	0.2	—	—	—	—	0.2	0.2	0.5	—	0.1	—
LADWP	—	—	0.1	—	—	—	—	—	0.1	0.1	—	—
NorthWestern	—	0.1	0.1	0.3	—	0.1	0.3	1.0	0.2	—	0.5	0.8
NV Energy	0.0	0.7	0.4	1.0	0.8	0.2	—	0.1	0.1	0.1	0.2	0.0
PacifiCorp East	0.0	0.0	—	0.1	0.1	0.1	0.2	0.1	—	0.1	—	0.0
PacifiCorp West	0.0	0.0	0.1	0.2	0.1	0.0	—	0.1	0.1	—	0.1	—
Portland GE	0.3	0.0	—	—	—	0.0	0.4	0.1	0.1	0.2	1.0	0.1
Powerex	0.2	0.0	—	0.1	—	—	—	0.3	0.1	—	—	—
PSC New Mexico	—	—	0.1	0.0	0.1	—	0.4	—	0.0	0.2	0.1	0.8
Puget Sound En	—	—	0.0	0.1	—	0.1	0.4	0.2	0.3	—	0.0	—
Salt River Proj.	0.2	—	0.6	0.5	0.2	0.5	0.6	1.1	0.6	0.6	0.5	0.8
Seattle City Light	—	—	0.1	—	—	—	0.2	0.0	0.2	—	0.1	0.0
Tacoma Power			—	—	0.1	0.1	0.0	0.1	0.1	—	0.2	—
Tucson Elec.					0.1	—	—	—	0.4	0.0	—	0.2
Turlock ID	—	—	—	—	—	—	—	—	0.1	—	—	1.2

Figure 3.12 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 PS	0.3	—	—	—	0.0	0.0	—	—	—	—	—	0.1
Avista			—	—	—	—	0.2	—	—	0.0	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—
BPA					—	—	—	—	0.1	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	0.6	—	—	—	—	—	—	—
LADWP	0.3	—	—	—	0.2	—	—	—	—	—	—	—
NorthWestern	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	—	0.1	0.5	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—
Portland GE	—	—	—	—	—	0.0	—	—	—	—	—	—
Powerex	0.1	—	0.1	—	0.1	—	—	0.0	—	—	0.0	—
PSC New Mexico	—	—	0.1	—	0.1	—	—	—	—	—	—	—
Puget Sound En	—	—	—	—	0.0	0.7	0.1	—	—	—	—	—
Salt River Proj.	—	0.2	0.3	—	0.4	0.5	0.1	0.2	1.1	0.2	0.3	—
Seattle City Light	—	—	0.1	—	—	0.0	0.1	—	0.2	—	—	—
Tacoma Power			—	0.8	0.1	—	0.6	0.3	—	0.1	—	0.2
Tucson Elec.					—	0.0	—	—	—	—	—	—
Turlock ID	0.1	0.0	—	0.1	—	—	—	—	—	—	—	—

2022

Figure 3.13 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 PS	1.4	0.4	0.8	0.3	0.5	0.2	—	—	0.1	0.2	0.2	0.1
Avista			—	—	—	0.1	—	—	0.1	0.2	—	0.0
BANC	—	—	0.1	0.0	0.1	0.1	—	—	—	—	—	—
BPA					0.1	0.2	—	0.0	0.3	—	0.2	0.2
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	0.0	—	0.3	0.4	—	—	0.0	—	—	—	—
LADWP	0.1	—	—	—	—	—	—	—	—	—	—	—
NorthWestern	—	—	—	—	0.5	1.9	0.2	—	—	—	0.0	0.1
NV Energy	0.6	4.1	1.7	3.2	1.3	2.0	0.6	0.2	0.5	0.5	0.6	0.1
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	0.0	0.0	0.1	0.4	0.5	—	—	0.1	—	0.0
Portland GE	—	—	—	—	—	0.2	—	—	—	—	—	—
Powerex	—	0.0	0.2	0.0	0.3	0.2	—	0.1	0.1	0.1	—	—
PSC New Mexico	0.3	0.0	1.2	0.3	1.8	0.7	0.0	0.0	0.2	0.2	0.1	—
Puget Sound En	—	—	—	—	0.2	2.3	0.1	—	—	0.1	—	—
Salt River Proj.	0.1	1.0	1.5	0.2	0.4	0.5	0.2	0.2	1.0	0.2	0.9	0.3
Seattle City Light	—	—	0.1	0.1	0.1	0.3	0.1	0.8	0.3	—	0.2	0.6
Tacoma Power			—	0.4	0.3	—	0.5	0.2	—	—	—	0.1
Tucson Elec.					—	—	—	—	—	—	0.0	—
Turlock ID	0.2	—	0.5	0.6	0.1	0.5	0.1	0.1	—	—	0.1	—

2022

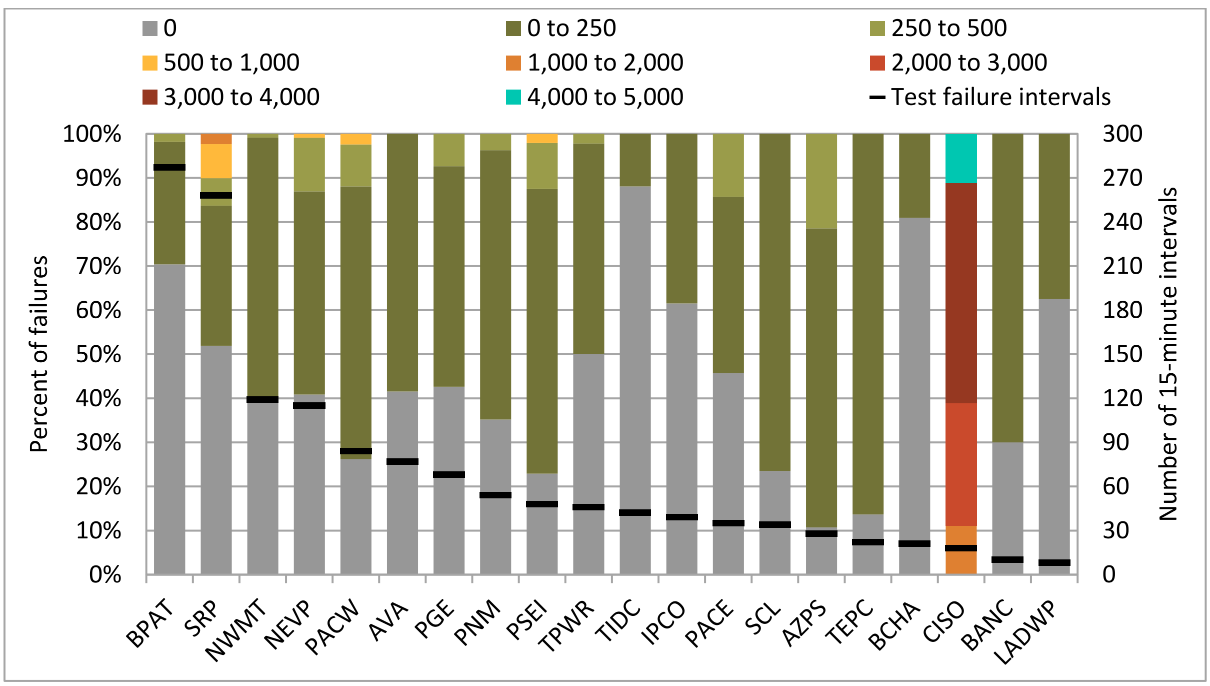
WEIM import limits and transfers following a test failure

This section summarizes the import limits that are imposed when a WEIM entity fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction. When either test fails, imports will be capped at the greater of the base transfer or the optimal transfer from the last 15-minute market interval. These limits are also compared against actual WEIM transfers during these insufficiency periods in this section.

Figure 3.14 summarizes dynamic import limits, excluding base transfers (fixed bilateral transactions between entities), imposed after failing either test during the year. From this perspective, the dynamic import limit after a test failure is set by the greater of (1) zero or (2) the transfer from the last 15-minute market interval *minus* the current base transfer. The dynamic import limit therefore shows the incremental flexibility that is available through the WEIM after a resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with an import limit imposed after a test failure, while the bars (left axis) show the frequency of various quantity ranges.[178]

The figure also shows that the dynamic import limit for the CAISO following a resource sufficiency evaluation failure is typically large, between 1,000 and 5,000 MW. The CAISO does not have base transfers and often has a high volume of dynamic imports prior to any upward test failure, which will set the import limit during the failure interval. Substantial imbalance conformance adjustments entered by the CAISO operators can further contribute to this outcome. Here, the optimal transfer in the last 15-minute interval increases as the optimization solves for load plus imbalance conformance, potentially setting a higher import limit than would have existed otherwise.

Figure 3.14 Imposed dynamic import limit following upward test failure (2022)



[178] Test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

Figure 3.15 summarizes transfers optimized in the real-time market following an upward resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity test or a flexibility test failure, while the bars (left axis) show the percent of failure intervals in which the balancing area was a net importer or net exporter in the corresponding real-time market interval. Figure 3.16 summarizes the same information with the net transfer quantity categorized by various levels. These figures summarize dynamic WEIM transfers only and therefore base transfers are excluded.

As shown by Figure 3.15, balancing areas were commonly optimized as net exporters in 2022, despite failing the resource sufficiency evaluation for that interval. This result is in part driven from net load *uncertainty* that is included in the flexibility tests. In some cases, the balancing area would fail the flexibility in part because of the uncertainty component, but then in the real-time market it could be economically optimal to export if that uncertainty does not materialize.

Other factors can also contribute to this outcome as a net exporter. A decrease in the load forecast (or an increase in wind or solar forecasts) from the resource sufficiency evaluation to the real-time market can lead to greater resource sufficiency and WEIM exports. A negative imbalance conformance adjustment entered by the WEIM operators can also be included in the market run to effectively lower load, but will not be included in the resource sufficiency evaluation.

Figure 3.17 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers.[179] It shows the percent of failure intervals in which the resulting transfers were constrained to the limit imposed after failing the test. These results are shown separately for 15-minute (FMM) and 5-minute (RTD) markets. During 2022, the California ISO was the only area in which 5-minute market WEIM imports were never impacted by limits set following an upward resource sufficiency evaluation failure. This pattern is in part driven from substantial imbalance conformance adjustments in the 15-minute market that increase CAISO load well above load realized in the 5-minute market. As discussed earlier, higher imbalance conformance adjustments entered by CAISO operators can result in higher transfer limits following a test failure.

[179] Test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

Figure 3.15 Dynamic WEIM transfer status during upward test failure (2022)

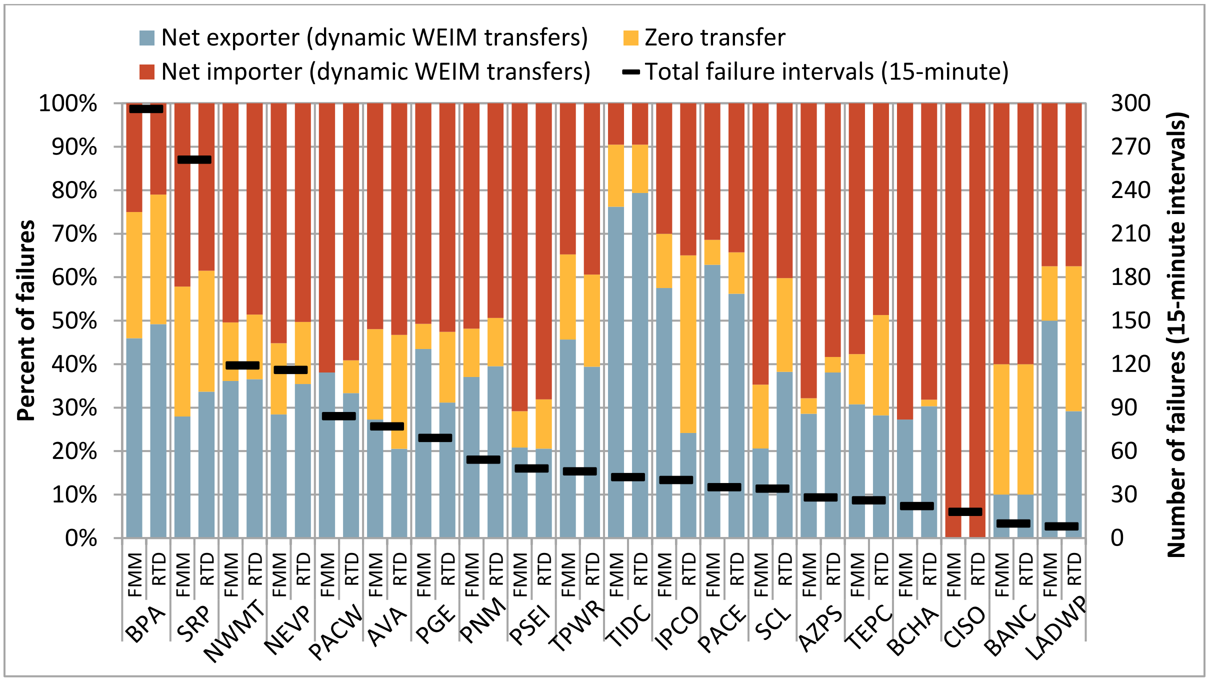


Figure 3.16 Dynamic WEIM transfer amount during upward test failure (2022)

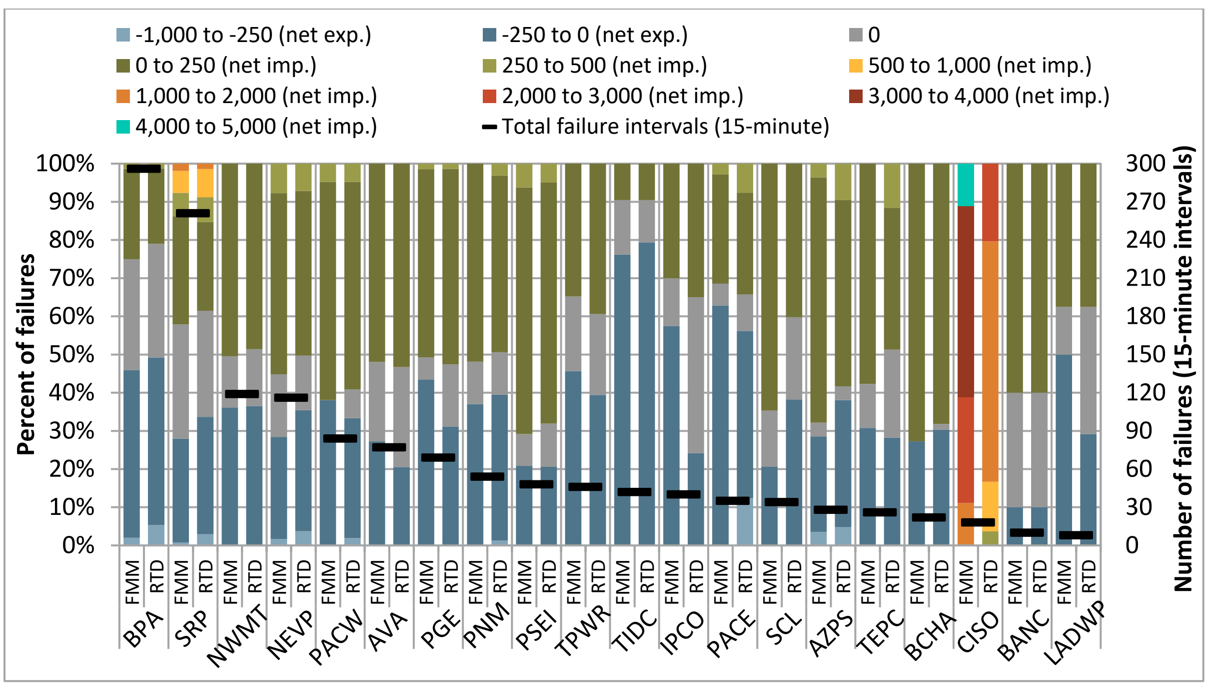
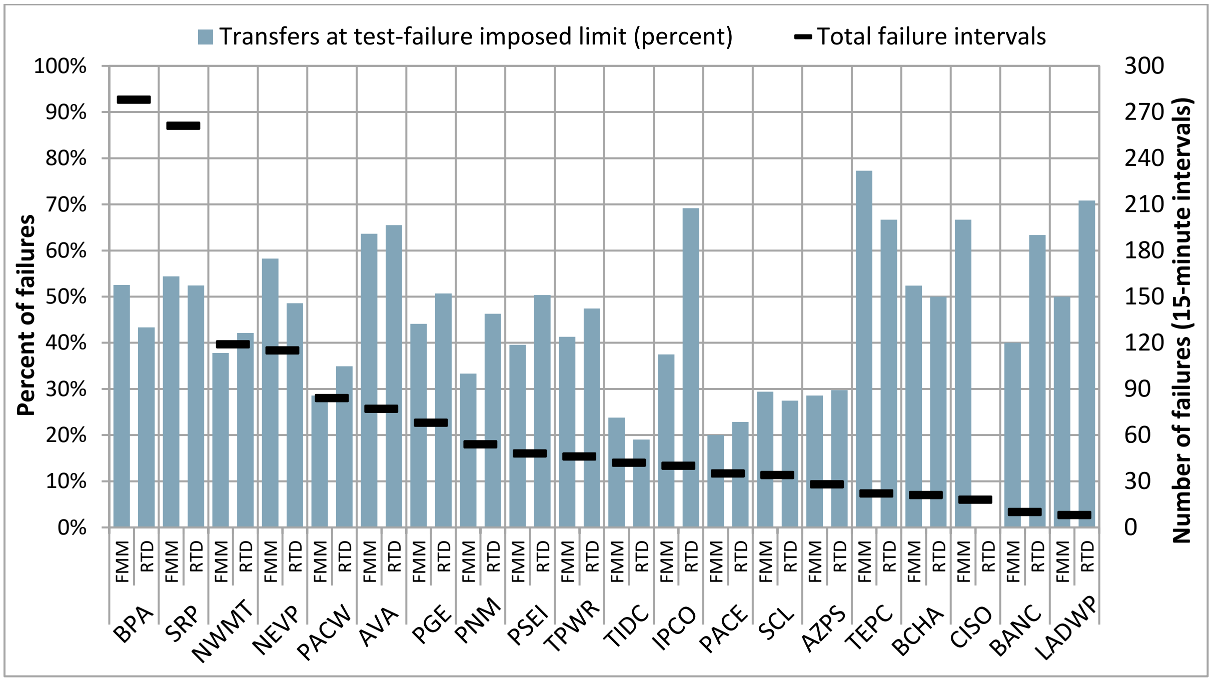


Figure 3.17 Percent of upward test failure intervals with market transfers at the imposed cap



Resource sufficiency evaluation monthly reports

DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[180] These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process, as well as a detailed look at the net load uncertainty adders used in the tests.

3.5 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.

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

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 6.1.2, can also impact WEIM prices.

3.5.1 Energy market prices

Figure 3.18 and Figure 3.19 show average hourly market prices throughout the day in 2022.[181] The color gradient highlights deviation from the average hourly system marginal energy cost (SMEC), shown in the top row. Here, blue represents prices below that hour's average system price, and orange indicates prices above. The CAISO prices in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) areas are included as points of comparison.

Figure 3.20 shows average monthly prices in the 15-minute market, by area, from 2021 through 2022. Prices in California tend to be higher than prices in balancing areas outside of California because of the greenhouse gas compliance cost for energy that is delivered within the state.[182] In addition, average prices in the north (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, Powerex, Tacoma Power, and Bonneville Power Administration) are regularly lower than in CAISO and other balancing areas because of limited transfer capability out of the region and high availability of lower cost hydroelectric generation within the region. Other differences in prices reflect congestion and transfer limitations between the different areas. Prices followed the CAISO net load pattern with the lowest energy prices during the mid-day hours and the highest energy prices during the evening peak net load hours.

Figure 3.18 Average hourly 15-minute market prices ($/MWh)

	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	$77	$74	$73	$72	$77	$85	$90	$78	$66	$60	$57	$57	$56	$57	$64	$81	$100	$120	$138	$142	$116	$101	$90	$80
PG&E (CAISO)	$84	$82	$80	$80	$84	$92	$97	$87	$73	$67	$65	$64	$63	$65	$74	$91	$110	$129	$147	$152	$129	$112	$97	$86
SCE (CAISO)	$82	$79	$78	$77	$81	$89	$94	$80	$62	$53	$50	$49	$49	$51	$60	$81	$104	$127	$152	$157	$127	$110	$96	$85
BANC	$82	$79	$78	$77	$82	$90	$94	$84	$73	$69	$67	$66	$66	$67	$77	$92	$110	$126	$142	$144	$119	$107	$95	$84
Turlock ID	$83	$81	$79	$79	$83	$90	$95	$85	$77	$72	$72	$72	$72	$73	$81	$97	$110	$125	$143	$149	$123	$108	$95	$86
LADWP	$82	$78	$77	$77	$81	$89	$93	$80	$64	$55	$52	$51	$51	$53	$62	$82	$105	$127	$151	$158	$127	$108	$96	$85
NV Energy	$72	$70	$69	$69	$72	$79	$80	$70	$63	$53	$51	$51	$51	$51	$58	$75	$93	$111	$135	$138	$109	$91	$85	$75
Arizona PS	$75	$72	$69	$70	$74	$82	$84	$71	$58	$50	$47	$46	$46	$48	$56	$74	$95	$114	$137	$142	$114	$97	$88	$77
Tucson Electric*	$85	$82	$80	$80	$85	$93	$93	$80	$68	$63	$62	$63	$64	$66	$75	$99	$120	$141	$173	$167	$131	$107	$100	$89
Salt River Project	$62	$59	$58	$58	$64	$71	$72	$62	$49	$46	$43	$44	$46	$46	$50	$63	$81	$101	$123	$112	$96	$81	$78	$67
PSC New Mexico	$51	$51	$51	$52	$55	$64	$67	$56	$47	$42	$37	$39	$38	$41	$49	$65	$78	$92	$113	$114	$86	$66	$56	$53
PacifiCorp East	$59	$57	$56	$55	$60	$67	$70	$62	$54	$52	$49	$49	$48	$50	$55	$68	$83	$96	$110	$113	$89	$75	$69	$62
Idaho Power	$65	$62	$61	$61	$65	$73	$77	$73	$64	$61	$61	$60	$60	$61	$63	$75	$90	$97	$108	$115	$93	$81	$76	$68
NorthWestern	$60	$57	$56	$56	$60	$67	$73	$68	$63	$63	$60	$60	$58	$58	$60	$70	$79	$86	$89	$87	$81	$73	$71	$62
Avista Utilities*	$65	$62	$60	$60	$64	$71	$75	$71	$67	$66	$66	$66	$64	$64	$66	$77	$85	$90	$93	$90	$85	$78	$77	$68
BPA*	$75	$70	$67	$67	$70	$78	$81	$80	$77	$78	$78	$79	$78	$79	$81	$87	$100	$110	$110	$116	$108	$103	$91	$78
Tacoma Power*	$67	$63	$61	$61	$64	$69	$71	$71	$70	$71	$71	$72	$70	$69	$72	$75	$84	$90	$93	$95	$87	$80	$79	$70
PacifiCorp West	$62	$58	$57	$57	$60	$66	$67	$67	$63	$62	$63	$62	$60	$59	$61	$69	$81	$90	$97	$99	$81	$73	$73	$63
Portland GE	$61	$58	$57	$57	$60	$66	$68	$69	$65	$64	$64	$62	$61	$60	$62	$70	$83	$93	$98	$99	$82	$75	$73	$64
Puget Sound Energy	$62	$58	$56	$56	$60	$65	$65	$66	$65	$65	$65	$65	$64	$63	$65	$69	$76	$83	$87	$87	$79	$73	$73	$65
Powerex	$60	$57	$56	$56	$59	$61	$62	$59	$60	$58	$58	$58	$56	$56	$58	$62	$70	$72	$72	$72	$71	$69	$67	$62
Seattle City Light	$64	$58	$56	$56	$60	$64	$65	$66	$66	$65	$65	$65	$63	$63	$65	$69	$76	$83	$85	$86	$80	$74	$72	$64

Hour

*Since joining the WEIM

181 Prices for Avista Utilities, Tacoma Power, Tucson Electric Power, and Bonneville Power Administration (BPA) are the average from their respective WEIM go-live dates to December 31, 2022.

182 See Section 3.7 for more information about California's greenhouse gas compliance cost and its impact on both the California ISO and the Western Energy Imbalance Market.

Figure 3.19 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	$79	$75	$72	$72	$75	$80	$85	$79	$64	$57	$55	$54	$54	$55	$58	$68	$77	$88	$108	$106	$96	$91	$87	$80
PG&E (CAISO)	$90	$85	$84	$83	$86	$91	$96	$91	$74	$67	$63	$62	$62	$64	$68	$77	$86	$98	$120	$120	$112	$104	$98	$90
SCE (CAISO)	$84	$80	$78	$78	$80	$85	$89	$79	$59	$46	$44	$43	$44	$47	$52	$68	$80	$96	$121	$120	$108	$100	$95	$86
BANC	$87	$82	$82	$80	$83	$88	$93	$88	$74	$70	$67	$66	$66	$68	$74	$79	$89	$96	$117	$112	$105	$102	$96	$88
Turlock ID	$89	$84	$83	$82	$84	$89	$94	$90	$79	$76	$73	$72	$73	$75	$78	$84	$88	$95	$118	$118	$109	$102	$96	$90
LADWP	$84	$79	$77	$76	$79	$83	$88	$79	$60	$48	$46	$45	$46	$49	$53	$68	$81	$96	$121	$120	$106	$99	$94	$86
NV Energy	$75	$71	$69	$69	$71	$76	$78	$73	$61	$48	$49	$48	$48	$50	$51	$66	$73	$86	$111	$109	$94	$84	$84	$76
Arizona PS	$76	$71	$69	$71	$75	$79	$81	$72	$55	$44	$42	$43	$43	$45	$50	$64	$75	$92	$113	$112	$98	$93	$91	$81
Tucson Electric*	$86	$83	$81	$82	$86	$92	$94	$85	$65	$57	$58	$60	$60	$64	$70	$90	$99	$112	$138	$136	$117	$103	$97	$88
Salt River Project	$65	$58	$59	$58	$63	$68	$70	$59	$45	$44	$41	$43	$46	$51	$48	$64	$70	$82	$102	$94	$84	$77	$74	$63
PSC New Mexico	$56	$55	$53	$53	$57	$65	$66	$61	$47	$40	$35	$36	$36	$39	$44	$58	$60	$71	$91	$88	$73	$62	$60	$58
PacifiCorp East	$59	$56	$55	$55	$59	$64	$67	$62	$51	$48	$47	$46	$46	$49	$50	$59	$64	$73	$88	$87	$73	$68	$69	$62
Idaho Power	$64	$61	$60	$60	$63	$69	$73	$71	$60	$59	$59	$57	$57	$58	$58	$66	$74	$78	$90	$91	$76	$73	$73	$66
NorthWestern	$59	$57	$56	$55	$59	$65	$70	$68	$63	$62	$58	$58	$60	$56	$55	$62	$66	$70	$74	$73	$69	$66	$68	$63
Avista Utilities*	$63	$60	$58	$58	$61	$67	$72	$72	$66	$65	$66	$64	$63	$63	$62	$68	$71	$74	$77	$73	$73	$70	$74	$66
BPA*	$70	$67	$65	$65	$67	$74	$79	$76	$71	$75	$75	$75	$74	$75	$75	$80	$86	$87	$91	$91	$91	$89	$83	$72
Tacoma Power*	$65	$62	$59	$59	$62	$67	$71	$70	$68	$70	$70	$69	$67	$67	$66	$70	$74	$77	$81	$79	$78	$75	$76	$68
PacifiCorp West	$60	$56	$55	$55	$58	$64	$66	$66	$60	$61	$60	$59	$58	$56	$55	$61	$66	$70	$77	$76	$70	$68	$70	$61
Portland GE	$59	$56	$54	$55	$58	$63	$68	$67	$60	$60	$60	$58	$57	$56	$56	$62	$66	$73	$78	$76	$71	$69	$69	$61
Puget Sound Energy	$59	$56	$54	$55	$57	$62	$65	$64	$63	$64	$64	$63	$61	$60	$60	$63	$68	$71	$76	$73	$71	$69	$70	$63
Powerex	$58	$56	$55	$55	$57	$59	$62	$59	$57	$58	$57	$56	$54	$53	$55	$59	$65	$67	$67	$68	$68	$65	$64	$60
Seattle City Light	$59	$56	$54	$55	$57	$62	$65	$64	$63	$64	$64	$63	$61	$60	$59	$64	$68	$70	$74	$73	$73	$69	$69	$62

*Since joining the WEIM

Figure 3.20 Average monthly 15-minute market prices ($/MWh)

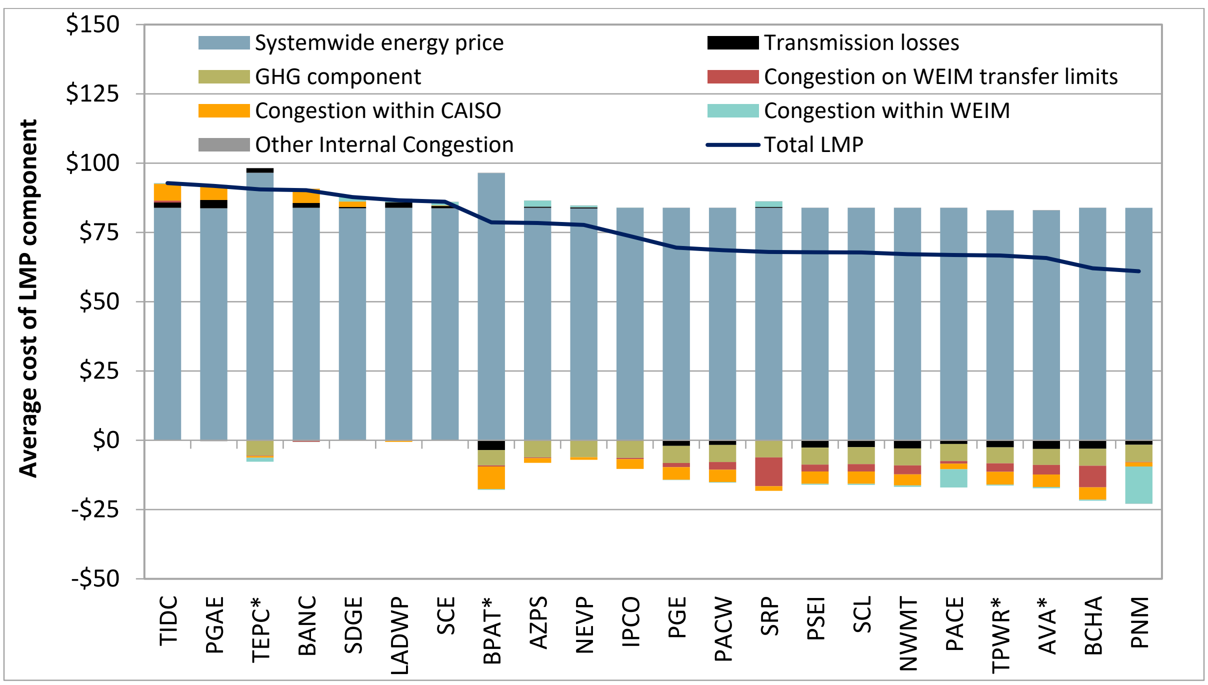
	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022
SMEC	$31	$61	$31	$33	$32	$42	$64	$54	$68	$61	$54	$57	$51	$44	$42	$59	$59	$55	$69	$97	$125	$69	$90	$246
PG&E (CAISO)	$33	$49	$34	$37	$37	$45	$70	$57	$72	$67	$58	$60	$54	$48	$47	$63	$68	$82	$74	$103	$136	$73	$95	$257
SCE (CAISO)	$31	$78	$30	$30	$28	$44	$67	$56	$70	$56	$55	$58	$52	$43	$40	$55	$60	$69	$78	$108	$135	$64	$83	$246
Avista Utilities															$35	$57	$41	$12	$36	$68	$72	$65	$86	$246
Arizona PS	$23	$63	$20	$23	$24	$37	$54	$44	$57	$42	$39	$41	$39	$34	$31	$45	$52	$64	$72	$97	$118	$56	$80	$251
BANC	$33	$48	$35	$38	$39	$44	$69	$56	$70	$71	$57	$60	$53	$48	$48	$65	$69	$68	$72	$106	$131	$75	$95	$252
BPA																	$46	$10	$46	$80	$91	$65	$86	$251
Idaho Power	$26	$51	$27	$28	$26	$36	$49	$45	$57	$55	$40	$46	$43	$41	$35	$57	$47	$32	$69	$82	$92	$63	$84	$237
LADWP				$30	$29	$42	$63	$52	$66	$56	$54	$57	$50	$42	$41	$55	$57	$63	$77	$108	$135	$67	$87	$256
NV Energy	$26	$63	$26	$29	$27	$41	$54	$42	$56	$45	$40	$45	$40	$38	$35	$49	$53	$55	$69	$93	$117	$58	$79	$243
NorthWestern						$37	$41	$41	$66	$79	$38	$44	$41	$37	$34	$57	$41	$15	$42	$69	$73	$64	$87	$243
PacifiCorp East	$24	$52	$25	$26	$24	$34	$47	$38	$51	$42	$37	$38	$37	$35	$32	$45	$43	$40	$65	$81	$99	$59	$72	$193
PacifiCorp West	$22	$34	$24	$29	$29	$30	$40	$42	$56	$53	$40	$44	$39	$35	$32	$59	$42	$13	$42	$76	$89	$64	$85	$244
Portland GE	$22	$34	$24	$30	$28	$31	$41	$46	$57	$53	$38	$43	$38	$35	$33	$59	$43	$16	$43	$77	$92	$65	$87	$244
Powerex	$22	$35	$26	$29	$27	$29	$35	$38	$44	$50	$40	$39	$36	$34	$32	$52	$46	$15	$37	$61	$69	$67	$82	$212
PSC New Mexico				$24	$23	$34	$51	$41	$54	$42	$38	$36	$37	$34	$30	$43	$47	$49	$67	$84	$102	$58	$64	$114
Puget Sound Energy	$21	$34	$26	$29	$29	$30	$39	$41	$48	$48	$39	$41	$37	$34	$31	$60	$44	$13	$41	$74	$81	$64	$85	$249
Seattle City Light	$21	$34	$24	$29	$28	$29	$39	$40	$50	$47	$38	$41	$37	$34	$31	$60	$45	$12	$40	$74	$80	$64	$85	$249
Salt River Project	$23	$66	$22	$25	$24	$41	$60	$50	$55	$42	$43	$37	$39	$34	$33	$47	$56	$67	$67	$88	$93	$56	$76	$157
Tucson Electric																	$54	$64	$72	$96	$111	$57	$76	$222
Turlock ID				$38	$41	$45	$67	$56	$71	$75	$57	$61	$54	$49	$48	$69	$76	$68	$72	$100	$136	$76	$95	$266
Tacoma Power															$30	$59	$44	$13	$39	$74	$80	$64	$85	$248

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 2022. The system marginal energy price is the same for all entities in each hour.[183] The price difference between balancing authority areas is determined by area specific elements including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint violations.

Congestion on WEIM transfer constraints often drives price separation between areas. In some cases, the power balance constraint may be relaxed within the constrained region at a high penalty parameter. The red segments in the figures reflect price differences caused by congestion on transfer constraints, including any power balance constraint relaxations that increase the price in a single area.

Congestion on internal constraints has been split out to show congestion from CAISO and WEIM internal constraints. Congestion within the WEIM particularly affected PacifiCorp East and PNM where it lowered 15-minute market prices in these areas by $6.58/MWh and $13.38/MWh, respectively.

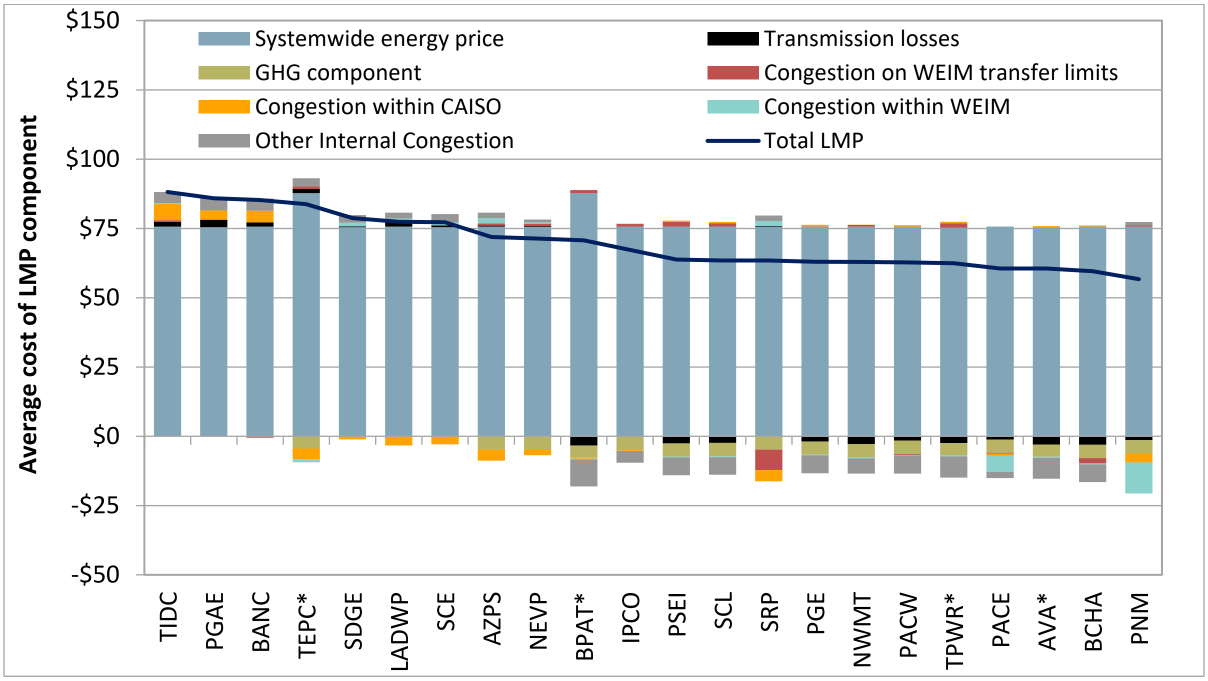
Figure 3.21 Annual average 15-minute price by component (2022)



*Since joining the WEIM

183 Areas that joined the WEIM partway through the year will have a different average system marginal energy price than other areas as their respective averages are only from the time they joined.

Figure 3.22 Annual average 5-minute price by component (2022)



*Since joining the WEIM

3.5.2 Power balance constraint

WEIM area prices can be significantly impacted by the frequency in which the power balance constraint 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.[184] During the first six months after 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.

Figure 3.23 shows the frequency of power balance constraint relaxations in the 15-minute and 5-minute markets by quarter for undersupply (shortage) and oversupply (excess) conditions.[185] The frequency of undersupply infeasibilities are shown in the upward direction, while the frequency of oversupply infeasibilities are shown in the downward direction.

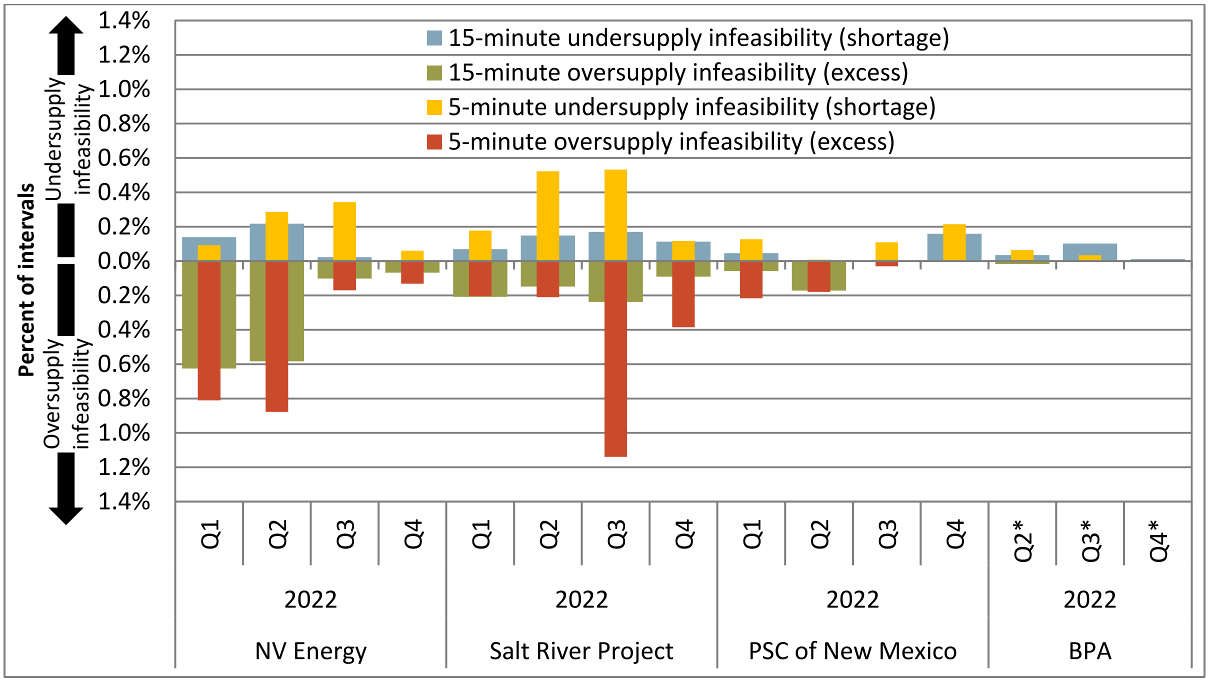
Balancing authority areas in the Southwest region, including NV Energy, Salt River Project, and Public Service Company of New Mexico, had a relatively high frequency of power balance constraint relaxations. Most of these occurred following a resource sufficiency evaluation failure. Here, reduced transfer 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. This contributed to a higher frequency of power

184 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.

185 Areas that did not incur undersupply or oversupply infeasibilities in at least 0.1 percent of 15-minute market intervals for more than one quarter during the year were excluded from the chart. Infeasibilities that were either invalid or resolved by the imbalance conformance limiter were omitted.

balance constraint relaxations. Bonneville Power Administration had a number of power balance infeasibilities in the first and second quarters. However, the area was under transition period pricing during these quarters such that prices were not impacted by relaxing the power balance constraint.

Figure 3.23 Frequency of power balance constraint relaxations by market



*Area under transition period pricing for the quarter

3.5.3 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.[186]

Table 3.4 summarizes the annual frequency of upward and downward available balancing capacity, both offered and scheduled, in each area during 2022.[187] BANC, Turlock Irrigation District, Salt River Project, Powerex, NorthWestern Energy, and Arizona Public Service offered both upward *and* downward balancing capacity during most hours; Portland General Electric only offered *upward* balancing capacity during most hours. The table also shows the average magnitude of the available balancing capacity when offered in their hourly resource plan. Similar to previous years, Powerex offered an average of

[186] 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

[187] 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.

1,029 MW and 600 MW of upward and downward available balancing capacity during 2022, respectively.

PacifiCorp West and Puget Sound Energy offered available balancing capacity in either direction infrequently. Seattle City Light and Idaho Power did not offer upward or downward available balancing capacity for any hour during the year.

Overall, available balancing capacity was dispatched very infrequently for scarcity conditions during 2022. Upward and downward available balancing capacity offered by Salt River Project was dispatched during 0.4 percent and 0.8 percent of 15-minute and 5-minute market intervals, respectively.

Table 3.4 Frequency of available balancing capacity offered and scheduled (2022)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
Upward ABC				
BANC	100%	87	0.1%	0.0%
Turlock Irrigation District	100%	12	0.1%	0.1%
Salt River Project	100%	97	0.4%	0.7%
Powerex	99%	1,029	0.0%	0.0%
Portland General Electric	99%	25	0.0%	0.0%
NorthWestern Energy	98%	8	0.0%	0.1%
Arizona Public Service	97%	20	0.0%	0.1%
NV Energy	89%	50	0.4%	0.4%
Avista Utilities*	83%	20	0.1%	0.1%
Tacoma Power*	80%	3	0.0%	0.0%
Bonneville Power Admin.*	66%	308	0.1%	0.1%
Tuscon Electric*	66%	42	0.0%	0.2%
PacifiCorp East	43%	39	0.0%	0.0%
PSC New Mexico	34%	29	0.0%	0.0%
LADWP	23%	74	0.0%	0.0%
PacifiCorp West	1%	61	0.0%	0.0%
Puget Sound Energy	0.0%	30	0.0%	0.0%
Seattle City Light	0.0%	N/A	0.0%	0.0%
Idaho Power	0.0%	N/A	0.0%	0.0%
Downward ABC				
BANC	100%	97	0.0%	0.0%
Turlock Irrigation District	100%	5	0.0%	0.0%
Salt River Project	98%	48	0.4%	0.8%
Powerex	100%	600	0.1%	0.1%
Portland General Electric	0%	0	0.0%	0.0%
NorthWestern Energy	95%	6	0.0%	0.0%
Arizona Public Service	96%	20	0.0%	0.1%
NV Energy	79%	52	0.4%	0.4%
Avista Utilities*	83%	20	0.0%	0.0%
Tacoma Power*	82%	7	0.0%	0.0%
Bonneville Power Admin.*	66%	326	0.2%	0.1%
Tuscon Electric*	66%	39	0.0%	0.0%
PacifiCorp East	14%	176	0.0%	0.0%
PSC New Mexico	49%	64	0.0%	0.1%
LADWP	3%	121	0.0%	0.0%
PacifiCorp West	2%	71	0.0%	0.0%
Puget Sound Energy	2%	43	0.0%	0.0%
Seattle City Light	0%	N/A	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%

*Since joining the WEIM.

