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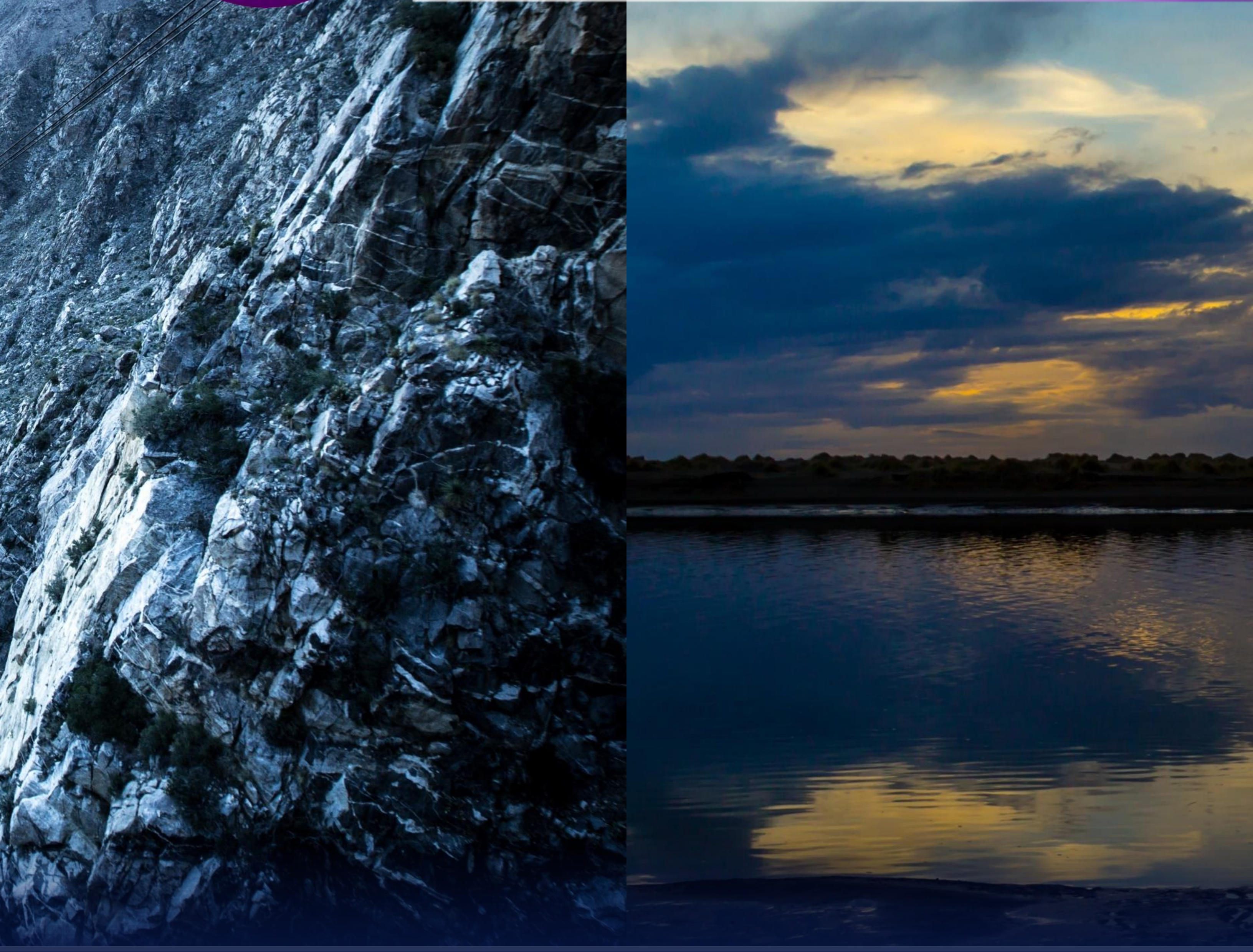
California Public Utilities Commission

Scaling Up and Crossing Bounds: Energy Storage in California

May 1, 2024



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ABBREVIATIONS AND TERMS

CAISO	California Independent System Operator
CCA	Community Choice Aggregation
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DER	distributed energy resource
ELCC	effective load-carrying capability
ESP	electric service provider
GHG	greenhouse gas
GW	gigawatt(s)
GWh	gigawatt-hour(s)
HFTD	high fire threat district (from least to most threat: non-HFTD, Tier 1, Tier 2, Tier 3)
IOU	investor-owned utility (informally, utility)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LMP	locational marginal price
LSE	load-serving entity (includes IOU, CCA, ESP)
MW	megawatt(s)
MWh	megawatt-hour(s)
NQC	net qualifying capacity
PG&E	Pacific Gas and Electric Company
RA	resource adequacy
RCAM	Redwood Coast Airport Microgrid
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SOC	state of charge
subLAP	CAISO-defined sub-load aggregation point
VPP	virtual power plant
WDAT/WDT	Wholesale Distribution Access Tariff/ Wholesale Distribution Tariff

$/kW-month	Dollars per kW (capacity) per month. Many benefits and costs in this report are expressed as this metric due to its prevalence in resource adequacy planning and markets. The metric normalizes benefits and costs so resources of different sizes and in operation for varying lengths of time are more comparable. For example, a 2 MW resource operating for 6 months that yields $192,000 in benefits is twice as beneficial per kW and per month ($192,000÷2,000 kW÷6 months = $16/kW-month) as a 100 MW resource operating for 12 months that yields $9.6 million in total benefits ($9.6 million÷100,000 kW÷12 months = $8/kW-month). For more information about our calculations please see **Appendix A**.
2021 Preferred System Plan	An outcome of the CPUC's 2019–2020 Integrated Resource Plan cycle and the adopted portfolio that meets a statewide 38 million metric tons (MMT) greenhouse gas target for the electric sector in 2030 and 35 MMT for 2032. Includes 13,571 MW of new battery storage plus 1,000 MW new pumped (long-duration) storage installed in 2022–2032. See the CPUC's February 10, 2022 Decision 22-02-004, Table 5 (CPUC 2022a, 101).

2023 Preferred System Plan	An outcome of the CPUC's 2022–2023 Integrated Resource Plan cycle and the adopted portfolio that meets a statewide 30 million metric tons (MMT) greenhouse gas target for the electric sector in 2030 and 25 MMT for 2035. Includes 14,100 MW of new short-duration battery storage (mostly 4-hour), 500 MW new pumped storage, and 400 MW other new long-duration storage installed by 2032. New resources grow to 16,700 MW short-duration battery storage and 500 MW other long-duration storage by 2035, then to 35.2 MW short-duration battery storage (mostly 8-hour) by 2045. See the CPUC's February 15, 2024 Decision 24-02-047, Table 4 (CPUC 2024a, 68).
ancillary services	Ancillary services provide grid operational flexibility and stabilization for the purposes of reliable electricity delivery. CAISO ancillary services markets include non-spinning and spinning contingency reserves, and regulation up and down. We use the term more broadly to include additional services like blackstart and voltage support (reactive power).
capacity credit/contribution	A generic term referring to a resource's ability to provide resource adequacy capacity service relative to its full capacity. Not to be confused with the formal definition of RA capacity in the CPUC's RA program and RA procurements.
capacity value	A generic term referring to the monetization of capacity credit or capacity contribution.
co-located resource	In the context of the CAISO marketplace, multiple resources behind a single point of CAISO interconnection, each of which participates independently with their own individual Resource ID. *See also* hybrid resource. Both co-located and hybrid resources may be subject to an aggregate output constraint at the CAISO point of interconnection.
duration	The number of consecutive hours an energy storage resource can discharge at its power capacity, starting from a full charge. Duration reflects physical configuration and technical limits, not the full range of operational capability. For example, a 10 MW 4-hour battery can also discharge 5 MW over 8 hours.
effective load-carrying capability	A probabilistically-derived metric that summarizes a resource's or group of resources' ability to serve electricity demand across all time periods—as opposed to more traditional metrics that reflect available capacity during a single peak load hour. ELCC has become an increasingly important planning and performance metric as California achieves increasingly high renewables and energy storage penetration.
energy capacity	The maximum technical limit of total MWh an energy storage resource can provide without recharging or replenishing stored energy.
energy storage	Mechanical, chemical, and thermal technologies as defined in California Assembly Bill 2514 (Skinner, 2010) and clarified in CPUC Decision 16-01-032.
energy time shift	Refers to the service provided by energy storage to move large volumes of renewable generation from one time period to another.
grid domain	Refers to the general electrical location. Energy storage can be connected at the bulk grid level on the transmission network (transmission domain), on the distribution network and in front of the

	utility's customer meter (distribution domain), or behind the utility's customer meter (customer domain).
hybrid resource	In the context of the CAISO marketplace, multiple mixed-fuel resources (referred to as "components") behind a single point of CAISO interconnection, such as solar PV and battery energy storage, which participate as a combined resource with a single Resource ID. *See also* co-located resource. Both co-located and hybrid resources may be subject to an aggregate output constraint at the CAISO point of interconnection.
marginal resource	The last and most expensive resource cleared in a competitive market. In this report, we may refer to the marginal resource in a wholesale electricity marketplace for energy, ancillary services, or RA capacity.
marginal value	Derived from an actual or counterfactual market-clearing price for a service in a competitive market. In this report, we convert market revenues or avoided costs into a standardized $/kW-month metric for ease of comparison of marginal value among supplier costs and many types of supplier services.
microgrid	As defined in California Public Utilities Code Section 8370(d), a microgrid is an interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure.
power capacity	The maximum technical limit of instantaneous MW an energy storage resource can provide.
roundtrip efficiency	The ratio of useful energy discharged to energy consumed for charge.
short-/long- duration	While there is no standard industry definition, we use "short-duration" as resources configured to discharge at full MW capacity for up to 10 hours, and long-duration as those configured to discharge at full MW capacity for more than 10 hours.
state of charge	The share of energy capacity held in a battery at a given time. For example, a 10 MWh battery at 50% state of charge is capable of discharging 5 MWh without recharging. State of charge factors into operating performance, operating capabilities, and battery degradation.
tonne	A metric ton (1,000 kilograms).
use case	A technical, operational, and/or financial model for developing and operating an energy storage resource to provide a specific set of services (e.g., microgrid use case). Use cases are varied and may or may not "stack" services within a grid domain (e.g. customer outage mitigation plus bill savings) and/or across grid domains (e.g., community outage mitigation plus energy services to the bulk grid).

PREFACE

In 2010, California Assembly Bill 2514 (Skinner) directed the California Public Utilities Commission (CPUC) to determine appropriate targets for the procurement of energy storage systems by electricity load-serving entities under its jurisdiction. The bill enabled several policy innovations to explore and accelerate the scalability of then-emerging stationary energy storage technologies.

CPUC Decision 13-10-040 subsequently launched an energy storage procurement framework that, by the end of 2021, played a crucial role in the acceleration of commercially viable and scalable energy storage in the state. The CPUC Energy Division's inaugural assessment of the framework's ability to meet the goals of AB 2514—the 2023 *CPUC Energy Storage Procurement Study*—presents evidence of this success. The 2023 study also identifies several remaining challenges to accessing the full suite of services energy storage offers, and it highlights opportunities to unlock additional benefits from the energy storage fleet.

Scaling Up and Crossing Bounds is the CPUC's second evaluation of its energy storage procurement framework. This study continues the CPUC's examination of energy storage growth, performance in electricity markets, use cases, and policy pathways to unlock full value from this flexible and modular resource. As the state's energy storage fleet scales up, this report demonstrates real-world implications for energy, ancillary services, and resource adequacy markets and identifies policy adjustments that may be needed. As energy storage continues to cross traditional industry boundaries in planning, procurements, and operations, this report provides additional guidance towards beneficial multiple use applications that provide services both to (a) customers or the local distribution system, and (b) the bulk (wholesale) grid.

The authors would like to thank Gabe Petlin, Andrew Dugowson, and Dilin Naidoo of the CPUC Energy Division for their valuable feedback and guidance. The authors are grateful to the many stakeholders who contributed by providing data and feedback to this study, with a special thanks to the CPUC, California Energy Commission, California ISO, Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, Redwood Coast Energy Authority, The Energy Authority, and Schatz Energy Research Center.

For full study context we highly recommend review of the 2023 *CPUC Energy Storage Procurement Study,* available at: www.lumenenergystrategy.com/energystorage.

EXECUTIVE SUMMARY

Scaling Up and Crossing Bounds is the California Public Utilities Commission's (CPUC) second evaluation of its energy storage procurement framework. This study continues the CPUC's examination of energy storage growth, performance in electricity markets, use cases, and policy pathways to unlock full value from this flexible and modular resource.

The first evaluation, *CPUC Energy Storage Procurement Study*, was published mid-2023. Pursuant to CPUC Decision 13-10-040, both evaluations seek to learn from historical stationary energy storage procurements and operations to assess the evolution of California's energy storage industry. Both evaluations' key observations and guiding recommendations are meant to highlight policy levers that will support development of a cost-effective energy storage portfolio that effectively contributes to meeting the state's goals of electricity grid optimization, renewables integration, and greenhouse gas (GHG) emissions reductions.

This report is organized around two study goals, each building from the objectives, findings, and recommendations of the 2023 *CPUC Energy Storage Procurement Study*.

The first study goal is to assess the real-world implications for energy, ancillary services, and resource adequacy markets as the energy storage fleet scaled up dramatically in 2022 and 2023, then to identify policy adjustments that may be needed.

The second study goal is to build a record of data-driven cross-domain multiple use application (MUA) case studies which demonstrate the benefits and challenges to an energy storage resource's ability to provide services both to (a) customers or the local distribution system, and (b) the bulk (wholesale) grid. These case studies are designed to improve the CPUC and stakeholders' understanding of what types of cross-domain MUA are feasible and scalable; to what degree a resource can provide RA capacity service when it is built for the purpose of outage mitigation or distribution deferral (or vice versa); and how MUA operations can optimize cross-domain services when they conflict.

<u>Scaling Up</u>

Installed energy storage capacity participating in the CAISO marketplace is growing rapidly as the state continues to build storage to meet future reliability needs while also decarbonizing its grid. We observe continued significant growth in system benefits—but also lack of transparency in hybrid and customer-sited resources, and a need to adjust policies to actual operating performance—as operating battery energy storage scales up to unprecedented levels.

The *CPUC Energy Storage Procurement Study* analyzes energy storage resources across all grid domains, including about 1,100 MW transmission-connected and distribution-connected resources participating in the CAISO marketplace and installed by mid-2021. That study includes a forward-looking analysis of expected benefits, in anticipation of fleet growth that is now being realized.

By the end of 2021, actual grid-scale battery resources in the CAISO marketplace more than doubled to about 2,500 MW. Then, by the end of 2023, installations reached nearly 7,500 MW. We analyze detailed market and operations data provided by the CAISO to understand how this growth has translated into energy, ancillary, and reliability services to the bulk grid.

In 2022 and 2023 the energy storage use case in the CAISO marketplace continued to transition from ancillary services to energy time shift, meaning most resources now regularly charge during low-priced periods in the day and discharge during high-priced periods in the evening. With more emphasis on energy time shift, the majority of CAISO's storage fleet is more effectively reducing GHG emissions. The storage fleet is also increasingly helping with integration of renewable energy resources by mitigating oversupply. Energy storage co-located with solar PV provided higher benefits than standalone storage, due to more operational focus on energy time shift and location in southern California where the marketplace signals a higher need.

Overall, the CAISO-participating storage fleet provided substantial benefits to the electric system in the 2017–2023 timeframe. Figure 1 shows how most new energy storage resources incremental to the *CPUC Energy Storage Procurement Study* provided system benefits above $15/kW-month, comparable to the higher end of the 2017–2021 resource-level benefits calculated in the 2023 study (Lumen 2023, A-29). Average energy value of storage resources in CAISO grew by about 2×, to over $5/kW-month, relative to results from the first evaluation. RA capacity accounts for an increasing share of the value provided by the storage fleet. These observed real-world results and market trends are consistent with the forward-looking analysis included in the *CPUC Energy Storage Procurement Study*.

One challenge, however, is that energy storage configured as part of a hybrid resource, and customer-sited energy storage, continue to be non-transparent in the CAISO marketplace. Their size, operating restrictions, and actual operations cannot be determined with the available market data. For this reason they have been excluded from the above-described analysis. These resources are also scaling up, but until they can be understood and analyzed alongside other bulk grid resources they will continue to pose unique planning and policy challenges. As emphasized in the *CPUC Energy Storage Procurement Study*, improvements in data management are imperative as energy storage scales up in different forms and across all grid domains. The 2023 study recommendations include development of universal and standardized data collection, retention, quality control, and reporting of interval-level operations for all ratepayer-funded energy storage resources.

Another challenge comes with the increasing importance of energy storage operating performance as its contributions to the RA capacity market and system reliability grows. We investigate historical availability and performance of the storage fleet in CAISO market in 2022 and 2023, including during grid-stressed periods, to help validate and improve future resource planning and procurement efforts in California.

We find that energy storage resources experienced more than 2× higher forced outage rates relative to assumptions in the state's grid planning studies and significant seasonal and daily variation. In the months of August and September, and in the evening when the CAISO grid is typically the most strained, the average outage rate is 1 percentage point higher than the year as a whole. During these peak periods, daily average forced outage rates exceeded 15% in 1 out of every 5 days. This is in comparison to the 5% outage rate currently assumed in grid planning studies.

Furthermore, an extended outage due to safety events at Moss Landing facilities, plus delays in local approval processes driven by safety concerns, illustrate the important link between management of safety risks and the storage fleet's impact on grid reliability—an issue also raised in the *CPUC Energy Storage Procurement Study*.

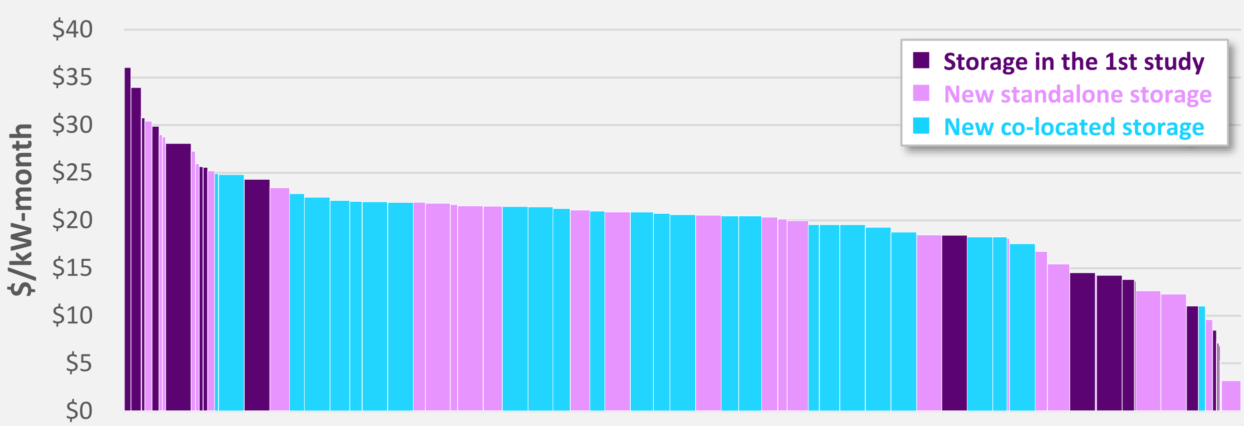


Figure 1: Estimated system (gross) benefits of storage resources in CAISO (2023 $).

<u>Crossing Bounds</u>

The *CPUC Energy Storage Procurement Study* highlights low success rates and lack of market acceleration in distribution-connected energy storage resource development, despite: (a) growing needs for community resilience solutions, (b) a need for distributed solutions to natural gas-fired peaker replacements in order to avoid or reduce transmission upgrades for otherwise cost-effective resource solutions, (c) the unique ability to produce value streams both to the transmission system and distribution system, and (d) evidence that these smaller distributed resources can produce high ratepayer value.

The 2023 study also highlights a disconnect between customer-sited energy storage resources and services they could provide to the broader grid, coupled with increasing pressure for financially accessible customer-sited resilience solutions. Value-stacking across grid domains, through multiple use applications (MUA), has been demonstrated in the market, and it is key to overcoming the financial barriers to distribution-connected and customer-sited resources. But many questions remain about feasibility of cross-domain MUAs to scale up in the number of installations, and in the benefits they provide to both ratepayers and customers. Figure 2 summarizes the full spectrum of potential services provided by energy storage (check marks), and the specific multiple value streams in focus in this study (purple areas).

We utilized four types of data to develop and learn from a set of cross-domain MUA case studies: (1) circuit-level outage data for the 2015–2019 period at 8 selected locations to understand a diversity of outage risks faced by customers, (2) the characteristics of 63 individual distribution deferral opportunities (DDOs) identified by utilities, (3) system RA capacity and local (sub-LAP) energy market prices, and (4) the characteristics of 10 actual energy storage projects in **Appendix E (Case Study Fact Sheets).**

To estimate cross-domain MUA opportunities, operations, and value we simulated energy storage operations under alternative MUA scenarios using an hourly (8,760 consecutive hours for a year) dispatch optimization model. These case studies are designed to improve the CPUC and stakeholders' understanding of what types of cross-domain MUA are feasible and likely scalable; to what degree a resource can provide RA capacity service when it is built for the purpose of outage mitigation or distribution deferral (or vice versa); and how MUA operations can optimize cross-domain services when the need for those services conflict.

		Grid Domains		
	Services to Grid and Customers	**Transmission**	**Distribution**	**Customer**
Energy & AS Markets and Products	Energy	✓	**✓**	**✓**
	Frequency Regulation	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Flexible Ramping	✓	✓	✓
	Voltage Support	✓	✓	✓
	Blackstart	✓	✓	✓
Resource Adequacy	System RA Capacity	✓	**✓**	**✓**
	Local RA Capacity	✓	✓	✓
	Flexible RA Capacity	✓	✓	✓
T & D Related	Transmission Investment Deferral	✓	✓	✓
	Distribution Investment Deferral		**✓**	✓
	Microgrid/Islanding		**✓**	**✓**
Site-Specific & Local Services	TOU Bill Management			✓
	Demand Charge Management			✓
	Increased Use of Self-Generation			✓
	Backup Power			**✓**

Figure 2: Scope of possible energy storage services, and focus of cross-domain MUA analysis (purple).

Cross-domain MUA with customer outage mitigation

We observe **customer-sited resources** provide scalable outage mitigation serving individual customers and the surrounding community. Actual development of solar plus storage, which protects against the most impactful long duration outages, is relatively high, especially for residential customers. As discussed in the *CPUC Energy Storage Procurement Study*, key influencers to cross-domain value-stacking are retail rates and programs. That study's recommendations to bring stronger grid signals to customers are still applicable here.

The scalability of **substation and feeder-level distribution-connected resources** for outage mitigation—such as such as SDG&E's Borrego Springs, Butterfield, and Shelter Valley microgrids and PG&E's temporary substation microgrids—is limited by the prevalence of distribution-level outage risks.

In comparison, **community-level microgrids** are closer to customers but they are still connected to the distribution system. These resources offer distinct advantages for the purposes of outage mitigation and could be broadly scalable across the state—but they face significant barriers. The Redwood Coast Airport Microgrid provides a template for CPUC Rulemaking 19-09-009 for an LSE/IOU co-development process, operating agreement, and tariff, but financial barriers have yet to be overcome.

We find that stacking RA capacity and energy value with outage mitigation is possible and could significantly reduce financial barriers. For a specific resource, the optimal cross-domain MUA strategy depends on local outage characteristics, outage impacts, and customer risk tolerances. A policy approach to reducing financial barriers will need to better enable MUA, and it will need to recognize MUA challenges in parts of the state where outage risks compete with system RA needs (e.g., areas with a summer outage problem).

Cross-domain MUA with distribution deferral

The *CPUC Energy Storage Procurement Study* observed, in the advanced stages of procurement, distribution-connected energy storage developed to defer specific distribution investments faced major challenges as the size and timing of identified needs changed over time.

Digging deeper into the underlying distribution deferral (DD) planning and procurement processes, we find several challenges that limit the visibility of a large number of energy storage distribution deferral opportunities (DDOs). Most of the problem stems from a "just-in-time" forecasting methodology through which the IOUs cannot identify a DDO until it is too late to procure a non-wires solution for it. Combined, the DDO timing and market screens excluded over 95% of opportunities for distribution-connected storage identified over the past 5 years. The resulting distribution deferral procurement marketplace, mostly supplied by distribution-connected energy storage providers, is so thin that only 19% of procurements yield viable energy storage-eligible opportunities, representing <1% of total potential DDOs and only about a dozen projects in total. Third party developers thus have a low chance of securing a revenue stream through this procurement process.

Value-stacking RA capacity and energy services is an important ingredient to the economic feasibility of storage procured for distribution deferral. Our analysis demonstrates this cross-domain use case is feasible and beneficial. Out of 63 potential projects analyzed, most DDOs can capture >50% of potential RA benefits through value-stacking, and about a third can capture >80% of potential RA benefits. Un-stackable value is mostly due to the (longer) minimum duration requirements of some DDOs and/or the timing and duration of DD calls.

Ultimately, for developers to consider distribution-connected projects rather than transmission-connected projects, they need a positive revenue outlook for distribution deferral services. In the planning phase when considering siting, developers need better 3+ year forecasts of when and where distribution deferral needs will likely occur. They also need a policy mechanism to ensure that once a resource is built, they will have access to the distribution deferral marketplace for when and where those needs actually arise—even if the IOUs cannot identify needs until they are imminent.

Observations on actual benefits and challenges during the 2022–2023 period

System reliability and resource adequacy needs continue to drive significant growth in transmission-connected energy storage capacity.

Installed battery storage capacity in the CAISO marketplace reached almost 7.5 GW by the end of 2023, compared to about 1 GW online as of April 2021 and analyzed in the *CPUC Energy Storage Procurement Study*. This rapid growth is largely driven by Integrated Resource Plan (IRP) procurements to meet system reliability needs.

A large share of new energy storage resources in the CAISO marketplace is paired with solar PV.

About 70% of the new energy storage capacity incremental to the *CPUC Energy Storage Procurement Study* is paired with solar PV generating resources.

Most of these paired energy storage resources are co-located with solar PV systems: energy storage and solar PV resources are metered and settled separately under different CAISO Resource IDs.

A smaller share of energy storage resources paired with solar PV system are in a hybrid configuration: energy storage resources and solar PV resources are metered and settled under a shared Resource ID at a shared point of interconnection.

The characteristics and operations of hybrid and customer-sited energy storage in the CAISO marketplace continue to be non-transparent.

Energy storage in a hybrid configuration, such as those hybridized with solar installations or natural gas-fired generators, do not yet systematically report the operations of their energy storage components for evaluation purposes.

Similarly, customer-sited energy storage resources participating in the CAISO marketplace through the Proxy Demand Resource (PDR) model cannot be identified through market data and the market data do not reflect complete operational data of energy storage components for evaluation purposes.

As foreseen in the 2023 *CPUC Energy Storage Procurement Study*, lack of these data creates significant barriers to analysis of these types of resources, especially within the relatively short timeframe of this study.

The predominant energy storage use case in the CAISO marketplace continues to transition from ancillary services to energy time shift.

In the 2023 *CPUC Energy Storage Procurement Study* we observed an increase in energy value and corresponding GHG emissions reductions for most resources participating in the CAISO marketplace in 2021. That trend continues through 2022 and 2023.

Non-hybrid energy storage fleetwide average ancillary services value continued to decrease, from about $4/kW-month in 2021, to $1.5/kW-month in 2023. Concurrently, energy value continued to increase, from about $3.5/kW-month in 2021, to $5/kW-month in 2023.

Under this use case, most of the CAISO-participating energy storage resources now regularly charge during low-priced periods in the day and discharge during high-priced periods in the evening.

With increased focus on energy time shift, CAISO-participating energy storage resources provide significant GHG emissions reductions.

With more emphasis on energy time shift, the majority of CAISO's storage fleet is more effectively reducing GHG emissions.

The non-hybrid CAISO-participating battery energy storage fleet enabled almost 1,000,000 metric tons (tonnes) of GHG emissions reductions in the December 2022–November 2023 timeframe.

On average, energy storage co-located with solar PV provides higher GHG emissions reduction benefits than standalone storage.

Among the newer non-hybrid resources analyzed, energy storage co-located with solar PV provided an average of 19 tonnes/MW-month in GHG emissions reductions, compared to about 10 tonnes/MW-month from standalone energy storage.

The difference is partly due to more operational focus on energy time shift, and partly due to location. Most co-located storage is in southern California, where GHG emissions reduction potential is higher due to lower marginal GHG emission rates when energy storage is charged.

Energy storage resources, especially ones paired with PV, are also helping with renewable integration by reducing curtailments.

CAISO market data indicates the storage fleet is increasingly helping with integration of renewable energy resources by mitigating oversupply.

Avoided renewable curtailments are significantly higher for the new energy storage resources, especially those co-located with solar PV. These resources are sited in areas experiencing higher curtailments; they also charge regularly when renewable oversupply conditions emerge.

The associated benefits are also increasing as the cost of meeting the state's Renewables Portfolio Standard (RPS) rises. The CPUC's October 2023 market price benchmarks used in its Power Charge Indifference Adjustment (PCIA) calculations includes an RPS adder of $30/MWh for 2023 (CPUC 2023c), about 2x higher than prior years' RPS adder.

RA capacity value accounts for an increasing share of the total quantified benefits provided by the energy storage fleet.

As described earlier, most of the new CAISO market-participating energy storage installed in 2022 and 2023 is driven by Integrated Resource Plan (IRP) procurements to meet system reliability needs.

Average systemwide RA capacity prices in 2023 are $14.4/kW-month (CPUC 2023c), up from about $3/kW-month prior to 2019, and $5–8/kW-month in the 2020–2022 timeframe.

Overall, the CAISO-participating battery energy storage fleet provides substantial and increasing electric system benefits.

Most new resources incremental to the 2023 *CPUC Energy Storage Procurement Study* analysis provided system benefits above $15/kW-month, comparable to the higher end of 2017–2021 resource-level benefits calculated in the 2023 study (Lumen 2023, A-29). The relatively high benefits of newer resources, higher system RA capacity value on a $/kW-month basis, and higher energy value are all interrelated and contribute to an increasing trend of system benefits.

With increased focus on energy time shift, the RA capacity contributions of CAISO-participating energy storage resources during grid-stress periods have improved.

In recent history, the CAISO experienced two extreme heat waves leading to system-level emergency declarations. In mid-August, 2020, the CAISO had 337 MW of grid-scale battery storage operating. Most resources focused on the ancillary services market. Aggregate Net Qualifying Capacity (NQC), a measure of RA capacity contribution, was **37%** of installed MW.

In early September, 2022, the CAISO's battery storage fleet grew to 3.7 GW. Most new resources focused on energy time shift. Aggregate NQC was **84%** of installed MW.

Actual average forced outage rates of CAISO market-participating battery energy storage are significantly higher than long-term resource planning assumptions.

The CPUC's Integrated Resource Planning models assume a **5%** expected forced outage rate for battery storage (CPUC 2023d, 131), based on early data on the energy storage fleet just as it was reaching the GW scale. In 2022 and 2023, the non-hybrid fleetwide actual battery storage forced outage rate averaged **11.5%** across all months and hours—more than 2x the planning assumption.

Actual forced outage rates during August and September peak periods are higher than the annual average, and they indicate a larger share of high-outage days than the rest of the year.

In 2022 and 2023, the non-hybrid fleetwide actual battery energy storage forced outage rate during August and September evening peak periods (hour ending 17 through hour ending 21) was **12.6%**—one percentage point higher than the year-wide average. During these peak periods, forced outage rates exceeded 15% in 1 out of every 5 days.

The historical record is too short to analyze year-to-year variability in CAISO market-participating battery energy storage outages, but Moss Landing safety events had a striking impact on overall fleet performance September 2021 through May 2022.

Moss 300's outage added 16–18 percentage points to fleetwide forced outage rates in September and October 2021, then 10–16 percentage points to fleetwide planned outage rates in November 2021 through May 2022, after the outage was recategorized. The magnitude of impact on fleetwide outage rates is due to the resource's relatively large MW compared to the size of the battery energy storage fleet at the time.

Cross-domain multi-use applications: opportunities and challenges

We analyze two types of cross-domain multi-use applications (MUA): customer outage mitigation services combined with services to the transmission grid (wholesale marketplace), and distribution deferral services combined with services to the transmission grid.

Cross-domain MUA with customer outage mitigation

Customer-sited resources provide scalable outage mitigation serving individual customers and the surrounding community.

Installed customer-sited storage is already at the GW scale, and rapid growth is driven by outage mitigation needs and use case. Over 1,600 MW customer-sited energy storage is interconnected through November 2023. In a survey conducted by Verdant Associates, LLC as part of their 2021 market assessment, 84–99% of customers with storage stated that backup/emergency power is among the top 3 drivers of their installation decision.

Installations at non-residential sites—such as critical facilities, community centers, and other facilities providing critical services—provide broader community-level outage mitigation and help support residents who may face technical, logistical, or financial barriers to home installations.

The scalability of distribution substation- and feeder-level resources for outage mitigation is limited by prevalence of distribution-level outage risks.

Most customer outage experiences and risks are driven by hazards to—and failures on—the distribution system. Transmission-level outage risks are comparatively low.

Existing outage mitigation-focused distribution-connected microgrid projects—such as SDG&E's Borrego Springs, Butterfield, and Shelter Valley microgrids and PG&E's temporary substation microgrids—effectively serve communities exposed to outages further upstream on the grid. But these types of resilience and reliability resource solutions address a relatively uncommon grid topology and/or outage risk situation and thus are not broadly scalable across the state.

Targeted distribution-connected community-level microgrids offer distinct advantages and could be scalable, but they face significant barriers.

Targeting a set of critical and essential facilities in a community with distribution-connected resource solutions placed electrically closer to customers reduces the amount of distribution grid hardening needed for outage mitigation, while still offering broad community-level benefits. It can also reduce investments costs due to economies of scale and resources-sharing with load diversity across individual sites.

However, customers and communities face a suite of challenges to developing these multi-property solutions on the distribution system that are electrically upstream of onsite and campus-level "behind-the-meter" solutions.

The Redwood Coast Airport Microgrid provides a template for an LSE/IOU co-development process, operating agreement, and tariff, but financial barriers have yet to be overcome.

The Redwood Coast Airport Microgrid (RCAM) offers one of the industry's few examples of successful development and application of a multi-property distribution-connected outage mitigation solution. RCAM is a template for policy advancements to create a multi-property operating agreement and tariff under CPUC Rulemaking 19-09-009.

RCAM provides energy and ancillary services in the CAISO marketplace nearly every hour of the year. But it has yet been unable to access the RA capacity revenues crucial to a viable business case.

Stacking RA capacity and energy value with outage mitigation is possible; the optimal MUA strategy depends on outage characteristics & risk tolerance.

Energy storage capacity kept in reserve for outage mitigation reduces how much can be provided as services to the transmission grid (and vice versa).

Not all outage mitigation solutions can provide RA capacity value to the grid without significantly increasing local outage exposures, but our analysis of 8 outage mitigation case studies demonstrates that many can. In 5 out of the 8 case studies, customers retained most of their outage mitigation capability through a resilience-focused use case that also captures most of an energy storage resource's potential RA capacity and energy value.

Exclusion of RA capacity value reduces potential market revenues to offset resilience investment cost by 2/3, and it reduces the incentive for those in need of a resilience solution to participate in the wholesale marketplace at all.

Without RA capacity as a revenue stream for those who can actually and verifiably provide it, our analysis demonstrates how only customers and communities with a relatively low value of lost load (i.e., the cost of outages to them) would be willing to trade energy market revenues to accept some additional outage risk. Ironically, these would be the customers and communities with the least need for a resilience solution in the first place.

Cross-domain MUA with distribution deferral

Current distribution deferral planning and procurement processes face several challenges that limit the visibility of a large number of energy storage opportunities.

The current distribution deferral opportunity (DDO) screening and selection process aggressively eliminates energy storage as a solution. Most of the problem stems from a "just-in-time" forecasting methodology through which the IOUs cannot identify a DDO until it is too late to procure a non-wires solution for it. This systematic under-forecasting of procurement opportunities, plus other elimination screens, excluded 95% of opportunities identified over the past 5 years. Without those restrictions, on the order of 100–200 energy storage development opportunities would be identified and procured every year.

Review of the distribution deferral planning and procurement process confirms the current policy framework as an unreliable revenue source for 3rd party developers to build a viable business case.

Given the planning challenges, the resulting distribution deferral procurement marketplace, representing only 5% of potential opportunities, is so thin that 45% of the procurements were unsuccessful due to lack of offers, lack of a feasible portfolio, or lack of cost-effectiveness. Another 16% of procurements were canceled or delayed during the procurement process due to stringent requirements on project size and timing.

The thin market and procurement challenges ultimately reduced viable energy storage-eligible opportunities to 19% of procurements, representing <1% of total potential DDOs and only about a dozen projects in total. Third party developers thus have a low chance of securing a revenue stream through this procurement process.

The operating requirements of most distribution deferral opportunities synergize well with system RA capacity needs.

Our analysis of 63 distribution deferral opportunity case studies shows that most distribution deferral resources analyzed can capture >50% of potential RA benefits through value-stacking and 1/3 can capture >80%—even conservatively assuming each project operates to meet its maximum distribution deferral service calls and is subject to charging constraints when not called.

Though the experience is limited to a few projects and a short timeframe, the operations of installed projects confirms these value-stacking synergies. Of the three actually-installed distribution deferral projects to date, Acorn I and two Wildcat I projects, all were procured under a bundled RA capacity and distribution deferral contract, and all participate in CAISO's wholesale marketplace.

Value-stacking wholesale market services with distribution services significantly improves the economic feasibility of most storage solutions to meet distribution deferral needs, and it is an important ingredient to a viable business case for distribution deferral.

The *CPUC Energy Storage Procurement Study* made several policy recommendations to remove barriers to distribution-connected energy storage installations and emphasized the need for value-stacking.

In this study, our case studies demonstrate the financial implications of value-stacking. At current market prices, total energy plus RA capacity value potential of storage is about $60/kWh-year. We estimate that most storage-eligible DDOs could capture at least 50% of this value ($30/kWh-year or more) through value-stacking. This could pay for a large portion of the storage investment and accordingly reduce the distribution service payments needed.

But for developers to consider distribution-connected projects rather than transmission-connected projects, they need a positive revenue outlook for distribution deferral services.

Battery energy storage costs tend to include economies of scale (Viswanathan et al. 2022). Distribution-connected energy storage will likely include a cost premium compared to transmission-connected, as shown in the *CPUC Energy Storage Procurement Study* (Lumen 2023, 23).

Developers can access RA capacity revenues at scale with transmission-connected resources and through the IOU's RA capacity procurements. For developers to consider incurring additional cost to build on the distribution system, regardless of the procurement mechanism, they need some positive revenue outlook for stackable distribution services.

In the planning phase when considering siting, developers need better 3+ year forecasts of when and where distribution deferral needs will likely occur. They also need a mechanism to ensure that once a resource is built, it will have access to the distribution deferral marketplace when and where those needs actually arise—even if the IOUs cannot identify needs until they are imminent.

Recommendations on policy efforts going forward

The 2023 *CPUC Energy Storage Procurement Study* made policy recommendations in 6 categories:

1. Evolve Signals for Resource Adequacy Capacity Investments
2. Bring Stronger Grid Signals to Customers
3. Remove Barriers to Distribution-Connected Installations
4. Improve the Analytical Foundation for Resilience-Related Investments
5. Enhance Safety
6. Improve Data Practices

All recommendations from the 2023 evaluation continue to be relevant and important to the development of an energy storage fleet that effectively and efficiently meets state goals. This report reaffirms and builds upon several of those recommendations.

Continue to Improve Data Collection Practices

Ongoing efforts to improve data collection are needed to enable meaningful evaluations and policy adjustments as the energy storage fleet grows and changes.

In 2023 the CPUC and CAISO worked together to update their data-sharing arrangements to include ongoing and standardized reporting of energy storage performance in the CAISO marketplace (CPUC 2023a). Understanding the operations of the energy storage components of hybrid resources and behind-the-(utility)-meter resources (Proxy Demand Resources, or PDRs) participating in the CAISO marketplace, however, continues to be a challenge.

As a next step, our recommendations for the CPUC are to:

- Continue to monitor the reported hybrid data collected by CAISO; work with the CAISO to refine those reporting requirements if needed; and, when those data become available and quality-controlled, **include an analysis of hybrid resources in future energy storage evaluations**.
- As recommended in the *CPUC Energy Storage Procurement Study,* require that ratepayer-funded resources participating as Proxy Demand Resources (PDRs) in the CAISO marketplace **report their complete (charge and discharge) interval-level operations**, modeled after the SGIP requirements for

Performance Based Incentives and expanded to include information on state of charge, standby losses, and operations during upstream grid outages. In future energy storage evaluations, **use that information to better understand the capabilities of customer aggregations** (e.g., Virtual Power Plant, or VPP) to provide RA capacity services, and how they might balance the tradeoffs of services to the CAISO marketplace with onsite customer needs.

Update Outage and Performance Assumptions

Similarly, as we observe the energy storage fleet's real-world operations and market performance change over time, those operating patterns and trends will need to be incorporated into planning and procurement assumptions regularly and on an ongoing basis.

As part of its ongoing planning and procurement updates, our recommendations for the CPUC are to:

- Validate and update the energy storage forced outage rate assumptions throughout the CPUC's grid planning and RA program activities to incorporate the most current information. This includes **incorporation of a higher (11.5%) annual average forced outage rate, and consideration of the hourly, daily, and monthly outage patterns and variations**—particularly during summer evening peak periods.
- **Consider and incorporate market trends** towards lower ancillary services revenues, slightly higher and leveling-out energy revenues in the CPUC's RA capacity procurement tracks and IOU resource evaluation methodologies.
- As recommended in the *CPUC Energy Storage Procurement Study,* **continue to explore the safety-reliability link**, firstly to inform improvements in safety practices, but also to identify and reduce risks to the reliability of the bulk grid.

Improve Investment Synergies of Community Resilience Solutions

Improving access to the wholesale marketplace for all types of resources that can provide actual and verifiable services to the transmission grid will unlock the potential of cross-domain multiple use applications (MUA), reduce financial barriers to local resource solutions, and provide more RA capacity options to support system reliability.

Towards this strategy that starts with enabling cross-domain MUA, our recommendations to the CPUC are to:

- As recommended in the *CPUC Energy Storage Procurement Study*, explore opportunities to **bring stronger grid signals to customers** and, as part of that effort, consider mechanisms that **allow customers to tailor their participation in programs** based on their reliability and resilience risk tolerances, and based on the time profile (e.g., monthly and hourly) of their local outage risks.
- **Explore planning and procurement refinements for community-level resources to access and better synergize with the RA capacity marketplace**, such as incorporation of new information on community-level resources and community resilience planning activities in the IRP process, exploration of appropriate procurement mechanisms for community-level resources, and consideration of how community-level resources can utilize the Slice-of-Day framework to enter the RA capacity marketplace.
- Implement solutions to **help smaller local developers overcome the logistical and financial roadblocks to IOU and CAISO deliverability assessments and potential wires upgrades needed**, such as clearer information sources on a specific resource's pathway to RA capacity qualification, and consideration of a Transmission Project Review-like stakeholder engagement process for future WDAT/WDT refinements and modernization.
    - **Consider RA capacity market participation models for resources in parts of the state where local outage risks compete with providing RA capacity to the bulk grid**, for example, program and compensation mechanisms to verifiably self-supply RA capacity during grid emergencies, regardless of upstream distribution and transmission deliverability.

Remove Barriers to the Distribution Deferral Marketplace

Most of the elements of the CPUC and IOU's distribution deferral opportunity planning process can be re-framed into a planning and procurement process which improves both (a) the success of distribution deferral procurements and (b) the business case for developers to consider resources capable of providing distribution deferral services. This is achieved by circumventing the many planning and procurement barriers stemming from the IOUs' "just in time" (but too late for new energy storage development) forecasts of distribution deferral opportunities.

To better enable scaling of distribution deferral services, our recommendations to the CPUC are to:

- Reframe the GNAs and DDORs to **produce an annually updated data library which includes the IOU's best and most granular information on when a distribution deferral need is likely to occur on each distribution feeder and substation**.
  - This is similar to what the GNAs/DDORs produce today, but stops short of the filters, screens, and rankings (tiering) the IOUs apply to narrow hundreds of potential DDOs to a handful of procurements. It also provides more comprehensive information on distribution deferral characteristics across all feeders and substations.
  - Importantly, the information should include an estimate of distribution deferral call windows and of potential deferred distribution investment costs.
- **Provide this information on a timely basis to developers** potentially participating in the RA capacity program, with sufficient data granularity and accessibility to enable developers to refine the 3+ year forecasts of when and where distribution deferral needs will occur.
- Allow developers to offer distribution-connected resources into RA capacity procurements with **contract provisions that guarantee if and when contracted resources are "right" about distribution deferral needs they will have the option to provide that service and be compensated accordingly**.
  - This option to provide distribution deferral service should be available regardless if their siting choice is based on the IOU's DDO forecast or the developer's own forecast.
- During the RA contract term, to determine when and where actual distribution deferral needs occur, **use the IOUs' existing GNA and DDOR analytical architecture to estimate DDOs assuming the counterfactual without the contracted resource**. If a DDO is identified, the contract option to provide distribution deferral service is activated, and avoided distribution deferral payments are based directly or indirectly on the planning estimate (above).
- Assuming RA capacity is the primary use case, **allow distribution deferral service to be provided voluntarily, with performance-based distribution deferral payments and a wires upgrade backstop**. In the IOUs' GNA and DDOR analysis (above) implement facility loading thresholds that trigger a backstop distribution wires upgrade. The backstop would be implemented based on actual distribution facility loadings and energy storage resource performance during distribution deferral call windows.

Concluding remarks

CPUC Scaling Up and Crossing Bounds reaffirms and builds upon several recommendations from the inaugural evaluation in 2023, *CPUC Energy Storage Procurement Study*. All recommendations from the 2023 evaluation continue to be relevant and important to the development of an energy storage fleet that effectively and efficiently meets state goals.

Installed energy storage capacity participating in the CAISO marketplace is growing rapidly as the state continues to build storage to meet future reliability needs while also decarbonizing its grid. Most of the CAISO-participating energy storage resources now regularly charge during low-priced periods in the day and discharge during high-priced periods in the evening. This trend further strengthens the storage fleet's contributions towards the state's Assembly Bill 2514 (Skinner, 2010) goals of electricity grid optimization, renewables integration, and greenhouse gas emissions reductions.

As transmission-connected battery energy storage scales up, this report recommends policy actions, incremental to recommendations in the 2023 *CPUC Energy Storage Procurement Study,* to support improved planning and procurement of energy storage participating in the wholesale marketplace.

But distribution-connected and customer-sited energy storage resources also have the potential to provide benefits at a larger scale—and they have the unique ability to provide services to the distribution system and directly to customers and their communities. This report offers case studies to facilitate a better understanding of those opportunities, and it presents recommended policy actions to reduce barriers to development while also improving investment synergies for both customers and ratepayers.

In our evaluations we expand upon the state's planning and analytical practices to learn from historical resource-specific storage operations, at a fine temporal and spatial granularity, across all grid domains, and across all potential services offered by energy storage resources. In future studies we recommend continuing to build upon this framework. We expect themes in future evaluations to include ongoing policy adjustments towards data collection improvements and refinements, updates to grid planning assumptions, and new and refined procurement strategies as the energy storage fleet scales up and resource types evolve.

INTRODUCTION

The purpose of this report is to assist the CPUC and its stakeholders to learn from its energy storage market transformation and actual operations, identify current and future challenges, and adapt policies accordingly. Building upon the 2023 *CPUC Energy Storage Procurement Study,* we analyze the performance of energy storage resources participating in the CAISO marketplace in 2022 and 2023. We also explore opportunities and challenges in the development of energy storage resources to provide services to the distribution system, and to customers and their communities.

The state's clean energy goals call for a major grid transformation towards almost all renewables with a large share of variable solar and wind generation. Energy storage provides key services for efficient use of renewable capacity by transmitting excess renewable generation to times of deficiency. However, it must do so at a large scale with proven technologies, and with procurements and market mechanisms that appropriately value those services.

Going forward, policies must continue to evolve with the market to unlock the full potential of the state's energy storage portfolio.

California is a world leader in innovative energy policies to transform markets to address the true costs of environmental damage and climate change to people and their quality of life. As part of its path towards clean energy goals the state dramatically transformed its stationary energy storage market. In 2010, almost 15 years ago, the CPUC and its stakeholders faced many unknowns and risks in terms of energy storage costs, operating capabilities, ability to participate in wholesale markets, and long-term cost-effectiveness. While we now have much more information to understand those unknowns and risks, we also face new questions about how to scale and diversify the energy storage portfolio to yield as much benefit to Californians as possible.

The purpose of this report is to assist the CPUC and its stakeholders to learn from its energy storage market transformation and actual operations, identify current and future challenges, and adapt policies accordingly. This report is organized in three chapters:

- **Chapter 1 (Scaling Up)** explores the market and policy implications of the continued acceleration of energy storage resources participating in the CAISO marketplace in 2022 and 2023.
- **Chapter 2 (Crossing Bounds)** explores case studies to facilitate a better understanding of where cross-domain Multi-Use Application (value-stacking) opportunities lie, and how they can be tapped to accelerate development of a diverse energy storage portfolio that provides a full suite of benefits to both customers and ratepayers.
- **Chapter 3 (Recommendations)** highlights policy actions that can help address barriers to the benefits of energy storage that are apparent in today's energy storage marketplace, recognizing that the state's electric system needs and market dynamics will continue to change dramatically over time.

This report includes several appendices providing more detail on analytical approach, calculations, and research-related findings to support our key observations and recommendations.

California's Energy Policy Challenges and the Role of Energy Storage

California's clean energy goals include 33% renewable energy by 2020, rising to 60% by 2030, and carbon neutrality by 2045 (Figure 3). To achieve those goals, the state is in the process of a major grid transformation towards an electricity supply portfolio of mostly solar photovoltaic (PV) generation, plus generation from hydroelectric, wind, biomass, geothermal, and natural gas resources. Stationary energy storage plays an essential role in the total resource portfolio, and its key benefit is to support the efficiency, cost-effectiveness, and reliability of a system with high levels of renewable generation.

Energy storage has the potential for a wide range of services (Figure 4). Electrically, the closer an installation is to the customer, the more services it can theoretically provide. Storage resources interconnected directly to transmission system can provide a suite of services to the wholesale marketplace. Distribution-connected storage resources can provide the same set of services to the transmission system, in addition to distribution system services. Customer-sited resources can provide all of the above, plus customer-specific services, like bill management and onsite backup power. Some services shown in the figure are not fully additive or additive at all. However, the primary purpose and value in California's energy storage portfolio is its ability to move large volumes of renewable generation from one timeframe to another in a controllable fashion—so-called "energy time shift." This enables efficient use of renewables. Energy time shift is most evident both in the energy value and in the resource adequacy capacity value of energy storage as these two services can be closely intertwined.

MW or MWh?

An energy storage resource's capacity to discharge electricity has two key dimensions: its maximum instantaneous output (expressed as MW capacity) and its total energy output with full charge (expressed as MWh capacity).

If only one metric must be expressed then MWh capacity is generally the more informative choice. However, many electricity resource planning and market constructs express resource capacity, costs, and market value in terms of MW.

In this study we often reference MW capacity to facilitate a better understanding of how energy storage fits into these planning and market constructs and how it may compare to other more traditional resources on the grid.

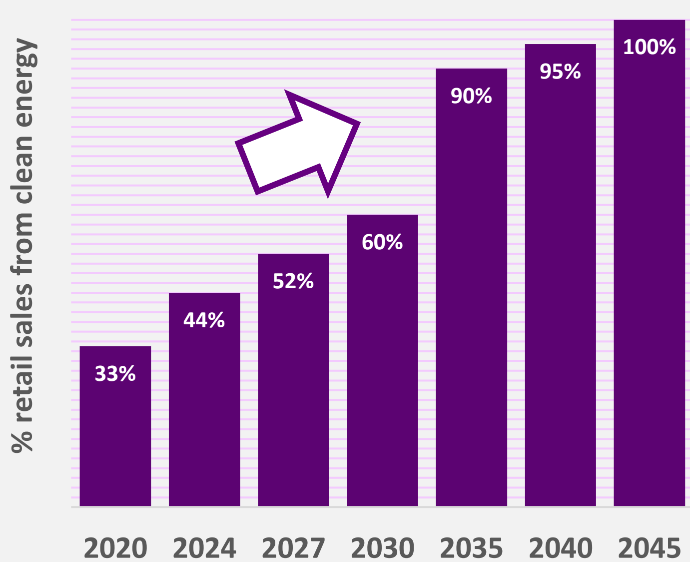


Figure 3: California's clean energy goals.

Energy & AS Markets and Products	Energy
	Frequency Regulation
	Spin/Non-Spin Reserve
	Flexible Ramping
	Voltage Support
	Blackstart
Resource Adequacy	System RA Capacity
	Local RA Capacity
	Flexible RA Capacity
T & D Related	Transmission Investment Deferral
	Distribution Investment Deferral
	Microgrid/Islanding
Site-Specific & Local Services	TOU Bill Management
	Demand Charge Management
	Increased Use of Self-Generation
	Backup Power

Figure 4: Scope of possible energy storage services.

Policies for Accelerated Market Development

In 2010, almost 15 years ago, Assembly Bill 2514 (Skinner) formally identified energy storage as a potential game-changer to address a variety of renewables integration and infrastructure development challenges. But some type of energy storage technology would need to become more cost-effective and more quickly scalable to large quantities beyond what is feasible with traditional alternatives (e.g., pumped storage hydroelectric, multi-state transmission). The policy challenge was thus to initiate a market for novel energy storage technologies and, within ten years, achieve commercial scaling and cost-competitiveness with alternative resource solutions. Key questions for energy storage market development are explored in the 2023 *CPUC Energy Storage Procurement Study.*

Figure 5 shows a summary of the progression of energy storage procurements since 2010. In response to AB 2514, CPUC's Decision 13-10-040 created an umbrella procurement framework and common goal for the utilities to procure 1,325 MW energy storage by 2020, with operations by 2024. The market for stationary energy storage in California grew and matured significantly, from initial use cases including pilots and local RA capacity (2014), to Assembly Bill 2868 opening the door to more development (2016–17), to distribution investment deferral procurements (2018–19), to expanded procurements for resource adequacy and system reliability (2020–24). The development pathway required investment in a diversity of technologies—and testing of a variety of use cases and business models. At the heart of this effort was a spectrum of CPUC procurement orders and programs (including SGIP) that could count towards meeting Decision 13-10-040 requirements, the CEC's technology innovation and advancement programs, the CAISO's initiatives to integrate energy storage into markets, and the utilities' pilot and incentive programs. The 2023 *CPUC Energy Storage Procurement Study* discusses this policy journey in more detail.

Chapter 1 (Scaling Up) of this report explores the market and policy implications of the more recent acceleration of energy storage resources participating in the CAISO marketplace in 2022 and 2023.

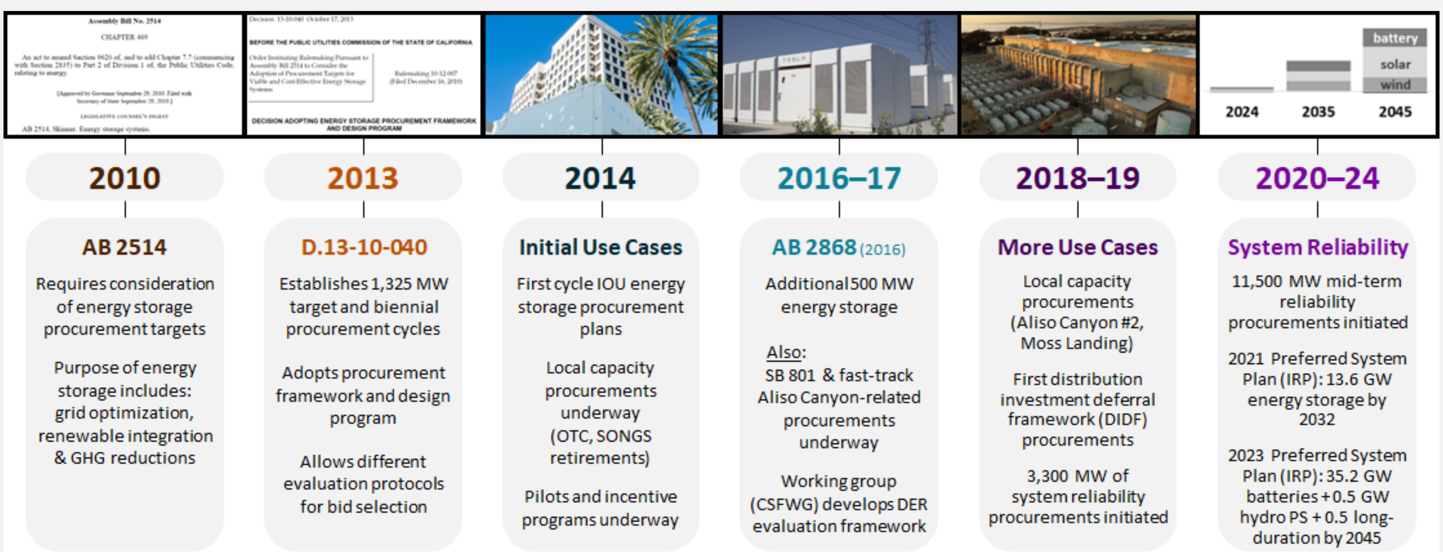


Figure 5: Timeline of California's key energy storage mandates and procurements.

Energy storage is a flexible and modular resource group, capable of being interconnected at many different points of the grid, and capable of providing a wide range of services beyond the wholesale marketplace. Distribution-connected and customer-sited energy storage resources have the potential to provide benefits at a larger scale—and they have the unique ability to provide services to the distribution system and directly to customers and their communities.

The CPUC Energy Storage Procurement Study highlights low success rates and lack of market acceleration in distribution-connected energy storage resource development, despite: (a) growing needs for community resilience solutions, (b) a need for distributed solutions to natural gas-fired peaker replacements in order to avoid or reduce transmission upgrades for otherwise cost-effective resource solutions, (c) the unique ability to produce value streams both to the transmission system and distribution system, and (d) evidence that these smaller distributed resources can produce high ratepayer value.

The 2023 study also highlights a disconnect between customer-sited energy storage resources and services they could provide to the broader grid, coupled with increasing pressure for financially accessible customer-sited resilience solutions.

Value-stacking across grid domains, through multiple use applications (MUA), has been demonstrated in the market, and it is key to overcoming the financial barriers to distribution-connected and customer-sited resources. But many questions remain about feasibility of cross-domain MUAs to scale up in the number of installations, and in the benefits they provide to both ratepayers and customers.

Chapter 2 (Crossing Bounds) explores case studies to facilitate a better understanding of where those cross-domain MUA opportunities lie, and how they can be tapped to accelerate development of a diverse energy storage portfolio that provides a full suite of benefits to both customers and ratepayers.

Policies that Evolve with the Market

Policies must continue to evolve as the energy storage penetration increases and as the grid transforms to meet the state's goals. In early 2022 the CPUC adopted its 2021 Preferred System Plan including an incremental 13,571 MW battery storage plus 1,000 MW pumped (long-duration) storage by 2032 (CPUC 2022a, 101). The plan suggests an average build of 1,325 MW new storage per year over a 10-year period.

