2023 Special Report on Battery Storage

July 16, 2024

Prepared by: Department of Market Monitoring

California Independent System Operator

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1 Summary

1.1 Background

As energy markets switch from fossil fuels to intermittent 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 states like California, Washington, and Oregon have ambitious decarbonization goals. California is projected to need 79 GW of new renewable generation and around 50 GW of battery storage to meet its 2045 greenhouse gas reduction goals.[1]

The integration of large amounts of battery storage poses new challenges and opportunities. Most large-scale storage systems in operation use lithium-ion technology, which is currently preferred over other battery technologies because it provides fast response times and high-cycle efficiency (low energy loss between charging and discharging), while still being cost-effective. Several longer-duration energy storage technologies are currently in their pilot and demonstration phase with the California Energy Commission (CEC).[2]

Batteries do not generate energy, but rather store energy and move it from one time of day to another. Batteries can profit with this strategy—called arbitrage—so long as the price difference between charging and discharging is large enough to make up for efficiency losses in storage and variable operation costs. Batteries can purchase energy during midday hours when solar is plentiful and system prices are lowest, then sell power back to the grid in the evening when power is in high demand, solar output is low, and prices are much higher. In addition to providing flexible generating capacity during critical hours, the fleet of battery storage resources now represents a significant amount of additional demand during other hours of the day.

Batteries contribute other services and benefits to the grid besides energy. 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, batteries can moderate the extremes in daily price swings through arbitrage, by increasing demand for renewables during the very low-priced hours of the day and increasing supply in the evening to bring prices down.

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

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

2 California Energy Commission, *Information item on Current Activities of the Long Duration Energy Storage (LDES) Program*, June 16, 2023: https://www.energy.ca.gov/filebrowser/download/5579

1.2 Key findings

- **Battery storage capacity grew from about 500 MW in 2020 to 11,200 MW in June 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 3,500 MW of participating battery capacity as of June 2024**. This is a nearly three-fold increase in battery capacity in the WEIM since June 2023.
- **Batteries account for a significant portion of energy and capacity during the late afternoon and early evening when net loads are highest.** On average during hours 17 to 21, batteries provided about 5.6 percent of the CAISO balancing area's energy in 2023.
- **Batteries account for a significant portion of load during peak solar hours**. From hours-ending 10 to 13, battery charging represented around 8.3 percent of load in the CAISO balancing area in 2023. During these hours, batteries help reduce the need to curtail or export surplus solar energy at very low prices.
- **Batteries provide the majority of the ISO's regulation up and regulation down requirements**. However, in recent years the percentage of total battery storage capacity being scheduled for ancillary services has decreased as batteries have transitioned to providing more energy during the net peak load hours.
- **Net market revenue for batteries decreased from about $103/kW-yr in 2022 to $78/kW-yr in 2023.** This decrease was driven largely by lower energy prices and lower loads than in 2022.
- **Bid cost recovery payments for batteries increased by 16 percent in 2023** and these payments represent 7 percent of batteries' total net market revenues. In 2023, battery resources received 10 percent of all bid cost recovery paid to resources in the CAISO balancing area. 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 only about 174 MW of battery capacity per hour had bids lowered under the ISO's local market power mitigation procedures in 2023. Mitigation of bids potentially increased battery dispatch by an average of about 71 MW per hour during hours-ending 19 to 21 of the day-ahead market.
- **DMM continues to find that a significant portion of battery capacity used to meet resource adequacy requirements is unavailable to the market in some hours during tight system conditions.** There are 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 how batteries are bid into the real-time market, state-of-charge constraints set by battery operators, and other resource and modeling limitations.

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. In order 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 to indicate the available energy on the first participation interval of the trading day in the day-ahead market. The market software will default this value to the ending state-of-charge from the previous day if market participants do not submit an initial state-of-charge, or zero MWh if neither are available. One reason that the initial state-of-charge on a given day would differ from the ending state-of-charge from a previous market run is that the market software currently does not model state-of-charge changes due to a battery providing frequency regulation services.[3]

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-

[3] The ISO models the impact of batteries providing regulation through another constraint, which is similar to state-of-charge. This "attenuation factor" approach is described in more detail in Section 2.9 of this report.

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 intraday 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.

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 NGR resources 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.

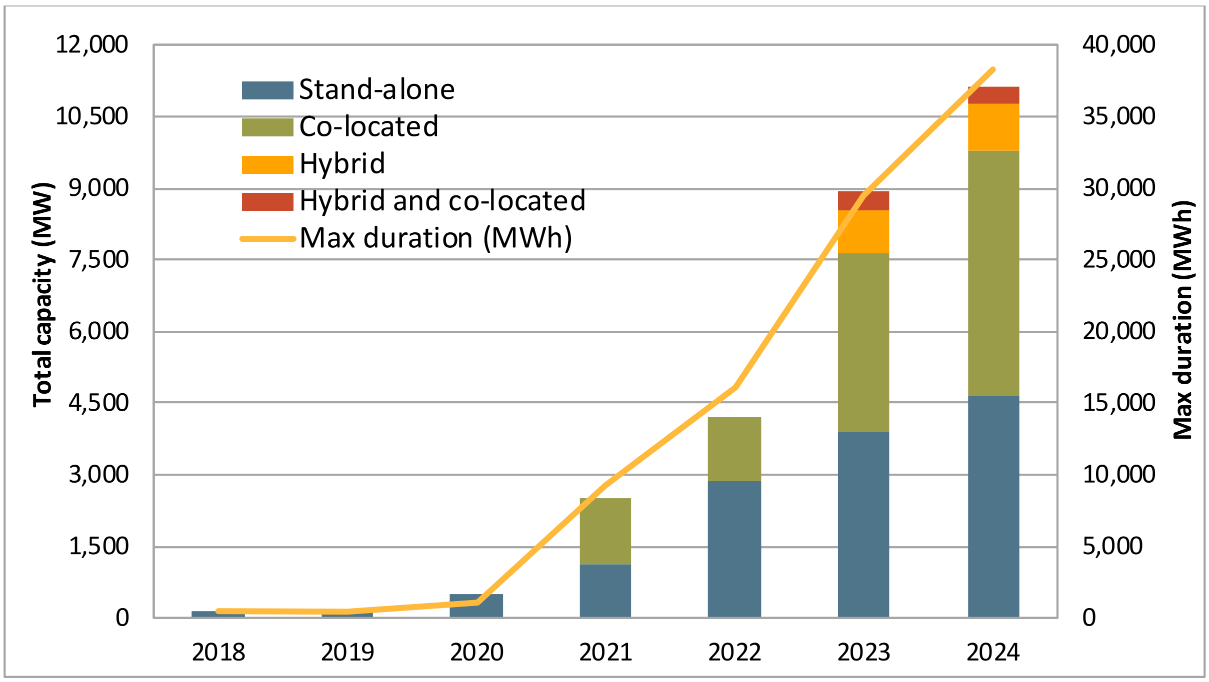
[4] Department of Market Monitoring, *2022 Special Report on Battery Storage*, July 7, 2023, p 32: https://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

2.3 Installed battery capacity

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

In June 2024, active battery capacity totaled about 11,100 MW—with 4,700 MW from stand-alone projects and 5,100 MW from co-located projects, and about 1,300 MW from the storage components of hybrid resources and co-located hybrids.[6] Total hybrid capacity, including generation components, was 4,900 MW. The aggregate maximum duration of the CAISO balancing area's battery fleet reached about 38,300 MWh.

Figure 2.1 Active battery capacity in CAISO balancing area (2018–2024)



Battery storage is the fastest growing resource type in the CAISO balancing area. As of June 1, 2024, NGR batteries make up nearly 12 percent of the CAISO's nameplate capacity. Figure 2.2 shows the steady growth of battery capacity in the CAISO area compared with other resource types.

The majority of projects waiting to connect to the CAISO grid contain a battery component. As of June 2024, batteries account for about 45 percent of total capacity in the interconnection queue. Almost half of planned new battery capacity comes from projects that combine batteries with generating resources (mainly solar) using the co-located or hybrid modeling options. Historically, many planned resources

[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.

drop out before the interconnection process is finished, so much of the capacity currently in the queue is expected to never come online.

The size of active batteries varies widely, ranging from 470 kilowatts 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

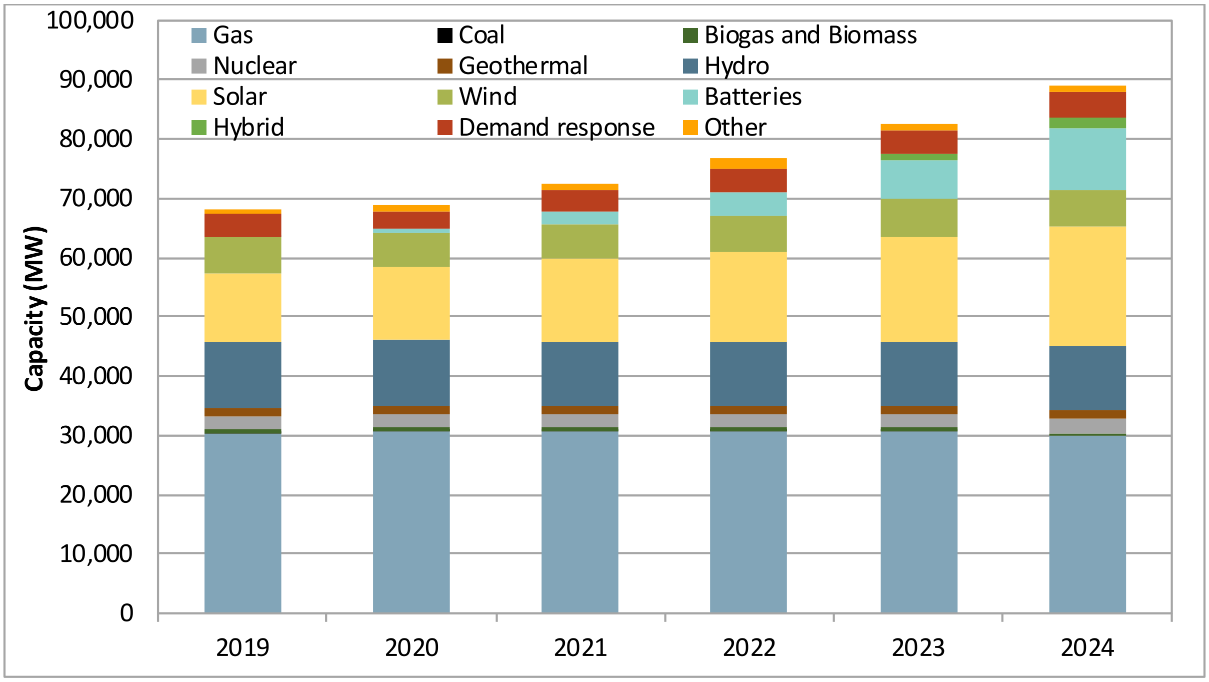
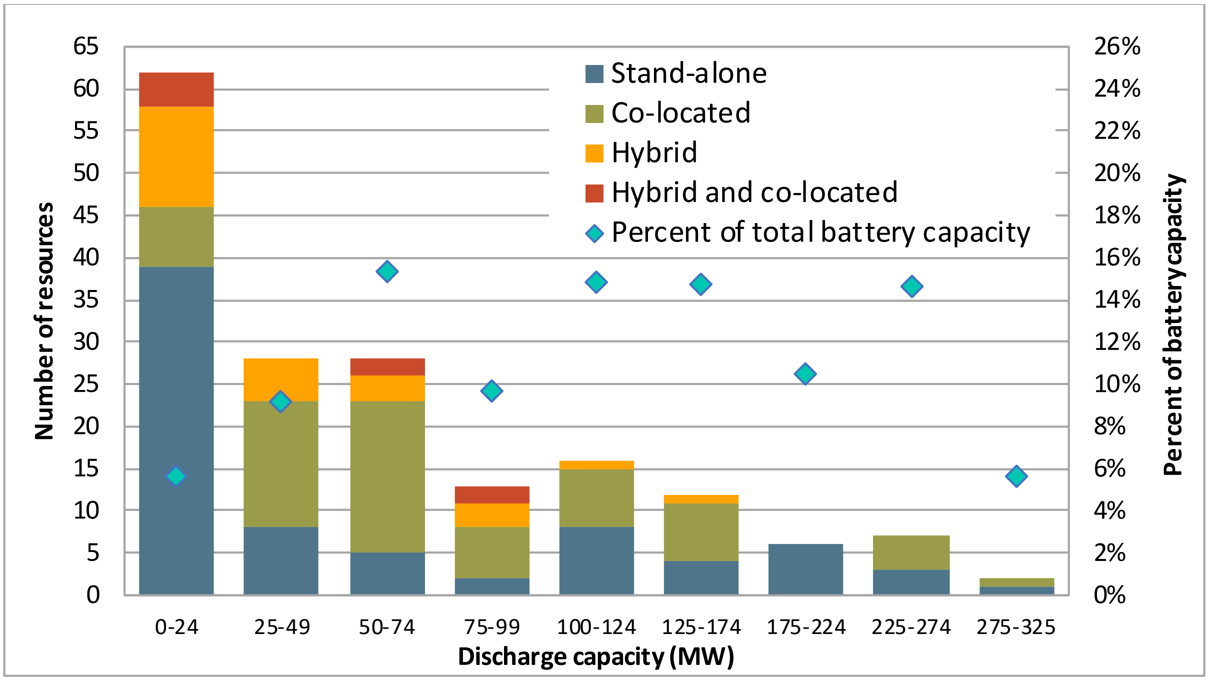


Figure 2.3 Histogram of battery sizes



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.[7]

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.[8] As shown in Figure 2.4, the spread of average energy bids remained high throughout 2023 in the day-ahead market. Average bid

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

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

prices to charge were $89 lower and bids to discharge were $145 higher than the nodal price, with an average bid price spread of $235. In comparison, the average bid price spread was $251 in 2022.

