STRATEGEN

Gridlocked:

How Local Planning and Energy Storage Can Help Surmount Grid Congestion and Enable a Clean and Just Energy Transition

Prepared for

CESA
CALIFORNIA ENERGY STORAGE ALLIANCE

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This report is prepared by Strategen Consulting, Inc. on behalf of the California Energy Storage Alliance (CESA).
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Background and Motivation

As California evaluates how to cost-effectively ensure grid reliability while transitioning the energy system to clean resources, the state faces unique challenges in decarbonizing energy supply in transmission-constrained urban areas such as the Los Angeles (LA) Basin because the statewide planning processes are not currently structured to address both local decarbonization and local reliability planning.

Electric system reliability in the LA Basin is currently dependent on 12,640 MW of fossil-fueled generating capacity, 8,666 MW of which serve as peaking capacity. While the peaker fleet includes many relatively new assets, it also relies heavily on some of California's oldest and most inefficient power plants. As of 2023, the average peaker plant in the LA Basin fleet is already at its expected retirement age of 40 years old.[1] Of the overall operational peaking capacity in the region, 60% is over that same age. These plants, on average, operate only 3% of the year due to operational costs and inefficiency, yet are still relied on for maintaining reliability.

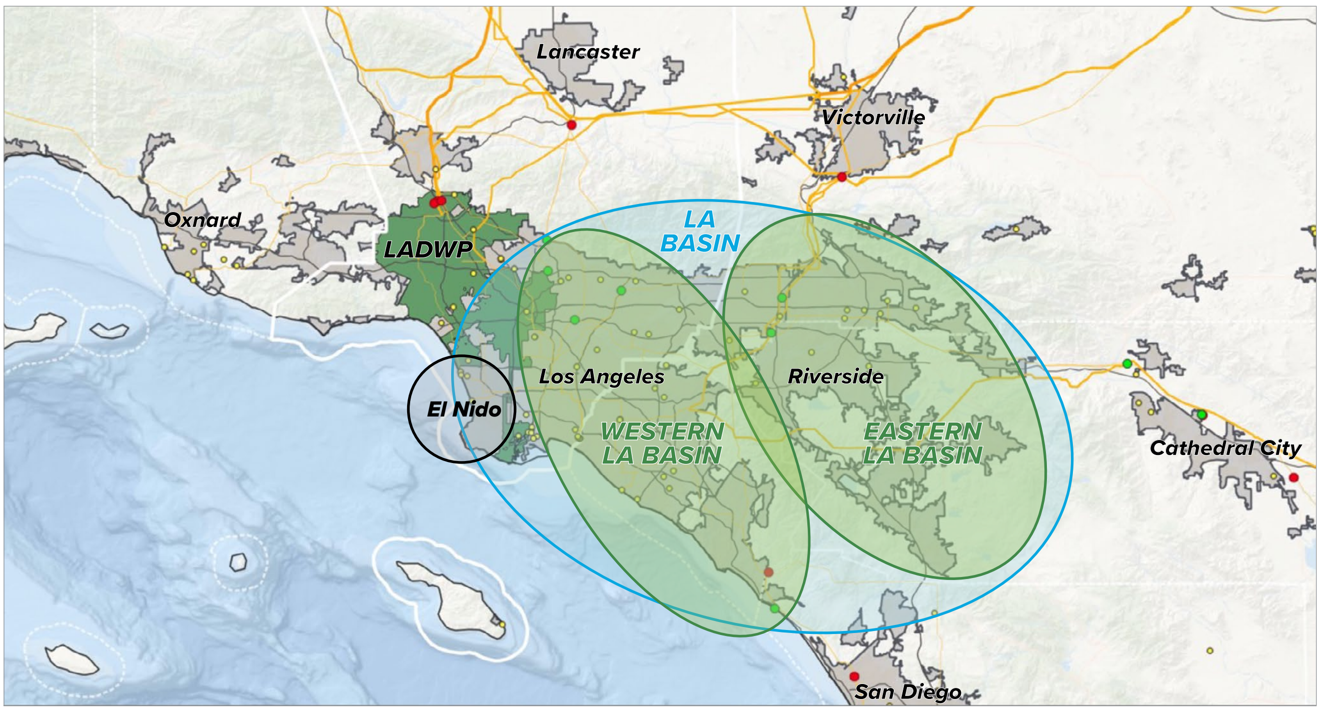

FIGURE 1: Local Reliability Areas in the Los Angeles Basin

Source: Strategen, based on data from CAISO (figure 3.3-89 LA Basin LCR Area)

Emissions from natural gas power plants in the LA Basin are expected to cause nearly $490 million in environmental and health damages annually by 2025 based on the social cost of carbon and the morbidity and mortality impacts from NO_x and SO_2 as precursors of $PM_{2.5}$. Furthermore, many of these health impacts will be concentrated in disadvantaged communities (DACs), given the localized nature of NO_x and SO_2 emissions. Approximately 80% of the fossil-fueled resources in the LA Basin are within 3 miles of a disadvantaged community.