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.[188] 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 in to California to the difference between a resource's base schedule and their upper economic bid limit.

The greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which can contribute to higher prices for WEIM areas in California.[189] 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 in to California.

Greenhouse gas prices

Figure 3.24 shows monthly average cleared WEIM greenhouse gas prices and hourly average quantities for energy delivered to California from 2020 to 2022. 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.

---

188 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

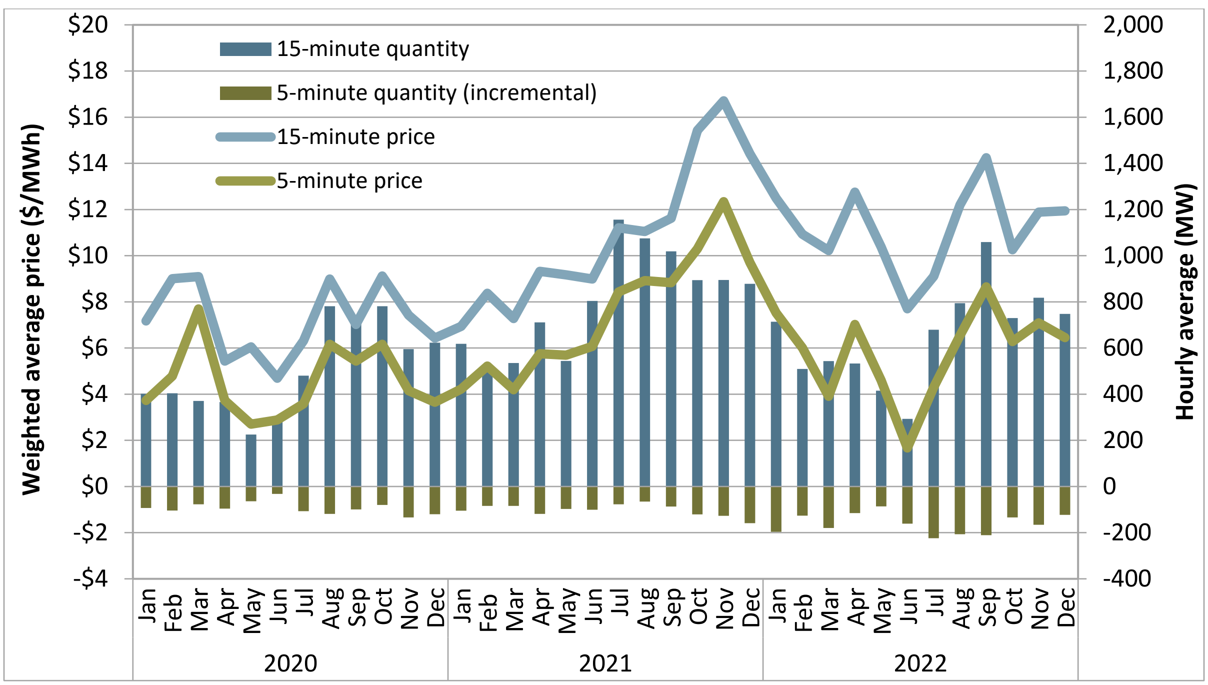
189 Further detail on the determination of deemed delivered greenhouse gas megawatts within the WEIM optimization is available in the Western Energy Imbalance Market Business Practice Manual Change Management, Energy Imbalance Market: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

In 2022, weighted 15-minute greenhouse gas prices averaged $11.18/MWh, while 5-minute prices averaged $5.84/MWh. Prices were similar to 2021 when they averaged $10.90/MWh and 7.50/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 2022, the average cost of greenhouse gas allowances in bilateral markets averaged $29.47/ mtCO$_2$e, a 27 percent increase from 2021. Allowance costs in 2021 were 35 percent higher than they were in 2020, highlighting the recent upward trend. The $29.47/ mtCO$_2$e cost of allowances translates to about $12.52/MWh for a relatively efficient gas unit.[190]

Weighted average greenhouse gas prices in the 5-minute market averaged about 50 percent lower than 15-minute prices throughout 2022. In comparison, average 5-minute market greenhouse gas prices were 32 percent lower than 15-minute prices in 2021. 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.

Prices in the end of 2021 and early 2022 may have also been affected by an issue with the CAISO greenhouse gas obligation calculation. After Los Angeles Department of Water and Power (LADWP) joined the WEIM on April 1, 2021, the market was incorrectly including LADWP's base schedule transfers as market transfers in the real-time imbalance energy market. This led to higher attribution of greenhouse gas quantities, which affected both the real-time energy transfers attributed to resources and the payments made to those resources. The California ISO fixed this issue on January 27, 2022.[191]

Figure 3.24 WEIM greenhouse gas price and cleared quantity



[190] Discussed further in Section 1.2.8.

[191] Market Performance and Planning Forum, June 16, 2022, slides 6-7: http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun162022.pdf

Figure 3.25 High 15-minute WEIM greenhouse gas prices

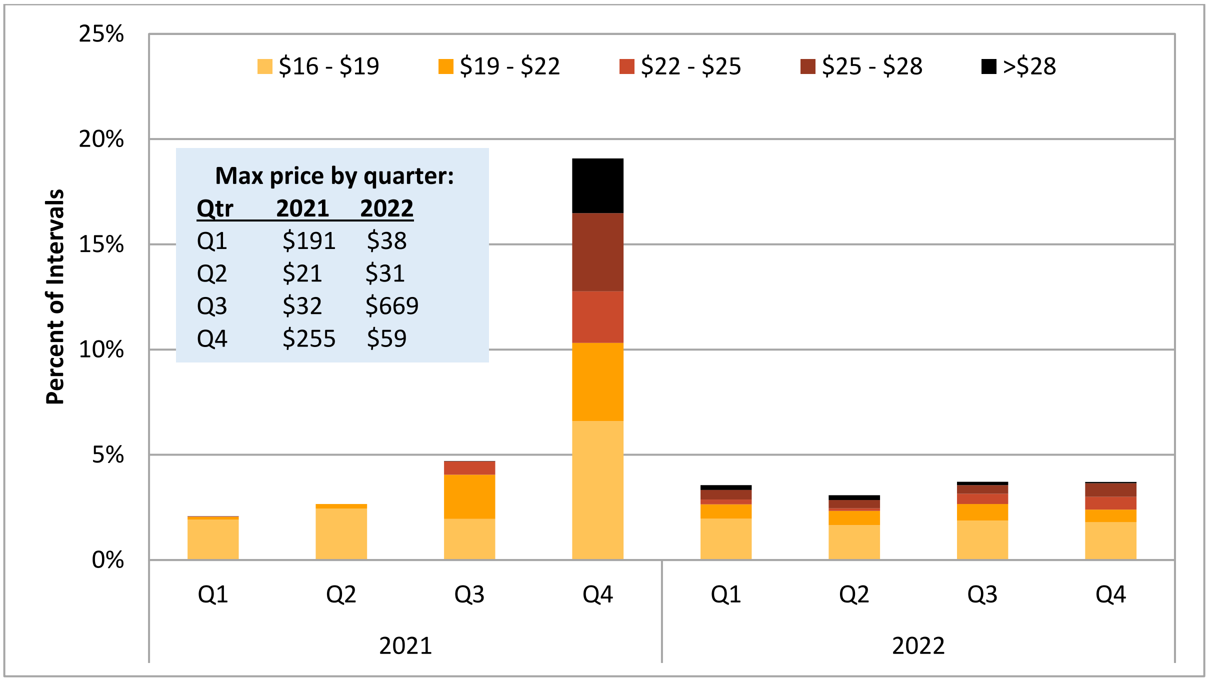


Figure 3.26 High 5-minute WEIM greenhouse gas prices

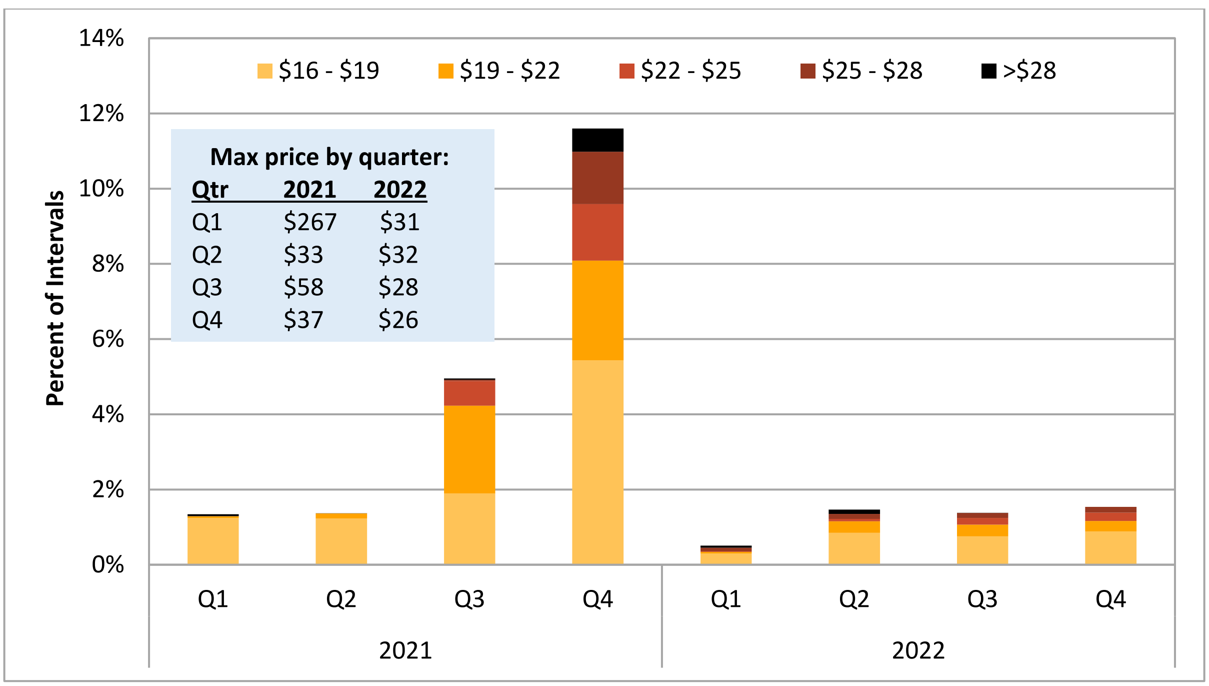


Figure 3.25 and Figure 3.26 illustrate the frequency of high prices for each market and quarter of the last two years, as well as the maximum price by quarter. In Figure 3.25, we see a drastic increase in WEIM greenhouse gas compliance prices in the second half of 2021, where prices in the 15-minute market were over $16/MWh in almost 20 percent of intervals in the fourth quarter. While prices remained high

in 2022, there were fewer than 5 percent of intervals with prices over $16/MWh. This trend was similar for greenhouse gas prices in the 5-minute market as well, as seen in Figure 3.26.

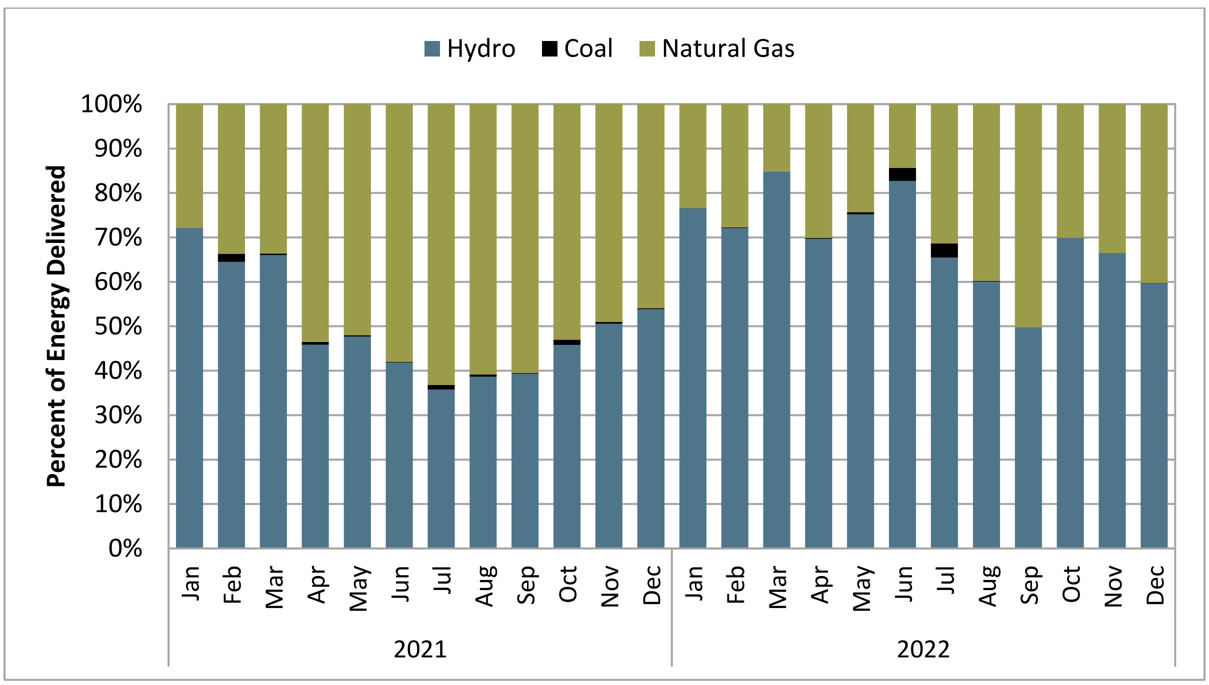
After the secondary dispatch policy change in November 2018, which limited the capacity that could be deemed delivered, there were some price spikes that were not set by bids from emitting generators. Greenhouse gas supply can be exhausted, limiting the total transfer of energy imported to California through the WEIM and setting greenhouse gas prices that exceed the highest cleared bid. The highest 15-minute and 5-minute prices in 2022 were $669/MWh and $32/MWh, respectively.

Energy delivered to California by fuel type and balancing area

Figure 3.27 shows hourly average greenhouse gas energy by fuel type. In 2022, about 70 percent of WEIM greenhouse gas compliance obligations were assigned to hydro resources, compared to about 50 percent in 2021. The increase in WEIM greenhouse gas compliance obligations assigned to hydro resources may be due in part to the new entities who joined the WEIM who brought significant hydro capacity to the market.[192]

Figure 3.28 shows the percentage of total greenhouse gas energy cleared by area. In 2022, 75 percent of greenhouse gas energy came from entities in the Northwest areas with large fleets of hydroelectric resources, compared to about 60 percent in 2021. Since joining WEIM in 2022, Avista accounted for 10 percent of total greenhouse gas energy delivered to California. Salt River project accounted for 20 percent of the total greenhouse gas energy deemed delivered in 2021 but only 8 percent in 2022.

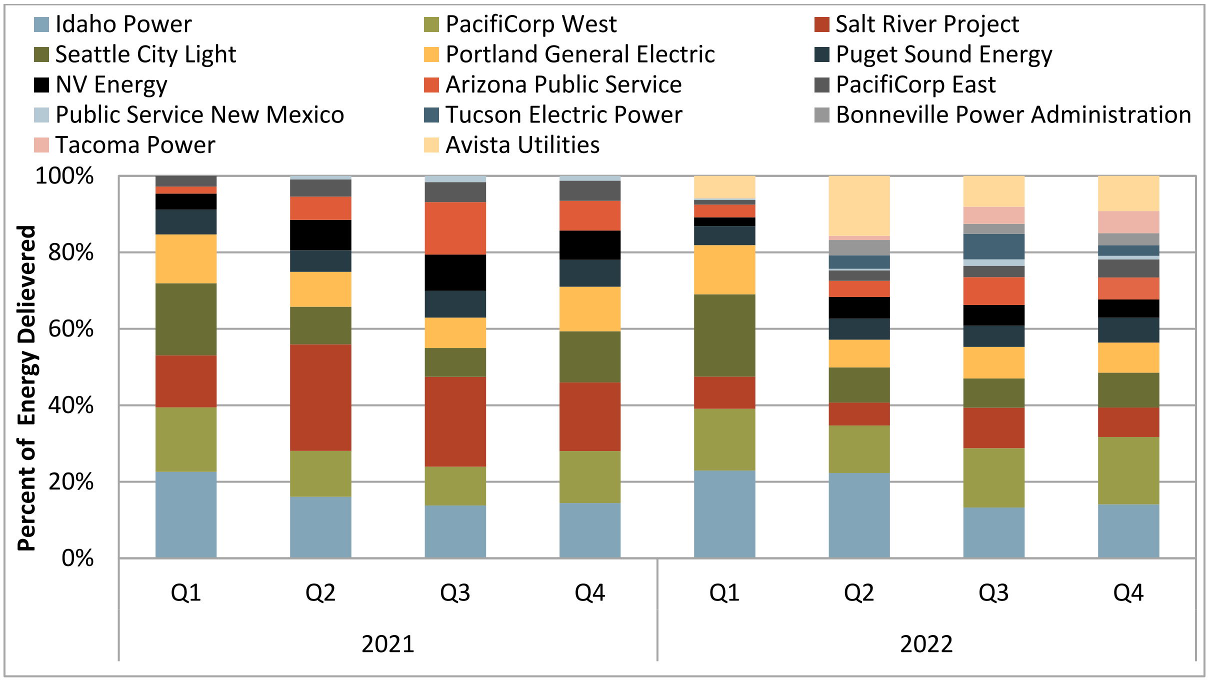
Figure 3.27 Percentage of greenhouse gas energy delivered to California by fuel type[193]



192 See Figure 3.2.

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

Figure 3.28 Percentage of greenhouse gas energy delivered to California by area[194]

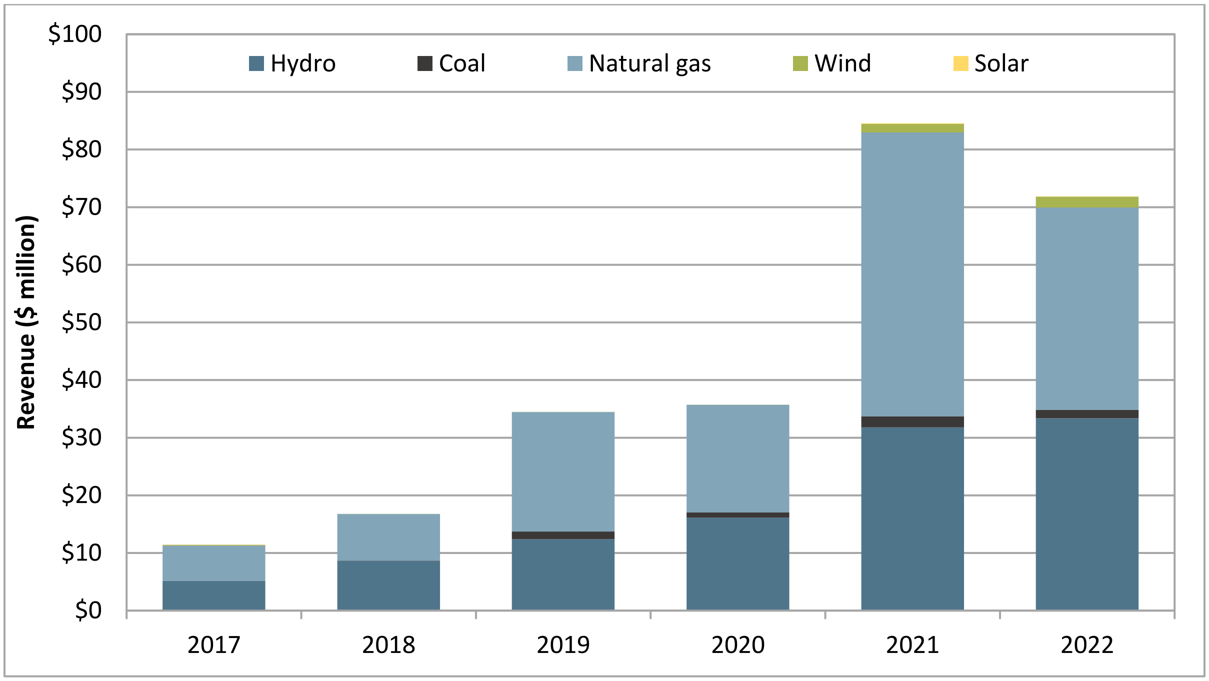


WEIM greenhouse gas revenues

Figure 3.29 shows revenues accruing to WEIM resources for energy delivered to California by fuel type. In 2022, revenues totaled roughly $71.9 million, a decrease from last year when revenues averaged almost 85 million but still much higher than the previous years, as seen in Figure 3.29. Higher revenues the last two years are due to the higher prices of compliance obligations in 2021 and 2022. In 2022, natural gas revenues comprised 49 percent of revenues, while hydroelectric revenues comprised 46 percent. Coal and wind revenues comprised about 2 to 3 percent of revenues each. 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.

194 Powerex and NorthWestern Energy are not included due to no GHG attribution in 2021 or 2022.

Figure 3.29 Annual greenhouse gas revenues



3.7 Imbalance offset costs

Real-time congestion imbalances occur when payments made to schedules reducing flows on binding transmission constraints differ from payments collected from schedules increasing flows on constraints. A deficit is created when payments to flow reductions exceed collections from flow increases. When collections exceed payments, there is a congestion surplus.

The California ISO allocates real-time congestion imbalance deficits 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.

WEIM base schedules can create flows above limits on constraints internal to a balancing authority area. If base scheduled flows exceed internal constraint limits, the 15-minute market must adjust schedules to reduce flows. The reduced flows would be paid without corresponding flow increases from which to collect payments, causing a congestion revenue deficit. This leads to concerns that congestion revenue deficits that are created when base schedule flows exceed internal constraint limits can be allocated to third-party customers who are not responsible for submitting base schedules or transmission limits to the California ISO.

During 2022, real-time congestion imbalance offset charges for Arizona Public Service were high, with around $69 million in offset charges in December. Figure 3.30 shows real-time congestion imbalance offset charges for Arizona Public Service and Idaho Power during the year. All other WEIM participants had negative congestion revenue imbalances (surplus) over this period.

Almost all of the congestion offset costs for Arizona Public Service in December were associated with *15-minute market imbalances*. Figure 3.31 shows the 15-minute market congestion offset costs for Arizona Public Service in December split out by individual market constraints associated with those imbalances. Here, the majority of offset charges were associated with congestion on the Four Corners – Cholla constraint.

Figure 3.30 WEIM real-time congestion imbalance offset costs (2022)

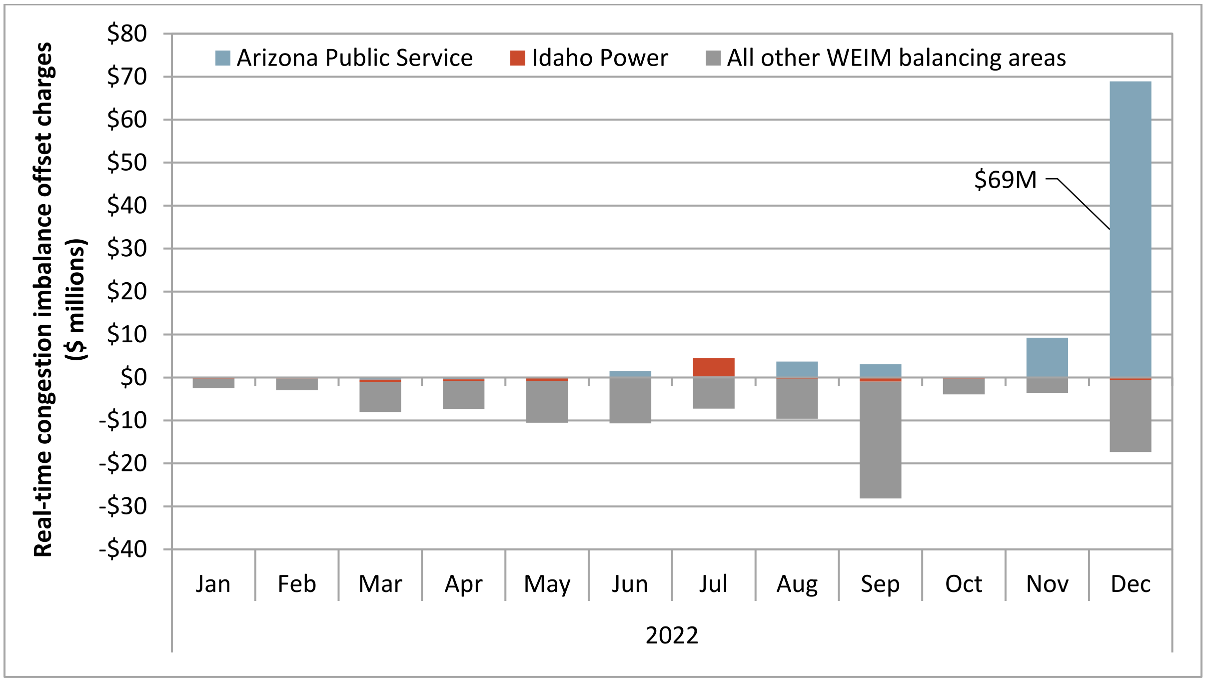
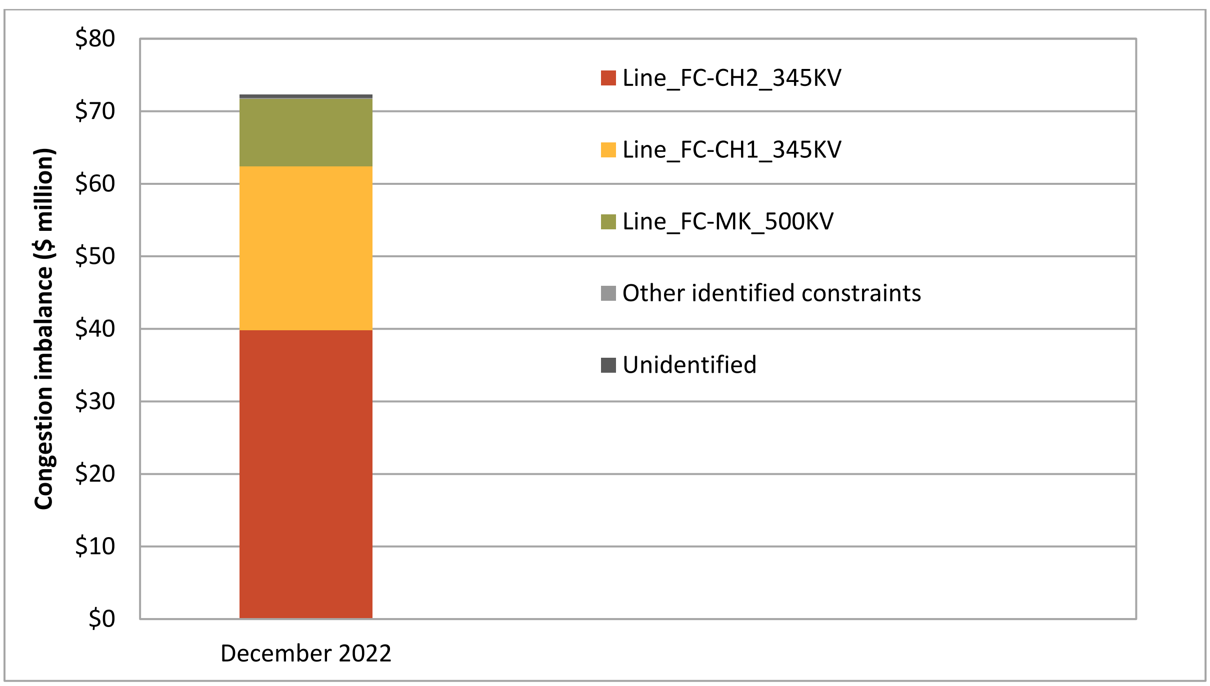


Figure 3.31 Arizona Public Service 15-minute market congestion imbalance by constraint (December 2022)



4 Ancillary services

This chapter provides a summary of the ancillary service market in 2022. Key trends highlighted in this chapter include the following:

- **Ancillary service costs increased to $237 million,** up from $165 million in 2021.
- **Operating reserve and regulation down requirements increased, while regulation up requirements remained similar to those in 2021**. Regulation down requirements increased 18 percent to 808 MW. Average combined requirements for spinning and non-spinning operating reserves increased by 3 percent from the previous year to 1,822 MW.
- **Provision of ancillary services from limited energy storage resources continued to increase, replacing procurement from imports and natural gas.** Average hourly procurement of ancillary services served by battery resources has been steadily increasing the past three years, growing from 190 MW in 2020 to 730 MW in 2022.
- **The frequency of ancillary service scarcity intervals continued to decrease.** There were 6 intervals in the 15-minute market with ancillary service scarcity, compared to 55 in 2021 and 129 in 2020.
- **Twenty-two percent of resources failed** ancillary service performance audits and unannounced compliance tests for spinning and non-spinning reserves, compared to 30 percent in 2021 and 30 percent in 2020.

The California ISO ancillary service market design includes co-optimizing energy and ancillary service bids provided by each resource. 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.[195]

4.1 Ancillary service costs

Costs for ancillary services totaled about $237 million in 2022, a significant increase from $165 million in 2021.

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. About 6 percent of payments were rescinded in 2022.

Figure 4.1 shows ancillary service costs both as percentage of wholesale energy costs and per megawatt-hour of load from 2020 to 2022. Following a decrease in ancillary service costs in 2021, the cost per megawatt-hour increased from $0.78 to $1.12 in 2022. As a percent of energy costs, ancillary service costs decreased to 1.1 percent from 2.2 percent in 2020, 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 2021, ancillary service costs were highest in the third quarter, although costs in the third quarter of 2022 were substantially higher than the previous year. Payments increased 61 percent and 97 percent for spinning reserve and non-spinning reserve, respectively. Of all ancillary service products, spinning reserve payments increased the

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

most in absolute terms, at $28.7 million over payments in 2021. Regulation down and regulation up payments increased 15 percent and 65 percent, respectively.

Figure 4.1 Ancillary service cost as a percentage of wholesale energy costs (2020–2022)

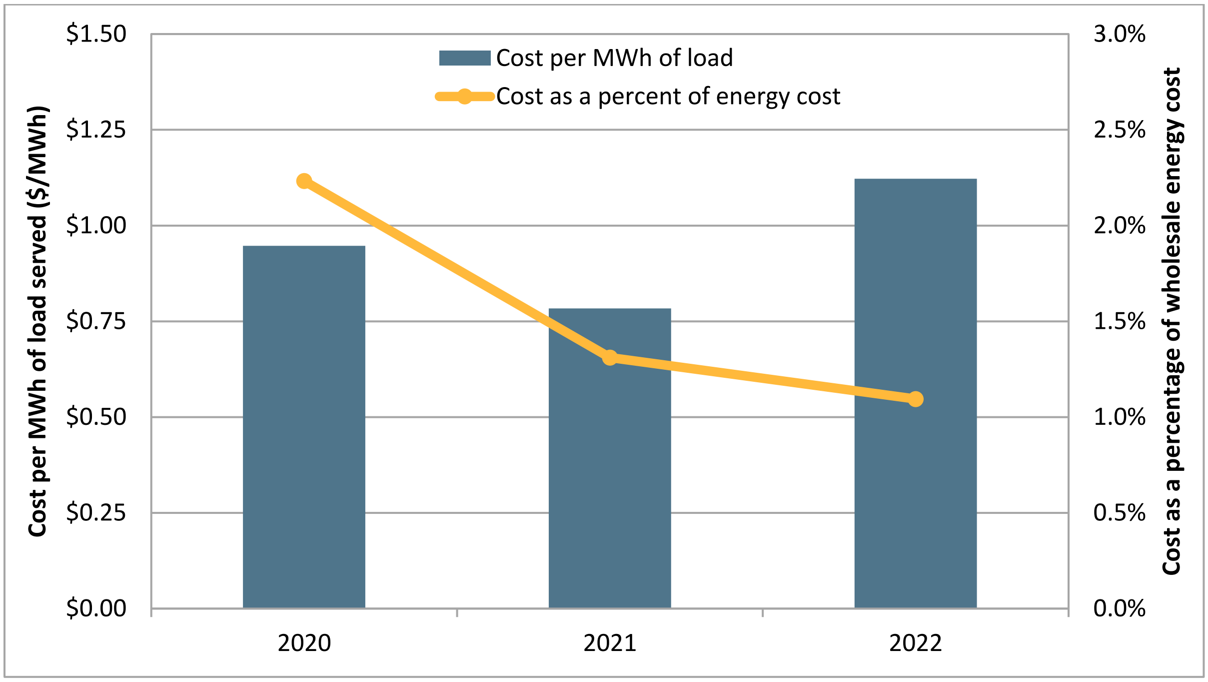
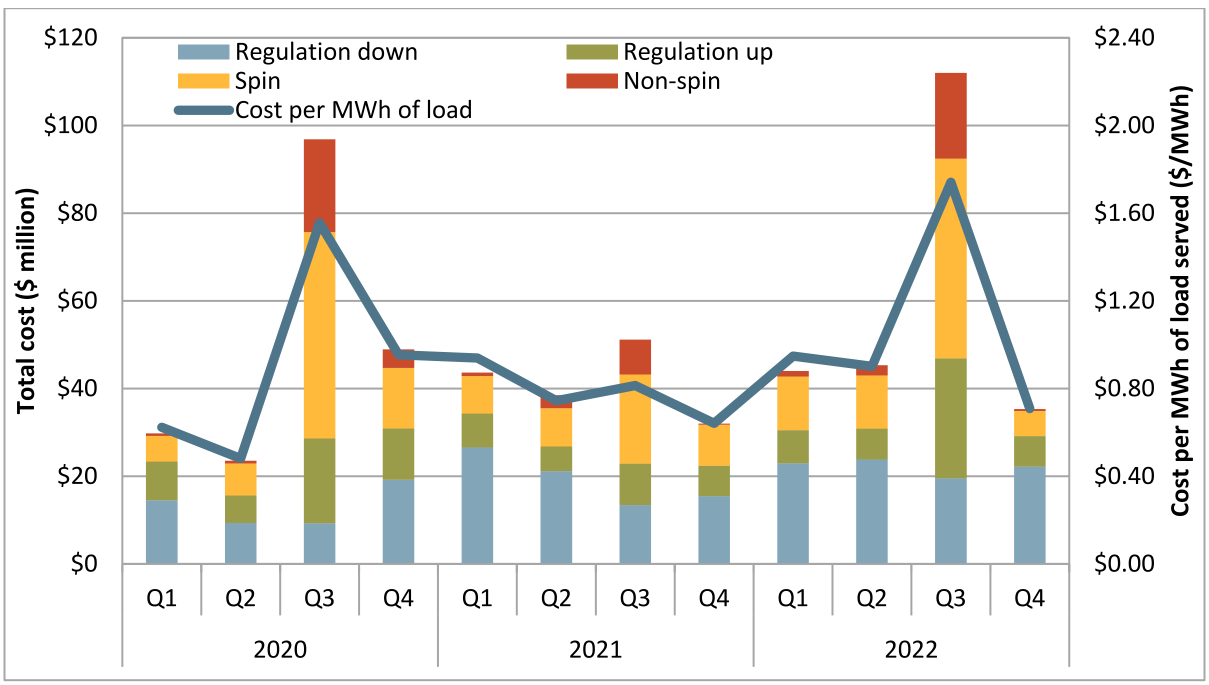


Figure 4.2 Total ancillary service cost by quarter and type



The value of self-provided ancillary services was 1 percent of the total cost of ancillary services, an increase from 0.4 percent in 2021. 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 less than $2.3 million in 2022.

4.2 Ancillary service requirements and procurement

The California ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.[196] Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's minimum operating reliability criteria and North American Electric Reliability Corporation's control performance standards. The CAISO attempts to procure all ancillary services in the day-ahead market to the extent possible.

The CAISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions. The expanded regions are identical to the corresponding internal regions but include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are all nested within the system and corresponding expanded regions. Therefore, ancillary services procured in a more inward region also count toward meeting the minimum requirement of the wider outer region. Ancillary service requirements are then met by both internal resources and imports, where imports are indirectly limited by the minimum requirements from the internal regions.

Six of these regions are typically utilized: expanded system (or expanded CAISO), internal system, expanded South of Path 26, internal South of Path 26, expanded North of Path 26, and internal North of Path 26.

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) 15 percent of forecasted solar production.[197] 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.[198] The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.

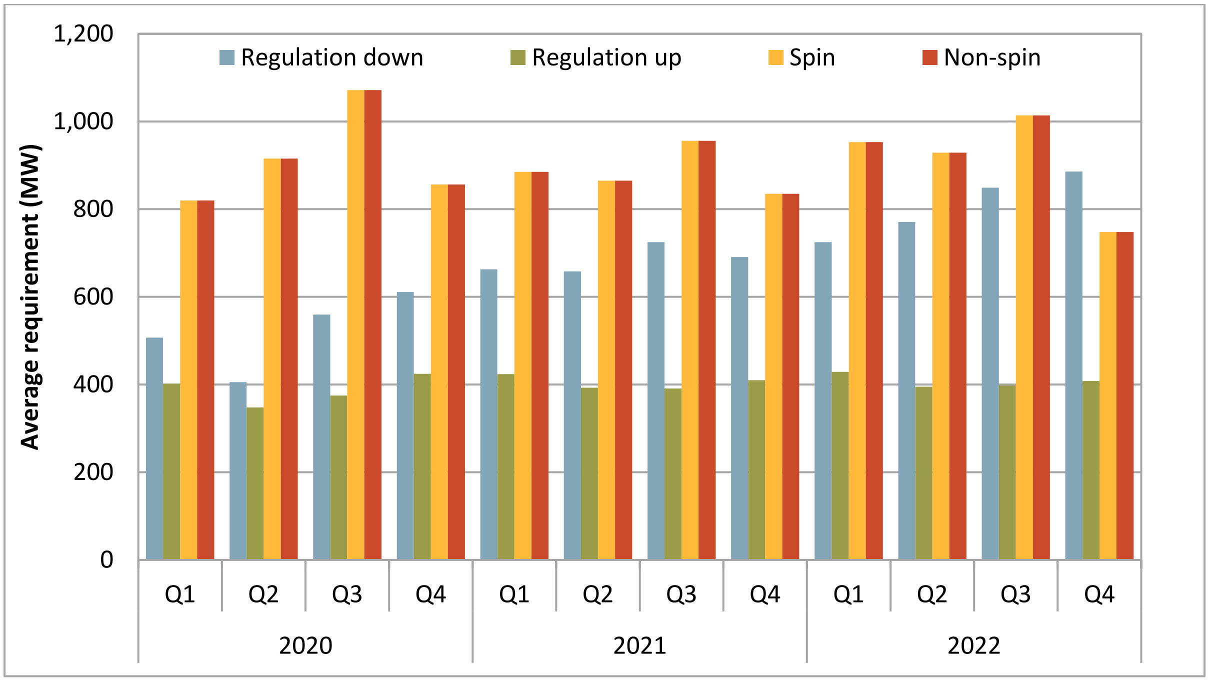
196 In addition, in June 2013, the California ISO added a performance payment referred to as mileage to the regulation up and down markets, in addition to the existing capacity payment system.

197 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.

198 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 includes quarterly average day-ahead operating reserve requirements since 2020. Operating reserve requirements in the day-ahead market averaged 1,822 MW in 2022, a 3 percent increase from 2021.

Figure 4.3 Quarterly average day-ahead ancillary service requirements



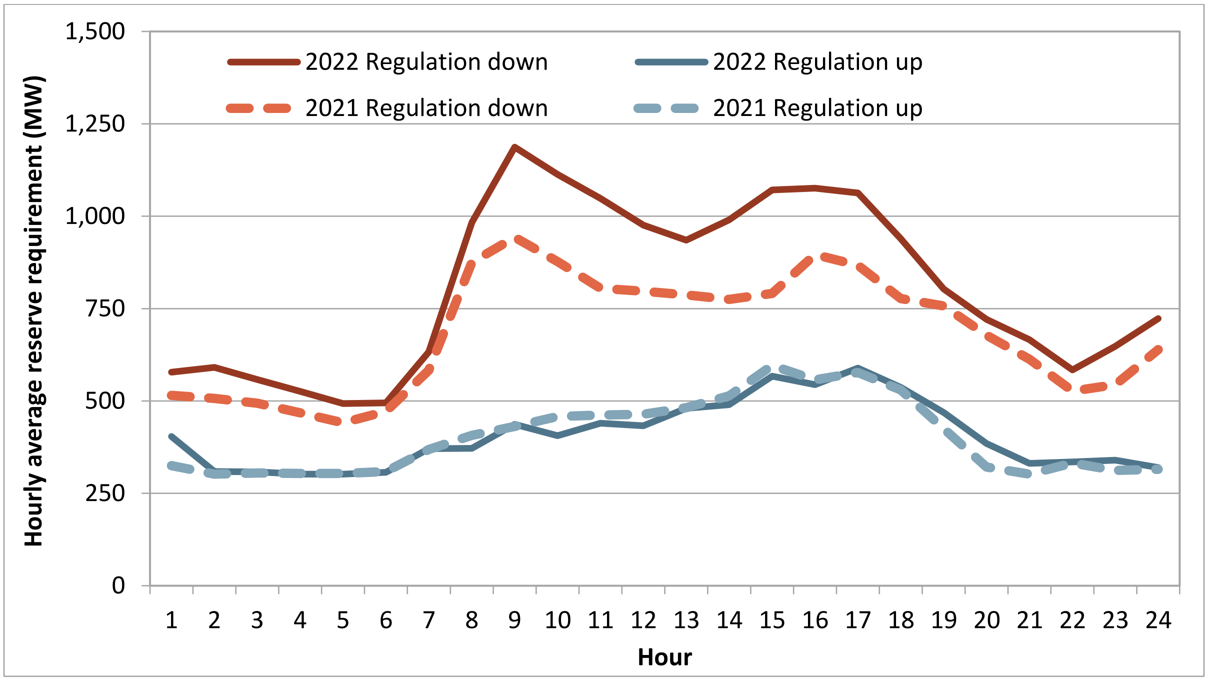
Regulation requirements

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 also shows average regulation requirements by quarter. During 2022, day-ahead requirements for regulation down increased substantially, especially during ramping periods and peak solar production hours. Regulation down requirements averaged 808 MW, an 18 percent increase from 2021. At 407 MW, average day-ahead regulation up requirements did not change substantially from 2021.

Figure 4.4 summarizes the average hourly profile of the day-ahead regulation requirements in 2021 and 2022. Requirements for regulation down were higher than requirements for regulation up. Regulation up requirements were highest during mid-day hours, particularly in the early evening. Requirements for regulation down were highest from hour ending 8 to 19, particularly in the morning and evening hours when solar was ramping either up or down.

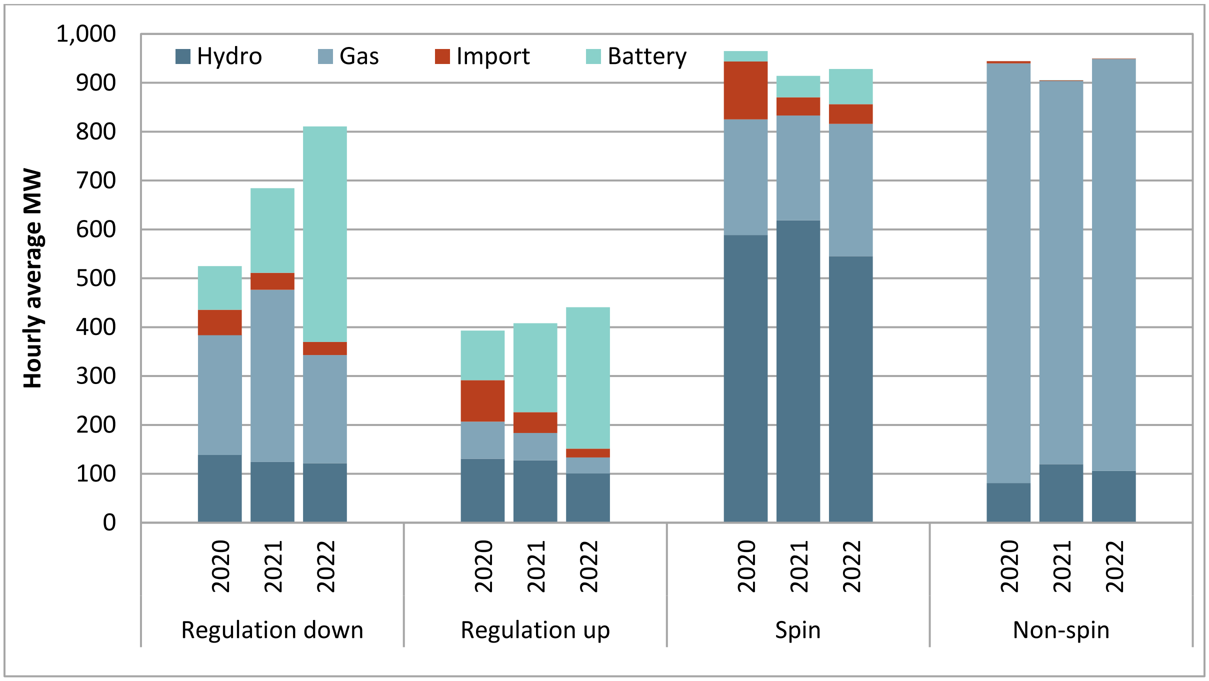
Figure 4.4 Hourly average day-ahead regulation requirements (2022)



Ancillary service procurement by fuel

Figure 4.5 shows the portion of ancillary services procured by fuel type from 2020 through 2022. 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 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 resource has been steadily increasing the past three years, growing from 212 MW in 2020 to 802 MW in 2022. In 2022, battery resources provided the majority of regulation capacity. Average procurement from gas and hydroelectric resources dropped 3 percent and 12 percent, respectively, in 2022, though these resource types still provide the majority of required operating reserves. Hourly average of procurement served by imports was 86 MW, a 26 percent decrease from 2021.

