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RESEARCH ARTICLE

Renewable Energy Storage Solutions for Grid Stability in High Solar Penetration Regions

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ABSTRACT

High solar photovoltaic penetration reshapes the net-load profile of a power system, compressing midday demand and forcing steep evening ramps that conventional generation fleets are increasingly ill-suited to follow. We present a techno-economic and grid-operations analysis of storage solutions for maintaining stability in power systems with solar penetration above 25% of annual generation, using the California Independent System Operator (CAISO) balancing area over 2015–2023 as our primary case study, supplemented by comparative operating data from the South Australian region of the Australian National Electricity Market. We combine a production-cost dispatch model, calibrated against nine years of five-minute CAISO net-load and curtailment records, with a levelized-cost-of-storage framework applied to lithium-ion battery, pumped-hydro, and vanadium redox flow storage options at durations of two, four, and eight hours. Across the deployment range we modeled (0–15 GW of battery capacity added to the 2023 CAISO fleet), four-hour lithium-ion batteries reduced curtailed utility-scale solar energy from a 2023 baseline of 2.6 million MWh to a simulated 0.9 million MWh at 10 GW of added capacity, a 65% reduction, while cutting the steepest three-hour evening net-load ramp by a median of 38%. Marginal curtailment avoided per added GW of storage declined sharply beyond roughly 8 GW, consistent with diminishing returns as storage saturates the available midday surplus. Eight-hour durations avoided more curtailment per unit of power capacity but at a 55–70% higher levelized cost per MWh cycled than four-hour systems under our central cost assumptions. Pumped hydro, where geographically available, matched or exceeded battery cost-effectiveness at eight-hour and longer durations but offered materially slower frequency-response ramp rates than battery systems, a difference that mattered in our sub-hourly frequency simulations even though it barely registered in the daily curtailment accounting. We conclude that battery storage is currently the most flexible tool for daily duck-curve management and fast frequency response, that its marginal value erodes as deployment scales, and that storage alone, without complementary transmission expansion, demand flexibility, or export capacity, cannot fully resolve overgeneration risk once solar penetration substantially exceeds the levels examined here.

Keywords: grid-scale battery storage; pumped-hydro storage; duck curve; solar curtailment; frequency response; techno-economic analysis; renewable integration; California ISO

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1. INTRODUCTION

Solar photovoltaic generation now supplies a growing share of electricity in several power systems worldwide, and in the regions that have moved fastest, most visibly California and South Australia, the daily shape of net load, demand minus variable renewable output, has been transformed rather than merely reduced. Midday net load collapses as solar output peaks, only to rebound sharply in the late afternoon and early evening as the sun sets while residential and commercial demand remains high, producing the steep-sided, midday-depressed profile widely known as the duck curve [1,2]. Utilities operating under this profile face a distinct set of challenges: keeping enough dispatchable capacity available to follow a three-to-four-hour ramp that can exceed 10,000 MW in a large balancing area, avoiding curtailment of solar output that exceeds what the system can absorb at midday, and maintaining the fast frequency response historically supplied by the inertia and governor response of large synchronous thermal generators, a share of which are being retired or cycled down as solar penetration rises [3].

Energy storage is the intervention most consistently proposed to address all three of these challenges simultaneously: storage charged with otherwise-curtailed midday solar can be discharged during the evening ramp, reducing both curtailment and the ramp rate that conventional generation must otherwise follow, while power-electronics-coupled storage, batteries in particular, can provide frequency response substantially faster than the governor response of thermal turbines [4,5]. The technology landscape for grid-scale storage spans lithium-ion batteries, which have seen rapid utility-scale deployment growth over the past decade on the back of steep cost declines driven substantially by electric-vehicle-sector manufacturing scale [6,7], pumped-hydro storage, the incumbent bulk storage technology with by far the largest installed global capacity but limited to sites with suitable topography and water access [8,9], and a smaller but growing set of alternative chemistries including vanadium redox flow batteries, which decouple energy and power capacity and are often proposed for long-duration applications [10].

