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ENERGY RESEARCH AND DEVELOPMENT DIVISION

FINAL PROJECT REPORT

Evaluating the Value of Long-Duration Energy Storage in California

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

Energy storage will play an increasingly important role in California's transitioning energy system. Specifically, long-duration storage (storage with a duration of eight or more hours) will be important during critical periods such as nighttime and during cloudy days, particularly in winter. This project examines various scenarios to better understand the value of long-duration energy storage in meeting California's zero-emissions target for retail sales of electricity in 2045, while exploring duration, cost, and other attributes required for future energy storage. The need for storage depends on several factors, including the choice of generation technologies, availability of transmission, ability to shift load, and many other details of the grid. This project shows that California's solar-driven grid will benefit from 8-hour duration storage installed with a power rating that can meet peak demand, which typically occurs just after sunset. Longer-duration storage (e.g., 100-hour) is projected to capture 10 percent of the market if the cost per kilowatt-hour ($/kW) is less than the $/kW cost of lithium-ion batteries for 40 percent efficient 100-hour storage or if the $/kW is less than twice the lithium-ion cost for 80 percent efficient 100-hour storage. As the energy transition matures in the 2045 timeframe, 100-hour storage is projected to capture an increasing fraction of the market. High round-trip efficiency is important, with lithium-ion setting the system-level efficiency target at about 85 percent. Low efficiencies are more acceptable for storage that is used infrequently, as is expected for 100-hour storage. The results are strongly dependent on the cost assumptions and on the cap that is imposed on the amount of each resource that can be adopted. The selection of more wind and geothermal could increase greatly if low-cost sites are identified for these. Thus, the report focuses on identifying trends rather than concluding on specific targets, and it cautions the reader to use the results in this context.

Keywords: Long-duration energy storage, solar energy, wind energy, flexible load

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Executive Summary

Background

Senate Bill 100 sets the goal of zero-carbon retail sales of electricity by 2045. California has made significant progress toward that goal; in 2023, more than 50 percent of the electricity in the state was generated from renewable resources, with 28 percent coming from solar electricity. Given the inherent variability of solar and wind resources, energy storage is becoming increasingly important. California has already invested in utility-scale storage and is using it daily, sometimes meeting up to 20 percent of the load by discharging batteries. However, when these batteries are operated at full capacity, they last for only four hours, which is not long enough to supply electricity between sunset and sunrise, motivating the development of energy storage that can last longer. The California Energy Commission is funding development of long-duration energy storage that can last at least 8 hours, and many companies are developing products with the goal of being cost effective for providing the grid with energy storage even in the most difficult of times.

Project Purpose and Approach

The project's goal was to understand the role and cost targets of long-duration energy storage needed to reach zero-carbon and related goals by 2045. This understanding will guide the California Energy Commission's investments in technology development, companies in product development, and policymakers. It will also guide planning and investment strategies for infrastructure development.

Energy storage plays multiple roles in today's electrical grid and will play expanded roles in future energy systems. These roles will be highly dependent on investment in electricity generation technology and on investment in infrastructure that will shape electricity demand. Thus, the project considered multiple scenarios to understand how energy policy and the grid's conditions may affect the need, benefit, and desired attributes of energy storage. The primary challenges of this project included the large number of variables, numerous novel technology options with uncertain development timelines and no clear winners. These challenges were addressed by approaching the problem from multiple perspectives to find the lowest-cost grid buildout.

This project leveraged existing modeling tools and made the necessary modifications to ensure that accurate results could be obtained. The RESOLVE tool, designed to model the expansion of California's grid, was developed with California Energy Commission funding and has been applied to identify pathways to meeting California's energy goals. RESOLVE was selected for this project so that the results could be more easily accessed and interpreted. It was modified to enable 365-day modeling, so that storage could be charged on one day and discharged on another day later in the year. Additionally, SWITCH (which has similar functionality but includes many generators and loads outside of California) was used to leverage previous investments at the University of California, Berkeley and elsewhere, and it was further developed to enable

365-day modeling for the first time. Input was gathered through both public and private mechanisms.

Key Results

The project concluded that a mixture of storage durations would support the grid in different ways. The cost targets that long-duration storage must reach to compete with today's 4-hour utility-scale storage depend on both the duration and the efficiency of the storage.

Storage with an 8-hour duration will make up the largest proportion of long-duration energy storage, complementing solar energy. With an efficiency greater than 80 percent, 8-hour storage can enter the market if its energy cost is even a little lower than that of 4-hour, 85 percent efficient batteries. If the round-trip efficiency drops to about 50 percent, the energy cost will need to be about a factor of two lower than that of 4-hour, 85 percent efficient batteries to enter the market.

The cost targets for 100-hour storage products to enter the market are similar to those for 8-hour storage when considered on a "per watt" basis. For example, a 100-megawatt, 100-hour product must have a cost that approaches that of a 100-megawatt, 8-hour product. When the efficiency of the 100-hour storage is decreased from 80 percent to 50 percent, a 40 percent-lower cost would be needed to compete in the market.

Today's flexible loads are too small to balance supply and demand of electricity, but daytime electric vehicle charging and electrolyzers for hydrogen generation are poised to increase sufficiently to have significant roles in balancing the grid.

The use of daytime charging of electric vehicles directly reduces the need for energy storage, compared with charging vehicles at midnight. By 2045, replacing nighttime charging with daytime charging could reduce the costs of needed storage by up to $1 billion, motivating investment in low-cost daytime charging infrastructure. Daytime charging could also motivate the use of vehicles to support the grid during peak times, while nighttime charging would require additional investment in grid energy storage. This would obviate the benefit of using the batteries in electric vehicles to support the grid, since additional grid-level storage would be needed if nighttime charging were used.

Electrolyzers, which can convert electricity into hydrogen during periods of high renewable generation, were found to be able to contribute to seasonal load balancing by turning off during the winter. The availability of under-used assets (curtailed electricity combined with ample electricity storage) enabled green hydrogen.

Oxy-combustion (the process of burning a fuel using pure oxygen, or a mixture of oxygen and recirculated flue gas, instead of air), coupled with carbon capture and sequestration, could help reduce the need for energy storage. While California has prioritized eliminating combustion to reduce air pollution, oxy-combustion occurs without air, avoiding generation of NOx (oxides of nitrogen). The pathway for the use of oxy-combustion in California is unclear, because it is still under development and will need to be located near a place where the CO_2 (carbon dioxide) can be injected into the ground.

The volatility and seasonality of electricity prices in a zero-emissions 2050 grid could be mitigated by instating energy capacity storage mandates to support reliability during the energy transition.

During execution of the project, long-duration energy storage technology advanced, with several companies deploying large-scale demonstrations. This project guides companies to focus on products that provide about 8 hours of storage for the larger market and 100 hours of storage for a smaller market, with a focus on products with high round-trip efficiency.

Knowledge Transfer and Next Steps

Researchers for this project engaged directly with storage companies and individuals from GridLab, The Utility Reform Network (TURN), and Strategen. In the initial months, interviews with energy storage companies were conducted to obtain a better understanding of the potential of various storage technologies. Interactions with some of the storage companies continued throughout the project. A large Technical Advisory Committee was assembled to represent utilities, research organizations, and community organizations. A subset of that committee engaged with the project team on a regular basis. A presentation was given to the project team for the California Energy Commission project EPC-19-051, Hybrid-Modular Storage Solution Rapid Integration and Commercialization Unit, in March 2022, to provide the most recent results of this project. Webinars were held both to hear input from external speakers and to share results and gather feedback from the project team.

Four public workshops were held between December 2020 and Fall 2023. Results were presented at 15 conferences or expert meetings. Nineteen technical papers have been published, five other papers are in review, and three additional papers are in progress. The research team actively engaged with the research community studying long-duration energy storage and participated in five panels discussing the opportunities and challenges of long-duration energy storage.

Preliminary results of this project were presented in an Expert Briefing on Energy Storage that was hosted by the California Council on Science and Technology (CCST) in July 2021, with more than 100 participants. An Informational Hearing for the Assembly Select Committee on California's Clean Energy Economy was also hosted by CCST in August 2021.

A more complete summary of the results of this project can be found online at the link shown below.[1]

[1] https://sites.ucmerced.edu/ldstorage/publications%20version%202

CHAPTER 1: Introduction

This project's goal was to understand the role and cost targets of long-duration energy storage (LDES), to reach zero-carbon emissions and related goals by 2045. While, clearly, low-cost, efficient LDES is desirable, it is less clear what duration (hours of discharge that can be sustained at the LDES' rated power) will be most beneficial.

The optimal solution for California is likely to include some LDES, with durations suitable to provide power through the night, longer durations that will provide power during a few cloudy days, and even longer durations that provide power during the most difficult seasons. The efficiencies and other attributes of LDES, as well as the details of the electric grid, will affect the optimal mix.

Understanding the combinations of attributes that will enable solar and wind to provide electricity around the clock will guide investments in the many promising LDES technologies. A critical attribute will be the cost each type of LDES will need to reach to be able to capture market share.

California has a unique mixture of energy resources, including abundant solar energy and a wind resource that is stronger in summer than in winter (most locations have stronger wind during winter). Thus, studies describing how LDES broadly complements solar and wind generation for other locations may not provide the optimal solutions for California (Mahmud et al., 2022).

Additionally, California is exploring investment in offshore wind, has the largest geothermal generation in the country, and could benefit from using woody biomass from the forests for electricity generation as a means for reducing wildfires. If any of these processes were installed at a multi-gigawatt (GW) scale, the need for LDES would change. Electric vehicle (EV) charging, electrolysis, and heat pumps are examples of three loads that are anticipated to increase. These loads are significant because they are more flexible than today's loads, and they may be more significantly influenced by state policy and actions that guide design of demand management and incentive programs such as time-of-use rates and load shifting. For example, investments for EV charging could incentivize: use of on-site storage to enable fast charging (increasing the use of LDES), installation and use of infrastructure for daytime charging in parking lots (reducing the need for LDES), and/or installation of residential charging infrastructure that would be used primarily at night (increasing the need for LDES).

This project focuses on longer-term questions and a wide-range of scenarios, differentiating it from the California Energy Commission's (CEC) *Integrated Energy Policy Report* (IEPR), which focuses more on near-term energy needs and issues (California Energy Commission, 2003-2016). This project, which complements the related study by Energy and Environmental Economics, Inc. (CEC, 2022), considers how solar and wind generation profiles may be designed to more closely match load profiles, how loads may be shifted to reduce the need for storage, and how the Western Electricity Coordinating Council (WECC) resources may interact with California's resources.

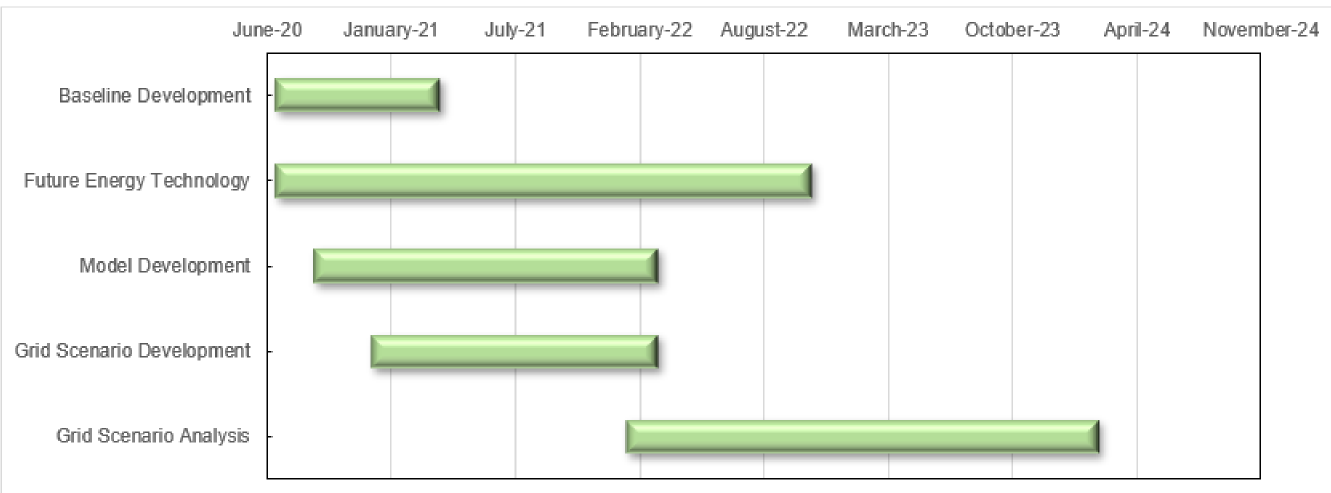
Thus, this project explores a wide variety of scenarios to understand how actions by the state may affect the need for and benefit of LDES in the future, aiding and informing both policy makers and companies that are developing long-duration storage projects.

CHAPTER 2: Project Approach

Project Timeline and Approach

The project timeline is shown in Figure 1. An initial survey of the currently available LDES technologies identified the technology options and their attributes (Shan et al., 2022) and later was used to refine the implementation of storage in the modeling. The model was modified to enable consecutive 365-day modeling to that ensure LDES benefits could be fully appreciated by the model. Finally, in discussion with the CEC, the scenarios were developed and analyzed.

Figure 1: Project Timeline



Project Partners

The project was led by the University of California (UC), Merced (Sarah Kurtz). Subcontracts were provided to UC Berkeley (Dan Kammen and Sergio Castellanos), and UC San Diego (Patricia Hidalgo-Gonzalez), to access their capability to model the western part of the United States, exploring the roles of imports and exports for balancing California's grid. The University of North Carolina at Chapel Hill (Noah Kittner) provided experience with technology evaluation, including the use of learning curves for understanding the potential of storage technologies. The Technical Advisory Committee is identified at the beginning of this report.

Individuals and companies providing input are identified in Appendix A.

Research Objectives

The project's primary objectives were to understand the roles and cost targets of LDES in reaching California's zero-carbon emissions and related goals by 2045, considering a broad context of the generation technologies that would be installed and the use of transmission to connect to the rest of the WECC.

LDES Technology Background and Summary

As part of the project, the project team conducted an assessment of several LDES technologies, which provided the basis for the capacity expansion modeling (Shan et al., 2022; Kurtz, 2022; Kurtz, 2023). The assessment "Evaluating emerging long-duration energy storage technologies" provides an overview of standardized metrics comparing LDES technologies with lithium-ion based counterparts. That assessment developed innovative storage metrics for comparing technologies, such as a standardized average capital cost of different storage technology as a function of discharge duration at rated power, the equivalent efficiency considering idle loss rates, and land footprints as a function of energy rating. The project also analyzed current shortcomings in storage modeling with opportunities for cross-sector applications (Kittner et al., 2021), as explored the section in Chapter 3 titled Impact of Electrolyzers on Selected Storage. Table 1 provides an abbreviated overview of the available LDES technologies.

Table 1: Long-Duration Energy Storage Summary

Storage type	Discharge duration (hours)	Lifetime (years)	Roundtrip efficiency (%)	Capital cost ($/kW)	Capital cost ($/kWh)
Compressed air, adiabatic	10-100	20-30	55-75	700-1100	40-90
Flow battery, vanadium	4-24	5-20	65-85	600-1650	160-1150
Flow battery, zinc	4-24	5-20	65-75	700-2700	160-1800
Pumped hydropower	10-100	25-100	60-85	1800-3400	5-200
Gravity	2-15	35	>80	*	200-300
Thermal	4-24	*	*	*	< 10
Li-ion battery	1-4	5-20	85-90	1600-2500	300-900

*Depends on energy conversion technology.

Real project cost estimates for gravity storage have increased from $200 per kilowatt-hour (kWh) to $300/kWh to approximately $880/kWh, based on pilot projects developed in China. However, there is potential for further cost adjustments (Latief, 2023). (The Chinese project entailed a total investment of 650 million renminbi, approximately $880/kWh, for a 100-megawatt [MW] project.)

The dynamic LDES market offers a wide range of technology options, each catering to specific applications. It is critical to consider factors like self-discharge rates, modularity (smallest deliverable capacity), heat management, cost-effectiveness, land footprint, and depth of discharge when determining the most suitable solution for specific applications.

Proton exchange membrane (PEM) electrolyzers provide flexibility in their operation, enabling them to better complement variable renewable energy sources compared to alkaline electrolyzers. Thus, they act as a type of storage. Electrolyzers are rapidly coming down in price (Lindogan et al., forthcoming).

Based on feedback and the observation that the attributes of the storage technologies are not yet well-defined, the capacity expansion modeling used a matrix of attributes, as defined in the section in this chapter titled Core Scenario Description Used for SWITCH Modeling, below, rather than specifically modeling each technology. However, the information in Table 1 can be used to relate specific technologies to the modeling results.

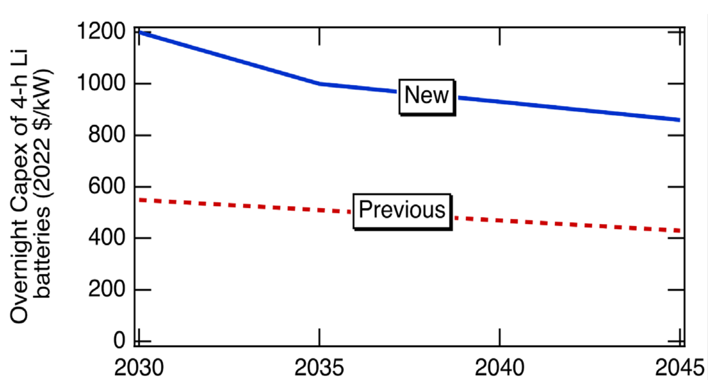
Community feedback encouraged studies covering the entire range of durations, efficiencies, and costs, reflecting the uncertainty of which technologies will succeed. In response to this feedback, the project explored the full range of durations, efficiencies, and costs, defining a large matrix to survey in competition with 4-hour (4-hr) Lithium-Ion (Li) batteries that were modeled after today's Li batteries, though another short-duration storage technology could still displace Li batteries. Efficiencies as low as 30 percent were explored but were not selected by the model in the price ranges that were explored.

The model's selection of the lowest-cost solution can result in highly variable results when the costs of two candidate resources are similar. This report, therefore, emphasizes how the selected solution depends on the input costs while still considering how the other inputs affect the solutions.

To underscore the challenge of predicting the future costs of energy storage technologies, Figure 2 highlights how *Inputs & Assumptions: 2022-2023 Integrated Resource Planning (IRP)* noted the decision to essentially double the modeled cost of Li batteries (CPUC, 2023b; see Figure 7 on p. 81). The cost of Li batteries is the basis for the modeled 4-hr storage, so it is a critical input to the model because the selection of LDES to displace the current trend of using GWs of 4-hr Li batteries is dependent on their relative cost. While the uncertainty in Li battery costs is high, the uncertainty in LDES costs is even greater.

On the other hand, Bloomberg recently reported that Li battery prices are now falling again, with battery pack prices in November 2023 averaging $139/kWh and the cells averaging $89/kWh (BloombergNEF, 2023).