1 Within California's CPUC-led IRP process, 40 years has been used as the expected retirement age for gas turbines.

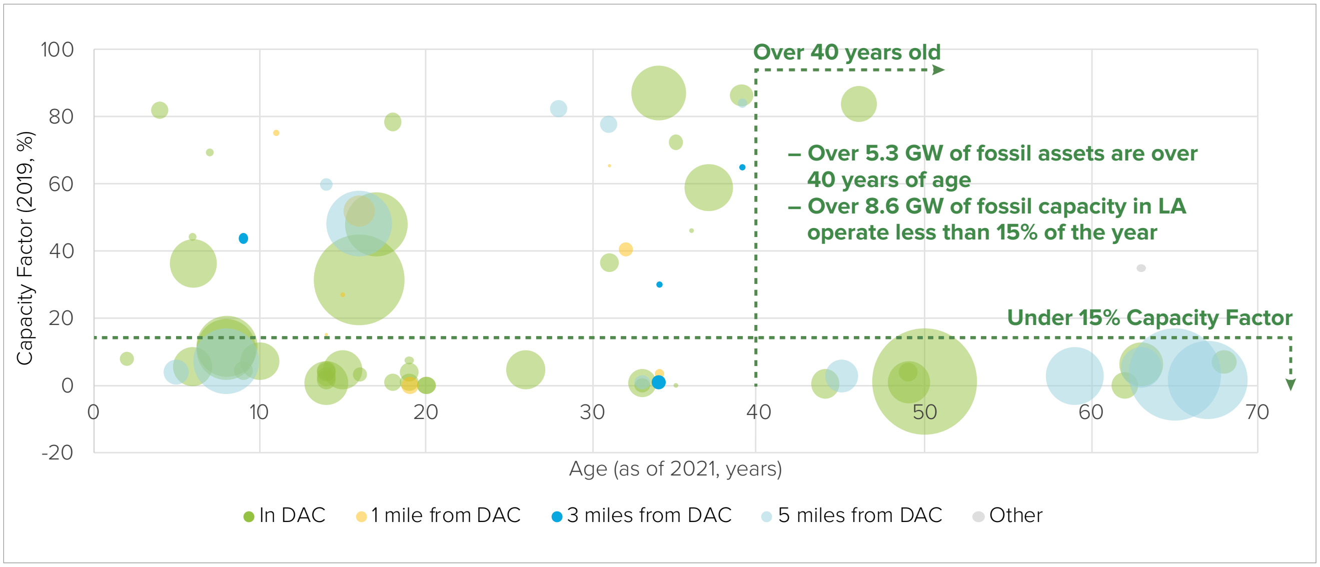

FIGURE 2: Fossil Fuel Resources in the LA Basin

Source: Strategen analysis of data from S&P Global

Continued reliance on these fossil-fueled power plants is largely motivated by transmission constraints that limit the ability to import power into the LA Basin. Given these limited electrical import and export capabilities, transitioning to a low- or zero-carbon energy system in LA will require locally sited, clean, flexible resources. This study, conducted by Strategen Consulting on behalf of the California Energy Storage Alliance (CESA), focuses on strategies to achieve a clean and reliable energy supply in the LA Basin, one of California's most constrained and highly polluted areas. This report serves as a case study to highlight the benefits of improved local reliability planning through an examination of current challenges and detailed analyses to assess potential opportunities for energy storage resources to enable a transition away from reliance on fossil-fueled energy. While the analysis and findings in this report are focused specifically on the LA Basin, these findings are intended to be widely applicable in other locally constrained regions.

Summary of Findings

The LA Basin is currently heavily dependent on aging fossil assets for continued local reliability. Nearly 70% of the fossil capacity in the LA Basin is used to provide peaking capacity. While peakers are not often used, they tend to be located in or near LA's disadvantaged communities. Of those peakers, 60% are particularly inefficient and are at or past their expected retirement age of 40 years, according to the California Integrated Resource Planning (IRP) process, making them priority targets for retirement and replacement.