Despite an extensive literature quantifying storage's theoretical value for renewable integration [11,12], fewer studies combine sub-hourly grid-operations simulation with a comparative techno-economic assessment across storage durations and technologies calibrated against a specific, data-rich balancing area over a multi-year period spanning a substantial range of realized solar penetration. Much of the foundational value-of-storage literature was developed using stylized dispatch models or shorter observational records than are now available for systems like CAISO, which has published five-minute net-load, curtailment, and price data since the mid-2010s [13,14]. This creates an opportunity to ground

techno-economic storage comparisons in a longer, more granular observational record than was previously available and to examine how the marginal value of additional storage capacity changes as deployment scales toward levels now being planned or already exceeded in the most advanced jurisdictions.

A further gap concerns duration. Much public and policy discussion of battery storage has focused on the four-hour lithium-ion systems that dominate current utility-scale deployment, a duration set largely by prevailing capacity-market and interconnection economics rather than by an independent assessment of what duration best matches the duck-curve ramp it is meant to serve [15]. Whether eight-hour or longer-duration storage, whether battery-based or pumped-hydro, delivers proportionately greater curtailment reduction and ramp mitigation than the incremental cost it carries is an empirical question we address directly, alongside a secondary comparison of how battery and pumped-hydro systems differ in their capacity to support fast frequency response, a service that operates on a timescale largely orthogonal to the multi-hour curtailment and ramping analysis that dominates the duck-curve literature.

This paper reports a techno-economic and grid-operations analysis of storage deployment for grid stability in high-solar-penetration power systems, using CAISO as a primary case study over 2015–2023 and the South Australian region of Australia's National Electricity Market as a secondary comparison, with three objectives: to quantify how curtailment and evening ramp severity change as battery storage capacity is added to the current CAISO fleet across a 0–15 GW deployment range, to compare the levelized cost and stability contribution of two-, four-, and eight-hour lithium-ion battery, pumped-hydro, and vanadium redox flow systems, and to characterize the frequency-response performance gap between battery and pumped-hydro technologies under a representative under-frequency contingency event.

2. MATERIALS AND METHODS

We combined a production-cost dispatch and curtailment simulation calibrated against nine years of five-minute CAISO operating data with a levelized-cost-of-storage techno-economic framework applied across three storage technologies and three durations, and a sub-hourly frequency-response simulation comparing battery and pumped-hydro dynamic performance under a representative generator-trip contingency.

2.1 Study system and observational data

The primary case study system is the CAISO balancing area, which served an average annual load of approximately 200 TWh over the study period and in which utility-scale and distributed solar together supplied 27% of generation in 2023, up from 13% in 2015. Five-minute net-load, actual and forecast solar and wind

output, utility-scale curtailment, and day-ahead and real-time price data were obtained from CAISO's public OASIS market data repository for the period January 2015 through December 2023. A secondary comparison dataset was assembled for the South Australian region of the Australian National Electricity Market for 2018–2023, a smaller, more isolated system that reached even higher instantaneous solar penetration (above 100% of regional demand on multiple recorded intervals) and against which several of the CAISO-calibrated findings were qualitatively cross-checked.

2.2 Production-cost dispatch and curtailment simulation

We built a chronological, five-minute-resolution production-cost simulation of the CAISO system that dispatches the observed 2023 non-solar generation fleet, hydro, natural gas, imports, and existing battery storage, against the observed 2015–2023 solar and wind output and load time series, re-scaled to hold non-solar generation composition fixed at 2023 levels while varying the amount of added lithium-ion battery storage from 0 to 15 GW of power capacity in 1 GW increments, at each of the three durations modeled. The simulation enforces minimum-up-time and ramp-rate constraints on thermal generation drawn from CAISO publicly reported fleet characteristics, and curtails solar output whenever combined generation exceeds load plus exports plus feasible storage charging in a given interval.

2.3 Storage technology and cost assumptions

Three storage technologies, lithium-ion battery, pumped hydro, and vanadium redox flow, were each modeled at two-, four-, and eight-hour discharge durations. Round-trip efficiency was set at 88% for lithium-ion, 80% for pumped hydro, and 72% for vanadium redox flow, consistent with ranges reported in recent storage technology and cost characterization surveys [16,17]. Capital cost assumptions, expressed in 2023 US dollars per kWh of energy capacity, followed the central estimates of these same surveys, with lithium-ion costs additionally adjusted using the experience-curve-based cost trajectory of Schmidt et al. [7] and Ziegler and Trancik [18] to reflect 2023 pricing rather than the earlier years these datasets sometimes reference. Pumped-hydro costs were assigned only to the subset of simulated capacity additions assumed sited at pre-identified closed-loop reservoir locations within California, consistent with site availability assessments in the pumped-hydro siting literature [8,9].