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 2020 and 2021, weighted by the quantity settled.[199]

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) increased compared to the previous year. This increase is consistent with the upsurge of natural gas prices in 2022. Following natural gas prices, prices for these upward products spiked in the third quarter of 2022. Regulation down prices decreased in 2022 despite increases in requirements, largely due to more participation from battery storage resources.

199 Values reported here differ slightly from the previous year due to an update in the data source.

Figure 4.6 Day-ahead ancillary service market clearing prices

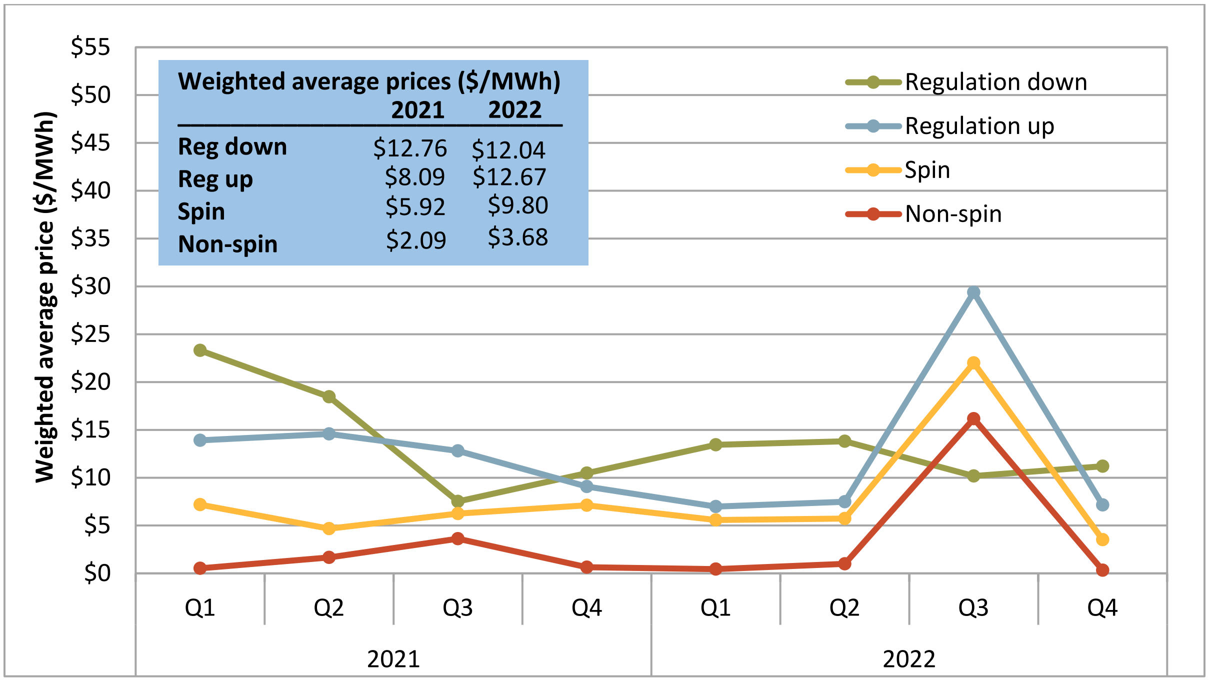
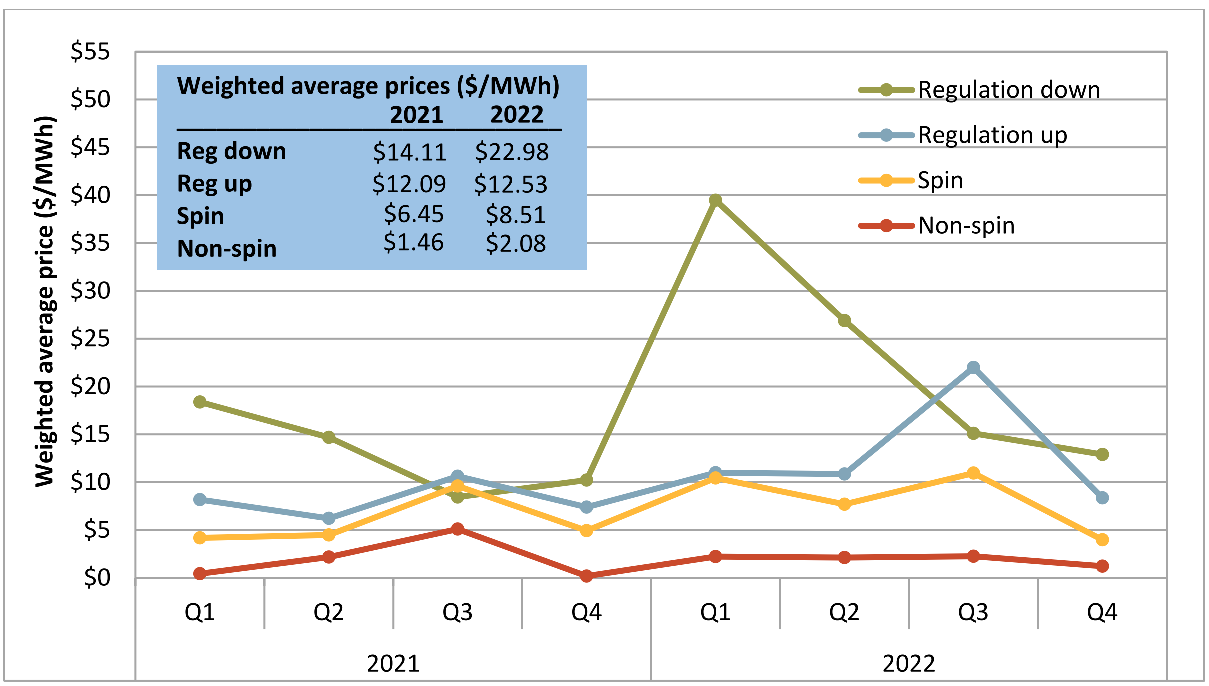


Figure 4.7 shows that the weighted average prices for ancillary services increased for all products in the real-time market. However, ancillary costs are largely determined by day-ahead market prices since most ancillary services are procured in the day-ahead market, with only 7 percent of ancillary costs incurred in the real-time market.

Figure 4.7 Real-time ancillary service market clearing prices



4.4 Special issues

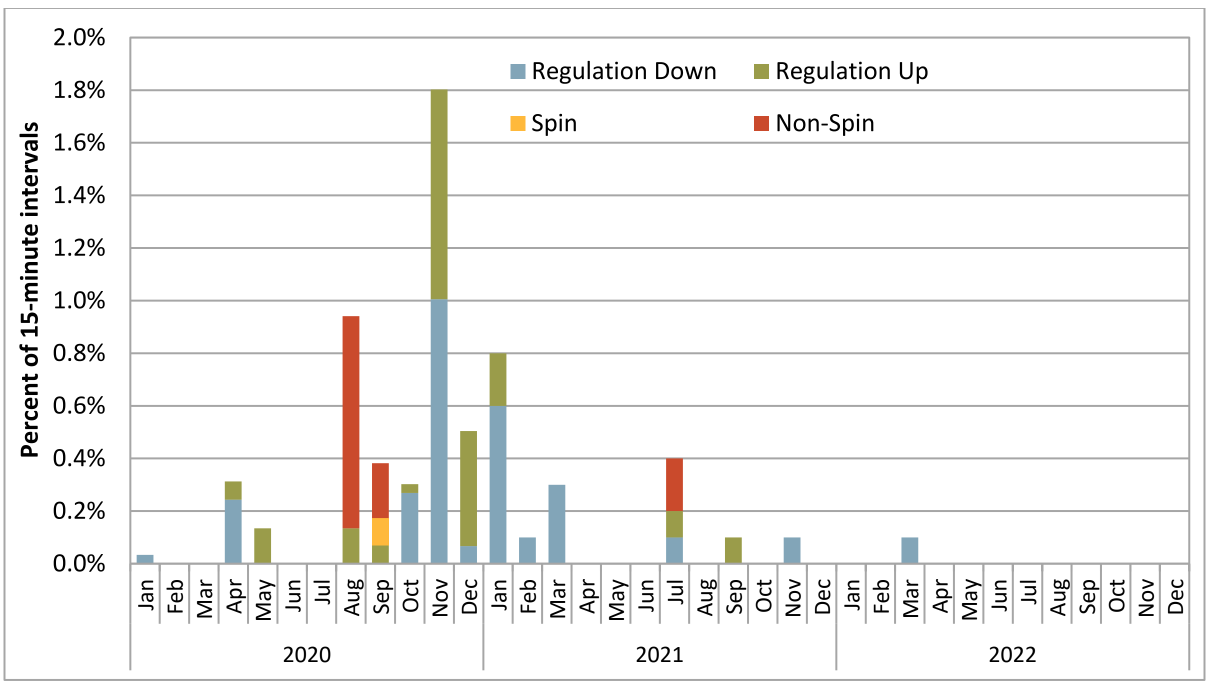
4.4.1 Ancillary service scarcity

Ancillary service scarcity pricing occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California ISO 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.

Figure 4.8 shows the monthly frequency of ancillary service scarcities in the 15-minute market by type. In 2022 there was a substantial decrease in ancillary service scarcities compared to previous years. There were only six scarcities in 2022, compared to 55 in 2021 and 129 in 2020. All of the scarcities in 2022 were caused by a lack of regulation down, and all were in the 15-minute market.

This lack of scarcity events can be attributed in part to the rapidly increasing participation of battery storage resources. However, the CAISO has reported on an increasing frequency of resources—especially batteries—that fail to deliver awarded regulation in real-time.[200] In these cases, resources either do not get on automatic generation control (AGC), or do not follow the AGC signals. These failures are not reflected in the market results that generate scarcity alerts.

Figure 4.8 Frequency of ancillary service scarcities (15-minute market)



[200] California ISO, *Market Performance and Planning Forum*, March 16, 2023, slides 42-47: Presentation-MarketPerformancePlanningForum-Mar16-2023.pdf (caiso.com)

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.[201]

During 2022, the California ISO performed a total of 241 performance audits and unannounced compliance tests for resources with either spinning or non-spinning reserves, which was a slight increase from the 234 tests performed in 2021. The failure rate was 22 percent for unannounced tests, an improvement over 30 percent in 2021. The failure rate for performance tests was 3 percent in 2022.

201 For more information about the California ISO ancillary service testing procedures including updates to regulation performance audits, see: California ISO, *Operating Procedure 5370*: http://www.caiso.com/Documents/5370.pdf

5 Market competitiveness and mitigation

This chapter assesses the competitiveness of the California ISO energy markets, local capacity areas, 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.[202]
- **There were significantly fewer structurally uncompetitive hours** in the 2022 day-ahead energy market, which accounts for most of the California ISO total wholesale energy market. This follows a decrease in uncompetitive hours from 2020 to 2021 as well. This downward trend in uncompetitive hours is due in part to the significant additions in battery capacity in recent years.
- **The market for capacity needed to meet local resource adequacy requirements was structurally uncompetitive in half of the local areas.** In both the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures.
- **The dynamic path assessment used to trigger local market power mitigation accurately identified non-competitive constraints** in 2022. The percent of non-competitive constraint intervals increased slightly in the day-ahead and real-time markets, relative to 2021.[203]
- **The performance of local market power mitigation on Western Energy Imbalance Market transfer remained high.** In both the 15-minute and 5-minute markets, the percent of congested constraint-intervals that were under-predicted slightly increased from 2021 to 2022, but overall remained low.
- **Effective November 1, 2021, battery energy storage resources were also subject to mitigation** in the local market power mitigation process. In the day-ahead market, an average of 200 MW of bids from battery resources were subject to mitigation, 106 MW of which were lowered on average.[204]
- **Energy subject to mitigation increased in both the day-ahead and real-time markets,** for both the California ISO and Western Energy Imbalance Market balancing areas. For the California ISO, the increase was due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.
- **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 220 MW per hour in the California ISO and 156 MW per hour in the Western Energy Imbalance Market. In the 5-minute market, capacity with bids lowered by mitigation averaged 250 MW per hour in the California ISO and 120 MW in the Western Energy Imbalance Market.
- **Local market power mitigation limited above-market costs for exceptional dispatches for energy** in 2022, reducing these costs by about $368 thousand.

---

[202] Further information on DMM's estimation of overall market competitiveness is available in Section 2.2.

[203] For a detailed description of DMM's framework to analyze overall accuracy of transmission competitiveness, see: Department of Market Monitoring, *2020 Annual Report on Market Issues & Performance*, August 2021: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

[204] Department of Market Monitoring, *2022 Special report on Battery Storage*, July 7, 2023, p. 27: http://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

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 test, supply of the three largest suppliers is removed.
- **Residual supply index:** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[205] 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 2022, DMM again observed fewer hours with a residual supply index less than one compared to the previous year. Table 5.1 shows the annual number of hours with a residual supply index ratio less than one since 2018, based on the assumptions listed above. Figure 5.1 shows the same information graphically by quarter. For 2022, the residual supply index with the three largest suppliers removed

[205] 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.

(RSI_3) was less than one during 130 hours, and the index was less than one during 79 hours with the two largest suppliers removed (RSI_2). With the largest single supplier removed (RSI_1), there were 44 hours in 2022 with the index less than one.

Figure 5.2 shows the lowest 500 RSI_3 values for each year. During the lowest 50 hours, structural competitiveness in 2022 was similar to that of 2021. However, in most hours, structural competitiveness was greater in 2022 compared to previous years. During 2022, with the three largest suppliers removed, the RSI_3 was less than 0.9 in 57 hours and less than 0.8 in 13 hours. At its lowest, the RSI_3 was around 0.75 in 2022, compared to around 0.76 in 2021, 0.67 in 2020, and 0.87 in 2019.

Figure 5.3 summarizes non-pivotal supply with the three largest suppliers excluded in the same 500 hours with lowest RSI_3 values. In particular, significant additions in battery capacity in recent years contributed to a decrease in potentially non-competitive hours. Greater non-pivotal supply counted from gas and hydro resources as well as imports also increased the structural competitiveness in 2022, compared to 2021.

Table 5.1 Hours with residual supply index less than one by year

Year	RSI_1	RSI_2	RSI_3
2019	2	50	166
2020	129	333	524
2021	84	189	316
2022	44	79	130

Figure 5.1 Hours with residual supply index less than one by quarter

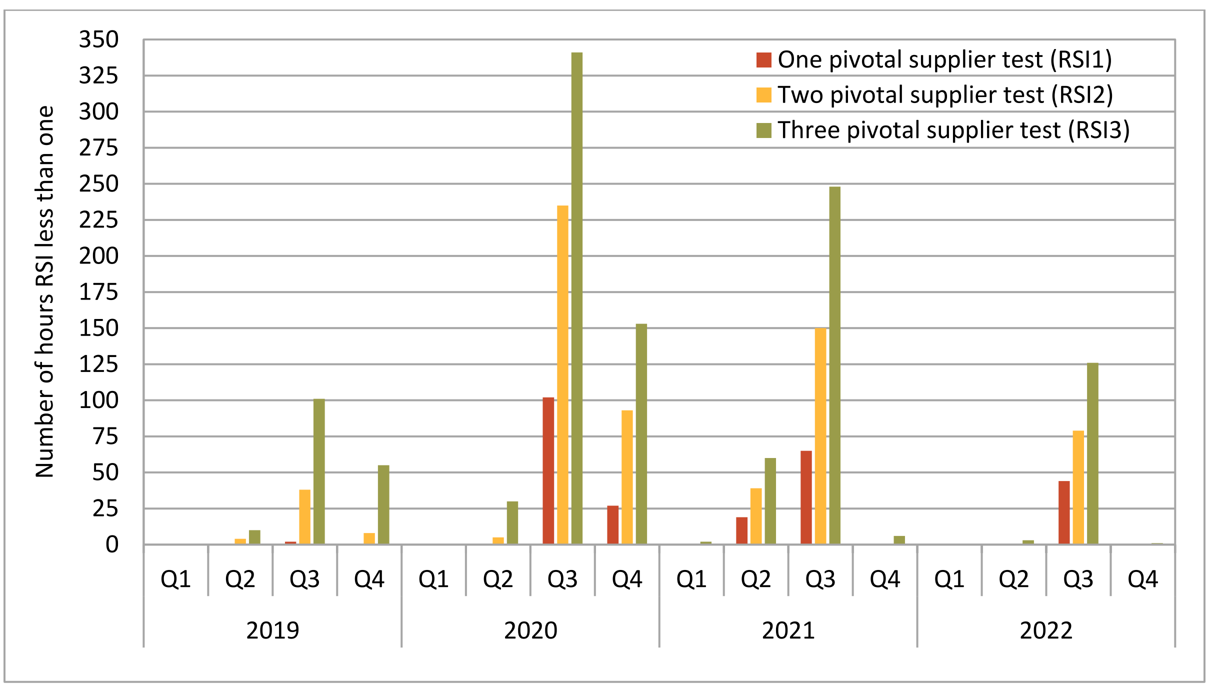


Figure 5.2 Residual supply index with largest three suppliers excluded (RSI_3) – lowest 500 hours

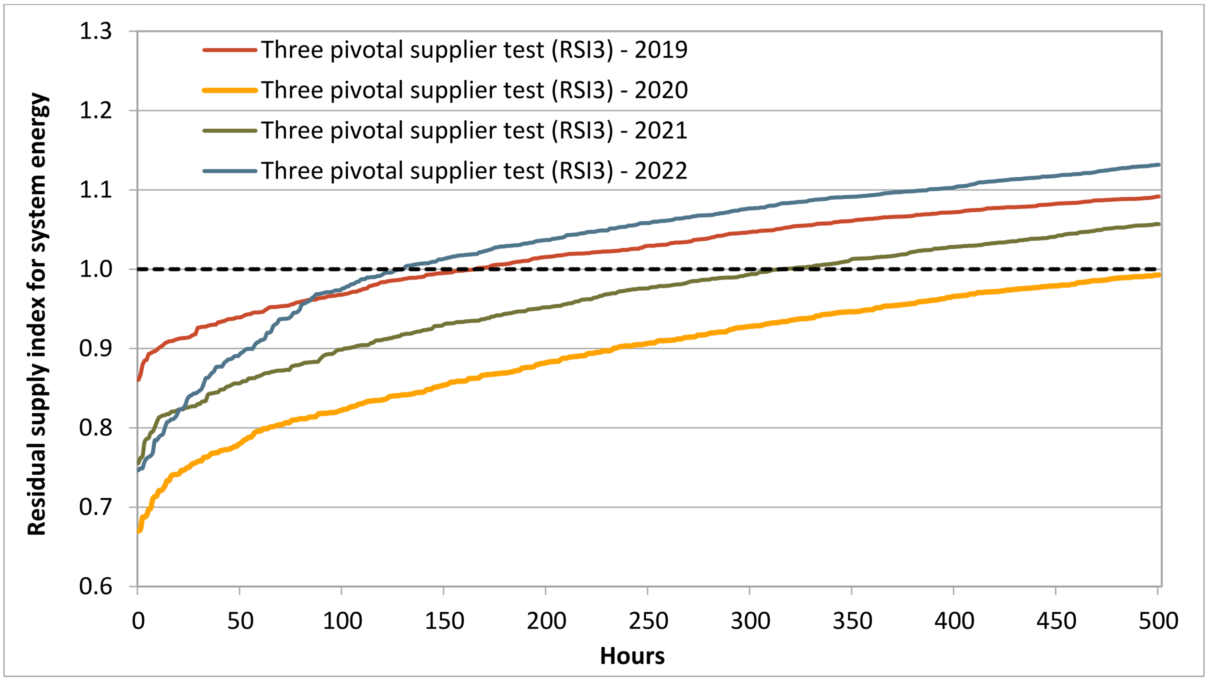
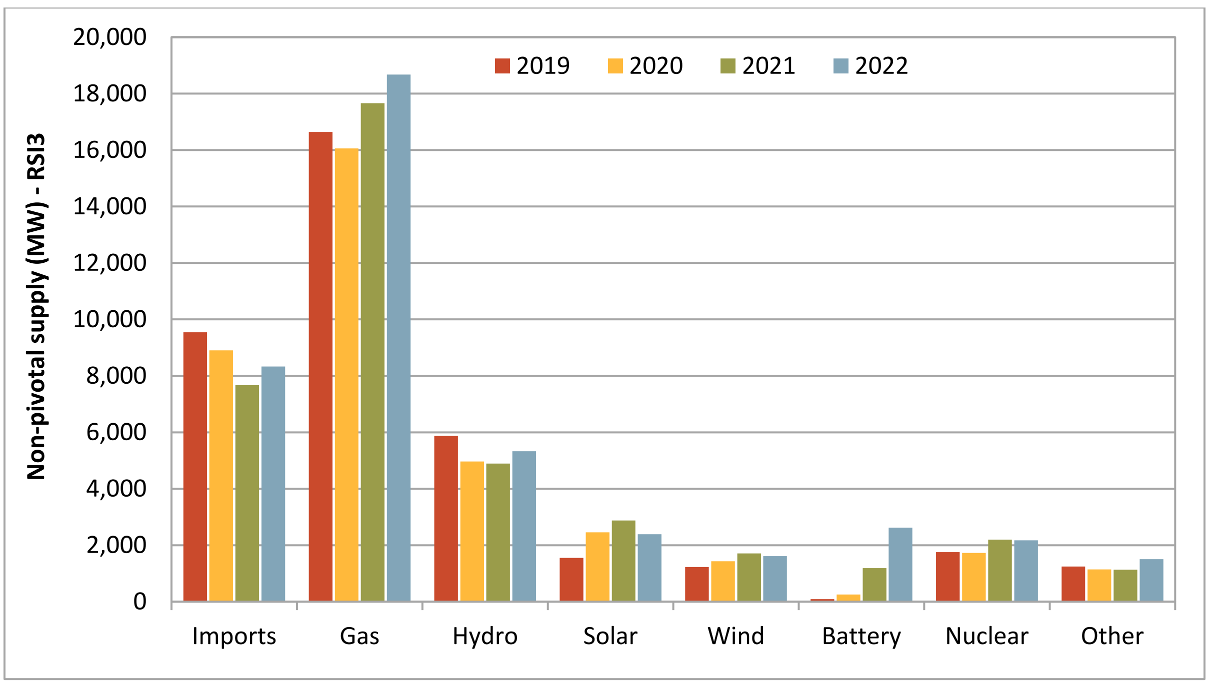


Figure 5.3 Non-pivotal supply with the largest three suppliers excluded (RSI_3) – lowest 500 hours



5.1.2 Local capacity requirements

In 2022, 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.[206]

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. In some areas, at least one supplier is individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of these suppliers' capacity is needed to meet local requirements.

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 2022.[207] As a result, the total local capacity requirement increased by around 4 percent between 2021 and 2022 with a considerable increase to the Greater Bay local capacity area requirement.

Key finding of this analysis include the following:

- The Greater Bay, Kern, North Coast/North Bay, Stockton, LA Basin, and San Diego/Imperial Valley 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 2022, the LA Basin local area capacity requirement increased from 2021 due to a change in transmission allocation, however there are no pivotal suppliers due to the small remaining required procurement.

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

[206] 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 is likely a conservative assessment of competitiveness in local areas.

[207] California ISO, *2022 Local Capacity Technical Study*, April 30, 2021: http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf

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.[208]

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	3,901	4,414	1.13	0.49	0.10	0.05	2
Kern	212	322	1.52	0.09	0.01	0.00	1
North Coast/North Bay	683	757	1.11	0.02	0.00	0.00	1
Stockton	41	46	1.13	0.58	0.11	0.03	2
SCE TAC area							
LA Basin	100	2,758	27.56	5.55	3.76	2.76	0
San Diego/Imperial Valley	1,173	1,726	1.47	0.96	0.45	0.18	2

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. 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 and impact of non-automated mitigation procedures that are applied for exceptional dispatches, or additional dispatches issued by grid operators to meet reliability requirement issues not met by results of the market software.

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 2022, relative to 2021. 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

[208] For further information on the capacity procurement mechanism, see Section 9.6.

increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers. Effective November 1, 2021, the California ISO implemented the ESDER 4 initiative, which introduces local market power mitigation to battery energy storage resources.[209]

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 (LMPM) 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 market 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.[210]

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 2022, the average incremental energy subject to mitigation increased by 40 percent relative to 2021.

- Bids for an average of 1,877 MW per hour were subject to mitigation but not lowered in 2022, an increase from 1,347 MW in 2021. Out of 1,877 MW that is subject to mitigation, about 870 MW is from gas resources, followed by 448 MW from hydro resources.
- Effective November 1, 2021, battery energy storage resources are also subject to mitigation. On average, about 200 MW per hour from battery resources was subject to mitigation in 2022 and about 94 MW had bids not lowered.[211]
- Bids for an average of 477 MW per hour were changed in 2022, up from 293 MW in 2021. About 97 percent of this incremental energy that had bids lowered came from gas, hydro, and battery energy storage resources. Although the quantity of bids lowered increased in 2022, the percentage of bids lowered to bids subjected to mitigation is similar to 2021.
- Day-ahead dispatch instructions from bid mitigation increased by about 21 MW per hour in 2022, compared to 17 MW per hour in 2021.

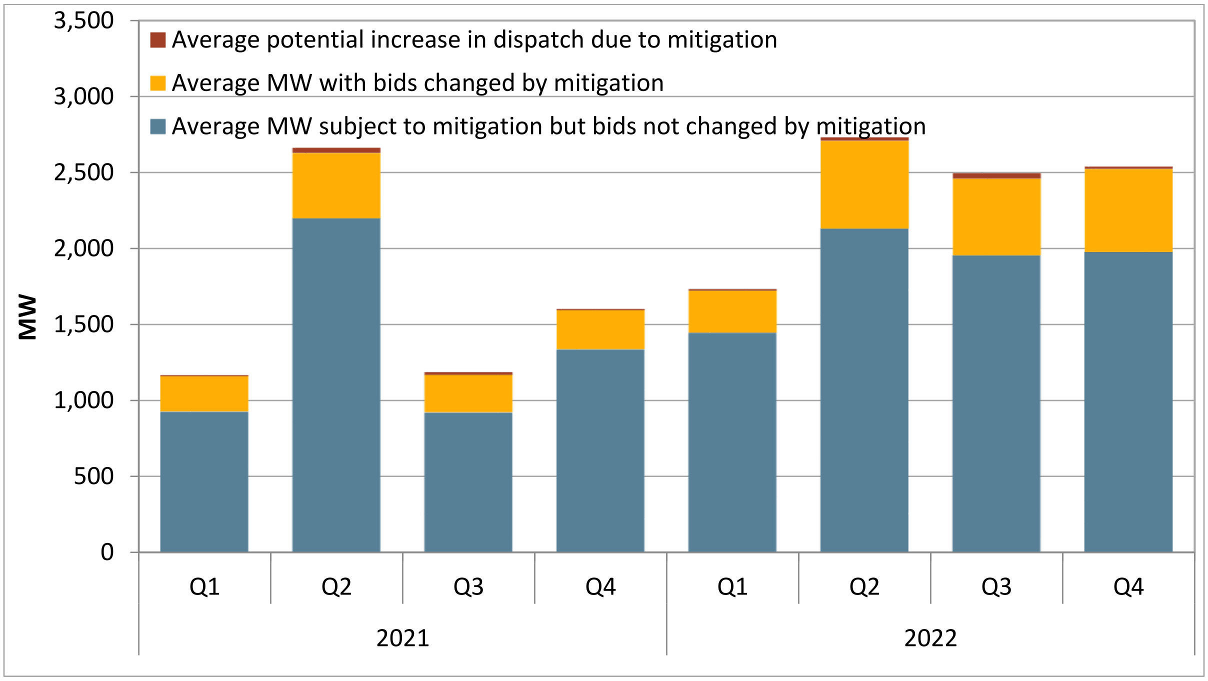
---

209 California ISO Market Notice*: ESDER Phase 4 Initiative: Deployment Effective for Trade Date 11/1/21,* October 29, 2021: http://www.caiso.com/Documents/ESDERPhase4Initiative-DeploymentEffectiveforTradeDate-11121.html

210 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.

211 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.

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 2022 increased by 83 percent and 49 percent in the 15-minute and 5-minute market, respectively.

- In the 15-minute market, an average of 1,228 MW of incremental energy bids was subject to mitigation but bids not lowered, which is an increase from 673 MW in 2021. About 220 MW had bids lowered due to mitigation. Bids that were lowered came primarily from hydro (110 MW), gas resources (47 MW) and battery energy storage resources (47 MW).
- In the 5-minute market, an average of 1,886 MW of bids was subject to mitigation but not lowered, and only 250 MW were lowered.
- On average, the potential increase in 15-minute dispatch due to bid mitigation increased to 23 MW in 2022 compared to 14 MW in 2021. Potential increase in 5-minute dispatch from bid mitigation increased to 33 MW per hour in 2022 compared to 19 MW per hour in 2021.

Figure 5.5 Average incremental energy mitigated in 15-minute real-time market (CAISO)

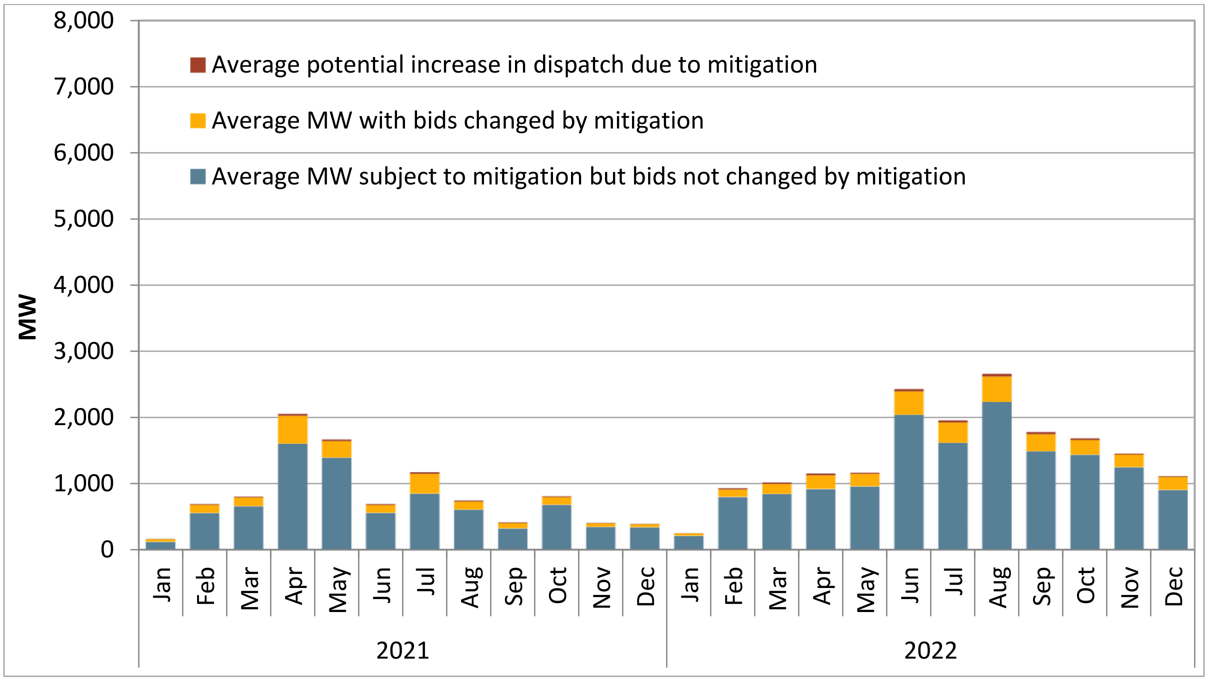


Figure 5.6 Average incremental energy mitigated in 5-minute real-time market (CAISO)

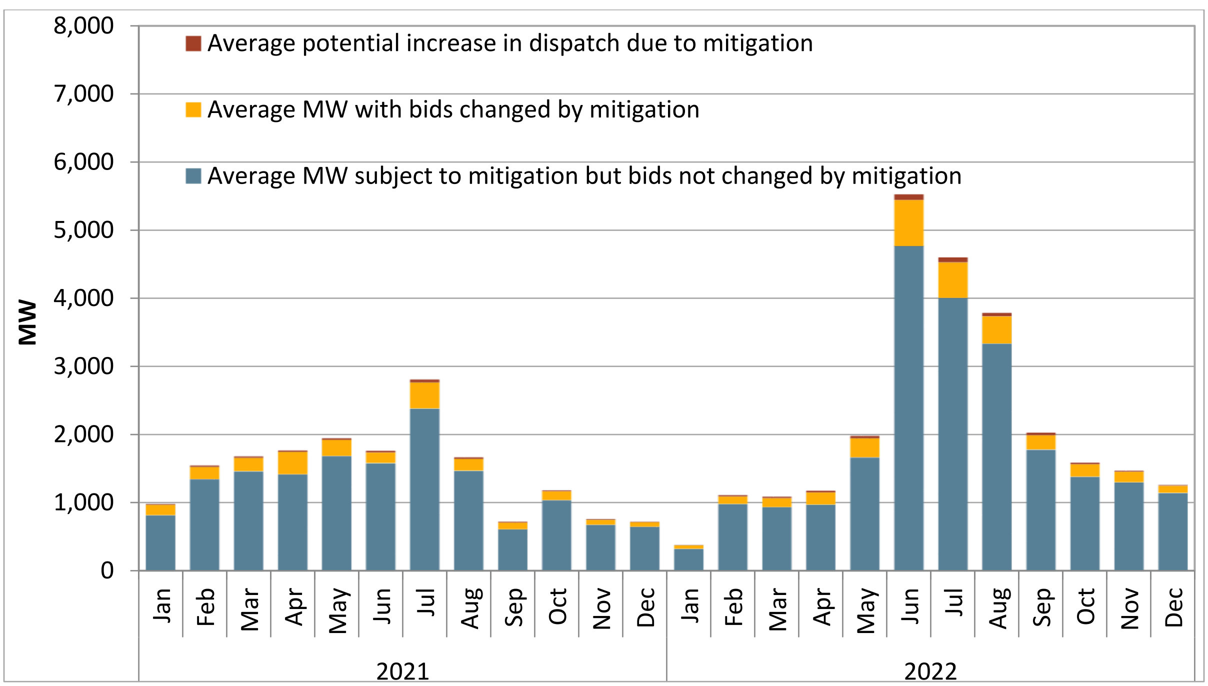


Figure 5.7 and Figure 5.8 highlight the frequency and volume of 15-minute and 5-minute market mitigation in all of the WEIM balancing areas outside the California ISO. Mitigation rates in 2022 increased by more than 50 percent in both 15-minute and 5-minute markets compared to 2021. Part of the increase can be attributed to four new balancing areas joining WEIM in 2022.

Figure 5.7 Average incremental energy mitigated in 15-minute real-time market (WEIM)

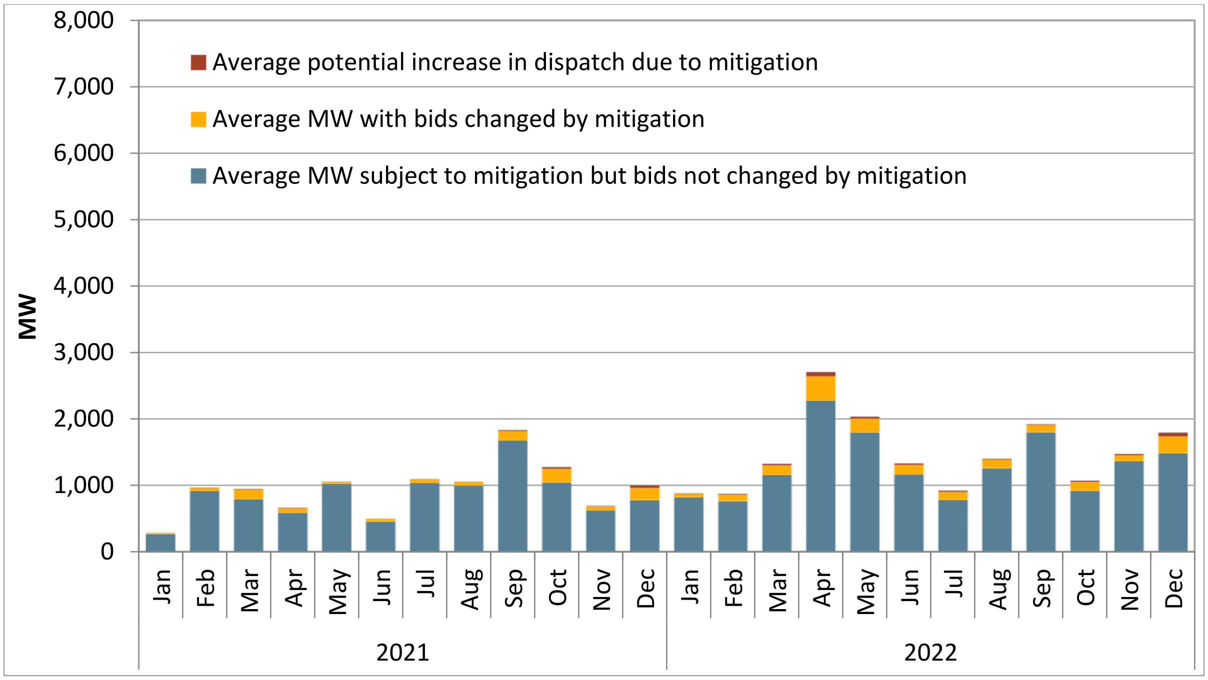
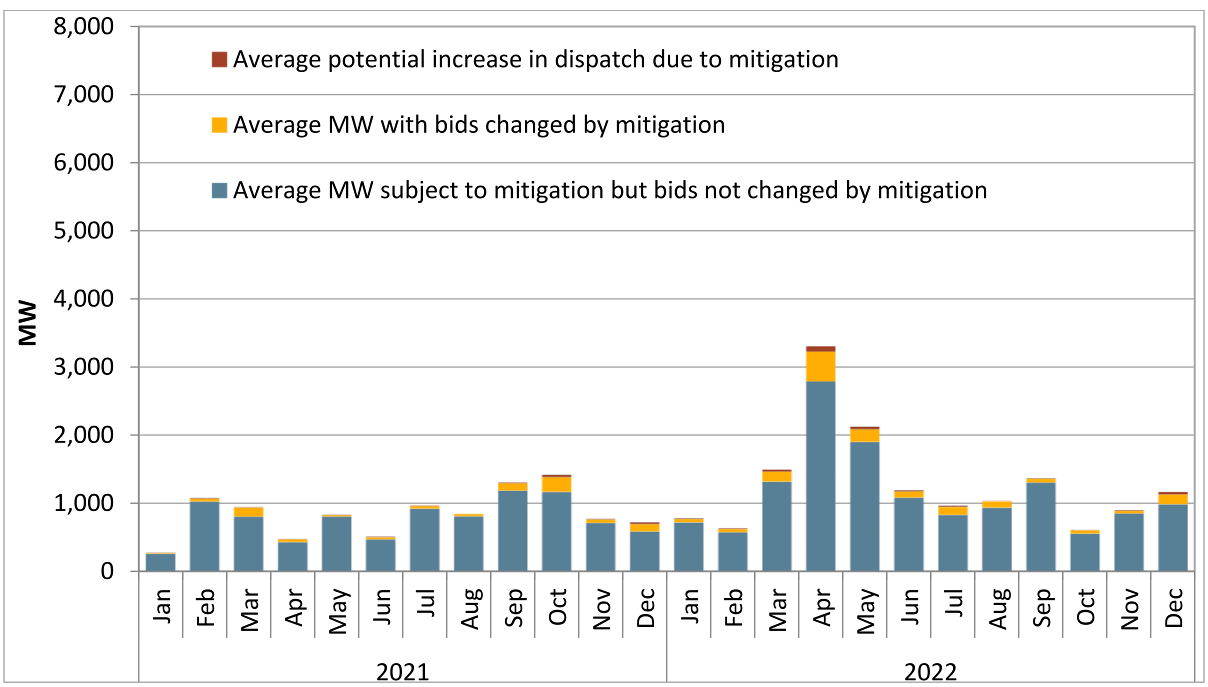


Figure 5.8 Average incremental energy mitigated in 5-minute real-time market (WEIM)



- As shown by blue bars in the figures, in the 15-minute market, bids for an average of 1,300 MW were subject to mitigation but not lowered in 2022 compared to 853 MW in 2021. In the 5-minute market, bids for about 1,158 MW were subject to mitigation but not lowered in 2022 compared to 768 MW in 2021.

- Average incremental energy with bids lowered because of mitigation continues to be very low in 2022, as seen by the red bars in the figures below.
- Because of decreased bid mitigation in 2022, the average potential increase in dispatch also decreased in 15-minute and 5-minute markets.

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.[212] Total energy from exceptional dispatches in 2022 declined about 45 percent from the previous year. The above-market costs for exceptional dispatches decreased totaling $14 million in 2022 compared to $27 million in 2021. 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*.

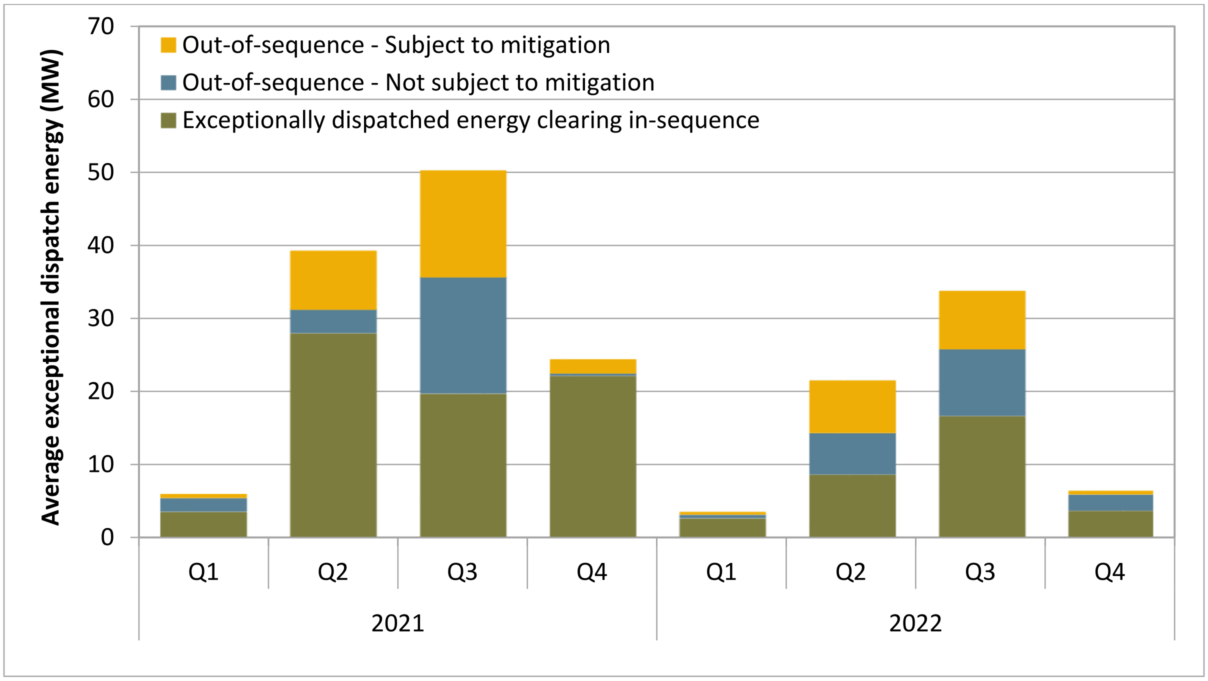
In 2022, local market power mitigation played a large role in limiting above-market costs for exceptional dispatches for energy, reducing these costs by $368 thousand.

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 45 percent in 2022 when compared to 2021. As discussed in Chapter 8, 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 increased by about a fifth in 2022 compared to 2021. Out-of-sequence exceptional dispatches subject to mitigation decreased by about a third in 2022 compared to 2021.

212 A more detailed discussion of exceptional dispatches is provided in Section 8.1.

Figure 5.9 Exceptional dispatches subject to bid mitigation



Impact of exceptional dispatch energy mitigation

Out-of-sequence costs for exceptional dispatch energy are out-of-market costs paid for this energy with bids that exceed the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to local market power mitigation provisions, this energy is out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

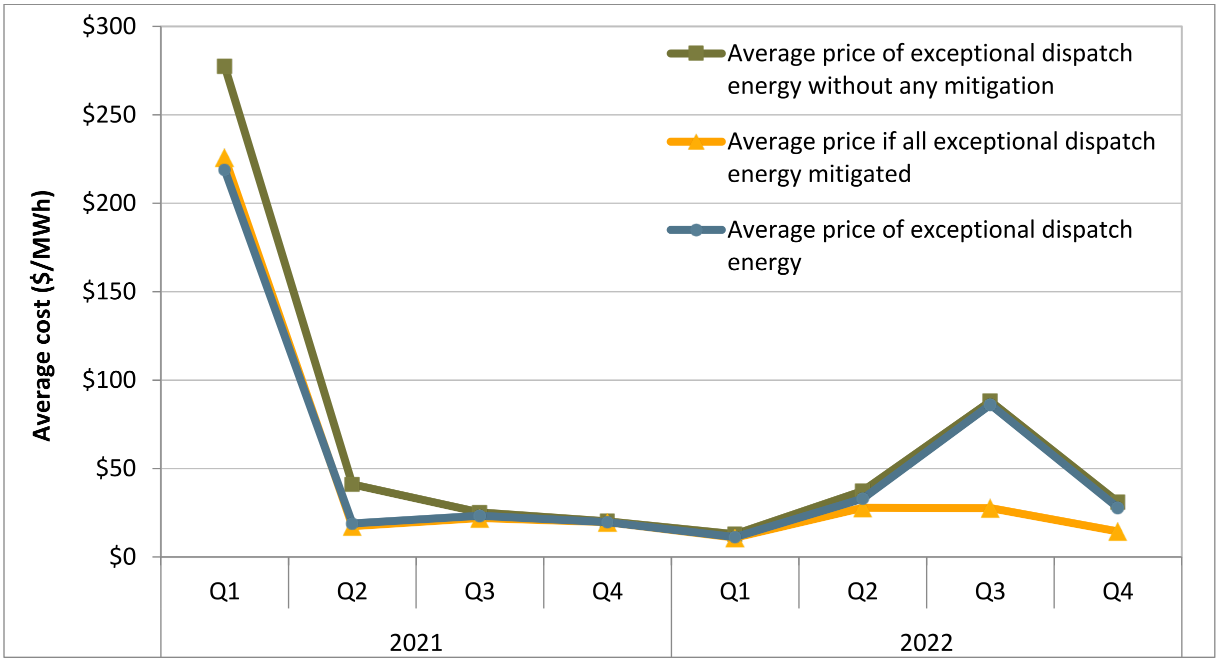
Using the value of out-of-sequence costs with the corresponding megawatt quantities of out-of-sequence exceptional dispatch energy, one can calculate the average price of out-of-sequence exceptional dispatch energy. This price is the amount per megawatt-hour by which out-of-sequence exceptional dispatch energy exceeds the locational marginal price.