Exacerbating existing challenges of retiring and replacing peakers, load growth and changes to CAISO's capacity accreditation approach indicate continued strain on local reliability. Strategen's analysis shows that changes to peaker capacity counting, uncertainties in transmission development timing, and risks related to aging assets could lead to a shortfall of as much as 2,600 MW of local capacity by 2031.

Against the backdrop of these reliability challenges, the importance of new clean, flexible capacity solutions is paramount. Energy storage is necessary to replace the capacity historically provided by fossil peakers and to ensure sufficient energy is available during times of peak demand. Energy storage sited in the LA Basin itself is particularly valuable, and California's reliability and progress towards achieving its clean energy goals will benefit from maximizing potential in-Basin deployment. Further, energy storage is a cost-effective solution to replace fossil-fueled peaking assets. Strategen's cost-benefit analysis of the levelized costs and market revenues of peakers and energy storage finds that by 2026 it will be cost-effective to deploy energy storage to replace the existing peaker fleet, and this replacement would already be cost-effective if the social cost of carbon is considered.

In the longer term, California aims to reach 100% clean electricity by 2045, which will necessitate reduced reliance on fossil-fueled assets for regional and local reliability. Decarbonization of the LA Basin will require the deployment of energy storage and renewables both within the LA Basin itself, as well as in the broader CAISO region. Out-of-Basin renewables or other clean energy resources will be critical to reliably charge in-Basin energy storage during off-peak hours, but this necessary configuration will also further contribute to transmission congestion. The development of increased transmission capacity between the LA Basin and the rest of CAISO will help to reduce overall resource costs and accelerate the retirement of fossil assets to reach California's longer-term goals. Additionally, longer-duration storage resources will be required to retire fossil assets while maintaining local reliability; 10-hour storage can create value as soon as 2035, and storage with as much as 100 hours of dispatch capability could be valuable if all fossil assets in the region were to be retired.

Summary of Recommendations

To reach California's short and long-term decarbonization goals, improved statewide planning processes that incorporate local reliability requirements are needed to avoid capacity shortages and ensure that adequate amounts of clean, flexible capacity are deployed where they can create the most value. The following recommendations have been developed to address the need for improved local reliability planning to enable longer-term reliability and decarbonization in California.

+ 1. **The California Public Utilities Commission (CPUC) IRP process and the California Independent System Operator (CAISO) Transmission Planning Process (TPP) should be Further integrated.** Today, the outputs of the CPUC's IRP proceeding are used to inform the CAISO's TPP, but there are opportunities for tighter integration to reduce regulatory lag, improve consistency between planned energy and transmission resources, and maximize opportunities for decarbonization in local areas.
+ 2. **The CPUC IRP process should incorporate both local and system planning.** A key limitation of the CPUC's IRP process is that it typically focuses on the needs of the system as a whole, with limited quantitative consideration of local reliability needs. Increased geographic granularity down to local areas in system planning will support the development of a cost-effective portfolio that achieves reliability and decarbonization needs at both a local and statewide level.
+ 3. **The CPUC IRP process should model a more comprehensive portfolio of storage solutions.** Historic IRP analyses have included only a limited selection of storage technologies – flow batteries, lithium-ion batteries, and pumped storage hydropower, which serves as a proxy for long-duration energy storage (LDES). Modeling a more comprehensive portfolio of energy storage solutions that represent a wider range of dispatch durations, round trip efficiencies, and levelized costs would enable a more accurate representation of the role that emerging storage technologies can play in a decarbonized grid.
+ 4. **The CPUC IRP modeling methodology should incorporate longer optimization horizons.** Modeled energy storage dispatch and optimization are significantly impacted by both the optimization horizon and the available dispatch window. Inappropriately short optimization horizons can produce model results that understate the value of energy storage. Given their longer dispatch window, long-duration energy storage resources are even more significantly impacted by these types of model design decisions. To accurately reflect the contributions of LDES and design an optimal forward-looking resource portfolio, the CPUC should ensure that IRP models use an optimization horizon of 365 consecutive days.