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 $167/MWh in 2022 to $202/MWh in 2023.

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.

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

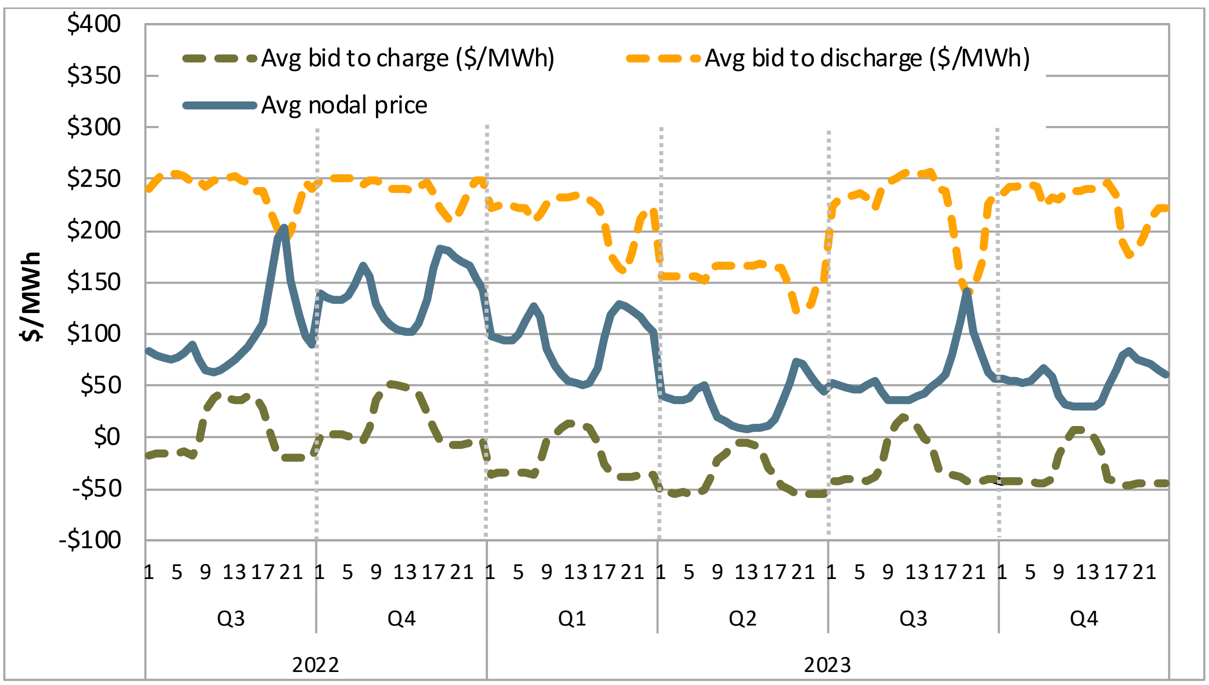


Figure 2.5 Hourly average real-time battery bids and nodal prices (by quarter)

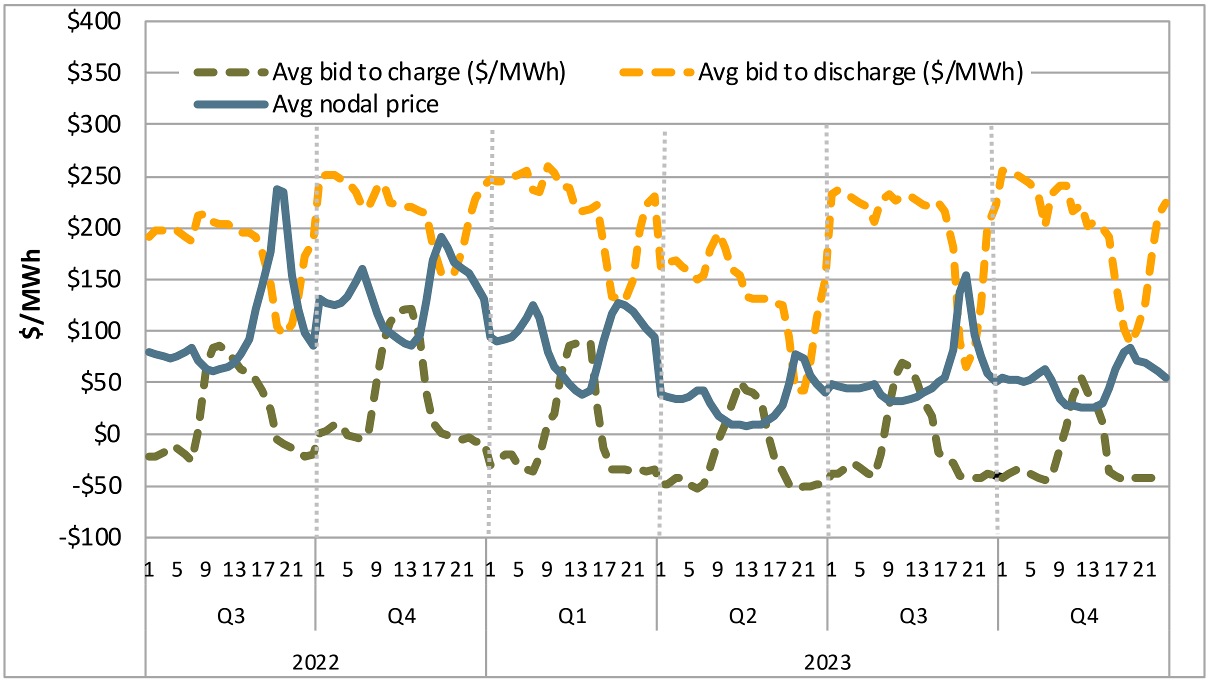


Figure 2.6 shows the volume of batteries' submitted fifteen-minute market bids by price range in each hour on August 12, 2023, which was the median day of the third quarter of 2023 in terms of average load-weighted day-ahead prices.[9] Though some battery capacity was bid-in at the $1,000/MWh price cap throughout the day, most capacity was bid in at lower than $100.

Figure 2.7 compares fifteen-minute market battery bids during hour-ending 12 across several days. September 4, August 12, and August 16, respectively, represent the lowest, median, and highest average day-ahead load-weighted prices in the third quarter of 2023. The CAISO balancing area experienced its most severe supply shortage of the year on July 20. Batteries greatly increased their discharge bids at all levels of production during this hour on August 16, reflecting batteries' high estimation of the opportunity cost to discharging in the early afternoon.

Similar to Figure 2.7, Figure 2.8 shows fifteen-minute market battery bid curves during hour-ending 21 across the same days. Like with the previous figure, this shows that batteries changed their bids most on August 16 in anticipation of high peak real-time prices.