Figure 2: Revised 4-hr Li Battery Capital Cost From 2022 to 2023 IRP



Core Scenario Description Used for RESOLVE Modeling

RESOLVE (CPUC, 2023a) was developed by Energy and Environmental Economics, Inc., and models expansion of the California Independent System Operator (CAISO) grid while retaining generation and load for surrounding states. The limitation of building only new resources within CAISO introduces uncertainty, but modeling of resources outside of CAISO was included in the studies using SWITCH (see the section below titled Core Scenario Description Used for SWITCH Modeling).

The Final Core Scenario using the RESOLVE software includes baseline assumptions to reflect the 2021 CPUC IRP Preferred System Plan and the 2020 PATHWAYS high electrification analysis for the growth of EV loads.

Following are additional characteristics of the Final Core Scenario:

- Use fixed hydropower profiles for a dry year.
- Offer 85 percent efficient, 4-hr Li batteries as short-duration storage (the model does not adjust the duration).
- Vary the duration and efficiency of candidate LDES resources without assigning them to specific technologies.
- Use the critical-time-steps approach, which shortens the computation time, enabling many calculations while allowing 365-day continuous simulations (ZareAfifi et al., 2023). (Some calculations used 8760 time points to confirm the accuracy of the critical-time-steps calculations.)
- Exclude the constraint of a planning reserve margin (meeting the reserve was considered for every hour of the year rather than identifying whether the installed generation capacities had adequate electrical load carrying capacity).

Using RESOLVE, LDES was modeled with a predefined duration using four methods:

1. Fixed efficiency and cost ($/kW) with varied (defined) duration for a single storage type, ranging from durations of 4 hrs to 100 hrs.
2. Fixed duration and efficiency of a single LDES type, with cost varied to identify the cost target that would result in selection of the LDES at a target penetration level.
3. Fixed duration, efficiency, and cost for a single LDES type selected from Table 2, in competition with 4-hr Li batteries from the baseline to quantify the selected adoption for the least-cost solution.
4. Four LDES types with duration, efficiency, and cost defined as in Table 3, in competition with each other and with 4-hr Li batteries. The “Vary cost” scenario defined in Table 3 can be implemented with a range of efficiencies, denoted as “Y” in the table, where the same “Y” efficiency is used for all LDES types.

Table 2: LDES Assumptions for Adoption of a Single LDES Type

Duration	60% Efficient	80% Efficient
8-hr	1.2 X 4-hr Li battery power cost; 0.6 X 4-hr Li battery energy cost	1.2 X 4-hr Li power cost; 0.6 X 4-hr Li energy cost
12-hr	1.4 X 4-hr Li battery power cost; 0.47 X 4-hr Li battery energy cost	1.4 X 4-hr Li power cost; 0.47 X 4-hr Li energy cost
100-hr	1.8 X 4-hr Li battery power cost; 0.072 X 4-hr Li battery energy cost	1.8 X 4-hr Li power cost; 0.072 X 4-hr Li energy cost

Table 3: Scenarios Offering Four Types of LDES Simultaneously

Duration	Vary efficiency, constant power cost	Vary cost, constant "Y" efficiency
4 hrs	1 X 4-hr Li power cost or 1 X 4-hr Li energy cost; 85%	1 X 4-hr Li power cost or 1 X 4-hr Li energy cost; 85%
8 hrs	1 X 4-hr Li power cost or 0.5 X 4-hr Li energy cost; **75%**	**1.2** X 4-hr Li power cost or **0.6** X 4-hr Li energy cost; **Y%**
12 hrs	1 X 4-hr Li power cost or 0.33 X 4-hr Li energy cost; **70%**	**1.4** X 4-hr Li power cost or **0.47** X 4-hr Li energy cost; **Y%**
24 hrs	1 X 4-hr Li power cost or 0.17 X 4-hr Li energy cost; **60%**	**1.6** X 4-hr Li power cost or **0.27** X 4-hr Li energy cost; **Y%**
100 hrs	1 X 4-hr Li power cost or 0.04 X 4-hr Li energy cost; **50%**	**1.8** X 4-hr Li power cost or **0.072** X 4-hr Li energy cost; **Y%**

Core Scenario Description Used for SWITCH Modeling

SWITCH-WECC[2] modeled the WECC with 50 load zones featuring a high geographic and temporal resolution for renewable resources in the WECC.

In the case of the WECC, the model included all 365 days in 2050, sampling every 4 hours, and imposed a zero-emissions carbon cap constraint. The model considered 7,000 plus possible candidate projects geolocated for deployment of solar, wind, geothermal, etc. (considering land and environmental constraints). The optimization model was free to choose power capacity and energy capacity for the installed storage assets, i.e., duration was not predetermined; it was an output.

Within SWITCH, LDES was modeled by providing a cost for $/kW and a separate cost for $/kWh with the duration selected by the model to provide the lowest-cost outcome. The two cost inputs were varied to explore a wide parameter space. The efficiency was fixed at 75 percent, the efficiency used for the 8-hr LDES in the left side of Table 3, reflecting an efficiency that was achievable for several LDES technologies.

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[2] More information on the SWITCH power system planning model is available at https://github.com/REAM-lab/switch.

Sensitivity Analysis

Modifications to the core scenarios include testing the impacts of:

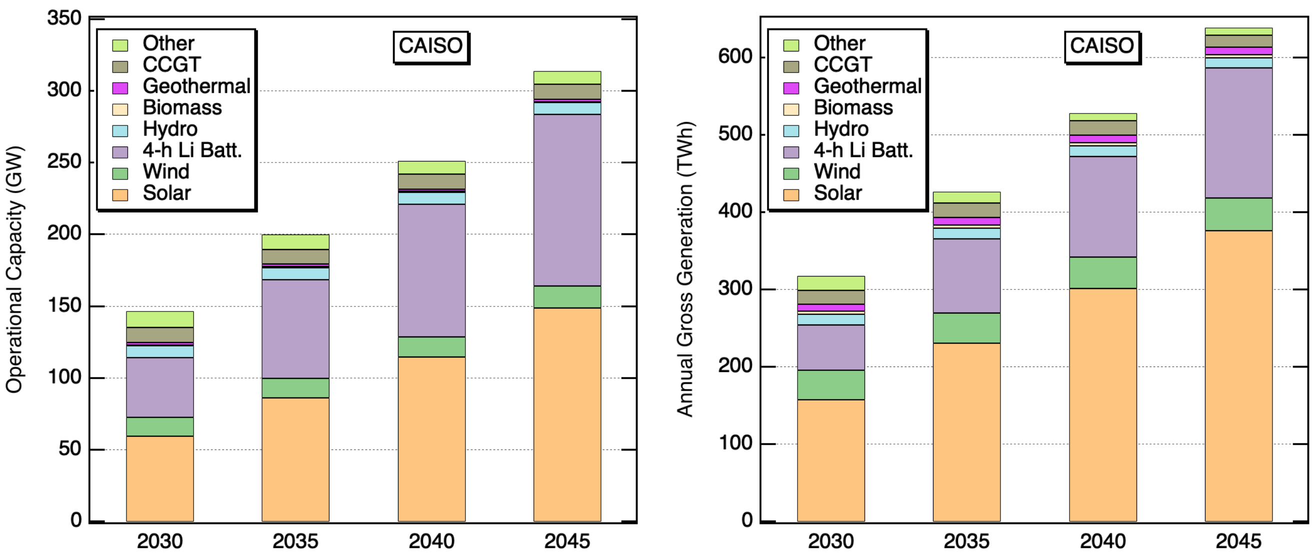
a. EV charging profiles on the need of storage
b. Solar and wind generation profiles on the need of storage
c. Oxy-combustion on the need of storage
d. Use of electrolyzers as a flexible load
e. Storage costs and transmission deployment caps in the WECC
f. Storage implementation in the WECC

CHAPTER 3:
Results

Core Scenario

The capacity expansion for the core scenario before introduction of LDES is shown in Figure 3. Subsequent graphs omit hydro, biomass, geothermal, combined-cycle gas turbine (CCGT), and other (mainly non-CCGT fossil and nuclear), as they are usually unchanged with the introduction of LDES.

Figure 3: Capacity Expansion Selected for RESOLVE Core Scenario Without LDES



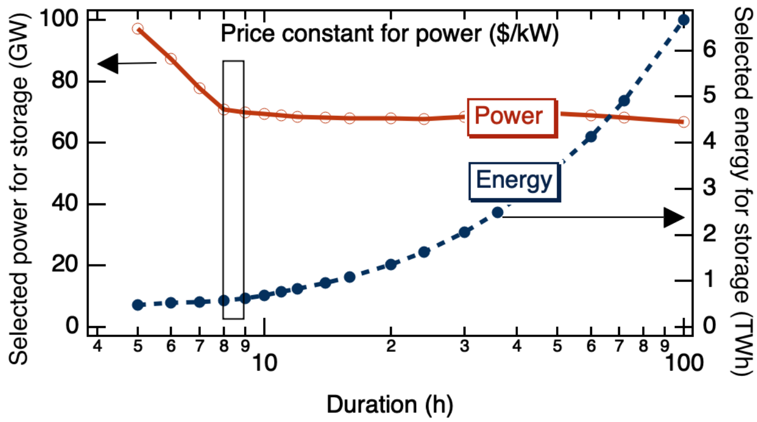
Core Scenario — Optimal Duration

A capacity expansion model is designed to select the lowest-cost solution. However, there is large uncertainty in future costs. As discussed above, even the cost of Li batteries currently has an uncertainty factor of two. A strategy for evaluating the grid's need for LDES when the costs are not clear is to document the needed power capacity and needed energy capacity as a function of LDES duration when only one storage option is offered to the model (method "a" in the section titled Core Scenario Description Used for SWITCH Modeling, above). For shorter duration storage, the energy capacity can be sized to meet the most stressful time, while the power capacity must be overbuilt. On the other hand, as shown in Figure 4,[3] for the longest duration storage, the power rating (the solid red curve plotted on the left y axis) is lower, but the energy capacity (the dotted blue curve plotted on the right y axis) is overbuilt. Although the ideal duration depends on the cost(s) and efficiencies, if a duration between 8 hrs and 9 hrs is selected (the rectangle in Figure 4), the power overbuild will be less than 2 percent and the energy capacity overbuild will be less than 15 percent. This straightforward

[3] For 2045, this assumes LDES with 85 percent efficiency and a cost of $66/(kW-y), which translates to about $950/kW.

assessment can be repeated for each scenario to identify how the need for storage changes. However, the ideal solution includes multiple storage types.

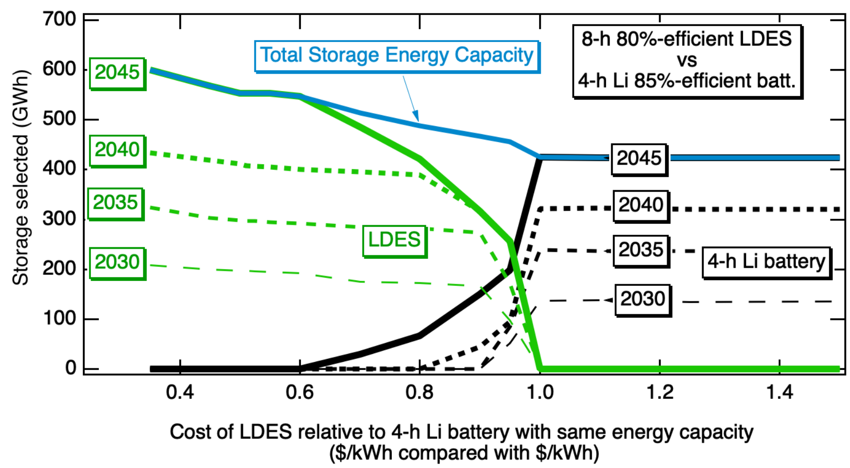
Figure 4: Power and Energy Capacity Selected for RESOLVE Baseline Scenario

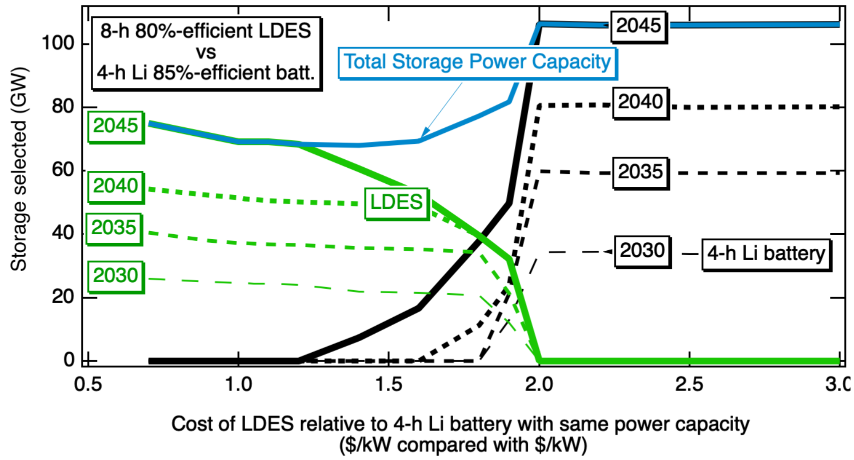


Core Scenario — Competitive Cost

The competition between LDES and 4-hr Li batteries can be probed directly by fixing the 4-hr Li battery cost and varying the LDES cost (Figure 5). In this case, an 8-hr 80 percent efficient LDES needs to be lower in cost than a 4-hr Li 85 percent efficient battery when considering the cost of the energy capacity.

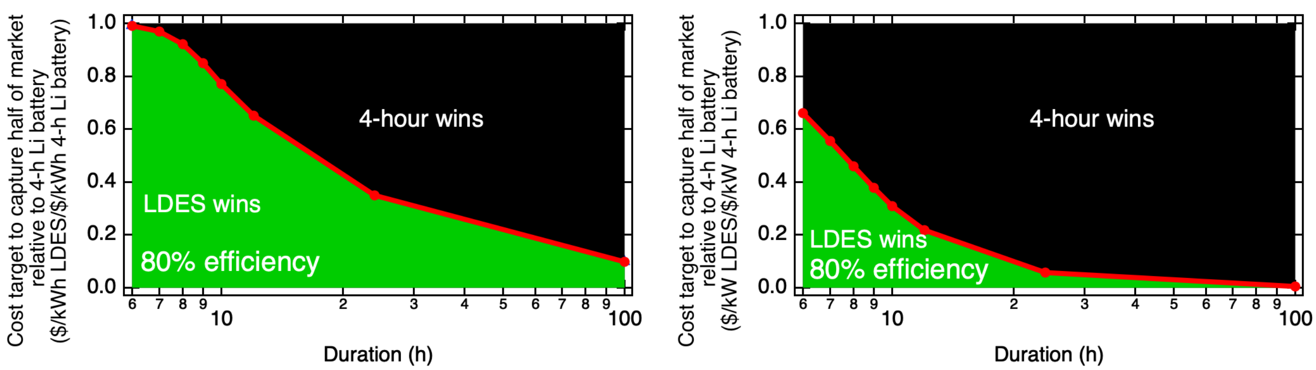
Figure 5: Selection of 4-hr Li Batteries Versus LDES





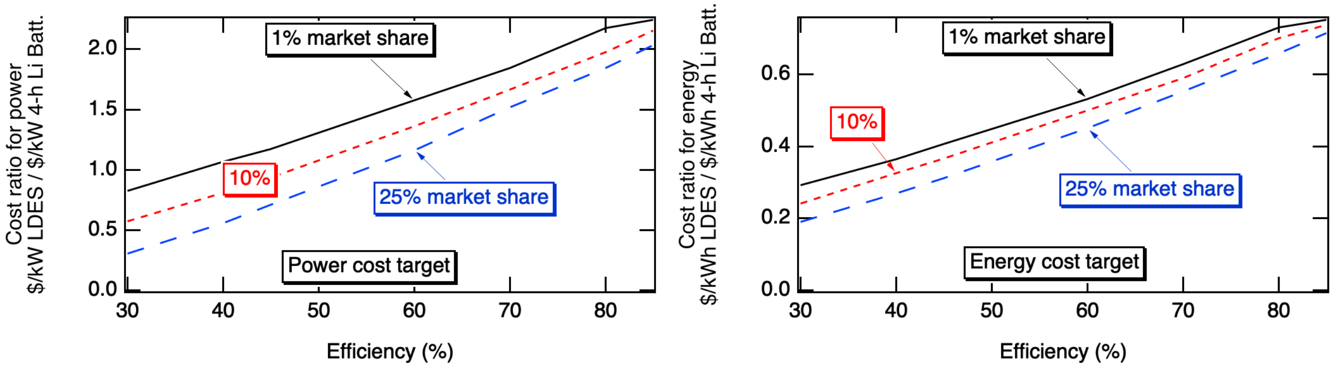
The target price for 50 percent adoption of an LDES product can be derived from Figure 5 by identifying the cost ratio at which the LDES and 4-hr Li battery selections are equal (about 0.95 when comparing the energy costs, or 1.8 when comparing power costs in Figure 5). Figure 6 shows this target price as a function of the 80 percent LDES duration, with the relative cost per installed kWh on the left and the relative cost per installed kW on the right. Up to about an 8-hr duration, the competitive cost in $/kWh for the LDES approximately equals the $/kWh for the 4-hr Li batteries. For durations greater than 8 hrs, the LDES $/kWh target cost drops quickly.

Figure 6: Cost Target for 50 Percent Market Share as a Function of LDES Duration



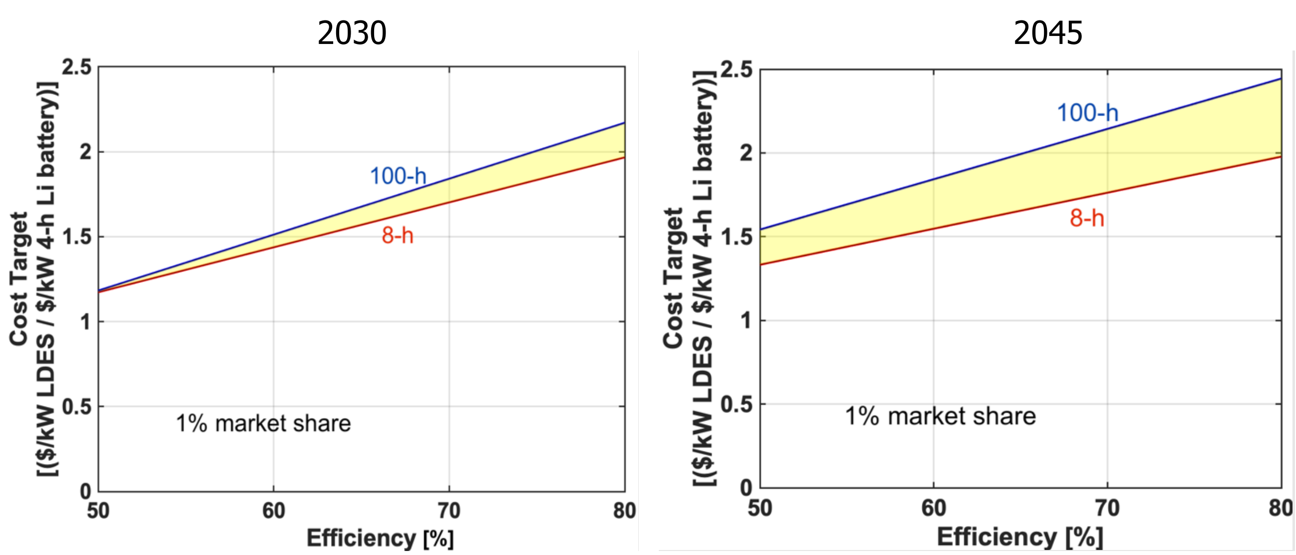
Longer duration LDES that may be needed to cycle only a few times per year may provide higher value, justifying a higher cost target, if the adoption level is taken to be small. Figure 7 shows higher cost targets for lower efficiency 12-hr LDES that is adopted for a small fraction of the market (e.g., 1 percent).