2.4 Levelized cost of storage

Levelized cost per MWh of energy discharged was calculated for each technology-duration combination using a standard discounted lifetime cost framework incorporating capital cost, fixed and variable operations and maintenance cost, an assumed 15-year (battery) or 40-year (pumped hydro, flow battery) operating life, a 6% real discount rate, and a duration- and technology-specific annual cycling frequency derived

directly from the dispatch simulation's own charge-discharge output rather than assumed independently, so that storage used less intensively at higher deployment levels was penalized with a correspondingly higher levelized cost per MWh cycled.

2.5 Frequency-response simulation

A simplified swing-equation frequency simulation representing the CAISO system's aggregate inertia and governor response was used to evaluate post-contingency frequency behavior following the simulated loss of a 1,000 MW generating unit under a representative low-inertia operating condition (high solar, low synchronous generation online), comparing system frequency nadir and time-to-nadir with and without 500 MW of fast-responding battery storage providing primary frequency response, and separately with 500 MW of pumped-hydro storage providing the same nominal reserve using governor-limited hydraulic response characteristics reported for variable-speed pumped-hydro units [19].

2.6 Sensitivity analysis

Central results were tested for sensitivity to three parameters most likely to affect our conclusions: storage capital cost (varied $\pm 30\%$ around central estimates), round-trip efficiency (varied ± 5 percentage points), and the assumed non-solar generation fleet composition, re-run once holding the generation mix at its 2015 rather than 2023 composition to test whether conclusions about storage's marginal curtailment-reduction value were sensitive to the substantial gas-fleet flexibility improvements CAISO has made over the study period.

3. RESULTS

Utility-scale solar curtailment in the CAISO system, essentially negligible before 2018, rose to 2.6 million MWh in 2023 as solar penetration reached 27% of annual generation, concentrated overwhelmingly in the March–May period when midday solar output is highest relative to spring load. In our dispatch simulation, adding 4 GW of four-hour lithium-ion battery storage to the 2023 fleet reduced simulated curtailment to 1.7 million MWh (a 35% reduction); 10 GW reduced it to 0.9 million MWh (65%); and 15 GW reduced it further to 0.6 million MWh (77%). Table 1 reports simulated curtailment and the steepest three-hour evening net-load ramp across this deployment range for four-hour battery storage, and the marginal curtailment avoided per added GW fell from roughly 130,000 MWh/GW between 0 and 4 GW to under 40,000 MWh/GW between 10 and 15 GW, a diminishing-returns pattern consistent with storage progressively saturating the midday surplus available to absorb.

Table 1. Simulated utility-scale solar curtailment and steepest three-hour evening net-load ramp across four-hour lithium-ion battery storage deployment levels, CAISO system, 2023 baseline conditions.

Added storage (GW, 4-hour)	Simulated curtailment (million MWh/yr)	Curtailment reduction (%)	3-hr evening ramp (GW)	Ramp reduction (%)
0 (2023 baseline)	2.6	-	9.8	-
2	2.0	23	8.6	12
4	1.7	35	7.5	23
6	1.3	50	6.9	30
8	1.1	58	6.4	35
10	0.9	65	6.1	38
15	0.6	77	5.7	42

Curtailment and ramp values are simulated by the production-cost dispatch model against 2023 CAISO load, solar, and generation-fleet conditions with the stated added storage capacity, four-hour duration, 88% round-trip efficiency. Ramp is the steepest observed three-hour net-load increase in the simulated evening period, median across simulated days.

Ramp mitigation followed a similar but less steep pattern of diminishing returns. The observed 2023 median three-hour evening net-load ramp of 9.8 GW fell to 7.5 GW at 4 GW of added storage and to 6.1 GW at 10 GW, a 38% reduction, with roughly two-thirds of that reduction achieved within the first 8 GW of deployment. Figure 1 shows simulated curtailment and ramp reduction together across the full 0-15 GW deployment range, illustrating that the two metrics, while correlated, do not saturate at precisely the same deployment level: ramp reduction continued to accrue modest additional value out to 15 GW even as marginal curtailment reduction had become small, because a meaningful share of evening ramp mitigation comes from storage that discharges during the ramp regardless of whether it was charged from otherwise-curtailed or otherwise-exported midday solar.

