CALIFORNIA ENERGY COMMISSION

ENERGY RESEARCH AND DEVELOPMENT DIVISION

FINAL PROJECT REPORT

Assessing 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 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/) (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

This project studied the value of long duration energy storage (LDES) to support decarbonization at three geographic levels: (a) meeting Senate Bill 100 (De León, Chapter 312, Statutes of 2018) and statewide electric sector decarbonization planning, (b) providing local capacity and criteria air pollutant reductions in a Los Angeles Basin case study, and (c) support microgrids for customer resilience. This study found that LDES could cost effectively support bulk grid decarbonization and environmental justice; however, the more stringent resilience requirements of a customer microgrid potentially make LDES-based microgrids less cost-effective.

Keywords: long duration energy storage, decarbonization, microgrid

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Executive Summary

Background

California is a leader in the energy transition and adoption of energy storage technologies. Previous studies show that the electric sector could reach 80 percent or greater decarbonization with existing technologies (Long 2021); achieving deeper levels of decarbonization while maintaining a reliable electricity system, however, is likely to remain cost-prohibitive without innovations in long-duration energy storage. In the past, fossil fuels provided a cheap and abundant source of energy storage for dispatchable capacity to both balance renewables and meet grid reliability requirements. More recently, cost declines have made lithium-ion a viable short-duration energy storage resource to help meet daily evening net peak electricity demand.

As the grid continues to transition to cleaner generating resources, it is likely that the need for duration of energy needs will extend from evenings into intra- or multi-day needs and be increasingly driven by renewable lulls and extreme weather. Within this context, emerging technologies like long-duration energy storage (LDES) promises to deliver zero-emissions energy to the grid when it is most needed.

Project Purpose and Approach

This project studied the role of LDES in the future of California's decarbonizing grid and developed tools, data, and approaches for other proceedings (like the California Public Utilities Commission's Integrated Resource Plan) to leverage and capture the value of LDES. This study evaluated California's electricity grid at three levels:

1. **California Independent System Operator Portfolio Value**
   Assess the value of LDES as part of a California Public Utilities Commission integrated resource plan-like study to meet Senate Bill 100 (De León, Chapter 312, Statutes of 2018) and electricity-sector decarbonization goals. These values include energy arbitrage and system resource adequacy values as well as system investment and operational cost savings associated with more cost-effective Renewable Portfolio Standard, Senate Bill 100, and greenhouse gas policies.

2. **Los Angeles Basin Local Capacity Case Study**
   Assess the value of LDES to provide both local capacity (based on the California Independent System Operator's local capacity technical studies) and local criteria air pollutant reductions, which historically has not been captured in detail in planning studies.

3. **University of California San Diego Microgrid Case Study**
   Assess the distributed LDES's ability to support microgrids (instead of long-duration outages like public safety power shutoffs) and its potential for LDES in low-emission microgrids.

Key Results

California Independent System Operator System

- The role of LDES varies across policy scenarios. Under business-as-usual Senate Bill 100 policies, which allow for 12 million metric tons of electricity-sector emissions and retain all existing gas resources, up to 5 GW of LDES may be cost-effective by 2045; however, the role of LDES increases dramatically in deeper decarbonization scenarios (such as allowing in-state gas retirements [0 MMT]) where potentially up to 37 GW of LDES by 2045 could be achieved under a 0 MMT scenario.
- LDES provides energy during key grid stress events to support grid reliability. In addition, LDES operates throughout the year, providing intra-day, multi-day, and seasonal energy balancing, and reducing renewable curtailments, in-state gas generation, and criteria air pollutant emissions for the same Renewable Portfolio Standard, Senate Bill 100, and greenhouse gas reduction scenarios.
- LDES enables retirement of existing gas capacity from the California Independent System Operator's transmission-control system while maintaining reliable grid operations over simulations across 35 historic weather years. Portfolios that retire in-state gas by using LDES were found to achieve cost parity, and in some cases cost savings, relative to those that retain existing in-state gas. Further analysis is needed to evaluate reliability implications, ratepayer impacts, and the environmental justice benefits of retiring gas-fueled generation more quickly.

Los Angeles Basin Local Capacity Case Study

- Bulk system studies like the California Public Utilities Commission's integrated resource plans have not historically captured detailed local resource capacities. As a complementary analysis, the team demonstrates that LDES also has a potential role in cost effectively maintaining local capacity requirements while reducing the need to retain emitting resources in disadvantaged communities. These present two incremental benefits that LDES can provide — local reliability and local environmental justice — that to date have not been studied in depth in traditional long-term portfolio planning studies.

UCSD Microgrid Case Study

- LDES can support high-reliability microgrids, pairing with other distributed energy resources to deliver 48-hour resilience (islanding) capability and protecting against most public safety power shutoff events, while generating operational benefits through peak load shaving and shifting between periods of high and low electric rates.
    - The customer value of lost load needed to justify LDES-based microgrids ranges between \$5-18/kWh for small campus buildings, while certain large buildings demonstrated a negative value of lost load (below -\$8/kWh) reflecting that some microgrids improve reliability while reducing lifecycle electricity cost. These VOLLs are much lower than those reported in commercial and industrial customer surveys (\$12-295/kWh) (Sullivan, Josh and Blundell 2015).

- Under policy today for microgrids, the economic benefits of LDES microgrids are eclipsed by lower cost gas generator-dominant microgrids. Limited space for behind-the-meter photovoltaic solar (BTM PV) in the case study also limits LDES and PV-plus-LDES economic potential—resulting in LDES microgrids with 2-20¢/kWh higher levelized cost of energy than thermal generator-based (for example gas gensets) microgrids.
- Under future conditions of rapidly falling PV and LDES costs and rising electricity and gas prices, LDES microgrids are still not cost competitive relative to thermal generator-based microgrids.
- Even with LDES, the more gas generator-dominant microgrids increase annual CO_2 emissions 5-to-6 fold relative to utility service. Under policies that restrict a microgrid's CO_2 and other criteria pollutant emissions, niche cases emerge where behind-the-meter photovoltaics + LDES-based microgrids are more cost-effective than renewable gas + fuel cells alternatives.

Knowledge Transfer and Next Steps

Knowledge Transfer

- Results were shared over the course of the grant in a series of public workshops and technical advisory committee meetings and materials available on the CEC website.
- The updated Resolve model is available under GNU AGPLv3 open-source license on GitHub: https://github.com/e3-/resolve.
- Weather-correlated renewable and load data used for the SB 100 Gas Retirement Sensitivity developed by Form Energy will be released on Zenodo. https://doi.org/10.5281/zenodo.8045596

In addition, the updated Resolve model is continually developed and is being used in multiple ongoing and upcoming California studies:

- **CEC EPC-19-060**, Modeling of LDES for decarbonization of California's energy system. UC Merced-led team also leveraging new Resolve model to study LDES value, using novel "critical timestep" method to capture inter-day and seasonal energy shifting dynamics (CEC 2020).
- **CPUC Integrated Resource Plan**, 2023 Preferred System Plan and 2024-25 Transmission Planning Process. California Public Utilities Commission staff using updated Resolve model for next integrated resource plan cycle. Proposed sensitivities will include new load, wind, solar profiles extending for 1998-2020 weather years. Sensitivities will include emerging technologies (e.g., offshore wind, LDES, electrolytic hydrogen) and updated Independent Energy Policy Report electrification scenarios and load flexibility assumptions from Lawrence Berkeley National Laboratory Phase 4 Demand Response study (CPUC 2023).
- **CEC EPC-21-041**, Climate-informed load forecasting and electric grid modeling to support a climate-resilient transition to zero-carbon. E3 team extending Resolve to study electric sector resilience under a wider range of future climate scenarios,

leveraging downscaled CMIP6 climate projections and additional functionality to study uncertain and robust resource portfolios (CEC 2022).

- **CEC GFO-22-304**, Assessing the role of hydrogen in California's decarbonizing electric system (proposed award). E3-led team studying siting, economics, and environmental impacts of electrolytic hydrogen production in California, leveraging Resolve and other modeling tools (CEC 2023).

Policy Implications and Areas for Future Research

This study identifies five key policy implications for future work:

1. Policymakers should engage with technology providers to track emerging technology developments.
2. Planners should ensure planning processes send clear market signals on grid needs such as clean energy and resource adequacy.
3. Planners should use the best-available modeling methodologies to ensure that resources are evaluated with sufficient detail and on an equal basis.
4. Policymakers should direct future planning and procurement to optimize local system resource needs and ensure resources are fully compensated for both their local capacity value and avoided local air pollution.
5. New revenue streams, electric tariff structures, and incremental environmental policies could change the relative economics of LDES microgrids. Revenue streams help offset costs, while policies that restrict or price emissions drive up costs. Tariff reforms that shift the utility's revenue requirement from volumetric to fixed costs would hurt the case for microgrids, while reforms toward real-time pricing would benefit it.

CHAPTER 1: Introduction

Previous studies have shown that the electric sector could reach 80 percent or more decarbonization with existing technologies; however, the incremental cost of achieving deeper decarbonization remains cost-prohibitive without innovations to deliver energy consistently at times when the grid needs it most (Long 2021, N. A. Sepulveda, et al. 2018). These include energy-constrained periods lasting for several days, which will become increasingly frequent for a grid dominated by intermittent renewables and prone to extreme weather. Long-duration energy storage (LDES) is a technology class that can serve this critical reliability function as a cleaner, cheaper energy storage alternative to current Li-ion battery technology. Some LDES technologies can provide non-electricity services like heat and offer opportunities to diversify the energy storage supply chain to use other more abundant elements such as sodium and iron, as shown in Table 1.

Table 1: Examples of LDES Categories and Additional Use Cases

	Electrochemical	Mechanical	Thermal	Electrolytic Fuels
Example Technologies	Li-ion Flow Metal-air	Pumped hydro Rail Other gravity	Cryogenic Molten salt Thermo-photovoltaic	Hydrogen Synthetic methane Ammonia
Additional Use-Cases (not studied)	-	-	Heat (such as industry, building)	Fuels (such as industry, transportation)

Source: EPC-19-056

Policy and Industry Context

California Trends

As California continues to transition toward a decarbonized grid to meet SB 100, electric system reliability and resource adequacy have become key issues. Most recently, the California Public Utilities Commission (CPUC) issued its Mid-Term Reliability procurement order, (CPUC 2023) highlighting the urgent and continued need to use resources to maintain system reliability while decarbonizing California's electricity system. In this order, the CPUC called out specific clean technologies such as emerging low-carbon generation and LDES. In addition, the CPUC's upcoming 2023 Integrated Resource Plan and 2023 Preferred System Plan cycle will include modeling LDES (CPUC 2023).

A previous study demonstrated that achieving a net-zero electric sector while maintaining resource adequacy in California could require a significant build out of renewables and Li-ion batteries (on the order of more than 400 GW of nameplate capacity) when compared with approximately 100 GW for the entirety of California's generation portfolio today; that study concluded that emerging technologies such as carbon capture, advanced nuclear, and LDES, could significantly reduce the need to deploy so much capacity over the next three decades (Long 2021). Similarly, the California Energy Storage Association published a study in 2020 that found that up to 55 GW of LDES could be part of a future California resource portfolio (CESA 2020).

National Trends

Other states, such as New York (NYSDPS 2023) and Massachusetts, (MassCEC 2023) are conducting storage studies and setting resource specific targets. In addition, in March 2023, the Department of Energy (DOE) released its "Pathways to Commercial Liftoff: Long Duration Energy Storage" report, focusing on "inter-day" (10- to 36-hour) and "multi-day" (36- to 160-hour) LDES. That report concluded that the United States grid may need 225-460 GW of LDES by 2060 to achieve a net-zero economy, a total investment of $330 billion.

Best Practices for LDES Modeling

Previous studies have highlighted the importance of modeling methodology when studying LDES in long-term planning models. Dowling, et al., demonstrated that LDES balances across intra-day, inter-day, seasonal, and even potentially interannual horizons, when optimally operated, underscore the need to capture temporal granularity and weather variability when modeling LDES (Dowling, et al. 2020). Kotzur et al., highlighted that time sampling methods underestimate the role of storage in system balancing and renewable curtailment, while also overestimating baseload generator operations (Kotzur, et al. 2018). Sanchez-Perez, et al., demonstrated the importance of optimizing across an 8,760-hour chronology when modeling LDES in their Western Interconnection case study, showing that increasing storage balancing horizons from one week to a year resulted in an order of magnitude increase in selected LDES capacity (Sánchez-Pérez, et al. 2022). While these studies highlight the ideal role and methods for identifying the role for LDES, planners will still need to carefully consider the impact of imperfect foresight on storage values, which was outside the scope of this study.

Study Purpose and Goals

While there is growing interest in LDES, it is not yet standard practice to include emerging LDES technologies in long-term planning studies. This study highlighted the role for LDES in the future of California's grid to support decarbonization goals and, along the way, develop tools and approaches that capture the value of LDES for other proceedings (like the CPUC IRP) to leverage.

The team identified three modeling scopes of interest to highlight different value streams and use-cases for LDES (Figure 1). For each geographic scope, the reliability challenge is slightly different, but this study highlights the different tradeoffs and roles for LDES in these contexts.

Figure 1: Overview of Three Modeling Scopes: California Independent System Operator, Los Angeles Basin, University of California San Diego Campus

ISO Portfolio
Based on 2021 CPUC IRP Preferred System Plan, studying bulk system LDES value.

Source: Energy Knowledge Base

Reliability needs driven by 0.1/year LOLE planning standard.

Los Angeles Basin
Identifying local capacity and criteria air pollutant reduction benefits.

Source: Wikipedia

Reliability needs driven by Cal ISO local transmission contingencies & local capacity requirements.

UCSD Microgrid
Assessing low-carbon LDES microgrids for commercial & institutional settings.

Source: UCSD Climate Action Plan

Reliability defined as meeting a grid outage survivability requirement informed by historical PSPS outage data.

California Independent System Operator System

This study assesses the value of LDES to meet Senate Bill (SB) 100 (De León, Chapter 312, Statutes of 2018) and electric sector decarbonization goals. These values include energy arbitrage and System Resource Adequacy (RA) value, as well as system investment and operational cost savings associated with more cost-effective RPS, SB 100, and greenhouse gas (GHG) policy achievements.

To this end, this study leverages existing modeling by the CPUC IRP and answers the following key questions (KQ):

KQ1. What is the effect that LDES has on total system cost when planning to meet California's RPS, SB 100, and electric sector GHG mandates?

KQ2. What bulk-system cost savings could different deployments of LDES achieve?

KQ3. What is the role for LDES under scenarios of grid decarbonization beyond SB 100 in California?

KQ4. Do different modeling choices result in different amounts of LDES selected at system levels?

Los Angeles Basin Local Capacity Case Study

This case study assesses the value of LDES to provide local capacity (based on Cal ISO's local capacity technical studies) and local criteria air pollutant reductions, which historically have not been captured in detail in planning studies like the CPUC IRP. This portion of the analysis answers the following questions:

KQ5. Can LDES be used to support local capacity needs that have not been incorporated into previous CPUC IRP studies?

KQ6. What are the potential criteria pollutant impacts of LDES?

UCSD Microgrid Case Study

This case study assesses distributed LDES's ability to support microgrids against long-duration outages such as Public Safety Power Shutoffs (PSPS) and the potential for LDES in low-emissions microgrids. This portion of the analysis answers the following:

KQ7. What role can LDES play in supporting microgrids with high (48-hour) resilience needs?

KQ8. What is the operational role for LDES microgrids during typical "blue-sky" days?

KQ9. Given these resilience and operational roles, how does LDES compare with other microgrid DER configurations such as thermal generation or fuel cells?

KQ10. How does the introduction of LDES affect microgrid emissions, and can policy steer microgrids toward more cost-effective decarbonization?

CHAPTER 2: Project Approach

California Independent System Operator System

Modeling Framework

For the Cal ISO portfolio analysis, the team used two capacity expansion models for parallel modeling work:

Resolve is an open-source capacity expansion and economic dispatch model developed by Energy and Environmental Economics, Inc. (E3). The CPUC uses Resolve in its Integrated Resource Plan proceeding to develop load serving entities (LSE) filing requirements, and Resolve has been used to support the SB 100 Joint Agency Report and California Air Resources Board (CARB) Scoping Plan (CPUC, 2019-2020 IRP Events and Materials 2021, CEC 2021, CARB 2022, CPUC 2023). Past versions of Resolve used a representative day sampling approach (the CPUC IRP used 37 days), which was appropriate for modeling solar, wind, and Li-ion portfolios; as part of this grant, the project team updated Resolve to leverage updated time-series clustering techniques and capture a range of operational horizons more flexibly, from sampled days to 8,760 hours/year and multiple weather years.

Bulk system cost savings calculated from Resolve-derived portfolios represent the reduction in system investment and operational costs over the lifetime of LDES archetypes installed in 2030, 2035, and 2045. This change in system cost is levelized over the LDES archetypes' lifetime to develop an estimated levelized ($/kW-year) cost that represents a proxy for the cost target for an LDES system to be cost-effectively deployed to the grid.

Formware is the capacity expansion, unit commitment, and economic dispatch model developed by Form Energy. Formware differs from other industry models because it performs its optimization over 8,760 hours per year, across multiple weather years. It is thus better able to simulate the operation of LDES technologies and capture the impacts of weather variability on high-renewable grids. Used in the preliminary analysis phase of this grant, Formware was benchmarked against E3's Resolve model and was shown to produce similar results when using the same input assumptions and time sampling chronologies. In this final phase, Formware is used for a sensitivity analysis that co-optimizes resource builds across eight weather years and evaluates the economics of, and future demand for, LDES.

Data Inputs and Assumptions

System Assumptions

Most of the data used to characterize California's future electricity system was from data provided in the 2021 CPUC Integrated Resource Plan Preferred System Plan (CPUC IRP PSP). These included resource costs, load forecasts, and System Resource Adequacy (RA), RPS, SB 100, and GHG planning targets. Fixed operation and maintenance (O&M) costs for were updated based on the California Energy Commission's (CEC) Estimated Cost of New

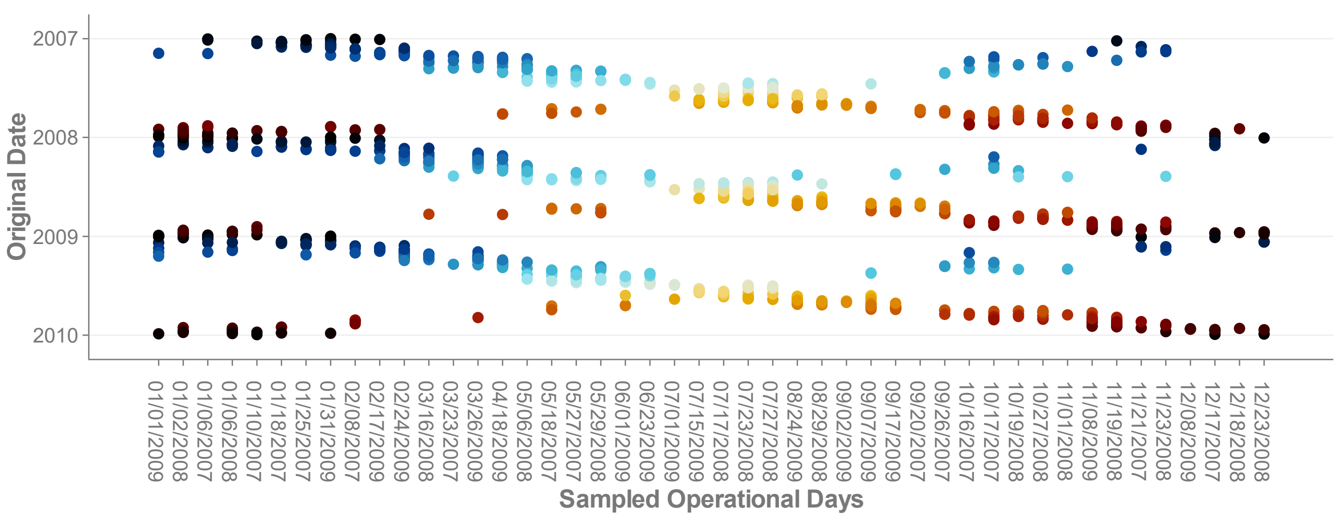
Utility-Scale Generation in California: 2018 Update report: $34.26/kW-year for combustion turbines and $43.05/kW-year for combined-cycle gas turbines, to reflect the latest view on the cost of retaining in-state gas capacity (Neff 2019).

For the SB 100 gas retirement sensitivity, additional load and renewable profile data were developed to study the effects of updated weather sensitivity input profiles on the selection of LDES technologies as part of a least-cost resource portfolio. These are critical to capturing the impacts of weather-driven events in system reliability planning and therefore the value that LDES technologies can bring during periods of grid stress. More information on the development of these profiles is provided in Appendix B; these data are publicly available for scrutiny and future use via Zenodo (Burger, et al. 2023).

Sampled Operational Days

For this study, the team updated Resolve from the 37 sampled days used in previous CPUC IRP cycles, instead using a new, medoids-based clustering algorithm. Unlike the older 37 sampled days, the updated clustering also captures the chronological load and generation availability dynamics — not just within but also across days, which allowed the modeling to accurately differentiate the value of storage duration. For the Resolve results shown, the three weather years were clustered into 46 sampled days, as shown in Figure 2.

Figure 2: Illustration of Chronological Ordering of Sampled Operational Days



Source: EPC-19-056

Calculating Portfolio Reliability

For most of the results presented in the Cal ISO system analysis, the team retained the System RA Planning Reserve Margin (PRM) and Effective Load Carrying Capability (ELCC) paradigm used by the CPUC IRP. Appendix A illustrates that — all else being equal — LDES has higher ELCC than comparable incremental additions of short-duration storage. However, the team recognized that interactive effects associated with different LDES penetrations could have potentially significant effects on ELCC and portfolio reliability that may not be fully captured in either an incremental ELCC curve or surface. The team therefore performed iterative loss-of-load probability modeling to calculate "point estimate" ELCCs for each resulting portfolio modeled in Resolve, achieving similar portfolio reliability metrics as CPUC IRP cases, as shown in Figure 40.

For the SB 100 gas retirement sensitivity, the team did not use the PRM constraint and instead modeled eight weather years of operations as a counterfactual modeling exercise and reliability paradigm. See SB 100 Gas Retirement Sensitivity for more discussion on the method and results.

Criteria Pollutant Emission Rates

Given the high-level, statewide nature of the Cal ISO portfolio analysis, technology category-level estimates for criteria pollutant emissions rates are based on data provided by the CEC (Table 2). Five criteria pollutants are estimated: NO_x, VOC, CO, SO_x, PM10. Future studies leveraging EIA (Energy Information Administration) and U.S. EPA data could provide a more detailed plant-by-plant look at criteria pollutant reductions, similar to the approach used for the Los Angeles Basin Local Capacity Case Study.

Table 2: Assumed Gas Generation Criteria Pollutant Emissions Rates

	Combustion Turbine (lbs./MWh)	Combined Cycle Gas Turbine (lbs./MWh)
NO_x	0.279	0.070
VOC	0.054	0.024
C0.368	0.208	
SO_x	0.013	0.005
PM_{10}	0.134	0.037

Source: (Neff 2019)

Technology Assumptions

LDES Archetypes

Given the rapidly evolving landscape of LDES technologies, this study models a range of archetypes representing reasonable operational characteristics for key duration milestones (Table 3). These archetypes span from 12 to 100 hours, representing a range of inter-day and multi-day storage (Figure 4).