Figure 5.10 shows the difference in the average price for out-of-sequence exceptional dispatch energy under three scenarios. The distance between the green and blue lines in Figure 5.10 illustrates the impacts of exceptional dispatch mitigation. The distance between these lines is the difference between the settled average price of out-of-sequence exceptional dispatch energy (blue line) and the average price of out-of-sequence exceptional dispatch energy in the absence of mitigation (green line). Greater distance between these two lines implies a larger overall impact of mitigation. As Figure 5.10 shows, this price difference decreased in 2022 compared to 2021.

The yellow line in Figure 5.10 shows the average price of out-of-sequence exceptional dispatch energy if all exceptional dispatch energy had been subject to mitigation. A greater distance between the green line and the yellow line is indicative of lower quantities of exceptional dispatch energy subject to mitigation.

The average price of out-of-sequence exceptional dispatch energy decreased in 2022 to $40/MWh from $70/MWh in 2021. The decrease in average prices for exceptional dispatch energy was driven by the higher average price in the first quarter of 2021 at $218/MWh.

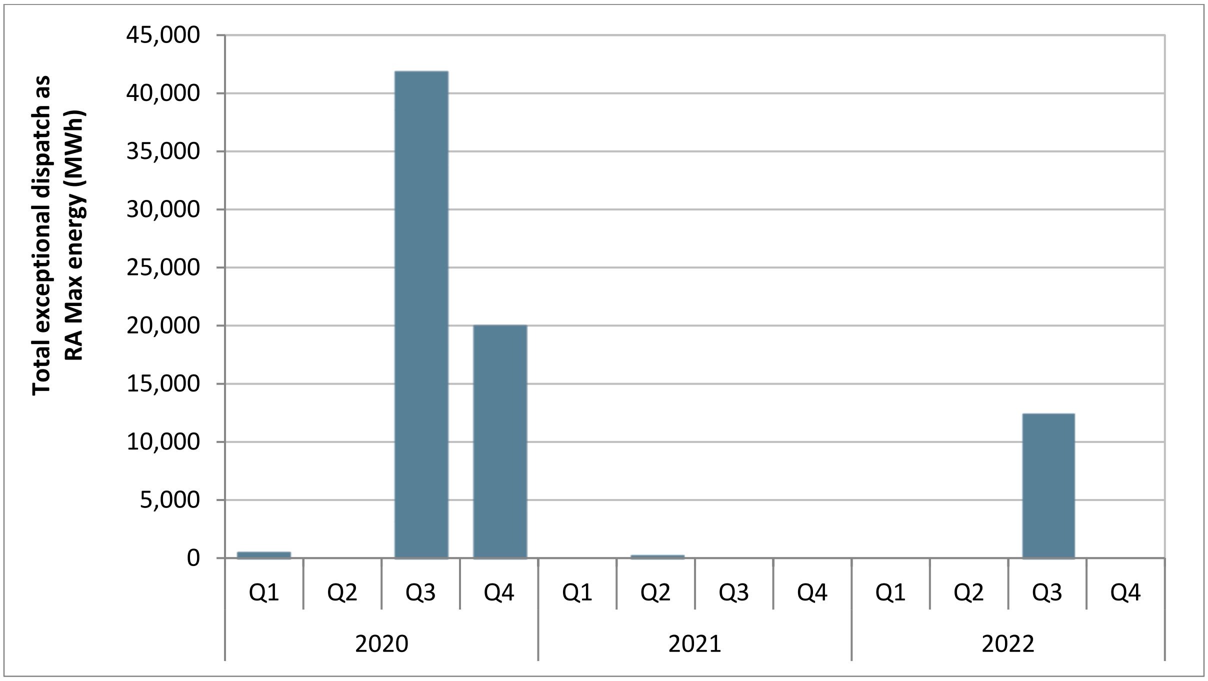
Figure 5.10 Average prices for out-of-sequence exceptional dispatch energy



Exceptional dispatches as RA max

As shown in Figure 5.11, the overall volume of exceptional dispatch energy above minimum load increased by about 5,000 percent in 2022 when compared to 2021, but decreased by 80 percent from 2020. The concern with RA max exceptional dispatches is that they are not subject to mitigation, and thus can become out-of-sequence with energy. As discussed in Chapter 8, out-of-sequence energy is energy with bid prices or default energy bids above the market clearing price. The RA max exceptional dispatches created $344,000 in excess costs in 2022, compared to $3.4 million and $214,000 in 2020 and 2021, respectively.

Figure 5.11 Exceptional dispatches with an RA max designation



5.3 Start-up and minimum load bids

This section analyzes commitment cost bid behavior for California ISO (CAISO) gas capacity – excluding use-limited resources – under the proxy cost option.[213] For 2022, DMM estimates that about 57 percent of the CAISO's total bid cost recovery payments, approximately $145 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. Commitment cost bids are capped at 125 percent of reference proxy costs. About 94 percent of these payments are for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

Figure 5.12 and Figure 5.13 highlight how proxy commitment costs were bid into the day-ahead and real-time markets in 2022 compared to 2021.[214,215]

As shown in Figure 5.12, about 39 percent of the capacity submitted start-up bids at or near the proxy cost cap in 2022, similar to 2021. About 34 percent of capacity submitted start-up bids at or below the proxy cost in the day-ahead market in 2022, compared to 31 percent in 2021. About 39 percent of the startable capacity submitted bids at or near the proxy cost cap in the real-time market in 2022, up from 37 percent in 2021.

---

213 Background on start-up and minimum load bidding rules can be found in DMM's 2021 annual report, p. 195: http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

214 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.

215 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 reasonable thresholds and manual requests are evaluated on a case-by-case basis with supporting documentation.

As shown in Figure 5.13, in both the day-ahead and real-time markets, the percent of minimum load capacity bidding at or below the proxy cost declined from 48 percent in 2021 to 35 percent in 2022.

Figure 5.12 Day-ahead and real-time gas-fired capacity under the proxy cost option for start-up cost bids (percentage)

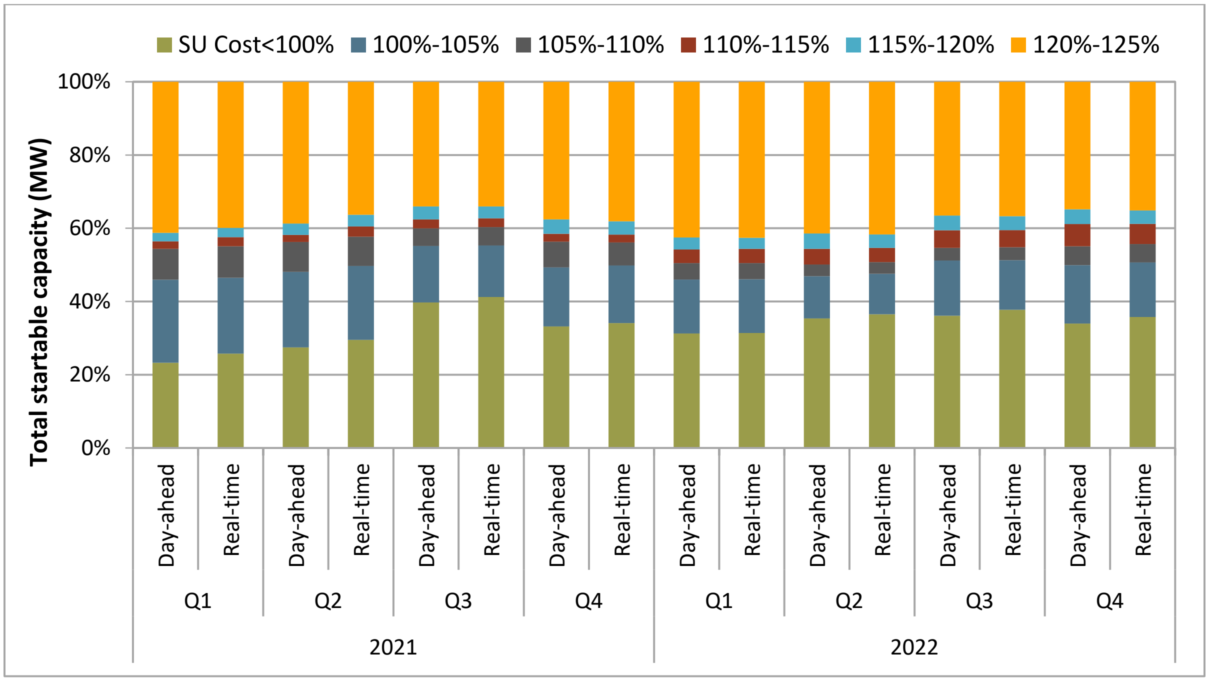
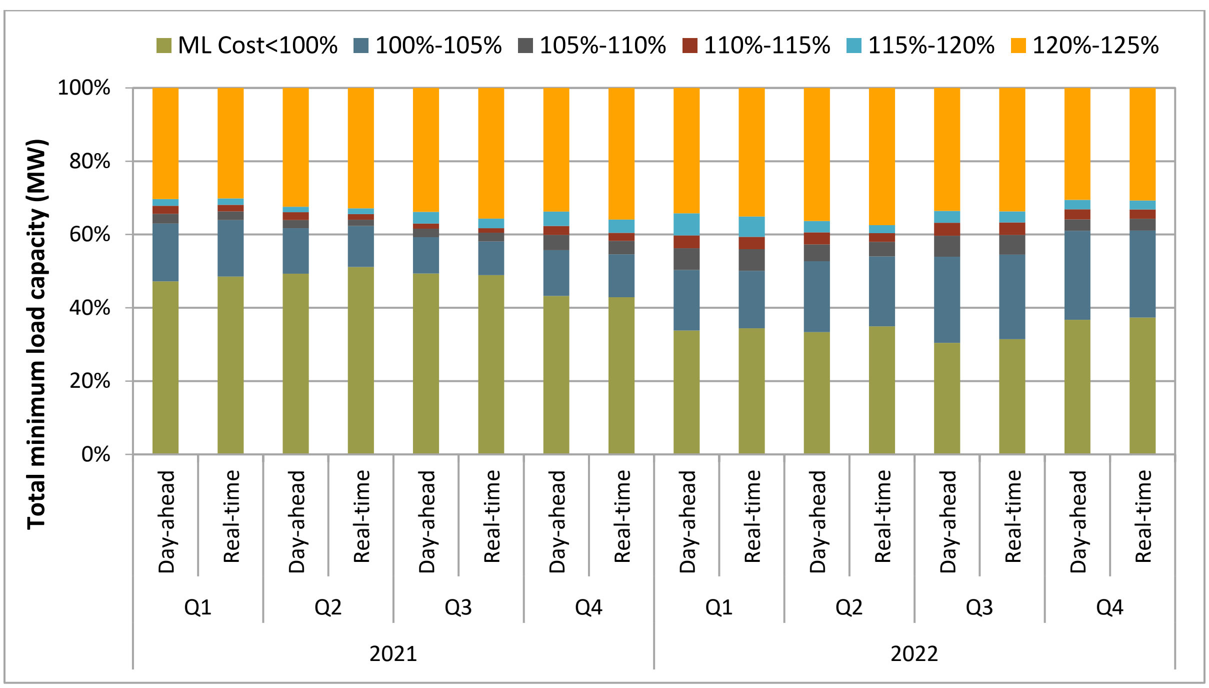


Figure 5.13 Day-ahead and real-time gas-fired capacity under the proxy cost option for minimum load cost bids (percentage)



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.[216,217] This process can be automated or manual, depending on the resource's bid and reasonableness threshold. The reasonableness threshold is a new measure, which includes an additional multiplier meant to reflect variability in fuel or fuel-equivalent costs.[218] 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.

In 2022, the frequency of automated requests from gas resources increased significantly in December, when western gas prices spiked. These requests were also used by resources which faced higher gas prices due to pipeline outages. There were only a few manual requests for higher gas prices not covered by automated requests that were approved for September 8 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.

5.4 Market-based rate authority in the Western Energy Imbalance Market

Western Energy Imbalance Market participants that are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) must seek authority from FERC to sell at market-based rates in the WEIM. Once granted, each entity's authority to continue selling at market-based rates in the WEIM and other markets is reviewed by FERC on a triennial basis. Currently, all FERC jurisdictional WEIM participants have authority to sell in the Western Energy Imbalance Market at market-based rates. This includes participants that were granted market-based rate authority at the beginning of their participation in the WEIM, as well as participants that have since undergone triennial review by FERC and retained this authority.

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

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

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

6 Congestion

This chapter provides a review of congestion and the congestion revenue rights auction in 2022. Findings from this chapter include the following:

- **Day-ahead market congestion increased.** Both the frequency and the price impact of day-ahead congestion were higher in 2022 than in 2021. The primary constraints impacting price separation in the day-ahead market were the Midway-Vincent #2 500 kV line, the Quinto-Los Banos 230 kV line, and the Panoche-Gates #2 230 kV line. In 2022, day-ahead congestion revenues totaled about 5.3 percent of total day-ahead market energy costs, about the same as in 2021.
- **Real-time market congestion increased**. Both the 15-minute and 5-minute markets had patterns of congestion that followed seasonal trends in both solar production and load. The three primary constraints creating price separation in the real-time market were a Malin-Round Mountain nomogram, the Quinto-Los Banos 230 kV line, and the Four Corners-Cholla 345 kV line.
- **The frequency and impact of transfer constraint congestion increased**. Similar to prior years, the frequency of congestion was highest for load areas located in the Pacific Northwest, where it primarily decreased prices.
- **Intertie congestion increased**. Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $343 million, up from $164 million in 2021. This increase was largely driven by increased congestion on the two major interties linking the CAISO with the Pacific Northwest: the Malin 500 and the Nevada/Oregon Border (NOB).

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 $118 million, up from $43 million in 2021 and $71 million in 2020**. 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.
- **Transmission ratepayers received about 55 cents in auction revenue per dollar paid out to these rights purchased in the auction, down from 71 cents in 2021.** Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $143 million. Losses from auctioned congestion revenue rights totaled about 11 percent of total day-ahead congestion rent in 2022, compared to about 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 congestion on locational price differences in the day-ahead and real-time markets.[219] This section also assesses the impact of congestion to the major load serving areas in the California ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the Western Energy Imbalance Market.

Highlights of 2022 include:

- In the day-ahead market, the impact and frequency of congestion increased in 2022 relative to 2021. This congestion increased average day-ahead prices in the Pacific Gas and Electric area and decreased average prices in the Southern California Edison and San Diego Gas & Electric areas.
- In the 15-minute market, congestion followed seasonal trends in solar production and load. The top three constraints that had the greatest impact on price separation in the 15-minute market were a Malin-Round Mountain nomogram, the Quinto-Los Banos 230 kV line, and the Four Corners-Cholla 345 kV line.
- In the WEIM, congestion decreased prices in the majority of areas. Internal congestion from constraints within the CAISO and the WEIM had significant impacts on prices everywhere. Transfer congestion significantly impacted prices in the Pacific Northwest and parts of the Desert Southwest.

6.1.1 Day-ahead congestion

Congestion rent and loss surplus

Total congestion rents and loss surpluses grew sharply through 2022. At $1.07 billion, total day-ahead congestion rents were about 5.3 percent of the day-ahead market energy costs, about the same portion as in 2021. Congestion rents were highest in the fourth quarter while the loss surplus peaked in the third quarter.

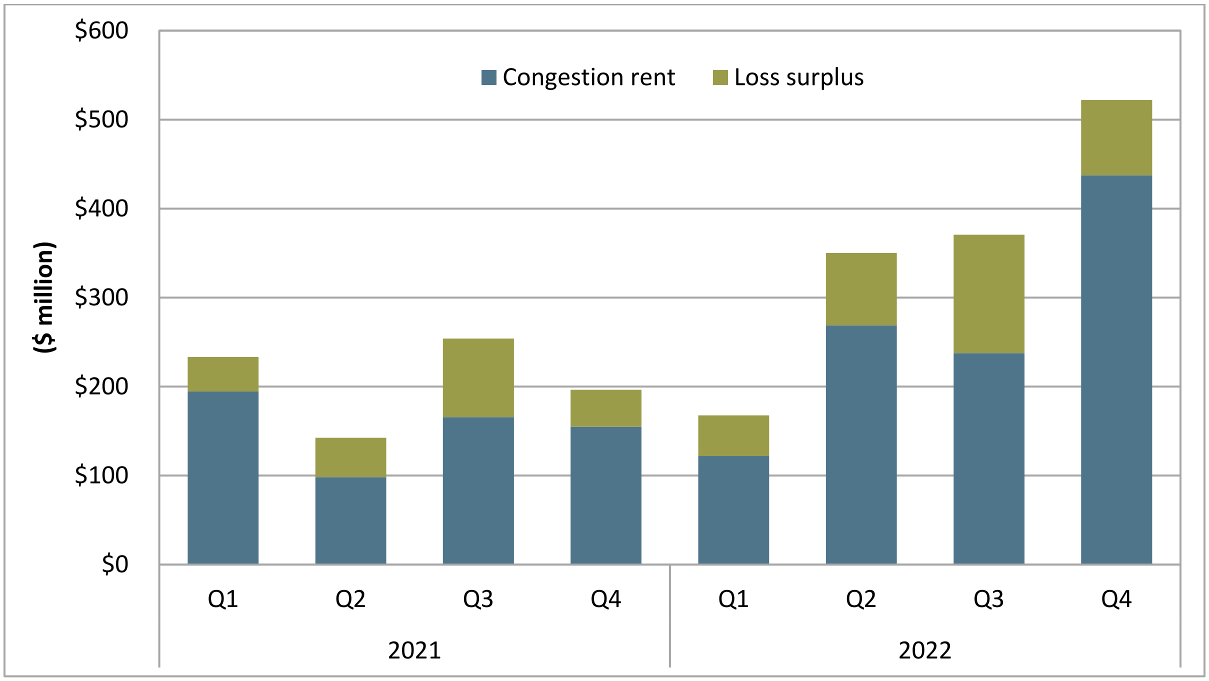
In the day-ahead market, *hourly congestion rent* collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The *daily congestion rent* is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. *The daily 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.[220]

---

[219] For a detailed background of congestion, from how it is calculated to how it interacts with other market elements, see: Department of Market Monitoring, *2019 Annual Report on Market Issues & Performance*, June 2020, Section 8.1: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

[220] For more information on marginal loss surplus allocation, refer to the California ISO Business Practice Manual Change Management, *Settlements and Billing, CG CC 6947 IFM Marginal Losses Surplus Credit Allocation*: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

Figure 6.1 Congestion rent and loss surplus by quarter (2021–2022)



Congestion impact in the day-ahead market from internal, flow-based constraints

The impact and frequency of day-ahead congestion increased in 2022, relative to 2021. This congestion increased average day-ahead prices in the Pacific Gas and Electric area, and decreased average prices in the Southern California Edison and San Diego Gas & Electric areas.

- For Pacific Gas and Electric, congestion increased prices in the area by about $1.79/MWh (1.9 percent), compared to $0.60/MWh (1.1 percent) in 2021.
- For Southern California Edison, congestion drove prices down by about $1.06/MWh (1.2 percent), compared to $0.47/MWh (0.9 percent) in 2021.
- For San Diego Gas & Electric, congestion decreased average prices by about $0.60/MWh (0.7 percent), compared to an increase of about $1.05/MWh (2.0 percent) in 2021.

Figure 6.2 Overall impact of congestion on price separation in the day-ahead market

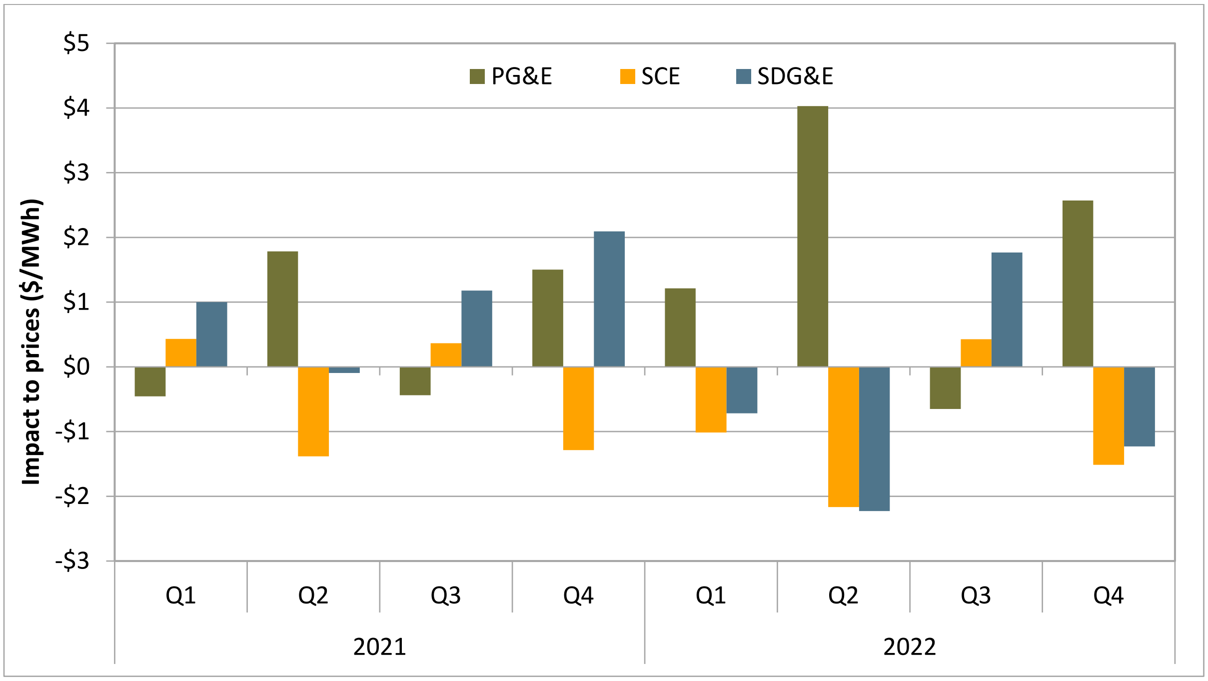


Figure 6.3 Percent of hours with congestion impacting prices by load area

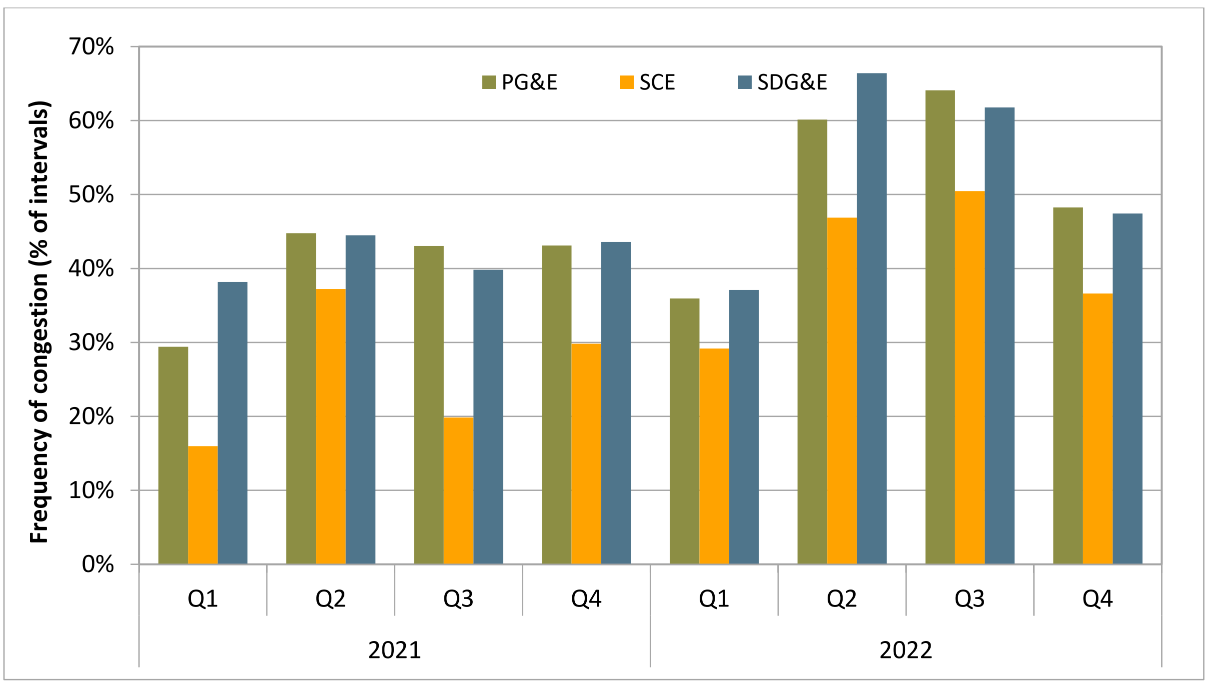


Table 6.1 shows the quarterly frequency and annualized impact of congestion from individual constraints on prices in each load aggregation area.[221] The three constraints that had the greatest impact on price separation over the year were the Midway-Vincent #2 500 kV line, the Quinto-Los Banos 230 kV line, and the Panoche-Gates #2 230 kV line.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) was primarily congested during the third quarter and limited north-to-south flows within the California ISO. This resulted in higher prices in SCE and SDG&E, and lower prices in PG&E. This line was congested due to the parallel Midway-Vincent 500 kV.

Quinto-Los Banos 230 kV line

The Quinto-Los Banos 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1_1) was frequently congested during the second quarter and limited south-to-north flows within the California ISO. This resulted in higher prices in the PG&E area and lower prices in SCE and SDG&E. This line bound primarily due to the Tesla-Los Banos 500 kV line and limited the ability for renewable resources in the south to meet demand in the north.

Panoche-Gates #2 230 kV line

The Panoche-Gates #2 230 kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) was congested throughout the year and in more than 10 percent of intervals during the first and fourth quarters. Congestion on the constraint raised prices in PG&E and lowered them in SCE and SDG&E. The line was mitigated for the contingency of the Los Banos-Gates #1 500 kV line.

---

221 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

Table 6.1 Impact of constraint congestion on overall day-ahead prices during all hours (2022)

Constraint Location	Constraint	Frequency				PG&E		SCE		SDG&E	
		Q1	Q2	Q3	Q4	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PG&E	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	4.9%	25.5%	15.6%	8.8%	$0.49	0.53%	-$0.14	-0.16%	-$0.12	-0.13%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.3%	23.9%	4.5%	8.6%	$0.45	0.48%	-$0.35	-0.40%	-$0.31	-0.35%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	10.8%	6.5%	1.0%	14.2%	$0.45	0.48%	-$0.25	-0.29%	-$0.21	-0.24%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	0.5%	9.2%	18.3%	8.1%	$0.26	0.28%	-$0.21	-0.24%	-$0.20	-0.23%
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	0.0%	7.6%	0.0%	0.0%	$0.10	0.11%	-$0.07	-0.08%	-$0.08	-0.09%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.1%	0.0%	0.0%	4.0%	$0.10	0.10%	-$0.08	-0.09%	-$0.07	-0.08%
	7440_MetcalfImport_Tes-Metcalf	1.4%	2.0%	3.5%	0.6%	$0.08	0.09%	-$0.07	-0.08%	-$0.07	-0.07%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.7%	0.0%	0.1%	5.7%	$0.08	0.09%	-$0.06	-0.07%	-$0.06	-0.06%
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	0.0%	2.5%	0.0%	0.0%	$0.06	0.07%	-$0.04	-0.05%	-$0.04	-0.05%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.3%	1.3%	0.1%	3.1%	$0.06	0.06%	-$0.05	-0.05%	-$0.04	-0.05%
	30735_METCALF _230_30042_METCALF _500_XF_12	0.0%	1.4%	0.0%	0.0%	$0.04	0.04%	-$0.03	-0.03%	-$0.03	-0.03%
	30733_VASONA _230_30735_METCALF _230_BR_1 _1	0.0%	0.5%	0.1%	0.0%	$0.04	0.04%				
	7440_MetcalfImport_Mossld-Metclf	8.2%	0.0%	0.0%	0.0%	$0.04	0.04%	-$0.03	-0.03%	-$0.03	-0.03%
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	3.8%	0.0%	0.0%	0.0%	$0.03	0.04%	-$0.03	-0.03%	-$0.03	-0.03%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.1%	2.4%	0.0%	0.0%	$0.02	0.03%	-$0.02	-0.02%	-$0.02	-0.02%
	30735_METCALF _230_30042_METCALF _500_XF_13	0.0%	1.4%	0.0%	0.0%	$0.02	0.02%	-$0.02	-0.02%	-$0.02	-0.02%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	0.3%	0.0%	0.8%	0.0%	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	0.8%	0.0%	0.0%	0.1%	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.0%	0.9%	13.1%	0.1%	-$0.49	-0.53%	$0.32	0.37%	$0.30	0.34%
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.5%	4.2%	0.0%	0.2%	-$0.04	-0.05%	$0.05	0.06%	$0.01	0.01%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.1%	1.1%	0.0%	0.0%	-$0.01	-0.01%	$0.01	0.01%	$0.00	0.00%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	0.0%	0.0%	0.0%	4.3%					-$0.02	-0.03%
SDG&E	7820_TL 230S_OVERLOAD_NG	8.6%	10.9%	0.2%	1.2%	-$0.02	-0.03%	$0.00	0.00%	$0.26	0.29%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	1.1%	2.7%	12.6%	4.3%					$0.26	0.29%
	MIGUEL_BKs_MXFLW_NG	0.3%	0.8%	0.0%	1.3%	-$0.01	-0.01%			$0.12	0.13%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.9%	1.3%	0.0%	0.5%	-$0.02	-0.02%			$0.10	0.12%
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	1.0%	1.2%	6.6%	4.3%					$0.10	0.11%
	OMS_11281965_SUNCREST BK81_NG	3.5%	0.0%	0.0%	0.0%	-$0.01	-0.01%			$0.08	0.10%
	OMS 11368744_50001_OOS_NG	0.0%	1.6%	0.0%	0.0%	-$0.01	-0.01%			$0.06	0.07%
	OMS 11396189_50002_OOS_TDM	0.0%	0.9%	0.0%	0.0%					$0.04	0.05%
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1	0.8%	0.0%	0.1%	0.0%	-$0.01	-0.01%			$0.04	0.05%
	22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1	0.0%	0.0%	0.4%	0.0%					$0.03	0.04%
	22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_2	0.0%	0.0%	0.4%	0.0%					$0.03	0.04%
	22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1	0.1%	0.5%	1.0%	1.0%					$0.03	0.03%
	OMS_12018815 ML_BK80_NG	0.0%	0.0%	0.0%	0.5%	$0.00	-0.01%			$0.02	0.03%
	OMS 11364971_50002_OOS_TDM	0.0%	0.7%	0.0%	0.0%					$0.02	0.03%
	7820_TL23040_IV_SPS_NG	0.0%	0.3%	0.3%	1.0%	$0.00	0.00%			$0.02	0.03%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	0.1%	0.5%	1.3%	0.0%					-$0.06	-0.07%
	7820_13810A_RAS_MS-SA_NG	0.0%	0.0%	0.0%	2.9%			$0.00	0.00%	-$0.08	-0.09%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	13.0%	23.1%	0.3%	0.0%					-$0.71	-0.80%
Other						$0.07	0.08%	$0.01	0.01%	$0.07	0.08%
Total						**$1.79**	**1.93%**	**-$1.06**	**-1.22%**	**-$0.60**	**-0.67%**

6.1.2 Real-time congestion

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. These congestion scenarios impact prices across the CAISO and WEIM. Congestion in the 15-minute real-time market was similar to the 5-minute market, but had a lower impact on locational price differences. Below is an analysis of the frequency and effects of internal congestion in the 15-minute market.

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

Figure 6.4 shows price separation resulting from internal congestion on load areas in the CAISO and WEIM by quarter. Internal congestion resulted in a net increase to prices in the CAISO area and a net decrease for most areas in the WEIM.

On a quarterly basis, net price separation due to internal congestion grew significantly in the second quarter and remained high for the rest of 2022. Internal congestion throughout the year was driven by a variety of factors including renewable production, unscheduled flows, high demand, and equipment maintenance.

Figure 6.4 Overall impact of internal congestion on price separation in the 15-minute market

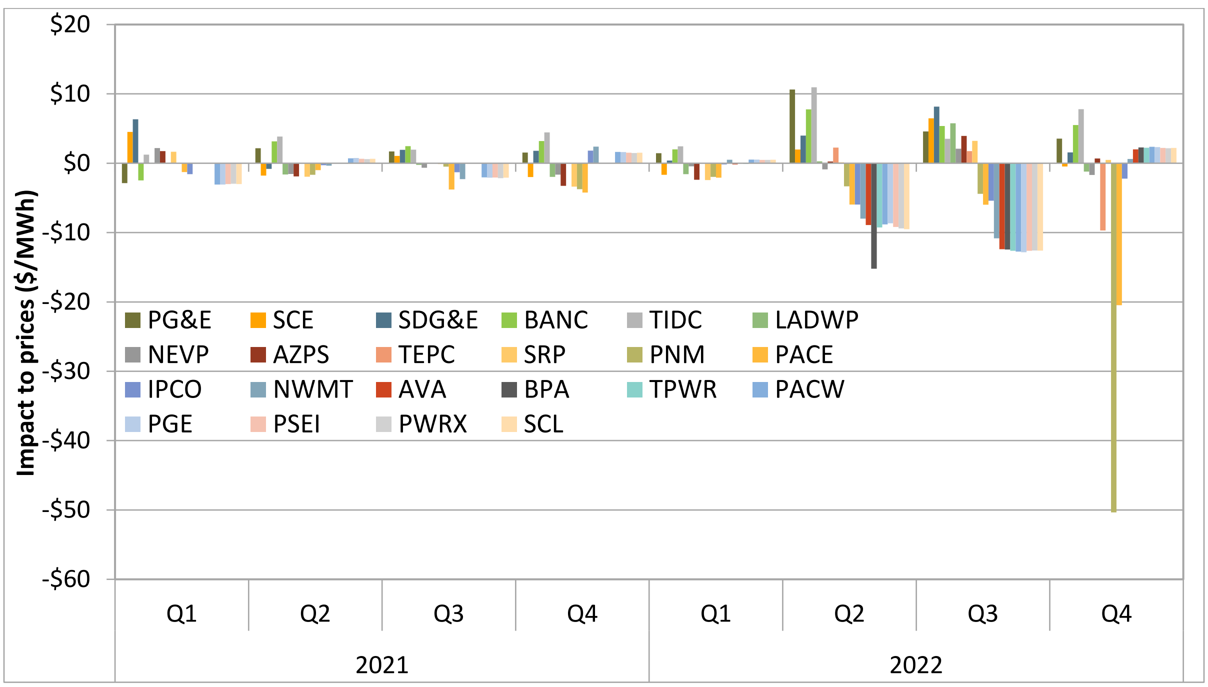


Table 6.2 shows the annualized impact of 15-minute market congestion from individual constraints on prices in each load area. The impact from transfer constraints are included at the bottom of the table and are discussed in greater depth in Section 6.1.3. This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The three constraints that had the greatest impact on price separation in the 15-minute market were a Malin-Round Mountain nomogram, the Quinto-Los Banos 230 kV line, and the Four Corners-Cholla 345 kV line.

Malin-Round Mountain nomogram

A Malin-Round Mountain nomogram (ML_RM12_NS) had the greatest impact on average 15-minute prices in 2022. This nomogram heavily impacted prices within California and the Pacific Northwest. This nomogram was frequently used to mitigate unscheduled flows over Path 66 (COI) in the 15-minute market.

Quinto-Los Banos 230 kV line

The Quinto-Los Banos 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) impacted most WEIM areas. It had a significant impact on prices in Turlock Irrigation District, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light. The line was congested due to the contingencies of the Tracy-Los Banos 500 kV and the Tesla-Los Banos 500 kV lines.

Four Corners-Cholla 345 kV line

The Four Corners-Cholla 345 kV line (Line_FC-CH2_345KV) impacted prices across most of the WEIM, and had the strongest impact during the fourth quarter. This constraint is located outside the California ISO, and were likely impacted by maintenance in the area. Congestion in the Four Corners area was a significant contributing factor to the sharp increase in downward dispatch of wind and solar in the WEIM during the fourth quarter.[222]

[222] Downward dispatch in the WEIM is discussed in Section 1.2.2 and shown in Figure 1.13.

Table 6.2 Impact of internal constraint congestion on overall 15-minute prices during all hours

Constraint Location	Constraint	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	TEPC*	SRP	PNM	PACE	IPCO	NWMT	AVA*	BPA*	TPWR*	PACW	PGE	PSEI	PWRX	SCL
AZPS	Line_FC-CH2_345KV	$0.00	$0.59	$0.87	$0.00	$0.00	$0.45	$0.09	$1.35	-$0.02	$1.34	-$6.52	-$1.56	-$0.51	-$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Line_FC-CH1_345KV	$0.00	$0.38	$0.48	$0.00	$0.00	$0.32	$0.06	$0.72	-$0.08	$0.70	-$3.49	-$0.80	-$0.23	-$0.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	CC XFMR8 A 69KV	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Line_FC-MK_500KV	$0.11	$0.41	$0.26	$0.02	$0.09	$0.45	$0.47	$0.00	-$0.98	$0.00	-$3.51	-$0.66	-$0.24	-$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
BANC	XFMR1 500.TRY	$0.01	$0.00	$0.00	$0.01	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
BPA	INTRP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.05	-$0.08	$0.03	-$0.07	$0.03	$0.11	-$0.05	-$0.12	-$0.13
IPCO	IMNH-OBPR1_B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.14	$0.41	-$0.16	-$0.34	-$0.14	-$0.20	-$0.10	-$0.13	-$0.16	-$0.18	-$0.17
	HEMWY	-$0.09	$0.00	$0.00	-$0.10	-$0.09	$0.05	$0.06	$0.03	$0.04	$0.03	$0.06	$0.23	$0.36	$0.00	-$0.08	-$0.10	-$0.12	-$0.12	-$0.12	-$0.10	-$0.09	-$0.10
	T342.MPSN	$0.00	-$0.01	-$0.02	$0.01	$0.01	-$0.04	-$0.03	-$0.03	-$0.03	-$0.03	-$0.04	-$0.11	$0.13	$0.00	$0.04	$0.04	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04
	BLPR-HCPR1_A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.12	$0.00	-$0.06	-$0.04	-$0.06	-$0.04	-$0.03	-$0.05	-$0.05	-$0.05
	PATH_14	-$0.01	$0.00	$0.00	-$0.01	-$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.08	$0.00	-$0.03	-$0.02	-$0.03	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	WECC_PATH_14	$0.00	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.02	$0.03	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	T341.MPSN	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NWMT	RIMROCK_PAR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.06	$0.00	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	PATH_C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	-$0.01	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	EAST_WYO_EXP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	WINDSTAR EXPORT TCOR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.56	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	TOTAL_WYOMING_EXPORT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$3.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PACW	WPTH75	$0.02	$0.00	$0.00	$0.02	$0.02	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.06	-$0.09	$0.00	$0.02	$0.02	$0.03	$0.03	$0.03	$0.02	$0.02	$0.02
PG&E	ML_RM12_NS	$2.29	$1.33	$1.19	$2.23	$2.20	$0.97	$0.44	$0.92	$0.83	$0.91	$0.57	-$1.20	-$2.26	-$2.71	-$3.66	-$3.09	-$3.78	-$3.18	-$3.21	-$3.16	-$3.13	-$3.15
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.75	$0.06	$0.05	-$0.88	-$0.64	$0.02	-$0.02	$0.02	$0.02	$0.02	$0.00	-$0.06	-$0.25	-$0.30	-$0.40	-$0.35	-$0.42	-$0.36	-$0.36	-$0.35	-$0.35	-$0.35
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.45	-$0.16	-$0.15	$0.13	$0.25	-$0.15	-$0.12	-$0.14	-$0.14	-$0.14	-$0.13	$0.00	-$0.05	-$0.06	-$0.08	-$0.07	-$0.08	-$0.07	-$0.07	-$0.07	-$0.07	-$0.07
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.29	$0.19	$0.17	$0.19	$0.28	$0.11	$0.10	$0.13	$0.12	$0.13	$0.09	-$0.12	-$0.26	-$0.29	-$0.42	-$0.34	-$0.43	-$0.37	-$0.37	-$0.36	-$0.36	-$0.36
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.28	-$0.82	-$0.77	$1.18	$2.50	-$0.70	-$0.41	-$0.67	-$0.42	-$0.67	-$0.57	-$0.01	$0.21	$0.41	$0.62	$0.36	$0.65	$0.57	$0.57	$0.55	$0.54	$0.55
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.19	-$0.55	-$0.52	$0.48	$0.60	-$0.47	-$0.05	-$0.44	-$0.21	-$0.44	-$0.27	$0.00	$0.00	$0.01	$0.02	$0.02	$0.03	$0.13	$0.13	$0.12	$0.12	$0.12
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.18	$0.03	$0.02	$0.44	$0.17	$0.02	$0.00	$0.01	$0.01	$0.01	$0.00	-$0.01	-$0.15	-$0.20	-$0.33	-$0.29	-$0.36	-$0.30	-$0.31	-$0.30	-$0.29	-$0.30
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.17	-$0.11	-$0.06	$0.00	$0.02	-$0.04	$0.00	-$0.02	-$0.01	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.16	-$0.26	-$0.25	$0.19	$0.20	-$0.26	-$0.14	-$0.22	-$0.22	-$0.22	-$0.19	-$0.03	$0.06	$0.11	$0.15	$0.14	$0.16	$0.14	$0.14	$0.14	$0.13	$0.13
	RM_TM12_NG	$0.14	$0.08	$0.07	$0.08	$0.12	$0.07	$0.00	$0.04	$0.04	$0.04	$0.00	-$0.08	-$0.15	-$0.18	-$0.24	-$0.20	-$0.24	-$0.21	-$0.21	-$0.20	-$0.20	-$0.20
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.13	-$0.30	-$0.29	$0.22	$0.22	-$0.29	-$0.15	-$0.25	-$0.23	-$0.25	-$0.21	-$0.04	$0.06	$0.13	$0.19	$0.16	$0.21	$0.18	$0.18	$0.17	$0.17	$0.17
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.12	$0.08	$0.08	$0.09	$0.12	$0.05	$0.05	$0.06	$0.05	$0.06	$0.04	-$0.06	-$0.12	-$0.14	-$0.19	-$0.16	-$0.19	-$0.16	-$0.16	-$0.16	-$0.16	-$0.16
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.11	-$0.13	-$0.13	$0.12	$0.13	-$0.12	-$0.05	-$0.11	-$0.07	-$0.11	-$0.08	-$0.01	$0.01	$0.05	$0.07	$0.05	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.09	-$0.03	-$0.03	$0.00	$0.04	-$0.02	-$0.02	-$0.03	-$0.03	-$0.03	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	$0.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6110_SOL10_NG	$0.08	$0.07	$0.06	$0.35	$0.09	$0.04	$0.02	$0.05	$0.05	$0.05	$0.03	-$0.04	-$0.09	-$0.11	-$0.15	-$0.16	-$0.19	-$0.13	-$0.17	-$0.15	-$0.15	-$0.15
	7440_MetcalfImport_Tes-Metcalf	$0.07	-$0.05	-$0.05	$0.04	$0.06	-$0.05	-$0.03	-$0.05	-$0.02	-$0.05	-$0.04	$0.00	$0.00	$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
	TMS_DLO_NG	$0.06	$0.01	$0.01	$0.08	$0.06	$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	-$0.01	-$0.02	-$0.05	-$0.08	-$0.06	-$0.08	-$0.07	-$0.07	-$0.07	-$0.06	-$0.07
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	$0.05	-$0.01	-$0.01	$0.03	$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	$0.05	$0.00	$0.00	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1	$0.05	$0.00	$0.00	$0.08	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.05	-$0.06	-$0.05	-$0.07	-$0.06	-$0.06	-$0.05	-$0.05	-$0.05
	30640_TESLA C _230_30040_TESLA _500_XF_6H	$0.04	$0.00	$0.00	$0.02	$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.02	-$0.01	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	$0.03	-$0.01	-$0.01	$0.00	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30624_TESLA E _230_30670_WSTLYSMD_230_BR_1 _1	$0.03	-$0.01	-$0.01	$0.02	-$0.08	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6310_CP7_NG	$0.03	-$0.07	-$0.07	$0.06	$0.08	-$0.07	-$0.03	-$0.04	-$0.04	-$0.04	-$0.03	-$0.01	$0.00	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.03	-$0.07	-$0.06	$0.05	$0.05	-$0.06	-$0.03	-$0.05	$0.00	-$0.05	-$0.05	$0.00	$0.02	$0.03	$0.05	$0.00	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04
	30005_ROUND MT_500_30245_ROUND MT_230_XF_1 _P	$0.03	$0.02	$0.02	$0.03	$0.03	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.01	-$0.03	-$0.03	-$0.04	-$0.04	-$0.05	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	SUMMIT_BG	$0.03	$0.00	$0.00	$0.06	$0.00	$0.00	-$0.16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.03	-$0.04	-$0.03	$0.03	$0.03	-$0.03	-$0.02	-$0.03	$0.01	-$0.03	-$0.03	$0.00	$0.01	$0.01	$0.02	-$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
	RM_TM21_NG	$0.02	$0.02	$0.01	$0.01	$0.02	$0.01	$0.00	$0.01	$0.00	$0.01	$0.01	-$0.01	-$0.02	-$0.02	-$0.03	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1	$0.02	$0.00	$0.00	$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.03	-$0.04	-$0.06	-$0.05	-$0.06	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05
	7440_MetcalfImport_Mossld-Metclf	$0.02	-$0.01	-$0.01	$0.00	$0.01	-$0.01	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30015_TABLE MT_500_30040_TESLA _500_BR_1 _3	$0.01	$0.01	$0.01	$0.01	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.01	-$0.02	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.01	-$0.02	-$0.02	$0.02	$0.02	-$0.02	-$0.01	-$0.02	$0.00	-$0.02	-$0.02	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	-$0.01	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	$0.00	-$0.03	-$0.03	$0.04	$0.08	-$0.02	$0.00	-$0.02	-$0.01	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	PACI_SN	-$0.04	-$0.03	-$0.02	-$0.04	-$0.04	-$0.02	-$0.01	-$0.02	$0.00	-$0.02	-$0.01	$0.01	$0.03	$0.03	$0.04	$0.00	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.31	$0.26	$0.24	-$0.30	-$0.31	$0.25	$0.15	$0.21	$0.21	$0.21	$0.18	$0.00	-$0.12	-$0.17	-$0.24	-$0.20	-$0.26	-$0.23	-$0.23	-$0.22	-$0.21	-$0.22
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.59	$0.49	$0.47	-$0.55	-$0.58	$0.46	$0.28	$0.41	$0.41	$0.40	$0.34	$0.00	-$0.23	-$0.32	-$0.46	-$0.40	-$0.48	-$0.42	-$0.41	-$0.40	-$0.40	-$0.40
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1	$0.00	$0.00	$0.00	$0.05	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	-$0.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$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	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7430_CP6_NG	$0.00	$0.00	$0.00	$0.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SCE	6410_CP1_NG	-$0.19	$0.15	$0.15	-$0.17	-$0.18	$0.15	$0.09	$0.13	$0.13	$0.13	$0.11	$0.00	-$0.07	-$0.10	-$0.14	-$0.12	-$0.15	-$0.13	-$0.13	-$0.12	-$0.12	-$0.12
	OP-6610_ELD-LUGO	$0.03	$0.03	$0.01	$0.02	$0.02	-$0.06	-$0.05	-$0.04	-$0.04	-$0.04	-$0.04	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _4	$0.02	$0.02	-$0.01	$0.01	$0.01	$0.03	$0.03	-$0.08	-$0.09	-$0.08	-$0.13	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.04	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	OMS 10666077_OP-6610	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24219_PISGAH _230_24085_LUGO _230_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24384_EAST TS _500_24092_MIRALOMA_500_BR_1 _1	$0.02	-$0.01	-$0.03	$0.01	$0.01	-$0.01	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	6410_CP7_NG	$0.12	-$0.18	-$0.17	$0.12	$0.12	-$0.18	-$0.09	-$0.15	-$0.15	-$0.15	-$0.13	-$0.02	$0.03	$0.06	$0.09	$0.08	$0.09	$0.08	$0.08	$0.08	$0.08	$0.08
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.11	$1.26	$0.00	$0.00	$0.00	-$0.09	-$0.26	-$0.11	-$0.28	-$0.22	-$0.09	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	$0.00	$0.06	$0.56	$0.00	$0.00	$0.00	-$0.06	-$0.18	-$0.16	-$0.18	-$0.14	-$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS_11281965_SUNCREST BK81_NG	$0.00	$0.01	$0.18	$0.00	$0.00	$0.00	-$0.01	-$0.06	$0.00	-$0.06	-$0.05	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 11364971_50002_OOS_TDM	$0.00	$0.00	$0.15	$0.00	$0.00	$0.00	$0.00	-$0.03	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	MIGUEL_BKs_MXFLW_NG	$0.00	$0.00	$0.15	$0.00	$0.00	$0.00	$0.00	-$0.04	-$0.04	-$0.05	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS_12018815 ML_BK80_NG	$0.00	$0.00	$0.13	$0.00	$0.00	$0.00	-$0.02	-$0.04	-$0.04	-$0.05	-$0.04	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_TL 230S_TL50001OUT_NG	$0.00	$0.01	$0.09	$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 11368744_50001_OOS_NG	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 12618319_IV_NBUS_NG	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 12455416_TL23055_NG	$0.00	$0.01	$0.04	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS_12685980_TL23055_NG	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 11065185_50004_OOS_NG	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	$0.00	$0.00	$0.04	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 12212473 TL50005_NG	$0.00	$0.00	$0.03	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.00	$0.00	-$0.03	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_13810A_RAS_MS-SA_NG	$0.00	$0.00	-$0.10	$0.00	$0.00	$0.00	$0.00	-$0.05	-$0.05	-$0.05	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.01	$0.01	-$0.11	$0.01	$0.01	$0.01	$0.00	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	$0.00	-$0.57	$0.00	$0.00	$0.00	$0.00	-$0.12	-$0.02	-$0.13	-$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TIDC	TID_NET_INT_BG	$0.00	$0.00	$0.00	$0.00	$0.25	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Other	-$0.19	$0.06	$0.00	$0.19	-$0.06	$0.06	$0.03	-$0.09	-$0.95	-$0.17	-$0.29	-$0.08	-$0.02	$0.04	$0.06	-$2.45	$0.01	-$0.01	$0.01	$0.02	$0.01	$0.02
	Internal Total	**$5.06**	**$1.59**	**$3.54**	**$5.16**	**$6.16**	**$0.83**	**-$0.23**	**$0.64**	**-$2.50**	**$0.37**	**-$15.19**	**-$8.68**	**-$3.44**	**-$4.43**	**-$5.79**	**-$7.48**	**-$5.89**	**-$4.66**	**-$4.66**	**-$4.77**	**-$4.83**	**-$4.84**
	Transfers				-$0.50	$0.71	-$0.06	$0.06	-$0.34	-$0.47	-$10.69	-$0.19	-$0.97	-$0.37	-$3.08	-$3.73	$0.45	-$2.28	-$2.69	-$1.44	-$2.24	-$7.59	-$2.40
	Grand Total	**$5.06**	**$1.59**	**$3.54**	**$4.66**	**$6.87**	**$0.77**	**-$0.17**	**$0.30**	**-$2.97**	**-$10.32**	**-$15.38**	**-$9.65**	**-$3.81**	**-$7.51**	**-$9.52**	**-$7.03**	**-$8.17**	**-$7.35**	**-$6.10**	**-$7.01**	**-$12.42**	**-$7.24**

