2024 Special Report on Battery Storage

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Prepared by: Department of Market Monitoring

California Independent System Operator

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1 Summary

1.1 Background

As energy systems evolve from fossil fuels to renewable resources, battery storage resources are playing an increasingly important role in maintaining the flexibility and resilience of the power grid. This is especially true in the Western U.S., where ambitious decarbonization goals and widespread solar energy development are helping drive the growth of battery storage.

To meet California's goal of using renewable energy and zero-carbon resources to supply 100 percent of electric retail sales in the state by 2045, the California ISO projects the need for 165.1 GW of new generation across the CAISO market footprint, including nearly 58 GW of electricity storage.[1] Most of the planned battery capacity to come on-line by 2034 in the western interconnection will be sited outside of California, in either the Northwest Central or Desert Southwest regions.[2]

Battery capacity is also beginning a period of rapid expansion in Western Energy Imbalance Market (WEIM) areas outside of the CAISO balancing area. Battery capacity in WEIM areas grew from about 2,600 MW in 2023 to about 5,000 MW by the end of 2024. According to the Energy Information Agency's March 2025 electric generator inventory, from 2025 to 2028 about 8,230 MW of battery capacity is scheduled to come on-line in California, and another 19,350 MW is planned for WEIM states.[3]

Most large-scale storage systems in operation have a maximum duration of 4 hours and use lithium-ion technology, which provides fast response times and high-cycle efficiency (low energy loss between charging and discharging), while still being cost-effective. These 4-hour resources primarily operate through intra-day arbitrage, buying power during mid-day hours when solar is plentiful and system prices are lowest, then selling it back to the grid in the evening when power is in high demand, solar output is low, and prices are much higher.

Because of their fast response times, batteries are ideal for providing services used to balance very short-term differences in supply and demand, such as frequency regulation and flexible ramping product. In addition, battery charging now represents a significant amount of energy demand, especially in the afternoon.

This report provides a description of the state of battery storage resources in the California ISO and Western Energy Imbalance Market. The report includes analysis of the performance of batteries using several key metrics, and assesses the recent market enhancements for battery resources.

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1 *2024 20-Year Transmission Outlook*, California ISO, July 31, 2024, p 3: https://www.caiso.com/documents/2024-20-year-transmission-outlook-jul-31-2024.pdf

2 *Western Assessment of resource Adequacy 2024 Planned Resource Additions by Subregion*, Western Electricity Coordinating Council: https://www.wecc.org/sites/default/files/documents/products/2025/WARA%202024%20Planned%20Resource%20Additions%20by%20Subregion%20v2.pdf

3 *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)*, U.S. Energy Information Administration, March 2025: https://www.eia.gov/electricity/data/eia860m/xls/march_generator2025.xlsx

1.2 Key findings

- **Battery storage capacity grew from about 500 MW in 2020 to 13,000 MW in December 2024** in the CAISO balancing area. Over half of this capacity is physically paired with solar or wind generation, either sharing a point of interconnection under the co-located model or as a single hybrid resource.
- **The Western Energy Imbalance Market (WEIM) includes about 5,000 MW of participating battery capacity as of December 2024.** In comparison, battery capacity totaled 2,600 MW in the WEIM in December 2023.
- **Batteries account for a significant portion of energy and capacity during the late afternoon and early evening when net loads are highest.** During hours 17 to 21, batteries provided an average of about 8.6 percent of the CAISO balancing area's energy in 2024.
- **Batteries account for a significant portion of load during peak solar hours**. From hours-ending 10 to 13, battery charging represented around 14.7 percent of load in the CAISO balancing area in 2024. During these hours, batteries help reduce the need to curtail or export surplus solar energy at very low prices.
- **Batteries provided 84 percent of the ISO's regulation up and regulation down requirements in 2024**. However, as the amount of battery capacity has increased in recent years, the percentage of total battery storage capacity being scheduled for ancillary services has decreased, with batteries providing more energy during the net peak load hours.
- **Net market revenue for batteries decreased from an average of about $78/kW-yr in 2023 to $53/kW-yr in 2024.** This decrease was driven largely by lower peak energy prices and lower loads than in 2023.
- **Batteries received $17.9 million of real-time bid cost recovery payments in 2024, representing 11 percent of total bid cost recovery to generators.** In comparison, battery resources received 10 percent of all bid cost recovery paid to resources in the CAISO balancing area in 2023. These payments represent 4 percent of batteries' total net market revenues. DMM continues to recommend enhancements to the market design of bid cost recovery for batteries.
- **Local market power mitigation has had minimal impact on the dispatch of batteries.** An average of about 363 MW of battery capacity per hour had bids lowered under the ISO's local market power mitigation procedures in 2024. Mitigation of bids potentially increased battery dispatch by an average of only about 35 MW per hour.
- **DMM continues to find that some battery capacity used to meet resource adequacy requirements is unavailable to the market during consecutive hours with tight system conditions.** There is a combination of factors which prevent batteries from being fully charged and then discharging up to their nameplate capacity during some peak net load hours. These factors include short discharging durations, modeling limitations, and bidding behavior.

2 Battery storage market participation

2.1 Battery resource modeling

In the ISO market, storage resources participate under the non-generator resource (NGR) model. NGRs are resources that operate as either generation or load (demand) and bid into the market using a single supply curve with prices for negative capacity (charging) and positive capacity (discharging).

NGRs are constrained by an energy limit to generate or consume energy on a continuous basis. They can produce at any point in their operating range and can switch immediately between generating and consuming energy. To reflect the physical operational capabilities of batteries, the ISO models minimum and maximum storage capability, upper and lower operating limits, and round-trip efficiency for each storage resource.

For their day-to-day operations, NGRs have the option to use several biddable parameters to manage their state-of-charge. They can submit upper and lower charge limits for each trading day, which represent the highest and lowest stored energy values (in MWh) that must be maintained in the resource. For greater control in how their state-of-charge changes throughout the day, resources may use the end-of-hour state-of-charge parameter, described in more detail below in Section 2.2.

NGRs can also submit an initial state-of-charge value as part of their day-ahead market bid to indicate the expected available energy on the first participation interval of the following day. This initial state-of-charge value should be a forecast based on anticipated real-time battery operations, including ancillary service delivery.

Batteries require constraints in the day-ahead and real-time markets to manage state-of-charge to ensure the deliverability of the awarded ancillary services for the duration required by the ISO tariff. These constraints are referred to as the ancillary services state-of-charge constraints (ASSOC). When a resource is providing either regulation up or regulation down, it will respond to four-second automatic generator control (AGC) instructions, which impacts the battery's state-of-charge. Real-time regulation delivery can result in discrepancies between day-ahead and real-time state-of-charge, and can cause the ASSOC to bind in real-time to charge or discharge storage resources so that they are able to fulfill regulation awards.

In November 2023, the California ISO implemented market design changes to model the impact of batteries providing ancillary services on their state-of-charge. For this implementation, the CAISO kept the original calculation for battery state-of-charge the same—in that it only accounts for the impact of energy schedules—and introduced a new market constraint for batteries which accounts for the impact of regulation and energy schedules. The new state-of-charge constraint works by using multipliers for regulation up and regulation down MW—called attenuation factors—which model the state-of-charge as being depleted or increased by a certain percentage of the regulation schedule. The ISO chooses multipliers based on historical usage of regulation and updates the multipliers on a quarterly basis to account for seasonality of regulation usage.

Currently, there are two modeling options that allow resources to combine batteries with other generation technologies in their operations: the *hybrid* and *co-located* models. However, many resources operate as *stand-alone* batteries, which do not share a point of interconnection with other resources and do not use multiple generation technologies.

2.2 Multi-interval optimization

The California ISO uses a multi-settlement market design where bidding and dispatch are managed in a set of successive market runs—first in the day-ahead market, then in the real-time market. Each of these markets uses a multi-interval optimization to effectively dispatch resources such that they are positioned to anticipate future conditions. The day-ahead market optimizes over a 24-hour horizon to determine the least costly way of dispatching resources to meet load.

As part of the ISO's real-time processes, the 15-minute market generates optimal dispatch solutions for up to two hours into the future. The 5-minute market develops solutions for 65 minutes, or up to 13 5-minute intervals. Because of the computational complexity inherent with a large optimization, the length of these time horizons is limited. The ISO real-time market design includes the settlement of one financially binding interval in the time horizon, with the schedules for the remaining intervals being advisory.

Given that storage resources are energy limited, the multi-interval optimization is essential to ensuring that inter-temporal conditions are factored into battery schedules. For example, the multi-interval optimization allows the market to hold state-of-charge, or even dispatch batteries to charge uneconomically in a given interval, in anticipation of higher future prices—so long as those high prices occur within the optimization horizon of its respective market.

One challenge of the limited optimization horizon in the real-time market is that the software may dispatch batteries to discharge earlier than desired when high real-time prices materialize early in the day. This can result in batteries entering peak net load hours with a diminished state-of-charge. During the summer of 2022, the ISO used a newly-implemented market constraint called the minimum state-of-charge (MSOC) requirement, which was designed to address this issue.[4] The constraint was activated on days when there was a shortfall between supply and forecasted demand in the day-ahead market, causing a residual unit commitment (RUC) infeasibility.

Before the MSOC was activated in the real-time market, market operators would decide on a series of "critical hours" which would represent the period where the system is most at risk of undersupply. The market software would then optimally dispatch batteries such that their states-of-charge would be preserved until the critical hours.

The MSOC was a temporary initiative which expired in September 2023. The functionality of the MSOC can be replicated if needed, using enhanced exceptional dispatch functionality for batteries. This functionality allows exceptional dispatch to hold state-of-charge, and considers forgone market opportunities in the exceptional dispatch settlement. Battery operators may also reflect intra-day opportunity costs in real-time energy bids to preserve limited stored energy for the highest-valued hours.

Another feature of the multi-interval optimization that presents challenges is that batteries may be dispatched to charge at prices above their bid prices to charge if high advisory prices in future intervals signal that the energy can be sold to the grid at a profit. However, advisory prices are not financially binding, and are subject to change based on real-time conditions.

[4] *2022 Special Report on Battery Storage*, Department of Market Monitoring, July 7, 2023, p 32: https://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

In light of the challenges of having a limited optimization horizon, the ISO proposed measures to help prevent sub-optimal market outcomes as part of its Energy Storage and Distributed Energy Resources (ESDER) Phase 4 stakeholder initiative. One solution proposed in this initiative was the end-of-hour state-of-charge (EOH SOC) bid parameter, which was approved by the Federal Energy Regulatory Commission (FERC) in May 2021.

The EOH SOC bid parameter is an optional, real-time-only bid parameter for NGRs that scheduling coordinators submit hourly as a range with an upper and lower state-of-charge limit. The market dispatches resources such that their states-of-charge end the hour within the submitted range, while respecting minimum and maximum energy bid limits.

2.3 Installed battery capacity

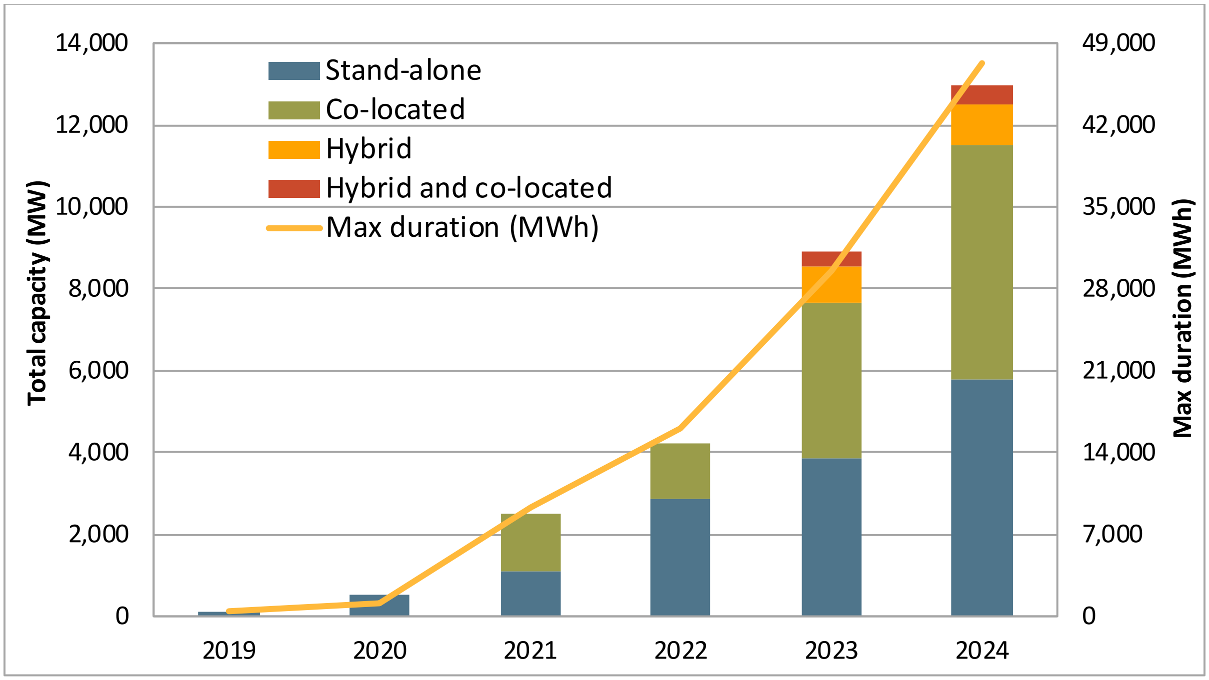
Battery storage capacity has increased dramatically in the CAISO balancing area in recent years. Figure 2.1 shows the total capacity of CAISO balancing area-participating battery storage as of December 2024, represented in terms of maximum output (MW) and maximum duration (MWh).[5]

In December 2024, active battery capacity totaled about 13,000 MW—with 5,800 MW from stand-alone projects and 5,700 MW from co-located projects, and about 1,500 MW from the storage components of hybrid resources and co-located hybrids.[6] Total hybrid capacity, including generation components, was 5,800 MW. The aggregate maximum energy storage capacity of the CAISO balancing area's battery fleet reached about 47,300 MWh.

5 These values may differ from other battery capacity measures. This metric only includes capacity of participating resources, 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.

6 For individual battery resources, the minimum power output (or potential demand to charge batteries) tends to be the negative value of its maximum power output.

Figure 2.1 Active battery capacity in CAISO balancing area (2019–2024)



Battery storage is the fastest growing resource type in the CAISO balancing area. As of January 1, 2025, limited energy storage resource (LESR) batteries make up nearly 14 percent of the CAISO's nameplate capacity. The aqua bars in Figure 2.2 show the steady growth of battery capacity in the CAISO balancing area compared with other resource types.

Nearly half of all projects waiting to connect to the CAISO grid contain a battery component. As of Q2 2025, batteries account for about 46 percent of total capacity in the interconnection queue. Historically, many planned resources drop out before the interconnection process is finished, so much of the capacity currently in the queue is expected to never come on-line.

The size of active batteries varies widely, ranging from 470 kW to 325 MW. Figure 2.3 shows the size distribution of active battery resources, along with the percentage of active battery capacity represented by each histogram bin. Most batteries in the CAISO market have a duration of four hours.

