ATTACHMENT A: HISTORICAL BENEFIT-COST ANALYSIS AND SCORING OF ENERGY STORAGE PROJECTS IN CALIFORNIA[1]

This attachment provides details on our analysis of actual energy storage operations, benefits, and costs within the 5-year study period 2017–2021. From this analysis, we seek to better understand to what degree the CPUC energy storage procurement framework helps to meet state policy goals. We also assess:

- Are ratepayers realizing net benefits from its energy storage investments?
- What types of installations and use cases demonstrate meaningful growth in value?
- Are any sources of ratepayer value left untapped?
- Are some types of installations and use cases not scaling up and what are the challenges?

In this attachment, we define the scope of the historical analysis, describe key assumptions and metrics, and present the results of the cost-benefit analysis and scoring towards AB 2514 goals.

CONTENTS

Evaluation Framework

The study follows a two-pronged approach considering both monetized and non-monetized evaluation metrics calculated at the project or cluster level:

1. Cost-effectiveness test reflects monetized benefits and costs, unadjusted for statutory and solicitation-specific preferences, and
2. Effectiveness at meeting AB 2514 goals is quantified via scores that reflect the alignment of project's use cases with the state goals.

	Evaluation scope	Evaluation metrics
Monetized	Cost-effectiveness	Benefit-cost ratios
Quantified	Effectiveness at meeting AB 2514 goals	Scorecards

Figure 1: Two-pronged study scope and approach.

The overall approach utilized in the study is grounded in California's existing practices and methodologies, namely those reflected in the state's Standard Practice Manual for cost-effectiveness tests, the state's Avoided Cost Calculator for distributed energy resources, and the utilities' various Least-Cost Best-Fit calculations for bid evaluations in resource procurements. For an apples-to-apples comparison among projects, we applied a single framework across all types of energy storage projects across all grid domains considered. Consistent with the state practices, estimated benefits reflect the avoided cost of market alternatives to the energy storage resource analyzed. Benefit-cost analysis focuses mostly on total ratepayer impacts but also consider societal impacts such as GHG emissions reductions, and benefits that flow directly to customers with energy storage installed such as resilience value associated with customer outage mitigation.

Data Sources

Energy storage operational data was provided by California IOUs, CAISO, and CPUC. CAISO also provided detailed historical market data, including resource-specific settlements, market prices, and other system data. PG&E, SCE, and SDG&E provided detailed information on most of their energy storage procurements including bid evaluation results, contract information, actual ratepayer costs, resource characteristics, and a variety of other supporting information.

Interpretation of Evaluation Results

Our evaluation metrics are designed to show relative performance of individual energy storage resources or groups of resources with the purpose to identify successes and challenges in use cases and their potential to support the state's energy goals.

While this historical analysis offers a reality check on conceptual pro-storage rhetoric and generally accepted resource planning assumptions, it also has a few drawbacks. Most importantly, historical market value reflects market and grid conditions that are at times volatile and cyclical, and thus not directly comparable to prospective planning study outcomes under normalized and smoothed future conditions. See Chapter 2 of the main report for more discussion.

Storage Resources Analyzed

Energy storage in our historical analysis includes resources procured by load-serving entities under CPUC jurisdiction. Most of these projects:

- Are counted towards utilities' requirements under CPUC Decision 13-10-040;
- Operated within the 5-year study period 2017–2021; and
- Reached commercial operations by April 2021 (for sufficient operational data to analyze).

To make full use of available data, we also analyzed the operations of three resources procured for system reliability and resource adequacy (Gateway, Vista, Blythe) and not counted towards utilities' requirements under the CPUC Decision 13-10-040.

Overall, the resource set represents 1,571 MW/5,176 MWh of total nameplate capacity, with 976 MW counted by the IOUs towards their CPUC Decision 13-10-040 requirements and 1,374 MW included in our analysis of historical operations. Figure 2 summarizes basic characteristics of these resources, including where they connected to grid, who owns the project, underlying technology, and procurement track. Figure 3 provides a full list of the resources considered in the study, including some of the resources that could not be analyzed due to data limitations.

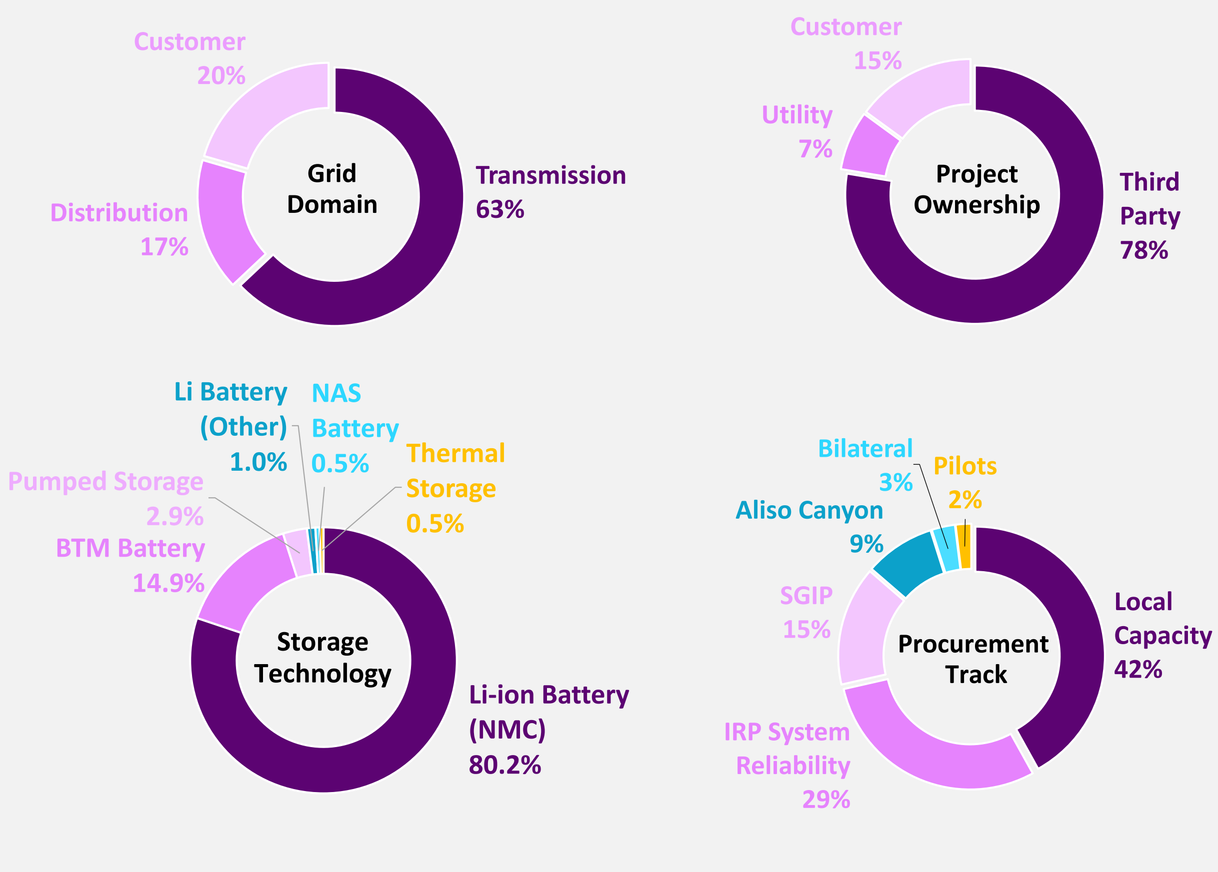


Figure 2: Characteristics of energy storage resources included in the 2017–2021 historical analysis.

	Count	Nameplate MW	Nameplate MWh	LSE	Online	Technology	Owner	CAISO?	Procurement Track	MW IOU AB 2514	MW Analyzed
Transmission-Sited	**8**	**865**	**3,053**							**460**	**865**
3rd-Party	**6**	**845**	**3,044**							**440**	**845**
Vista Energy Storage	1	40	44	SDG&E	Jun-18	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	40
Gateway Energy Storage	1	250	700	Various	Sep-20	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	250
Lake Hodges Pumped Hydro	1	40	240	SDG&E	Aug-12	Pumped Storage	Third Party	Y	Bilateral	40	40
Vistra Moss Landing	1	300	1,200	PG&E	Dec-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	300	300
AES Alamitos ES	1	100	400	SCE	Dec-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	100	100
Blythe Energy Storage II	1	115	460	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	115
Utility-Owned	**2**	**20**	**8.6**							**20**	**20**
SCE EGT - Center	1	10	4.3	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	10	10
SCE EGT - Grapeland	1	10	4.3	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	10	10
Distribution-Sited	**33**	**236**	**925**							**236**	**227**
3rd-Party	**7**	**146**	**583**							**146**	**145**
W Power - Stanton - 1	1	1.3	5.2	SCE	May-20	Lithium-Ion (NMC)	Third Party	Y	Energy Storage RFO	1.3	no data
ACORN I ENERGY STORAGE LLC	1	2	6	SCE	Mar-21	Lithium-Ion (NMC)	Third Party	Y	IDER Pilot	1.5	2
AltaGas Pomona	1	20	80	SCE	Dec-16	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	20	20
Powin Energy - Milligan ESS 1	1	2	8	SCE	Jan-17	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	2	2
Orni 34 LLC	1	10	40	SCE	Feb-21	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	10	10
Silverstrand Grid, LLC	1	11	44	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	11	11
Ventura Energy Storage (formerly Strata Saticoy)	1	100	400	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	100	100
Utility-Owned	**26**	**90**	**342**							**90**	**82**
Vaca-Dixon	1	2	14	PG&E	Jul-14	Sodium-Sulfur	Utility	Y	EPIC / PIER / DOE	2	2
Yerba Buena	1	4	28	PG&E	Jun-13	Sodium-Sulfur	Utility	Y	EPIC / PIER / DOE	4	4
Browns Valley	1	0.5	2	PG&E	Sep-16	Lithium-Ion (NMC)	Utility	N	EPIC / PIER / DOE	0.5	0.5
Tehachapi Storage Project (TSP)	1	8	32	SCE	Apr-16	Lithium-Based	Utility	Y	EPIC / PIER / DOE	8	8
Escondido	1	30	120	SDG&E	Mar-17	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	30	30
El Cajon	1	7.5	30	SDG&E	Feb-17	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	7.5	7.5
Tesla - Mira Loma	1	20	80	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	20	20
Smart Grid Stabilization System (SGSS) Unit 1	1	2	0.5	SCE	Jun-11	Lithium-Ion (NMC)	Utility	N	General Rate Case	2	no data
Smart Grid Stabilization System (SGSS) Unit 2	1	2	0.5	SCE	Jun-11	Lithium-Ion (NMC)	Utility	N	General Rate Case	2	no data
Mercury 4	1	2.8	5.6	SCE	Dec-18	Lithium-Ion (NMC)	Utility	N	General Rate Case	2.8	2.8
Distribution Energy Storage Integration (DESI) 1	1	2.4	3.9	SCE	May-15	Lithium-Based	Utility	N	General Rate Case	2.4	no data
Distribution Energy Storage Integration (DESI) 2	1	1.4	3.7	SCE	Dec-18	Lithium-Based	Utility	N	General Rate Case	1.4	1.4
Borrego Springs Unit 1	1	0.5	1.5	SDG&E	Sep-12	Lithium-Ion (NMC)	Utility	N	EPIC / PIER / DOE	0.5	0.5
Borrego Springs Unit 2	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
Borrego Springs Unit 3	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
Borrego Springs Unit 4	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
GRC Energy Storage Program Unit 1	1	0.5	1.5	SDG&E	Sep-12	Lithium-Based	Utility	N	General Rate Case	0.5	0.5
GRC Energy Storage Program Unit 2	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 3	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 4	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 5	1	1	3	SDG&E	Jun-14	Lithium-Ion (NMC)	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 6	1	1	1.5	SDG&E	Jun-14	Lithium-Based	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 7	1	1	2.3	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	no data
GRC Energy Storage Program Unit 8	1	1	1.5	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 9	1	1	3	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	1
Catalina Island Battery Storage	1	1	7.2	SCE	Aug-12	Sodium-Sulfur	Utility	N	General Rate Case	1	1
SGIP Customer-Sited	**22,660**	**390**	**858**							**200**	**205**
SGIP Nonresidential (as of Apr'21)	**1,160**	**244**	**504**							**177**	**205**
SGIP Nonresidential PG&E	330	63	126	PG&E	Various	BTM Battery	Customer	N	SGIP	62	48
SGIP Nonresidential SCE	580	142	293	SCE	Various	BTM Battery	Customer	N	SGIP	85	126
SGIP Nonresidential SDG&E	250	39	84	SDG&E	Various	BTM Battery	Customer	N	SGIP	30	31
SGIP Residential (as of Apr'21)	**21,500**	**147**	**355**							**23**	0
SGIP Residential PG&E	9,900	71	173	PG&E	Various	BTM Battery	Customer	N	SGIP	23	no data
SGIP Residential SCE	7,000	45	108	SCE	Various	BTM Battery	Customer	N	SGIP	0	no data
SGIP Residential SDG&E	4,600	31	73	SDG&E	Various	BTM Battery	Customer	N	SGIP	0	no data
Non-SGIP Customer-Sited	**1,705**	**80**	**340**							**80**	**76**
BTM Battery CAISO PDR	**900**	**70**	**280**							**70**	**70**
HEBT Irvine1 DRES	10	5	20	SCE	Nov-17	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	5	5
HEBT Irvine2 DRES	10	5	20	SCE	Feb-18	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	5	5
HEBT WLA1 DRES	50	25	100	SCE	Apr-19	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	25	25
HEBT WLA2 DRES	30	15	60	SCE	Mar-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	15	15
Stem Energy DRES - 402040	800	20	80	SCE	Aug-18	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	20	20
BTM Battery non-CAISO	**1**	**0.1**	**0.5**							**0.1**	0
Discovery Science Center	1	0.1	0.5	SCE	Jun-14	Metal Hydride	Customer	N	Other	0.1	no data
PLS/TES	**804**	**10**	**60**							**10**	**6**
Ice Bear PLS - 431058	250	1.92	11.52	SCE	Jan-19	Thermal	Third Party	N	Local Capacity	1.92	1.92
Ice Bear PLS - 431061	250	1.92	11.52	SCE	Apr-19	Thermal	Third Party	N	Local Capacity	1.92	1.92
Ice Bear PLS - 431151	150	1.28	7.68	SCE	Mar-20	Thermal	Third Party	N	Local Capacity	1.28	1.28
Ice Bear PLS - 431154	150	1.28	7.68	SCE	Dec-20	Thermal	Third Party	N	Local Capacity	1.28	1.28
PLS/TES - Chaffey College	1	0.8	4.8	SCE	Jul-16	Thermal	Customer	N	PLS	0.8	no data
PLS/TES - Cypress College	1	0.7	4.2	SCE	Jun-18	Thermal	Customer	N	PLS	0.7	no data
PLS/TES - Mt San Antonio College	1	1.5	9	SCE	Mar-17	Thermal	Customer	N	PLS	1.5	no data
PLS/TES - Santa Ana College Central	1	0.53	3.18	SCE	Jun-19	Thermal	Customer	N	PLS	0.53	no data
Total Storage Across All Domains >>		**1,571**	**5,176**							**976**	**1,374**

Figure 3: List of energy storage resources included in the 2017–2021 historical analysis.

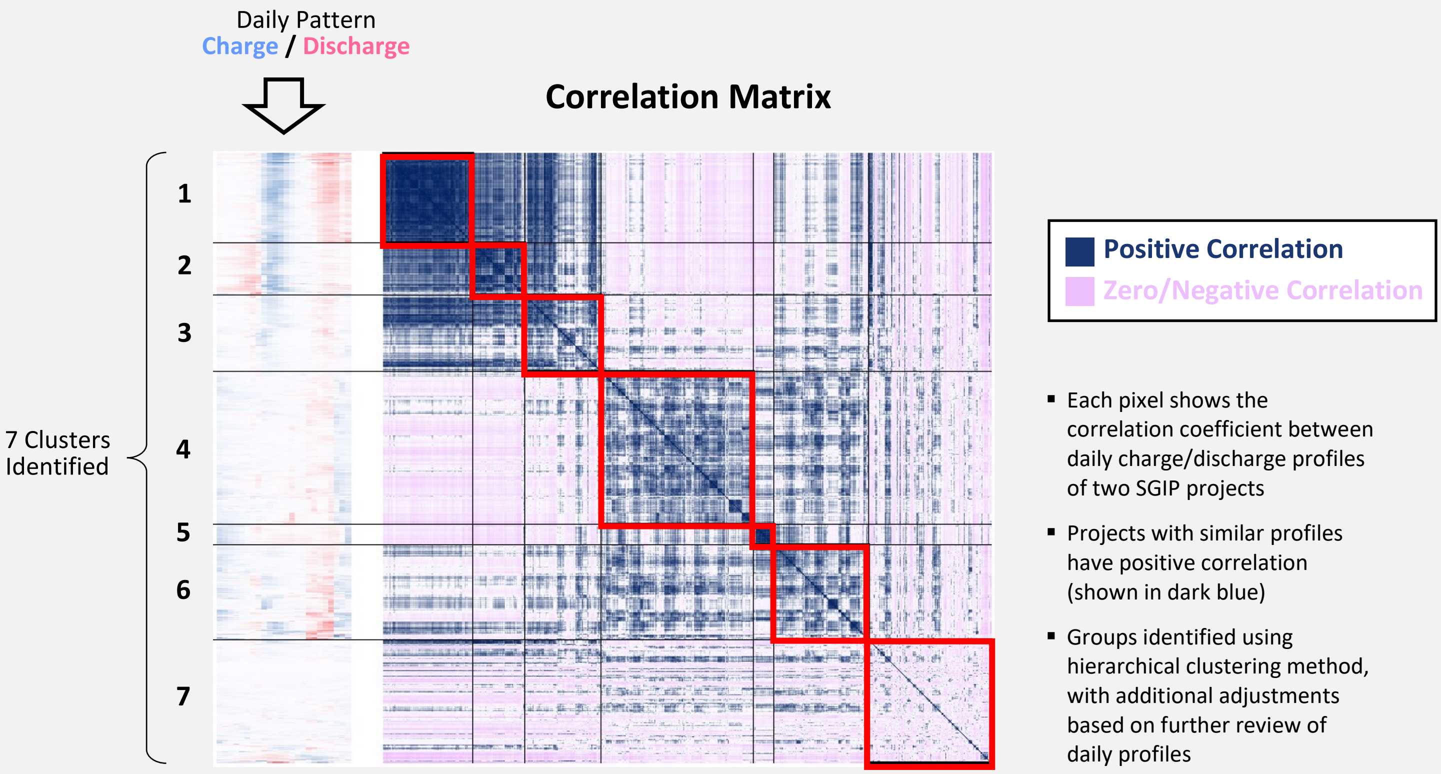
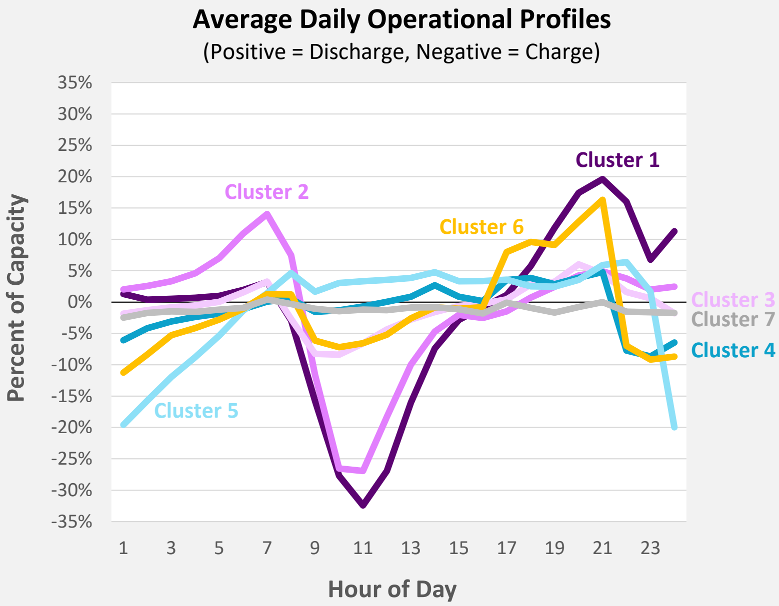


Figure 4: Cluster analysis of nonresidential SGIP-funded energy storage projects.