9 Discharging bids from $750/MWh through $998/MWh were negligible, and thus excluded from this figure.

Figure 2.6 Fifteen-minute market bid stack on August 12, 2023

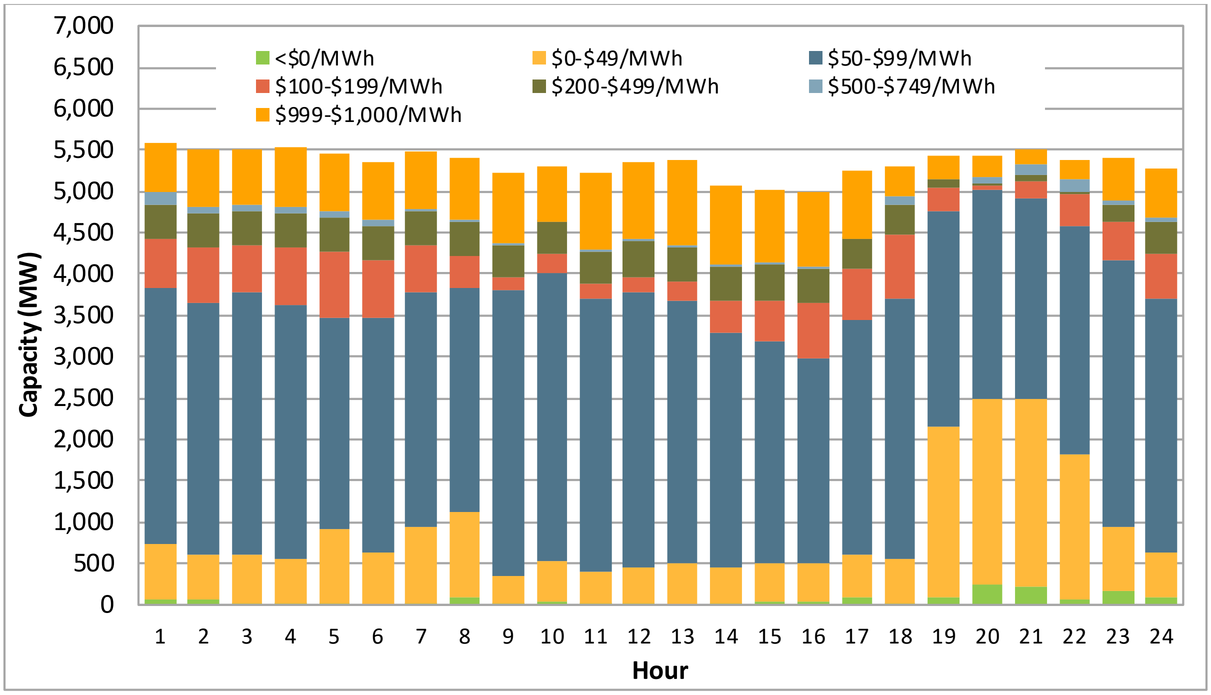


Figure 2.7 Fifteen-minute market bid curve comparison for hour-ending 12

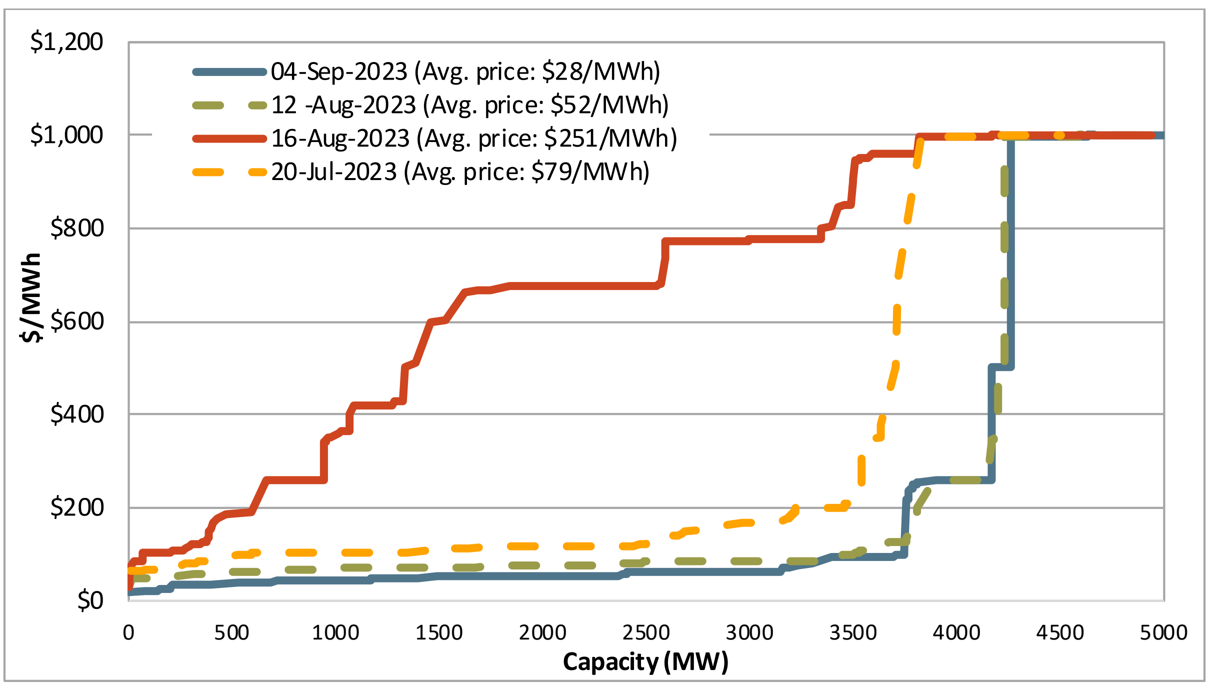
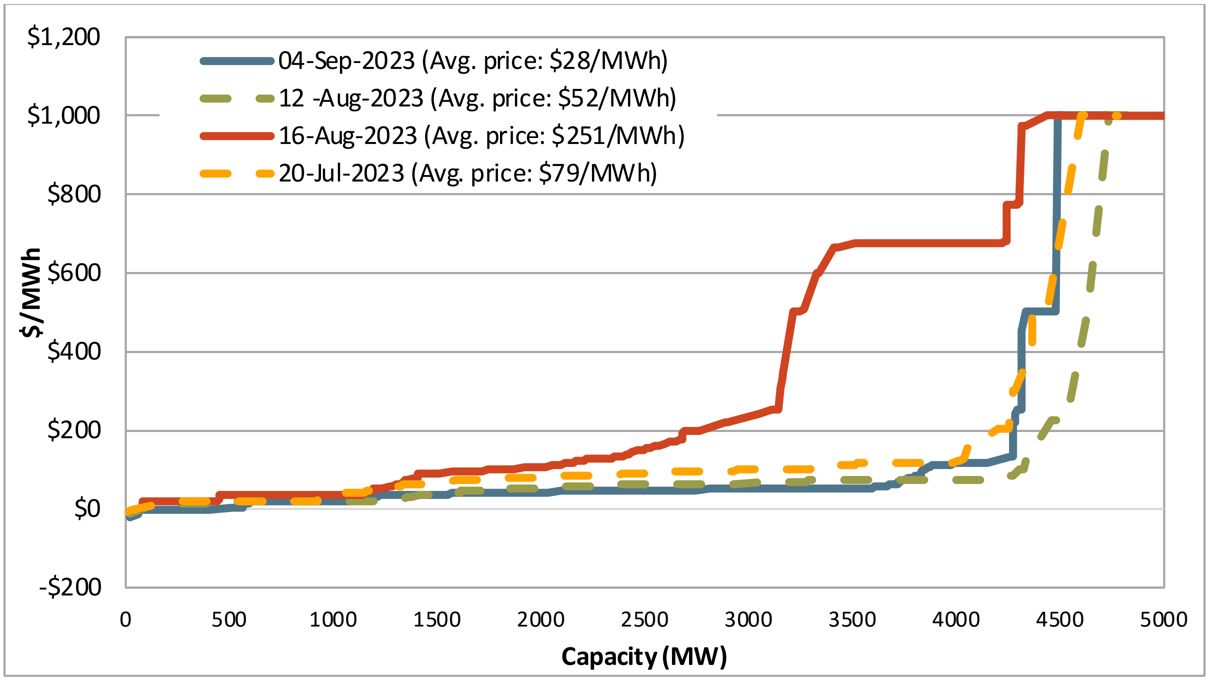


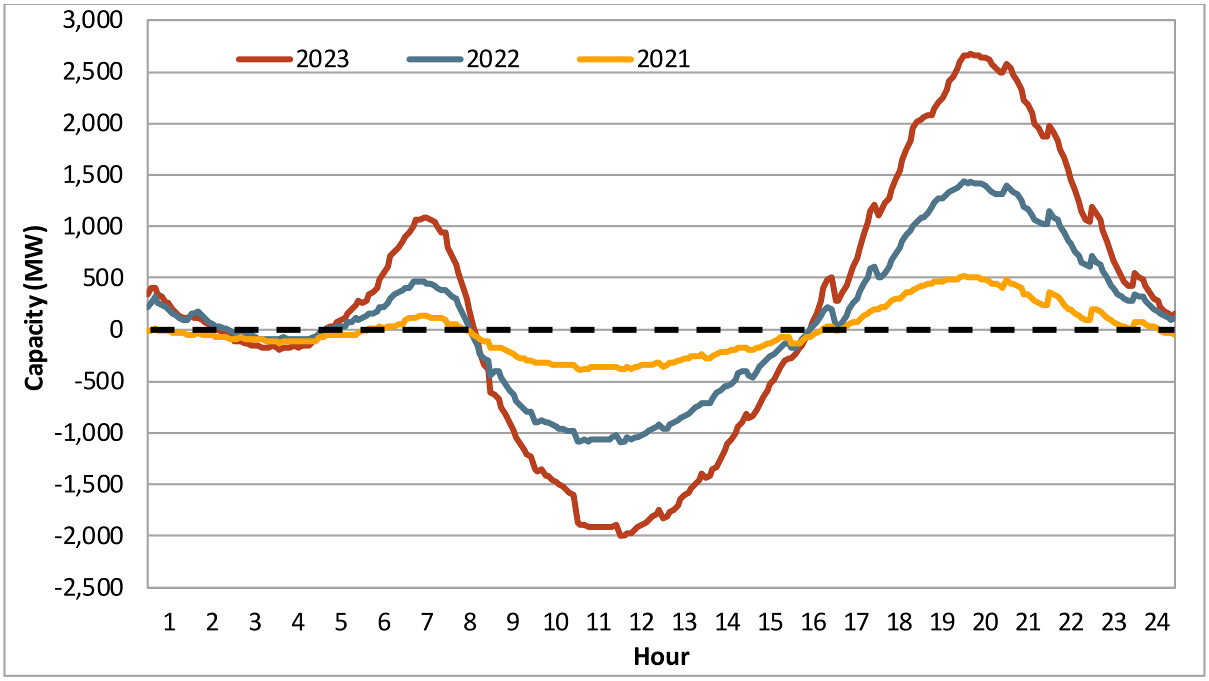
Figure 2.8 Fifteen-minute market bid curve comparison for hour-ending 21



2.5 Battery schedules

Figure 2.9 shows average battery energy schedules in the 5-minute market from 2021 to 2023, where points below the zero axis represent charging and points above represent discharging. The average energy output from batteries peaked at about 2,700 MW during hour-ending 20 in 2023, compared to 520 MW in 2021.

Figure 2.9 Average 5-minute battery energy schedules



In addition to energy, battery capacity is generally available to provide ancillary services and flexible ramping product. Figure 2.10 shows average hourly real-time (15-minute market) schedules of all battery storage resources in 2023. Batteries are especially well-suited to provide regulation up and down in that they can provide up to 2 MW of regulation for every 1 MW of capacity, depending on their state-of-charge and energy schedules in a given interval.

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 2023, battery charging represented around 8.3 percent of load in the CAISO balancing area.

Figure 2.11 shows average 15-minute battery schedules as a percentage of participating capacity in a given interval from 2022 to 2023. For the past several years, increases in battery capacity have outpaced increases in ancillary service requirements. In 2023, the percentage of aggregate battery capacity scheduled for ancillary services continued to decrease, though not as drastically as in previous years.

Figure 2.10 Average hourly battery schedules by product (2023)

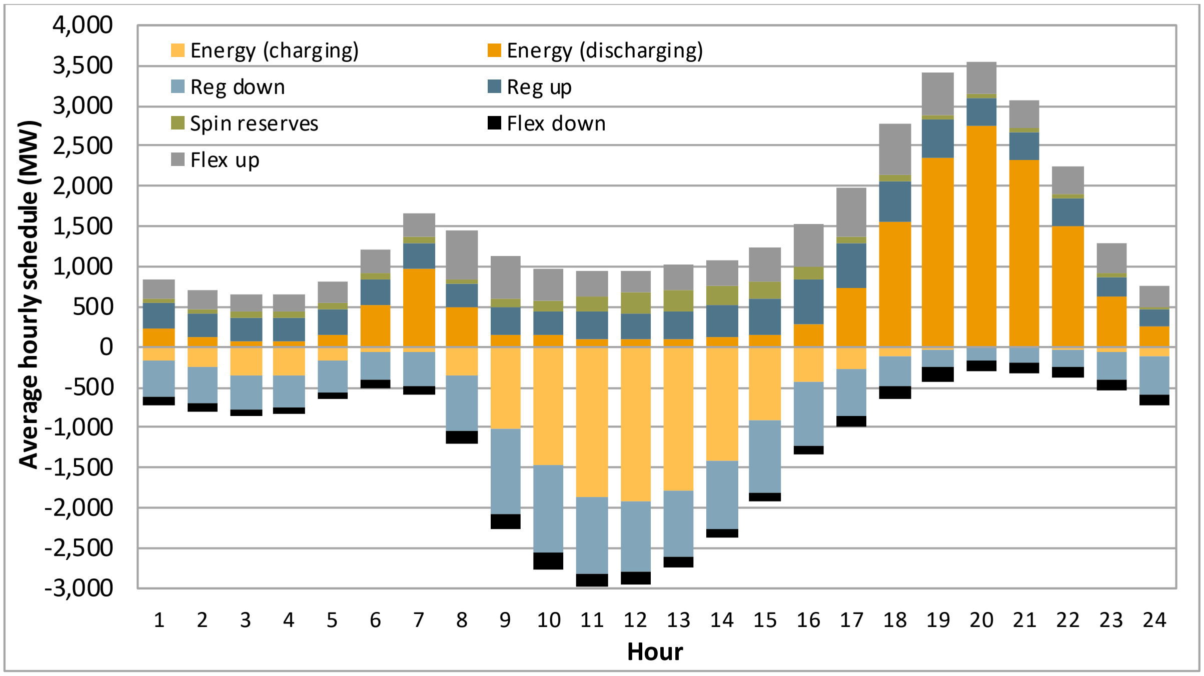
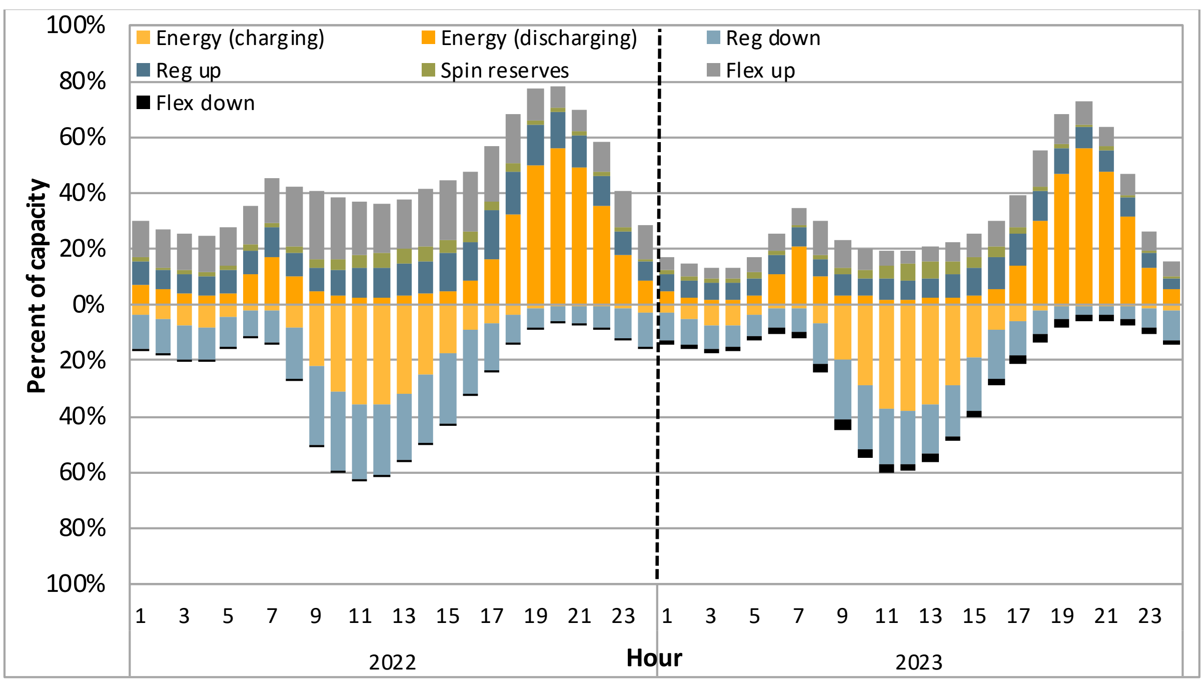