Figure 2.2 Total CAISO balancing area nameplate capacity by fuel type and year[7]

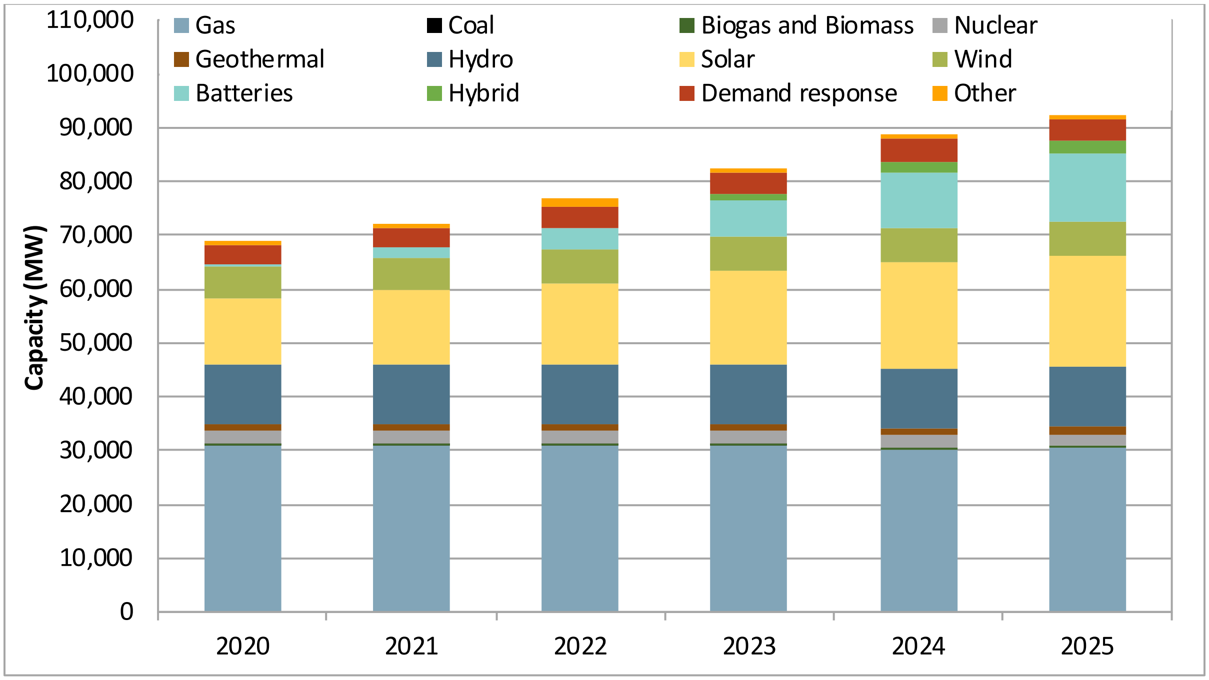
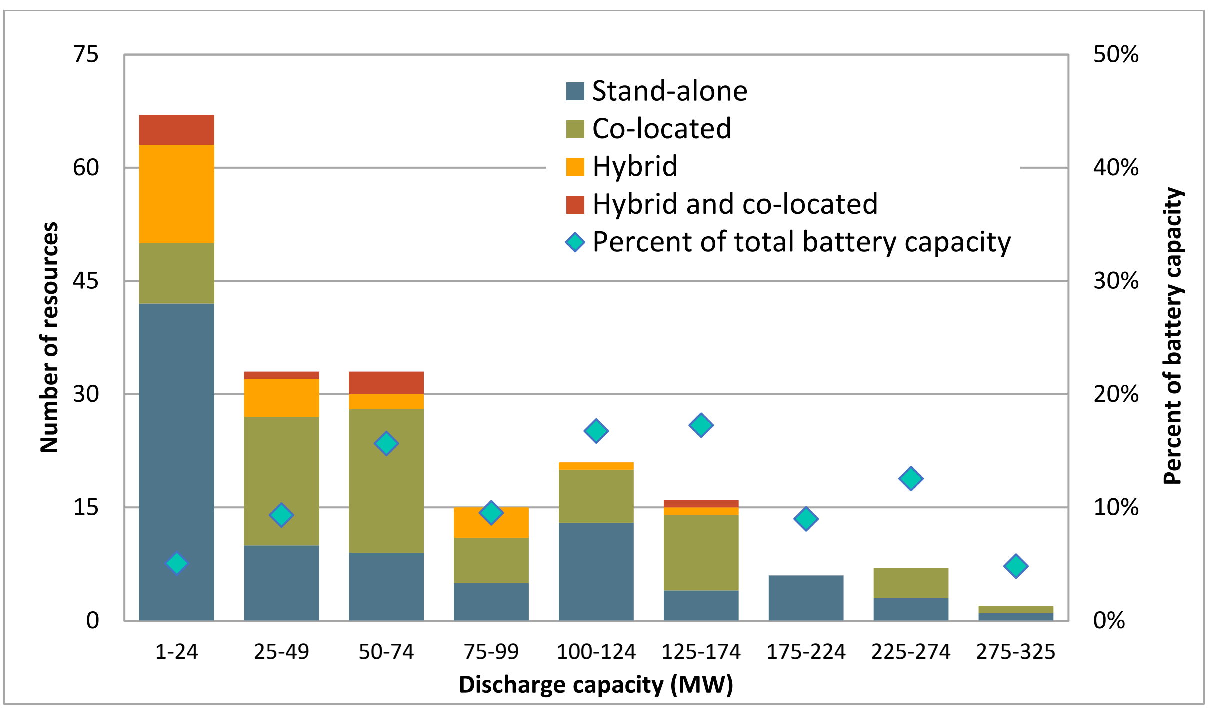


Figure 2.3 Histogram of battery sizes



[7] Values for 2020 through 2024 show capacity as of June 1 of the respective year. The value for 2025 shows capacity as of January 1.

2.4 Energy bids and prices

With the ISO's non-generator resource model, batteries submit a single energy bid curve, which reflects both willingness to charge and discharge. Battery resources do not submit energy price bids solely based on the actual costs of providing energy. Rather, they also consider the *opportunity costs* of discharging or charging in one particular part of the day. For example, discharging energy during low-demand hours may preclude batteries from discharging during high-demand hours. The difference in market prices between low-demand and high-demand hours can represent an opportunity cost of discharging in lower priced hours.

Batteries participating in the resource adequacy (RA) program are subject to must-offer obligations, meaning they are required to bid their entire upward RA capacity into the market. These resources tend to manage opportunity cost through their bid prices, rather than by limiting the quantity of their bids. For example, to avoid being dispatched when market prices are low, batteries may submit bid prices to discharge that greatly exceed the prices they paid to charge, especially in earlier hours of the day. Conversely, batteries may submit excessively low downward energy bids to avoid charging in certain hours.[8]

Figure 2.4 and Figure 2.5 show average energy bids of battery resources compared to average nodal prices by quarter in both the day-ahead and real-time markets, respectively.[9] As shown in Figure 2.4, the spread of average energy bids remained high throughout 2024 in the day-ahead market. Average bid prices to charge were $81 lower and bids to discharge were $230 higher than the nodal price, with an average bid price spread of $312. In comparison, the average bid price spread was $235 in 2023.

Figure 2.5 shows average real-time bids of battery resources for the portion of a resource's dispatch range that is available to the real-time market (i.e., operating range that is not covered by real-time self-schedules or day-ahead ancillary service awards held in real-time). The average price spread in battery bids in the real-time market increased from $202/MWh in 2023 to $223/MWh in 2024.

In both the real-time and day-ahead markets, batteries expressed their highest willingness to charge in the afternoon during peak solar production hours, when nodal prices are lowest on average. Batteries submitted their lowest discharging bids for peak demand hours, when their opportunity cost for discharging is lowest.

8 Currently, only batteries with flexible resource adequacy capacity are subject to must-offer requirements on their downward capacity (i.e., to charge).

9 Both bids and nodal prices are weighted average values, weighted by the bid quantity at each price and location.

Figure 2.4 Hourly average day-ahead bids and nodal prices (by quarter)

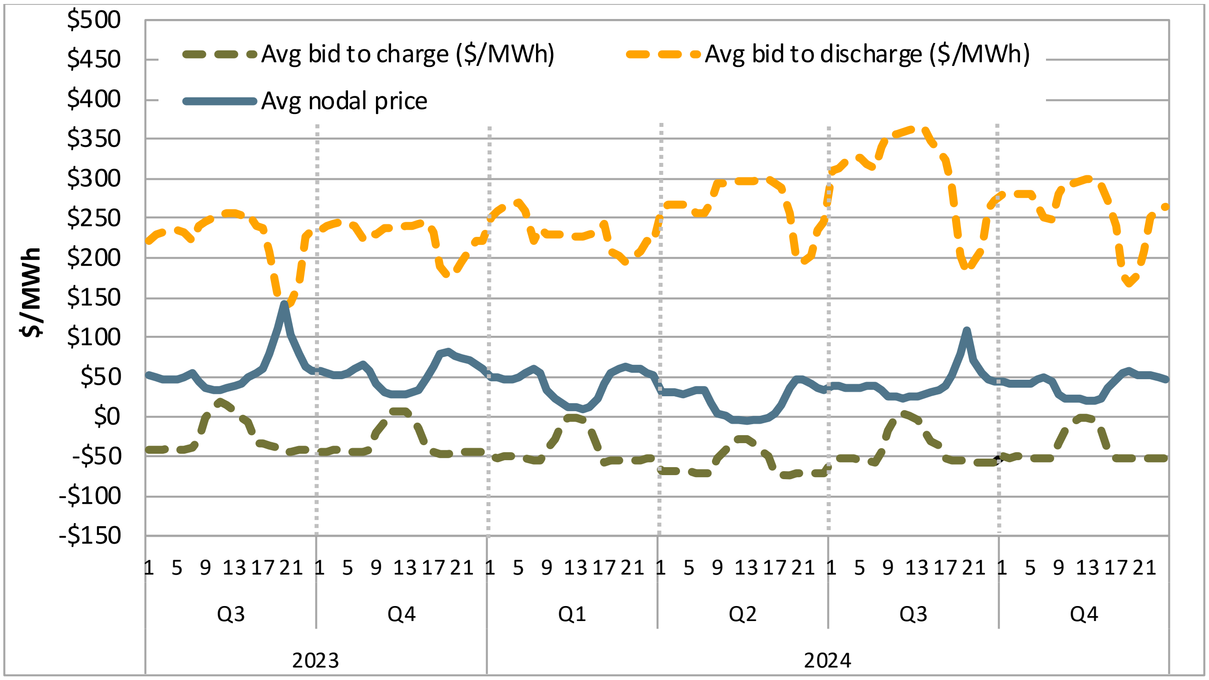


Figure 2.5 Hourly average real-time battery bids and nodal prices (by quarter)

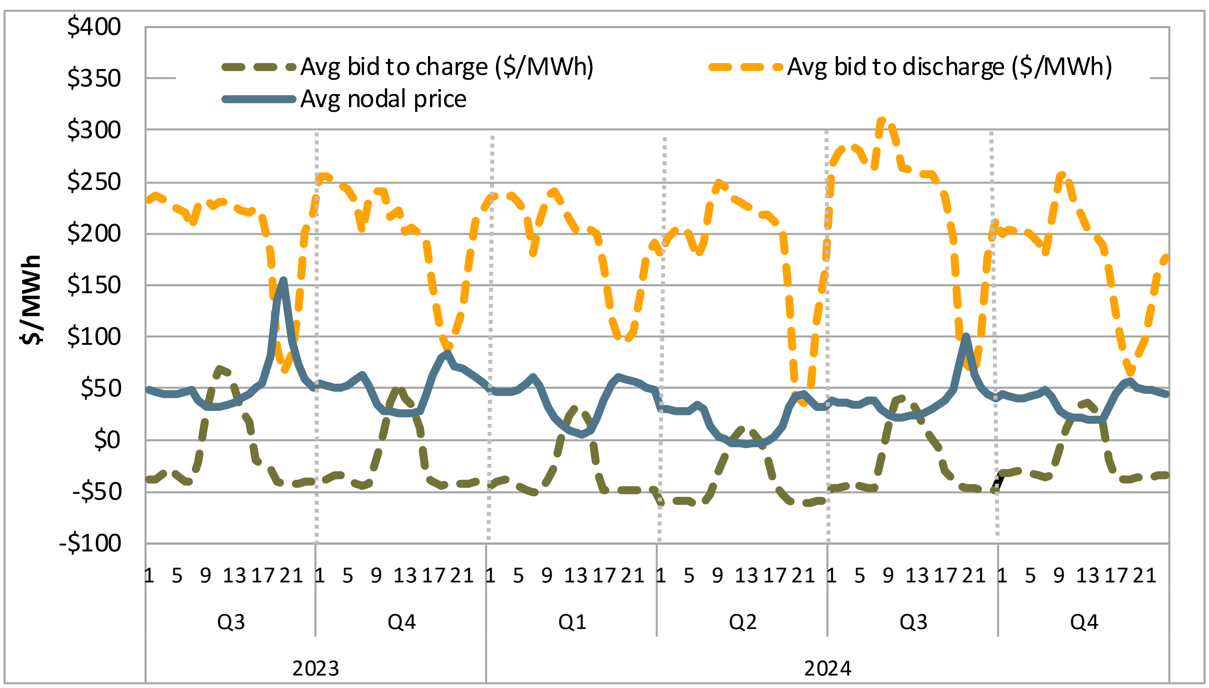
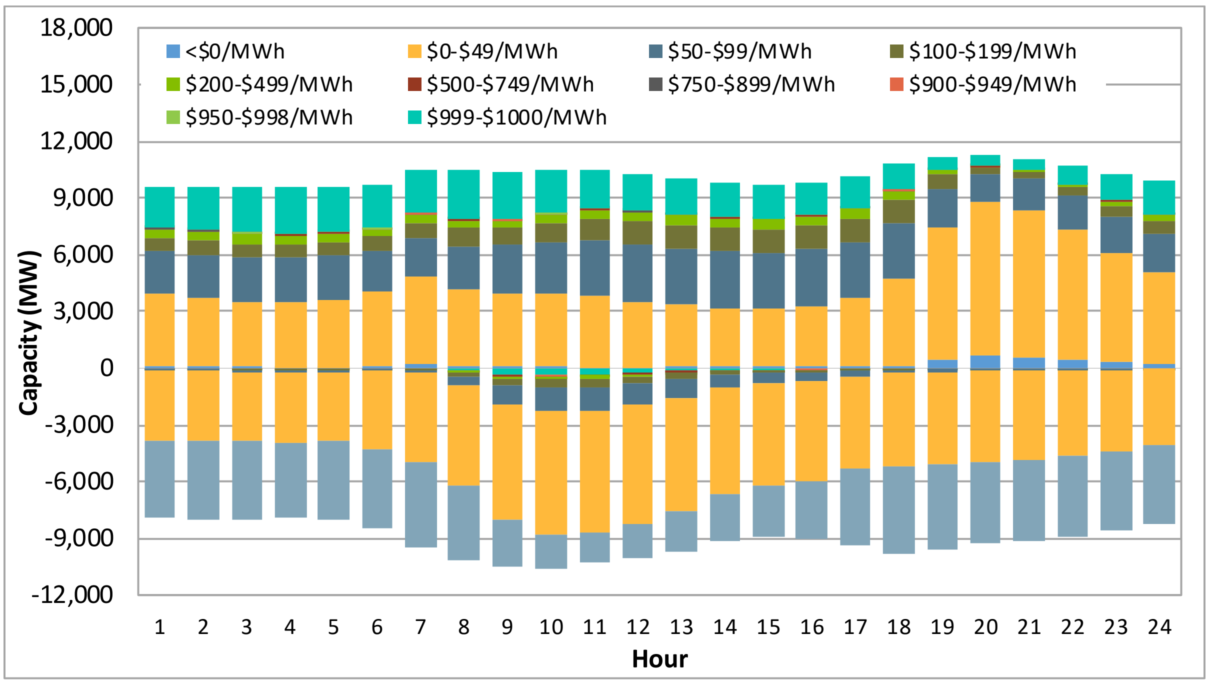


Figure 2.6 shows the average of batteries' submitted 15-minute market bids by price range in each hour in Q3 2024. Though some battery capacity was bid-in at the $1,000/MWh price cap throughout the day, most capacity was bid in at lower than $100, on average.

Figure 2.7 compares 15-minute market battery bids during hour-ending 12 across several days. August 24, August 19, and August 5, respectively, represent the lowest, median, and highest average day-ahead load-weighted prices in the third quarter of 2024. The CAISO balancing area experienced its most severe supply shortage of the year on July 24.