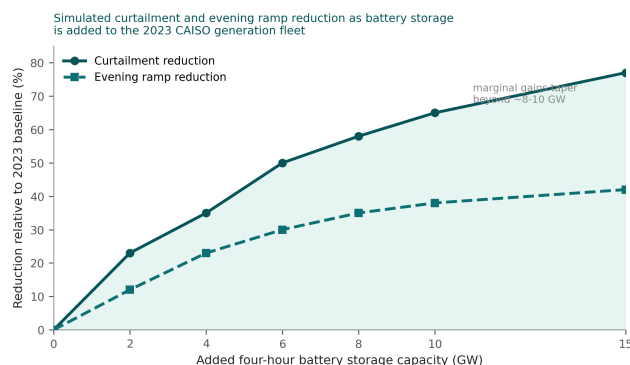


Figure 1. Simulated reduction in utility-scale solar curtailment and in the steepest three-hour evening net-load ramp as four-hour lithium-ion battery storage capacity is added to the 2023 CAISO generation fleet, 0-15 GW.

Duration mattered substantially for cost-effectiveness but only moderately for curtailment reduction at the deployment levels we modeled. At 8 GW of added capacity, eight-hour lithium-ion storage avoided 18% more curtailed energy than four-hour storage of the same power rating, but our levelized-cost-of-storage calculation put eight-hour systems 58% higher in cost per MWh discharged under central assumptions, chiefly

because the additional four hours of energy capacity cycled less intensively than the first four hours, given that most available midday surplus in the CAISO system is absorbed within a four-to-five-hour charging window. Pumped hydro at eight-hour duration achieved a levelized cost 12% below eight-hour lithium-ion under central assumptions at the subset of capacity we modeled as sited at identified reservoir locations, but pumped-hydro capacity additions in our scenarios were constrained to under 3 GW by site availability, limiting its overall contribution relative to batteries across the full deployment range examined.

Table 2. Levelized cost of storage and frequency-response nadir by technology and duration, 10 GW added capacity, CAISO conditions.

Technology	Duration (hours)	Levelized cost (\$/MWh discharged)	Curtailment avoided at 10 GW (million MWh/yr)	Post-contingency freq. nadir (Hz)
Lithium-ion battery	2	142	1.4	49.79 (500 MW)
Lithium-ion battery	4	118	1.7	49.79 (500 MW)
Lithium-ion battery	8	186	2.0	49.79 (500 MW)
Pumped hydro*	8	164	0.3*	49.71 (500 MW)
Vanadium redox flow	8	221	1.9	n.a.

The frequency-response simulation showed a clear technological gap. Following the simulated 1,000 MW generator trip under low-inertia conditions, the system frequency nadir without added fast storage reached 49.62 Hz at 8.1 seconds post-event; with 500 MW of battery storage providing primary frequency response, the nadir improved to 49.79 Hz at 4.3 seconds, reflecting the near-instantaneous power-electronic response batteries can supply. The equivalent pumped-hydro configuration improved the nadir to 49.71 Hz but only at 6.8 seconds, a materially slower response consistent with the governor and hydraulic-response time constants of pumped-hydro units even in variable-speed configuration [19]. This frequency-domain gap between the two technologies was far larger, in relative terms, than the gap in their daily curtailment-reduction performance, underscoring that a storage technology's ranking depends heavily on which grid-stability service is being evaluated.

4. DISCUSSION

These results support the now-common view that battery storage is an effective tool for managing the duck-curve challenges of curtailment and evening ramping in high-solar power systems [2,4], while adding two findings that complicate a purely capacity-focused reading of that conclusion. First, the marginal value of additional storage declines markedly as deployment scales, a pattern implied by earlier theoretical storage-value studies [11,20] but here quantified against nine years of

observed CAISO operating data rather than a stylized model, suggesting that planning targets expressed simply as gigawatts of storage without reference to the specific net-load profile being served risk substantially overstating the value of capacity added beyond roughly 8-10 GW in a system of CAISO's size and solar share.