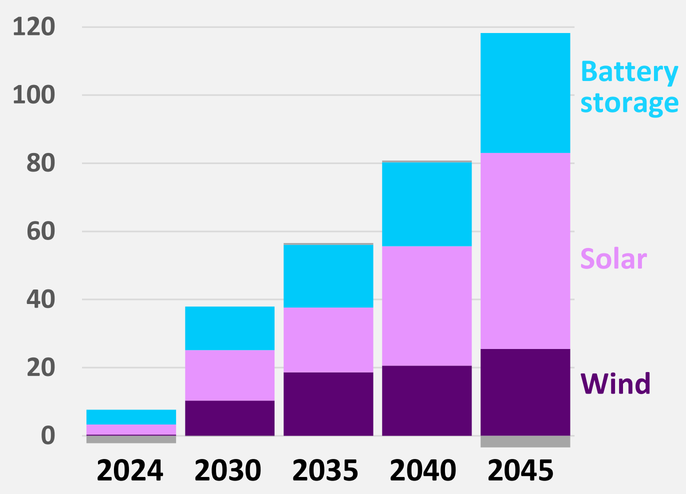


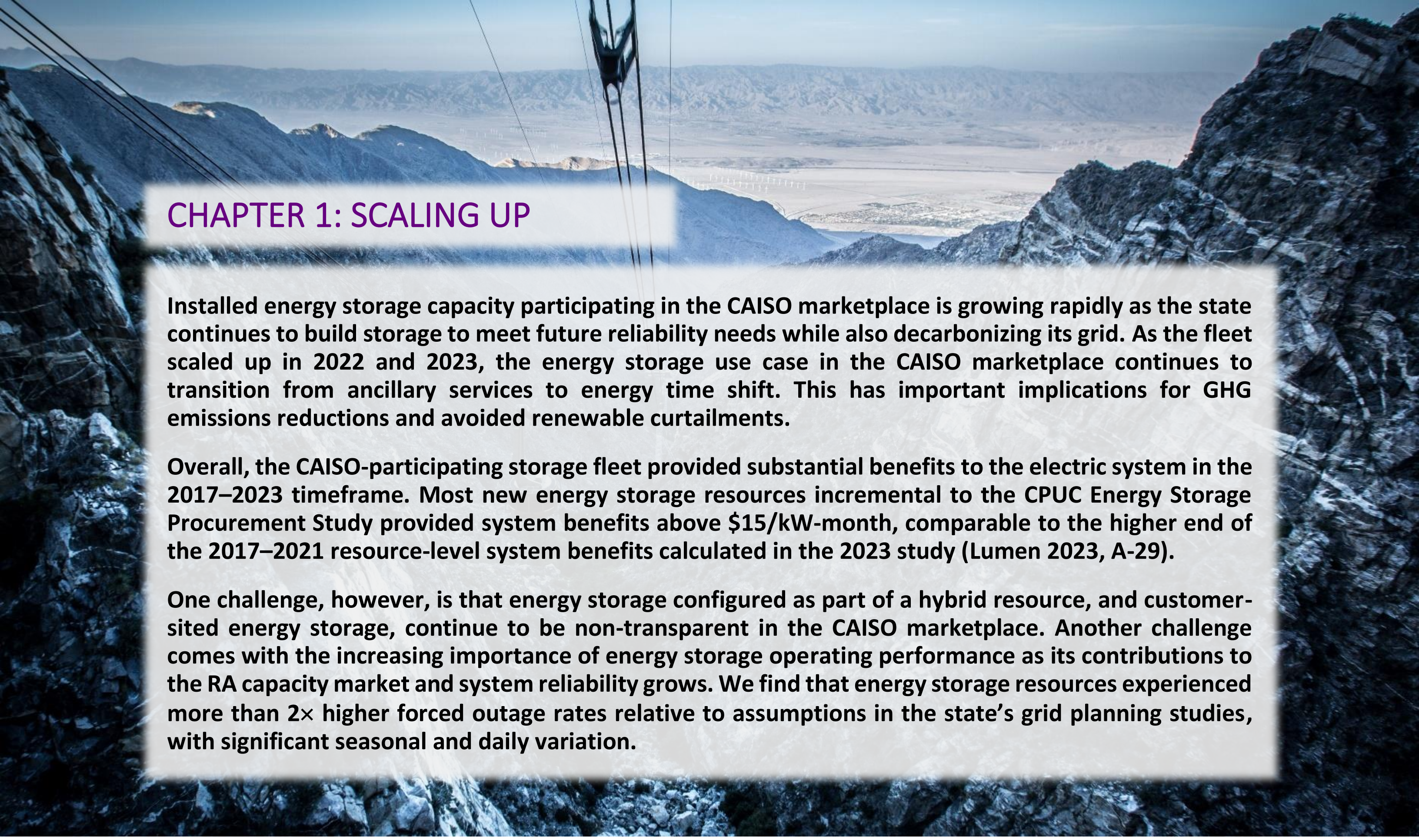
Figure 6: New resource buildout in the CPUC's 2023 Preferred System Plan.

(CPUC 2024a)

In early 2024 and at the conclusion of its 2022–2023 IRP cycle, the CPUC adopted its 2023 Preferred System Plan (Figure 6). Importantly, the 2023 PSP lowers the statewide greenhouse gas reduction trajectory after 2026. Resources to meet reliability and GHG reduction targets include 14,100 MW of new short-duration battery storage (mostly 4-hour), 500 MW new pumped storage, and 400 MW other new long-duration storage installed by 2032 (CPUC 2024a, 68). New resources grow to 18,500 MW short-duration battery storage and 500 MW other long-duration storage by 2035, then to 35,200 MW short-duration battery storage (growth is in 8-hour storage) by 2045 (CPUC 2024a, 68). The plan suggests an average build of 1,290 MW new mostly 4-hour battery storage per year through 2035, then accelerating to 1,670 MW new 8-hour battery storage per year through 2045.

As the energy storage fleet scales and diversifies across the grid, it is doing so in the context of a rapidly evolving energy landscape. Solar PV on the grid is expected to reach nearly 58 GW by 2045. Wind resources—from a mix of in-state, out-of-state, and offshore sites—is expected to reach almost 26 GW by 2045. Based on technology and market trends, a large share of new energy storage and solar PV can be expected to be developed at or near customer sites. And it remains to be seen what other types of both short-duration and long-duration energy storage will achieve commercial scalability along that journey.

Chapter 3 (Recommendations) highlights policy actions that can help address barriers to the benefits of energy storage that are apparent in today's energy storage marketplace, recognizing that the state's electric system needs and market dynamics will continue to change dramatically over time.



CHAPTER 1: SCALING UP

Installed energy storage capacity participating in the CAISO marketplace is growing rapidly as the state continues to build storage to meet future reliability needs while also decarbonizing its grid. As the fleet scaled up in 2022 and 2023, the energy storage use case in the CAISO marketplace continues to transition from ancillary services to energy time shift. This has important implications for GHG emissions reductions and avoided renewable curtailments.

Overall, the CAISO-participating storage fleet provided substantial benefits to the electric system in the 2017–2023 timeframe. Most new energy storage resources incremental to the CPUC Energy Storage Procurement Study provided system benefits above $15/kW-month, comparable to the higher end of the 2017–2021 resource-level system benefits calculated in the 2023 study (Lumen 2023, A-29).

One challenge, however, is that energy storage configured as part of a hybrid resource, and customer-sited energy storage, continue to be non-transparent in the CAISO marketplace. Another challenge comes with the increasing importance of energy storage operating performance as its contributions to the RA capacity market and system reliability grows. We find that energy storage resources experienced more than 2× higher forced outage rates relative to assumptions in the state's grid planning studies, with significant seasonal and daily variation.

The 2023 *CPUC Energy Storage Procurement Study* analyzed energy storage resources across all grid domains, including about 1,100 MW transmission-connected and distribution-connected resources participating in the CAISO marketplace and installed by mid-2021. That study included a forward-looking analysis of expected benefits, in anticipation of fleet growth that is now being realized.

By the end of 2021, actual grid-scale battery energy storage in the CAISO marketplace more than doubled to about 2,500 MW. Then, by the end of 2023, installations reached nearly 7,500 MW. As the fleet scales up, this evaluation seeks to learn from historical actual operations to assess the evolution of California's energy storage industry.

In this chapter we assess the real-world implications for energy, ancillary services, and resource adequacy markets as the energy storage fleet in the CAISO marketplace scaled up dramatically in 2022 and 2023. Our analysis includes inspection of new capacity installed, energy and ancillary services markets, GHG emissions reductions, renewable curtailments, and RA capacity value and contributions. We estimate resource-level total quantified electric system benefits and compare results for different resource types. We also inspect outage patterns throughout the year, with a focus on time periods when the grid is the most strained.

Our analysis validates key observations in the *CPUC Energy Storage Procurement Study* and identifies challenges and needs for policy refinements to improve the effectiveness of the CPUC's planning and procurement activities.

Scope of Historical Analysis

Our historical analysis includes around 6 GW of grid-scale energy storage resources that were online by September 2023 and participated in the CAISO markets under the Non-Generator Resource (NGR) model. Due to several data collection barriers discussed in our report, we excluded hybrid and customer-sited resources in our analysis.

Growth in CAISO-Participating Installations

Energy storage capacity in CAISO is growing rapidly as the state continues to build resources to meet future reliability needs while also decarbonizing its grid. Total energy storage capacity in California is at an unprecedented level compared to other states. As shown in Figure 7 (right), California's operating grid-scale battery storage represents nearly half of all installations in the U.S.

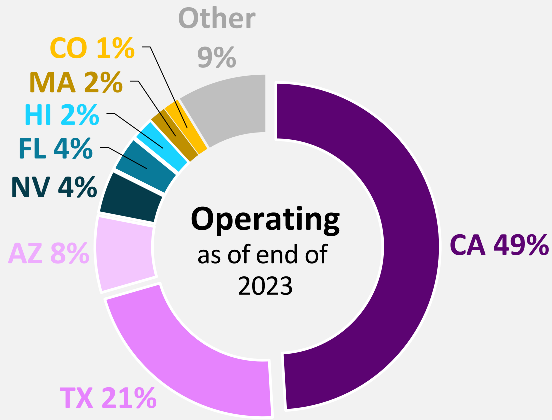


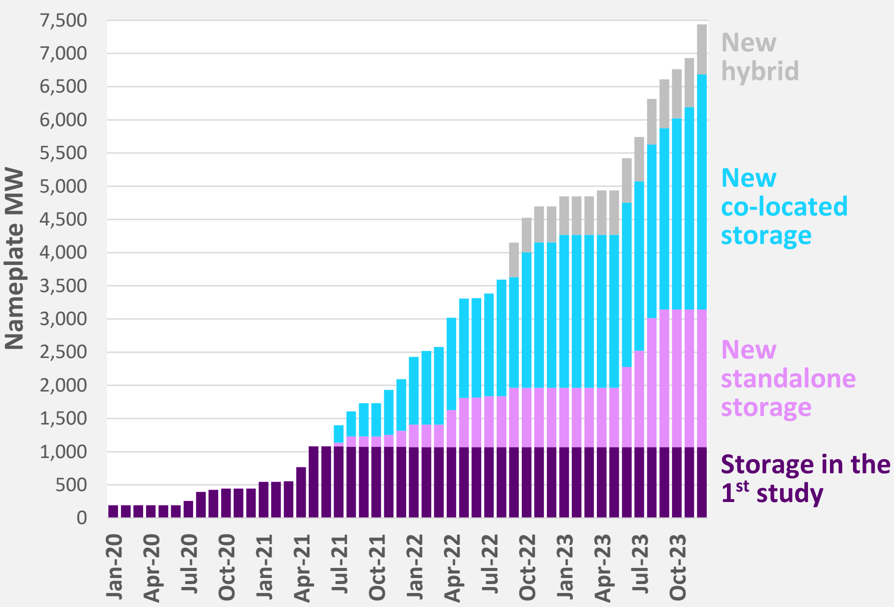
Figure 7: State shares of operating grid-scale battery storage installations in the U.S.

(EIA 2024)

The 2023 *CPUC Energy Storage Procurement Study* analyzed energy storage resources across all grid domains, including about 1 GW of transmission-connected and distribution-connected resources participating in the CAISO marketplace, installed by mid-2021. The grid-scale storage installations grew to nearly 7.5 GW by the end of 2023, largely driven by procurements under the IRP track to meet system reliability needs in California.

Figure 8 (below) shows the installed capacity of the grid-scale energy storage fleet in CAISO. While the resources analyzed in our first study were mostly standalone projects, new energy storage resources are increasingly paired with solar PV. Most of the paired resources are co-located, i.e., energy storage and solar PV share an interconnection but operate and settle in the market separately under different CAISO Resource IDs.

A smaller share of energy storage resources paired with solar PV system is in a hybrid configuration, where the energy storage and solar PV resources are metered and settled as a combined resource at a shared point of interconnection, under a shared CAISO Resource ID.



Notes:

Bars represent installed capacity at the start of each month.

Hybrid values reflect the storage component of CAISO-participating resources based on CPUC data and Lumen research. These MW values are not included in the CAISO's 2022–2023 monthly Key Statistics reports.

CAISO's monthly Key Statistics on battery capacity are estimates, subject to change. The December 2023 value of ~7,500 MW in this chart, for example, includes ~6,300 MW reported in CAISO's November 2023 Key Statistics (estimated value as of 12/1/2023), plus ~500 MW installed during November 2023 and not included in CAISO's estimate, plus ~700 MW of estimated capacity from hybrid resources.

Figure 8: Growth in CAISO-participating grid-scale energy storage capacity.

The characteristics and operations of hybrid and customer-sited energy storage resources that are participating in the CAISO marketplace continue to be non-transparent.

Energy storage in a hybrid configuration, such as those hybridized with solar installations or natural gas-fired generators, do not yet systematically report the operations of their energy storage components for evaluation purposes. For many resources, it is not even clear how much energy storage nameplate capacity is installed and what operating restrictions are in place at the point of interconnection.

Similarly, customer-sited energy storage resources participating in the CAISO marketplace through the Proxy Demand Resource (PDR) model cannot be fully identified through market data as they are aggregated and/or bundled with other types of demand-side resources, and their operations are only partially visible. Underlying resource types and configurations for PDRs are known only to the resource operators and only the CAISO-dispatched portion of discharge can be observed directly from market data.

As foreseen in the 2023 *CPUC Energy Storage Procurement Study*, lack of these data creates significant barriers to analysis of these types of resources, especially within the relatively shorter timeframe of this study.

Due to these data collection barriers, we excluded hybrid and customer-sited storage resources from our historical analysis.

Energy and Ancillary Services Market Value and Trends

We expanded our 2017–2021 historical energy storage evaluation in the *CPUC Energy Storage Procurement Study* to include operations and market results for 2022–2023. During this period, the storage fleet in the CAISO's market experienced significant growth, reaching over 6 GW of installed capacity.

Energy storage can provide a suite of wholesale energy and ancillary services market benefits. We rely on actual metered data and resource-specific settlements in the CAISO's day-ahead and real-time markets to calculate energy and ancillary services value of grid-scale resources in CAISO.

Figure 9 shows the capacity-weighted average market values for the energy storage fleet. During 2018–2020, high revenue opportunities in the CAISO regulation market attracted many of the resources and resulted in use cases more focused on ancillary services. In the 2023 *CPUC Energy Storage Procurement Study*, we highlighted the early signs of saturation in the ancillary services market and use case due to the rapid growth of storage resources connected to the CAISO system.

In 2022–2023, we observe a continuation of this trend, with the share of storage capacity used for ancillary services declining, while the wholesale market value proposition shifts to bulk energy time shift.

Energy storage fleetwide average ancillary services market value continued to decrease, from about $4/kW-month in 2021, to $1.5/kW-month in 2023. Concurrently, energy value continued to increase, from around $3.5/kW-month in 2021, to $5/kW-month in 2023.

Most CAISO-participating energy storage resources now regularly charge at low-priced periods in the day and discharge at high-priced periods in the evening. This transition in market use case has significant implications for the energy storage fleet's contributions to reducing GHG emissions and facilitating renewable integration, as we discuss next.

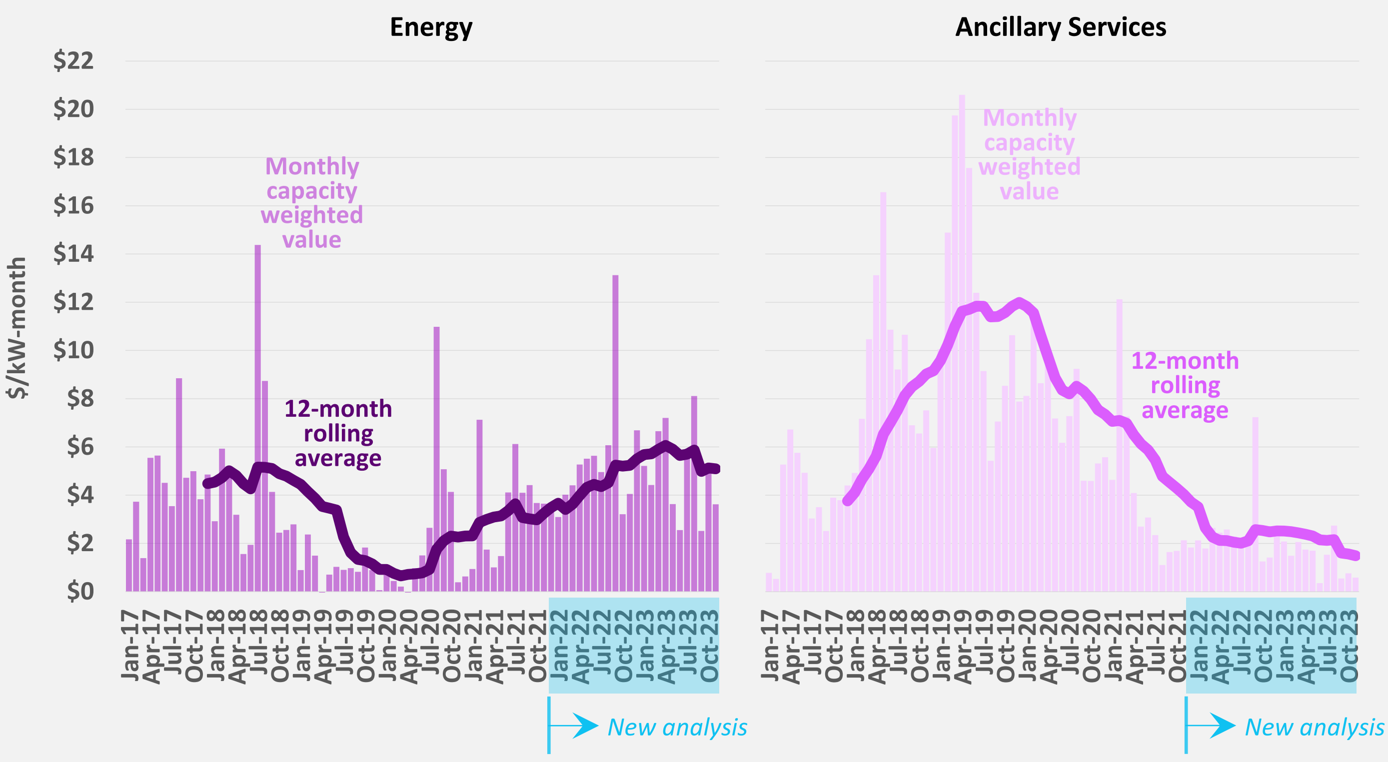


Figure 9: Average CAISO energy and ancillary services revenues across energy storage fleet (2023 $).

GHG Emissions Impacts

Energy storage resources reduce GHG emissions at the marginal rate when discharging and increase emissions at the marginal rate when charging. We rely on the historical real-time marginal GHG signal created by WattTime and adopted by the CPUC to align resource performance in the Self Generation Incentive Program with the program's GHG emissions reduction goals (CPUC 2019).

For energy storage resources to reduce GHG emissions, they need to be highly efficient, and their use cases should allow shifting bulk energy from periods with low GHG emissions intensity to periods with high GHG emissions intensity. The *CPUC Energy Storage Procurement Study* highlighted the drawbacks of the frequency regulation use case resulting in GHG emissions increases. With more emphasis on energy time shift, the majority of CAISO's storage fleet is reducing GHG emissions.

The non-hybrid CAISO-participating energy storage resources enabled nearly 1 million tonnes of GHG emissions reductions during the 12-month period ending in November 2023. The subset of resources analyzed in the 2023 *CPUC Energy Storage Procurement Study* provided almost 200,000 tonnes of those reductions. Newer energy storage resources scaled up those benefits as the fleet grew, providing close to 800,000 tonnes of additional GHG emissions reductions in that 12-month period.

Figure 10 shows the resource-specific results. On average, energy storage co-located with solar PV provided higher GHG emissions reduction benefits than standalone energy storage. Among the newer resources analyzed, storage co-located with PV enabled 19 tonnes/MW-month in GHG emissions reductions, compared to 10 tonnes/MW-month for standalone storage. This difference is partly due to more operational focus on energy time shift, and partly due to location. Most co-located energy storage resources are in southern California, where the GHG reduction potential tends to be higher due to lower marginal GHG rates during the day.

GHG emissions reduction values are based on allowance prices observed in the cap-and-trade market and already reflected in the CAISO's market prices and energy value of storage projects. As discussed in our first study, electric sector GHG targets implemented in the IRP may require investments at a cost higher than the California's cap-and-trade prices, but this incremental cost (GHG adder) is estimated to be zero through 2030 due to the amount of renewables already procured for reliability and tax credits.

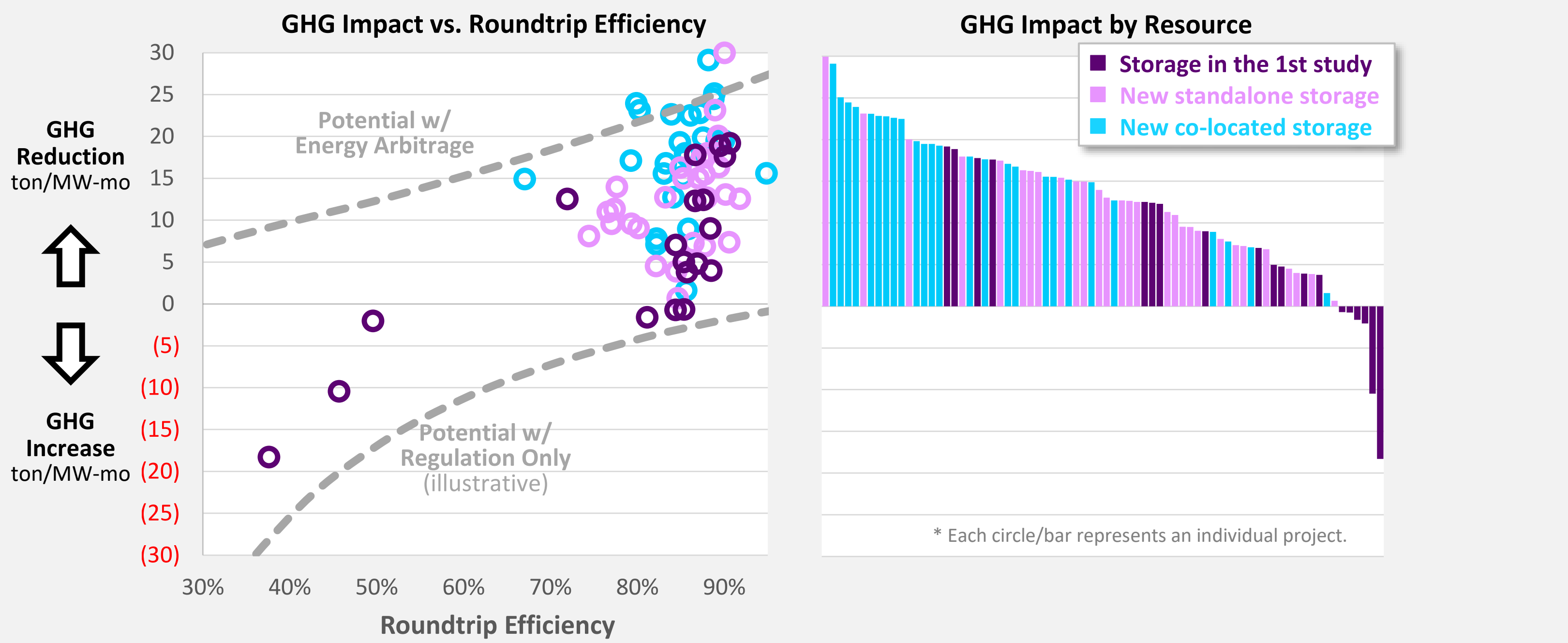


Figure 10: Estimated average GHG emissions impact of energy storage resources in CAISO.

Renewable Curtailment Impacts

Energy storage can reduce renewable curtailments by charging to mitigate oversupply conditions. The avoided renewable curtailments reduce the need (and cost) to procure additional renewable energy credits to meet Renewables Portfolio Standard (RPS) and other clean energy targets. We expect full utilization of renewable output will become more challenging over time as California continues to decarbonize its electric system.

We estimate the impact of energy storage on renewable curtailments based on their net charge during intervals with actual curtailments, using system data provided by CAISO. We utilize historical nodal real-time LMPs to determine if an energy storage resource is in a curtailment zone when curtailment events are driven by local grid congestion and not systemwide oversupply.

Figure 11 shows the resource-specific impacts on renewable curtailments. The results highlight that the energy storage fleet is increasingly helping with the integration of renewable energy resources by mitigating oversupply.

Avoided renewable curtailments are significantly higher for the newer resources, especially energy storage co-located with PV. These resources are sited in areas experiencing higher curtailments and they charge more regularly when oversupply conditions emerged.

We quantify the benefits for avoided renewable curtailments using the RPS adders published in CPUC's Power Charge Indifference Adjustment reflecting incremental value of RPS-eligible energy based on historical transactions (CPUC 2023c). The RPS adders were in the range of $13 to $16.5/MWh through 2022, but increased to $30/MWh recently in 2023, which indicates that the cost of meeting the state's RPS is rising.

These results translate to RPS benefits of up to $1.5/kW-month for the top resources and around $0.5/kW-month for the energy storage fleet, on average.

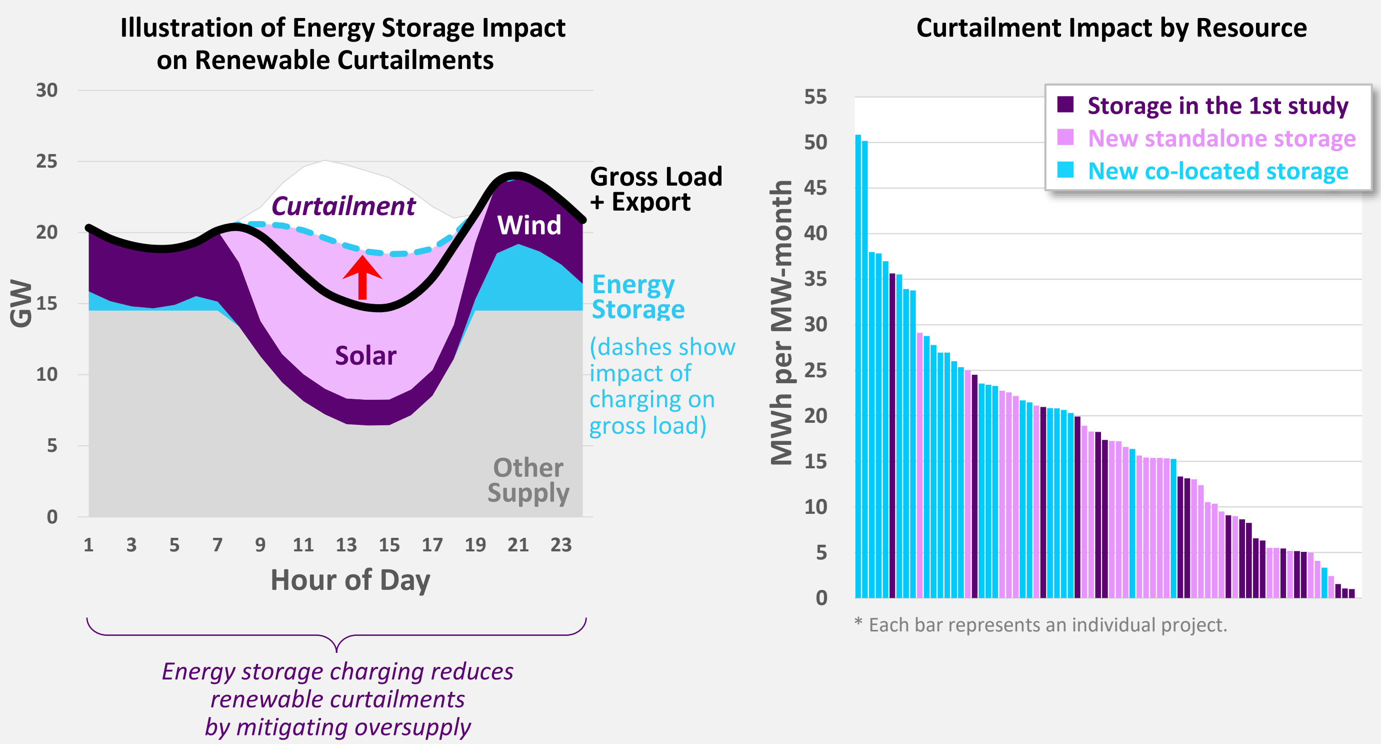


Figure 11: Estimated average renewable curtailment impact of energy storage resources in CAISO.

RA Capacity Value and Contributions

Energy storage resources can be available to discharge during peak periods to help meet system Resource Adequacy (RA), local RA, and flexible RA capacity requirements to ensure grid reliability in California.

Our analysis of RA capacity value reflects the avoided cost of the market alternative to each energy storage resource analyzed, which varies based on its location and circumstances under which it was procured. Most energy storage resources in our study were procured to address various grid reliability and resource adequacy needs. Specific RA needs, development timelines, and available alternatives depend on the procurement track, thus require a different counterfactual for the purposes of estimating RA capacity value. For each storage procurement track, we reviewed numerous documents including the underlying procurement orders, utility applications, solicitation materials, and related data and reports to develop counterfactual cases that reflect the specific market environment under which the resources were procured.

The growth of energy storage installations in 2020 through mid-2021 was driven by various procurements to address local capacity needs in load pockets with a relatively high RA value. Most grid-scale projects included in our first study were procured for local reliability to replace retirement of once-through-cooling plants, to address challenges caused by the natural gas leak at Aliso Canyon, or to eliminate the need for reliability-must-run (RMR) contracts. An overview of these procurement tracks, counterfactual cases, and estimated RA values ranging from \$7 to \$20 per kW-month are provided in the 2023 *CPUC Energy Storage Procurement Study*.

Energy storage installations from the second half of 2021 through 2023 are primarily a result of the procurement orders to address emerging system reliability needs identified in CPUC's Integrated Resource Planning (IRP) studies. To estimate the RA capacity value of these projects, we relied on historical RA contract and price data compiled by the CPUC based on information submitted by the LSEs.

First, we filter the data for annual strips to get an estimate of average year-around RA prices, excluding short monthly or seasonal RA contracts. Then, to approximate marginal RA values, we use the 90th percentile (P90) of the RA prices for contracts. Here, the use of P90 rather than the highest price is to exclude possible outliers of small RA contracts priced at a premium.

Figure 12 summarizes the results. The prices reflect the combined value of system and local RA capacity attributes, rising from \$3/kW-month in 2018 up to over \$10/kW-month by 2022. Current prices are even higher. The 2023 market price benchmarks in CPUC's latest available Power Charge Indifference Adjustment (PCIA) show average system RA price at \$14.37/kW-month (CPUC 2023c), which is nearly 2x higher than the level published with prior PCIAs.

While storage can also provide flexible RA to meet forecasted net load ramps, our initial study found no historical price premiums for this service. Thus, we did not incorporate any additional value for it, beyond what is already captured under the system and local RA capacity values.

	2018	2019	2020	2021	2022
CAISO System	\$2.8	\$3.1	\$7.9	\$8.2	\$10.9
Bay Area	\$3.3	\$4.7	\$8.1	\$8.3	\$13.6
Big Creek-Ventura	\$3.9	\$4.7	\$8.1	\$8.4	\$12.4
LA Basin	\$3.6	\$5.5	\$8.0	\$9.0	\$14.0
San Diego-IV	\$2.7	\$4.1	\$8.0	\$8.1	\$16.4

Figure 12: Estimated marginal RA value based on bilateral RA contracts (2023 \$/kW-month).

In recent history, CAISO has experienced two extreme heat waves leading to system-level emergency declarations. The overall scale and contributions of energy storage fleet in these events were very different.

During August 2020, CAISO had 337 MW of grid-scale battery storage. Most resources still focused on ancillary services and aggregate NQC was 37% of installed MW (Figure 13, top).

By September 2022, CAISO's battery storage fleet grew to 3.7 GW. Most of the new resources focused on energy time shift, regularly charging midday and discharging during evening peak period. Aggregate NQC was 84% of installed MW (Figure 13, bottom). Despite the software issues CAISO had at that time, which prevented storage resources from charging early in the day, the energy storage portfolio provided significant capacity during emergency events.

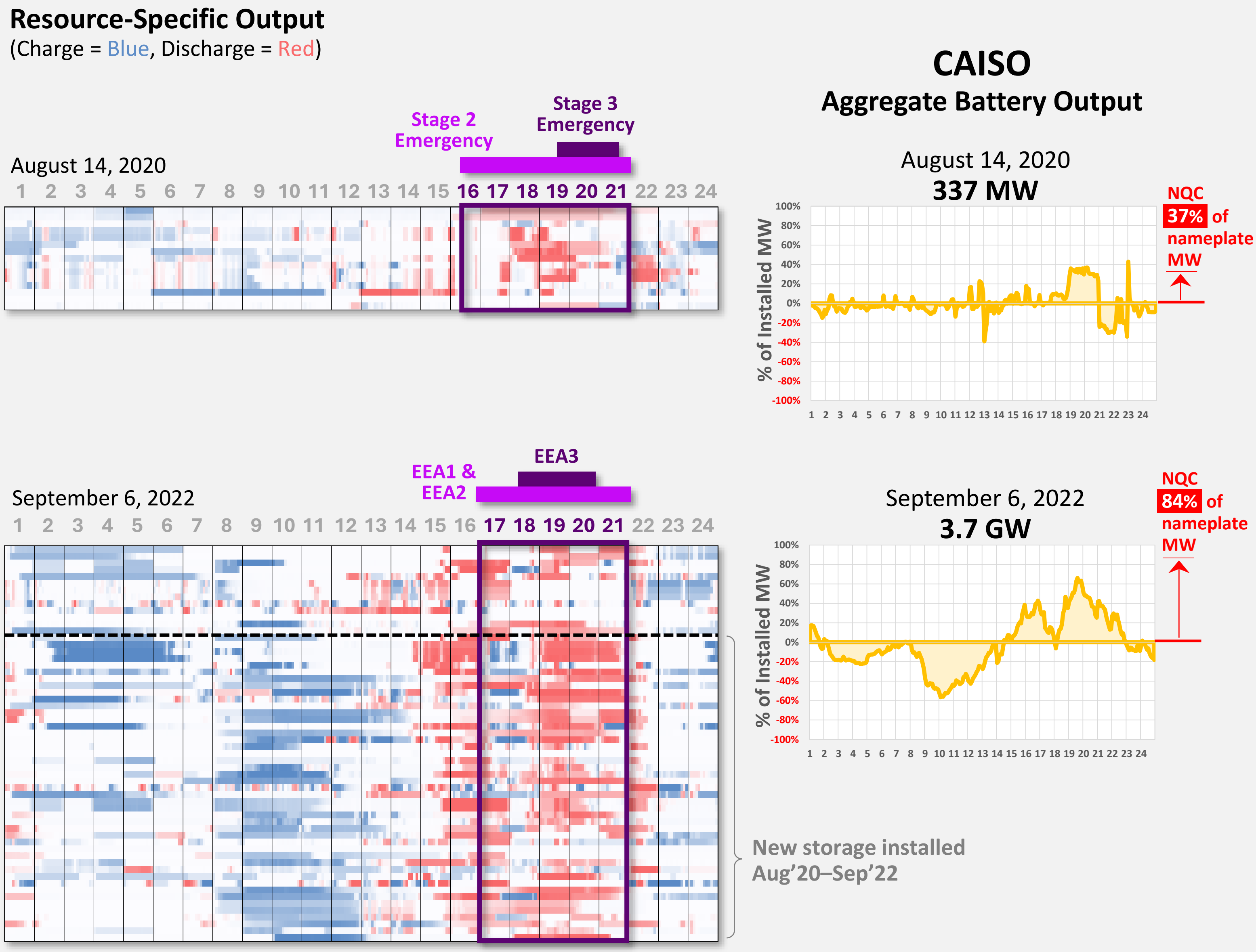


Figure 13: CAISO battery storage output during emergency events on August 14, 2020 and September 6, 2022.

T&D Investment Deferral Value

Energy storage resources can defer the need for new transmission investments by offsetting peak demands on the transmission system. If interconnected to the distribution system, energy storage can defer the need for new distribution investments by reducing local peak loading on the distribution grid. As discussed in the 2023 *CPUC Energy Storage Procurement Study*, and despite the existing Distribution Deferral Investment Framework discussed in **Chapter 2 (Crossing Bounds)** of this report, these storage use cases are still in early pilot and demonstration phase.

Overall, none of the resources in our historical analysis deferred an actual transmission or distribution investment, so these benefit streams are set to zero.

Energy storage resources procured as non-wires alternatives have faced major challenges as the size and timing of the identified needs have changed over time, and the development plans and utility-contracted use cases were not flexible to adjust (Lumen 2023, 61–62).

In the 2020–2021 Transmission Planning Process, CAISO identified two storage projects as preferred non-transmission alternatives to address reliability needs in the PG&E service area: a 95 MW 4-hour battery storage at the Kern-Lamont 115 kV system and a 50 MW 4-hour battery storage at the Mesa 115 kV substation. PG&E's procurement efforts, pursuant to CPUC's Decision 22-02-004, so far have not been successful (PG&E 2022a; PG&E 2022b).

Three projects originally procured for distribution deferral are included in our historical analysis but not assigned any distribution deferral value: Acorn I and two Wildcat I projects. As of late 2023, none have yet been used for distribution deferral. **Chapter 2 (Crossing Bounds)** discusses challenges with the distribution deferral use case in more detail.

Customer Outage Mitigation Value

Customer outage mitigation is a crucial component of resilient electricity service to serve essential loads and to protect vulnerable customers, communities, and critical facilities. Distribution-connected storage resources can improve resilience by supporting islanding and microgrid capabilities for sections of the distribution grid and thus help to mitigate the risk of power interruptions at the community level. Storage resources interconnected behind the utility meter can also provide backup power to mitigate impacts of power outages.

The majority of the grid-scale storage resources in the CAISO markets are not sited or configured to provide outage mitigation, which underscores the challenges with cross-domain value-stacking. However, some more recent distribution-connected microgrids which include energy storage are designed to support customer resilience while also providing bulk grid services.

Due to their hybrid participation and/or limited operating history, these new microgrid projects were either not included in the historical benefits analysis, or were not assigned an outage mitigation value in dollar terms. However, we did include these projects and discussed their unique characteristics as a part of the cross-domain multi-use application (MUA) case studies; *see* **Chapter 2 (Crossing Bounds)** and **Appendix E (Case Study Fact Sheets)**.

Total Quantified Benefits

Figure 14 shows the total quantified electric system benefits over the 2017–2023 timeframe. The top chart highlights the aggregate benefits, color coded by project group, while the bottom chart provides a breakdown of benefit metrics.

The results demonstrate the CAISO-participating energy storage fleet provided substantial and increasing benefits to the electric system. Across the resources analyzed, we estimate median quantified system benefits at $21/kW-month, with individual results ranging from $3/kW-month to $36/kW-month. Quantified system benefits include avoided cost of energy, ancillary services, system and local RA, and RPS-related investments.

Most new energy storage resources incremental to the 2023 *CPUC Energy Storage Procurement Study* provided system benefits above $15/kW-month, comparable to the higher end of the 2017–2021 resource-level system benefits calculated in the 2023 study (Lumen 2023, A-29).

The relatively high benefits of newer resources, higher system RA capacity value on a $/kW-month basis, and higher energy value are all interrelated and contribute to an increasing trend of system benefits from the energy storage fleet.

Appendix A (Historical Energy Storage Benefits) provides more detail on these calculations. The appendix also includes project scores reflecting each resource's contributions towards AB 2514 goals of grid optimization, renewables integration, and greenhouse gas (GHG) emissions reductions.

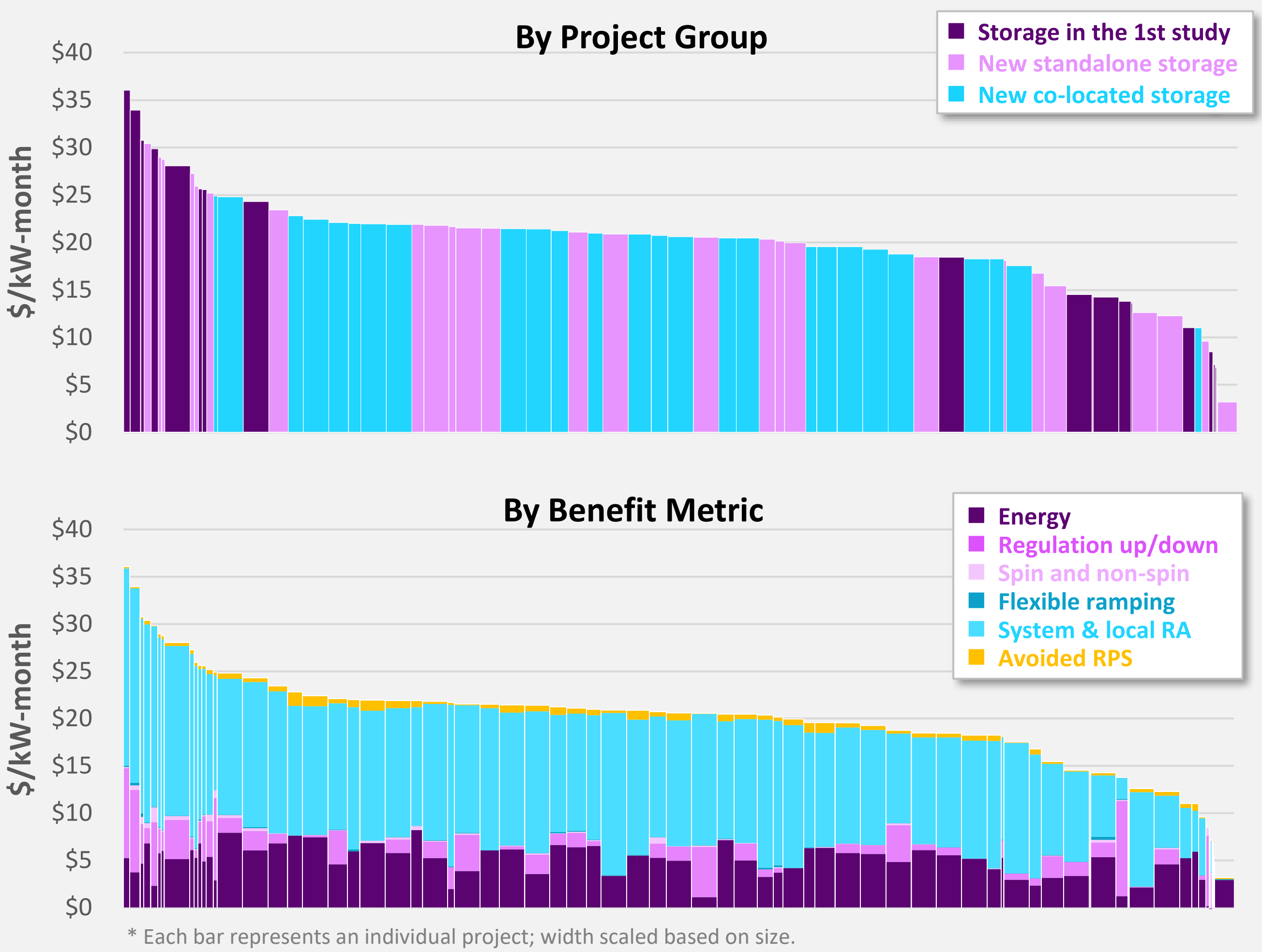


Figure 14: Estimated system (gross) benefits of energy storage resources in CAISO (2023 $).

Outage Patterns in Large-Scale Battery Energy Storage Systems

We analyzed the actual resource-specific capacity derates and outage events published by the CAISO for the 2022–2023 period to understand availability and performance of the energy storage fleet during grid-stressed periods.

Average fleetwide outages over time

Figure 15 shows the estimated capacity-weighted average outage rates for the battery storage fleet over time and by outage type. The CAISO designates resource outages as either planned or forced based on how far in advance the outage is reported. Outage requests within 7 days prior to the start of the outage event are designated as forced outages; remaining outages are designated as planned. Work type (e.g., "Plant Trouble") provides additional information on the nature of the outages recorded by the CAISO.

Forced (unplanned) plant derates and outages reduced the available capacity of battery storage resources in the CAISO marketplace by an average of 11.5% over the two-year period analyzed. Plant trouble, including equipment failures, was the primary cause of unavailable capacity during these forced outages. Fleetwide average forced outage rates were higher in 2022, at around 14%, relative to 10% in 2023.

These results are generally consistent with data the CAISO's Department of Market Monitoring (DMM) presented in a January 16, 2024 resource adequacy working group meeting, showing the availability of the grid-scale energy storage fleet at 90% in 2023 (CAISO 2024b).

Safety events at Moss Landing facilities had a striking impact on overall fleet performance, especially September 2021 through May 2022. These events contributed to the relatively high fleetwide outage levels shown in Figure 15 during January–May 2022. Both forced and planned outage rates are impacted, since extended events can be reclassified from forced to planned outages after an initial period.

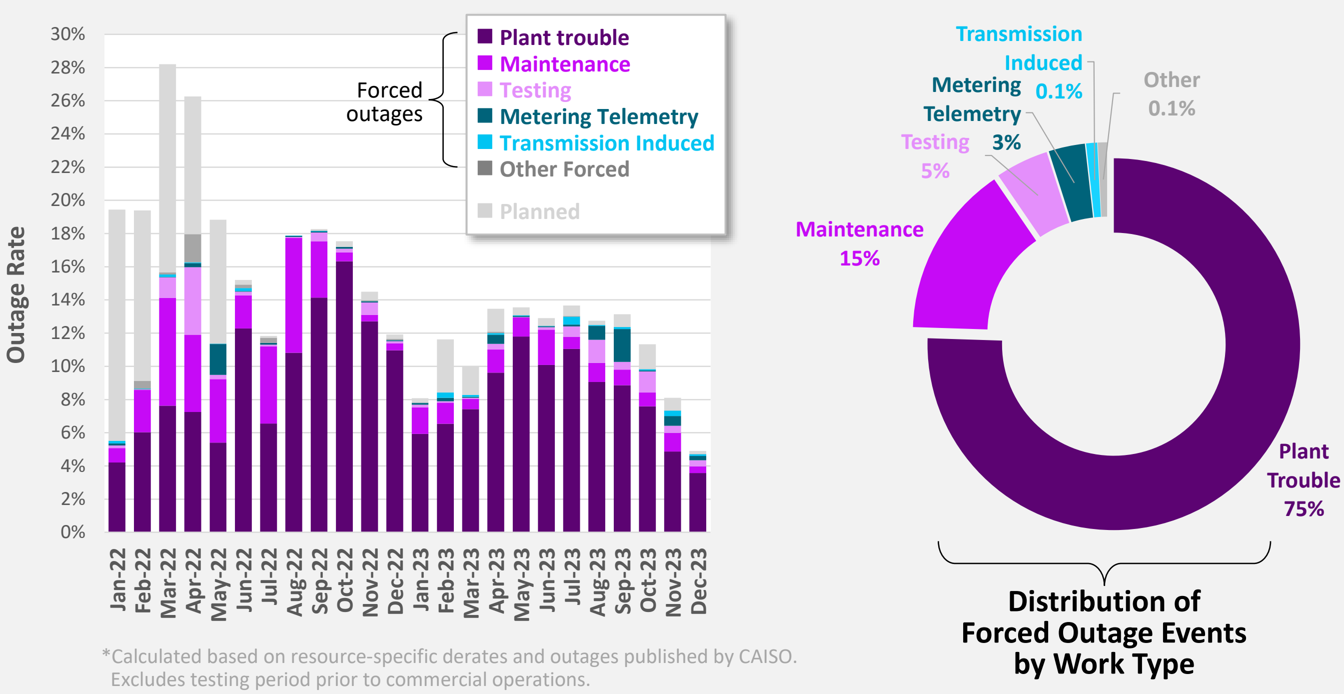


Figure 15: Capacity-weighted average outage rates of the battery storage fleet in CAISO.

Outages during CAISO grid emergency periods

We inspect energy storage performance during actual grid emergency periods to further validate our findings on average outage rates and patterns, and in terms of the classification of forced outages.

Planned versus forced outage is an important distinction in long-term resource planning. For that purpose, planned outages can be rescheduled if a grid emergency is anticipated, while forced outages tend to be unexpected and cannot be rescheduled in a grid emergency. With CAISO's classification, it is not immediately clear for our purposes which types of forced outages can be postponed when the system has its greatest need for capacity.

Figure 16 shows the aggregate hourly forced outage profile of the energy storage fleet over an extended heat wave in September 2022 resulting in CAISO system emergency declarations for five consecutive days. During CAISO's emergency events, 290–760 MW of energy storage capacity was unavailable due to derates and outages.

Inspection of this 5-day heat wave yields results consistent with our broader analysis of outages during peak periods. With 3.7 GW of total energy storage capacity installed at the time excluding hybrids, hourly outage rates range from 8% to 20%, and average 12%, across emergency hours.

The figure also shows outages by work type. Plant troubles related to equipment failures were responsible for most outages during the CAISO emergency period analyzed. Other types of work, including plant maintenance and unit testing accounted for non-trivial amounts of the outages experienced by the energy storage fleet. This indicates that some plant maintenance and testing are not actually being rescheduled in grid-stressed periods and thus are appropriately categorized as forced for long-term planning purposes.

Furthermore, most of the unavailable capacity for plant maintenance and testing during emergency hours came from energy storage resources with a net qualifying capacity for September 2022.

With these findings, we conclude that it is appropriate to include all CAISO-designated forced outage events in our analysis, and that exclusion of any forced outages based on work type (e.g., maintenance) will inadvertently understate availability of the planned energy storage portfolio when the system has its greatest need for capacity.

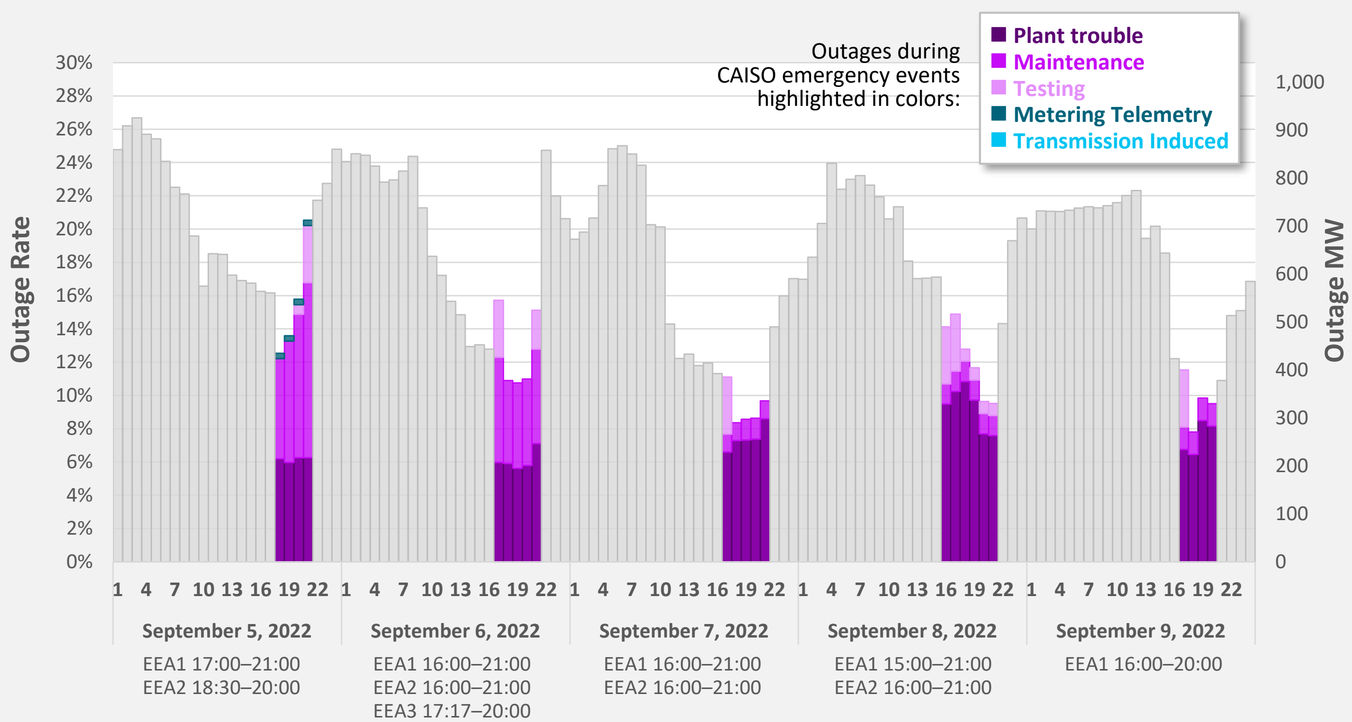


Figure 16: Aggregate hourly forced outage profile of the battery storage fleet in CAISO, September 5–9, 2022.

Outages by month and peak period

The 2022–2023 historical data indicate significant variation in monthly and daily forced outage patterns of the battery storage fleet participating in the CAISO marketplace.

As illustrated in Figure 17, forced outage rates have been consistently higher in spring and summer months compared to the rest of the year. Specifically, during August and September, storage forced outage rates averaged 3 percentage points above annual levels.

This is partly offset by 2 percentage points lower outages during evening peak hours. Throughout the day, storage capacity derates and outages have been lower in the evening hours compared to morning and late-night periods. While it is not clear exactly why outage rates vary by time of day, we believe it could be related to the effects of battery state of charge (SOC) levels on maximum power output, and other technical and operating constraints, managed through outage reports.

Considering these seasonal and daily patterns, we estimate that, during 2022–2023, the non-hybrid fleetwide actual battery storage forced outage rate in August and September evening peak periods (hour ending 17 through 21) averaged 12.6%—one percentage point higher than the average across all months and hours of the year.

These results highlight that actual realized average forced outage rates of the CAISO-participating battery storage resources were significantly higher than long-term resource planning assumptions. For example, the CPUC's IRP models assume a 5% expected forced outage rate for battery storage (CPUC 2023d, 131), based on early data for the energy storage fleet just as it was reaching the GW scale.

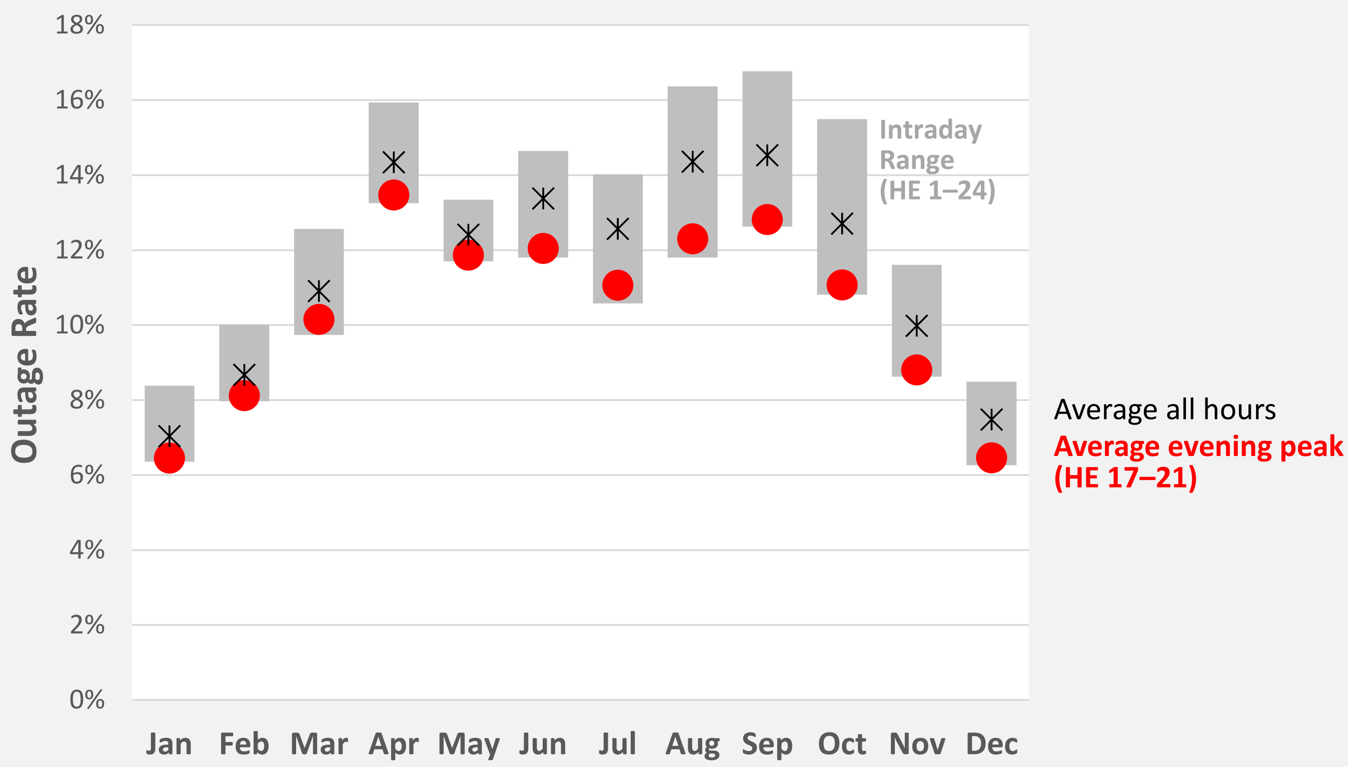


Figure 17: Monthly and daily variation of forced outage rates of the battery storage fleet in CAISO.

Distribution of daily forced outages during August–September peak period

For grid planning, it is important to consider not only the average outage rates, but also the range of possible outcomes. While the fleetwide average forced outage rate provides a useful metric, it does not fully capture the risks associated with more widespread simultaneous outage events across the fleet.

If outage events were all random and independent across resources, the percentage variability of the aggregate fleetwide outage rates would decline as the fleet grows. This is due to increased diversity of resources and outage events in a larger fleet. For example, if the fleet had only one resource, the outage rate would be either 0% or 100% each day, excluding derates. When the total number of resources in the fleet rises to, say, 100 or more, the fleetwide outage rates should become considerably less volatile, clustered closer to expected outage levels.

If, on the other hand, the outage events share a common driver, such as weather, then it becomes more probable for a disproportionately large share of the fleet to experience outages simultaneously, thereby increasing the likelihood of more extreme outcomes.

We have not analyzed the impacts of weather on fleetwide battery storage outages or correlations of outage events across resources. However, the seasonal outage patterns described earlier could be indicative of such interactions, which warrants further investigation as more operational data becomes available in the future.

Figure 18 shows the distribution of forced outage rates during the evening peak hours from 4pm to 9pm (HE 17–21). The results highlight a higher average and a fatter upper tail for outages in August and September (Figure 18, right), compared to the rest of the year (Figure 18, left).

During August–September evening peak periods, the forced outage rate of the battery storage fleet was 15% or higher in about 1 out of every 5 days over the two-year period analyzed. In the same timeframe, the observed fleetwide forced outage rates have reached 20% or higher in 1 out of every 16 days.