For non-residential SGIP-funded projects, we conducted an analysis to group 654 resources into 7 clusters based on each installation's interval-level operating behavior during the historical period. The results of the cluster analysis are shown in Figure 4 above, and the observed characteristics of the clusters are summarized in Figure 5 next page.

- Clusters 1, 2, and 3 have operating patterns synergistic with the grid: they charge during the day and discharge during the grid's morning and evening ramps into and out of solar generation periods. These resources are mostly schools and colleges, and they have a high solar attachment rate.
- Clusters 4 and 5 demonstrate a traditional demand charge management pattern that operates in discord with wholesale energy markets: storage is discharged steadily throughout the day, mostly unresponsive during morning and evening ramps, then charged at night.
- Cluster 6 operates similar to clusters 1–3, but with significant night charging when renewable supply is not abundant.
- Cluster 7 is a catch-all category for installations that operate with no clear use case consistent with how other non-residential installations operate.



Cluster ID	Project Count (# of projects)	Energy Storage Capacity (MW)	Average Roundtrip Efficiency (%)	Average Daily Discharge (hours/day)
1	96	17.6	78%	1.3
2	56	9.1	75%	1.1
3	82	23.6	75%	0.6
4	164	60.6	77%	0.8
5	22	9.7	83%	1.1
6	102	41.6	77%	1.2
7	132	43.0	65%	0.6
Total	**654**	**205.3**	**74%**	**0.9**

Cluster 1
- Midday Charge
- Evening Peak Discharge

Cluster 2
- Midday Charge
- Morning Discharge

Cluster 3
- Midday Charge
- Morning+Evening Discharge
- Low Utilization

Cluster 4
- Night Charge
- Distributed Discharge
- Low Utilization

Cluster 5
- Extended Night Charge
- Distributed Discharge

Cluster 6
- Midday+Night Charge
- Evening Peak Discharge

Cluster 7
- No apparent charge/discharge pattern
- Low Utilization
- Low Efficiency

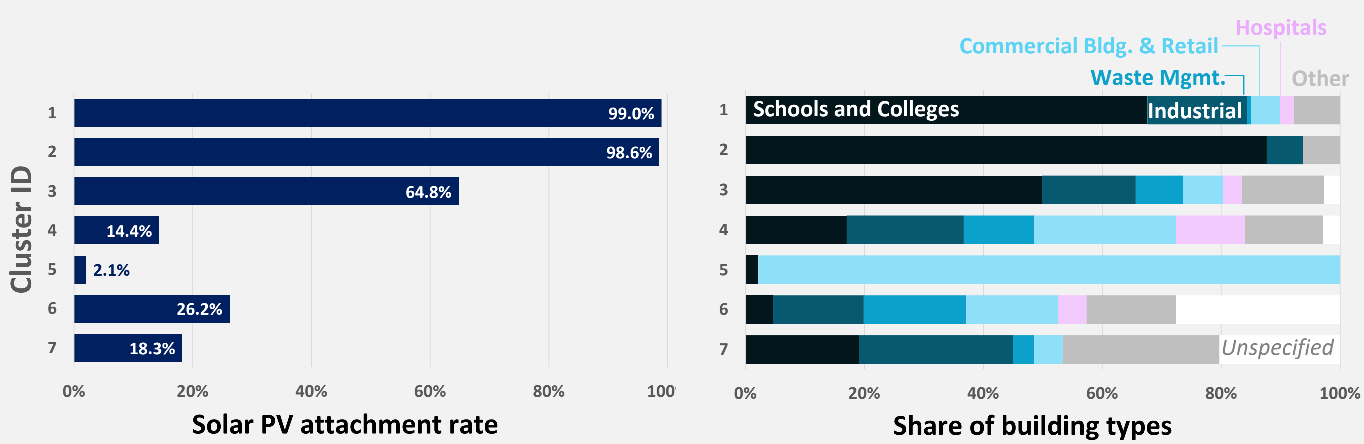


Figure 5: Observed characteristics of non-residential SGIP-funded installations (654 installations in 7 clusters).

Benefit-Cost Analysis

The foundation of the benefit-cost analysis in our study is the California Standard Practice Manual (SPM), which outlines methods for evaluating demand-side programs using various cost-effectiveness tests. The CPUC's 2019 decision under D. 19-05-019 provides guidelines for applying the Standard Practice Manual in an effort to move closer to "a consistent universal framework for assessing the cost effectiveness of all resources, both distributed energy resources and supply side resources." The approved framework adopts total resource cost (TRC) test as primary test for DER filings, and program administrator cost (PAC) and ratepayer impact measure (RIM) as secondary tests.

The scope of our evaluation includes operational energy storage projects across all grid domains, including transmission-, distribution-, and customer-sited projects. Our goal is to apply a consistent approach for projects in all domains, so the results can be compared and ranked across all projects. Even though the Standard Practice Manual was originally developed for distributed energy resources only, the underlying methodology and principles apply to all demand- and supply-side resources, which is why we used it as the foundation of this study.

Figure 6 below summarizes 4 main cost-effectiveness tests and corresponding perspectives:

- First two (participant and RIM tests) are not included because program participant vs. non-participant distinction does not apply to storage projects evaluated in our study. These two metrics typically inform potential cross-subsidies that are importanat for program and rate design, but that is not relevant to this study.
- Our benefit-cost analysis focuses on the total impact to all ratepayers, which is reflected in the perspective of the PAC test.
- We were able to calculate TRC only partially. While we included all societal benefits for all resources, actual project costs were available only for utility-owned projects. Costs of 3rd-party-owned projects under utility contracts are kept confidential, and they are not disclosed to the CPUC or utilities. Given the very diverse scope of procurements, domains, locations, and timelines considered in the study, we decided not to use generic cost assumptions to fill in missing data.

Cost-Effectiveness Test	**Approach**		
Participant Test	Measures quantifiable benefits and costs to the customers participating in a program	✗	**Participant vs. non-participant distinction does not apply to our study**
Ratepayer Impact Measure (RIM) Test	Measures what happens to customer bills or rates due to changes in utility revenues and costs (only non-participant)	✗	
Program Administrator Cost (PAC) Test	Measures net cost of a program as a resource option based on costs incurred by the utility or program administrator	✓	**For our study, this reflects total ratepayer impact excluding out-of-pocket participant costs**
Total Resource Cost (TRC) Test	Measures net cost of a program as a resource option based on total costs, including both participants' and utility's costs **Societal cost test is a variant of TRC test; (<u>Key differences:</u> lower societal discount rate, effects of externalities (e.g., air quality) and social cost of CO_2 emissions)*	**Partial**	**All benefit streams included, but the actual project costs are available only for a small subset of projects that are utility-owned**

Figure 6: Various cost-effectiveness tests and perspectives.

Energy and ancillary services value	Net of charging costs; Not included under total ratepayer benefits if under RA only contract
Resource adequacy (RA) capacity value	Includes system, local, and flexible RA
Transmission investment deferral value	Overlaps with local RA value; Considered only if storage defers an actual transmission alternative
Distribution investment deferral value	Considered only for distribution-interconnected and customer-sited storage
Avoided RPS cost	Based on avoided renewable curtailments
GHG emission reduction value	A portion of this is already captured under energy value; Considered only incremental value (if any)
Customer outage mitigation value	Private benefit to customers who install distributed storage; Not included under total ratepayer benefits

Figure 7: Benefit metrics considered in the study.

The table above shows various benefit metrics considered in our storage evaluation.

From a societal perspective we consider all benefit metrics listed above, although some can only be provided by distribution- or customer-sited energy storage projects, such as distribution investment deferral or outage mitigation.

Under total ratepayer perspective, we consider net benefits to all ratepayers as a whole. Accordingly, energy and ancillary services value is not included if a storage project is under an “RA only” contract, where the 3rd-party owner of the project keeps wholesale market revenues. Customer outage mitigation is also not included under total ratepayer benefit, as it is a private benefit to customers or communities who install energy storage as a distributed resource.

Bill savings provided by customer-sited storage projects, from societal or total ratepayer perspective, are not additive to other benefits. E.g.; If a residential battery reduces utility costs by $100 and saves $80 in electric bills to the customer who owns the battery, the total ratepayer benefit would be $100, of which $80 would go to the battery owner and remaining $20 would go to other ratepayers. For the purpose of this evaluation, we focus on the total ratepayer impact, and we look into individual bill impacts of customer-sited storage only to understand rate design related barriers towards meeting the state policy goals.

On the cost side, we focused on ratepayers’ share of project costs. For utility-owned storage, we compiled data on actual capital investments and operating costs of the projects based on information provided by the IOUs. For 3rd-party-owned storage, we compiled data on utility contract terms and payments based on in depth review of utility filings, contracts, and actual contract settlement information provided by the IOUs. As described earlier, the total cost of these 3rd-party-owned projects are not available; therefore, we were able to calculate final B/C ratios only from ratepayer perspective. However, we still separately calculate and show all gross benefits from a societal perspective to demonstrate progress towards value stacking.

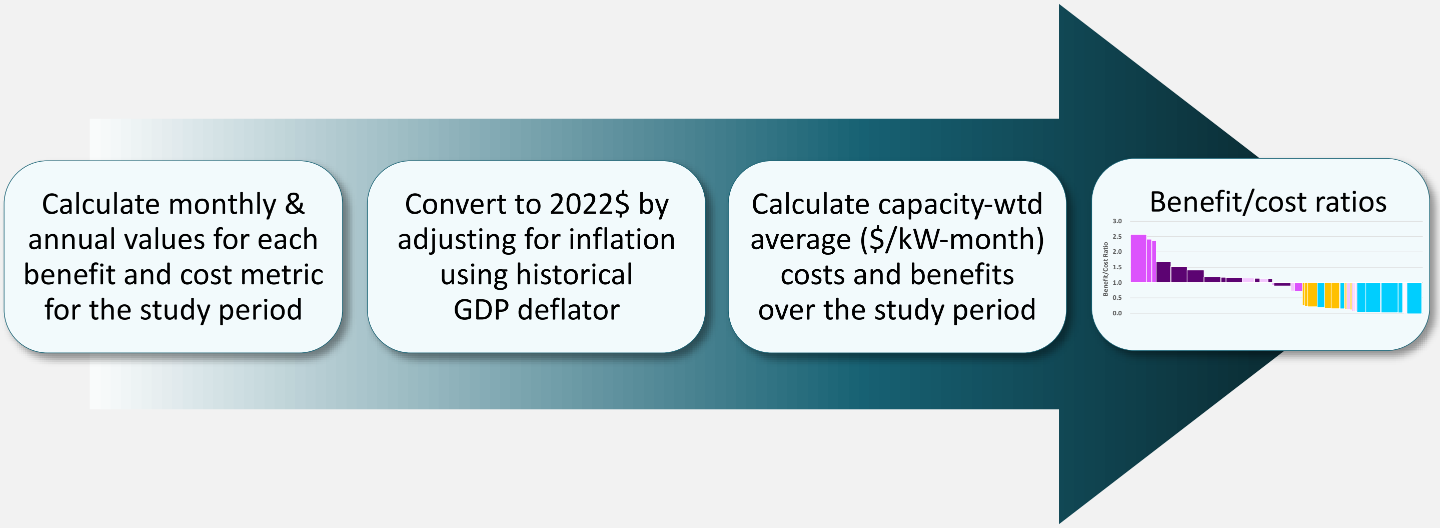


Figure 8: Calculation of benefit-cost ratios for final comparisons.

Figure 8 above shows how final benefit-cost ratios are calculated.

- We first calculate monthly and annual benefit and cost metrics in nominal dollars for each storage resource or groups of resources analyzed. Methodology for calculating each metric is described later in this attachment.
- We then convert the results to real 2022 dollars by adjusting for inflation using historical GDP deflator published quarterly at https://fred.stlouisfed.org/
- Since this is a retrospective study, we do not apply a discount rate or calculate present values.
- After we adjust for inflation, we calculate the total $ over the operational period within 2017–2021 and divide them by the total kW-month over the same period. This normalizes the results for storage capacity and duration of operations. It also accounts for any changes of the project capacity over time (e.g., due to phased development, degradation).
- Last step is to add up all benefits and add up all costs, then divide total benefits by total costs to estimate final B/C ratios that can be compared across projects.

Our evaluation covers only the initially years of operations of most energy storage projects, rather than their full economic lives. This creates an inherent bias against front-loaded cost recovery for utility-owned storage projects. For example, if we had two identical projects with same overall costs and benefits, but one is in the rate base and the other one is contracted, the project in the rate base would have a lower B/C ratio if only initial costs are considered. To address this issue, we estimate and use the levelized cost of lump-sum investments instead of revenue requirements.

Energy and Ancillary Services Market Value

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

- **Energy arbitrage** 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,
- **Black start** by self-starting without an external power supply and helping the grid recover from a local or system-level blackout.

Figure 9 summarizes how historical energy and ancillary services market benefits are calculated for each type of product.

For resources participating in the CAISO markets, we rely on actual metered data and resource-specific settlements in day-ahead and real-time markets.

For resources that are behind the CAISO meter and not participating in CAISO wholesale markets, we only include energy value estimated based on actual interval-level metered resource output multiplied by real-time LMP of the relevant sub-LAP. Sub-LAPs are CAISO-defined subsets of pricing nodes created to reflect price separation associated with the major transmission constraints within utility territories. For resource mapping, we first identified the areas covered by the clusters of pricing nodes for each sub-LAP and determined the closest sub-LAP for each storage resource based on geographic proximity using a GIS software.

<table>
<tr><th></th><th>CAISO Market Participants
(including demand response)</th><th>Non-Participant
Behind CAISO Meter</th></tr>
<tr><td>Energy</td><td rowspan="4">Valued at resource-specific day-ahead market (DAM) & real-time market (RTM) prices and settlements</td><td>Valued at RTM sub-LAP price</td></tr>
<tr><td>Frequency Regulation</td><td>n/a</td></tr>
<tr><td>Spin/Non-Spin Reserve</td><td>n/a</td></tr>
<tr><td>Flexible Ramping</td><td>n/a</td></tr>
<tr><td>Voltage Support</td><td rowspan="2">Based on CAISO contract payments (if any)</td><td>n/a</td></tr>
<tr><td>Black Start</td><td>n/a</td></tr>
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Figure 9: Calculation of historical energy and ancillary services market benefits.

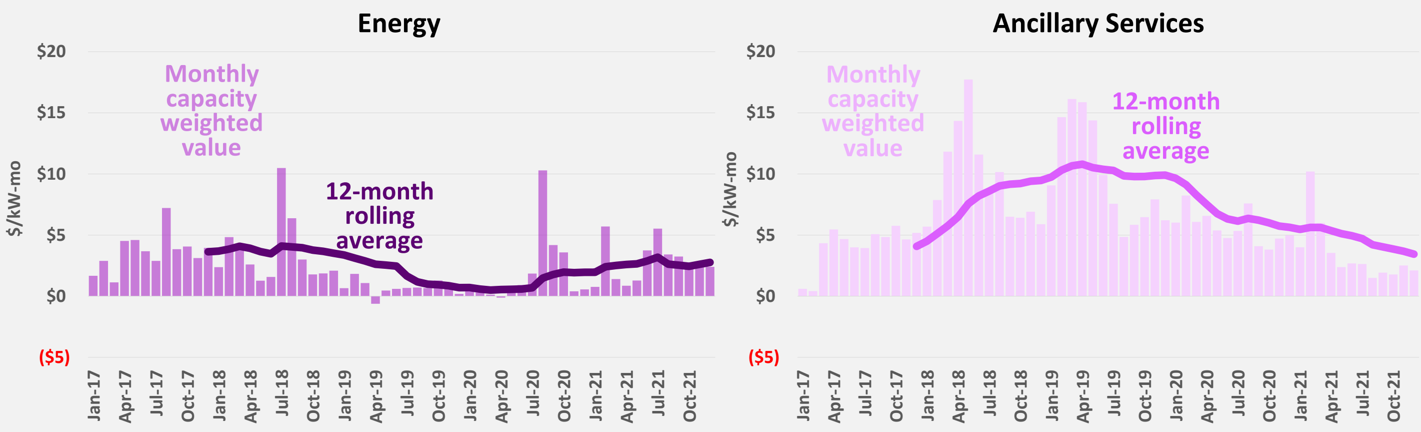


Figure 10: Average CAISO energy and ancillary services revenues across the storage fleet (in 2022$).

