ATTACHMENT C: COST-EFFECTIVENESS OF PEAKER REPLACEMENT[1]

This attachment provides details on the special study of the replacement of gas peakers in California with energy storage.

California currently has about 100 operating gas-fired peaking units with a total capacity of 10 GW on the system. These peaking units are needed mainly for reliability. They are far less efficient than other generators, so they tend to run in fewer hours only when peaking capacity is needed and/or when market prices are sufficiently high. Despite their low utilization, gas peakers are often responsible for significant amounts of GHG and air pollutant emissions because of their low efficiency, and their start/stop cycles are typically more emission intensive. Energy storage has the potential to mitigate adverse environmental impacts of the gas peakers by replacing parts or all of their output, while providing similar levels of capacity. California already demonstrated this as a viable use case by procuring several energy storage projects to address local capacity needs created by retirement of conventional plants, to eliminate the need for reliability must-run (RMR) contracts with existing gas plants, and to replace construction of a new gas peaker needed for local reliability.

In this study, we screen the cost-effectiveness of individual natural gas peaker units' replacement with energy storage under the challenging system conditions observed in 2020. We test alternative storage configurations, with respect to duration levels and whether they are developed on a standalone basis or paired with solar PV.

CONTENTS

Study Approach and Analytical Framework

Our approach to evaluating cost-effectiveness of replacing gas-fired peaking units in California with energy storage is summarized below:

1. **Collect peaker data:** Compile historical hourly generation and emission profiles for all gas-fired peaker units in California. Use 2020 as the "base year" during which there were significant system-level supply shortages.
2. **Analyze replacement scenario:** For each unit, use energy storage dispatch model to determine minimum level of storage capacity that can displace all of unit's historical generation. Optimize storage charge and discharge decisions to replace 100% of the peaker output while also maximizing market revenues under perfect foresight of nodal prices.
3. **Test alternative storage duration levels:** Run the peaker replacement analysis described above for storage with 4, 6, 8, and 10 hours of duration.
4. **Analyze costs and benefits:** For the smallest storage configurations identified above, estimate levelized costs and net market revenues, and compare incremental net costs across various energy storage duration levels and against going-forward cost of peakers.
5. **Analyze solar + storage sensitivity:** Re-run Steps 2–4 with a solar plus storage configuration.

The goal of the study is to develop an *indicative* unit-by-unit assessment of the economic feasibility of replacing peaker generation based on their operations under historical system conditions. We selected 2020 as it was an extreme year with severe heat waves and multiple grid emergency events. A similar approach can be used with forward-looking data inputs. But estimating real-time needs and operations of gas peakers under future market scenarios is a significant undertaking and left outside the scope of the study.

The study assumes historical output of individual peak units in 2020 is a reasonable approximation of the reliability needs met by those units. While we review and benchmark results against recent reliability and transmission studies by the CAISO, we do not include a power flow modeling or detailed assessment of reliability and resource adequacy needs in this study.

Data Collection on Peaker Operations and Emission Profiles

We compiled the unit-level hourly generation and emission profiles of peakers based on EPA's Continuous Emissions Monitoring Systems (CEMS) data using their Air Markets Program (AMPD) tool. The final unit list includes all of the gas-fired combustion and steam turbines in the CAISO system. We matched the unit list against CAISO resource list and EIA Form 923 data to make sure units that are part of combined cycle, combined heat and power (CHP) or cogeneration systems are not considered.

We identified 97 peaking units with a capacity adding up to 10 GW in total. Most of these units are located in CAISO-designated local capacity areas and over 75% of their installed capacity is in southern California. Figure 1 below shows the breakdown of peakers capacity analyzed by area and corresponding generation and emission levels based on 2020 CEMS data. In total, gas peakers generated 5.7 million MWh of total energy in 2020 at a capacity factor of 6.6% on average. They were responsible for almost 3 million tons of CO_2 emissions, which accounted for over 8% of total emissions from power plants in the CAISO footprint (even though they generated only 3.5% of total). Figure 2 shows the aggregate hourly generation profile, with highest output in August–September 2020 during extreme heat wave.

Utility Area	Local Capacity Area	Unit Count (#)	Unit Capacity (MW)	Total Generation (MWh)	Capacity Factor (%)	CO_2 Emissions Total (metric tons)	CO_2 Emissions Avg (ton/MWh)	NO_X Emissions Total (lbs)	NO_X Emissions Avg (lbs/MWh)
PG&E	Humboldt	0	0	-	-	-	-	-	-
PG&E	North Coast/North Bay	0	0	-	-	-	-	-	-
PG&E	Sierra	2	97	70,649	8.3%	33,322	0.47	45,082	0.64
PG&E	Stockton	0	0	-	-	-	-	-	-
PG&E	Greater Bay	15	1,281	546,657	4.9%	288,380	0.53	60,053	0.11
PG&E	Greater Fresno	9	437	140,617	3.7%	66,494	0.47	18,167	0.13
PG&E	Kern	0	0	-	-	-	-	-	-
SCE	Big Creek/Ventura	4	1,587	792,155	5.7%	406,514	0.51	58,541	0.07
SCE	LA Basin	40	4,526	2,705,766	6.8%	1,468,999	0.54	313,015	0.12
SDG&E	San Diego/Imperial Valley	21	1,418	816,610	6.6%	406,303	0.50	76,519	0.09
	CAISO System	6	493	682,661	15.8%	295,738	0.43	61,670	0.09
	TOTAL	**97**	**9,839**	**5,755,115**	**6.7%**	**2,965,750**	**0.52**	**633,046**	**0.11**

Figure 1: Summary of peaker capacity analyzed and their 2020 generation and emission levels