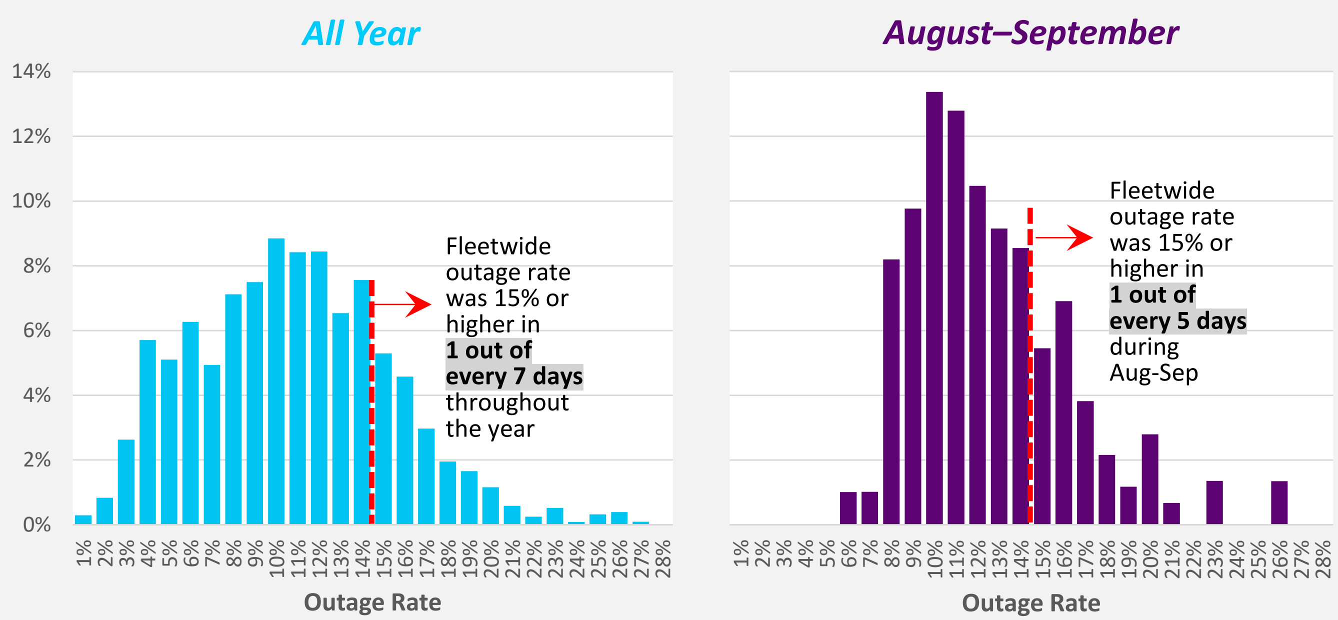


Figure 18: Frequency distribution of forced outage rates during evening peak periods (HE17–21).

Key Observations for Chapter 1 (Scaling Up)

System reliability and resource adequacy needs continue to drive significant growth in transmission-connected energy storage capacity.

A large share of new energy storage resources in the CAISO marketplace is paired with solar PV.

The characteristics and operations of hybrid and customer-sited energy storage in the CAISO marketplace continue to be non-transparent.

The predominant energy storage use case in the CAISO marketplace continues to transition from ancillary services to energy time shift.

With increased focus on energy time shift, CAISO-participating energy storage resources provide significant GHG emissions reductions.

On average, energy storage co-located with solar PV provides higher GHG emissions reduction benefits than standalone storage.

Energy storage resources, especially ones paired with PV, are also helping with renewable integration by reducing curtailments.

RA capacity value accounts for an increasing share of the total quantified benefits provided by the energy storage fleet.

Overall, the CAISO-participating battery energy storage fleet provides substantial and increasing system benefits.

With increased focus on energy time shift, the RA capacity contributions of CAISO-participating energy storage resources during grid-stress periods have improved.

Actual average forced outage rates of CAISO market-participating battery energy storage are significantly higher than long-term resource planning assumptions.

Actual forced outage rates during August and September peak periods are higher than the annual average, and they indicate a larger share of high-outage days than the rest of the year.

The historical record is too short to analyze year-to-year variability in CAISO market-participating battery energy storage outages, but Moss Landing safety events had a striking impact on overall fleet performance September 2021 through May 2022.

CHAPTER 2: CROSSING BOUNDS

Distribution-connected and customer-sited energy storage resources also have the potential to provide benefits at a larger scale, but their development pathways and the services they provide cross traditional industry boundaries and require novel policy, planning, and procurement mechanisms.

We focus on addressing challenges with two types of resources capable of reaching the GW scale through cross-domain multi-use applications.

Community-level resources developed for community outage mitigation are closer to customers but they are still connected to the distribution system. These resources offer distinct advantages and could be broadly scalable across the state—but they face significant barriers. We find that stacking RA capacity and energy value with outage mitigation is a scalable use case and could significantly reduce financial barriers to community- and customer-driven resilience solutions.

The visibility of a large number of energy storage distribution deferral opportunities is limited by challenges with distribution deferral planning and procurement processes. Value-stacking RA capacity and energy services is an important ingredient to the economic feasibility of distribution deferral, and our analysis demonstrates this cross-domain use case is feasible and beneficial.

The *CPUC Energy Storage Procurement Study* highlights low success rates and lack of market acceleration in distribution-connected energy storage resource development, despite: (a) growing needs for community resilience solutions, (b) a need for distributed solutions to natural gas-fired peaker replacements in order to avoid or reduce transmission upgrades for otherwise cost-effective resource solutions, (c) the unique ability to produce value streams both to the transmission system and distribution system, and (d) evidence that these smaller distributed resources can produce high ratepayer value.

The 2023 study also highlights a disconnect between customer-sited energy storage resources and services they could provide to the broader grid, coupled with increasing pressure for financially accessible customer-sited resilience solutions. Value-stacking across grid domains, through multiple use applications (MUA), has been demonstrated in the market, and it is key to overcoming the financial barriers to distribution-connected and customer-sited resources. But many questions remain about feasibility of cross-domain MUAs to scale up in the number of installations, and in the benefits they provide to both ratepayers and customers.

In this chapter we explore a set of case studies designed to improve the CPUC and stakeholders' understanding of what types of cross-domain MUA are feasible and likely scalable; to what degree a resource can provide RA capacity service when it is built for the purpose of outage mitigation or distribution deferral (or vice versa); and how MUA operations can optimize cross-domain services when the need for those services conflict.

Scope of Cross-Domain MUA Analysis

We utilize four types of data to develop and learn from a set of cross-domain MUA case studies:

(1) Circuit-level outage data at 8 selected locations to understand a diversity of outage risks faced by customers,
(2) The characteristics of 63 individual distribution deferral opportunities (DDOs) identified by utilities,
(3) System RA capacity and local (sub-LAP) energy market prices, and
(4) The characteristics of 10 actual energy storage projects in **Appendix E (Case Study Fact Sheets).**

Figure 19 shows the scope of possible services provided by transmission-connected, distribution-connected, and customer-sited energy storage. The focus of this chapter is on the specific grid services emphasized in Figure 19 (purple areas). We model and analyze the value-stacking opportunities of distribution-connected resources (middle column).

However, the architecture of this table does not fully capture the complexities of outage mitigation services provided to customers. Accordingly, we also emphasize services from customer-sited resources (last column) due to the important relationship between distribution-connected resources and outage mitigation services provided directly to customers through a combination of onsite residential resource, onsite non-residential resources, and community-level resources.

To estimate cross-domain MUA opportunities, operations, and value we simulate energy storage operations under alternative MUA scenarios using an hourly (8,760 consecutive hours for a year) dispatch optimization model.

		Grid Domains		
	Services to Grid and Customers	**Transmission**	**Distribution**	**Customer**
Energy & AS Markets and Products	Energy	✓	**✓**	**✓**
	Frequency Regulation	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Flexible Ramping	✓	✓	✓
	Voltage Support	✓	✓	✓
	Blackstart	✓	✓	✓
Resource Adequacy	System RA Capacity	✓	**✓**	**✓**
	Local RA Capacity	✓	✓	✓
	Flexible RA Capacity	✓	✓	✓
T & D Related	Transmission Investment Deferral	✓	✓	✓
	Distribution Investment Deferral		**✓**	✓
	Microgrid/Islanding		**✓**	**✓**
Site-Specific & Local Services	TOU Bill Management			✓
	Demand Charge Management			✓
	Increased Use of Self-Generation			✓
	Backup Power			**✓**

Figure 19: Scope of possible energy storage services, and focus of cross-domain MUA analysis (purple).

The Customer Outage Problem

Outage trends and risks. Figure 20 shows a metric that multiplies the grid reliability metrics SAIDI (average duration of outages per year) by SAIFI (average frequency of outages per year) to approximate system-wide average total outage hours per year experienced by customers. The figure blends metrics reported to the CPUC by the 3 large IOUs, both on major event days (MEDs) and non-MEDs. The transmission-level interruptions are adjusted to include rolling blackouts in 2020.

The figure illustrates how most (99%) customer outage experiences and risks are driven by hazards to—and failures on—the distribution system.

The figure also demonstrates why transmission-connected resources won't necessarily solve distribution-level grid failures, and why resilience solutions must include investments in the distribution system and customer sites, including distributed energy resources (DERs).

One drawback from these average system-wide reliability indicators is that they do not show the wide range of customer experiences with electricity service interruptions, nor do they provide information on how outages can have a different degree of impact across different customers and communities.

Another limitation to these indicators is that they do not fully reflect the recent and likely future acceleration of hazards to the grid and grid failures, particularly as climate-driven hazards amplify and as grid infrastructure ages.

Several CPUC efforts and proceedings aim to more deeply understand and address risks to the reliability and resilience of electricity service to customers, including efforts towards climate adaptation and vulnerability assessments, grid resiliency and microgrids development, and integrated resource planning.

Outage mitigation solutions must crucially be tailored to the unique reliability and resilience needs of individual customers and communities. This includes consideration of the current and future underlying hazards driving outage risks, key failure points on the grid, outage characteristics, and customer and community vulnerabilities and risk tolerances. A series of workshops and informational sessions led by the CPUC's Grid Resiliency and Microgrids team develops a 4-Pillar Methodology reflecting best practices in resilience planning, and explores several real-world applications and case studies using that methodology (CPUC 2024b).

The role of energy storage. As a highly modular and flexible resource, energy storage provides many types of tailorable outage mitigation solutions for individual customers, for communities, and for parts of the distribution system. Energy storage can provide backup power as a standalone resource, or it can provide extended outage relief through microgrid configurations. For all of the above, the solution can be installed in individual homes, at a variety of non-residential facilities, in a community-level configuration, and all the way upstream to distribution feeders and substations. Energy storage can be paired with renewable resources and/or conventional resources. And the resource size can be tailored, both in terms of MW capacity and MWh capacity, to meet the local needs.

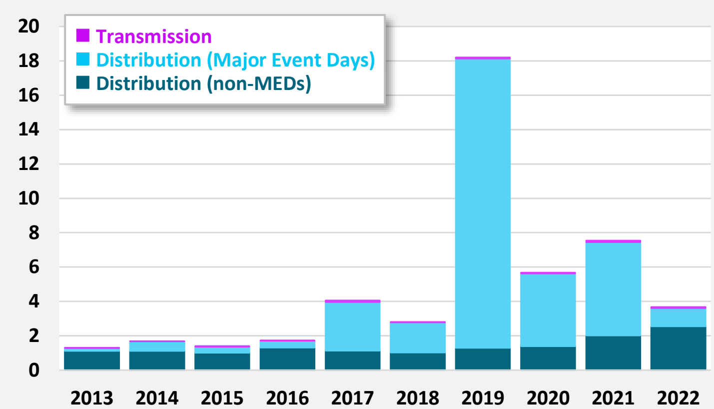


Figure 20: Average hours of electricity service interruptions per customer per year (SAIDI × SAIFI).

Customer-Sited Resources for Outage Mitigation

Motivation. About 25% of households with energy storage have experienced an outage lasting longer than a day (Verdant 2022). Customer-sited storage resources, both residential and non-residential, can effectively provide outage mitigation for a wide range of hazards and potential failure points on the electric grid.

Residential resources. These include standalone energy storage and hybrid resources serving single- or multi-family homes. As illustrated in Figure 21, these systems typically include Level 1 microgrids, which provide outage mitigation for individual buildings through a single meter. Examples can be found in residential SGIP-funded storage and solar plus storage projects.

Non-residential resources. These include standalone or hybrid resources serving non-residential facilities, which can be configured as Level 1 microgrids providing outage mitigation for individual buildings or Level 2 microgrids serving multiple buildings, controlled by one meter. Distributed resources at non-residential sites such as critical facilities, community centers, and other facilities providing essential services can support broad community-level outage mitigation needs. They can also be designed as resilience hubs offering community members reliable power for their essential needs in emergencies. Examples include non-residential SGIP-funded standalone and hybrid storage projects, Santa Rosa Jr. College microgrid (campus) (Liebman 2023), and AVA Energy's Resilient Critical Municipal Facilities Program (resilience hubs) (Energy resilient municipal critical facilities 2023).

Scalability of customer-sited resources. Customer-sited resources provide scalable outage mitigation serving individual customers and the surrounding community.

Customer-sited energy storage installations have already reached the GW scale, with over 1.6 GW of capacity interconnected through November 2023 (Energy Solutions 2023). The rapid growth of the customer-sited resources is driven by customers' outage mitigation needs. A recent survey found that, depending on funding category, 84–99% of customers with energy storage stated backup/ emergency power was among the top 3 drivers of their installation decision (Verdant 2022).

Energy storage is a key component of clean microgrids built to improve the resilience of electricity service. California's energy storage marketplace presents several examples of (a) non-residential onsite and (b) campus-level microgrids serving a broader community—*see* (Energy resilient municipal critical facilities 2023) and (Liebman 2023), respectively.

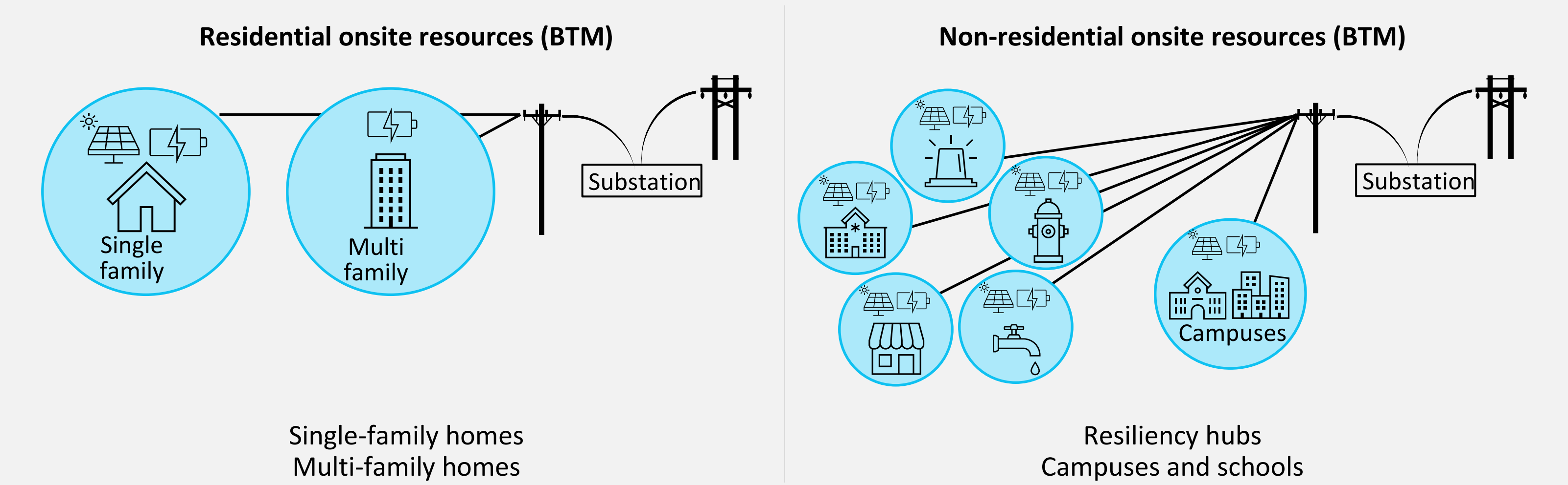


Figure 21: Example of customer-sited resources for outage mitigation.

Distribution-Connected Resources for Outage Mitigation

Motivation. Substation/feeder-level distribution-connected resources can be designed to address one or more entire communities' needs for outage mitigation at once.

Topology of substation/feeder-level resources. Resources at this level mitigate outage risks on the substation or further upstream on the transmission system. However, customers may still be exposed to outages within the distribution system, downstream from the substation or feeder.

Figure 22 illustrates configuration of substation/ feeder-level microgrids. Substation- and feeder-level projects can be an effective solution for outage mitigation, but only if the downstream distribution system does not pose major outage risks or if that system is hardened against current and potential future hazards and stressors such as storms and wildfires.

Examples of these resources include PG&E's temporary substation microgrids and SDG&E's Butterfield and Shelter Valley microgrids, which have been developed as a part of wildfire mitigation planning efforts to address public safety power shutoff (PSPS) outage risks in remote areas. These microgrid areas are outside of the PSPS footprint, but still at risk because circuits feeding them go through high fire-threat areas upstream on the grid. In other cases, like the Borrego Springs microgrid, the community is at the end of a single transmission line, at risk of an outage if that transmission line fails or needs maintenance.

Scalability of distribution-connected resources. Existing outage mitigation-focused distribution-connected microgrid projects, like the examples mentioned earlier, effectively serve communities exposed to outages further upstream on the grid. But these types of resilience and reliability resource solutions address a relatively unique grid topology and/or outage risk situation and thus are not broadly scalable across the state.

As described above, most (99%) customer outage experiences and risks are driven by hazards to—and failures on—the distribution system. For most customers, the relevant outage problem is likely to be downstream of the nearest substation/feeder-level and thus unlikely solved for a resource sited as such.

Appendix E (Case Study Fact Sheets) provides more information on the above-referenced resources.

Substation/feeder-level microgrid (dx-connected)

Special grid topologies/cases

Example of PG&E's temporary substation microgrid configuration

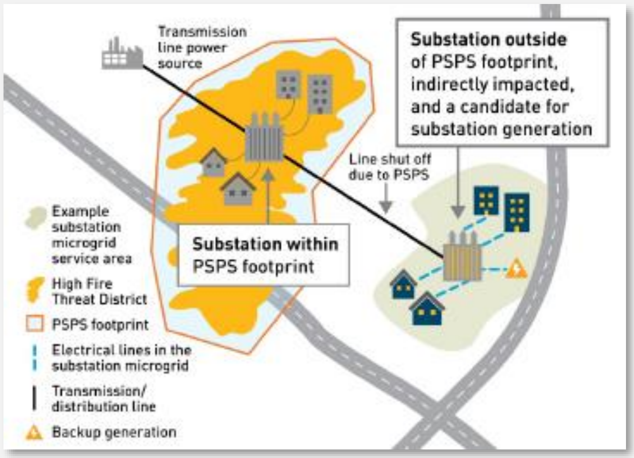


Figure 22: Example of substation/feeder-level distribution-connected resources for outage mitigation.

Community-Level Resources for Outage Mitigation

Motivation. These resources target a set of critical and essential sites in communities with distribution-connected resources electrically closer to customers. They reduce the amount of distribution grid hardening needed for outage mitigation, while still offering broad community-level benefits.

Distribution-connected microgrids cannot mitigate failure points further downstream unless the local distribution grid is hardened, which can be costly. However, compared to customer-sited resources, distribution-connected energy storage offers lower per unit resource cost due to economies of scale and reduced soft costs. For example, as described in the 2023 *CPUC Energy Storage Procurement Study*, all-in installed cost of stationary storage projects has been around $320/kWh for grid-scale systems, $400/kWh for commercial systems, and over $1,400/kWh for smaller residential systems. This difference is largely due to soft costs.

Also, in distribution-connected microgrid projects, DERs can be designed/operated more efficiently, taking advantage of load diversity and resource sharing opportunities. This could reduce the total capacity investment needed for resilience, relative to a set of individual customer-sited resources.

Topology of community-level resources. While they don't require a very specific topology like substation/feeder microgrids, community- and circuit-level distribution-connected resources can be configured surgically to meet community needs, such as serving the most critical sites needed in an emergency or clusters of homes in vulnerable communities (Figure 23). *See* Redwood Coast Airport, Ramona Air Attack Base, Boulevard, Clairemont, Elliot, and Paradise Microgrids in **Appendix E (Case Study Fact Sheets)**. New build resilience-focused housing developments can optimize for multiple layers of electricity service redundancy through a mix of grid-connection, community-level resources, and onsite resources (Carpenter 2022; Dean 2022).

Scalability of community-level resources. Targeted community-level microgrids, closer to customers, offer distinct advantages and could be scalable, but customers and communities face challenges to developing multi-property solutions on the distribution system going beyond onsite and campus-level "behind the meter" solutions. Connecting to all customers in an existing community to form a microgrid can be difficult and expensive, especially if customers are spread out. Community-level or "town-center" microgrids offer a more targeted community solution, but there is limited deployment to date. Such projects are also rare at the national level. See (Pfeiffer 2021) for a discussion of technical, financial, and policy barriers limiting development nation-wide.

The Redwood Coast Airport Microgrid (RCAM). RCAM offers one of the industry's few examples of successful development and application of a multi-property distribution-connected outage mitigation solution. RCAM is a template for policy advancements to create a multi-property operating agreement and tariff under CPUC Rulemaking 19-09-009.

RCAM is an $11MM pilot and demonstration project in McKinleyville, CA, funded through grants facilitated by the state's Electric Program Investment Charge (EPIC) program ($5MM) and Redwood Coast Energy Authority ($6.3MM). As part of the project, key value streams were identified and the business case was evaluated.

Chapter 3 (Recommendations) includes more discussion of valuable lessons learned from RCAM.

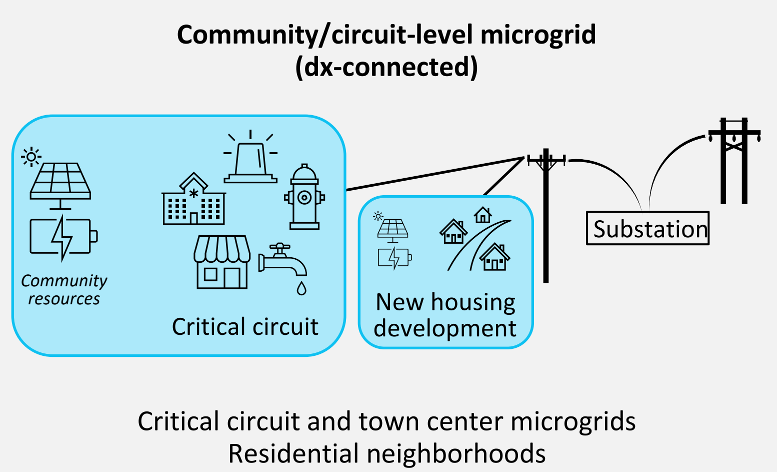


Figure 23: Example of community/circuit-level distribution-connected resources for outage mitigation.

Value-Stacking Opportunities for Outage Mitigation Solutions

Selected case studies. The 8 selected locations for outage mitigation solution case studies are summarized in Figure 24. These locations represent areas with relatively high actual total outage hours and frequency of outages historically. Most outage profiles are developed based on detailed distribution circuit outage data in the 5-year period 2015–2019. The case study locations also are meant to represent a diversity of built environments and community types, geographies, weather conditions and other environmental hazards to the grid, and electricity market conditions.

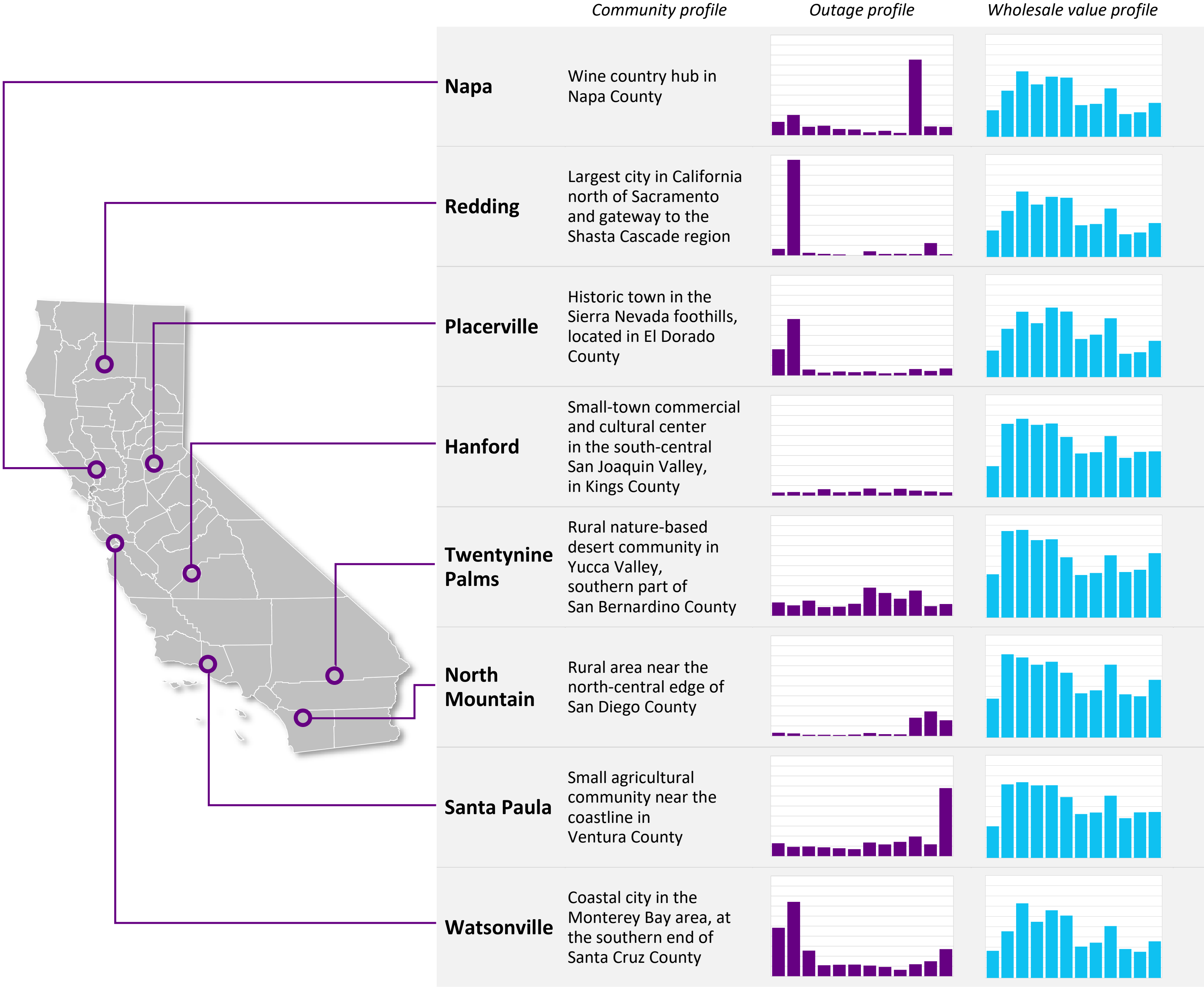


Figure 24: Selected locations for the MUA analysis with outage mitigation.

Wholesale market value potential

We consider 3 value streams for the wholesale market use case, including energy arbitrage, RPS benefits, and system RA capacity value. We do not include ancillary services in this analysis due to its relatively small market size, where we already see signs of saturation.

Energy arbitrage: We estimate energy value by simulating energy storage dispatch under historical prices from 2019 to 2022. We map each location to a CAISO-defined sub-load aggregation point (subLAP) and use the corresponding subLAP prices as inputs to our model. In the optimization algorithm, the energy storage dispatch is set to maximize market revenues assuming 4 hours of duration and 85% of roundtrip efficiency. We limit cycling to once per day on average and apply a 11.5% forced outage rate, consistent with historical levels.

Figure 25 shows monthly results. The estimated net energy arbitrage value ranges from $5 to $7 per kW-month, on average over the 4-year period analyzed. Locations in southern California have higher energy value potential due to more opportunities for market price arbitrage, relative to northern California.

RPS benefits: Charging storage during periods with renewable oversupply can reduce curtailments and lower the need (and cost) to procure additional resources to meet Renewables Portfolio Standard (RPS) and other clean energy targets. To estimate the amounts of renewable curtailments that storage resources can avoid at selected locations, we consider intervals with very low or negative locational marginal prices (LMPs) as indicators of renewable oversupply. We quantify associated benefits at $32 per MWh of avoided renewable curtailments, based on the RPS adder forecast from the CPUC's latest Power Charge Indifference Adjustment (CPUC 2023c).

The average estimated RPS benefit ranges from $1 to $2.2 per kW-month depending on location. The results vary seasonally, with a significant share of the benefits concentrated in the spring months, when renewable curtailment risks are typically higher. During that period, RPS benefits reach up to $6/kW-month. Locations in southern California tend to have higher RPS benefits due to increased renewable curtailment risks, compared to northern California.

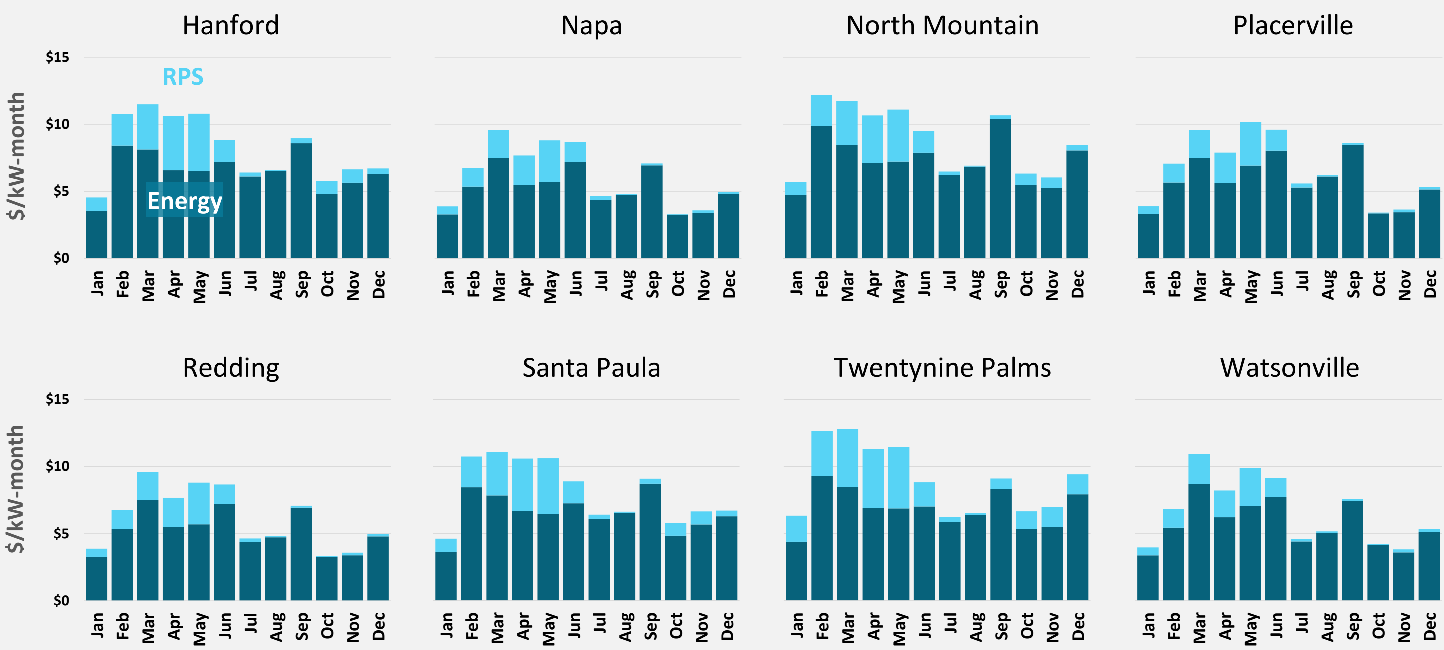


Figure 25: Estimated monthly energy and RPS benefits by location (2023 $).

System RA value: Energy storage capacity available to discharge during peak periods can help meet the RA capacity needs to ensure system reliability. We estimate associated benefits at $15/kW-month, consistent with the 2024 system RA price forecast in the CPUC's Power Charge Indifference Adjustment (CPUC 2023c) and recent RA contract data.

We allocate the system RA capacity value to August and September evening hours, based on findings from the CPUC's 2022 planning reserve margin study (CPUC 2022b). This allocation also aligns with the historical record of CAISO system emergencies observed in recent years, during the heat waves of August–September 2020 and September 2022.

Figure 26 shows total estimated market value potential for the energy storage resources in selected communities. The RA value is kept the same across all locations at $15/kW-month, which translates to $180/kW-year annually. This accounts for a large share of the total market value potential. Energy and RPS benefits add $75 to $115/kW-year of value, depending on the location.

These findings assume 100% market participation, with the full capacity of the resource offered to the CAISO's markets throughout the year. However, under the multiple-use application (MUA) analysis discussed next, when the resource's capacity is reserved for outage mitigation, the realized market value of storage resources would be lower than the levels shown here.

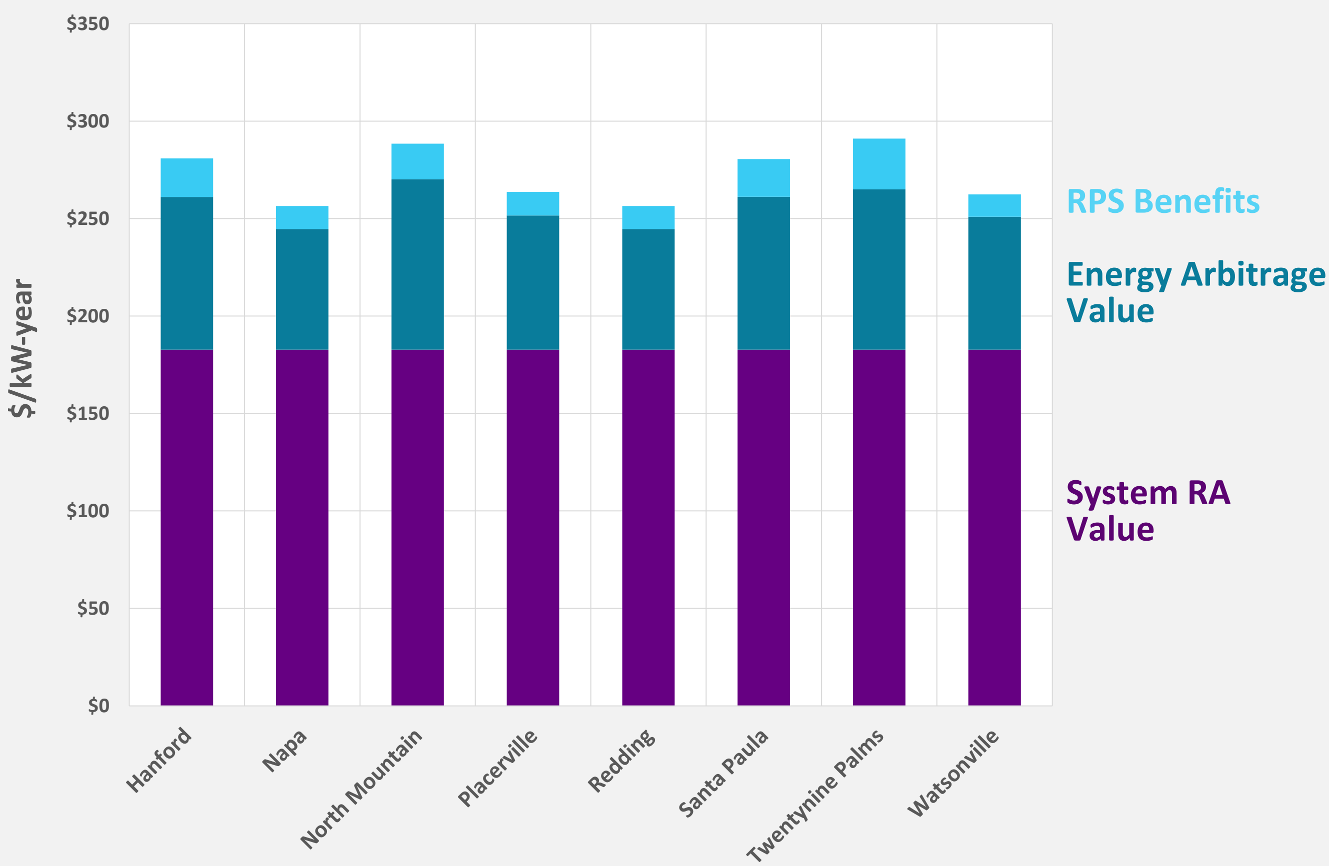


Figure 26: Total estimated market value potential by location (2023 $).

Value-stacking scenarios and results

For the MUA case studies, we develop four value-stacking scenarios with different priorities on market participation vs. customer outage mitigation use cases:

- **No mitigation scenario:** Energy storage is 100% available in wholesale market (benchmark case);
- **Market focus scenario:** Storage capacity is offered to market to capture at least 80% of market value and held in reserve during months with low value potential;
- **Resilience focus scenario:** Storage capacity is held in reserve to achieve 90% outage mitigation and offered to market in months when outage risk is the lowest; and
- **Full mitigation scenario:** Energy storage capacity is 100% reserved for customer outage mitigation (benchmark case).

Figure 27 demonstrates that storage in most areas can capture significant market value without giving up much outage mitigation. In some areas though, power outage risks coincide with high market value periods (e.g., in summer/early fall). In those areas, value-stacking opportunities would be more limited. For instance, customers in Twentynine Palms would give up nearly half of their outage mitigation benefits with a market focus due to outages concentrated in summer, while a resilience focus to mitigate their outage risks would result in a loss of around 90% of market value.

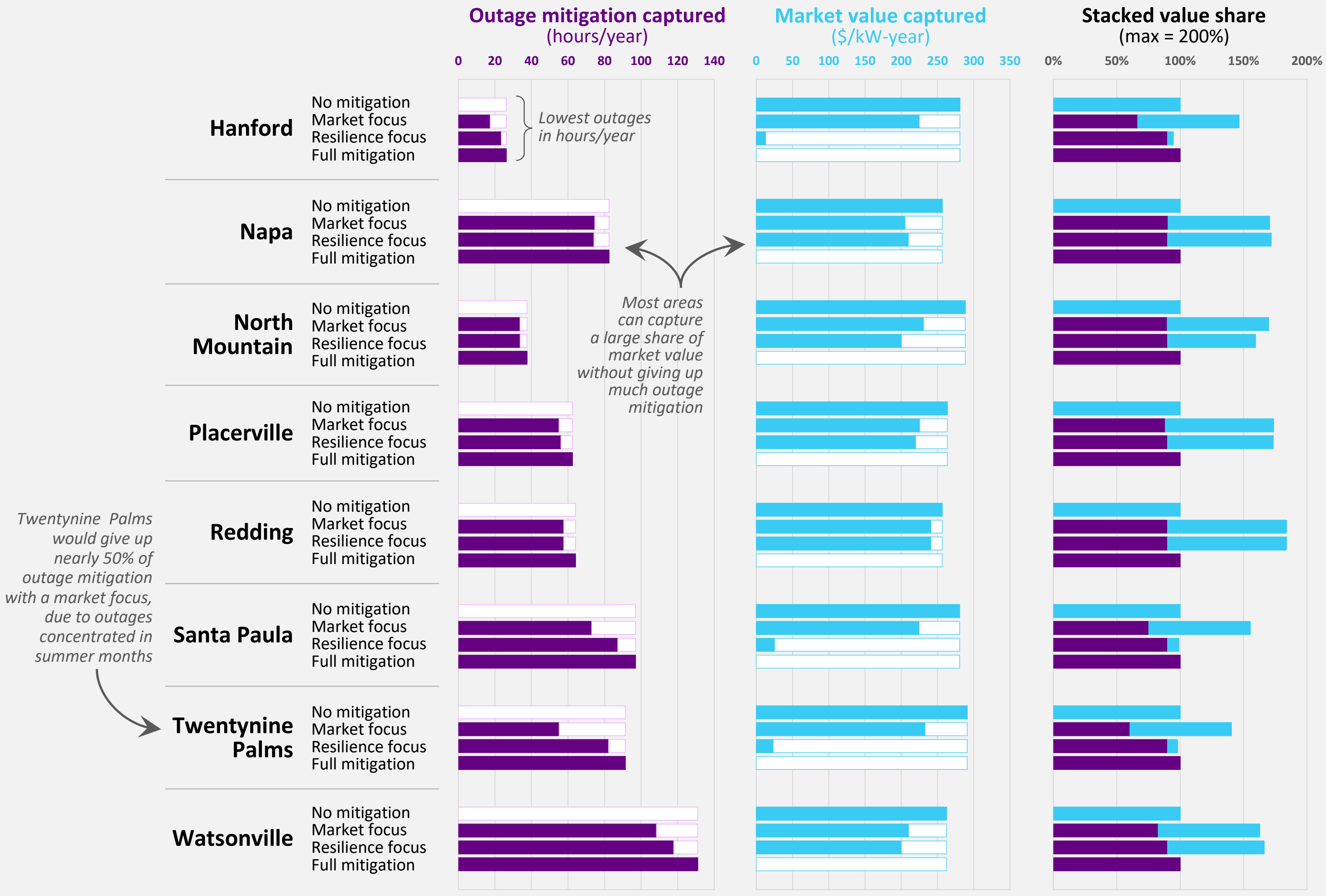


Figure 27: Results for value-stacking with outage mitigation, by scenario.

Our analysis does not incorporate the full flexibility of value-stacking, considering weather-driven outages (e.g., PSPS, winter storms) are seasonal and customers often get some notice of an outage risk. Considering risk profiles and grid needs, customers can dynamically adjust reserve targets to balance their outage exposure and value-stacking.

Impact of RA capacity revenues. Figure 28 illustrates the results for a sensitivity case excluding resource adequacy (RA) value. Without RA attributes, the total estimated market value potential of energy storage resources would be significantly lower, accounting for approximately one-third of the total value with RA capacity.

Non-RA benefits (energy arbitrage + RPS benefits) are distributed more evenly throughout the year compared to RA value, which is concentrated in August and September. Thus, a market-focused use case would require extended participation in the wholesale market to achieve the same revenue targets. This would reduce the periods when energy storage capacity can be reserved for customer outage mitigation and limit overall value-stacking opportunities.

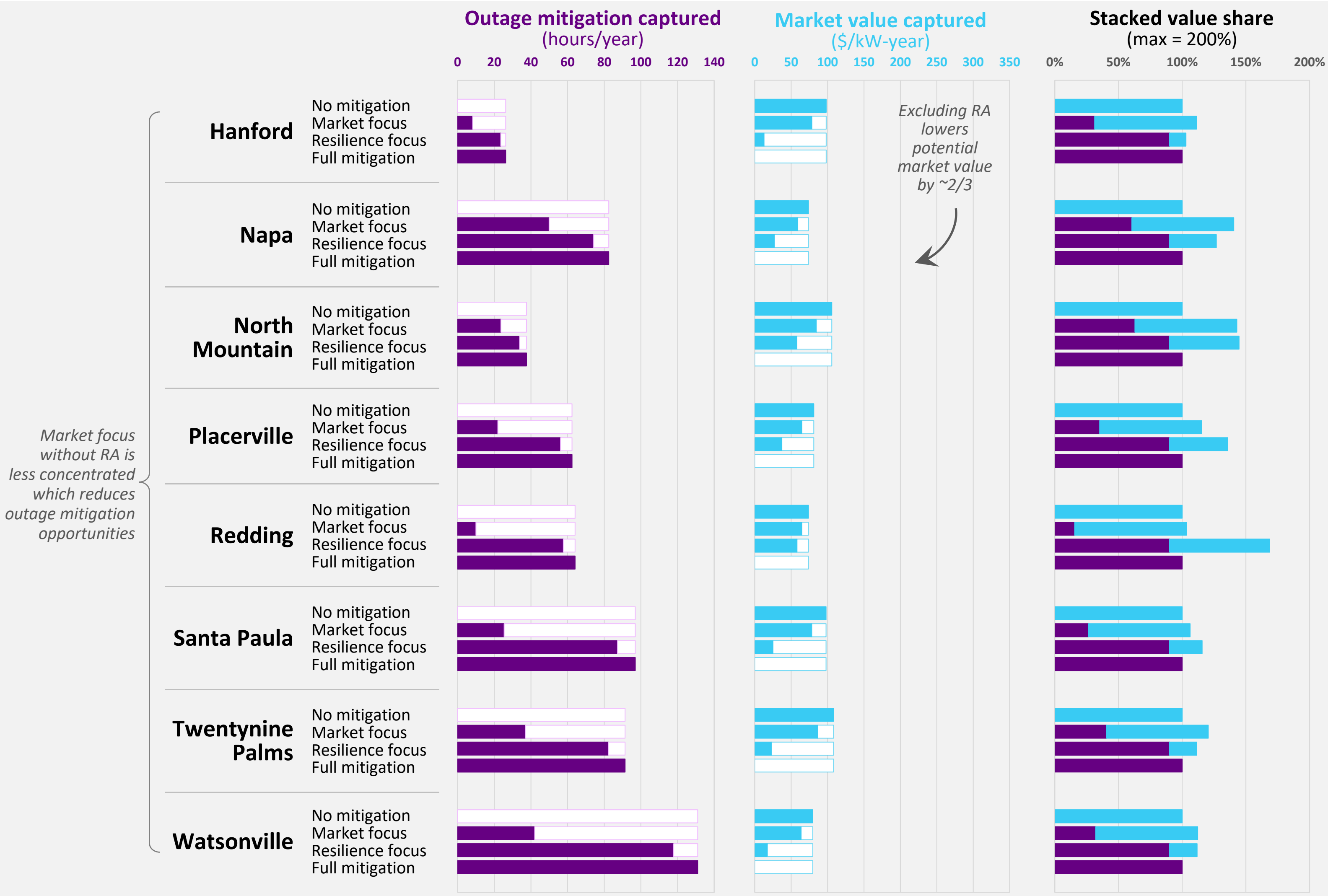


Figure 28: Results for value-stacking with outage mitigation, sensitivity case with no RA value.

Optimal cross-domain MUA strategy with outage mitigation

We compare the scenarios to quantify the risk-value tradeoff, based on the amount of market revenues that a customer would need to give up for each additional MWh of reduction in expected outage levels. Results indicate optimal MUA zones as a function of customers' intrinsic value of lost load (VoLL) level at selected locations. VoLL varies by customer, depending on how inconvenient or costly power outages are for them. Interrupting discretionary loads, like heating a swimming pool, is not much of an inconvenience, and thus yields a relatively low VoLL. On the other hand, critical loads have low tolerance for outages and their VoLLs are much higher.

Figure 29 summarizes our results. In areas with less outages, customers need to give up a lot of revenues to mitigate very few outages, so value-stacking is attractive even under high VoLL. Full mitigation comes at a high opportunity cost in most areas, so market participation in periods with low outage risk tends to be more cost-effective.

Example: Hanford (top left on the chart below)

- Annual market value potential $280/kW-year
- Annual expected outages 26 hours/year
- Translates to 13 kWh of lost load assuming 1 kW at 50% load factor
- $280 ÷ 13 = $21.5/kWh or $21,500/MWh
- If customer's VoLL is above this level, it indicates market revenues are not sufficient to justify value-stacking: **best strategy → full mitigation**
- Market focus scenario captures 80% of market value ($225/kW-year) while reducing expected outages from 26 hours/year to 9 hours/year
- Lost market value 280–225 = $55/kW-year
- Customer outage mitigation 26–9 = 17 hours/year, which translates to 8.5 kWh/year per 1 kW at 50% load factor
- $55 ÷ 8.5 = $6.5/kWh or $6,500/MWh
- If customer's VoLL is below this level, it indicates outage mitigation is not sufficient to justify value-stacking: **best strategy → market only**
- Value-stacking is optimal only if customer's VoLL is between these two levels, from $6,500 to $21,500/MWh: **best strategy → market focus**

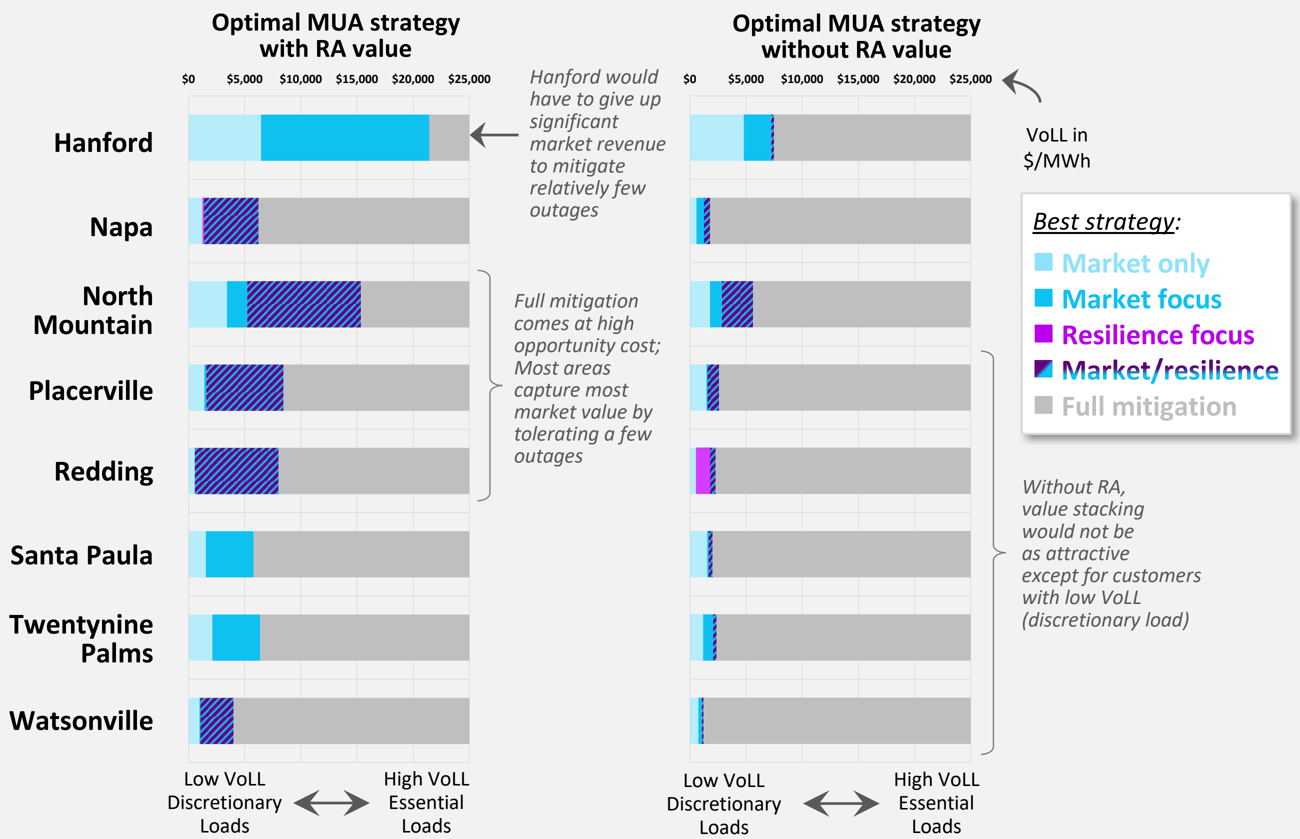


Figure 29: Optimal MUA strategy based on value of lost load (VoLL) levels.

Challenges with the Distribution Deferral Planning and Procurement Framework

Systematic under-forecasting in DDOs. The current distribution deferral opportunity (DDO) screening and selection process aggressively eliminates energy storage as a solution. Most of the problem stems from a "just-in-time" forecasting methodology through which the IOUs cannot identify a DDO until it is too late to procure a non-wires solution for it.

This systematic under-forecasting of procurement opportunities, plus other elimination screens, excluded 95% of opportunities identified over the past 5 years (Figure 30). Figure 31 shows the impact on SCE's 3+ year forward forecast of DDOs.

Without those restrictions, on the order of 100–200 energy storage development opportunities would be identified and procured every year.

Impact on distribution deferral procurements. Given the planning challenges, the resulting distribution deferral procurement marketplace, representing only 5% of potential opportunities, is so thin that 45% of the procurements were unsuccessful due to lack of offers, lack of a feasible portfolio, or lack of cost-effectiveness. Another 16% of procurements were canceled or delayed during the procurement process due to stringent requirements on project size and timing.

The thin market and procurement challenges ultimately reduced viable energy storage-eligible opportunities to 19% of procurements, representing <1% of total potential DDOs and only about a dozen projects in total. Third party developers thus have a low chance of securing a revenue stream through this procurement process.

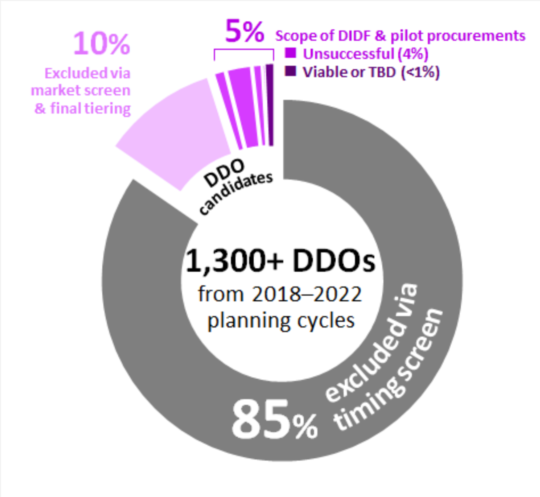


Figure 30: Screening and selection process for distribution deferral opportunities.

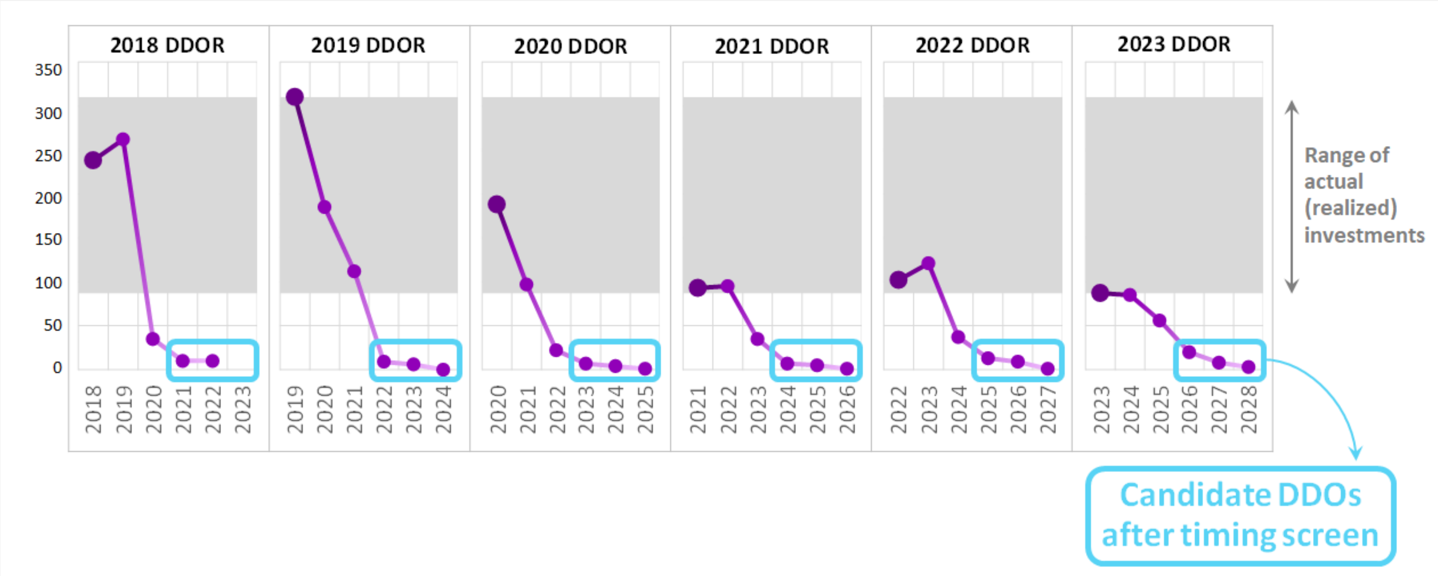


Figure 31: Systematic under-forecasting of distribution deferral opportunities (# projects per year).

Value-Stacking Opportunities for Distribution Deferral Solutions

Selected DDO case studies

As of August 2023, the IOUs have selected a total of 98 potential DDO projects based on distribution deferral (DD) procurement cycles from 2017/18 through 2022/2023.

We start with a dataset for these 98 projects, developed by PA Consulting and released under Rulemaking 21-06-017, which includes project location, MW/MWh need, delivery period, and limit on DD calls.

Energy storage attributes were suitable for 73 of these DDO projects, of which only 63 had sufficient public data needed for our analysis. Total capacity needed for these 63 projects were 210 MW and 1,084 MWh.

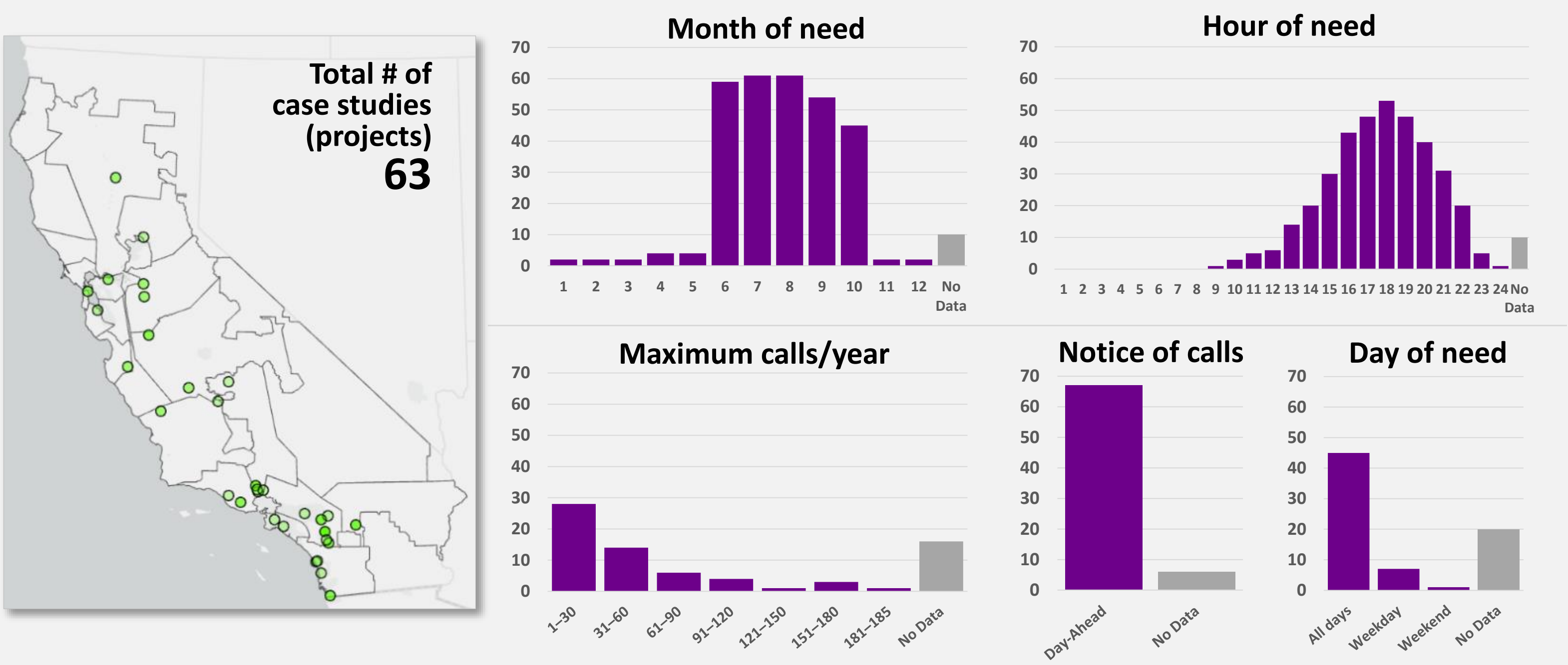
Of these DDOs, only 3 projects were actually installed: Acorn I and two Wildcat I projects, all with energy storage.

Figure 32 shows the locations of these 63 projects we selected for DDO case studies and their characteristics.

The DD needs are concentrated in the summer period, mostly from June through September, and extending into October for about two-thirds of the cases. Most DD needs occur throughout all days of the week, typically spanning the afternoon and evening peak periods.

In approximately half of the cases, annual DD calls are limited to 30 per year or less, while for some projects, it can be as high as 185 per year.