Figure 2.8 shows 15-minute market battery bid curves during hour-ending 21 across the same days. Batteries increased bids for their highest discharging levels to reflect expectations of high prices in hour-ending 21. However, the supply curves in Figure 2.7 and Figure 2.8 show low responsiveness to day-ahead market prices compared to trends in 2023.[10]

Figure 2.6 15-minute market average bid stack in Q3



10 *2023 Special Report on Battery Storage*, Department of Market Monitoring, July 16, 2024, pp 12-13: https://www.caiso.com/documents/2023-special-report-on-battery-storage-jul-16-2024.pdf

Figure 2.7 15-minute market bid curve comparison for hour-ending 12

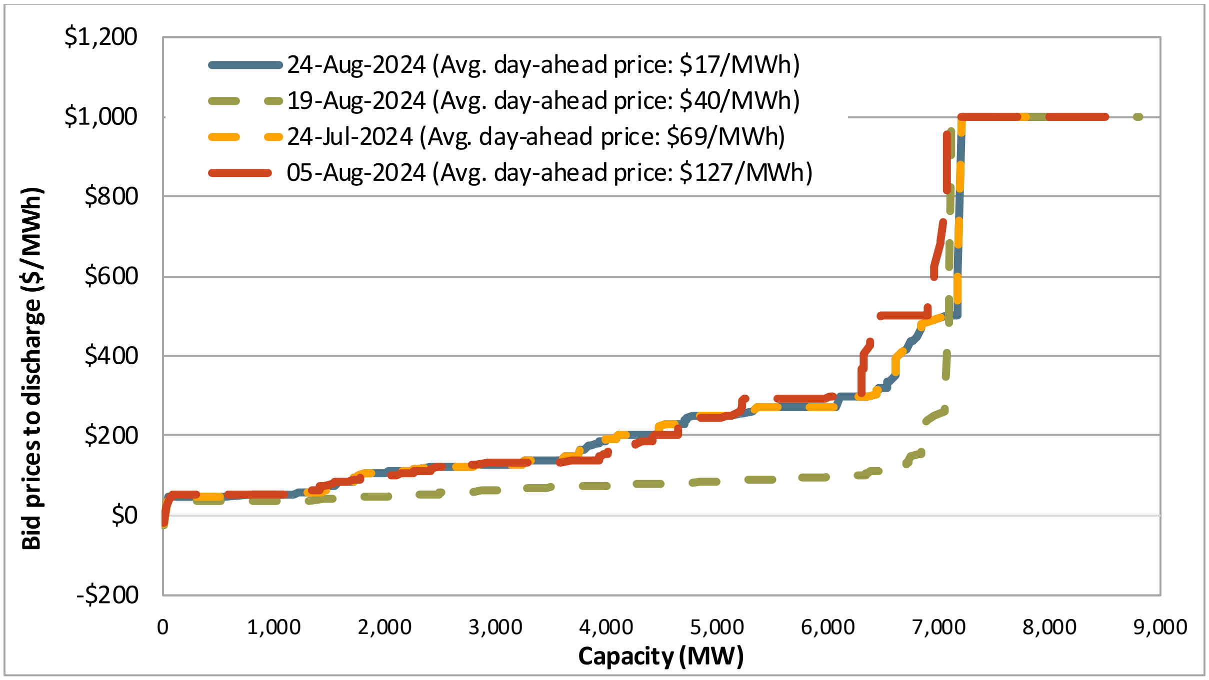
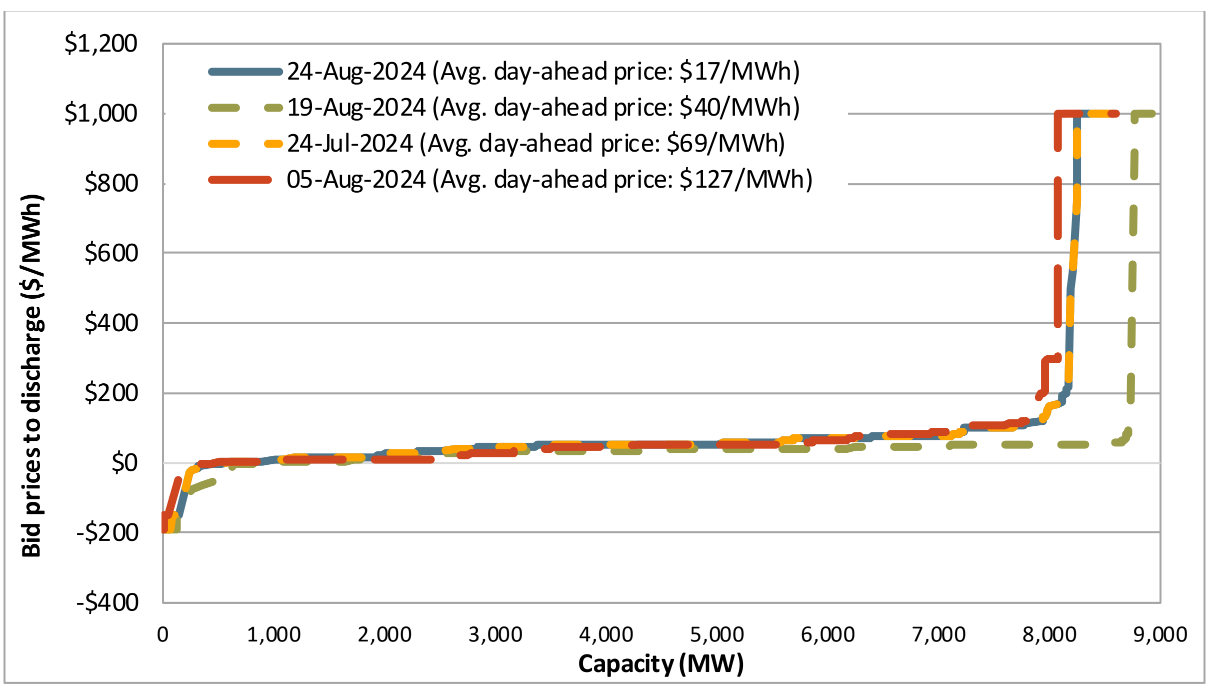


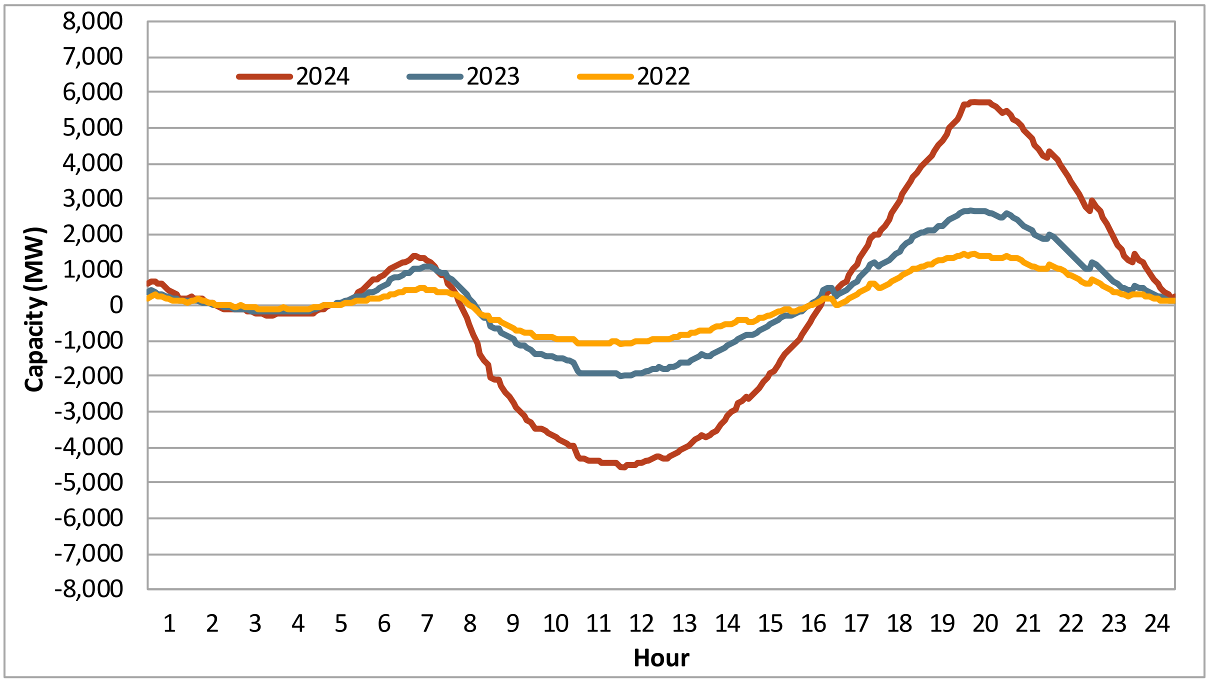
Figure 2.8 15-minute market bid curve comparison for hour-ending 21



2.5 Battery schedules

Figure 2.9 shows average battery energy schedules in the 5-minute market from 2022 to 2024, where points below the zero axis represent charging and points above represent discharging. The average energy output from batteries peaked at about 5,700 MW during hour-ending 19 in 2024, compared to 2,700 MW in 2023.

Figure 2.9 Average 5-minute battery energy schedules



In addition to energy, batteries can provide all ancillary services. Initially, batteries favored providing ancillary services, especially frequency regulation, because it allows them to avoid deep charging and discharging cycles which cause rapid cell degradation. Batteries consistently offer many times more regulation than the market requires.

As shown in Figure 2.10, batteries provided most of the CAISO balancing area's regulation in 2024, at nearly 84 percent. For the past six years, battery capacity has grown faster than ancillary service requirements. As a result, the portion of total battery capacity scheduled for ancillary services has declined. Figure 2.11 shows how the percentage of battery capacity scheduled for ancillary services has decreased as battery capacity has grown.

Figure 2.10 Ancillary service procurement by resource type

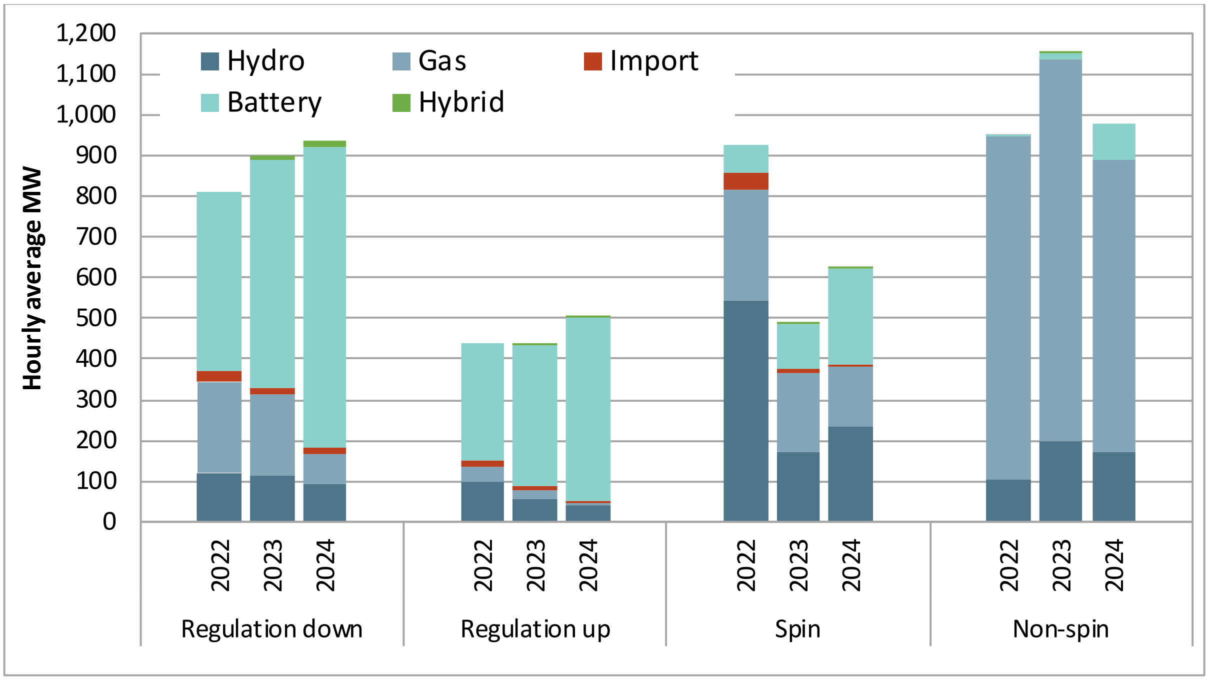
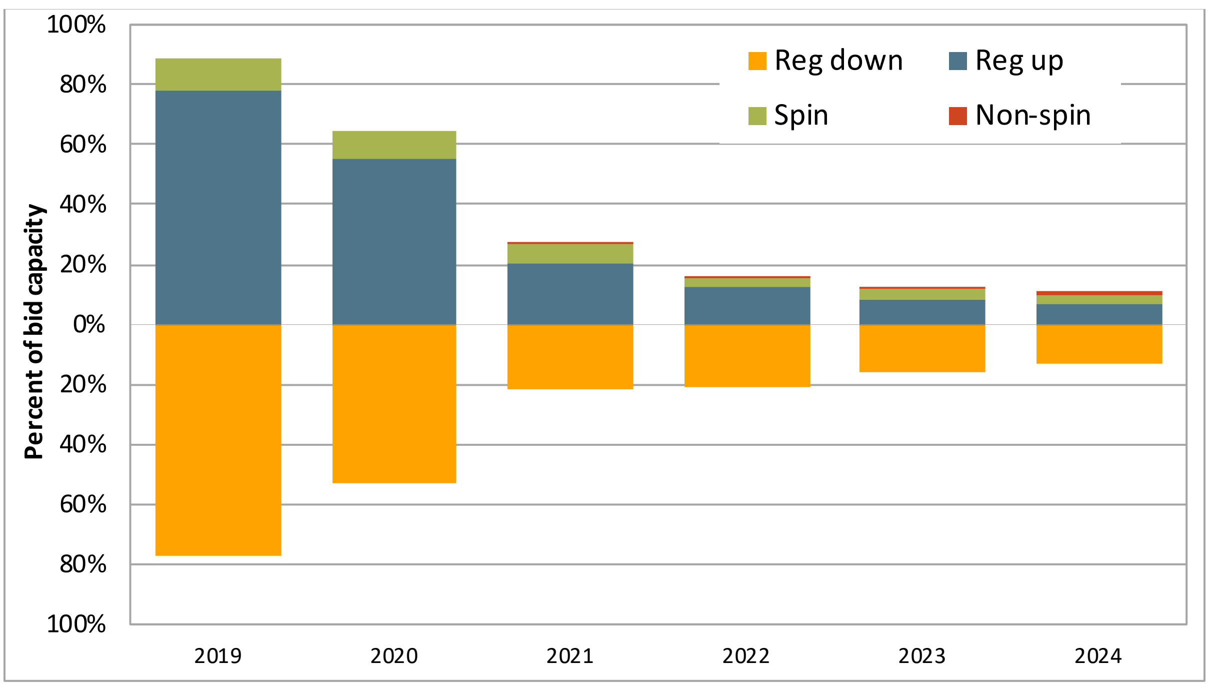


Figure 2.11 Percent of battery capacity scheduled for ancillary services



Battery resources are also frequently scheduled to provide flexible ramping capacity, a product designed to manage volatility and uncertainty of real-time imbalance demand. Figure 2.12 shows the percentage of upward and downward flexible ramping capacity procured by batteries on a monthly basis in the 15-minute market.