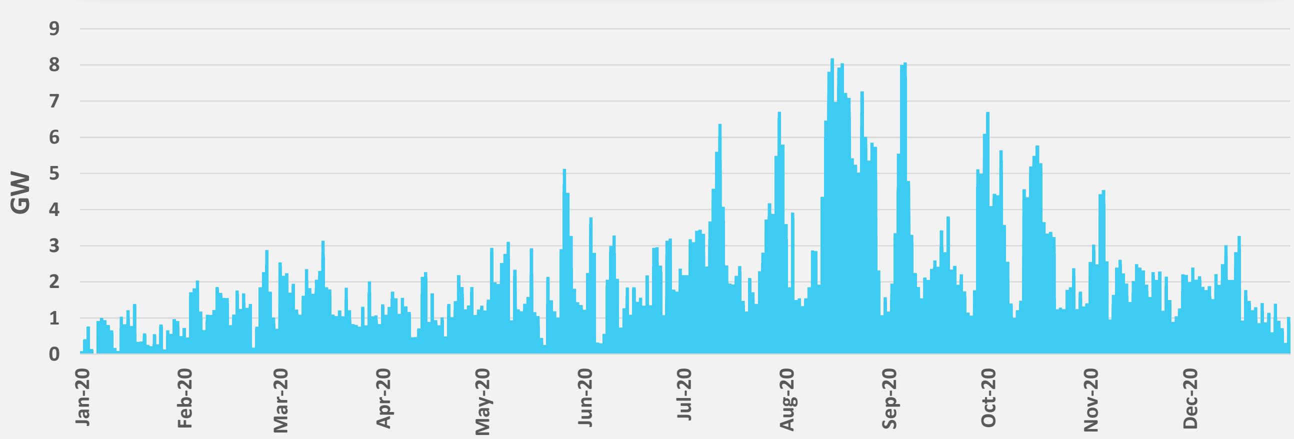
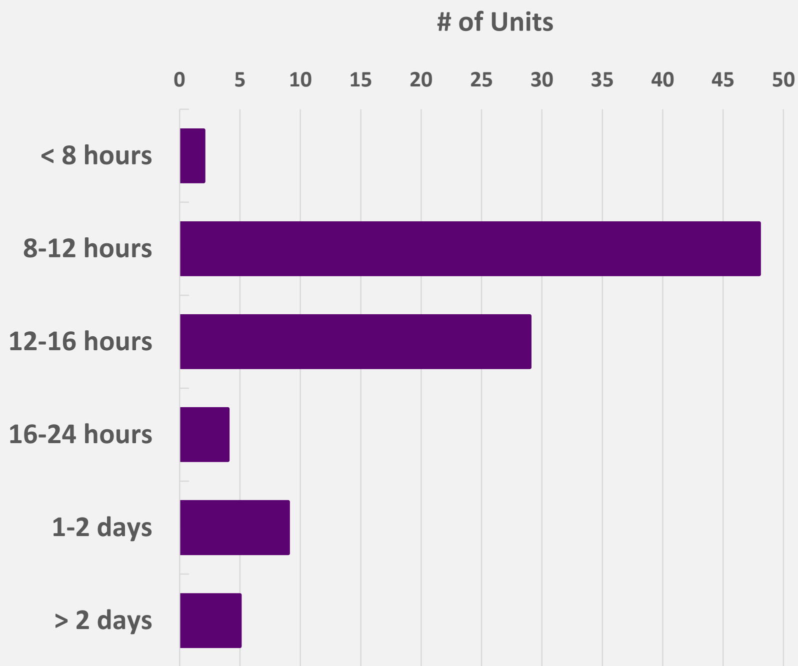


Figure 2: Aggregate hourly 2020 generation profile for the CAISO peaking units.



* Runtime is calculated as unit's cumulative energy output in a cycle divided by Pmax, rather than simply counting the hours in that cycle. This is to reflect duration need at full capacity. Periods when a unit operates below 30% of Pmax are excluded.

Figure 3: Distribution of peakers' maximum continuous runtime in 2020.

Figure 3 shows that most of the peaking units in California had at least one cycle during which they ran for 8 hours or more consecutively during 2020. We excluded the periods when a peaker operates below 30% of its capacity assuming that the unit is running during that time due to operational inflexibilities (such as minimum uptime) rather than a system reliability need. Applying this threshold effected only steam turbines that cannot turn on and off quickly.

Overall, 77 out of the 97 peakers analyzed had a runtime of 8–16 hours and 18 units had it above 16 hours. Only 2 units had a maximum runtime under 8 hours.

Peaker runtimes shown here impacts the minimum amount of storage capacity needed for replacement. For instance, If a 100 MW peaker has a maximum runtime of 10 hours at full load, it generates 1,000 MWh of energy during that cycle. Accordingly, at least 1,000 MWh of storage capacity would be needed to replace the peaker's output, assuming time between peaker's operating cycles are sufficient for a full recharge. Storage can be configured with different duration levels to meet the same 1,000 MWh need. If sized to match the MW capacity of the peaker, it would be a 100 MW storage with 10-hour duration. Alternatively, if the system has enough transmission capacity to interconnect larger MW, it can be sized at 250 MW with only 4-hour duration. Even though both configurations can replace the peaker's output in this example, their cost function and stacked value can be very different and need to be considered to determine which option is more cost effective.

Energy Storage Dispatch Analysis

For each peaking unit, we use Lumen's energy storage dispatch tool to determine minimum level of storage capacity that can displace all of unit's historical generation. The dispatch tool solves for minimum storage MW for a set duration level and optimizes charge and discharge decisions to replace 100% of the peaker output except when peaker operates at min load, while also maximizing market revenues under perfect foresight of nodal prices. We assume storage resources to have a roundtrip efficiency of 85% and apply an average of 1 cycle/day limit over the course of a year simulated.