Figure 10 above shows the capacity-weighted average value of energy and ancillary services provided by the CAISO-participating energy storage projects included in our study. In the beginning of the study period, most of the early pilot projects' use cases included both energy and ancillary services with similar levels of value. During 2018–2020, significant revenue opportunities in the CAISO regulation market attracted many of the existing and new storage resources and resulted in use cases that are increasingly more focused on ancillary services. However, the ancillary services market is relatively small, currently averaging at around 400 MW for regulation up, 700 MW for regulation down, and 900 MW for spinning reserves. Starting in 2021, with significantly more battery storage connected to the CAISO system, the share of storage capacity used for ancillary services declined rapidly as the market started to saturate. This coincides with the overall wholesale market value proposition moving back to bulk energy time-shift.

Figure 11 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 2017–2021 timeframe. As shown, the largest share of historical market revenues came from regulation market for most of the projects, although this is rapidly changing. Other ancillary services revenues have been small, except for a couple of unique use cases focusing on contingency reserves. Energy revenues started to increase in 2021 and account for a large share of wholesale market revenues for the new projects.

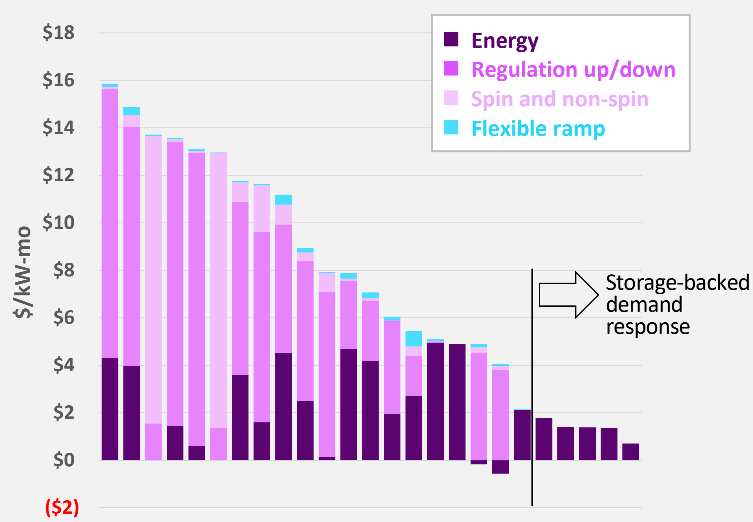


Figure 11: Average CAISO energy and ancillary services revenue by storage project (in 2022$).

For all distributed energy storage resources that do not participate in the CAISO wholesale market, we estimated their energy value based on metered output multiplied by real-time LMP of the sub-LAPs they are mapped to.

Figure 12 plots the estimated results for individual nonresidential SGIP-funded storage projects, where the colors indicate identified clusters based on their operating profiles. Projects in clusters 1, 2, and 3 yield higher energy value relative to other projects. Projects in cluster 6 performs slightly worse due to their practice of night charging. Most projects in clusters 4, 5, and 7 produce negative energy value, indicating operations at a net cost to ratepayers. Due to underused capacity, very few storage projects produce above $1/kW-month of value.

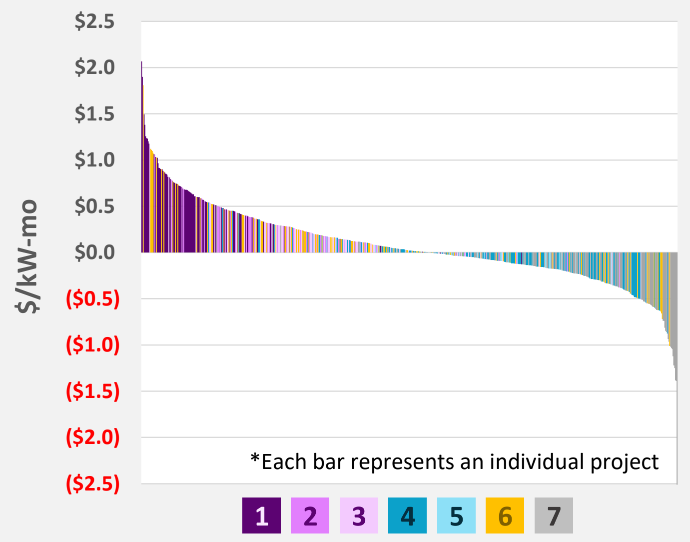


Figure 12: Average energy value of nonresidential SGIP-funded storage resources (in 2022$).

Figure 13 below compares the range of energy values across SGIP-funded projects and other customer aggregations procured under demand response (DR) contracts. For reference, we also included the energy value range for grid-scale transmission- and distribution-connected storage resources participating in the CAISO market. Although we could not access data to directly analyze residential SGIP-funded storage resources, we expect their behavior to be similar to nonresidential Clusters 1–2 with equally high solar PV attachment. Customer aggregations under utility DR contracts operate similarly to SGIP nonresidential Clusters 4–5 as they discharge steadily throughout the day, are unresponsive during morning and evening ramps, then charge at night. They do not participate in the CAISO marketplace and produce negative value on average. The CAISO-participating customer aggregations perform better than non-CAISO resources, but still below their potential. These resources produce $1/kW-month of energy value on average.

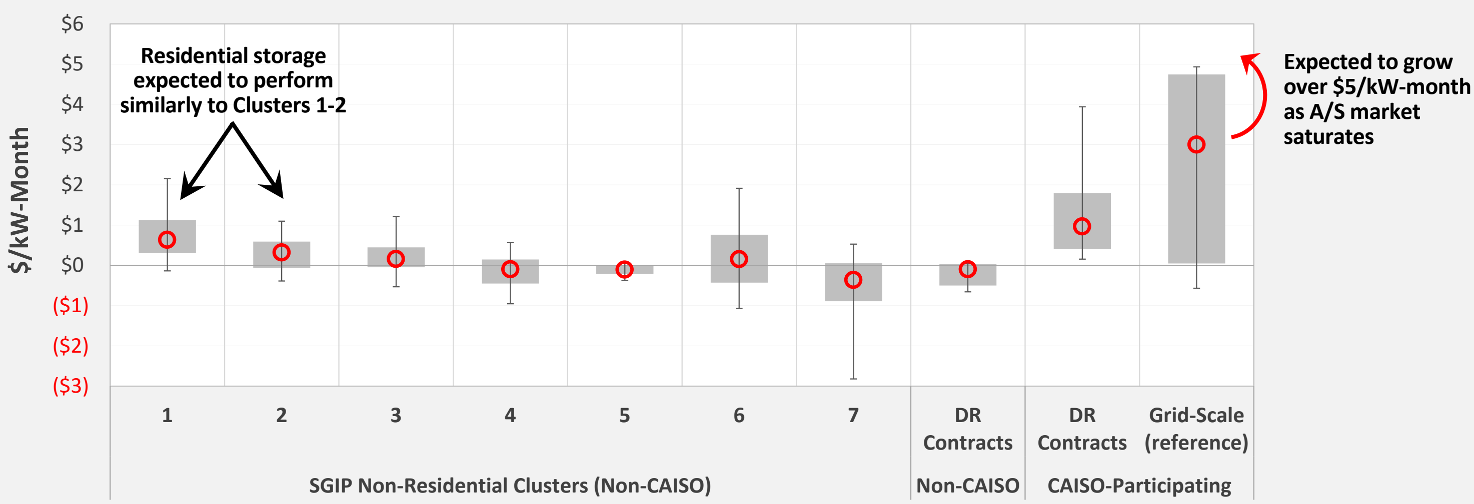


Figure 13: Average energy value produced by customer-sited energy storage (in 2022$).

* Red circle represents capacity-weighted average, gray bar represents P10–P90 range, and error bar shows minimum and maximum values across the group of resources analyzed.

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 requirements to ensure system reliability in California.

Our analysis of the RA capacity value depends on the counterfactual, which varies for each individual storage resource depending on its location and circumstances under which it was procured. As shown in Figure 14 below, if a project addresses local RA need, the counterfactual case would include procurement of an alternative local resource. Depending on supply availability at the time of procurement, this could be a short-term contract to retain an existing resource in that local area or it could be a long-term contract or investment in new generation or demand response (DR) resource. The local RA need can also be addressed by upgrading the transmission system, but we found this alternative not to be applicable for the resources analyzed in our study.

If a project is not in a local capacity area, or it is in a local area that doesn't have a deficiency, that project may still be providing system RA capacity. In this case, the counterfactual would include an alternative system RA procurement of an existing or new resources, or possibly from imports into CAISO, depending on needs and supply availability at the time of procurement. The main difference from the counterfactuals considered in the local RA track is that the associated avoided costs would be from a system RA resource from a larger pool of potential resources and locations.

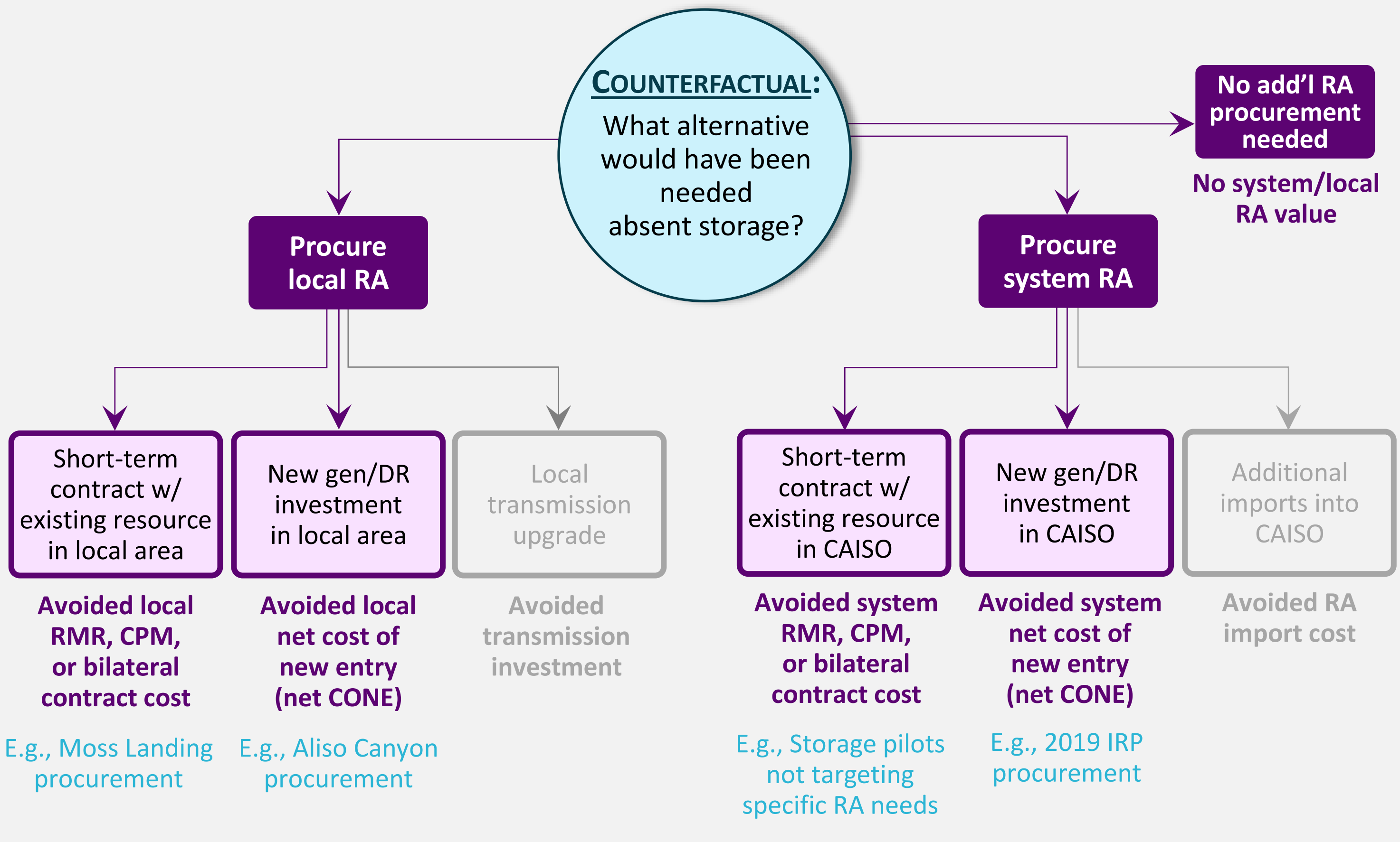


Figure 14: Calculation of historical RA capacity value based on counterfactual.

Most storage projects 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 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 circumstances under which the storage resources were procured.

An overview of the various procurement tracks and counterfactual cases is provided below:

SCE's 2013 LCR Western LA RFO selected 264 MW of energy storage, of which 182 MW was online by 2021. This was an all-source RFO to procure up to 2,500 MW of capacity in Western LA local area to address the need created by retirement of once-through-cooling (OTC) power plants. The RFO had a carve-out of minimum 50 MW of energy storage plus 550 MW of preferred resources, such as demand response, energy efficiency, and renewables. Storage was cost-competitive with other preferred resources and accounted for more than half of preferred resource capacity procured at the end. Without storage, it is likely additional gas-fired resources would be procured to meet the local capacity need. RA capacity value is estimated based on offer prices of marginal gas peakers participated in the same solicitation.

SCE's Preferred Resources Pilot (PRP) 2 RFO selected 125 MW of energy storage, of which 50 MW was online by 2021. Resources that became online are all distribution-connected storage resources. Several customer-sited storage procured in the same RFO got cancelled due to delays in approval process. The RFO intended to fill the gap from 2013 LCR RFO and help with the outstanding LCR need in Western LA driven by OTC and SONGS retirement. Timeline overlaps with the unexpected challenges created by the Aliso Canyon gas leak in southern California in 2016 so new gas-fired generation would not be a plausible alternative due to gas supply constraints in the area. Demand response (DR) is the most viable resource to consider in the counterfactual. RA capacity value is estimated based on non-storage DR cost for programs available in southern California at the time.

SCE and SDG&E's Aliso Canyon Energy Storage (ACES) RFOs procured nearly 100 MW of energy storage that began operations in 2017 to address local reliability issues caused by prolonged natural gas leak at Aliso Canyon. Gas leak was discovered in October 2015 and governor proclaimed a state of emergency in January 2016, requesting state agencies take all necessary actions to ensure reliability. CPUC required expedited competitive procurements of energy storage and the entire process was completed in record time: solicitations, development, permitting, construction, and interconnection of 7 projects in 9 months. Gas-fired generation would not be plausible due to gas supply constraints. DR is the most viable alternative for the counterfactual. RA capacity value is estimated based on non-storage DR cost for programs available in southern California at the time.

SCE's 2018 ACES 2 and LCR Moorpark RFOs resulted in a combined 195 MW of energy storage in the Moorpark area, of which 121 MW was online by 2021. Moorpark LCR needs were initially identified in 2013, driven by OTC retirements. Through an 2013 RFO, SCE contracted a 262 MW gas peaker, but CEC rejected permitting of the plant due to environmental concerns. CEC's decision was informed by a CAISO study finding preferred resource alternatives were feasible. SCE's 2018 solicitations addressed the remaining LCR need in Moorpark, along with localized resilience needs in Santa Barbara/Goleta area. Without storage, non-storage DR would be a viable alternative, but it would be difficult to scale within the local sub-area so counterfactual would include the cancelled gas peaker. Accordingly, RA value is estimated based on blended cost of the cancelled gas peaker plus non-storage DR up to 20 MW (original ACES 2 target).

PG&E's 2018 LCR Moss Landing RFO selected 567.5 MW of energy storage, of which 482.5 MW was online by 2021. PG&E's solicitation was open to energy storage resources only and intended to eliminate or reduce the need for reliability-must-run (RMR) contracts in the Moss Landing local capacity area. While PG&E was conducting the LCR RFO, CAISO identified and approved transmission upgrades to address the local need, but storage was needed to reduce risk of future deficiencies. In CAISO's 2022 LCR study, Moss Landing subarea would have a capacity deficiency if storage resources and Metcalf unit were not included. Based on this, counterfactual case is assumed to include an RMR resource, and RA capacity value is estimated based on the 2018 RMR contract prices negotiated for the Metcalf unit.

Figure 15 below summarizes the counterfactual cases and estimated long-term RA capacity values for the relevant procurement tracks.

Procurement Track	Specific RA Capacity Need Addressed	Type of Resource Procured in Counterfactual	Approach to Estimate RA Value	Estimated RA Value (2022$/kW-mo)
2013 LCR Western LA	Local capacity needs in Western LA to replace OTC & SONGS retirements	New gas peaker	Net CONE based on 2013 LCR RFO bids	**$16–$18**
Preferred Resources Pilot 2	Same as above; Fill in shortfall of Preferred Resources in 2013 LCR RFO	New demand response	Net CONE based on DR cost	**~$20**
Aliso Canyon Energy Storage	Urgent reliability needs in southern CA due to gas supply limitations	New demand response	Net CONE based on DR cost	**~$20**
Aliso Canyon Energy Storage 2	Same as above; PLUS local capacity needs in Moorpark	New gas peaker and DR	Net CONE based on gas peaker & DR cost	**$14–$16**
2018 LCR Moorpark	Local capacity needs in Moorpark to replace OTC retirements	New gas peaker and DR	Net CONE based on gas peaker & DR cost	**$14–$16**
2018 LCR Moss Landing	Local capacity needs in Moss Landing to replace existing RMR generation	Existing RMR resources	Avoided RMR cost based on Metcalf	**~$7**
Other	n/a	Existing generic resources	Short-term bilateral RA contracts	**$3–$8**

Figure 15: Summary of RA counterfactuals and estimated RA capacity value by procurement track.

For energy storage resources that were not procured for specific reliability or resource adequacy needs, we estimated their RA capacity values based on bilateral RA contracts executed by the LSEs. We relied on the historical RA price data compiled by the CPUC for 2018–2021. 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 executed within one year prior to delivery. Here, the use of P90 rather than the highest price is to exclude possible outliers of small RA contracts priced at a premium. The results are summarized in Figure 16 on the right.

	2018	2019	2020	2021
CAISO System	$2.7	$3.0	$7.5	$8.2
Bay Area	$3.1	$4.4	$7.6	$8.0
Big Creek-Ventura	$4.0	$4.4	$7.6	$8.3
LA Basin	$3.4	$4.5	$7.8	$7.9
San Diego-IV	$2.9	$3.9	$7.5	$7.9

Figure 16: Estimated marginal RA value based on short-term bilateral RA contracts (in 2022$).

The prices shown above reflect combined value of system RA and local RA attributes. As highly flexible resources, energy storage can also provide additional value towards flexible RA needs to meet forecasted net load ramps.