Figure 2.11 Scaled average 15-minute schedules (2022-2023)



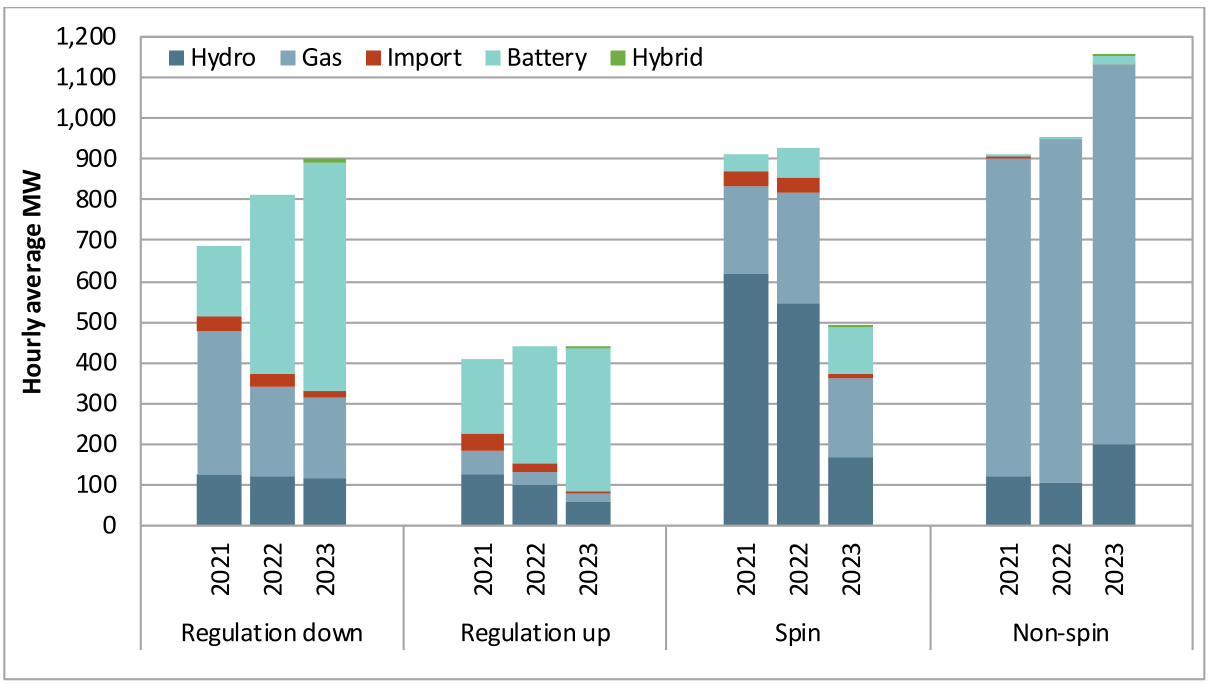
In 2023, an average of about 72 percent of upward capacity from batteries was scheduled to provide energy, ancillary services, or upward flexible ramping capacity in hour-ending 20, as shown in Figure 2.11. Batteries tend to charge over a longer period during the afternoon hours, and the average percentage of battery capacity having downward energy, regulation, or flexible ramping product schedules peaked at about 60 percent in hour-ending 11 during 2023.

While batteries represent a small proportion of the CAISO balancing area's capacity, these resources provide a relatively large amount of its ancillary services. Figure 2.12 shows the portion of ancillary services procured by fuel type from 2021 through 2023. In this period, average hourly procurement of ancillary services served by batteries increased from 400 MW to 1,038 MW. Batteries have provided the majority of the CAISO's regulation requirements since 2022.

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 2.13 shows the percentage of upward and downward flexible ramping capacity procured by batteries on a monthly basis in the 15-minute market.[10]

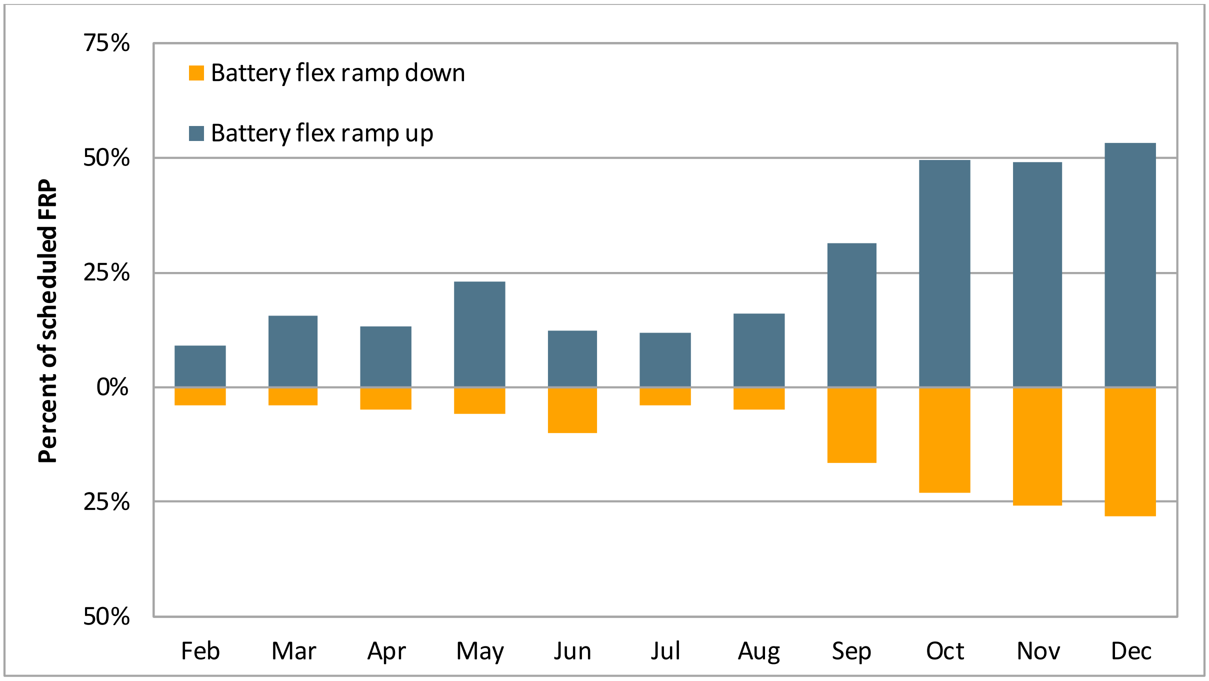
Flexible ramping capacity provided from batteries increased substantially in the fourth quarter of 2023. This increase coincided with a market enhancement implemented in September 2023, which started enforcing nomogram constraints in the deployment scenarios for procuring flexible ramping capacity. This enhancement likely caused a shift in procurement from hydroelectric resources in the Pacific Northwest to batteries in the CAISO balancing area.

Figure 2.12 Ancillary service procurement by resource type



10 January 2023 is excluded from Figure 2.13 to highlight the period after the ISO implemented nodal procurement of flexible ramping product on February 1, 2023.

Figure 2.13 15-minute flexible ramping product procured from batteries (2023)



2.6 WEIM battery capacity and schedules

As of June 1, 2024, there were 37 actively-participating non-CAISO balancing area resources with battery components in the Western Energy Imbalance Market (WEIM), with a total of around 3,500 MW of discharge capacity and a 10,800 MWh maximum state-of-charge. In comparison, WEIM battery capacity totaled 286 MW in December 2022.

Figure 2.14 shows the number of actively participating batteries and their capacity for each balancing area that has active battery resources. Of the capacity shown, 1,300 MW are from stand-alone units, 1,700 MW are from co-located units, and 500 MW are from the battery components of hybrid resources. Batteries accounted for under one percent of participating nameplate capacity in the WEIM (outside of the CAISO balancing area) in 2022, and grew to around 3 percent as of June 1, 2024.

Figure 2.15 shows that WEIM batteries have somewhat 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 2.14 Active battery capacity by WEIM balancing area (2024)

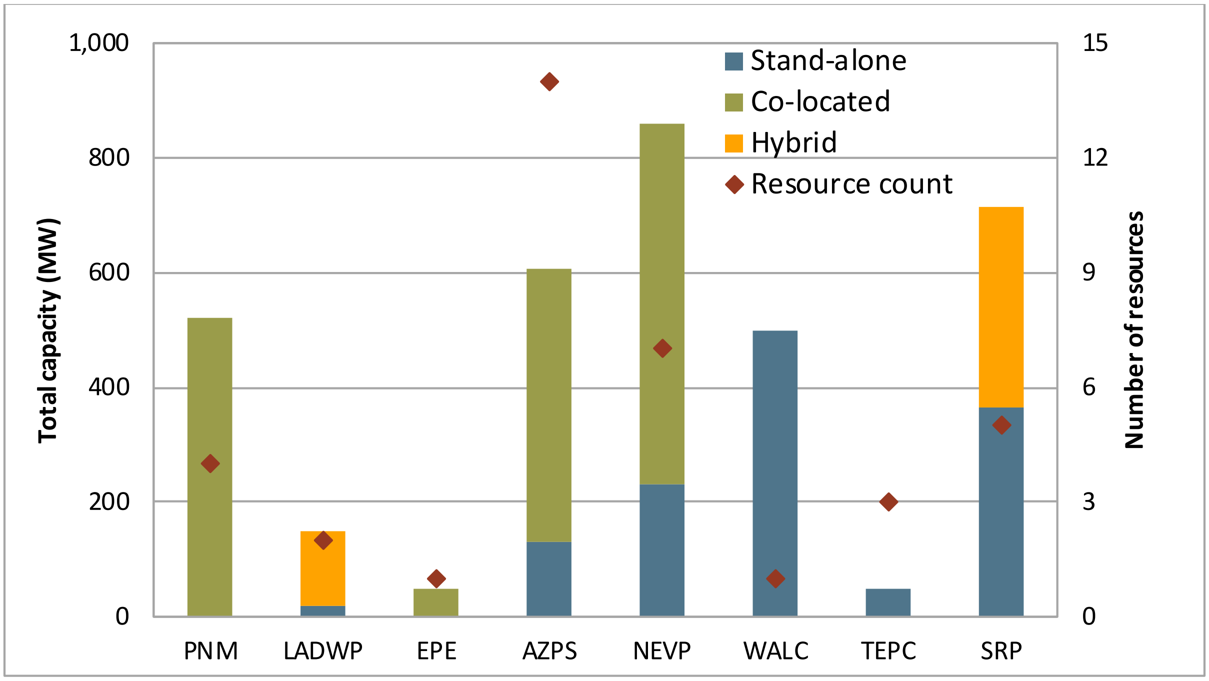
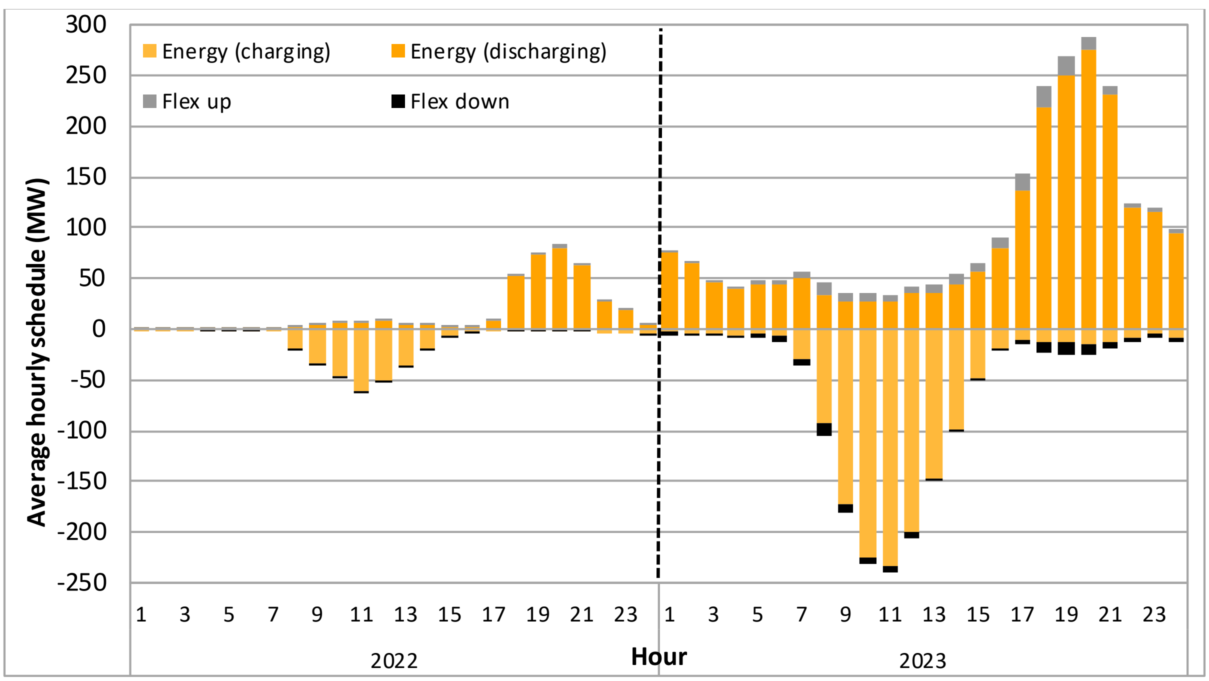


Figure 2.15 WEIM average hourly battery schedules (2022-2023)



2.7 Batteries combined with generation resources

The CAISO market allows batteries to be combined with other generation technologies (usually solar) at a single point of interconnection using the hybrid model and the co-located model. The primary difference between these designations is that hybrids are modeled as a single resource, whereas the market software treats the different components of co-located facilities as separate resources.