The study considers four storage duration levels (4-, 6-, 8- and 10-hour) for the replacement of each peaker. Figure 4 shows a weekly snapshot of results for an actual case similar to the example described earlier. In this case, model evaluates replacement of a 100 MW peaker and finds that the smallest storage configuration to be 100 MW with 10-hour duration and 250 MW with 4-hour duration. While the primary goal is the replace the peaker's output (shown in red), storage also responds to LMP signals to stack energy revenue. For the week starting August 17, 2020, the 10-hour storage (shown in blue) charges from midnight to late morning at an average cost of $32/MWh and discharges in the afternoons and evenings at an average price of $94/MWh, which results in net market revenue of $393,000. The 4-hour storage (shown in pink) is much more flexible to take advantage of intraday price volatility, and charges at a lower average cost of $28/MWh and discharges during top-priced hours at an average price of $114/MWh, with a net market revenue of $577,000 for the same 7-day period.

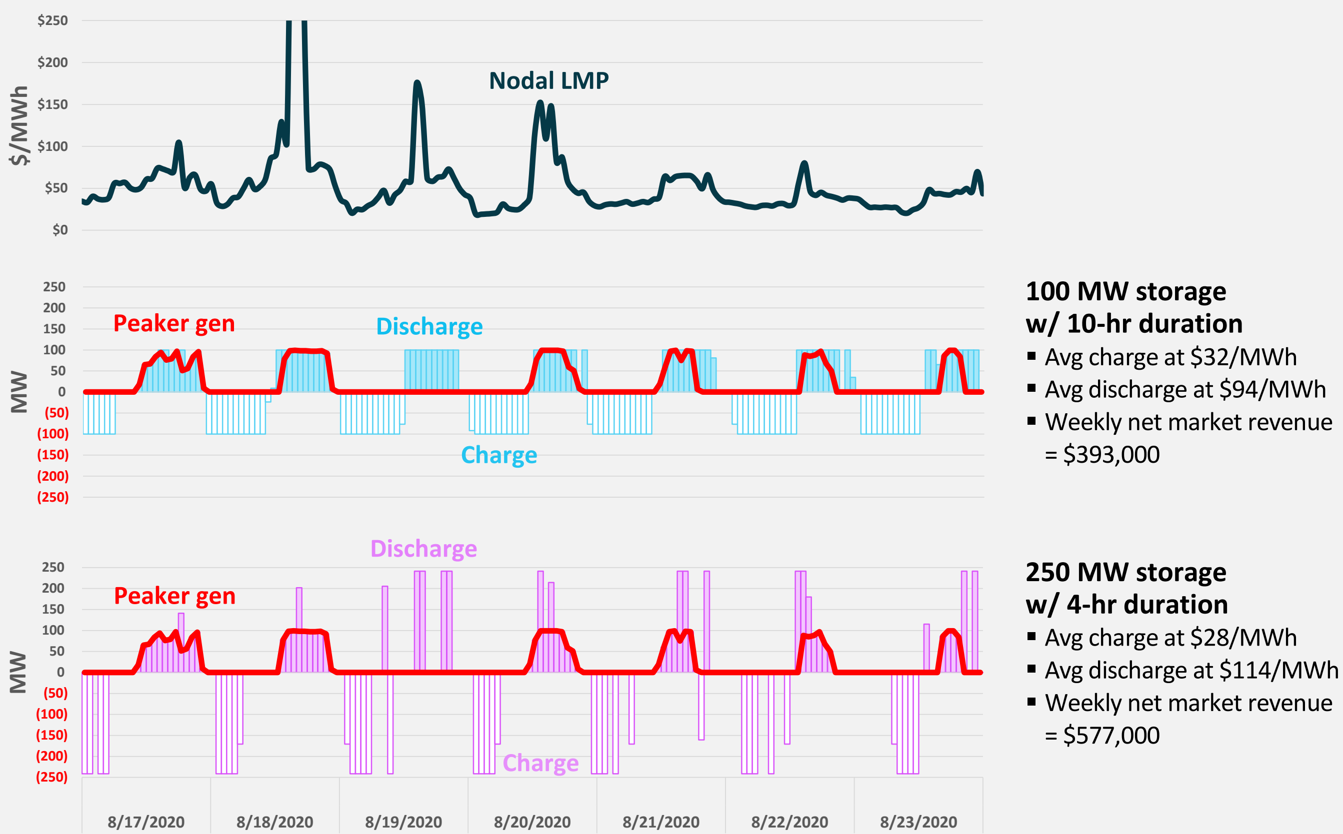


Figure 4: Illustration of optimized storage dispatch to replace peaker output and maximize energy revenues.

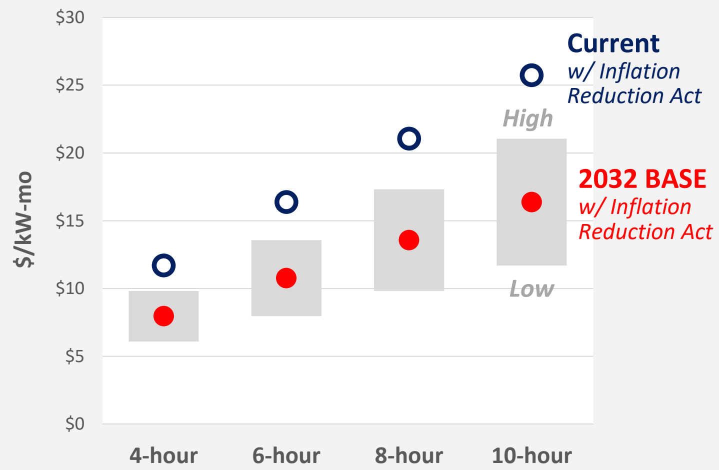
Net Replacement Cost

To determine cost effectiveness of the replacement scenarios, we estimate levelized costs and net market revenues for the smallest storage configurations identified at the unit level and compare incremental net costs across various energy storage duration levels and against going-forward cost of peakers.

For storage cost, we use the same assumptions developed for our study on cost-effectiveness of future storage in California; see Attachment B (Cost-Effectiveness of Future Procurement).