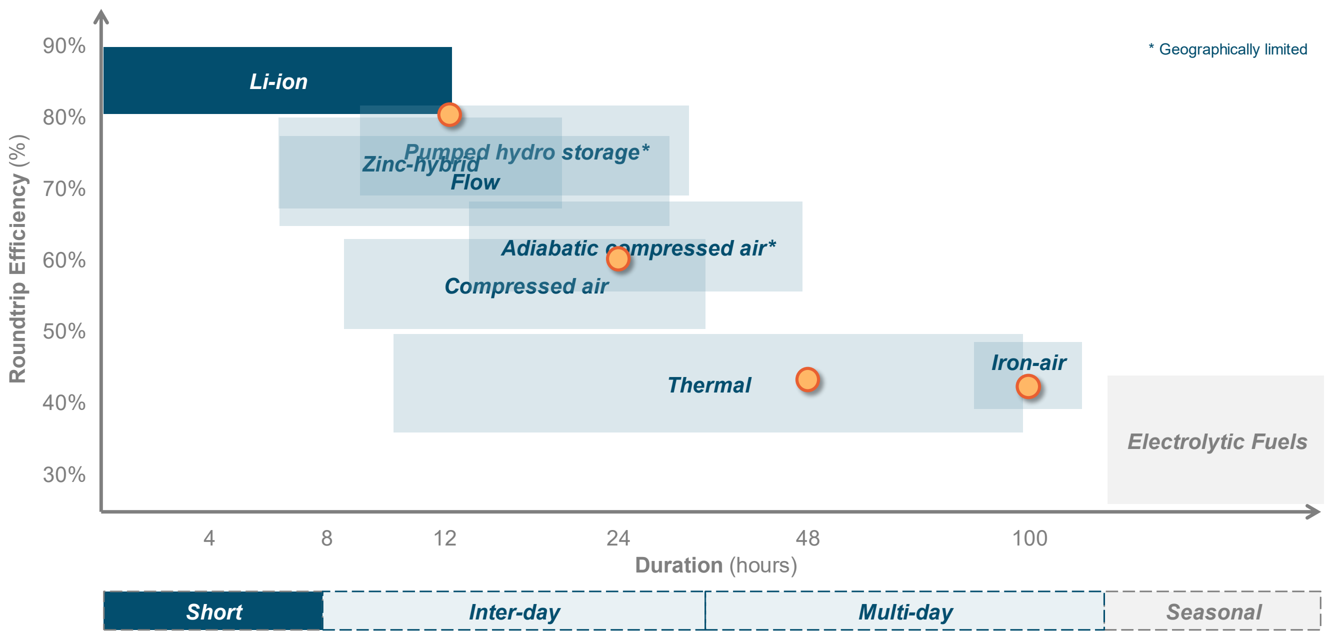
Table 3: LDES Archetype Operational Characteristics

LDES Archetype	Round Trip Efficiency (%)	Parasitic Losses (%/day)	Reference Technologies
12	81%	--	Flow, Metal-air
24	60%	1.0	Adiabatic CAES

LDES Archetype	Round Trip Efficiency (%)	Parasitic Losses (%/day)	Reference Technologies
48	45%	1.0	Thermo-photovoltaic
100	46%	--	Iron-air

Source: EPC-19-056

Figure 3: LDES Archetypes (orange circles) Analyzed Relative to Storage Design Spaces

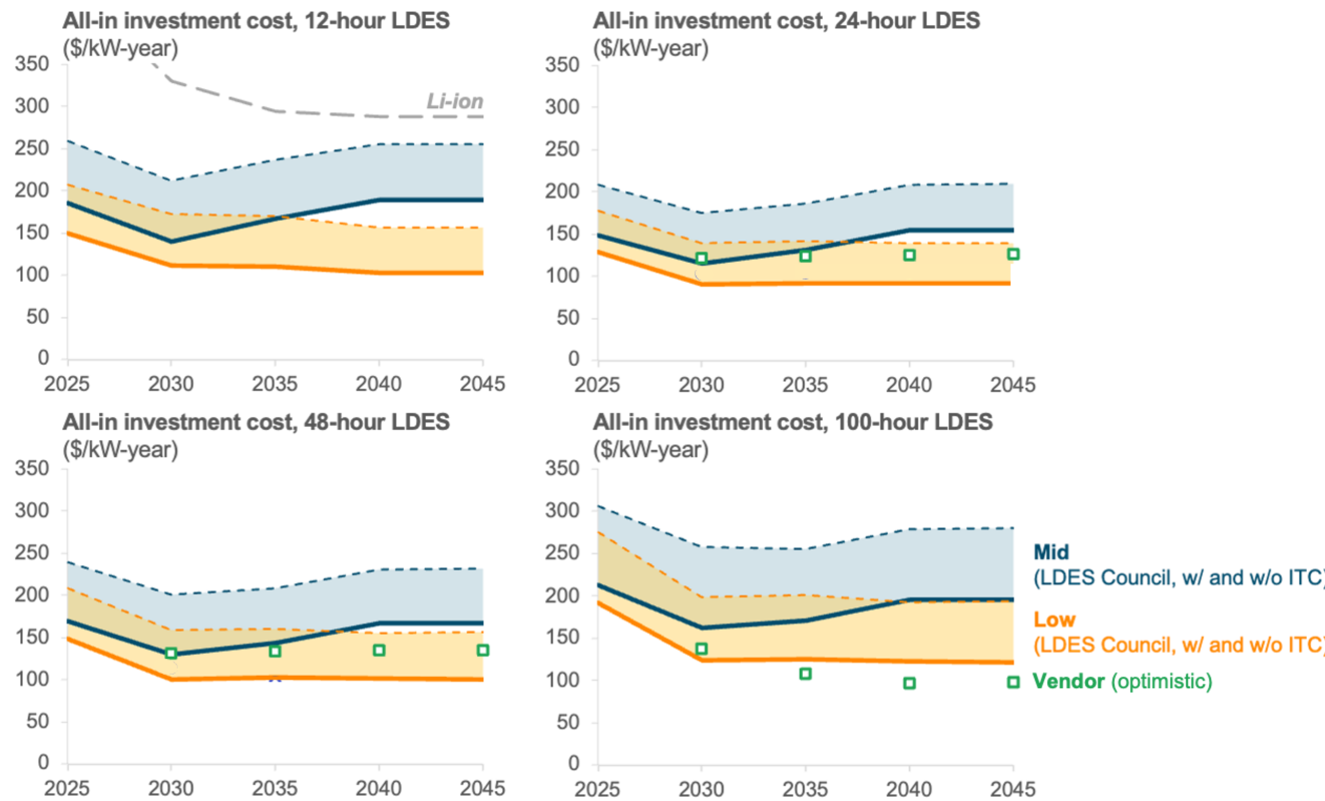


Source: EPC-19-056

As previously noted, developing technology cost projections require assumptions on both the rate of market growth and industrial learning. For emerging technologies, the rate of learning and cost reductions in both the near term and future can vary greatly and depend on how technologies, their competitors, and other complementary industries evolve in the coming years. The cost projections assumed in this study therefore represent a certain view of technological progress that may or may not materialize.

Costs shown in Figure 5 project ranges for LDES archetypes are shown without (dotted line) and with (solid line) IRA tax credits. Note that the "mid" cost projection increases over time due to increases in assumed fixed operation and maintenance (O&M) costs (data based on a survey of technology providers conducted by the LDES Council in 2022). Additionally, 12-hour Li-ion battery costs are shown for comparison (for 24-hours and above; equivalent Li-ion costs are off the y-axis scale).

Figure 4: Projected Levelized, All-in Investment Cost for Various LDES Archetypes



Source: LDES Council technology provider survey (unpublished)

Emerging Low-Carbon Generation Technologies

The CPUC IRP dataset includes cost and resource characteristics for some emerging technologies, such as offshore wind. For this study, the team supplemented that data with data for three additional emerging low-carbon generation technologies: Allam Cycle carbon capture and sequestration, advanced nuclear, and enhanced geothermal. As with LDES, these technologies are not yet commercialized so have limited data availability and large cost uncertainties as technological learning advances. To simplify the sensitivities presented in this study, the team used a single cost projection estimate for each technology, as shown in

Table 4. As a result, further cost sensitivities for these emerging technologies are needed to validate LDES value estimates when modeling these emerging options.

Table 4: Assumed Costs for Emerging Low-Carbon Generation Alternatives

Emerging low-carbon generation	**All-In Levelized Investment Cost** ($/kW-year)			**Average Heat Rate** (MMBtu/MWh)
	2030	**2035**	**2045**	
Enhanced geothermal	$649	$640	$615	-
Advanced nuclear	$450	$444	$417	-

Emerging low-carbon generation	All-In Levelized Investment Cost ($/kW-year)			Average Heat Rate (MMBtu/MWh)
	2030	**2035**	**2045**	
Allam cycle carbon capture & sequestration (CCS)	$293	$287	$264	6.4

Source: (CPUC, 2019-2020 IRP Events and Materials 2021)

Policy Scenarios and Sensitivities

The Cal ISO portfolio analysis builds on established policy scenarios from the CPUC IRP and SB 100 Joint Agency Report (CEC 2021). This study analyzes two main policy futures.

- **SB 100 Policy**
  Consistent with the 2021 CPUC IRP Preferred System Plan (PSP), qualifying clean generation must be equivalent to 100 percent of retail sales by 2045. This is equivalent to the 12 MMT of in-state and the unspecified imported CO_2 emissions, by 2045.
- **0 MMT by 2045 Policy**
  No in-state emissions or unspecified imports by 2045 require critical understanding of the role of LDES under more stringent decarbonization goals to inform future policymaking.

In addition to these two policy environments, the project team studied several technology and policy sensitivities, as described in Table 5.[2]

Table 5: Cal ISO System Analysis Scenarios and Sensitivities

	SB 100 Policy	0 MMT Policy
Base Policy	SB 100 31 MMT by 2030 12 MMT by 2045 Existing gas & unspecified imports allowed	SB 100 **24 MMT** by 2030 **0 MMT** by 2045 **No in-state gas** or unspecified imports in 2045
AB 525 Require 20 GW of offshore wind (OSW) by 2045.	✓	
Gas retirement Retire existing CA gas generation fleet in 2045	✓	✓

[2] The project team also conducted a SB 100 sensitivity using Lawrence Berkeley National Laboratories (LBNL) "California Demand Response Potential Study, Phase 3" data; however, no significant impact on LDES value was found due to the relatively short duration of residential and commercial loads characterized in that study, (up to 6 hours of flexibility). As such, this flexible load sensitivity is not discussed in this report. New Phase 4 data characterizes a wider range of flexible loads but was not available at the time of this study.

	SB 100 Policy	0 MMT Policy
Emerging low-carbon gen. alternatives Enable adv. geothermal, CCS, and adv. nuclear candidate resources		✓

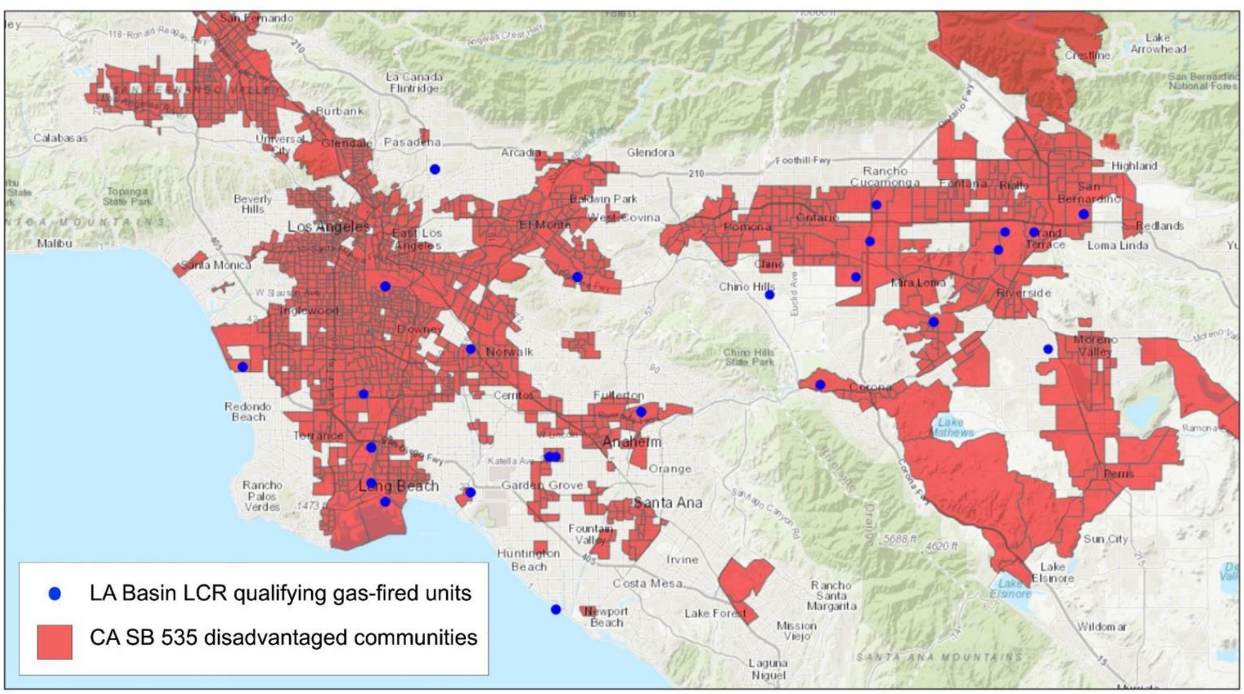
Source: EPC-19-056

Los Angeles Basin Local Capacity Case Study

System-wide planning studies like the CPUC IRP have historically not captured local capacity needs in detail. While the CPUC continues to research how to better capture these needs in future IRP cycles (CPUC 2023), this LA Basin Local Capacity Case Study illuminates the potential value of LDES in addressing local capacity challenges. The Cal ISO 20-Year Transmission Outlook identifies 14.4 GW of gas-fired generation to be retired, based on disadvantaged communities criteria.

The LA Basin, which includes the Los Angeles metropolitan area and surrounding regions, is defined as a local capacity requirement (LCR) area. Based on the 2027 LCR study, the area contains 6.4 GW of gas-fired generation. The team used geospatial data from the CEC's SB 535 map of disadvantaged community census tracts, totaling 3.4 GW of capacity (Figure 5). Based on the CPUC IRP unified modeling database (CPUC, 2019-2020 IRP Events and Materials 2021), each gas plant was mapped to one of six gas-fired generation types, with specific operational characteristics.

Figure 5: Siting of Gas-Fired Generation in LA Basin Local Capacity Area, Overlaid with SB 535-Defined Disadvantaged Communities



For clarity of the map, the West of Devers sub-area is not included.

Source: (CEC 2022)

The team compared two portfolios: (1) a baseline scenario that retained all in-basin gas generation, and (2) a portfolio where the 3.4 GW of gas generation in disadvantaged community areas is retired. This is modeled in two stages:

1. Formware selects the optimal replacement resource portfolio (assuming flat hourly pricing of imports from the Cal ISO) so that storage build is purely driven by reliability needs rather than energy arbitrage values. The model requires that load in the LA Basin be met across all hours of the year, subject to transmission constraints and available local generation.
2. Formware simulates 8760-hour local portfolio dispatches (similar to what is shown in the Cal ISO Local Capacity Technical Study (LCTS) (CAISO 2022) — to quantify the change in local emissions due to optimized gas retirements. Gas plants are constrained to operate at their historical 2020 capacity factor, at minimum, to account for the fact that these gas units also serve load outside of the LA Basin. Emissions factors and capacity factor data for each gas-fired unit were based on measured 2020 plant-level values in the U.S. EPA Clean Air Markets Program Data (CAMPD) database (US EPA 2023).

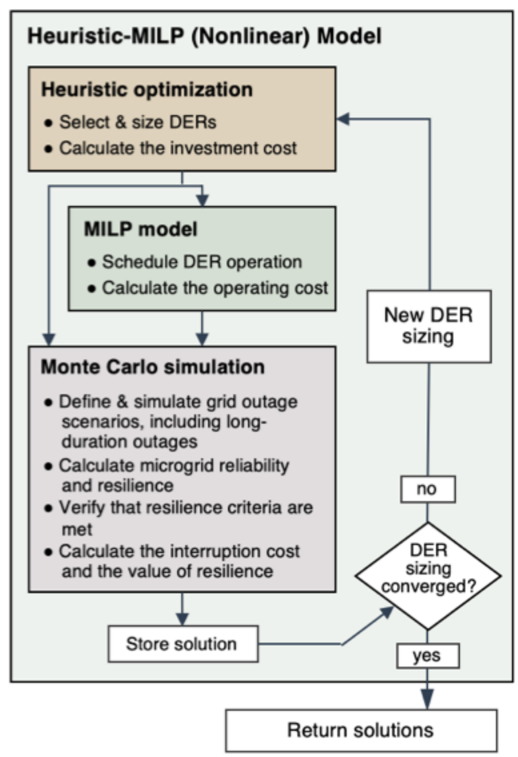
UCSD Microgrid Case Study

Modeling Framework

The team updated an existing microgrid model (Hanna, Ghonima, et al. 2017, Hanna, Disfani and Haghi, et al. 2019), based on the U.S. Department of Energy's (DOE) Distributed Energy Resources Customer Adoption Model (DER-CAM) optimization platform, which calculates the economics of customer-sited microgrids alongside other key measures like resilience, energy supply, and emissions. This model quantifies reliability by simulating discrete power outages, periods of islanded microgrid operation, and other DER failures and maintenance periods (Hanna, Disfani and Kleissl 2018, Hanna, Disfani and Haghi, et al. 2019).

The model's microgrid portfolios co-optimize purchases of utility gas and electricity alongside new DER investment and operations that minimize customer energy costs over a 25-year lifetime (Figure 6). DER operations are divided into two categories:

Figure 6: Microgrid Model Diagram



Source: (Hanna and Marqusee 2021), reproduced here without modification under a CC BY 4.0 license.

- During typical "blue-sky" operation, the microgrid seeks to reduce customer energy bills (such as through peak demand reduction, energy arbitrage).

- During "grey sky" grid outage events, the microgrid loses grid supply and must supply critical loads itself. Microgrids are sized by the model to provide 48 hours of resilience where they can operate autonomously without grid power.

A microgrid's CO_2 emissions are by-products of these cost-minimizing investment and dispatch decisions. Simulated microgrids are not operated to minimize emissions.

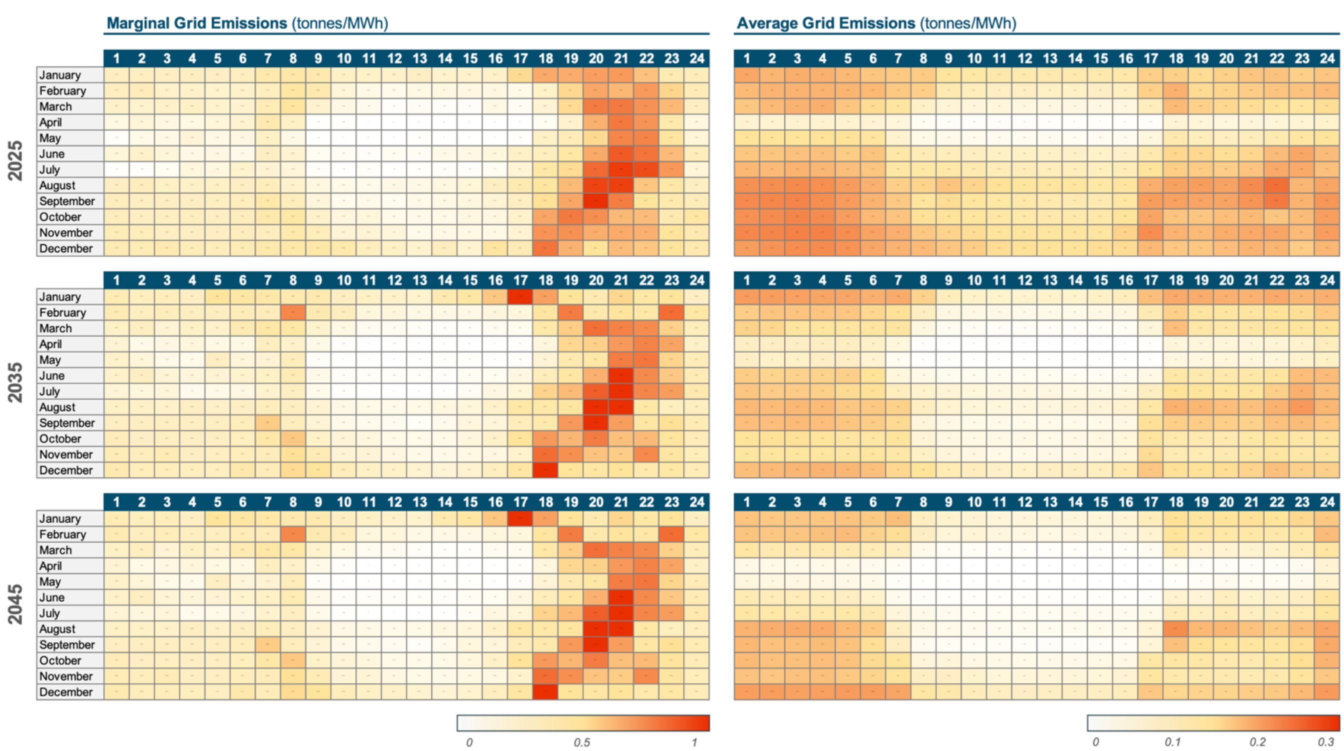
Data Inputs and Assumptions

Utility Electricity and Fuel Price Assumptions

The microgrid model uses recent public data such as the CPUC Avoided Cost Calculator (CPUC 2022) to estimate average and marginal emissions. To calculate microgrid emissions, baseline utility customer load is assigned system **average** emission rates because existing buildings are "legacy" demands on the grid. In contrast, incremental changes to building load constitute an intervention and are assigned system **marginal** emission rates.

Electric rates are taken from San Diego Gas & Electric's (SDG&E) AL-TOU tariff from 2021-22, which has volumetric rates of $0.12-0.17/kWh and demand charges of $21-33/kW over both on- and off-peak periods (SDG&E 2018). Given uncertainty in how rate structures might change, this study assumes that rate structures stay the same while electric rates increase at a nominal rate of 3 percent per year (0.8 percent real), and gas prices at 3.6 percent and 2.8 percent per year (nominal) for commodity and delivery charges (1.4 percent and 0.6 percent real).

Figure 7: Average and Marginal Grid Emissions Factors

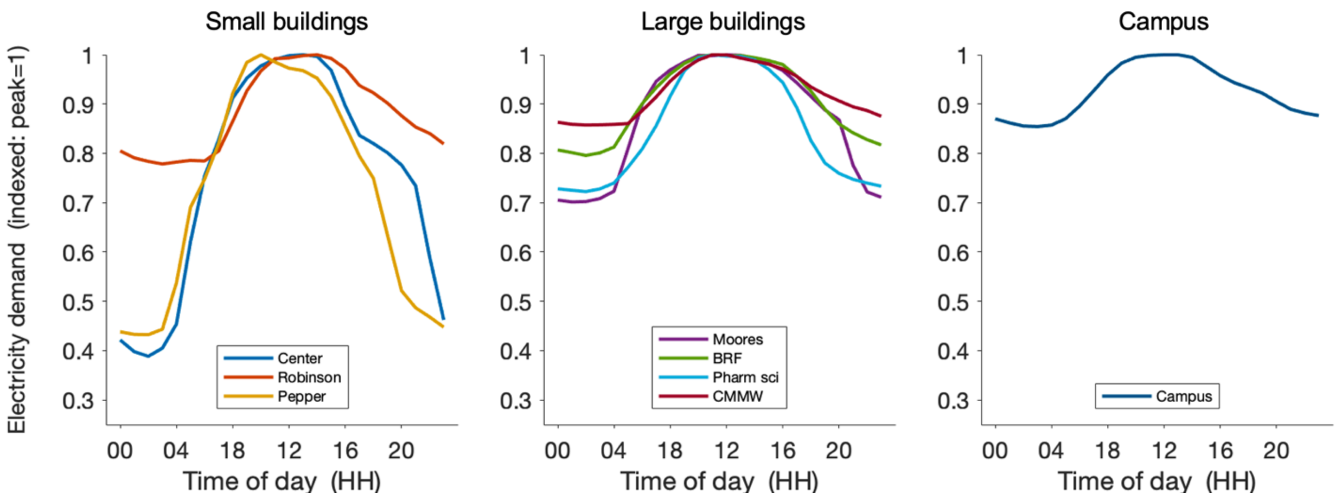


Source: EPC-19-056

Campus Buildings

The UCSD campus has numerous large buildings with higher-than-average energy density compared with the California building stock. The team obtained demand data for seven distinct buildings (three small and mixed use and four large/biomedical) on UCSD's campus, as well as for the whole campus (Figure 8 and Table 6). For simplicity and general comparison, each building is modeled as a standalone customer (separate from the existing UCSD microgrid), receiving utility service on the applicable commercial and industrial (C&I) electric tariff—the situation for most C&I customers in California.

Figure 8: Average Weekday Load Shape by Building Type and Individual Building



Source: EPC-19-056

The three building categories differ in key ways:

- Small buildings have lower load factors ("peakier" load shapes) than the large buildings and campus, making them more favorable for PV + storage microgrids.
- Large buildings have higher load factors, a smaller fraction of which is considered critical load.
- The campus lacks space for additional onsite BTM PV, which limits the technical potential feasibility for PV + storage microgrids to serve the full campus demand.

Table 6: Buildings Studied for UCSD Zero-Carbon Microgrid Analysis

Building & Description	Annual Load (GWh)	Peak Load (kW)	Load Factor	Critical Load	Space for PV	Existing DERs
Pepper Canyon *Small, mixed-use*	0.5	110	0.78	-	1,750 m^2	
Robinson Hall *Small, classrooms*	0.8	140	0.90	-	400 m^2	

Building & Description	Annual Load (GWh)	Peak Load (kW)	Load Factor	Critical Load	Space for PV	Existing DERs
Center Hall *Small, classrooms*	1	210	0.79	-	2,400 m^2	
Cellular & Molecular Medicine West (CMMW) *Large, biomedical research*	3.5	460	0.94	10%	2,000 m^2	
Pharmacological Science *Large, biomedical research*	6.7	1,040	0.88	32%	2,000 m^2	
Biomedical Research Facility II (BRF) *Large, biomedical research*	7.5	1,030	0.92	39%	3,650 m^2	
Moores Cancer Center *Large, biomedical research*	8.3	1,200	0.87	47%	6,000 m^2	
Campus *Campus, mixed-use*	297	47,600	0.94	-	3.1 MW	27 MW gas turbine 3 MW steam turbine 2.8 MW fuel cell 2.5 MW (2-hr) Li-ion battery 15 MW diesel gensets[3]

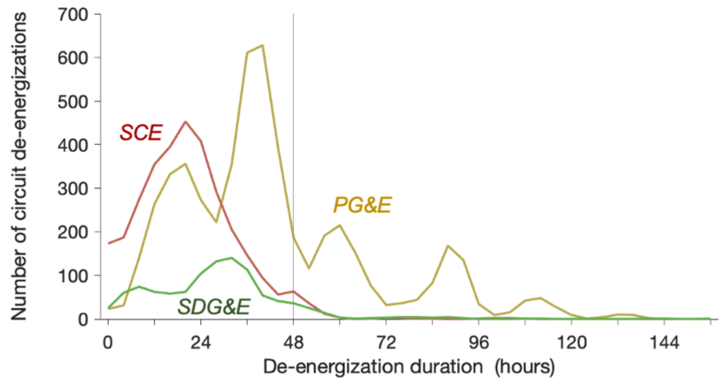
Source: EPC-19-056

Public Safety Power Shutoff (PSPS) Grid Outage Survivability Constraint

In this study, microgrids are sized to meet a survivability requirement, calculated at 48 hours per analysis of 2017-2020 PSPS circuit de-energizations (Figure 9) where 78 percent of all de-energizations did not exceed 48 hours, including 88 percent of those in SDG&E's service territory.