In all cases, the DD calls are scheduled to occur on a day-ahead basis.



Sources: Lumen summary of PA Consulting's August 2023 DIDF Tracking Spreadsheet in R.21-06-017 High DER Proceeding.

Figure 32: Distribution deferral case study characteristics.

Analytical approach to DD MUA

We analyze hypothetical energy storage projects to meet the distribution deferral (DD) need at each location, assuming DD is the primary use case. Only residual capacity after serving DD need is used to provide wholesale market services—this gives us a conservative view of what can be “counted on” from a wholesale market perspective.

DD services are assumed called at the annual maximum number of times, for the maximum number of hours, and on days when wholesale market value (opportunity cost) is highest, providing a very conservative estimate of the value-stacking opportunity. Within DD peak months, and on days when DD services are not called, we assume energy storage is subject to charging constraints, recognizing the need to minimize creation of a new peak load on the distribution system.

We characterize market value based on the same approach we used for the MUA analysis with outage mitigation. Figure 33 shows the estimated value potential under 100% market participation (benchmark).

We consider 3 value streams:

Energy arbitrage: Each location is mapped to a CAISO sub-load aggregation point (subLAP); market value estimated based on energy storage dispatch against historical LMPs for 2019–2022.

RPS benefits: Energy storage charged during periods with renewable oversupply can reduce curtailments and lower the need (and cost) to procure additional resources to meet Renewables Portfolio Standard (RPS) and other clean energy targets; benefits quantified at $32/MWh consistent with the RPS adders from the CPUC’s Power Charge Indifference Adjustment (CPUC 2023c).

System RA value: Energy storage capacity available to discharge during peak periods can help meeting the RA capacity needs to ensure system reliability; benefits estimated at $15/kW-month consistent with the 2024 system RA price forecast in CPUC’s Power Charge Indifference Adjustment (CPUC 2023c) and recent RA contract data. Allocated to August–September evening hours based on findings from the CPUC’s 2022 planning reserve margin study (CPUC 2022b).

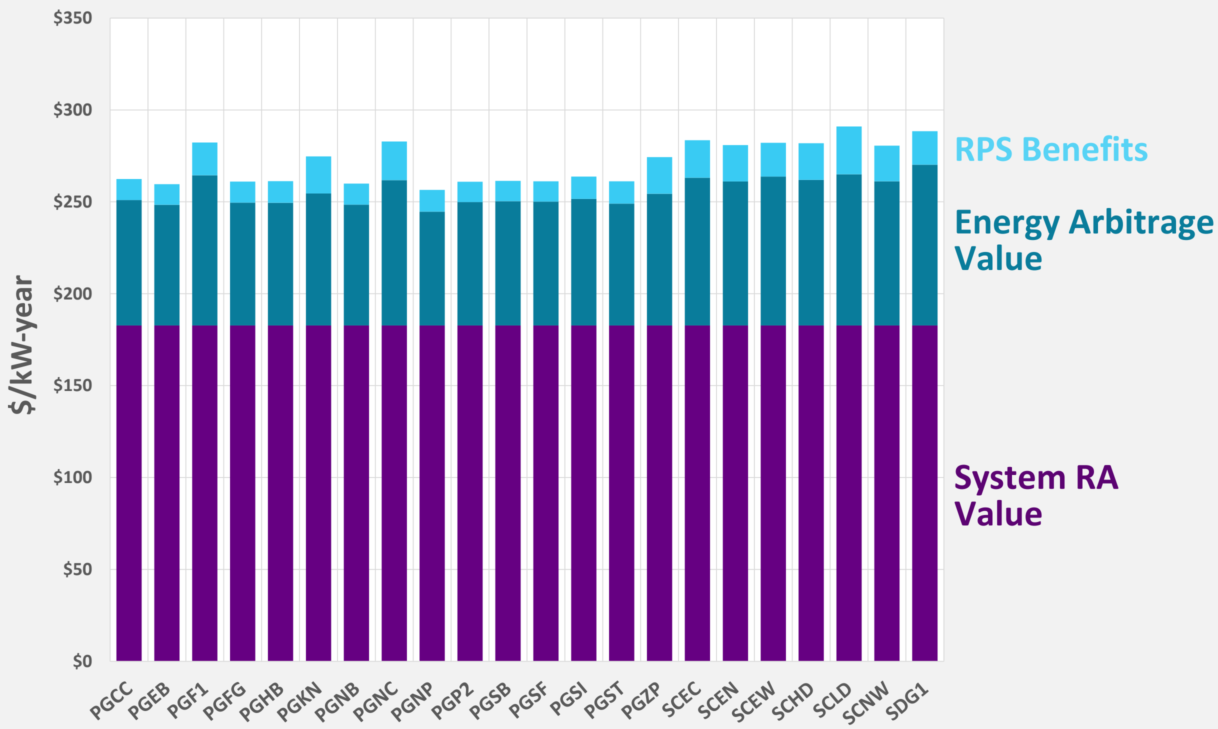


Figure 33: Total estimated market value potential by CAISO subLAP (2023 $).

DD MUA results

Figure 34 illustrates the estimated share of potential RA benefits captured versus lost due to distribution-related constraints including DD service calls, minimum duration, and charging limitations.

The DDOs requiring fewer hours of service and lower limit on annual calls allow for high RA value. We estimate that most distribution deferral opportunities analyzed can capture at least 50% of the potential RA benefits through value-stacking, while the top 1/3 of the storage-eligible DDOs capture more than 80% of the value provided by RA-only storage.

Extended DD service windows require storage configurations with longer durations, which reduces RA value per kWh of investment under the current RA program parameters. As such, we find that storage-eligible DDOs with 6+ hours of duration would capture only 30% of the value provided by RA-only storage.

A high limit on the number DD service calls is also a barrier to RA value, because dispatch signals do not always line up with RA needs. Our analysis shows projects with up to 20 DD service calls per year would capture 2x more RA value than projects with 50 or more calls per year.

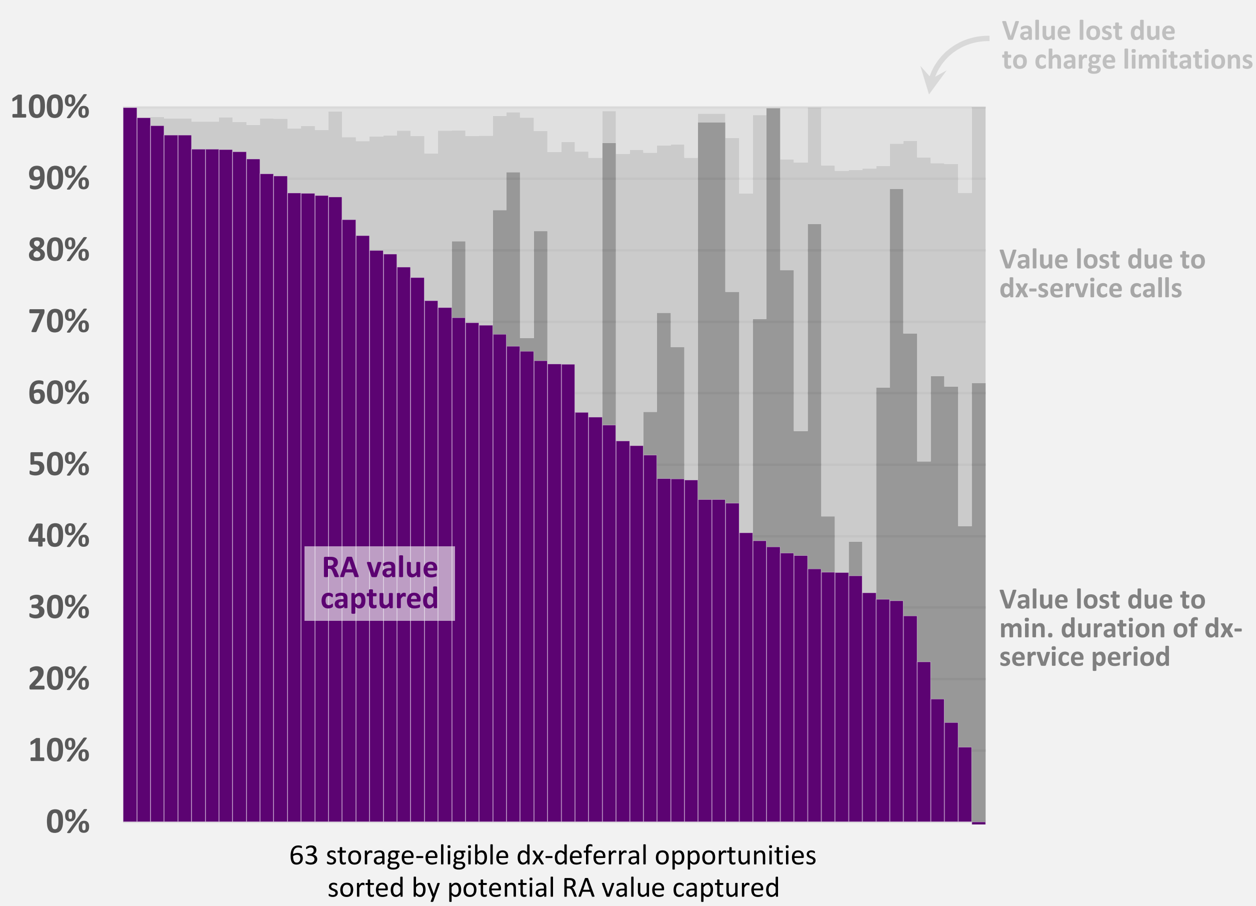


Figure 34: Share of potential RA capacity benefits captured under distribution deferral related constraints.

Impact on financial feasibility of DDOs

As shown in Figure 35, RA capacity benefit is an important component to this cross-domain multi-use application. As with the prior Figure 34, this figure shows incremental energy and RA benefits that could be captured by energy storage—even conservatively assuming each project operates to meet its maximum distribution deferral service calls and is subject to operating constraints when not called.

The relatively high share of RA capacity benefits is driven by system RA capacity prices forecasted at \$15/kW-month (CPUC 2023c), up from about \$3 prior to 2019, and \$5–8 in 2020–2022.

Energy storage can also stack a significant amount of energy market value and RPS benefits because operating constraints from distribution deferral service needs tend to be minimal when market opportunities are high (e.g., in the springtime).

At current prices, the total wholesale market value potential of storage is ~\$60/kWh-year, including energy arbitrage, RPS benefits, and system RA value. We estimate that most storage-eligible DDOs could capture at least 50% of this value—\$30/kWh-year or more.

This wholesale market value could pay for a large portion of storage investment and accordingly reduce the distribution deferral service payments needed. In the 2023 CPUC *Energy Storage Procurement Study*, we estimated grid-scale energy storage project costs ranged from \$9 to \$14 per kW-month based on all-in utility contracts approved during the 2020–2021 timeframe. This translates to \$27–\$42 per kWh-year in total project costs.

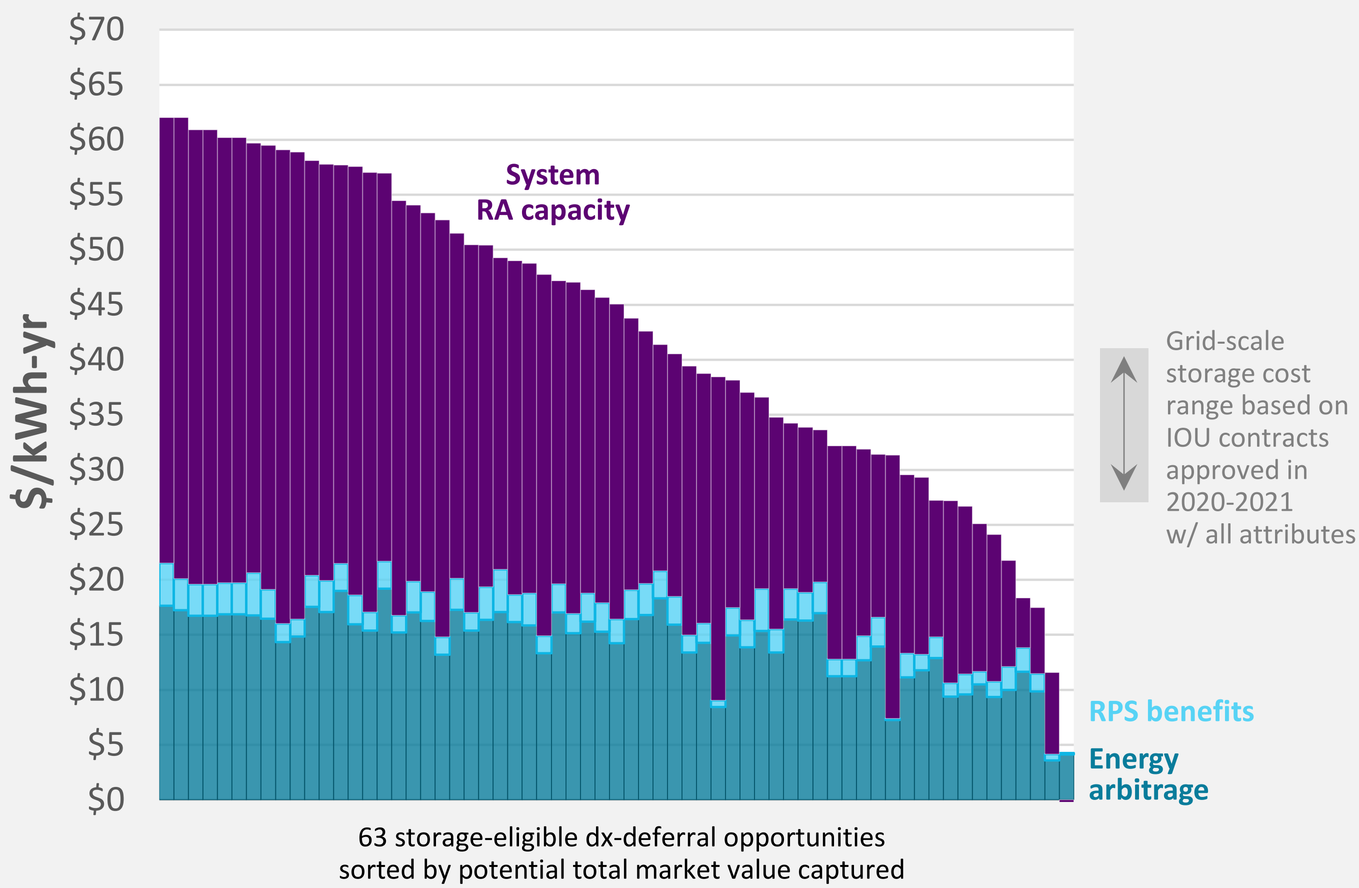


Figure 35: Potential "stackable" energy and RA capacity with distribution deferral services.

Key Observations for Chapter 2 (Crossing Bounds)

Cross-domain MUA with customer outage mitigation

Customer-sited resources provide scalable outage mitigation serving individual customers and the surrounding community.

The scalability of distribution substation- and feeder-level resources for outage mitigation is limited by prevalence of distribution-level outage risks.

Targeted distribution-connected community-level microgrids offer distinct advantages and could be scalable, but they face significant barriers.

The Redwood Coast Airport Microgrid provides a template for an LSE/IOU co-development process, operating agreement, and tariff, but financial barriers have yet to be overcome.

Stacking RA capacity and energy value with outage mitigation is possible; the optimal MUA strategy depends on outage characteristics & risk tolerance.

Exclusion of RA capacity value reduces potential market revenues to offset resilience investment cost by 2/3, and it reduces the incentive for those in need of a resilience solution to participate in the wholesale marketplace at all.

Cross-domain MUA with distribution deferral

Current distribution deferral planning and procurement processes face several challenges that limit the visibility of a large number of energy storage opportunities.

Review of the distribution deferral planning and procurement process confirms the current policy framework as an unreliable revenue source for 3rd party developers to build a viable business case.

The operating requirements of most distribution deferral opportunities synergize well with system RA capacity needs.

Value-stacking wholesale market services with distribution services significantly improves the economic feasibility of most storage solutions to meet distribution deferral needs, and it is an important ingredient to a viable business case for distribution deferral.

But for developers to consider distribution-connected projects rather than transmission-connected projects, they need a positive revenue outlook for distribution deferral services.

CHAPTER 3: RECOMMENDATIONS

A massive grid transformation is underway in California in order to meet the state's clean energy goals and achieve carbon neutrality by 2045.

The 2023 *CPUC Energy Storage Procurement Study* estimates the energy storage fleet has the potential to yield $835 million to $1.34 billion of annual net grid benefits by 2032, compared to a grid without energy storage. A large share of that potential is likely to be realized under current policies and planning practices as transmission-connected energy storage scales up to 10 GW or more.

Novel and emerging resource types and use cases offer additional, but yet-unquantified, benefits. The benefits of reducing barriers to community resilience investments, and to distribution deferral resources, for example, are not currently quantifiable but are likely substantial. Recommended policy actions reaffirm and build upon several recommendations from the first evaluation, lay the foundation for better understanding important new or maturing energy storage resource types and use cases as they emerge, and focus on removing barriers to their potential benefits.

Based on key observations on the performance of energy storage resources participating in the CAISO marketplace in 2022 and 2023 in **Chapter 1 (Scaling Up)** and on the opportunities and challenges with cross-domain multiple use applications in **Chapter 2 (Crossing Bounds)**, in this third chapter we identify policy actions that would further expand benefits of the energy storage fleet.

The 2023 *CPUC Energy Storage Procurement Study* made policy recommendations in 6 categories, all of which continue to be relevant and important to the development of an energy storage fleet that effectively and efficiently meets state goals:

1. Evolve signals for resource adequacy capacity investments;
2. Bring stronger grid signals to customers;
3. Remove barriers to distribution-connected installations;
4. Improve the analytical foundation for resilience-related investments;
5. Enhance safety; and
6. Improve data practices.

This report reaffirms and builds upon several of those recommendations, with additional policy actions to support improved planning and procurement of market-participating energy storage, and to support cross-domain MUA with outage mitigation and with distribution deferral. Additional recommended categories described in this chapter aim to:

1. Continue to improve data collection practices;
2. Update outage and performance assumptions;
3. Improve investment synergies of community resilience solutions; and
4. Remove barriers to the distribution deferral marketplace.

Recommended policy actions to support improved planning and procurement of market-participating energy storage

We observe the energy storage use case in the CAISO marketplace continued to transition from ancillary services to energy time shift. Most of the CAISO-participating energy storage resources now regularly charge at low-priced periods in the day and discharge at high-priced periods in the evening. This has important implications for GHG emissions reductions and avoided renewable curtailments. With more emphasis on energy time shift, the majority of CAISO's storage fleet is now reducing GHG emissions and helping with integration of renewable energy resources. Storage co-located with solar PV provided higher benefits than standalone storage—partly due to more operational focus on energy time shift, and partly due to location in southern California where the marketplace signals a higher need.

Overall, the CAISO-participating storage fleet provided substantial system benefits in the 2017–2023 timeframe. Average energy value of storage resources in CAISO grew by about 2× to over $5/kW-month, relative to results from the first evaluation. RA capacity accounts for an increasing share of the value provided by the storage fleet. These observed real-world results and market trends are consistent with the forward-looking analysis included in the 2023 *CPUC Energy Storage Procurement Study*.

One challenge, however, is that energy storage configured as part of a hybrid resource, and customer-sited energy storage, continue to be non-transparent in the CAISO marketplace. As emphasized in the *CPUC Energy Storage Procurement Study*, improvements in data management are imperative as energy storage scales up in different forms and across all grid domains. The 2023 study recommendations include development of universal and standardized data collection, retention, quality control, and reporting of interval-level operations for all ratepayer-funded energy storage resources.

With our analysis, we see a need to continue to improve data collection practices for energy storage evaluation purposes.

Recommendations. Ongoing efforts to improve data collection are needed to enable meaningful evaluations and policy adjustments as the energy storage fleet grows and changes.

In 2023 the CPUC and CAISO worked together to update their data-sharing arrangements to include ongoing and standardized reporting of energy storage performance in the CAISO marketplace (CPUC 2023a). Understanding the operations of the energy storage components of hybrid resources and behind-the-(utility)-meter resources (Proxy Demand Resources, or PDRs) participating in the CAISO marketplace, however, continues to be a challenge.

As a next step, our recommendations for the CPUC are to:

- Continue to monitor the reported hybrid data collected by CAISO; work with the CAISO to refine those reporting requirements if needed; and, when those data become available and quality-controlled, **include an analysis of hybrid resources in future energy storage evaluations**.
- As recommended in the *CPUC Energy Storage Procurement Study,* require that ratepayer-funded resources participating as Proxy Demand Resources (PDRs) in the CAISO marketplace **report their complete (charge and discharge) interval-level operations**, modeled after the SGIP requirements for Performance Based Incentives and expanded to include information on state of charge, standby losses, and operations during upstream grid outages. In future energy storage evaluations, **use that information to better understand the capabilities of customer aggregations** (e.g., Virtual Power Plant, or VPP) to provide RA capacity services, and how they might balance the tradeoffs of services to the CAISO marketplace with onsite customer needs.

Energy storage operating performance is increasingly important as its contributions to the RA capacity market and system reliability grows. We investigated historical availability and performance of the storage fleet in CAISO market in 2022 and 2023, including during grid-stressed periods, to help validate and improve future resource planning and procurement efforts in California.

We find that energy storage resources experienced 2.3× higher forced outage rates relative to assumptions in the state's grid planning studies. Historical data indicate significant monthly and daily variation on forced outages of storage resources. In the months of August and September, when the CAISO grid is typically the most strained, average outage rates are one percentage point higher than the average across all months and hours of the year. During the evening peak hours of August and September, outage rates of the storage fleet averaged at about 12.6%, exceeding 15% in 1 out of every 5 days. This is in comparison to the 5% outage rate currently assumed in grid planning studies.

The historical record is too short to analyze year-to-year variability in CAISO market-participating battery energy storage outages, but safety events at Moss 100 and Moss 300 clearly had a major impact on overall fleet performance September 2021 through May 2022.

Moss 300, for example, is a 300 MW/1,200 MWh transmission-connected system installed at the end of 2020. The entire resource went on outage in September 2021 due to a safety event then mostly restored in June 2022. The outage was recorded as a forced outage in September and October 2021, then as a planned outage for the remainder of 2021 and in 2022. The entire outage is not included in our forced outage analysis described above.

Moss 300's outage added 16–18 percentage points to fleetwide forced outage rates in September and October 2021, then 10–16 percentage points to fleetwide planned outage rates in November 2021 through May 2022, after the outage was recategorized. The magnitude of impact on fleetwide outage rates is due to the resource's relatively large MW compared to the size of the battery energy storage fleet at the time.

Energy storage operations in 2022 and 2023 points to a need to update and further explore some energy storage outage and performance assumptions.

Recommendations. Similarly, as we observe the energy storage fleet's real-world operations and market performance change over time, those operating patterns and trends will need to be incorporated into planning and procurement assumptions regularly and on an ongoing basis.

As part of its ongoing planning and procurement updates, our recommendations for the CPUC are to:

- Validate and update the energy storage forced outage rate assumptions throughout the CPUC's grid planning and RA program activities to incorporate the most current information. This includes **incorporation of a higher (11.5%) annual average forced outage rate, and consideration of the hourly, daily, and monthly outage patterns and variations**—particularly during summer evening peak periods.
- **Consider and incorporate market trends** towards lower ancillary services revenues, slightly higher and leveling-out energy revenues in the CPUC's RA capacity procurement tracks and IOU resource evaluation methodologies.
- As recommended in the *CPUC Energy Storage Procurement Study,* **continue to explore the safety-reliability link**, firstly to inform improvements in safety practices, but also to identify and reduce risks to the reliability of the bulk grid.

Recommended policy actions to support cross-domain MUA with outage mitigation

We observe **customer-sited resources** provide scalable outage mitigation serving individual customers and the surrounding community. Actual development of solar plus storage, to protect against the most impactful long duration outages, is growing, especially amongst residential customers. As discussed in the 2023 *CPUC Energy Storage Procurement Study*, key influencers to cross-domain value-stacking are retail rates and programs. That study's recommendations to bring stronger grid signals to customers are still applicable here.

The scalability of **substation and feeder-level distribution-connected resources** for outage mitigation is limited by the prevalence of distribution-level outage risks. Resilience-focused microgrids installed on this part of the grid, for example, primarily address special situations in which outage risks are mostly upstream (e.g., on the transmission system). The downstream distribution system within the microgrid thus is not in need of major investment cost to harden against outage risks. This use case is likely to remain an important tailored solution for some communities, but niche compared to other use cases, and unlikely to reach GW scale in California's resource portfolio.

In comparison, **community-level distribution-connected resources**, including those serving entire communities—or clusters of vulnerable customers and community-serving facilities—are sited closer to customers while still connected "front of the (utility) meter" on the distribution system. Community-level resources offer distinct advantages to individual customer-sited resources in cost-effective mitigation of both transmission- and distribution-level outages. These types of resources are tailorable to a diversity of communities and they could be broadly scalable across the state.

However, community-level resources are a new paradigm in local energy system planning and operations, and they face significant technical, financial, and policy barriers (Pfeiffer 2021). As a consequence, the industry has very few examples of this resource type nationwide, and even fewer examples of community resources serving cross-domain MUA. New-construction resilience-focused housing developments provide examples of what is possible (Carpenter 2022; Dean 2022), but they cannot be realistically implemented in an already-built environment. Alternatively, the use case is sometimes proxied with a collection of customer-sited resources without the benefit of resource-pooling (Energy resilient municipal critical facilities 2023).

Wholesale market revenues are essential to the community resource business case. The Redwood Coast Airport Microgrid (RCAM) is one of the few demonstrations of cross-domain MUA of community-level energy storage in the industry. RCAM provides a template under CPUC Rulemaking 19-09-009 for addressing several technical and policy barriers to multi-property microgrids, including demonstration of a workable LSE/IOU co-development process, operating agreement, and tariff.

The energy storage in RCAM happens to be part of a microgrid—as are many examples of community-level energy storage. Our discussion and recommendations around community-level resources are not aimed at microgrids *per se*, but at any community-level energy storage resource.

One goal of the RCAM project is to assess business model viability, recognizing (a) that the resource is nearly fully subsidized through state and local grant programs, and (b) that RCAM itself does not demonstrate a business case absent those grants.

RCAM provides outage mitigation for its community, and it provides services to the CAISO marketplace. At the time of this report, RCAM does not qualify for any amount of RA capacity. In RCAM's planning stage, its outage mitigation value was assessed through a community engagement process. Revenues from the wholesale marketplace during "blue sky" conditions—including benefits for providing energy, ancillary services, renewable energy credits, and RA capacity services—were also estimated and weighed against project costs. These wholesale market revenues have been identified by the RCAM project partners as important to a viable business model.

RCAM's assessment is consistent with our assessments of energy storage costs, ability to provide services, and performance, both in the *CPUC Energy Storage Procurement Study* and in this report. The *CPUC Energy Storage Procurement Study* recommends actions to enable multiple use applications as part of a strategy to remove barriers to distribution-connected energy storage installations. Our case study analysis, described further below, confirms the importance of wholesale market revenues in reducing financial barriers to resilience investments. Blue sky services including, but not limited to, wholesale market participation are also recognized in the CPUC's Resiliency Scorecard under its 4-Pillar Methodology for resiliency resource planning and development (CPUC 2024b). As such, we emphasize here that the ability to develop cross-domain MUA, and access associated cross-domain revenue streams, is essential for the business case of community-level resources.

Lack of RA capacity market participation is a major concern. In the few available examples of community-level resources, including RCAM, we find that financial barriers are still apparent and have yet to be overcome. Particularly, we find that RA capacity market participation is not well demonstrated. We recommend more policy focus, described further below, on ensuring the RA capacity revenue stream is not *de facto* inaccessible for a diversity of community-level resources that can actually and demonstrably provide the service. RA capacity revenues are significant: near-term RA prices are forecasted at about $15/kW-month, compared to about $5/kW-month average energy revenues, and we expect prices to stay high over the long-term as the state moves towards its clean energy goals. But regardless of price levels, RA capacity revenues also provide a long-term hedge to energy and ancillary services market price volatility and trends.

From the community's perspective, wholesale market revenues reduce net resilience investment costs. Depending on a community's value of lost load and ability to pay for outage mitigation resources, resilience benefits alone might not justify the local resilience investment. This cross-domain MUA, including RA capacity services, makes resilience investments financially feasible for more communities and customers.

As demonstrated by RCAM, which provides services to the CAISO marketplace in nearly every hour of the year and settles with CAISO 24/7, and by our case studies, a wide range of communities could offer RA capacity services from this use case while retaining most or all of their outage protection. In our case study analysis, we find that stacking RA capacity and energy value with outage mitigation is possible and could significantly reduce financial barriers. Exclusion of RA capacity revenue reduces potential market revenues to offset resilience investment cost by 2/3. We also find that exclusion of RA capacity as a revenue stream reduces the incentive for those in need of a resilience solution to participate in the wholesale marketplace *at all*.

From a bulk grid planning perspective, inclusion of community resources built for outage mitigation in the RA capacity market opens the market to a more diverse set of resources already being developed, thus providing more opportunity for the entry of innovative and low-cost capacity solutions. Additionally, as described above, if community resources successfully compete in the RA capacity market, these market revenues are part of the equation in facilitating community resilience investments. This can be a pathway for LSEs to address California Public Utilities Code Section 454.52(a)(1)(G), which requires LSEs, through the Integrated Resource Planning (IRP) process, to: "Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."

Considering both perspectives, successful RA capacity procurements of outage mitigation resources enable customer and community resilience investments *and* provide more options for, and more resource diversity in, RA capacity procurements. Making this connection is a key focus of this report's recommendations. Several types of policies need to work together to support more integration of community resources in the RA capacity market, including those around the RA capacity planning process (i.e., integrated resource planning), resource interconnection and deliverability, and RA capacity procurements.

Opportunities for inclusion of community resources in RA planning. In 2023, the CPUC's Resiliency and Microgrids team hosted a series of workshops and informational sessions to explore resiliency standards and a variety of applications of the CPUC's 4-Pillar Methodology for resiliency resource planning and development (CPUC 2024b). The 2023 workshops and informational sessions build from the CPUC Resiliency and Microgrid team's earlier work to explore and develop best practices in resilience risk management, including work under its Resiliency and Microgrids Working Group and activities under CPUC Rulemaking 19-09-009. As part of the series, application of the 4-Pillar Methodology in IRP was explored with stakeholders, including discussion of relevant definitions, metrics, and methodologies in resilience planning. The potential IRP application identified mutually beneficial opportunities to connect (a) local perspectives and resilience investments with (b) LSE- and state-level grid planning.

Those findings are highly relevant to our recommendations here. We recommend further exploration and consideration of the process to integrate community resilience resource planning with IRP, as documented in the referenced CPUC workshops and informational sessions.

Two important outcomes of such a process will be for (1) IRP to gain a better understanding of distributed capacity growth, use cases, and resources attributes available to serve the bulk grid, and (2) local planners to gain a better understanding of grid needs and the benefits and tradeoffs of providing cross-domain services. These planning outcomes will set the stage for a more successful exchange in the RA capacity procurement marketplace.

Considerations for community resource interconnection and deliverability. How a resource is interconnected, and to what degree its services can reach load delivery points on the transmission grid during peak periods, are important determinants to a resources' ability to provide RA capacity. We did not conduct an interconnection or deliverability study on any of the hypothetical case studies we analyzed, but we did review available data on the characteristics of actual resources online and under development, as shown in **Appendix E (Case study Fact Sheets**). The RCAM project, through project documentation and interviews of the project partners, provides among the most comprehensive information on challenges with interconnection and deliverability.

RCAM includes 2.2 MW 4-hour energy storage and 2.2 MW solar PV (Carter 2020). Onsite peak load is 330 kW. Through an interconnection agreement with its IOU and project partner, PG&E, RCAM is subject to an operating limit of 1.48 MW for imports and 1.778 MW for exports. RCAM is interconnected through PG&E's Wholesale Distribution Tariff and participates as a hybrid resource in the CAISO marketplace, just as transmission-connected solar and storage hybrid resources participate. At the time of this report, RCAM does not qualify for any amount of RA capacity. Currently, a transmission deliverability assessment and potential transmission upgrades are needed to qualify for its operating limit of 1.778 MW. To qualify for its full 2.2 MW of energy storage capacity, RCAM would need to (a) establish deliverability to the distribution system, including required distribution upgrades, and (b) establish deliverability to the transmission system, including required transmission upgrades.

Whether or not identified distribution and/or transmission system upgrades for deliverability should be implemented—and who should pay for them—is a complex topic of debate that is not included in the scope of this report. But two issues are apparent in the RCAM demonstration that likely pose challenges to other resources with this use case.

The first issue is that RCAM does not qualify for RA capacity up to its onsite load without a transmission deliverability study. It is unclear why transmission deliverability is needed to serve onsite load. This is a topic of discussion in the CAISO's Resource Adequacy Modeling and Program Design Working Group (CAISO 2024b). We recommend that the CPUC works with the CAISO and their stakeholders to align these rules to recognize this as a form of RA capacity "self-supply" that can qualify through demonstration of actual net load reductions, similar in concept to how load reductions qualify under CAISO's Proxy Demand Resource (PDR) participation model.

The second issue is that the transmission deliverability assessment and RA capacity qualification process is difficult for community-level planners, with relatively limited resources, to understand and navigate. RCAM chose to not immediately pursue RA capacity qualification. Although RCAM was used to examine business model viability, the project partners' decision to abandon RA capacity qualification before installation is not necessarily indicative of the long-term private-sector economics of doing so. As a demonstration project they are subject to the project schedule and (gross) cost constraints which are conditions of their grant funding arrangements. In interviews, RCAM project partners highlighted non-transparency and challenges in the RA capacity qualification process. Again, we did not conduct an interconnection or deliverability study, but we understand that Wholesale Distribution Access Tariff/ Wholesale Distribution Tariff (WDAT/WDT) interconnection is known by developers as a difficult process (for example, *see* (Schwartz 2023)).

Regarding RCAM's path to future qualification, it is not clear to us why the storage component of RCAM is not listed in PG&E's Wholesale Distribution Tariff queue (PG&E 2024), if or how RCAM was considered in the CAISO's subsequent annual distributed generation deliverability assessments (CAISO 2024a), nor what the outcome of those assessments means for RCAM specifically (including whether or not it needs to apply to the CAISO's cluster study process). Interconnection rules are extremely complex. We recommend the CPUC explores refinements to bring more clarity to this process for community-level planners who seek to determine if RA capacity qualification is worth pursuing, regardless if the resource is in a planning stage or already installed.

One desired outcome of this clarification is for communities to more easily access and understand specific information on how to qualify their WDAT/WDT-interconnected resource(s) for RA capacity, including timeline, roles and responsibilities of each party involved, and resource operating requirements during the qualification process.

For any WDAT/WDT-interconnected resources installed as "energy only" (i.e., no transmission deliverability established) or with partial deliverability, another desired outcome of this clarification is for resource owners to automatically receive resource-specific information on how much of the resource can qualify without additional wires upgrades, plus a time and cost estimate to upgrade to full deliverability. This may be achievable through refinements to the IOUs' interface with the CAISO's annual distributed generation deliverability assessments—both in the data IOUs provide to the assessments, and in the way IOUs communicate results to their WDAT/WDT-interconnected resources.

We understand that both the design and implementation of WDAT/WDT is driven by the utilities and under federal jurisdiction. As a consequence, the CPUC is extremely constrained in what it can do to improve WDAT/WDT, and WDAT/WDT is less amenable to California stakeholder-driven refinements and modernization compared to the CPUC's Rule 21 and the CAISO's interconnection process for larger resources. Recognizing those constraints, we see progress in local resource developers' experience with WDAT/WDT as essential to enabling a more robust market for community-level resources. Ongoing, meaningful, improvements to WDAT/WDT should be a priority for enabling community resources, observing that WDAT/WDT has been problematic for developers, and with the understanding that interconnection processes can create major barriers to resource developers through lengthy and highly uncertain timelines, and through large and highly uncertain upgrade costs.

Through its advocacy at FERC with other state agencies, the CPUC established a Transmission Project Review Process (TPR Process), launching January 1, 2024, which enables more robust engagement of California stakeholders in the development of the utilities' FERC-jurisdictional transmission investment plans (CPUC 2023b). A similar concept for stakeholder review may be possible for future WDAT/WDT refinements and modernization. We recommend that the CPUC continue to seek and implement solutions to help smaller local developers overcome the logistical and financial roadblocks to IOU and CAISO deliverability assessments and potential wires upgrades needed, including consideration of a TPR-like process for WDAT/WDT which explores additional fast track options and financing options for identified wires upgrades.

Integration of community resources in RA capacity procurements, evaluations, and contracts.

Through the above-proposed planning refinements, when long-term RA capacity is procured, local resource owners will better understand what services provide the most value to the grid, and capacity-procuring LSEs will better understand the attributes and availability of community-level resources.

As demonstrated through our case study analysis, community resources providing cross-domain MUA with outage mitigation will be available to different degrees to the wholesale marketplace depending on the time profile of a community's outage risks and individual community needs and priorities. The CPUC's RA capacity program architecture already allows for RA capacity procurement on a monthly scale, although, in practice, that is used for shorter-term capacity procurements rather than long-term contracts. The CPUC's emerging Slice-of-Day framework provides even more potential for community-level resources to participate in the RA capacity marketplace, by defining RA capacity needs and obligations both by month and hour of day (CPUC 2022c). We recommend further exploration of how community-level outage mitigation resources can integrate with the Slice-of-Day framework, develop monthly and hourly profiles to their RA capacity supply offers, and compete side-by-side with transmission-connected resources in the RA capacity marketplace.

We also recommend consideration of how community resilience resources can be recognized in the LSE's RA capacity procurements for their attributes towards California Public Utilities Code Section 454.52(a)(1)(G) requirements for IRPs to: "Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."

To be clear, we are not proposing a procurement carveout for community resources. But one way their resource attributes which strengthen diversity, sustainability, and resilience can be recognized, for example, is through prioritization in the LSEs' "best fit" evaluations.

Not all customer- and community-serving resources will be able to provide RA capacity services to the transmission system.

In some parts of the state, outage risks mostly do not compete with system RA needs, such as in areas with a distinct winter outage problem. In these areas, customers could operate energy storage normally during an RA emergency, accepting some RA-driven outage risks, and provide RA capacity value through a Slice-of-Day-based mechanism.

In other parts of the state, outage risks compete with system RA needs and cross-domain MUA is more challenging, such as in areas with a summer and fall outage problem. In these areas, the policy approach should seek to limit the situation in which energy storage is held fully on reserve for outage mitigation and the customer is withdrawing from the grid during an RA emergency. An RA participation or contribution model that compensates customers for islanding and verifiably self-supplying RA during RA emergencies, for example, would improve synergies with customers and the grid, and would support energy independence for these customers. We recommend further exploration of this issue, in tandem with the issue raised above on RA capacity qualification up to onsite load without a transmission deliverability study.

Recommendations. Improving access to the wholesale marketplace for all types of resources that can provide actual and verifiable services to the transmission grid will unlock the potential of cross-domain multiple use applications (MUA), reduce financial barriers to local resource solutions, and provide more RA capacity options to support system reliability.

Towards this strategy that starts with enabling cross-domain MUA, our recommendations to the CPUC are to:

- As recommended in the *CPUC Energy Storage Procurement Study*, explore opportunities to **bring stronger grid signals to customers** and, as part of that effort, consider mechanisms that **allow customers to tailor their participation in programs** based on their reliability and resilience risk tolerances, and based on the time profile (e.g., monthly and hourly) of their local outage risks.
- **Explore planning and procurement refinements for community-level resources to access and better synergize with the RA capacity marketplace**, such as incorporation of new information on community-level resources and community resilience planning activities in the IRP process, exploration of appropriate procurement mechanisms for community-level resources, and consideration of how community-level resources can utilize the Slice-of-Day framework to enter the RA capacity marketplace.
- Implement solutions to **help smaller local developers overcome the logistical and financial roadblocks to IOU and CAISO deliverability assessments and potential wires upgrades needed**, such as clearer information sources on a specific resource's pathway to RA capacity qualification, and consideration of a Transmission Project Review-like stakeholder engagement process for future WDAT/WDT refinements and modernization.
- **Consider RA capacity market participation models for resources in parts of the state where local outage risks compete with providing RA capacity to the bulk grid**, for example, program and compensation mechanisms to verifiably self-supply RA capacity during grid emergencies, regardless of upstream distribution and transmission deliverability.

Recommended policy actions to support cross-domain MUA with distribution deferral

The 2023 *CPUC Energy Storage Procurement Study* observed, in the advanced stages of procurement, distribution-connected energy storage developed to defer specific distribution investments faced major challenges as the size and timing of identified needs changed over time.

Digging deeper into the underlying distribution deferral (DD) planning and procurement processes, we also find several challenges that limit the visibility of energy storage opportunities. The utilities' distribution deferral opportunity (DDO) forecasting methods cannot foresee nearly 90% of DDOs more than 3 years ahead of time, yet their timing screens only consider a DDO viable if identified far in advance. This is driven, in part, by short notice on "known loads" and the approach to define a DDO only if a wires solution is already partly through the planning process. This yields a "just-in-time" forecasting methodology through which the IOUs cannot identify a DDO until it is too late to procure a non-wires solution for it, in other words, systematic under-forecasting of DD procurement opportunities.

In addition, the utilities' market screens consider a DDO viable if the need is small enough and spread across a large enough geography such that an aggregator would have a relatively high chance of enrolling enough customer-sited resources—excluding, in the process, DDOs that would be best met by the more centralized and more easily scalable solution of distribution-connected energy storage.

Combined, the DDO timing and market screens excluded 95% of opportunities for distribution-connected storage identified over the past 5 years. The resulting distribution deferral procurement marketplace, dominated by distribution-connected energy storage providers (not customer aggregators), is so thin that 45% of the procurements were unsuccessful due to lack of offers, lack of a feasible portfolio, or lack of cost-effectiveness. Another 16% of procurements were canceled or delayed during the procurement process due to stringent requirements on project size and timing.

It is clear that developers relying on the current distribution deferral procurement process have a low chance of securing a revenue stream.

For the economic viability of storage procured for distribution deferral, actual installations plus our analysis of 63 potential projects highlight both the feasibility and the importance of value-stacking with RA capacity and energy markets. But for developers to consider building distribution-connected projects at a cost premium rather than transmission-connected projects, they crucially need a positive revenue outlook for distribution deferral services.

Our research and analysis indicate that removing barriers to the distribution deferral marketplace could unlock a resource potential on the order of 100–200 distribution deferral projects every year.

As a replacement to the current DD procurement framework, integration of DD with the more robust RA capacity procurements would facilitate this beneficial cross-domain MUA, but three issues would need to be addressed for a successful marketplace. Firstly, mechanisms to access, improve upon, and expand the 3+ year forecasts of DDOs across all potential distribution facilities need to be in place. Secondly, bidders, developers, and resource operators would require clear and detailed information from the GNA and DDO planning processes in order to best understand the likely timing, call windows, and DD payments of each potential DDO—plus assurances that if their resource is installed at the right time and place they will have the option to provide DD services. Thirdly, contracts need to be clear about the prioritization of services and value-stacking rules when RA capacity needs conflict with DD needs, but contracts should also provide the flexibility needed to enable value-stacking (rather than "all or nothing" revenue streams).

The CPUC's Track 1 Phase 1 Staff Proposal under Rulemaking 21-06-017 discusses a number of challenges in overall distribution system planning, especially in light of rapid transportation electrification and a need to identify priority investments (CPUC 2024c). Our suggested policy changes to enable a more robust DD marketplace would remove major barriers to cost-effective, community-focused, MUA energy storage solutions when and where needed wires investments are likely to be delayed or costly.

Recommendations. Most of the elements of the CPUC and IOU's distribution deferral opportunity planning process can be re-framed into a planning and procurement process which improves both (a) the success of distribution deferral procurements and (b) the business case for developers to consider resources capable of providing distribution deferral services. This is achieved by circumventing the many planning and procurement barriers stemming from the IOUs' "just in time" (but too late for new energy storage development) forecasts of distribution deferral opportunities.

To better enable scaling of distribution deferral services, our recommendations to the CPUC are to:

- Reframe the GNAs and DDORs to **produce an annually updated data library which includes the IOU's best and most granular information on when a distribution deferral need is likely to occur on each distribution feeder and substation**.
    - This is similar to what the GNAs/DDORs produce today, but stops short of the filters, screens, and rankings (tiering) the IOUs apply to narrow hundreds of potential DDOs to a handful of procurements. It also provides more comprehensive information on distribution deferral characteristics across all feeders and substations.
    - Importantly, the information should include an estimate of distribution deferral call windows and of potential deferred distribution investment costs.
- **Provide this information on a timely basis to developers** potentially participating in the RA capacity program, with sufficient data granularity and accessibility to enable developers to refine the 3+ year forecasts of when and where distribution deferral needs will occur.
- Allow developers to offer distribution-connected resources into RA capacity procurements with **contract provisions that guarantee if and when contracted resources are "right" about distribution deferral needs they will have the option to provide that service and be compensated accordingly**.
    - This option to provide distribution deferral service should be available regardless if their siting choice is based on the IOU's DDO forecast or the developer's own forecast.
- During the RA contract term, to determine when and where actual distribution deferral needs occur, **use the IOUs' existing GNA and DDOR analytical architecture to estimate DDOs assuming the counterfactual without the contracted resource**. If a DDO is identified, the contract option to provide distribution deferral service is activated, and avoided distribution deferral payments are based directly or indirectly on the planning estimate (above).
- Assuming RA capacity is the primary use case, **allow distribution deferral service to be provided voluntarily, with performance-based distribution deferral payments and a wires upgrade backstop**. In the IOUs' GNA and DDOR analysis (above) implement facility loading thresholds that trigger a backstop distribution wires upgrade. The backstop would be implemented based on actual distribution facility loadings and energy storage resource performance during distribution deferral call windows.

Concluding Remarks

CPUC Scaling Up and Crossing Bounds reaffirms and builds upon several recommendations from the inaugural evaluation in 2023, *CPUC Energy Storage Procurement Study*. All recommendations from the 2023 evaluation continue to be relevant and important to the development of an energy storage fleet that effectively and efficiently meets state goals.

Installed energy storage capacity participating in the CAISO marketplace is growing rapidly as the state continues to build storage to meet future reliability needs while also decarbonizing its grid. In the last half of 2021 actual grid-scale battery resources in the CAISO marketplace more than doubled from about 1,100 MW to about 2,500 MW. Then, by the end of 2023, installations reached nearly 7,500 MW. This growth is driven by procurements to meet system resource adequacy needs.

In 2022 and 2023 the energy storage use case in the CAISO marketplace continued to transition from ancillary services to energy time shift. Most of the CAISO-participating energy storage resources now regularly charge during low-priced periods in the day and discharge during high-priced periods in the evening. This trend further strengthens the storage fleet’s contributions towards the state’s goals of electricity grid optimization, renewables integration, and greenhouse gas (GHG) emissions reductions.

As transmission-connected battery energy storage scales up, this report offers a few recommended policy actions, incremental to recommendations in the 2023 *CPUC Energy Storage Procurement Study,* to support improved planning and procurement of energy storage participating in the wholesale marketplace.

But distribution-connected and customer-sited energy storage resources also have the potential to provide benefits at a larger scale—and they have the unique ability to provide services to the distribution system and directly to customers and their communities. This report offers case studies to facilitate a better understanding of those opportunities, and it presents recommended policy actions to reduce barriers to development while also improving investment synergies for both customers and ratepayers.

In our evaluations we expand upon the state’s planning and analytical practices to learn from historical resource-specific storage operations, at a fine temporal and spatial granularity, across all grid domains, and across all potential services offered by energy storage resources. In future studies we recommend continuing to build upon this framework. We expect themes in future evaluations to include ongoing policy adjustments towards data collection improvements and refinements, updates to grid planning assumptions, and new and refined procurement strategies as the energy storage fleet scales up and resource types evolve.

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APPENDICES

Appendix A: Historical Energy Storage Benefits

This appendix provides details on our analysis of actual energy storage operations and resource-specific benefits as the energy storage fleet scaled up dramatically in 2022–2023. Figure A-1 shows the list of resources considered in this analysis, including 6 GW of grid-scale energy storage resources that were online by September 2023 and participated in the CAISO marketplace under the Non-Generator Resource model. Due to several data collection barriers discussed in our report, we exclude hybrid and customer-sited resources in our analysis.

CAISO Resource ID	Commercial Online Date	Storage MW	Paired with Renewables
ALAMIT_7_ES1	12/4/2020	100.5	N
ALMASL_2_AL6BT6	6/27/2022	50.0	Y
BIGSKY_2_AS2BT1	9/2/2022	127.0	Y
BIGSKY_2_ASLBT2	7/30/2022	100.0	Y
BLKCRK_2_GMCBT1	6/30/2021	230.0	Y
BLKDIA_2_BDEBT1	3/17/2022	200.0	N
BLM W_2_COSBT1	2/28/2022	60.0	Y
CALFTN_2_CFSBT1	8/31/2021	60.0	Y
CENTPD_2_BMSX2	12/21/2022	112.0	Y
CHINO_2_APEBT1	12/31/2016	20.0	N
CHINO_2_PESBT1	7/8/2023	20.0	N
CRELMN_6_AABBT1	8/15/2023	0.5	N
CRIMSN_2_CRMBT1	9/16/2022	200.0	Y
CRIMSN_2_CRMBT2	10/28/2022	150.0	Y
DRACKR_2_DSUBT1	8/12/2021	63.0	Y
DRACKR_2_DSUBT2	4/8/2021	115.0	Y
DRACKR_2_DSUBT3	7/23/2021	115.0	Y
DRACKR_2_DSUBT4	9/28/2022	47.0	Y
DSRTHV_2_DH2BT1	6/10/2021	35.0	Y
DSRTSN_2_DS2X2	8/28/2022	230.0	Y
ELCAJN_6_EB1BT1	2/18/2017	7.5	N
ELKHRN_1_EESX3	4/7/2022	182.5	N
ESCNDO_6_EB1BT1	3/6/2017	10.0	N
ESCNDO_6_EB2BT2	3/6/2017	10.0	N
ESCNDO_6_EB3BT3	3/6/2017	10.0	N
ESNHWR_2_WC1BT1	10/13/2021	3.0	N
FALBRK_6_FESBT1	5/3/2023	40.0	N
FIFTHS_2_FSSBT	9/15/2023	137.0	Y
GARLND_2_GARBT1	1/31/2022	88.0	Y
GASKW1_2_GW2BT1	5/5/2023	20.0	Y
GATEWY_2_GESBT1	9/16/2020	250.0	N
GOLETA_2_VALBT1	2/4/2021	10.0	N
HENRTA_6_HDEBT1	11/4/2021	10.0	N
HIGHDS_2_H5SBT1	12/8/2021	50.0	Y
JOANEC_2_ST3BT3	6/2/2023	40.0	N
JOANEC_2_STABT1	6/11/2021	20.0	N
JOANEC_2_STABT2	6/6/2022	20.0	N
JOHANN_2_JOSBT1	10/29/2021	10.0	N
JOHANN_2_JOSBT2	10/29/2021	10.0	N
JOHANN_2_OCEBT2	12/7/2021	9.0	N
JOHANN_2_OCEBT3	12/7/2021	6.0	N
KEARNY_6_NESBT1	3/10/2022	10.0	N
KEARNY_6_SESBT2	3/10/2022	10.0	N
KRAMER_1_R1BX3	7/1/2023	75.0	Y
KRAMER_1_R2BX2	8/30/2023	40.0	Y
KYCORA_6_KMSBT1	2/13/2020	1.0	N
LECONT_2_LESBT1	9/1/2022	125.0	N
MARVEL_2_MARBT3	7/24/2023	74.9	N
MARVEL_2_MARBX2	7/18/2023	325.0	N
MIRLOM_2_MLBBTA	12/30/2016	10.0	N
MIRLOM_2_MLBBTB	12/30/2016	10.0	N
MONLTH_6_BATTRY	4/8/2016	8.0	N
MOORPK_2_ACOBT1	3/31/2021	2.0	N
MRGT_6_TGEBT1	6/30/2021	30.0	N
MSTANG_2_MTGBT1	11/1/2021	75.0	Y
NORCNV_1_NCVBT1	8/30/2023	132.0	N
PEASE_1_TBEBT1	6/1/2022	6.0	N
PRCTVY_1_MIGBT1	12/12/2018	2.0	N
SANBRN_2_ESABT1	11/19/2021	100.0	Y
SANBRN_2_ESBBT1	11/1/2021	100.0	Y
SANTGO_2_MABBT1	1/14/2017	2.0	N
SISPRG_2_DS3BT2	8/24/2023	60.0	Y
SISPRG_2_DS3BT3	9/5/2023	12.5	Y
SISPRG_2_DS3BT4	8/24/2023	15.0	Y
SNCLRA_2_SILBT1	4/1/2021	11.0	N
SNCLRA_2_VESBT1	4/20/2021	100.0	N
STANTN_2_SBEBX2	7/19/2023	68.8	N
SUNCAT_2_A1ABT1	8/1/2022	47.0	Y
SUNCAT_2_A1BBT1	8/1/2022	63.0	Y
SUNCAT_2_A2ABT2	8/16/2022	132.0	Y
SWIFT_1_NAS	6/30/2013	4.0	N
TRNQLT_2_RETBT1	3/16/2022	72.0	Y
VACADX_1_NAS	7/30/2014	2.0	N
VISTRA_5_DALBT1	3/23/2021	100.0	N
VISTRA_5_DALBT2	3/23/2021	100.0	N
VISTRA_5_DALBT3	4/6/2021	100.0	N
VISTRA_5_DALBT4	7/28/2021	100.0	N
VISTRA_5_PLABT1	5/13/2023	100.4	N
VISTRA_5_PLABT2	6/1/2023	100.4	N
VISTRA_5_PLABT3	5/16/2023	74.6	N
VISTRA_5_PLABT4	6/2/2023	74.6	N
VLCNTR_6_VCEBT1	11/29/2021	54.0	N
VLCNTR_6_VCEBT2	12/16/2021	85.0	N
VSTAES_6_VESBT1	6/26/2018	40.0	N
WESCAN_2_BDSBT1	6/23/2023	131.0	N
WSTWND_2_M89BT2	5/25/2023	70.6	Y
WSTWND_2_SBSBT1	5/23/2023	80.0	Y
YELPIN_2_YP2BT1	7/26/2023	65.0	Y

Figure A-1: List of energy storage resources included in the 2017–2023 historical analysis.

Data Sources

For our analysis, we primarily rely on market data provided by the CAISO, including interval-level resource-specific storage operations, day-ahead and real-time market settlements, market prices, and other system data from January 2017 through November 2023. CPUC provided updated information on RA contracts and prices for the study.

We also use the data and documents previously compiled for the 2023 *CPUC Energy Storage Procurement Study*, including storage resource characteristics, procurement details, and a variety of other supporting information.

Benefit Analysis and Metrics

The study focuses on total electric system impacts and benefits, developed using the same methodology applied for the 2023 *CPUC Energy Storage Procurement Study*.

We consider the following benefit metrics:

- **Energy and ancillary services value**, net of storage charging costs;
- **GHG emissions reduction value**, already captured under energy value;
- **RPS benefits**, associated with avoided renewable curtailments;
- **Resource adequacy (RA) capacity value**, including system, local, and flexible RA attributes;
- **T&D investment deferral value**, set to zero as none of the CAISO resources in our study deferred an actual wires investment;
- **Customer outage mitigation value**, a private benefit to customers installing distributed storage; not applicable for the grid-scale CAISO resources analyzed, except distribution-connected storage in microgrids.

As shown in Figure A-2, estimated benefits are expressed in $/kW-month, which allows for comparison among resources with different sizes and operational periods. All final metrics are converted to real 2023 dollars by adjusting for inflation using the GDP deflator.

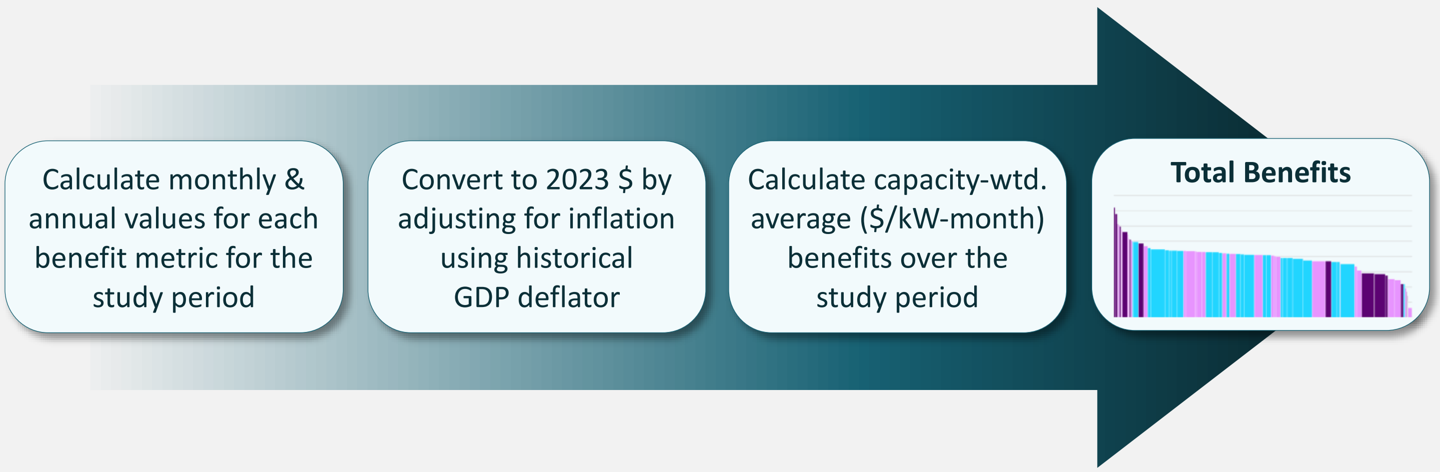


Figure A-2: Calculation of total system benefit metrics for final comparisons.

Energy and Ancillary Services Market Value

Energy storage can provide various bulk grid-level energy and ancillary services benefits, including:

- **Energy time shift** by charging at low-priced hours and discharging at high-priced hours,
- **Frequency regulation** by automatically responding to CAISO's control signals to address small random variations in supply and demand,
- **Contingency reserves (spin and non-spin)** to quickly respond in case of an unexpected loss of supply on the system,
- **Flexible ramping** by providing upward and downward ramping capability to help CAISO manage rapid changes in the system due to demand and renewable forecasting errors,
- **Voltage support** to help dynamically maintain stable voltage levels in the distribution system or transmission grid, and
- **Blackstart** by self-starting without an external power supply and helping the grid recover from a local or system-level blackout.

We rely on actual metered data and resource-specific settlements in the day-ahead and real-time markets to calculate energy and ancillary services market benefits of grid-scale storage resources participating in the CAISO marketplace.

Figure A-3 shows the monthly and 12-month rolling average value of energy and ancillary services provided by the CAISO's storage fleet. During 2018–2020, high revenue opportunities in the regulation markets attracted many of the resources and resulted in use cases that are more focused on ancillary services. Starting 2021, with significantly more battery storage connected to the CAISO system, the share of storage capacity used for ancillary services declined rapidly and the wholesale market value proposition moved to bulk energy time shift.