- **5. The CPUC IRP process should incorporate improved stakeholder engagement, especially for members of Disadvantaged Communities.** Increased efforts to engage stakeholders in IRP processes will support the integration of community needs and local development challenges into resource plans, resulting in realistic plans that address local needs and are fit-for-purpose. Residents in disadvantaged communities are disproportionately impacted by the environmental and public health impacts of energy supply and use and thus are significantly affected by energy policy and resource planning. To create just planning processes and an equitable clean energy grid, members of disadvantaged and overburdened communities should have a voice in planning efforts.
- **6. The CAISO and the CPUC should implement a capacity valuation methodology that captures forced outage rates.** Currently, counting frameworks do not incorporate forced outage rates into the capacity valuation. Changing counting methodologies to reflect outages is desirable as it would provide a more accurate representation of a resource's capabilities, particularly those of aging, inefficient, and unreliable fossil-fueled assets.
- **7. The California Energy Commission (CEC) should collaborate with the CPUC and the CAISO to identify local areas where pilot, demonstration, and commercialization efforts related to LDES and other emerging technologies can advance replacement of aging, polluting assets.** The work of all relevant agencies to build the operational experience and confidence in emerging technologies such as LDES will be fundamental to bolster their procurement. To this effect, the CEC should deploy available funds dedicated to spur the development and commercialization of LDES assets across the state in a manner aligned with peaker replacement goals, particularly in transmission and generation constrained settings.

Background

The LA Basin is home to a portfolio of 8.67 GW of fossil fuel peakers, 80% of which are located in or within one mile of a disadvantaged community and 60% of which have exceeded their expected useful life. However, for many of these resources, there is no clear pathway to retire and replace them with clean, flexible alternatives due to the constraints of the state-led planning process. This section provides an overview of the reliability, resourcing, and policy frameworks that have enabled the continued reliance on fossil fuel resources in the LA Basin.

California's Resource Planning Process

Today, California identifies resource needs and directs the development of new resources via a series of processes overseen by the CEC, the CPUC, and the CAISO. The paramount long-term planning venue for load-serving entities (LSEs) under the jurisdiction of the CPUC is the CPUC's IRP process. The IRP process assesses the long-term electricity needs of all CPUC jurisdictional customers to develop a system-wide cost-effective plan that meets these needs through a mix of generation, transmission, and distribution resources, while achieving the greenhouse gas (GHG) emission reduction targets set forth by California's Legislature.[2] As such, the IRP process is intended to ensure that utilities have sufficient resources to meet the projected demand for electricity, while also considering factors such as reliability, affordability, and environmental targets.

California's IRP process has typically focused on the needs of the system as a whole and has not incorporated a structured process to assess emission reductions and reliability needs, specifically in local areas with transmission limitations. This gap in the long-term planning process leaves it up to other market and regulatory frameworks to

2 The most stringent of these goals were set forth in Senate Bill (SB) 100, which established a landmark policy requiring renewable energy and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045.

provide economic incentives for curing local reliability deficiencies. In California, this responsibility falls squarely within the Resource Adequacy (RA) framework. California's RA framework is designed to ensure that the state's electric sector, collectively and on an LSE basis, has sufficient capacity to meet the projected electricity demand. The RA framework is the primary tool used to determine the ability of the electric system to deliver electricity to customers when it is needed, an essential function for the reliability and stability of the grid. California's RA framework is responsible for ensuring that there is sufficient capacity available to meet the projected demand for electricity on a local level, as well as on a system-wide level. This is achieved through the establishment of System and Local requirements and the assignment of System or Local characteristics to RA resources.

Existing LA Basin Fossil Fueled Resources

The LA Basin has traditionally relied on fossil fuel power plants for local reliability due to restricted transfer capability resulting from transmission constraints. Many of the emissions from these plants are local pollutants, meaning that they will remain close to their geographic point of origin, and their impacts will be felt most acutely by the surrounding communities and the residents who live closer to these plants. Further, fossil-fueled power plants have historically been sited in and near DACs, with 80% of fossil fuel resources in the LA Basin located within 3 miles or fewer of a DAC. These populations are disproportionately exposed to the negative environmental and health impacts caused by fossil plants.