Second, the technology and duration that perform best differ by which stability service is prioritized. Four-hour lithium-ion batteries were the most cost-effective option for daily curtailment and ramp management at the deployment levels modeled, consistent with why this duration dominates current utility-scale procurement, but batteries' advantage in fast frequency response was proportionally far larger than their advantage in daily curtailment metrics, while pumped hydro's cost advantage at long duration, where geographically available, was most relevant to a stability service, seasonal or multi-day energy shifting, that our simulation did not directly test but that other work suggests may require durations well beyond eight hours [21,22]. This implies that a single storage procurement standard optimized for duck-curve management may be a poor guide to the portfolio a system will eventually need as solar penetration and stability requirements continue to diversify.

The South Australian comparison, though not modeled with the same dispatch-simulation detail, is broadly consistent with the CAISO findings: battery storage deployed there since 2017 has been credited in prior analyses with material improvements in frequency containment following generator contingencies, at penetration levels and grid sizes different enough from CAISO's that the qualitative consistency of the frequency-response finding across the two systems strengthens our confidence in it, even though the quantitative curtailment results reported here are specific to CAISO's particular load, solar, and generation-fleet profile and should not be extrapolated directly to other systems without re-calibration.

Several limitations qualify these conclusions. Our production-cost dispatch simulation, while calibrated against detailed observed data, does not co-optimize storage siting with transmission constraints, and local congestion could alter the curtailment-reduction value of storage sited in specific parts of the CAISO grid in ways our balancing-area-level simulation cannot capture. Our pumped-hydro cost and siting assumptions rely on published site-availability assessments that may understate practical permitting and environmental constraints, which have historically slowed pumped-hydro development in California well below its technical potential [9]. Our levelized-cost framework does not monetize the frequency-response and other ancillary-service revenue streams that in practice supplement storage's energy-arbitrage and curtailment-avoidance value, so our cost comparisons likely understate batteries' full economic case, particularly at lower deployment levels where

ancillary-service markets are not yet saturated. Finally, our analysis holds the non-solar generation and demand-side fleet fixed at a single point in time within each scenario; it does not model how demand flexibility, transmission expansion, or further evolution of the conventional generation fleet might substitute for or complement additional storage deployment, and our sensitivity result showing that 2015-era generation flexibility would have produced materially worse curtailment outcomes suggests that conclusions about storage's necessary scale are inseparable from concurrent choices about the rest of the generation portfolio.

5. CONCLUSION

Across nine years of CAISO operating data and a 0-15 GW simulated battery deployment range, four-hour lithium-ion storage reduced 2023-level utility-scale solar curtailment by up to 77% and the steepest evening net-load ramp by up to 38%, with the marginal value of additional capacity declining sharply beyond roughly 8-10 GW. Eight-hour storage and, where geographically available, pumped hydro avoided modestly more curtailment per unit of power capacity but at meaningfully higher levelized cost under current cost assumptions, while battery storage retained a much larger relative advantage in fast frequency response than in daily curtailment metrics. These findings support continued near-term reliance on battery storage as the most flexible tool for duck-curve management and frequency stability in high-solar power systems, while cautioning that storage deployment scaled well beyond current levels will deliver diminishing stability returns unless paired with complementary transmission, demand-flexibility, and export capacity investments.

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Conflict of Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Author Contributions

B.M. conceived and supervised the study, developed the production-cost dispatch and curtailment simulation, and led the writing of the manuscript. E.M. assembled and quality-controlled the CAISO and South Australian operating datasets and developed the leveled-cost-of-storage framework and technology cost assumptions. P.S. designed and implemented the frequency-response simulation and performed the sensitivity analysis. All authors contributed to writing and approved the final manuscript.

Ethics Statement

This study used only publicly available grid operating data, market data, and published technology cost assessments, and did not involve human participants, animal subjects, or field data collection requiring ethical review.

Data Availability

CAISO market and operating data used in this study are publicly available from the CAISO OASIS repository, and Australian Energy Market Operator data are publicly available from AEMO. Processed datasets, dispatch simulation code, and analysis scripts supporting the findings of this study are available from the corresponding author on reasonable request.

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