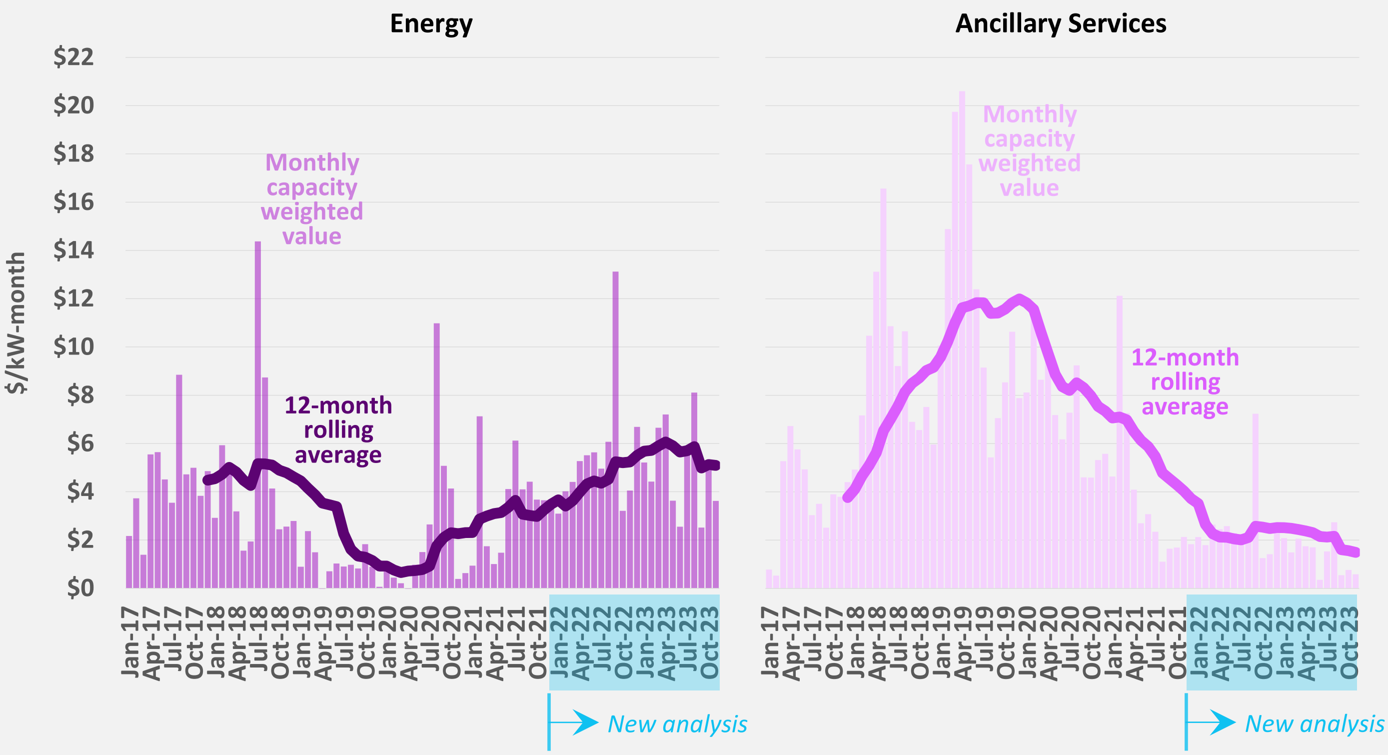


Figure A-3: Average CAISO energy and ancillary services revenues across energy storage fleet (in 2023 $).

Figure A-4 (right) compares historical energy and ancillary services revenues across all CAISO-participating storage projects included in our study. Each bar corresponds to a project, with the stacked value sorted from highest to lowest. The values are averaged over each project's operational period within the 2017–2023 timeframe.

For early storage projects included in our first study, a large share of wholesale revenues came from the CAISO's regulation markets. However, for many of the new storage projects installed in recent years, energy revenues accounted for the bulk of CAISO market revenues. For these new projects, average energy revenues have been \$5–\$7 per kW-month, which is consistent with the future value potential we estimated in the 2023 *CPUC Energy Storage Procurement Study*.

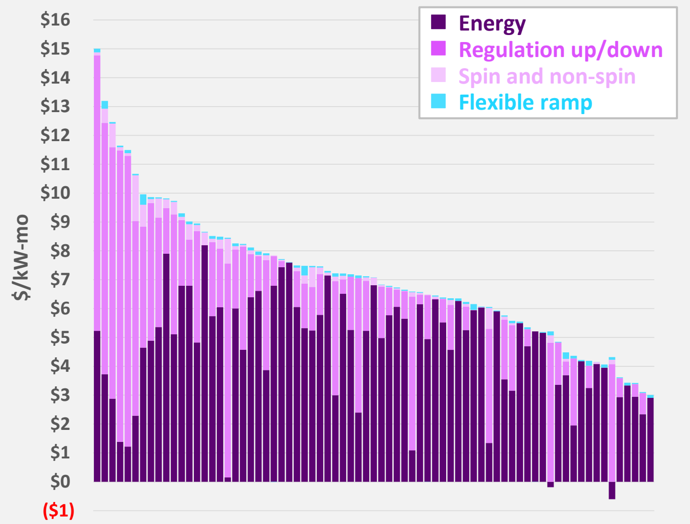


Figure A-4: Average CAISO energy and ancillary services revenue by storage project (in 2023 \$).

GHG Emissions Reduction Value

We estimate net GHG emissions impact of energy storage resources based on their actual energy output multiplied by historical marginal GHG emission rates at the 5-minute interval level. Energy storage reduces emissions at the marginal rate when discharging, and it increases emissions at the marginal rate when charging. We rely on WattTime's historical real-time marginal GHG signal, which was created to evaluate emissions impacts of SGIP projects. CPUC adopted the use of this GHG signal in 2019 under D.19-08-001 to align resource performance with the program's emission reduction goals. Under the approved methodology, the GHG signals are derived from 5-minute real-time marginal energy prices. Within the CAISO, the GHG signals are calculated for each of the three IOUs: PG&E, SCE, and SDG&E.

Figure A-5 (below) illustrates the distribution of marginal GHG intensity based on a heatplot of GHG signals used in the study. Blue indicates low emission rates and red indicates high emission rates. Pixels moving horizontally correspond to each 5-minute interval of the day, and pixels moving vertically correspond to each day of the year over the study period.

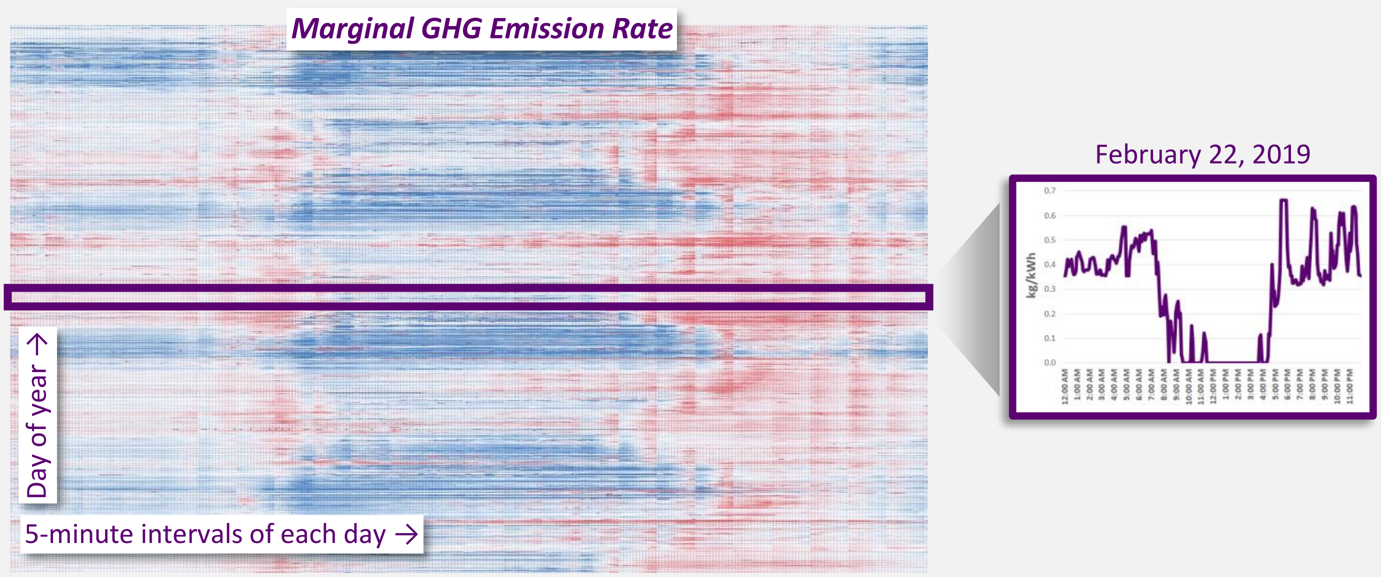


Figure A-5: Heatplot of historical marginal GHG emission rates used in the study.

For energy storage resources to reduce GHG emissions, (a) they need to be highly efficient, and (b) their use cases should allow shifting bulk energy from periods with low GHG emissions intensity to periods with high GHG emissions intensity. The 2023 *CPUC Energy Storage Procurement Study* highlighted the drawbacks of the frequency regulation use case resulting in GHG emissions increases. With more emphasis on energy time shift, the majority of CAISO's storage fleet is now actively reducing GHG emissions.

Total fleetwide GHG emissions reductions over the 2017–2023 study period were around 1.6 million tonnes, most of which were realized in recent years. The CAISO-participating energy storage resources in our analysis enabled nearly 1 million tonnes of GHG emissions reductions during the 12-month period ending in November 2023. The subset of resources analyzed in the 2023 *CPUC Energy Storage Procurement Study* provided almost 200,000 tonnes in reductions. Newer resources scaled up those benefits as the fleet grew, providing close to 800,000 tonnes of additional GHG emissions reductions in that year.

Figure A-6 shows the resource-specific results. On average, energy storage co-located with solar PV provided higher GHG emissions reduction benefits than standalone energy storage. Among the newer resources analyzed, energy storage co-located with solar PV reduced 19 tonnes of GHG emissions per MW-month, compared to 10 tonnes/MW-month for standalone storage. This difference is partly due to more operational focus on energy time shift, and partly due to location. Most co-located energy storage resources are in southern California, where the GHG reduction potential tends to be higher due to lower marginal GHG rates during the day.

The GHG emissions reduction dollar value based on allowance prices observed in the cap-and-trade market are already reflected in the CAISO's market prices and energy value of storage projects. As discussed in our first study, electric sector GHG targets implemented in the IRP may require investments at a cost higher than the California's cap-and-trade prices, but this incremental cost (GHG adder) is estimated to be zero through 2030 due to the amount of renewables already procured for reliability and tax credits. Consistent with this finding from the CPUC's 2022 Avoided Cost Calculator, we set the GHG adder to $0 for our study period 2017–2023.

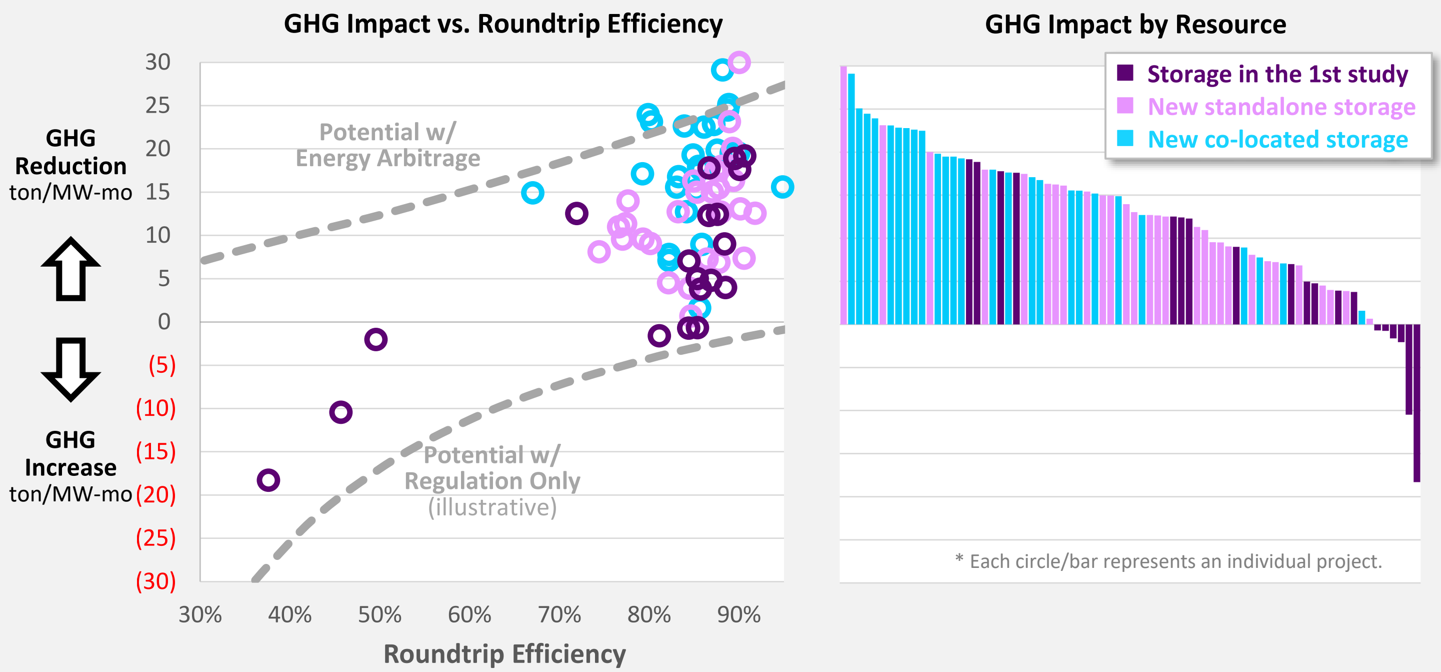


Figure A-6: Estimated average GHG emissions impact of energy storage resources in CAISO.

RPS Benefits

Curtailing the output of renewable resources is a necessary tool for CAISO to manage oversupply, when there is excess generation above what can be consumed within the system or exported. With rapid growth in solar and wind resources, the curtailments in CAISO have been rising steadily. In 2017, CAISO curtailed around 400,000 MWh of renewable generation. By 2023, curtailments reached almost 2.7 million MWh per year.

Energy storage can reduce renewable curtailments by charging to mitigate oversupply conditions, which may become more challenging as California continues to decarbonize its electric system. As illustrated in Figure A-7, charging of energy storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

The avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet Renewables Portfolio Standard (RPS) and other clean energy targets. We estimate the impact of energy storage on renewable curtailments based on their net charge during intervals with actual curtailments, using system data provided by CAISO. In recent years, local congestion accounted for around 70–80% of the renewable curtailments in CAISO, while the remaining 20-30% was due to systemwide oversupply. To determine if an energy storage resource is in a curtailment zone when the curtailment events are driven by local transmission congestion, rather than systemwide oversupply, we utilize historical nodal real-time LMPs. During such events, the local areas where the renewable resources are curtailed experience very low or even negative LMPs, while prices for the rest of the system remain considerably higher. On the other hand, during curtailments related to systemwide oversupply, the entire CAISO system experiences significantly reduced or negative LMP levels.

Based on historical data, we estimate that most of the energy storage resources were at locations experiencing 1 to 2 hours of curtailments per day, on average. Charging at full capacity in these hours would yield 30–60 MWh of monthly curtailment reductions per MW of storage capacity. The 2023 *CPUC Energy Storage Procurement Study* unveiled much smaller realized benefits, as very few resources focused on bulk energy time shift at that time. However, as the wholesale market use case continues to evolve, most CAISO-participating energy storage resources now regularly charge during low-priced periods in the day and discharge during high-priced periods in the evening, which facilitates renewable integration by reducing curtailments.

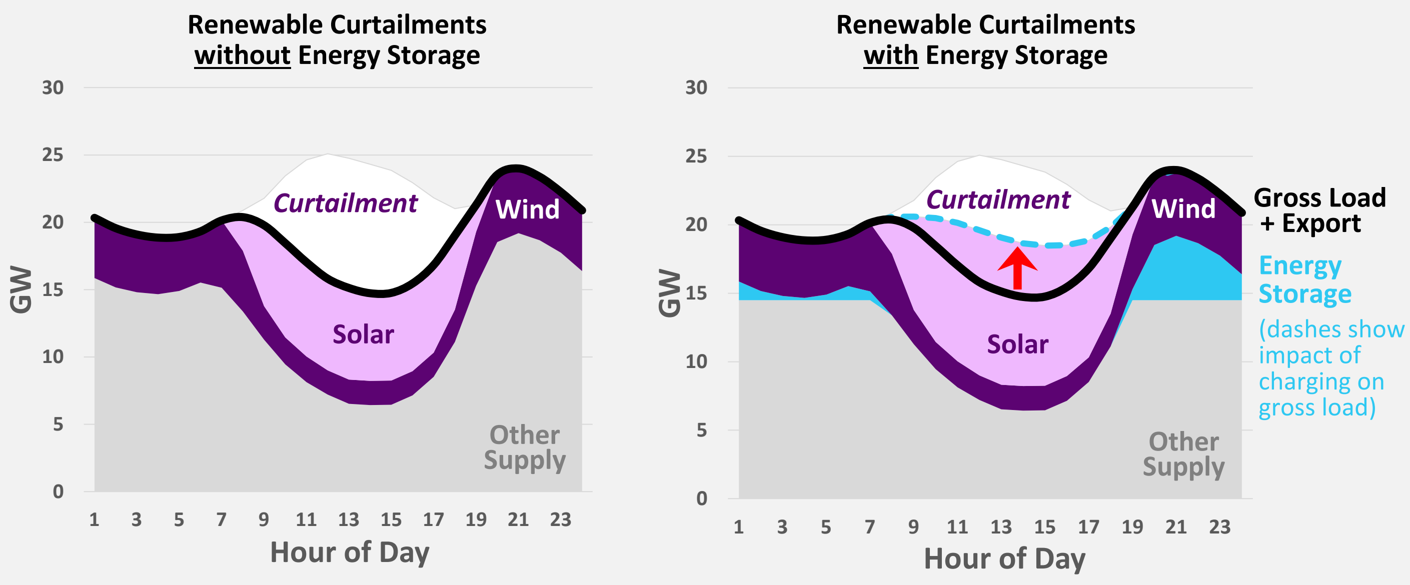


Figure A-7: Illustration of energy storage impact on renewable curtailments.

Figure A-8 shows the resource-specific impacts on renewable curtailments. The results highlight that the energy storage fleet is increasingly helping with the integration of renewable energy resources by mitigating oversupply.

Avoided renewable curtailments are significantly higher for the newer resources, especially energy storage co-located with PV, because they were sited in areas experiencing higher curtailments and they charged more regularly when oversupply conditions emerged.

We quantify the benefits for avoided renewable curtailments using the RPS adders published in CPUC's Power Charge Indifference Adjustment reflecting incremental value of RPS-eligible energy based on historical transactions. The RPS adders were in the range of $13 to $16.5/MWh through 2022, but increased to $30/MWh recently in 2023, which indicates that the cost of meeting the state's RPS is rising.

These results translate to RPS benefits of up to $1.5/kW-month for the top resources and around $0.5/kW-month for the energy storage fleet, on average.

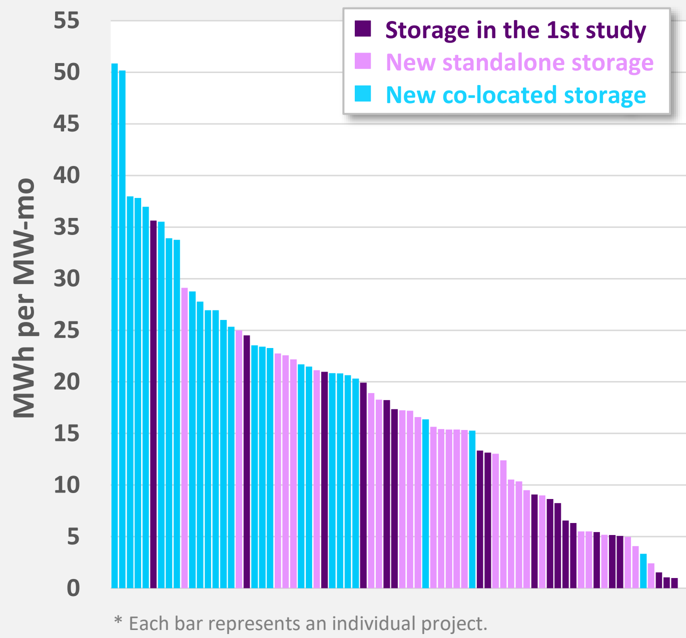


Figure A-8: Estimated average renewable curtailment impact of energy storage resources in CAISO.

Resource Adequacy (RA) Capacity Value

Energy storage resources can be available to discharge during peak periods to help with meeting the system RA, local RA, and flexible RA capacity requirements to ensure grid reliability in California.

Our analysis of the RA capacity value reflects the avoided cost of market alternatives to the energy storage resource analyzed, which varies based on its location and circumstances under which it was procured. Most energy storage resources in our study were procured to address various reliability and resource adequacy needs in California. Specific RA needs, development timelines, and available alternatives depend on the procurement track, thus require a different counterfactual for the purposes of estimating RA capacity value. For each storage procurement track, we reviewed numerous documents including the underlying procurement orders, utility applications, solicitation materials, and related data and reports to develop counterfactual cases that reflect the specific environment under which the resources were procured.

The significant growth of energy storage installations in 2020 through mid-2021 was driven by various procurements to address *local capacity needs* near load pockets, with a relatively high RA capacity value. Most grid-scale projects included in our first study were procured for local reliability to replace retirement of once-through-cooling (OTC) power plants, address challenges caused by the prolonged natural gas leak at Aliso Canyon and eliminate the need for reliability-must-run (RMR) contracts. An overview of these procurement tracks, counterfactual cases, and estimated RA values ranging from $7 to $20 per kW-month are provided in the 2023 *CPUC Energy Storage Procurement Study*.

Energy storage installations from the second half of 2021 through 2023 are primarily a result of the procurement orders to address emerging *system reliability needs* identified in CPUC's Integrated Resource Planning (IRP) studies. To estimate the RA capacity value of these projects, we relied on the historical RA contract and price data compiled by the CPUC based on information submitted by LSEs.

First, we filter the data for annual strips to get an estimate of average year-around RA prices, excluding short monthly or seasonal RA contracts. After that, to approximate marginal RA values, we use the 90th percentile (P90) of the RA prices for contracts. Here, the use of P90 rather than the highest price is to exclude possible outliers of small RA contracts priced at a premium.

Figure A-9 summarizes the results. The prices reflect the combined value of system and local RA capacity attributes, rising from $3 in 2018 up to over $10 per kW-month by 2022. Current prices are even higher. The 2023 market price benchmarks in CPUC's latest Power Charge Indifference Adjustment show average system RA price at $14.37 per kW-month (CPUC 2023c) which is nearly 2x higher than the level published in prior PCIA.

While storage can also provide flexible RA to meet forecasted net load ramps, our initial study found no historical price premiums for this service. Thus, we did not incorporate any additional value for it, beyond what is already captured under the system and local RA capacity values.

	2018	2019	2020	2021	2022
CAISO System	$2.8	$3.1	$7.9	$8.2	$10.9
Bay Area	$3.3	$4.7	$8.1	$8.3	$13.6
Big Creek-Ventura	$3.9	$4.7	$8.1	$8.4	$12.4
LA Basin	$3.6	$5.5	$8.0	$9.0	$14.0
San Diego-IV	$2.7	$4.1	$8.0	$8.1	$16.4

Figure A-9: Estimated marginal RA value based on bilateral RA contracts (in 2023 $/kW-month).

T&D Investment Deferral Value

Energy storage can defer the need for new transmission investments by charging during periods with low transmission use and discharging when local transmission system is constrained. If interconnected to the distribution system, energy storage can also defer the need for new distribution investments by reducing local peak loading on the distribution grid. As discussed in the 2023 *CPUC Energy Storage Procurement Study*, these storage use cases are still in early pilot and demonstration phase.

Energy storage resources procured as non-wires alternatives faced major challenges as the size and timing of the identified needs have changed over time, and the development plans and utility-contracted use cases were not flexible to adjust. None of the resources in our historical analysis deferred an actual transmission or distribution investment, so these benefit streams are set to zero.

Customer Outage Mitigation Value

Customer outage mitigation is a crucial component of resilient electricity service to meet essential loads and to protect vulnerable customers, communities, and critical facilities. Distribution-connected storage resources can improve resilience by supporting islanding and microgrid capabilities for sections of the distribution grid and thus help to mitigate the risk of power interruptions at the community level. Storage resources interconnected behind the utility meter can also provide backup power to mitigate impacts of power outages.

Most grid-scale storage resources in the CAISO markets are not sited or configured to provide customer outage mitigation, which underscores the challenges with cross-domain value-stacking. However, there are some recent distribution-connected microgrids with storage designed to support customer resilience while also providing bulk grid services. Due to their hybrid participation and/or limited operating history, these new microgrid projects were not part of this analysis. But separately, we included these projects and discussed their unique characteristics as a part of the cross-domain multi-use application (MUA) case studies—*see* **Appendix E(Case Study Fact Sheets)**.

Total Quantified Benefits

Figure A-10 shows the total quantified electric system benefits over the 2017–2023 timeframe. The top chart highlights the aggregate benefits, color coded by project group, while the bottom chart provides a breakdown of benefit metrics. Each bar represents an individual resource, with its width scaled based on size.

The results demonstrate that CAISO-participating energy storage fleet provided substantial and increasing benefits to the electric system. Across the resources analyzed, we estimate median quantified system benefits at $21/kW-month, with individual results ranging from $3/kW-month to $36/kW-month. Quantified system benefits include avoided cost of energy, ancillary services, system and local RA, and RPS-related investments. As described earlier, the GHG emissions reduction value is already reflected in the CAISO's market prices and estimated energy value of storage projects shown here.

The relatively high benefits of newer resources, higher system RA capacity value on a $/kW-month basis, and higher energy value are all interrelated and contribute to an increasing trend of system benefits from the energy storage fleet.

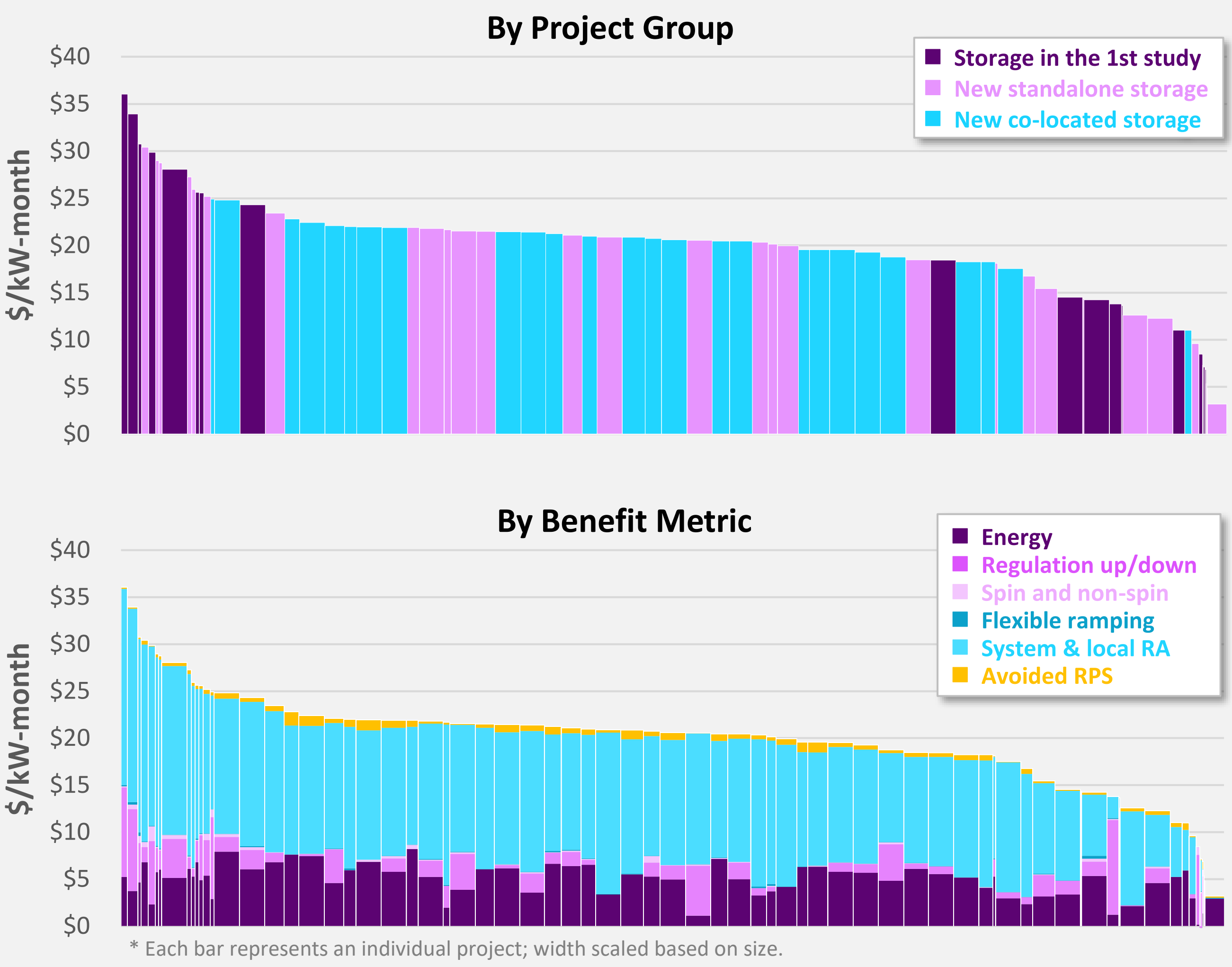


Figure A-10: Estimated system (gross) benefits of energy storage resources in CAISO (in 2023 $).

Project Scoring towards State Goals

Following the same methodology developed for the 2023 *CPUC Energy Storage Procurement Study*, we estimate project scores towards meeting the policy goals identified in the CPUC Decision 13-10-040, including grid optimization, integration of renewable energy, and reduction of greenhouse gas (GHG) emissions.

Figure A-11 shows the list of services and associated benefits considered in our study. Our approach to scoring involves several steps, as described below:

1. First, we map each of the services and benefits to the stated policy goals, as shown in the table;
2. Then, we determine a project score for each service and benefit category based on the use case, utilization of capacity towards providing that service, and observed grid impacts;
3. Later, we calculate a normalized score (0–100) towards each policy goal by averaging individual scores for the relevant services and benefits mapped to that policy goal, and re-scale them so that project at the bottom gets 0 and project at the top gets 100;
4. Last, we develop the final project scores based on the average of their scores for grid optimization, renewables integration, and GHG emissions reduction.

Contribution towards State Goals

	Grid Optimization	Renewables Integration	GHG Emissions Reduction
Energy	✓	indirect	indirect
Ancillary services	✓	✓	indirect
GHG emissions reduction			✓
RPS benefits		✓	indirect
RA capacity	✓		indirect
T&D investment deferral	✓		
Customer outage mitigation	✓		

Figure A-11: Benefit metrics and contributions to state goals.

Grid Optimization

We consider several services and benefits contributing to grid optimization. Through energy time shift and ancillary services, energy storage projects help with more optimal scheduling and dispatch of resources in the wholesale markets, reducing the overall system production cost. With resource adequacy (RA) capacity, transmission deferral, and distribution deferral, storage projects help with meeting grid reliability needs more efficiently at a lower cost. And by providing customer outage mitigation, they increase resilience of the grid and reduce cost of power interruptions.

Renewable Integration

Energy storage projects' contributions towards renewables integration have two components: one based on energy time shift, and another based on ancillary services.

With energy time shift, energy storage can enable renewable integration by charging when the system has oversupply to reduce excess renewable energy that would otherwise get curtailed (see prior Figure A-8). The scores are normalized between 100 for the project with the highest avoided renewable curtailments and 0 for projects not reducing curtailments.

By providing ancillary services, energy storage projects help with meeting the flexibility needs to address increased variability and uncertainty of the net load driven by renewable generation. The scores are normalized between 100 for the project with the highest ancillary services value and 0 for projects not providing ancillary services.

GHG Emissions Reduction

Energy storage charge and discharge patterns impact the GHG emissions on the grid. As described earlier, we estimate net GHG emissions impact of energy storage based on actual output multiplied by historical marginal GHG emission rates. Energy storage resources reduce GHG emissions at the marginal rate when discharging and increases GHG emissions at the marginal rate when charging (see prior Figure A-6). The scores are normalized between 100 for the project with the highest GHG emissions reduction and 0 for projects not reducing emissions.

Final Scores

Figure A-12 shows the scoring for contributions towards meeting state goals based on operations during the 2017–2023 period. Final score (height of bar) is an average of 3 individual scores for grid optimization, renewables integration, and GHG emissions reduction normalized between 0 and 100 in each category. New storage resources paired with PV ranked relatively high, indicating that their use case and services are well-aligned with all three state goals. In contrast, most standalone storage projects ranked lower because their operations did not yield the same level of GHG emissions reductions or avoided renewable curtailments.

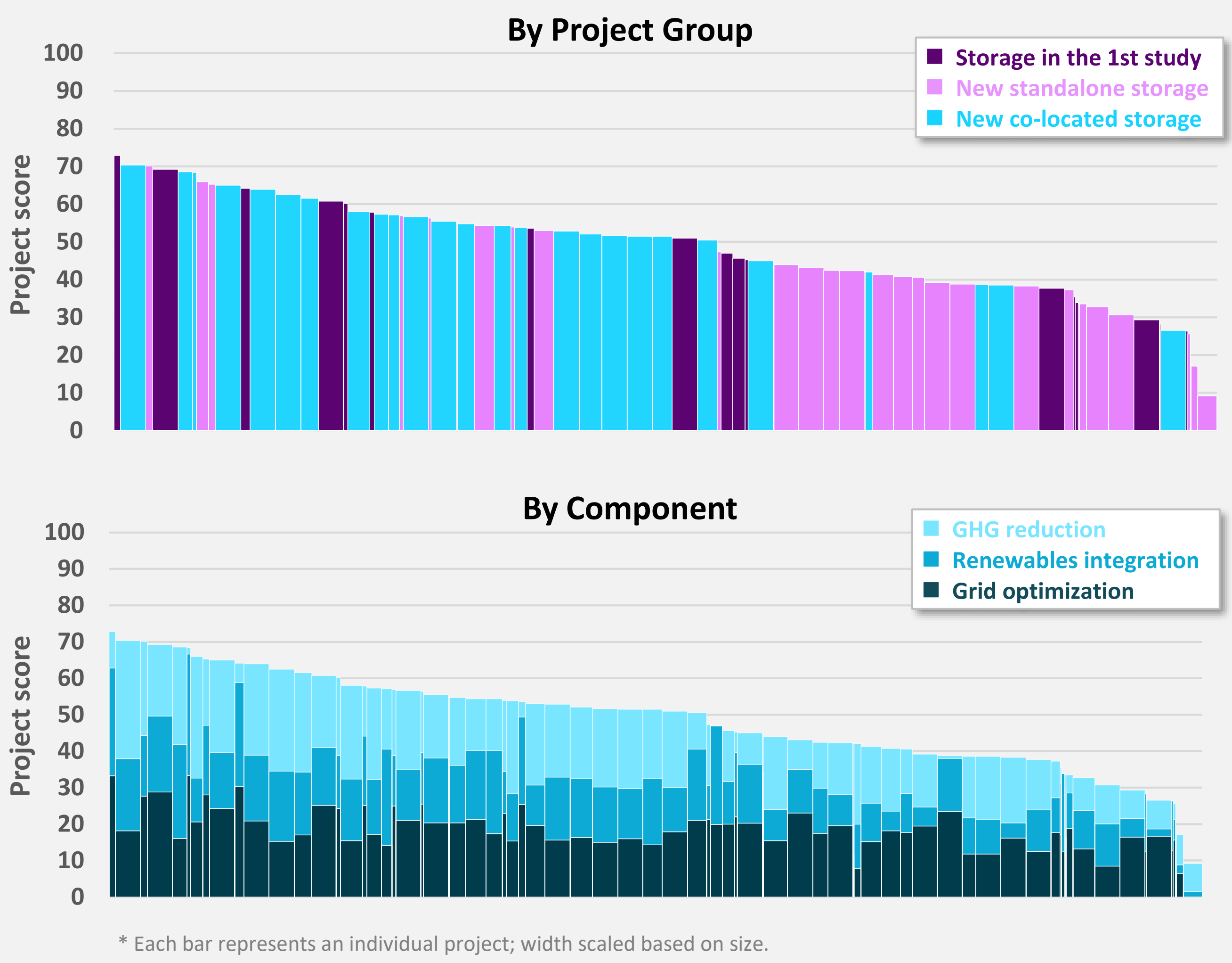


Figure A-12: Final project scores towards state goals.

Appendix B: Historical Energy Storage Performance during Grid-Stressed Periods

This appendix provides details on our investigation of the patterns in, and challenges to, energy storage resource availability in recent years, including during grid-stressed periods. Analyzing historical availability and performance of storage resources during periods such as recent heat waves and system emergency events can help validate and improve future resource planning and procurement efforts of the CPUC and its stakeholders.

The 2023 *CPUC Energy Storage Procurement Study* examined the 2017–2021 period. Nearly all CAISO grid emergencies in that timeframe were observed during the extreme heat waves in August and September of 2020, when there were only a few grid-scale energy storage resources participating in the CAISO market. Since then, energy storage capacity in CAISO grew by more than tenfold as a result of the procurements for system reliability (Figure B-1). Evaluating the operations of this expanded storage fleet during recent grid events, including during the September 2022 heat wave, provides valuable insights on their contributions to system reliability and RA capacity needs in California.

Our analysis includes the same set of CAISO-participating grid-scale energy storage resources considered for the historical benefit analysis—*see* **Appendix A (Historical Energy Storage Benefits)** for a complete list of resources. Details in Figure B-2 through Figure B-15 show the charge and discharge patterns of the energy storage fleet during CAISO systemwide grid emergency events from 2020 through 2023 using interval-level resource-specific meter data provided by the CAISO. The results highlight how the scale and contributions of the resources during grid-stressed periods have changed over time.

In addition to investigating the historical operations of the energy storage fleet during grid emergencies, we also analyze actual resource-specific capacity derates and outage events published by the CAISO for 2022–2023.

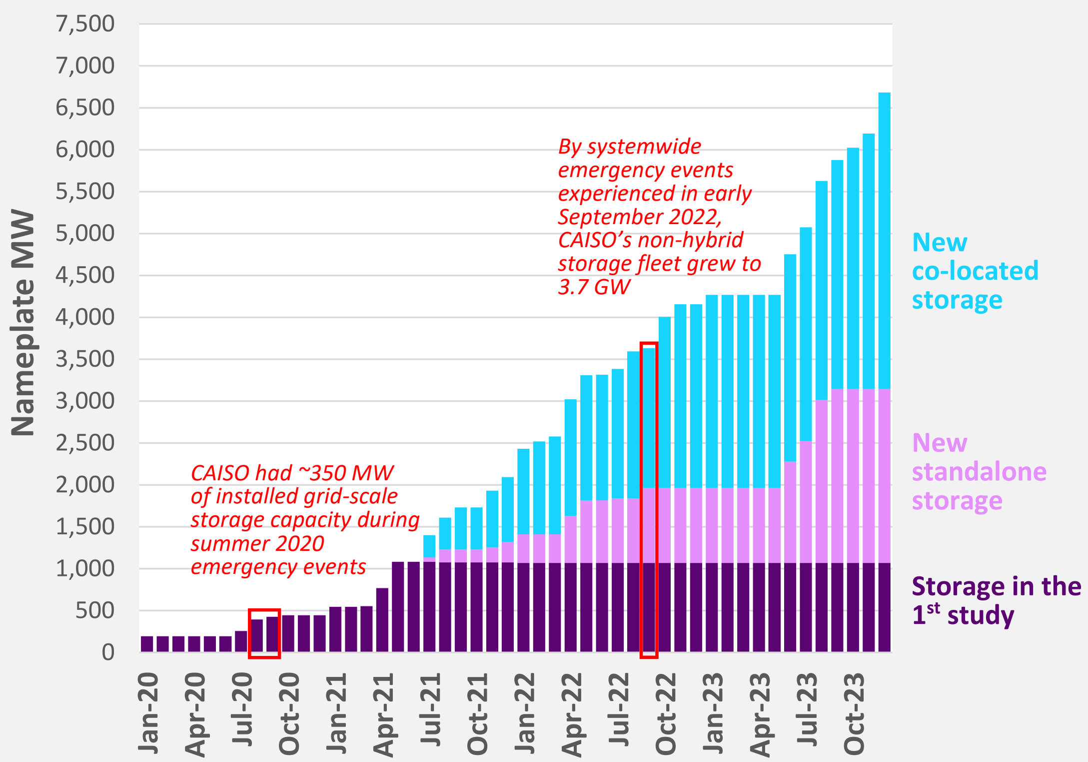
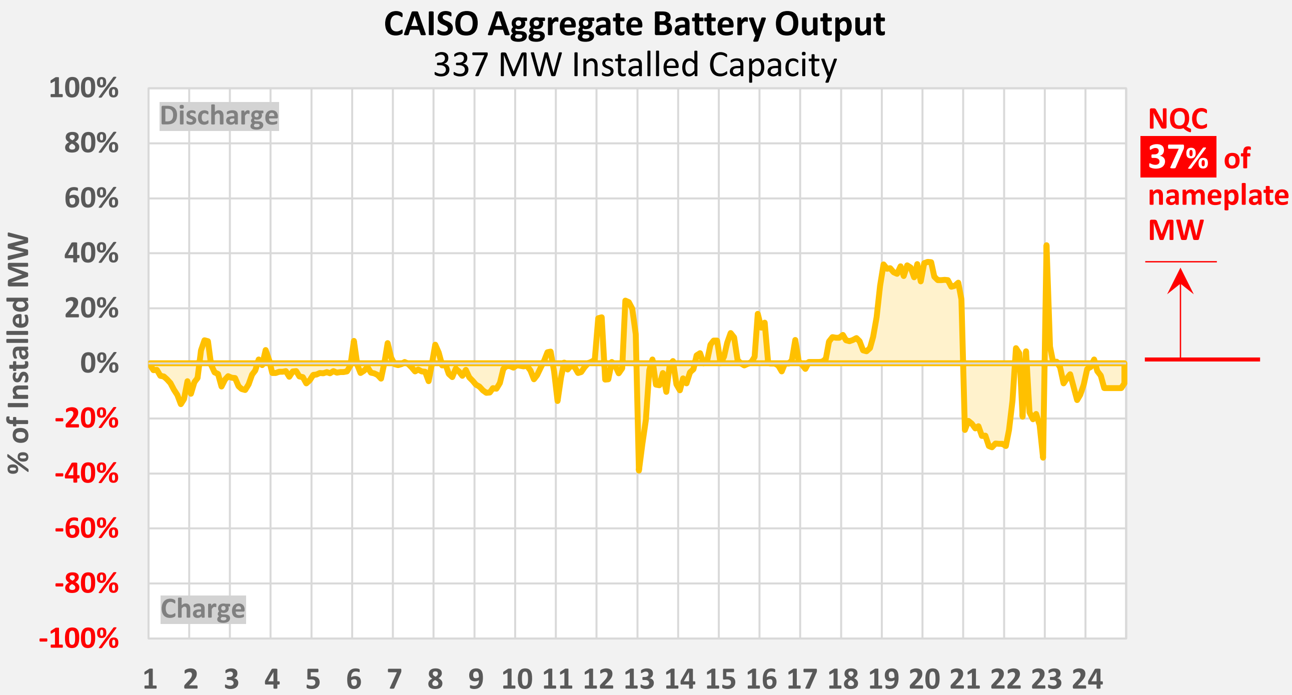


Figure B-1: Grid-scale non-hybrid energy storage capacity in CAISO.

August 14, 2020



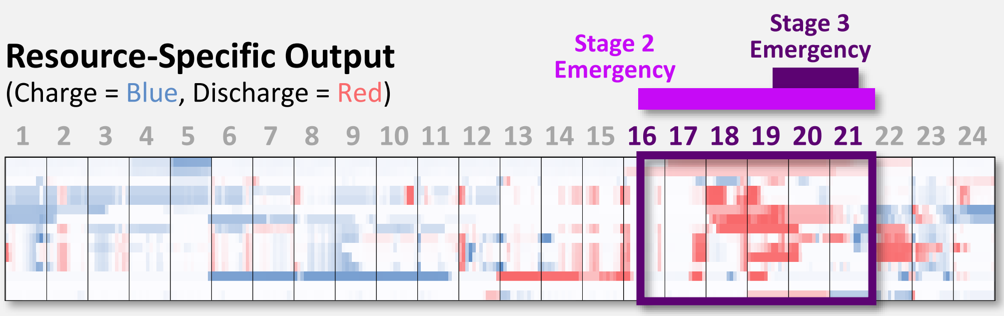
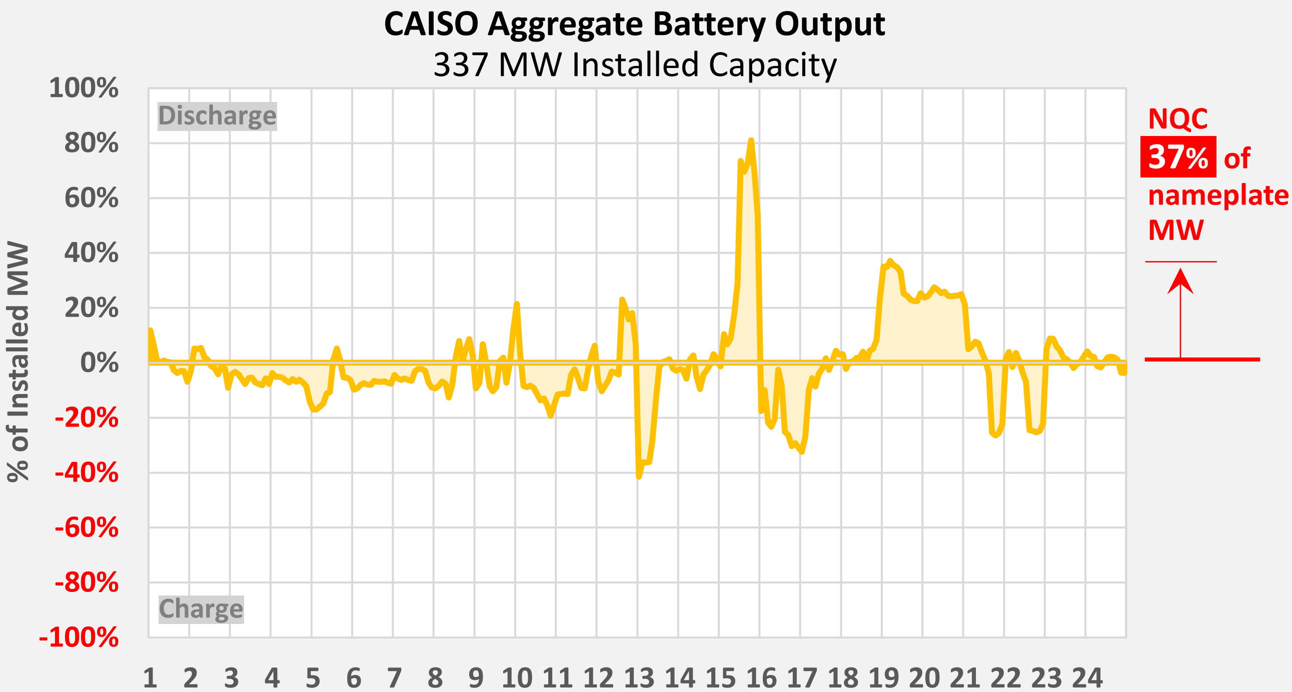


Figure B-2: CAISO battery storage output during emergency event on August 14, 2020.

August 15, 2020



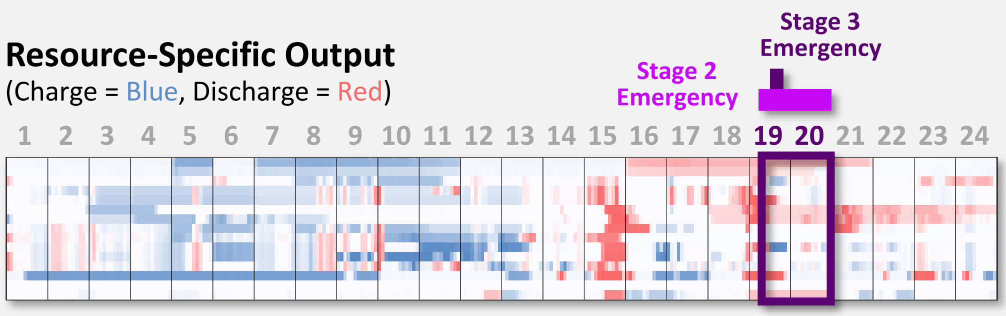
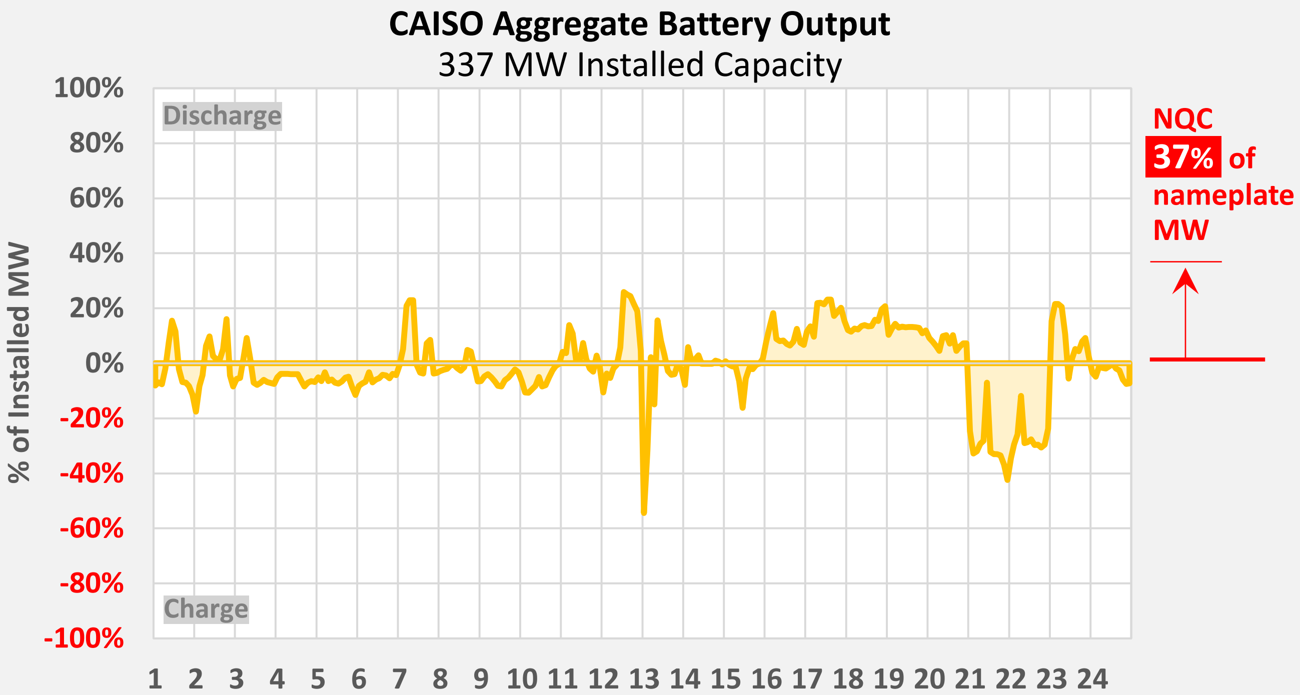


Figure B-3: CAISO battery storage output during emergency events on August 15, 2020.

August 17, 2020



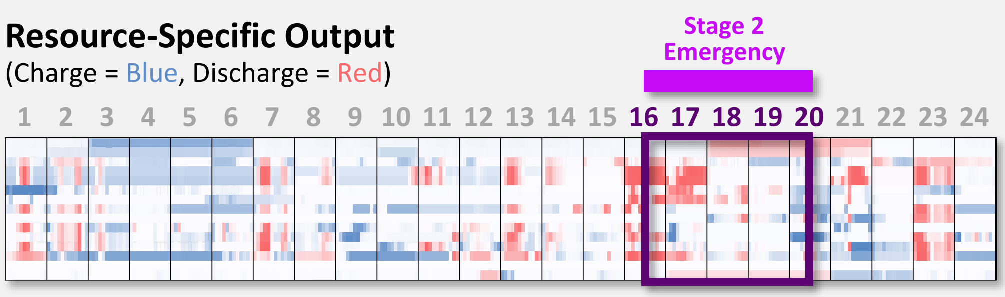
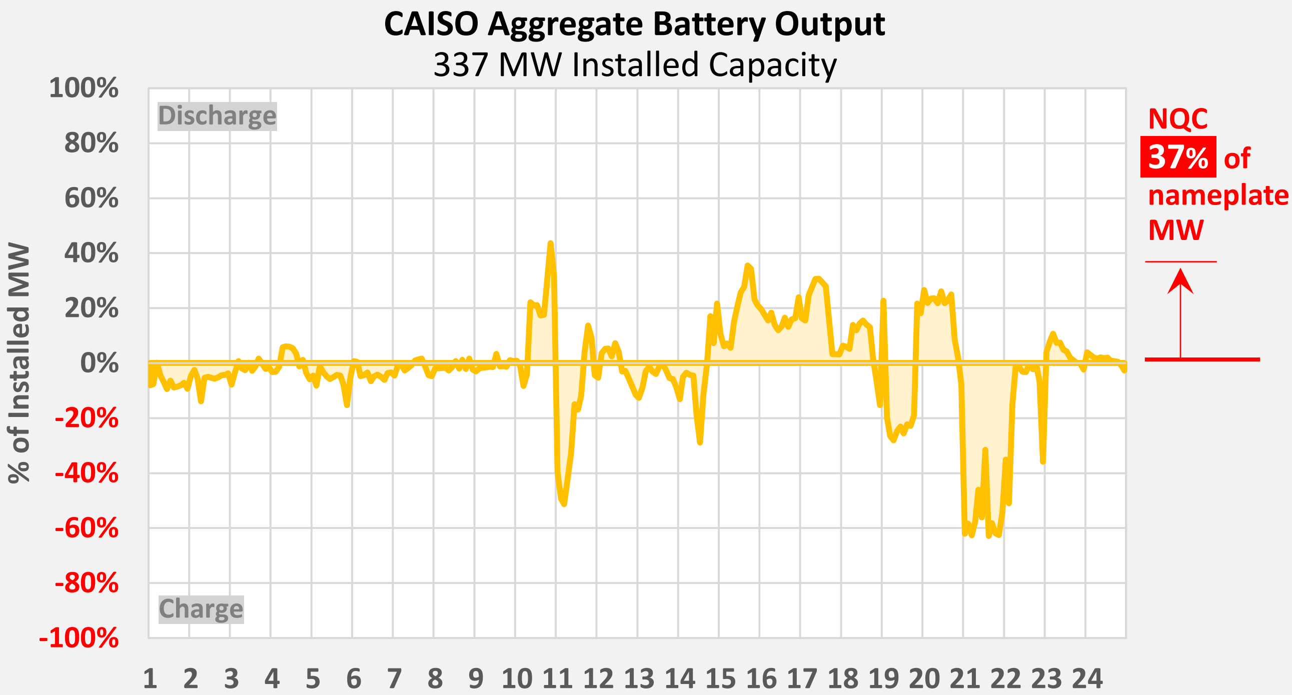


Figure B-4: CAISO battery storage output during emergency events on August 17, 2020.

August 18, 2020



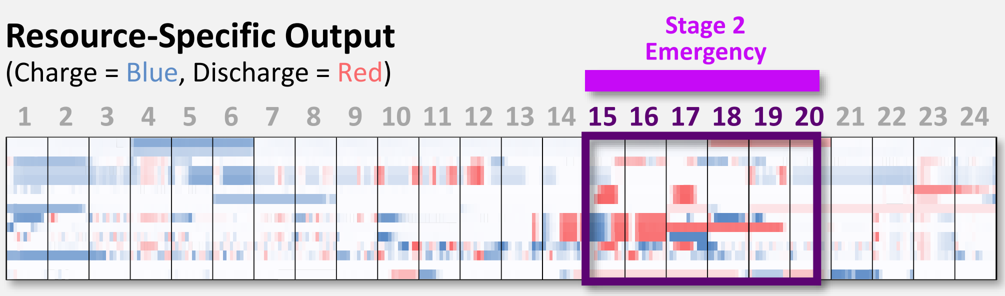
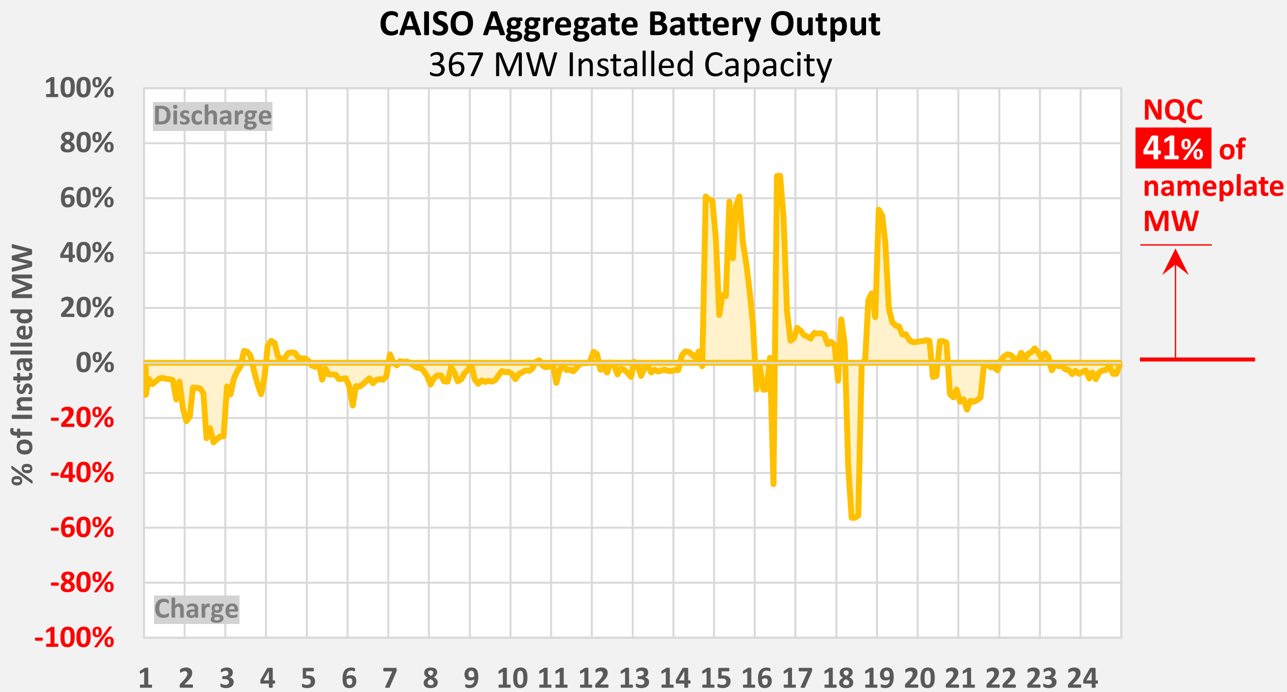


Figure B-5: CAISO battery storage output during emergency events on August 18, 2020.