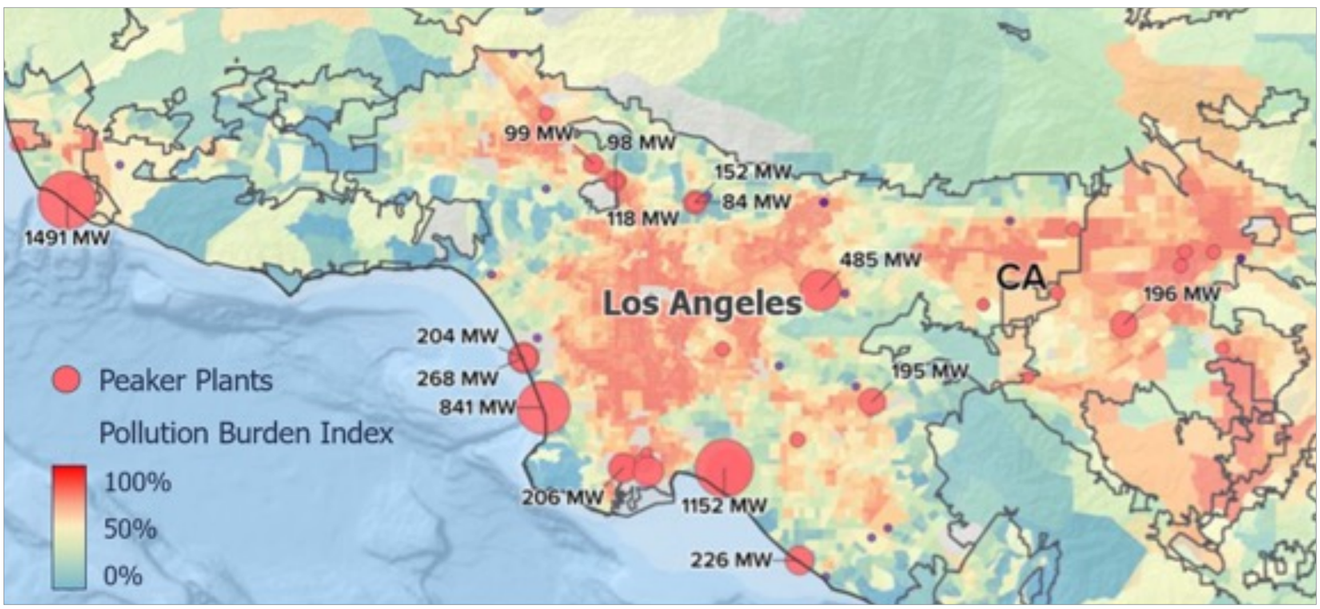

FIGURE 3: Peaker Plants in the LA Basin and Proximity to Communities Burdened by Pollution
Source: Strategen, based on data from EIA and CalEnviroScreen 3.0

Within the LA Basin, more than 40% of the fossil-fueled generating capacity is more than 40 years old, with nearly 25% over 60 years old. Most of these plants operate at just a fraction of their total capacity, with more than half of the units, representing almost 70% of fossil-fueled capacity, running less than 15% of the year. Such units typically only operate during system peaks, when energy demand rises above normal levels, and are therefore commonly referred to as "peaker" plants. Due to their inefficiencies and frequent starts, peakers are highly polluting and expensive to operate. Furthermore, these plants tend to be located in under-resourced and environmental justice communities. Approximately 80% of peakers in the LA Basin are sited within 1 mile of a DAC.

The emissions produced by peakers and other gas plants in the LA Basin cause negative impacts on air quality and the health of local populations. The most common pollutants emitted from fossil fuel plants are nitrogen oxides (NO_X), sulfur dioxide (SO_2), and carbon dioxide (CO_2). NO_X is a contributor to ozone, which can cause respiratory problems and other health and environmental impacts.[3] SO_2 can also lead to respiratory damage, particularly for children and people with asthma, and is a precursor to small particulate matter such as $PM_{2.5}$, which can further impact the lungs because it penetrates deeper than larger particulates.[4]

The retirement and replacement of natural gas plants in the LA Basin presents an opportunity to reduce emissions and their adverse environmental and health impacts. The retirement of the region's gas fleet would result in annual reductions of 8.1 million tons of CO_2, 1,080 tons of NO_X, and 55 tons of SO_2, which account for 22%, 33%, and 29% of total power sector pollution in California from these emissions, respectively.[5] The benefits of lower risks of respiratory illness, cancer, disease, and premature mortality associated with the emission of local pollutants such as SO_2 and NO_X can be quantified through the avoided cost of these impacts. Local emissions from the natural gas power plants in the LA Basin would be expected to cost an estimated $13.2 million annually by 2025, increasing to $14.8 million by 2030, based on the morbidity and mortality of NO_X and SO_2 as precursors of $PM_{2.5}$.[6]

In addition to producing local pollutants that can have localized impacts on health and mortality, fossil-fueled power plants produce global pollutants such as carbon dioxide. Global emissions cause damage by concentrating in the atmosphere and have an effect on climate changes worldwide, regardless of where the source of emission is located. These climate changes lead to societal impacts related to changes in net agricultural productivity, property damages from increased flood risks, human health, energy system costs, and other aspects of the economy that are accounted for in the cost of carbon.