Currently, CAISO divides the flexible RA needs into 3 categories:

- Base flexibility to meet the largest 3-hour secondary net load ramp,
- Peak flexibility to meet the difference between 95% of the maximum 3-hour net load ramp and 3-hour secondary net load ramp, and
- Super-peak flexibility to meet the remaining 5% of the maximum 3-hour net load ramp.

All resources providing flexible RA capacity are required to submit bids in CAISO day-ahead and real-time markets, where their must-offer obligation (MOO) depends on the category. Base flexibility resources must submit bids for 17 hours/day every day of the week. Peak flexibility resources must submit bids for 5 hours/day every day. Super-peak flexibility resources must also submit bids for 5 hours/day but only during non-holiday weekdays. The 5-hour window changes depending on the month of the year.

Energy storage is increasingly used to meet super-peak flexibility needs. According to 2021 DMM report, energy storage provided 371 MW of the super-peak flexible capacity, accounting for 86% of the capacity procured in that category. However, the overall flexible RA requirement was largely met by gas and hydro generation. Despite more stringent must-offer obligations, flexible RA procured for the base category well above the minimum requirement, and the excess was used towards meeting the requirements for peak or super-peak categories. This suggest there is still plenty of traditional resources procured for local or system RA capacity that can also provide flexible RA, and accordingly, incremental cost of procuring flexible RA would be minimal.

This observation is consistent with our review of the historical RA contract prices. Across all historical years, bundled prices of system/local RA + flexible RA were not higher than prices of system/local RA only. This is described in various CPUC Resource Adequacy Reports. We also ran a statistical analysis of the historical RA prices controlling for delivery periods and areas, and we found there was no price premium related to providing flexible RA during the 2018–2021 period. Given these findings, we set the flexible RA value of storage resources to zero in our study.

For energy storage resources participating in the CAISO market, we estimate RA capacity value based on their net qualifying capacity (NQC) at the project level. For the projects included in our study, the NQC determinations follow the CPUC's initial "4-hour rule" requiring energy storage resources to have at least 4 hours of duration to qualify for full credit. The NQC of resources with less than 4-hour of duration would be de-rated proportional to their durations (e.g., 2-hour storage gets 50% credit).

Behind-the-meter (BTM) distributed and customer-sited energy storage resources can provide capacity value either:

- By participating in DR programs that are integrated to the CAISO market on the supply-side, or
- As a load modifying resource under various retail incentive programs and rates.

For CAISO-participating BTM storage resources, we use their actual NQCs to calculate RA capacity value. If the NQC data is not available or the BTM resource does not participate in the CAISO market, we estimate capacity contribution based on actual net discharge during capacity-constrained periods. For our study, we focused on performance during the system emergencies in 2020–2021.

Figure 17 includes an example illustrating the operations of nonresidential SGIP-funded storage projects during the Stage 3 emergency that CAISO declared on August 14, 2020 between 6:36 pm and 8:38 pm. Each row shows the charge/discharge profile of an individual unit on that day, sorted by the clusters they are mapped to. On the left, CAISO load and aggregate storage output are plotted. Altogether, these nonresidential storage projects provided around 12 MW of energy during the emergency period, which corresponds to 6% of the 205 MW installed.

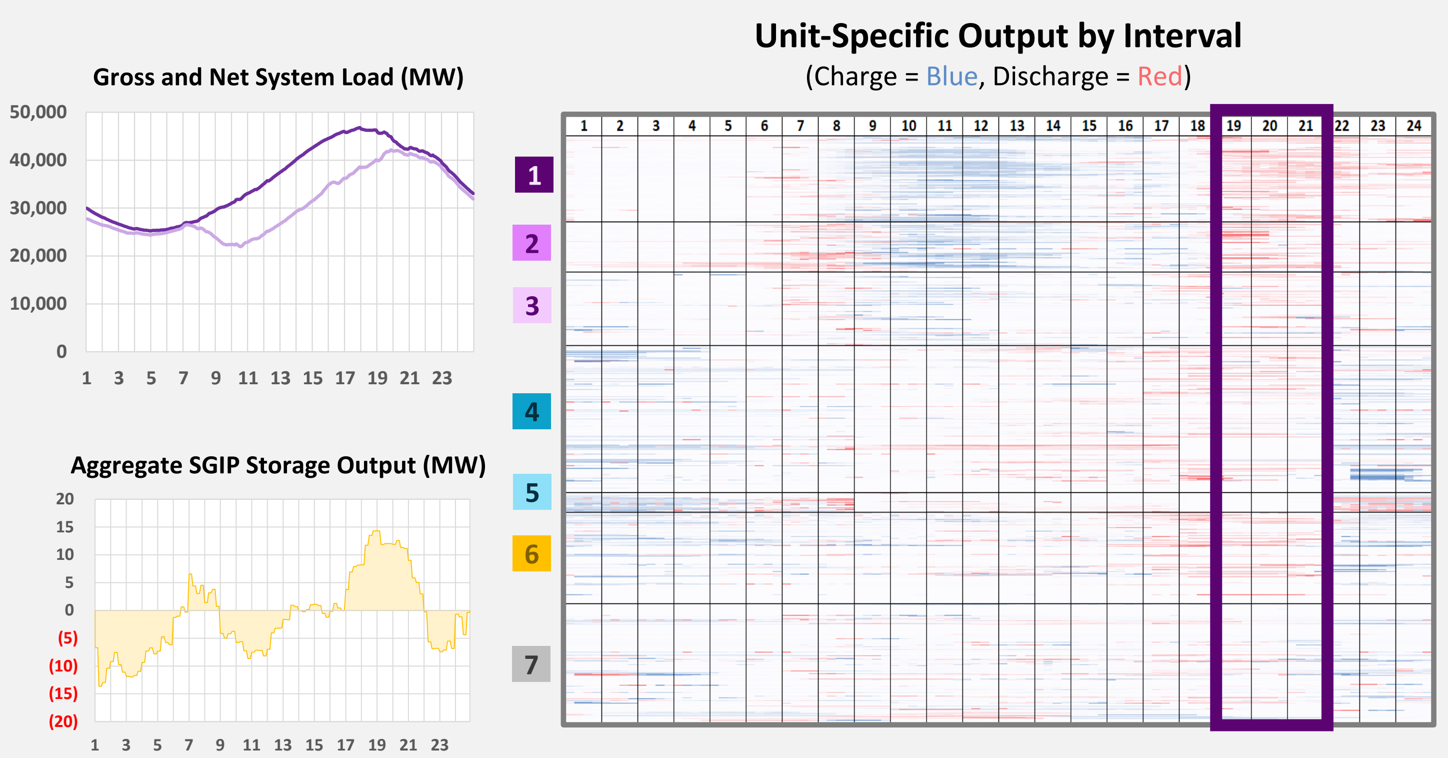


Figure 17: Nonresidential SGIP storage project performance during CAISO stage 3 emergency on August 14, 2020.

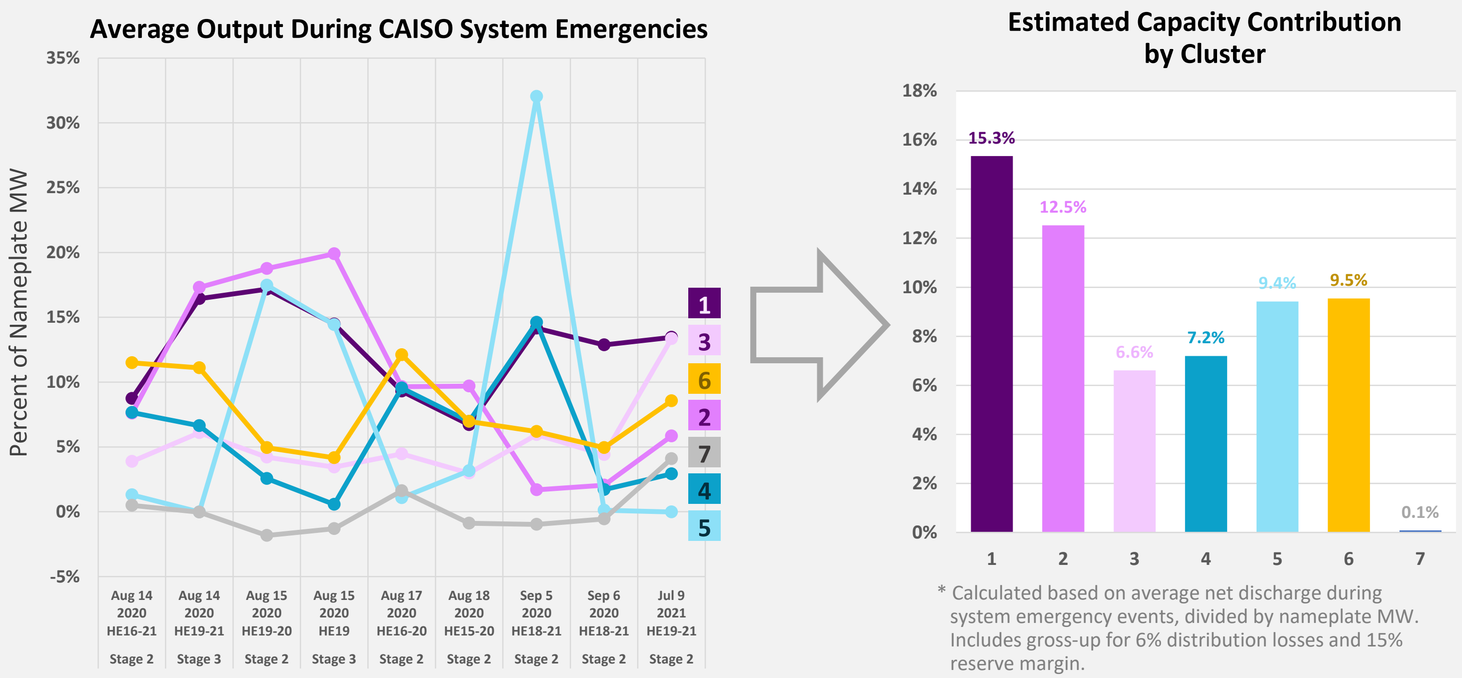


Figure 18: Observed capacity contribution of nonresidential SGIP storage projects by cluster.

Figure 18 above shows the estimated capacity contribution of nonresidential SGIP storage projects for each cluster, based on their operations during 9 system emergency events that took place in 2020–2021. All clusters except for cluster 7 discharged net energy on average during emergencies, based on which we estimated capacity contributions. Clusters 1–2 contributed more than others, providing 12–15% of each MW installed. Clusters 3–6 provided 7–10% of each MW, and cluster 7 provided no net relief.

Figure 19 shows the range of results for other distributed storage projects. Distribution-connected projects that do not participate in the CAISO market have been mostly unresponsive during system emergencies. Customer-sited storage under utility DR contracts met the capacity requirements defined in their contracts, but these requirements were not aligned with the evolving grid needs shifted to late evenings and extended to weekends.

Based on limited number of observed emergency events occurred during the historical period, the capacity contributions estimated here are <u>*indicative*</u> at best. Load-modifying distributed and customer-sited energy storage resources do not have a firm obligation to offer their capacity during system emergencies. Accordingly, their contributions can vary significantly from one event to another as shown in Figure 18. Nevertheless, many of these storage resources, especially ones that are paired with solar, have operating patterns that are synergistic with the grid needs and they are much more likely to discharge than charge when the grid is stressed. It is important to capture the associated benefits to the grid and not ignore it due to data limitations.

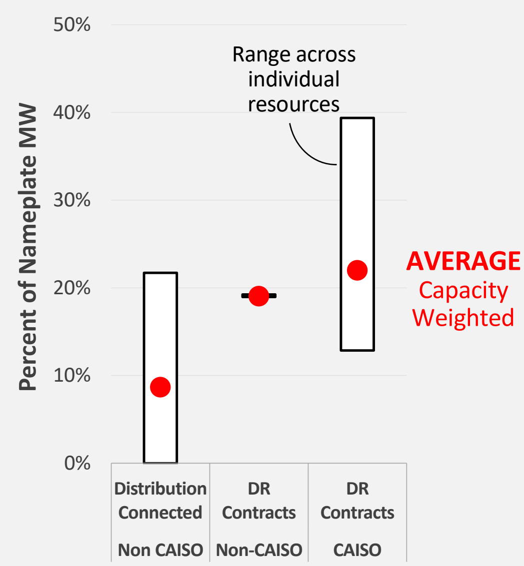


Figure 19: Observed capacity contribution of distribution- and customer-sited storage.

Transmission Investment Deferral Value

Energy storage resources can defer the need for transmission investments under two distinct use cases: (1) energy storage acts as an energy resource, alters load and generation balance to relieve transmission bottlenecks, and thus replaces transmission solutions that could do the same, or (2) storage is used by the system operator like a controllable transmission asset and could be operated, for example, to redirect power flow and prevent overloads on specific circuits.

Several energy storage projects operating during 2017-2021 were procured to meet local capacity needs driven by generation retirements or issues related to Aliso Canyon. Since these energy storage resources were procured under RA procurement tracks where the alternative is a generation or load resource, we allocate these services and benefits towards local RA capacity, rather than transmission deferral. As part of the CAISO's transmission planning, generating resources, including energy storage, are considered as alternatives to transmission investments. In 2017–2018 TPP, CAISO approved a 10 MW energy storage project as part of a combined transmission/generation solution to prevent overloads in the Oakland area. Development of that project has been hampered by changes in scope identified in subsequent TPPs and it is not clear if or when the project will be developed.

Development of energy storage projects operated as a controllable transmission asset is still in pilot phase. In 2017–2018 TPP, CAISO approved a 7 MW energy storage projects as a cost-effective solution to manage a transmission contingency that would interrupt service to the town of Dinuba. PG&E conducted a competitive solicitation in 2019 and selected a winning bidder. However, when the transmission need increased to 12 MW in a subsequent TPP, PG&E cited challenges with procurement and contracting.

Distribution Investment Deferral Value

If interconnected to the distribution system, storage can defer the need for distribution investments by reducing local peak loading on the distribution grid. While there have been several storage projects procured to defer distribution investment, many of these projects have either been delayed or cancelled. None of the operational projects included in our analysis deferred an actual distribution investment need, so this value stream is set to zero for all projects in the study.

One of the early pilot projects funded by an EPIC grant (Browns Valley) was deployed by PG&E in 2017 to demonstrate autonomous peak-shaving capability needed for distribution deferral use case. While the project provided valuable experience about this use case, as described in the final EPIC report, the project did not defer an actual distribution upgrade or investment.

Storage developed to act as a distributed energy resource and relieve constraints on the distribution system was explored through an incentive pilot, the CPUC's Integrated Distributed Energy Resources (IDER) proceedings. The pilot resulted in 6 contracts, four of which were canceled, and two were online in 2021. Of these two, one project (Acorn 1) became online in early 2021 and included in our study. However, the underlying distribution need went away due to reduction in load forecast, and the project did not defer an actual investment. The other distribution deferral project (Wildcat 1) got online in late 2021 and it was not included in the study due to not having sufficient operational history.

Storage developed to directly defer or avoid distribution investments is procured through an annual process under the CPUC's Distribution Investment Deferral Framework (DIDF). That process has not yet yielded an operational project. Many of the utility DIDF solicitations either resulted in no selected offers or were not held at all. Three out of the four DIDF offers ever selected were canceled and the fourth resource is due online in 2023.

Avoided RPS Cost

Energy storage can reduce renewable curtailments by mitigating oversupply conditions, which will get increasingly more challenging as California continues to decarbonize its electric system. As illustrated in Figure 20, charging of storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

Avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet RPS and other clean energy targets. To estimate benefits, we first determine the impact on renewable curtailments based on net charge of energy storage resources when there are actual curtailments on the system. It is important to differentiate curtailments driven by local vs. system-wide constraints. To do that we overlay CAISO's real-time 5-minute curtailment data with resource specific real-time LMPs. In an interval with curtailments, we assume a storage project impacted curtailments only if its nodal real-time LMP was zero or negative. If its nodal price was positive, it implies that storage unit was outside of the local area where curtailment occurred and there was a transmission constraint preventing from storage resource to reduce or eliminate that curtailment.

Based on historical data, we estimated that most storage projects were at locations subject to 1–2 hours of curtailments per day, on average. If the storage projects charged at full capacity in these hours, it would have translated to 30–60 MWh of monthly curtailment reduction per MW of storage capacity. Actual realized benefit during the 2017–2021 study period was much smaller because most storage projects focused on use cases that didn't help with renewable curtailments.

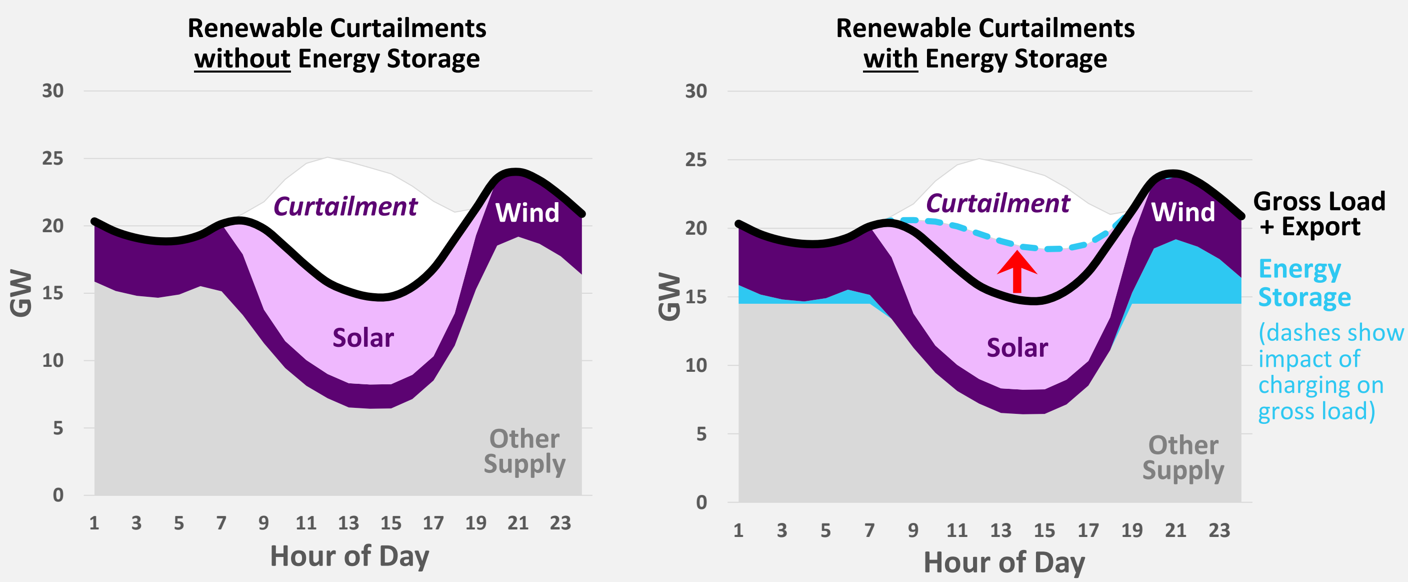


Figure 20: Illustration of energy storage impact on renewable curtailments.