September 5, 2020



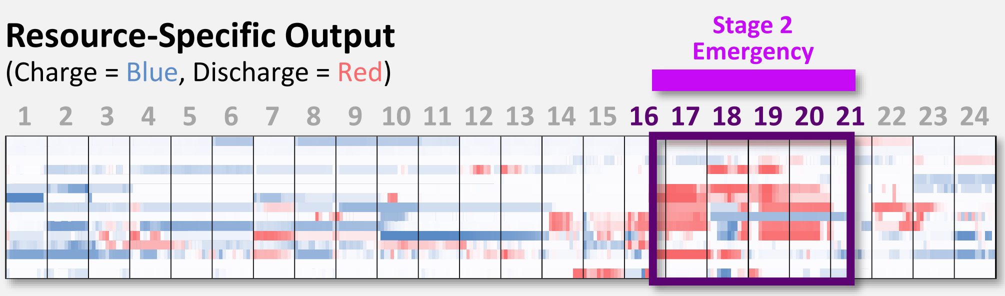
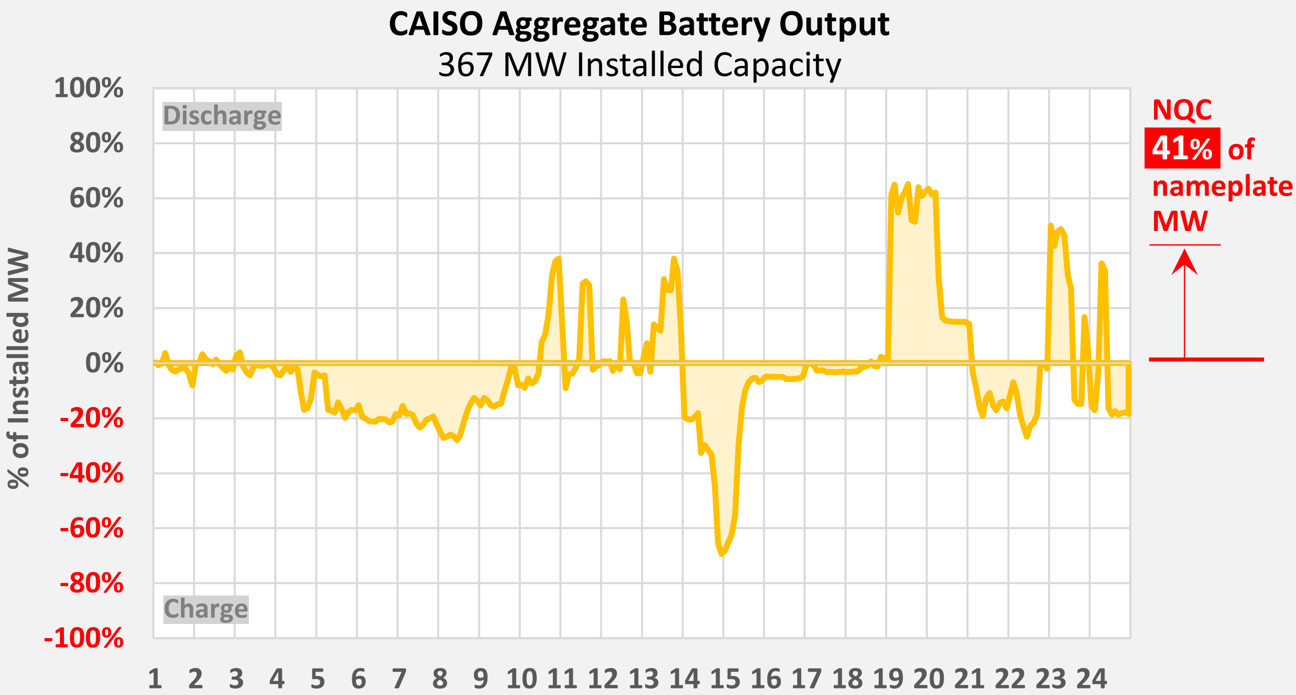


Figure B-6: CAISO battery storage output during emergency events on September 5, 2020.

September 6, 2020



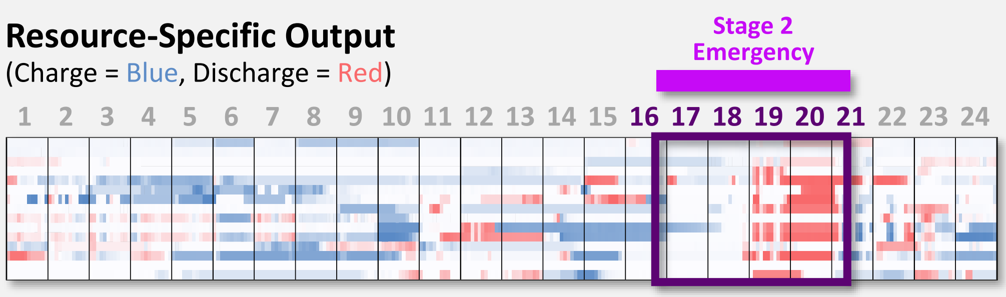
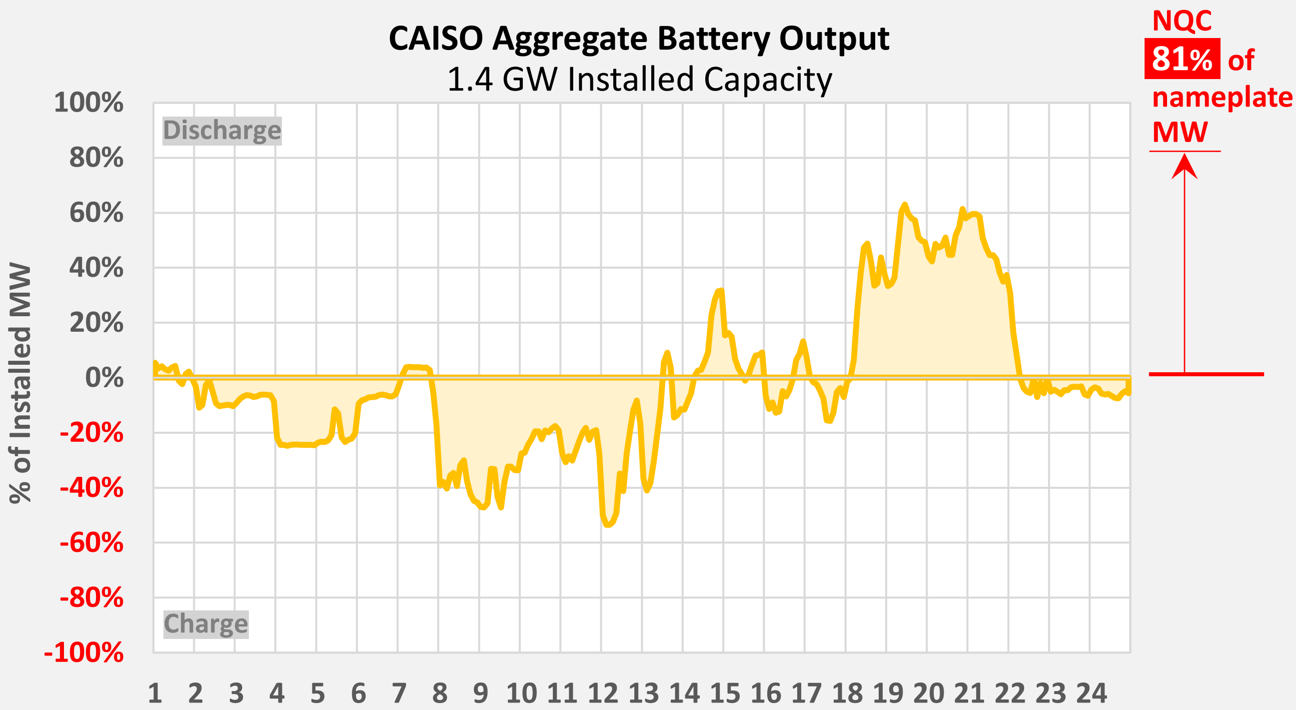


Figure B-7: CAISO battery storage output during emergency events on September 6, 2020.

July 9, 2021



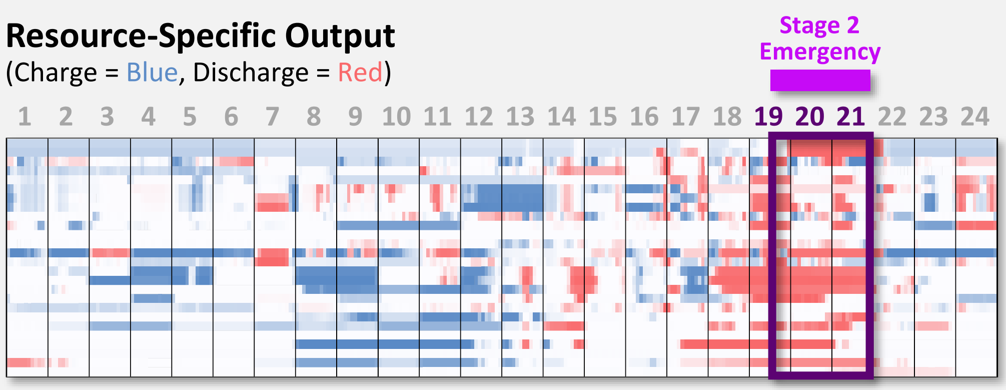
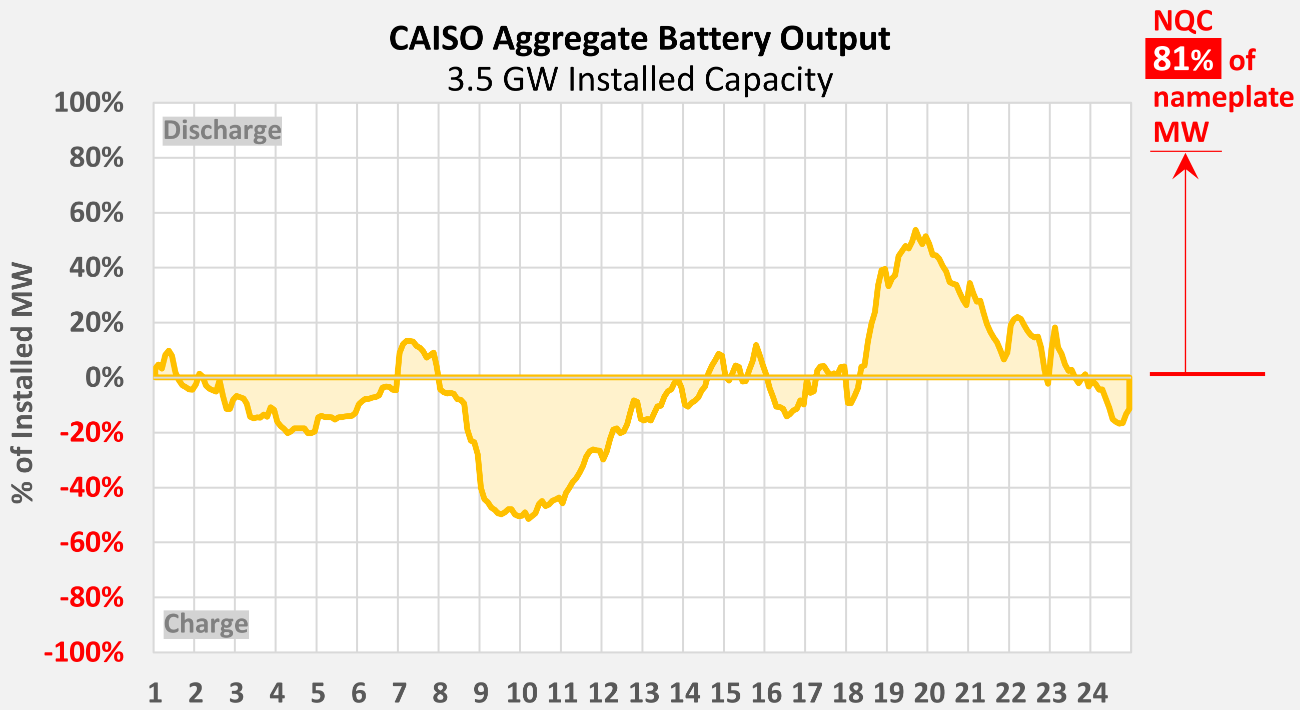


Figure B-8: CAISO battery storage output during emergency events on July 9, 2021.

August 31, 2022



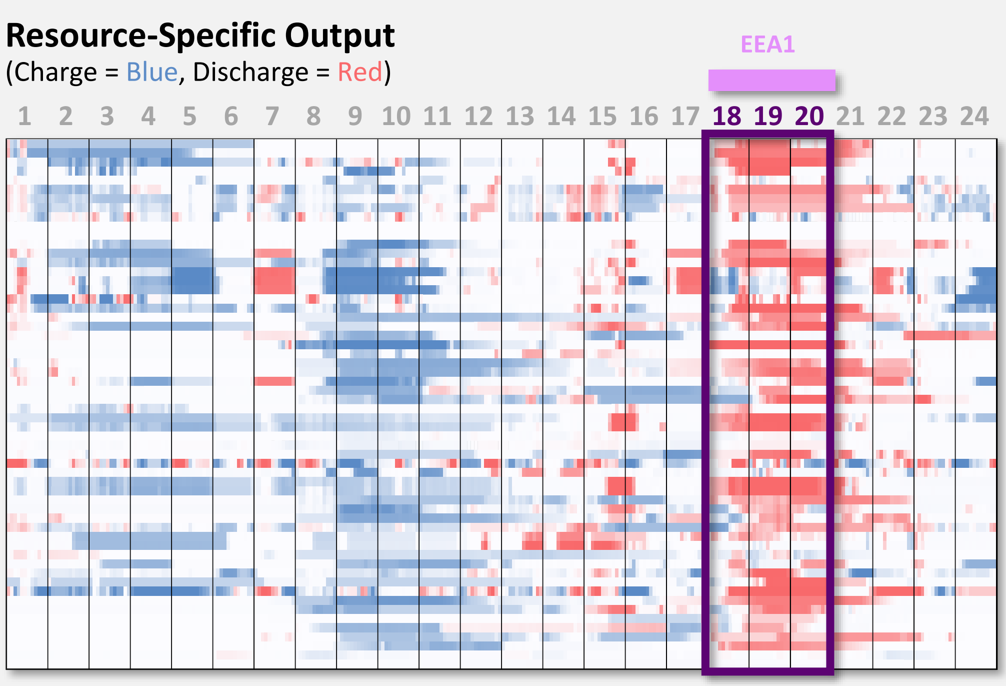
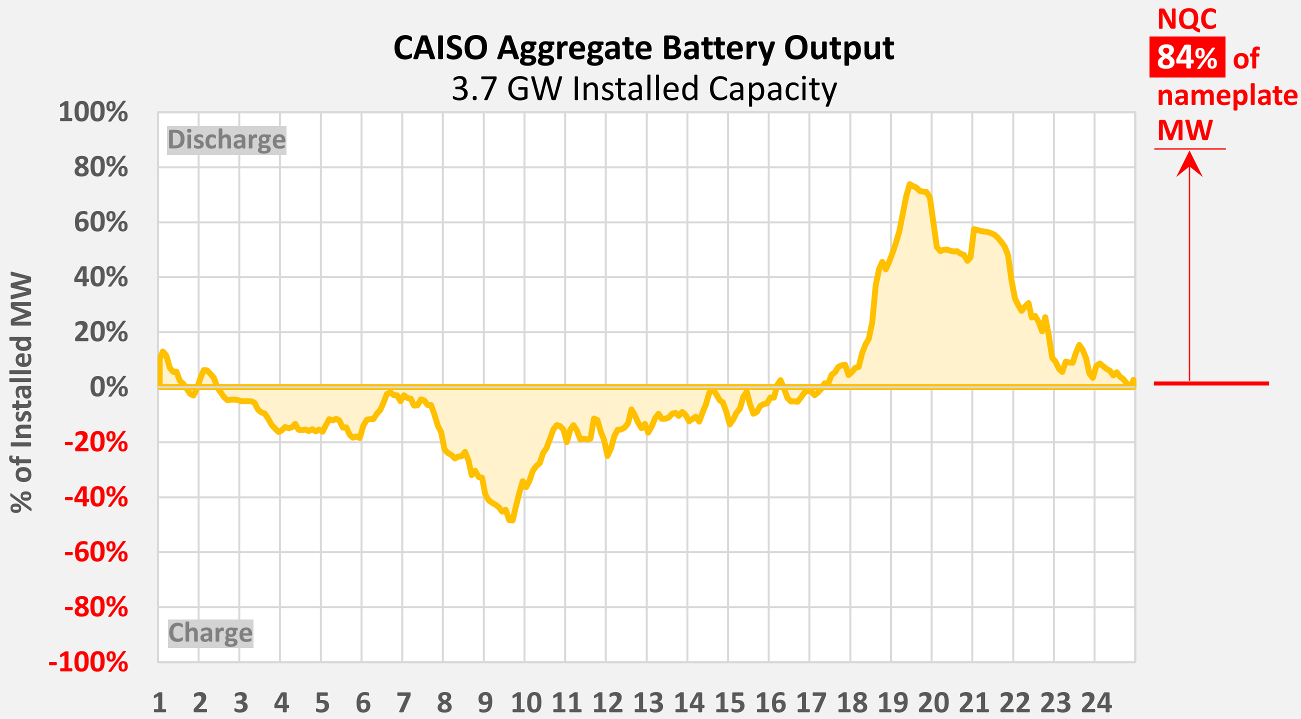


Figure B-9: CAISO battery storage output during emergency events on August 31, 2022.

September 5, 2022



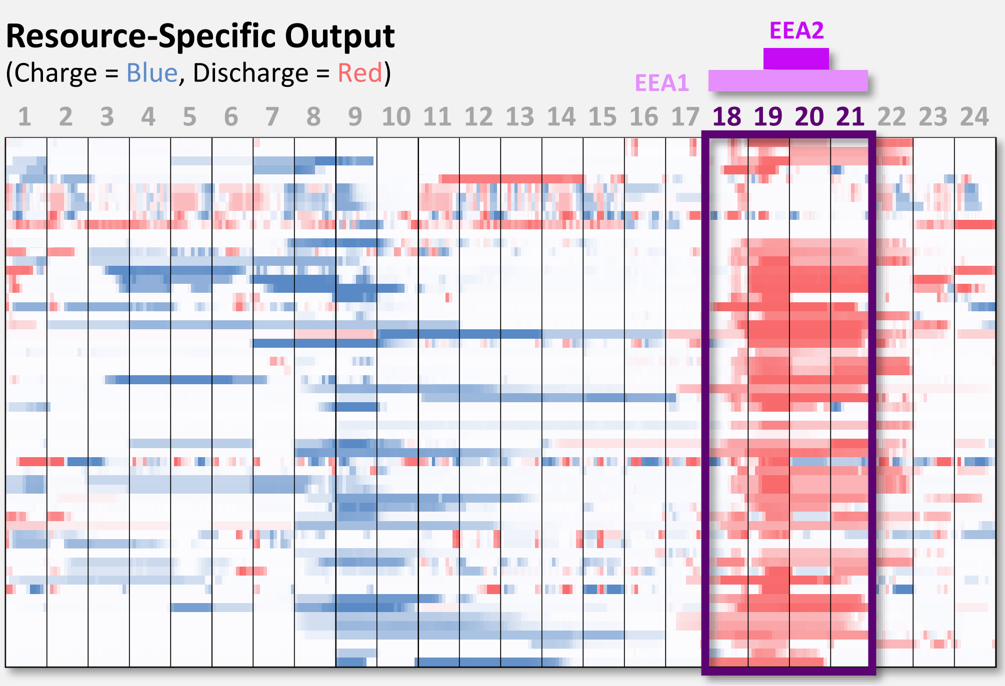
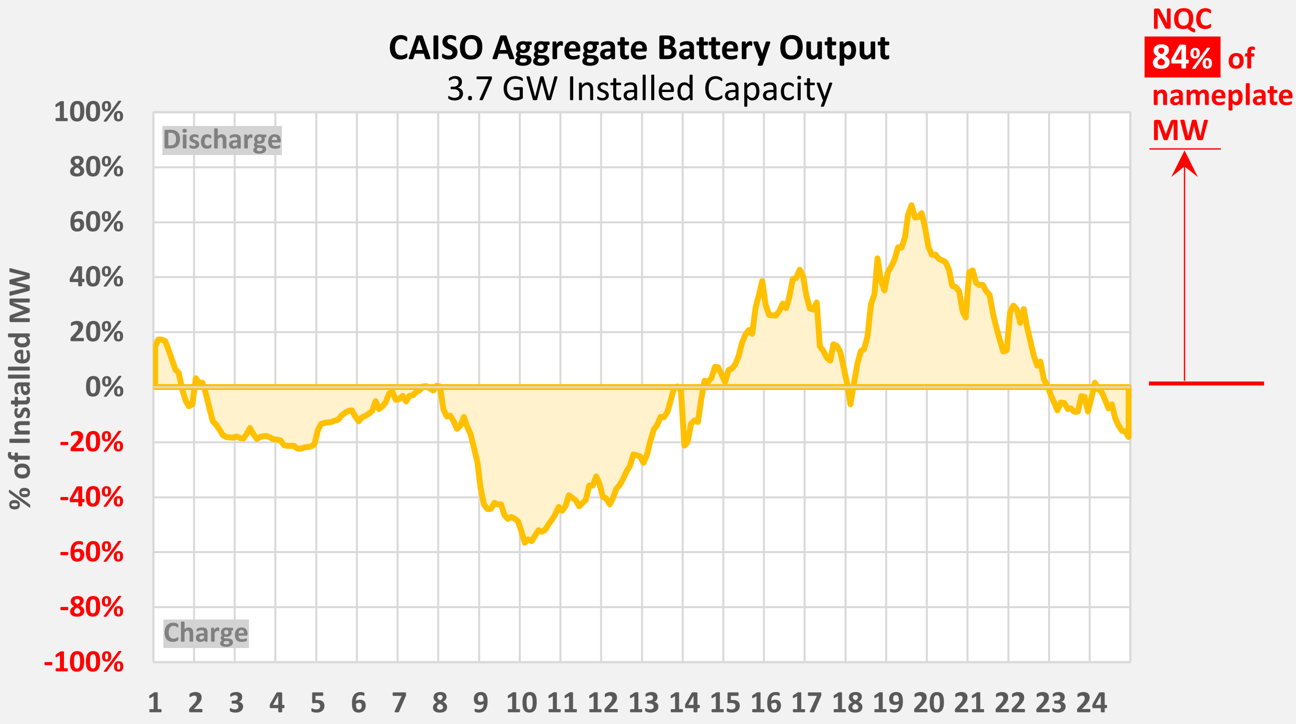


Figure B-10: CAISO battery storage output during emergency events on September 5, 2022.

September 6, 2022



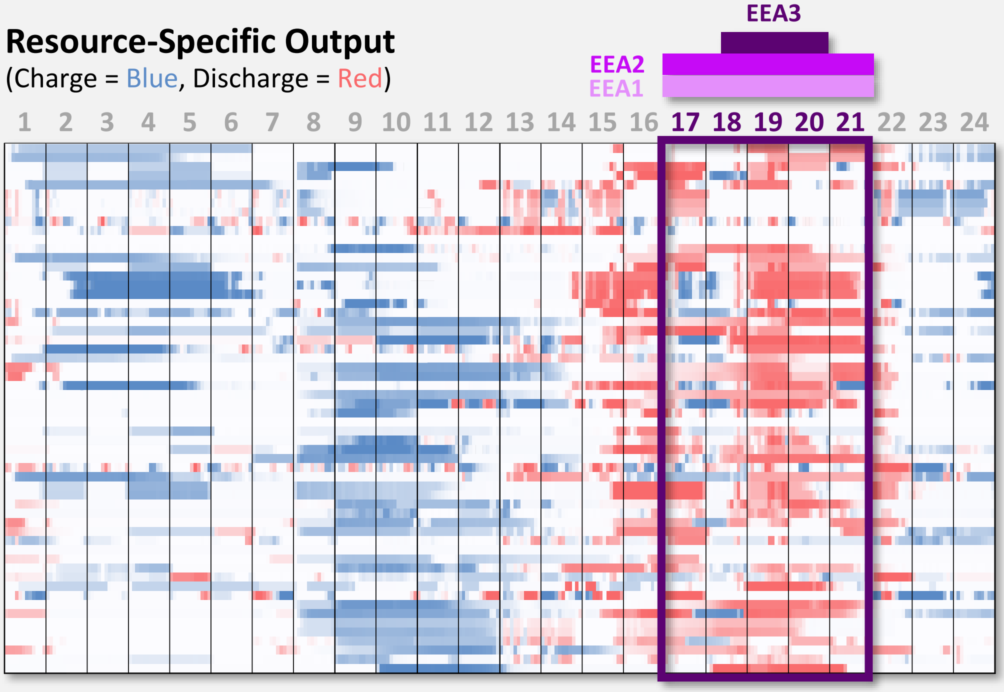
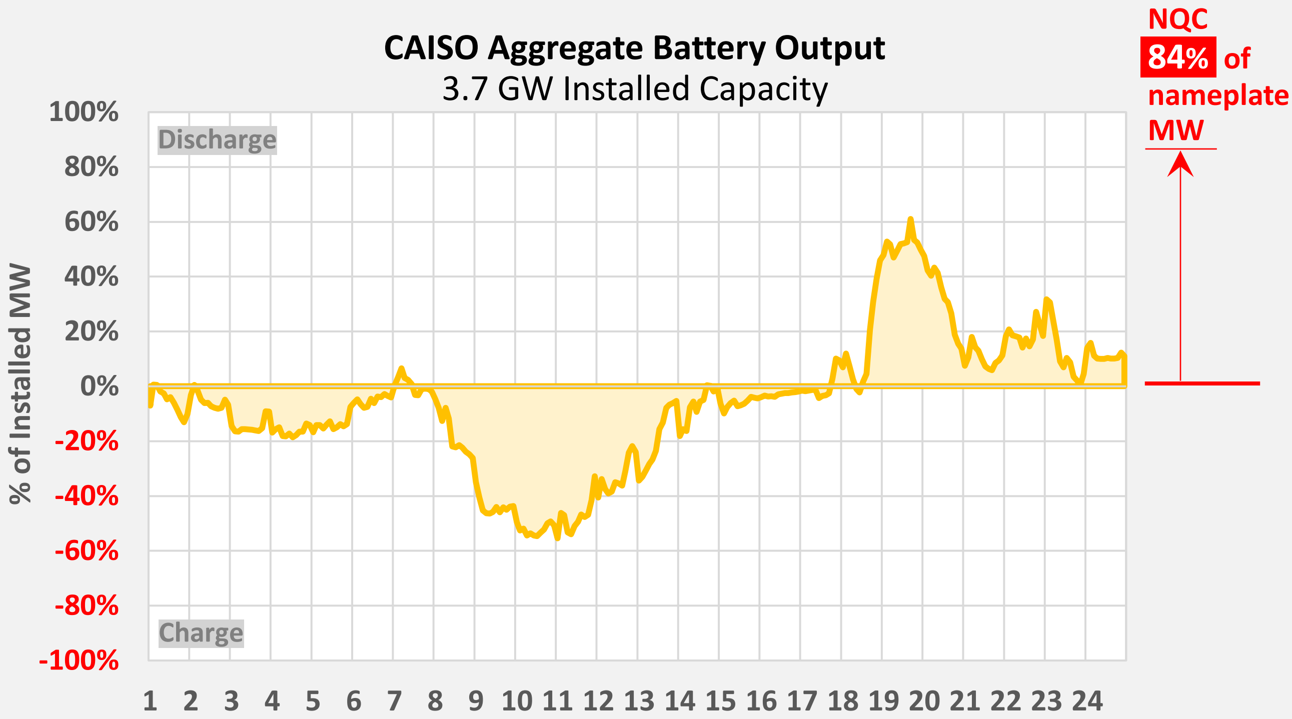


Figure B-11: CAISO battery storage output during emergency events on September 6, 2022.

September 7, 2022



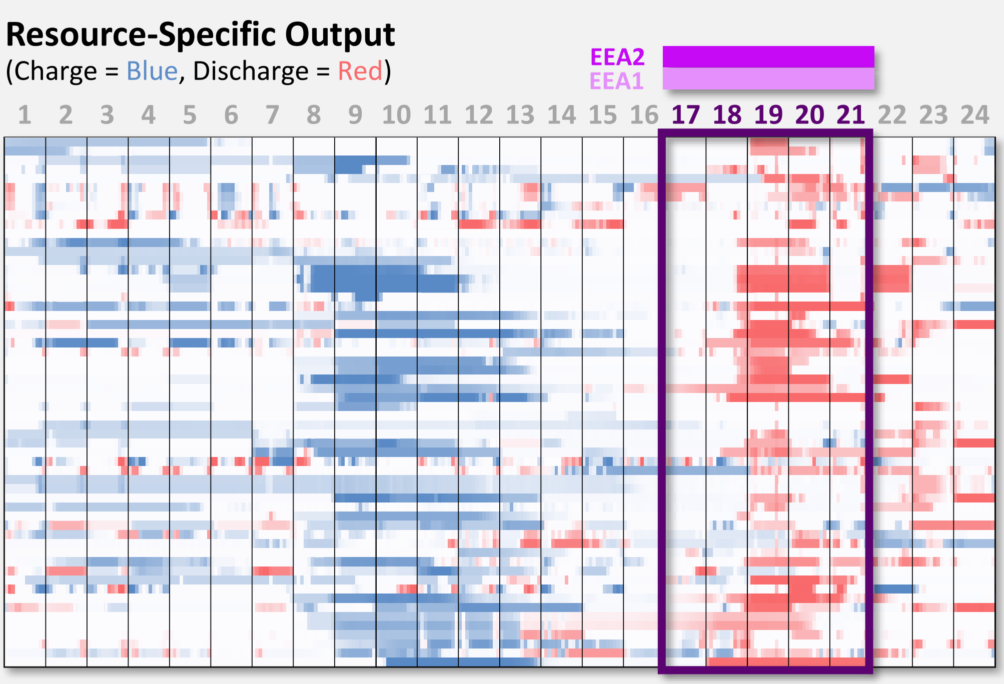
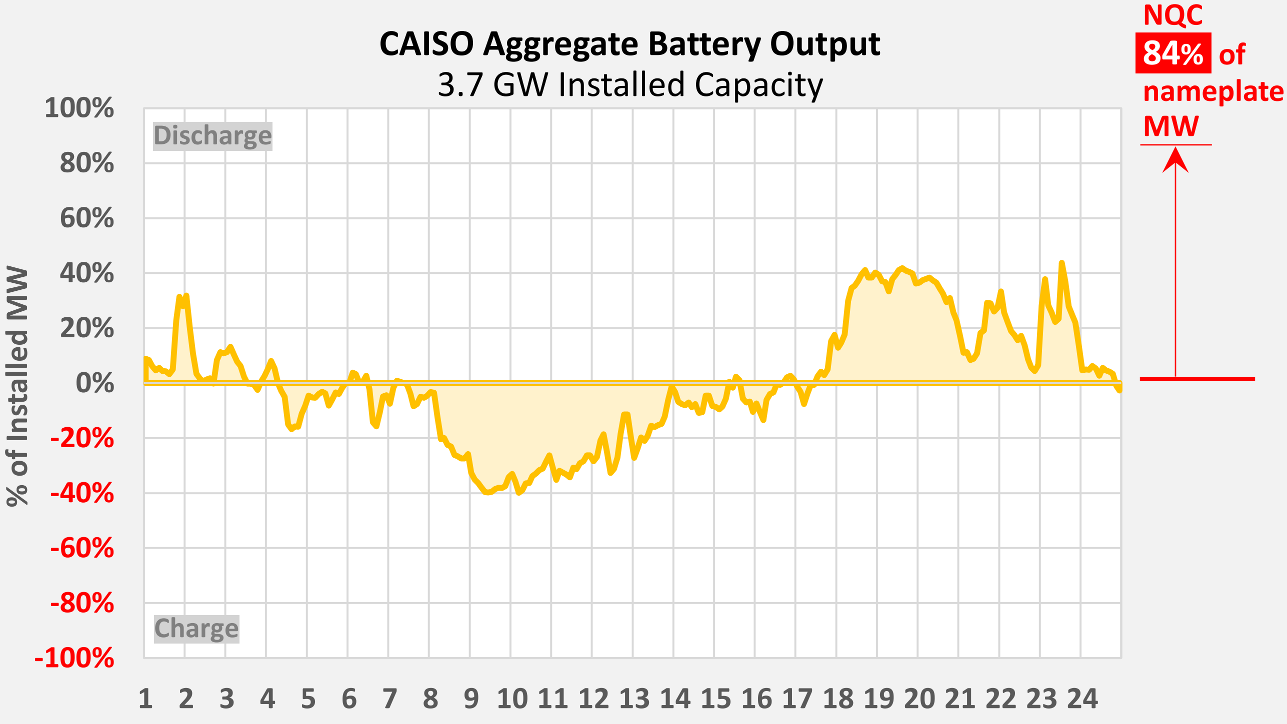


Figure B-12: CAISO battery storage output during emergency events on September 7, 2022.

September 8, 2022



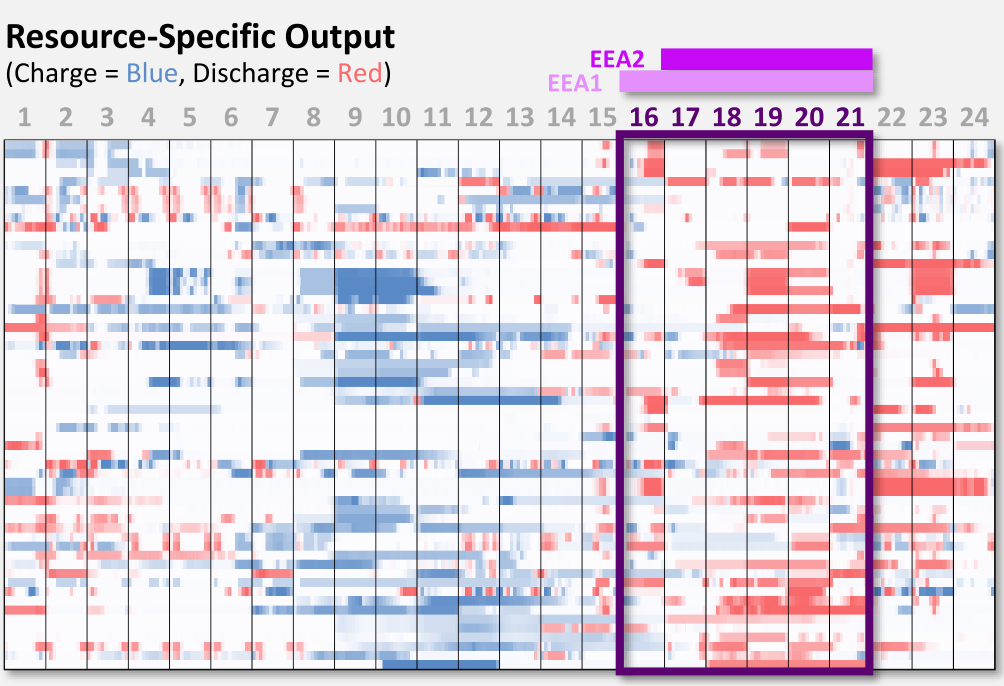


Figure B-13: CAISO battery storage output during emergency events on September 8, 2022.

September 9, 2022

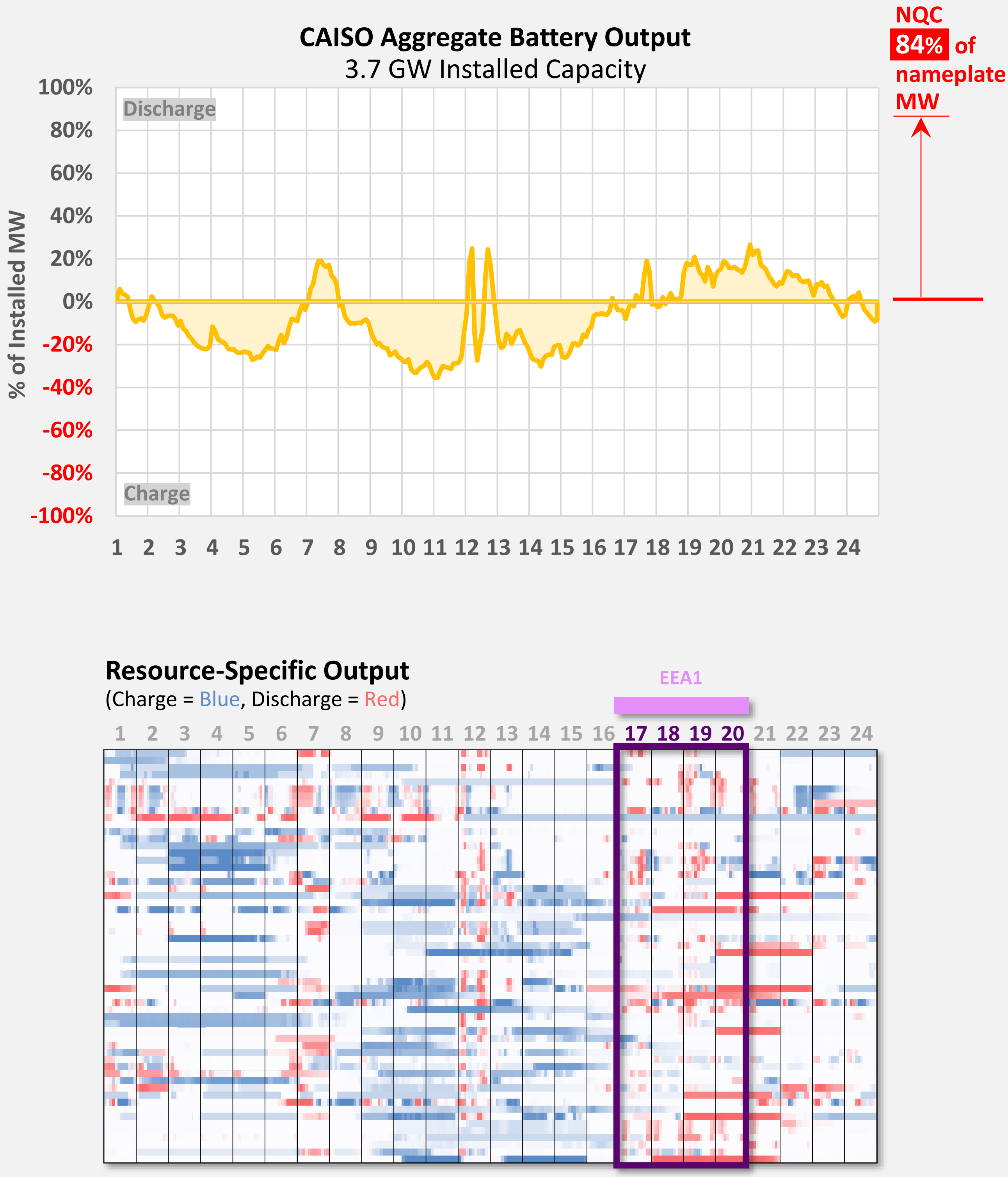
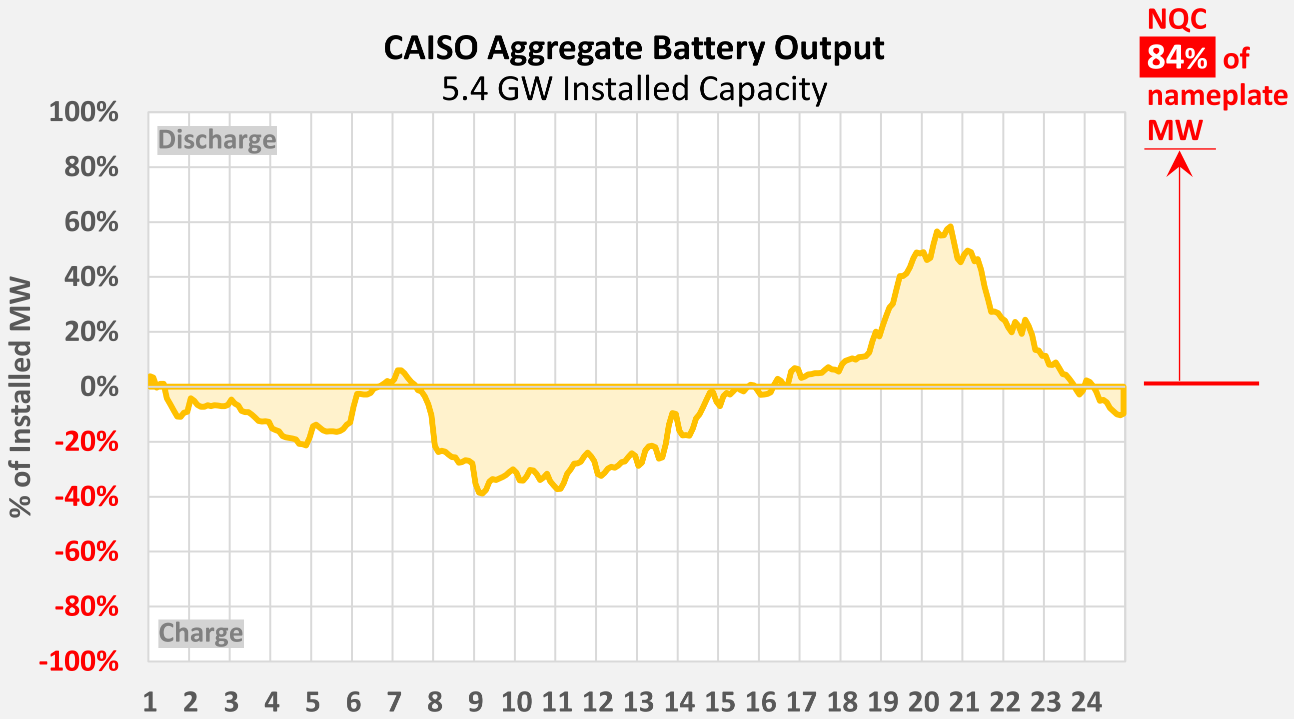


Figure B-14: CAISO battery storage output during emergency events on September 9, 2022.

July 20, 2023



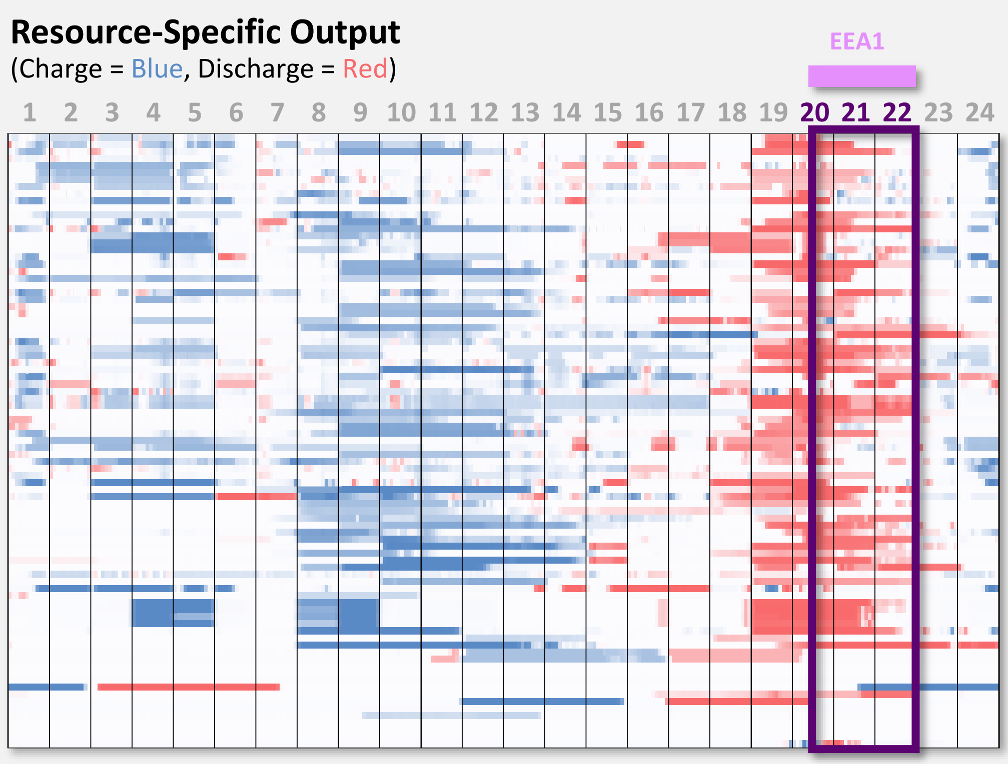


Figure B-15: CAISO battery storage output during emergency events on July 20, 2023.

Outage Patterns in Grid-Scale Battery Installations

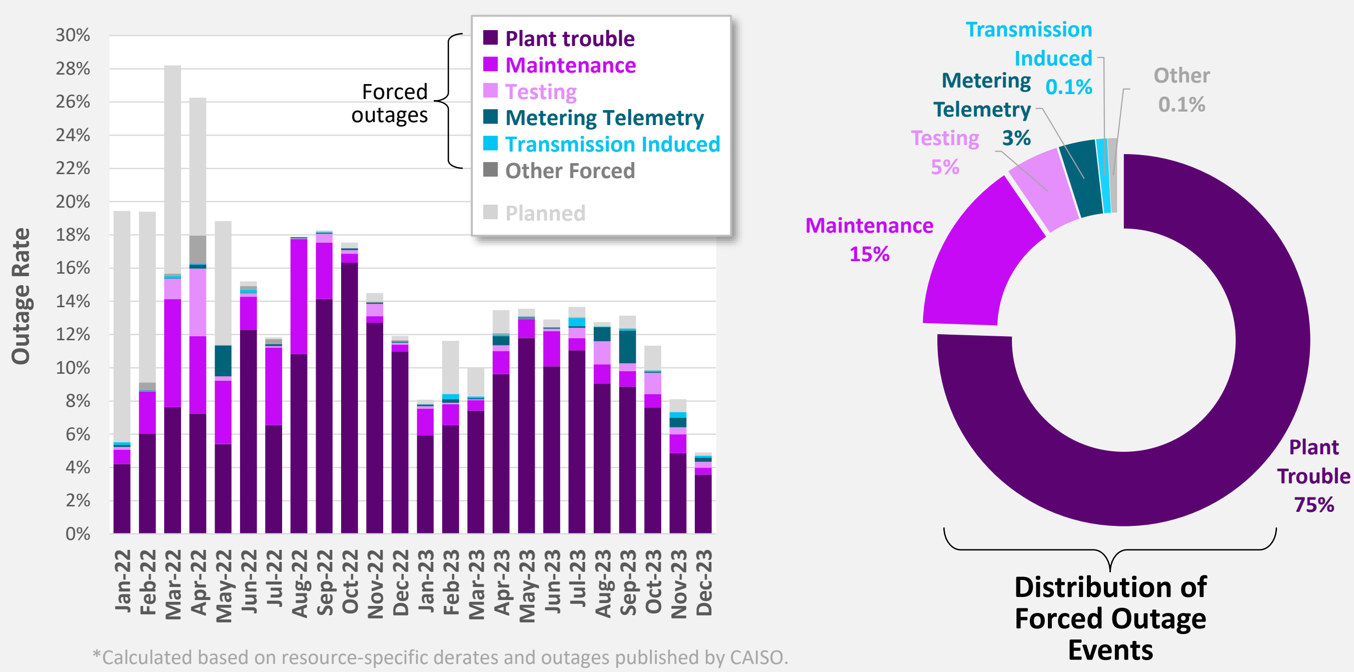
We analyzed the actual resource-specific capacity derates and outage events published by CAISO for the 2022–2023 period to understand availability and performance of the energy storage fleet during grid-stressed periods. The historical outage reports are available daily on the CAISO's website, with details on start and end times of all outage events that occurred during the previous trade date.

Average fleetwide outage rates over time

Figure B-16 shows the estimated capacity-weighted average outage rates for the battery storage fleet over time and by outage category. CAISO designates resource outages as either planned or forced. This distinction is important for resource planning, in which planned outages are those that can be rescheduled if a grid emergency is anticipated, while forced outages tend to happen unexpectedly and are less flexible if rescheduling is needed.

Forced (unplanned) plant derates and outages reduced the available capacity of battery storage resources in CAISO by an average of 11.5% over the two-year period analyzed. Equipment failures were the primary cause of unavailable capacity during these forced outage events. The fleetwide average forced outage rates were higher in 2022, at around 14%, and averaged 10% in 2023.These results are generally consistent with the data CAISO's Department of Market Monitoring (DMM) presented in January 2024 in a resource adequacy (RA) working group meeting, which highlighted the availability of energy storage fleet averaged at 90% during 2023, which aligns with our results for the 2023 period.

CAISO classifies outage requests within 7 days prior to the start of the outage event as forced outages. With this classification, it is unclear which forced outages can be postponed vs. not when system needs capacity. Our investigation of data during grid emergencies reveals the storage fleet experienced outages due to various types of work, including plant maintenance and testing, not solely due to plant trouble, in these capacity-constrained periods. Planned outages represented a relatively small portion of total outages and were scheduled during non-summer months when the grid stress was lower. However, there were instances of extended events initially triggered by forced outages in 2021, but subsequently reclassified as planned outage after an initial period. These events contributed to a relatively high fleetwide outage level observed during January–May 2022.



*Calculated based on resource-specific derates and outages published by CAISO. Excludes testing period prior to commercial operations.

Figure B-16: Capacity-weighted average outage rates of the battery storage fleet in CAISO.

Hourly outages during September 2022 heat wave.

The extended heat wave in September 2022 resulted in CAISO systemwide emergency declarations for five consecutive days.

- **September 5, 2022:** EEA1 17:00–21:00, EEA2 18:30–20:00
- **September 6, 2022:** EEA1 16:00–21:00, EEA2 16:00–21:00, EEA3 17:17–20:00
- **September 7, 2022:** EEA1 16:00–21:00, EEA2 16:00–21:00
- **September 8, 2022:** EEA1 15:00–21:00, EEA2 16:00–21:00
- **September 9, 2022:** EEA1 16:00–20:00

**See https://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx for additional information on CAISO's emergency notifications and details on historical grid emergency events.*

Figure B-17 illustrates the aggregate hourly outage profile of the storage fleet over that period. During CAISO's emergency events, 290–760 MW of energy storage capacity was unavailable due to derates and outages. Inspection of this 5-day heat wave yields results consistent with our broader analysis of outages during peak periods. With 3.7 GW of total energy storage capacity installed at the time, excluding hybrids, hourly outage rates range from 8% to 20%, and average 12%, across emergency hours.

The figure also shows a breakdown of the outages by the nature of work. Plant troubles related to equipment failures were responsible for the majority of outages during the CAISO emergency period analyzed. Other types of work, including plant maintenance and unit testing accounted for non-trivial amounts of the outages experienced by the energy storage fleet. This tells us some plant maintenance and testing, categorized as forced outages, are not actually being rescheduled on grid-stressed periods. Additionally, most of the unavailable capacity for plant maintenance and testing during emergency hours came from energy storage resources with a net qualifying capacity for September 2022. With these findings, we conclude that it is appropriate to include all CAISO-designated forced outage events in our analysis, and that exclusion of any forced outages based on work type (e.g., maintenance) will inadvertently understate availability of the planned energy storage portfolio when the system has its greatest need for capacity.

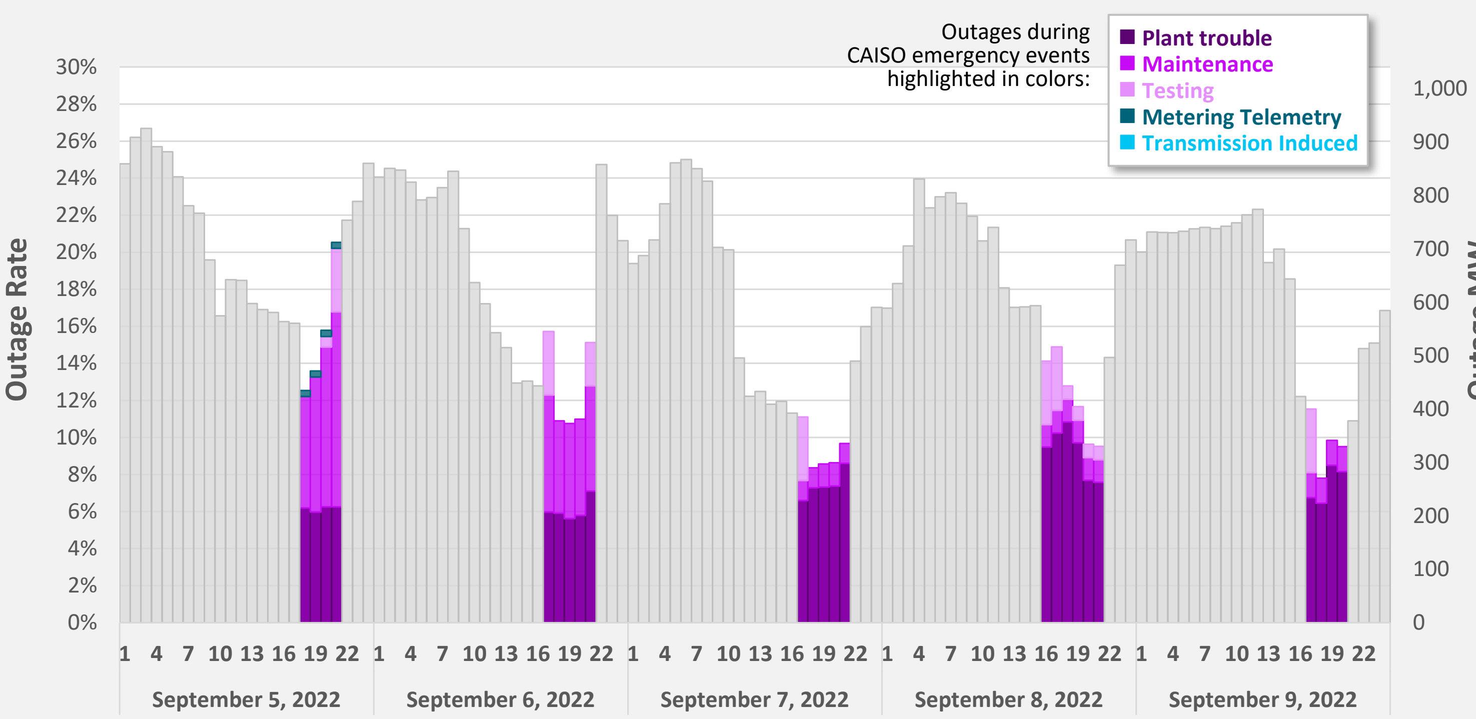


Figure B-17: Aggregate hourly outage profile of the battery storage fleet in CAISO, September 5–9, 2022.

<u>Outages by month and peak period</u>

The historical data indicate significant variation in monthly and daily forced outage patterns of battery storage resources.

Figure B-18 shows the estimated capacity-weighted average forced outage rates of the storage fleet by month and time of day based on 2022–2023 data. Outage rates have been consistently higher in spring and summer months, compared to the rest of the year. Specifically, during August and September, storage forced outage rates have averaged 3 percentage points above the annual levels. This is partly offset by 2 percentage points lower outages during evening peak hours. Throughout the day, storage capacity derates and outages have been lower in the evening hours than morning or late-night periods. While it is not clear exactly why outage rates vary by time of day, we believe it could be related to the effects of battery state of charge (SOC) levels on maximum power output, and other technical and operating constraints, managed through outage reports.

Considering these seasonal and daily outage patterns, we estimate that, during the 2022–2023 timeframe, the non-hybrid fleetwide actual battery storage forced outage rate in August and September evening peak periods (hour ending 17 through 21) averaged 12.6%—one percentage point higher than the average across all months and hours of the year.

These results highlight that actual realized average forced outage rates of the CAISO-participating battery storage resources were significantly higher than the long-term resource planning assumptions. For example, the CPUC's IRP models assume a 5% expected forced outage rate for battery storage resources (CPUC 2023d, 131), based on early data for the storage fleet just as it was reaching the GW scale.

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	**Aug**	**Sep**	Oct	Nov	Dec	Annual
1	6.9%	8.2%	10.1%	14.0%	12.0%	13.8%	12.6%	15.3%	14.7%	12.4%	10.2%	8.1%	11.5%
2	7.2%	8.3%	10.5%	14.6%	12.1%	13.8%	12.9%	15.7%	15.4%	12.9%	10.5%	8.2%	11.8%
3	7.3%	8.2%	10.6%	14.6%	12.0%	13.8%	13.1%	15.8%	15.6%	13.1%	10.4%	8.0%	11.9%
4	7.1%	8.2%	10.7%	14.5%	12.1%	13.9%	13.3%	15.9%	15.8%	13.3%	10.2%	8.1%	11.9%
5	7.0%	8.4%	10.4%	14.7%	12.3%	14.1%	13.3%	15.9%	16.0%	13.6%	10.2%	8.1%	12.0%
6	7.0%	8.6%	10.6%	14.7%	12.4%	14.2%	13.1%	15.8%	16.0%	13.8%	10.6%	8.0%	12.1%
7	7.5%	9.0%	11.4%	15.3%	13.0%	14.5%	13.7%	15.8%	16.1%	14.3%	10.9%	8.1%	12.5%
8	8.2%	9.9%	12.3%	15.9%	13.3%	14.5%	14.0%	16.4%	16.8%	15.5%	11.5%	8.3%	13.1%
9	8.4%	10.0%	12.6%	15.5%	13.2%	14.1%	13.7%	15.6%	16.2%	14.8%	11.6%	8.5%	12.8%
10	8.0%	9.5%	12.2%	14.9%	13.0%	14.1%	13.4%	15.2%	15.2%	13.8%	11.1%	8.2%	12.4%
11	7.4%	9.2%	12.0%	14.8%	13.0%	13.5%	12.9%	14.4%	14.7%	13.2%	10.4%	7.9%	11.9%
12	7.2%	9.0%	11.5%	14.6%	13.0%	13.6%	12.7%	14.2%	14.4%	13.3%	9.9%	7.5%	11.8%
13	6.8%	9.0%	11.5%	14.2%	12.8%	13.3%	12.8%	13.7%	13.9%	13.0%	9.5%	7.2%	11.5%
14	6.6%	8.8%	11.4%	13.6%	12.5%	13.2%	12.5%	13.4%	14.0%	12.6%	9.3%	7.1%	11.3%
15	6.6%	8.6%	11.1%	13.6%	12.7%	12.5%	12.4%	13.0%	13.8%	12.4%	9.1%	6.8%	11.0%
16	6.5%	8.1%	10.8%	13.4%	12.6%	12.2%	11.9%	12.7%	13.1%	11.9%	8.9%	6.6%	10.7%
17	6.6%	8.0%	10.5%	13.8%	12.0%	11.8%	11.5%	**12.4%**	**12.8%**	11.4%	8.6%	6.3%	10.5%
18	6.4%	8.0%	10.3%	13.4%	11.7%	11.9%	11.2%	**11.8%**	**12.8%**	11.1%	8.7%	6.3%	10.3%
19	6.4%	8.0%	9.7%	13.2%	11.7%	12.1%	10.6%	**11.8%**	**13.2%**	11.1%	8.7%	6.4%	10.2%
20	6.4%	8.1%	10.0%	13.4%	11.9%	12.1%	10.7%	**12.4%**	**12.7%**	11.0%	8.8%	6.5%	10.3%
21	6.6%	8.5%	10.2%	13.5%	11.9%	12.4%	11.4%	**13.1%**	**12.6%**	10.8%	9.2%	6.8%	10.6%
22	6.9%	9.0%	10.4%	13.8%	11.9%	12.9%	12.1%	14.0%	13.7%	11.4%	10.0%	7.1%	11.1%
23	7.2%	9.0%	10.6%	14.7%	12.1%	14.1%	12.8%	15.0%	14.4%	12.0%	10.9%	7.8%	11.7%
24	6.9%	8.6%	10.4%	15.4%	12.3%	14.6%	12.8%	15.5%	14.8%	12.3%	10.1%	7.6%	11.8%
All hours	**7.0%**	**8.7%**	**10.9%**	**14.3%**	**12.4%**	**13.4%**	**12.6%**	**14.4%**	**14.5%**	**12.7%**	**10.0%**	**7.5%**	**11.5%**
HE17–21	**6.4%**	**8.1%**	**10.1%**	**13.5%**	**11.9%**	**12.0%**	**11.1%**	**12.3%**	**12.8%**	**11.1%**	**8.8%**	**6.5%**	**10.4%**

Figure B-18: Monthly and daily variation of forced outage rates of the battery storage fleet in CAISO.

Distribution of daily forced outages during August–September peak period

For grid planning, it is important to consider not only the average outage rates, but also the range of possible outcomes. While the fleetwide average forced outage rate provides a useful metric, it does not fully capture the risks associated with more widespread simultaneous outage events across the fleet.

If outage events were all random and independent across resources, the percentage variability of the aggregate fleetwide outage rates would decline as the fleet grows. This is due to increased diversity of resources and outage events in a larger fleet. For example, if the fleet had only one resource, the outage rate would be either 0% or 100% each day, excluding derates. When the total number of resources in the fleet rises to, say, 100 or more, the fleetwide outage rates would become considerably less volatile, clustered closer to expected outage levels. If, on the other hand, the outage events share a common driver (such as weather) then it becomes more probable for a disproportionately large share of the fleet to experience outages simultaneously, thereby increasing the likelihood of more extreme outcomes.