While our study approach is technology-neutral, we simulate energy storage operations and analyze value utilizing cost and performance assumptions based on lithium-ion batteries as they are the dominant technology accounting for most of the new energy storage capacity procured in California today.

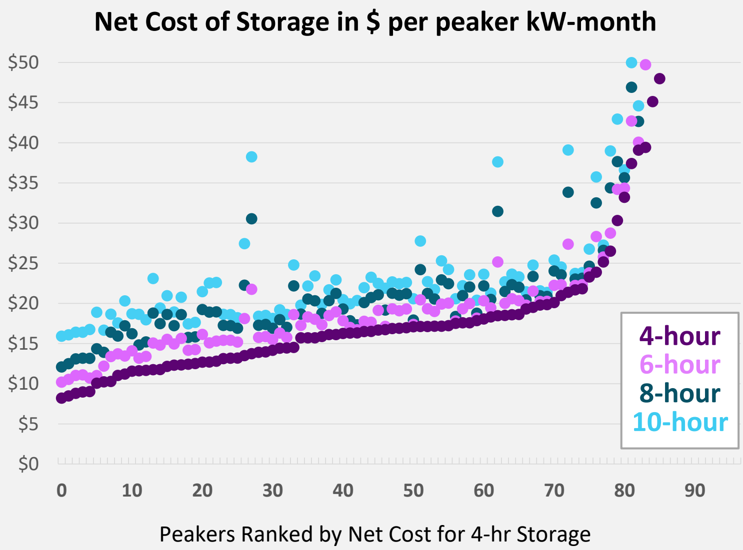
Figure 5 shows estimated levelized cost of storage expressed in $/kW-month (2022 dollars) including only capital and O&M costs. We consider charging costs when we estimate net energy market value of storage.



* Level-real values in 2022 dollars escalating by inflation over time. Includes amortized capex and O&M costs including augmentation and battery replacement. Excludes charging costs.

Figure 5: Estimated levelized storage cost by duration.

We estimate net cost based on levelized capital and O&M cost *minus* energy value, normalized for the peaker's capacity replaced. The final metric is in $ per peaker kW-month, which can be compared across alternative storage durations analyzed and benchmarked against going-forward cost of the peakers considered for replacement. Figure 6 shows results assuming storage cost at current levels.



- 4-hour storage has lower net cost than longer durations, because its energy value more than offsets cost of overbuilding MW capacity
- But overall net cost level above $10/kW-month is relatively high compared to peaker to-go costs

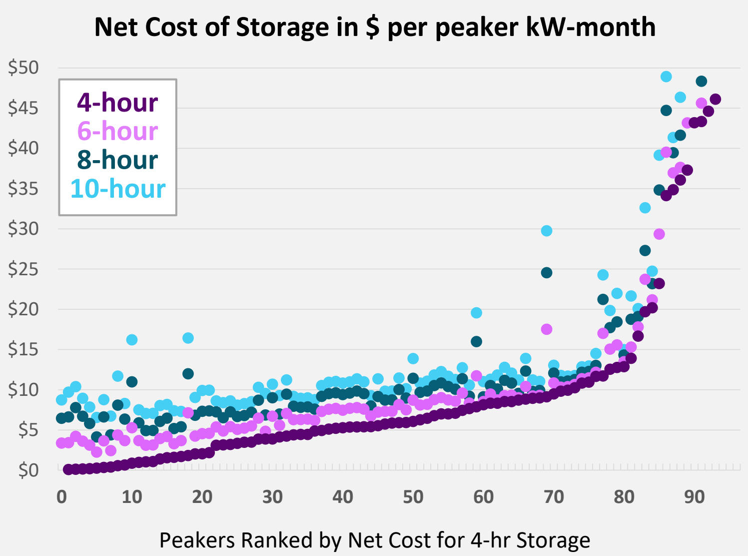
Figure 6: Estimated net cost of replacing peakers with standalone storage (current costs scenario).

The results suggest relatively high net cost levels above $10/kW-month because the options for replacing most peakers involve either significantly overbuilding storage MW or installing a storage configured to provide longer durations.

For the grid-scale battery systems, most of the installed costs are driven by energy-related costs such as cost of battery packs. As a result, building the same amount of energy capacity in MWh with a 4-hour duration costs only slightly more expensive compared to a configuration with longer duration. For example, we estimate the current levelized cost of 4-hour storage at $12/kW-month and 10-hour storage at over $25/kW-month (in 2022 dollars). At these cost levels, a 250 MW storage with 4-hour duration would cost $35 million/year, which is about 13% higher than a 100 MW storage with 10-hour duration at $31 million/year. Under historical prices analyzed, this cost differential would be more than offset by the incremental energy value that 4-hour storage can get by charging at lower-priced hours and discharging at higher-priced hours.

We ran a sensitivity case with approximately 40% lower storage costs, corresponding to the 2032 base case cost assumptions we developed for the study on value of future storage. With the assumed cost reductions, estimated net replacement cost drops under $8 per kW-month for 60 out of the 97 peakers. The results show 4-hour storage would still be more cost effective than storage modeled with longer durations, due to higher energy value they capture.

As discussed earlier, this study relies on analysis of peaker operations and market conditions in 2020 and effects of future market changes are not modeled. **Attachment B (Cost-Effectiveness of Future Procurement)** presents the findings of a separate study on value of future storage in California and show that increased renewables and upcoming retirements will increase energy time-shift value of today's storage, but marginal value decline as more storage is added. The study finds that "crossover point" for cost-effective long-duration storage (8-10 hour) is in sight over the next 5-10 years, but timing and magnitude of the need is highly uncertain and sensitive to ELCC modeling assumptions. Although the underlying study focuses on broad system-level benefits, we expect to see similar future trends in the local areas depending on relative levels of solar and storage added within the constrained zones.