Figure 21 below shows the average monthly impact of energy storage projects on renewable curtailments and the associated benefits monetized.

Project with the highest impact reduces an average of 25 MWh of monthly renewable curtailments per MW of storage capacity, which is closer to the lower end of our estimated potential. Most projects provide far less benefits, which is somewhat expected given the historical focus on ancillary services participation and other use cases that do not incentivize bulk energy time-shift. Lowest-performing resources are estimated to increase renewable curtailments by discharging energy in the middle of the day. These are thermal energy storage resources procured under permanent load shift (PLS) contracts reducing A/C loads in early afternoons, which overlaps with the periods when grid experiences renewable curtailments.

We monetize the RPS cost savings using the RPS adders published in CPUC's Power Charge Indifference Adjustment (PCIA) reflecting the incremental value of RPS-eligible energy based on historical transactions. For our study period, the RPS adders were in the range of \$14–\$16 per MWh, depending on the year. Accordingly, the storage project with the highest renewable curtailment impact is estimated to provide \$0.42/kW-month of RPS benefits, and at the tail end of the distribution storage projects procured under the PLS contracts are estimated to increase RPS costs by \$0.10/kW-month, on average.

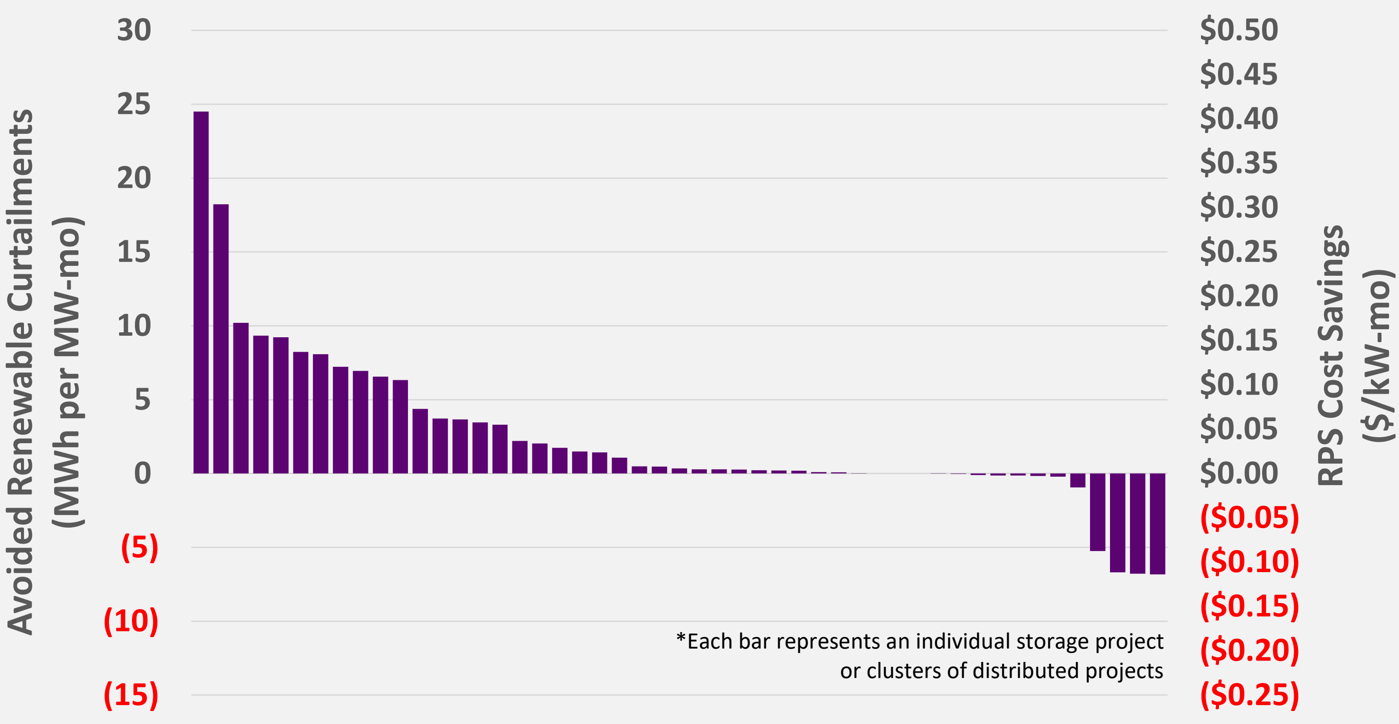


Figure 21: Estimated average renewable curtailment impact and associated RPS cost savings (in 2022$).

GHG Emission Reduction Value

We estimate net GHG emission impact of energy storage resources based on their actual energy output multiplied by historical marginal GHG emission rate at the sub-hourly interval level and added up over the study period. Energy storage reduces emissions at the marginal rate when discharging, and it increases emissions at the marginal rate when charging. We use the historical real-time marginal GHG signal created by WattTime to evaluate emission impact 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 for each balancing authority in California. Within the CAISO, the GHG signals are calculated for each of the three IOUs: PG&E, SCE, and SDG&E.

Figure 22 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.

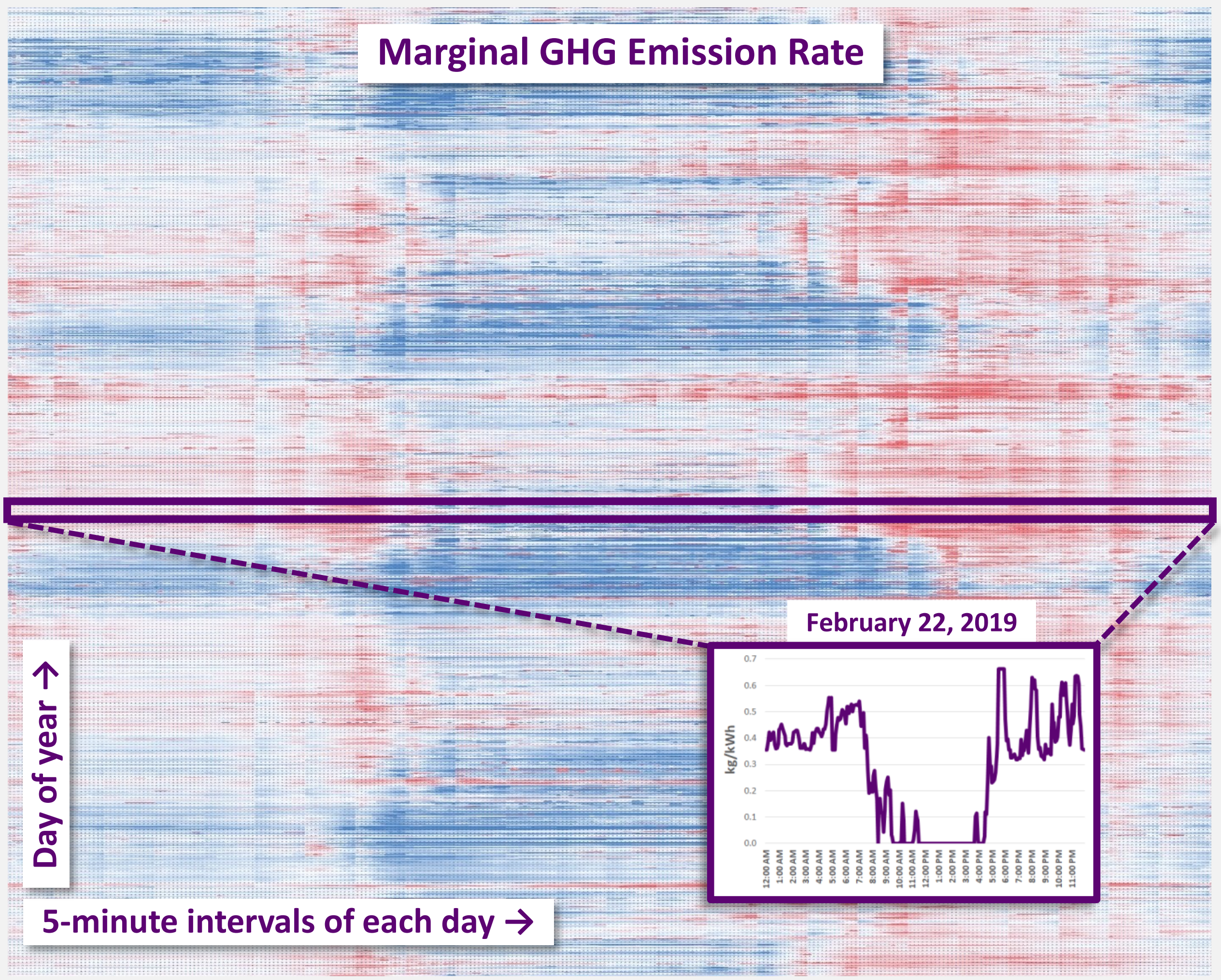


Figure 22: Heatplot of historical marginal GHG emission rates used in the study.

We apply the same methodology across all energy storage resources included in our study. For resources participating in the CAISO market, when they provide ancillary services, their emission impact is calculated to the extent it translates changes in actual energy charged or discharged. For example, if a battery sells regulation in the CAISO market and rapidly adjusts its output to follow AGC signals, it shows up as a part of the metered 5-minute charge and discharge reported by the CAISO, and we would calculate GHG impact as the regulation-related energy movements multiplied by the marginal GHG rate.

There may be a secondary GHG impact associated with the A/S capacity displacement, but we expect it to be small relative to GHG emissions associated with A/S-related changes in energy output. For example, consider an energy storage unit selling 1 MW of regulation up capacity when the marginal resource for regulation up is a gas-fired plant. If the storage unit didn't sell regulation, the marginal gas plant would need to increase its headroom by 1 MW to provide an extra 1 MW of regulation up capacity. By increasing its headroom, the gas plant ends up generating 1 MW less in the energy market, which means another resource, presumably with a similar emission rate, needs to be dispatched to make up for reduced energy from the gas plant. At the end, the net GHG impact associated with the regulation capacity would be relatively small and the overall GHG impact would be driven by regulation mileage and the related changes in energy output.

For energy storage resources to provide GHG reduction benefits, (a) they need to be highly efficient, and (b) their use cases should allow shifting bulk energy from periods with low GHG intensity to periods with high GHG intensity.

Energy storage is a net consumer of energy: it can retrieve less energy than the energy initially used for charging, due to operational losses. While most storage projects in California have relatively high efficiency in the of 80%–90% range when they operate regularly, their average efficiency drops significantly when they remain on standby for extended periods of time. To provide GHG emission benefits, it is essential for energy storage resources to have highly efficient operations.

Being efficient is necessary, but not sufficient for reducing GHG emissions. Storage use case also needs to allow for shifting bulk energy from periods with low marginal emissions (e.g., midday) towards periods with high marginal emissions (e.g., evening peak). Today's energy storage technologies are very flexible and can provide significant value by helping with grid's needs for frequency regulation. However, the signals for frequency regulation are typically not correlated with GHG intensity of the system, so this use case can result in net GHG increase after losses are factored in.

To benchmark results, we first estimated the average GHG emission reduction potential of energy storage, by simulating optimal dispatch under an energy time-shift use case (no ancillary services) with historical energy prices for 2017–2021. We accounted for market uncertainty by first solving for next day's hourly schedule using day-ahead LMPs, then evaluating economic dispatch deviations for each interval using real-time LMPs assuming only prices up to the current interval are known, before moving to the next interval. Based on these simulations, we estimated the average GHG reduction potential for a 4-hour energy storage to range from 7 ton/MW-month at 30% efficiency to 25 ton/MW-month at 90% efficiency, which is shown as dashed pink line in Figure 23 below. We also included an order of magnitude estimate of the GHG increase under a regulation only use case, shown as dashed purple line, although these values are illustrative and highly sensitive to mileage assumptions.

The actual GHG emission impacts of individual energy storage projects are shown as circles on the chart. To highlight the contrast, the CAISO-participating storage resources are split into 2 groups based on share of wholesale revenues from regulation service. CAISO resources with more than 75% revenues from regulation market are shown in red, and they contributed to a net increase in GHG emissions. CAISO resources with less regulation focus are shown in blue and they all reduced GHG emissions, even though most resources' contributions were far below their potential. Customer-sited nonresidential SGIP projects are shown in yellow, and their GHG impact depends on project cluster (see next page). Other storage projects that did not participate in CAISO marketplace are shown in gray. Most of these projects were underutilized and they were often on extended periods of standby, which translated to low operational efficiency and resulted in marginal increases in GHG emissions. In one distinct use case, storage was placed in an island to help a diesel generator maintain high output for NO_X control equipment function. While this may have reduced NO_X emissions, it also led to significant increase in GHG emissions because the diesel generator had to produce more energy to make up for losses of the battery system.

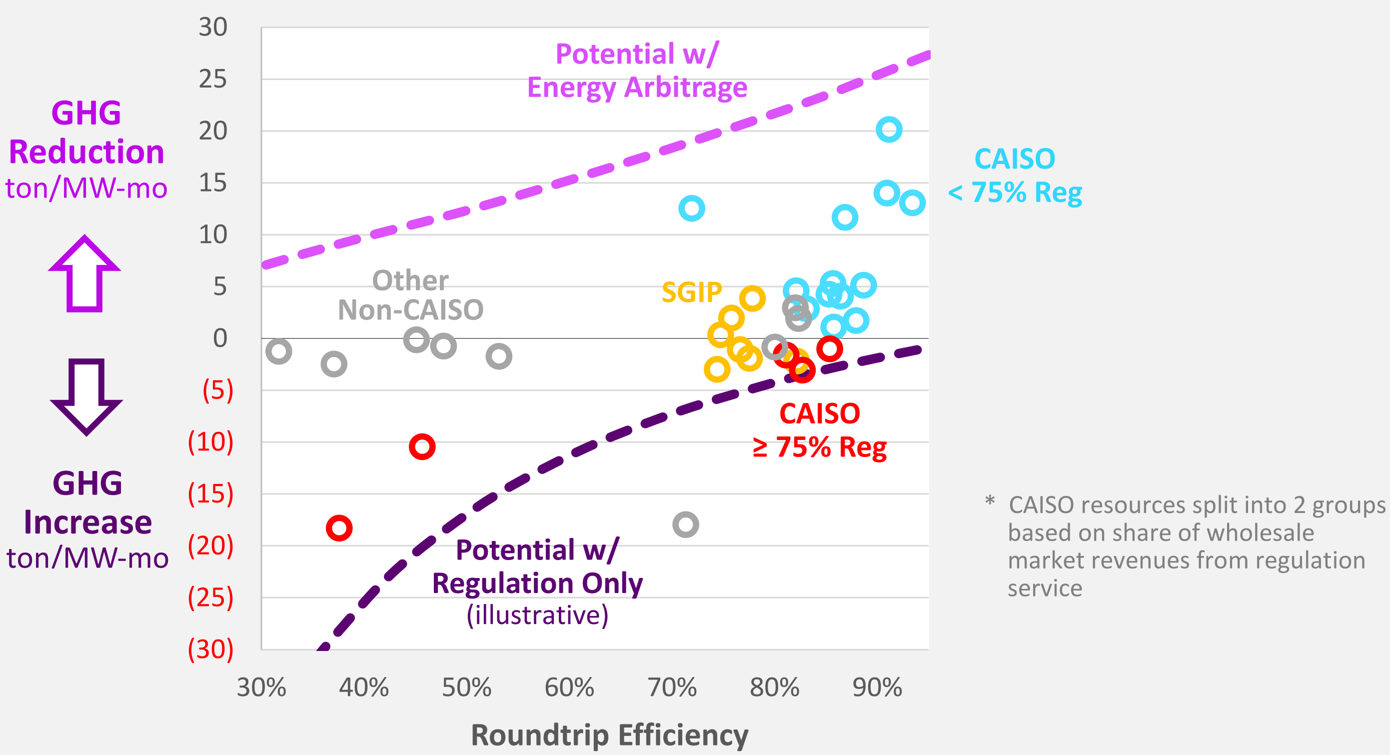


Figure 23: Estimated average GHG emission impact of energy storage resources.

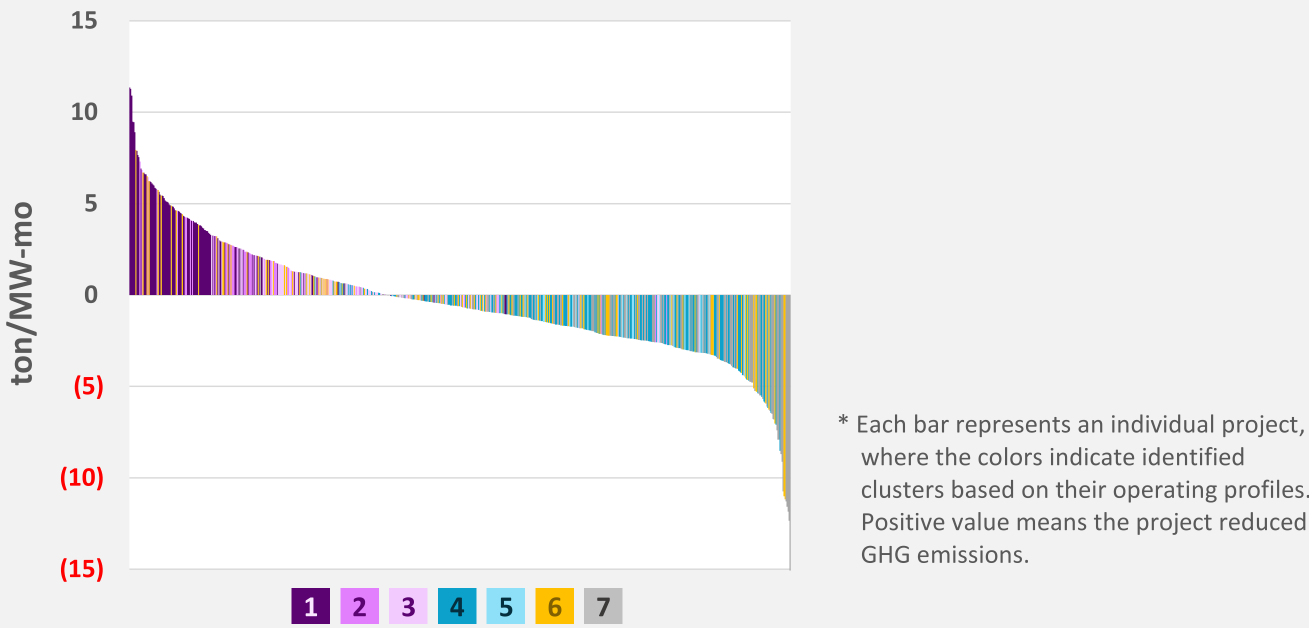


Figure 24: Average GHG emission reduction from nonresidential SGIP-funded storage resources.