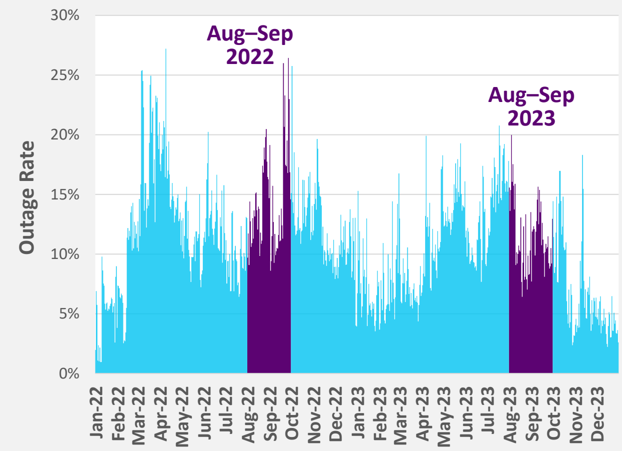


Figure B-19: Daily fleetwide average forced outage rates during evening peak periods (HE17–21).

We have not analyzed the impacts of weather on fleetwide battery storage outages or correlations of outage events across resources. However, the seasonal outage patterns described earlier could be indicative of such interactions, which warrants further investigation as more operational data becomes available in the future.

Figure B-19 and Figure B-20 show the distribution of forced outage rates for the evening peak hours from 4pm to 9pm. The results highlight higher average and fatter upper tail for outages in August and September, compared to the rest of the year. During August–September evening peak periods, the forced outage rate of the battery storage fleet was 15% or higher in about 1 out of every 5 days over the two-year period analyzed. In the same timeframe, the observed fleetwide forced outage rates have reached 20% or higher in 1 out of every 16 days.

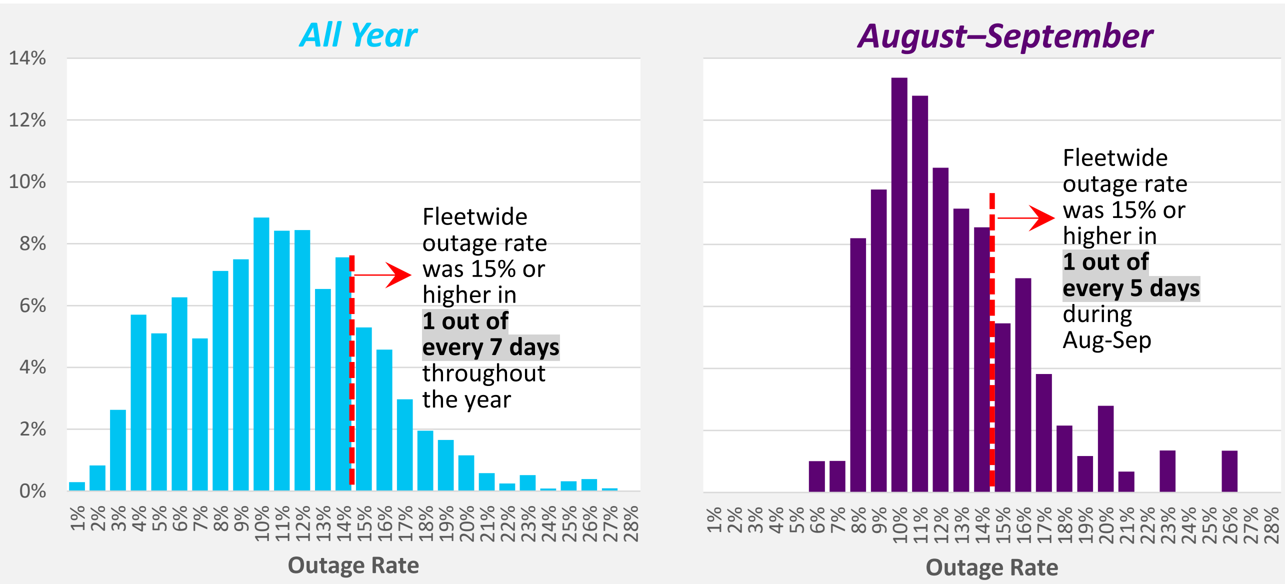


Figure B-20: Frequency distribution of forced outage rates during evening peak periods (HE17–21) in 2022–2023.

Appendix C: MUA with Outage Mitigation

This appendix provides details on our cross-domain multi-use application (MUA) analysis, focusing on value-stacking opportunities for customer outage mitigation solutions. The diagram in Figure C-1 shows 8 locations selected for outage mitigation case studies, representing areas with relatively high actual total outage hours and frequency of outages historically. Most outage profiles are developed based on detailed distribution circuit outage data in the 5-year period 2015–2019. The case study locations also are meant to represent a diversity of built environments and community types, geographies, weather conditions and other environmental hazards to the grid, and electricity market conditions.

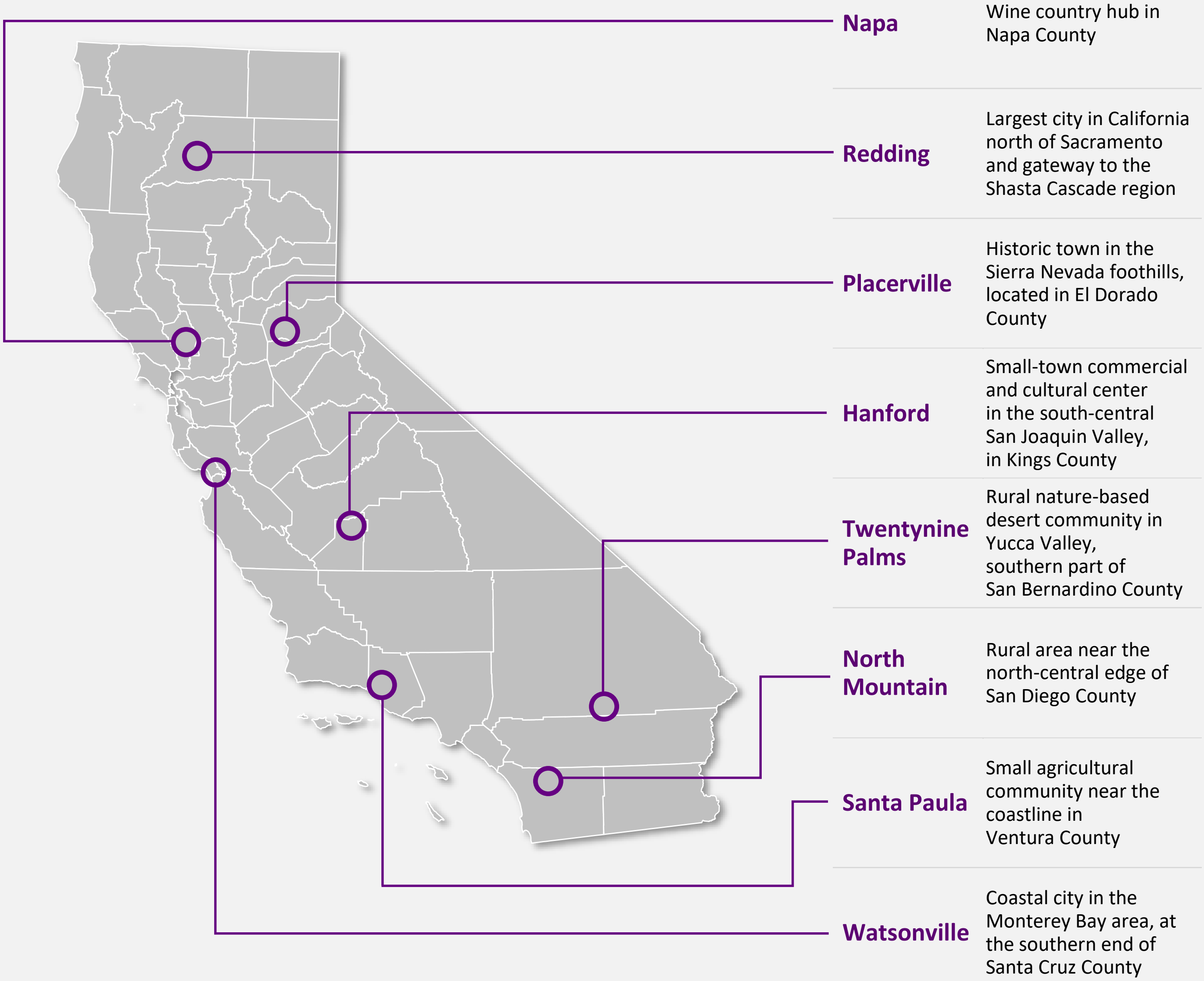
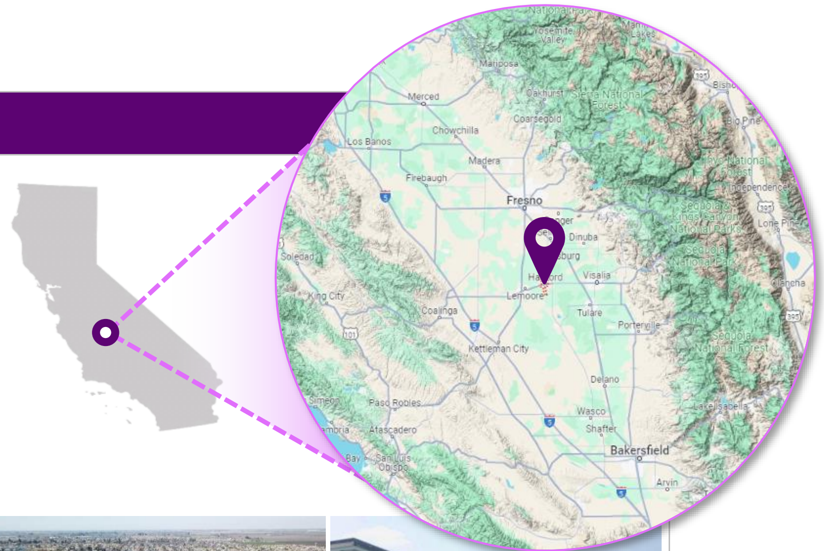


Figure C-1: Selected locations for the MUA analysis with outage mitigation.

Community and Outage Characteristics

Hanford

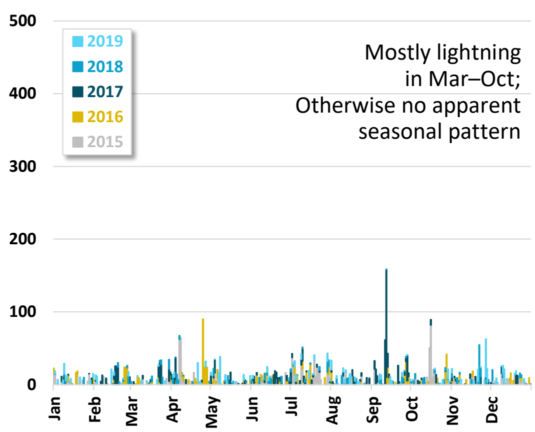
- Utility: mostly SCE, some PG&E customers
- Small-town commercial and cultural center in the south-central San Joaquin Valley, in Kings County
- About 59,000 people
- Customer mix (% of 2023 electricity use)
  21% residential, 79% non-residential
- CalEnviroScreen 4.0 score: 73.4 percentile
  62.3% pollution burden
  74.9% population/socioeconomic
- DER capacity as of Dec'23
  ~6,800 installations
  110,000 kW solar + 1,800 kW storage



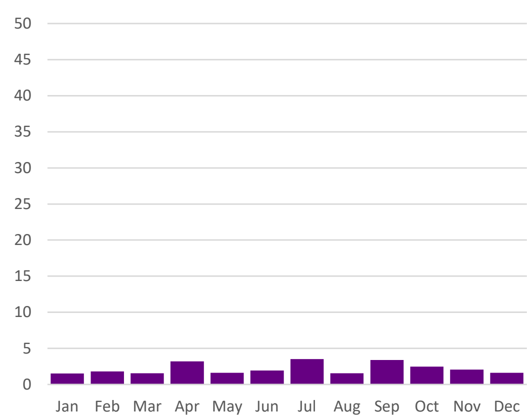
Images: (left) Hidden Valley Park, credit: City of Hanford
(right) Fox Theater, credit: City of Hanford

- Total of 891 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 34
- Average 26.2 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



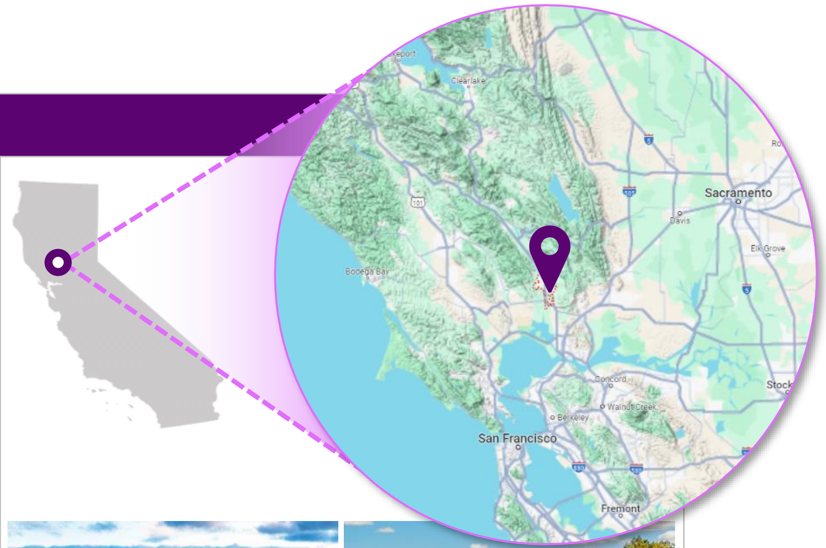
Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

Napa

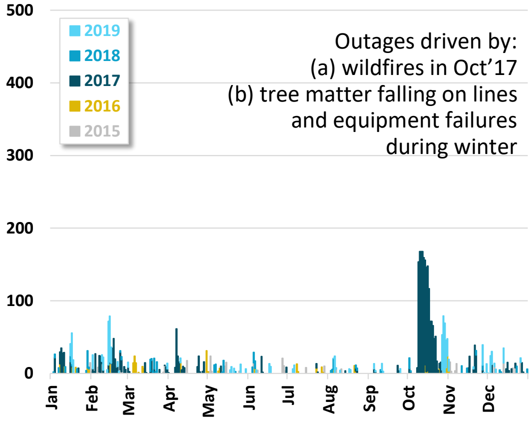
- Utility: PG&E
- Wine country hub in Napa County
- About 78,000 people
- Customer mix (% of 2023 electricity use)
  38% residential, 62% non-residential
- CalEnviroScreen 4.0 score: 38.3 percentile
  38.8% pollution burden
  38.1% population/socioeconomic
- DER capacity as of Dec’23
  ~5,100 installations
  53,100 kW solar + 4,300 kW storage



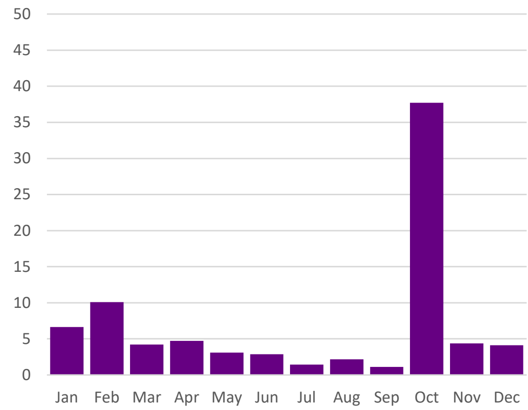
Images: (left) Downtown Napa riverfront, credit: visitnapavalley.com
(right) A vineyard in Napa, credit: City of Napa

- Total of 907 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 11
- Average 82.5 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



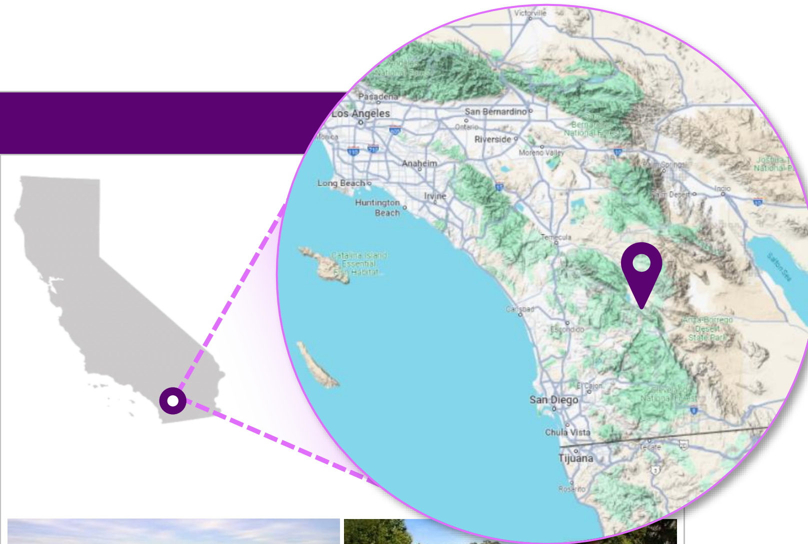
Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

North Mountain

- Utility: SDG&E
- Rural area near the north-central edge of San Diego County
- About 3,000 people
- Customer mix (% of 2023 electricity use)
  Data not available
- CalEnviroScreen 4.0 score: 27.1 percentile
  32.3% pollution burden
  26.2% population/socioeconomic
- DER capacity as of Dec'23
  Data not available

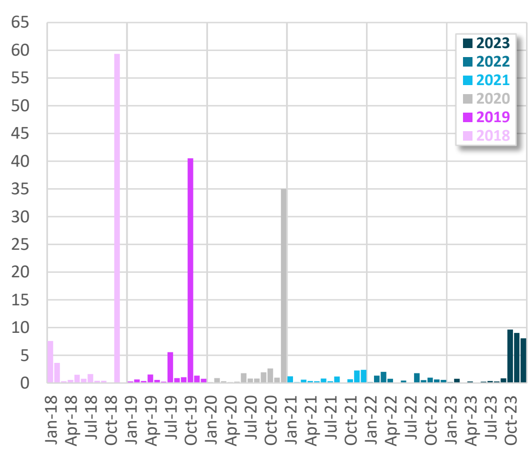


Images: (left) Palomar Observatory, credit: Caltech
(right) Santa Ysabel Mission, credit: hiddensandiego.com

- Average 37.6 hours out per year (2018–2023)
- Outage data at distribution circuit level not available.

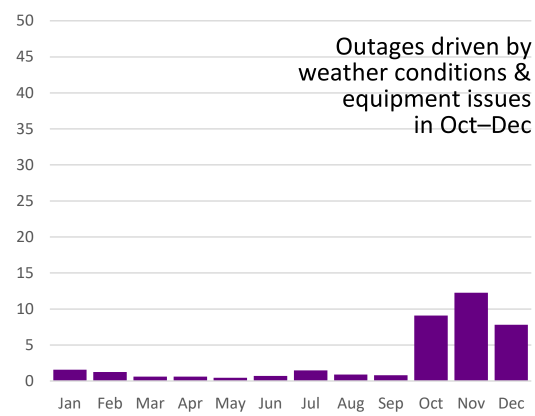
Time Profile of Monthly Customer Outages

(average hours per month)



Monthly Average Customer Outages

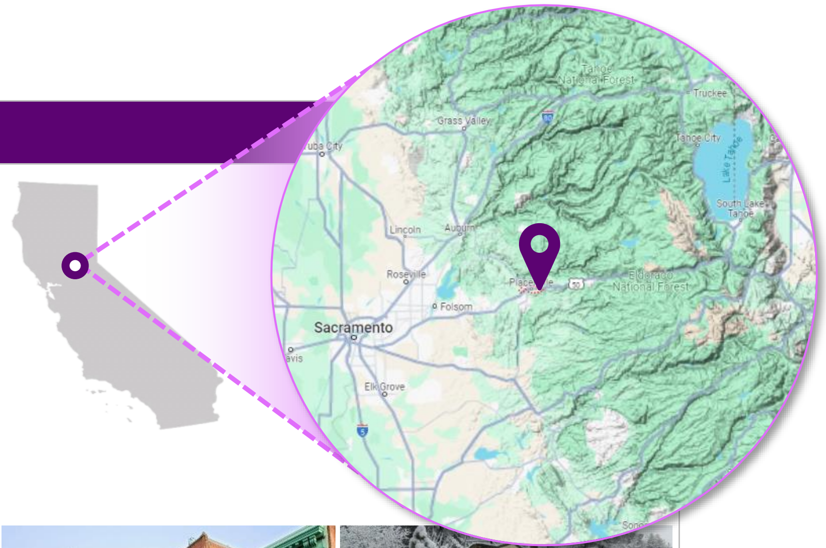
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

Placerville

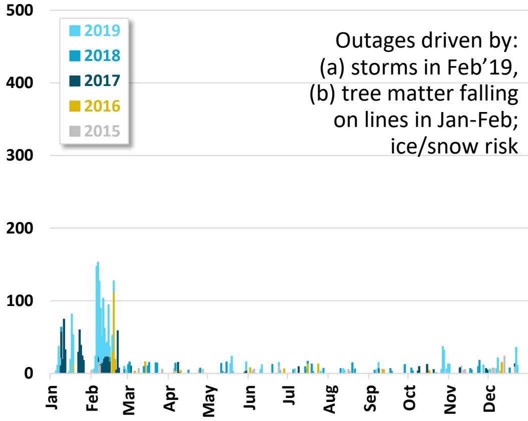
- Utility: PG&E
- Historic town in the Sierra Nevada foothills, located in El Dorado County
- About 11,000 people
- Customer mix (% of 2023 electricity use)
  59% residential, 41% non-residential
- CalEnviroScreen 4.0 score: 38.8 percentile
  37.9% pollution burden
  39.4% population/socioeconomic
- DER capacity as of Dec'23
  ~3,100 installations
  27,600 kW solar + 2,100 kW storage



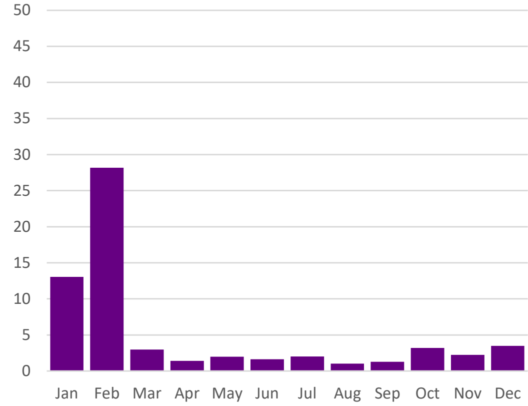
Images: (left) Historic Main Street, credit: visit-eldorado.com
(right) Placerville Soda Works building in winter, credit: Pat Lakey

- Total of 562 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 9
- Average 62.4 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

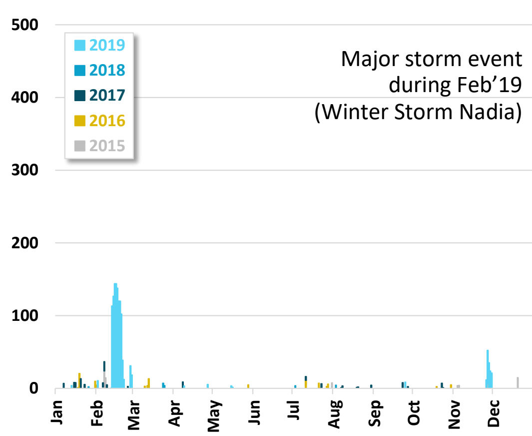
Redding

- Utility: mostly Redding Electric Utility + some PG&E customers
- Largest city in California north of Sacramento and gateway to the Shasta Cascade region
- About 93,000 people
- Customer mix (% of 2023 electricity use) 56% residential, 44% non-residential
- CalEnviroScreen 4.0 score: 30.3 percentile
  16.3% pollution burden
  47.7% population/socioeconomic
- DER capacity as of Dec'23
  ~2,100 installations
  21,200 kW solar + 600 kW storage

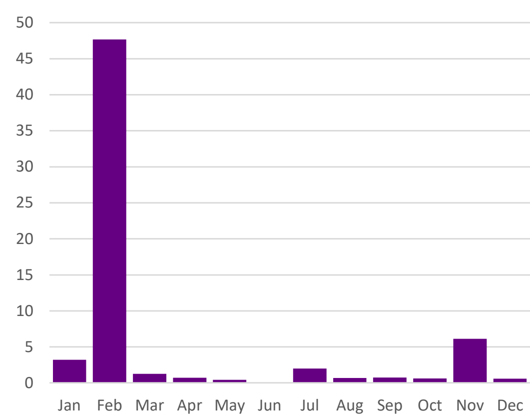
Images: (left) Aerial view of downtown Redding, credit: visitredding.com
(right) Sundial Bridge, credit: turtlebay.org

- Total of 320 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 5
- Average 64.1 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



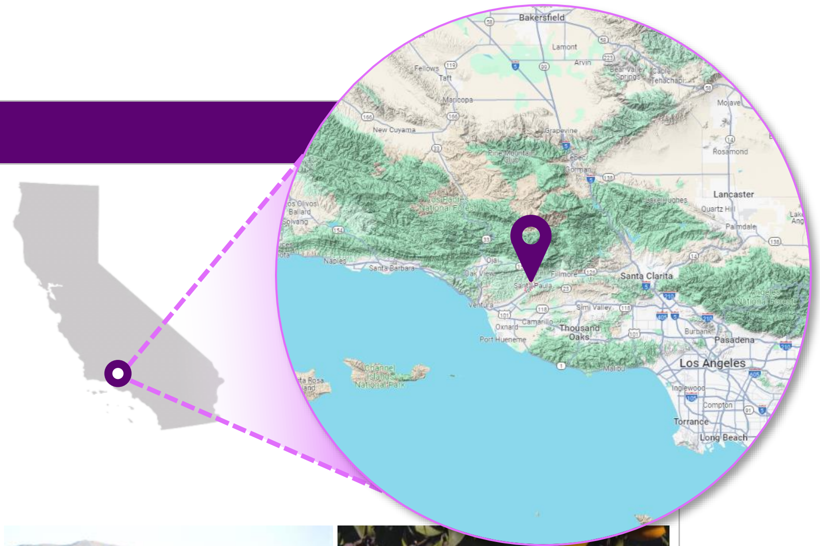
Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

Santa Paula

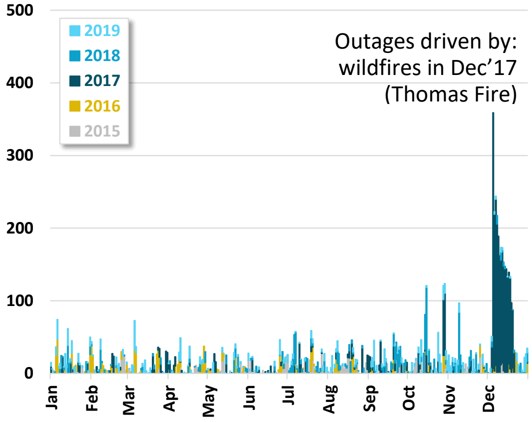
- Utility: SCE
- Small agricultural community near the coastline in Ventura County
- About 31,000 people
- Customer mix (% of 2023 electricity use)
  17% residential, 83% non-residential
- CalEnviroScreen 4.0 score: 57.5 percentile
  44.6% pollution burden
  62.7% population/socioeconomic
- DER capacity as of Dec'23
  1,150+ installations
  7,500 kW solar + 700 kW storage



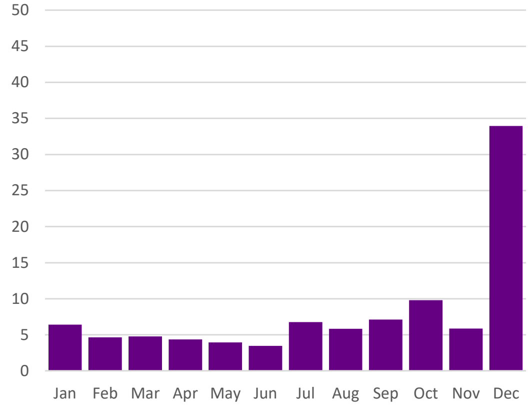
Images: (left) South Mountain, Santa Paula, credit: Craig Mailloux
(right) Oranges on a tree, Santa Paula, credit: Craig Mailloux

- Total of 1,746 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 18
- Average 97.0 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



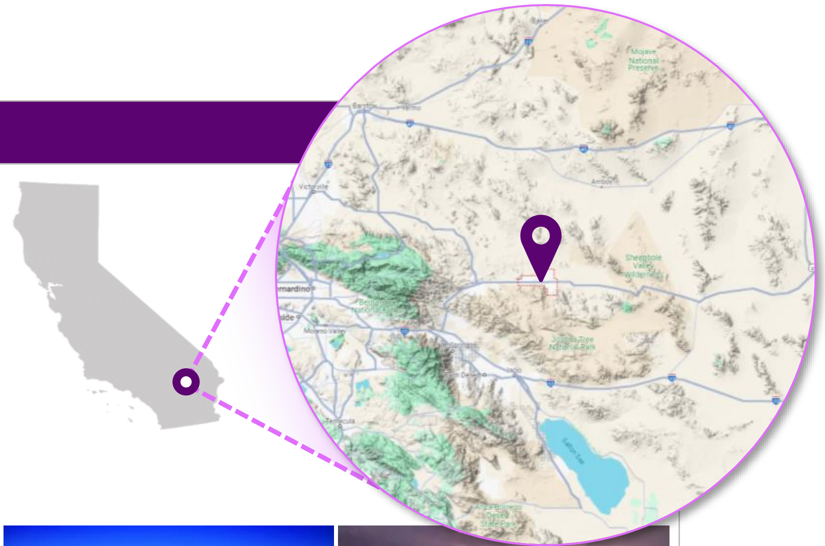
Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

Twentynine Palms

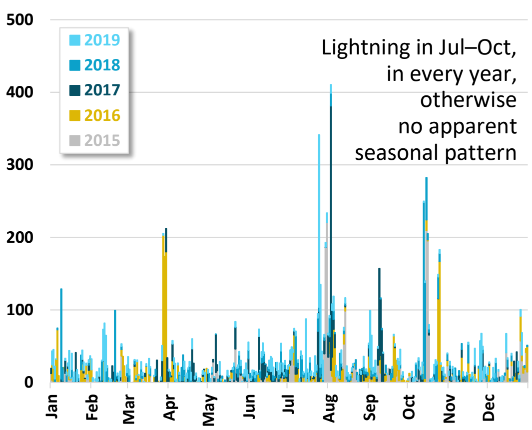
- Utility: SCE
- Rural nature-based desert community in Yucca Valley, southern part of San Bernardino County
- About 28,000 people
- Customer mix (% of 2023 electricity use)
  67% residential, 33% non-residential
- CalEnviroScreen 4.0 score: 27.5 percentile
  4.4% pollution burden
  63.9% population/socioeconomic
- DER capacity as of Dec'23
  1,700+ installations
  12,800 kW solar + 650 kW storage



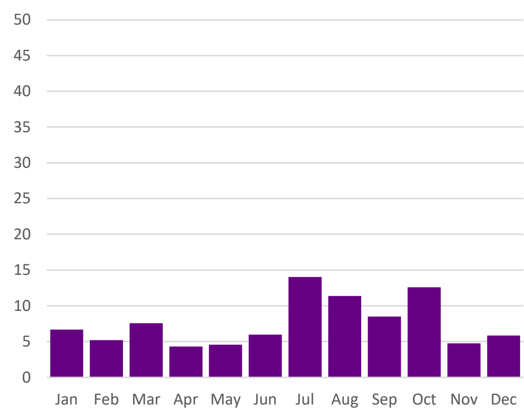
Images: (left) Donnel Hill; credit: City of Twentynine Palms
(right) Tropical storm Hilary; credit: Timothy Curr

- Total of 2,467 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 27
- Average 91.4 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



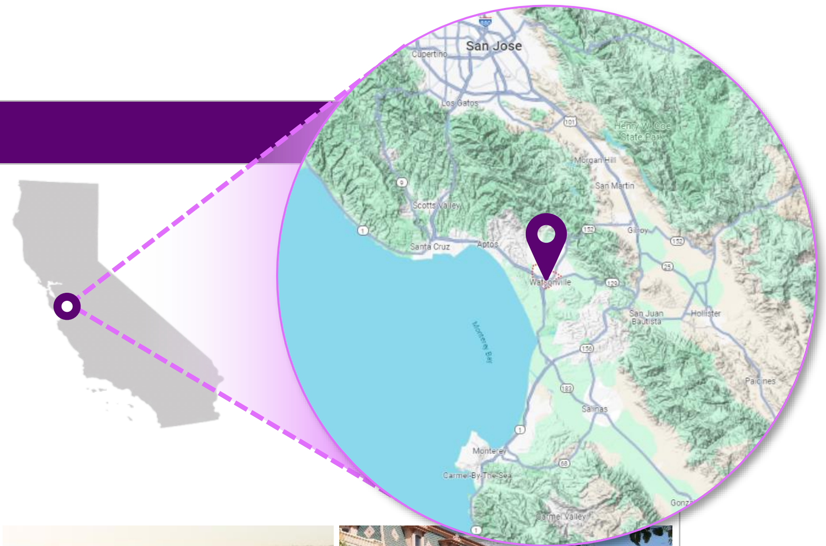
Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

Watsonville

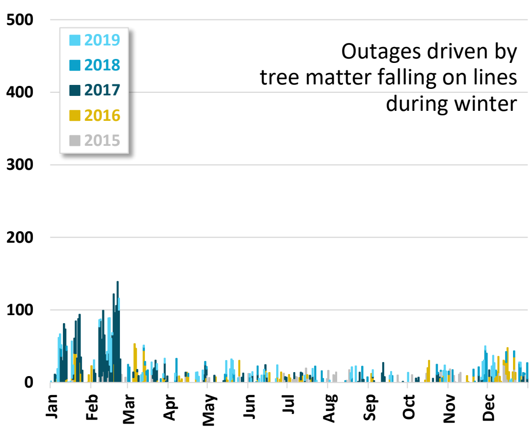
- Utility: PG&E
- Coastal city in the Monterey Bay area, at the southern end of Santa Cruz County
- About 52,000 people
- Customer mix (% of 2023 electricity use)
  24% residential, 76% non-residential
- CalEnviroScreen 4.0 score: 66.9 percentile
  57.4% pollution burden
  66.9% population/socioeconomic
- DER capacity as of Dec'23
  ~2,600 installations
  22,500 kW solar + 900 kW storage



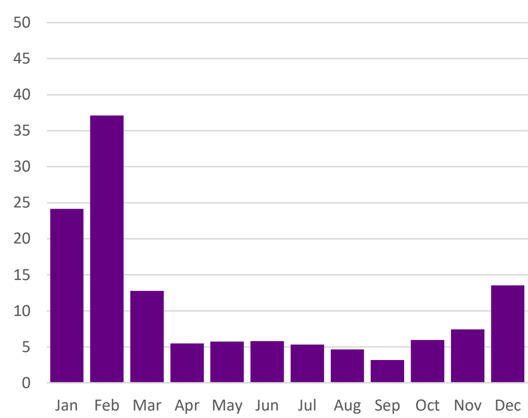
Images: (left) Aerial view of Watsonville, credit: City of Watsonville
(right) Mansion House; credit: City of Watsonville

- Total of 1,048 distribution circuit-hours on outage per year (2015–2019 average)
- Number of circuits = 8
- Average 131.0 hours out per year

Time Profile of Daily Circuit Outages
(total circuit-hours)



Monthly Average Customer Outages
(hours per month)



Sources and notes: Population reflects the U.S. Census Bureau estimates for 2022. Customer mix is calculated based on electricity usage reports filed by the IOUs pursuant to CPUC Decision 14-05-016. CalEnviroScreen 4.0 scores are published by California Environmental Protection Agency in October 2021. DER capacity is based on data from California DG Stats including projects interconnected as of December 31, 2023. Circuit outages are based on analysis of 2015–2019 public data reported by the IOUs with their Wildfire Mitigation Plans (PG&E and SCE areas) and PowerOutage.us data (SDG&E areas).

Wholesale market value potential

We considered 3 value streams for the wholesale market use case, including energy arbitrage, RPS benefits, and system RA capacity value. We did not include ancillary services in this analysis due to its relatively small market size, where we already see signs of saturation.

__Energy arbitrage__:

We estimated energy value by simulating energy storage dispatch under historical prices from 2019 to 2022. We mapped each location to a CAISO-defined sub-load aggregation point (subLAP) and used the corresponding subLAP prices as inputs to our model.

In the optimization algorithm, the energy storage dispatch is set to maximize market revenues assuming 4 hours of duration and 85% of roundtrip efficiency. We limited cycling to once per day on average and applied 11.5% of forced outage rate, consistent with historical levels.

Figure C-2 shows the results by location. The estimated energy arbitrage value (net of charging cost) ranges from $5 to $7 per kW-month, on average over the 4-year period analyzed. Locations in southern California have higher energy value potential due to more opportunities for market price arbitrage, relative to northern California. Market prices and volatility levels fluctuate from year to year, which affects the estimated arbitrage values. Thus, we use the 2019–2022 average values rather than relying on a single year's estimates.

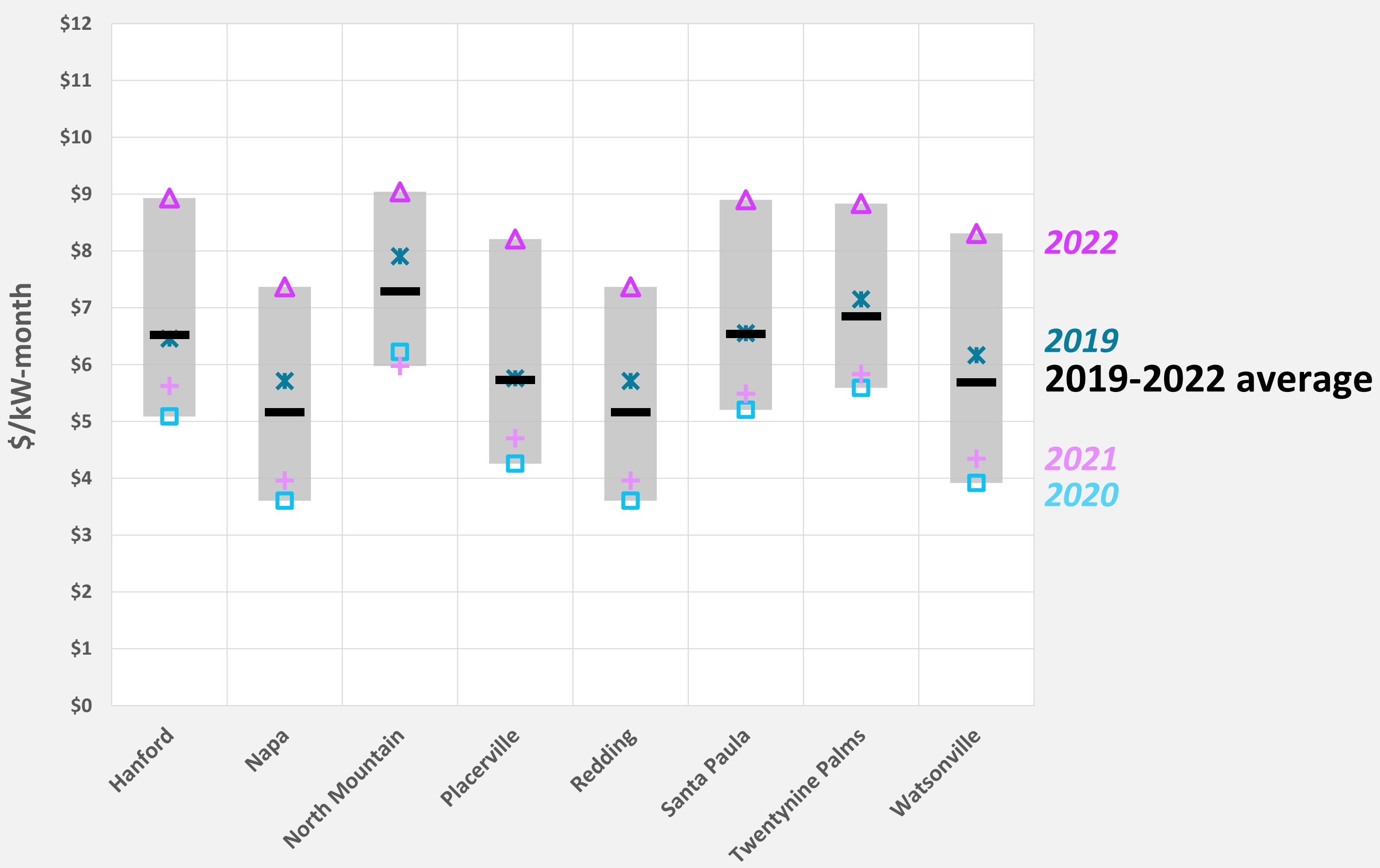


Figure C-2: Estimated average energy arbitrage value by location (in 2023 $).

RPS benefits:

Energy storage can reduce renewable curtailments by mitigating oversupply conditions, which may become more challenging as California continues to decarbonize its electric system. As discussed in the report and **Appendix A (Historical Energy Storage Benefits)**, charging of energy storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

The avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet RPS and other clean energy targets. To estimate the amounts of renewable curtailments that storage resources can avoid at selected locations, we consider intervals with very low or negative LMPs as the indicators of renewable oversupply. We quantify associated benefits at $32 per MWh of avoided renewable curtailments, based on the RPS adder forecast from the CPUC's latest Power Charge Indifference Adjustment.

Figure C-3 shows the results by location. The average estimated RPS benefit ranges from $1 to $2.2 per kW-month depending on location. The results vary seasonally, with a significant share of the benefits concentrated in the spring months, when renewable curtailment risks are typically higher. During that period, RPS benefits can reach up to $6/kW-month. Locations in southern California tend to have higher RPS benefits due to increased renewable curtailment risks, compared to northern California. Market conditions change from one year to another, so we used the 2019–2022 average values rather than relying on a single year's estimates.

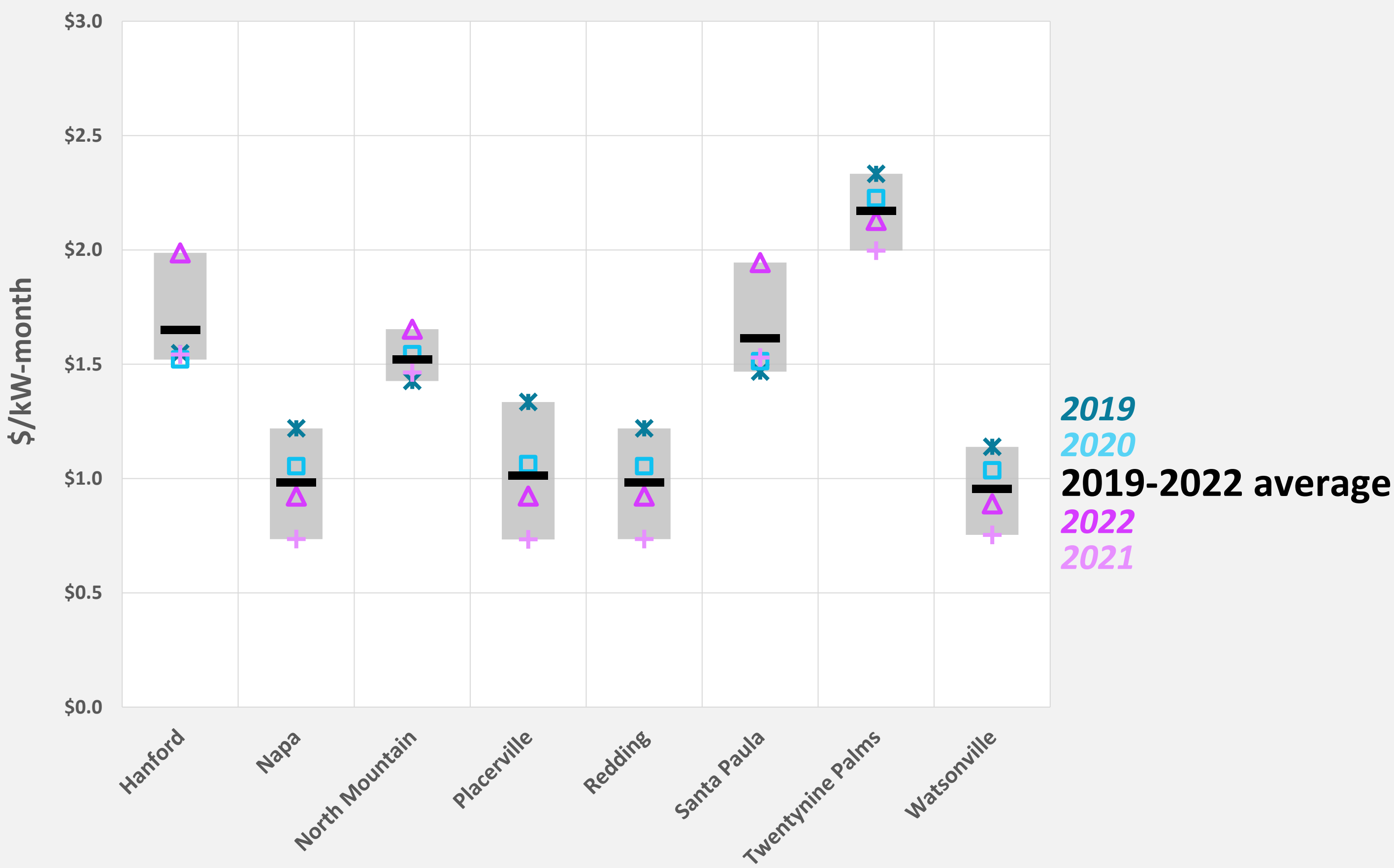


Figure C-3: Estimated average RPS benefits by location (in 2023 $).

System RA value:

Energy storage capacity available to discharge during peak periods can help meet the RA capacity needs to ensure system reliability. We estimate associated benefits at $15/kW-month, which is consistent with the 2024 system RA price forecast in the CPUC's Power Charge Indifference Adjustment and recent RA contract data we analyzed.

We allocate the system RA capacity value to August and September evening hours, based on findings from the CPUC's 2022 planning reserve margin study. This allocation also aligns with the historical record of CAISO systemwide emergency events observed in recent years, during the heat waves of August–September 2020 and September 2022.

Total market value potential:

Figure C-4 shows total estimated market value potential for the energy storage resources in selected communities. The RA value is kept the same across all locations at $15/kW-month, which translates to $180/kW-year annually. This accounts for a large share of the total market value potential. Energy and RPS benefits add $75 to $110/kW-year of value, depending on the location.

These findings assume 100% market participation, with the full capacity of the resource offered to the CAISO's markets throughout the year. However, under the multiple-use application (MUA) analysis discussed next, when the resource's capacity is reserved for outage mitigation, the realized market value of storage resources would be lower than the levels shown here.

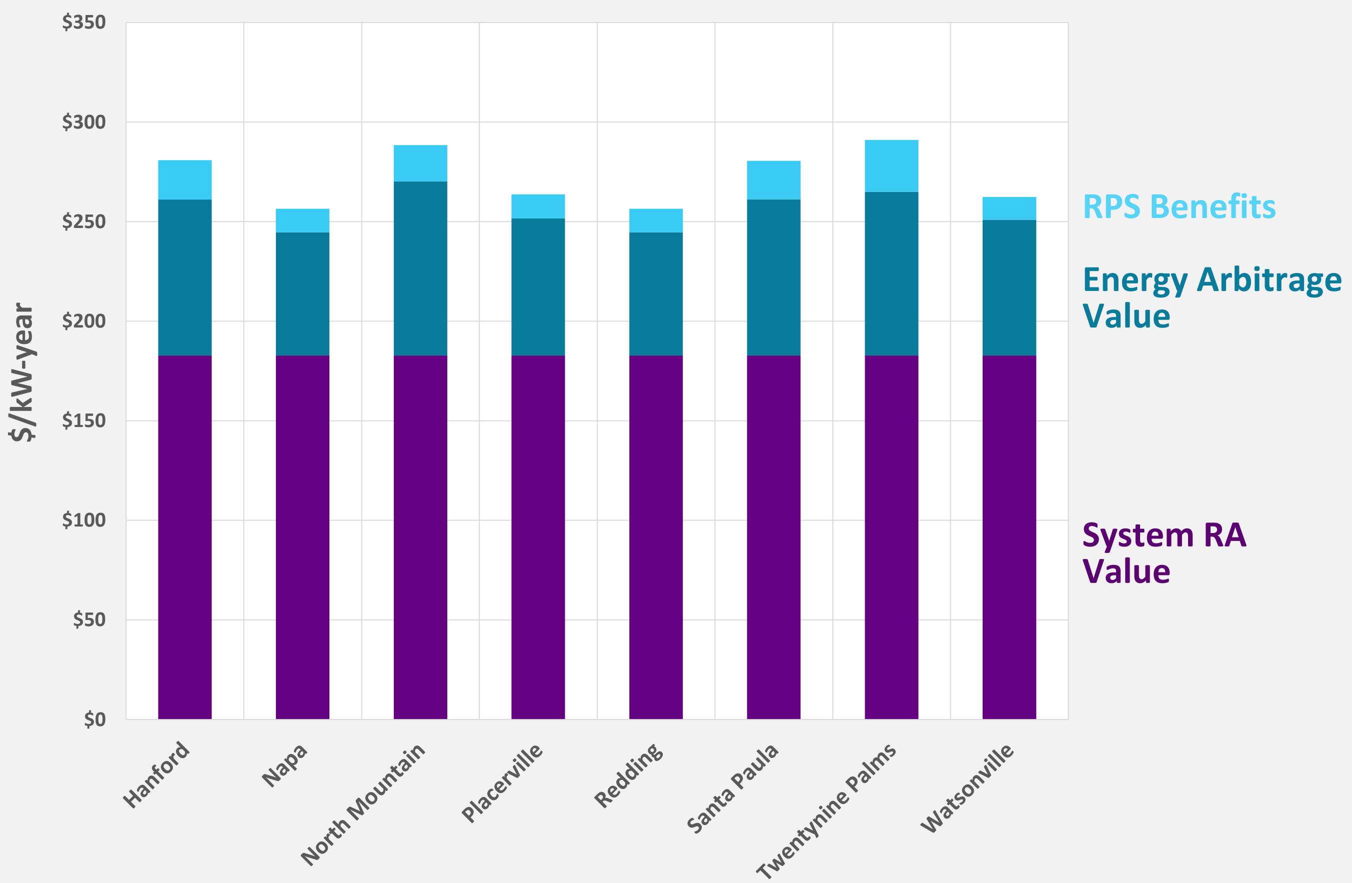


Figure C-4: Total estimated market value potential by location (in 2023 $).

Value-stacking scenarios

For the multiple-use application (MUA) case studies, we developed four separate value-stacking scenarios with different priorities on wholesale market participation vs. customer outage mitigation use cases. Comparing the results across these four scenarios enables us to quantify the tradeoffs between expected customer outage risks and wholesale market revenues that can be utilized to offset the cost of resilience investments.

Figure C-5 describes these scenarios:

Scenario Name	Description
No mitigation scenario	This is a benchmark case prioritizing wholesale market use case with no outage mitigation. Energy storage is fully available in the wholesale market, where resources capture 100% of the estimated market values as shown in Figure C-4, but they do not offer any protection against power outages.
Market focus scenario	This scenario prioritizes wholesale market use case but also allows for some outage mitigation. Energy storage is offered to the wholesale market to capture at least 80% of the estimated market value potential. Resource capacity is reserved for customer outage mitigation during months with low market opportunities.
Resilience focus scenario	This scenario prioritizes customer outage mitigation but also allows for some wholesale market participation to offset costs. Energy storage is reserved to achieve 90% outage mitigation and offered to the wholesale market in months when power outage risk is relatively low.
Full mitigation scenario	This is a benchmark case prioritizing outage mitigation with no wholesale market participation. Energy storage capacity is fully reserved to protect customers against power outages, but customers do not get any market revenues to offset cost of their resilience investment.

Figure C-5: Description of value-stacking scenarios developed for the MUA case studies.

Scenario results

Figure C-6 shows estimated customer outage mitigation and wholesale market value captured in each scenario, including normalized stacked values. The results demonstrate that energy storage in most selected areas can capture significant market value without giving up much outage mitigation. In some areas though, power outage risks coincide with high market value periods (e.g., in summer and early fall). In those areas, value-stacking opportunities would be much more limited. For instance, customers in Twentynine Palms would give up nearly half of their outage mitigation benefits with a market focus due to outages concentrated in summer, while a resilience focus to mitigate their outage risks would result in a loss of around 90% of market value.

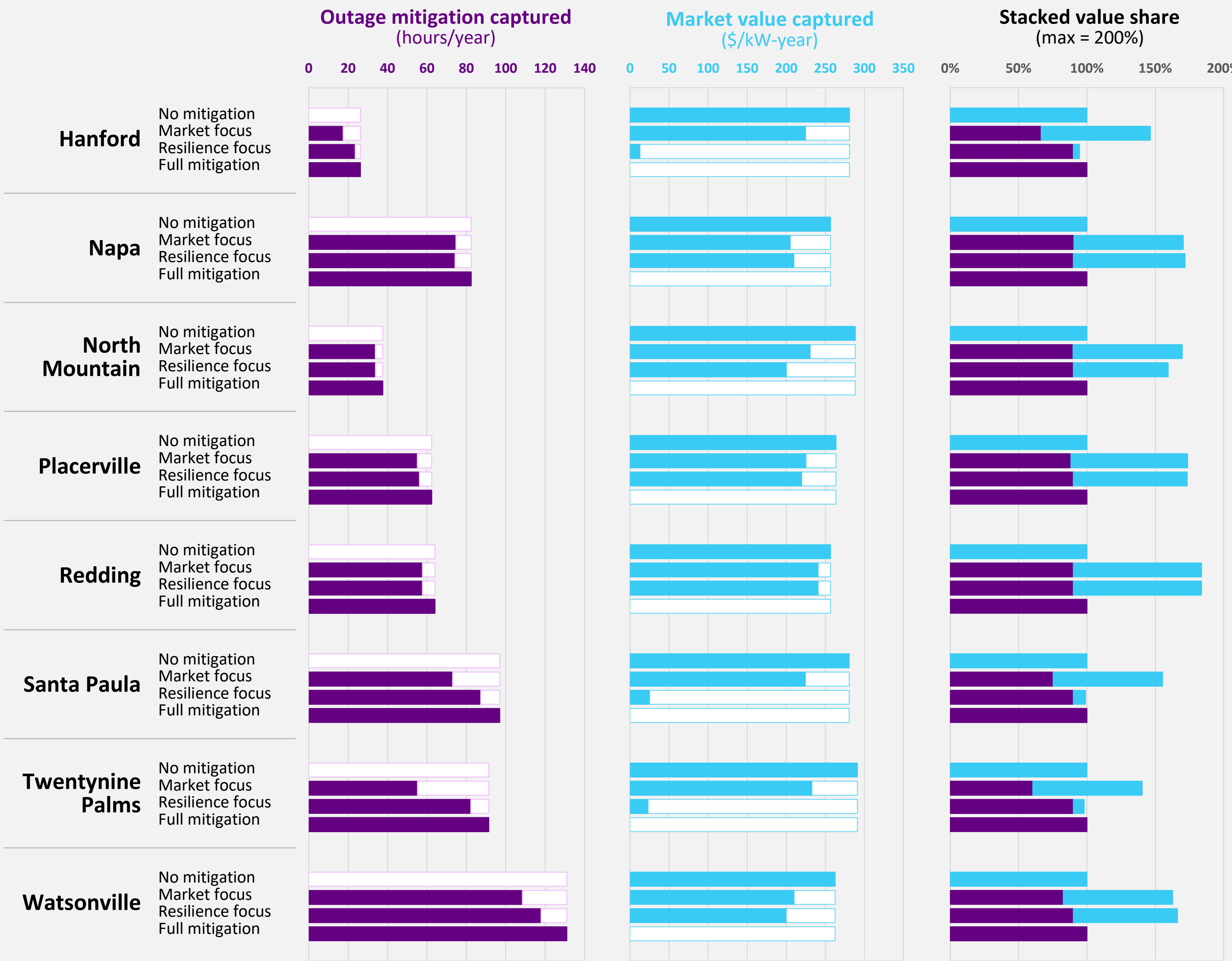


Figure C-6: Results for value-stacking with outage mitigation, by scenario.

Sensitivity case with no RA value

We ran a sensitivity case excluding resource adequacy (RA) value. Figure C-7 illustrates the results of this sensitivity case. Without RA attributes, the total estimated market value potential of energy storage resources would be significantly lower, accounting for approximately one-third of the total value with RA capacity. Non-RA benefits, including energy arbitrage and RPS benefits, are distributed more evenly throughout the year compared to RA value, which is concentrated in August and September. Thus, a market-focused use case would require extended participation in the wholesale market to achieve the same revenue targets. This would reduce the periods when energy storage capacity can be reserved for outage mitigation and limit overall value-stacking opportunities.

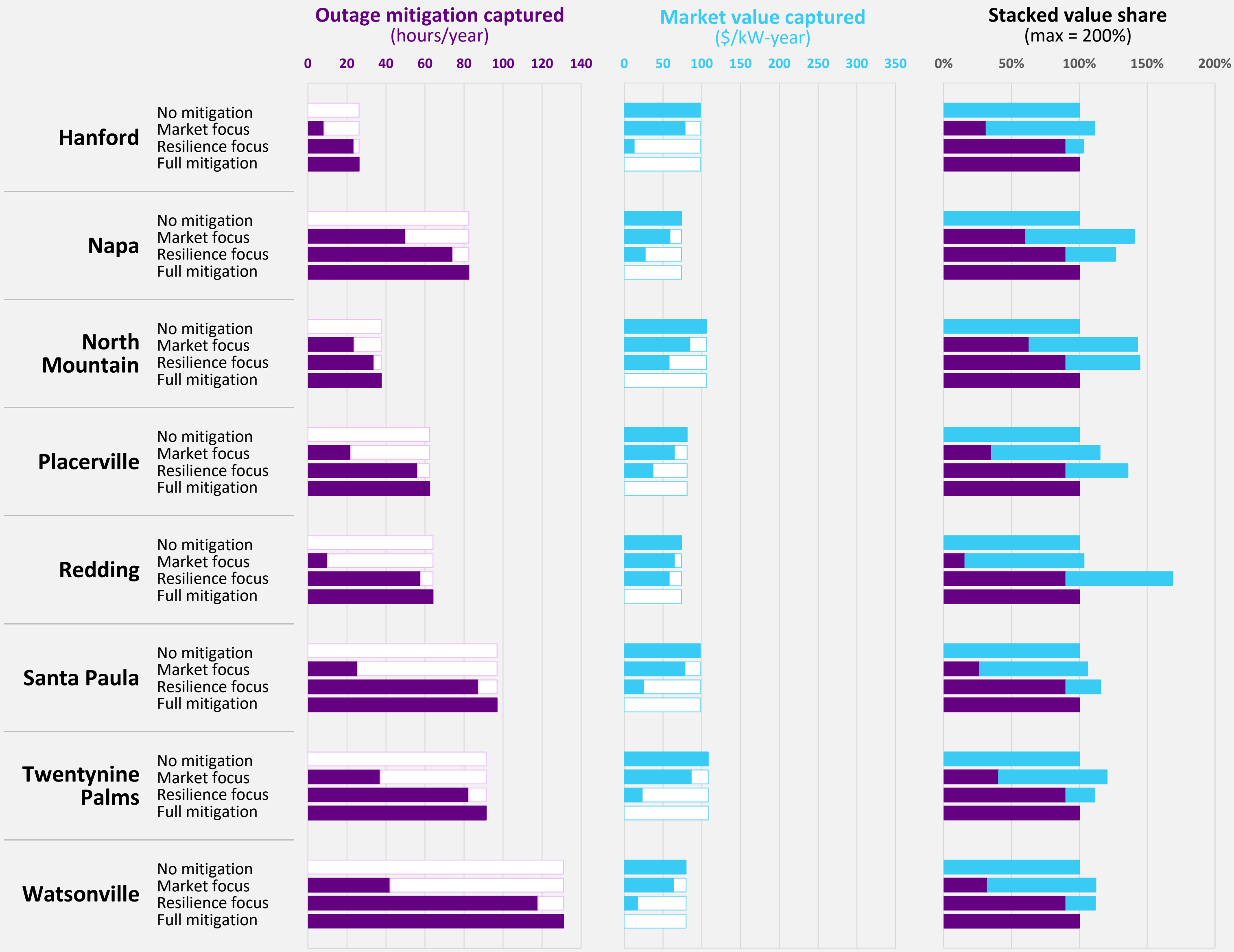


Figure C-7: Results for value-stacking with outage mitigation, sensitivity case with no RA value.