- With assumed storage cost reductions, net cost of peaker replacement drops under $8 per kW-month for over half of units analyzed
- 4-hour storage still looks more cost effective than longer duration alternatives, absent interconnection limitations

Figure 7: Estimated net cost of replacing peakers with standalone storage (2032 base case cost scenario).

Solar + Storage Sensitivity

Pairing solar and storage can reduce the need for overbuilding MW or installing long-duration storage to replace the peaking units. There has been a growing interest in developing co-located solar + storage projects in California driven by cost synergies and tax incentives. One of the key benefits of pairing solar with storage is to achieve cost savings from shared infrastructure and interconnection. Until recently, only energy storage co-located with solar could get the federal investment tax credits (ITC) of up to 30%, which is now extended to stand-alone storage under the Inflation Reduction Act (IRA) of 2022. Although these cost savings and tax benefits reduce installed cost of the projects relative to stand-alone development, they also reduce the value due to additional operating constraints and interconnection limits.

For this sensitivity case, co-located solar resource and total grid interconnection capacity are both sized to match the nameplate MW capacity of storage. Storage is allowed to be charged only from solar output (no grid charging). Hourly profiles of the solar resources are based on actual 2020 zonal solar generation output. Figure 8 below illustrates how pairing solar and storage affects the results relative to standalone storage. Top 2 charts are from Figure 4, showing nodal LMPs and optimized dispatch of the 250 MW storage needed to replace a 100 MW peaker. The bottom chart shows the results under the solar + storage sensitivity. Because the paired solar also displaces some of the peaker's output, only 165 MW of storage capacity is needed, instead of 250 MW. Storage responds to market signals to maximize revenue, but total output is capped the interconnection limit and grid charging is not allowed.

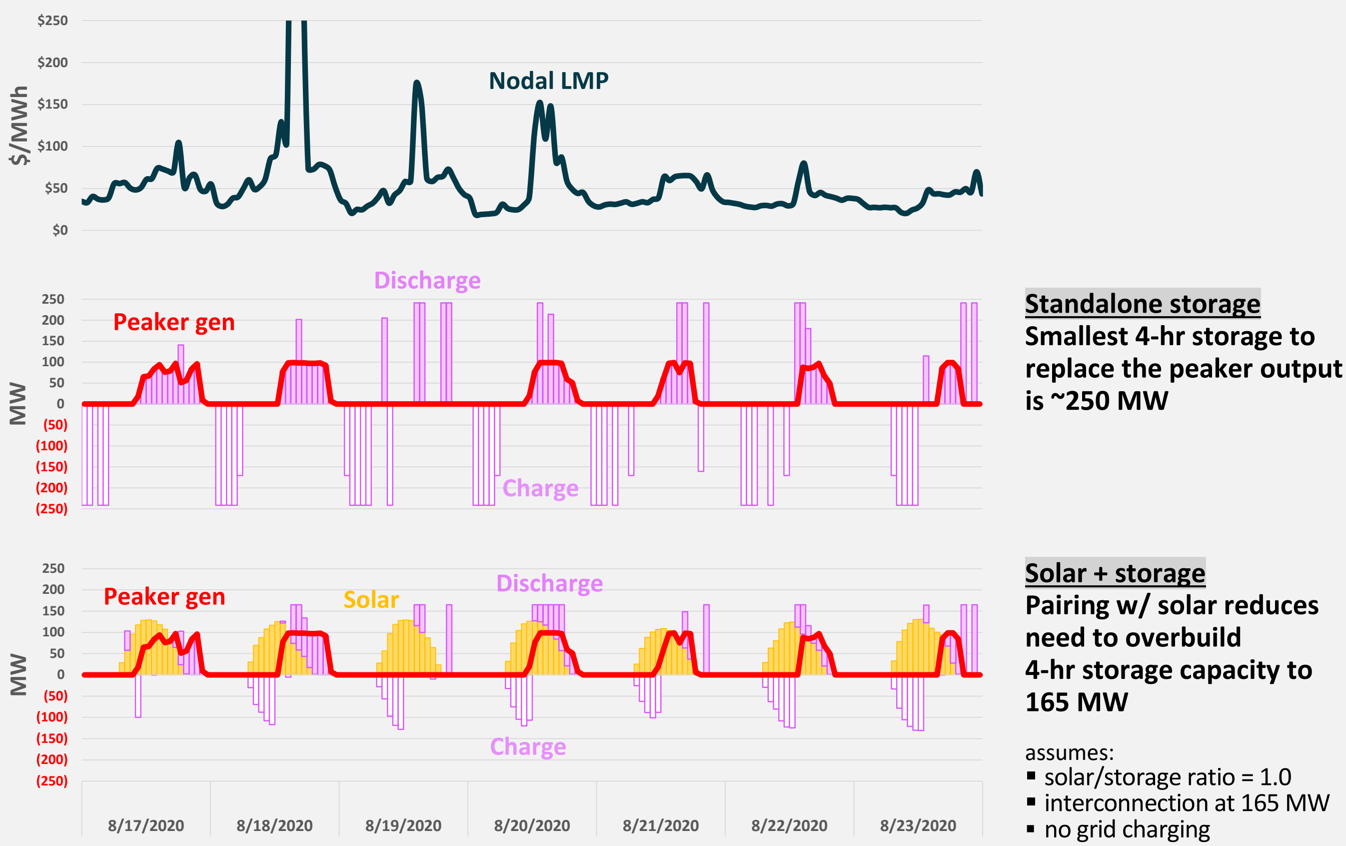


Figure 8: Comparison of simulated solar + storage operations against standalone storage.