Figure 2.12 15-minute flexible ramping product procured from batteries (2024)

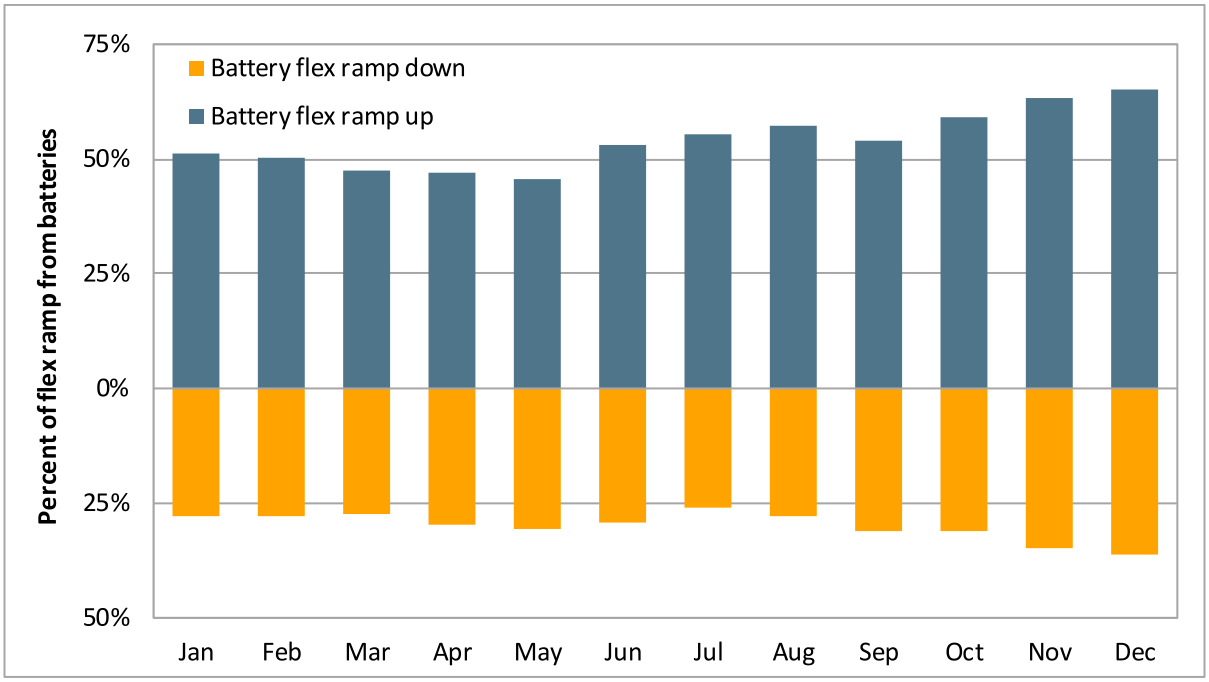


Figure 2.13 shows average hourly real-time (15-minute market) schedules of all battery storage resources in 2024. Batteries provide much of the CAISO balancing area's regulation down capacity when requirements are the highest during peak solar production hours of the afternoon. During these same periods, batteries represent a significant amount of the system's energy demand. From hours-ending 10 to 13 in 2024, battery charging represented around 14.7 percent of load in the CAISO balancing area.

Figure 2.14 shows average 15-minute battery schedules as a percentage of participating capacity in each hour from 2023 to 2024. As previously noted, as the amount of has battery capacity has grown, the portion of battery capacity used for ancillary services has declined over the last six years. The portion of total battery capacity scheduled for upward regulation, spin, and non-spin dropped from 12 percent in 2023 to 9 percent in 2024.

Figure 2.13 Average hourly battery schedules by product (2024)

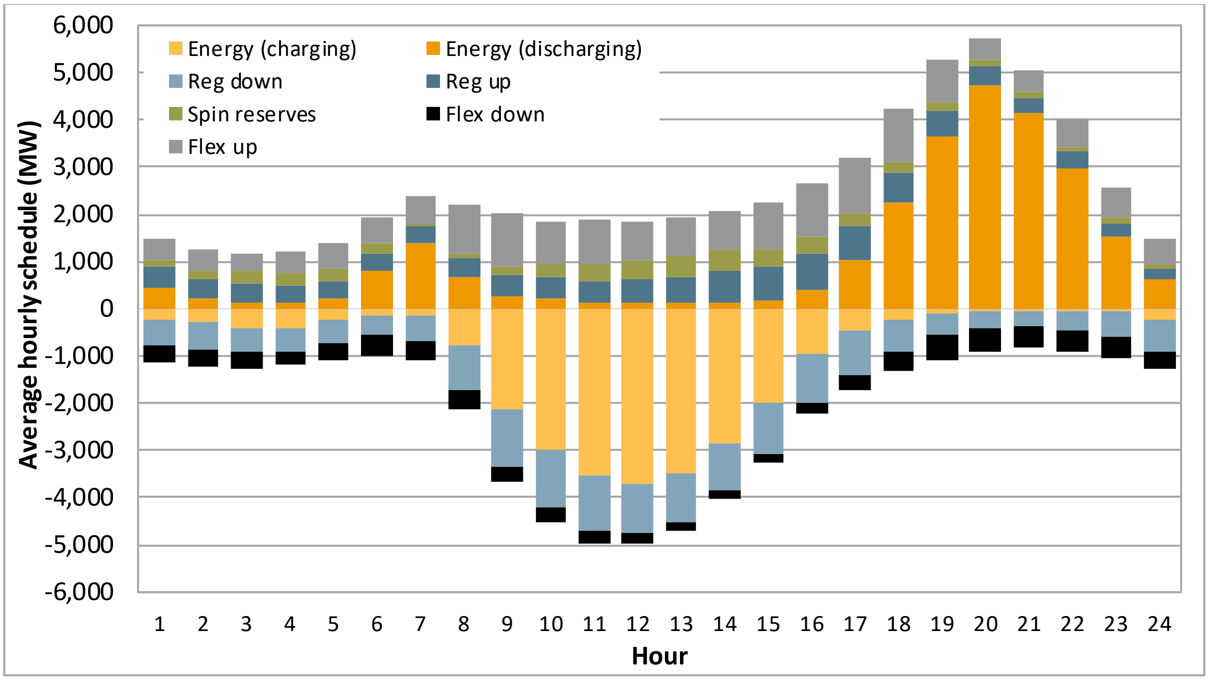
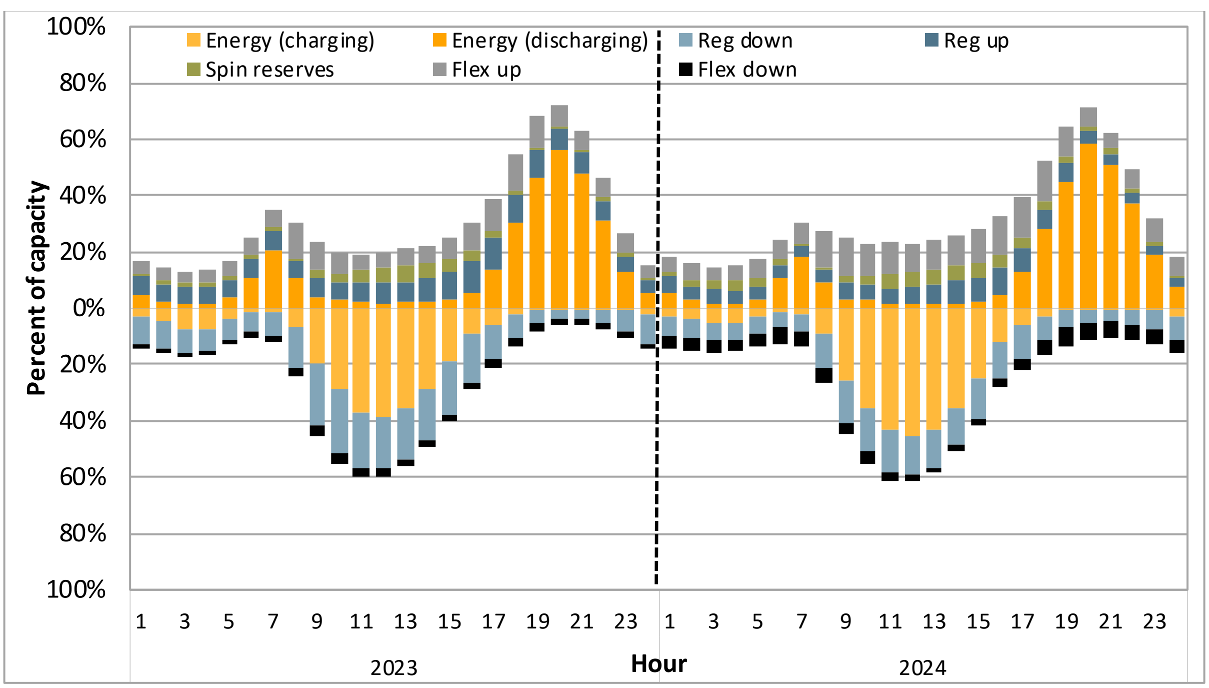


Figure 2.14 Scaled average 15-minute schedules (2023–2024)



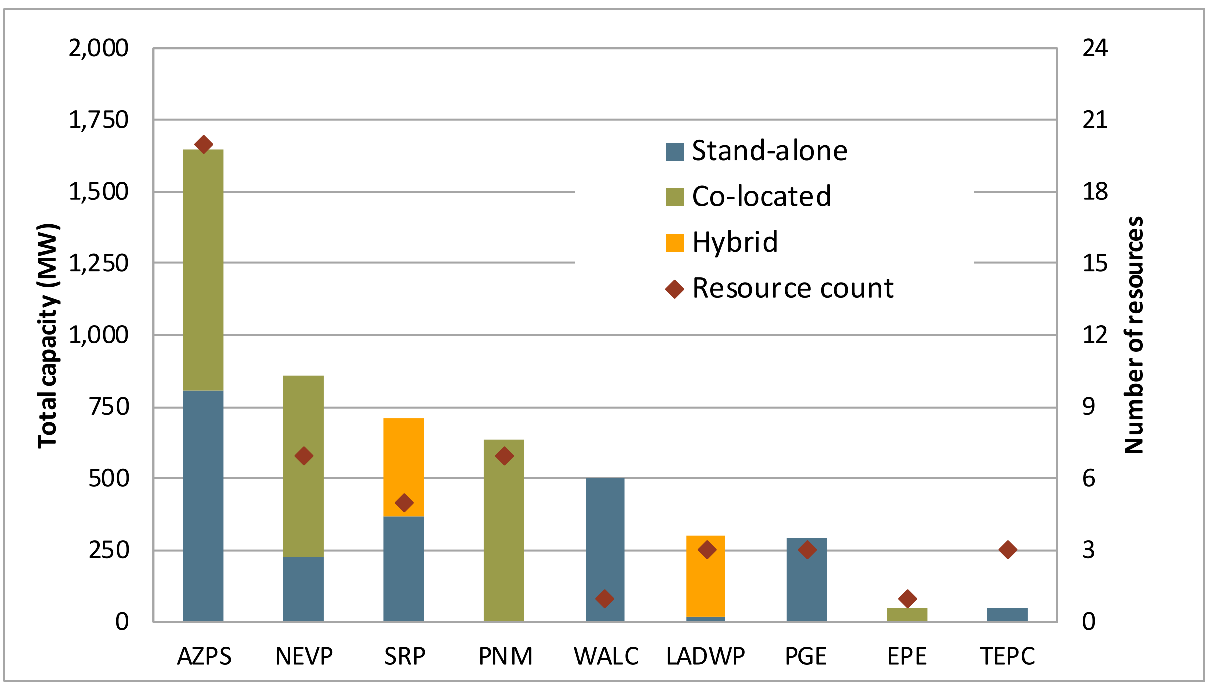
2.6 WEIM battery capacity and schedules

At the end of 2024, there were 50 actively participating resources with battery components in the Western Energy Imbalance Market (WEIM) outside of the CAISO balancing area, with a total of around 5,000 MW of discharge capacity and a 16,700 MWh maximum state-of-charge. In comparison, WEIM battery capacity totaled 2,600 MW in December 2023.

Figure 2.15 shows the number of actively participating batteries and their capacity for each balancing area with active battery resources. Of the capacity shown, 2,300 MW are from stand-alone units, 2,100 MW are from co-located units, and 600 MW are from the battery components of hybrid resources. Batteries accounted for 5 percent of participating nameplate capacity in the WEIM (outside of the CAISO balancing area) in 2024, and grew to around 9 percent as of January 1, 2025.

Battery capacity in WEIM states is expected to grow faster than battery capacity in the CAISO balancing area in the coming years. Figure 2.16 compares currently installed capacity in various Western states to the amount of battery capacity planned for completion from 2025 to 2028. The blue bars in Figure 2.16 show the amount of battery capacity registered with the ISO as operational at the end of 2024. The green bars show the amount of capacity reported as operational in 2024 by the U.S. Energy Information Agency, while the yellow bars show the amount of capacity planned for completion in each state from 2025 to 2028 according to Energy Information Agency data.[11]

Figure 2.15 Active battery capacity by WEIM balancing area (2024)



[11] Differences between CAISO/WEIM data compiled by DMM (blue bars) and EIA data on installed capacity in 2024 (green bars) in Figure 2.16 may be due to differences in on-line dates, MW ratings of projects, and differences in how hybrid resources are rated.

Figure 2.16 Installed and planned battery capacity in Western states as reported Energy Information Agency

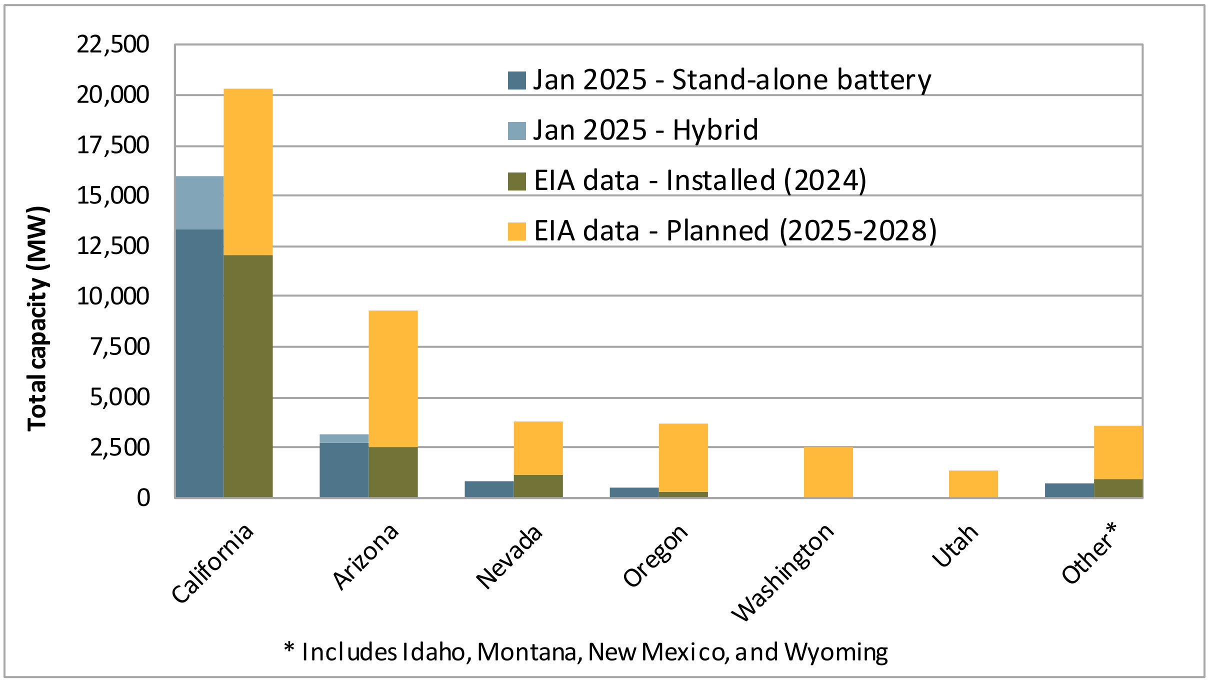
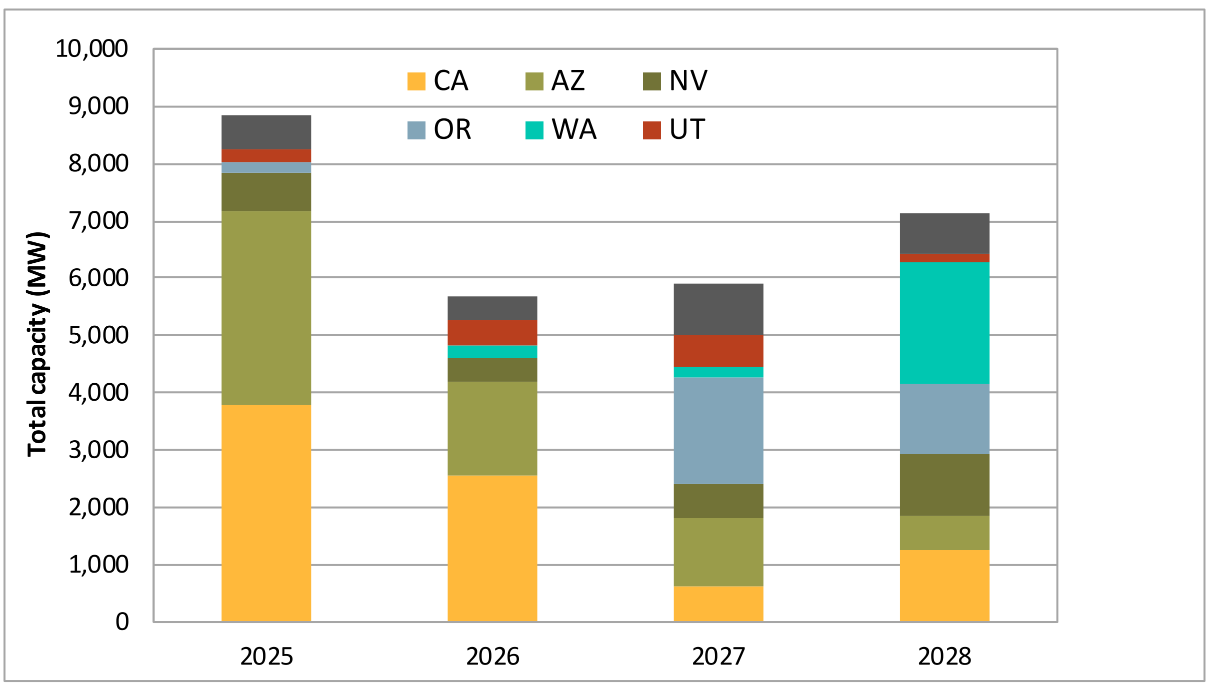