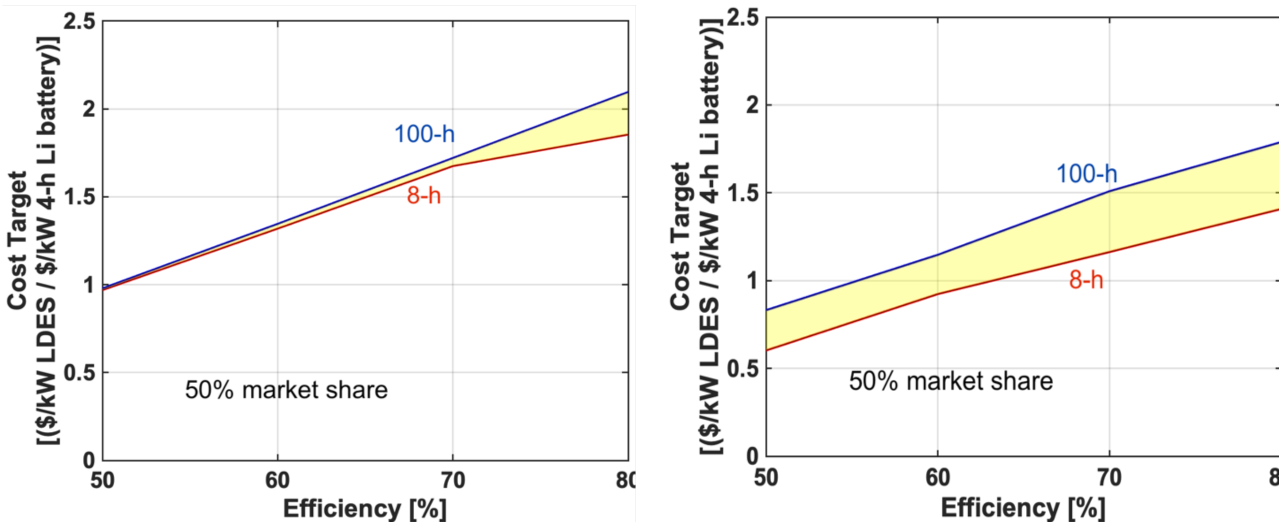
Figure 7: Cost Target for LDES Versus Efficiency for Three Market Share Levels



The cost target to capture 1 percent or 50 percent of the market in 2030 or 2045 is shown as a function of LDES efficiency in Figure 8 for 8-hr and 100-hr LDES. As anticipated, efficiency is a very important metric, with cost targets changing by a factor of about two as the efficiency increases from 50 percent to 80 percent. The effect of efficiency is less critical for early adoption (1 percent of market share) (Figure 7 or 8).

Figure 8: Cost Targets for LDES as a Function of Efficiency

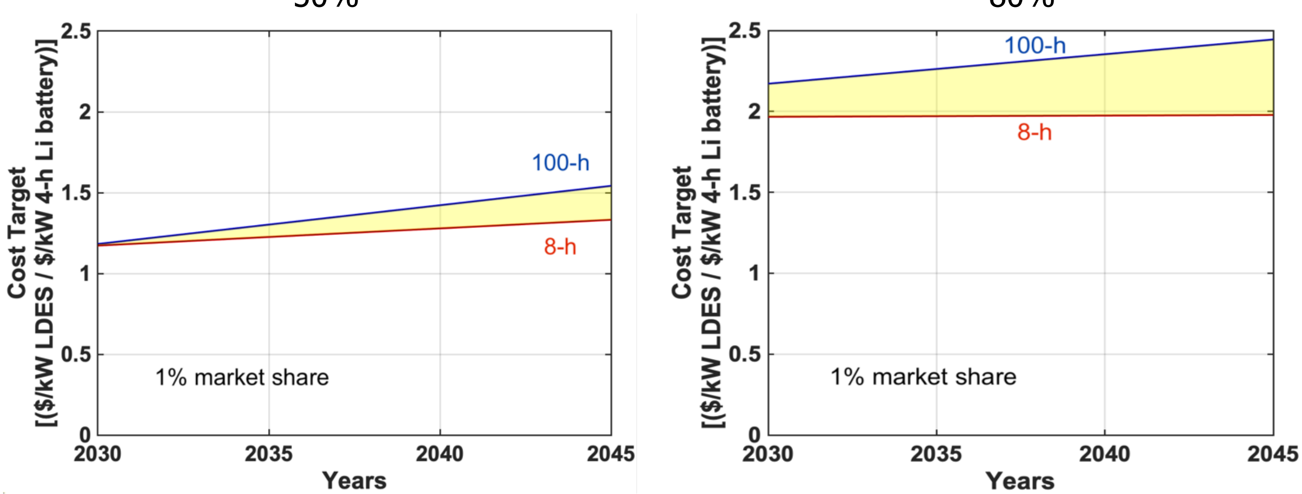


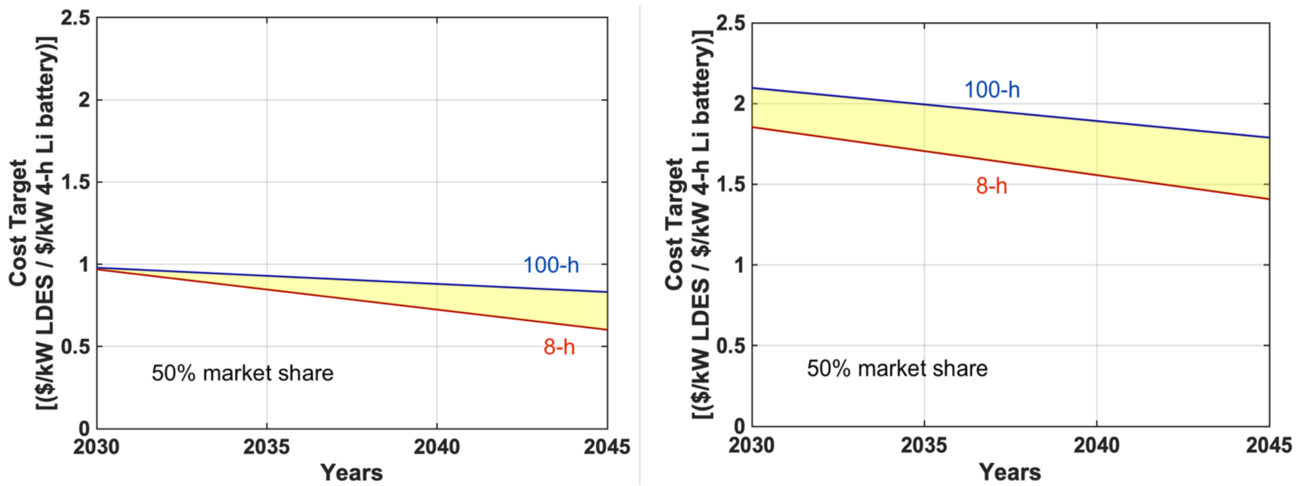


As restrictions on emissions are tightened, the need for LDES is likely to increase and the market will be willing to pay more for LDES relative to a 4-hr Li battery in 2045 than in 2030. Indeed, this appears to be true for the adoption of a small amount of 100-hr LDES, as shown in Figure 8 in the top graphs (1 percent market share). However, surprisingly, for 50 percent market share adoption in 2045, the model shows that LDES has to drop in price faster than the 4-hr Li batteries, suggesting that the best time to launch LDES products for wide adoption may be before 2030 rather than waiting until closer to 2045. This effect is seen more clearly in Figure 9 for the 50 percent and 80 percent efficiency cases, where the cost targets are plotted as a function of adoption year.

Figure 9: Cost Targets for LDES as a Function of Modeled Year

50% 80%

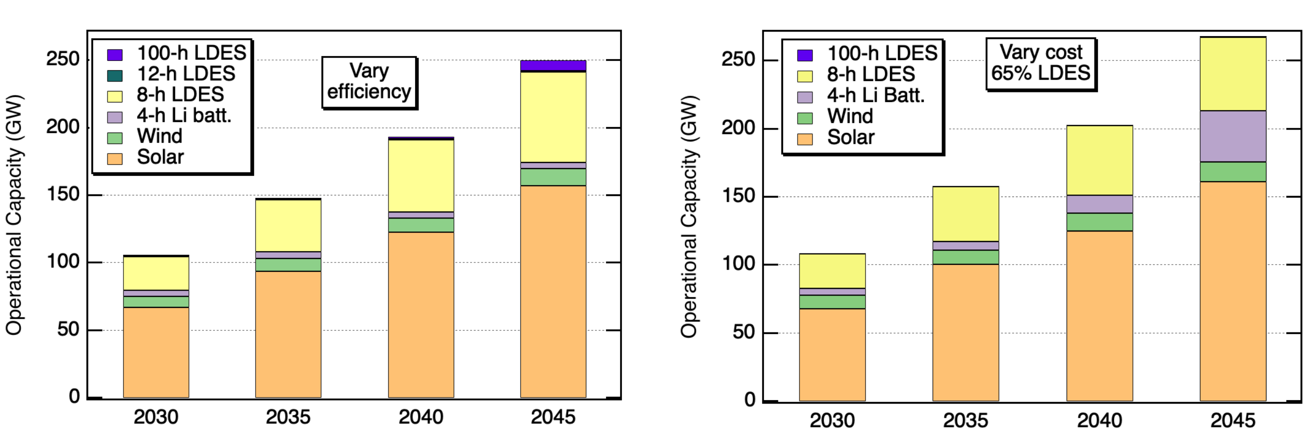




Core Scenario — Adding Multiple Types of LDES Simultaneously

The capacity expansion results for the core scenario are shown in Figure 10 for LDES scenarios simultaneously offering four types of LDES, as described in Table 3. No 24-hr LDES was selected. For the selected scenarios; the model had difficulty differentiating between 4-hr Li, 8-hr, and 12-hr storage. As shown in Figure 9, a very small change in the assumed cost can change the conclusion about which storage dominates. Nevertheless, the conclusions for the set of storage options in Table 3 show that 4-hr Li and 8-hr storage dominate, with 100-hr becoming more attractive in 2045. When higher efficiency and lower cost were assumed, LDES gained market share.

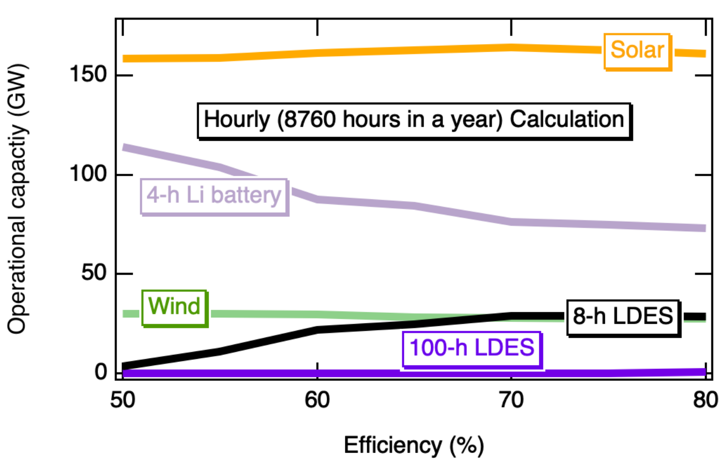
Figure 10: Capacity Expansion Selected for Table 4 Scenarios



Core Scenario — Optimal Efficiency and Duration

For the LDES scenario "vary cost" in Table 3, the efficiency (Y% in the table) has a profound effect on the LDES' competition with 4-hr Li batteries, with LDES benefiting from at least 60 percent to 70 percent efficiency, as shown in Figure 11. The calculation in Figure 11 was only for 2045, using an hourly calculation to differentiate between the types of storage more accurately.

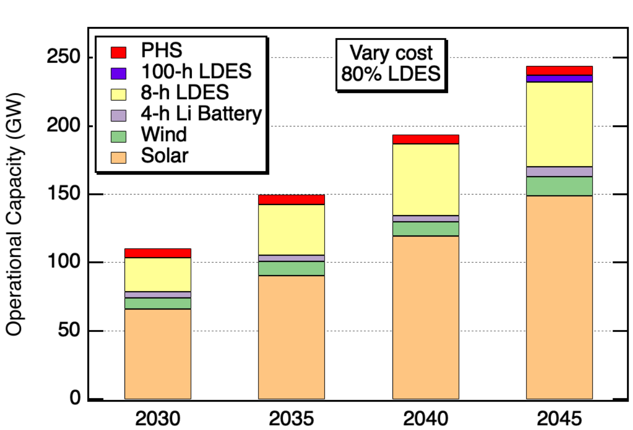
Figure 11: Selected Operational Power Capacities, as a Function of LDES Efficiency

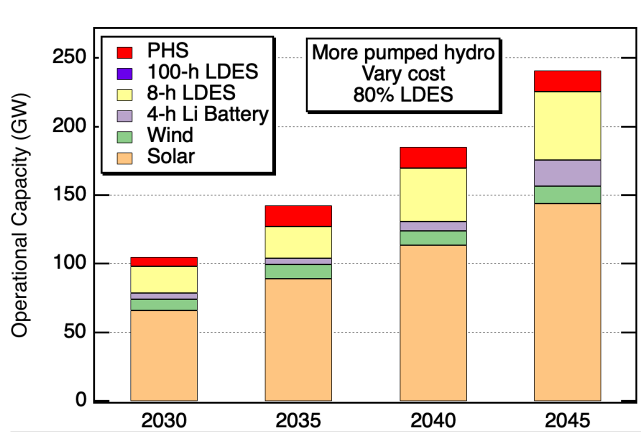


Pumped Hydropower Storage

Historically, pumped hydropower storage (PHS) has been the largest LDES technology. As storage is becoming more critical, several additional PHS projects have been proposed (see Kurtz, 2023). The results for the anticipated capacity expansion, in Figure 12 on the right, show how the additional pumped hydropower primarily replaces 100-hr LDES. PHS is a well-proven technology and, if sites can be identified that are both economical and have minimal environmental impact (as may be the case for closed-loop systems), PHS could serve as a primary asset for the storage with the longest durations.

Figure 12: Capacity Expansion for Baseline (left) and High Pumped Hydro





Impact of EV Charging Profiles on Selected Storage

The project studied the effects of three light-duty EV charging profiles on the need for storage. The profiles were taken from a recent study funded by the CEC (2024). As illustrated in Figure 13, the first case, called 'Nighttime charging,'[4] pictures a situation where 95 percent of EV owners have access to home charging and these EVs commence charging at midnight, reflecting existing time-of-use pricing. Consequently, in this case, EV charging demand peaks

[4] In the CEC study, this case is called the "High Residential Access" alternative future.

at midnight and is followed by a gradual decrease. The second scenario, referred to as 'Unconstrained charging' in Figure 13, assumes a spontaneous charging pattern without controlled schedules or economic incentives. Here, the peak charging is projected to occur in the evening, when individuals return home from work and plug in. Finally, the 'Daytime charging'[5] case incorporates two distinct periods of high demand: one during the middle of the day and another at midnight. This load profile assumes that daytime charging is common, probably using workplace charging stations.

Figure 13: Light-duty Electric Vehicle Load (GW) Profiles

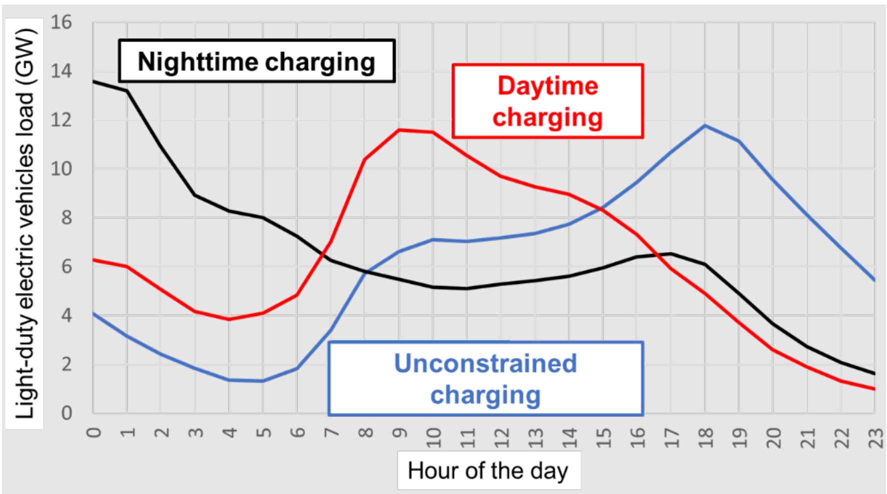
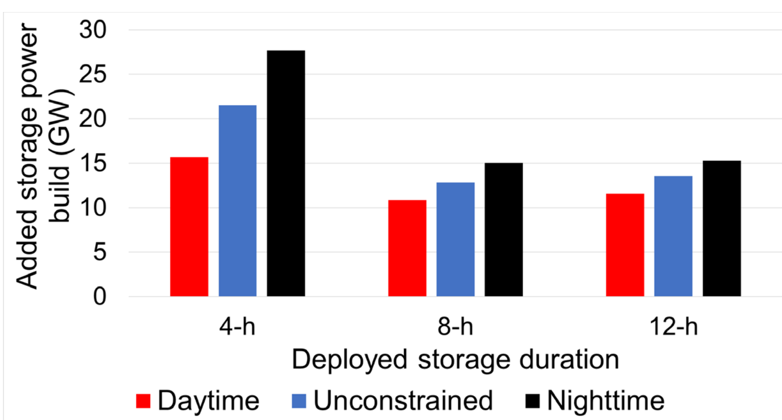


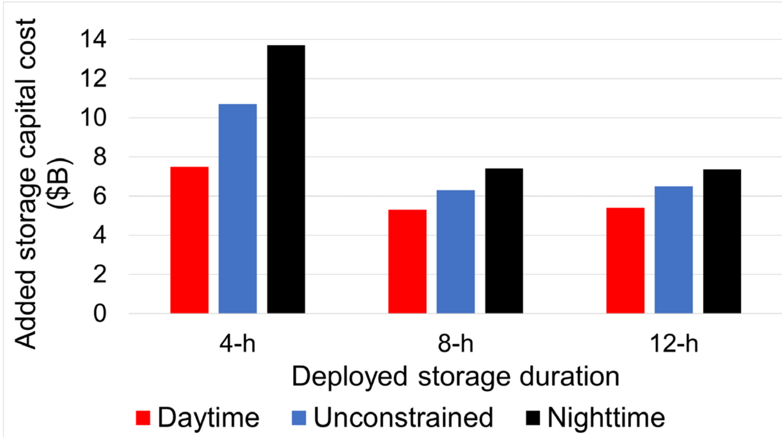
Figure 14 exhibits the effect of the three charging cases on the additional storage that is needed to provide charging for 15 million vehicles, assuming 40 miles/day, resulting in total load of 55 trillion watt-hours per year (TWh/y). The LDES technologies analyzed here are 4-, 8- and 12-hour storage with 85 percent efficiency and the baseline power costs $/kW for 4-hr Li batteries. As Figure 14 indicates, and as expected, daytime charging shows the smallest need for storage. The smaller storage needed when deploying daytime charging could correspond to cost differences of up to $1 billion, according to Figure 15. This result motivates investment in daytime (e.g., workplace) charging infrastructure (ZareAfifi and Kurtz, 2023).