[3] There are additional, smaller diesel gensets tied to individual buildings on the UCSD campus that were not included due to data limitations.

Figure 9: Duration of 2017-2020 PSPS Circuit De-Energizations, by Electric Utility



Source: EPC-19-056, based on data from (CPUC, Utility PSPS Reports 2023)

DER Technology Assumptions

The microgrid case study uses 8-hour Li-ion (Table 7) and leverages the same LDES data sources that model 12- to 100-hour LDES archetypes for technology assumptions.

For other DER technologies, the team surveyed investment, O&M, and fuel costs for distributed solar PV, fuel cells, gas generators, and diesel generators, and assessed a "balance-of-system" cost for each microgrid. See Table 8.

Table 7: Overnight Investment and Fixed O&M Cost for DERs

	Investment		Fixed O&M	
	2025	2045	2025	2045
Solar PV	$1320/kW	$740/kW	$15/kW/y	$10/kW/y
Li-ion	$269/kWh $133/kW	$176/kWh $87/kW	$10.8/kW/y	$10.8/kW/y
Fuel cell	$7000/kW	$6700/kW	$36/kW/y	$36/kW/y
Gas generator	$2800/kW	$2800/kW	$26/kW/y	$26/kW/y
Diesel generator	$2900/kW	$2900/kW	$28/kW/y	$28/kW/y
Balance-of-system	$162/kW	$162/kW	6.1% of capex	6.1% of capex

Source: EPC-19-056 technology review deliverable

Table 8: Microgrid Fuel Costs

	2025	2035	2045
Gas	$5.40/MMBtu	$6.30/MMBtu	$7.20/MMBtu
Diesel	$4/gallon	$4/gallon	$4/gallon
Biomethane	$24.85/MMBtu	$18.40/MMBtu	$16.85/MMBtu

Source: EPC-19-056 technology review deliverable

Policy Scenarios and Sensitivities

The microgrid case study envisions three policy environments (Table 9):

Table 9: Microgrid Policy Scenarios

Policy Scenarios[4]	Onsite Emissions Restrictions	Description	General Effect on Microgrid Composition
Reference *(Ref)*	No restrictions	Current policy for small, decentralized sources	-
Zero-Carbon *(Zc)*	**No onsite CO_2 emissions**	Aligned with California's goal of 100 percent clean electricity	Requires substitution of gas for carbon neutral RNG options
Zero-Carbon + Zero-Pollution *(Zc+Zp)*	No onsite CO_2 emissions **No onsite criteria air pollutant emissions**	Further aligned with California's environmental justice goals	Further requires substitution of combustion generators (e.g., gas turbines) for non-combustion alternatives (e.g., fuel cell)

Source: EPC-19-056

To assess LDES's role, the team analyzed five microgrid configurations that differ by DER portfolio, including LDES used. See Table 10.

Table 10: Various Microgrid Configurations

Microgrid Configuration	Code	DERs Available for Investment	Anchor DER
Utility Customer	Uc	None	None
Microgrid without LDES	Ref	Any, except LDES	None
Microgrid with 8-hour LDES	8-h	Any	8-hour LDES
Microgrid with 12-hour LDES	12-h	Any	12-hour LDES
Microgrid with 100-hour LDES	100-h	Any	100-hour LDES

Source: EPC-19-056

[4] For generalizability, all scenarios do not include incentives such as investment and production tax credits, net energy metering, and the self-generation incentive program. These incentives shape microgrid DER portfolios by reducing PV and storage costs. This case study captures such reductions in other ways—by analyzing microgrid adoption in future years (through 2045) which see large declines in PV and storage costs.

CHAPTER 3: Results

California Independent System Operator System

At the Cal ISO system level, this study develops estimated bulk system cost savings for inter-day and multi-day LDES archetypes under different policy scenarios. Comparing the change in bulk system cost with projected costs, the modeling suggests that there is a role for up to 5 GW of LDES under the reference SB 100 policy, which allows 12 MMT of GHG emissions from in-state generation or unspecified imports; however, the role for LDES under deeper decarbonization scenarios (for example scenarios that allow for in-state gas retirement, 0 MMT) is significantly larger, with potentially up to 37 GW of LDES by 2045 under a 0 MMT scenario.[5]

LDES technologies have a notable impact on reducing renewable curtailments and criteria pollutant reductions. This study also demonstrates that LDES can serve much the same role as in-state gas capacity for providing energy during energy-constrained or "renewable drought" conditions, potentially allowing California to accelerate decarbonization goals while maintaining system reliability at cost parity with SB 100 policy.

SB 100 Policy Scenario

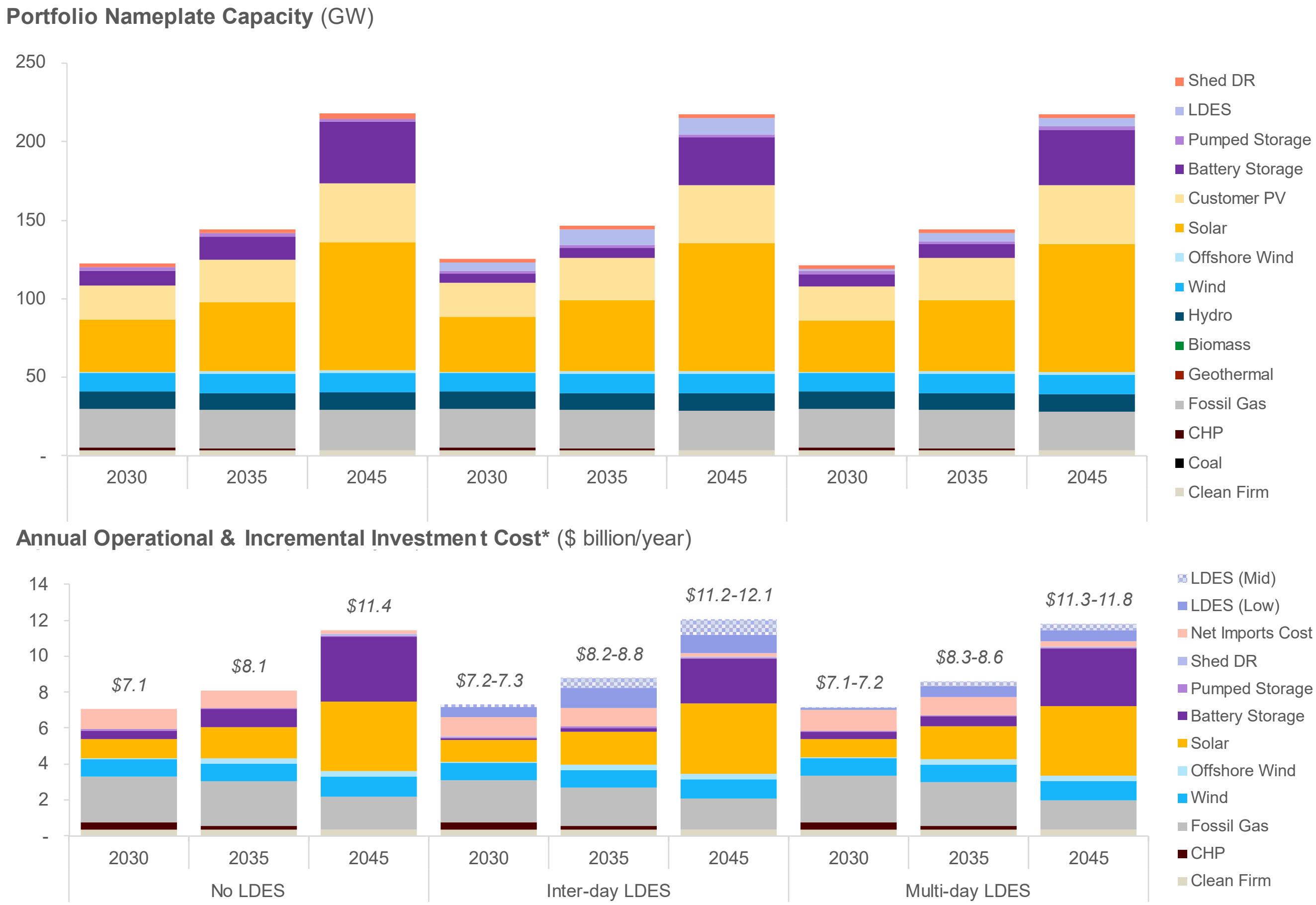
Reference Policy

Under the reference SB 100 policy scenario, the availability of inter-day and multi-day LDES has a modest impact on system portfolios, with approximately 5 GW of LDES included in California's resource portfolio by 2045. These portfolios were developed by forcing, in 1, 5, 10, 15, 20 increments of LDES, and allowing Resolve to re-optimize other portfolio investments (for example, renewables) and operations around these LDES deployments.

Figure 10 compares three portfolios: without LDES, with inter-day LDES, and with multi-day LDES. These portfolios illustrate three potential technology pathways for California's grid that are all similar in incremental system costs.

[5] The team studied additional sensitivities for the impact of (a) higher projected LDES roundtrip efficiencies (RTE) (such as increasing 100-hour LDES RTE from 46 percent to 60 percent and (b) residential and commercial load flexibility. In both cases, the impact on LDES value was relatively small. While higher RTE certainly increased the value of LDES, it did not change the relative ordering of LDES compared to other flexibility and clean firm options. In the case of load flexibility, the team found that the relatively constrained flexibility profiles of residential and commercial loads made these imperfect substitutes for LDES.

Figure 10: Total Resource Portfolios (top) and System Costs (bottom) Under SB 100 Policy Scenario, with no LDES, Inter-day LDES, and Multi-day LDES



** Costs shown here do not include sunk utility costs (estimated at $35 billion in 2030 and $42 billion in 2045) or CAISO transmission system upgrade costs*

Bulk System Cost Savings

Modeling finds that 5 GW of inter-day LDES is able to reduce bulk system costs more than multi-day LDES due to higher roundtrip efficiencies (RTE) (in 2045, $120-150/kW-year for inter-day vs. $90-125/kW-year for multi-day). However, in both cases, the bulk system cost savings are within the range of the projected LDES costs assumed in this study. The marginal bulk system cost savings for deploying 10 GW or 20 GW of LDES fall by up to 29 percent or 55 percent, respectively. For reference, the 2021 CPUC IRP PSP assumed 4-hour Li-ion battery cost projections, reaching as low as $62/kW-year by 2045 (CPUC, 2019-2020 IRP Events and Materials 2021).[6]

[6] Note that supply chain constraints have significantly changed the outlook for Li-ion cost projections for the next CPUC IRP planning cycle.

Figure 11: Change in Bulk System Cost as a Function of LDES Use in Modeled Year Under SB 100 Policy Scenario

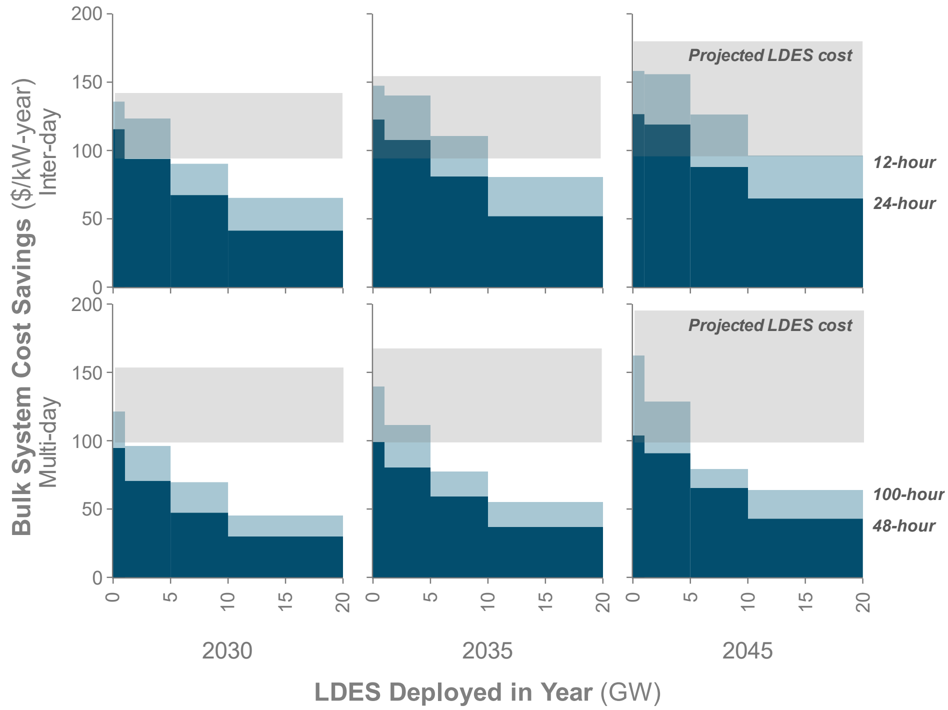


Figure 11 also highlights that within the inter-day and multi-day LDES typologies, the duration/RTE tradeoff has a noticeable impact on the value of LDES in the portfolio. For example, the higher RTE associated with the 12-hour LDES archetype reduces bulk system costs by 20-33 percent more than the lower RTE 24-hour archetype. In contrast, the 48- and 100-hour LDES archetypes have similar RTEs (45 percent), which therefore is a 26-56 percent greater reduction in system costs associated with the 100-hour archetype.

Operational Role for LDES

Long-duration energy storage operates throughout the year (Figure 12), with inter-day LDES utilized more often for shorter-duration cycles due to its higher RTE and multi-day LDES for more conservative operation. In 2030, when inter- and multi-day energy shifting needs are less pronounced in the operational data, inter-day LDES operates at a 25 percent capacity factor (charging for 2,840 hours and discharging for 3,090 hours per year, not always at full rated power), while multi-day LDES operates at an approximate 8 percent capacity factor (discharging for 1,480 hours per year). By 2045, capacity factors increase to 27 percent and 13 percent, respectively. For reference, Li-ion storage was found to operate at a capacity factor of 15 percent in 2030, indicating that LDES reaches a use level comparable to that of shorter-duration technologies on today’s grid.

Figure 12: Normalized LDES Dispatch Across Three Weather Years, SB 100 Policy Scenario

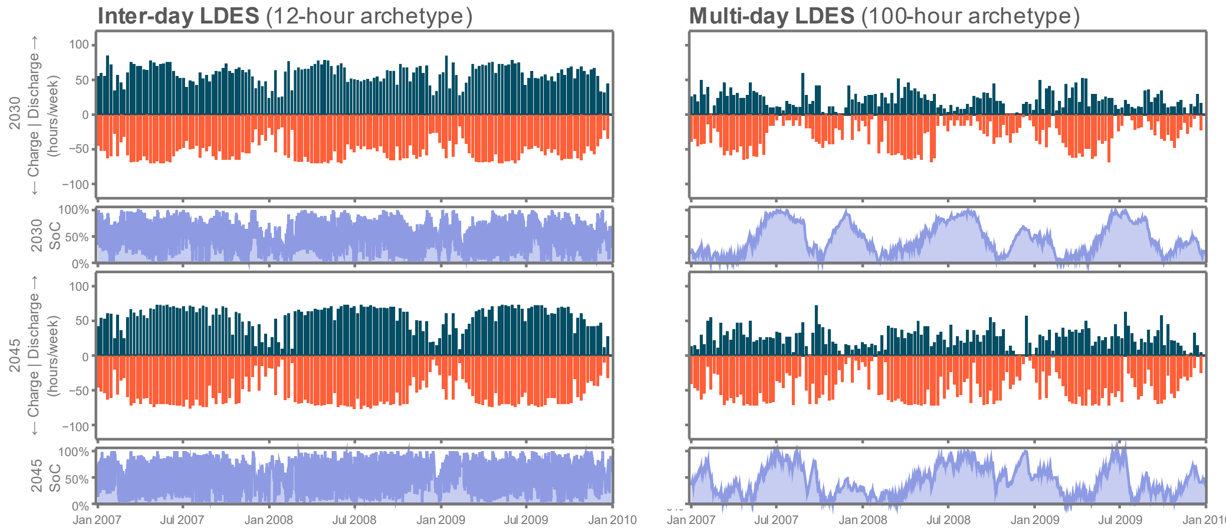


Figure 13 and Figure 14 show how criteria pollutant emissions and renewable curtailment are affected by increasing LDES deployment in each modeled year. These figures suggest that multi-day LDES is better at reducing renewable curtailment, while inter-day LDES is better able to reduce emitting generation dispatches and their associated criteria pollutant emissions.

Figure 13: Impact of LDES Use on Criteria Pollutant Emissions Under SB 100 Policy

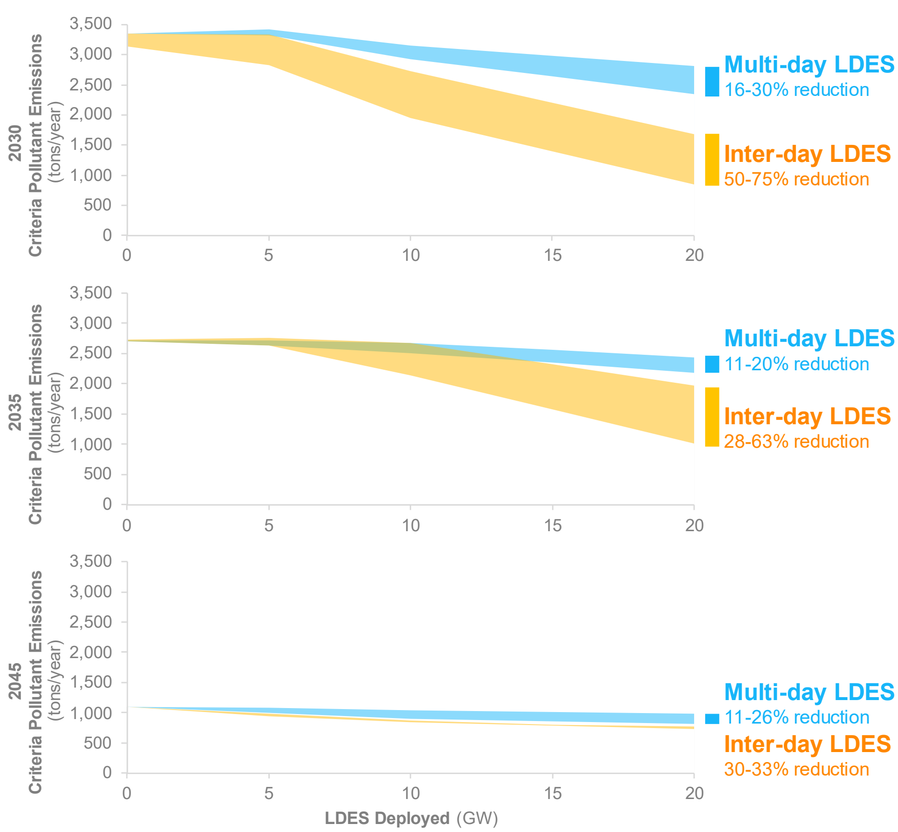
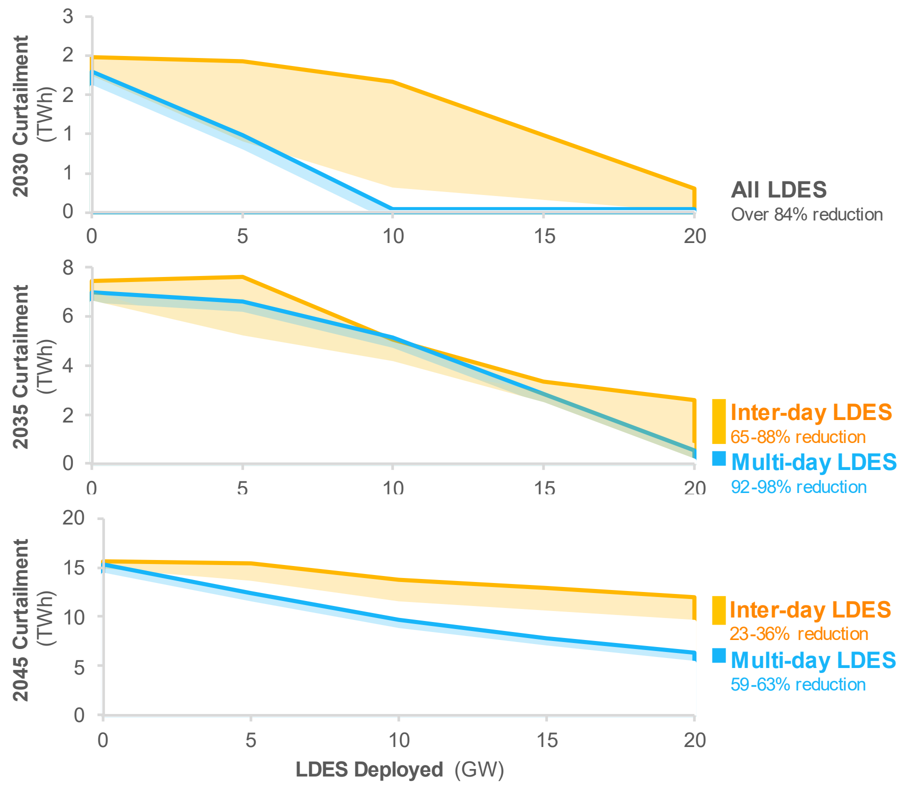


Figure 14: Impact of LDES Use on Renewable Curtailment Under SB 100 Policy

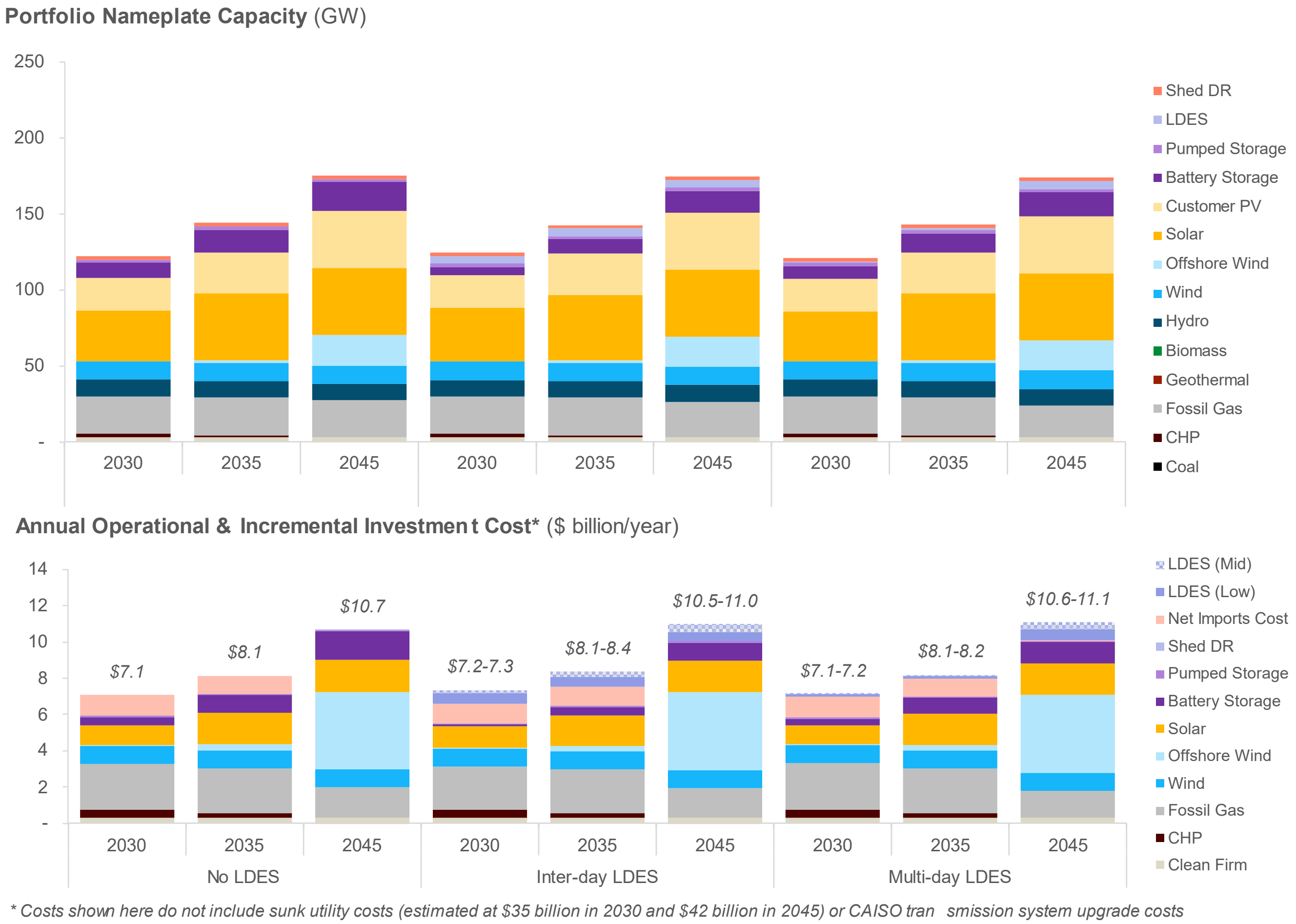


** Note y-axis scale change in each year*

AB 525 Offshore Wind Sensitivity

Long-duration energy storage buildout under SB 100 decreases only slightly under Assembly Bill (AB) 525 sensitivity. Offshore wind has the major effect of changing the solar buildout while not significantly changing the relative impact of inter-day or multi-day LDES on the portfolio, as shown in Figure 15.

Figure 15: Total Resource Portfolios (top) and System Costs (bottom)



Under AB 525 sensitivity with no LDES, with inter-day LDES, and with multi-day LDES.