Figure 2.17 Planned battery capacity in Western states by year as reported Energy Information Agency



As shown in Figure 2.16, data from the Energy Information Agency (EIA) show about 8,230 MW of planned battery capacity in California and about 19,350 MW of planned capacity in other WEIM states that may come on-line from 2025 to 2028. Figure 2.17 shows EIA data on planned capacity for each state by year from 2025 to 2028.

Based on these EIA data, about 43 percent of new battery capacity in these Western states over the next four years will be in California, with about 35 percent being located in in Arizona, and about 14 percent in Nevada. Together, Oregon and Washington account for about 30 percent of this new planned capacity, with most of this potentially being completed in 2027 or 2028.

Batteries in the WEIM are mainly self-scheduled through base schedules, rather than through bids in the day-ahead or real-time market. As shown in Figure 2.18, batteries participating in the WEIM have similar schedules to batteries in the CAISO balancing area (i.e., primarily charging in the morning and early afternoon hours, then discharging in the evening). However, WEIM batteries do not have ancillary service schedules, since ancillary services are not procured through the market in WEIM balancing areas.

Figure 2.19 compares average base schedules and net 5-minute market schedules for batteries participating in the WEIM. In the real-time market, WEIM batteries were dispatched to charge slightly less than base schedules in the afternoon (around 35 MW from hours-ending 10 through 13 on average) and were dispatched to provide slightly less discharging in the evening (around 50 MW on average from hours-ending 19 through 22). There were about 530 MW of non-participating batteries in WEIM that were actively base scheduled in 2024. The average peak base schedule for these resources in 2024 was about 200 MW in hour-ending 20.

WEIM batteries tend to bid in more charging capacity during peak solar hours—an average of up to four times as much capacity compared to the lowest solar charging hours. Similarly, they offer the most discharging capacity during peak net load from hours-ending 19 through 22. Participating batteries tend to bid discharging capacity at prices well above locational marginal prices (LMPs) during all hours, and bid charging capacity at prices well below LMPs during non-charging hours. As a result, the market infrequently increments or decrements away from these resources' base schedules, and most of these dispatches coincide with increases in bid quantities.

Figure 2.18 WEIM average hourly battery schedules (2023–2024)

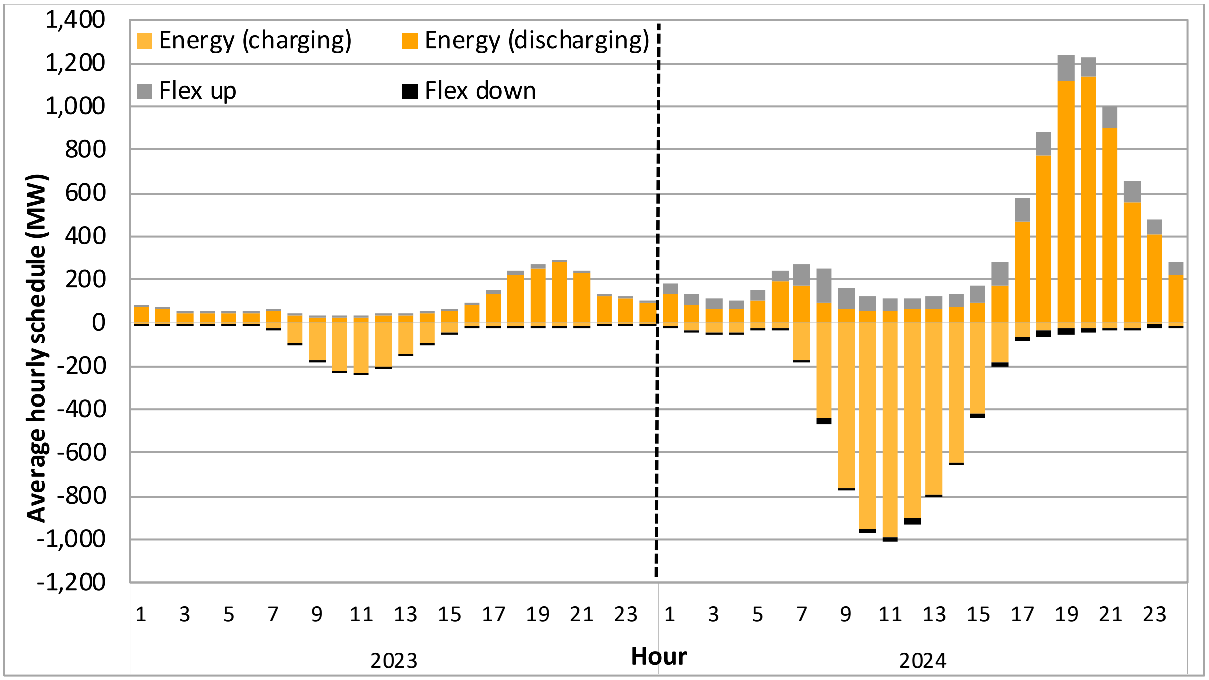
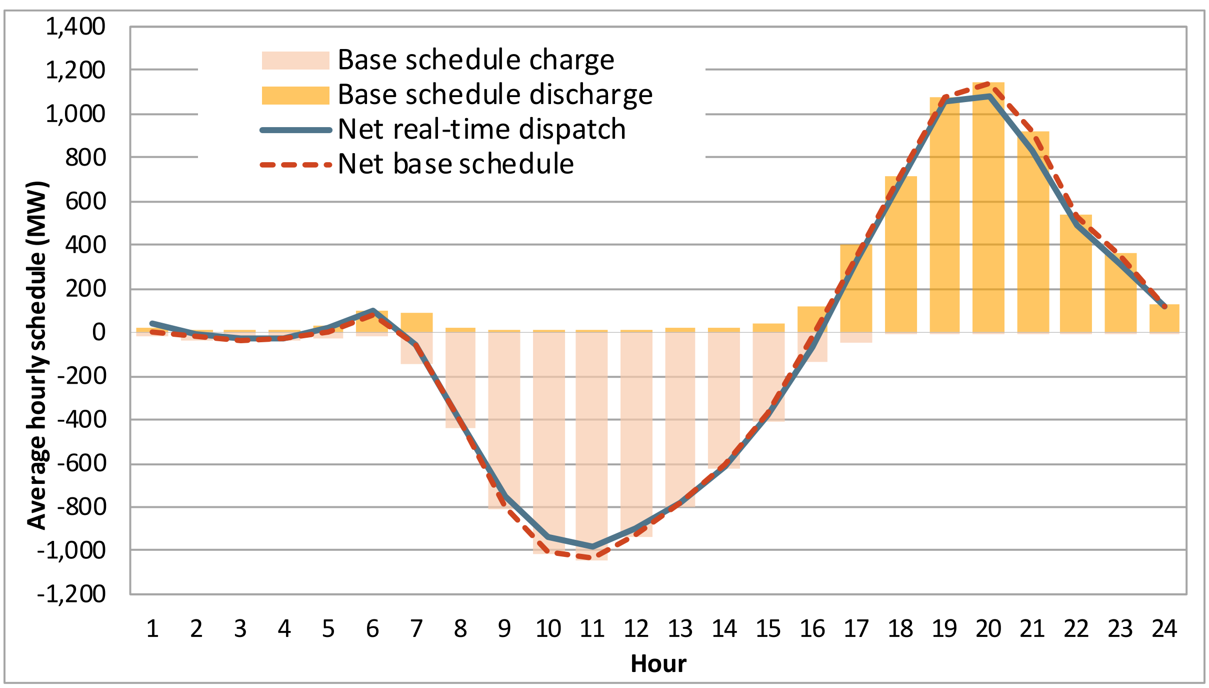


Figure 2.19 Average base schedules and real-time dispatch of participating batteries in 2024



2.7 Co-located battery resources

Co-location framework allows the ISO to model multiple resources participating at a single point of interconnection. Resources in co-located facilities submit separate energy bid curves, have separate metering arrangements, submit separate outages, receive separate dispatch instructions, and may be operated by different entities.

Though there are benefits for batteries co-locating with renewable resources, resources co-located together do not necessarily need to use different generation technologies. As of January 1, 2025, seven out of 76 sets of co-located resources have a single generation technology.

One benefit of the co-located model is that shared infrastructure between co-located facilities can reduce equipment, interconnection, and permitting costs. In 2022, the National Renewable Energy Laboratory (NREL) estimated that the cost of co-locating storage with photovoltaic solar systems is 7 percent lower than siting these units separately.[12] In addition, co-located resources with renewable and storage components have historically been able to benefit from a federal investment tax credit, which could offset up to 30 percent of investment costs. The 2022 Inflation Reduction Act extended the investment tax credit for stand-alone energy storage.[13] In California, some co-located storage and renewable resources also benefit from county property tax incentives.

Co-located batteries also differ from stand-alone batteries in that they are subject to several special market constraints. One of these is the aggregate capability constraint (ACC), which ensures that dispatch instructions to co-located resources behind a common point of interconnection do not exceed interconnection limits. The ACC can also restrict a battery's regulation awards.

Also, as of November 2023, co-located batteries have access to an hourly electable parameter that prevents them from grid charging. This new constraint was meant to help co-located batteries capture federal investment tax credits and local property tax benefits by allowing them to restrict charging when their renewable facilities weren't producing energy. The maximum observed hourly amount of co-located battery capacity that restricted grid charging was nearly 750 MW in 2024.

Figure 2.20 shows average hourly real-time schedules for active co-located batteries (not including hybrids with battery components) compared to that of active stand-alone battery resources, scaled by total capacity from active batteries. On average, co-located batteries supply more energy and less ancillary services than stand-alone batteries per MW of capacity. Co-located batteries tend to profit more from energy arbitrage compared to stand-alone batteries because of low energy prices in the afternoon, caused by close proximity to solar generation. Figure 2.21 shows this trend by comparing average hourly LMPs on a quarterly basis for nodes with either co-located or stand-alone batteries.

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12 *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory, September 2022, p 50: https://www.nrel.gov/docs/fy22osti/83586.pdf

13 Title 26—Internal Revenue Code Section 48E, *Clean electricity investment credit*, April 15, 2025: https://uscode.house.gov/view.xhtml?req=granuleid:USC-prelim-title26-section48E&num=0&edition=prelim#sourcecredit

Figure 2.20 Average hourly schedules: co-located versus stand-alone batteries

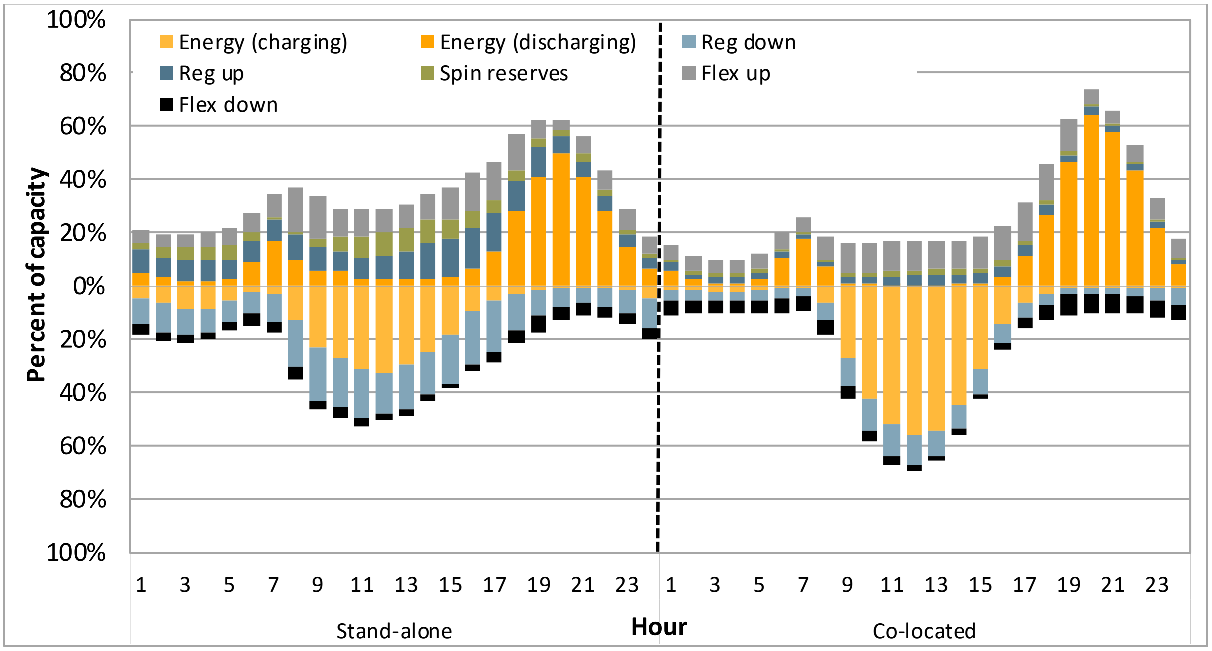
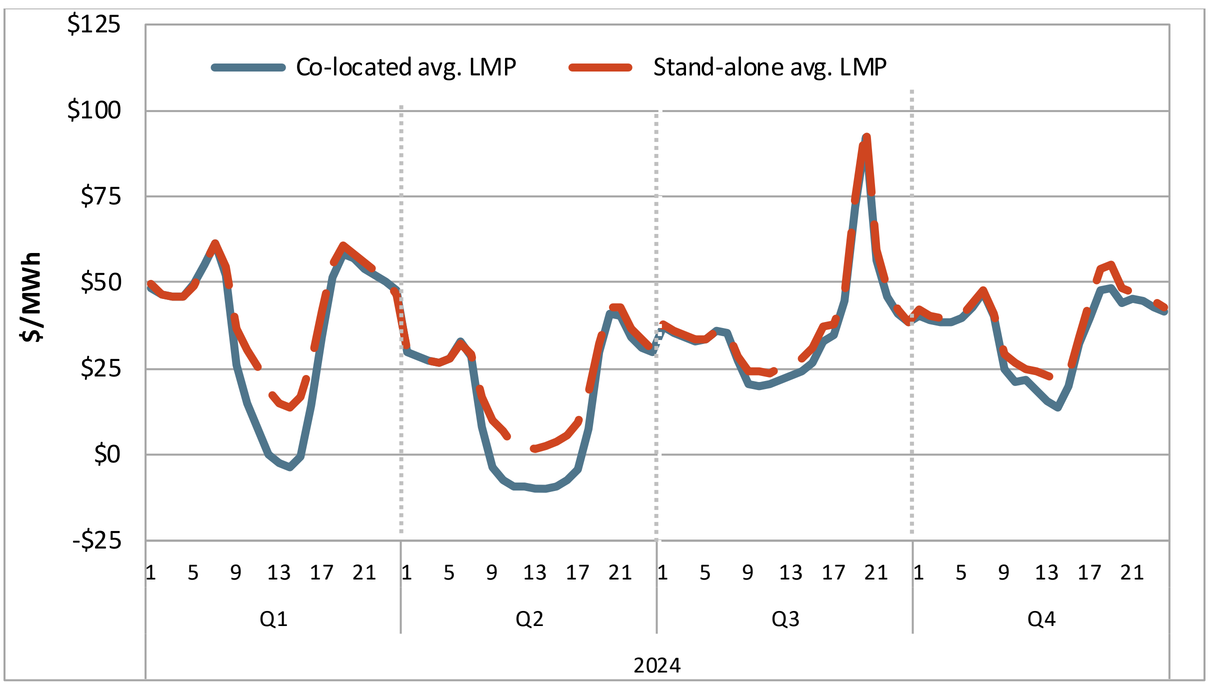