*Since joining the WEIM only

6.1.3 Congestion on Western Energy Imbalance Market transfer constraints

Table 6.3 shows the frequency of transfer constraint congestion and average price impact in the 15-minute and 5-minute markets for 2022. The highest frequency occurred either into or away from the WEIM load areas located in the Pacific Northwest. Similar to previous years, transfer congestion reduced prices in those areas in first, second, and third quarters, but raised prices in the fourth quarter. Notably, the impact of transfer congestion changed from negative to positive and vice-versa between markets in a number of areas.

The results of this section are the same as those found in Section 3.3 of this report. Both sections analyze transfer constraint congestion in the WEIM; however, each focus on different aspects. Section 3.3 focuses on the impact of transfer constraint congestion on transfer capability. Thus, Section 3.3 discusses congestion frequency split by the direction of congestion into (import congestion) or out of (export congestion) the WEIM area. On the other hand, this section discusses the same data as an increase or decrease to prices. When congestion decreases prices in the WEIM area relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area relative to the system, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load (i.e., import capability is limited).

Table 6.3 Average price impact and congestion frequency on WEIM transfer constraints (2022)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0%	-$0.50	0%	-$0.35
L.A. Dept. of Water and Power	1%	-$0.06	0%	$0.11
Arizona Public Service	1%	-$0.34	1%	$0.74
NV Energy	2%	$0.06	2%	$0.88
Public Service Company of NM	2%	-$0.19	2%	$0.43
Turlock Irrigation District	2%	$0.71	2%	$0.66
PacifiCorp East	7%	-$0.97	6%	-$0.29
Tucson Electric Power*	6%	-$0.47	7%	$0.66
Idaho Power	13%	-$0.37	11%	$0.83
Salt River Project	16%	-$10.69	16%	-$7.64
NorthWestern Energy	20%	-$3.08	16%	$0.62
Avista*	20%	-$3.73	16%	-$0.09
PacifiCorp West	30%	-$2.69	19%	-$0.63
Portland General Electric	34%	-$1.44	21%	-$0.29
Bonneville Power Admin.*	42%	$0.45	36%	$0.84
Tacoma Power*	46%	-$2.28	43%	$1.52
Puget Sound Energy	46%	-$2.24	42%	$1.32
Seattle City Light	46%	-$2.40	42%	$0.93
Powerex	50%	-$7.59	69%	-$2.28

*Since joining the WEIM

Transfer congestion in the 15-minute market

Figure 6.5 shows the frequency of congestion on transfer constraints by quarter for 2021 and 2022. Figure 6.6 shows the average impact to prices in the 15-minute market by quarter over the same period. Similar to previous years, the frequency of congestion was highest among the load areas located in the Pacific Northwest. The impact of transfer congestion on price separation varied over the year but trended in the same positive or negative directions each quarter. The impact of transfer congestion in Salt River Project increased sharply in the fourth quarter due to failed resource sufficiency evaluations which limited transfers out of the area.

Figure 6.5 WEIM transfer constraint congestion frequency in the 15-minute market

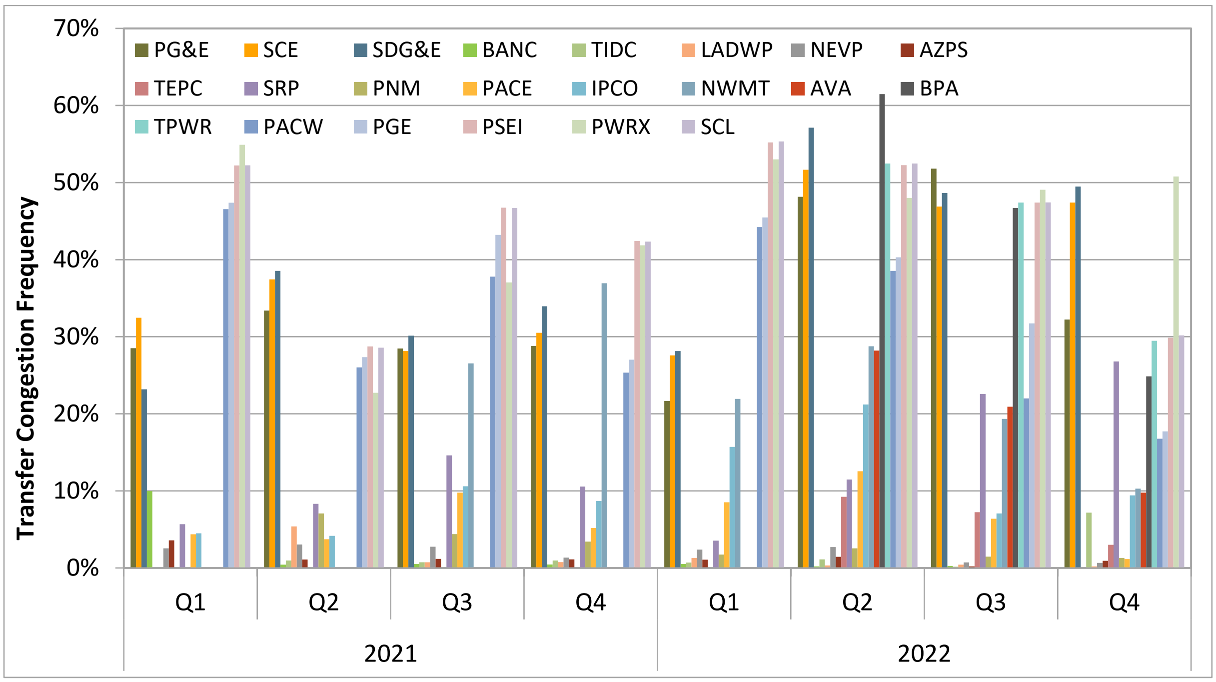
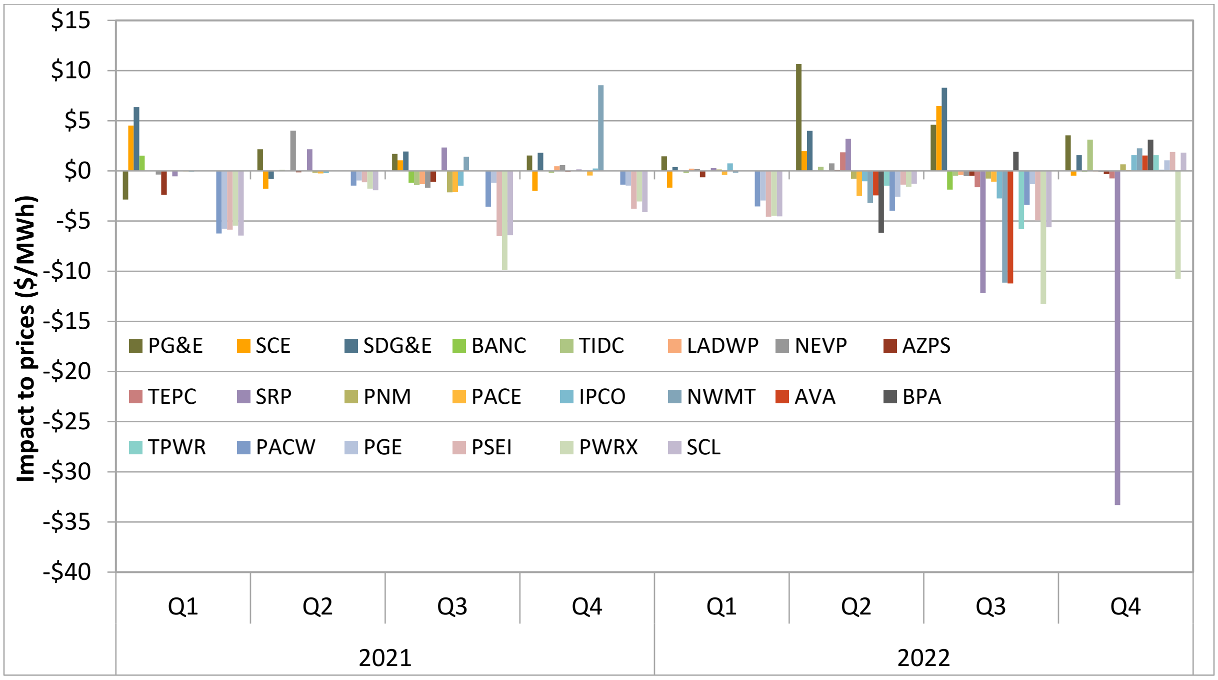


Figure 6.6 WEIM transfer constraint congestion average impact on prices in the 15-minute market



6.2 Congestion on interties

The frequency and financial impact of congestion on most interties connecting the CAISO with other balancing authority areas increased relative to 2021, particularly on interties connecting the CAISO to the Pacific Northwest.

Congestion on interties between the CAISO and other balancing areas impact the price of imports 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 congestion frequency on interties including average day-ahead congestion charges and the total congestion charges from the day-ahead, 15-minute, and 5-minute markets. The congestion price reported in Table 6.4 is the megawatt weighted average shadow price for the binding intertie constraint. 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 the import on the CAISO side of the intertie and the lower price 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 6.7 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years. Figure 6.8 shows the total congestion charges on major interties between 2018 and 2022. Additionally, the figure includes the intertie congestion charges as a percentage of total day-ahead congestion rent during the same time period.

Trends in impact of congestion on interties

Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $343 million, higher than 2021 and 2020. The increase was largely driven by increased congestion on intertie constraints in the real-time markets and on the two major interties linking the CAISO with the Pacific Northwest: Malin and the Nevada/Oregon Border (NOB). On Malin and NOB, total congestion charges rose to $211 million, returning to levels more similar to 2020. In the 15-minute and 5-minute markets, import congestion charges on interties increased by $55 million and $48 million from 2021, respectively.

Table 6.4 Summary of import congestion (2020–2022)

Import region	Intertie	Day-ahead frequency of import congestion			Day-ahead average congestion charge ($/MW)			Total import congestion charges* (thousands)		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Northwest	Malin	35.4%	23.0%	18.2%	$13.24	$13.41	$25.91	$140,802	$77,112	$115,049
	NOB	26.4%	11.0%	20.4%	$22.54	$13.96	$22.35	$95,249	$31,432	$95,954
	COTPISO	8.3%	0.5%	5.1%	$22.85	$12.59	$19.57	$518	$73	$1,148
	Cascade	0.1%		0.7%	$54.17		$15.44	$88	$0	$75
	Summit	0.1%		0.4%	$28.95		$33.41	$7		$70
Southwest	Palo Verde	2.5%	6.6%	4.9%	$12.33	$37.37	$34.74	$10,239	$25,178	$22,668
	IPP Utah	9.0%	5.8%	6.6%	$15.21	$17.25	$52.24	$2,757	$2,412	$9,014
	IPP DC Adelanto	0.1%	0.2%	1.6%	$33.50	$4.91	$34.88	$2,813	$396	$3,230
	Mona		0.1%	0.1%		$186.66	$20.46		$2,320	$544
	Mead	0.8%	0.2%	0.3%	$27.71	$40.81	$18.27	$1,398	$749	$494
	Merchant		0.1%	0.0%		$19.65	$79.24	$9	$150	$101
	Silver Peak			0.6%			$47.86		$0	$34
	Mercury			0.0%			$192.86			$10
	Other							$9,362	$23,943	$95,055
Total								***$263,243***	***$163,765***	***$343,445***

* Total import congestion charges is the combined total from the day ahead, 15-minute, and 5-minute markets.

Figure 6.7 Percent of hours with day-ahead congestion on major interties (2020–2022)

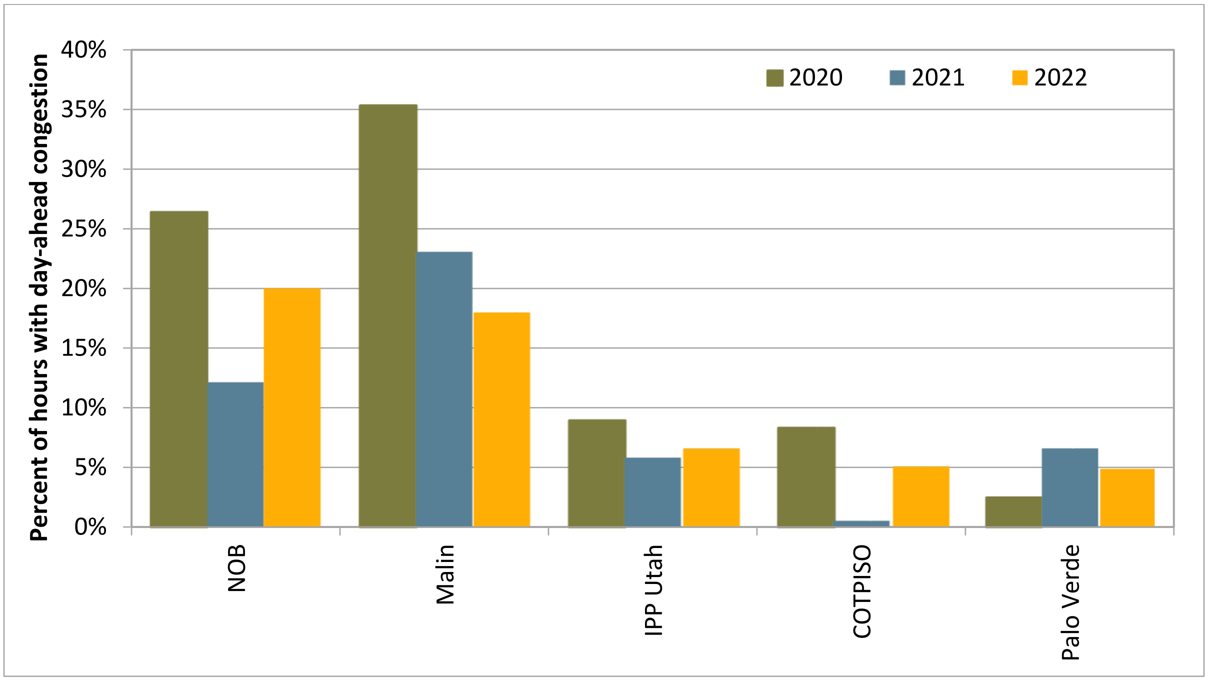
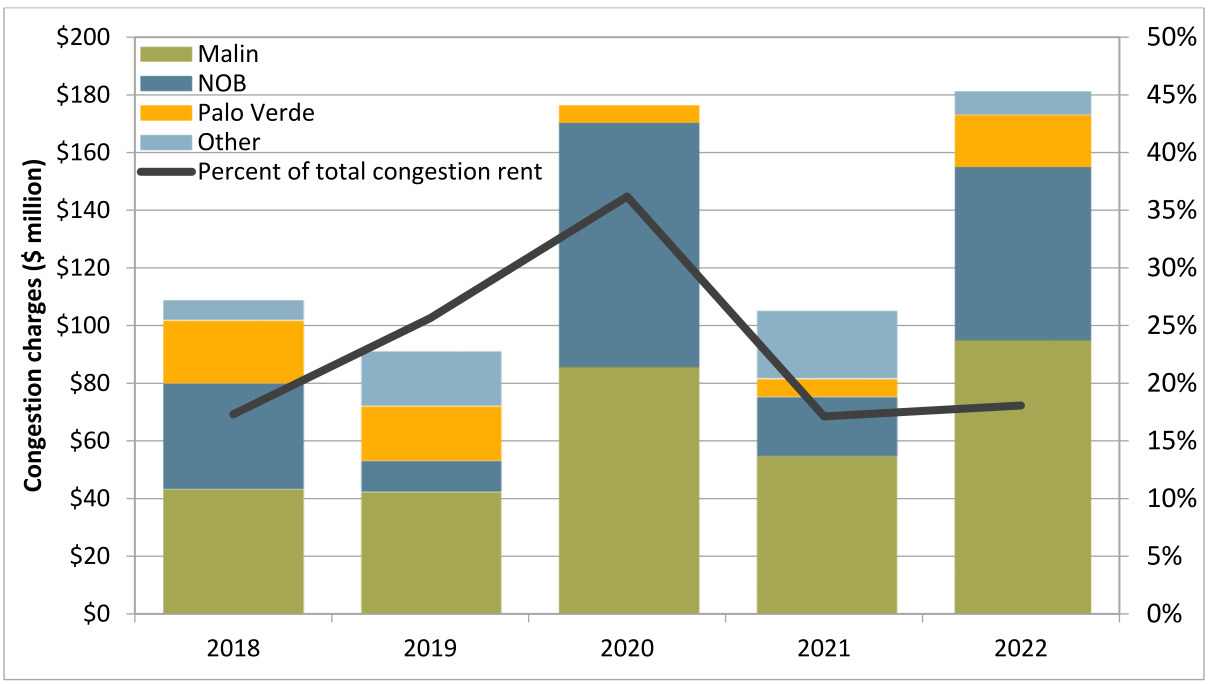


Figure 6.8 Day-ahead import congestion charges on major interties (2018–2022)



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.[223]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[224]
- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[225]

In 2022, transmission ratepayer losses from congestion revenue right auctions totaled over $118 million significantly up from $43 million in 2021. Transmission ratepayers received about 55 cents in auction revenue per dollar paid out to these rights purchased in the 2022 auction.

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.

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

223 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

224 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

225 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

terms. Monthly auctions are held the month prior to the settlement month; rights sold in the monthly auction have monthly terms.[226]

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 the sale of 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.

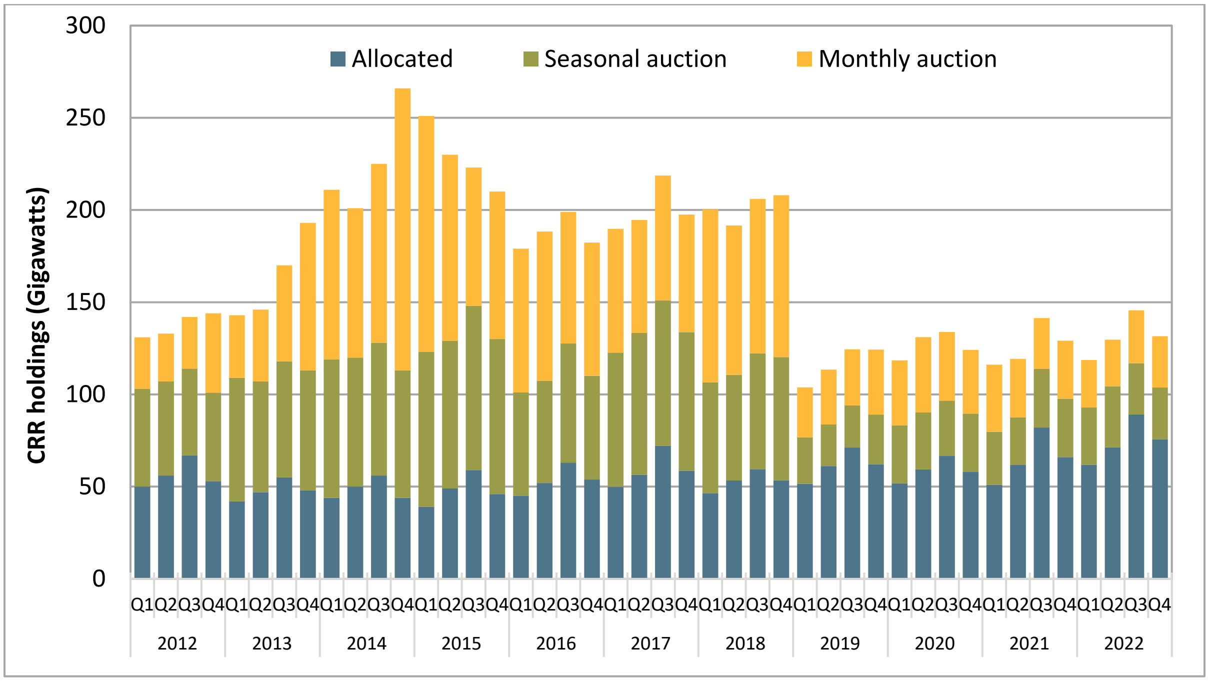
Congestion revenue right holdings

Interpreting congestion revenue right megawatt holding changes can be difficult, as it is not clear what the megawatt volume represents. Consider a participant holding 10 MW from node A to node B, and 10 MW from node B to node A. The participant's net holding of transmission rights is 0 MW, but the total megawatts of congestion revenue rights held is 20 MW. Total congestion revenue right megawatts do not give a complete view of the transmission rights held.

Figure 6.9 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 2022, the share of allocated congestion revenue rights was about 57 percent of the total megawatts held, and auctioned rights shared were about 43 percent of the total. As shown in the figure, the change in the trend in 2019 was because of the Track 1A changes implemented, beginning in the 2019 auction, which limited allowable source and sink pairs to "delivery path" combinations.

[226] For a more detailed explanation of the congestion revenue right processes, see California ISO, *2015 Annual CRR Market Results Report*, March 9, 2015: http://www.caiso.com/Documents/2015AnnualCRRMarketResultsReport.pdf.

Figure 6.9 Congestion revenue rights held by procurement type (2012–2022)[227]



6.3.2 Congestion revenue right auction returns

The CRR auction returns compares 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.[228] 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.[229]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[230]

227 Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs).

228 For further information, see DMM's whitepaper, *Shortcomings in the congestion revenue right auction design*, November 28, 2016: http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf.

229 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

230 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, 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.[231]

DMM believes the current auction is unnecessary and could be eliminated.[232] 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 6.10 compares the following for each of the last several years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars).[233]
- 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).

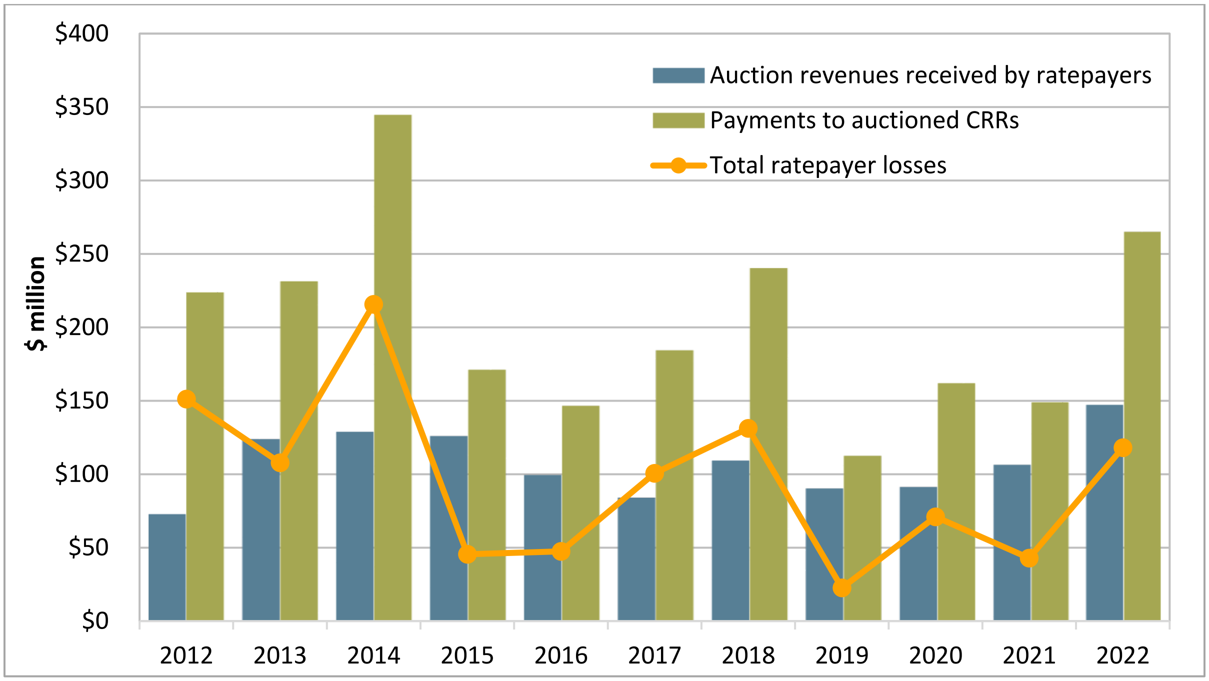
---

[231] California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

[232] DMM whitepaper, *Problems in the performance and design of the congestion revenue right auction,* November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

[233] 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 6.10 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 2022, ratepayer auctions losses were around $118 million, or about 11 percent of day-ahead market congestion rent. Ratepayers received an average of 55 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 $143 million.

In 2021, losses were around $43 million, or about 7 percent of day-ahead market congestion rent. Ratepayers received an average of 71 cents in auction revenue per dollar paid out. Track 1B revenue deficiency offsets reduced payments to auctioned rights by about $81 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 CAISO 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 6.11 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 reduced ratepayer losses by almost $11 million in 2022.

Figure 6.11 Estimated CRR auction loss breakout by CAISO and load serving entity

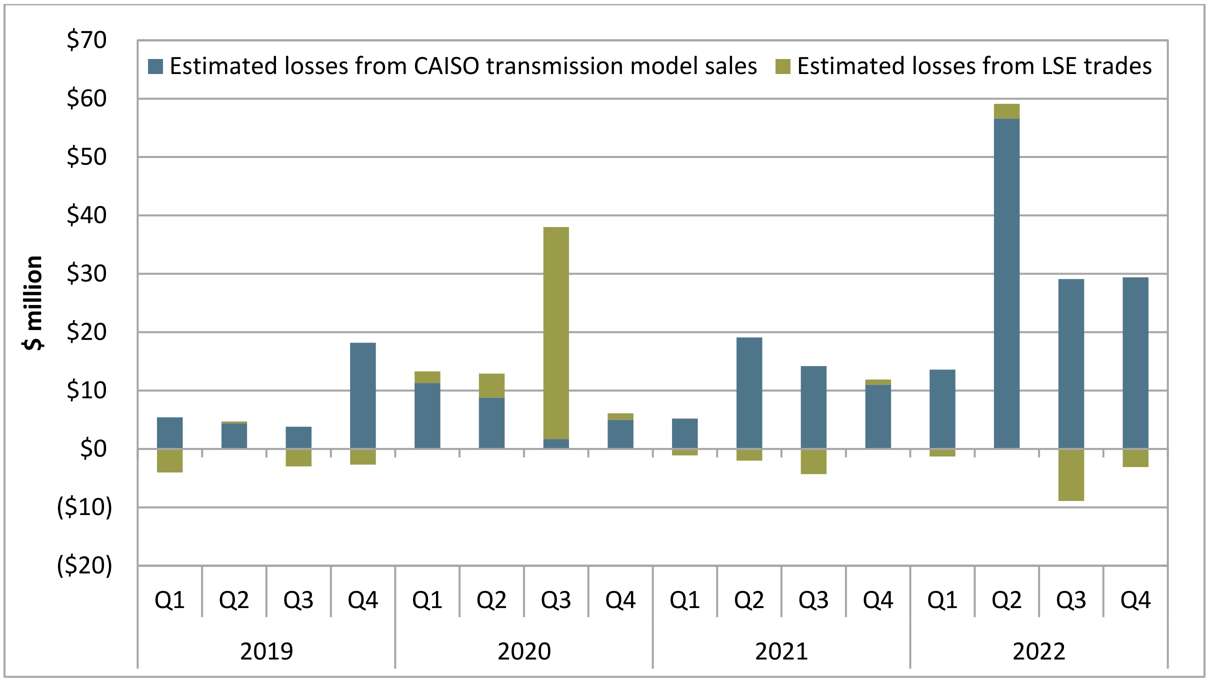


Figure 6.12 through Figure 6.14 compare the auction revenues paid for and payments received from congestion revenue rights traded in the auction by market participant type.[234] The difference between auction revenues and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities received net revenue of nearly $71 million in 2022, up from $28 million in 2021. Total revenue deficit offsets were about $105 million.
- Marketers received net revenues of nearly $33 million from auctioned rights in 2022, up significantly from $6 million in 2021. Total revenue deficit offsets were nearly $34 million.
- Physical generation entities received about $12 million in net revenue from auctioned rights in 2022 up from about $8 million in 2021. Total revenue deficit offsets were about $4 million.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2022 physical generators as a group continued to account for a 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

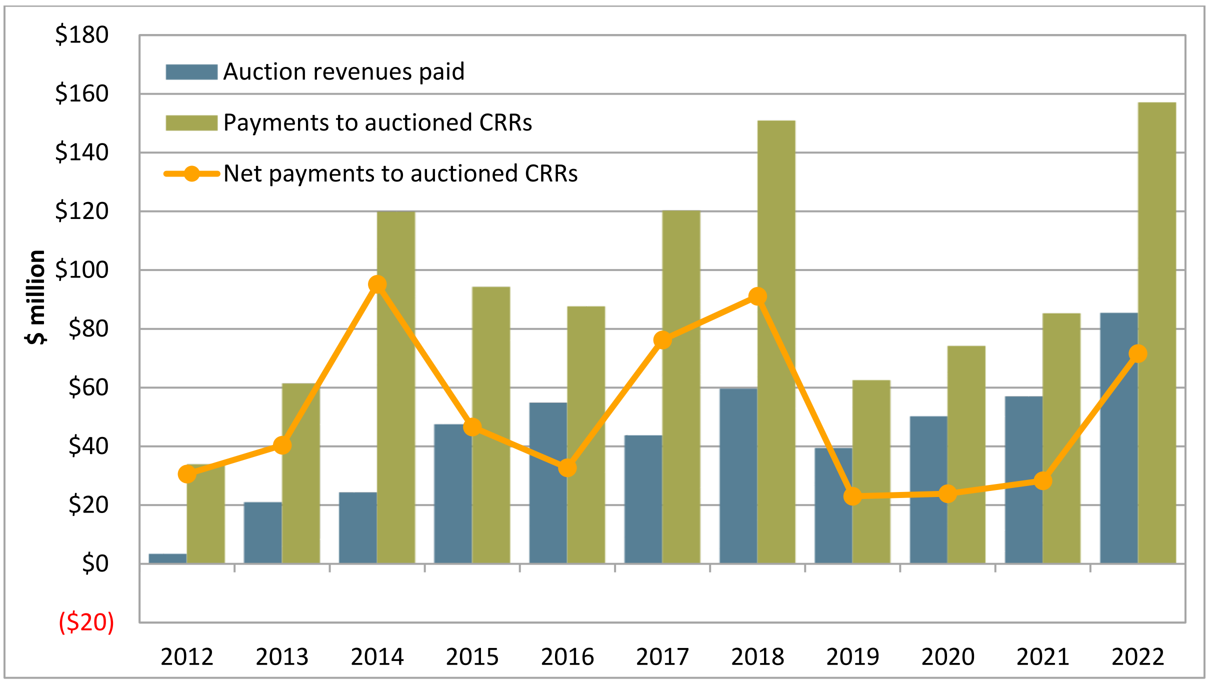
[234] DMM has defined financial entities as participants who own no physical energy and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the CAISO as physical generators and load serving entities, respectively. Marketers include participants on the interties and participants whose portfolios are not primarily focused on physical or financial participation in the CAISO 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.

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.[235,236] 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.

Figure 6.12 Auction revenues and payments (financial entities)



[235] DMM whitepaper, *Problems in the performance and design of the congestion revenue right auction,* November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

[236] DMM whitepaper, *Market alternatives to the congestion revenue rights auction,* November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

Figure 6.13 Auction revenues and payments (marketers)

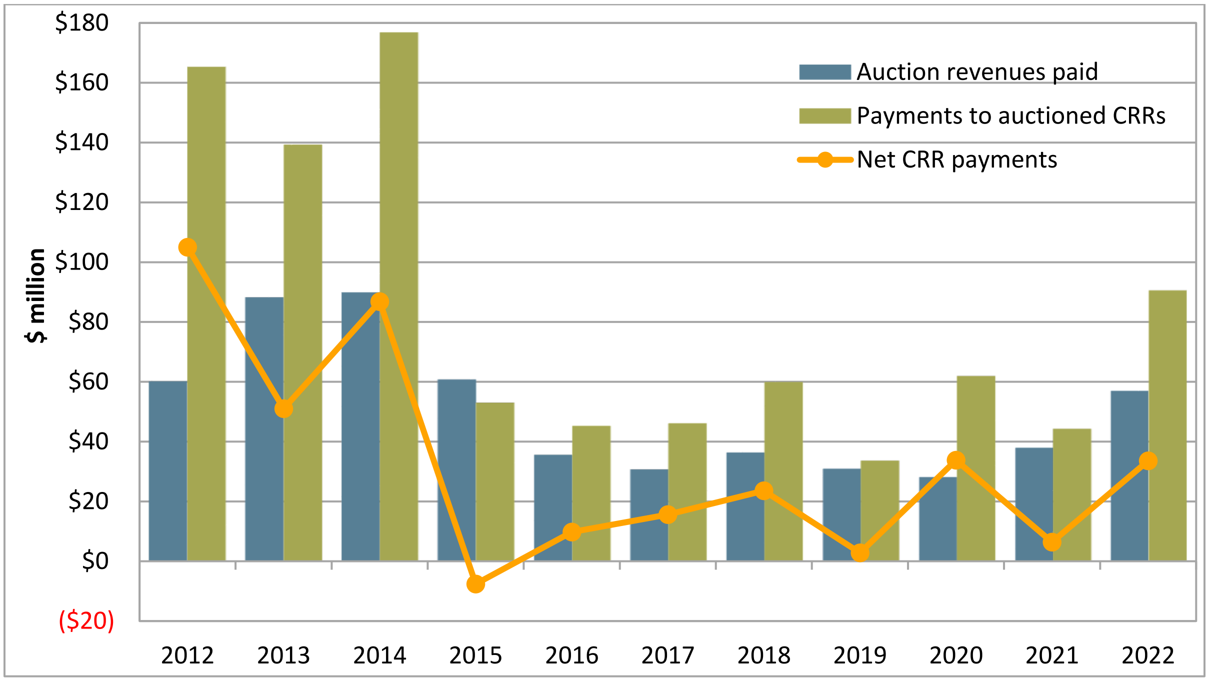
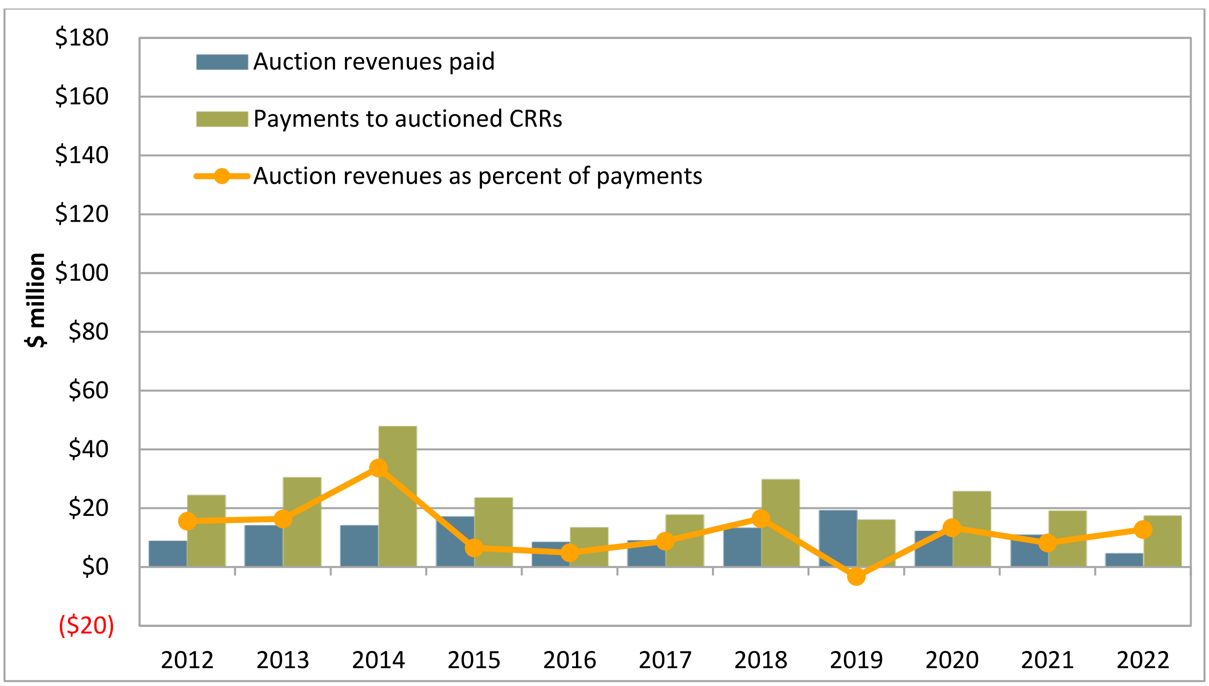


Figure 6.14 Auction revenues and payments (generators)



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 and pricing runs 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 declined in 2022** and continued to account for a relatively low portion of total system load at 0.25 percent in 2022, down from 0.5 in 2021. Exceptional dispatch energy above minimum load decreased by approximately 46 percent in 2022 from 2021, while minimum load energy from unit commitments decreased by 50 percent.
- **Total above-market costs from exceptional dispatch decreased** by about 45 percent to $14 million from $27 million in 2021.
- **Out-of-market dispatches of both imports and emergency assistance increased significantly**. In 2022, the California ISO imported about 17,400 MWh of non-emergency assistance out-of-market dispatches on the ties, a substantial increase from 6,300 MWh in 2021. In 2022, 2,450 MWh of emergency assistance was dispatched into the ISO from neighboring balancing authority areas, compared to none in 2021.
- **California ISO operator residual unit commitment adjustments increased** by 147 percent compared to 2021. In the third quarter, the average adjustment was about 1,384 MW per hour compared to 724 MW in the same quarter in 2021. In 2022, these manual adjustments were primarily issued to address reliability concerns and load forecast errors.
- **High levels of real-time market load adjustments by the California ISO continued in solar ramping periods.** Imbalance conformance adjustments averaged over 2,000 MW during the net load peak in the 15-minute market, about 800 MW over the average for the same time last year. This continued the increase in operator use of imbalance conformance that began in 2017. Maximum load adjustments in the morning ramp were around 2,500 MW in the morning peak while the maximum evening ramp reached 5,000 MW in hour-end 17 to 21 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 not fully recovered by affecting market prices, and 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 0.25 percent of system loads in 2022, down from about 0.50 percent in 2021.

Exceptional dispatch energy above minimum load decreased by approximately 46 percent in 2022 from 2021, while minimum load energy from unit commitments decreased by 50 percent. As shown in Figure 7.1, minimum load energy from units committed via exceptional dispatch accounted for 74 percent of all exceptional dispatch energy in 2022. About 14 percent of energy from exceptional dispatches was from out-of-sequence energy (to operate above minimum load), and the remaining 13 percent was from in-sequence energy.