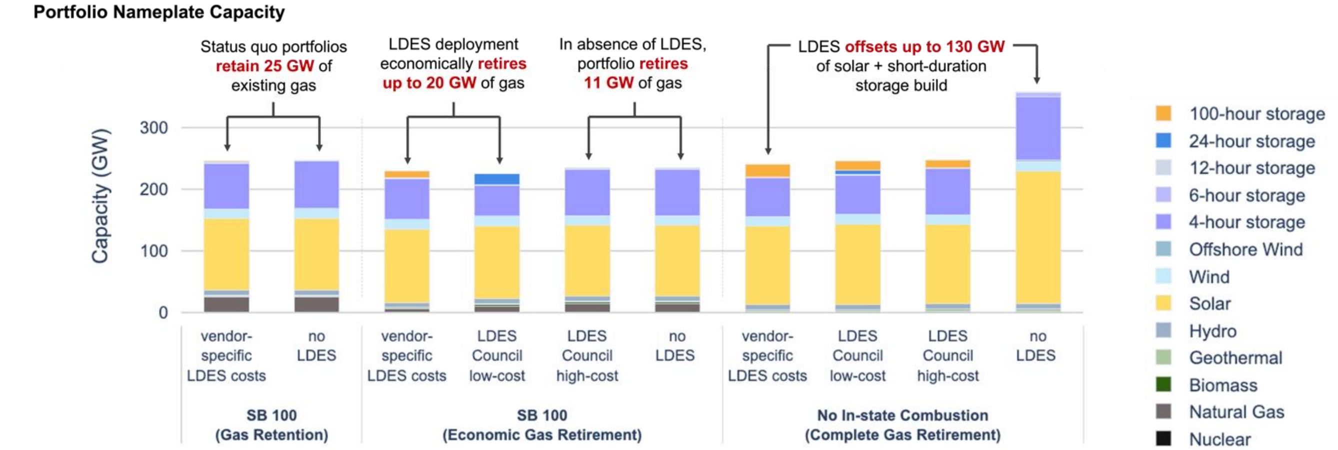
SB 100 Gas Retirement Sensitivity

LDES Could Enable More Cost-Effective In-State Gas Retirement by 2045

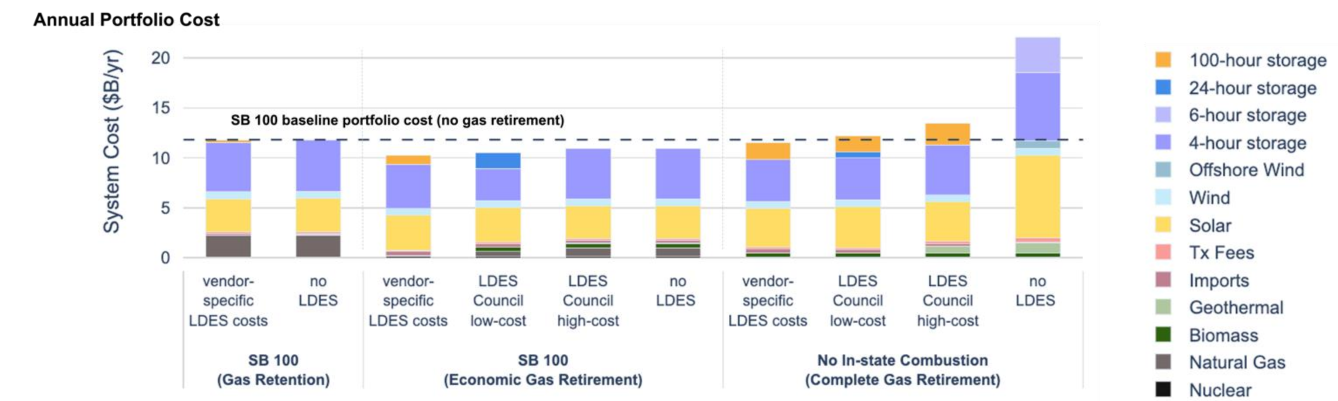
As a sensitivity analysis in the SB 100 scenario, the team utilized Formware to demonstrate how LDES could potentially serve system loads in place of existing gas generation. Least-cost portfolios were determined for various gas retirement scenarios, using a co-optimization of eight years of historical weather data (2007-2014).[7] In this capacity-expansion framework, resource build is optimized to serve load across all 8,760-hour load for eight historical weather years. This approach avoided the use of reserve-margin-based planning techniques, which require uncertain and outside load-carrying capacity inputs. See Appendix B for more details on how load and weather data were generated for this sensitivity, as well as benchmarking for the Formware and Resolve portfolios.

[7] Note: Unspecified import limits were assumed to stay the same as reference assumptions from 2021 CPUC IRP.

Figure 16: Portfolio Installed Capacities and Annual Costs Under Gas Retirement Scenarios



LDES (GW)	2	0	11	18	0	0	21	22	13	0
Natural Gas (GW)	25	25	5	10	14	14	0	0	0	0
Solar + Short-duration Storage (GW)	190	193	185	167	190	190	190	194	203	322



In scenarios where gas is allowed to retire, the Cal ISO's least-cost portfolios include between 11 GW and 22 GW of LDES (equivalent to up to 2.2 TWh of energy storage capacity) and offset solar and Li-ion build requirements by up to 130 GW. Additionally, this gas replacement sensitivity achieves a reduction of up to 4 MMT of electric sector emissions, or 33 percent relative to the SB 100 scenario. The remaining emissions come from imports.

The portfolio costs illustrate that Cal ISO can achieve cost parity, or even costs savings, relative to the SB 100 baseline portfolio while still retiring some existing gas capacity. In the case of economic gas retirement, the selection of LDES in LDES Council low-cost and vendor-cost scenarios results in 11-14 percent cost savings when compared with 8 percent cost savings without LDES.

Further, the results indicate that, under certain LDES cost forecasts, complete retirement of in-state gas could be more cost effective than the SB 100 baseline scenario. Depending on the LDES cost projection, the difference in total system cost between the SB 100 baseline and a portfolio with no in-state combustion was found to range from a 3 percent cost savings to a

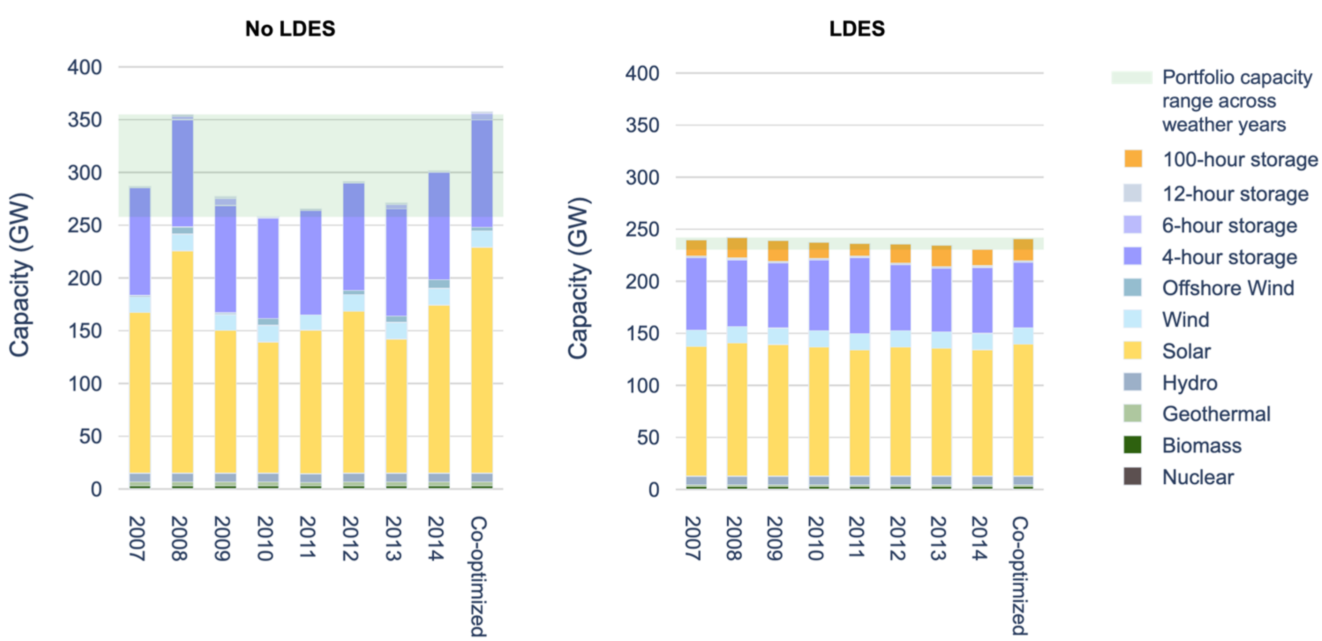
14 percent cost premium. In contrast, an 87 percent cost premium is required to achieve a “no in-state” combustion system without LDES.

Appendix C summarizes a reliability analysis for in-state gas retirement portfolios across a wider range of 35 weather years, demonstrating similar levels of reliability. All portfolios shown achieve an expected unserved energy (EUE) of <0.001 percent, meeting typical EUE reliability planning standards.[8] These results are a promising indicator that LDES and other technologies can cost-effectively replace existing gas capacity while maintaining grid reliability. Future studies such as the CPUC IRP and resource adequacy proceedings should continue to examine gas replacement reliability implications at the bulk-system and local transmission zone level, ratepayer impacts, and environmental justice benefits.

LDES Allows Robust Portfolios Against Annual Load and Renewable Variability

Figure 17 shows 2045 capacity expansion results[9] across eight modeled weather years, demonstrating how uncertainty in load and renewables could significantly impact potential resource buildout needs.

Figure 17: Variation in Capacity Expansion Results Across Weather Years



When LDES is excluded from the resource selection, there is significant variation in portfolios, ranging from 260-350 GW. In contrast, when LDES is included as an option in resource selection, resource-build requirements remain nearly constant across the single-year optimizations, ranging from 230-240 GW. In the co-optimized portfolio, LDES avoids more than 100 GW of capacity, or approximately 29 percent, relative to the “no LDES” case. These results highlight that LDES helps “hedge” the system against annual weather variability by reducing the year-to-year variance in resource needs. Furthermore, these results underscore

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[8] See https://www.epri.com/research/products/000000003002022192 for a review of reliability standards.

[9] Portfolios based on in-state gas retirement portfolios, using tech-specific LDES cost projections (see Figure 16).

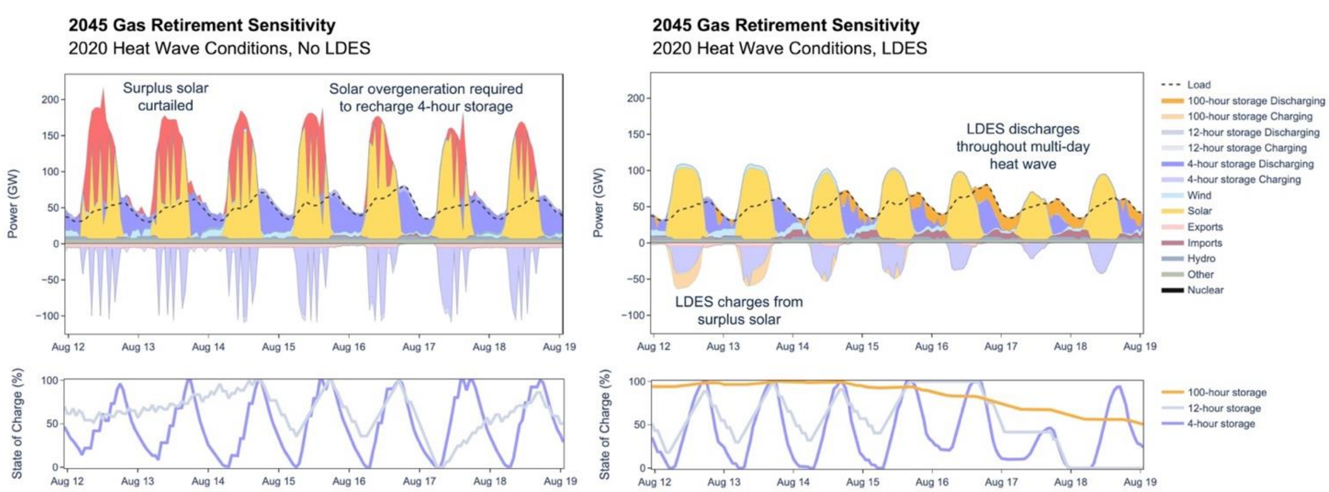
the methodological importance of capturing a wide range of weather years in capacity expansion modeling, as differences in load and renewable generation profiles between years can produce significant disparities in modeled resource builds.

LDES Provides Energy During Grid Stress Events

The left panel of Figure 18 illustrates resource dispatch in the Cal ISO during the week of 2020 heat waves and outages without LDES, showing significant solar generation curtailment throughout the entire period. This is because the nearly 100 GW of extra solar capacity needed to maintain a similar level of reliability without clean firm alternatives is otherwise "overbuilt" under typical conditions; at the end of each day, the stored energy reserves in 4-hour storage are completely depleted, leaving the system vulnerable to additional grid contingencies. Six-hour and 12-hour storage demonstrate similar behaviors, discharging to <50 percent state of charge every day, before recharging with solar.

In contrast, the right panel illustrates how a portfolio with LDES absorbs solar during periods of surplus generation (August 12-13). During the multi-day heat wave (August 14-18), LDES discharges over five consecutive days to meet demand. LDES serves a similar function for existing gas resources, providing flexible capacity to the grid throughout the period of grid stress. The state of charge of 100-hour storage is depleted to 50 percent by the end of the heat wave, indicating a margin of stored energy reserves for grid contingencies. Because of these stored energy reserves, 100-hour storage does not need to recharge during the energy-constrained grid stress period. Any surplus solar generation is instead made available for 4-hour storage to recharge and provide peaking capacity in the afternoon hours.

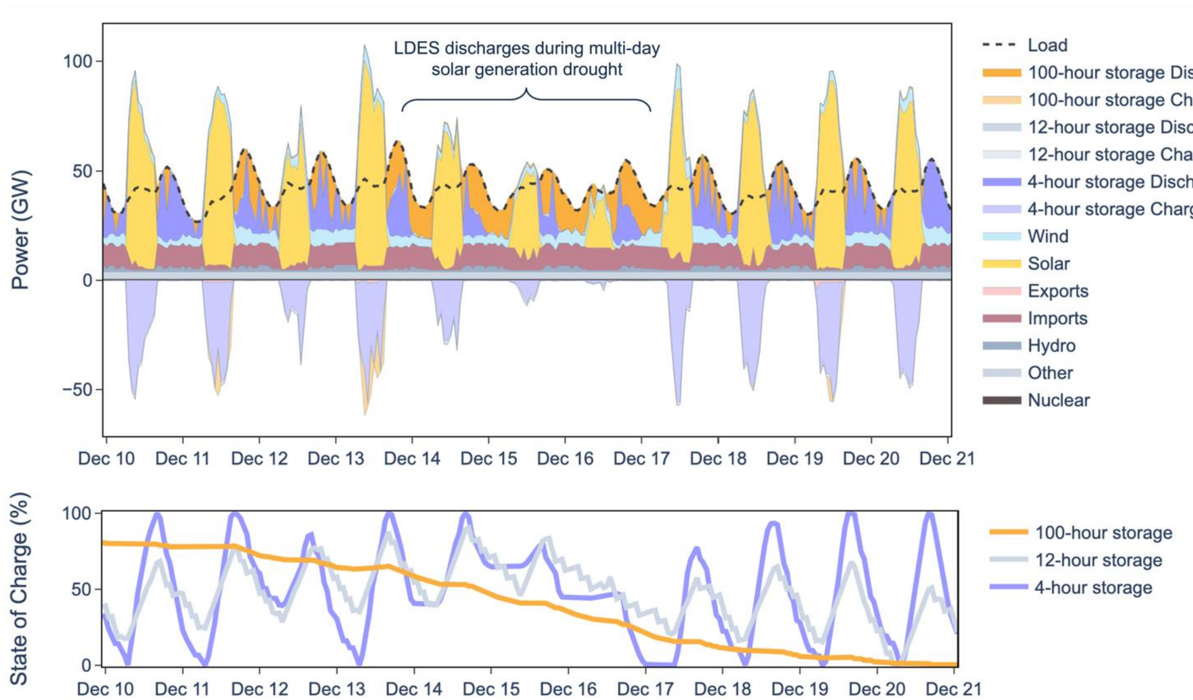
Figure 18: Resource Dispatch and Storage State of Charge



Without LDES (left) and with LDES (right), 2045 gas replacement scenario (2020 heat wave conditions)

Renewable droughts are another category of grid stress events, during which LDES played a key role in maintaining grid reliability. Renewable droughts are continuous periods during which the average capacity factor of solar or wind resources is significantly below the annual capacity factor. Figure 19 illustrates dispatch of an optimal portfolio under the 2045 No In-state Combustion case during a solar lull (Dec 14-17) in the 2014 weather year. At the start of the lull, LDES (modeled as 100-hour storage) has a 70 percent state of charge. Throughout the lull period, LDES discharges its stored energy reserves continuously to meet demand during evening peak and nighttime hours. Discharge of 4-hour storage is limited during the lull due to lack of surplus renewable energy available for charging.

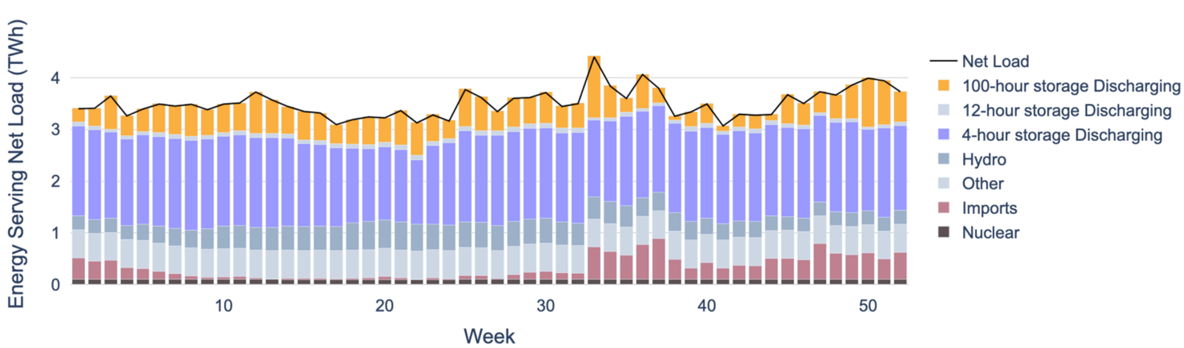
Figure 19: Resource Dispatch with LDES, 2045 Gas Replacement Scenario, Solar Generation Drought (2014 Weather Year)



LDES delivers energy to meet system load throughout the year, not solely during extreme weather-related events.

Figure 20shows the energy dispatched to serve net load (load minus renewable generation) in the 2020 weather year for the No Combustion scenario. In this scenario, 62 GW of 4-hour storage serves 47 percent of net load, primarily through the diurnal energy shifting of solar. Twenty-one GW of LDES serve 15 percent of total net load over the entire year (roughly one-third the installed capacity and one-third the fraction of net load relative to 4-hour storage).

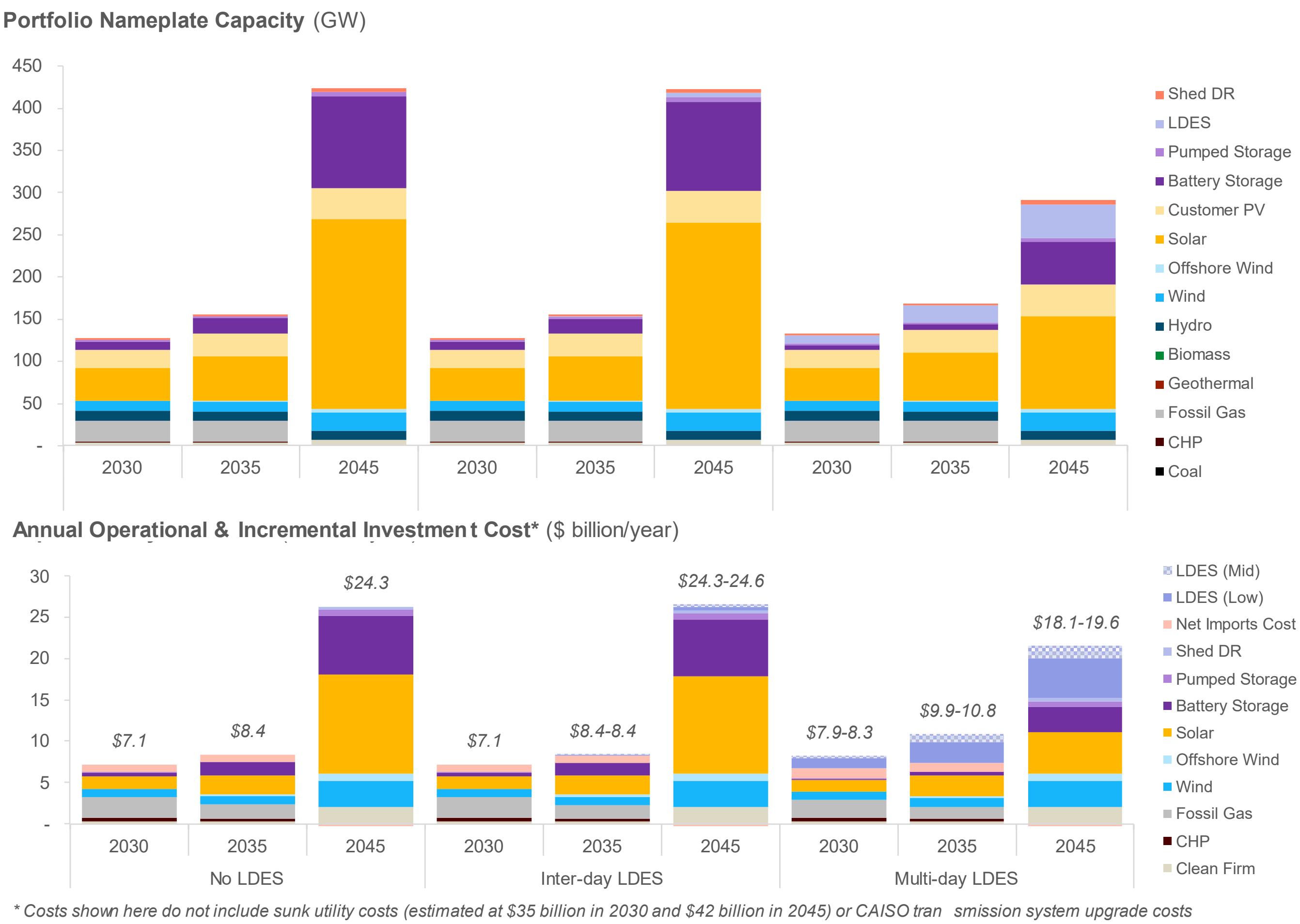
Figure 20: Energy Serving Net Load (Load Net of Renewables)



0 MMT Policy Scenario

The 0 MMT policy scenario studies a potential future where California's grid has no in-state emissions and no unspecified imported emissions,[10] achieving a fully decarbonized electricity system by 2045. Without LDES or other emerging technologies, Figure 21 shows that more than 400 GW of resources are needed by 2045 to achieve such a stringent electric sector emissions goal, which is consistent with previous studies (Long 2021). Consistent with the gas retirement sensitivity discussed in the previous section, LDES has the potential to significantly reduce the cost for California to achieve a more stringent 0 MMT policy, with upwards of 40 GW of LDES included in a cost-minimizing portfolio.

Figure 21: Total Resource Portfolios (top) and System Costs (bottom) Under 0 MMT Policy Scenario



With no LDES, with Inter-Day LDES, and with Multi-Day LDES

For the 0 MMT policy scenario, the value of System resource agency (RA) is significantly higher than the SB 100 scenario due to the retirement of all in-state gas and the restriction on

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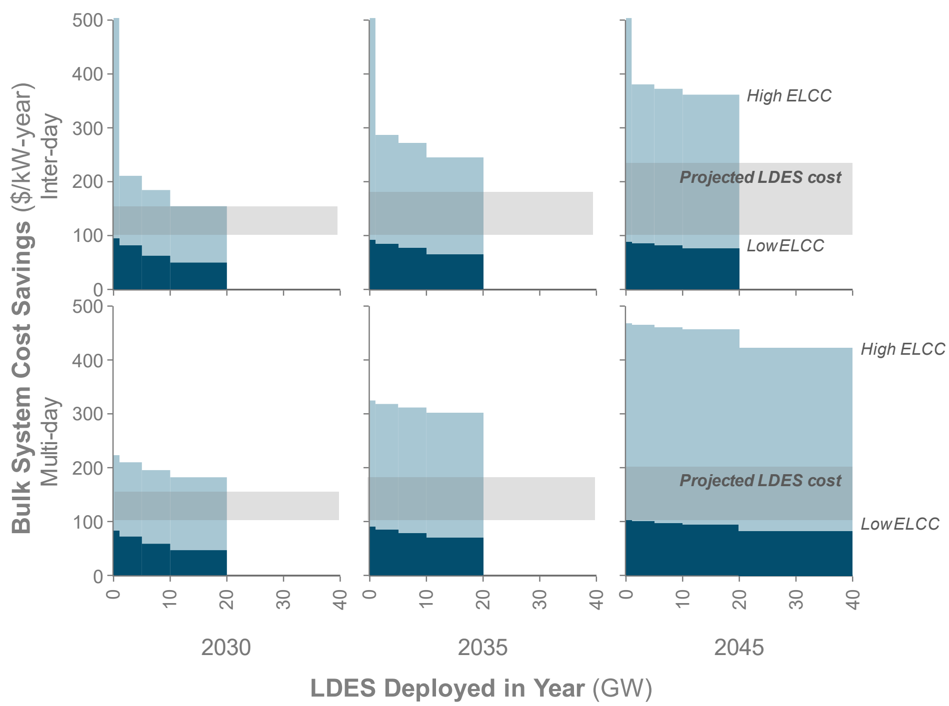
[10] Unspecified imports are defined by the California Air Resources Board (CARB) as any imports where the generation source is unknown (e.g., market purchases). https://ww2.arb.ca.gov/sites/default/files/classic/cc/reporting/ghg-rep/ghg-rep-power/epe-faqs_2021.pdf.

imports. The CPUC IRP Resolve model that this study was based on includes a planning reserve margin constraint. The shadow price of that constraint serves as a proxy for the marginal cost of meeting System RA needs. In the reference 0 MMT policy scenario (without emerging technologies), this value exceeds $500/kW-year. For comparison, the value of System RA in the SB 100 policy scenario is $118/kW-year.