Figure 2.21 Average nodal prices: co-located versus stand-alone batteries



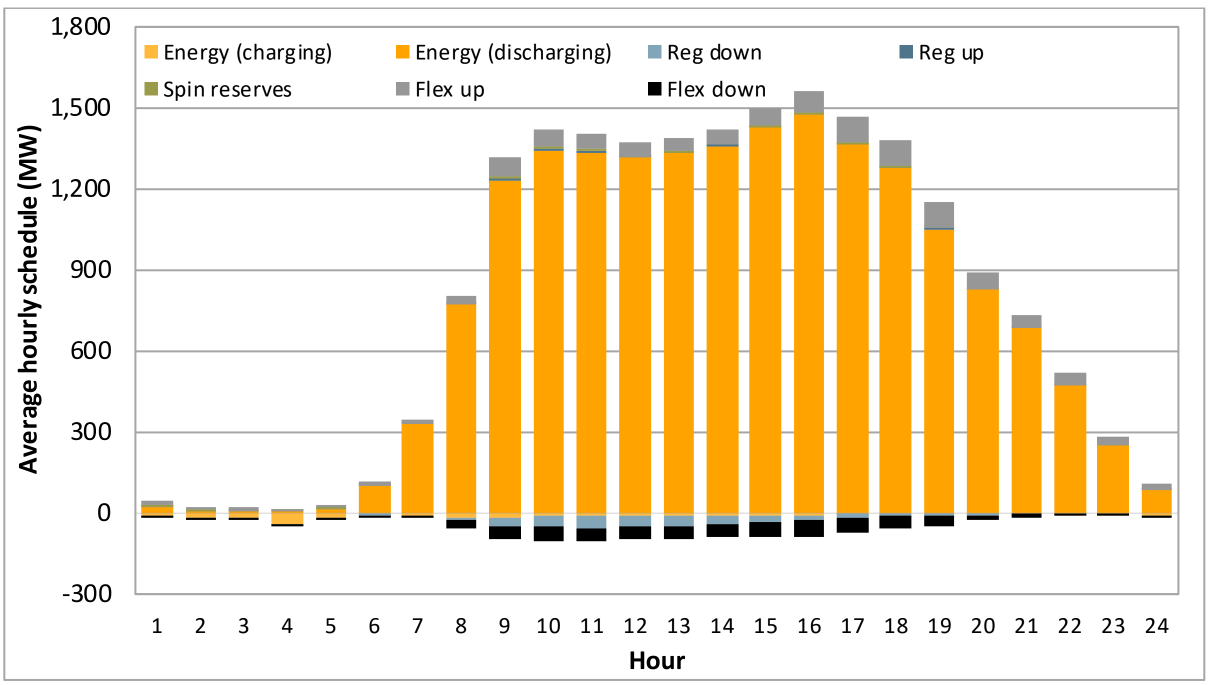
2.8 Hybrid battery resources

Hybrid battery resources are batteries combined with a generation resource (usually solar) which choose to be modeled as single resource. Hybrid resources have a single bid curve that applies to all their component parts and receive one dispatch instruction from the ISO. The hybrid resource operator self-optimizes the components of its resource to meet that dispatch instruction. As of December 2024, there are 35 actively participating hybrid resources with battery technology in the CAISO and the WEIM.

Figure 2.22 shows average hourly real-time (15-minute market) schedules of all active hybrid resources in 2024. Hybrids differ from battery-only resources in that most of their energy schedules occur during the afternoon when solar is abundant. Then, in the evening when solar is unavailable, hybrids can still discharge energy that they have stored in battery components during the day.

In 2024, 96 percent of registered hybrids participated as NGRs. However, only around 40 percent of these resources had the operational capabilities which would make them eligible to charge from the grid. In 2024, hybrids received very few market awards to charge from the grid and mostly charged from on-site renewables.

Figure 2.22 Average hourly hybrid battery resource schedules



Whereas the ISO manages the efficient dispatch of individual co-located renewable and storage resources using tools such as renewable forecasts and state-of-charge tracking, hybrids self-optimize generation across their different components. Though hybrids have discretion in how they manage their generation, the resource operators are still required to respond to dispatch instructions from the ISO. Hybrid resources are required to manage their state-of-charge such that they have sufficient headroom (either upward or downward) to fulfill their ancillary service awards.

In February 2023, the ISO implemented dynamic limits, a tool for hybrids to communicate their operational capabilities in real time. The ISO requires hybrid operators to update their upper and lower dynamic limits—representing the minimum and maximum MW value they can operate at—for every 5-

minute real-time market interval where they have an economic bid, for a rolling six-hour look-ahead period. The real-time market treats these inputs as constraints, such that the resource will not be dispatched outside of the dynamic limits.

2.9 Market revenue

2.9.1 Total net market revenues

In 2024, total net market revenues for CAISO balancing area batteries increased by around 20 percent as the result of increases to the battery fleet. However, net annual revenues per kW of battery capacity decreased due to lower peak hour prices in 2024. Figure 2.23 shows weighted average revenue by category for batteries in the CAISO balancing area with a full year of operation. Net market revenue for these resources was $53/kW-yr in 2024, compared to $78/kW-yr in 2023, and $103/kW-yr in 2022.

Figure 2.24 shows quarterly net market revenues for battery resources in the CAISO balancing area by category from January 2023 through December 2024.[14] As shown in these figures, batteries continued to generate the majority of their market revenues—nearly 82 percent—from providing energy in 2024.

Net real-time market revenues for batteries outside of the CAISO balancing area were negative overall in 2024, at -$8.8 million.[15] WEIM settlements are determined by the amount of energy imbalance, i.e., the difference between submitted base schedules and the market output, in the real-time market. As shown in Figure 2.19 in Section 2.6 of this report, WEIM batteries were often dispatched above base scheduled charging in the afternoon, and below base scheduled discharging in the evening. Negative prices in the afternoon and positive prices in the evening both could have led to net negative settlements, given the energy imbalance shown in Figure 2.19.

Although settled payments for CAISO and non-CAISO BA batteries are not directly comparable, we can assess the value of energy provided by non-CAISO batteries using base schedule MW quantities and 15-minute nodal prices. Using this approach, the value of energy provided by non-CAISO batteries participating throughout 2024 was about $32/kW-year.[16]

14 The regulation down category contains payments and charges from settlements codes 6600, 6624, 6670, and 7261. Regulation up includes 6500, 6524, 6570, and 7251. Energy includes 6011, 6800, 6824, 6460, 6470, and 6475. Real-time bid cost recovery includes 6620. Other includes codes 6100, 6124, 6170, 7071, 6200, 6224, 6270, 6482, 6488, 7081, 7070, and 6630. More details can be found on the CAISO settlements page: https://www.caiso.com/market/Pages/Settlements/Default.aspx

15 This figure accounts for invoices related to instructed imbalance energy, uninstructed imbalance energy, bid cost recovery, flexible ramping product, and greenhouse gas emission settlements.

16 Energy value for a given resource and interval was derived using the following equation:
0.25 * Fifteen-minute base scheduled capacity (MW) * Fifteen-minute LMP (dollars/MWh)

Figure 2.23 Average revenue for batteries with a full year of operation

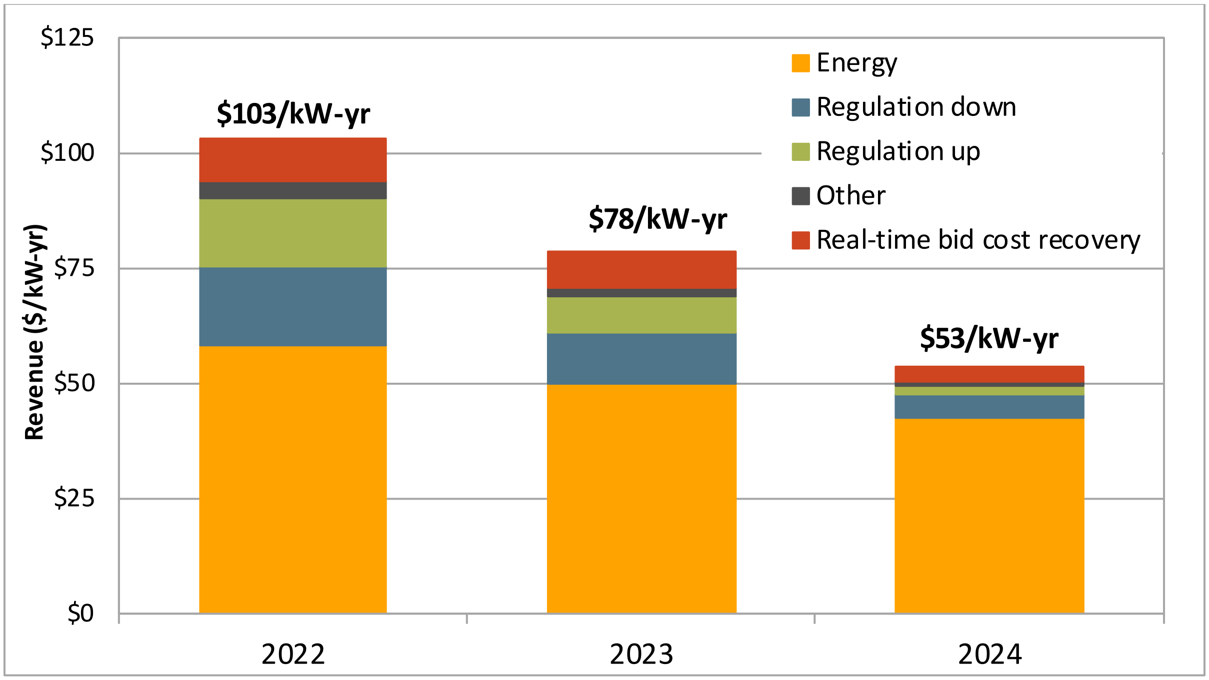
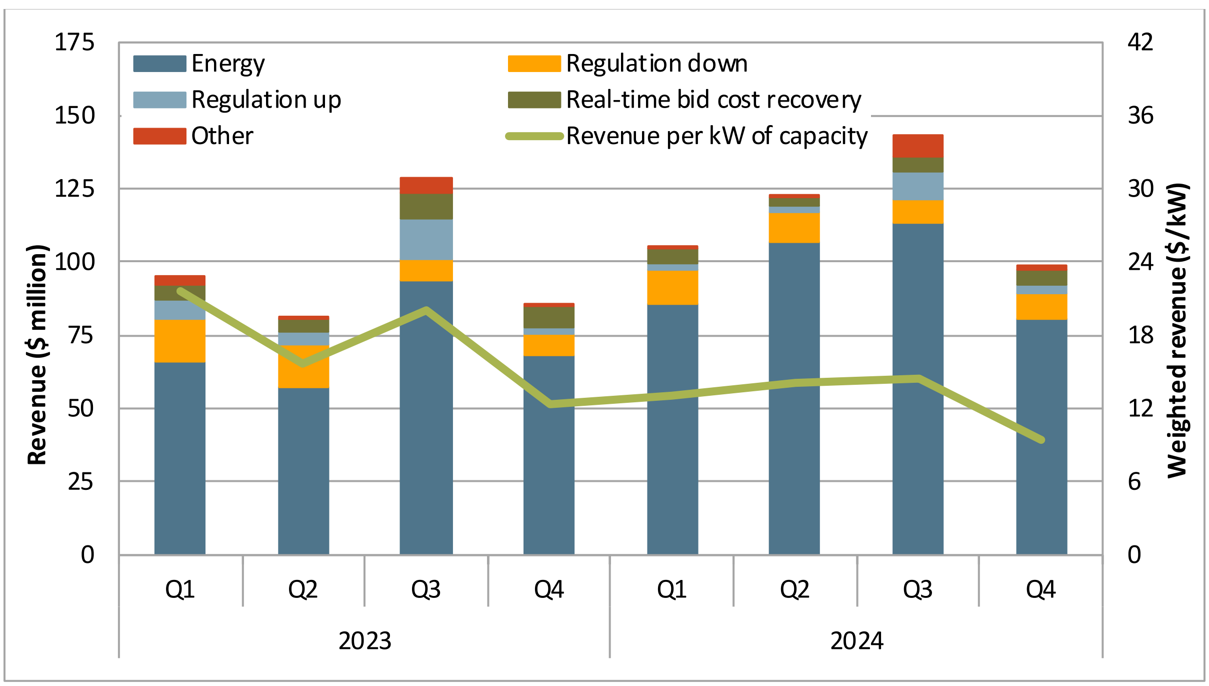


Figure 2.24 Quarterly net market revenues for battery resources (2023–2024)



2.9.2 Bid cost recovery

Generating units are eligible to receive bid cost recovery (BCR) payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. The main purpose of bid cost recovery for gas and other thermal generators is to alleviate the risk that the net revenues from energy sales will provide insufficient revenue to cover the units' start-up and minimum load costs.

Generating units may also be eligible to receive bid cost recovery if they are dispatched out of merit order (in the current settlement interval) due to the multi-interval optimization, and the associated excess bid costs are not recovered over the rest of the operating day. For example, slower ramping units whose bids are economic in future intervals may be ramped up during intervals when the market price is lower than their energy bid price.

Batteries lack all traditional drivers of BCR in that they are continuously dispatchable, and therefore do not have startup, shutdown, minimum load, or transition costs. Batteries also do not have most of the operational constraints that current bid cost recovery rules are designed to address (such as minimum on and off times, relatively slow ramp rates, etc.).

Bid cost recovery payments to batteries are extremely low in the day-ahead market. This reflects the fact that batteries have few operational limitations that create a need to schedule batteries out of merit order given the 24-hour optimization timeframe of the day-ahead market. All non-negligible instances of day-ahead bid cost recovery paid to batteries identified by DMM since 2022 have been the result of scheduling coordinator-submitted parameters interacting with the day-ahead optimization to cause uneconomic market dispatches.