Resources co-located together do not necessarily need to use different generation technologies. As of June 2024, eight out of 65 sets of co-located resources have a single generation technology. There are only two co-located points of interconnection that do not have at least one battery storage component.

The ISO expects significant deployment of co-located and hybrid resources in the CAISO and WEIM balancing areas in the next several years. Most of these resources will combine batteries with solar photovoltaic or wind resources.

2.7.1 Co-located battery resources

The most common way in which batteries are combined with generation resources is by participating under the ISO's co-located model. Since they are modeled as separate resources, 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.

The co-located resource model has historically provided several benefits to co-located resource owners, especially for facilities with both batteries and renewable generation. Shared infrastructure between co-located facilities can reduce equipment, interconnection, and permitting costs. The National Renewable Energy Laboratory (NREL) estimates that the cost of co-locating storage with photovoltaic solar systems is 7 percent lower than siting these units separately.[11] In addition, co-located resources 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.[12] In California, some co-located storage and renewable resources may 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.

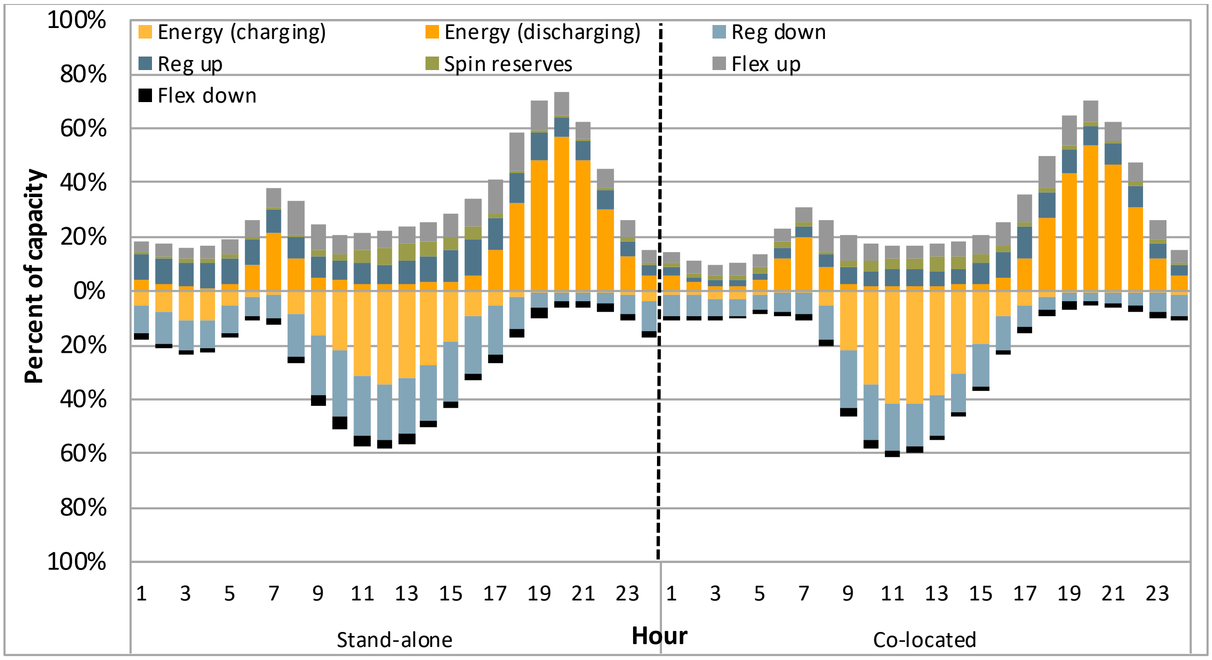
Also, as of November 2023, co-located batteries have access to an hourly electable parameter that prevents them from grid charging. This new constraint was meant to help co-located batteries capture federal investment tax credits and local property tax benefits by allowing them to restrict charging when their renewable facilities weren't producing energy. As of June 2024, scheduling coordinators have used this electable parameter very rarely.

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

12 CleanEnergy.gov, *Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action*, January 2023, p 14: https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf

Figure 2.16 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. This figure demonstrates that, despite extra market constraints imposed on co-located battery participation, co-located batteries tend to have similar schedules to stand-alone batteries.

Figure 2.16 Average hourly schedules: co-located versus stand-alone batteries



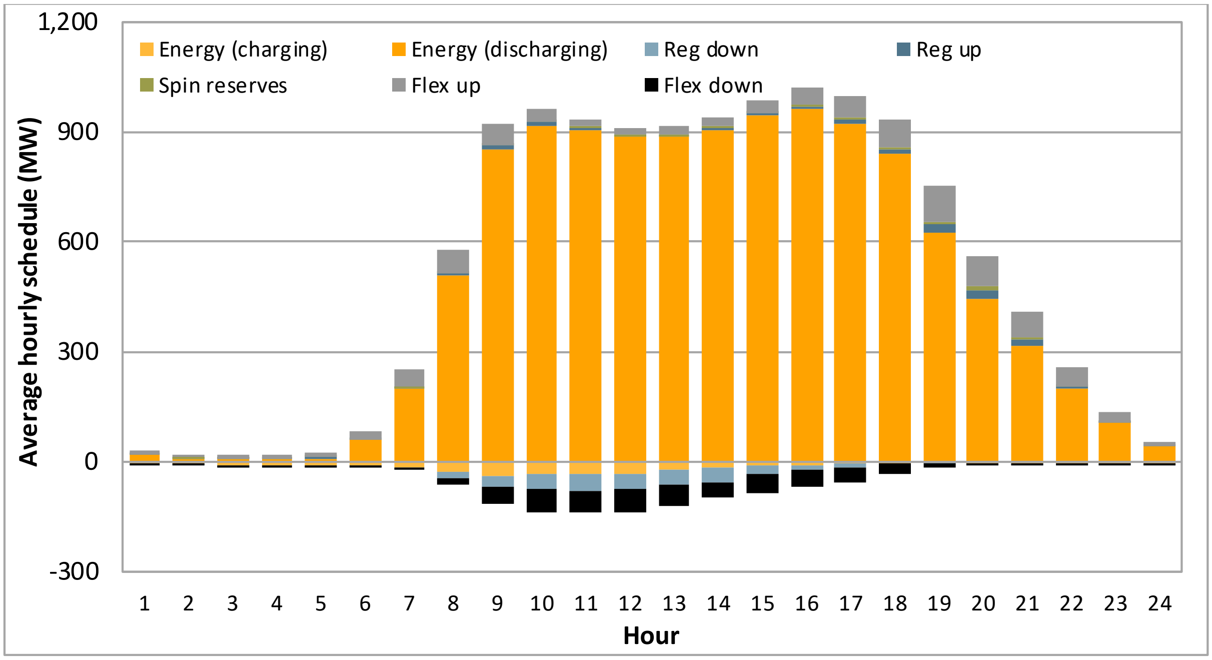
2.7.2 Hybrid battery resources

Hybrid 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 June 2024, there are 36 actively participating hybrid resources with battery technology in the CAISO and the WEIM.

Figure 2.17 shows average hourly real-time (15-minute market) schedules of all active hybrid resources in 2023. 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 2023, all resources in the WEIM registered as hybrids participated as NGRs. However, only around 37 percent of this capacity had the operational capabilities which would make them eligible to charge from the grid. In 2023, hybrids received very few market awards to charge from the grid, and mostly charged from on-site renewables.

Figure 2.17 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.

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.

2.8 Market revenue

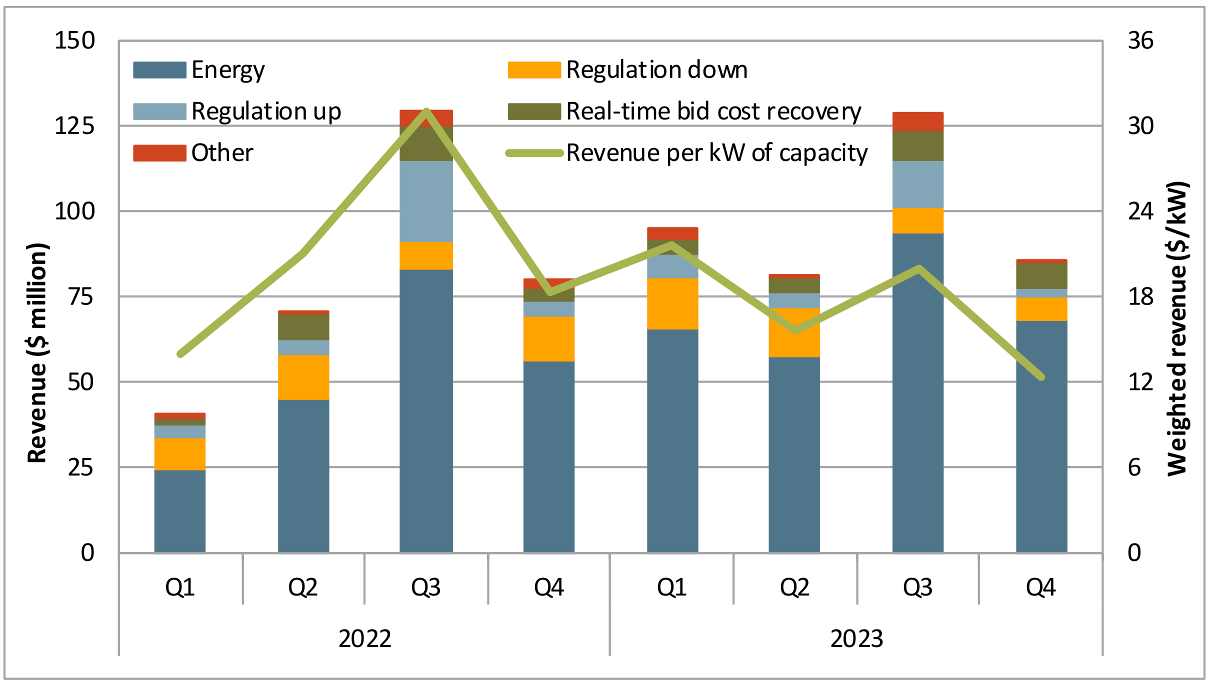
2.8.1 Total net market revenues

In 2023, total net market revenues for batteries increased by around 22 percent as the result of increases to the battery fleet. Net annual revenues decreased on a capacity-weighted basis from \$103/kW-year in 2022 to \$78/kW-year due to lower overall market prices in 2023. Nearly 62 percent of batteries' net revenues in 2023 were generated from providing energy, compared to 65 percent in 2022.

Figure 2.18 shows quarterly net market revenues for battery resources by category from January 2022 through December 2023.[13] Batteries earn most of their revenue through energy cycling on days with a high spread between afternoon and evening prices. Because of high energy prices during the prolonged heat wave in summer 2022, batteries earned the most revenue per kilowatt of capacity in the third quarter of 2022.[14] The next most profitable period for batteries per kilowatt of capacity was the first quarter of 2023, when natural gas supply constraints caused high wholesale energy prices.