Bulk System Cost Savings

Under a 0 MMT policy scenario, the first increments of LDES deployment result in large marginal system cost savings, due to the significant reduction in potential renewable + Li-ion buildout, with cost savings estimates of $380-450/kW-year for 5 GW of deployed LDES in 2045 (Figure 22). Unlike the SB 100 policy scenario, the marginal system cost savings of increased LDES deployment (20+ GW) remains reduced by only 5 percent, suggesting a durable value proposition for LDES under this more stringent policy future where the need for clean, firm resources is higher.

Figure 22: Change in Bulk System Cost as a Function of LDES Deployment in Modeled Year Under 0 MMT Policy Scenario

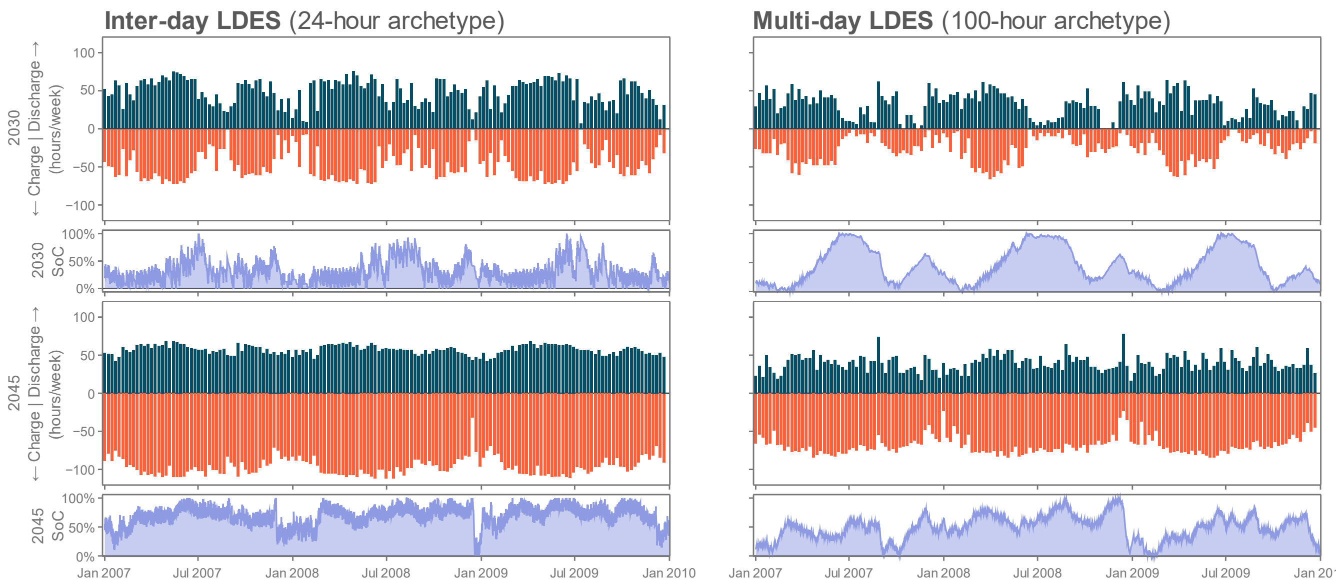


In addition, this highlights that potentially large uncertainty associated with the value of LDES depending on the System RA value of LDES. This value is uncertain due to the interactive effects with other resources in the portfolio, suggesting the need for additional study in future long-term planning studies.

Operational Role for LDES Under 0 MMT Policy

As in the SB 100 policy scenario, Figure 23 shows LDES resources operating throughout the year; however, in the 0 MMT policy scenario, the lack of fossil generation results in more pronounced LDES dispatch during the most energy-constrained weeks when renewable production is abnormally low. By 2045, the 100-hour LDES archetype averages 39 discharge hours each week throughout the year.

Figure 23: Normalized LDES Dispatch Across Three Weather Years, 0 MMT Policy Scenario



The 0 MMT policy scenario shows similar renewable curtailment and criteria pollutant reduction dynamics as the prior SB 100 policy scenario. Notably, however, multi-day LDES has the potential to significantly reduce renewable curtailment in 2045 (by more than 300 TWh/year) by reducing the amount of solar capacity needed to support reliable grid operation (by more than 110 GW of nameplate solar capacity).

Figure 24: Impact of LDES Deployment on Criteria Pollutant Emissions Under 0 MMT Policy

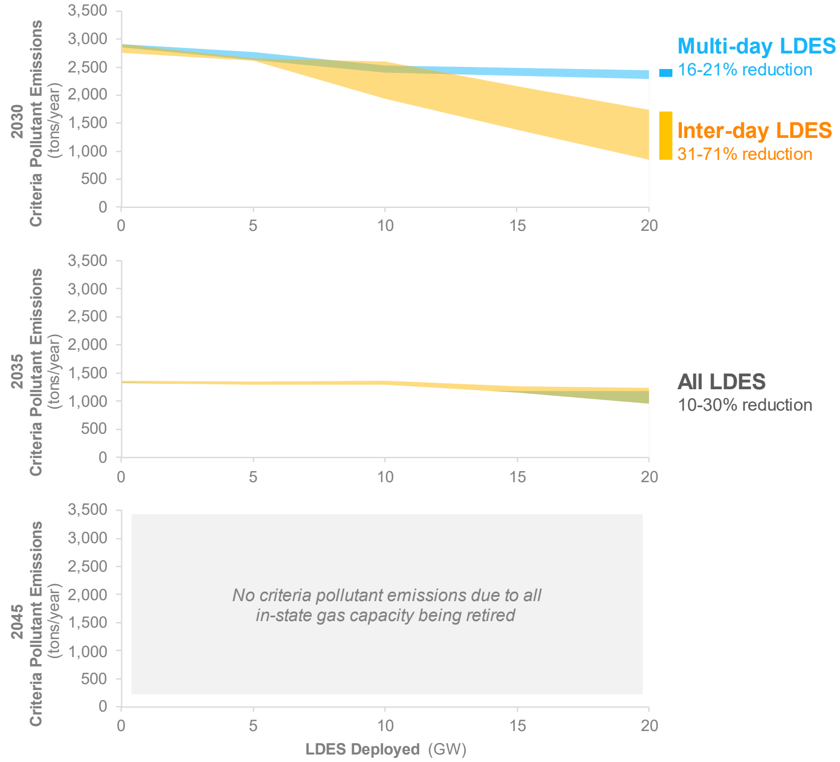
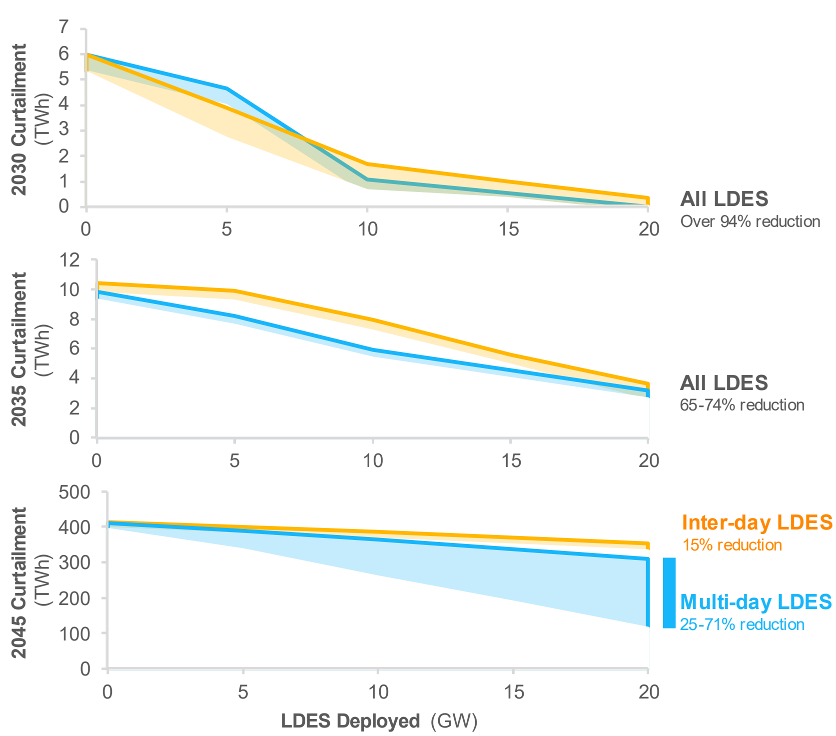


Figure 25: Impact of LDES Deployment Renewable Curtailment Under 0 MMT Policy

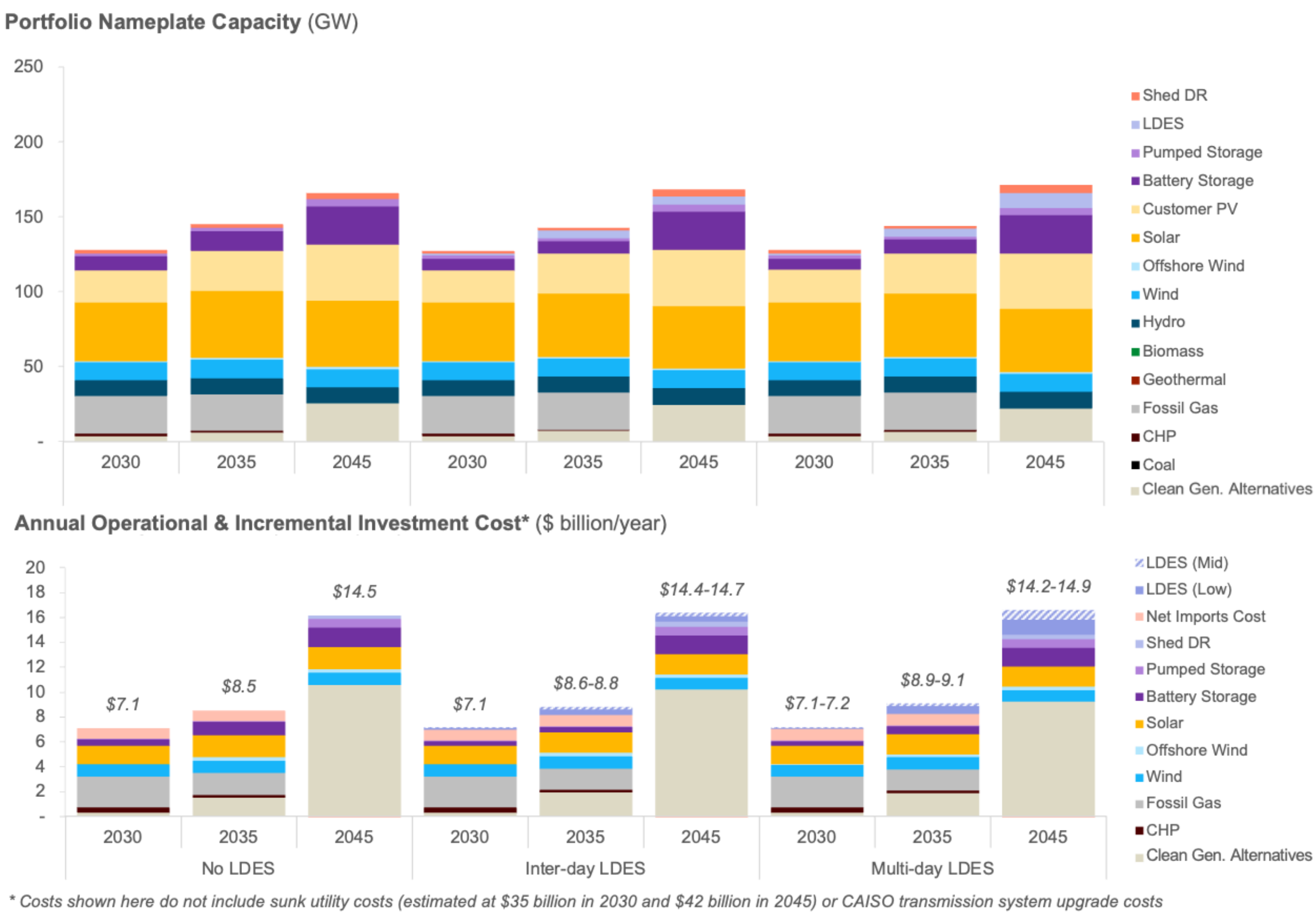


* Note y-axis scale change in each year

Emerging Low-Carbon Generation Alternatives Sensitivity

If the emerging low-carbon generation technologies studied in this sensitivity can scale, they could also make achieving a 0 MMT policy significantly more feasible, as shown in Figure 27. These numbers are highly uncertain for at least two reasons. First, as noted, the team did not model cost uncertainties for these emerging low-carbon generation technologies. Second, the team uses outside ELCC values for all technologies that are subject to substantial uncertainty in the long term; the charts are produced using a point estimate for these ELCC values. Nonetheless, even when CCS and advanced nuclear are assumed to be available, between 5-10 GW of inter- or multi-day LDES could still be part of the cost-minimizing resource portfolio.

Figure 26: Total Resource Portfolios (top) and System Costs (bottom) Under 0 MMT Policy with Emerging Low-Carbon Generation Alternatives

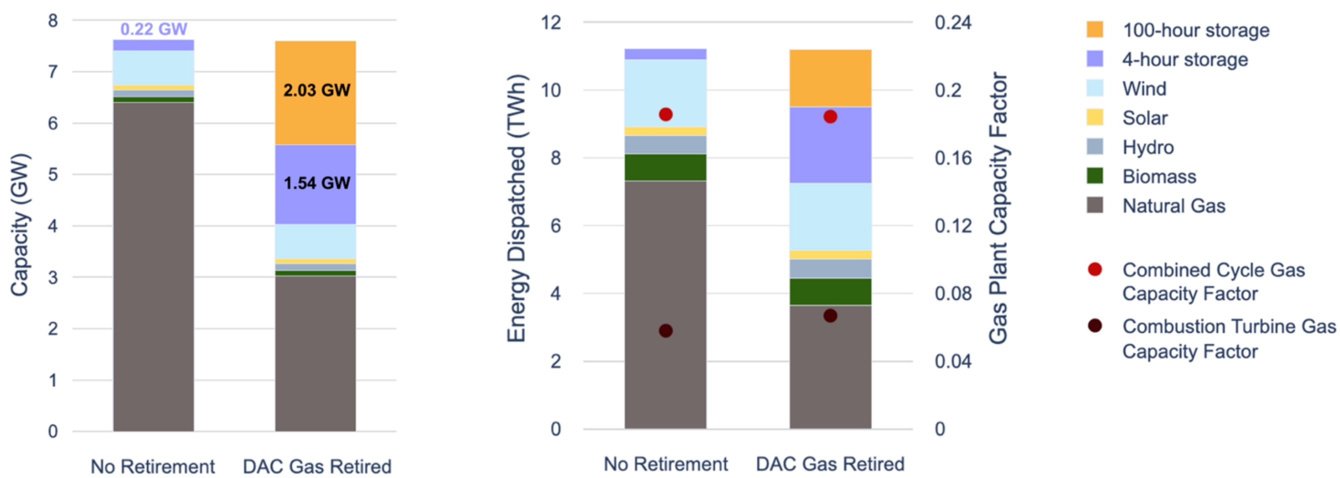


Los Angeles Basin Local Capacity Case Study

The LA Basin case study demonstrates that LDES can be used to reduce in-basin system costs by 3 percent and enable the retirement of emitting resources in disadvantaged communities while still meeting local capacity requirements. These results, while preliminary and not a complete power-flow analysis, are indicative of a broader role LDES can play in transmission-constrained pockets within the Cal ISO that have historically not been captured in bulk-system capacity expansion modeling like the CPUC IRP.

Figure 27 compares the LA Basin resource build and annual energy dispatch in 2030 while retaining disadvantaged communities' gas capacity and retiring disadvantaged communities' gas capacity. In both cases, the LA Basin's planned resources from the Cal ISO's 2027 Local Capacity Requirement Technical Study are fixed into the portfolios. However, in the disadvantaged communities' gas retirement case, gas plants in disadvantaged community areas within the LA Basin are replaced by a least-cost mix of 4-hour storage and LDES technologies as determined by portfolio optimization. The study finds that when all 3.4 GW of disadvantaged communities' gas plants are retired, 2 GW of LDES and 1.3 GW of 4-hour storage are built to maintain local reliability.

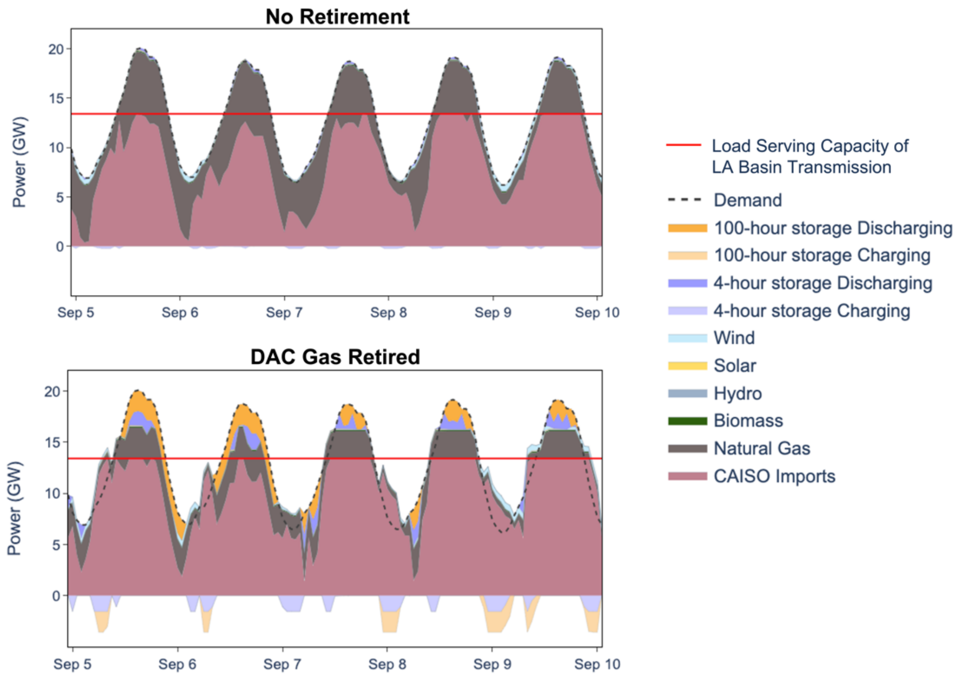
Figure 27: Least-Cost Resource Portfolios and Annual Dispatch of Local Resources in LA Basin, Retaining Disadvantaged Community Gas Capacity (left) and Retiring Disadvantaged Community Gas (right)



On an annual energy basis, the capacity factor of in-basin gas generators remains constant (shown in red dots) between the two cases; this suggests that storage resources can interchangeably replace generation from retired disadvantaged communities' gas plants without meaningfully increasing operations of gas resources. Storage offsets missing generation from disadvantaged communities' gas plants by charging from the bulk Cal ISO grid during hours when the LA Basin is not transmission constrained and discharging that energy during hours when the system is transmission constrained. Short- and long- duration storage dispatch energy are roughly equally in maintaining system reliability.

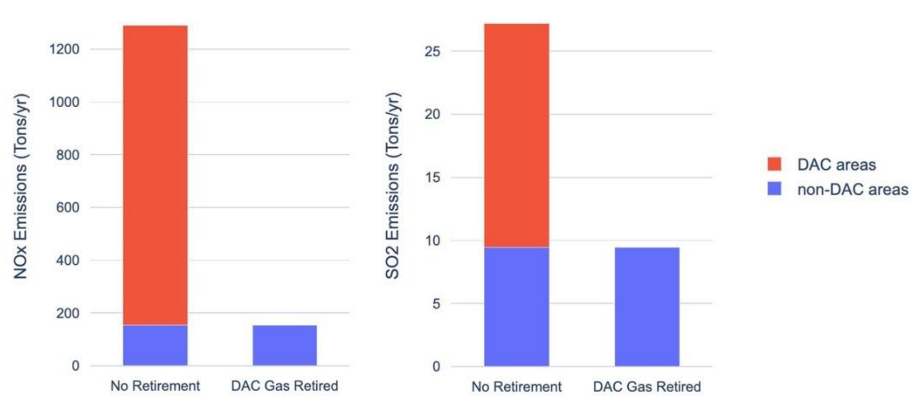
Figure 28 illustrates resource dispatch during the week of peak demand in the case of disadvantaged community gas retirement. Imports from the Cal ISO are limited by the load serving capability of transmission lines into the LA Basin. When demand exceeds this transmission limit, local generation resources provide capacity. Gas generation provides this capacity in the No Retirement case. In the disadvantaged communities Gas Retirement case, 4-hour storage provides peaking capacity during peak demand hours, while 100-hour storage and gas provide energy throughout afternoon and night hours.

Figure 28: Resource Dispatch in LA Basin During Peak Demand Week, Existing Local Gas (left) and Gas Retired in Disadvantaged Communities (right)



One key challenge associated with storage in local capacity areas is transmission limitations on charging. LDES is well-suited for charging in these applications because of its high ratio of energy capacity to power capacity, which enables LDES to charge from the Cal ISO grid while contributing minimally to transmission congestion.

Figure 29: Impact of Disadvantaged Communities' Gas Retirement on Criteria Pollutant Emissions in LA Basin



Finally, Figure 29 illustrates the reduction in local criteria pollutant emissions, which are linked to respiratory illness and other chronic health conditions, by replacing gas capacity in disadvantaged communities. These results are based on 2020 plant-level emissions data in the U.S. EPA's CAMPD dataset. Eighty-eight percent of NO_x emissions and 65 percent of sulfur dioxide emissions in the LA Basin occur in disadvantaged communities, as seen in the left bars in each chart. Retirement of gas plants in the LA Basin, enabled by a combination of short-duration storage and LDES, can materially reduce this pollution burden that disproportionately impacts disadvantaged communities.

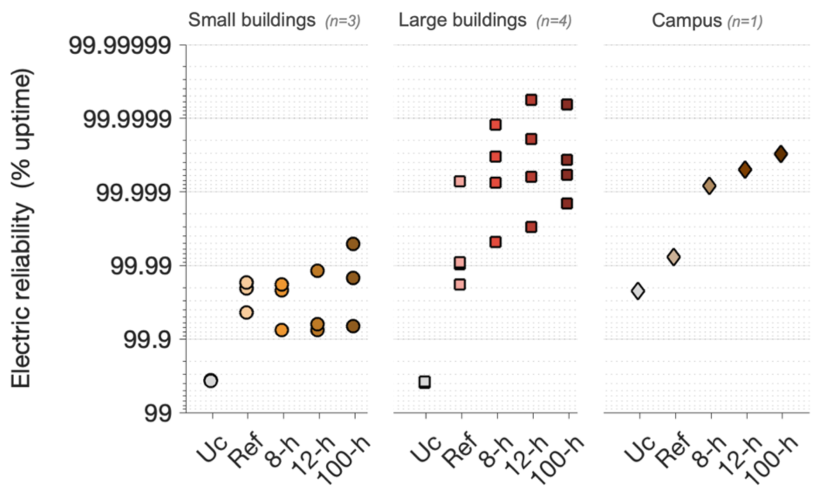
UCSD Microgrid Case Study

This study investigated four overlapping roles for LDES in microgrids. The study found little rationale for LDES in a campus-wide microgrid due to the campus's existing highly optimized microgrid, lack of rooftop space for new PV, and a very flat daily load curve. In contrast, campus buildings with peakier loads and available rooftop space are more favorable for LDES and PV-plus-LDES configurations.

1. **Reliability Role:** Across all building typologies, LDES can effectively be sized and operated to deliver 48 hours of islanding capability during "grey-sky" grid outages.
2. **Operational Role:** During normal "blue-sky" days, LDES reduces customer energy bills through peak shaving and energy arbitrage. For these operations, building type affects LDES value since buildings with lower load factors and more space for BTM renewable generation are more favorable for PV + LDES configurations. Buildings with limited rooftop space or higher load factors are less conducive to LDES-based microgrids.
3. **Economic Role:** The economics of LDES-based microgrids stem from its reliability and operational roles. In most cases, deploying LDES-based microgrids does not reduce the customer levelized cost of electricity (LCOE) because the cost of sizing LDES to meet critical load during grid outages exceeds operational benefits during "blue-sky" days.
4. **Environmental Role:** In this study, microgrids are not optimized to reduce emissions; instead, emissions reductions are byproducts of least-cost investment and operations. Without a policy that explicitly prohibits CO_2 emissions, most microgrids (with or without LDES) increase CO_2 emissions relative to utility service; most microgrids use gas generators to achieve high reliability at lowest cost. Policies can successfully reduce microgrid emissions but still drive up the cost of microgrids.

In all cases, microgrids improve electric service reliability (Figure 30), increasing uptime from approximately 99.6 percent for individual buildings to upwards of 99.98 percent (reducing expected outage duration from 33 hours to fewer than 2 hours per year). For the campus, increases in reliability are smaller, from 99.978 percent to upwards of 99.998 percent (from 2 to less than 0.25 hours per year) since the campus microgrid is already very reliable. Reliability does not necessarily increase monotonically with LDES duration due to interactions with other DERs in least-cost microgrid portfolios.