Optimal cross-domain MUA strategy with outage mitigation

We compare the scenarios to quantify the risk-value tradeoff, based on the amount of wholesale market revenues that a customer would need to give up for each additional MWh of reduction in their expected outage levels.

Results indicate optimal MUA zones as a function of customers' intrinsic value of lost load (VoLL) level at selected locations. VoLL varies by customer, depending on how inconvenient or costly power outages are for them. Interrupting discretionary loads, like heating a swimming pool, is not much of an inconvenience, and thus yields a relatively low VoLL. On the other hand, critical loads have low tolerance for outages and their VoLLs are much higher.

Example:
This example, based on analysis for Hanford, illustrates our calculations of optimal MUA zones based on the risk-value tradeoffs across the scenarios analyzed:

- Annual market value potential $280/kW-year
- Annual expected outages 26 hours/year
- Translates to 13 kWh of lost load assuming 1 kW at 50% load factor
- $280 ÷ 13 = $21.5/kWh or $21,500/MWh
- If customer's VoLL is above this level, it indicates market revenues are not sufficient to justify value stacking: best strategy → **full mitigation**
- Market focus scenario captures 80% of market value ($225/kW-year) while reducing expected outages from 26 hours/year to 9 hours/year
- Lost market value 280−225 = $55/kW-year
- Customer outage mitigation 26−9 = 17 hours/year, which translates to 8.5 kWh/year per 1 kW at 50% load factor
- $55 ÷ 8.5 = $6.5/kWh or $6,500/MWh
- If customer's VoLL is below this level, it indicates outage mitigation is not sufficient to justify value stacking: best strategy → **market only**
- Value stacking is optimal only if customer's VoLL is between these two levels, from $6,500 to $21,500/ MWh: best strategy → **market focus**

Figure C-8 summarizes our results. In areas with little outage problem, customers would need to give up a lot of revenues to mitigate very few outages, so value-stacking could be attractive even under high VoLL. Full mitigation of outages comes at a high opportunity cost in most areas selected, so market participation in periods with low outage risk tends to be more cost-effective.

The results for the sensitivity case excluding RA value are shown on the right. Without any RA attributes, value-stacking would not be as attractive except for customers with low VoLL (discretionary load).

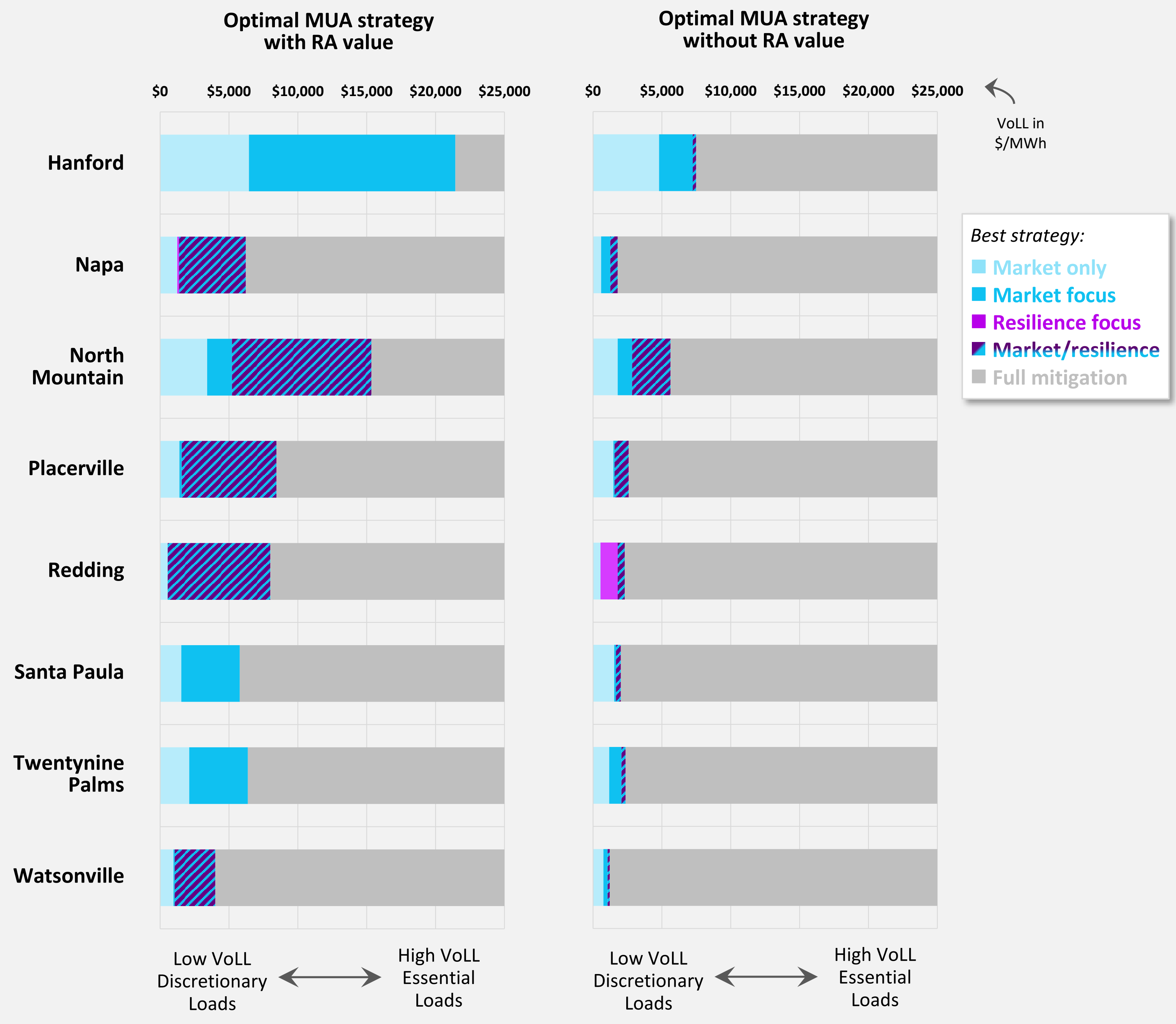


Figure C-8: Optimal MUA strategy based on value of lost load (VoLL) levels.

Appendix D: MUA with Distribution Deferral

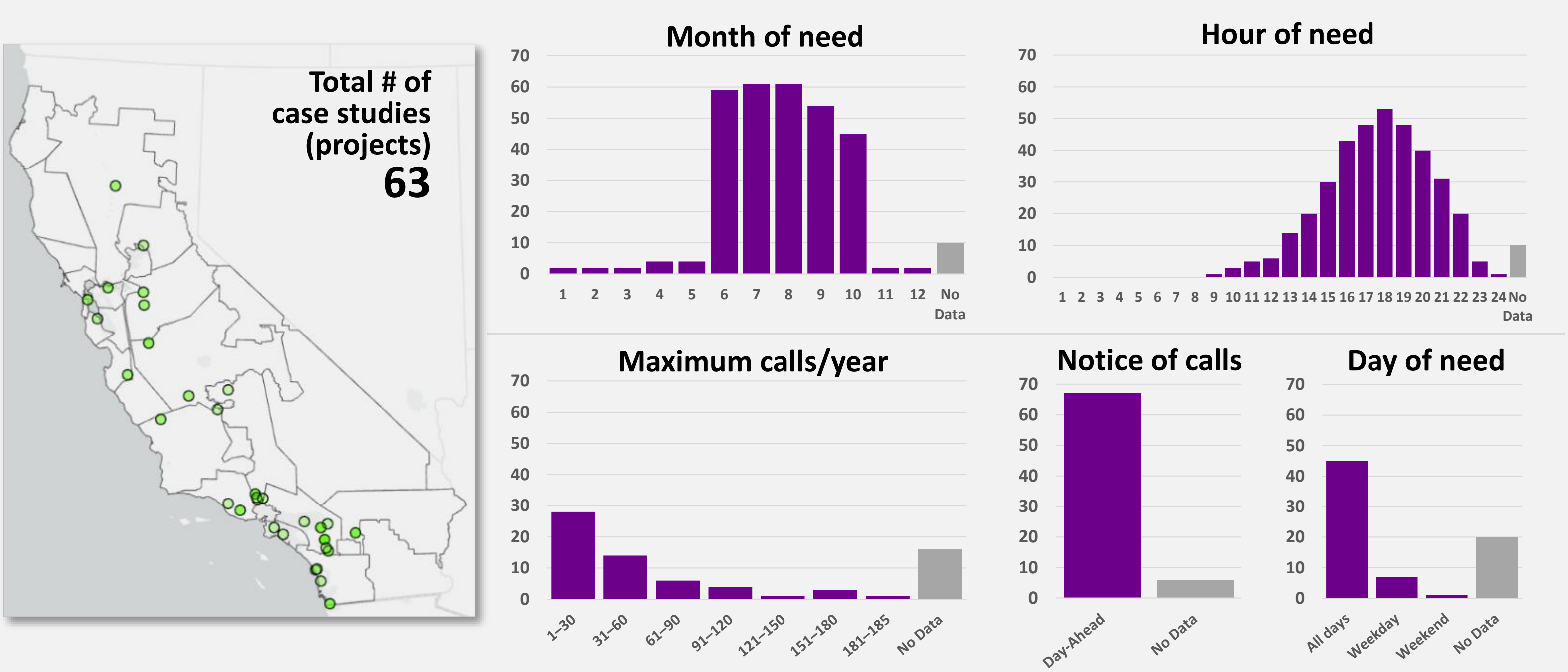
This appendix provides details on our cross-domain multi-use application (MUA) analysis, focusing on value-stacking opportunities for distribution deferral solutions.

As of August 2023, the IOUs have selected a total of 98 potential projects based on distribution deferral (DD) procurement cycles from 2017/18 through 2022/2023. We start with a dataset for these 98 projects, developed by PA Consulting and released under Rulemaking 21-06-017, which includes project location, MW/MWh need, delivery period, and limit on DD calls.

Energy storage attributes were suitable for 73 of these DDO projects, of which only 63 had sufficient public data needed for our analysis. Total capacity needed for the 63 projects were 210 MW and 1,084 MWh. Of these DDOs, only 3 projects were actually installed: Acorn I and two Wildcat I projects, all with energy storage.

Figure D-1 shows the locations of these 63 projects we selected for MUA case studies with distribution deferral and their characteristics. The DD needs are concentrated in the summer period, mostly from June through September, and extending into October for about two-thirds of the cases. Most DD needs occur throughout all days of the week, typically spanning the afternoon and evening peak periods. In approximately half of the cases, annual DD calls are limited to 30 per year or less, while for some projects, it can be as high as 185 per year. In all cases, the DD calls are scheduled to occur on a day-ahead basis.

On the next page, Figure D-2 includes a full list of the selected projects with additional details on timing of the underlying DD needs.



Sources: Lumen summary of PA Consulting's August 2023 DIDF Tracking Spreadsheet in R.21-06-017 High DER Proceeding.

Figure D-1: Characteristics of projects selected for MUA case studies with distribution deferral.

Cycle	Deferral Project Location	IOU	SubLAP	MW need	MWh need	Month of need	Day of need	Hour of need	Max calls per year	Notice of calls
2017/2018	Eisenhower	SCE	SCLD	2.54	4.62	Jun-Oct	-	HE 16-18	15	Day-Ahead
2017/2018	Eisenhower, Desert Outpost	SCE	SCLD	1.26	5.15	Jun-Oct	-	HE 16-23	40	Day-Ahead
2017/2018	Newbury, Belpac	SCE	SCNW	1.47	4.17	Jun-Oct	-	HE 15-19	25	Day-Ahead
2017/2018	Newbury, Hooligan	SCE	SCNW	2.84	12.22	Jun-Oct	-	HE 15-22	40	Day-Ahead
2017/2018	Newbury, Intrepid	SCE	SCNW	1.91	4.36	Jun-Oct	-	HE 17-20	25	Day-Ahead
2017/2018	Gonzalez Bank 3	PG&E	PGCC	0.50	2.00	Jun-Sep	Weekday	HE 19-21	12	Day-Ahead
2017/2018	Gonzalez Bank 4	PG&E	PGCC	1.50	6.00	Jun-Aug	All days	HE 10-12	12	Day-Ahead
2017/2018	Carlsbad, 303	SDG&E	SDG1	1.41	3.48	Jun-Oct	All days	HE 20-21	-	-
2017/2018	Carlsbad, 783	SDG&E	SDG1	2.71	10.62	Jun-Oct	All days	HE 16-22	-	-
2018/2019	Sun City Substation	SCE	SCEC	9.60	37.52	Jun-Oct	-	HE 15-21	50	Day-Ahead
2018/2019	Sun City, Equinox Circuit	SCE	SCEC	7.50	61.55	Jun-Oct	-	HE 13-24	159	Day-Ahead
2018/2019	Sun City, Bradley Circuit	SCE	SCEC	4.80	29.42	Jun-Oct	-	HE 13-21	152	Day-Ahead
2018/2019	Sun City, Lusk Circuit	SCE	SCEC	1.80	7.62	Jun-Oct	-	HE 14-19	100	Day-Ahead
2018/2019	Mira Loma, Matterhorn	SCE	SCEC	1.20	5.28	Jun-Oct	-	HE 16-21	50	Day-Ahead
2018/2019	Huron Bank 1 (a)	PG&E	PGF1	3.70	37.00	Jun-Aug	All days	HE 13-22	33	Day-Ahead
2018/2019	Huron Bank 1 (b)	PG&E	PGF1	1.60	11.20	Apr-Jun,Sep-Oct	All days	HE 11-16	131	Day-Ahead
2018/2019	Santa Nella, Canal 1102	PG&E	PGF1	0.60	3.60	Jun-Aug	Weekday	HE 14-19	82	Day-Ahead
2018/2019	Santa Nella, Canal 1102	PG&E	PGF1	2.60	20.80	Jun-Sep	All days	HE 13-20	82	Day-Ahead
2018/2019	Santa Nella, Ortiga Bank 1	PG&E	PGF1	2.20	15.40	Jun-Aug	All days	HE 14-20	31	Day-Ahead
2019/2020	Elizabeth Lake #1	SCE	SCEN	6.80	18.40	Jun-Oct	All days	HE 16-18	15	Day-Ahead
2019/2020	Elizabeth Lake #2	SCE	SCEN	7.80	23.40	Jun-Oct	All days	HE 16-19	15	Day-Ahead
2019/2020	Eisenhower, Crossley 33 kV	SCE	SCLD	2.50	4.30	Jun-Oct	All days	HE 18-19	15	Day-Ahead
2019/2020	Newhall 66/16 kV	SCE	SCNW	12.50	39.60	Jun-Oct	All days	HE 17-20	90	Day-Ahead
2019/2020	Alessandro, Elsworth 12 kV	SCE	SCEC	1.80	9.80	Jun-Oct	All days	HE 13-19	25	Day-Ahead
2019/2020	Alessandro, Fantastico 12 kV	SCE	SCEC	1.90	6.40	Jun-Oct	All days	HE 17-21	20	Day-Ahead
2019/2020	Alessandro, Kingsway 12 kV	SCE	SCEC	0.30	0.60	Jun-Oct	All days	HE 16-17	15	Day-Ahead
2019/2020	Pechanga, Lazaro 12 kV	SCE	SCEC	0.70	0.70	Jun-Oct	All days	HE 18	15	Day-Ahead
2019/2020	Pechanga, Matera 12 kV	SCE	SCEC	0.20	0.50	Jun-Oct	All days	HE 17-18	15	Day-Ahead
2019/2020	Pechanga, Noche 12 kV	SCE	SCEC	1.00	2.00	Jun-Oct	All days	HE 18-20	15	Day-Ahead
2019/2020	Alpaugh, Corcoran 1112	PG&E	PGZP	4.40	30.80	Jun-Sep	All days	HE 16-22	113	Day-Ahead
2020/2021	Sun City, Goetz 12kV	SCE	SCEC	3.00	15.20	Jun-Oct	All days	HE 15-22	20	Day-Ahead
2020/2021	Sun City, Harnage 12kV	SCE	SCEC	0.40	0.40	Jun-Oct	All days	HE 17-19	15	Day-Ahead
2020/2021	Sun City, Oakdale 12kV	SCE	SCEC	1.80	6.10	Jun-Oct	All days	HE 16-21	15	Day-Ahead
2020/2021	Elizabeth Lake, Guitar 16kV	SCE	SCEN	1.30	4.90	Jun-Oct	All days	HE 16-22	40	Day-Ahead
2020/2021	Elizabeth Lake, Oboe 16kV	SCE	SCEN	2.10	12.30	Jun-Oct	All days	HE 11-18	85	Day-Ahead
2020/2021	Willow Pass Bank 1	PG&E	PGEB	0.30	0.60	Jun-Aug	Weekend	HE 15-20	8	Day-Ahead
2020/2021	Willow Pass Bank 3	PG&E	PGEB	5.10	30.60	Jun-Sep	All days	HE 15-22	101	Day-Ahead
2020/2021	San Miguel 1104	PG&E	PGZP	1.00	4.00	Jun-Sep	Weekday	HE 18-22	66	Day-Ahead
2020/2021	Paso Robles 1107	PG&E	PGZP	0.60	2.40	Jul-Sep	Weekday	HE 16-21	21	Day-Ahead
2020/2021	Ripon 1705, Vierra 1707	PG&E	PGST	3.70	18.50	Jun-Sep	All days	HE 16-22	102	Day-Ahead
2021/2022	Mormon 1102	PG&E	PGST	0.75	3.00	Jun-Jul	All days	HE 18-22	41	Day-Ahead
2021/2022	East Stockton Bank 3	PG&E	PGST	0.31	0.62	Aug-Sep	Weekday	HE 13-19	45	Day-Ahead
2021/2022	Ripon 1705, Manteca Bank 7	PG&E	PGST	1.09	3.27	Jul-Aug	All days	HE 18-20	52	Day-Ahead
2021/2022	Embarcadero (SF Z) 1116	PG&E	PGSF	0.11	0.22	Jul-Oct	All days	HE 13-16	22	Day-Ahead
2021/2022	Embarcadero (SF Z) 1118	PG&E	PGSF	0.38	1.90	Jan-Dec	All days	HE 12-17	22	Day-Ahead
2021/2022	Rocklin 1105, Del Mar Bank 2	PG&E	PGSI	0.34	0.68	Jun-Aug	All days	HE 18-20	23	Day-Ahead
2021/2022	Anita 1105, Nord Bank 1	PG&E	PGNP	1.23	4.92	Jun-Aug	All days	HE 18-22	70	Day-Ahead
2021/2022	Anita 1105, Nord Bank 2	PG&E	PGNP	1.39	5.56	Jun-Sep	All days	HE 18-22	60	Day-Ahead
2021/2022	Belle Haven Bank 4	PG&E	PGP2	3.21	35.31	Apr-Oct	All days	HE 10-21	154	Day-Ahead
2021/2022	El Casco, Jonagold 12kV	SCE	SCEC	0.40	0.70	Jun-Oct	All days	HE 17-18	15	Day-Ahead
2021/2022	Shawnee Transformer Upgrade	SCE	SCEW	6.90	31.50	Jun-Oct	Weekday	HE 13-19	15	Day-Ahead
2021/2022	Santa Clara - Colonia Substation	SCE	SCNW	22.30	172.60	Jan-Dec	Weekday	HE 9-21	185	Day-Ahead
2021/2022	Eisenhower, Crossley 33 kV	SCE	SCLD	2.90	8.50	Jun-Oct	All days	HE 14-18	50	Day-Ahead
2021/2022	San Ysidro, 1202	SDG&E	SDG1	0.86	7.74	Jun-Oct	All days	HE 15-22	-	-
2021/2022	San Ysidro, 1202	SDG&E	SDG1	1.58	17.38	Jun-Oct	All days	HE 14-23	-	-
2021/2022	North City West Substation	SDG&E	SDG1	0.50	1.50	Jun-Oct	All days	HE 19-20	-	-
2022/2023	Saugus-Haskell 66 kV	SCE	SCEN	4.00	8.10	Jun-Oct	All days	HE 17-18	15	Day-Ahead
2022/2023	Rector-Riverway 66kV	SCE	SCEN	21.00	128.70	Jun-Oct	All days	HE 13-23	55	Day-Ahead
2022/2023	Bullis, Colyer 16 kV	SCE	SCEW	2.60	14.40	Jun-Oct	All days	HE 14-23	15	Day-Ahead
2022/2023	North Oaks 66/16 kV Substation	SCE	SCEN	21.10	107.20	Jun-Oct	All days	HE 15-21	30	Day-Ahead
2022/2023	Alessandro 115/33 kV Substation	SCE	SCEC	1.30	2.20	Jun-Oct	All days	HE 16-17	15	Day-Ahead
2022/2023	Triton, Seawolf 12 kV	SCE	SCEC	3.72	6.90	Jun-Oct	All days	HE 15-22	40	Day-Ahead
2022/2023	San Ysidro, 1202	SDG&E	SDG1	0.86	7.74	Jun-Oct	All days	HE 15-22	-	-

Sources: Lumen summary of PA Consulting's August 2023 DIDF Tracking Spreadsheet in R.21-06-017 High DER Proceeding.

Figure D-2: List of projects selected for MUA case studies with distribution deferral.

Analytical approach

We analyze hypothetical energy storage projects to meet the distribution deferral (DD) need at each location, assuming DD is the primary use case. Only residual capacity after serving DD need is used to provide wholesale market services—this gives us a conservative view of what can be "counted on" from a wholesale market perspective.

We assume DD services are called at the annual maximum number of times, for the maximum number of hours, and on days when wholesale market value (opportunity cost) is highest, providing a very conservative estimate of the value-stacking opportunity. Within DD peak months, and on days when DD services are not called, we assume energy storage is subject to charging constraints, recognizing the need to minimize creation of a new peak load on the distribution system.

We characterized the market value potential based on the same approach we used for the MUA analysis with outage mitigation, including energy arbitrage, RPS benefits, and system RA value.

Energy arbitrage:

We mapped each location to a CAISO sub-load aggregation point (subLAP) and estimated market value based on energy storage dispatch against historical LMPs for 2019-2022. Figure D-3 shows the results by subLAP. The estimated energy arbitrage value (net of charging cost) ranges from $5 to $7 per kW-month, on average over the 4-year period analyzed. Locations in southern California tend to have higher energy value potential due to more opportunities for market price arbitrage, relative to northern California. Market prices and volatility levels fluctuate from year to year, which affects the estimated arbitrage values. Thus, we used the 2019–2022 average values rather than relying on a single year's estimates.

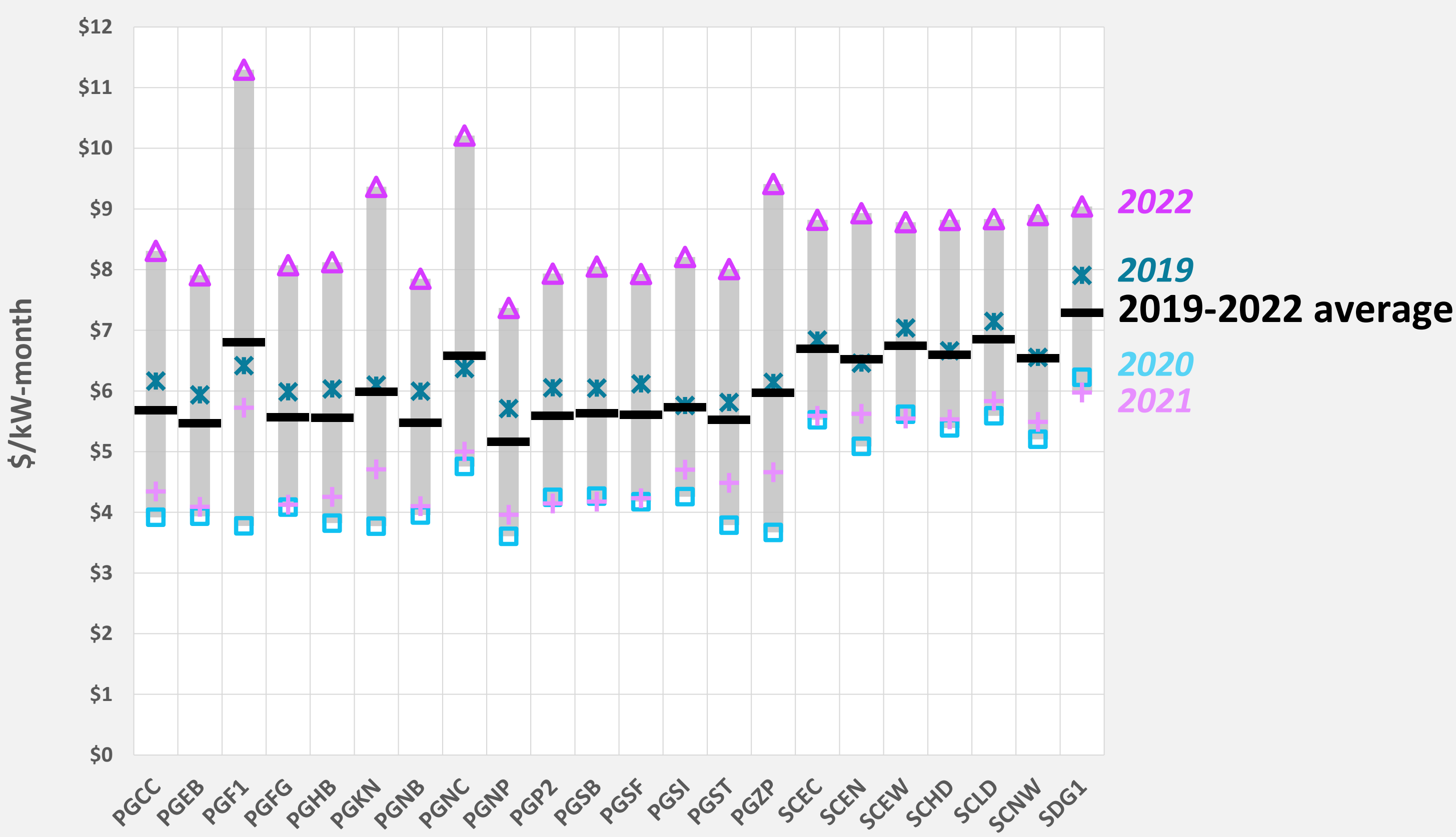


Figure D-3: Estimated average energy arbitrage value by CAISO subLAP (in 2023 $).

RPS benefits:

Energy storage can reduce renewable curtailments by mitigating oversupply conditions, which may become more challenging as California continues to decarbonize its electric system. As discussed in the report and **Appendix A (Historical Energy Storage Benefits)**, charging of energy storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

The avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet RPS and other clean energy targets. To estimate the amounts of renewable curtailments that storage resources can avoid at selected locations, we considered intervals with very low or negative LMPs as the indicators of renewable oversupply. We quantified associated benefits at $32 per MWh of avoided renewable curtailments, based on the RPS adder forecast from the CPUC's latest Power Charge Indifference Adjustment.

Figure D-4 shows the results by subLAP. The average estimated RPS benefit ranges from $1 to $2.2 per kW-month depending on location. The results vary seasonally, with a significant share of the benefits concentrated in the spring months, when renewable curtailment risks are typically higher. During that period, RPS benefits can reach up to $6/kW-month. Locations in southern California tend to have higher RPS benefits due to increased renewable curtailment risks, compared to northern California. Market conditions change from one year to another, so we used the 2019–2022 average values rather than relying on a single year's estimates.

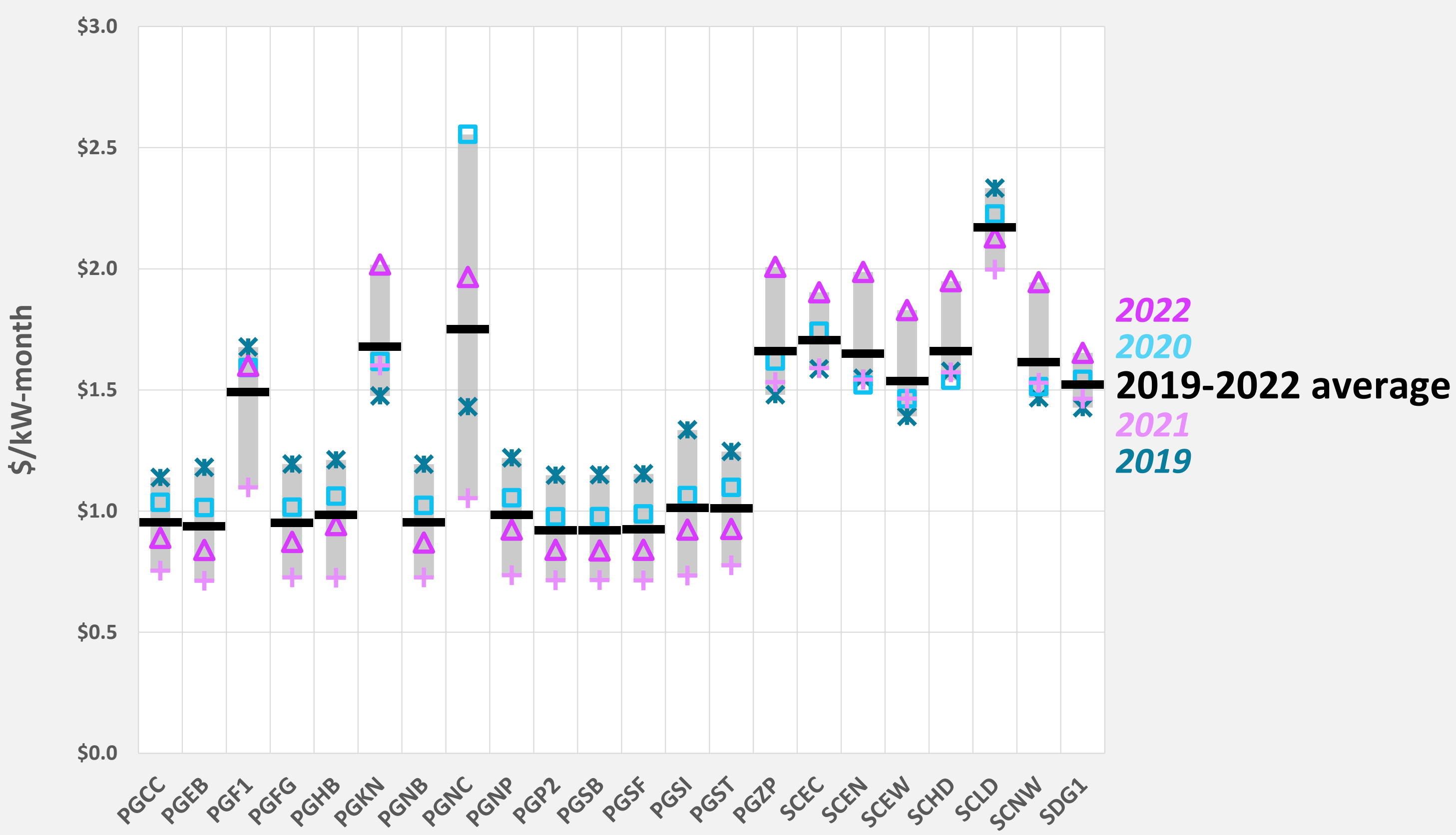


Figure D-4: Estimated average RPS benefits by CAISO subLAP (in 2023 $).

System RA value:

Energy storage capacity available to discharge during peak periods can help meet the RA capacity needs to ensure system reliability. We estimated associated benefits at $15/kW-month, which is consistent with the 2024 system RA price forecast in the CPUC's Power Charge Indifference Adjustment and recent RA contract data we analyzed.

We allocated the system RA capacity value to August and September evening hours, based on findings from the CPUC's 2022 planning reserve margin study. This allocation also aligns with the historical record of CAISO systemwide emergency events observed in recent years, during the heat waves of August–September 2020 and September 2022.

Total market value potential:

Figure D-5 shows total estimated market value potential for the energy storage resources at each subLAP. The RA value is kept the same across all locations at $15/kW-month, which translates to $180/kW-year annually. This accounts for a large share of the total market value potential. Energy and RPS benefits add $75 to $110/kW-year of value, depending on the location.

These findings assume 100% market participation, with the full capacity of the resource offered to the CAISO's markets throughout the year. However, under the multiple-use application (MUA) analysis discussed next, when the resource's capacity is used for distribution deferral needs, the realized market value of storage resources would be lower than the levels shown here.

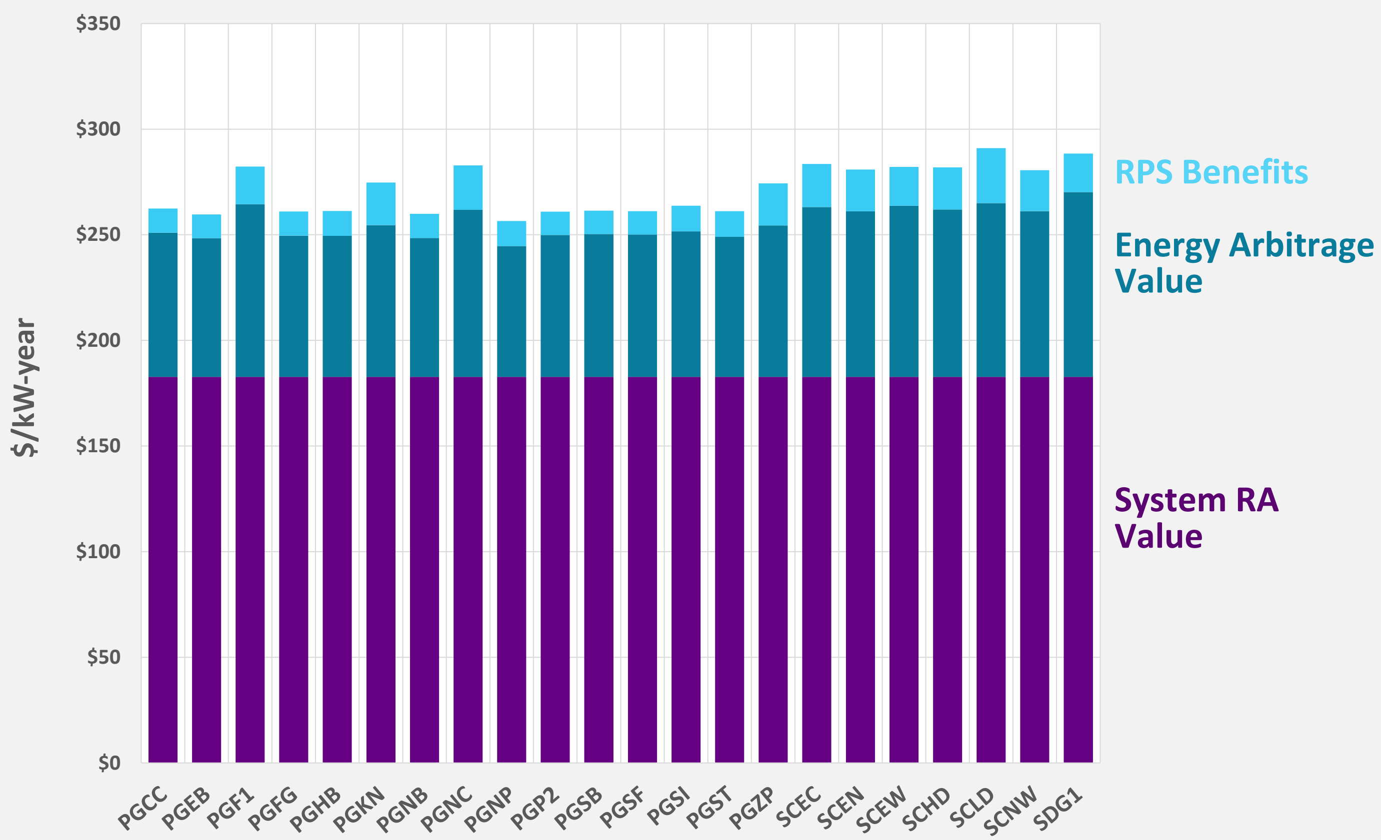


Figure D-5: Total estimated market value potential by CAISO subLAP (in 2023 $).

Value-stacking results

We start with the results of the benchmark case (100% wholesale market scenario) and re-simulate energy storage dispatch under distribution deferral (DD)-related constraints. We introduce constraints incrementally, one by one, and run the simulations iteratively to estimate the relative impact of each constraint on market value. Figure D-6 illustrates the estimated share of potential RA benefits captured vs. lost due to distribution-related constraints including DD service calls, minimum duration, and charging limitations.

The DDOs requiring fewer hours of service and lower limit on annual calls allow for high RA value. We estimate that most distribution deferral opportunities analyzed can capture at least 50% of the potential RA benefits through value-stacking, while the top 1/3 of the storage-eligible DDOs capture more than 80% of the value provided by RA-only storage.

Extended DD service windows require storage configurations with longer durations, which reduces RA value per kWh of investment. We find that storage-eligible DDOs with 6+ hours of duration would capture only 30% of the value provided by RA-only storage.

A high limit on the number of DD service calls is also a barrier to RA value, because dispatch signals do not always line up with RA needs. Our analysis shows projects with up to 20 DD service calls/year would capture 2x more RA value than projects with 50 or more calls/year.

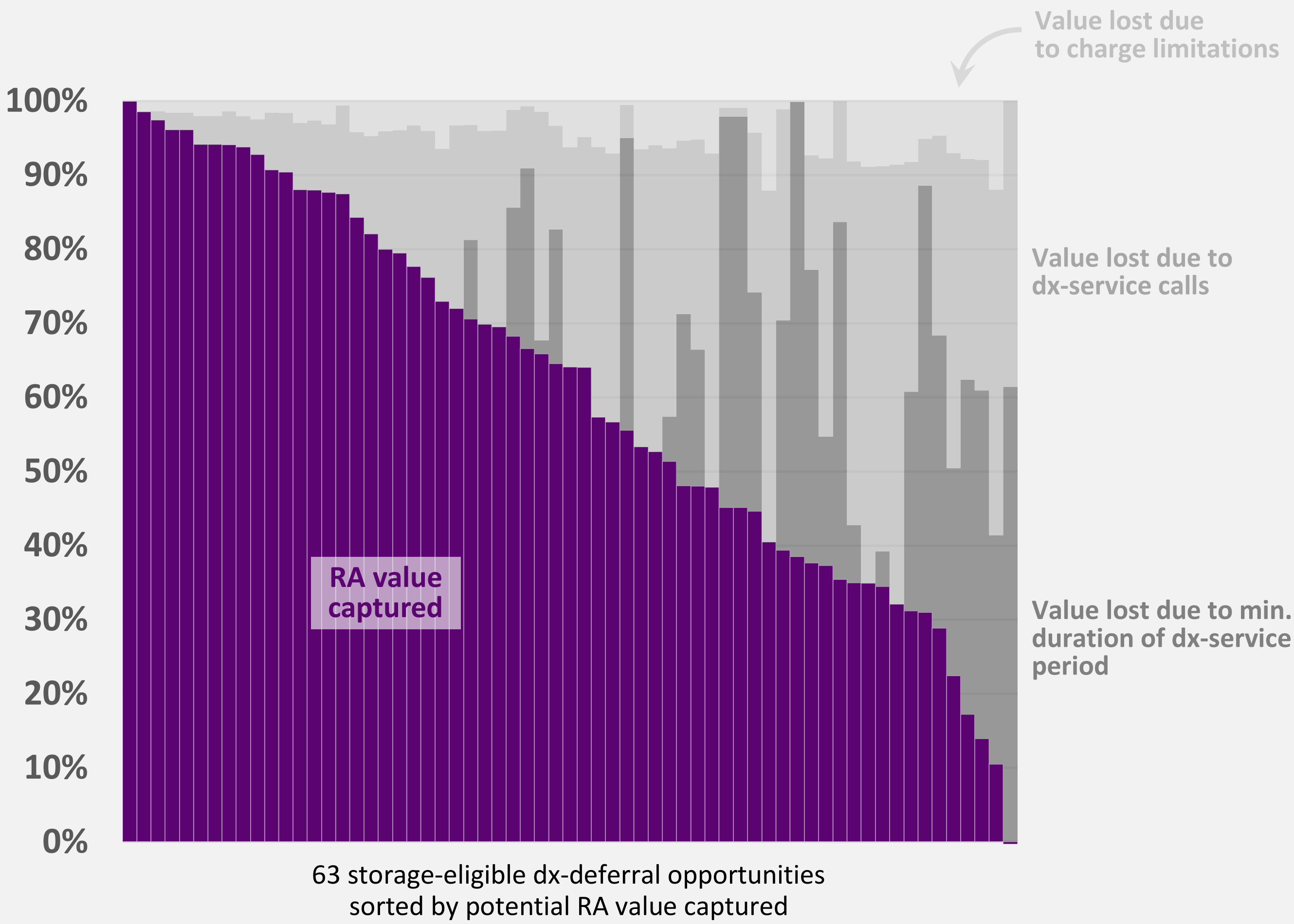


Figure D-6: Share of potential RA capacity benefits captured given distribution deferral related constraints.

Figure D-7 shows incremental wholesale market value that could be captured by energy storage—even conservatively assuming each project operates to meet its maximum distribution deferral service calls and is subject to operating constraints even when not called.

The relatively high share of RA capacity benefits is driven by system RA capacity prices forecasted by the CPUC at $15/kW-month, up from about $3 prior to 2019, and $5–8 in 2020-2022.

Energy storage resources can also stack a significant amount of energy arbitrage value and RPS benefits because operating constraints from distribution deferral service needs tend to be minimal when market opportunities are high (e.g., in the springtime).

At current prices, the total wholesale market value potential of energy storage is around $60/kWh-year, including energy arbitrage, RPS benefits, and system RA value. Our analysis finds that most storage-eligible DDOs could capture at least 50% of this value ($30/kWh-year or more). This could pay for a large portion of storage investment and accordingly reduce distribution service payments needed. In the 2023 *CPUC Energy Storage Procurement Study*, we estimated grid-scale energy storage project costs ranged from $9 to $14 per kW-month based on all-in utility contracts approved during the 2020–2021 timeframe. This translates to $27–$42 per kWh-year in total project costs.

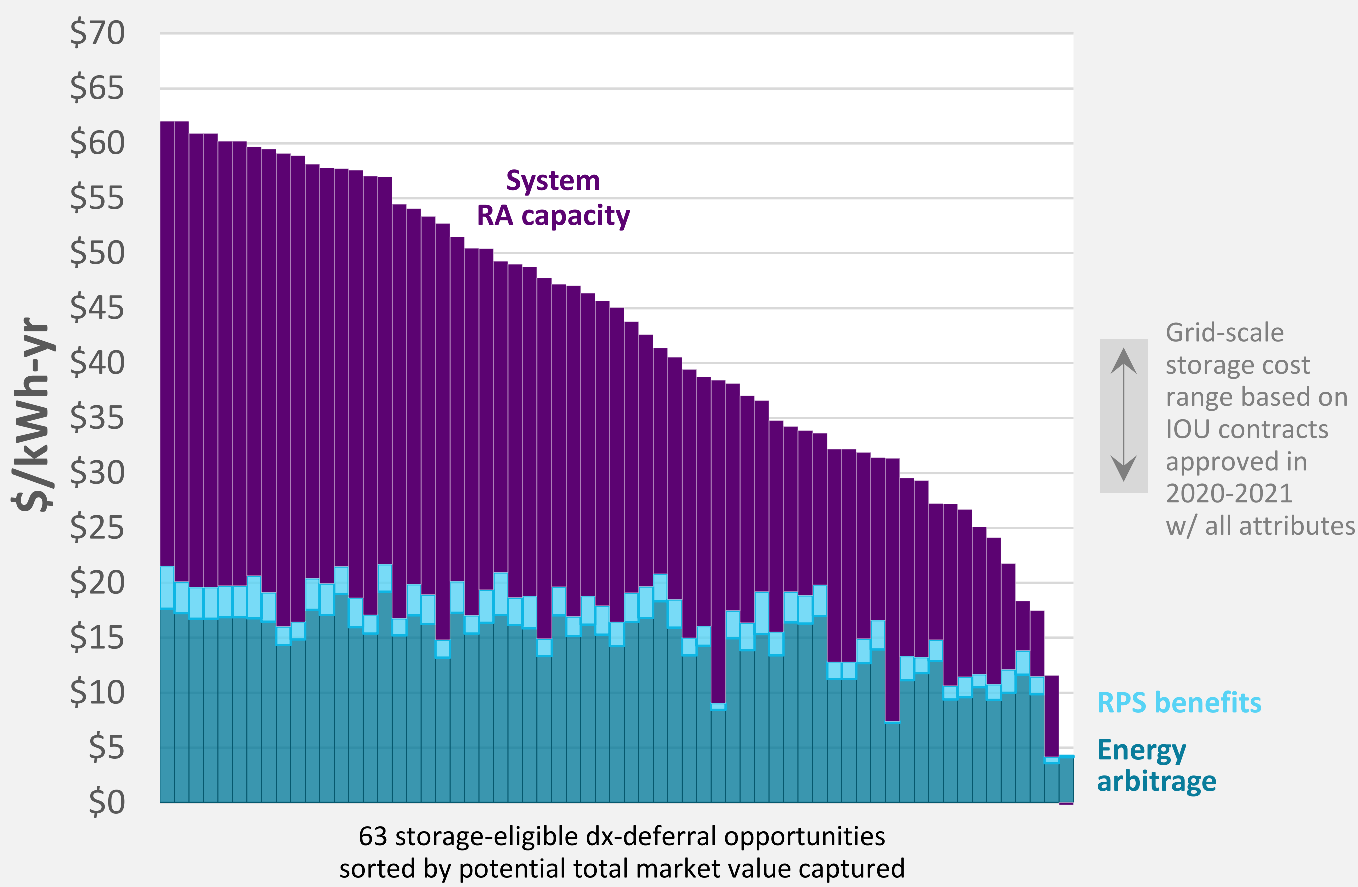


Figure D-7: Potential "stackable" wholesale market value with distribution deferral services.

Appendix E: Case Study Fact Sheets

- Redwood Coast Airport Microgrid
- Borrego Springs Microgrid
- Ramona Air Attack Base Microgrid
- Cameron Corners Microgrid
- Butterfield and Shelter Valley Microgrids
- Boulevard, Clairemont, Elliot, and Paradise Microgrids

Redwood Coast Airport Microgrid (RCAM)	
Project Status	Online *(Jun 2022, microgrid completion)*
Resource Configuration	• 2.2 MW 4-hour battery • 2.2 MW solar PV (DC-coupled) • 0.3 MW customer-sited solar PV • Includes undergrounding of distribution wires within the microgrid
Primary Use Case	**Outage mitigation** for critical facilities including a regional airport and a U.S. Coast Guard air station; supporting a community vulnerable to earthquakes, tsunamis, floods, and wildfires
CAISO Participation	✓ **Energy + ancillary services** • Initially NGR market participation model, then switched to hybrid model • Interconnection limit of 1.48 MW for imports and 1.778 MW for exports to avoid distribution upgrades
RA Capacity Eligibility	✗ Does not yet qualify due to interconnection challenges with distribution upgrades, and with required transmission deliverability study
Location	*Humboldt county, a remote community with limited and at-risk transmission infrastructure*

Image: Aerial view of the RCAM project, credit: Redwood Coast Energy Authority and Schatz Energy Research Center.

<u>Other key resource characteristics:</u>

➡ **Example of a community-level distribution-connected microgrid, built for outage mitigation, with a mix of customer-sited and community-level generating resources and equipment.**

➡ **RCAM provided a template leading to PG&E's Community Microgrid Enablement Program and Community Microgrid Enablement Tariff, which then informed development of a Microgrid Multi-Property Tariff under CPUC Rulemaking 19-09-009.**

➡ **RCAM demonstrates a productive collaboration among the CCA (Redwood Coast Energy Authority), the IOU (PG&E), the local community, and several other planning and technical experts, on project planning, development, and operations.**

➡ **The resource provides services to the local community and to the CAISO marketplace.** In most hours of the year RCAM provides services directly in CAISO's energy and ancillary services markets. RCAM settles with CAISO 24/7 regardless of grid-connected vs. island mode of operations. RCAM sets and adjusts its minimum state of charge in the marketplace, depending on local outage mitigation needs.

➡ **In the design and planning phase, market revenues through an MUA strategy were estimated to offset ~50% of the project's cost.** RA capacity is an important component to the business case, but RCAM does not currently qualify for RA capacity due to interconnection challenges.

To learn more, see: https://www.energizeinnovation.fund/projects/redwood-coast-airport-microgrid.

Borrego Springs Microgrid	
Project Status	Online *(Borrego 1.0: Sep 2012; Borrego 2.0: Jun 2014; Borrego 3.0: est. Dec 2024)*
Resource Configuration	• 1.5 MW 3-hour battery • 3.6 MW diesel generation • 0.25 MW ultracapacitor • Planned expansion (Borrego 3.0): 7.3 MW 2-hour battery + 0.25 MW 16-hour hydrogen
Primary Use Case	**Outage mitigation** for a remote "grid-edge" community vulnerable to transmission line outages, high temperatures, thunderstorms, flooding, and high wind; note the community has a significant quantity of solar PV that requires integration with the microgrid
CAISO Participation	✘ Not currently • Planned with Borrego 3.0
RA Capacity Eligibility	✘ Not currently; transmission deliverability study required for eligibility

Location

San Diego county, a remote desert community at the end of a single, long, radial transmission line

Image: Aerial view of the Borrego Springs microgrid, credit: SDG&E.

<u>**Other key resource characteristics:**</u>

➡ **Example of a substation/feeder-level distribution-connected microgrid, built for outage mitigation.**

➡ **Borrego Springs is the first utility-owned distribution-connected microgrid in the U.S. to test and showcase microgrid functions and operations for a grid-edge community in SDG&E with significant levels of solar PV.**

➡ **Its initial configuration served as a proof-of-concept to demonstrate microgrid functions in a real-world setting.** The pilot phase focused on developing technical capabilities and experience in microgrid operations, relying on two diesel generators.

➡ **A planned expansion (Borrego 3.0) will increase energy storage capacity and add controls needed to support transition to 100% renewable energy.** This shifts focus on leveraging around 40 MW of solar PV in the area, including grid-scale and customer-sited resources.

➡ **The additional storage capacity will create opportunities for cross-domain value-stacking, including outage mitigation, wholesale markets, system RA capacity, and GHG reductions.** Work to determine how much capacity to reserve for microgrid vs. offer into the CAISO marketplace is in progress.

To learn more, see SDG&E's October 19, 2023 presentation materials and recording, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids/resiliency-and-microgrids-events-and-materials.

Ramona Air Attack Base Microgrid

Project Status	Online *(Apr 2022)*
Resource Configuration	• 0.5 MW 4-hour battery • Includes undergrounding of distribution wires within the microgrid • Sized to provide backup power to critical facilities for up to 1.5 days
Primary Use Case	**Outage mitigation** for critical facilities where CAL FIRE and U.S. Forest Service's aerial firefighting assets are located; key concern is PSPS, wildfire emergencies, and other emergency situations during which functionality of the Base is needed
CAISO Participation	✓ **Energy + ancillary services** • LESR market participation model
RA Capacity Eligibility	✗ Not currently; transmission deliverability study required for eligibility

Location
San Diego county, a small-town community about an hour drive from San Diego; in Tier 2 HFTD & surrounded by Tier 3

Image: Aerial view of the Ramona Air Attack Base microgrid, credit: SDG&E.

<u>Other key resource characteristics:</u>

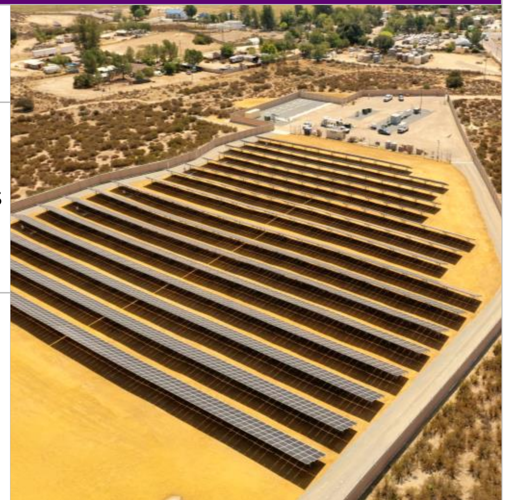
➡ **Example of a community-level distribution-connected microgrid built for outage mitigation.** Like RCAM, the Ramona Air Attack Base Microgrid is electrically close to the customer but installed on the distribution system. This interconnection enables future expansion of the microgrid: initial design considered adding a local wastewater treatment facility in Phase 2 of the project.

➡ **The Ramona Air Attack Base Microgrid is an example of a tailored and cost-conscious alternative to hardening long distribution circuits in remote areas for the purposes of wildfire mitigation and resilience.** This resource strategy is particularly attractive when the critical facilities needing support are clustered around one part of a circuit.

➡ **The Public Safety Power Shutoff (PSPS) forecasting and decision-making process demonstrates how onsite resilience risk management and upstream grid services can be balanced on a day-to-day basis.** In high wildfire threat areas, the day-to-day need for PSPS is a function of fire fuel conditions, wind speeds, and other changing factors. Utilities notify critical facilities of potential PSPS 2–3 days in advance, during which the microgrid operator and customers can plan for a transition from grid-connected mode to islanded mode. A similar degree of coordination is achievable beyond PSPS to the extent resilience hazards can be forecasted (e.g., weather-driven).

To learn more, see SDG&E's Wildfire Mitigation Plans. The 2023 plan is available at: https://www.sdge.com/2023-wildfire-mitigation-plan.

Cameron Corners Microgrid	
Project Status	In Development *(est. Q4 2024)*
Resource Configuration	• 0.5 MW 8-hour flow battery • 0.875 MW solar PV • Includes undergrounding of distribution wires within the microgrid
Primary Use Case	**Outage mitigation** for community facilities; key concern is community access to essential services during PSPS, wildfire emergencies, and other emergency situations
CAISO Participation	✓ Planned
RA Capacity Eligibility	✗ Not planned; transmission deliverability study required for eligibility



Location
San Diego county, a remote community in Tier 3 HFTD

Image: Aerial view of the Cameron Corners microgrid, credit: SDG&E.

Other key resource characteristics:

➡ **Example of a community-level distribution-connected microgrid built for outage mitigation.** Like RCAM, the Cameron Corners Microgrid is electrically close to the customer but installed on the distribution system. An earlier, temporary, solution utilizes a set of customer-sited conventional generators, consistent with traditional local emergency management practices.

➡ **The Cameron Corners Microgrid is an example of a tailored and cost-conscious alternative to hardening long distribution circuits in remote areas for the purposes of wildfire mitigation and resilience.** The permanent, solar-powered, microgrid solution serves a set of key community facilities identified through SDG&E's community engagement and feedback process, including a school, a health facility, gas stations, a convenience store, and other facilities.

➡ **As with the Ramona Air Attack Base Microgrid and other wildfire mitigation-focused resource solutions, the ability to forecast potential resilience events allows for day-to-day balancing of onsite resilience risk management and upstream grid services.**

To learn more, see SDG&E's Wildfire Mitigation Plans. The 2023 plan is available at: https://www.sdge.com/2023-wildfire-mitigation-plan. See also SDG&E's project fact sheet, available at: https://www.sdge.com/sites/default/files/FINAL_S2370123_CameronCorners_FS_ONLINE%20%281%29.pdf.

Butterfield Ranch and Shelter Valley Microgrids

Project Status	In Development *(est. Dec 2025)*	
Resource Configuration	• 1 MW 5.5-hour battery + 2.1 MW PV (Butterfield Ranch) • 1 MW 6.5-hour battery + 2.4 MW PV (Shelter Valley)	
Primary Use Case	**Outage mitigation** for all electrically downstream customers; key concern is the impact on the community of PSPS implemented to mitigate wildfire risks from the upstream distribution system	
CAISO Participation	✗ Project electrically far from CAISO; line losses for delivering power to/from the transmission system create a major economic hurdle	 **Location** *San Diego county, small and very remote communities adjacent to HFTD*
RA Capacity Eligibility	✗ Not planned	

Images: (top) Butterfield Ranch community residential area, credit: Google Maps; (bottom) Shelter Valley fire station and community center, example of critical facilities within the microgrid, credit: Stalbaum/Wikimedia Commons.

<u>Other key resource characteristics:</u>

➡ **Example of community-level distribution-connected microgrids built for outage mitigation—but addressing a unique grid topology.** The supported communities are not in HFTD, but the distribution line feeding the communities traverse Tier 3 HFTD and subject to relatively frequent PSPS. Similar to Borrego Springs and unlike other community-level microgrids, these communities experience outages mostly as a consequence of issues on the upstream grid.

➡ **The Butterfield Ranch and Shelter Valley Microgrids are examples of a tailored and cost-conscious alternative to hardening long distribution circuits in remote areas for the purposes of wildfire mitigation and resilience.** These microgrids sectionalize non-HFTD portions of the circuit feeding the target communities. Since the communities are not within HFTD, extensive distribution system hardening within the microgrid for the purposes of wildfire mitigation is not needed as it is for HFTD-located microgrids (e.g., Ramona Air Attack Base and Cameron Corners).

To learn more, see SDG&E's Wildfire Mitigation Plans. The 2023 plan is available at: https://www.sdge.com/2023-wildfire-mitigation-plan.

Boulevard, Clairemont, Elliot, and Paradise Microgrids	
Project Status	Online *(Feb 2024)*
Resource Configuration	• 10 MW 5-hour battery (Boulevard) • 9 MW 3.2-hour battery (Clairemont) • 10 MW 5-hour battery (Elliot) • 10 MW 5-hour battery (Paradise)
Primary Use Case	**System reliability** through services in the CAISO marketplace; also islanding and resiliency capability, via short-duration backup power (33 minutes at all times and up to 5 hours under certain conditions), prioritized for key local community facilities and critical loads
CAISO Participation	✓ As part of its reliability services, must participate in the CAISO marketplace
RA Capacity Eligibility	✓ Primary use case
Location	*San Diego county, various locations, most (except Boulevard) in urban communities; Boulevard in Tier 2 & Tier 3 HFTD*

Image: Aerial view of the Paradise microgrid, credit: SDG&E.

Other key resource characteristics:

➡ **Example of circuit-level distribution-connected microgrids built for cross-domain multiple use application (system reliability + local resilience).** Resources designed to address issues electrically upstream of the microgrid, at the substation and transmission level. The primary function is to provide services to the transmission grid, including RA capacity and services in the CAISO marketplace. In the event of (a) a transmission system RA capacity (reliability) failure, e.g., rolling blackouts, or (b) unexpected transmission- or substation-level outages, these microgrids can also mitigate service interruptions to the local community.

➡ **With the exception of Boulevard, these microgrids are not designed to protect against resilience events that result in failures on the distribution system.** Due to their placement on the grid and design of the microgrids, the Clairemont, Elliot, and Paradise microgrids do not mitigate customer outages caused by failures on the distribution system. The default battery reserve for backup power (33 minutes) is determined based on the historical observed maximum duration of upstream transmission- and substation-level outages. In contrast, the Boulevard microgrid is built with targeted undergrounding of distribution infrastructure to harden against resilience events. The Boulevard circuit is subject to PSPS and historically is among SDG&E's top 1% worst performing circuits.

To learn more, see the CPUC's Executive Resolution E-5219 (corrected) issued on July 27, 2022, in response to SDG&E's Advice Letter 3992-E and pursuant to Decision 21-12-004, available at: https://docs.cpuc.ca.gov/ResolutionSearchForm.aspx.