Figure 2.19 shows weighted average revenue by category for batteries with a full year of operation. In an analysis of the idealized dispatch of batteries using historical prices from 2018 through 2021, the CPUC estimated that a hypothetical battery could earn $51.6/kW-year under NP15 prices and $72/kW-year under SP15 prices through energy arbitrage alone.[15] This compares to actual net energy revenues for batteries system-wide of $58/kW-year in 2022 and $50/kW-year in 2023. In practice, batteries earn substantial additional revenues from sales of regulation and bid cost recovery payments, as shown in Figure 2.19.

Figure 2.18 Quarterly net market revenues for battery resources (2022-2023)

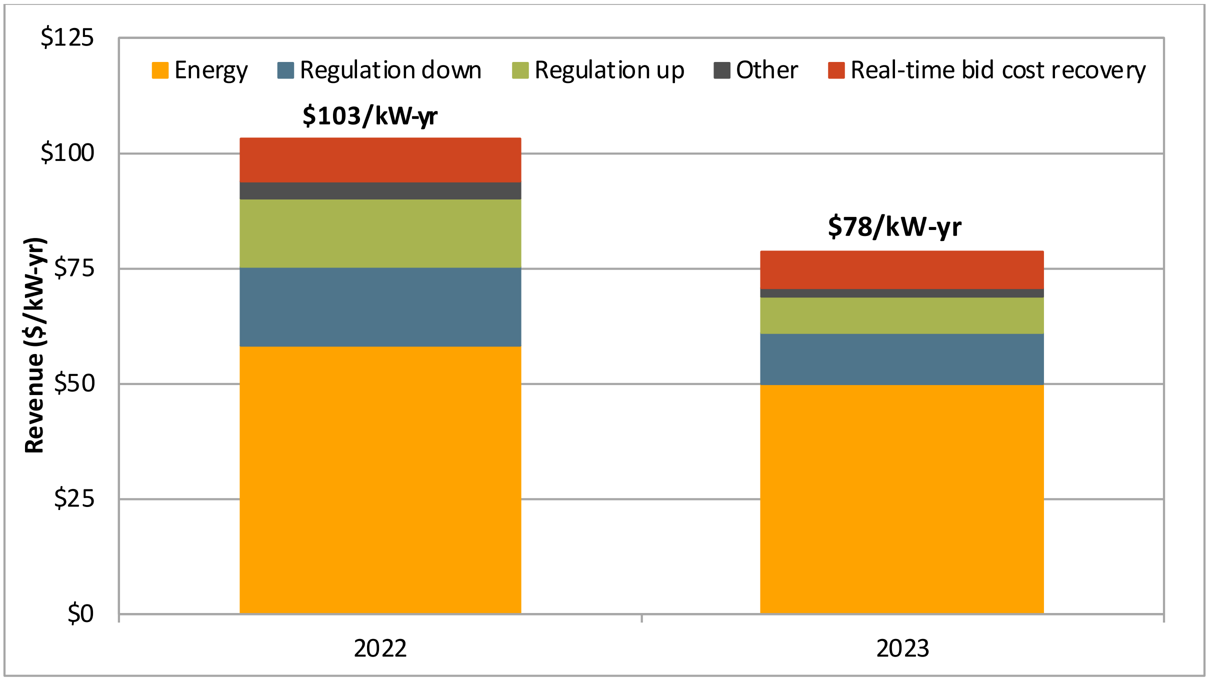


[13] The regulation down category contains payments and charges from settlements codes 6600, 6624, 6670, and 7261. Regulation up includes 6500, 6524, 6570, and 7251. Energy includes 6011, 6800, 6824, 6460, 6470, and 6475. Real-time bid cost recovery includes 6620. Other includes codes 6100, 6124, 6170, 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

[14] Here we weight daily revenue by active capacity on a given day to arrive at our figure for revenue per kW of capacity. This weighting method differs from methods we have used in previous metrics.

[15] Lumen Energy Strategy, *Energy Storage Procurement Study*, May 31, 2023, p 54: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-storage/2023-05-31_lumen_energy-storage-procurement-study-report.pdf

Figure 2.19 Average revenue for batteries with a full year of operation



2.8.2 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, however, are continuously dispatchable and do not require commitment. Therefore, batteries 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.). This suggests that bid cost recovery payments to batteries should be relatively low.

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.

Additionally, batteries may submit limitations on stored energy through minimum or maximum state-of-charge daily bid parameters or through outage cards. When these limitations bind and result in uneconomic dispatch, the resource also may be eligible for bid cost recovery payments under current settlement rules.

Current bid cost recovery rules were designed for traditional generators and do not consider state-of-charge limitations or other physical characteristics of batteries. This has led to several inappropriate or inefficient payments of bid cost recovery to batteries, and a need to design bid cost recovery rules for batteries that explicitly account for their specific attributes.

For example, in the case of outages, traditional generators are ineligible for bid cost recovery of costs associated with a de-rate or outage. However, batteries can effectuate outages through minimum or maximum stored energy values without having to de-rate their available capacity through an outage. In this situation, the battery may remain eligible to receive bid cost recovery since no outage was reported and settlement rules do not consider the impact of the state-of-charge constraint set by the battery operator.

Other situations exist where a battery may directly impose state-of-charge limitations that can lead to bid cost recovery payments. Batteries may also bid or take other actions to prevent charging or discharging in earlier intervals to restrict state-of-charge in later intervals in a manner that leads to undeliverable day-ahead schedules. These scenarios can contribute to inefficient market outcomes and additional bid cost recovery payments, and may be susceptible to gaming.

In 2023, batteries received nearly $28 million of bid cost recovery, or about 10 percent of all 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 supports the ISO's recently launched stakeholder initiative to address bid cost recovery rules for storage resources.[16]

In late 2022, the ISO established a targeted market enhancement to eliminate one source of inappropriate bid cost recovery for batteries identified by DMM. In November of 2022, the Federal Energy Regulatory Commission (FERC) approved a market rule change that precludes batteries from receiving bid cost recovery in situations where they are uneconomically dispatched by the market software in order to maintain a sufficient state-of-charge to fulfill ancillary service awards. This decision stipulated that bid cost recovery awarded for this reason could be rescinded retroactively as of September 20, 2022.

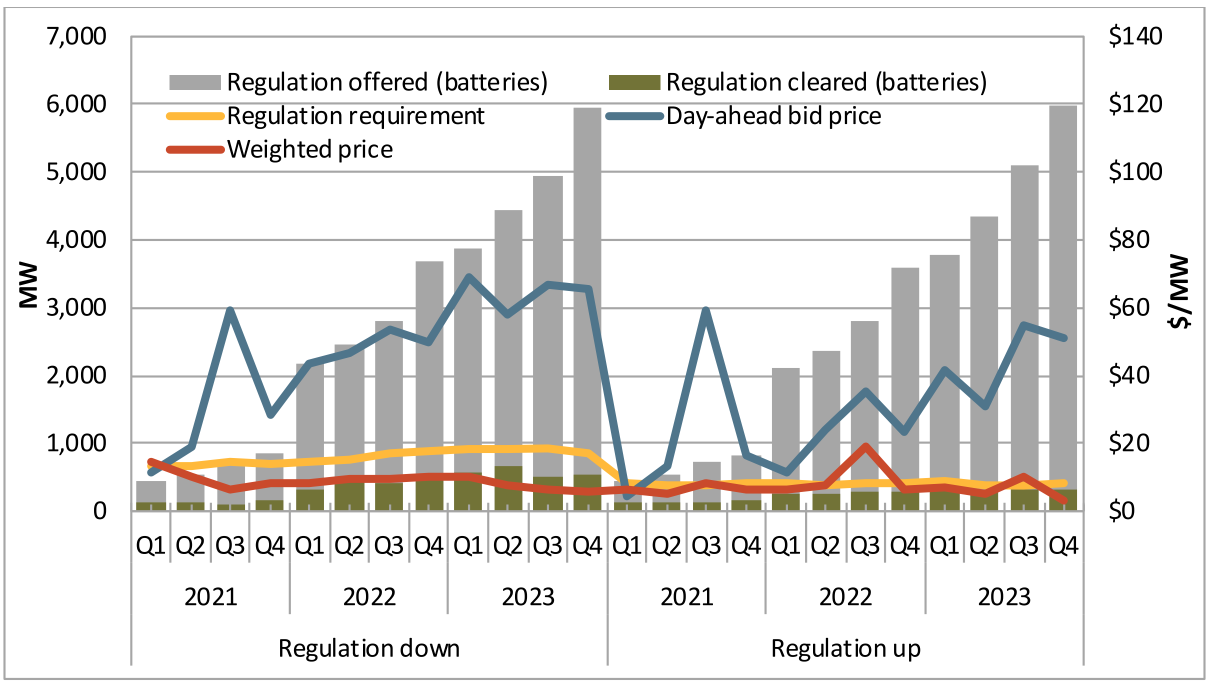
[16] *Storage bid cost recovery and default energy bid enhancements*, California ISO, June 27, 2024: https://stakeholdercenter.caiso.com/StakeholderInitiatives/storage-bid-cost-recovery-and-default-energy-bids-enhancements

2.9 Ancillary services

The California ISO procures four ancillary services for its balancing area in the day-ahead and real-time markets: regulation up, regulation down, spinning reserve, and non-spinning reserve. The CAISO uses regulation up and regulation down to maintain system frequency by balancing generation and demand. Spinning and non-spinning reserves, collectively known as operating reserves, are used to maintain system frequency stability during emergency operating conditions and major unexpected variations in load. Battery resources may 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. Figure 2.20 compares regulation capacity offered by batteries to their cleared regulation capacity and regulation requirements, along with weighted regulation prices and batteries' bid-in price. In recent years, regulation services offered by batteries have increased significantly. Batteries have consistently offered many times more regulation than the market requires, and this offered capacity has grown faster than the regulation requirements themselves.

Figure 2.20 Day-ahead regulation requirements met by battery storage



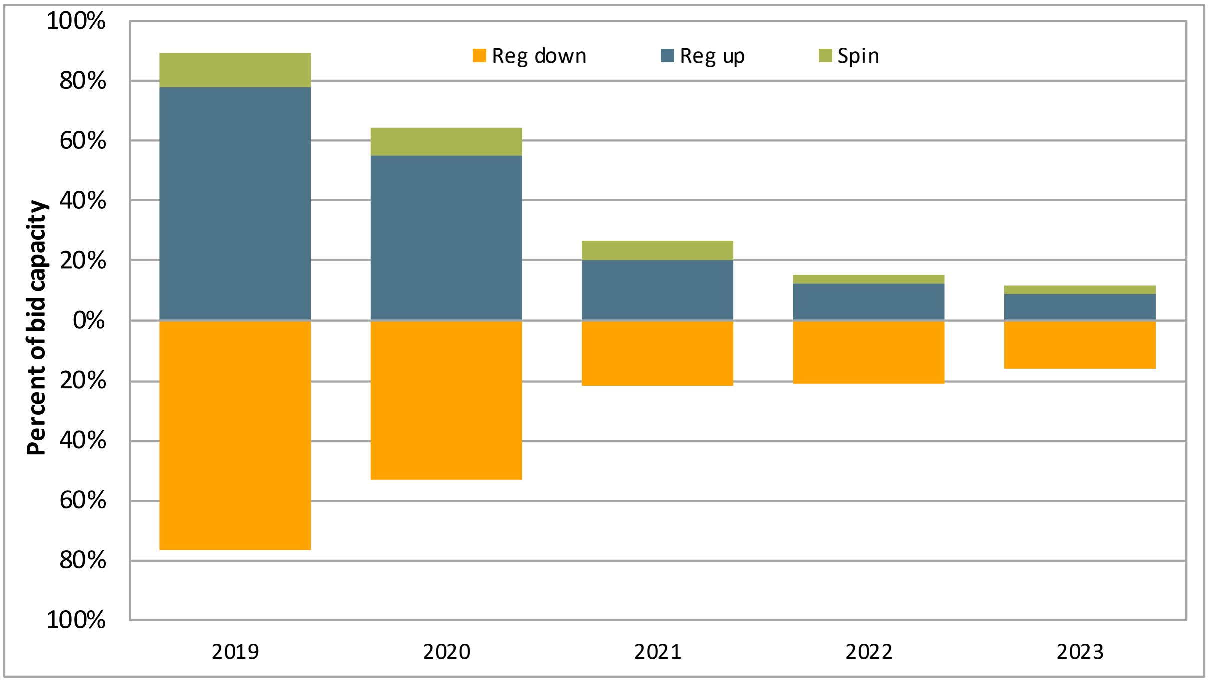
With many more battery resources online, ancillary services provided by batteries have decreased as a proportion of their total capacity. Figure 2.21 shows that ancillary services have gone from taking up the majority of battery capacity to a relatively small fraction.[17]

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. When non-hybrid batteries are awarded ancillary services, the day-ahead and real-time markets enforce constraints to manage state-

[17] Batteries provide a negligible amount of non-spinning reserve, so it is omitted from this figure.