Figure 24 shows the GHG impact of individual nonresidential SGIP-funded projects, averaged over their operations in the 5-year study period from 2017 to 2021.

- Projects in clusters 1–3 reduced GHG emissions, on average. As discussed earlier, storage projects in these clusters are mostly paired with solar and their operations typically involve midday charging when the system's GHG emission intensity is low, and either morning or evening discharge when the GHG emission intensity is relatively high.
- Clusters 4–7 account for around 70% of the SGIP storage capacity analyzed. Most projects in these clusters contributed to higher GHG emissions, as their use cases focused primarily on demand charge management and did not align well with GHG reduction goals of the program. Average GHG emissions increases are as high as 3 tons/MW-month at the cluster level over the study period, and as high as 16 tons/MW-month at the individual customer resource level.

The GHG emission increase associated with nonresidential SGIP storage projects were originally identified in the SGIP energy storage impacts evaluation report, published in late 2016. In response and after almost three years of study with stakeholders, in 2019 the CPUC adopted GHG emission reduction requirements and the use of a GHG signal to better align resource performance with the program's goals. Under the rules, new commercial projects after April 2020 are required to reduce GHG emissions by 5 kg per kWh annually, which translates to 0.83 ton/MW-month for storage with 2 hours of duration. This requirement is an outcome of the CPUC's stakeholder process, and it is well below the annual target CPUC Staff originally proposed and it is only a fraction of the potential we estimated for storage projects with access to grid signals.

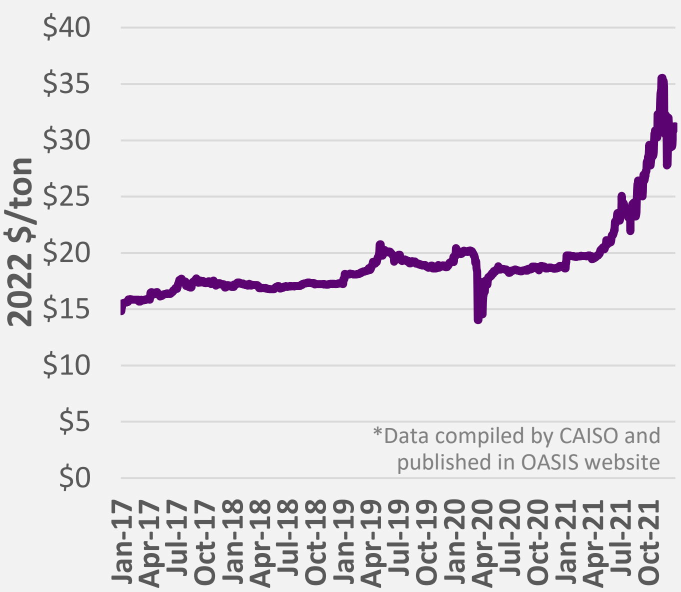
Even though the GHG rule for SGIP projects went in effect back in 2020, we have not observed its effect yet in operational data analyzed through September 2021 due to lags driven by exemptions for legacy projects and program enrollment timelines. The GHG requirements only apply to projects submitting applications after April 2020 and the approval process combined with operational data collection typically takes multiple years.

The GHG emission reduction value of energy storage projects includes two components:

1. Avoided short-term marginal cost of GHG abatement based on allowance prices observed in the cap-and-trade market,
2. Avoided cost of meeting GHG goals through additional investments in the electric sector based on the RESOLVE model GHG shadow prices used in CPUC's 2022 Avoided Cost Calculator, which is consistent with IRP studies.

Figure 25 below shows historical GHG allowance prices in the cap-and-trade market, based on data compiled and published by the CAISO. GHG prices have been around \$15–\$20 per ton through 2020, but increased significantly in the second half of 2021, trading at \$25–\$35 per ton in the secondary market, well above the auction reserve price setting the floor. GHG value based on prices seen in the cap-and-trade market are already reflected in the energy market prices and included under energy value of storage projects. The example in Figure 25 illustrates this based on a storage unit that charges in hour 14 when marginal GHG rate is low and discharges in hour 19 when marginal GHG rate is high. Associated energy value based on avoided cost is \$15/MWh, of which \$3/MWh is related to GHG costs.

Electric sector GHG targets implemented in the IRP studies may require new investments at a cost higher than cap-and-trade price. The "GHG adder" reflects this incremental cost of further reducing emissions to meet electric sector GHG targets. As described in the CPUC 2022 Avoided Cost Calculator documentation, the 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, we set the GHG adder to \$0 for our study period 2017–2021.



	Hour 14	Hour 19	Avoided Cost
Storage	charge	discharge	
Marginal unit	efficient gas	inefficient gas	
Heat rate (Btu/kWh)	6,500	10,000	
Fuel cost (\$/MMBtu)	\$3.5	\$3.5	
VOM (\$/MWh)	\$5	\$5	
GHG rate (ton/MMBtu)	0.053	0.053	
GHG cost (\$/ton)	\$15	\$15	
Fuel + VOM cost (\$/MWh)	\$28	\$40	\$12
GHG cost (\$/MWh)	\$5	\$8	\$3
Marginal Energy Cost (\$/MWh)	\$33	\$48	\$15

Figure 25: Historical GHG allowance price in the cap-and-trade market and illustration of how it impacts energy market prices and value.

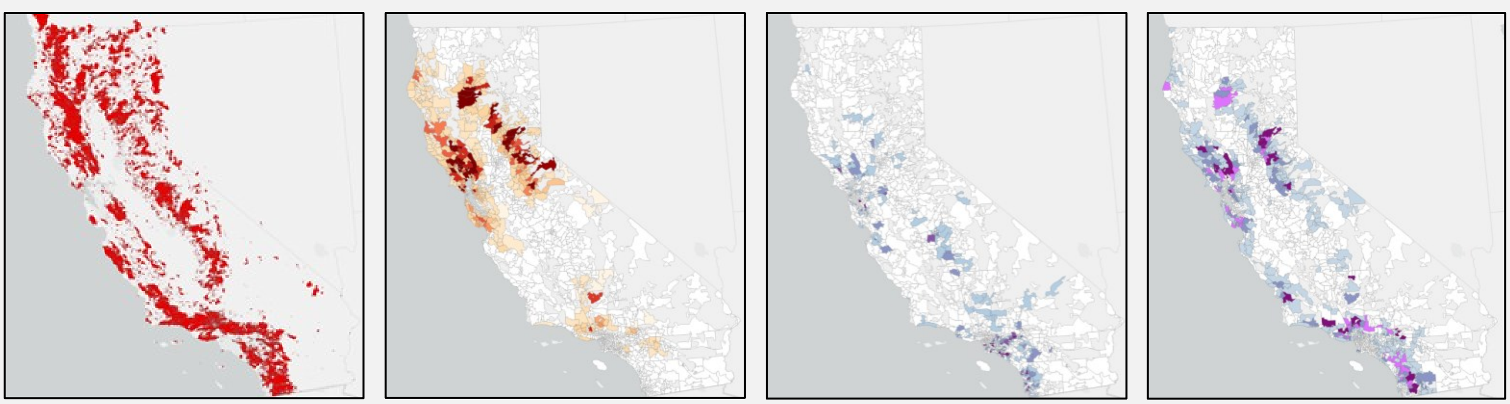
Customer Outage Mitigation Value

Customer outage mitigation is crucial component of resilient electricity service to meet essential loads and to protect vulnerable customers, communities, and critical facilities. On average around the country, sustained service interruptions to customers last about 1.5 hours at a time. Although this can vary widely across customers and circumstances, a typical customer can reasonably expect an hour or two of total outage time per year, possibly spread over multiple events.

Unfortunately, wildfire risks in the West have accelerated rapidly, revealing a complex relationship to electricity service and a strong dynamic of wildfire risks both to and from the grid. The IOUs have relied upon sustained day-long or multi-day outages to reduce ignition risks in the areas and times of the year with high risk of cascade into disastrous megafires. These Public Safety Power Shutoffs (PSPS) affect millions of people living or doing business in California, who can now reasonably expect multiple outages per year with each lasting several days at a time.

Our outage mitigation value estimates focus on these extended PSPS outages and impacts to customers. Energy storage (a) connected to either radial sections of the distribution grid or directly at customer sites, (b) co-located with a generation source such as solar PV, and (c) configured to operate during a grid outage hold the potential to mitigate the impact of extended outages lasting several hours or days. Standalone storage can also provide backup power during outage events, but for only a couple of hours unless they are significantly oversized.

In 2017–2021, customer outage mitigation value for SGIP installations was largely an untapped potential. In Figure 26 below, historical wildfire perimeters and PSPS areas compared to the distribution of nonresidential storage projects shows low spatial correlation. Recent storage projects funded under the SGIP Equity Resiliency budget are primarily installations that are paired with solar and concentrated in high wildfire threat areas. These projects however were not included in this study as they were mostly residential projects installed in 2021 and we could not access sufficient operational data.



Historical fire perimeters | Relative PSPS severity in total customer-hours | Distribution of nonresidential SGIP-funded storage installations | Distribution of storage + solar installations under SGIP Equity Resiliency budget

Figure 26: Comparison of various SGIP installations to wildfire threat areas.

To determine customer outage mitigation value, we first mapped nonresidential projects to the zip codes that experienced PSPS outages during the study period. We originally planned to track actual discharge and paired solar generation during outage events and estimate outage mitigation benefits at an assumed value of lost load. However, we later observed that the operational data during outage periods were incomplete and paired solar generation was also not included under the performance data collected from nonresidential energy storage projects. Given that, we adjusted our approach and focused on the "insurance value" of the projects against power service interruptions.

A key input to monetizing the outage mitigation benefits is the value of lost load (VOLL), which is typically linked to societal cost of outages. Although there are several studies and tools aimed at estimating VOLL, we found that there are currently no California-specific and statistically significant estimates of the cost of multi-hour and multi-day outages to customers available in the industry.

- A commonly cited LBNL/Nexant meta-analysis of 34 VOLL studies (Sullivan et al., 2015) focuses on short-duration outages lasting less than a day, and estimates average VOLL at $1–$3 per kWh for residential customers, $12–$22 per kWh for medium C&I customers, and >$200/kWh for small C&I customers (in 2013 dollars, for interruptions of 1–16 hours);
- Interruption Cost Estimate (ICE) Calculator also focuses on short-duration customer outages based on the LBNL/Nexant study and does not capture the full effects of long-duration (> 24 hours) outages;
- Under the microgrids proceeding, the CPUC's Resilience and Microgrids Working Group highlighted the Power Outage Economic Tool (POET) as a prototype extension of the ICE calculator, which is currently developed by LBNL in a pilot study for ComEd (Illinois), but it will be limited in its applicability to California until California customers are studied;
- A recent study in New England (Baik et al., 2020) found residential customers' stated willingness to pay at $1.7–$2.3/kWh in 2018 dollars to avoid a 10-day winter outage, but customer energy use and substitution options to meet essential needs (e.g., gas-fired heating) in New England are very different from California.

For our study, we assigned the outage costs for nonresidential customers at $30/kWh of essential load, which translates to $15/kWh of unserved load assuming half of customer's load is for essential activities. This value is similar to the interruption cost estimated in LBNL/Nexant study for medium and large C&I customers experiencing outages of 4–16 hours. For sizing, we assume essential load is equal to storage kWh. This is conservative because when paired with solar, the same storage system can support much larger levels of essential load. Figure 27 summarizes estimated outage mitigation values for nonresidential SGIP projects, averaged at cluster level. For projects paired with solar in PSPS areas, the average benefit is $16.1 per kW-month over the 5-year period. Standalone storage projects and projects outside of PSPS areas are assumed to have zero benefits. When they're included, the overall average benefit drops to $1.7/kW-month for the entire nonresidential SGIP portfolio.

SGIP Cluster ID	Total Energy Storage Capacity (MW)	Capacity Paired w/ Solar in PSPS Area (%)	Average Local Outages from PSPS (hrs/yr)	Average Outage Mitigation Value ($/kW-mo)	
				Paired w/ Solar in PSPS Area	All Energy Storage Projects
1	17.6	55%	47	$19.8	$11.6
2	9.1	25%	26	$12.6	$3.1
3	23.6	16%	41	$13.8	$3.4
4	60.6	3%	31	$13.5	$0.4
5	9.7	0%	-	-	$0.0
6	41.6	3%	50	$14.4	$0.4
7	43.0	7%	24	$10.7	$0.5
Total	**205.3**	**11%**	**40**	**$16.1**	**$1.7**

Figure 27: Estimated customer outage mitigation value of nonresidential SGIP projects by cluster (2022$).

Total Societal Benefits

Figure 28 shows the total benefits from a societal perspective for the 2017–2021 operating period. Top chart shows the aggregate benefits color coded by project group or cluster. Bottom chart shows stacking of individual benefit metrics. Most bars represent individual resources with their widths showing relative MW capacity. Customer-sited installations are aggregated into utility contracts or clusters.

The top-ranked resources provided $20–$35 per kW-month of average benefits over the 5-year period. These resources all participated in the CAISO wholesale markets and they did relatively well in stacking of energy, ancillary services, and RA capacity value. Many of them are distribution-connected projects that were procured to address various local RA and reliability needs.

Many of the recent large transmission-connected storage projects ranked in the middle, with higher focus on energy arbitrage and little/no ancillary services value. Their estimated RA capacity benefits were lower than the early projects procured for high-value local RA needs.

Customer-sited resources generally provided very low benefits due to lack of service to the transmission grid. However, one of the clusters of nonresidential SGIP projects provided relatively high resilience value by mitigating impacts of customer outages (shown in gray). Storage projects in this cluster are mostly paired with rooftop solar and located in areas that faced several Public Safety Power Shutoff (PSPS) events historically.

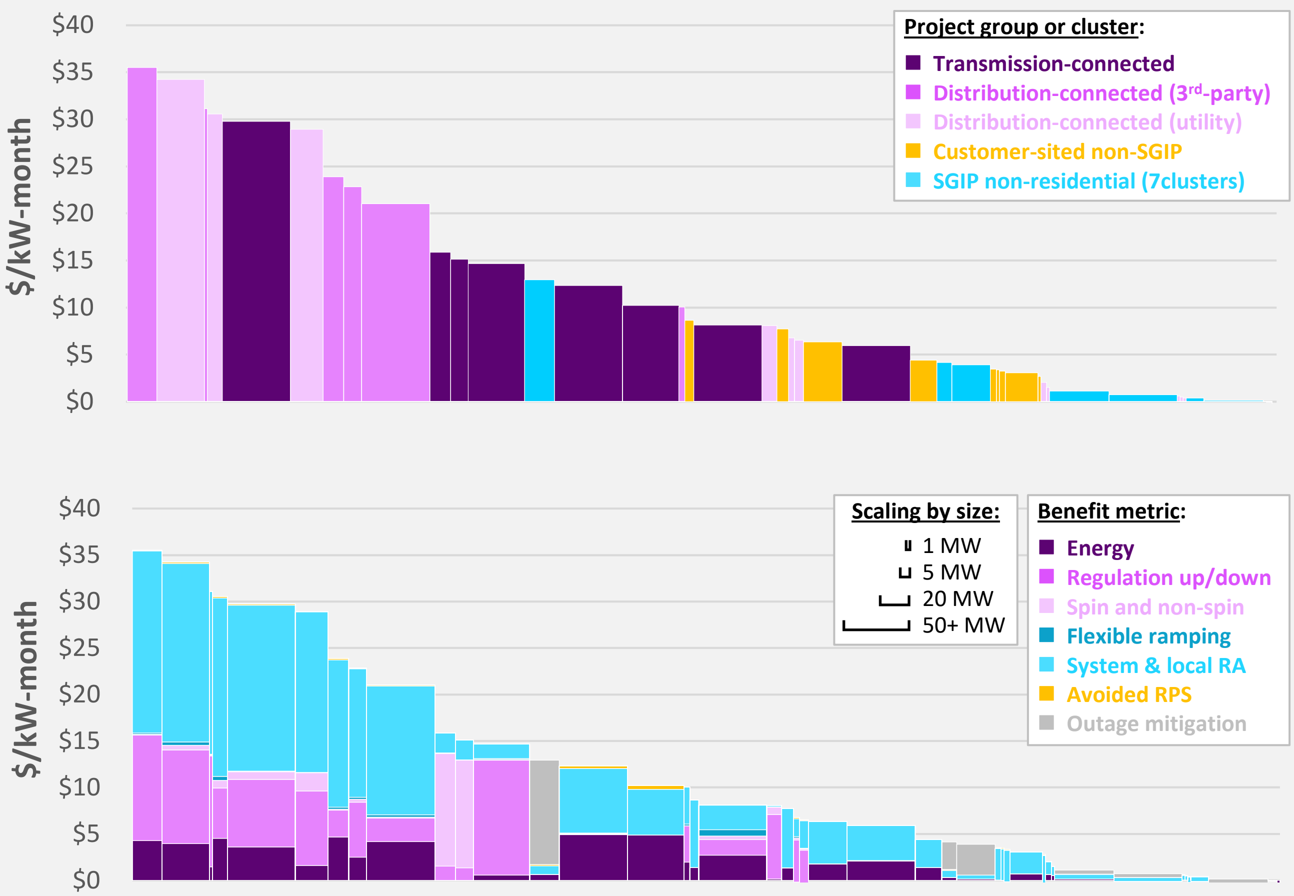


Figure 28: Summary of estimated societal benefits by project group (top) and benefit metric (bottom) (2022 $).

Utility-Owned Storage Costs

Utility-owned storage projects account for 110 MW of the storage capacity included in our evaluation, as shown earlier in Figure 3 of this attachment. Many of them are relatively small, distribution-connected pilot and demonstration projects installed prior to 2017.