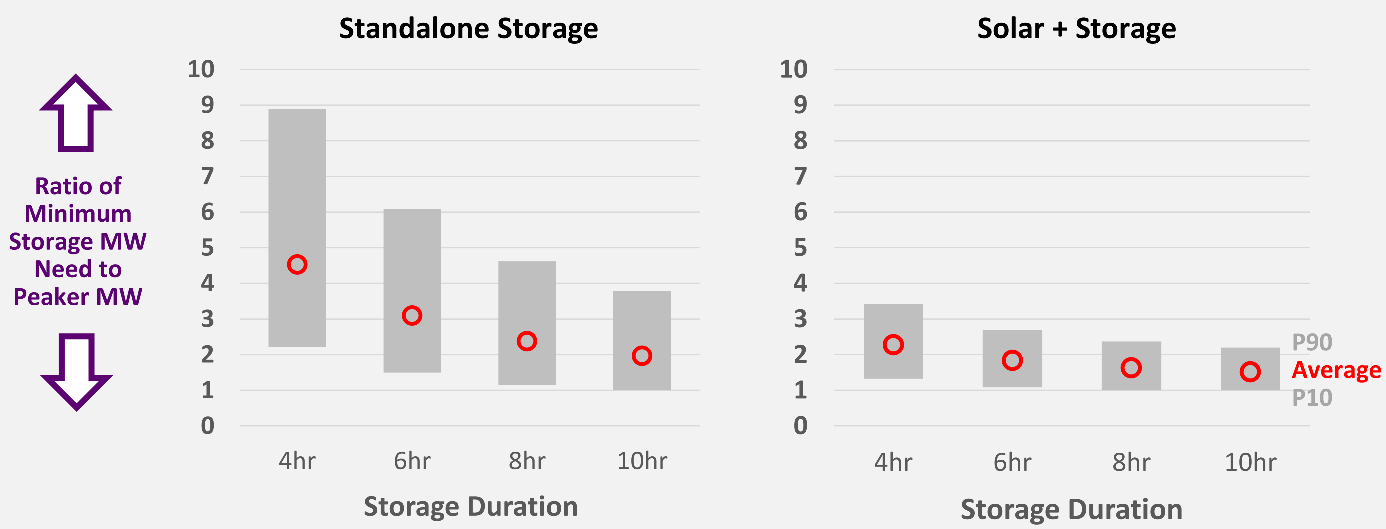
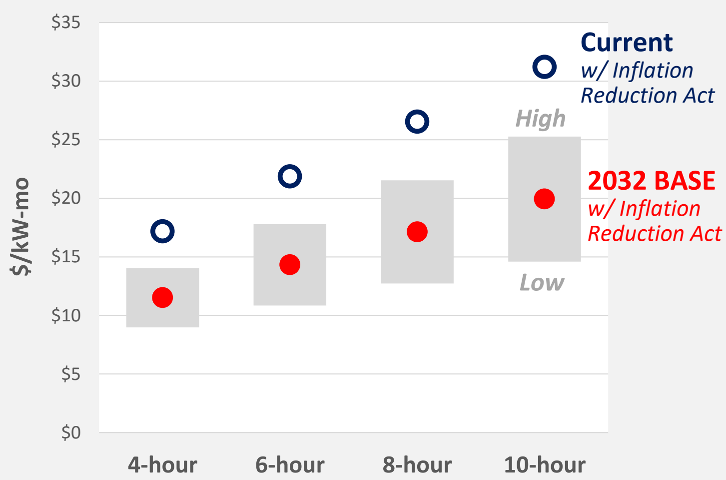


Figure 9: Minimum storage capacity needed for peaker replacement under standalone vs. hybrid development.

Figure 9 demonstrates the estimated need for overbuilding storage MW under standalone development, compared to hybrid development of solar and storage. To replace peaking units with standalone storage, storage MW needs to be 4.5x larger on average for projects with 4-hour duration. When paired with equal amounts of solar, the estimated average need for storage MW drops to 2.3x of peaker MW. Benefits of hybrid development is smaller for long duration storage. For example, for storage systems with 10 hours of duration, the average storage MW need is 2x for standalone projects and drops to 1.5x when paired with solar.

For the cost-benefit analysis, we start with the standalone storage cost assumptions discussed earlier. We estimate adding solar would increase levelized cost by $4–$5/kW-month in 2022 dollars relative to standalone storage, net of 30% ITC and cost savings associated with shared equipment and infrastructure.

Figure 10 shows total estimated levelized cost of solar + storage. As described earlier, solar resource capacity is assumed to match the nameplate MW capacity of storage. The 30% ITC benefit applies to capital cost of both solar and storage equipment. Cost savings relative to standalone development is assumed to be approximately $100/kW based on recent data from the [NREL study](#).



* Level-real values in 2022 dollars escalating by inflation over time. Includes amortized capex and O&M costs including augmentation and battery replacement. Excludes charging costs.

Figure 10: Estimated levelized solar + storage cost.

Figure 11 below shows the distribution of estimated net cost of replacing peaker capacity under various storage configurations. For solar + storage projects, estimated net costs reflect levelized capital and O&M cost *minus* energy and REC value, normalized for the peaker's capacity replaced. Energy value is calculated under 2020 nodal prices and REC value is assumed to be $15/MWh, which is consistent with the recent RPS adders in CPUC's Power Charge Indifference Adjustment (PCIA) estimates.

Under current storage cost levels, replacement of the local peakers in California will likely require significant investments. With 4-hour storage, very few peakers can be replaced with standalone storage at $10/kW-month and over 70% of the peaker capacity would require more than $15/kW-month, which is several times higher than the current RA price levels. With longer duration storage, distribution shifts to higher cost brackets.

If the site or local area has sufficient land that can be used to install solar capacity, developing storage paired with solar can reduce net replacement costs. With current cost levels and extended tax credits under the Inflation Reduction Act, about 3.8 GW of peaker capacity can be replaced with hybrid solar and 4-hour storage at an estimated net cost of $10/per kW-month, another 3.5 GW at $10–$15 per kW-month, 1.3 GW at $15–$20 per kW-month, and the remaining 1.4 GW at $20/kW-month or higher.