Figure 30: Microgrid Case Study Reliability Metrics



Campus-Wide Microgrid

Of the "customers" in this study, the campus is unique because it already hosts a gas co-generation-backed microgrid that is highly reliable, low cost, with substantial secondary and tertiary backup generation, and hosting maximum possible PV capacity. It already meets the 48-hour resilience requirement.

Under the reference microgrid policy, LDES improves reliability (Figure 30) but adds substantially to total lifecycle cost—$0.09/kWh on average, an increase of 57 percent. Because the campus already has a diverse optimized mix of DERs, lacks additional space to deploy PV, and has a flat daily load (94 percent load factor), LDES does not generate deep operational value through peak shaving. Under zero-carbon microgrid policy, the campus switches from gas to costlier RNG, which drives up LCOE by $0.10/kWh (59 percent) compared to Reference policy. While RNG-fueled co-generation is still economic, with higher fuel costs the campus imports more grid electricity, and LDES is cycled much more to shave peak load. Finally, under Zero-Pollution (Zc+Zp) Microgrid policy, the campus retires its backup gensets and co-generation, driving up LCOE again—by $0.15/kWh compared to Reference policy (94 percent). Here, LDES complements RNG- (or hydrogen-fueled) fuel cells to meet the 48-hour resilience requirement. But non-LDES microgrids backed with renewable natural gas (RNG) fuel cells are most economic.

Small Campus Building Microgrids

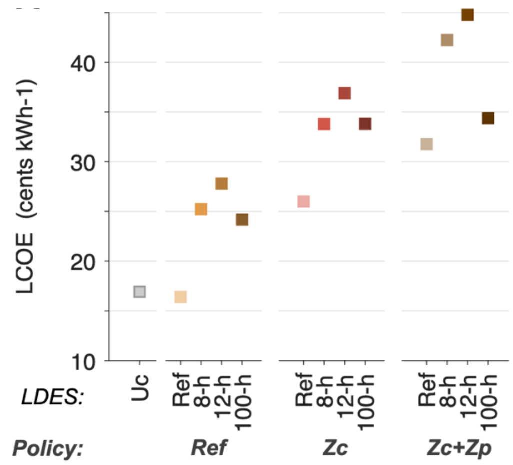
Reference (Non-LDES) Microgrid

Gas-fired generation is the key DER in the "Reference" (no LDES) microgrids, with investment capacity equal to 78 percent of peak building load. These non-LDES microgrids increase reliability from 99.6 percent to more than 87 percent and 11 percent, respectively, reflecting the strong investment case for gas when fuel is cheap ($6/MMBtu under the Reference policy). However, the tradeoff for higher reliability using gas is greater attributable emissions: small, decentralized gas gensets have higher carbon intensity (CI) than utility-scale gas power plants, and average and marginal emissions from Reference microgrids are, on average, 5.7-fold higher than those of associated with utility service, a 485 $kgCO_2/MWh$ increase in CI. Under the Zc and Zc+Zp Policy scenarios, microgrids that have "zero-carbon" DER portfolios, use RNG-fired fuel cells, PV, and storage that reduce CI relative to the bulk grid, but are not fully zero-carbon due to emissions attributed to imported grid electricity, which supplies 24 percent of demand.

LDES Microgrids

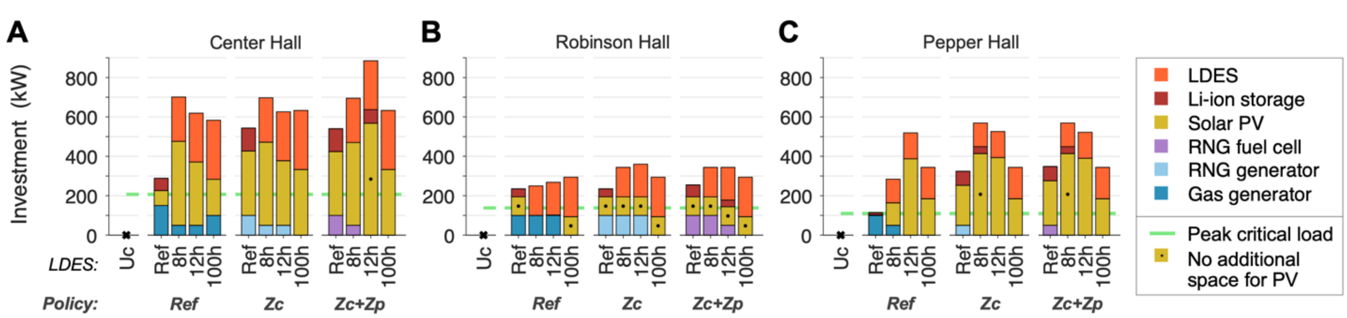
Under the Reference Policy scenario, two out of the three small buildings retain some onsite gas generator capacity even when introducing LDES to the micro-grids (Figure 31). Adding LDES generally increases investment in PV (though variance is high), drives decreases in gas generators, and substitutes for Li-ion batteries since LDES plays the same peak shaving role as Li-ion.

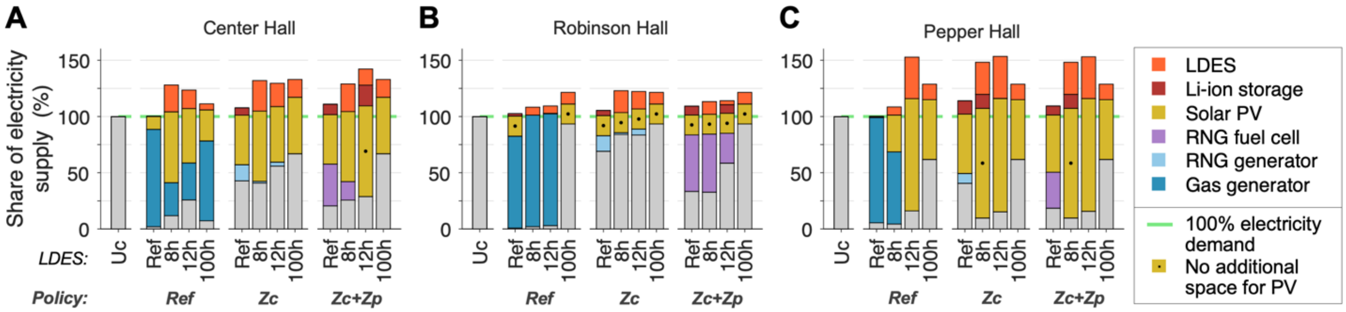
Figure 31: Campus Microgrid LCOE Under Various Policy Scenarios



With increasing LDES duration, it becomes cost-effective to invest in more PV to further mitigate utility demand charges. These larger PV-plus-storage systems supply more electricity during midday and evenings, cutting into the building's baseload and hence denting the economic case for running gas generators at high-capacity factors. As a result, gas investment falls and its lost power is replaced with lower-carbon utility electricity. In addition, with increasing duration LDES takes an increasing share of the 48-hour resilience requirement, decreasing the resilience need for gas generators (Figure 32).

Figure 32: DER Portfolio Investments (kW, top) and Energy Supply (Percent of Building Load, bottom) for Small Building Microgrids Under Different Policy Scenarios





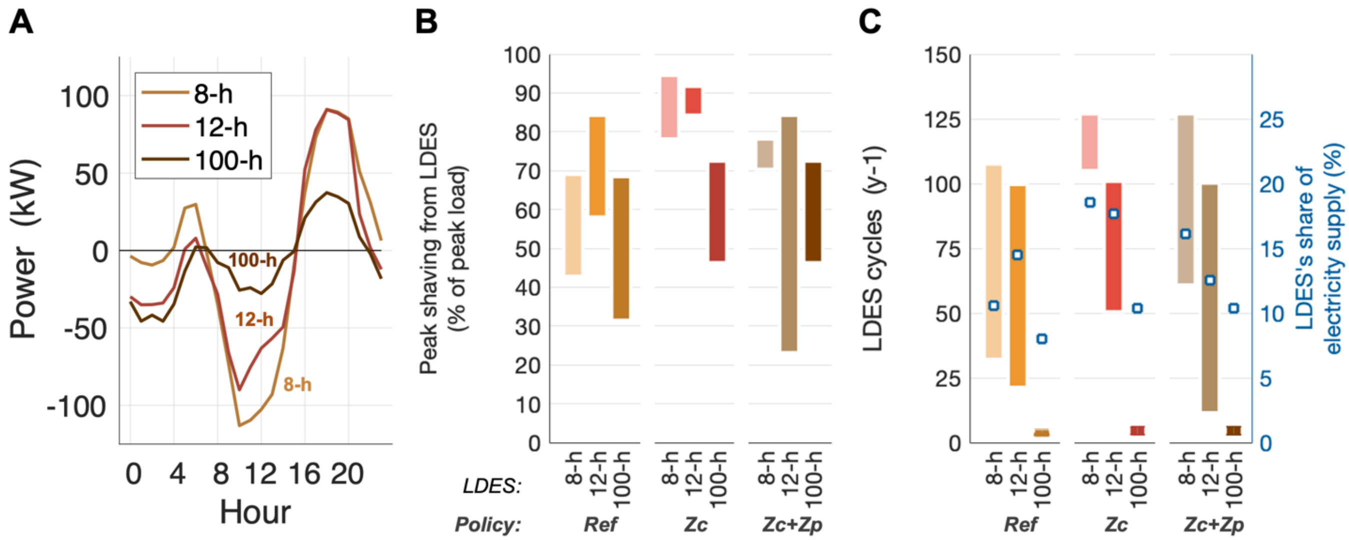
Black dot • on Solar PV bar indicates that 100 percent of rooftop space for solar PV has been utilized for microgrid. Share of electricity supply can exceed 100 percent due to load from storage charging's exclusion from the figure.

Zc and Zc+Zp policies prohibit cheap gas and gensets, increasing fuel and capital costs of fuel-burning generation and making LDES relatively more cost-competitive (compared to non-LDES microgrids) under Zc and Zc+Zp policy than under Reference policy. Under these policies, non-LDES microgrids deploy larger PV-plus-storage capacity and less fuel-burning generation capacity (Figure 34). Under Zc and Zc+Zp policy, 100-hour LDES fully displaces fuel-burning generation; these microgrids are fully electric using PV and LDES. For Pepper Hall, 8-hour and 12-hour LDES do the same. As configurations pivot from using gaseous fuels to solely PV-plus-LDES, they also import more grid electricity (Figure 30). Across all policies, increasing LDES duration does not lead to monotonic increases in PV-plus-storage self-supply but rather a reversion to use of grid electricity.

Operational Role for LDES

Although LDES supplies only a small fraction of electricity (<15 percent of total under Reference policy, for instance; Figure 33C), it mitigates residual peak loads by 31-84 percent for small buildings (Figure 33B). Peak shaving behavior differs not by LDES type but rather in magnitude (Figure 33A); on average, shorter-duration LDES (8- and 12-h) cycles more frequently, shaves larger peaks, and supplies a greater fraction of electricity. Its higher RTE makes it a better complement in PV-plus-storage systems that shave daily load peaks. Longer-duration LDES, with lower roundtrip efficiency, is cycled less frequently; its primary function is in meeting the 48-hour survivability requirement.

Figure 33: LDES's Typical 24-hour Dispatch Under Different Policy Scenarios

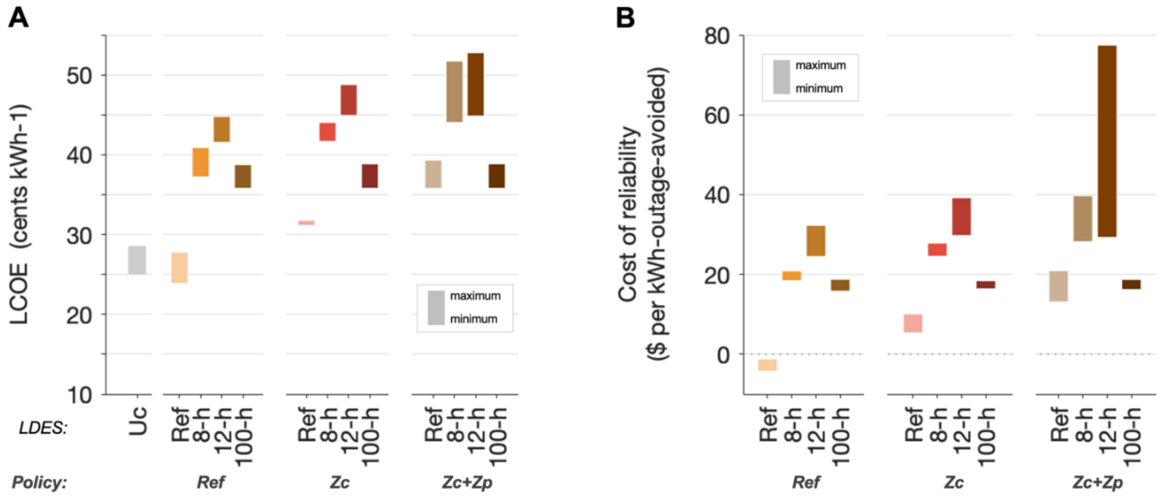


Contribution to peak shaving, cycling, and share of electricity supply for small building microgrids under different policy scenarios

Economic role for LDES

Under Ref and Zc policies, LDES microgrids have higher LCOE than utility service and non-LDES microgrids (Figure 34A) and pay higher effective costs for reliability than non-LDES microgrids (Figure 34B). Across small buildings, utility customers pay 25-29¢/kWh for utility service, while non-LDES microgrids deliver power at 24-28¢/kWh and LDES microgrids at ¢36-45/kWh, a 50-61 percent premium. This is because gas generators — the anchor in non-LDES microgrids — seamlessly play dual economic and reliability roles. Under Ref policy, it is cheaper to invest in gas generators and self-generate than to purchase utility electricity. This holds true even as LDES is added to the microgrid. In contrast, in this study, LDES is compensated only through utility bill reductions, which enforces an upper limit on the operational benefit (bill savings) that LDES can generate. In most cases, these bill reductions do not offset LDES's high capital cost.

Figure 34: LCOE and Cost of Reliability for Small Building Microgrids Under Various Policy Scenarios

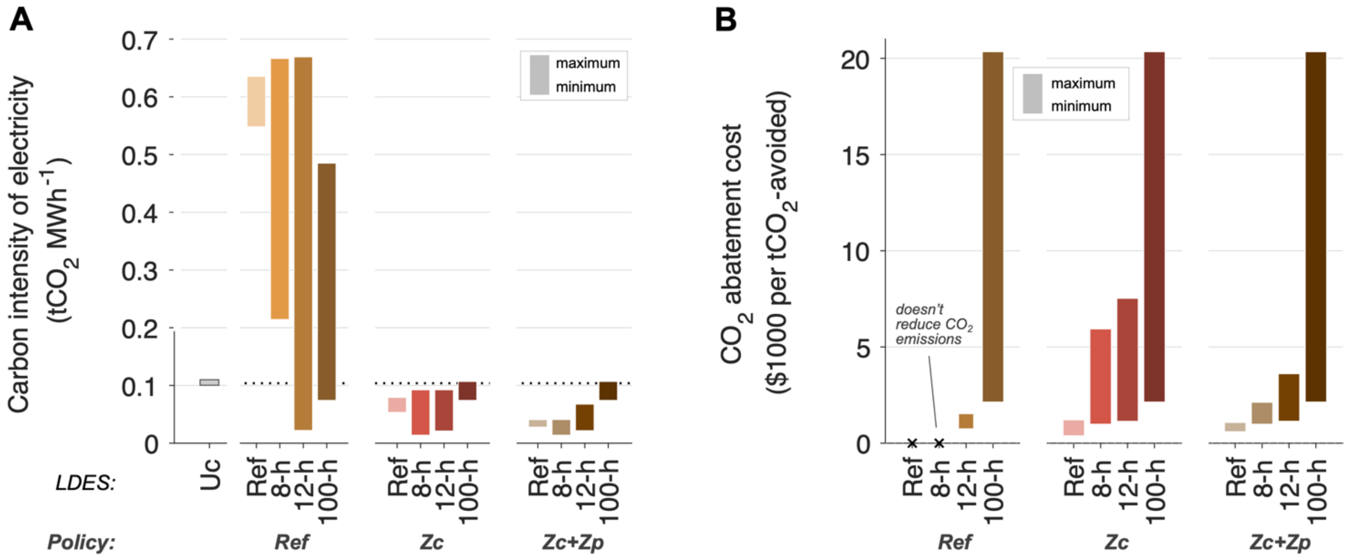


Only under Zc+Zp policy do LDES microgrids (here, 100-h) deliver a lower LCOE and lower cost of reliability (CoR) than the non-LDES alternative. 100-hour LDES is lowest cost because it adds the smallest capital cost to the total lifecycle cost, and this additional capital cost dominates energy cost savings that LDES's achieves through peak shaving.

Environmental role for LDES

Under the Reference policy scenario, most non-LDES and LDES microgrids use gas generators to supply a large fraction of building load (73 percent), consequently increasing CO_2 emissions substantially. Switching to LDES-based microgrids reduces but does not fully eliminate emissions from the microgrid portfolios. Where microgrids do reduce emissions, the team calculated an effective CO_2 abatement cost (CAC) — a \$/tCO_2 cost of emissions reductions. As Figure 35B shows, CAC varies by LDES microgrid — \$380-1,210/tCO_2 for non-LDES microgrids and up to \$20,350/tCO_2 for LDES microgrids — indicating that the microgrids are expensive and that they do not significantly reduce CO_2 emissions (Figure 36).

Figure 35: Carbon Intensity of Electricity Consumption and CO_2 Abatement Cost for Small Building Microgrids Under Various Policy Scenarios



Large Campus Building Microgrids

Large buildings in this study differ from small buildings in two key ways: (1) they have dedicated emergency circuits that are 10-40 percent of the total building load, so LDES is sized smaller to meet the same 48-hour survivability requirement; and (2) they have flatter diurnal load, which is less favorable for peak-shaving PV-plus-storage systems and more favorable for running fueled generators at high-capacity factor.

Reference (Non-LDES) Microgrid

As with small buildings, gas generation is key for large building non-LDES microgrids. Gas capacity equals 90 percent of peak building load and plays large energy-supply and reliability roles. All microgrids meet the 48-hour survivability requirement — improving service uptime from 99.6 percent to 99.99 percent. These non-LDES microgrids are largely self-reliant, generating 97 percent of energy for self-consumption, with 92 percent from gas generation due to the lower assumed spark spread and 5 percent from PV-plus-storage. They are never fully autonomous. The tradeoff for better reliability is higher emissions. Decentralized gas gensets (such as <500 kW capacity) have higher CI than utility-scale gas plants. Average and marginal emissions from these microgrids are, on average, 5-fold higher than those associated with utility service, a 424 $kgCO_2$/MWh increase in CI.

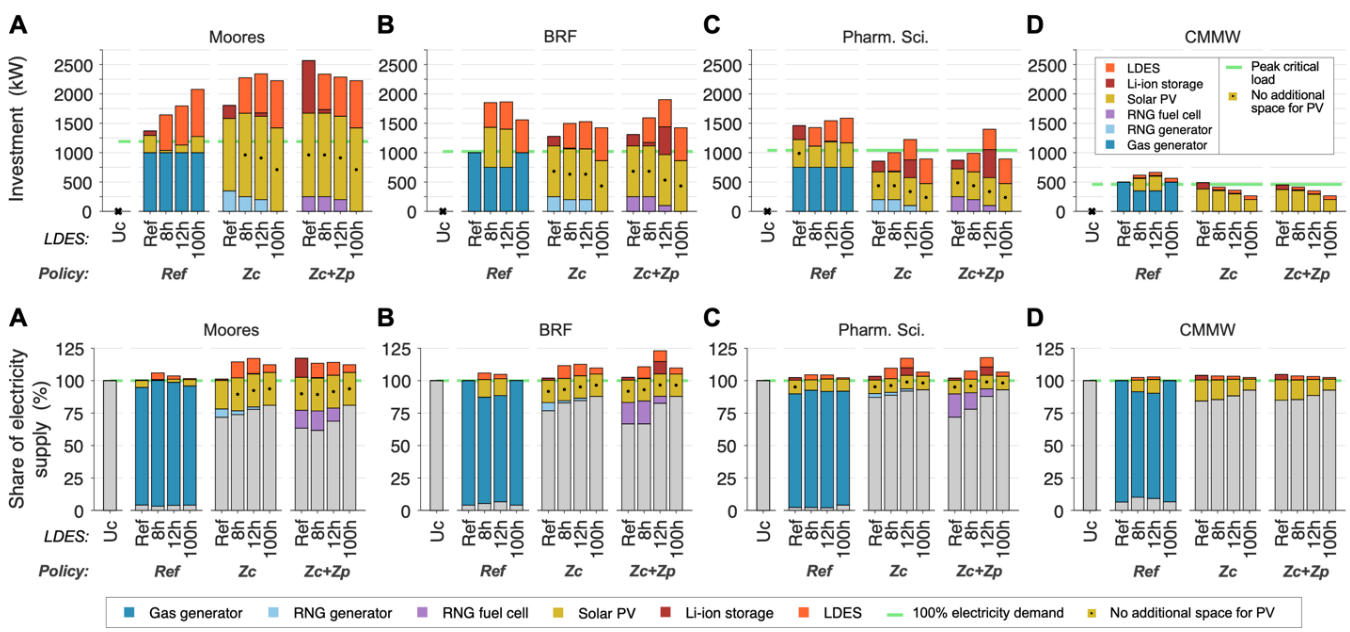
LDES Microgrid

Under the Reference Policy scenario, every large building retains onsite gas generator capacity even when introducing LDES to the microgrid (Figure 36). As with small buildings, adding LDES generally increases investment in PV (though variance is high), drives minor decreases in gas generator capacity, and substitutes for Li-ion batteries since LDES plays the same peak shaving role as Li-ion. These shifts are not necessarily monotonic with increasing LDES duration: although 8-hour and 12-hour LDES tend to pair with an increasing capacity of PV, 100-hour LDES microgrids generally pairs with less, and instead pairs with more gas (as discussed later). LDES is not a substitute but a complement for onsite fueled generation for self-supply: even with LDES, the model still invests and uses distributed fueled generation for a majority of self-supply (81-87 percent).

Zc and Zc+Zp policies, which raise prices on fuels and fuel-burning DERs, have a profound effect on the microgrid DER portfolio. With RNG's higher fuel prices in Zc policy, microgrids use substantially less gas generation: investment falls by 84 percent, while energy supply falls from 81-97 percent to 0-3 percent). PV-plus-storage, in turn, grows from 0-15 percent to 9-25 percent of supply. Notably, microgrids revert to purchasing utility electricity for 74-93 percent of demand.

Under Zc and Zc+Zp policy, PV-plus-storage is the primary source of local energy in all cases. Yet in most of these cases, PV deployments are constrained by available rooftop space. Customers would presumably deploy more PV and in turn more storage to reduce energy costs further, but they lack rooftop space to do so.

Figure 36: DER Portfolio Investments (kW, top) and Energy Supply (Percent of Building Load, bottom) for Large Building Microgrids Under Different Policy Scenarios



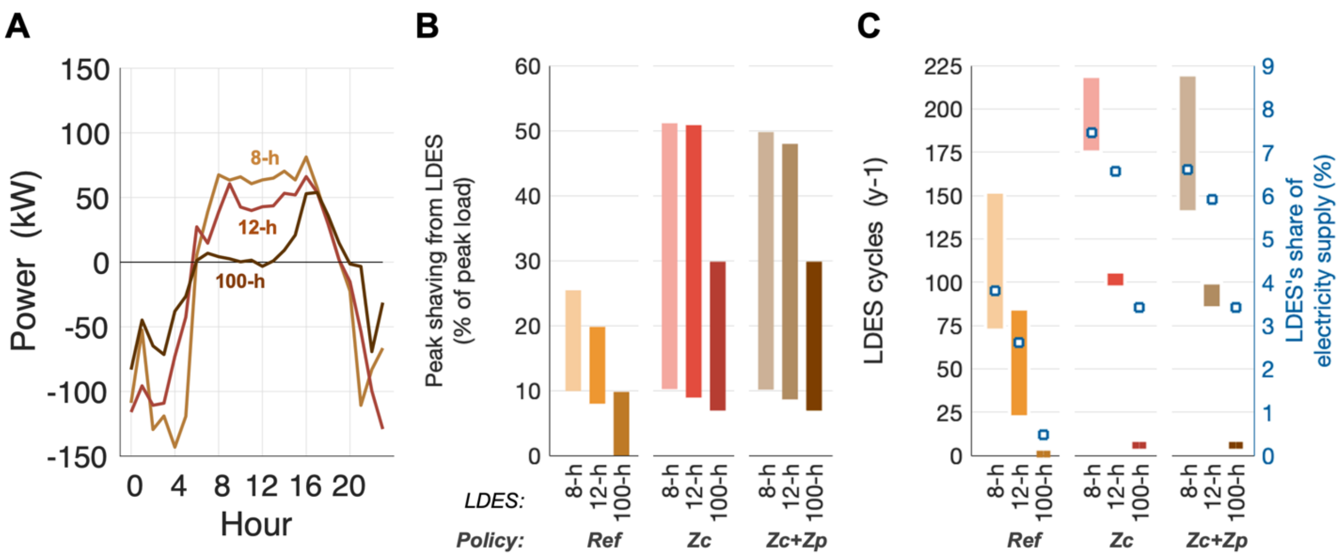
Black dot • on Solar PV bar indicates that 100 percent of rooftop space for solar PV has been utilized for microgrid. Share of electricity supply can exceed 100 percent due to load from storage charging being excluded from figure.