Figure 14: Added Storage to Meet EV Loads for Three EV Charging Profiles



[5] In the CEC study, this case is called the "Happy Hour" alternative future.

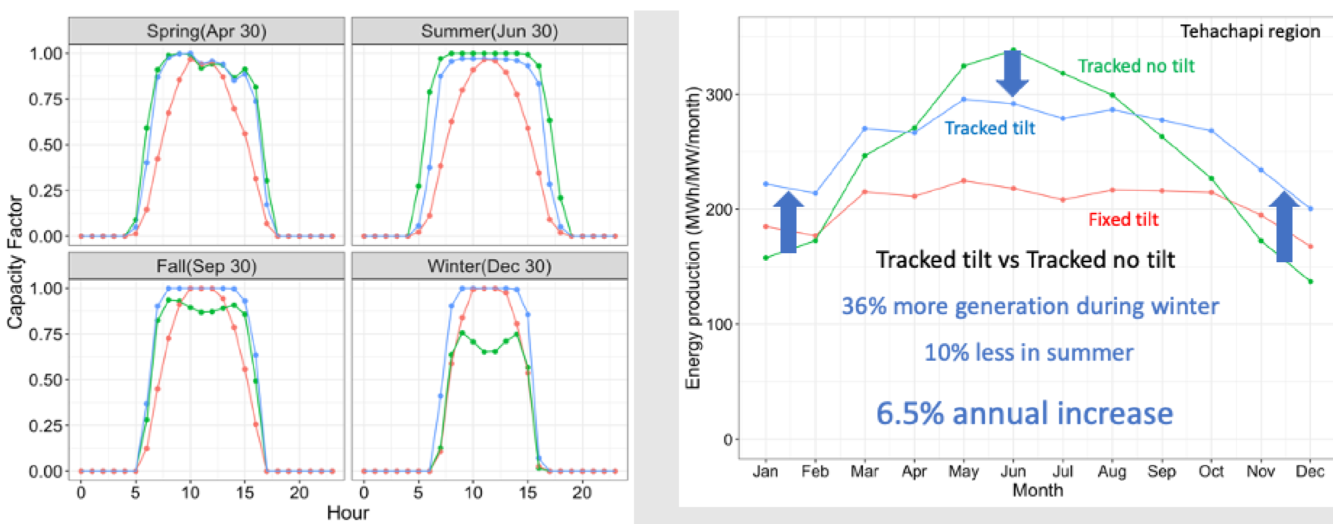
Figure 15: Storage Capital Costs for the Cases in Figure 14



Impact of Solar and Wind Generation Profiles on Storage

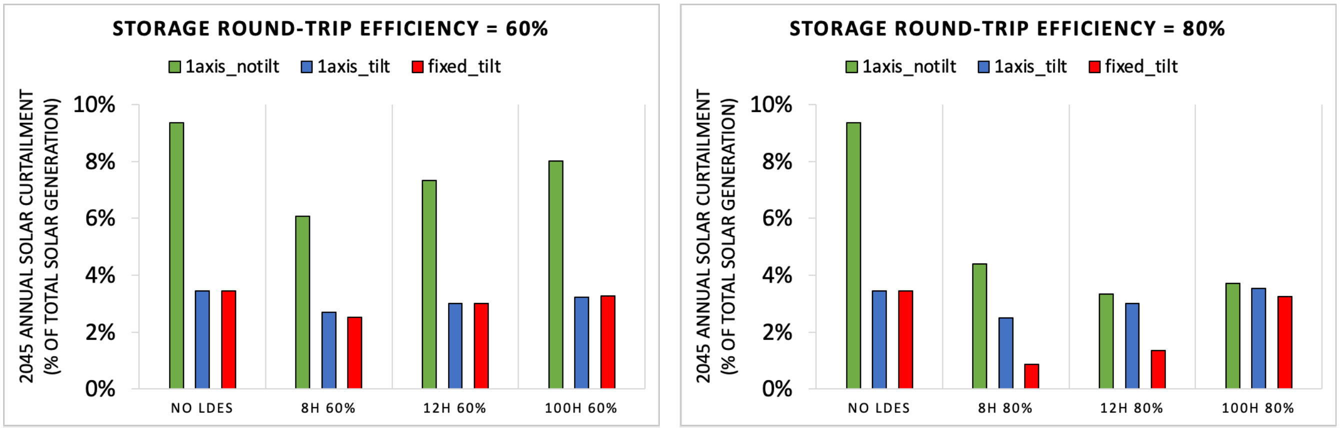
The need for storage is driven by the mismatch between the generation and demand profiles. The project included three solar mounting configurations: 1) one-axis tracked with no tilt (most common today), 2) one-axis tracked with south-facing tilt, and 3) fixed mounting with south-facing tilt. The solar generation profiles (Mahmud and Kurtz, 2023) are characterized in Figure 16.

Figure 16: Daily and Monthly Solar Generation Profiles for Three Solar Configurations



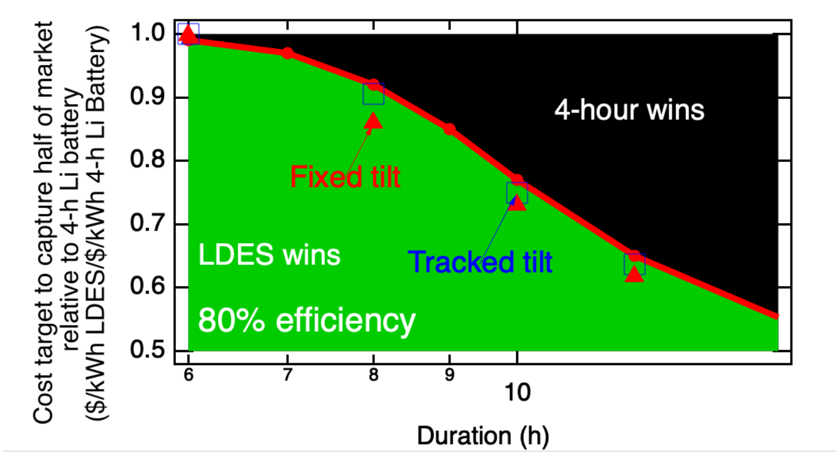
The effect of the mounting configurations is most apparent when comparing the curtailment, as shown in Figure 17, for the baseline and LDES described in Table 2. The strongly reduced curtailment for the south-facing tilt configurations reflects the better seasonal match between generation and demand profiles, but the effect may be too small to motivate using a higher cost design.

Figure 17: Annual Solar Curtailment for Three Solar Configurations



For 50 percent market adoption, the mounting configuration has little effect on the cost target, as shown in Figure 18, for a competition between 80-pecent LDES and 4-hr Li 85 percent storage. When the fixed-tilt mounting is used, the LDES needs to reach a slightly lower cost.

Figure 18: Cost Targets for LDES as a Function of Duration



Similarly, the effect of efficiency on the cost target does not change substantially when using the three mounting configurations, as shown in Figure 19. The capacity expansion results shown in Figure 20 show less solar built when south-facing tilt is added to the one-axis tracking and more solar built when south-facing tilt is used in a fixed configuration, reflecting the yields of these solar configurations. When 80 percent 8-hr LDES is added to the core scenario (using the cost shown in Table 2), the 4-hr Li batteries are replaced by 8-hr LDES with 49.5 GW of 8-hr LDES adopted for the two south-facing configurations, compared with 47 GW for the one-axis-tracked configuration with no tilt. This larger adoption of LDES correlates with a reduced use of wind, reflecting the added value of the south-facing tilt to the system. When 60 percent 8-hr LDES is added, 4-hr Li batteries are retained, with, again, more storage being built for the two south-facing tilt configurations, although, in this case, the connection to the reduced use of wind is less clear.

Figure 19: LDES Cost Target as Function of LDES Efficiency for Three Configurations

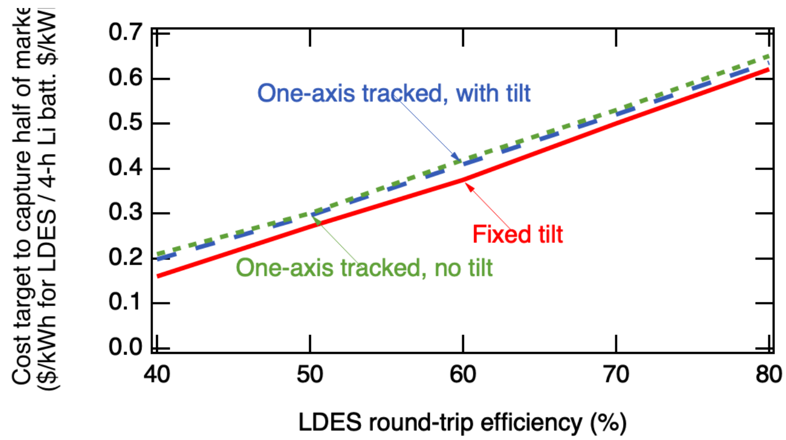
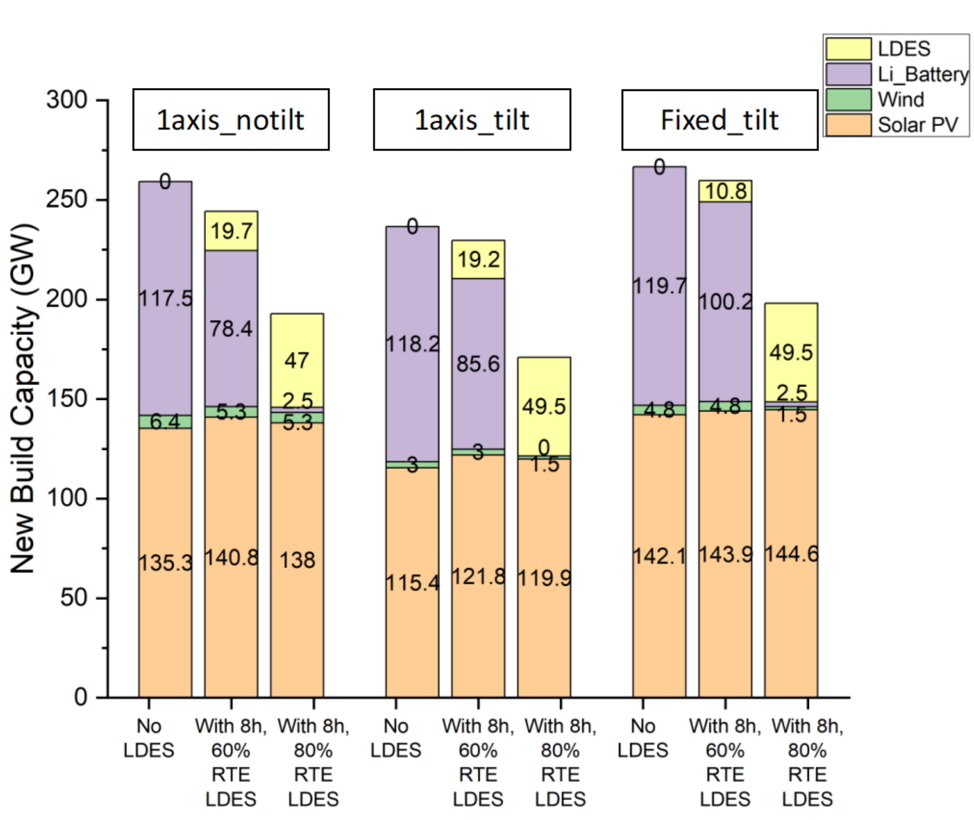


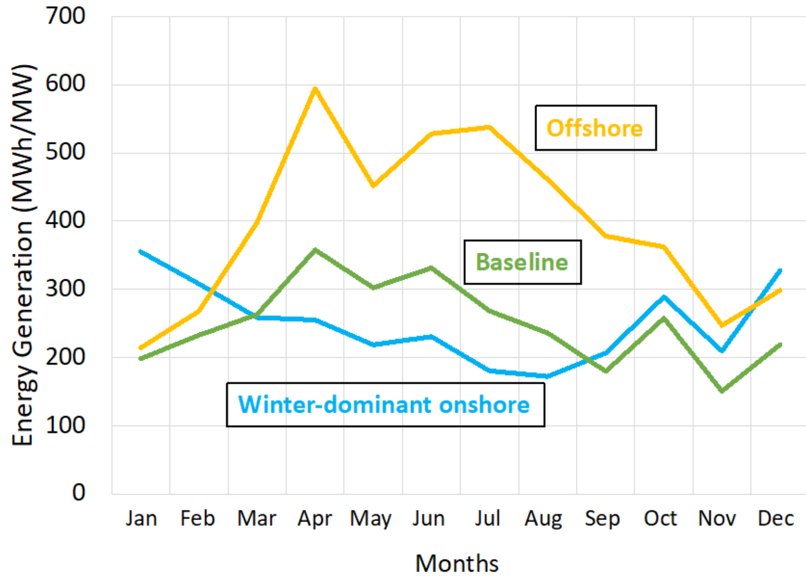
Figure 20: Selected Capacity Expansion for Three Solar Mounting Configurations



RTE =round-trip efficiency

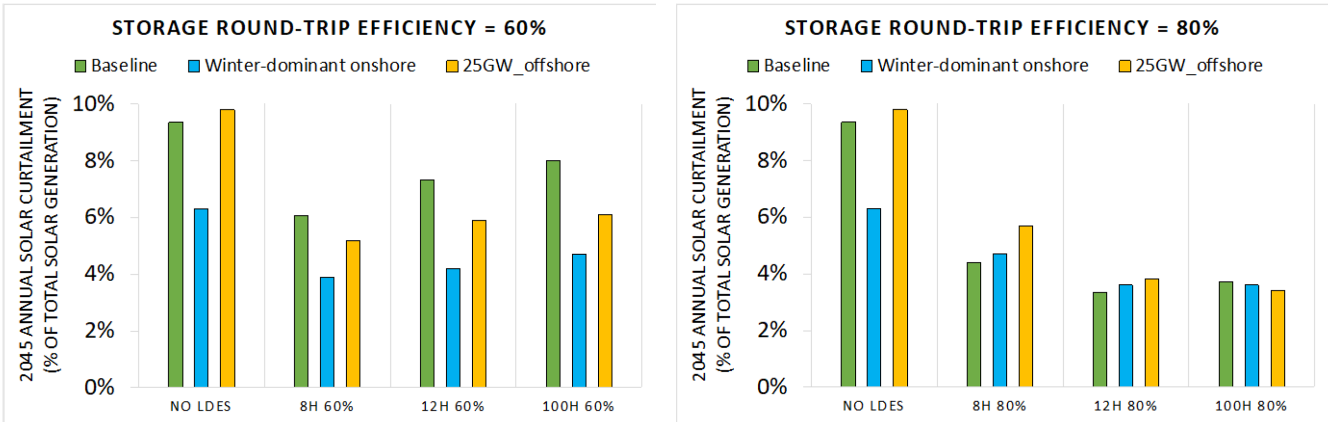
As with solar, wind generation profiles can affect the modeling results. Figure 21 shows a winter-dominant wind generation profile (Mahmud et al., 2022) and an offshore wind-generation profile (Mahmud and Kurtz, 2023) in comparison with the core scenario's generation profile. Notably, the winter-dominant profile can provide generation during the winter, when both solar and today's onshore wind have reduced generation.

Figure 21: Monthly Wind Generation Profiles



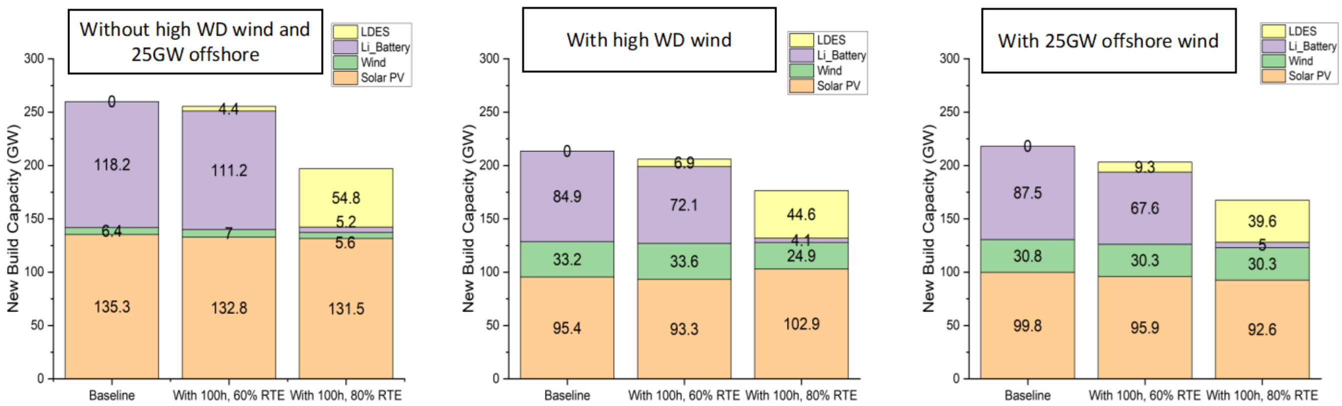
By providing better seasonal balance, the winter-dominant wind is effective at reducing curtailment of solar generation, as shown in Figure 22 for 60 percent efficient LDES. This optimization used the same LDES assumptions as those of Figure 21. When 80 percent LDES was used, the curtailment was relatively low in all cases.

Figure 22: Annual Solar Curtailment Comparing Wind Profiles



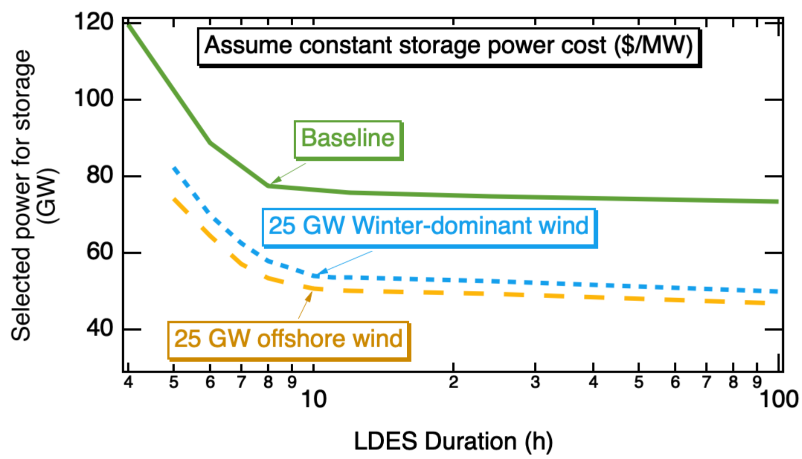
Adding winter-dominant wind or offshore wind reduces the storage needed (Mahmud et al., 2023), as shown in Figure 23, and it shifts the optimal duration to slightly longer, as shown in Figure 24.