Under a future cost scenario assuming installed costs decline by around 40% for storage and 20% for solar, economic feasibility of replacement scenarios improve further, especially when storage is paired with solar. With hybrid solar and 4-hour storage, net replacement cost drops below $5/kW-month for 9 GW *absent* interconnection and land use limitations (discussed next).

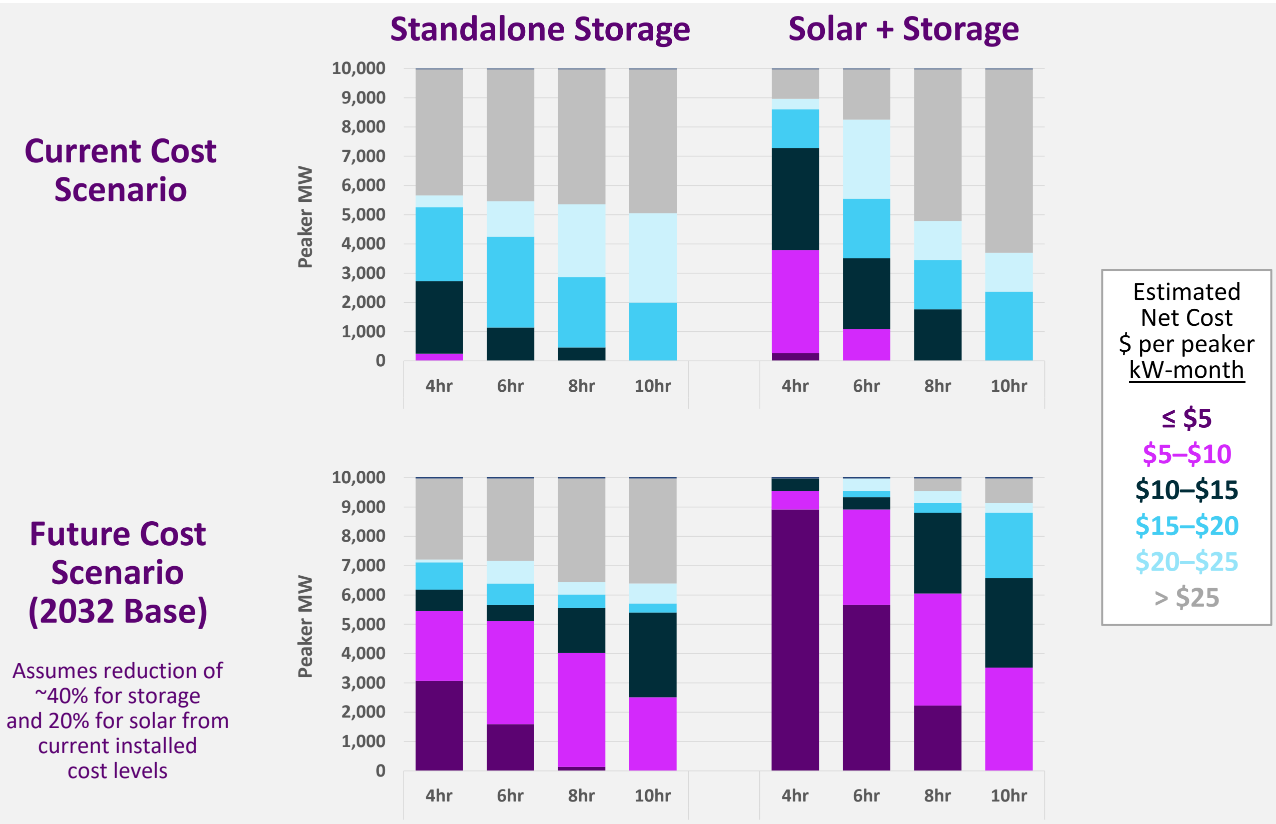


Figure 11: Distribution of net cost results with no limitations on grid interconnection (in 2022 dollars).

Impact of Grid Interconnection and Land Availability

As discussed earlier, all of the peakers in our analysis are located in CAISO-designated local capacity areas. Within these local areas, getting interconnection above what peakers' existing rights could be difficult and may require additional lead time to study deliverability and potentially result in network upgrade costs. Such limitations can prevent storage systems to be overbuilt.

While our study does not analyze interconnection capabilities at individual peaker sites or local areas, we included a sensitivity case with interconnection access of storage resources limited to 1.5x peaker MW. Figure 12 below shows the distribution of net cost results with this limitation, which makes a large share of peaker replacement options infeasible. Under this sensitivity, longer duration storage has more potential to replace peaking units if developed on a standalone basis. Pairing storage with solar creates some opportunities for 4- or 6-hour storage to more cost-effectively replace peakers, without exceeding the 1.5x interconnection limit.

Another important consideration is the land use for solar development, which is not included in our study. According to this LBNL report, recent utility-scale solar projects with tracking require 4 acres of land per MW installed. Therefore, replacing a 100 MW peaker with a 150 MW solar + storage would need around 600 acres of land. If land availability is limited in certain sites or local areas, pairing storage with solar may not be feasible.