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).

Figure 2.21 Percent of battery capacity scheduled for ancillary services



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. This results 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.

Originally, the CAISO planned to model the impact of regulation under a single state-of-charge constraint. However, in market simulations with a single state-of-charge constraint, the market produced solutions with negative regulation down prices. These solutions with negative prices reflect how the market's multi-interval optimization processed the connection between regulation down and energy. Since regulation down increases a battery's state-of-charge, which it can discharge later at high energy prices, the optimization found that charging a cost to batteries for providing regulation down resulted in the lowest cost to the market overall. The CAISO tariff currently prohibits negative ancillary service prices.

The new 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 CAISO chooses multipliers based on historical usage of regulation, and updates the multipliers on a quarterly basis to account for seasonality of regulation usage.

The CAISO has reported that there have been no material changes for awards held by batteries since the implementation of this new constraint.[18] In addition, there were no negative regulation down prices in either the day-ahead or 15-minute markets since implementation.[19] DMM observed fewer instances of batteries' ancillary service schedules becoming undeliverable in real-time in 2023 compared to 2022, even before the attenuation factors' implementation in November. Moreover, batteries provided a larger proportion of the CAISO's ancillary services in 2023, but had 25 percent fewer rescinded ancillary service payments incurred as a result of failure to provide awarded capacity than in 2022.

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

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 month. 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.

The CPUC calculates capacity for hybrid and co-located resources differently than either stand-alone renewables or stand-alone storage resources.[20] Currently, the CPUC uses an effective load carrying capability (ELCC) methodology to assign resource adequacy values to solar and wind resources. This methodology applies an "effectiveness factor" to the nameplate value of the resource to determine the resource adequacy capacity value for which the renewable resources count.

According to the CPUC's methodology, the qualifying capacity value of the renewable component of the mixed-fuel resource is determined by applying the ELCC percentage to the difference between the renewable's nameplate capacity and the capacity needed to charge the battery at a constant rate over the available charging hours. As a result, hybrid and co-located resources receive less qualifying capacity than identically sized stand-alone resources. The qualifying capacity value of the storage component of mixed-fuel resources is based on either the (1) maximum deliverable capacity of the battery, or (2) the renewable charging energy transferred to the battery in the allotted time period divided by four if the battery is not expected to fully charge.

[18] California ISO, *Q1 Market Performance and Planning Forum*, March 11, 2024, slides 26-32: https://www.caiso.com/Documents/Presentation-Market-Performance-Planning-Forum-Mar-11-2024.pdf

[19] Ibid, slides 33-34.

[20] This methodology assumes that the battery charges solely from on-site renewable components.

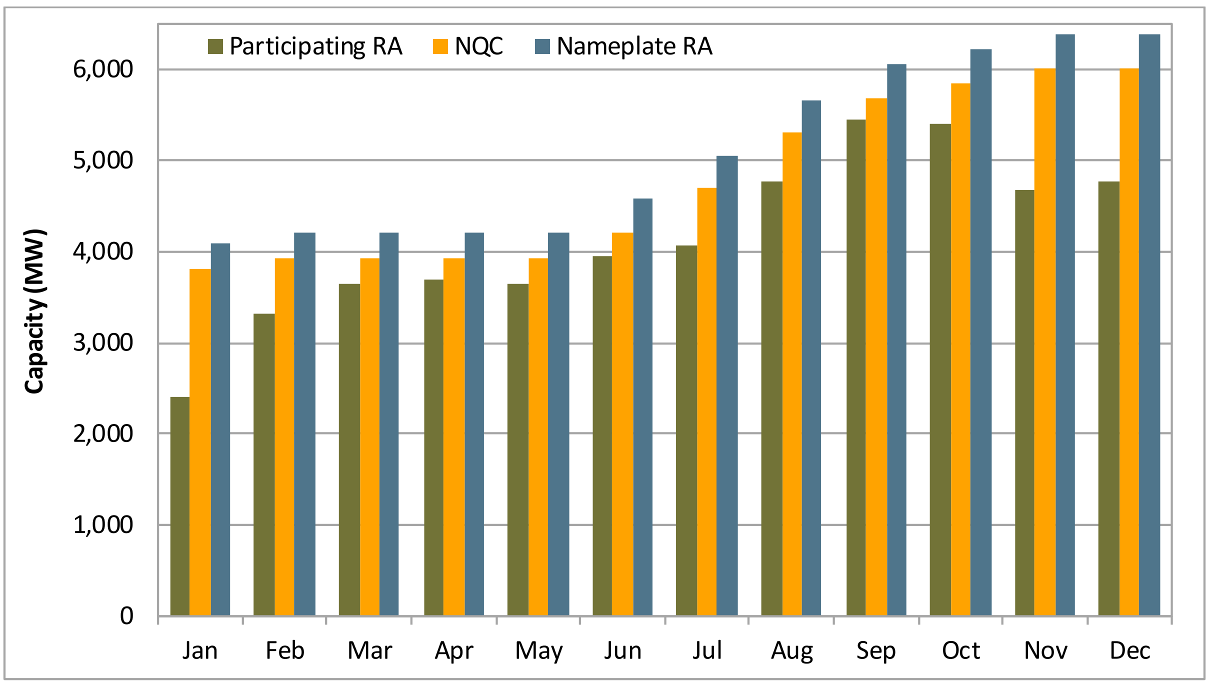
California Public Utilities Commission, *2020 Qualifying Capacity Methodology Manual*, November 2020, pp 19-21: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/q/6442466773-qc-manual-2020.pdf

Resources benefit by participating in the resource adequacy program by getting capacity payments when they contract with LSEs. 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.[21]

Figure 2.22 shows month-end participating resource adequacy capacity, aggregate battery NQC, and total nameplate battery capacity for 2023.[22] About 63 to 96 percent of the total available NQC from batteries was counted towards resource adequacy requirements, depending on the month.

In general, there tends to be a delay between new units coming online and those units' resource adequacy contracts going into effect. In addition, by taking advantage of the modularity of battery storage systems, some battery resources were built in phases ahead of their resource adequacy contracts, starting with target MW capacity at shorter durations offered into energy and ancillary services markets, and progressively adding more duration to meet their contract obligations.[23]

Figure 2.22 Resource adequacy capacity from batteries (2023)



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

22 For battery nameplate capacity, we count any battery which has a NQC rating from the CPUC.

23 Lumen Energy Strategy, *Energy Storage Procurement Study*, May 31, 2023, p 53: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-storage/2023-05-31_lumen_energy-storage-procurement-study-report.pdf

2.10.2 Availability of resource adequacy batteries

Like all resource types, a portion of battery resources are generally unable to provide their full resource adequacy capacity across the most critical four-hour period of most days. Unavailability of battery capacity results from 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. Batteries are energy-limited resources that 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 do 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.[24]

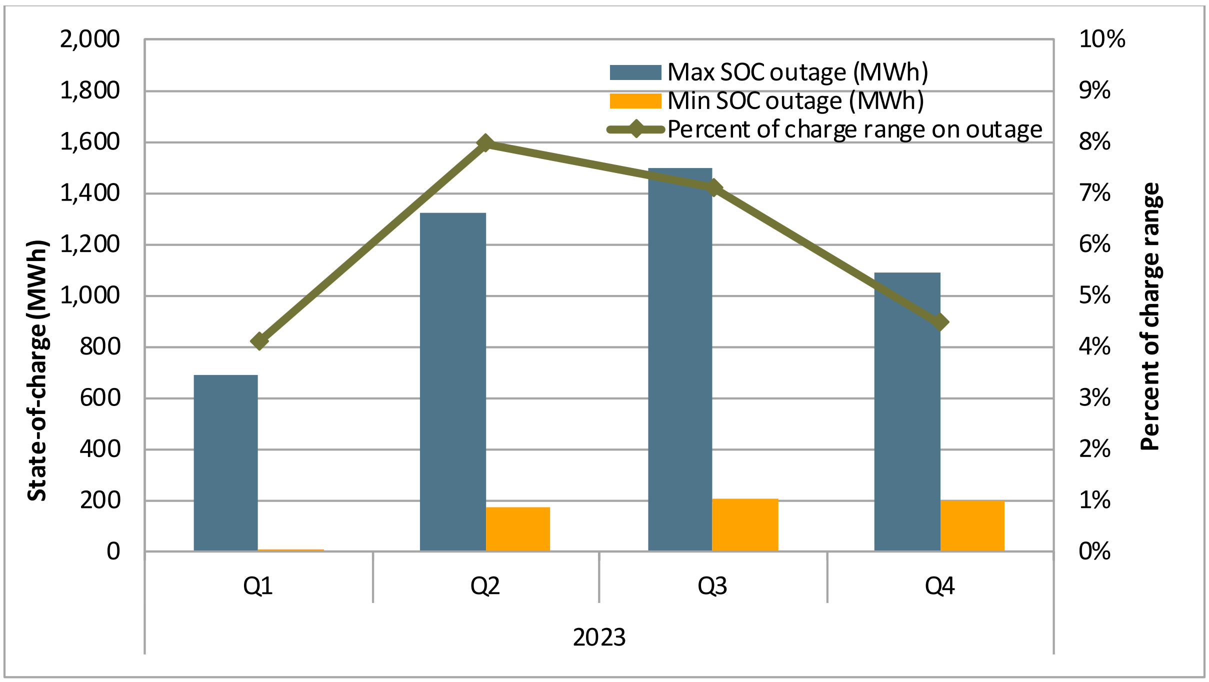
Market participants tend to reflect these physical limitations through outages and de-rates. The ISO gives batteries the option to reflect limitations on lower and upper state-of-charge bounds through the

[24] "Impact of cell balance on Grid Scale Battery Energy Storage Systems." *Energy Reports*, vol. 6, May 2020, Fantham, Thomas L., 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

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 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 2.23 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 2.23 shows the average percentage of aggregate charging range that was made unavailable through these outages. On average, around 5.8 percent of batteries' nameplate charge range was on outage in the real-time market in 2023.

Figure 2.23 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.[25]

For this report, DMM provides two different metrics of the availability of batteries providing resource adequacy capacity in 2023 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)

[25] *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

on the 5 days with the highest system average prices during these hours.[26] Results of this analysis are summarized in Figure 2.24.

The data in Figure 2.24 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 (LMP). Since this capacity was bid at prices below the battery's 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 (LMP).[27] 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 5 days.

The bars for each hour in Figure 2.24 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 98 percent of total resource adequacy capacity. Around 38 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, 30 percent of battery capacity was not dispatched for energy, half of which was 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 2.25 provides these same metrics for the resource adequacy battery fleet during the three hours when

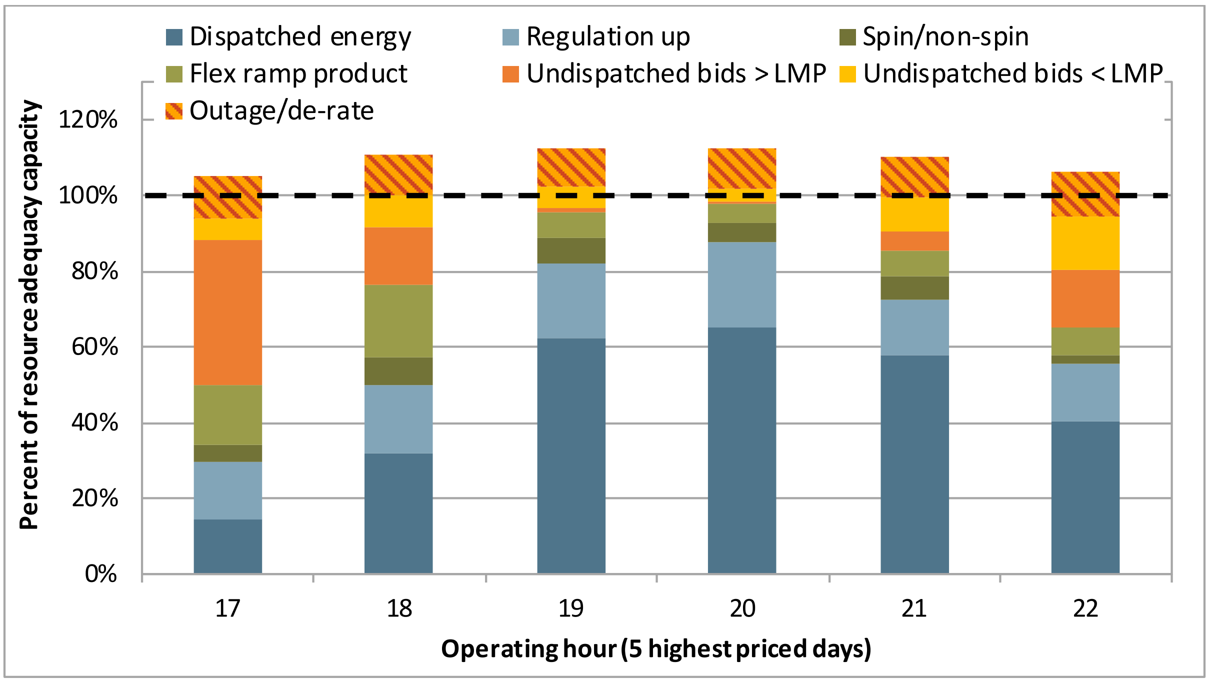
26 The days chosen in this analysis were based on load-weighted fifteen-minute prices of CAISO balancing area default load aggregation points (DLAPs) in 2023. In order from highest to lowest average prices, the days are August 16, August 15, July 26, July 25, and August 14.