Operational Role for LDES

As with small buildings, LDES shaves diurnal net load peaks (Figure 37A). With large buildings, net load peaks happen during midday, since PV generation alone does not mitigate peaks. (With small buildings, PV is generally larger relative to peak demand, so PV generation cuts into base load, pushing net load peaks to the evening.)

As with small buildings, peak shaving behavior does not differ by LDES type; it does differ in the magnitude of cycling and energy supply: shorter duration LDES, with higher RTE, is cycled more, supplies a greater fraction of load, and shaves larger peaks (Figure 37B-C).

Figure 37: LDES's Typical 24-Hour Dispatch Under Different Policy Scenarios

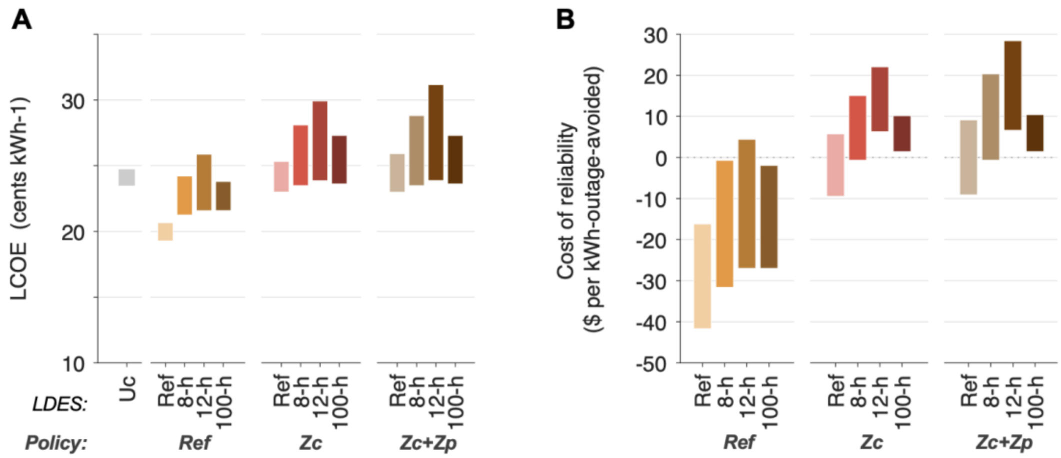


Contribution to peak shaving, cycling, and share of electricity supply for large building microgrids under different policy scenarios.

Economic Role for LDES

Under Reference Policy, LDES microgrids generally have lower LCOE than utility service (and hence negative CoR) but are costlier than non-LDES microgrids. Similar to small buildings, siting, and operational constraints reduce the ability for standalone LDES or PV-plus-LDES to deliver bill reductions and reliability benefits that are comparable to thermal generation-based microgrids. Zc and Zc+Zp policies increase LCOE and CoR of all microgrids because they prohibit use of the most cost-effective (least expensive) fuels and generators (Figure 39). But they increase these costs more for non-LDES microgrids, in effect reducing the cost gap between non-LDES and LDES microgrids, but not closing it.

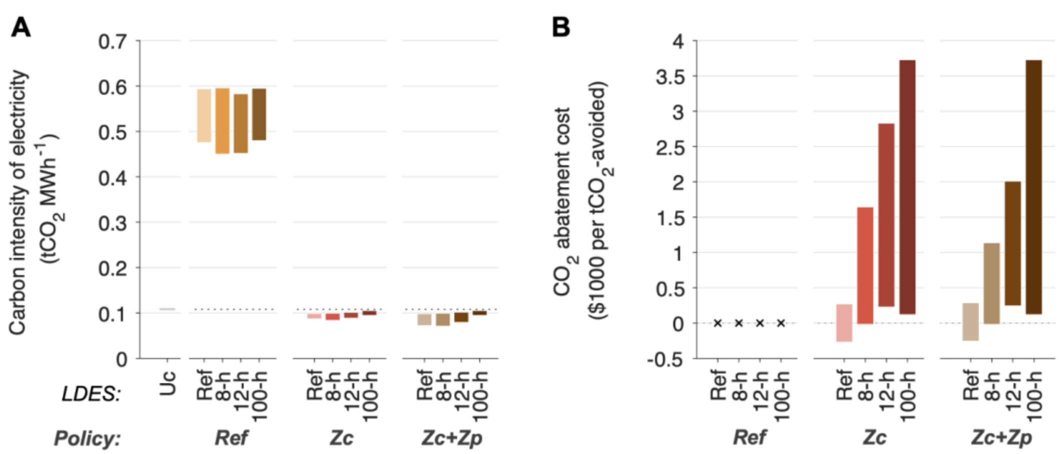
Figure 38: LCOE and Cost of Reliability for Large Building Microgrids Under Various Policy Scenarios



Environmental Role for LDES

Under the Reference policy scenario, both non-LDES and LDES microgrids generate a large fraction (>90 percent of electricity using gas generation. These systems increase CO_2 emissions substantially compared to utility electricity — a byproduct of investment and operation decisions to improve resilience at lowest cost. LDES microgrids generate only slightly fewer emissions than non-LDES microgrids. Under Zc and Zc+Zp policy, higher fuel prices associated with RNG cause microgrid portfolios to shift away from thermal generation (falling to 0-6 percent of supply) and back toward utility electricity (>72 percent of supply). PV-plus-storage supplies the remaining 10-38 percent. Consequently, microgrid CI closely mirrors that of the bulk grid (Figure 39A).

Figure 39: Carbon Intensity of Electricity Consumption and CO_2 Abatement Cost for Large Building Microgrids Under Various Policy Scenarios



Where microgrids do reduce emissions, their effective CAC varies widely from -\$270/tCO_2 to \$3,700/tCO_2 (Figure 39B). High CAC reflects the fact that many microgrids are costly yet do little to reduce emissions. In the few cases where CAC is negative (for some non-LDES microgrids), microgrids reduce CO_2 emissions and LCOE relative to utility service — a win-win for customers and the climate.

CHAPTER 4: Conclusion

Key Findings

Cal ISO Portfolio Value

The role for LDES varies by policy scenario. Under the reference SB 100 policy, there is a role for up to 5 GW of LDES, given the 12 MMT of GHG and existing gas power plants allowed in this scenario. The team demonstrated that LDES deployment can enable the cost-effective replacement of existing gas capacity on the Cal ISO system while maintaining reliable grid operations over 35 historical weather years. Finally, the role for LDES under deeper decarbonization scenarios (0 MMT by 2045) is significantly larger, with potentially up to 37 GW of LDES by 2045 under a 0 MMT.

Further study should continue investigating the broad implications of gas replacement on reliability, cost, and local air quality.

LA Basin Local Capacity Case Study

Using data available from the Cal ISO's Local Capacity Technical Study, the team demonstrated that LDES has a potential role in maintaining local capacity requirements while reducing the need to retain emitting resources in disadvantaged communities. These present two incremental benefits that LDES can provide — local reliability and local environmental justice — that have not been studied in-depth in traditional long-term, bulk system portfolio planning studies.

UCSD Microgrid Case Study

LDES can be used in microgrids to increase customer reliability and resilience. In most cases, LDES is not economic because the case for using gas generators is strong under current policy; however, in potential policy futures that restrict local emissions, the relative economics of LDES improves (compared to non-LDES microgrids) and it may be a viable economic choice for customers developing microgrids, even as these policies raise costs on all microgrids.

High building load factors and rooftop space constraints limit the capacity of onsite PV generation and hence limit the cost-effectiveness of LDES microgrids compared to non-LDES (gas-backed) microgrids (with either combustion generators or fuel cells). The study analyzed carbon-minded policies that provide incentives for customers to develop zero-carbon and zero-pollution microgrids and which improve the relative economics of LDES microgrids; however, these results suggest that, in addition to policy sticks, additional policies which open up new revenue streams for LDES (such as participation in markets or utility programs, which were not analyzed here) may be required for LDES microgrids to reach cost parity with alternative configurations that use gas.

Policy Implications and Areas for Future Research

The value of LDES depends on the future policy and resource mix. In all scenarios analyzed, both LDES and emerging low-carbon generation technologies have a large role to play as the state continues to set increasingly ambitious decarbonization goals.

Policymakers should engage with technology providers to track emerging technology developments.

Given the wide uncertainty in technological learning with emerging technologies, this study presented a range of LDES deployment scenarios. Policymakers should work to engage technology providers regularly to ensure that public data is available to understand how quickly emerging technologies are maturing.

Planners should ensure planning processes send clear market signals on grid needs, such as clean energy and resource adequacy.

California needs clean generation resources to reach its policy goals, and this study demonstrates that LDES can be one technology option. However, to ensure that these emerging technologies are deployed, regulators must send a clear market signal for what grid services are needed in the long run. While near-term actions like the CPUC's Mid-Term Reliability procurement order may be needed, planners should work toward developing stable, cyclical processes that allow developers to understand how resources with longer lead times will be valued so that they can be developed and financed.

Planners should use the best-available modeling methods to ensure that resources are evaluated with sufficient detail and on an equal basis.

The LDES and broader emerging technology space is heterogeneous, and planners must be able to differentiate the value of these wider spectrum technologies in long-term portfolio planning. A key finding of this study is that different storage technologies have specific features such as duration, roundtrip efficiency, and parasitic loss constraints, that do not make them exact substitutes; ELCC is a useful tool for near term (up to a few years ahead) capacity accreditation, as the baseline portfolio and demand forecasts are sufficiently well known and fixed. However, as the technology portfolio becomes more heterogenous, planning for system reliability is becoming more complex, and the heuristics that were used in the past no longer suffice. Given the distinct techno-economic constraints of different technologies, distinct LDES technologies need to be represented both for operations and reliability modeling; a single ELCC surface that blends power, duration, roundtrip efficiency — such as recently proposed in 2023 CPUC IRP proceeding (CESA 2022) — is not sufficient to characterize the potential reliability interactions between various technologies. In addition to portfolio indexing, ELCCs are impacted by ordering effects and other dynamics that make their use in long term planning models computationally challenging. Integrating reliability and economics in long-term deep decarbonization planning is a ripe area for continued research.

In addition, as described in Appendix B, the portfolio results were shown to be sensitive to weather data inputs. Since the data for the 2019 CPUC IRP PSP was published, the field has advanced significantly, and the team looks forward to upcoming new datasets from NREL, CPUC IRP, CEC, as well as the datasets published through this project, that capture updated perspectives on weather variability and climate impacts.

Policymakers should direct future planning and procurement to optimize local system resource needs and to ensure that resources are fully compensated for their local capacity value and avoided local air pollution.

This study demonstrates the potential reliability and environmental justice value for LDES in local capacity-constrained areas; additional research should study the locational energy, capacity, transmission, and distribution values of LDES. As part of the CPUC IRP process, the Cal ISO estimates the transmission impacts of candidate resource additions (potential upgrade needs and upgrade deferrals due to storage). These estimates did not exist for this study and would require more detailed transmission studies from Cal ISO.

New revenue streams, electric tariff structures, and incremental environmental policies could change the relative economics of LDES microgrids.

Even under policies that restrict microgrid CO_2 and pollutant emissions, the case for LDES is modest. LDES's potential in microgrids may rest with new carrots alongside these emission sticks, with new programs that allow select DERs (PV-plus-LDES) to participate in energy markets and utility load management programs. In some places, these programs already exist (e.g., peak day pricing tariffs (PG&E 2023), CPUC's Emergency Load Reduction Program (CPUC 2022)), but the project team did not analyze these cases, suggesting areas for future research.

Electric tariffs under which microgrids take service might also affect the value of LDES in microgrids. Rates that are more dynamic might make PV-plus-LDES systems (those that can respond quickly to price fluctuations or take advantage of prolonged periods of negative pricing) more valuable relative to today's gas-backed microgrids that find value is running fueled generators at high-capacity factors.

GLOSSARY

Term	Definition
AB	Assembly bill
BTM	behind the meter
C&I	commercial and industrial
CAMPD	Clean Air Markets Program Data
CARB	California Air Resources Board
CEC	California Energy Commission
CESA	California Energy Storage Association
CI	carbon intensity
CoR	cost of reliability
CPUC	California Public Utilities Commission
DER	distributed energy resource
EIA	Energy Information Administration
ELCC	effective load carrying capability
EUE	expected unserved energy
GHG	greenhouse gas
GW	gigawatt
IEPR	Integrated Energy Policy Report
IRP	integrated resource plan
ISO	California Independent System Operator
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LCR	local capacity requirement
LCTS	Local Capacity Technical Study
Li-ion	lithium-ion
LOES	long-duration energy storage
LSE	load serving entity
MMT	measurement and management
MTR	midterm reliability
O&M	operations and maintenance
PG&E	Pacific Gas and Electric Company
PRM	planning reserve margin
PSP	preferred system plan

Term	Definition
PSPS	public safety power shutoff
PV	photovoltaic
RA	resource adequacy
RNG	renewable natural gas
RPS	Renewable Portfolio Standard
RTE	round trip efficiency
SB	Senate bill
SDG&E	San Diego Gas & Electricity
TAC	technical advisory committee
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
VOLL	value of lost load

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Project Deliverables

California Baseline Inputs and Assumptions Presentation

LDES Technology Review Report

LDES Modeling Characteristics Report

California Future Energy Generation Technologies Report

California Scenario Assumptions Presentation

Preliminary LDES Analysis Report

Preliminary UCSD Zero-Carbon Microgrid Analysis Report

New Modeling Toolkit Documentation and User Guide

Final LDES Analysis Report

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Appendix A: LDES Provides Higher ELCC than Short-Duration Storage

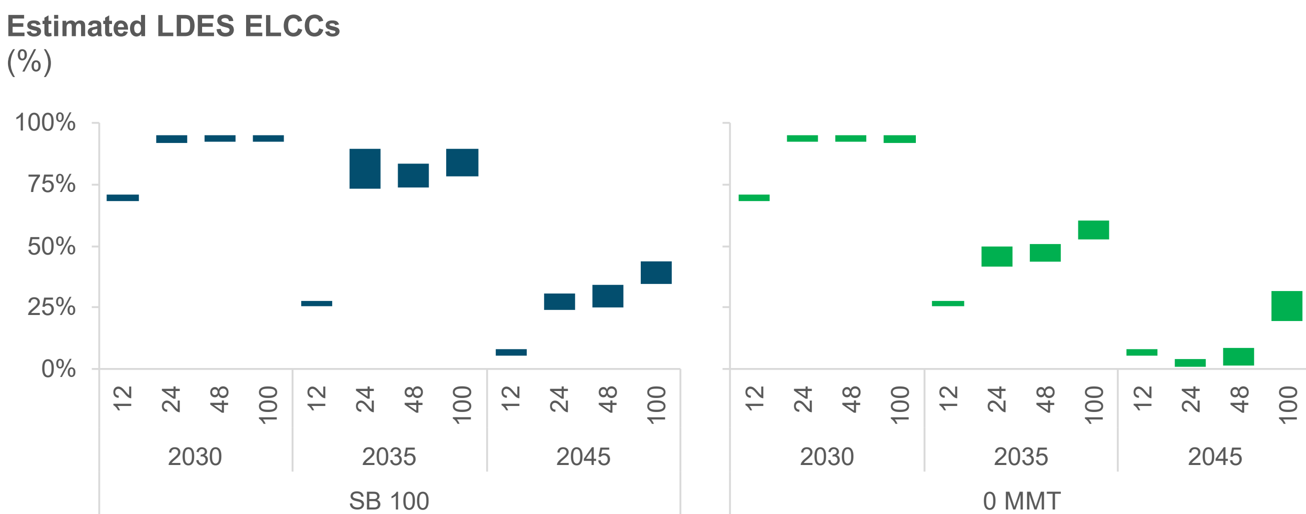
December 2023 | CEC-500-XXXX-XXX

APPENDIX A:
LDES Provides Higher ELCC than Short-Duration Storage

SB 100 and 0 MMT LDES ELCCs

For the purposes of the Cal ISO portfolio analysis, the team used a Monte Carlo loss-of-load probability (LOLP) simulation model to calculate the ELCC of the LDES in the resulting SB 100 and 0 MMT portfolios. These values estimate the ability for LDES—in conjunction with other generation resources in the portfolios—to serve load across a range of stochastically generated load & generation availability conditions. These estimated ELCC values are shown in Figure A-1.

Figure A-1: Estimated ELCCs for SB 100 and 0 MMT Cal ISO portfolios*



* Ranges represent modeling & statistical uncertainty associated with point estimates from Monte Carlo simulation process used to estimate ELCCs

While these results are representative of the two portfolios studied, additional study is needed to understand how ELCC may vary as a function of different long-term trajectories in resource mix (e.g., different levels of renewable and storage build, gas retirements, and hydrogen production).

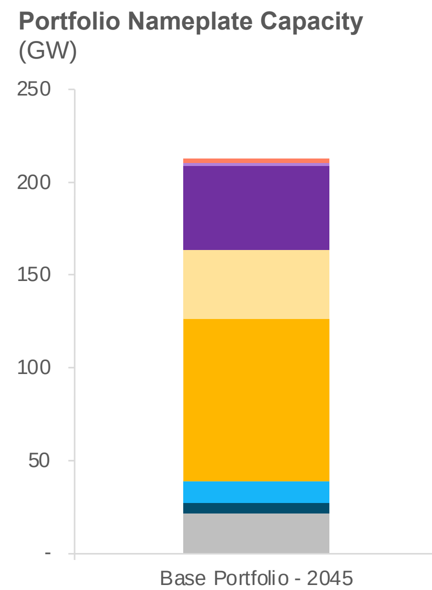
Assessing the Impact of Storage Losses on ELCC

In addition to estimating the ELCC of LDES for the Cal ISO portfolio analysis, the team further performed a simple study to understand the impact of roundtrip efficiency losses on the ability for various storage LDES technologies to provide ELCC. In this simple study, the team used the same underlying "base" portfolio as the 2045 SB 100 portfolio, as shown in Figure A-2, and incrementally added 0-20 GW of storage[11] and calculated the incremental increase in the total portfolio ELCC with these storage additions.

Figure A-3 shows the results of this incremental study, demonstrating:

- Incremental ELCC value does not scale linearly with duration; for example, increasing duration from 24 hours to 48 hours does not double ELCC.
- At equal roundtrip efficiencies, longer-duration storage will monotonically have higher ELCC value (due to more energy being in storage and available to serve load).
- When accounting for the lower RTE values assumed for the LDES archetypes, the incremental value of longer duration storage decreases, as less stored energy is able to be returned to the grid during times of grid stress. For example, at constant RTE, 48-hour LDES provides 25% greater ELCC than 24-hour; however, when using the archetypal RTE values, 48-hour LDES only provides 15% greater ELCC than equivalent 24-hour LDES.

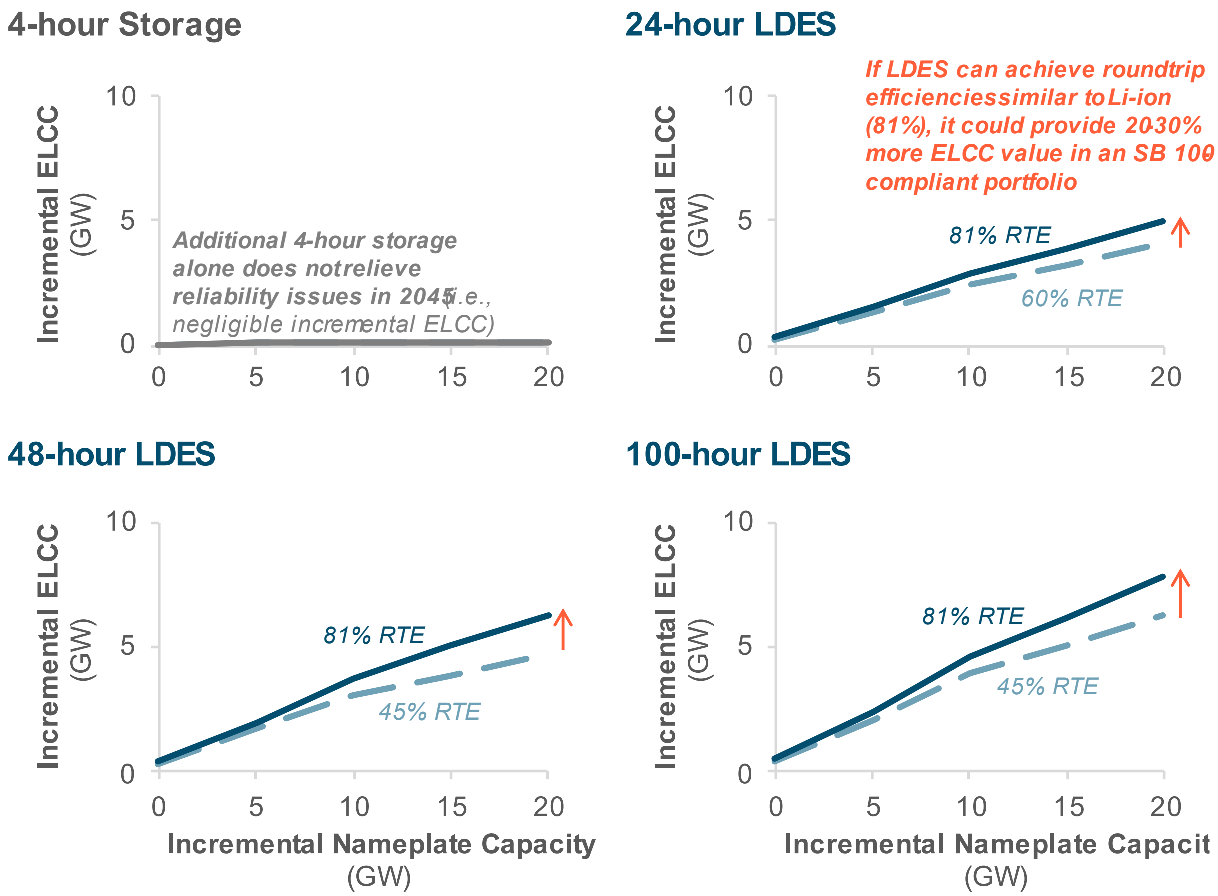
Figure A-2: Underlying Portfolio Used for Incremental ELCC Analysis



While these findings are directionally important to understanding the value of LDES compared to Li-ion storage, additional study is needed to properly assess the reliability contribution of LDES in other portfolios (such as with different mixes of solar, out-of-state wind, other novel emerging technologies, etc.).

[11] This simple study assesses the incremental ELCC of adding storage alone, but in practice, storage additions would likely be accompanied by additions of other clean generation resources that would also contribute to the total portfolio ELCC.

Figure A-3: Incremental ELCC of Different Storage Archetypes at Constant RTE (81 percent) and Lower RTEs Corresponding to LDES Archetypes



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Appendix B: Developing Load and Renewable Generation Profiles for Eight Weather Years

December 2023 | CEC-500-XXXX-XXX

APPENDIX B:
Developing Load and Renewable Generation Profiles for Eight Weather Years

Where noted in the Cal ISO Portfolio and LA Basin Local Capacity sections, updated load and renewable generation profiles were sampled to capture a wider range of weather years (2007-2014, compared to the 2007-2009 dataset available from the CPUC IRP).

Renewable Generation Profiles

Updated renewable generation profiles in this study are obtained from the National Renewable Energy Laboratory's (NREL) System Advisory Model (SAM) for the 2007 to 2014 weather years. Renewable generation profiles from SAM are produced from high quality weather datasets using the National Solar Radiation Database (NSRDB) for solar generation and the Wind Integration National Dataset (WIND) Toolkit for wind generation. The renewable generation data from these sources capture the influence of a wider range of weather variability on renewable generation.

Figure B-1: Comparison of Sites Sampled for Load and Renewable Generation Profiles

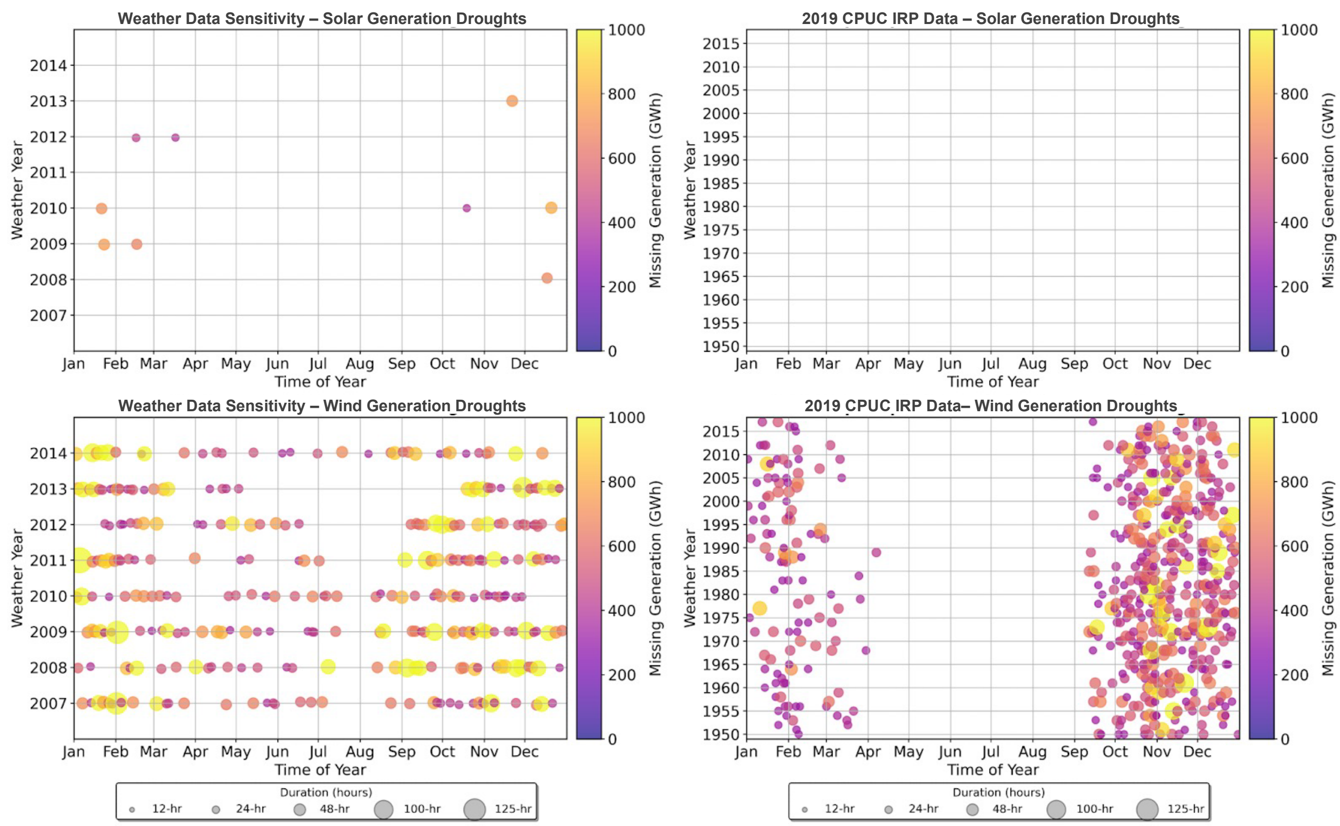
Locations Sampled by CPUC IRP Dataset

Locations Sampled for Updated 8-Year Dataset

In Figure B-2 the NREL dataset (left two panels) shows that lulls in solar generation are predominantly shorter than 24 hours with only a few lulls longer than 24-hours. Wind generation, however, exhibits lulls of longer durations ranging from 24-hours to 125-hours.