Figure 29 below shows their installed cost by online date on the left, with bubble sizes proportional to project sizes ranging from 25 kW to 30 MW. This cost data is compiled based on research of utility applications and CPUC decisions on various procurement tracks, supplemented with information provided by the IOUs. Earlier small pilot and demonstration projects are at the top of the curve, with most of them at $6,000–$11,500/kW in 2022 dollars. More recent projects in 2017–2019 were installed at a lower cost in the range of $2,000–$4,500/kW except for couple projects with very short durations. The cost trends shown here reflect an early phase of the learning curve and costs are expected to decline further. Newer utility-owned projects to be installed in late 2021 and 2022 have an estimated cost of $1,300–$1,700/kW, but those projects are not included in our historical benefit/cost analysis.

To develop a cost metric that can be compared against average benefits, and across all storage projects, we levelized capital and operating costs of the projects using utility-specific cost of capital assumptions. For retired projects, we amortized their costs over their actual lives. For projects under long-term service agreements and warranties, we amortized their costs over 15-year life assuming these service agreements get extended. For all other projects, we assumed 10-year economic life. Figure 29 shows the resulting levelized costs in $/kW-month (right) of capital and O&M costs. For projects that received state and other 3rd-party funding, we only included costs incurred by the ratepayers, net of external funds. As shown, the estimated levelized cost of these utility-owned projects are very high compared to today's cost levels. Most early pilot and demonstration projects have a levelized cost of over $100/kW-month, which is more than 10x higher than current costs of utility-scale storage projects. This is partly due to high capital costs, but also partly driven by extremely high operating costs of these early projects installed prior to 2015. Larger projects installed more recently in 2017 have levelized costs in the range of $25–$40/kW-month, which is also relatively high reflecting the storage market of that time, coupled with the cost premium of expedited procurement needed to address local reliability issues caused by prolonged natural gas leak at Aliso Canyon.

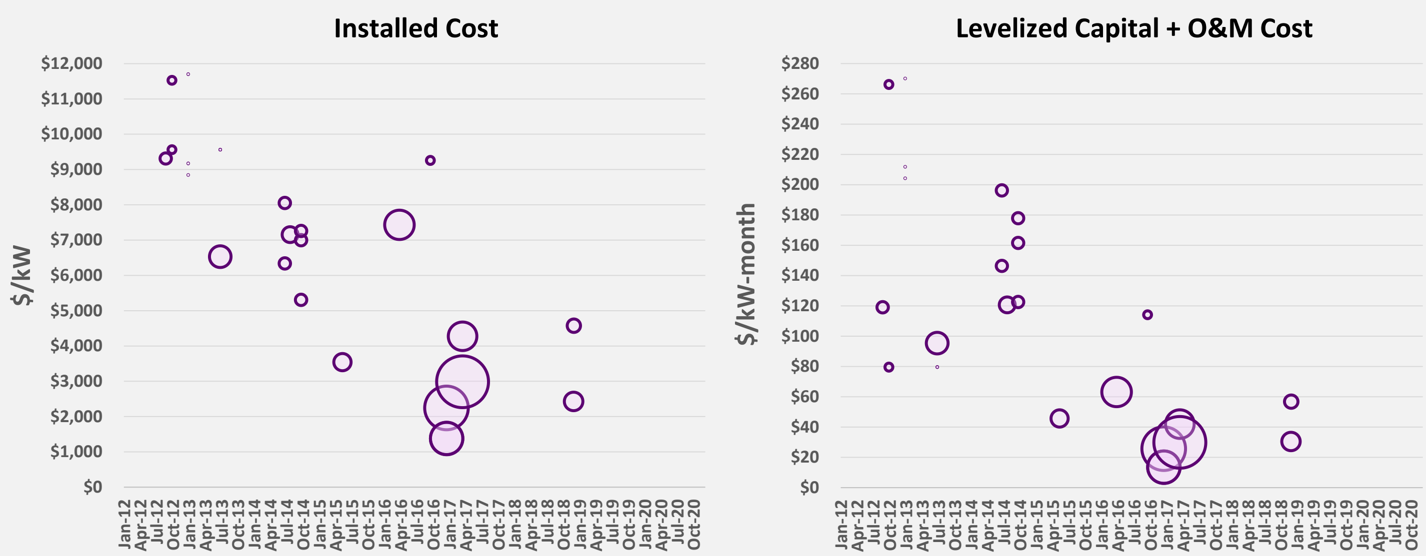


Figure 29: Cost of utility-owned storage projects included in the study (2022 $).

Third-Party Storage Contract Prices

While many of the initial pilot projects were utility-owned, a rapidly growing share of storage projects are procured under third-party contracts where the utility or load serving entity pays a contract price in exchange for the rights to the project's certain attributes. Most of the energy storage contracts executed by the California utilities have either a fixed flat price that remains constant over time or a price schedule escalating annually at a set rate.

Figure 30 below summarizes the energy storage contract prices for projects included in the study, with data aggregated by grid domain and type of contracts to preserve confidentiality. Overall, there is a wide range of prices depending on vintage, grid domain, procurement track, and project size. Earlier energy storage contracts were significantly more expensive across all grid domains, reflecting the high end of the ranges shown.

Recent contracts are predominantly with large transmission-connected energy storage projects, and they generally reflect the cost reductions seen in the storage industry. Among the operational transmission-connected projects included in the study, price was in the range of $6–$8 per kW-month for resource adequacy (RA) only contracts and $7–$22 per kW-month for all-in contracts where the utility gets all of the project's attributes for the contracted period. Many of the newer storage projects under development are contracted at $9–$14 per kW-month for all attributes, but those projects are not included in our historical benefit/cost analysis.

Under an RA only contract, the utility offtaker buys RA capacity and the third-party owner retains all other attributes. For example, they can participate in the CAISO energy and ancillary services markets and keep the associated revenues. This allows the owner of the project to offer project's capacity at a lower price point, relative to all-in contracts.

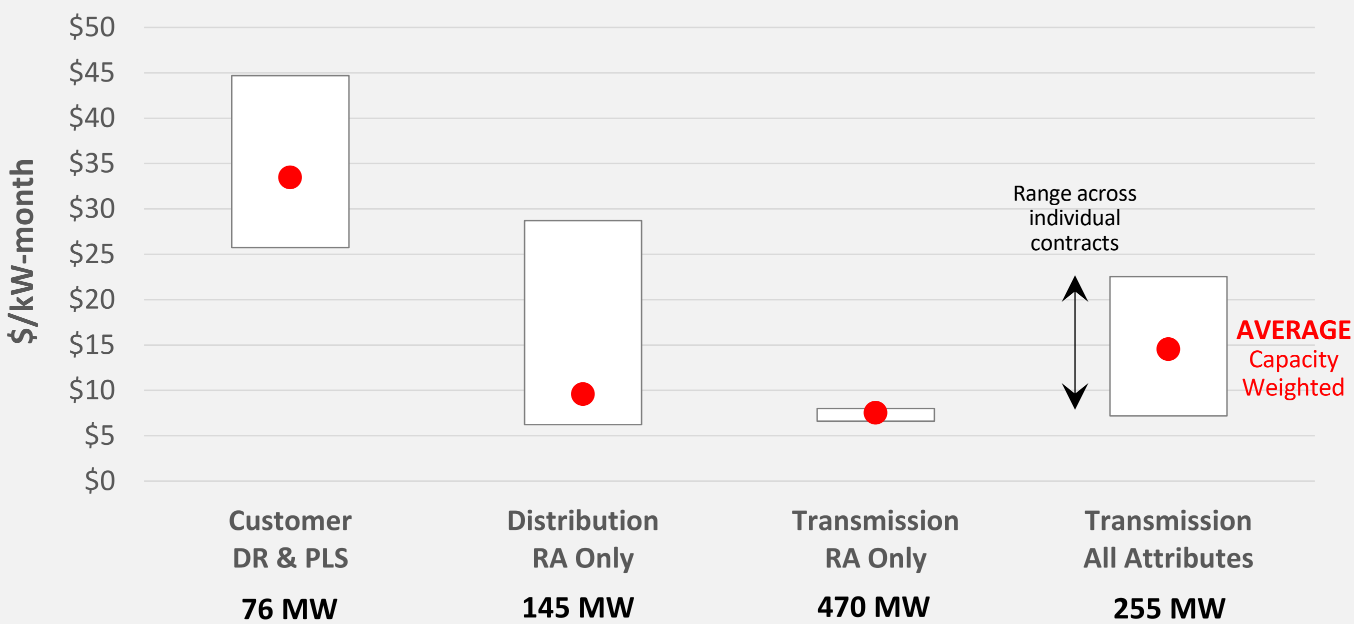


Figure 30: IOU third-party storage contract prices for storage projects included in the study (2022 $).

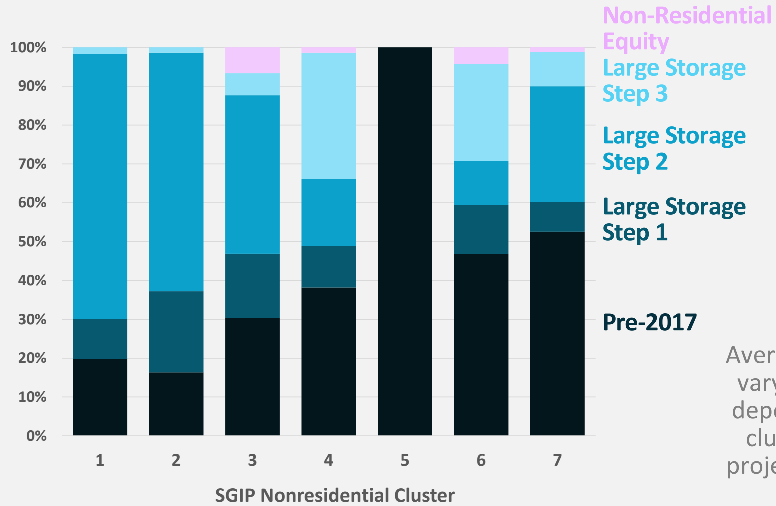
SGIP Project Incentive Payments

SGIP incentive payments are included as the ratepayer-funded portion of the costs for the SGIP storage projects in our study.

SGIP was established in 2001 to provide financial incentives for distributed generation. Standalone energy storage became eligible in 2011. Incentive levels for energy storage were initially set per kilowatt of capacity starting at $2,000/kW in 2011 and declining to $1,310/kW by 2016. The program went through a major transformation in 2016 and reallocated 75% of funding to energy storage, with incentive levels redefined per kilowatt-hour of capacity. Under the general budget, incentives are divided across five steps for large storage projects (> 10 kW), starting at $500/kWh in Step 1, declining to $250/kWh in Step 5. Most of the nonresidential SGIP-funded storage projects have only 2 hours of duration, as the incentives decline after the first 2 hours. For 2-hour storage projects, these incentives translate to $1,000/kW for Step 1, and $500/kW for Step 5. More recently, CPUC shifted focus to equity and customer resilience with increased budget and incentives for storage installations by lower-income, medically vulnerable customers who are in high fire-threat areas and at risk of outages due to utility Public Safety Power Shutoffs (PSPS) outages. The funds are also made available to critical facilities and infrastructure supporting community resilience in the event of PSPS or wildfire.

Figure 16 below (left) shows the mix of budget categories within each SGIP cluster we identified. Nearly all nonresidential SGIP projects with operational data for 2017–2021 were enrolled under program years prior to 2020, with incentives through Step 3. There are very few nonresidential projects enrolled under the equity budget (shown in pink) and no projects under the equity resilience budget.

The table in Figure 16 shows the capacity-weighted average incentive payments for each SGIP cluster, which varies from $750/kW to $2,174/kW (in 2022$) depending on the mix of projects by budget category. The table also shows the estimated levelized incentive costs in the range of $8–$25 per kW-month using utility-specific cost of capital assumptions and 10-year economic life.



Average incentives vary significantly depending on the clusters' mix of projects by budget category

Cluster ID	Average Incentive $/kW	Levelized Incentive $/kW-mo
1	$766	$9.3
2	$750	$8.1
3	$1,110	$16.1
4	$1,197	$17.7
5	$2,174	$25.4
6	$1,408	$21.0
7	$1,391	$19.1

Figure 31: Levelized incentive for nonresidential SGIP storage projects by cluster (2022 $).

Final Benefit-Cost Ratios

Figure 32 summarizes our ratepayer net benefit results for the 2017–2021 operating period, expressed as benefit/cost (B/C) ratios. The chart highlights the differences relative to a B/C ratio of 1.0, which indicates estimated benefits are equal to costs. About half of the analyzed storage capacity yielded more benefits than costs to ratepayers (B/C ratio above 1.0).Most bars on the chart represent an individual energy storage resource with the width of the bar showing relative MW capacity. Small customer-sited installations are aggregated into utility contracts or clusters with similar operational patterns. The bottom chart shows the underlying benefit and cost components. For storage under RA only contracts, energy and ancillary services values are not included as they are not ratepayer benefits. As explained earlier, there were no projects with T&D deferral benefits and the GHG reduction value is already reflected in energy value (no GHG adder). Avoided RPS costs were relatively small compared to core benefits from energy, ancillary services, and RA capacity.

Among all projects analyzed, top 3 of the third-party-owned distribution-connected resources performed particularly well compared to others. These resources provide high-value local resource adequacy (RA) capacity, and they participate in the CAISO marketplace. Transmission-connected resources and two utility-owned distribution-connected resources also performed relatively well, due to RA capacity service, participation in the CAISO marketplace for energy and ancillary services, and high efficiency achieved from daily operations. Customer-sited and some utility-owned distribution-connected resources performed the worst due to lack of service to the transmission grid and/or relatively high procurement costs. Low B/C ratio of these resources is not due to any inherent technological limitations. Rather, it reflects differences in use cases, priorities, and lack of access to grid signals that can be addressed by policy reforms.

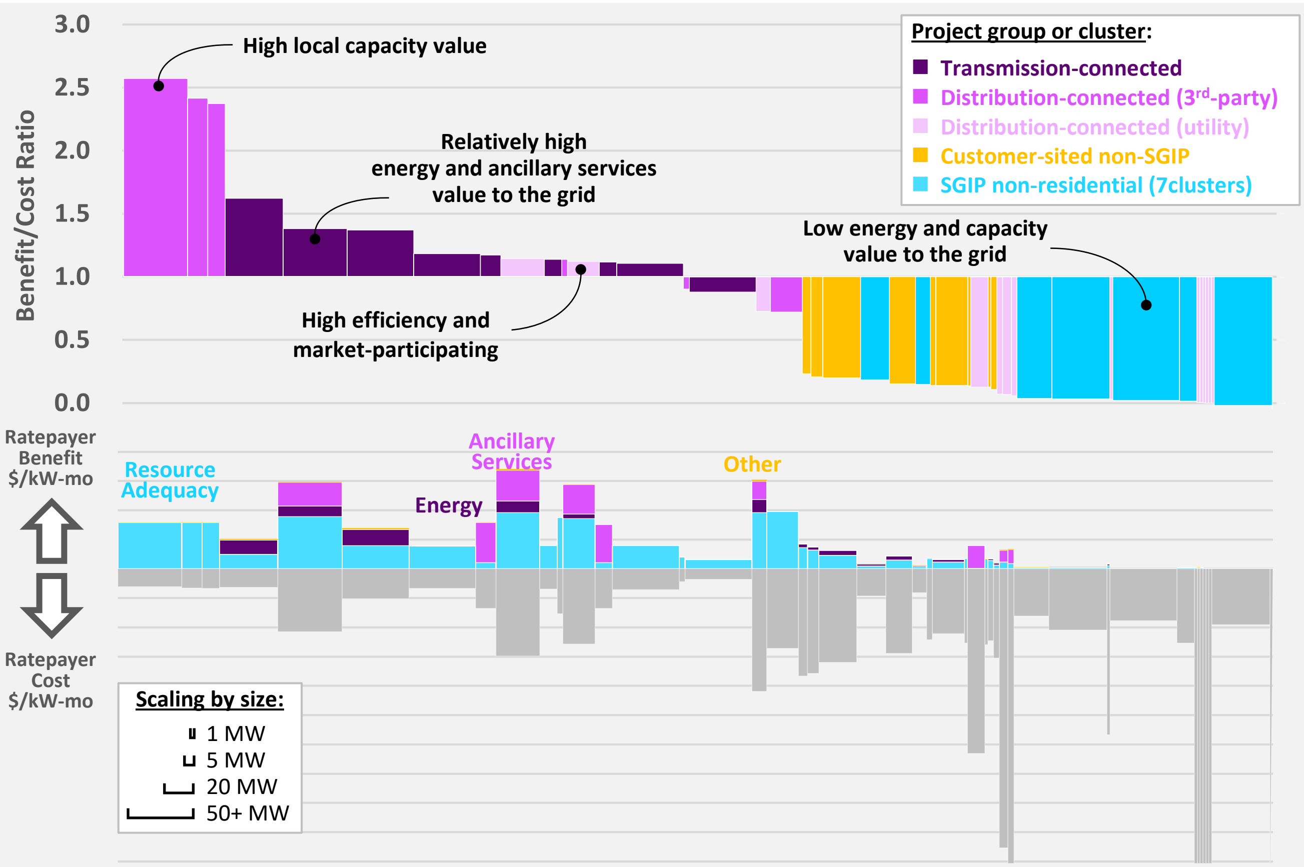


Figure 32: Summary of ratepayer benefit/cost ratio results (top) and underlying components (bottom).

Net Ratepayer Benefits over Time

In terms of absolute dollars, the benefit/cost ratios represent a portfolio-wide average of $72 million per year in net ratepayer cost over the 5-year study period. Exploratory pilots and incentive programs—including resources developed under pilots, demonstrations, SGIP, and/or first-in-kind procurement tracks—cost ratepayers an average $75 million per year. This is offset by $3 million per year net benefit from energy storage resources developed under mature use cases and procurement tracks. The $3 million per year is a diluted metric, which is derived from a total $16 million of benefits mostly incurred in 2021, but averaged over the entire 5-year study period.

The time profile of ratepayer impacts reveals three striking trends over time (Figure 33):

1. **Steady ongoing amortized investment cost of early utility-owned pilot and demonstration programs** (grey line) at almost $30 million per year;
2. **Steady buildup of net ratepayer cost of customer-sited installations** (yellow and turquoise lines) as the number of installations grow—due to lack of storage operations beneficial to the grid coupled with relatively high costs—reaching a rate of approximately $80 million per year by the end of 2021; and
3. **Recent growth in net ratepayer benefit of distribution- and transmission-connected storage installations** (magenta and purple lines) as the volume of capacity participating in the CAISO marketplace and providing local and system resource adequacy grows, landing at an annualized rate of $30 million per year by the end of 2021, which includes $22 million per year in net benefits produced by market-mature resources, plus $8 million from earlier market entrants.