Almost all bid cost recovery paid to batteries is in the real-time market. The main limitations on battery dispatch that lead to real-time bid cost recovery payments stem from state-of-charge constraints that limit charging and discharging. For example, when a battery does not have sufficient real-time state-of-charge to deliver a day-ahead market award, the real-time market software may force a battery to forgo charging or discharging out of merit order to "buy back" or "sell back" the day-ahead market award. Under the ISO's settlement rules, this can lead to payment of real-time bid cost recovery due to the difference between the battery's bid price and the real-time market clearing price.

DMM and the California ISO's Market Surveillance Committee (MSC) have noted that the current real-time BCR design incents inefficient battery bidding behavior by removing batteries' exposure to real-time prices, and reduces the reliability benefits of these resources.[17,18] In addition, the BCR design creates gaming opportunities, especially through manipulation of various biddable parameters used to manage state-of-charge. Gaming concerns are exacerbated by the fact that bid cost recovery payments are partly driven by submitted bid prices, meaning that inflated bids can cause BCR payments to drastically exceed any economic losses caused by reversal of day-ahead schedules.

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

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

At $17.9 million, real-time bid cost recovery payments to batteries represented 11 percent of all bid cost recovery payments in 2024. In comparison, batteries received nearly $28 million of real-time bid cost recovery in 2023, representing 10 percent of total bid cost recovery payments. DMM continues to recommend that the ISO enhance bid cost recovery rules for storage resources to consider state-of-charge limitations and other attributes unique to storage resources. DMM continues to support the California ISO's efforts to address bid cost recovery concerns in its ongoing stakeholder initiative.[19]

2.10 Resource adequacy

California's resource adequacy (RA) program is designed to ensure the California ISO system has enough resources to operate the grid safely and reliably in real-time and to provide incentives for the siting and construction of new resources to operate the grid reliably in the future. All load serving entities within the California Public Utilities Commission's (CPUC) jurisdiction are required to have enough capacity to meet peak demand and maintain a reserve margin, among other requirements.

2.10.1 Resource adequacy capacity from batteries

Starting in 2025, the CPUC implemented numerous reforms to the RA program. Notably, the CPUC's "slice-of-day" enhancement requires load serving entities (LSEs) to demonstrate sufficient capacity to satisfy its specific gross load profile—including a planning reserve margin—in all 24 hours on the ISO's "worst day" in each month.[20] In addition, under the slice-of-day approach, load serving entities' capacity portfolios must include sufficient surplus energy from non-storage resources to ensure batteries can be fully charged over the four most critical net peak hours, accounting for efficiency losses—this is verified through the CPUC's storage excess capacity test.[21]

California's resource adequacy program uses a metric called net qualifying capacity (NQC) to represent the maximum MW capacity that all resources—including batteries—can sell to an LSE to meet its resource adequacy obligations each hour. The CPUC determines the NQC of batteries based on testing of their sustained output over a four-hour period. Batteries with a longer discharge duration do not receive a different amount of credit for resource adequacy capacity than those that can only provide energy for four hours. Under slice-of-day, load serving entities must reflect daily resource capabilities (such as maximum daily run hours, maximum stored energy value, and storage efficiency) in their hourly capacity showing.

The CPUC calculates NQC for hybrid and co-located batteries based on the NQC of the individual components at shared facilities, minus any physical limitations due to sharing a point of interconnection. In addition, for these "paired" storage resources, load serving entities must account for charging needs—either from the storage excess capacity test in the case of grid-charging enabled resources, or

[19] *Comments on Storage Design and Modeling Working Group Session 2 and 3*, Department of Market Monitoring, March 7, 2025: https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-working-group-sessions-2-and-3-mar-07-2025.pdf

[20] The "worst day" is defined as the day of the month that contains the hour with the highest coincident peak load forecast. The CPUC has acknowledged that this definition can evolve over time if some other attribute is found to better reflect reliability challenges.

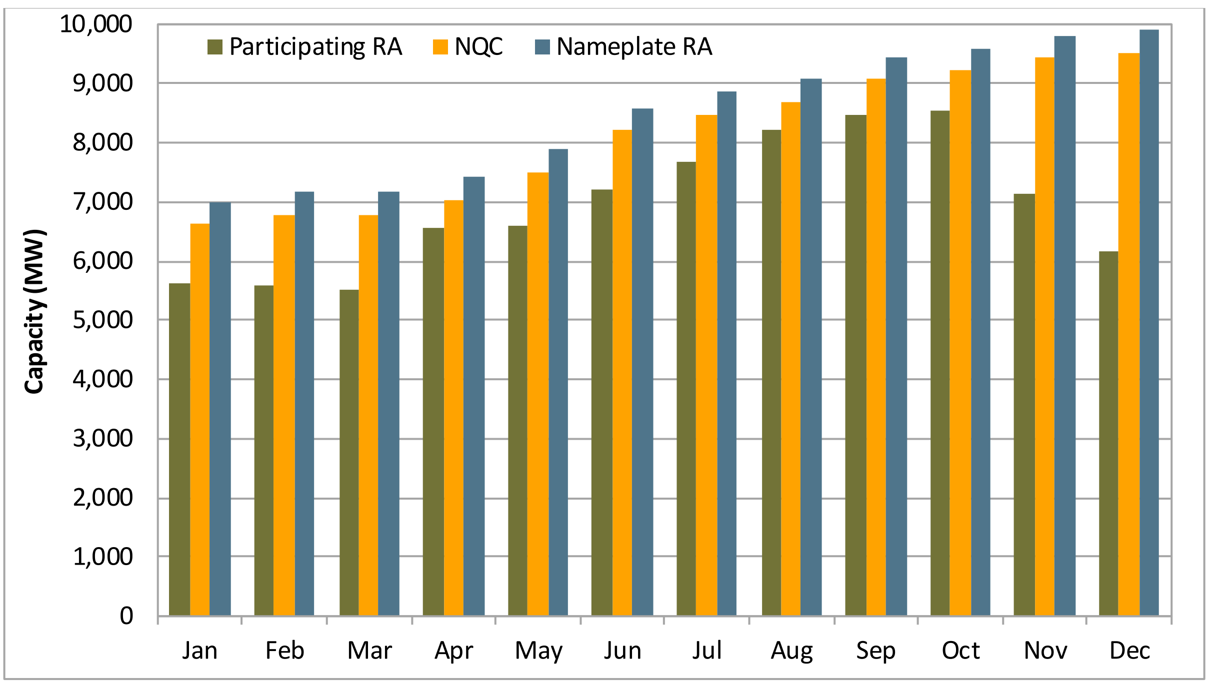
[21] *Resource Adequacy Slice-of-Day Showing Template User's* Guide, California Public Utilities Commission, July 2, 2024, p 25: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/rashowing_template_usersguide_rev30.docx

from the paired generating capacity for non-grid-charging storage. For co-located grid-charging restricted storage, the charging capabilities of the paired generating resource will be applied to charging the storage regardless of whether the load serving entity has the off-take rights to the generation. In addition, the total capacity of any non-storage resource that could be used toward the storage excess capacity test is reduced by the total charging energy of any paired or co-located grid-restricted storage resource.[22] As a result of modeled charging needs, hybrid and co-located battery components receive less qualifying capacity than identically sized stand-alone resources.

Resources benefit by participating in the resource adequacy program by getting capacity payments when they contract with load serving entities. However, resource adequacy resources are subject to numerous additional requirements when participating in the CAISO market. For example, batteries and other resource types with flexible resource adequacy capacity are subject to must-offer obligations, meaning that they must submit economic bids for energy for the full amount of their flexible resource adequacy value during specified hours of the real-time and day-ahead markets.[23]

Figure 2.25 shows month-end participating resource adequacy capacity, aggregate battery NQC, and total nameplate battery capacity for 2024.[24] About 65 to 94 percent of the total available NQC from batteries was counted towards resource adequacy requirements, depending on the month. Battery RA participation tends to decrease at year-end because load serving entities' obligations are lower.

Figure 2.25 Resource adequacy capacity from batteries (2024)



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22 Ibid.

23 *Fifth Replacement Electronic Tariff, section 40.10.6 Flexible RA Capacity Must-Offer Obligation*, California ISO, February 11, 2023, p 102: http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Feb11-2023.pdf

24 For battery nameplate capacity, we count Master File capacity values for any battery which has a NQC rating from the CPUC.

2.10.2 Availability of resource adequacy batteries

Battery capacity may become unavailable to the market due to a combination of factors. One cause is simply that on high-priced days, a portion of the battery fleet may begin to discharge early based on their bid prices, and do not have the opportunity to recharge prior to the most critical peak net load hours. In addition, batteries are subject to numerous special market constraints which ensure that a resource's state-of-charge does not fall outside its physical operating parameters or other important operational limits. These constraints include:

- **The ancillary services state-of-charge (ASSOC) constraint**, which can bind in the real-time market and cause batteries to either charge or discharge in order to give them sufficient headroom to fulfill their ancillary service awards.
- **The aggregate capability constraint**, which ensures that the combined generation of co-located resources does not exceed interconnection limits.
- **Upper and lower charge limits**, optional biddable parameters which represent the highest and lowest stored energy values (in MWh) that should be maintained in the resource in a trading day.
- **The end-of-hour state-of-charge (EOH SOC) bid parameter**, which is an optional real-time only parameter for use by NGR resources to manage their state-of-charge.
- **The attenuated state-of-charge constraint**, which models the impact of batteries' providing regulation on their state-of-charge, and can restrict provision of ancillary services from batteries until they have charged or discharged to provide sufficient headroom.
- **The off-grid charging indicator**, an optional biddable parameter which allows co-located batteries to restrict grid charging in specified intervals.

Batteries may use energy bids, as well as some of the biddable parameters described above, to signal when they do not want to be available to the market for charging or discharging. In general, batteries use their energy bids to signal a high willingness to discharge during peak net load hours, and a low willingness to discharge when prices are lower in the afternoon.

In addition, there are certain physical characteristics of batteries that the market does not currently account for, which may cause batteries to become unavailable. One such characteristic is called *foldback*, which is where maximum and minimum power levels can change when a battery is at the highest and lowest ends of its state-of-charge. Cell imbalance—which is caused by a variance in voltage across cells in a battery storage system—can also limit the maximum power of a battery resource.[25]

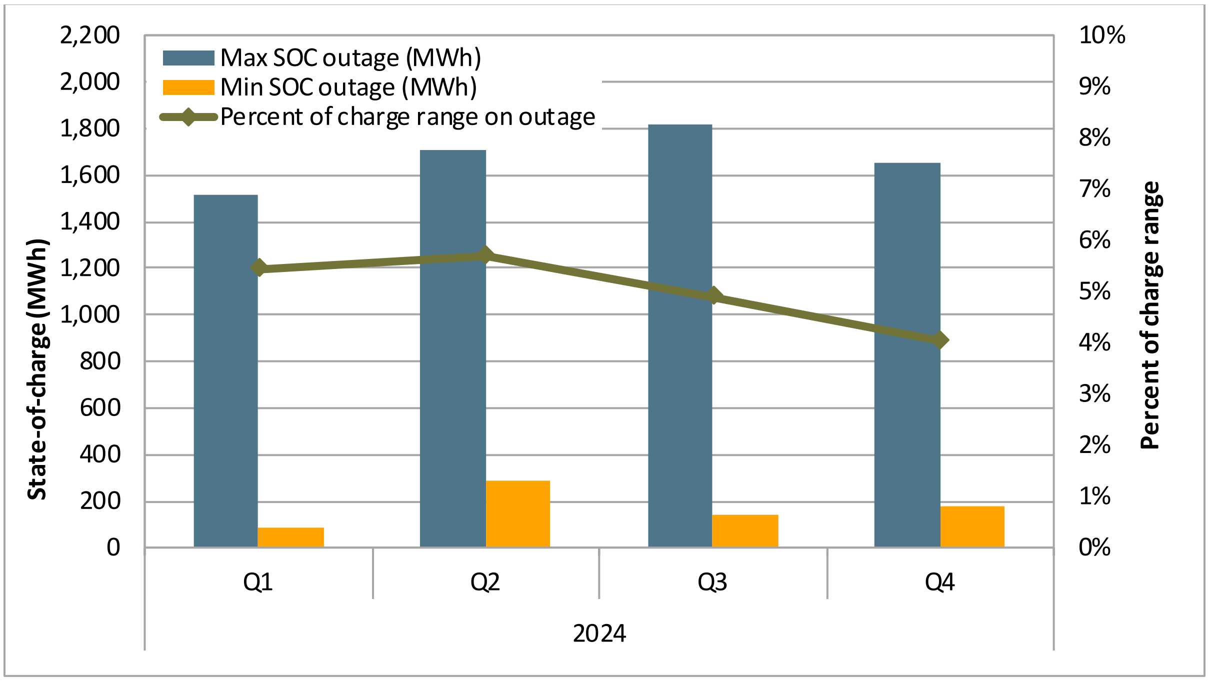
Market participants tend to reflect these physical limitations through outages and de-rates. The ISO gives batteries the option to reflect limitations on lower and upper state-of-charge bounds through the Outage Management System (OMS). Batteries may set their minimum required charge above their lower energy limit in Master File, and set their maximum allowable charge below their maximum energy limit. For example, a typical 100 MW, 4-hour duration battery would have a lower charge limit of zero MWh and an upper limit of 400 MWh in Master File—but in OMS they could set these values to 50 MWh

[25] "Impact of cell balance on grid scale battery energy storage systems." *Energy Reports*, vol. 6, May 2020, Thomas L. Fantham, and Daniel T. Gladwin, pp 209–216: https://www.sciencedirect.com/science/article/pii/S235248472030281X#:~:text=One%20aspect%20of%20grid%20scale,across%20a%20number%20of%20cells

and 350 MWh, respectively. In effect, both actions restrict the amount of energy that can be made available to the market.

The blue bars in Figure 2.26 reflect the average quarterly decrease in the upper charge limit, and the yellow bars reflect the average increase in the lower charge limit, compared to batteries' Master File values. The green line in Figure 2.26 shows the average percentage of aggregate charging range that was made unavailable through these outages. On average, around 5 percent of batteries' nameplate charge range was on outage in the real-time market in 2024.

Figure 2.26 Quarterly average real-time state-of-charge outages



Finally, there are also limitations in the market software that can cause batteries to be unavailable when they are needed to meet demand. Because of the computational complexity inherent with a large optimization, the ISO's real-time market has a limited optimization horizon. This limited optimization horizon can cause batteries to discharge earlier than desired when high real-time prices materialize early in the day, and can result in batteries entering peak net load hours with a diminished state-of-charge.[26]

For this report, DMM provides two different metrics of the availability of batteries providing resource adequacy capacity in 2024 during the most critical peak net load hours. The first metric is based on the average status of the resource adequacy battery fleet during each of the peak net load hours (17 to 22) on the five days with the highest average daily load in the CAISO balancing area.[27] Results of this analysis are summarized in Figure 2.27.

[26] *2022 Special Report on Battery Storage*, Department of Market Monitoring, July 7, 2023, p 33: https://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

[27] In order from highest to lowest average load, the days are September 6, September 5, July 24, July 23, and July 25.

The data in Figure 2.27 are shown in terms of the percentage of the total capacity of the battery fleet providing resource adequacy that falls into the following categories in the 15-minute market:

- The striped yellow and orange portion of each bar shows the portion of the battery fleet unavailable due to a reported outage or de-rate.
- The solid yellow bars show the average amount of undispatched energy bids offered at prices below the resources' locational marginal prices (LMPs). Since this capacity was bid at prices below the LMP but not dispatched, it may have been unavailable due to some of the various resource constraints that can limit the actual availability of battery capacity described above.
- The solid orange bars show the average amount of undispatched energy bids offered at prices greater than the resources' locational marginal prices (LMPs).[28] It is possible that some of this capacity also may not have been available due to state-of-charge and other constraints, but this cannot be determined.
- The dark green and light green bars show the average portion of battery capacity scheduled to provide spinning and non-spinning reserves and upward flexible ramping capacity, respectively.
- The dark blue and light blue bars show the average portion of battery capacity dispatched to provide energy and regulation up, respectively, during the peak net load on these five days.