Figure 23: New-Build Capacities for Added Wind Scenarios



WD = wind direction

Figure 24: LDES Power Capacity Selected Versus LDES Duration for Wind Scenarios



Impact of Oxy-combustion on the Selected Storage

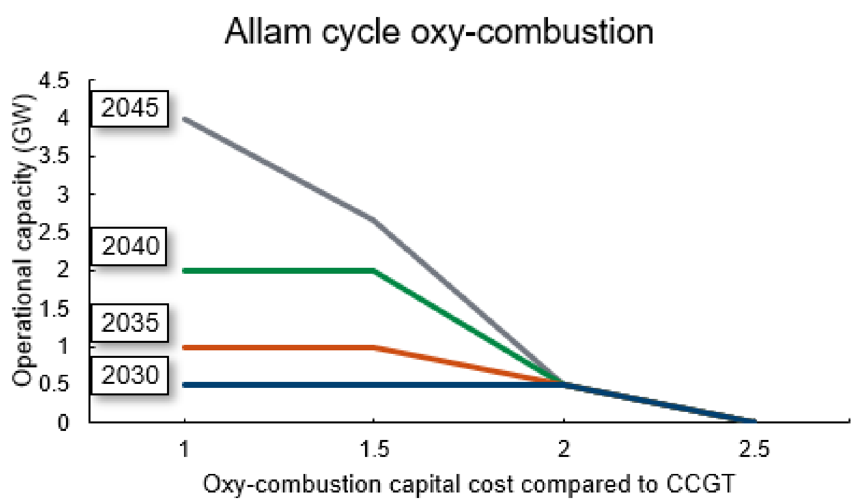
Oxy-fuel combustion, or oxy-combustion, is carbon capture and storage technology that involves burning fuel with nearly pure oxygen (instead of air), resulting in combustion gases primarily composed of CO_2 and water vapor, simplifying carbon dioxide capture in power plant applications. The Allam Cycle employs oxy-combustion technology in a closed-loop cycle, with high-pressure supercritical CO_2 as the working fluid and retaining all emissions by design (Allam et al., 2017). Allam Cycle oxy-combustion was modeled to evaluate its impact on the need for LDES. This technology, with natural gas as a fuel, has an efficiency comparable to a CCGT. For that reason, it was modeled as a CCGT with no associated emissions. The maximum operational capacity in California was limited to the values in Table 4, as an estimate of potential for deployment of additional infrastructure for CO_2 transportation and storage.

Table 4: Model Inputs for Operational Capacity for Oxy-combustion

Year	Maximum operational capacity (GW)
2030	0.5
2035	1
2040	2
2045	4

The cost range considered was from 1 to 2.5 times the cost of CCGT. The model selected to build oxy-combustion to the maximum capacity offered only the case of equal cost. Moreover, when the cost exceeded two times the cost of CCGT, oxy-combustion was not selected at all (Figure 25).

Figure 25: Operational Capacity of Oxy-combustion as a Function of Capital Cost



In this project, 100-hr LDES was considered, with two round-trip efficiencies (60 percent and 80 percent) at a power cost equal to 1.8 times the corresponding cost for 4-hr Li batteries. Figure 26 shows the operational capacities obtained in 2045 for the case without oxy-combustion (left) and the case with oxy-combustion (right). Without oxy-combustion, the selection of 100-hr 60 percent-efficiency LDES is limited. However, 80 percent-efficiency LDES is adopted at a higher level, reducing the capacities of solar photovoltaic (PV) and 4-hr Li batteries. When the oxy-combustion resource is offered at a cost equal to conventional CCGT (Figure 26, right), in all scenarios it is being built to the maximum operational capacity offered (4 GW in 2045). Moreover, solar PV and 4-hr Li batteries capacities are further reduced, while LDES capacities remain practically unchanged.

These results show that the combination of LDES and closed-loop oxy-combustion allows for a reduction in the capacity expansion needed by 2045, as well as in the total system cost.

Figure 26: 2045 Operational Capacities without (Left) and with (Right) Oxy-combustion

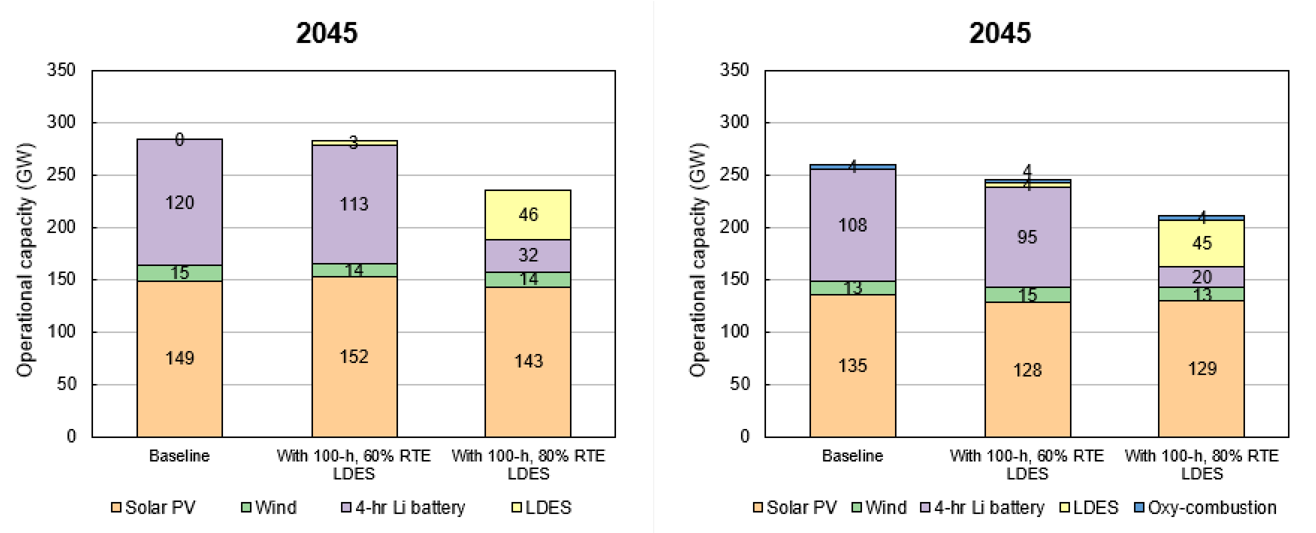
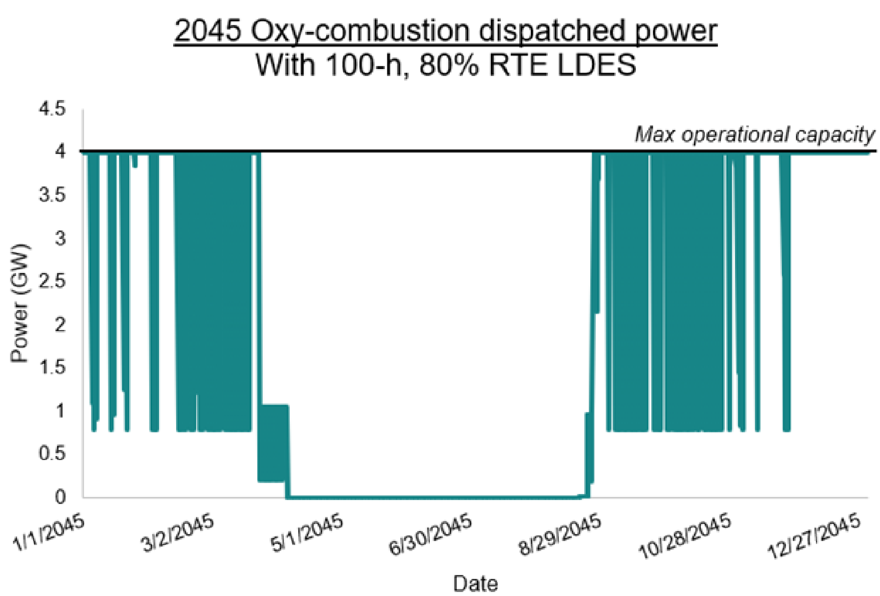


Figure 27 shows the selected operation of the Allam Cycle resource for 2045 and the scenario with 100-hr, 80 percent efficient LDES. Oxy-combustion is providing power during the winter months but is mainly off during the spring and summer months. For the rest of the months, oxy-combustion operates as a dispatchable resource, being on/off depending on the net load.

Figure 27: 2045 Oxy-combustion Dispatched Power



Impact of Electrolyzers on Selected Storage

Electrolyzers for hydrogen production were modeled as a flexible load, to help address demand-supply imbalances in the grid as the share of variable renewable energy increases. The hydrogen produced was considered to be sold at a selected price, for an unspecified use. For defining the hydrogen selling price, a production cost was calculated based on the best available resource for electricity generation in the grid, which was solar PV. In this calculation, an isolated solar PV plus electrolyzer system was defined, where the production cost was defined by the total all-in cost of the solar and electrolyzer, divided by the total hydrogen production. The hydrogen production was set by the capacity factor of the electrolyzer, which, in the isolated system, is equal to the solar resource capacity factor, and by the electrolyzer electricity-to-hydrogen conversion rate (50 kWh/kilogram [kg]). For the best solar resource, in 2030 this production cost was $2/kg of hydrogen ($H_2$).

For this project, multiple LDES were offered, at the same power cost but different efficiencies (Table 3).

The H_2 selling price selected for this project was 99 percent of the modeled production cost. In these conditions, an isolated solar PV plus electrolyzer system would not be selected by the model. However, when the electrolyzers were offered to the grid, the model selected to build up to 17 GW in 2045, as shown in Figure 28.

Figure 28: Operational Capacities, Without and With Electrolyzer

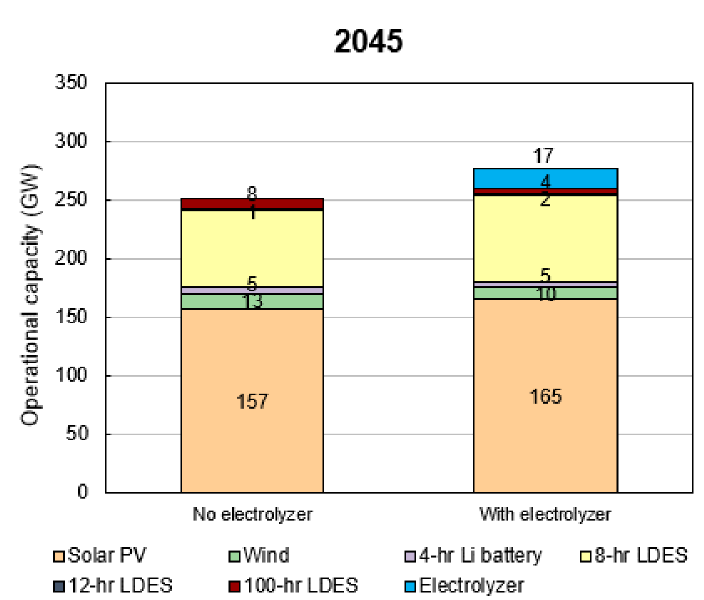


Figure 29 shows that electrolyzers effectively use excess solar generation that would otherwise be curtailed, resulting in a reduction in the total solar energy curtailment in 2045. Moreover, as seen in Figure 30, the capacity factor of the electrolyzers is around 40 percent, above the capacity factors of the solar resources, which are between 21 percent and 33 percent.

Figure 29: Solar Energy Curtailment With Electrolyzer

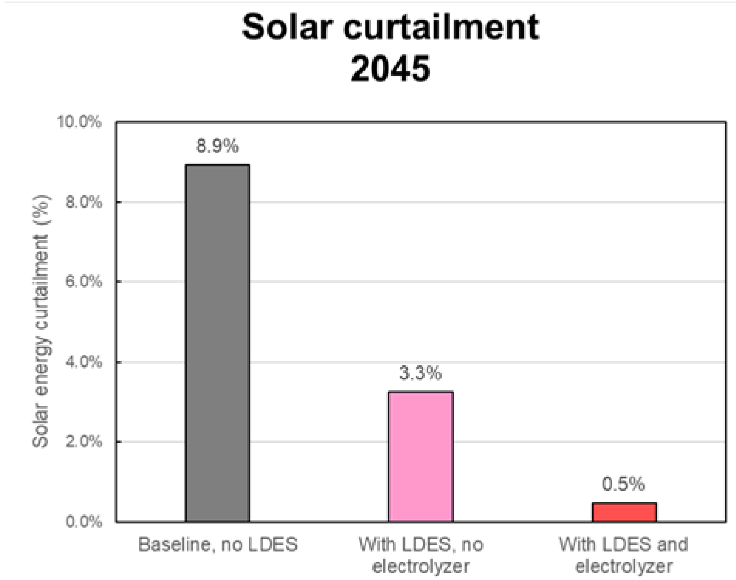
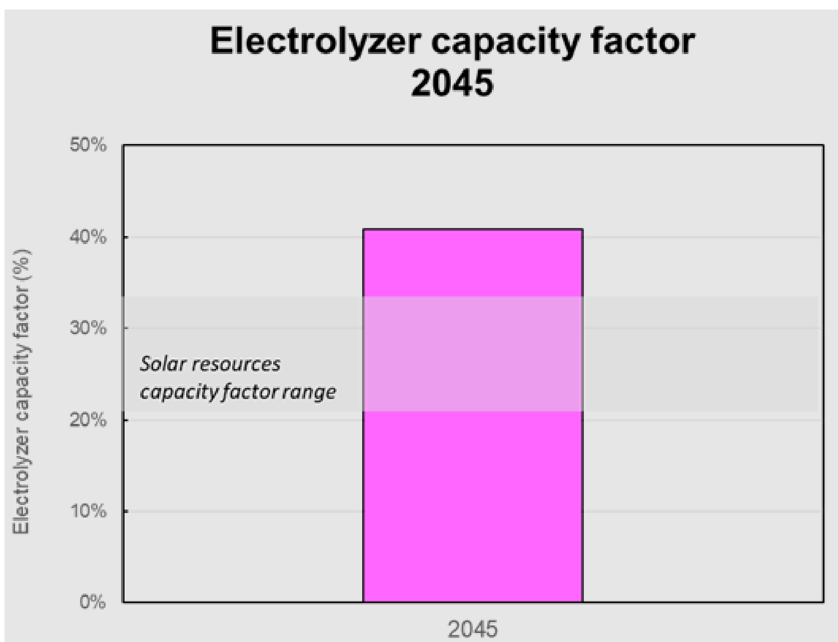


Figure 30: 2045 Electrolyzer Capacity Factor



These electrolyzers effectively work as a flexible load since they are off during winter months and on during summer and full sun days (Figure 31). In general, electrolyzer loads follow solar generation profiles. However, during some spring days they also operate at night (Figure 32). When evaluating the load together with the storage-provided power (Figure 33), it can be seen that, when the energy stored exceeds the demand, it is used for hydrogen generation, **increasing the value of the installed storage**.

Figure 31: 2045 Solar Power Profile, With Electrolyzer Load

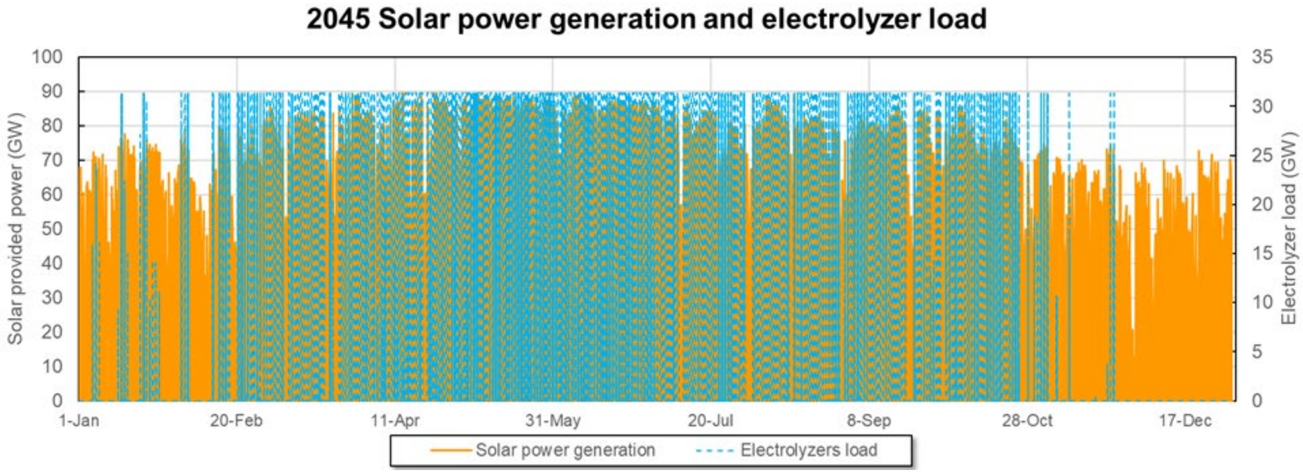


Figure 32: 2045 Solar and Storage Power Profiles, With Electrolyzer Load

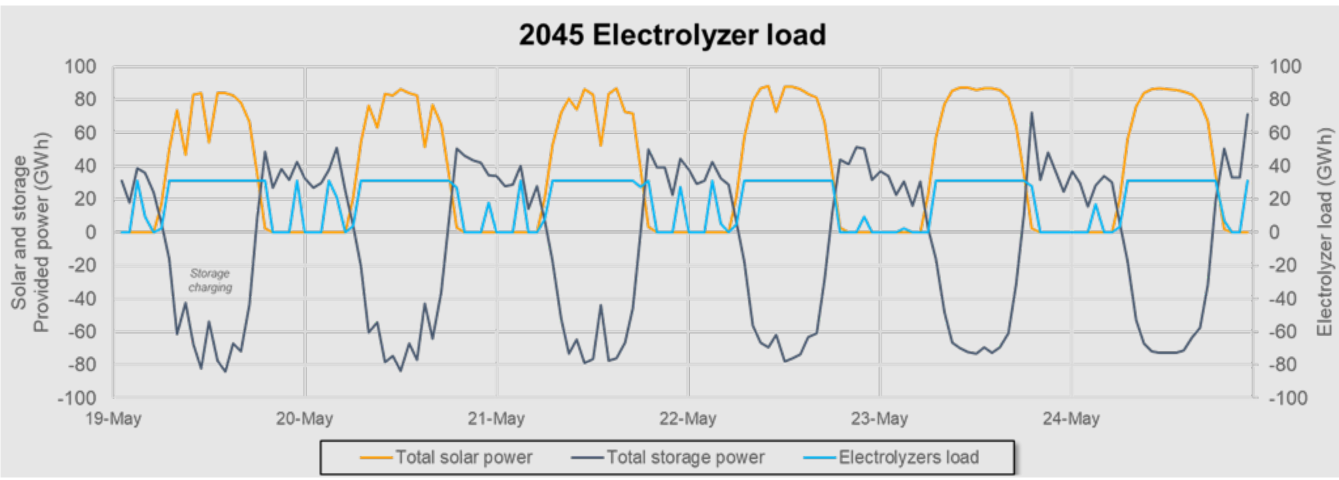
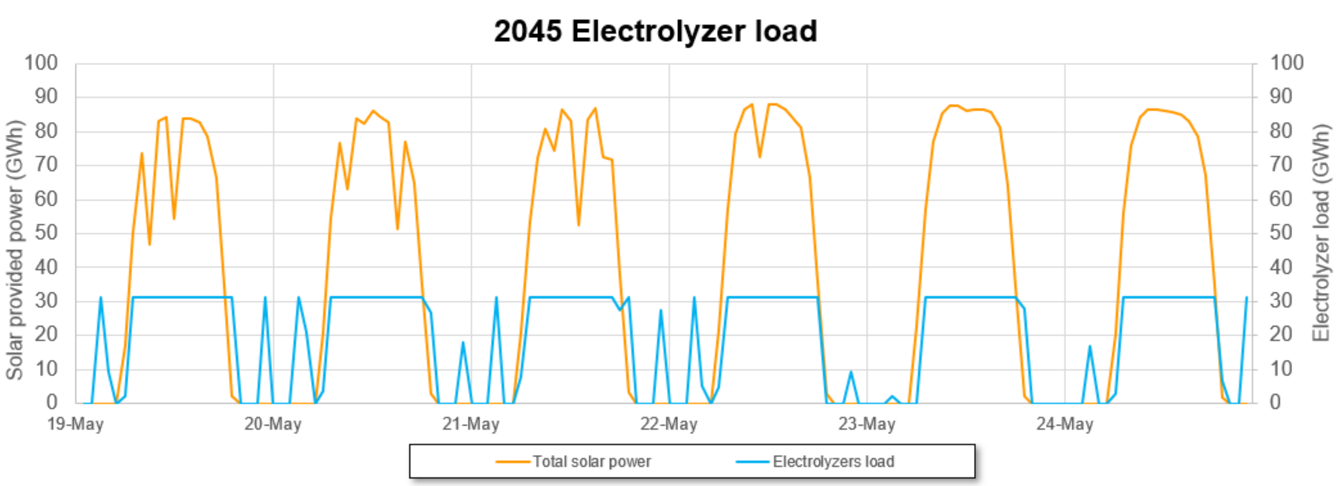


Figure 33: 2045 Solar and Storage Power Profiles



In the future, as the demand for green hydrogen grows, the addition of this large, flexible load will **help to stabilize the grid**, *possibly reducing the need for storage*, **while making the installed storage more valuable**.