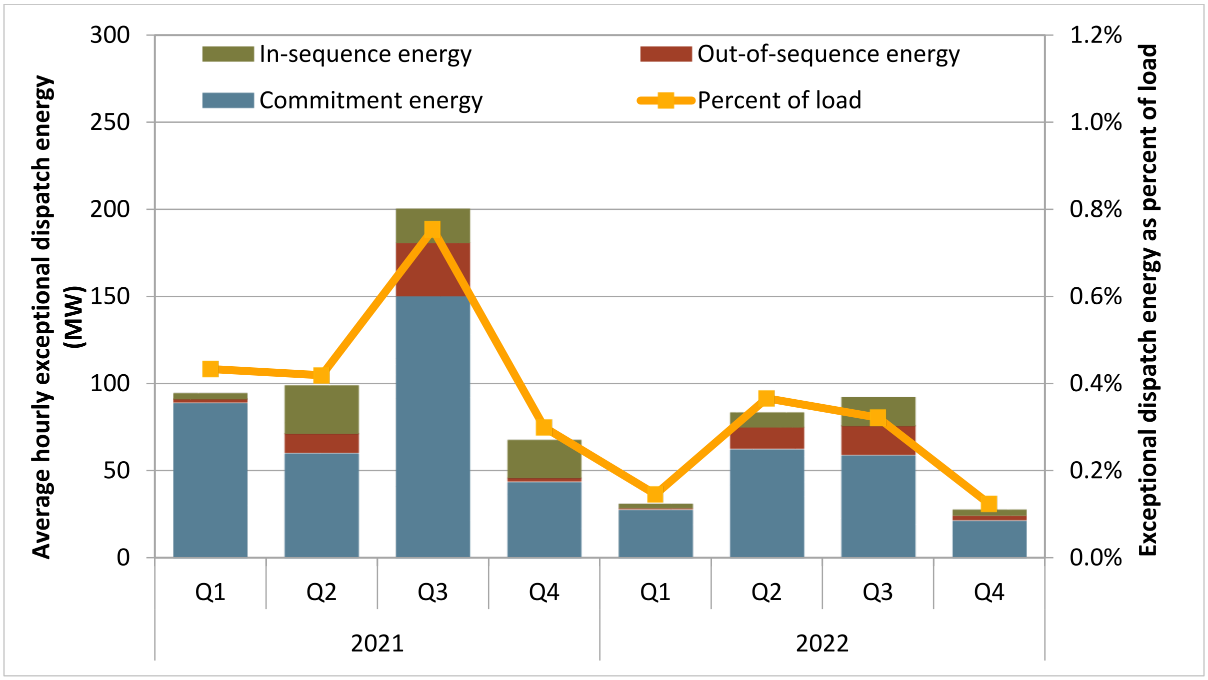
The decrease in above minimum load energy from exceptional dispatches in 2022 was due to a decrease of in-sequence energy from unit testing exceptional dispatches in the second quarter. Out-of-sequence energy from exceptional dispatch decreased year over year.

Although most exceptional dispatches are not priced and paid based on market clearing energy prices, they can affect the market clearing price for energy. 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, most exceptional dispatches appear to be made to resolve specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy if these constraints were incorporated in the market model.[237]

As discussed later in this section, the bulk of energy from exceptional dispatches is minimum load energy from unit commitments. Energy from this type of exceptional dispatch would not be eligible to set market prices if incorporated in the market model. In addition, because most exceptional dispatches occur after the day-ahead market, energy from these exceptional dispatches primarily affects the real-time market. If energy needed to meet these constraints was included in the day-ahead market, prices in the day-ahead market could be lower.

237 Section 39.10 of the CAISO tariff: https://www.caiso.com/Documents/Section39-MarketPowerMitigationProcedures-asof-May1-2023.pdf

Figure 7.1 Average hourly energy from exceptional dispatch

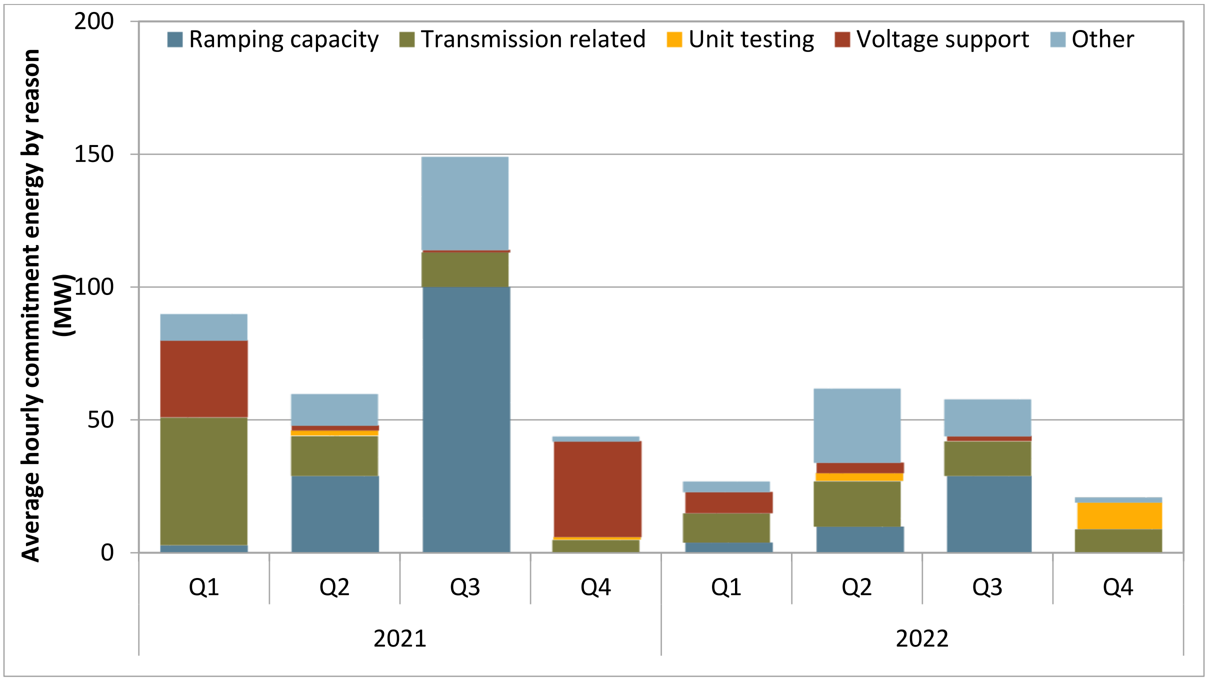


Exceptional dispatches for unit commitment

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 some 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.

Minimum load energy from exceptional dispatch unit commitments decreased in 2022 compared to 2021, with most occurring in the first and third quarters of 2022. Exceptional dispatch unit commitments in the third quarter of 2021 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. In the first quarter, exceptional dispatch unit commitments were predominately issued for transmission related modeling limitations and to provide voltage support due to generation outages.

Figure 7.2 Average minimum load energy from exceptional dispatch unit commitments



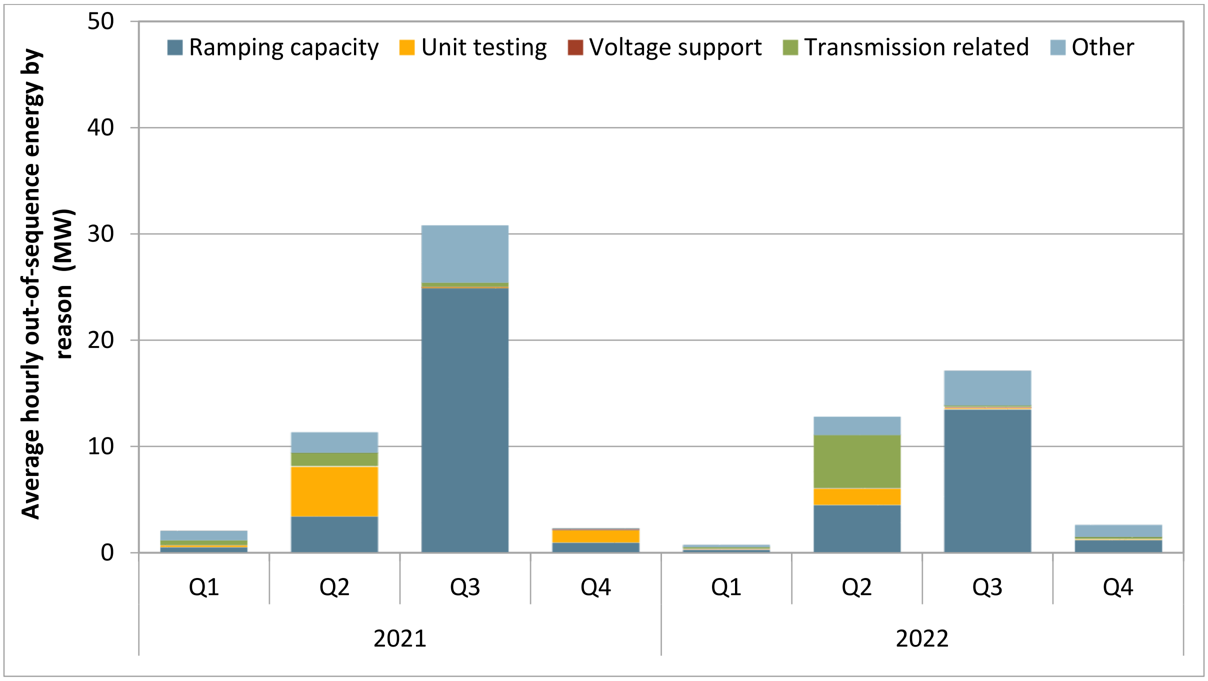
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load, or to ensure they do not operate below their regular market dispatch, decreased by 46 percent in 2022. As illustrated in Figure 7.1, about 14 percent of this type of exceptional dispatch was out-of-sequence, meaning the bid price was greater than the locational market clearing price.[238] While the level of exceptional dispatch energy was similar to the previous years, the amount of exceptional dispatch for out-of-sequence energy decreased.

Figure 7.3 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2021 and 2022. 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 a decline in 2022 from 2021. 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.

238 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

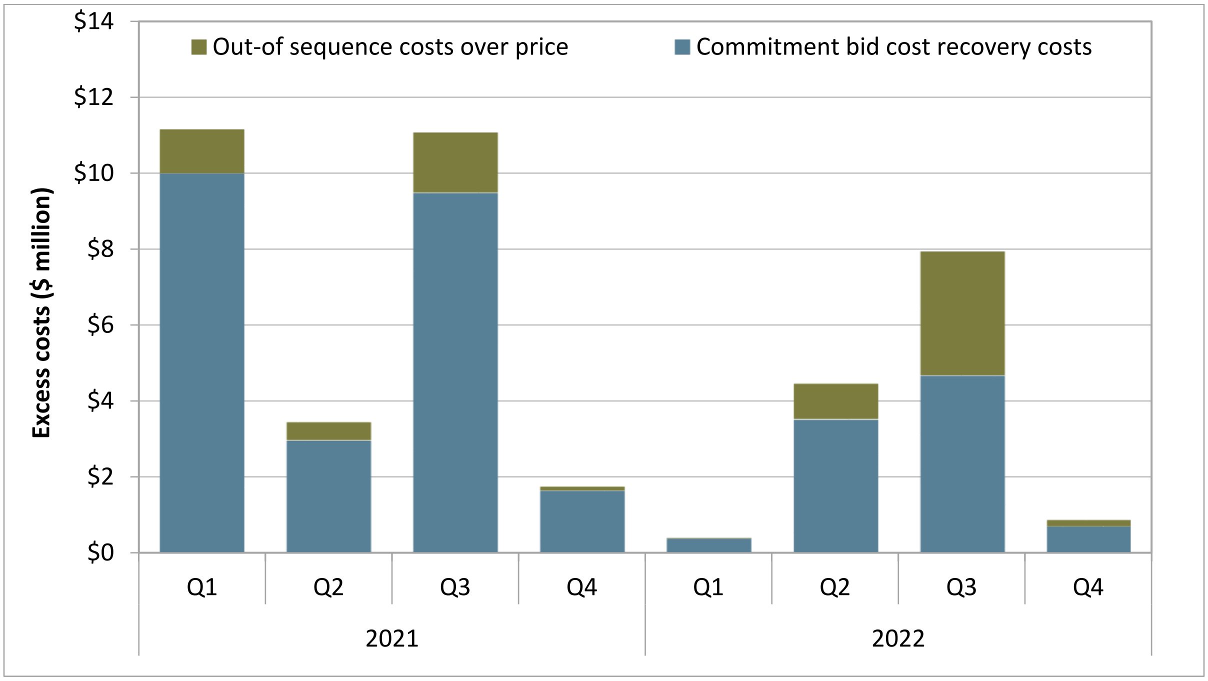
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- 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 costs for exceptional dispatch paid through bid cost recovery decreased from $24 million to $9.5 million and out-of-sequence energy costs increased from $3.3 million to $4.4 million in 2022.[239] Total above-market costs decreased by 50 percent to about $13.7 million in 2022 from $27.4 million in 2021. As discussed above, the total amount of exceptional dispatch energy decreased from 2021, corresponding to an overall decrease in exceptional dispatch costs.

[239] 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.

Figure 7.5 shows the total hourly megawatts from all manual dispatch and emergency assistance over the past two years. Imports coming from emergency assistance reflect energy imported from balancing authority areas with whom the California ISO has contractual agreements during emergency conditions. All other manual dispatches reflect energy from offers made by the California ISO operators for imports from neighboring balancing areas for imports in the real-time market. These types of imports are often paid a negotiated price, typically for 'bid or better'.[240]

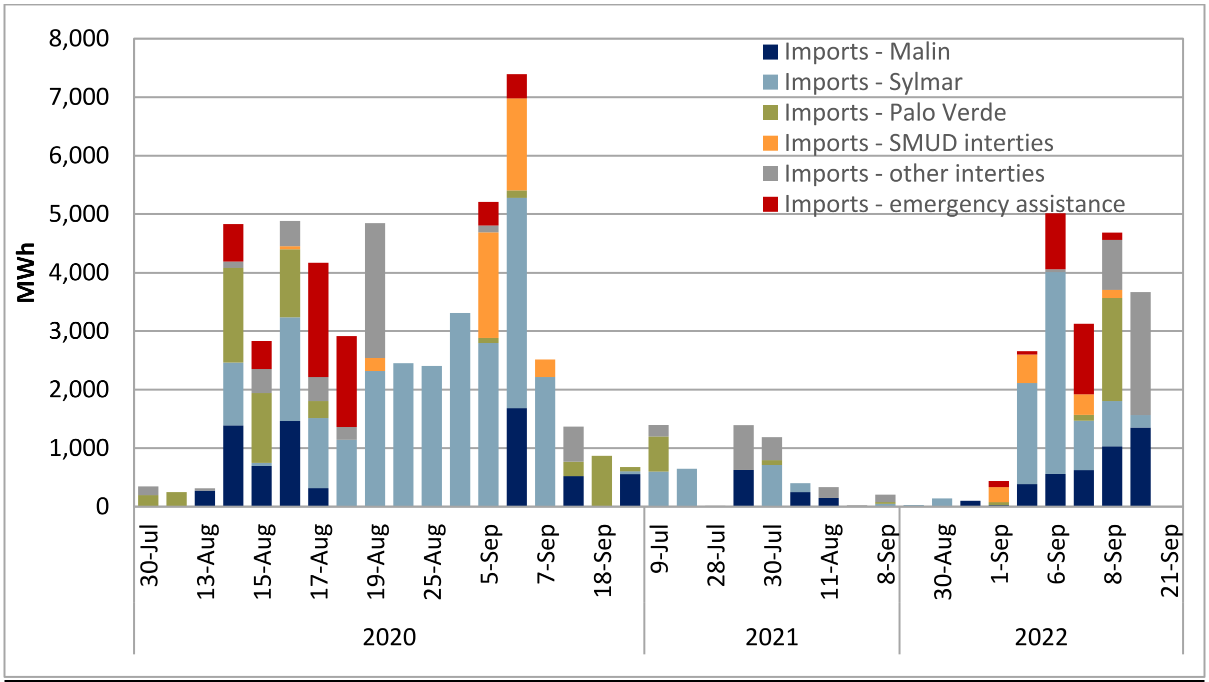
Out-of-market dispatches of both imports and emergency assistance increased substantially from 2021 to 2022. In 2022, the CAISO imported about 17,400 MWh of non-emergency assistance out-of-market dispatches on the ties, a large increase from about 5,600 MWh in 2021. No emergency assistance was received from neighboring balancing authority areas in 2021, while in 2022 there was 2,450 MWh of emergency assistance imported in to the California ISO in 2022. In addition to receiving emergency

---

240 For additional details on manual dispatch types and prices paid for out-of-market imports, see Department of Market Monitoring, *2019 Annual Report on Market Issues &* Performance, June 2020, pp. 206-207: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

assistance, the CAISO also provided emergency assistance to other balancing areas in 2021 and 2022, the majority going to only one balancing area.

Figure 7.5 Manual dispatch and emergency assistance on CAISO interties (July–September)



Western Energy Imbalance Market

Western Energy Imbalance Market 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 7.6 through Figure 7.8 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 7.6 WEIM manual dispatches – Arizona Public Service area

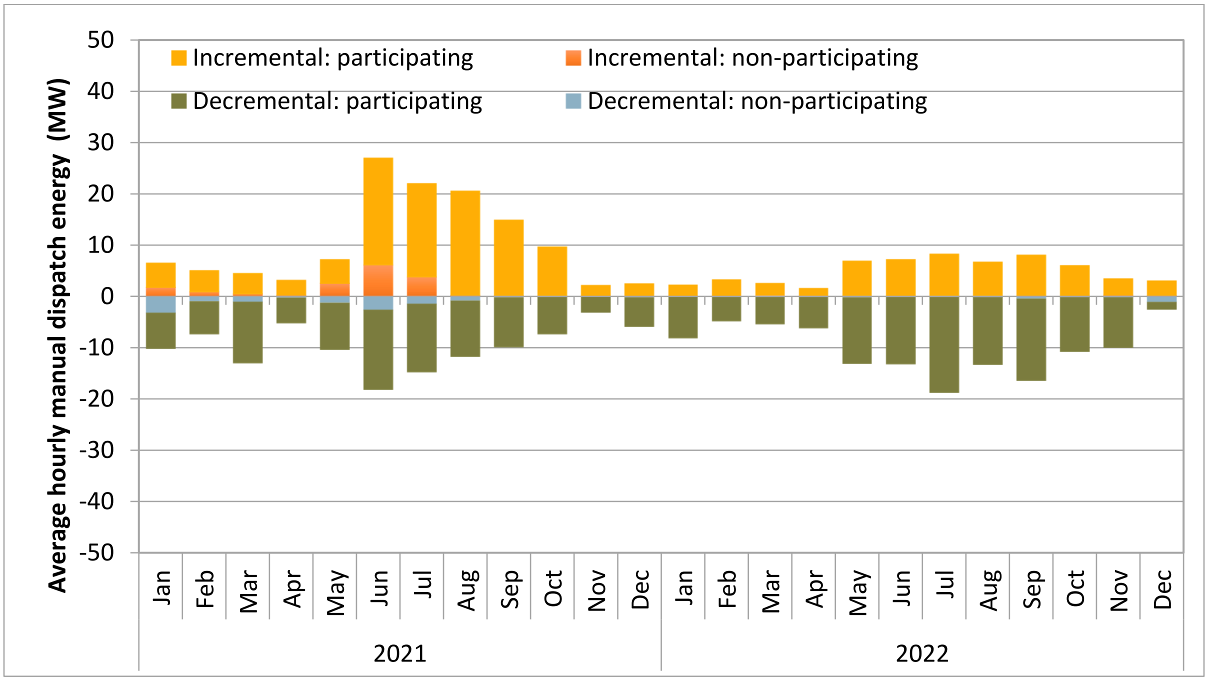


Figure 7.7 WEIM manual dispatches – Salt River Project area

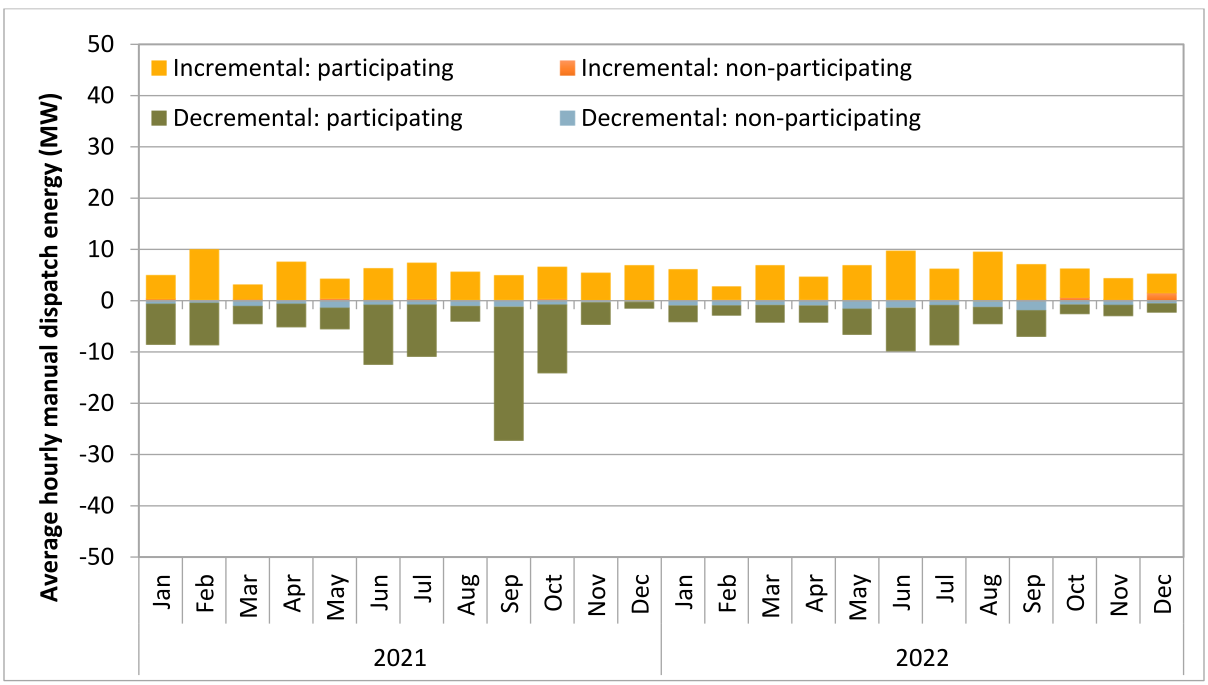
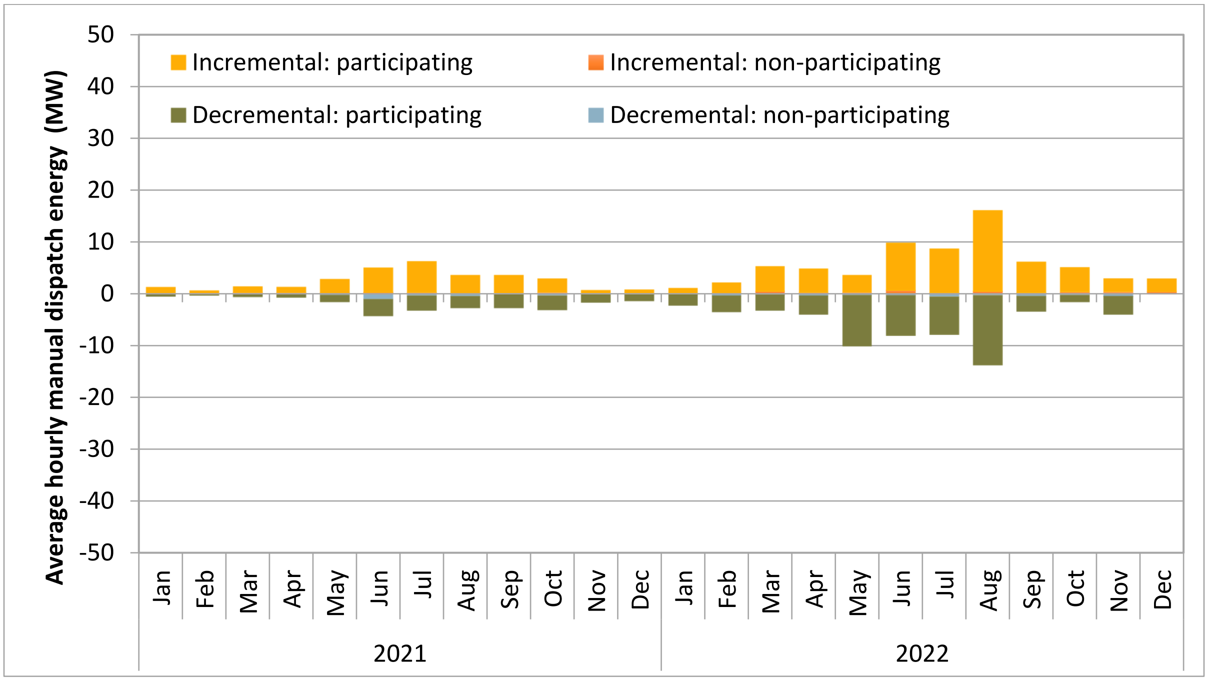


Figure 7.8 WEIM manual dispatches – Nevada Energy area



7.3 Residual unit commitment adjustments

The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any manual adjustment that operators make to increase residual unit commitment requirements for reliability purposes. In 2022, these operator adjustments increased significantly by 147 percent compared to 2021.

As noted in Section 2.4, 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) is ran 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.

Figure 7.9 shows the average hourly determinants of capacity requirements used in residual unit commitment process by quarter in 2021 and 2022.

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 7.9, was the primary driver of positive residual unit commitment requirement. The average increase in residual unit commitment requirements due to net virtual supply decreased to 658 MW in 2022 from 870 MW in 2021.

California ISO operators can also make manual adjustments to increase the amount of residual unit commitment requirements. These manual adjustments, shown in the red bar in Figure 7.9, contributed an average of 584 MW per hour to requirements, an increase from about 238 MW per hour in 2021. The figure also shows that these adjustments were most frequent during the third quarter. Figure 7.11 shows the hourly distribution of these operator adjustments during the third quarter of 2022. 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 90 days in the third quarter, out of the total 262 days it was used in 2022. The average adjustment in the third quarter was about 1,384 MW per hour, compared to 724 MW in the same quarter of 2021. These manual adjustments were primarily used to address reliability concerns and to account for load forecast errors.

The blue bars in Figure 7.9 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 difference increased residual unit commitment requirements by 61 MW on a yearly average basis 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 bar in Figure 7.9.

Figure 7.9 Determinants of residual unit commitment procurement

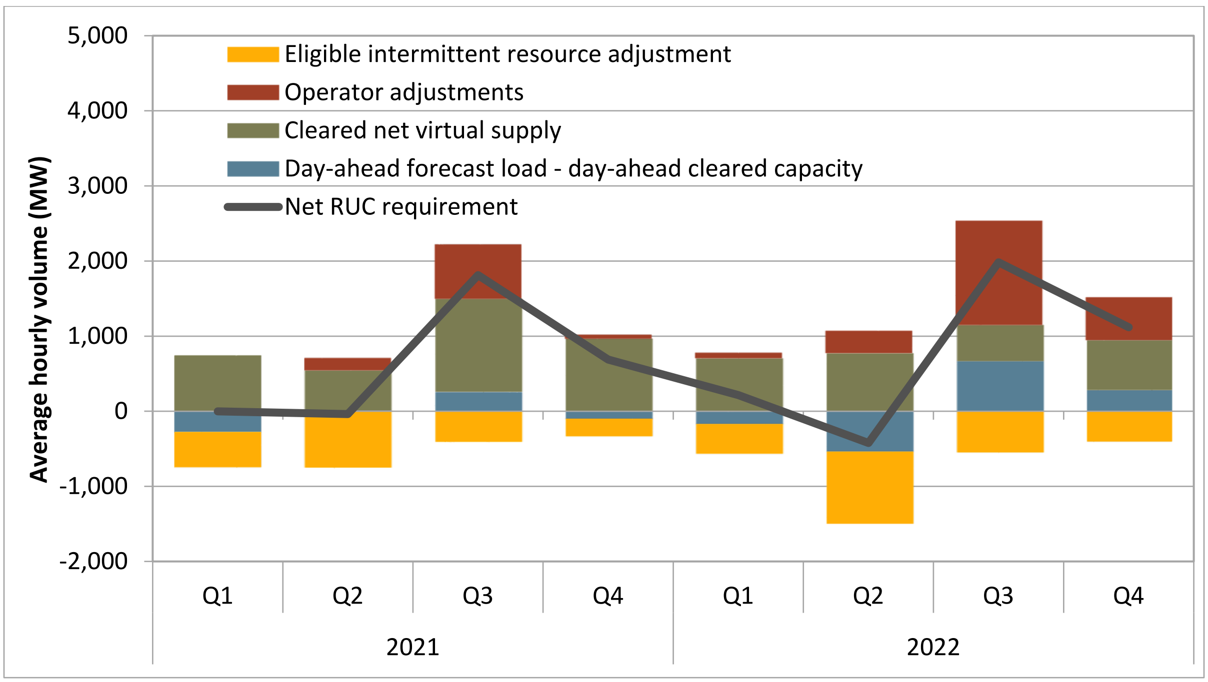


Figure 7.10 shows these same four determinants of the residual unit commitment requirements for 2022 by hour. As shown by the red bars in Figure 7.10, manual adjustments by grid operators tend to be greatest between the peak load hours ending 9 through 22. During the third quarter of 2022, operators increased the residual unit commitment requirement by about 2,145 MW on average for hours ending 9 through 22.

While operator adjustments were low 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 during all hours except 9 through 16 in 2022. Similar to 2021, the bulk of the intermittent resource adjustments occurred in hours ending 9 to 18.

Figure 7.10 Average hourly determinants of residual unit commitment procurement (2022)

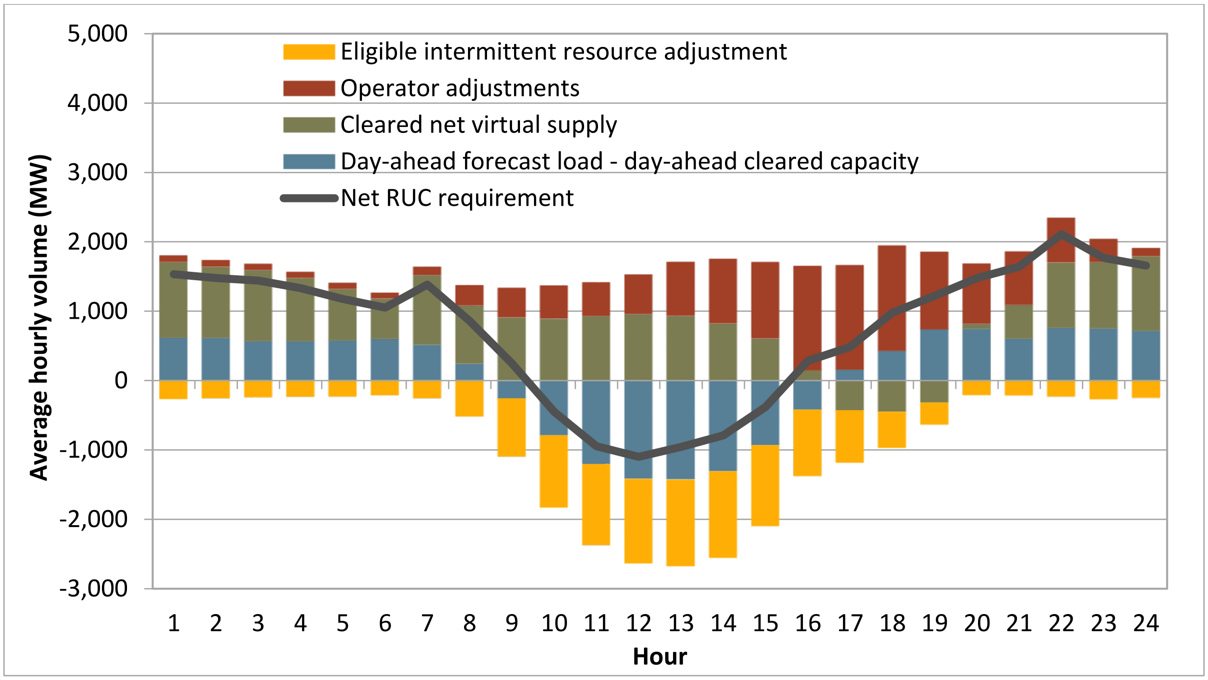
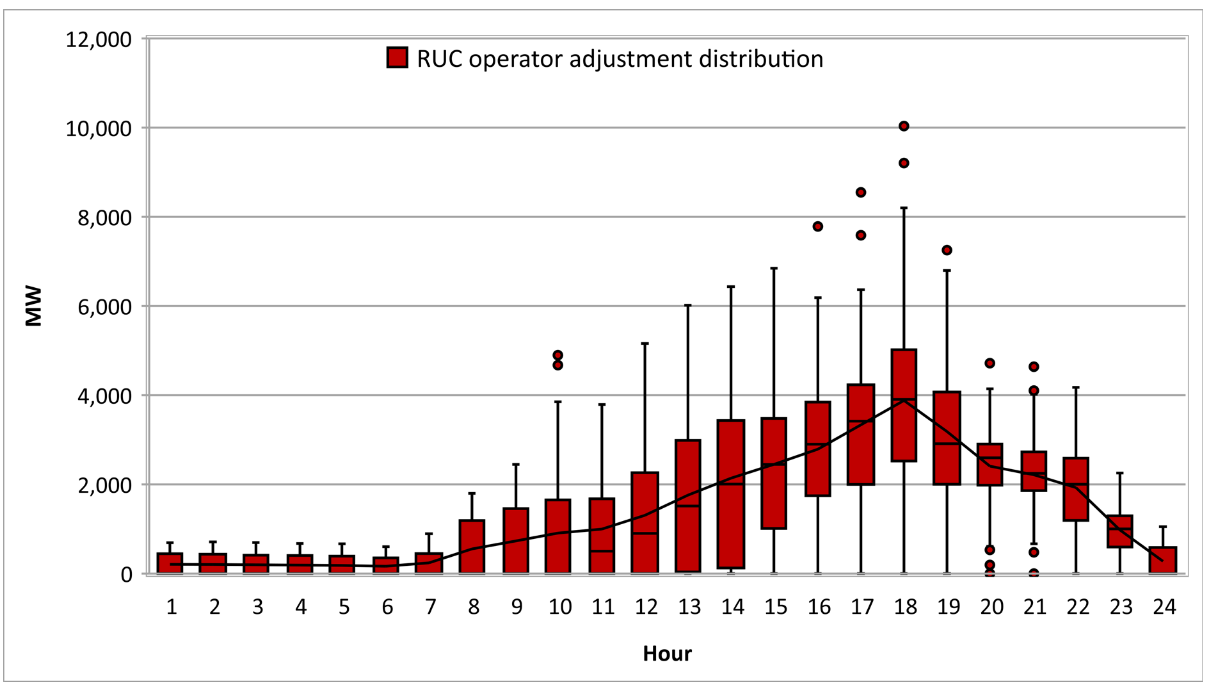


Figure 7.11 Hourly distribution of residual unit commitment operator adjustments (July–September)



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 CAISO uses the term *imbalance conformance* to describe these adjustments. Load forecast adjustments can be 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. The California ISO performed a counterfactual analysis showing that load adjustments led to additional hour-ahead imports, WEIM transfers, and additional internal generation.[241]

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 2022, with average hourly load adjustments in the hour-ahead and 15-minute markets peaking around 2,050 MW, a large increase from the previous year of about 1,250 MW, and about a four and half-fold increase from the 2016 peak of 460 MW.

Figure 7.12 shows the average hourly load adjustment profile for the hour-ahead and 5-minute markets for 2020 to 2022.[242] As in prior years, the general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments, only much more elevated in 2022. The 2022 morning ramping hour adjustments jumped to a maximum level of about 770 MW from about 380 MW and evening ramping hour adjustments increased to about 2,050 MW from 1,250 the prior year. The average hour-ahead load forecast adjustments in 2022 mirror the pattern of net loads over the course of the day, averaging nearly 630 MW over the entire day.

The load adjustments in the 5-minute market have a similar shape as the hour-ahead market, but less pronounced. In 2022, the 5-minute market more closely resembles the shape of 2021 with little adjustment prior to early morning ramp and after the evening ramp. However, greater positive adjustments occurred prior to the morning peak and late evening hours while very similar positive ramp just prior to the afternoon ramp. The largest positive deviations between the 5-minute and other markets were observed in hours ending 19 to 21, when the hour-ahead adjustments exceeded the 5-minute adjustments by around 1,800 MW.

Figure 7.13 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for 2022. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled 'dots', the outside whiskers do not include these outliers. For the year, there were outliers of 5,000 MW in hours ending 16 to 21, these occurred almost exclusively during the heat wave period. The maximum load adjustments – excluding identification of outliers – in the morning

[241] California ISO, Market Analysis and Forecasting, *WEIM Transfers, Hourly Interties and Load Conformance*, June 21, 2022: http://www.caiso.com/InitiativeDocuments/FinalAnalysisReport-WEIMTransfers-HourlyInterties-Load.pdf

[242] 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.

ramp were between 1,500 MW and 2,100 MW in hours ending 6 through 8, while the evening ramp was between 3,000 MW and 3,500 MW in hours ending 18 through 22.

Figure 7.12 Average hourly load adjustment (2020–2022)

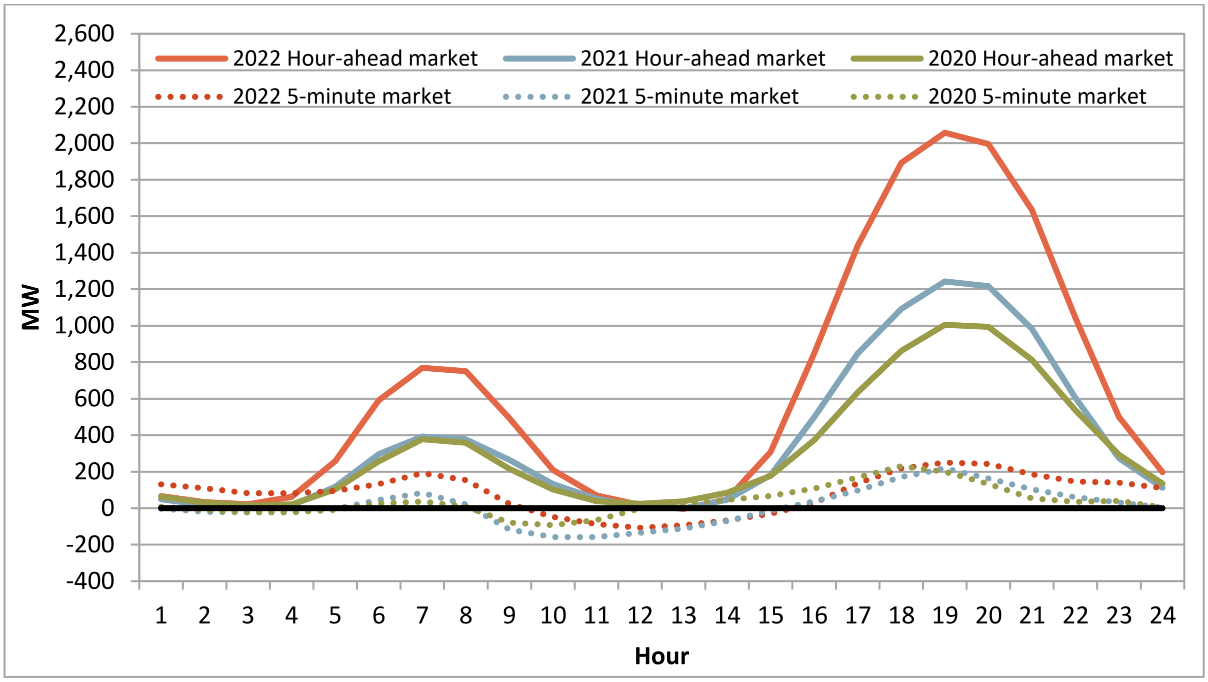
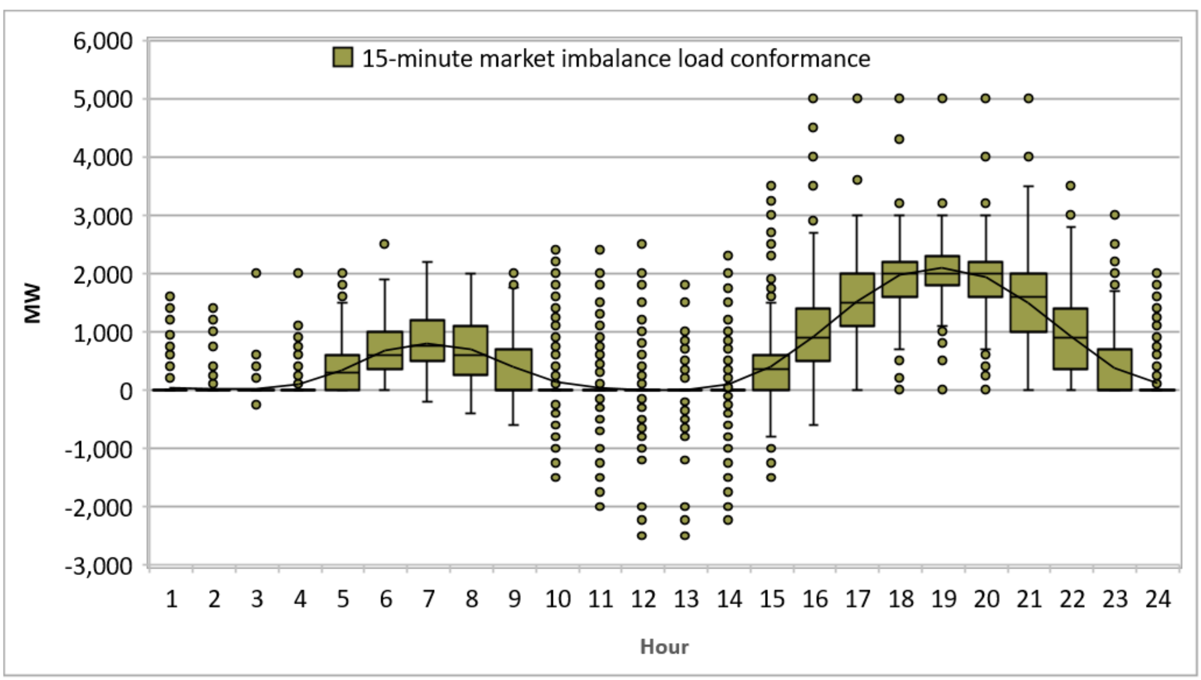


Figure 7.13 15-minute market hourly distribution of operator load adjustments (2022)



Adjustments are often associated with over- or under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods. The CAISO also adjusts loads in the 15-minute and 5-minute real-time markets to account for potential modeling inconsistencies. Some of these inconsistencies are due to changing system and market conditions, such as changes in load and supply (e.g., exceptional dispatches), between the executions of different real-time markets.[243] Operators have listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error correction, scheduled interchange variation, reliability events, and software issues.

High real-time market load adjustments in peak net load hours are associated with increasing hourly import bids in morning and evening ramping hours. Increasing imports in these hours increases the supply of internal generation that could be ramped up or down in the real-time market.

Similarly, since unit commitments and transitions for resources within the CAISO are made in the 15-minute market, maintaining a relatively high positive load bias in the 15-minute market can make additional generation available within the CAISO during the morning and evening ramping hours.

The impact of the hour-ahead load bias on real-time imports is reflected in Figure 7.14, which shows the incremental change in gross and net imports in the real-time market. The light green area in Figure 7.14 shows the average incremental increase in imports between the day-ahead and hour-ahead markets. The light blue area shows the incremental change in exports between the day-ahead and hour-ahead markets where an increased export is displayed as a negative value.

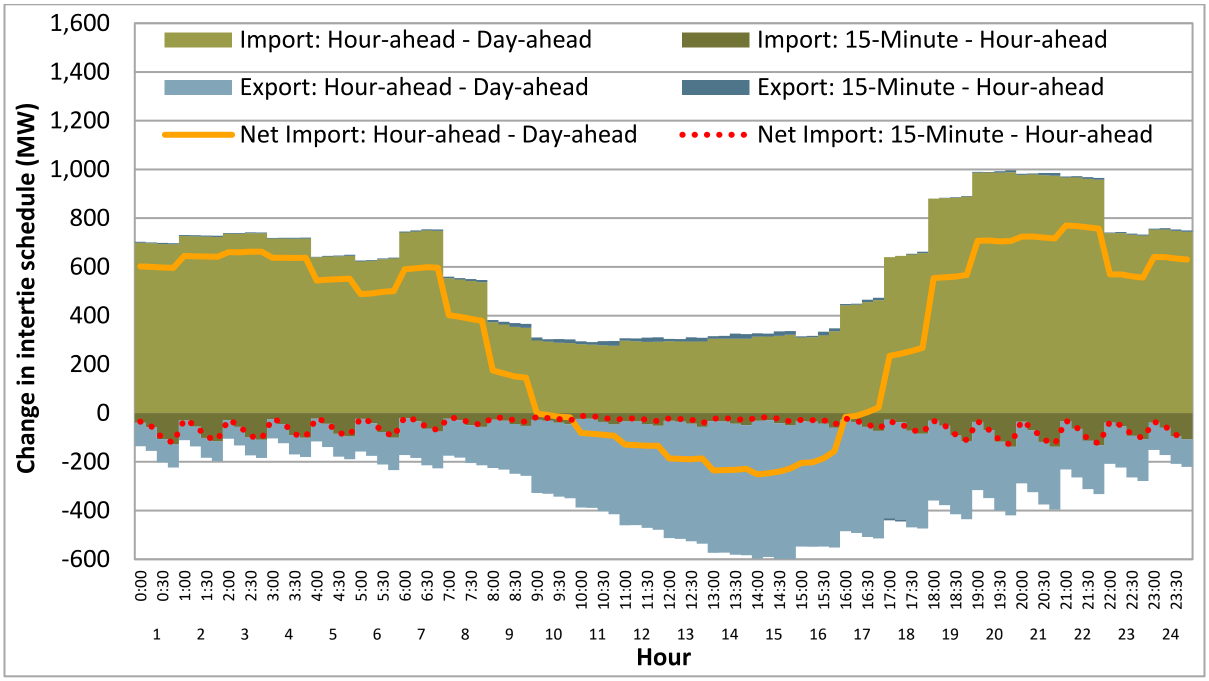
The yellow line in Figure 7.14 shows the change in net interchange, summing the effects of increased imports and exports. The red dotted line represents the change in net interchange between the 15-minute and hour-ahead markets, and is the sum of incremental decreases in imports (dark green) and exports (dark blue). These are lower values relative to the changes observed between the day-ahead and the hour-ahead.