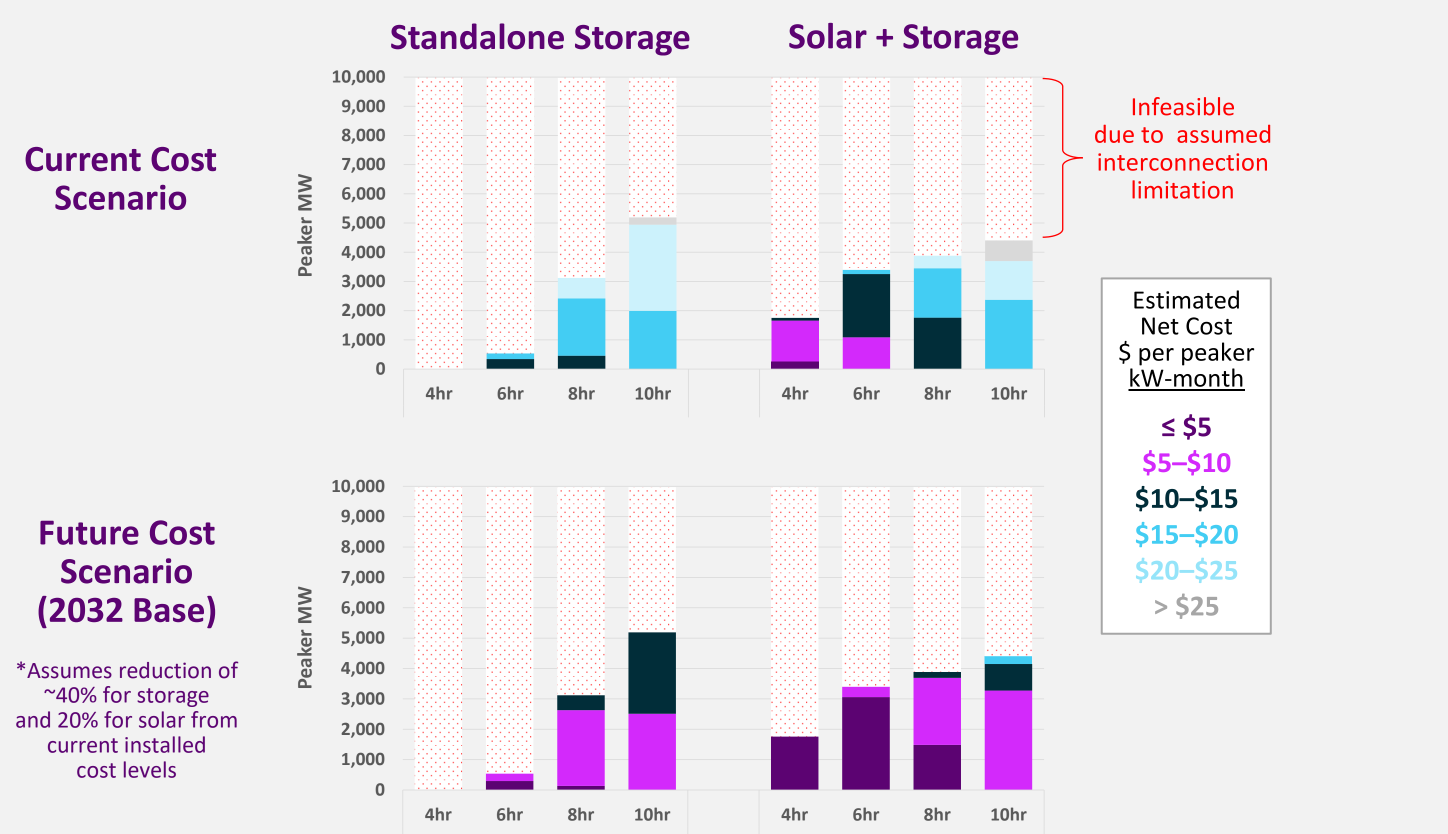


Figure 12: Distribution of net cost results with grid interconnection limited at 1.5x peaker MW (in 2022 dollars).

Key Observations

Most of the gas-fired peaking units analyzed (~10 GW total capacity) are in CAISO-designated local capacity areas and are needed for local reliability. In 2020, they generated a total of 5.7 million MWh accounting for approximately 3.5% of the total generation from resources in CAISO's footprint. Altogether, they were responsible for around 3 million metric tons of CO_2 emissions, which is slightly over 8% of total emissions from in-state generators.

Peakers' operations during 2020 suggest a reliability need over 8 consecutive hours for most of the units analyzed. This extended duration translates to an energy need that can be met by a variety of storage configurations with different mix of MW vs. duration, and developed on a standalone basis or paired with solar PV resources.

Replacing peakers' output with standalone energy storage would require either significantly overbuilding storage MW or installing long-duration storage at relatively high cost. Under current cost levels, net cost is estimated above $15/kW-month for over 70% of the total peaker capacity analyzed.

If the site or local area has sufficient interconnection capability, overbuilding storage MW with a 4-hour duration can be more cost-effective in replacing the peakers in California, than installing long-duration storage. Replacement with 4-hour storage requires more MW than storage with longer durations, but its higher energy time-shift value will likely offset incremental costs and make it more cost-effective under current/near-term outlook for battery costs.

Pairing storage with solar can significantly reduce net replacement costs. If the site or local area has sufficient land that can be used to install solar capacity, developing solar + storage can reduce the need for overbuilding MW or installing long-duration storage to replace peaking units, and accordingly results in lower net costs, relative to standalone storage. Co-location benefits such as cost savings from shared equipment and infrastructure and additional tax credits contribute to lower net cost, but these benefits need to be weighed against "lost" value associated with more stringent operational requirements such as inverter and interconnection limits, and grid charging constraints.

If storage (and solar) costs continue to decline as expected, economic feasibility of replacement scenarios will improve further, especially when storage is paired with solar. Under a scenario where installed storage costs drop from current levels of ~$350/kWh to $200–$250 per kWh and installed solar PV costs drop by ~20% from current levels of $1,000/kW to $800/kW, we estimate that net replacement cost could be below $5/kW-month for most of the peakers analyzed in our study.

Exactly how much peaker capacity can be replaced, however, will depend upon site-specific considerations, including: (a) the peaker's relative to-go costs to stay online, (b) whether or not the energy storage replacement can obtain interconnection rights to oversize its MW capacity relative to peaker's capacity, (c) charging and other operating constraints identified by the CAISO Local Capacity Technical studies, and (d) whether or not solar PV can be developed at a reasonable cost within the local capacity-constrained area.