27 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.

the CAISO issued stage 1 Energy Emergency Alerts (EEAs) from hours-ending 20 through 22 on July 20, shown in terms of total capacity.[28]

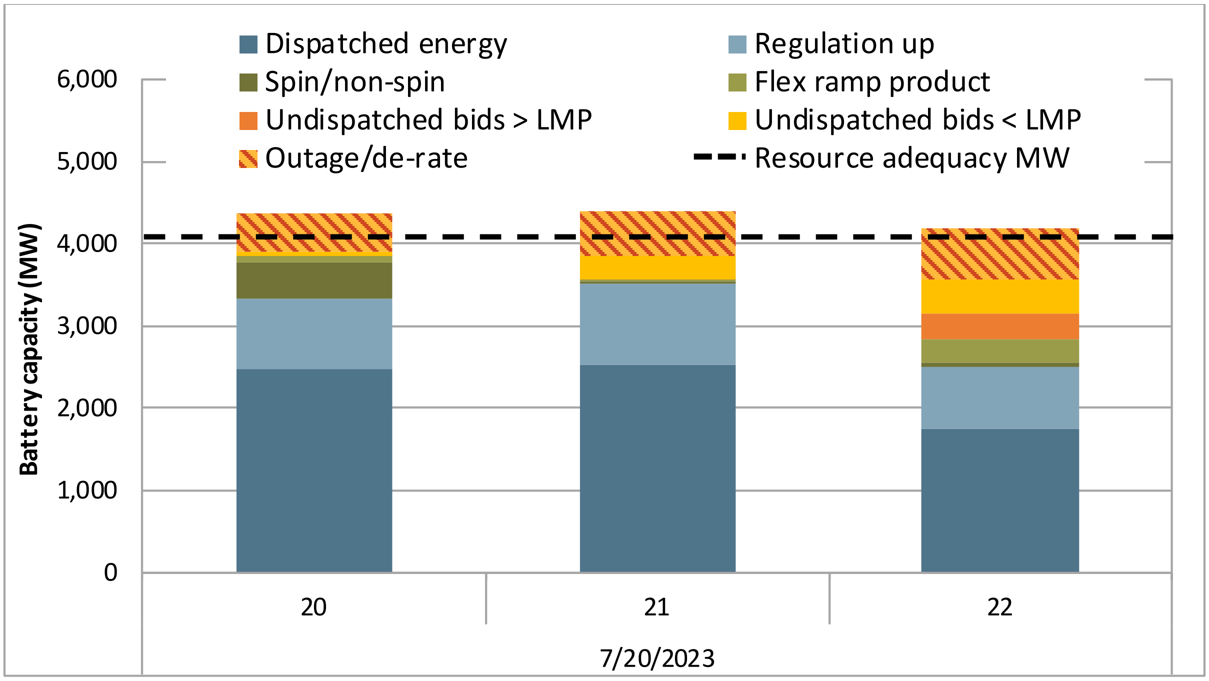
Real-time availability of battery resource adequacy capacity on July 20 was similar to the comparable hours shown in Figure 2.24. After accounting for battery capacity unavailable due to outages and de-rates, the average scheduled battery capacity in hour-ending 20 of the 15-minute market was about 95 percent. Batteries became most unavailable in hour-ending 22, where about 10 percent of battery capacity was not dispatched for energy despite being 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 2.24 Average 15-minute resource adequacy battery capacity during 5 highest priced days



[28] 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

Figure 2.25 15-minute resource adequacy capacity during EEA1 hours on July 20, 2023



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 five 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. Assuming competitive market conditions exist, batteries are incentivized to charge during times that maximize energy arbitrage spread. Competitive energy bids on the charging portion of the bid curve should reflect the opportunity cost of forgoing charging at a given point in time. If a resource submits very low charging bids, the resource will be less likely to receive a charging award, and the low bid reflects a low cost of forgoing charging.

However, if a resource submits a very high charging bid, the resource will be more likely to receive a charging award, which reflects a high cost of foregone charging. 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.[29]

Figure 2.4 and Figure 2.5 in Section 2.4 of this report show that, on average, charging bids are lower than nodal prices in most hours of the day. Consequently, as shown in Figure 2.26, charging bids were rarely changed by mitigation in either the day-ahead, 15-minute, or 5-minute markets in 2023.

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 have the opportunity to choose a "storage option" for their DEB calculation.[30] As of December 2023, around 74 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 **Error! Reference source not found.**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
δ: 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 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 day-ahead LMP, where N equals the discharge duration of the resource in hours. For example, if a storage resource has a four-hour discharge duration, the opportunity cost will be 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.

[29] 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.

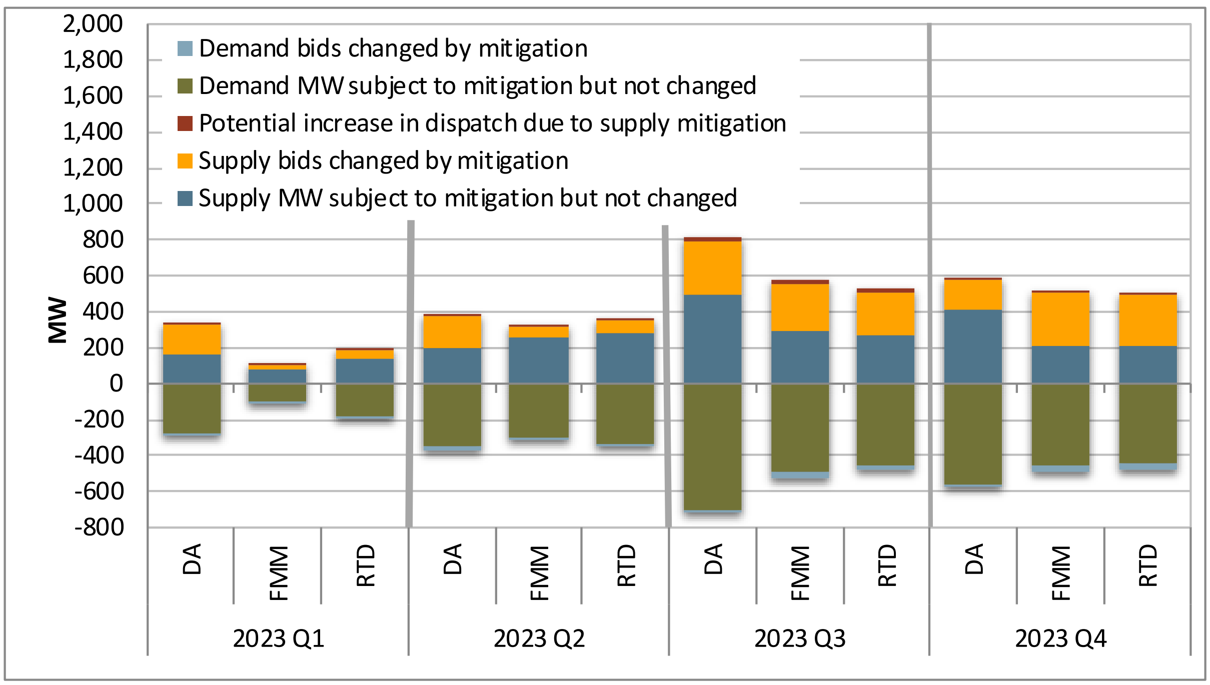
[30] California ISO, *Business Practice Manual Change Management, Market Instruments, Attachment D.9, Storage Default Energy Bid*: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

Figure 2.26 shows average quarterly battery mitigation by market in 2023. Batteries were subject to mitigation most often in the third quarter of 2023, especially in the day-ahead market, where nearly 800 MW of battery capacity were subject to mitigation hourly, on average.

Figure 2.27 Hourly average day-ahead battery supply mitigation (2023)Figure 2.27 shows average hourly battery supply mitigation for the day-ahead market in 2023. Outside of hours with the highest energy demand—especially hours-ending 19 through 21—battery discharging schedules were rarely increased as a result of mitigation. Battery schedules were potentially changed by mitigation the most in hour-ending 20, at around 100 MW on average. In cases where resources' bids were changed by mitigation, the bids were most often changed to the DEB rather than the competitive LMP.

Unlike stand-alone batteries, hybrid resources are currently exempt from mitigation regardless of size. Figure 2.28 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—on a monthly basis in 2023.[31]

Figure 2.26 Quarterly battery mitigation



[31] January is excluded in this figure because the hybrid fuel-type designation was only available in Master File as of February 2023.

Figure 2.27 Hourly average day-ahead battery supply mitigation (2023)

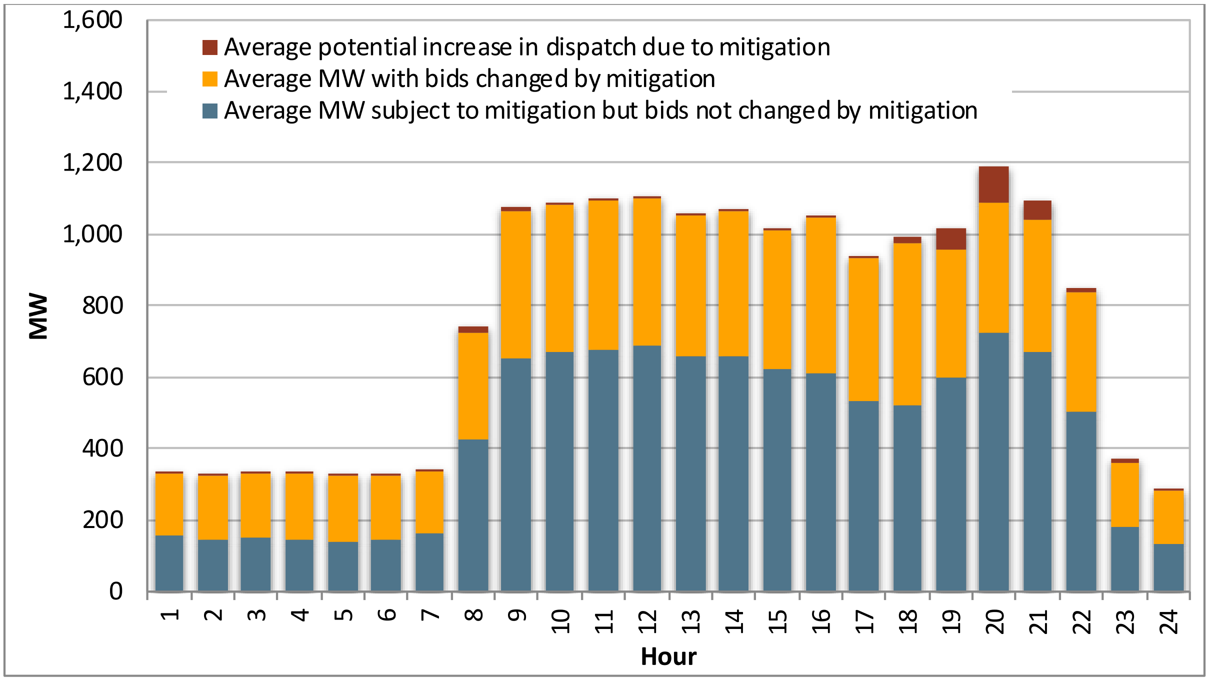


Figure 2.28 Hypothetical average day-ahead hybrid mitigation (2023)