As shown in Figure 7.14, 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 2022, net interchange averaged about 500 MW, an increase from an average of 390 MW during these hours in 2021. Similar to 2021, the highest average net interchange was in hours ending 19 to 22, reaching a peak of 750 MW in hour ending 22 compared to about 550 MW in 2021.

In 2022, as with the previous year, there was a noticeable increase in both imports and exports between the hour-ahead and day-ahead markets during mid-day solar peak periods. Net imports fell between the day-ahead and hour-ahead markets in these hours, similar to prior years. This appears to be associated with re-bidding of energy that did not clear the day-ahead market that then often cleared at price-taker bid floor levels associated with self-schedules in the real-time markets.

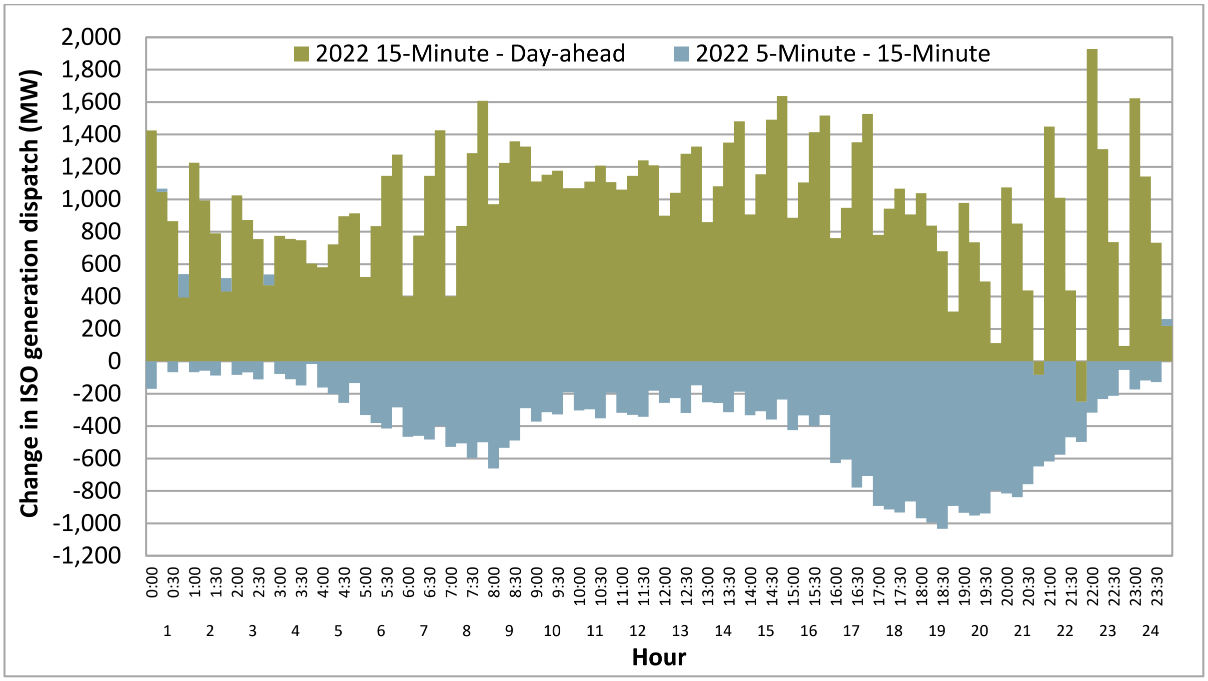
[243] FERC Docket No. ER15-861-006; *153 FERC ¶ 61,305 Order on Compliance Filing*, December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf

Figure 7.14 Net interchange dispatch volume



The incremental dispatch of internal generation between the day-ahead and 15-minute real-time markets tended to decrease during the morning and evening ramping hours, similar to the previous year. Figure 7.15 shows the average incremental change for internal generators between the day-ahead and the 15-minute market (green bars) and between the 15-minute market and the 5-minute market (blue bars). This decrease in generation within the CAISO tends to offset the increases in energy imports in the hour-ahead market as shown in Figure 7.14.

Figure 7.15 Imbalance generation dispatch volume



Load adjustments in the Western Energy Imbalance Market

Western Energy Imbalance Market operators can also make load adjustments in their respective balancing areas.[244] The frequency of positive and negative load forecast adjustments for the 15-minute and 5-minute markets are shown in Figure 7.16 through Figure 7.19.

For much of the year, in the 15-minute market, positive and negative load adjustments were most frequent in NorthWestern Energy, Puget Sound Energy, Seattle City Light, Avista Utilities, and Bonneville Power Administration. 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.

---

244 The Avista Utilities (AVA) and Tacoma Power (TPWR) are identified in the graphs beginning in Q1 since they joined the WEIM as market participants on March 2, 2022. The Bonneville Power Administration (BPA) and Tucson Electric Power (TEPC) joined on May 3, 2022 and are identified in the graphs beginning in Q2.

Figure 7.16 Average frequency of positive and negative load adjustments: 2022 WEIM – North (15-minute market)

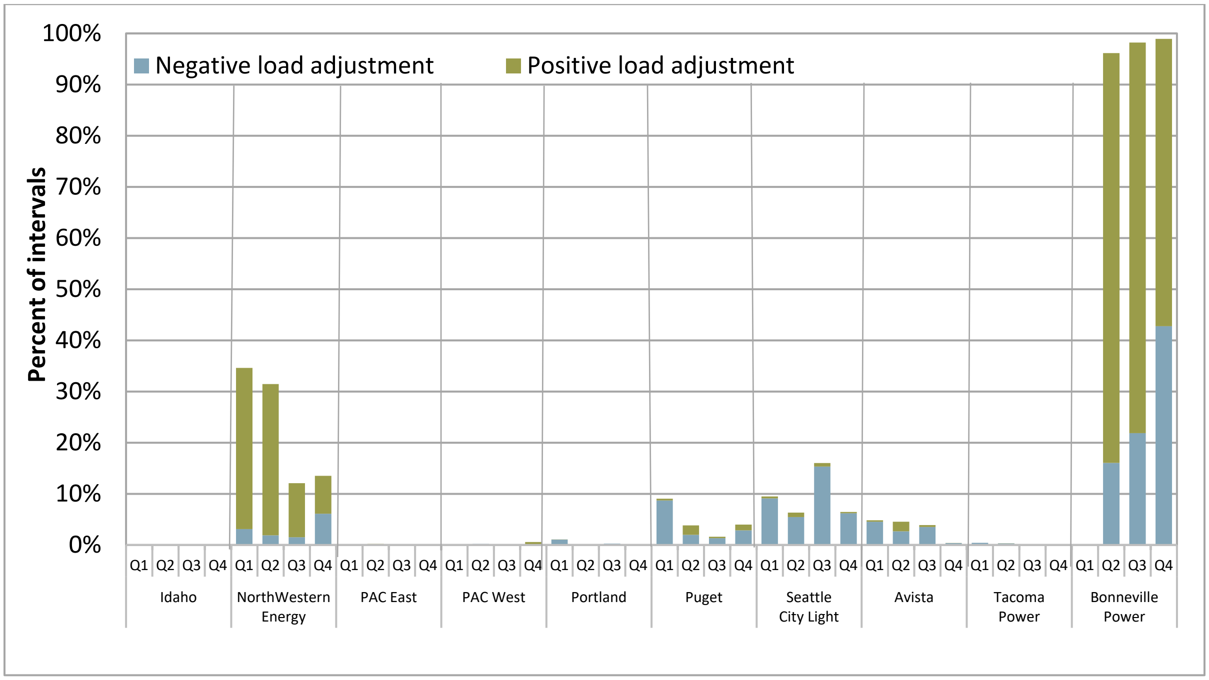


Figure 7.17 Average frequency of positive and negative load adjustments: 2022 WEIM – East and within California (15-minute market)

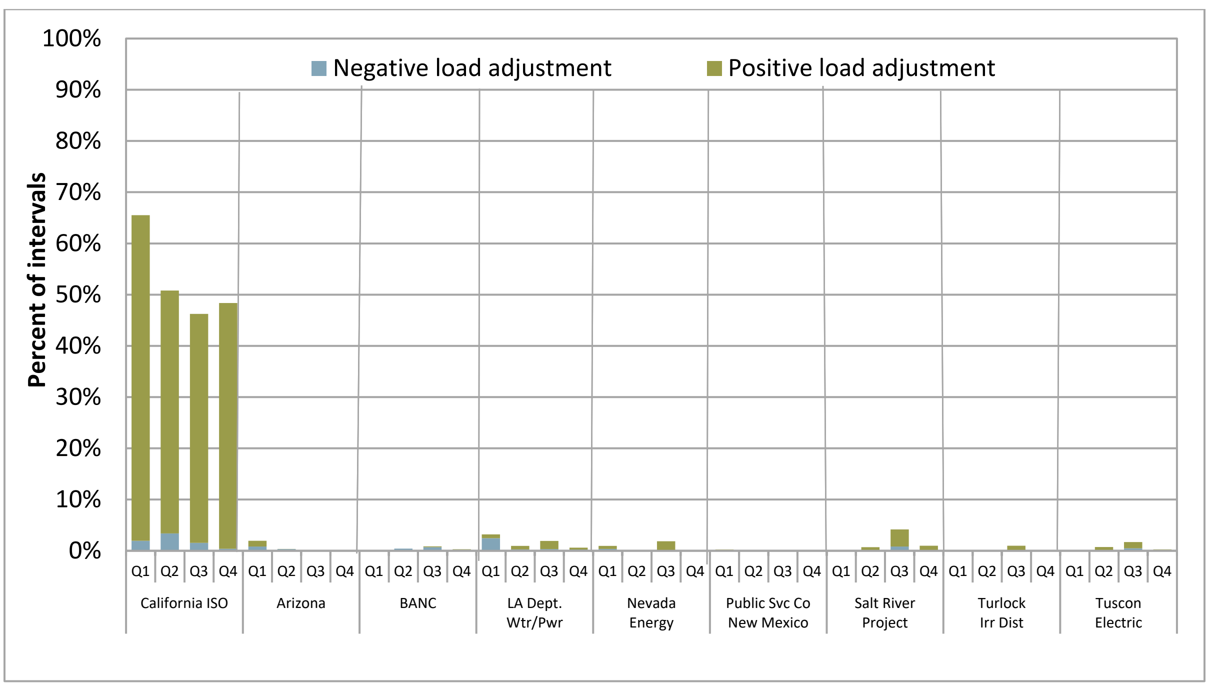


Figure 7.18 Average frequency of positive and negative load adjustments: 2022 WEIM – North (5-minute market)

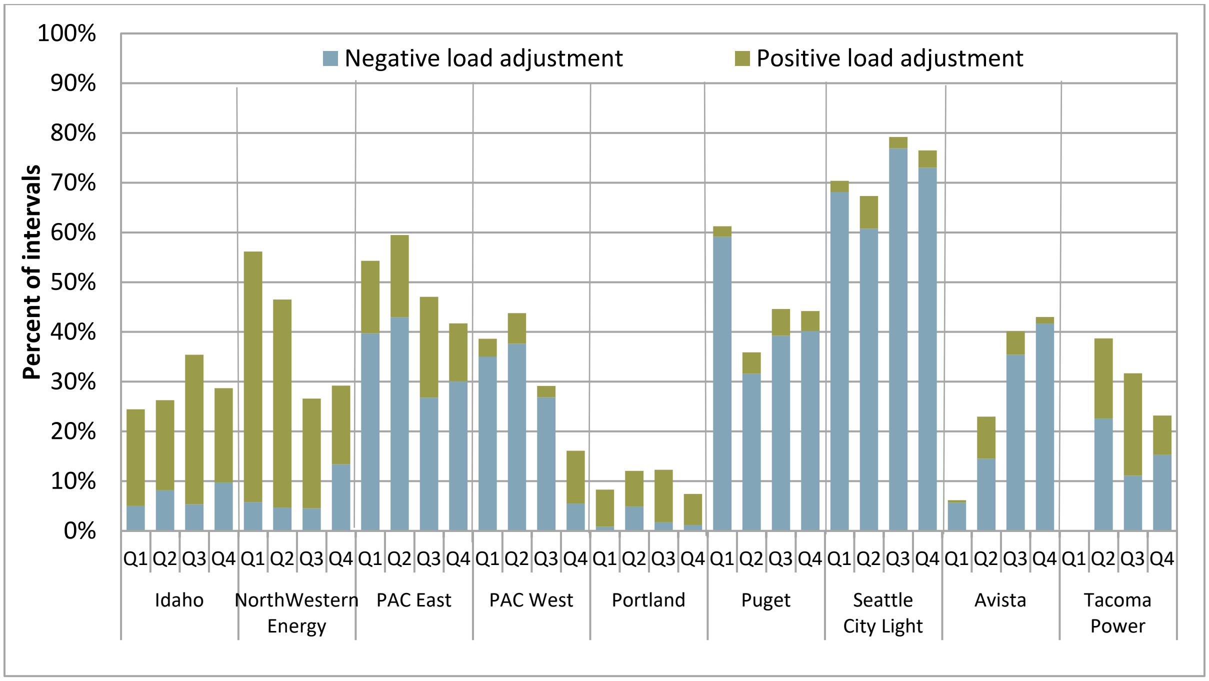
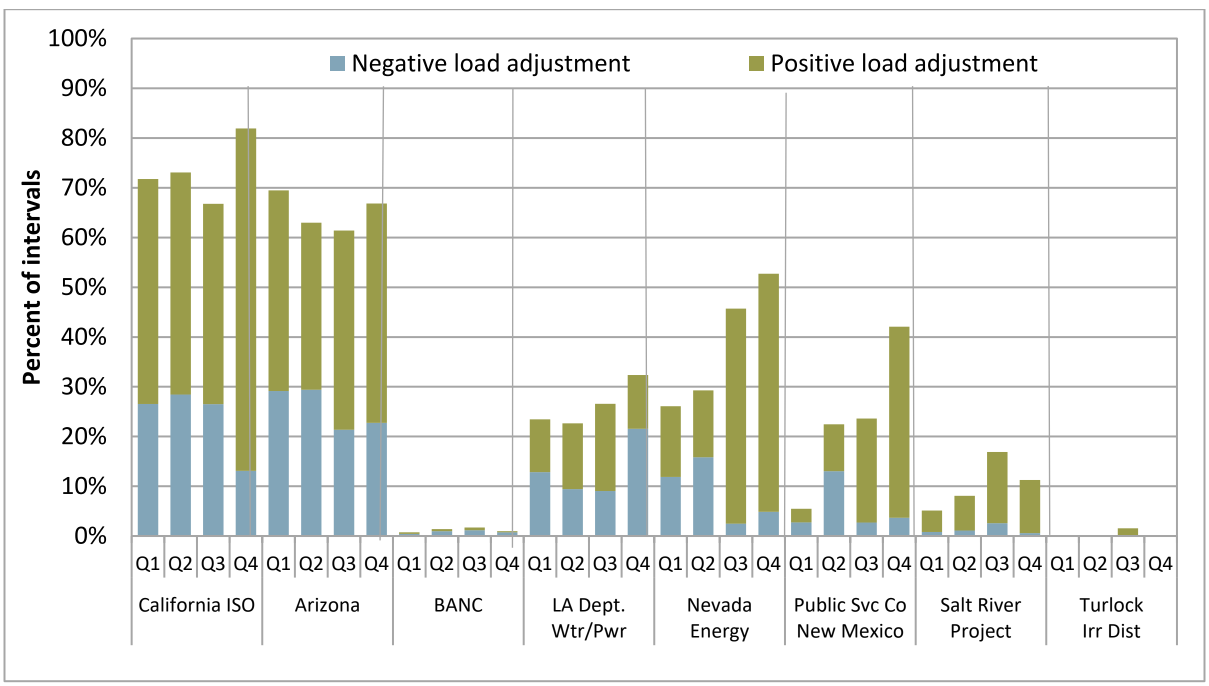


Figure 7.19 Average frequency of positive and negative load adjustments: 2022 WEIM – East and within California (5-minute market)



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.[245] This can occur for a variety of reasons, including the following:

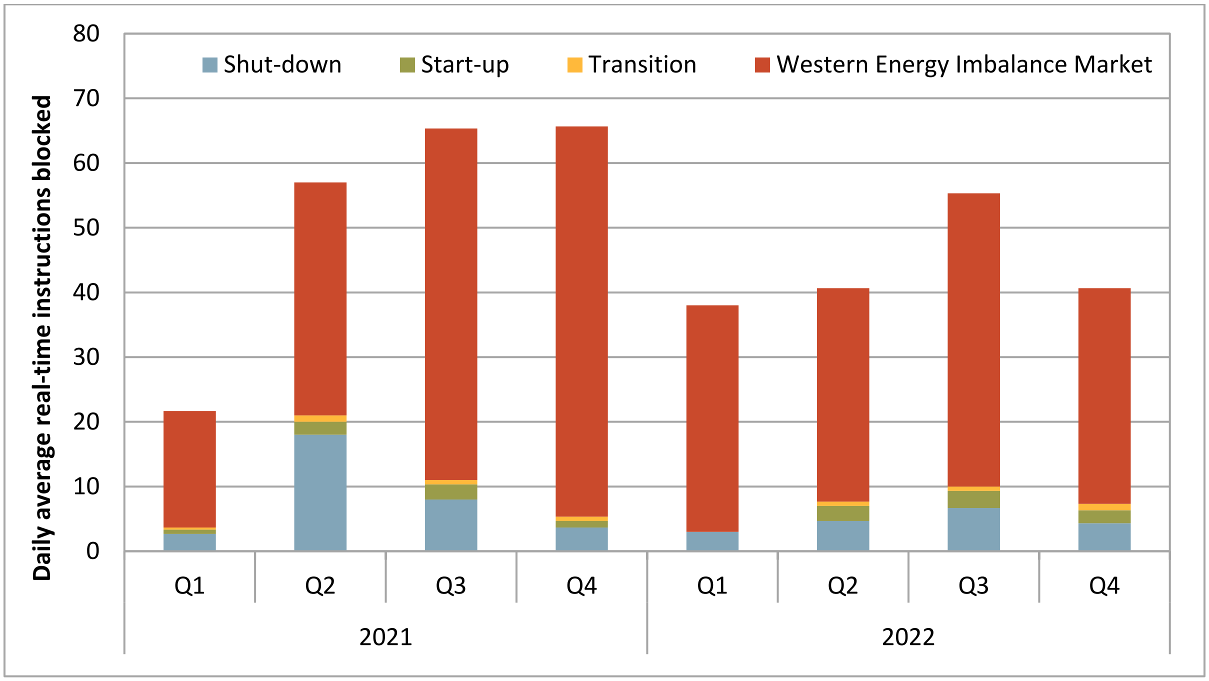
- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, telemetry data is an input to the real-time market system. If that telemetry is incorrect, the market model may try to commit or de-commit 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.

Within the CAISO, blocked instructions decreased from a daily average of ten (10) in 2021 to seven (7) in 2022 (blue, green, and gold bars in Figure 7.20). Figure 7.20 shows the frequency of blocked real-time commitment start-up, shut-down, and multi-stage generator transition instructions. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 67 percent in 2022, a decrease from about 79 percent in the previous year.

Blocked start-up instructions accounted for about 25 percent of blocked instructions within the CAISO in 2022, an increase from 15 percent the previous year. Blocked transition instructions to multi-stage generating units increased from about 6 percent in 2021 to about 8 percent in 2022. The average number of instructions blocked by Western Energy Imbalance Market operators (red bars in Figure 7.20) was 37 per day in 2022, a decrease from 42 in 2021.

[245] California ISO, *Market performance metric catalog 2020.* 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 7.20 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 the entire real-time dispatch instructions and prices from reaching the market.

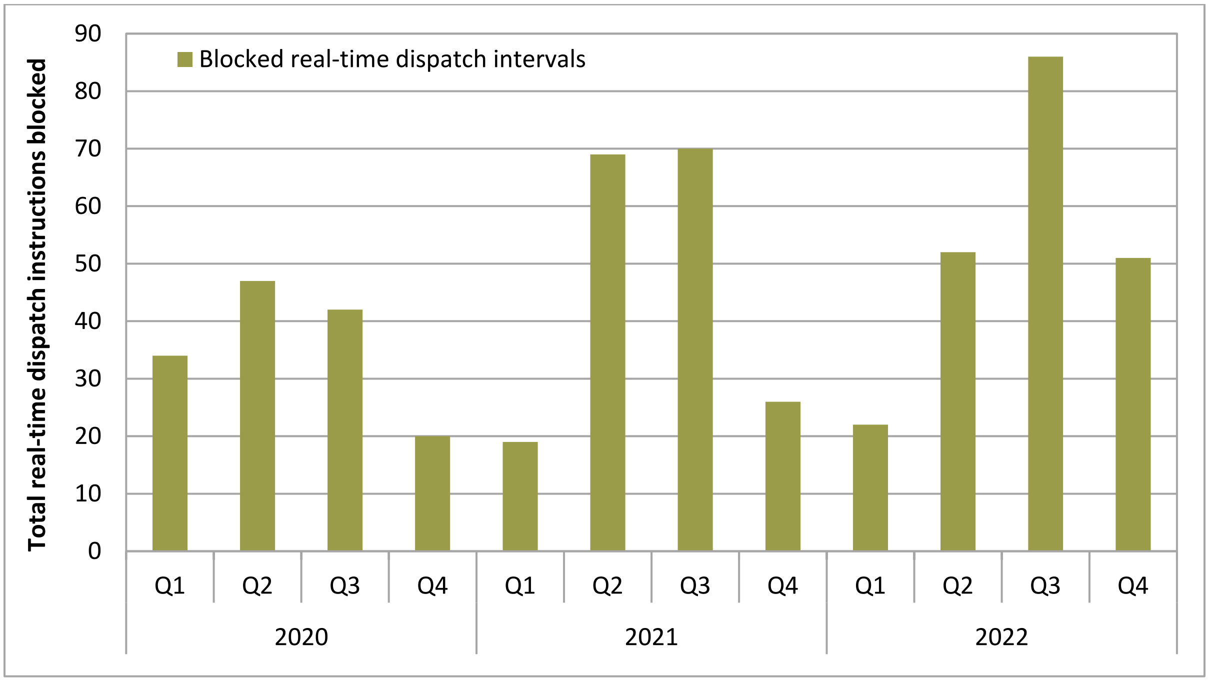
The California ISO began blocking dispatches in 2011, as both market participants and California ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often have caused participants to 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.[246]

Figure 7.21 shows the frequency that operators blocked price results in the real-time dispatch from the first quarter 2020 through 2022. The total number of blocked intervals in 2022 increased about 15 percent from the previous year.

246 For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

Figure 7.21 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 78 percent coverage of annual instantaneous peak load, contingency reserve, and self-scheduled exports.** The annual instantaneous peak load in 2022 reached 52,061 MW. Accounting for a 6 percent contingency reserve requirement and self-scheduled exports, resource adequacy capacity bids provided 79 percent coverage for the combined demand in the day-ahead market and 76 percent in the real-time market.
- **Investor-owned utilities procured most system resource adequacy capacity.** Investor-owned utilities accounted for about 61 percent of procurement, community choice aggregators contributed 22 percent, municipal utilities contributed 8 percent, and direct access services contributed 8 percent.
- **Use-limited resources comprised over half of resource adequacy capacity** and were thus exempt from California ISO bid insertion in all hours.
- **In the real-time market, 89 percent of system resource adequacy capacity was bid or self-scheduled during system emergency hours.** During "EEA Watch+" hours in 2022, 95 percent of system resource adequacy capacity was available in the day-ahead market after outages, with 91 percent offered. Real-time availability was 93 percent after outages, with 89 percent offered. This analysis caps offered bids at individual resource adequacy values.
- **Bids from CPUC jurisdictional import resource adequacy resources exceeded $0/MWh only during a few peak hours in 2022**. 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 fewer megawatts into the day-ahead market than the previous year for the second year in a row.** Imports bid in an average of about 2,900 MW during peak hours in August and September of 2022. This is down from an average of about 3,800 MW in the same months of 2021 and 5,300 MW in 2020.
- **Overall, total local resource adequacy capacity exceeded requirements in local capacity areas**. Significant amounts of energy beyond requirements were available in the day-ahead market for several local capacity areas, but procurement in other local capacity areas was lower than the local area requirements.
- **In 2022, RAAIM penalties and payments were fairly evenly distributed between generic and flexible resource adequacy resources.** In 2022, RAAIM charges were about $35 million and incentive payments were about $25 million. About 46 percent of penalties and 54 percent of payments were to generic resource adequacy resources.

8.1 Background

The purpose of the resource adequacy program is to ensure the California ISO system 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;
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, 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.[247]

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) which was between 20 and 22.5 percent for summers of 2022-2023.[248,249] 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.[250] 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 2022:

---

247 Previous annual reports analyzed resource adequacy availability during the top 210 load hours of the year.

248 The planning reserve margin reflects operating reserve requirements and additional capacity to cover potential forced outages and load forecast error.

249 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.

250 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 2022 resource adequacy year[251]

Decision	Title	Description
D.20-06-002	Decision on the Central Procurement of Resource Adequacy Program	Central Procurement Entities in the PG&E and SCE distribution service areas receive the total share of multi-year local RA requirements for the 2022-2024 compliance years. LSEs in these areas receive initial RA allocations for 2022 but are not allocated local requirements for 2023 and 2024. LSEs in the SDG&E area will continue to self-procure local resources to fulfill their local requirements.
D.20-06-031	Decision Adopting Local Capacity Obligations for 2021, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program	The Commission declined to adopt the reliability criteria in CAISO's Final 2021 LCR Report. The study used revised reliability criteria to align with NERC and WECC standards. This resulted in large increases in capacity requirements for some local areas compared to previous year reports. For the Greater Bay local area, the Commission adopted the 2020 Local Capacity Requirement study results for 2022 and 2023. The Commission adopted 2022 and 2023 Local Capacity Requirements for all other local areas.
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 or 2022 and 2023	The Commission ordered an increase in peak and net peak supply resources, reduced peak and net peak demand, and changes to the balancing accounts to cover the cost of these programs. Of the increase in supply resources, the Commission ordered the IOUs to procure of 2,000 MW to 3,000 MW of contingency reserves to meet an effective PRM of 20% to 22.5% for the summer months of 2022 and 2023.

251 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

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.[252] 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.[253] 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.[254]

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 be available at least 200 hours across summer months.[255]

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. As of 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.[256] Table 8.2 and Table 8.3 provide categories and descriptions of the AWE and EEA systems, respectively, and how hours with these notifications are included in the analysis of this section.

252 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.

253 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.

254 In addition, this analysis no longer filters out long-start resources that bid into the day-ahead but do not have a day-ahead or residual unit commitment schedule from real-time analysis.

255 200 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 200 hours across summer months. CPUC decision D.20-06-031 changed this number from 210 hours in previous years.

256 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)[257]

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 it has taken all actions listed above and cannot meet expected energy and contingency reserve requirements. 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.				

257 Upon declaration of EEA3, all impacted entities will be alerted without delay, within 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

Table 8.3 Alert, Warning, and Emergency notification categories and analysis groups (prior to 4/1/2022)

Notification Category	Description	Analysis Category		
		Flex Alert	RMO+	Alert+
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	
Alerts	Issued by 3 p.m. the day before anticipated energy deficiency. The California ISO may require additional resources to avoid an emergency.		X	X
Warnings	Indicate that grid operators anticipate using operating reserves. Activates demand response programs (voluntary load reduction) to decrease overall demand.		X	X
Stage 1 Emergency	Declared by the California ISO if Contingency Reserve shortfalls exist or are forecast to occur. Strong need for conservation.		X	X
Stage 2 Emergency	Declared by the California ISO when all mitigating actions have been taken and the California ISO is no longer able to provide for its expected energy requirements. Requires California ISO intervention in the market, such as ordering power plants on-line.		X	X
Stage 3 Emergency	Declared by the California ISO when unable to meet minimum contingency reserve requirements, and load interruption is imminent or in progress. Notice issued to utilities of potential electricity interruptions through firm load shedding.		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.		X	X
1-Hour Probable Load Interruptions	Declared by the California ISO to encourage maximum conservation efforts for the time period. Utility Distribution Companies and Metered Subsystems await further orders from the California ISO. This notice is being issued in compliance with the Governor's Executive Order D-38-01.		X	X

The following analysis groups emergency notification hours to show availability and performance during a variety of stressed system conditions. The last three columns in Table 8.3 show the system emergency analysis categories, which are necessary because the emergency notifications are not mutually exclusive and may not occur in a chronological fashion. The California ISO may request reliability coordinators to issue and EEA 1, EEA 2, or EEA 3, depending upon the circumstance.[258] 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.

[258] 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

There are three categories of analysis for each year, and while two of them remain consistent year-over-year, the third category underwent changes at the beginning of 2022. The *Flex Alert* and *RMO+* categories are consistent across years*.* 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 *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.[259] Flex Alerts typically 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 *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. Finally, the EEA Watch+ category includes hours in 2022 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.

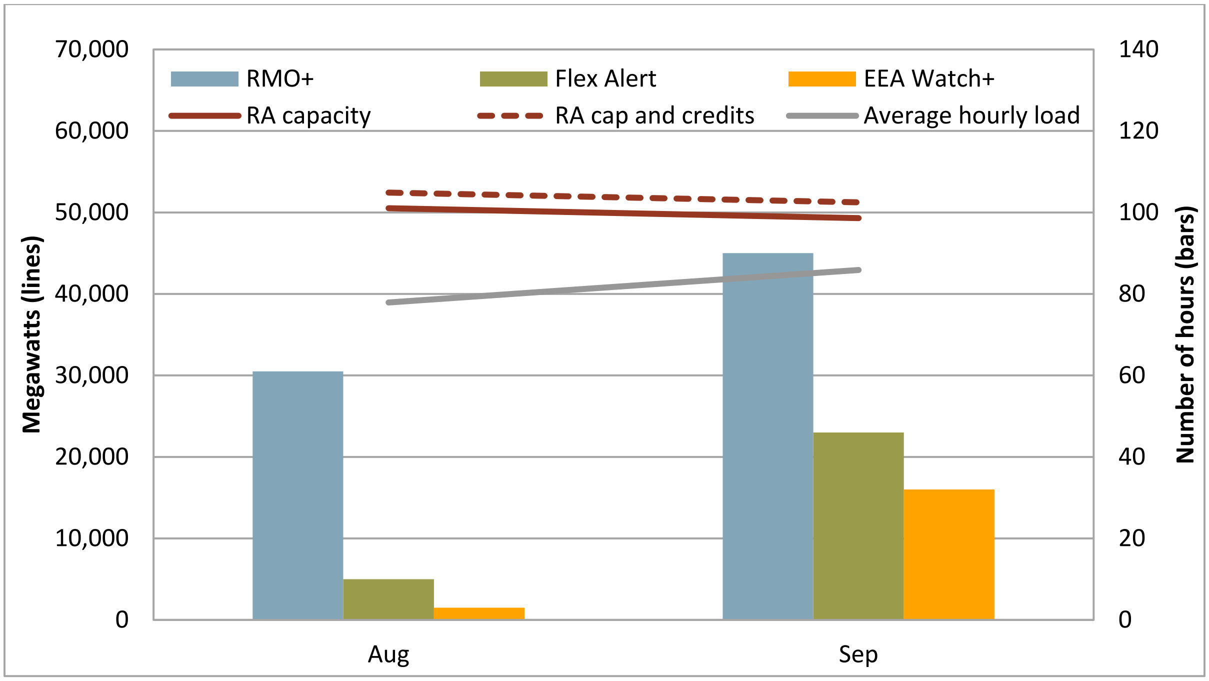
Figure 8.1 provides an overview of resource adequacy capacity during system emergency notification hours in 2022. The green, blue, and yellow bars show the number of hours, by month, that are in the *RMO+, Flex Alert*, and *EEA Watch+* categories, respectively. These categories are clustered bars, as 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.[260] The dashed red line adds the additional capacity the CPUC credits towards load serving entity obligations, as well as legacy reliability must-run capacity.[261]

[259] California ISO, *2021 Summer readiness:* http://www.caiso.com/about/Pages/News/SummerReadiness.aspx

[260] Monthly average load and procured resource adequacy capacity is weighted by the number of RMO+, Flex Alert, and Alert+ hours.

[261] These credits include capacity from utility demand response programs with a PRM adder as well as liquidated damage credits.

Figure 8.1 Average hourly resource adequacy capacity and load (2022 emergency notification hours)



Key findings of this analysis include:

- **Hours with stressed system conditions were constrained to the summer months in 2022.** There were 160 total hours with RMO+ emergency notifications, 66 Flex Alert hours, and 33 EEA Watch+ hours. These emergency hours were exclusively confined to August and September in 2022, especially during the exceptional heat wave that took place between late August and early September.
- **The most severe emergency notifications in 2022 occurred between August 31 and September 9.** There were 110 RMO+ hours, 61 Flex Alert hours, and 44 EEA Watch+ hours in this week. The EEA Watch+ hours include four hours on September 6 when the California ISO issued an Energy Emergency Alert 3 (EEA 3). During these hours, the California ISO market failed to meet its expected energy and contingency reserve requirement because of a record-breaking heat wave and demand, putting the system at risk of controlled power outages.
- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2022**. Average hourly load was 40,896 MW during these hours, while average resource adequacy capacity was 49,300 MW. During the EEA 3 event, the average hourly load and resource adequacy capacity increased to 43,429 MW and 49,379 MW for the load and capacity, respectively.
- **Energy Emergency Alert (EEA) Watch+ events occurred between hour ending (HE) 16 and 22.** The distribution of EEA Watch+ hours included: HE 16 (3 percent), HE 17 (11 percent), HE 18 (20 percent), HE 19 (26 percent), HE 20 (23 percent), HE 21 (11 percent), and HE 22 (6 percent).

Table 8.4 shows capacity procurement, de-rates, availability, and performance of system resource adequacy resources during emergency notification hours from 2020 to 2022. Bids and self-schedules, cleared schedules, and meter amounts are capped by resource adequacy capacity at the resource level, unless otherwise indicated.[262]

Table 8.4 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-schedule	Schedules	Capacity de-rate	Bids and self-schedule	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%

Key findings of this analysis include:

- **A small percentage of procured capacity was on outage during stressed hours from 2020 to 2022.** The day-ahead and real-time markets could access between 92 and 95 percent of procured capacity during these hours. Gas-fired generators and hydro generators de-rated their capacity 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 91 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 2022, 90-91 percent of the procured capacity was bid or self-scheduled into the day-ahead market, and 89-90 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 non-peak hours.
- **During the most critical hours with EEA 2 and EEA 3, the majority of resource adequacy was available to the market.** The California ISO declared EEA 2 and EEA 3 alerts for a total of 17 hours during the 2022 heatwave. Despite the challenging conditions, the percentage of outages was low, with 93-95 percent of resource adequacy available. Furthermore, 91 and 89 percent of capacity bid into the day-ahead and real-time market, respectively. On average, 86 percent of resource adequacy was scheduled during EEA 2 and EEA 3.
- **Resource adequacy capacity provided 78 percent coverage for the combined annual peak load, contingency reserve, and self-scheduled export.** On September 6, the annual instantaneous peak load reached 52,061 MW around the hour ending 17. The California ISO declared an Energy

262 The current metrics for schedule and bid only consider the discharge MW for all storage and hydro resources. In contrast, all reports from the past year included both discharge and charge MW in bids and schedules for these resources.

Emergency Alert 2 (EEA 2) during this particular hour.[263] Resource adequacy capacity bids amounted to 45,561 MW for the day-ahead market and 44,350 MW for the real-time market during this hour. Accounting for a 6 percent contingency reserve requirement and self-scheduled exports, the total demand was 57,493 MW for the day-ahead market and 58,041 MW for the real-time market. The resource adequacy capacity bids provided 79 percent coverage for the combined demand in the day-ahead market and 76 percent in the real-time market.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 8.5 shows capacity procurement by resource type, capacity de-rates, availability, and performance of system resource adequacy resources during EEA Watch+ hours in 2022.[264] 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).

Table 8.5 Average system resource adequacy capacity, availability, and performance by fuel type (EEA Watch+ hours)

Resource type	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedule	Schedules	Capacity de-rate	Bids and self-schedule	Schedules	Uncapped schedules	Uncapped schedules + AS		
Must-Offer:											
Gas-fired generators	19,415	93%	93%	91%	90%	90%	86%	88%	89%	89%	83%
Other generators	1,489	93%	93%	88%	93%	93%	91%	97%	97%	88%	93%
Subtotal	20,903	93%	93%	91%	91%	90%	86%	89%	90%	90%	83%
Other:											
Imports	3,171	98%	95%	93%	100%	94%	92%	94%	94%	90%	90%
Imports-MSS	273	100%	46%	46%	100%	49%	46%	46%	46%	46%	46%
Use-limited gas units	9,010	93%	92%	90%	91%	90%	73%	76%	86%	68%	68%
Hydro generators	5,335	97%	93%	92%	95%	92%	67%	78%	103%	63%	63%
Nuclear generators	2,774	100%	100%	100%	100%	100%	100%	104%	104%	99%	99%
Solar generators	2,036	100%	51%	51%	98%	57%	54%	157%	157%	47%	47%
Wind generators	1,141	100%	56%	55%	100%	80%	79%	165%	165%	65%	65%
Qualifying facilities	876	97%	95%	94%	92%	90%	88%	106%	106%	86%	86%
Demand response (PDR)	417	97%	67%	24%	94%	51%	35%	36%	36%	14%	14%
Storage	2,774	93%	92%	70%	92%	92%	51%	53%	84%	31%	31%
Other non-dispatchable	679	96%	91%	78%	93%	90%	83%	89%	96%	76%	76%
Subtotal	28,487	96%	88%	84%	95%	88%	73%	88%	99%	67%	79%
Total	**49,390**	**95%**	**90%**	**87%**	**93%**	**89%**	**79%**	**89%**	**95%**	**74%**	**81%**

Key findings of this analysis include:

- **Gas-fired generators accounted for about 58 percent of capacity procurement**. Gas-fired resources (gas-fired must-offer generators and use-limited gas units) supplied about 28,400 MW of resource adequacy capacity during the EEA Watch+ hours of 2022.

263 In 2022, the annual instantaneous peak load was observed on September 6 at 4:57 p.m. The California ISO issued an EEA 2 at 4:00 p.m. Subsequently, the ISO declared an EEA 3 at 5:17 p.m. For further information on the history of grid emergency, see: http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

264 Bids and self-schedules in the day-ahead and real-time markets are reported as the proportion of total resource adequacy capacity.

- **Resources that are not availability-limited accounted for just 42 percent of system capacity.** About 21,000 MW of system capacity was subject to California ISO bid insertion 24x7.[265] Gas-fired generation in this category made up about 19,400 MW (39 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 9,000 MW of total capacity (18 percent). Hydro generators contributed 11 percent, imports (including metered subsystems) contributed 7 percent, solar resources contributed 4 percent, nuclear resources contributed 6 percent, wind resources contributed 2 percent, qualifying facility resources contributed 2 percent, storage contributed 6 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 resource increased significantly in 2022.** In 2021, storage resources accounted for 2 percent of total resource adequacy capacity. However, in 2022, procured storage megawatts increased by 220 percent, causing storage resources to comprise 6 percent of the total capacity.
- **Storage and hydro resources significantly contributed to the provision of ancillary services during the EEA Watch+ hours.** The “uncapped schedules + AS” column presents real-time scheduling for RA and partial RA resources with their 15-minute ancillary service schedules. Initially, storage resources were scheduled at only 53 percent of their RA capacity. However, upon inclusion of ancillary service schedules, the percentage of scheduled capacity rose to 84 percent. Hydro units were scheduled 103 percent of their RA capacity incorporating RA and partial RA energy and ancillary service schedules.
- **Capacity available after reported outages and de-rates continued to be significant**. Average resource adequacy capacity was around 49,390 MW during the EEA Watch+ hours in 2022, similar to 49,359 MW in 2021. After adjusting for outages and de-rates, the remaining capacity in the day-ahead market was about 95 percent of the overall resource adequacy capacity, which was about 2 percent higher than in 2021.
- **The day-ahead market showed higher capacity availability in 2022 compared to the previous year.** 93 percent of must-offer and 96 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 EEA Watch+ 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 90 percent of must-offer and 88 percent of non-must-offer capacity bid or self-scheduled in the real-time market. These totals are capped by individual resource adequacy values. Most of proxy demand response and import MSS resources did not bid into the day-ahead and real-time market, with only 51 percent of demand response and 49 percent of import MSS capacity bidding into the real-time market. These resource categories typically exhibit low bid availability as a percentage of procured capacity. The performance of import resources in the real-time market showed an

[265] 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.

increase in 2022, with 94 percent of these resources bidding into the market, compared to 88 percent in 2021.

- **A higher percentage of procured must-offer resources cleared and generated in the real-time market compared to non-must-offer resources.** About 83 to 86 percent of procured must-offer capacity cleared the real-time market and metered, compared to 67 to 73 percent of non-must-offer capacity. These percentages are capped by individual resource adequacy values. The performance of must-offer and non-must-offer resources is more similar when accounting for the remaining capacity of partial resource adequacy resources in the uncapped schedules and meter. This is mainly due to the generation of wind resources above their NQC values.

Table 8.6 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.[266] 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.

Table 8.6 Average system resource adequacy capacity and availability by load type (EEA Watch+ hours)

Load Type	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedule	Schedules	Capacity de-rate	Bids and self-schedule	Schedules	Uncapped schedules		
Community choice aggregator	10,972	95%	90%	84%	93%	89%	80%	92%	75%	85%
Direct access	3,890	94%	88%	85%	91%	86%	79%	94%	75%	86%
Investor-owned utility	30,230	95%	92%	89%	93%	90%	78%	87%	73%	79%
Municipal/government	3,918	97%	86%	83%	97%	87%	80%	88%	77%	83%
Not on a plan	380	82%	78%	77%	82%	71%	76%	77%	75%	76%
Total	**49,390**	**95%**	**90%**	**87%**	**93%**	**89%**	**79%**	**89%**	**74%**	**81%**

Key findings of this analysis include:

- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 30,000 MW (or 61 percent) of system resource adequacy procurement, community choice aggregators contributed 22 percent, municipal utilities contributed 8 percent, and direct access services contributed 8 percent.
- **Capacity for all load types had similar availability in the day-ahead and real-time markets.** Resources bid on average 90 percent of procured capacity from the four load types in these markets. These bids are capped by individual resource adequacy values.
- **Investor-owned utilities, municipal utilities, and community choice aggregators contracted with a majority of resources with availability limitations that are not subject to California ISO bid**

[266] 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.

insertion. Investor-owned utilities procured 65 percent of their resource adequacy capacity from these resources, while municipal utilities procured 67 percent, community choice aggregators procured 39 percent, and direct access services procured 46 percent.

- **Municipal utilities were the only load type that procured a significant amount of imports to meet system resource adequacy requirements.** Municipal utilities procured 15 percent of their resource adequacy capacity from imports, while community choice aggregators procured 4 percent, direct access services procured 5 percent, and investor-owned utilities procured 7 percent. Omitting metered subsystem imports reduces this to 8 percent for municipal utilities.
- **Load type capacity performance was similar, but direct access service and municipal utilities had marginally lower bids in the market.** Direct access services and municipal utilities typically bid 2 to 6 percent lower in the day-ahead and real-time markets compared to other load types.

Table 8.7 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.[267]

Table 8.7 Average system resource adequacy capacity and availability by RAAIM category (EEA Watch+ hours)

RAAIM category	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedule	Schedules	Capacity de-rate	Bids and self-schedule	Schedules	Uncapped schedules		
Non-RAAIM exempt	40,044	95%	94%	90%	93%	92%	81%	85%	76%	79%
RAAIM exempt	9,346	94%	76%	74%	92%	78%	70%	106%	63%	91%
Total	**49,390**	**95%**	**90%**	**87%**	**93%**	**89%**	**79%**	**89%**	**74%**	**81%**

Key findings of this analysis include:

- **RAAIM exempt resources accounted for about 19 percent of overall resource adequacy capacity during the EEA Watch+ hours of 2022.** This was mostly solar, gas, and wind resources.
- **RAAIM exempt resources bid and performed at a lower percentage in the markets**. RAAIM exempt capacity bid 76 to 78 percent of their capacity, while non-RAAIM exempt bid 92 to 94 percent of their capacity into the markets during emergency notification hours. This considers bids capped at individual resource adequacy values. Including the remaining capacity from partial resource adequacy resources, nearly 120 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. About 106 percent of total capacity from RAAIM exempt resource adequacy and their partial resource adequacy resources cleared in real-time.