Renewable generation lulls are distributed throughout the year but occur more often during winter as compared to summer. The 2019 CPUC IRP dataset (right two panels) does not show any solar generation lulls longer than 24-hours. The RECAP wind dataset only shows lulls during the winter period, with zero summer lulls than 24-hours in the entire 70-year period. This distribution of wind and solar lulls observed in the 2019 CPUC IRP dataset differs substantially from observed historical NREL data, and, as described in the Results section of this report, drives a lower volume of LDES adoption when used in capacity expansion modeling.

Figure B-2: Comparison of Incidence of Solar and Wind "Drought" Event in Updated Weather Sensitivity Data (left) and 2019 CPUC IRP Dataset (right)



Generating Updated Weather Sensitivity Hourly Load Profiles

To model the impact of weather on load with high degree of fidelity, the load is split into two categories: (1) weather dependent loads and (2) weather independent loads. The weather dependent loads include space and water heating, space cooling and electric transport. Weather independent loads include industrial processes, military use, cooking, washing, lighting among others. The profiles of weather dependent loads change with the weather year used in the modeling, while the weather independent loads are assumed to remain unchanged.

Figure B-3 shows the process diagram to create the load profiles used in this study. The IEPR 2021 load profile for California was used as a starting point. Historical load shapes for the individual regions modeled were used to split out the IEPR load profile for each modeled region. The NREL electrification futures study was used to determine the ratio of annual energy consumption that came from weather dependent loads and weather independent loads. The normalized hourly profiles for weather dependent loads were created using Typical Meteorological Year (TMY) temperature profiles at the load centers for the regions modeled. The method used to calculate the normalized load shapes for the weather driven loads is very similar to the one described in Section 2.5 of Vibrant Clean Energy's WIS:dom-P model. The normalized hourly load shapes for the weather driven loads are shown in Figure B-4. The TMY was used to create the initial profiles as it is the basis of the IEPR loads. Formware was run using load profiles calculated using historical weather years as described next.

Figure B-3: Process Diagram for Creating the Weather Correlated Load Profiles

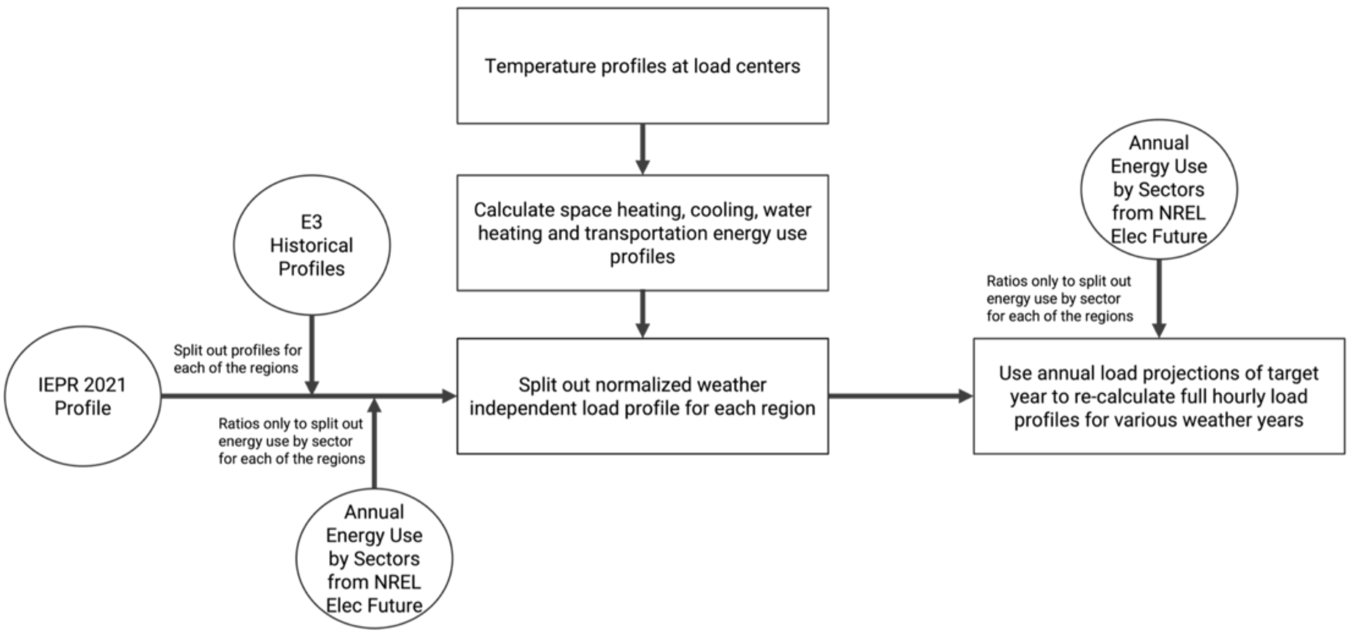
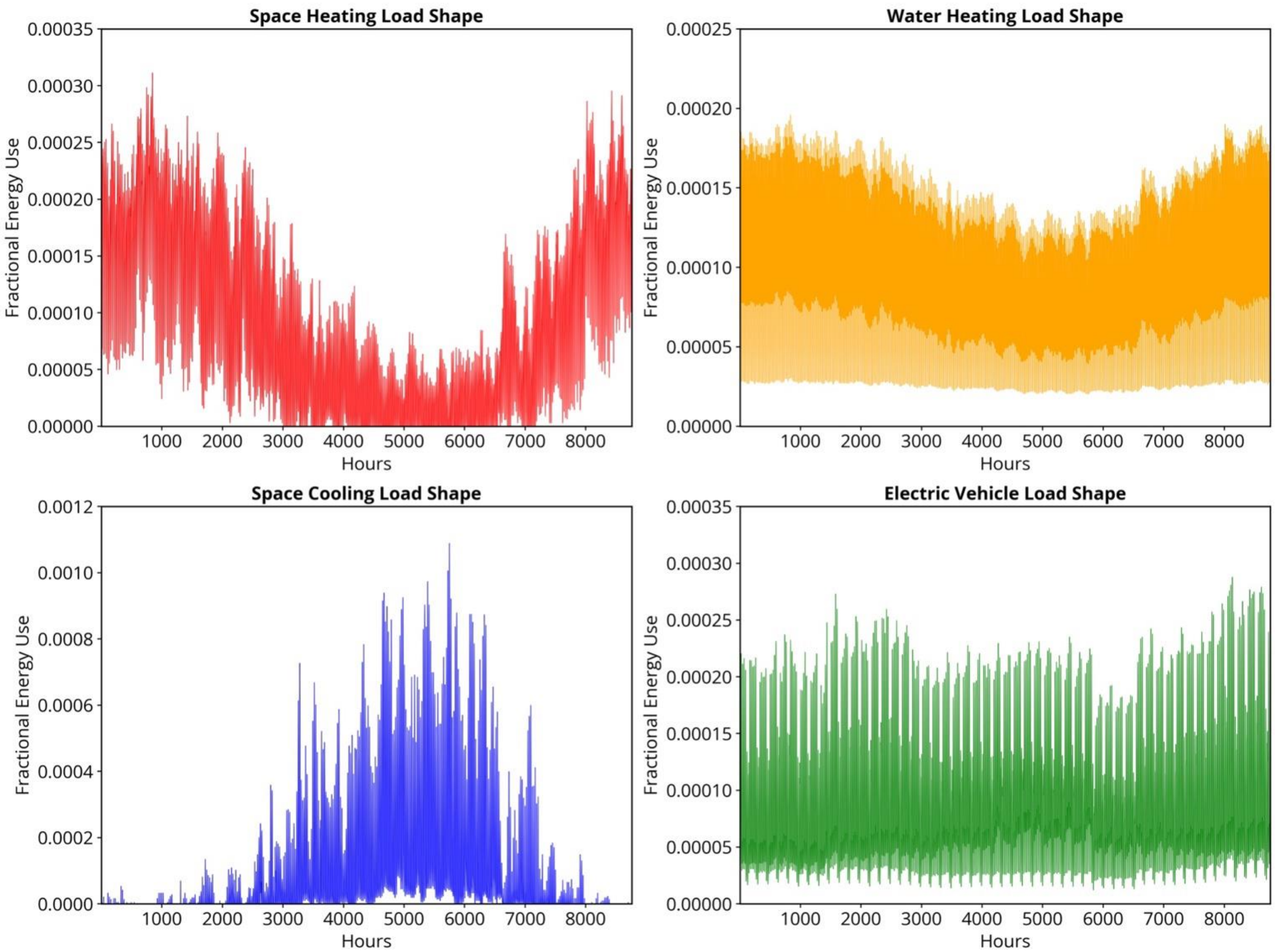


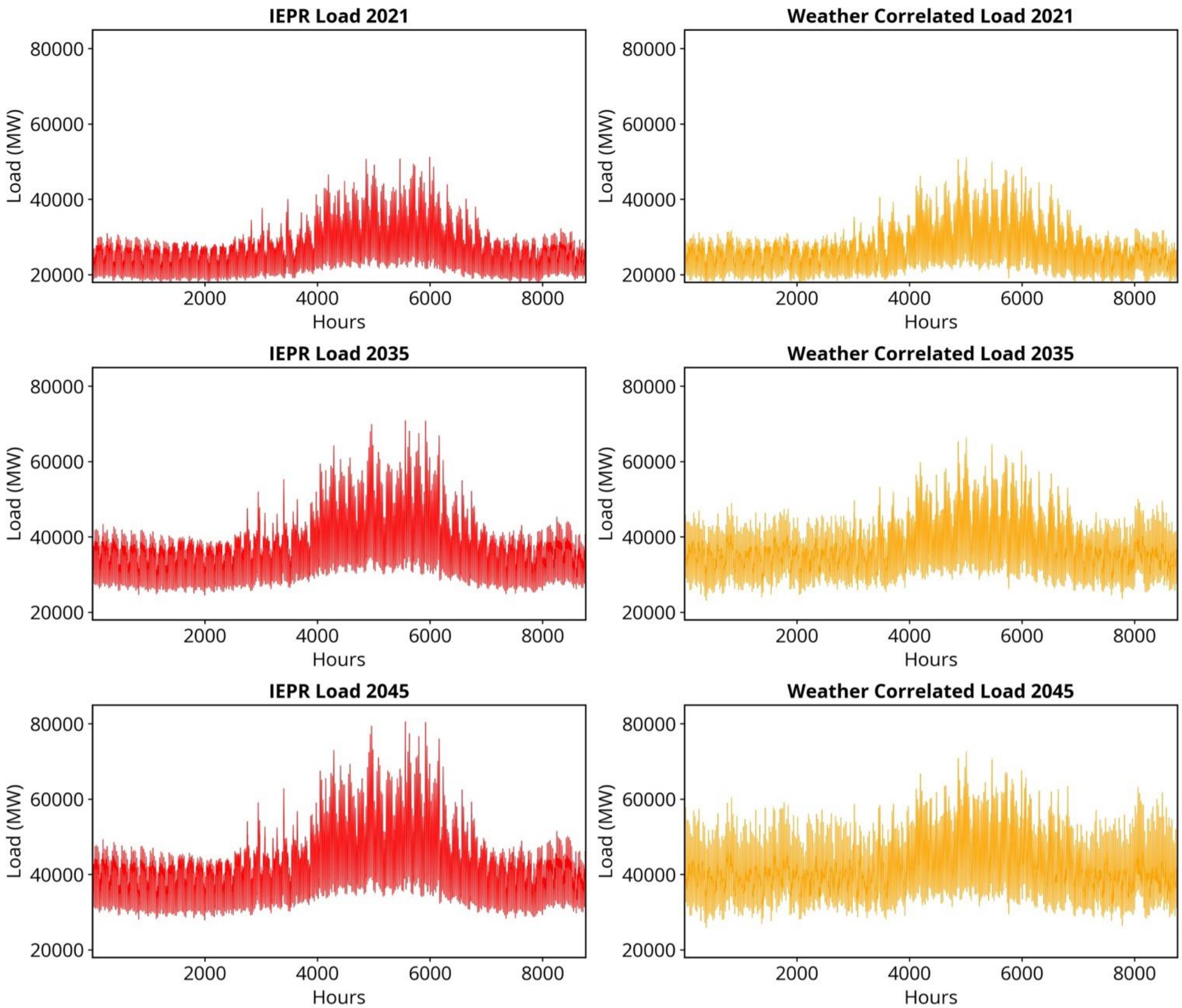
Figure B-4: Normalized Hourly Load Shapes for Weather Driven Loads in California



Once the hourly profiles for weather dependent loads are created, the normalized weather independent load profile can be calculated by subtracting the weather dependent load profile from the IEPR load profile. Load profiles for future years were calculated by using the load projections for each of the sectors and multiplying with their respective normalized load profiles. To create load profiles for the various weather years, the respective normalized weather dependent load profiles are used for the weather dependent loads, while the weather independent load is assumed to remain unaffected.

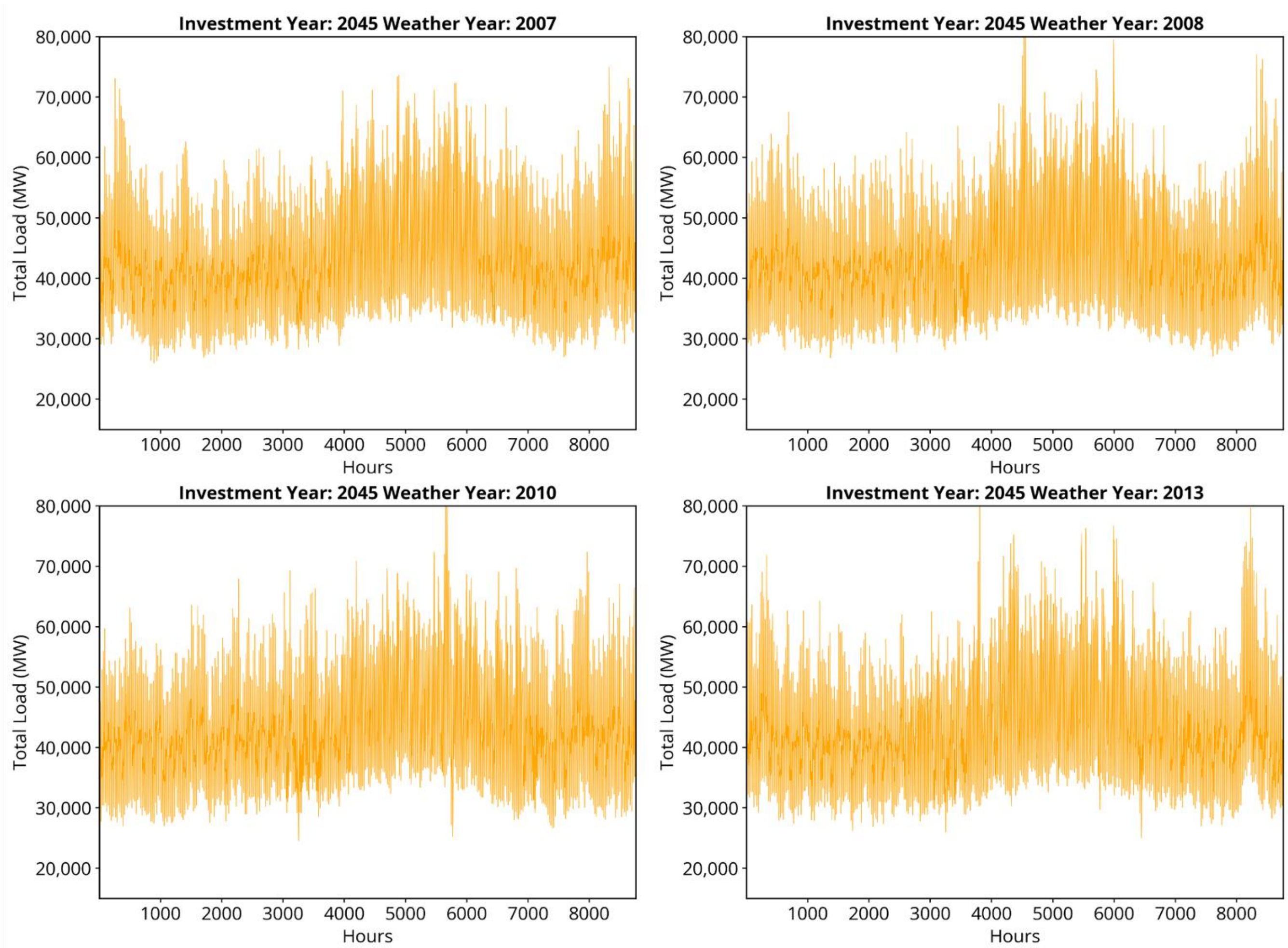
Figure B-5 shows the load profiles from IEPR and the load profiles used in Formware through high fidelity modeling of the impact of weather on loads. The load profiles for 2021 from IEPR and Formware are nearly identical as the IEPR load profile from 2021 is used as a starting point. In 2035, the IEPR load profile has a slightly higher summer peak, while in the Formware load shape the summer peak is lower. However, the winter loads in the Formware load profile show higher values due to electrification of heating and transport. By 2045, the impact of electrification of heating and transport are clear in the Formware load profile, while in the IEPR load profile, the load shape does not accurately respond to the change in the source of annual load increase.

Figure B-5: Comparison of Total Load Profiles from IEPR (left) and Updated Weather Sensitivity Sensitivities (right)



The load shapes in each of the weather years used in Formware exhibit significant changes in timing and magnitude of load peak observed due to the influence of weather (Figure B-6). Depending on the temperatures observed in each individual weather year, the timing of the load peak experienced in California can change from summer to winter or have multiple load peaks in a given year.

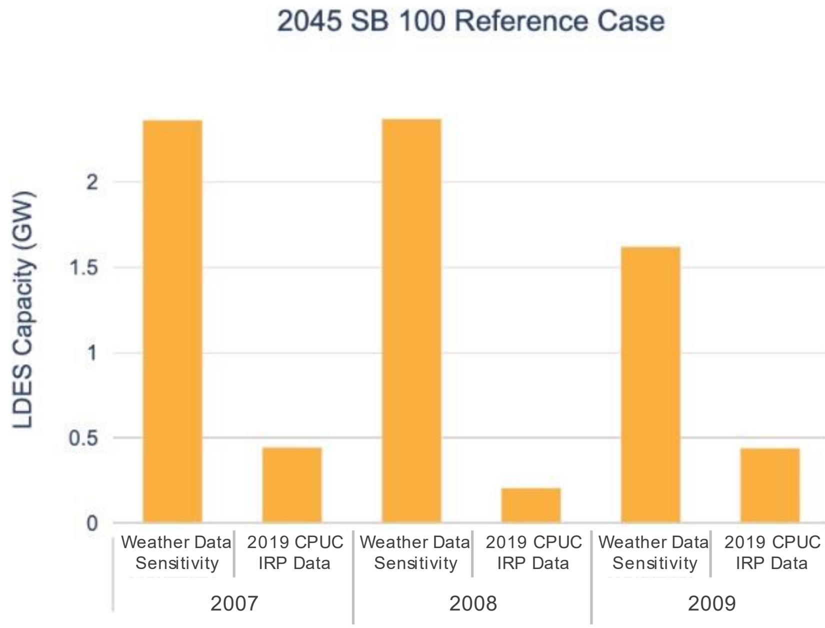
Figure B-6: 2045 Load Profiles for Four Weather Years



Studying the role of weather data uncertainty on Cal ISO portfolio results

As explained in Figure B-7 renewable generation and load profiles from different data sources were found to show significant disparities in lull characteristics and interannual variation. The team quantified the impact of these disparities on the observed value of LDES in the portfolio optimization model. The first dataset (labeled "Weather Data Sensitivity") consists of updated weather sensitivity renewable and load profiles for each modeled weather year, derived from historical weather data from NREL. The second dataset (labeled "2019 CPUC IRP") consists of the Resolve model inputs. The annual total load, annual peak load, and annual average capacity factor of the updated weather sensitivity inputs are scaled to be equivalent to the Resolve inputs. Differences exist solely in the hourly shape of load and renewable generation.

Figure B-7: Impact of Different Weather Datasets on Cal ISO Portfolio Results



The results are of Cal ISO SB 100 capacity expansion modeling performed are illustrated using both datasets, across three individual weather years using the tech-specific costs. The capacity of LDES present in the optimal resource portfolios is shown. The team observed up to tenfold increase in LDES adoption when updated weather sensitivity inputs are used instead of 2019 CPUC IRP inputs. This disparity is to be expected, based on the dataset characteristics discussed above.

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Appendix C: Reliability Assessment of SB 100 Gas Retirement Sensitivity

December 2023 | CEC-500-2024-003

APPENDIX C: Reliability Assessment of SB 100 Gas Retirement Sensitivity

This appendix describes reliability testing of the resource portfolios from the Gas Retirement Sensitivity Analysis. These portfolios were derived using Formware, a capacity expansion and production cost model that is designed to capture the dynamics of high renewable energy grids across hourly, seasonal, and interannual timescales. All portfolios maintain very high levels of reliability, with no meaningful reliability difference between portfolios with and without gas. This indicates that storage may be able to effectively replace the reliability function that gas serves on the Cal ISO bulk grid.

In the Gas Retirement Sensitivity Analysis, a multi-weather year co-optimization was implemented within the capacity expansion model to ensure system reliability. In this approach, a set of historical planning years is selected to capture a wide range of weather conditions. It should be noted that this capacity expansion model did not impose reserve-margin based reliability constraints on the system, due to the extreme uncertainty in estimating the effective load carrying capacity (ELCC) of renewables and storage resources on the 2045 grid.

Using Formware, resource build and retirement decisions are then optimized to minimize total system cost, while meeting demand across all 8,760 hours of the year within each planning year. Eight planning years were used (2007-2014), with weather data for each planning year sourced from NREL's System Advisor Model. More detail on development of load and renewable profiles for each planning year is provided in Appendix C.

To validate the reliability of portfolios derived from this analysis, an operational simulation of the portfolios on 35 historical weather years was performed. Unlike many reliability models, this simulation captures the actual correlated behavior of load and renewable generation over 35 years, rather than relying on synthetic weather data generated from a limited set of historical years. The weather years used for reliability testing (1980-2006 and 2015-2022) were distinct from the weather years used for resource planning years in the capacity expansion model (2007-2014). Weather data for the reliability testing years was sourced from Pfenninger and Staffell[12,13], based on the NASA MERRA reanalysis and CM-SAF SARAH datasets. The operational simulation optimized resource dispatch across 8,760 hours to minimize total system cost and total unserved energy in each of the 35 reliability testing years.

All portfolios derived from the gas sensitivity analysis achieved an expected unserved energy (EUE) of less than 0.001 percent These portfolios meet typical EUE reliability planning

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12 Pfenninger, Stefan and Staffell, Iain (2016). Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, pp. 1251-1265. doi: 10.1016/j.energy.2016.08.060

13 Staffell, Iain and Pfenninger, Stefan (2016). Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output. Energy 114, pp. 1224-1239. doi: 10.1016/j.energy.2016.08.068

standards,[14] including those established by the Alberta Electric System Operator[15] (0.0011 percent) and Australian Energy Market Operator[16] (0.002 percent). This is especially significant as several US markets are moving towards an EUE reliability standard, including Pennsylvania New Jersey Maryland Interconnection (PJM), Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP). Time-based metrics such as loss of load expectation (LOLE) were not calculated, as the model used in this study is only capable of optimizing dispatch to reduce total unserved energy rather than total load shed hours.

These results indicate that CAISO portfolios which retire in-state gas capacity via LDES deployment meet reliability planning standards and achieve comparable levels of reliability with portfolios that retain all 25 GW of existing gas. They also highlight multi-weather year co-optimization as a potential alternative to conventional reliability planning techniques, capable of producing resource portfolios that are robust against a wide array of weather-correlated system conditions.

Further studies should continue to explore the reliability implications of gas retirement via deployment of LDES and other technologies, at both the bulk-system and local transmission zone level.

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14 https://www.epri.com/research/products/000000003002022192

15 https://www.brattle.com/wp-content/uploads/2021/05/16623_albertas_capacity_market_demand_curve_-_marginal_reliability_impact_report.pdf

16 https://www.aemc.gov.au/market-reviews-advice/definition-unserved-energy