Storage-cost Impacts on WECC and California Transmission

This work investigates the least-cost grid expansion for the WECC and California in 2050 under zero-carbon emissions, considering declining storage costs and diminishing transmission capacity expansion, which could be the result of regulatory or political challenges (Table 5).

Lower storage costs and unrestricted transmission capacity expansion result in building up to 31 percent less WECC-wide transmission capacity and 19-pecent less California transmission capacity (Figure 34 and Figure 35). However, the transmission system becomes more loaded as less transmission capacity is built in lieu of storage deployment (the loading is shown as arrows in Figure 36). This is because lower storage costs lead to more solar capacity and to more storage energy and power capacity deployed throughout the WECC (Figure 35). That high solar and storage generation, with the high utilization of the existing transmission capacity, reduces the need for more transmission capacity.

However, high storage and solar installed capacities caused by low storage costs increase California's electricity imports by up to 14 percent of its demand, requiring up to 7.8 GW more transmission capacity between California and its neighbors (Figure 34).

Table 5: Scenarios Analyzed for 2050 WECC Grid Expansion

Scenario	Storage power capacity cost[1] ($/kW)	Storage energy capacity cost[2] ($/kWh)	Transmission capacity cap[3]	Inputs ← Results →	Solar capacity (GW)	Wind capacity (GW)	Storage energy capacity (GWh)	Duration (hrs)
1	325	275	100%		151	15.9	469	7.5
2	325	275	75%		153	15.9	469	7.6
3	325	275	50%		160	16.6	490	7.5
4	325	275	25%		171	16.8	515	7.5
5	325	275	10%		184	17.4	544	7.3
6	325	275	5%		184	17.4	547	7.2
7	140	170	100%		156	15.1	487	7.3
8	140	170	75%		160	15.3	508	7.4
9	140	170	50%		169	15.6	522	7.2
10	140	170	25%		182	16.6	559	7.2
11	140	170	10%		189	16.7	571	6.8
12	140	170	5%		189	16.7	567	6.8
13	10	10	100%		159	7.4	612	7.9
14	10	10	75%		165	8.2	666	8.2
15	10	10	50%		173	8.5	722	8.2
16	10	10	25%		190	9.8	848	9.0

Scenario	Storage power capacity cost[1] ($/kW)	Storage energy capacity cost[2] ($/kWh)	Transmission capacity cap[3]	Inputs ← Results →	Solar capacity (GW)	Wind capacity (GW)	Storage energy capacity (GWh)	Duration (hrs)
17	10	10	10%		205	10.1	1051	10.4
18	10	10	5%		205	10.3	1157	11.3

[1] Power-related costs ($/kW) of the candidate storage projects.
[2] Energy-related costs ($/kWh) of the candidate storage projects.
[3] The upper limit on total built transmission capacity in the WECC.
GWh = gigawatt-hour

Figure 34: Transmission Line Capacities Between the Modeled WECC Load Zones

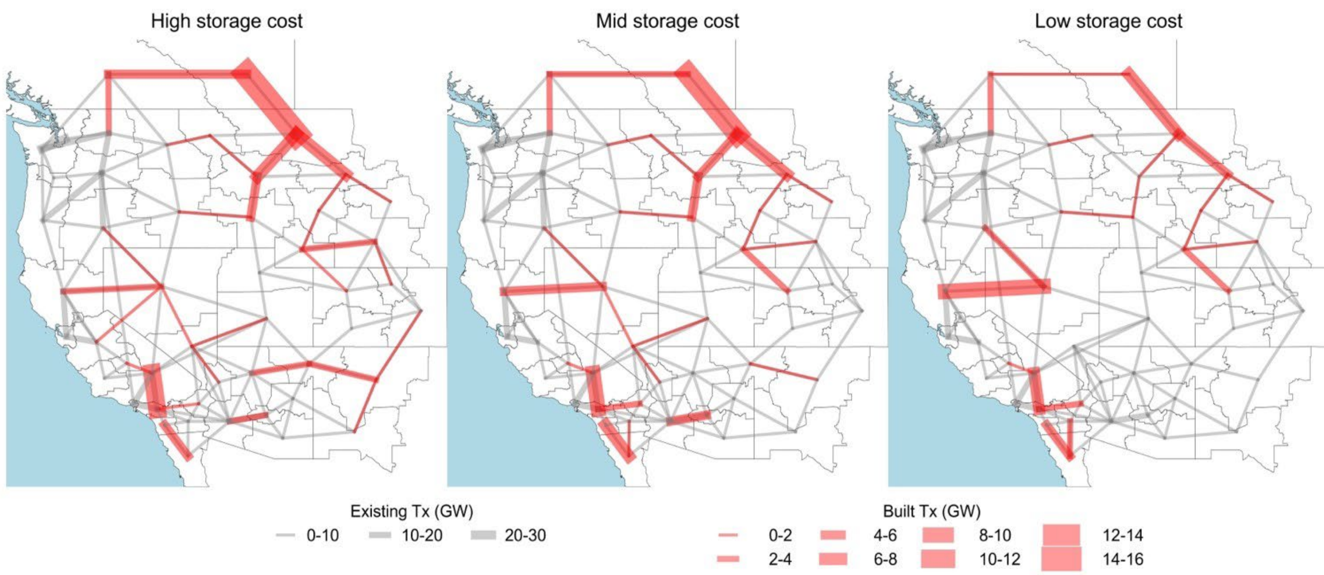


Figure 35: Annual Electricity Generation by State and Transmission Capacities

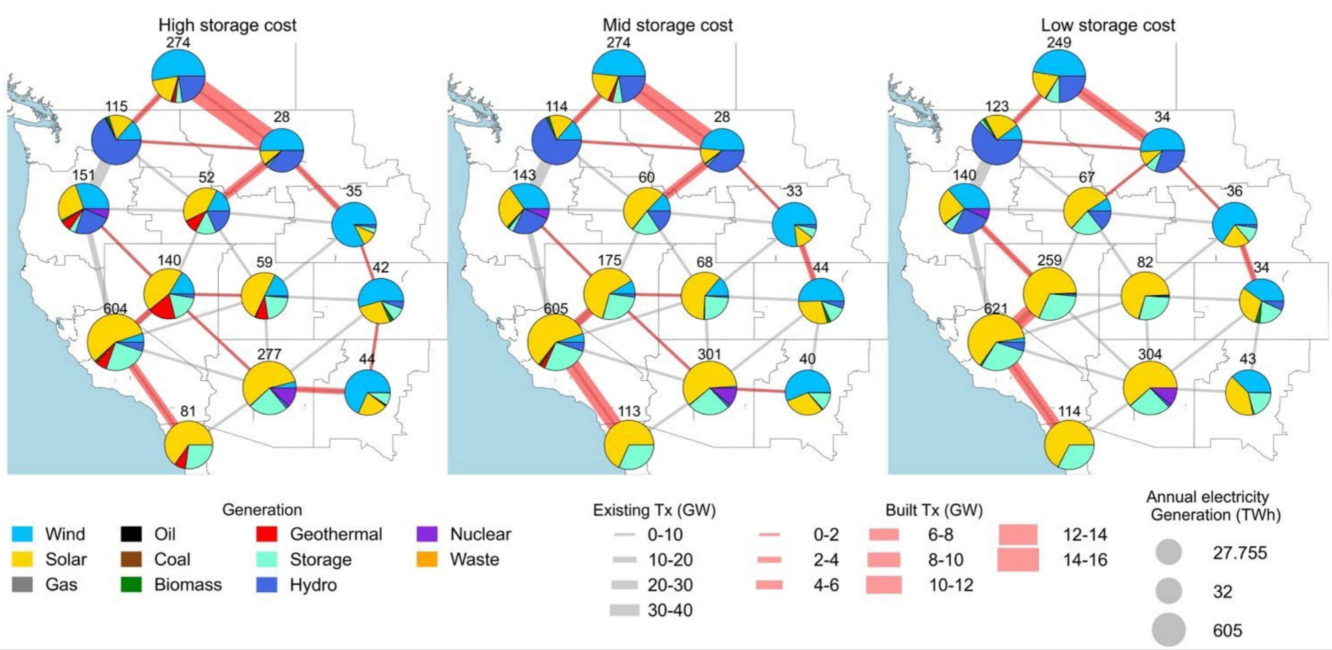
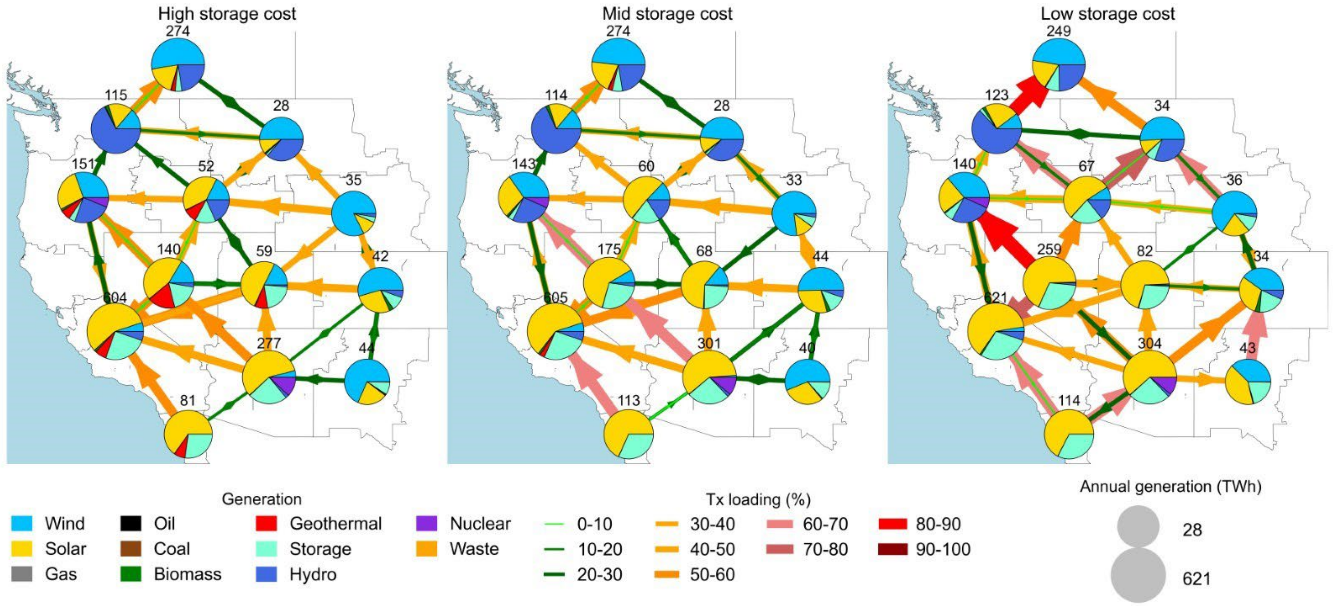


Figure 36: Annual Electricity Generation by State and Loading of Transmission



Declines in the cost of storage can lead to congestion in the transmission corridors, especially from Oregon to California and from California to Arizona. For instance, during California's peak demand of 85 GW (July 25, 2050, 8:00 p.m.), lower storage costs result in higher loading levels of the transmission corridors to supply California's demand. The affected corridors go from Nevada to California, from Oregon to California, and from Arizona to California (Figure 37). The loading levels during California's highest imports ratio (April 4, 2050, 3:00 a.m.) in the transmission corridors from Nevada to California and from Oregon to California were observed to be 90 percent to 100 percent, regardless of the storage costs (Figure 38).

Figure 37: Electricity Generation and Transmission Loading for 85-GW Demand

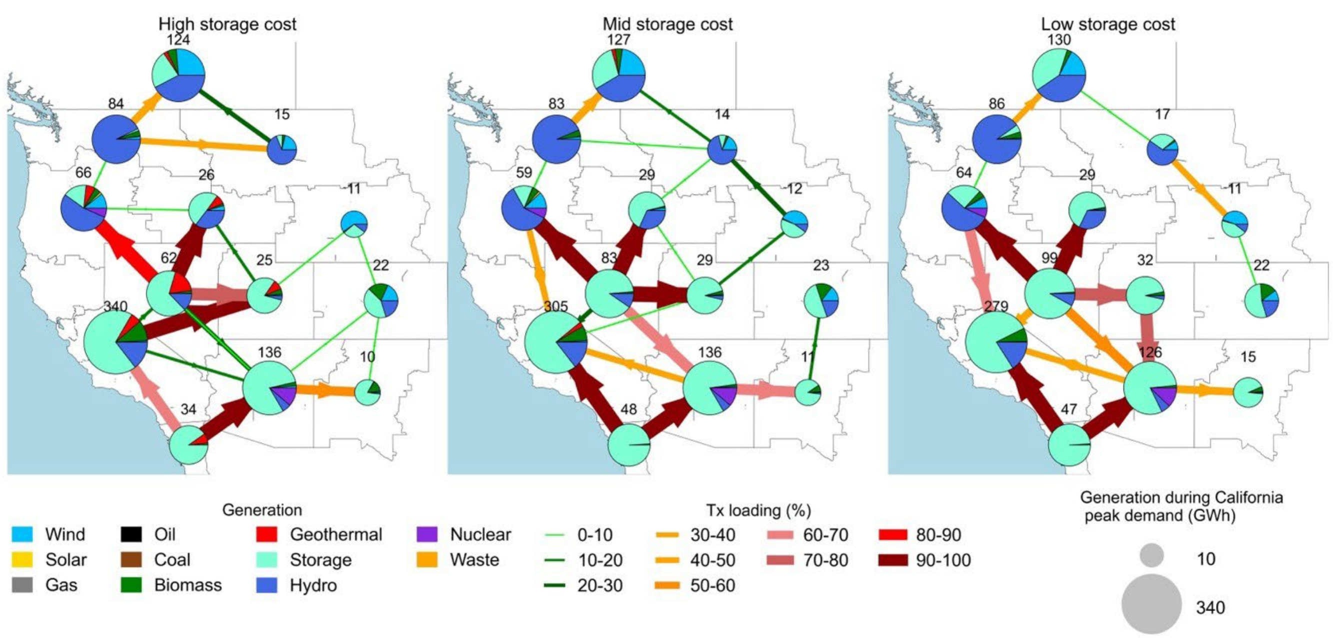
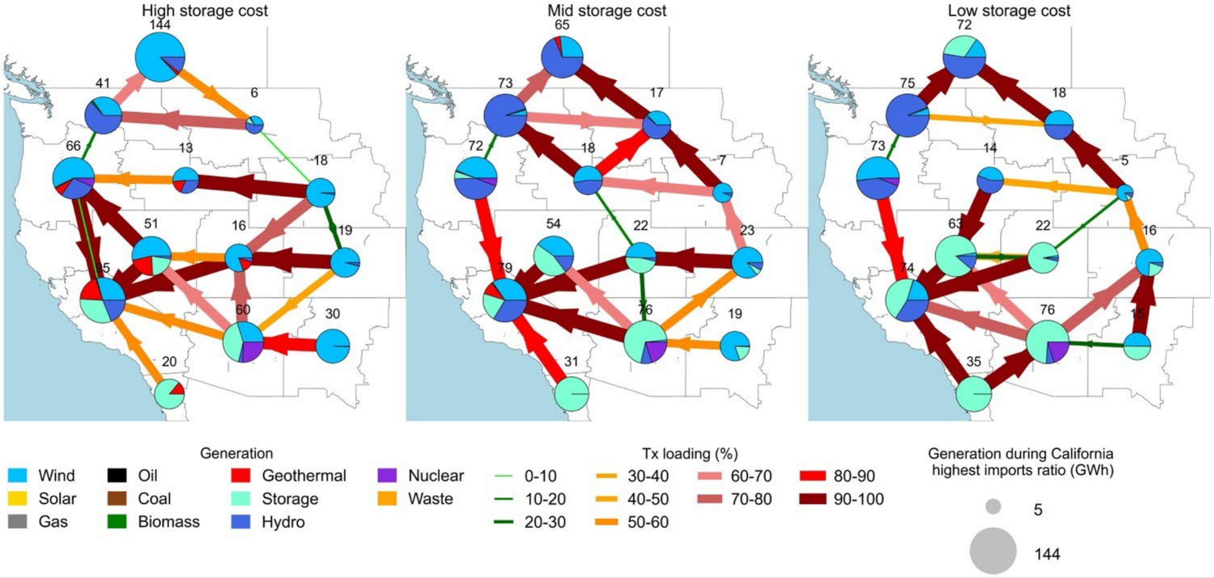


Figure 38: Electricity Generation and Transmission Loading for High Imports



Investigating California's situation amid the WECC grid expansion, lower storage costs lead California to increase: its solar capacity by up to 205 GW (a 15 percent increase) (Figure 39), its storage power capacity by up to 104 MW (a 50 percent increase) (Figure 40), and its storage energy capacity by up to 1157 GWh (a 150 percent increase) (Figure 41). Moreover, lower storage costs result in longer average storage duration in California, increasing from 6.8 hrs to 11.3 hrs (Figure 42). In contrast, lower storage costs lead to up to 60 percent slower deployment rates of wind capacity in California (Figure 43). This reveals that lower-cost wind would compete better with low-cost storage plus solar. In this manner, research and development (R&D) efforts are required to advance cost reductions and flexible deployments of wind resources.