[267] 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

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.[268]

DMM expressed concern that these rules could allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions. For example, imports could routinely bid significantly above projected prices in the day-ahead market to ensure they do not clear and would then have no further obligation to be available in the real-time market.

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, at minimum, during the availability assessment hours.[269] 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. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports. In 2022, CPUC-jurisdictional entities submitted import bids exceeding $0/MWh during only a limited number of hours within the Availability Assessment Hours period.

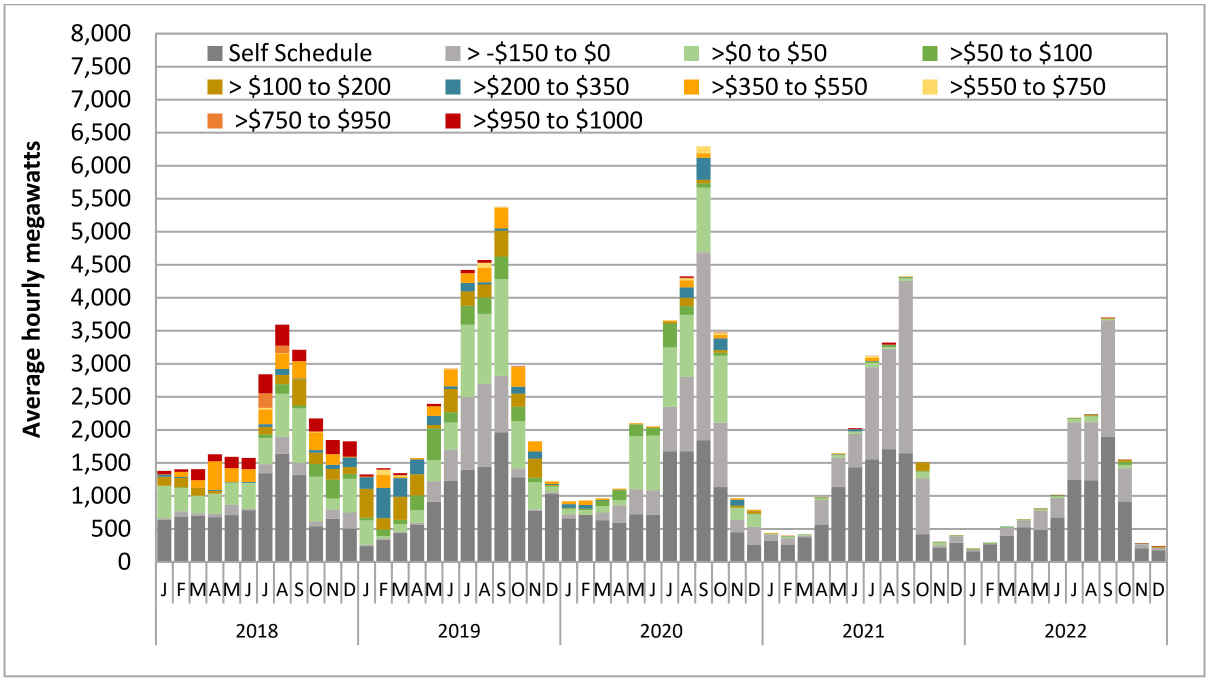
Figure 8.2 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market during peak hours.[270] The grey bars reflect import capacity that was either self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

[268] 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.

[269] CPUC Docket No. R.17-09-020, *Decision Adopting Resource Adequacy Import Requirements (D.20-06-028)*, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

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

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 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.[271]

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.

---

[271] For additional information, see: FERC Docket No. ER14-2574, *149 FERC ¶ 61,042, Order on Tariff Revisions,* October 16, 2014: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf

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.[272,273] 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.[274]

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.

- **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.

---

272 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.

273 Net load is total load less wind and solar production.

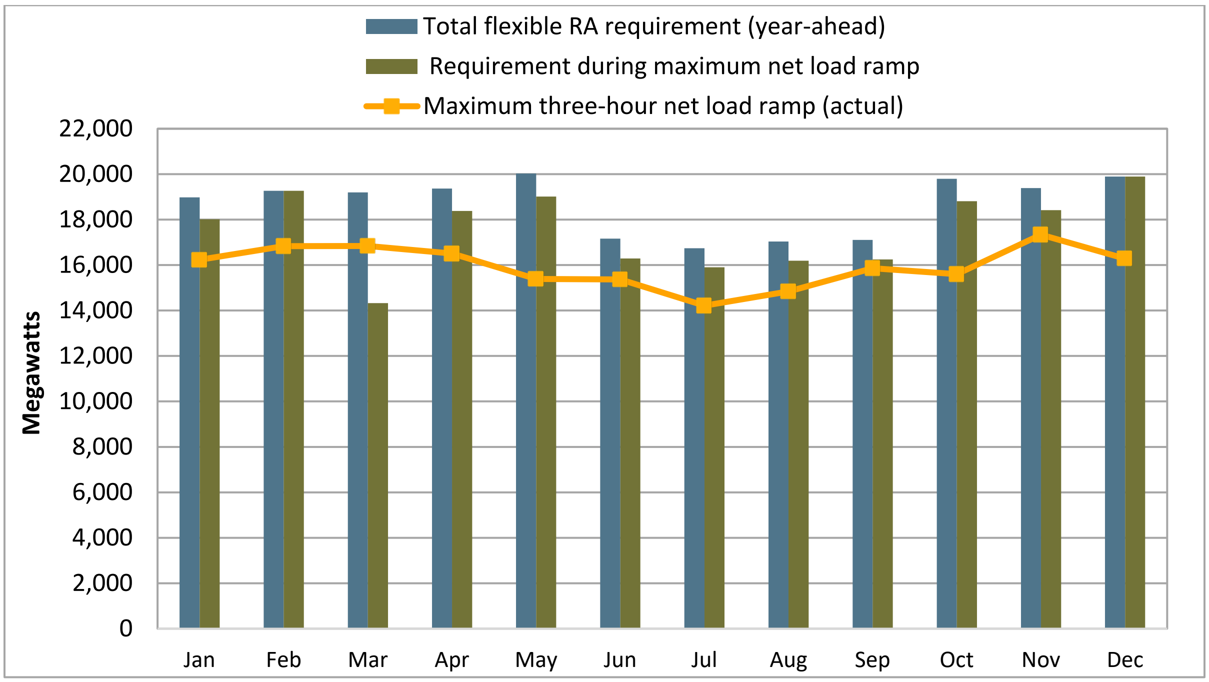
274 The California ISO system typically experiences two extended periods of net load ramps, one in the morning, and one in the evening. The magnitude and timing of these ramps change throughout the year. The larger of the two three-hour net load ramps (the primary ramp) generally occurs in the evening. The must-offer obligation hours vary seasonally based on this pattern for Category 2 and 3 flexible resource adequacy.

Requirements compared to actual maximum net load ramps

Figure 8.3 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2022 by comparing the requirements and the actual maximum three-hour net load ramp on a monthly basis.[275] 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.[276] 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.

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 2022.** 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 most months.** This is when the green bars

---

275 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.

276 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.

are higher than the gold line. Average requirements were not sufficient to meet the actual three-hour net load ramp in March.

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 2022 requirements and must-offer hours were sufficient in reflecting actual ramping needs in the vast majority of cases.

Table 8.8 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 8.8 Maximum three-hour net load ramp and flexible resource adequacy requirements

Month	Maximum 3-hour net load ramp (MW)	Total flexible RA requirement (MW)	Average requirement during maximum net load ramp (MW)	Date of maximum net load ramp	Ramp start time	Average requirement met ramp? (Y/N)	Why average requirement during max net load ramp was less than the maximum 3-hour net load ramp
Jan	16,234	18,979	18,019	1/23/2022	14:20	Y	
Feb	16,831	19,267	19,267	2/2/2022	14:25	Y	
Mar	16,843	19,199	14,326	3/11/2022	14:40	N	Ramp start time occurred before Category 2 requirement.
Apr	16,506	19,366	18,384	4/24/2022	16:20	Y	
May	15,390	20,027	19,012	5/8/2022	16:40	Y	
Jun	15,369	17,164	16,292	6/5/2022	16:50	Y	
Jul	14,216	16,740	15,905	7/2/2022	16:55	Y	
Aug	14,839	17,039	16,189	8/21/2022	15:55	Y	
Sep	15,862	17,107	16,251	9/17/2022	15:45	Y	
Oct	15,600	19,796	18,808	10/30/2022	14:55	Y	
Nov	17,336	19,385	18,413	11/13/2022	14:00	Y	
Dec	16,284	19,895	19,895	12/13/2022	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 most months.** The average requirement was at least 380 MW greater than the maximum 3-hour net load ramp in most months. The only month where average requirements were less than the net load ramp was March.
- **In March, the maximum net load ramp occurred at least partially outside of Category 2 and Category 3 must-offer hours.** The maximum net load ramp began an hour before Category 2 and Category 3 must-offer obligations.

Procurement

Table 8.9 shows what types of resources provided flexible resource adequacy and details the average monthly flexible capacity procurement in 2022 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 2022.

Table 8.9 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	10,732	54%	7	1%	0	0%
Use-limited gas units	5,522	28%	650	63%	50	9%
Use-limited hydro generators	1,270	6%	7	1%	0	0%
Other hydro generators	97	0%	0	0%	0	0%
Geothermal	420	2%	0	0%	0	0%
Energy Storage	1,675	8%	363	35%	521	91%
Total	**19,717**	**100%**	**1,027**	**100%**	**571**	**100%**

Key findings of this analysis include:

- **Gas-fired resources accounted for most flexible resource adequacy capacity procurement.** About 10,740 MW (or 50 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 2022.
- **Use-limited gas units made up the second largest volume of flexible resource adequacy capacity.** These generators made up 28 percent of Category 1 capacity and about 29 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 8 percent of Category 1 capacity.
- **Load serving entities procured more flexible capacity across all categories compared to the previous year.** Although the monthly average flexible RA requirement decreased by 300 MW in 2022 compared to the previous year, load serving entities procured 730 MW more capacity in category 1, 250 MW more in category 2, and 200 MW more in category 3.

Table 8.10 shows flexible resource adequacy procurement by load serving entity type in 2022 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 8.10 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	4,337	22%	86	8%	57	10%
DA	1,664	8%	32	3%	0	0%
IOU	13,072	66%	877	83%	514	87%
Muni	639	3%	62	6%	21	4%
Total	**19,712**	**100%**	**1,057**	**100%**	**592**	**100%**

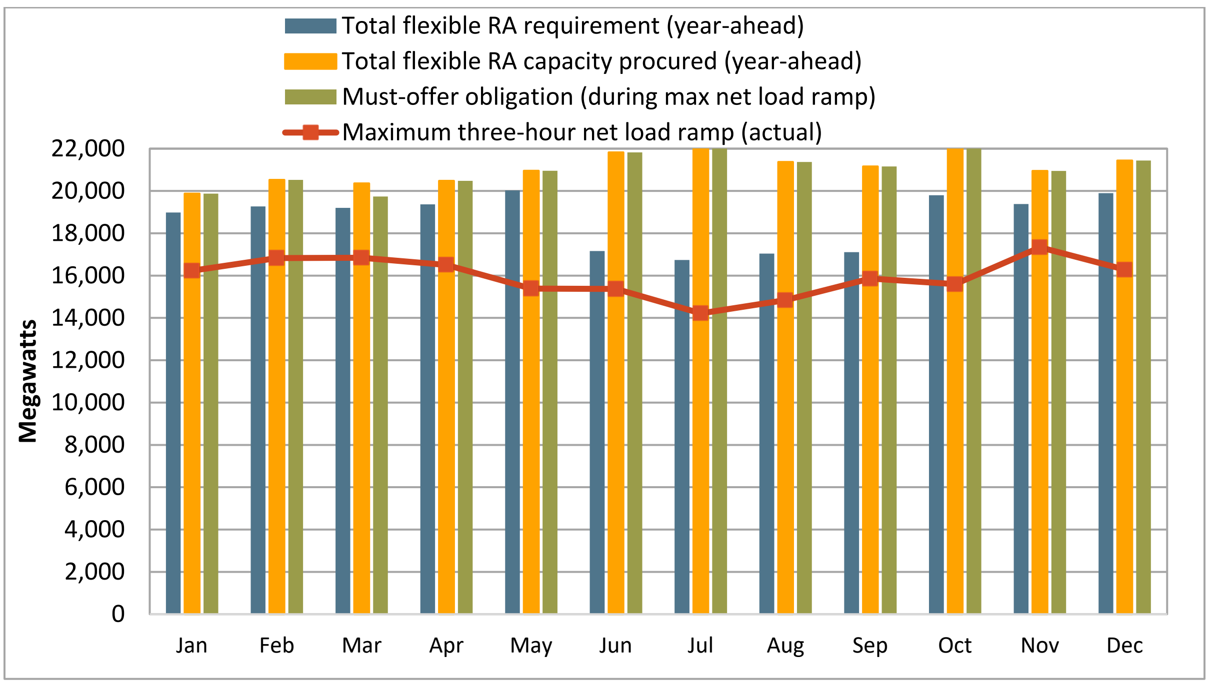
Key findings of this analysis include:

- **Investor-owned utilities procured the highest proportion of each flexible resource adequacy category**. Investor-owned utilities procured 68 percent of total flexible capacity, community choice aggregators procured 21 percent, direct access services procured eight percent, and municipal utilities procured three percent. Investor-owned utilities procured at least 66 percent of the capacity of each category.

- **Most load types procured resources for multiple flexible resource adequacy categories** Investor-owned utilities, community choice aggregators, and municipal utilities procured Category 1, 2, and 3 flexible resource adequacy resources. Direct access services did not procure any Category 3 capacity.
- **Community choice aggregators procured the second highest proportion of Category 3 flexible capacity**. CCAs procured most of their flexible capacity from Category 1 resources, but their procurement also contributed to a portion of total Category 3 (10 percent) capacity.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2022. 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.[277] 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

[277] 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.

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 2022.

Availability

Table 8.11 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 2022. This analysis is not intended to replicate the method by which how the resource adequacy availability incentive mechanism measures availability.

Table 8.11 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	18,886	17,252	91%	13,125	11,760	90%
February	19,250	16,004	83%	12,572	10,847	86%
March	18,661	13,365	72%	13,112	10,104	77%
April	19,123	14,999	78%	13,403	11,010	82%
May	19,803	15,490	78%	13,434	11,261	84%
June	21,033	18,347	87%	15,070	12,735	85%
July	21,083	18,646	88%	15,539	13,370	86%
August	20,490	18,263	89%	15,881	13,595	86%
September	20,208	17,245	85%	15,917	13,379	84%
October	21,274	18,666	88%	16,467	14,241	86%
November	19,824	16,455	83%	14,948	12,748	85%
December	19,536	16,915	87%	15,051	12,776	85%
Total	**19,931**	**16,804**	**84%**	**14,543**	**12,319**	**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 2022**. Average availability in the day-ahead market was 84 percent and ranged from 72 percent to 91 percent. This is slightly lower than 2021 when average availability in the day-ahead market was about 86 percent with a range from 78 percent to 90 percent. Average availability in the real-time market was 85 percent and ranged from 77 percent to 90 percent. This is slightly higher than 2021 when average real-time availability was 83 percent and ranged from 80 percent to 87 percent.

- **The real-time average must-offer obligation is much lower than the day-ahead obligation**. Flexible capacity must-offer requirements were about 16,800 MW in the day-ahead market and only about 12,300 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 8.12 includes the same data summarized in Table 8.11, but aggregates average flexible resource adequacy availability by the contracted resource load type. 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 8.12 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	4,389	3,764	86%	2,975	2,654	89%
DA	1,682	1,454	86%	1,295	1,158	89%
IOU	13,198	10,976	83%	9,663	8,001	83%
Muni	658	605	92%	607	502	83%
Total	**19,926**	**16,799**	**84%**	**14,539**	**12,315**	**85%**

Key findings from this analysis include:

- **Flexible resource adequacy resources had similar availability in the day-ahead and real-time markets across load types**. Resources that contracted with community choice aggregators had about 86 percent availability in the day-ahead market, those that contracted with direct access services had about 86 percent availability, and those that contracted with investor-owned utilities and municipalities had 83 to 92 percent availability. In the real-time market, these resources were available between 83 and 89 percent of the time, depending on load type.

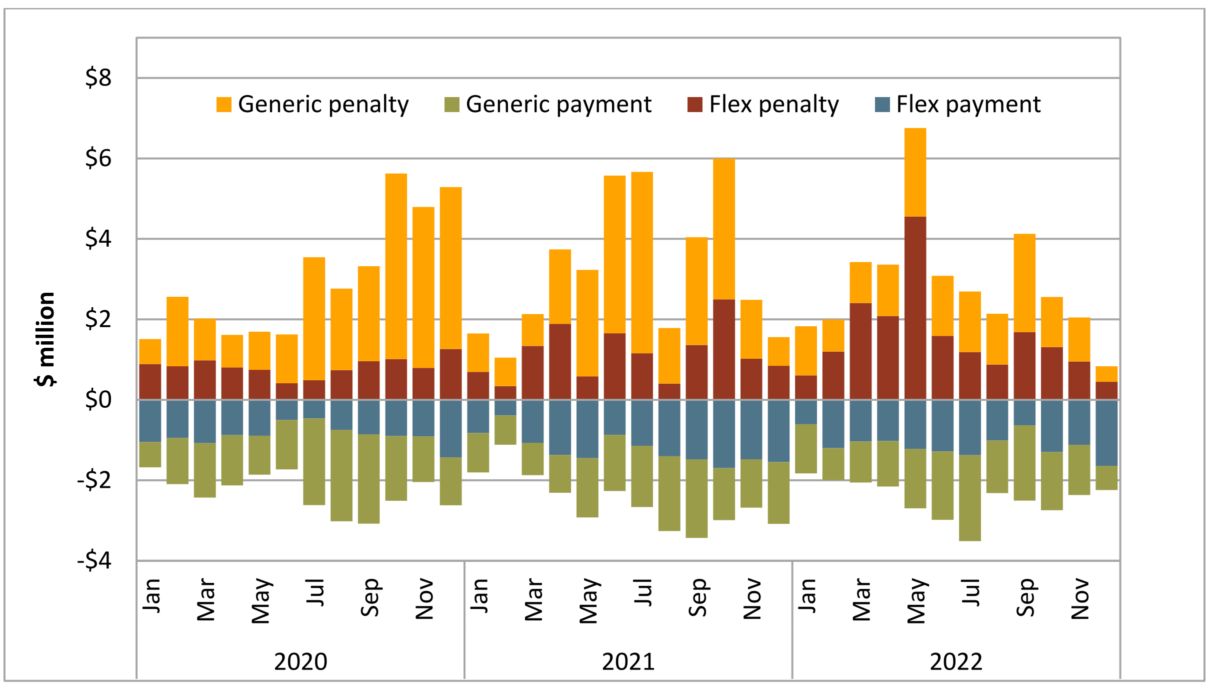
8.4 Incentive mechanism payments

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 2022 availability assessment hours for *system and local resource adequacy resources* were hours ending 17 to 21 and *flexible resource adequacy resources* were assessed for hours ending 6 to 22 for base ramping resources. For both peak ramping and super-peak ramping resources, these 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.[278]

Figure 8.5 summarizes monthly RAAIM charges and payments to resource adequacy resources from January 2020 to December 2022. 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



Key findings from this analysis include:

- **In 2022, RAAIM penalties and payments were fairly evenly distributed between generic and flexible resource adequacy resources.** In 2022, RAAIM charges were about $35 million and incentive

[278] 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.

payments were about $25 million. About 46 percent of penalties and 54 percent of payments were to generic resource adequacy resources.

- **In 2022, most RAAIM charges occurred in the second quarter.** In the second quarter, the RAAIM charges averaged 4.4 million per month, while in the first, third, and fourth quarters, it averaged about 2.4 million per month.

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 2022. Since the implementation of the current capacity procurement mechanism framework in 2016, the only annual designations were made in 2018.

Monthly designations

There were no monthly capacity procurement mechanism designations made in 2022, and there have not been any since the program was implemented in 2016.

Intra-monthly designations

Table 8.13 shows the intra-monthly capacity procurement mechanism designations that occurred in 2022. The table shows the designated resources, amount of megawatts procured, the date range of the designation, the price, estimated cost of the procurement, the area that had insufficient capacity, and the CPM designation details.

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
ELCAJN_6_UNITA1	19	8/31/22	10/29/22	ED	$6.31	$0.24	SDG	CPM Designation for Exceptional Dispatch to address a potential thermal overload in the San Diego Local Area for the next contingency event
MRCHNT_2_PL1X3	36	9/1/22	9/30/22	ED	$6.31	$0.23	SYS	Initial CPM Designation
PALOMR_2_PL1X3	64	9/1/22	9/30/22	ED	$6.31	$0.41	SYS	Initial CPM Designation
Total	120					$0.88		

Key findings of this analysis include:

- **In 2022, about 120 MW of capacity was procured through the competitive solicitation process at an estimated cost of $0.9 million, with the entire capacity being procured during the September heat wave period.** In response to climate change and extreme heat events in early September, the California ISO issued Exceptional Dispatch Capacity Procurement Mechanism (CPM) designations to address a system reliability. During this period, the California ISO procured 120 MW of capacity through the solicitation process at a total cost of about $0.9 million to address the exceptional dispatch system reliability need. During this time, the ISO procured extra capacity from a group of RA resources above their RA capacity. This extra procurement, along with its associated cost, is documented in Chapter 2. The cumulative expense for this additional procurement reached a total of $2.4 million.
- **In 2022, intra-monthly capacity procurement significantly dropped compared to 2021.** A total of 1,980 MW of capacity was procured through CPM in 2021, at a cost of $9.8 million. However, in 2022, the California ISO procured only 6 percent of the 2021 CPM capacity, amounting to a significantly lower cost of $0.9 million. Taking into account the extra procurement from a group of RA resources beyond their RA capacity, the total cost remained at $2.4 million in 2022.
- **Several 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 2022, capacity designated as reliability must-run (RMR) totaled about 469 MW. Total settlement for reliability must-run capacity was about $48 million, which is $10 million higher than in

2021. 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 8.16 shows designated reliability must-run resources from 2016 through 2022. 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.[279] 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.

Table 8.14 Designated reliability must-run resource capacity (2016–2022)

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.[280] Ultimately, this did not happen because it received a resource adequacy contract in 2022. On January 20, 2022, this

279 These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

280 California ISO, *Potential reliability must-run designation – Agnews Power Plant,* presented by Catalin Micsa, May 18, 2021: http://www.caiso.com/Documents/PresentationPotentialReliabilityMustRunDesignationAgnewsPowerPlant-May182021.pdf

resource notified the California ISO of its intention to retire on January 1, 2023, and repower the site. Since this resource is required to meet local reliability needs in San Jose sub-area, the California ISO is recommending designating it for reliability must-run services for year 2023.[281]

In 2022, the Kingsburg Cogen unit has secured a multi-year resource adequacy capacity contract, and as a result, will 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 RMR their contract effective midnight on December 31, 2022.[282] 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 will amount 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.[283] 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.

281 California ISO Market Notice, *Potential Reliability Must-Run Designation: Agnews Power Plant*, May 19, 2022: http://www.caiso.com/Documents/Potential-Reliability-Must-Run-Designation-Agnews-Power-Plant-Call-051922.html

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

283 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 California ISO's independent market monitor, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives to the California ISO, the California ISO Governing Board, FERC staff, state regulators, market participants, and other interested entities.[284] DMM participates in the CAISO stakeholder process and provides recommendations in written comments. DMM also provides recommendations in quarterly, annual, and other special reports, which are also posted on the CAISO 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 CAISO website.[285] A summary of key recommendations is provided in the executive summary of this report.

9.1 Extended day-ahead energy market

In 2022, the California ISO continued a multi-year process to develop a proposal for extending the day-ahead market (EDAM) which include other entities in the Western Energy Imbalance Market. In early 2023, the CAISO Board and WEIM Governing Body approved an extended day-ahead market (EDAM) proposal to be filed at FERC and implemented as soon as 2024.[286]

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 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 CAISO Board and WEIM Governing Body on the EDAM proposal.[287]

The ISO has made significant progress toward developing a workable design 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 the CAISO proceeding with the final EDAM design passed by the CAISO 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 revised 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 based on operational experience after implementation. The revised final proposal also includes a set of

---

[284] 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

[285] 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

[286] *Extended Day-Ahead Market Enhancements Revised Draft Final Proposal*, California ISO, 2023.

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

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 collaborating with the ISO and stakeholders on the next steps of developing and implementing a regional day-ahead market.

9.2 Day-ahead market enhancements

In 2022, the California ISO also continued to develop a proposal for day-ahead market enhancements (DAME). This initiative is intended to feed into the initiative to develop an extended (regional) day-ahead market (EDAM). In May 2023, the CAISO Board and WEIM Governing Body approved a proposal for day-ahead market enhancements (DAME) to be filed at FERC in 2023 and implemented as soon as 2024.[288]

Given the large potential long-term benefits of a west-wide day-ahead market, DMM supported approval of the DAME proposal, while recommending that the ISO continue working with stakeholders on enhancements to the design that could be implemented before and after EDAM's initial implementation. A more detailed summary of DMM's recommendations are provided in DMM's memo to the CAISO Board and WEIM Governing Body on the DAME proposal.[289]

The ISO's revised 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 based on operational experience after implementation. The revised 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 collaborating with the ISO and stakeholders on the next steps of developing and implementing a regional day-ahead market.

A key element of the DAME proposal 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.[290]

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.

---

288 Day-Ahead Market Enhancements Draft Revised Final Proposal, California ISO, April 6, 2023: http://www.caiso.com/InitiativeDocuments/DraftRevisedFinalProposal-Day-AheadMarketEnhancements.pdf

Day-ahead Market Enhancements Addendum: Imbalance Reserve Demand Curve: http://www.caiso.com/InitiativeDocuments/Addendum-ImbalanceReserveDemandCurve-Day-AheadMarketEnhancements.pdf

289 Memorandum ISO Board of Governors and WEIM Governing Body, Department of Market Monitoring, May 9, 2023: http://www.caiso.com/Documents/DepartmentofMarketMonitoringReport-May2023.pdf

290 Ibid.

Procuring imbalance reserves in the energy market with virtual bidding

Procuring imbalance reserves in the 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 in 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 market to continue to serve its current role of procuring excess capacity to address net load uncertainty after the IFM has issued energy awards. Therefore, in the event this scenario frequently occurs, 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 also 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 them 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 that exists over the real-time market's four-hour time horizon.

If these changes are not considered, the ISO should at least consider adding 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, 2, 4, and potentially even 8 hours out from the current market run). These new 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 Congestion revenue rights

Over the 10-year period 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 CAISO 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). 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.

In response to the consistently large losses from sales of congestion revenue rights, the CAISO instituted significant changes to the auction starting in the 2019 settlement year.[291] Although changes implemented in 2019 reduced ratepayer auction losses, these losses have continued to be very significant.

- In 2022, ratepayer losses from congestion revenue rights auctioned off by the ISO rose back up to $118 million as energy and congestion were driven up by gas prices. Ratepayers were paid only about 55 cents in auction revenues per dollar paid out to auctioned congestion revenue rights.

[291] Department of Market Monitoring, *2019 Annual Report on Market Issues & Performance,* June 2020, pp. 230-234: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

- In the four years after changes were implemented in 2019, ratepayer losses have averaged $64 million per year, compared to $114 million in the seven years before the changes. Ratepayers were paid an average of 63 cents per dollar paid out to auctioned congestion revenue rights, compared to about 48 cents per dollar before the changes.
- In the four years since the changes, auction losses have averaged about 10 percent of day-ahead congestion rent, down from 28 percent before the changes.

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 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.

Building on the existing reforms could further reduce ratepayer losses. Auction losses could be further reduced 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.

9.4 Resource sufficiency tests

The resource sufficiency tests for capacity and flexible ramping capacity are key elements of the Western Energy Imbalance Market 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.

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.[292] This phase includes changes to the capacity test that will exclude some capacity that is unavailable because of various operating limitations. It also includes the suspension of intertie and net load uncertainty in the capacity test, while the California ISO continues its efforts to develop a better approach for incorporating uncertainty into the requirement in phase 2. DMM supported both of these changes.[293]

In December 2022, the California ISO and WEIM Governing Body approved several additional changes that will take effect in 2023 as part of phase 2 of this initiative.[294]

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

292 California ISO initiative: *WEIM resource sufficiency evaluation enhancements*: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements

293 Department of Market Monitoring, *Comments on EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final Proposal*, January 11, 2022: http://www.caiso.com/Documents/DMM-Comments-EIM-Resource-Sufficiency-Evaluation-Enhancements-Phase-1-Revised-Draft-Final-Proposal-Jan-11-2022.pdf

294 *WEIM Resource Sufficiency Evaluation Enhancements Phase 2 – Revised Final Proposal,* California ISO, November 7, 2022: http://www.caiso.com/InitiativeDocuments/RevisedFinalProposalWEIMResourceSufficiencyEvaluationEnhancementsPhase2.pdf

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 under phase 2 of the resource sufficiency evaluation enhancements initiative will be 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 a penalty cost 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 believed the revised energy assistance option included in the proposal is 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 will allow implementation of this option by July 1, 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 into 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, the ISO should continue to refine the failure consequences for areas that elect to not opt into the energy assistance program.

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 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.

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 and consider adopting uncertainty calculations customized to the resource sufficiency evaluation, rather than using the flexible ramping product uncertainty calculation.

9.5 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 CAISO 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*.[295]

DMM continues to recommend these two enhancements.

Locational procurement

Analyses by DMM and the California ISO have shown that a significant portion of real-time flexible ramping product capacity procured was not deliverable because of transmission constraints.[296] Locational procurement that accounts for transmission constraints should result in deliverable reserves, which will significantly increase the efficiency of market awards and dispatches.

The California ISO implemented nodal procurement as part of the flexible ramping product refinements stakeholder initiative in February 2023. DMM has identified an error in the implemented calculation of the demand curves for procurement of flexible ramping product enforced in the market software. The prices on the demand curve are expected to reflect the expected cost of a power balance constraint violation for the level of flexible capacity procured. As less flexible capacity is procured, the likelihood of a power balance constraint relaxation (and the expected cost of this outcome) both increase. However, the implementation error lowers the value of flexible capacity in the market optimization, effectively making that capacity appear cheaper relative to the expected cost of a shortage.

New method for calculating net load uncertainty

In February 2023 the ISO implemented a new method of net load uncertainty estimation 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. 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.

---

295 Department of Market Monitoring, *2021 Annual Report on Market Issues & Performance*

296 California ISO Market Surveillance Committee Meeting, *Discussion on flexible ramping product*, presented by Lin Xu, Ph.D., September 8, 2017 pp. 16-17: http://www.caiso.com/Documents/Discussion_FlexibleRampingProduct.pdf

Department of Market Monitoring, *Q3 Report on Market Issues and Performance*, December 5, 2019, pp. 84-86: http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

9.6 Pricing under tight supply conditions

In 2021, the California ISO implemented numerous changes that feature steps to allow prices to rise and increase compensation for imports during tight supply conditions. First, the FERC Order No. 831 compliance filing included the following two provisions:

- Bids can now be submitted at prices above the $1,000/MWh soft offer cap, up to $2,000/MWh. These bids can set market prices if they are cost-justified prior to market operation.
- When a bid over $1,000/MWh is cost-justified prior to market operation, the CAISO will set the power balance constraint penalty price at the highest cost-justified bid (i.e., up to $2,000/MWh). Prices are set based on this penalty price when supply/demand infeasibilities occur in the market software.

In addition, in 2021 the California ISO developed and implemented the following changes on an expedited basis in order to improve pricing and compensation of needed supply under tight conditions:

- Hourly imports will receive the higher of their bid price or the 15-minute market price during tight system conditions. This removes the risk that hourly imports could be paid below their offer price in any given hour during tight system conditions.
- When the CAISO arms load to serve as operating reserves (i.e., prepares to shed load in a controlled manner, if needed), and then releases generation that was serving as reserves into the energy supply stack, the CAISO will set the bid price of the reserves added to the energy supply stack at the energy bid cap. This will help ensure that prices are relatively high when system conditions are extremely tight, such that controlled dropping of load needs to be relied upon for operating reserve.
- When reliability demand response resources (RDRR) are deployed in the real-time market, these resources will be included in the market dispatch and pricing. Adding the expected load curtailment from these dispatches onto the load forecast in each market should help to prevent them from inappropriately suppressing market prices.

DMM supported these changes and believes they will improve the functioning of the CAISO markets during tight system conditions.[297] The combined effect of these changes should increase the frequency of very high prices at or near the $1,000/MWh bid cap under tight conditions when scarcity is most likely to occur. Thus, DMM recommends the CAISO review and consider market performance since these changes have been in effect as it considers adding additional scarcity pricing provisions.

During the heat wave of summer 2022, prices in the CAISO markets rose to very high levels that appeared to be highly reflective of actual system and regional conditions. On the most critical days, the CAISO bid cap was raised up to $2,000/MWh based on the new process implemented in 2021 for increasing the cap based on observed prices at bilateral regional trading hubs. During the most critical hours on these days, CAISO market prices were set by penalty prices based on the $2,000/MWh bid cap.

The CAISO is beginning to consider changes to its scarcity pricing provisions under a broader price formation 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.

[297] Department of Market Monitoring, *Motion To Intervene and Comments (FERC Docket No.ER21-1536-000, EL10-56-000)*, April 16, 2021: http://www.caiso.com/Documents/DMM-Comments-on-ER21-1536-Summer-2021-Readiness-Apr-16-2021.pdf

9.7 Export and wheeling schedules

The summer 2020 heat wave highlighted the need to review the California ISO 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 appeared inconsistent with ISO tariff provisions and analogous provisions in the OATTs of other balancing areas in the West. DMM recommended that the ISO take steps to clarify priorities for curtailing native load vs non-high priority exports, and make ISO rules and procedures more equivalent to those of other balancing areas in the West.

In 2021, the California ISO began the transmission service and market scheduling priorities initiative.[298] The first phase of this is initiative developed and clarified interim rules that will be in effect until 2024. Key features of these interim rules include the following:

- Wheeling schedules and exports which clear the day-ahead residual unit commitment process are treated as firm (high priority) schedules that receive equal priority as native ISO load in real-time.
- Load serving entities outside of the CAISO can obtain firm (high priority) transmission to wheel power through the CAISO system by contracting with a supplier on a monthly basis.
- In the real tie market, the ISO will curtail lower priority exports and wheeling schedules prior fist, and then curtail higher priority exports, wheels and load on and equal (pro rata) basis as needed to maintain system reliability.

The second phase of this initiative was completed in 2022 and developed longer-term comprehensive rules for transmission scheduling priority to be effective by summer 2024. DMM supports the market design changes developed in the second phase of the transmission service and market scheduling priorities initiative as an improvement over the existing interim rules. A more detailed summary of DMM's comments on this issue is provided below.[299]

Transmission service and market scheduling priorities phase 2

The ISO's phase 2 proposal establishes a process for making transmission to wheel power through the ISO system that is not needed to serve native ISO load available to other entities on a longer term forward basis. This approach represents a significant improvement from the current interim rules for high priority wheeling access, and makes the ISO's rules much more similar to the open access transmission tariff (OATT) framework used across the west in balancing areas without organized markets.

Because the proposed approach does not include a detailed analysis of the impact of wheeling schedules on flows within the ISO, the proposal may make some additional wheeling capacity available compared to DMM's understanding of how this OATT framework is typically applied. However, under the proposal this high priority wheeling capacity will be somewhat less "firm" under extreme system conditions than firm transmission sold under this OATT framework.

This tradeoff seems to strike a reasonable balance between the preferences of ISO load serving entities and external users of the ISO transmission system. Going forward, the ISO and stakeholders could consider future refinements to address concerns of these different stakeholder groups. These changes

---

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

[299] 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

could result in making less transmission capacity available, while increasing the firmness of these transmission rights to a level more analogous to the OATT framework.

9.8 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 CAISO rules could allow imports that may not be available during critical system and market conditions to meet resource adequacy requirements. For instance, under current CAISO 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.[300]

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.[301]

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 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.[302] 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.

---

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

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

[302] Department of Market Monitoring, *Reply comments on proposed decision adopting local capacity obligations for 2024-2026, flexible capacity obligations for 2024, and program refinements*, 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

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.[303] 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 Planning Reserve Margin to the slice-of-day framework.[304] The CPUC will implement the framework starting in the 2025 compliance year.

In prior years, DMM recommended that capacity counting rules for different resource types should be modified to more accurately reflect actual resource availability during peak net load hours. 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 storage usage with capacity from other resources, as well as the counting rule methodology change from ELCC values to Top 5 Day exceedance values for wind and solar resources. Although the counting values are conservative, DMM believes that too much reliance on capacity that may not actually be available during peak net load hours is a reliability risk; especially with increased electrification and extreme weather patterns expected in California and the rest of the West.

Resource adequacy performance incentives

The current California ISO 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 CAISO CPM soft offer cap, which is currently $6.31/kW-month.[305]

As capacity becomes more limited and prices increase in the West, the difference between capacity payments and potential RAAIM penalties also increases. Additionally, starting in 2021, the CPUC's penalty costs for system resource adequacy showing deficiencies for summer months increased from $6.66/kW-month to $8.88/kW-month.[306] Starting in 2022, these penalties became much higher for load serving entities with repeated deficiencies.[307]

---

303 CPUC Docket No. R.19-11-009, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program (D.21-07-014),* July 15, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.pdf

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

305 California ISO Tariff Section 40.9.6.1(c): http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-Jun1-2022.pdf

306 CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2021–2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program (D.20-06-031),* June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF

307 CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2022–2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029),* June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

DMM is concerned that if the California ISO 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 California ISO rules in effect during summer 2022 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 California 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.

9.9 Demand response resources

In the last three 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 2022 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.[308] This results from a combination of how demand response resources are 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.

In prior reports, DMM has highlighted some recommendations that the CAISO and CPUC could consider to enhance the availability and performance of demand response resources, especially before increasing

[308] Department of Market Monitoring, *Demand response issues and performance 2022*, February 14, 2023: http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

reliance on demand response towards meeting resource adequacy requirements.[309] 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.[310]
- ***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 proposed eliminating this 9 percent reserve margin adder and the transmission loss factor (2.5 to 3 percent) beginning in 2024.[311] 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.

9.10 Energy storage resources

The amount of energy storage resources 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 sometimes 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 help mitigate availability concerns related to battery resources.[312]

---

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

310 CPUC Rulemaking 21-10-002, Adopting Local Capacity Obligations for 2024–2026.

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

312 Department of Market Monitoring, *2018 Annual Report on Market Issues & Performance*, May 2019, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Modeling energy storage costs

Energy storage resources face unique costs and operating parameters that may not align with current market mechanisms designed for traditional generators. DMM recommended that the California ISO and the energy storage community continue working together in the Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) stakeholder initiative to identify and develop modeling of unique energy storage resource costs in both market optimization and default energy bids used in local market power mitigation. A detailed discussion of this issue was included in DMM's 2019 annual report.[313]

The CAISO and DMM have made significant progress in understanding the costs of batteries through both the ESDER 4 and energy storage enhancements stakeholder processes. This information has led to the development of a default energy bid for energy storage resources, as well as proposals to model different operational limitations of these resources, and a proposal to develop a new energy storage model that reflects costs and bids based on state of charge.

DMM also recommends that the CAISO resume development of a new energy storage model based on state of charge as soon as practicable. This new model was initially proposed in the early phases of the energy storage enhancements initiative, but was later removed from that initiative and postponed to a later date.[314] This proposed model is likely to be a significant improvement in the ability of battery storage resources to accurately reflect costs applicable to a particular market interval.[315]

Exceptional dispatches

A key goal of enhancing how batteries are modeled and can be bid is to allow batteries to be used efficiently on a day-to-day basis through market bids and dispatches. However, experience during heat waves over the last few years has highlighted the need to take special steps to ensure that batteries are sufficiently charged and can provide their full capacity over the most critical net peak hours on days when system reliability is at stake. On these critical days, the ISO operators can help ensure batteries are available by issuing manual instructions (or exceptional dispatches) to batteries.

In 2022, the CAISO Board of Governors approved new exceptional dispatch functionality for energy storage resources. This new functionality will allow exceptional dispatch to be issued as a state of charge value rather than only as a minimum, maximum, or specific level of charging or discharging. These market rule changes also allow for compensation of batteries based on the opportunity costs associated with holding state of charge due to exceptional dispatch.

Given the growing importance of batteries for maintaining system reliability on critical days, DMM supports continued development and use of enhanced tools for grid operators to help ensure the availability of batteries to meet system reliability needs on critical days.

Bid cost recovery rules for batteries

DMM has previously recommended new bid cost recovery (BCR) rules for energy storage resources. New BCR rules are needed to mitigate inefficiencies and potential gaming opportunities that may result

---

[313] Department of Market Monitoring, *2019 Annual Report on Market Issues & Performance*, June 2020, pp. 306-307: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

[314] California ISO, *Energy Storage Enhancements – Second Revised Straw Proposal*, June 30, 2022: http://www.caiso.com/InitiativeDocuments/Second-Revised-Straw-Proposal-Energy-Storage-Enhancements.pdf

[315] Department of Market Monitoring, *Comments on Energy Storage Enhancements Revised Straw Proposal*, April 7, 2022: http://www.caiso.com/Documents/DMM-Comments-on-Energy-Storage-Enhancements-Revised-Straw-Proposal-Apr-7-2022.pdf

from differences between day-ahead and real-time state of charge. Recently observed market outcomes and the growing capacity of energy storage resources on the CAISO system continue to underscore the need to address BCR for energy storage resources. In September 2022, the CAISO filed with FERC to eliminate one large driver of inefficient bid cost recovery payments to storage resources.[316] DMM supported this change.

However, DMM continues to recommend that the CAISO develop more general revisions to BCR rules for storage resources as soon as practicable. These new BCR rules are needed to mitigate potential gaming opportunities and improve the efficiency of market dispatch when day-ahead state of charge values deviate significantly from actual state of charge values in real-time. More generally, new BCR rules are also needed to address BCR payments deriving from a range of operator actions that can constrain state of charge or otherwise force uneconomic dispatch.

In the day-ahead market, battery resources submit an initial state of charge value that the day-ahead market software assumes will be the level of charge that a battery has at the start of a market day. However, in real-time, a battery's actual state of charge may be different from the initial state of charge value submitted to the day-ahead market. Real-time market dispatches and regulation movements can further contribute to differences between day-ahead and real-time state of charge values. When these values diverge significantly, the real-time market may schedule a battery much differently than was predicted in the day-ahead market. In many of these cases, resources receive significant real-time bid cost recovery when they either buy back day-ahead awards or are paid back for day-ahead charging at a net loss.

DMM is concerned that significant deviations between day-ahead and real-time state of charge values can create opportunities for potential gaming of bid cost recovery payments. Early in the ESDER stakeholder processes, DMM recommended the CAISO consider the implications of a day-ahead submitted state of charge as a new and unique intertemporal constraint between markets.[317] DMM recommended that the CAISO revisit this topic in future initiatives to address potential settlement implications.

DMM has recently observed market outcomes that continue to support the need to revise bid cost recovery rules for energy storage resources. Some change may be needed to address significant differences between day-ahead and real-time state of charge of batteries that inevitably occur. Changes are also 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.

Resource adequacy battery 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, DMM has observed

---

316 California Independent System Operator Corporation, FERC Docket No. ER22-2881, *Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resources*, September 19, 2022: http://www.caiso.com/Documents/Sep19-2022-TariffAmendment-EnergyStorageBidCostRecovery-ER22-2881.pdf

317 Department of Market Monitoring, *Stakeholder Comments on Energy Storage and Distributed Energy Resources (ESDER), Revised Draft Final Proposal*, February 2, 2016: http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorageDistributedEnergyResources-RevisedDraftFinalProposal.pdf

that 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 current RAAIM framework may not provide very strong financial incentive for resource availability. However, considering the impact of additional storage resource parameters on resource availability would improve the current RAAIM framework.[318]

The new slice-of-day framework for that state's resource adequacy program being developed by the CPUC addresses this issue from the perspective of capacity portfolio planning. Under this slice-of-day approach, the resource adequacy portfolios of load serving entities will need to include sufficient surplus capacity during the peak solar hours to ensure that batteries can be fully charged over the four most critical net peak hours.

On an operational level, 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 market design enhancements aimed at ensuring battery storage resources can fully reflect the opportunity cost of discharging before the net load peak hours on the highest priced days, where peak prices may exceed $1,000/MWh.[319]

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 CAISO 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 Western Energy Imbalance Market and work towards extending mitigation to include hybrid resources, such as combined solar and battery storage facilities.

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 CAISO calculates a static default energy bid value over the day for each battery resource.[320] DMM is supportive

---

318 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.

319 Department of Market Monitoring, *Comments on Minimum State of Charge Extension Straw Proposal*, February 24, 2023: http://www.caiso.com/Documents/DMM-Comments-Minimum-State-of-Charge-Extension-Straw-Proposal-Feb24-2023.pdf

320 California ISO, *Energy Storage and Distributed Energy Resources – Storage Default Energy Bid – Final Proposal*, October 22, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4-DefaultEnergyBid.pdf

of this framework but has recommended several additional refinements.[321] DMM recommends that the CAISO 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 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 a more robust framework to allow 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 distant intervals.

321 Department of Market Monitoring, *Comments on Energy Storage and Distributed Energy Resources – Storage Default Energy Bid Final Proposal*, November 12, 2020: http://www.caiso.com/Documents/DMMComments-EnergyStorageandDistributedEnergyResources-StorageDefaultEnergyBidFinalProposal-Nov122020.pdf