These trends have key implications for future energy storage procurement and policy direction which we discuss in Chapter 3 of the main report (Moving Forward). The performance of more recent and market mature projects indicate an acceleration towards future growth in benefits. However, the net cost of earlier exploratory projects and incentive programs will continue at $89 million per year on average over their full amortization period.

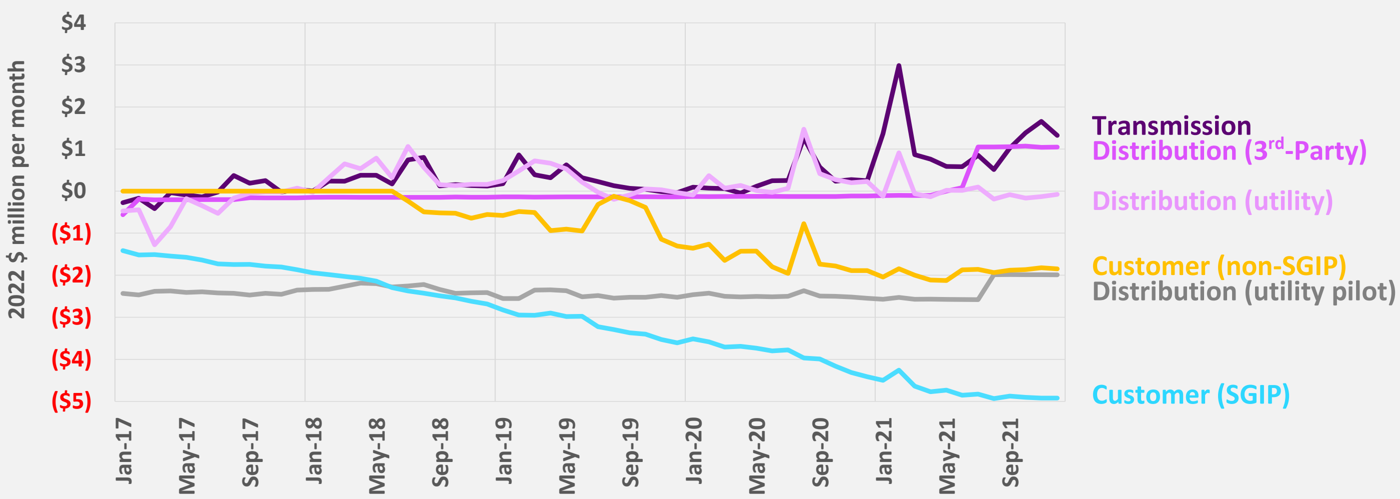


Figure 33: Net ratepayer benefits (costs) over time.

*Lump-sum capital costs or incentive payments are levelized over economic life of the projects.

Project Scoring towards State Goals

The CPUC decision D.13-10-040, which set the AB 2514 energy storage procurement target of 1,325 MW, identified 3 overarching policy goals:

- Grid optimization,
- Integration of renewable energy, and
- Reduction of greenhouse gas (GHG) emissions

A key objective of our study is to determine if the energy storage procurement meets these policy goals. We do this by developing scorecards for each project based on their operations during the 5-year period in 2017–2021.

Figure 34 below shows the list of services and associated benefits considered in our study. Our approach to scoring involves several steps, as summarized 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 emission reduction.

Contribution towards AB 2514 Goals

	Grid Optimization	Renewables Integration	GHG Emission Reduction
Energy time-shift	✓	indirect	indirect
Ancillary services	✓	✓	indirect
Resource adequacy (RA) capacity	✓		indirect
Transmission investment deferral	✓		
Distribution investment deferral	✓		
Avoided renewable curtailments		✓	indirect
GHG emission reduction			✓
Customer outage mitigation	✓		

Figure 34: Benefit metrics considered in the study and contribution to AB 2514 goals.

Scoring for Grid Optimization Impacts

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

For each service, we developed an individual score based on utilization of projects' capacity towards providing that service, as described below:

- Energy time-shift score based on average daily energy discharge duration;
- Ancillary services score based on average ancillary services provided as a % of nameplate MW;
- RA capacity score based on RA capacity credit as a % of nameplate MW, with a 1.5x multiplier if procured under a specific LCR track and 1.25x multiplier if in a local capacity area but not procured for LCR;
- Transmission deferral score is set to zero for all resources as there were no actual transmission investments deferred during the study period;
- Distribution deferral score is set to zero for all resources as there were no actual distribution investments deferred during the study period;
- Customer outage mitigation score is set to 100 for distribution-connected storage resources with microgrid capability and customer-sited storage resources that are paired with solar and located in areas that have experienced PSPS outages during the study period. For SGIP-funded storage, calculated a cluster-level score that reflects the average of individual scores for projects within that cluster.

The overall grid optimization score is calculated as the average of individual scores for the services above. The results are shown in Figure 35 below.

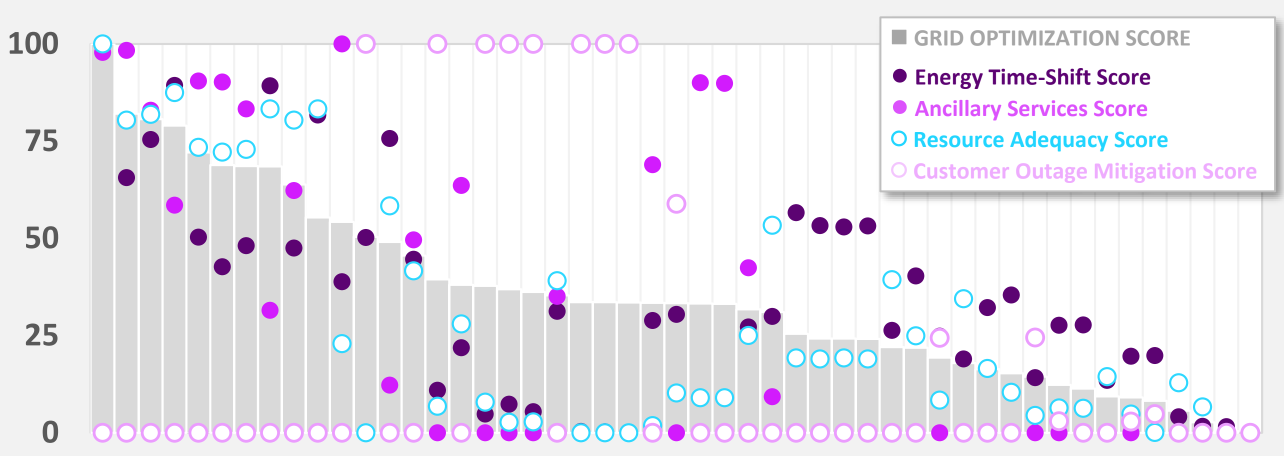


Figure 35: Grid optimization scores by project.

Scoring for Renewables Integration Impacts

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, storage projects can enable renewable integration by charging when the system has oversupply to reduce the excess renewable energy that would otherwise get curtailed. Associated renewable curtailment impacts are calculated based on the analysis described to estimate avoided RPS costs as described earlier (see Figure 21). The associated scoring is normalized between 100 for the project with the highest avoided renewable curtailments and 0 for all resources that had increased curtailments.

- By providing ancillary services, storage projects help with meeting the flexibility needs to address increased variability and uncertainty of the net load driven by renewable generation. The ancillary services score is calculated as described under grid optimization section, based on average ancillary services provided as a % of nameplate MW.

The overall renewable integration score is calculated as the average of the scores for avoided renewable curtailments and ancillary services. The results are shown in Figure 36 below.

As discussed earlier in the report, many of the CAISO-participating energy storage projects focused on ancillary services over the study period 2017–2021. These projects scored relatively high in terms of their contribution to renewables integration goal. Top-ranked projects were able to provide modest levels of renewable curtailment reduction via bulk energy time-shift, stacked with high-value ancillary services in the CAISO market.

Distribution-connected storage projects that did not participate in the CAISO market, and customer-sited projects (both CAISO and non-CAISO) ranked at the bottom with very low scores as they did not provide any ancillary services and their charging were not aligned well with renewable oversupply.

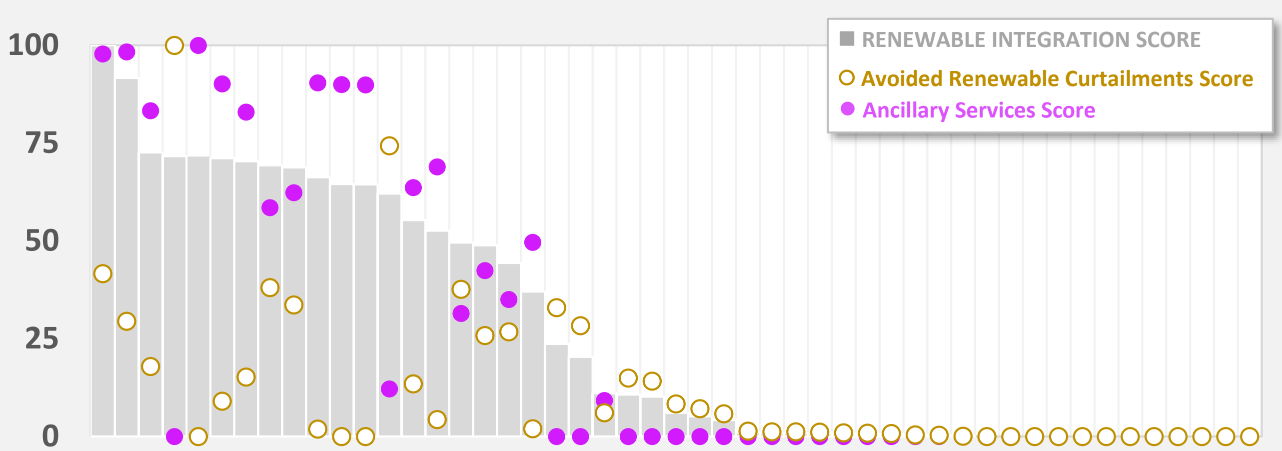


Figure 36: Renewable integration scores by project.

Scoring for GHG Emission Impacts

Energy storage use cases and the associated charge and discharge patterns impact the GHG emissions on the electric system. As described earlier in this report, we estimate net GHG emission impact of the energy storage resources based on their actual energy output multiplied by historical marginal GHG emission rate at the sub-hourly interval level and added up over the study period. Energy storage reduces emissions at the marginal rate when discharging, and it increases emissions at the marginal rate when charging. The results are shown in Figure 23.

As previously discussed, for energy storage resources to provide GHG reduction benefits, (a) they need to be highly efficient, and (b) their use cases should allow shifting bulk energy from periods with low GHG intensity to periods with high GHG intensity.

- The storage projects with the highest GHG emission reductions participated in the CAISO market and focused more on energy arbitrage, less on ancillary services. Projects with high ancillary services focus contributed to a net increase in GHG emissions as their charge/discharge patterns were uncorrelated with the GHG intensity of the system. With 10–15% average losses over time, they created more emissions when charging relative to emissions they avoided when discharging, which led to a net increase of GHG emissions.
- The GHG impacts of nonresidential SGIP projects vary by cluster. Clusters 1–3 reduced GHG emissions primarily by projects paired with solar PV and installed at schools, while clusters 4–7 contributed to higher GHG emissions as their use cases focused on demand charge management and did not align well with GHG reduction goals of the program.
- Other storage projects that did not participate in CAISO marketplace were mostly underutilized and they were often on extended periods of standby, which translated to low operational efficiency and resulted in marginal increases in GHG emissions.

The overall GHG emission reduction score is normalized between 100 for the project with the highest GHG emission reductions and 0 for all resources that had increased GHG emissions. The results are shown in Figure 37 below.

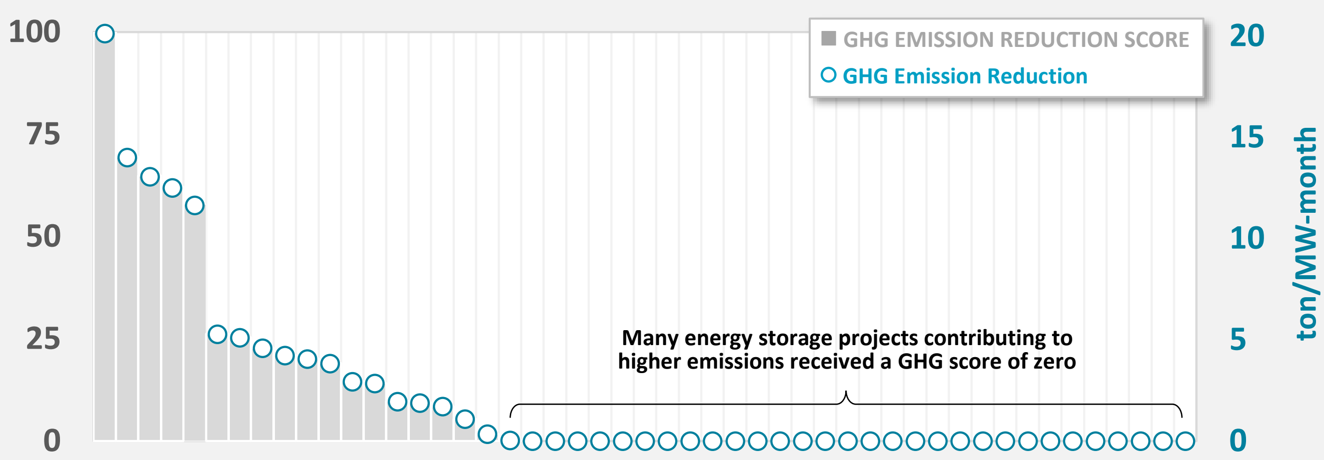


Figure 37: GHG emission reduction scores by project.

Final Project Scores

Figure 38 summarizes project scores on contributions towards meeting state goals of grid optimization, renewables integration, and GHG emissions reductions during the 2017–2021 study period.

Most bars represent individual resources with their widths showing relative MW capacity. Customer-sited installations are aggregated into utility contracts or clusters. Final score (height of bar) is an average of 3 individual scores for grid optimization, renewables integration, and GHG emission reduction normalized between 0 (worst performance) and 100 (best performance) in each category.

As with our benefit/cost analysis results, third-party-owned distribution- and transmission-connected resources performed relatively well while customer-sited resources performed at the bottom. Three key findings highlight the importance of taking this more societal perspective and considering contributions to meeting state goals beyond what can be monetized in benefit/cost metrics:

- Many distribution-connected resources demonstrate relatively high utilization across multiple grid services and significant reductions in local renewable curtailments—despite not capturing the highest market values as reflected in their B/C ratios;
- Transmission-connected resources that rank lower here than in benefit/cost ratios provide fewer types of services compared to their peers (e.g., narrow ancillary services focus, low RA capacity) or have extended outages limiting their overall performance.
- Resources that provide negligible GHG emissions reductions or increase GHG emissions are given a score of zero in that category. Several resources did not contribute towards the state's GHG emissions reductions goals. Likewise, several resources did not contribute meaningfully to renewables integration.

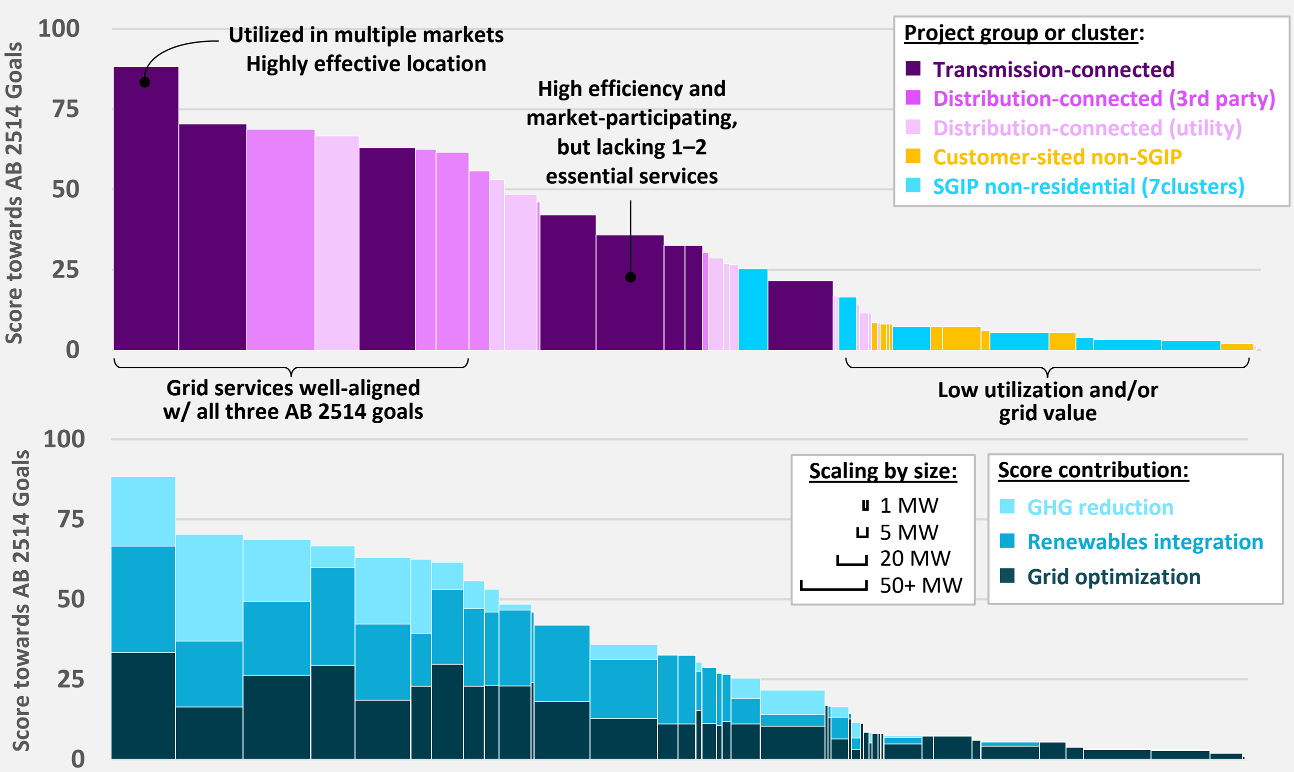


Figure 38: Final project scores towards state goals (top) and underlying components (bottom).