Figure 39: Solar Capacity in California Versus Transmission Buildout

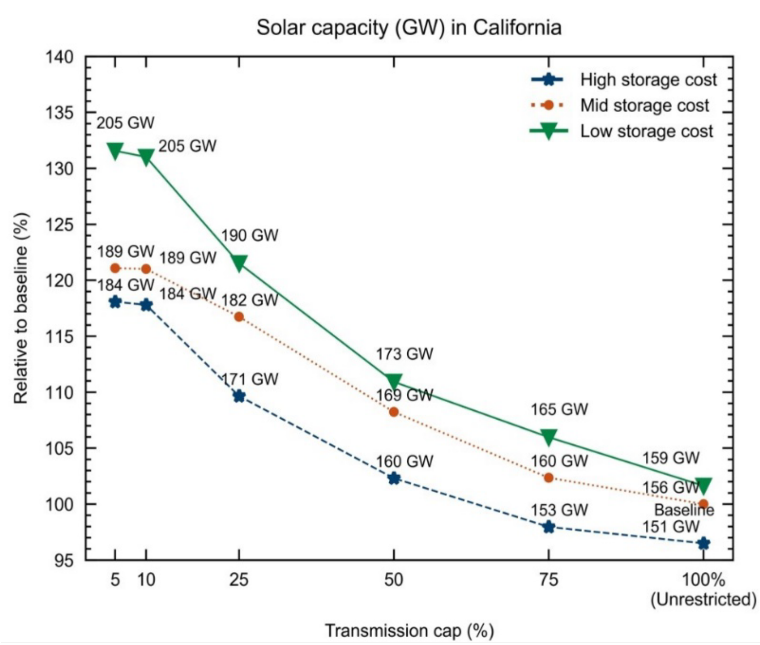


Figure 40: Storage Power Capacity Deployed in California Versus Transmission Build

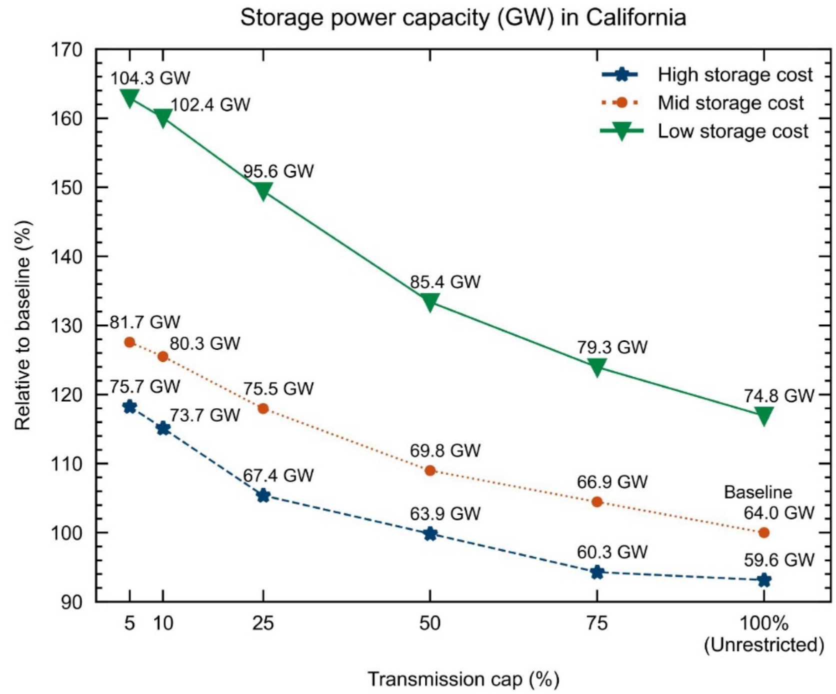


Figure 41: Storage Energy Capacity Deployed in California Versus Transmission Build

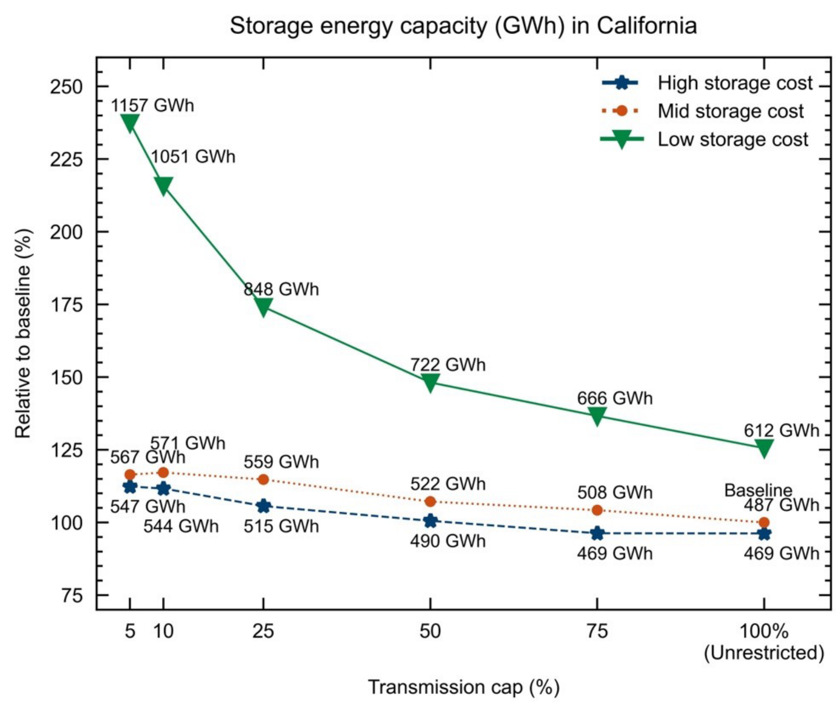


Figure 42: Average Storage Duration in California Versus Transmission Buildout

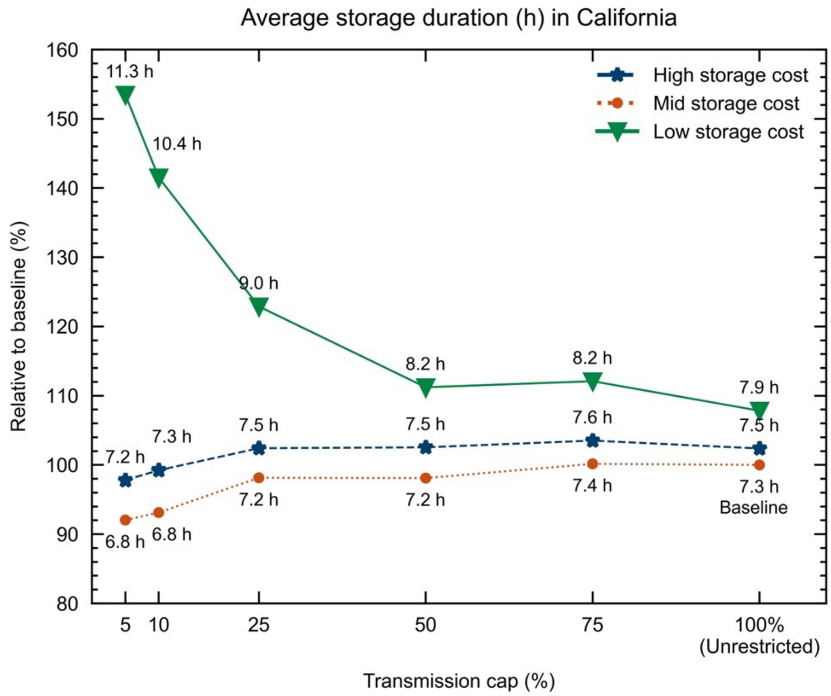
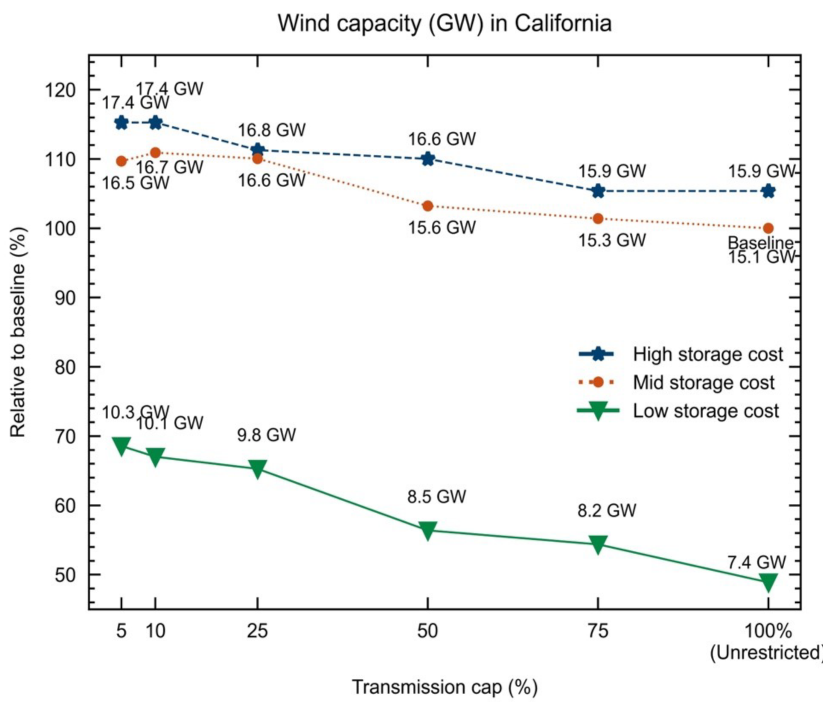


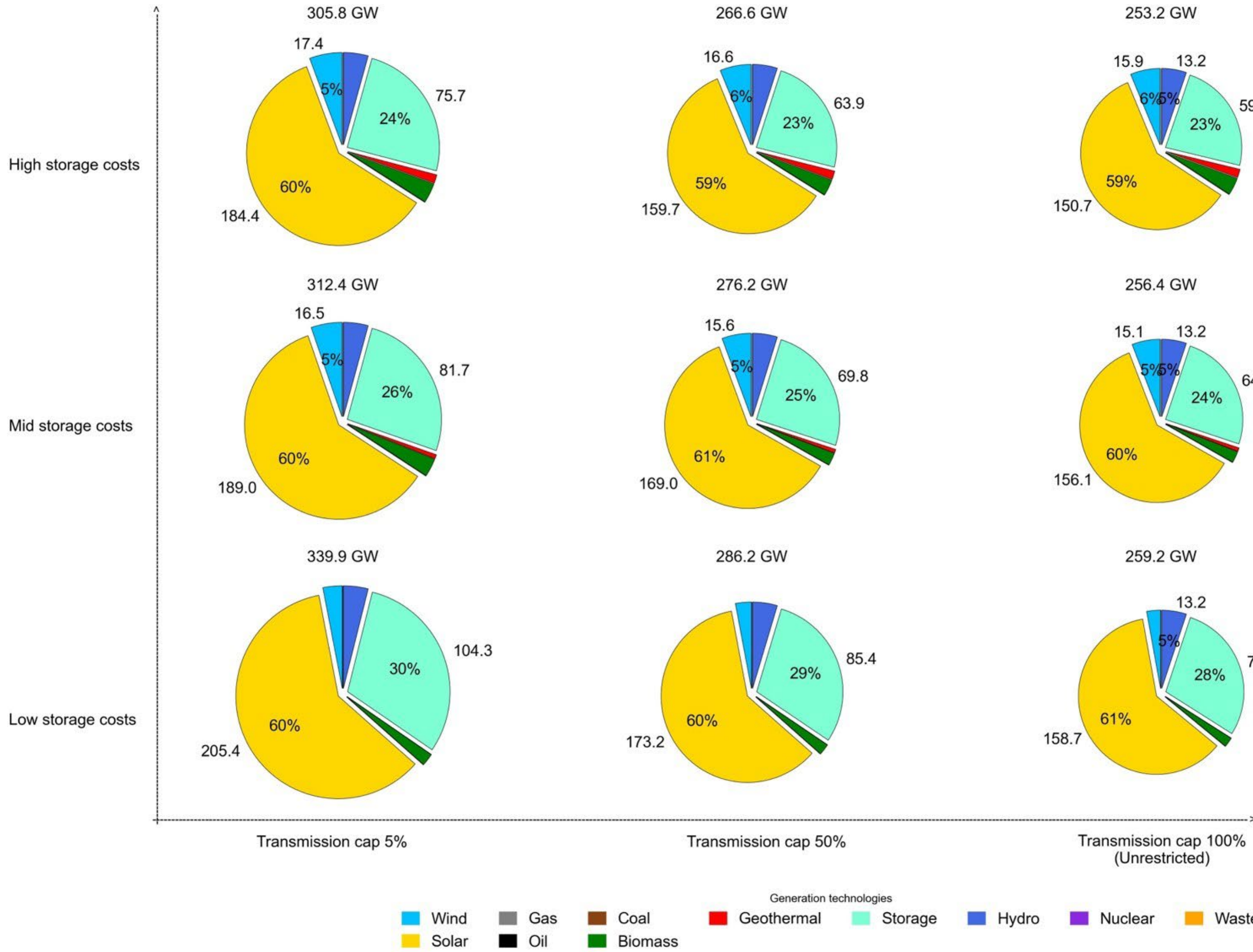
Figure 43: Wind Capacity Deployed in California Versus Transmission Buildout



Furthermore, regardless of storage costs declining, when almost no transmission expansion is allowed across the WECC, California requires up to 34 percent more in-state generation capacity for 2050 (Figure 44). In fact, up to 30 percent more solar capacity (Figure 39), up to 50 percent more storage power capacity (Figure 38), and up to 20 percent more wind capacity

(Figure 42) are deployed in California in response to restricting the expansion of transmission capacity across the WECC (Figure 43).

Figure 44: Installed Generation Capacity in California for 2050



Finally, despite lower storage costs and reduced transmission capacity across the WECC, California will continue being a net importer of electricity in 2050 (Figure 45). However, in the scenario when the expansion of transmission is highly restricted (a capacity cap of 5 percent) and storage costs are the lowest, California's monthly generation exceeds its monthly demand in July, August, and September. Hence, in 2050 it becomes a summer net exporter — when the rest of the WECC would benefit the most (Figure 46).

Figure 45: Fraction of Annual California Load Met by California Generation

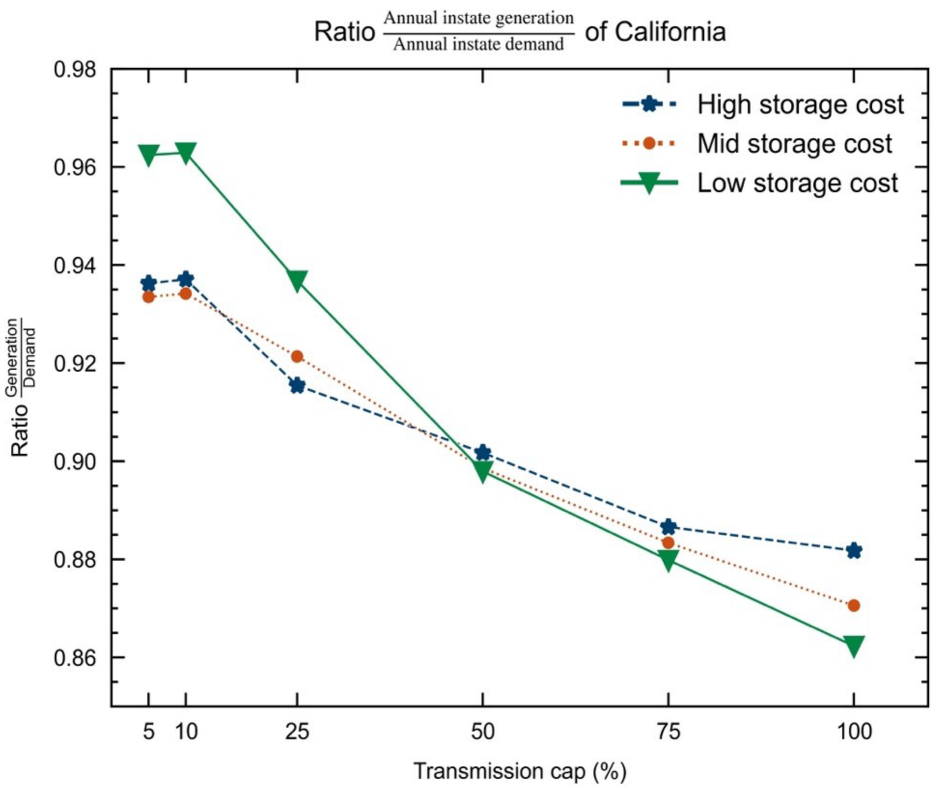
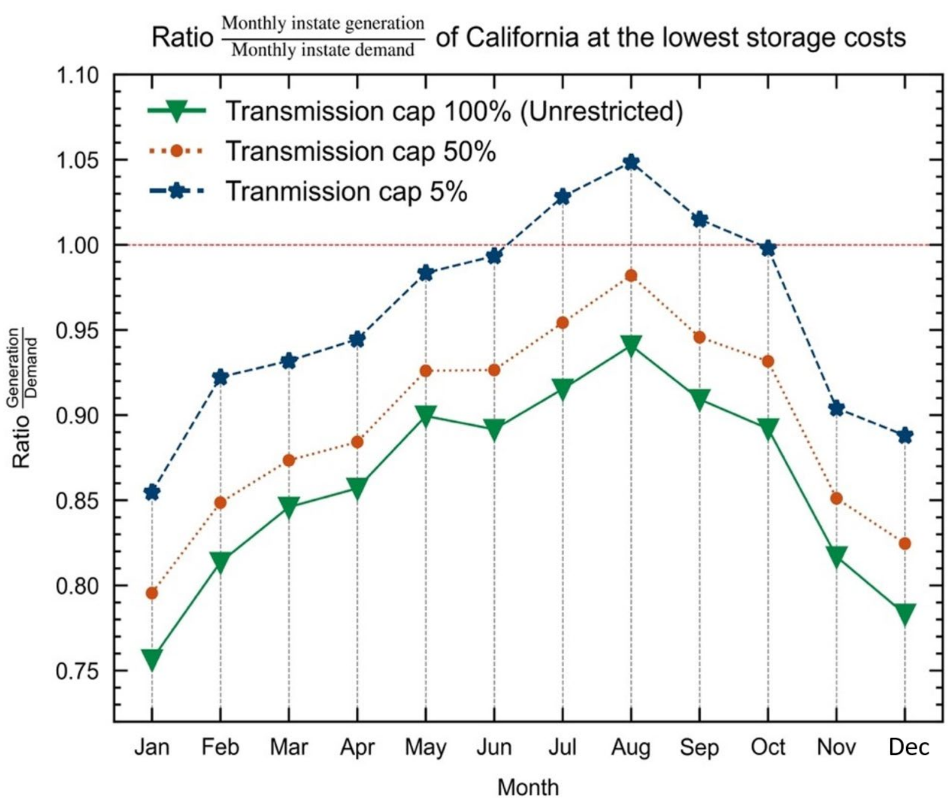