The bars for each hour in Figure 2.27 are higher than the dotted black line showing the total aggregate resource adequacy capacity from batteries. This reflects the fact that batteries tend to contract less than their maximum power capacity for resource adequacy, and can therefore theoretically provide more power than their resource adequacy value.

Battery availability (in terms of capacity scheduled for energy, ancillary services, or flexible ramping product) peaked in hour-ending 20. In this hour, after accounting for capacity unavailable due to outages and de-rates, the average scheduled battery capacity in the 15-minute market exceeded 100 percent of total resource adequacy capacity. Around 55 percent of this capacity was unavailable in hour-ending 17 because it was bid at prices above the resources' LMPs. Since real-time prices tend to peak after hour-ending 17, batteries reflected a high opportunity cost to discharge in their bids in this hour. In hour-ending 22, 34 percent of battery capacity was unavailable to the market, of which 13 percentage points were bid in at a price less than the LMP.

To illustrate how the availability of batteries can vary under the most critical system conditions, Figure 2.28 provides these same metrics for the resource adequacy battery fleet during the seven hours when the CAISO issued an Energy Emergency Alert Watch (EEA Watch) from hours-ending 18 through 24 on July 24, shown in terms of total capacity.[29]

Real-time availability of battery resource adequacy capacity on July 24 was similar to the comparable hours shown in Figure 2.27. After accounting for battery capacity unavailable due to outages and de-rates, the average scheduled battery capacity in hour-ending 20 of the 15-minute market was over 100 percent. In hour-ending 22, 19 percent of battery capacity was not dispatched for energy despite being

[28] This figure is most relevant as a metric for resource adequacy performance for units that are required to submit economic bids, e.g., units with flexible resource adequacy capacity.

[29] The CAISO uses Emergency Energy Alerts with 4 levels of urgency, from EEA Watch to EEA 3, to communicate potential energy shortages to market participants: https://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf

bid at a price less than the LMP. As previously noted, DMM cannot determine the extent to which some additional capacity providing operating reserves or bid at prices greater than the LMP may have been unavailable due to various constraints.

Figure 2.27 Average 15-minute resource adequacy battery capacity during 5 highest load days

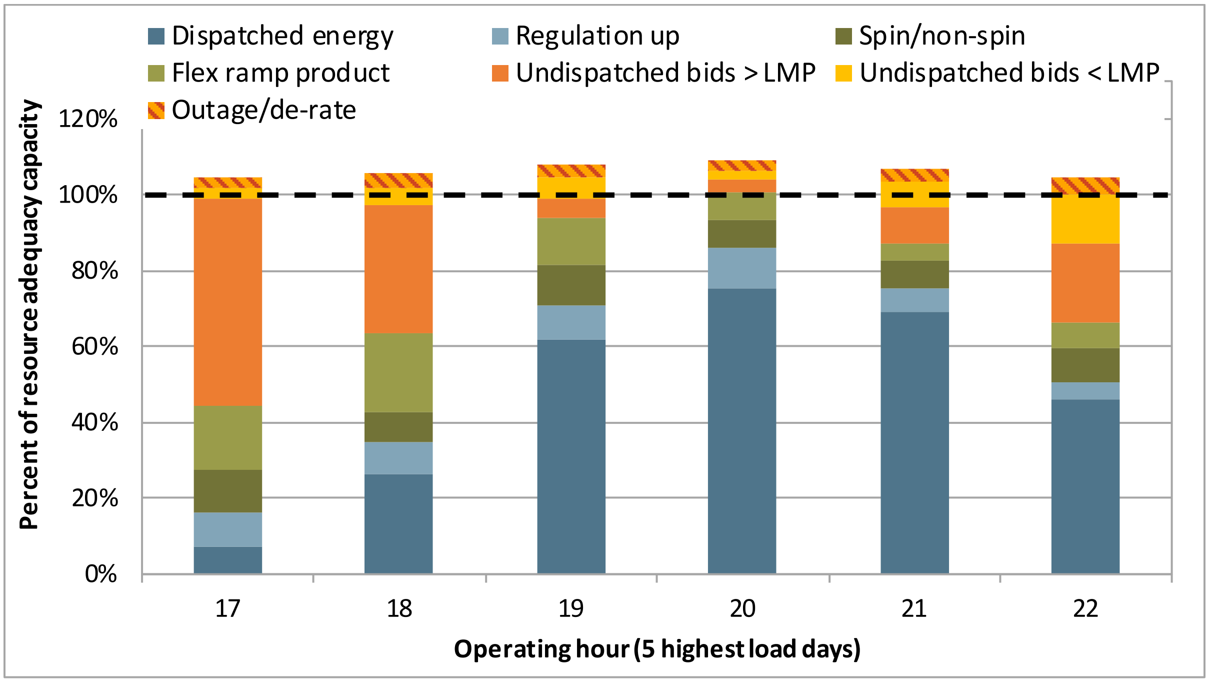
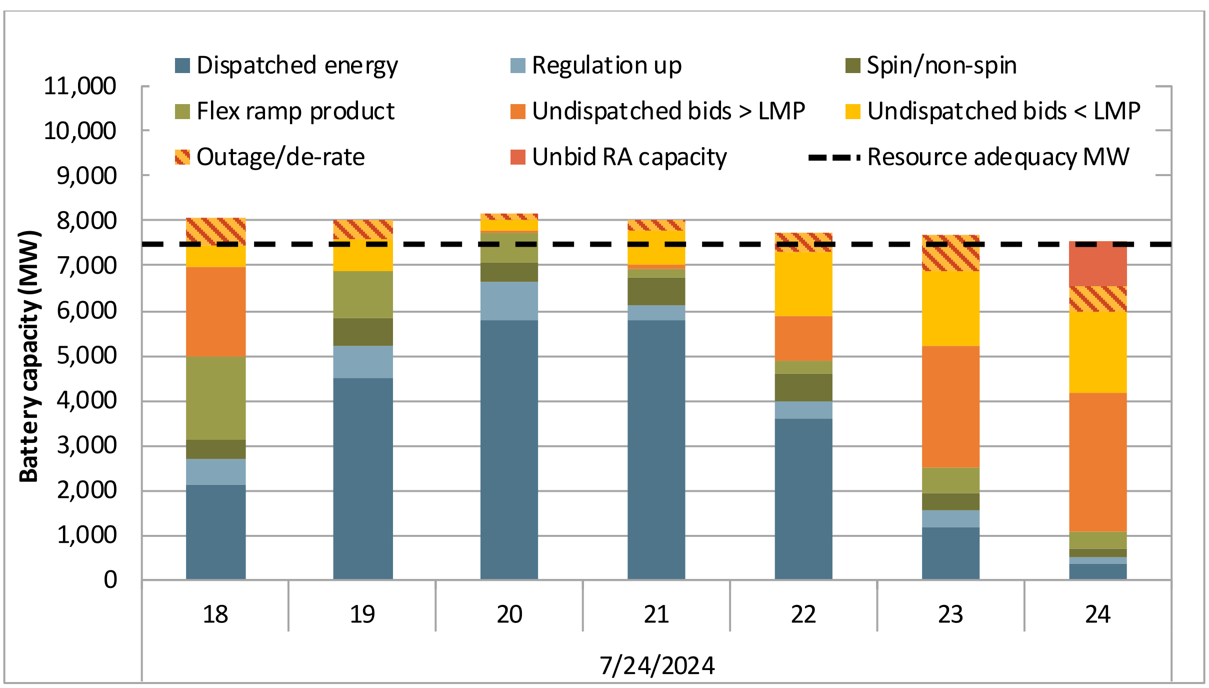


Figure 2.28 15-minute resource adequacy capacity during EEA hours on July 24, 2024



2.11 Local market power mitigation

As part of its day-ahead and real-time market processes, the ISO includes local market power mitigation (LMPM), an automated procedure meant to ensure that resources are providing energy at or near their cost of production. Beginning in November 2021, battery resources using the non-generator resource (NGR) model became subject to mitigation. Storage resources with 5 MW or less of capacity, and whose parent company is not a net-supplier in the ISO market, are exempt from mitigation. As with all resource types, batteries are subject to mitigation based on when they can provide counterflow to relieve congestion on a binding non-competitive transmission constraint.

Unlike other resource types, battery resources modeled as NGR may bid negative MW (for charging), and thus are subject to mitigation on their negative (charging) bids as well as their positive (discharging) bids. A resource can potentially withhold counterflow to a non-competitive constraint by submitting a high bid to charge when it may be uneconomic to do so. When the resource is mitigated, the charging bid can be lowered, resulting in the battery not receiving a market charging award. When charging is not awarded, flow on the non-competitive constraint is reduced.[30]

As with other resource types, battery bids are only changed during the LMPM processes if a resource has bid higher than their default energy bid (DEB) and the competitive locational marginal price (LMP) at the resource's location. Batteries can choose a "storage option" for their DEB calculation.[31] As of December 2024, around 90 percent of active CAISO balancing area batteries that are subject to LMPM had opted for the storage DEB. The day-ahead and real-time market storage DEBs are calculated using Equation 2.11.1.

Equation 2.11.1 Storage default energy bid formula

$$\boldsymbol{DEB = Max\left\{Max\left(En_{\frac{\partial}{\eta}}, 0\right) + \rho,\ OC_{\gamma}\right\} * 1.1}$$

Where:

En: Energy cost
∂: Energy charging duration
γ: Energy discharge duration
η: Round-trip efficiency
ρ: Variable storage operation cost
OC: Price-based opportunity cost

The energy cost component of the storage DEB is calculated under the assumption that the resource performs one cycle of charging and discharging per day, and that it will charge during the least expensive continuous block of time during the day. Resources may have individualized variable

[30] Battery storage resources could also potentially exercise market power in future intervals by submitting very low charging bids to prevent charging in the current interval. This could result in the battery being unable to discharge in a future interval when it has local market power in that interval. Mitigation of these bids would involve increasing charging bids to a level higher than submitted. This type of mitigation does not currently exist in the ISO market.

[31] *Business Practice Manual Change Management, Market Instruments, Attachment D.9, Storage Default Energy Bid*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

operation costs, which are validated by the ISO. These costs often reflect a conservative estimate of potential cell degradation costs that may be incurred should the battery cycle multiple times per day.

The storage DEB includes a priced-based opportunity cost parameter which is meant to prevent mitigated batteries from being dispatched at a time that is not profit-maximizing over the day. The opportunity cost component for a given resource is set to the N^{th} highest LMP for a trade date, where N equals the discharge duration of the resource in hours. For most storage resources (which have a four-hour discharge duration), the opportunity cost is based on the fourth highest day-ahead LMP. Whereas the real-time storage DEB uses day-ahead prices for the corresponding trade date to calculate the opportunity cost parameter, the day-ahead market uses advisory prices from the LMPM process.

Figure 2.29 shows average hourly battery mitigation for the 15-minute market in 2024. Both charging and discharging mitigation are aggregated together as positive values in this figure since both potentially increase net supply from the battery. On average, there was a potential increase in battery dispatch due to mitigation of 40 MW in the 15-minute market in 2024. Dispatch was potentially increased by mitigation by an average of 19 MW and 45 MW in the day-ahead and 5-minute markets, respectively, in 2024.

In 2024, the California ISO introduced a stakeholder initiative to consider changes to storage modeling, including the storage DEB. DMM has noted that the accuracy of the current real-time storage DEB as an estimate of opportunity cost is limited since it is a static value in each trade date, which is based on day-ahead prices. The limited real-time market optimization horizon, along with an inaccurate estimate for intra-day storage opportunity cost, can lead to inefficient dispatch when mitigation occurs.

As shown by Figure 2.29 and previous analysis by DMM, inefficient real-time dispatch caused by mitigation occurs infrequently.[32] Nonetheless, this could lead to reliability issues on days with stressed conditions. It could also lead to costly real-time energy buybacks for storage resources. Therefore, DMM has proposed allowing the storage DEB to vary by hour to better capture real-time conditions and get a more accurate estimate of opportunity cost.[33]

Unlike stand-alone batteries, hybrid resources are currently exempt from mitigation, regardless of size. Figure 2.30 shows average hybrid capacity that met the criteria for being subject to mitigation—including being owned by a potentially pivotal supplier and being able to supply counterflow to relieve congestion on a binding non-competitive transmission constraint—monthly in 2024.

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32 *Analysis of battery bid cost recovery and bid mitigation issues*, Department of Market Monitoring, September 11, 2024: https://www.caiso.com/documents/presentation-battery-bid-cost-recovery-and-mitigation-data-dmm-sep-11-2024.pdf

33 *Comments on Storage Design and Modeling Working Group Session 2 and 3*, Department of Market Monitoring, March 7, 2025: https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-working-group-sessions-2-and-3-mar-07-2025.pdf

Figure 2.29 Hourly average 15-minute market battery mitigation (2024)

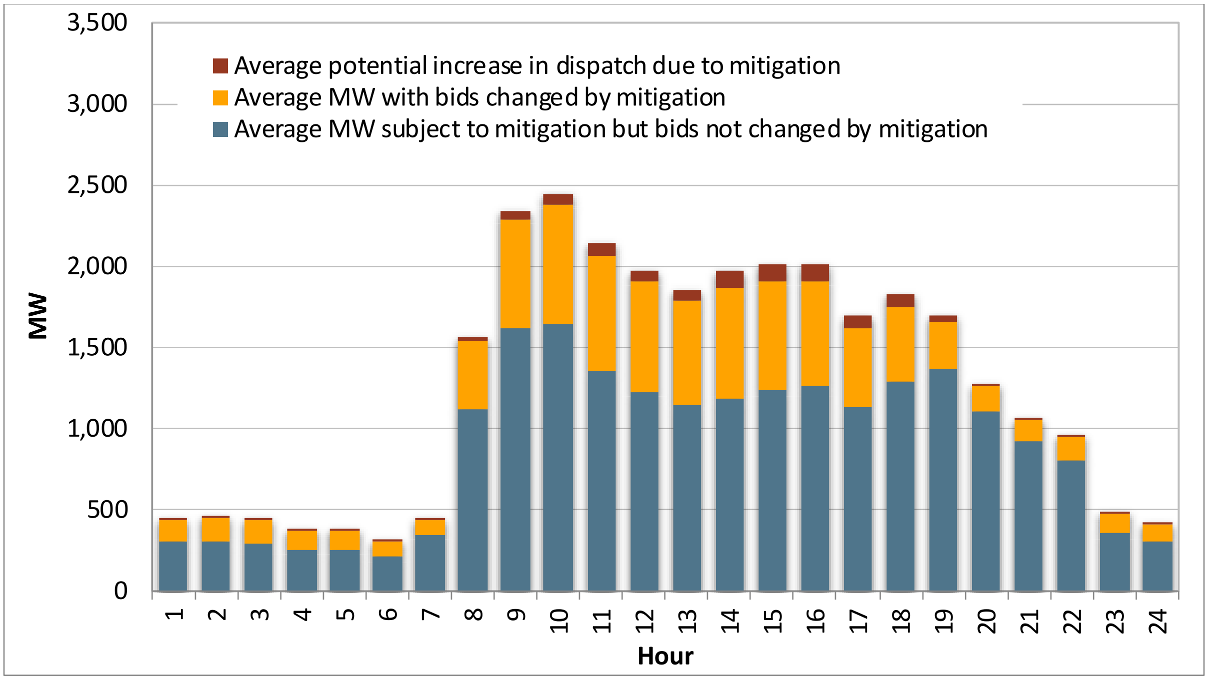

Figure 2.30 Hypothetical average day-ahead mitigation of hybrid battery capacity (2024)