Figure 46: Fraction of Monthly California Load Met by California Generation



In conclusion:

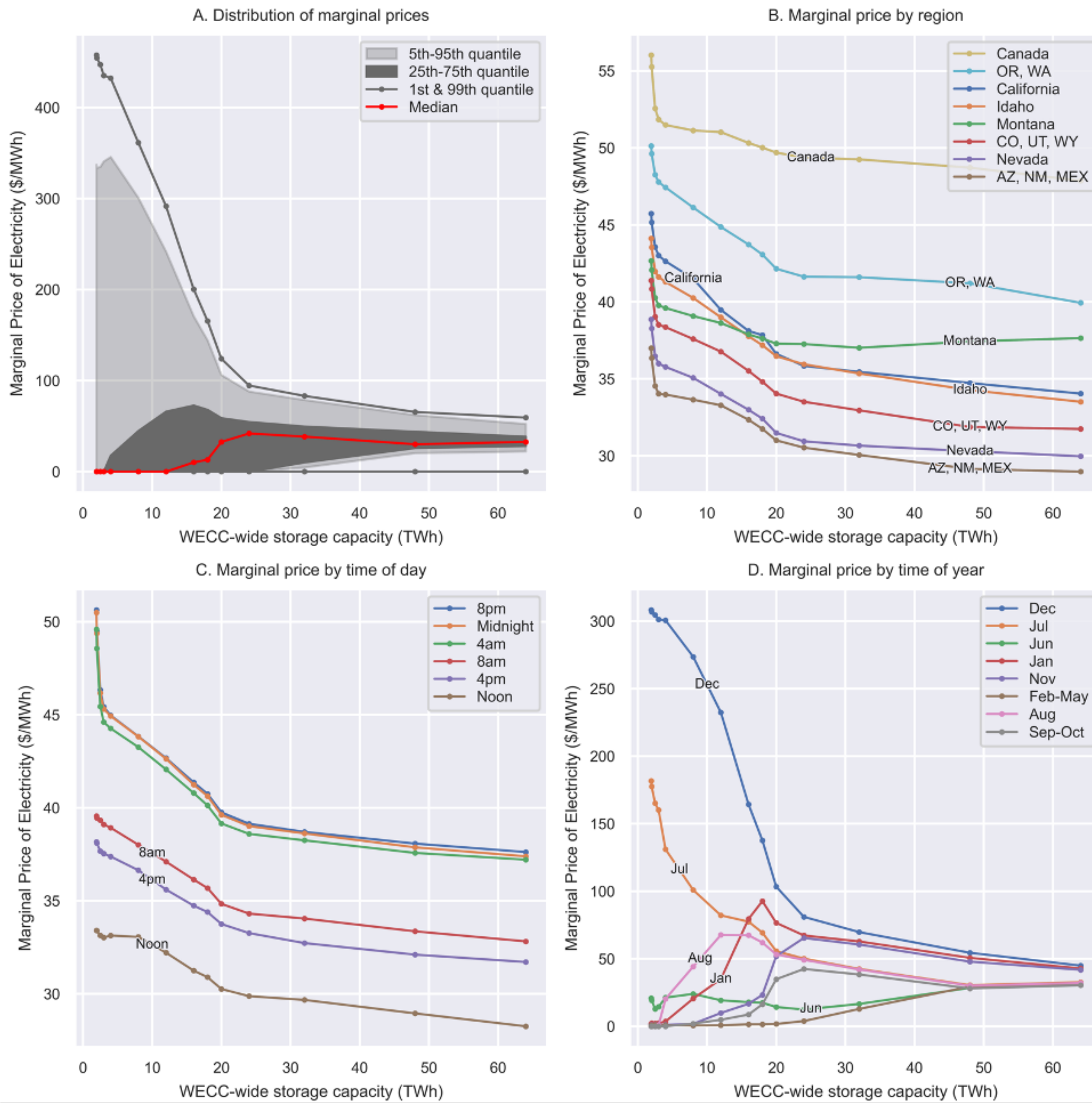
- As storage costs decline, the WECC deploys more solar capacity and more storage energy capacity.
- Storage cost declines result in:
    - Building less transmission in the WECC.
    - Higher loading for existing transmission lines.
    - Building less transmission within California.
    - Building more transmission between California and its neighbors.
- When transmission buildout is constrained to 5 percent of that selected for the baseline and when storage costs are the lowest that were modeled, California's storage duration increases by up to 11.3 hrs (compared to 7 hrs in the baseline).

Impact of Increasing LDES Deployment in the WECC

Looking to the day when LDES may be deployed broadly, analyzing the marginal electricity price reduction as a function of the LDES deployment helps to quantify the amount of LDES that can be expected in future years. An increase in energy storage could be achieved through policy, such as the implementation of LDES mandates, or R&D resulting in an LDES cost decrease, etc. As the deployment of LDES increases, electricity prices change. The baseline, containing 1.94 TWh of energy storage (no storage energy capacity was forced), was modified to study 13 scenarios where the amount of energy storage was forced to be anywhere from 2 TWh to 64 TWh (Staadecker et al., 2023). Figure 47a shows how the adoption of LDES reduces variability in electricity prices, especially for the first 20 TWh of installed LDES. Larger deployment of LDES results in higher investment costs, which are not reflected in the electricity prices plotted in Figure 47b.

In a zero-emissions 2050, marginal electricity prices are highest at night and the deployment of energy storage reduces marginal prices for all times of day (Figure 47c). The average marginal price of electricity is 29 percent to 52 percent higher at night (8:00 p.m., midnight, and 4:00 a.m.) than at noon, since cheap solar generation is not available during the night. In the baseline scenario, July and December marginal electricity prices are highest at 180 $/MWh and 310 $/MWh, respectively, due to high demand during these months (Figure 47d). As energy storage is added to the grid, the high July and December prices are reduced but prices in neighboring months increase. In the 20-TWh scenario, average marginal prices for July, August, November, December, and January range from 52 $/MWh to 100 $/MWh, while other months average 35 $/MWh or less.

Figure 47: Impact of LDES Mandates on the Marginal Price of Electricity



In summary, this work shows that a 2050 decarbonized grid with greater storage energy capacity would reduce daily and seasonal variability in the marginal price of electricity while also reducing the marginal price of electricity across all regions and times of the day. As such, policies, subsidies, mandates, technology development or other events that would increase the penetration of storage resources in the WECC would likely result in lower prices in the wholesale electricity market while reducing price surges in July and December and during nighttime hours.

Critical Factors Determining Sensitivity of Results

This project has quantified the optimal capacity expansion and hourly dispatch for many sets of input parameters, finding that some results are very clear and some results are highly uncertain. Just as a two-pan scale may shift from finding that one side is heavier than the other when a small weight is transferred, the selection of the model of one set of solutions can change to a very different set if input values are shifted by an amount that is small if the two components have almost equal value. Often this difference is small compared with our knowledge of that value.

The project was limited by uncertainties in the technologies that will be available in the future in terms of:

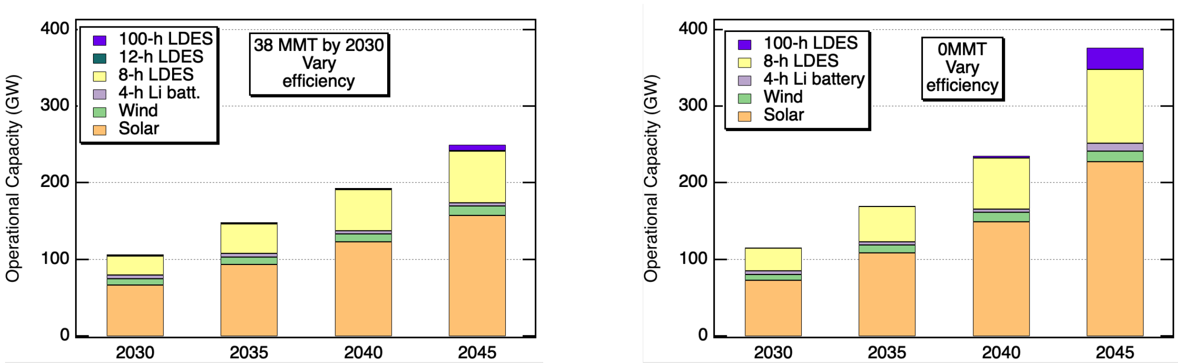
- Cost
- Potential (In many cases, the model chose to implement the resource to the limit offered. Appendix C summarizes the fraction of the offered potentials selected for the baseline scenario. In particular, wind and geothermal are often limited by the cap that has been applied).
- Performance (e.g., efficiency)

Additionally, the requirements for tomorrow's grid may vary substantially, depending on the rate of electrification and population growth.

As shown in the studies of the WECC, transmission is a critical element in defining a robust grid. Timelines for investment in transmission are often very long, and modeling the cost and timelines of specific transmission expansion projects was outside of this project's scope. Also, this project did not attempt to consider the importance of distribution, as local generation and demand may not be adequately balanced.

The project assumed that emissions would meet the SB 100 goals, as modeled, to reach 38 million metric tons of CO_2 equivalent by 2030. Requiring zero emissions by 2045 results in substantially more solar and storage being selected, but the largest relative increase is in the 100-hr LDES in the example shown in Figure 48.

Figure 48: Capacity Expansion for Two Emissions Scenarios



Despite the many uncertainties in the analysis, there are clear conclusions that fall outside of the uncertainty limits, as described in the following Conclusion chapter.

CHAPTER 4: Conclusion

As California transitions to a renewable-energy-driven grid with zero-carbon emissions for retail electricity by 2045, energy storage will be critical. Today's lithium batteries (about 7 GW) are providing very useful services to the grid, but the 4-hr duration will not be adequate for getting through each night as the state transitions away from natural gas. This project found that an 8-hr battery is well-suited for supporting California as solar electricity becomes dominant. The 8-hr batteries will be charged while the sun is up, discharge quickly during peak demand in the early evening, and then discharge more slowly for the lower demand experienced during the night.

Approximately 70 GW of 8-hr storage will be beneficial and may be cycled more than 300 times per year. The optimal duration for the most common type of storage may be as low as 7 hours when the entire WECC is considered, or it may increase to 10 hours to 12 hours when more wind generators are built or if the added cost of longer duration is quite small. However, it will be beneficial having short-duration storage to play a role that is more like the role of peaker plants today, alongside the 8-hr storage used most nights. Additionally, the models found that a small amount of 100-hr storage may be beneficial. For the scenarios modeled, the 100-hr storage typically displaced a few percent of the 8-hr storage, especially in 2045.

The relative cost that enabled an LDES product to displace 50 percent[6] of 4-hr Li batteries decreases to the future, suggesting that, while 8 hours of storage will still be needed to get through the night, reduced use of peaker plants to meet zero emissions targets may require an increased part of the storage fleet to function like peaker plants in 2045, increasing the attractiveness of 4-hr storage. The opposite dependence on years into the future was found when considering displacement of 1 percent of Li batteries, demonstrating that the value of 8-hr or 100-hr LDES relative to 4-hr storage will increase in the future but at approximately a 1-GW scale rather than a tens of GW scale.

While high efficiency increases the value of LDES that is cycled daily, the LDES that is adopted at the 1 percent level is cycled less frequently, reducing the importance of efficiency.

All modeled scenarios found that California will continue to be a net importer of electricity, although the state will export electricity during the day, when solar electricity is abundant. If additional transmission capacity is built, the electricity generated in California may decrease even more, with California net importing more than 10 percent of its electricity on an annual basis.

For decreasing storage costs, the model chose to build fewer transmission lines, though some lines connecting California to its neighbors were selected for building to larger capacity when

[6] Here, the market share is described based on the power ratings rather than the energy ratings. Note that a 100-hr LDES asset that captures 1 percent of the market share calculated according to the power ratings would be 50 percent of the market share when calculated according to the energy ratings.

storage costs were decreased. Wider deployment of storage was found to decrease both the price of electricity and the variability of the price of electricity.

Today's flexible loads are too small to be very helpful in balancing supply and demand of electricity, but tomorrow will bring two very large flexible loads: EV charging and electrolyzers for hydrogen generation. The use of daytime charging of EVs was found to reduce the selected storage by about 10 percent, saving on the order of $1 billion. Electrolyzers were found to contribute to seasonal load balancing by turning off during the winter. Surprisingly, the electrolyzers were found to operate at a capacity factor of 40 percent, exceeding the capacity factor of the solar plants that provided power for them; this suggests that batteries supply the electrolyzers with electricity at some hours. Thus, the availability of under-used assets (curtailed electricity combined with ample storage) may be enabling for green hydrogen.

The use of solar and wind generation profiles (by changing the solar mounting configuration and selecting wind locations with stronger wintertime wind) that had a better seasonal match to the load profiles reduced curtailment, but the reduction in curtailment must be balanced with the higher cost of solar electricity for non-optimal solar mounting.

The use of oxy-combustion could help to reduce the need for storage, but questions remain about the rate of scale-up of both the oxy-combustion generators and the infrastructure for sequestration of the generated carbon dioxide.

A more complete summary of the results of this project may be found online at the link below.[7]

[7] https://sites.ucmerced.edu/ldstorage/publications%20version%202

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
CAISO	California Independent System Operator
CCGT	combined-cycle gas turbine
CCST	California Council on Science & Technology
CEC	California Energy Commission
CO_2	carbon dioxide
EPIC	Electric Program Investment Charge
EV	electric vehicle
GW	gigawatt
GWh	gigawatt-hour
H_2	hydrogen
hr/hrs	hour/hours
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour
$/kWh	cost per kilowatt-hour
kW-y	kilowatt-year
LDES	long-duration energy storage
Li	lithium-ion
MW	megawatt
MWh	megawatt-hour
$/MWh	cost per megawatt-hour
NO_X	nitrogen oxides
O&M	operation and maintenance
PEM	proton exchange membrane
PHS	pumped hydrogen storage
PV	photovoltaic
R&D	research and development
RESOLVE	software package for capacity expansion modeling
RTE	round-trip efficiency

Term	Definition
SWITCH	software package for capacity expansion modeling
TAC	Technological Advisory Council
TWh	trillion watt-hour, or terawatt-hour
TWh/y	trillion watt-hours per year
TURN	The Utility Reform Network
UC	University of California
WD	wind direction
WECC	Western Electricity Coordinating Council
y	year

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Project Deliverables

Project deliverables are available upon request by submitting an email to pubs@energy.ca.gov. Some of them can be found at: https://sites.ucmerced.edu/ldstorage/downloadable-reports.

The project deliverables include:

- Baseline Description
- Modeling Approach Description
- Summary of Baseline Model Results
- Electricity Generation Technology Summary
- Storage Technology Summary
- Grid Scenario Summary
- Final Analysis Summary

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CALIFORNIA NATURAL RESOURCES AGENCY

ENERGY RESEARCH AND DEVELOPMENT DIVISION

Appendix A: Acknowledgment of Contributors Supplementary Information

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Appendix A: Acknowledgment of Contributors Supplementary Information

The following people are acknowledged for the time they took to provide information for this project. This list is intended as an acknowledgment and to document the scope of the effort; it is not an exhaustive list. Some individuals have now moved to other companies. Technological Advisory Council (TAC) members are included here if they participated in meetings outside of formal TAC meetings.

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Appendix B: Summary of Input Assumptions for RESOLVE Supplementary Information

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Appendix B: Summary of Input Assumptions for RESOLVE Supplementary Information

To supplement the information in Tables 2 and 3 for the range of assumptions made for the LDES cost, Table B-1 summarizes the range of input assumptions for other candidate resources for adoption in 2045. The value in the rightmost column is the value used by the model. For convenience to the reader, two Capital Costs are estimated using reasonable assumptions for the Cost Recovery Period. All values are considered to be 2020 dollars.

Table B-1: Summary of Input Assumptions for RESOLVE Calculations

Resource	Capital Cost ($/kW)	O&M Cost ($/kW-y)	Cost Recovery Period (years)	All-in Annualized Cost ($/kW-y)
Solar low	570	10	20	56
	710	10	30	56
Solar high	600	10	20	58
	740	10	30	58
Onshore wind low	1080	36	20	123
	1340	36	30	123
Onshore wind high	2190	36	20	212
	2700	36	30	212
Wyoming wind	2340	36	20	224
	2890	36	30	224
Geothermal low	4075	135	20	462
	5025	135	30	462
Geothermal high	5220	135	20	554
	6440	135	30	554
Offshore wind low	2180	44	20	219
	2690	44	30	219
Offshore wind high	2240	44	20	224
	2770	44	30	224
4-hr Li battery low	450	8.3	10	66.2
4-hr Li battery high	600	8.3	15	66.2

kW-y = kilowatt-year

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Appendix C: Build Fractions Supplementary Information

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Appendix C:
Build Fractions Supplementary information

The following data (Table C-1) are taken for the "Vary efficiency" scenario described in Table 3 and Figure 16. These data demonstrate how the resources that are selected to be built may reflect the cost and/or other constraints placed by the model rather than building all resources uniformly.

Table C-1: Summary of Selected Expansion Relative to Offered Expansion

Resource	Potential (MW)	Selected Capacity (MW)	Ratio
Baja_California_Wind	600	600	100%
Carrizo_Wind	287	181	63%
Central_Valley_North_Los_Banos_Wind	173	45.6	26%
Humboldt_Bay_Offshore_Wind	1607	20.5	1%
Humboldt_Wind	34	31	91%
Kern_Greater_Carrizo_Wind	60	60	100%
Morro_Bay_Offshore_Wind	3100	75	2%
New_Mexico_Wind	34580	0	0%
Northern_California_Wind	866	25	3%
NW_Ext_Tx_Wind	1500	0	0%
Solano_Wind	560	25	4%
Southern_Nevada_Wind	442	177	40%
SW_Ext_Tx_Wind	500	265	53%
Tehachapi_Wind	275	275	100%
Wyoming_Wind	33862	0	0%
Arizona_Solar	77080	0	0%
Distributed_Solar	125	125	100%
Greater_Kramer_Solar	30410	30410	100%
Greater_LA_Solar	3000	3000	100%
Imperial_Solar	35868	35868	100%
Northern_California_Solar	79975	1062	1%
Riverside_Solar	106392	54402	51%
Southern_NV_Eldorado_Solar	148848	4262	3%
Southern_PGAE_Solar	91663	13542	15%

Resource	Potential (MW)	Selected Capacity (MW)	Ratio
Tehachapi_Solar	6289	6289	100%
Greater_Imperial_Geothermal	1352	102	8%
Inyokern_North_Kramer_Geothermal	24	0	0%
Northern_California_Geothermal	469	0	0%
Riverside_Palm_Springs_Geothermal	32	0	0%
Solano_Geothermal	135	0	0%
Southern_Nevada_Geothermal	320	0	0%