The U.S. Environmental Protection Agency (EPA) provides guidance on the social cost of carbon and discount rate parameters, which allow for the calculation of the monetary value of climate change impacts caused by GHG emissions and the value of avoided damages.[7] Based on the EPA's guidelines, the 8.1 million tons of CO2 emitted by gas plants annually in the LA Basin, equivalent to about 22% of California's CO2 emissions from power plants, will cost the world about $475 million annually by 2025, increasing to $526 million by 2030.

Pollutant	Economic Value 2023 $/ton		Annual Emissions (Tons)	Annual Economic Impact by 2030 ($)
	2025	2030		
CO_2	$59	$65	8,068,352	$526,418,066
NO_x	$8,889	$9,960	1,080	$10,758,703
SO_2	$65,688	$74,137	55	$4,059,253
			TOTAL	**$541,236,022**

TABLE 1: Economic Impact of Gas-Fired Plants in the LA Basin[8]
Source: Strategen analysis of data from S&P Global

3 U.S. Environmental Protection Agency, Ground-Level Ozone Basics, Accessed October 2020, https://www.epa.gov/ground-level-ozonepollution/ground-level-ozone-basics

4 World Health Organization, Ambient (Outdoor) Air Pollution, Accessed October 2020, https://www.who.int/news-room/fact-sheets/detail/ambient-(outdoor)-air-quality-and-health

5 Based on data retrieved from S&P Global.

6 U.S Environmental Protection Agency, Estimating the Benefit per Ton of Reducing PM 2.5 and Ozone Precursors from 21 sectors, April 2023. https://www.epa.gov/system/files/documents/2021-10/source-apportionment-tsd-oct-2021_0.pdf

7 U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates under Executive Order 13990," February 2021. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

8 Emission Cost per Ton at a 3% discount rate for CO_2, NO_X and SO_2, in 2023 dollars, based on 2021 emissions. Reported values were converted to 2023$ using the historical rate of inflation.

Reduced reliance on fossil fuel resources would therefore offer substantial health and environmental benefits for communities in the LA Basin while also supporting the mitigation of climate change risks. As discussed in the next section, energy storage, including long-duration storage, can support the retirement and replacement of fossil-fueled resources, while potentially providing local air quality benefits through avoided damages if paired with and fueled by clean energy resources. Many storage technologies, including long-duration technology solutions, have significantly declined in cost and increased in maturity in recent years and are ripe for deployment. The following section discusses the need for new clean, flexible capacity and the role that energy storage can play in meeting that need.

Analysis and Results

To improve local resource planning and transition away from dependence on fossil fuels, there is a need for robust analysis that can properly assess the range of available solutions to achieve California's decarbonization goals, while maintaining reliability and addressing disproportionate community impacts. Strategen led two analyses that assess reliability in the LA Basin and quantify the cost-effectiveness of energy storage to close reliability gaps, and partnered with Pacific Northwest National Laboratory (PNNL) to evaluate potential resource deployment options to meet the reliability needs of the LA Basin. These analyses provide quantitative insight into the specific needs and challenges to ensuring reliability in the LA Basin and inform potential opportunities to replace aging fossil capacity with clean and reliable technologies.

These analyses consisted of three distinct components:

+ **1.** First, a preliminary analysis evaluated local capacity forecasts and transmission requirements in the region to assess resource sufficiency and identify potential contingency challenges in the near term, to understand how reliability needs and constructs are perpetuating the use of fossil fuel assets, and how storage may be able to bolster local reliability.
+ **2.** Second, a net cost analysis examined the cost-effectiveness of energy storage compared to fossil-fueled peaker power plants. The net cost analysis focused specifically on the energy market revenues that each resource would be able to access and how those revenues compare to installed asset costs to understand the relative cost-effectiveness of the two different flexible resources.
+ **3.** Finally, in collaboration with PNNL, GridPath was used to model future resource needs in the LA Basin. This analysis was intended to closely replicate California state policy and planning tools, incorporating local reliability constraints, to understand how those constraints might impact optimal resource deployment.

These three analyses, including their methodologies, assumptions, and findings, are laid out in greater detail below.

LA Basin Reliability Challenges

To assess local reliability needs and resources in the LA Basin, Strategen performed a "stack analysis" that quantifies resources available to contribute to the LA Basin capacity requirement. The key objectives of the near-term reliability stack analysis were to estimate the magnitude and timing of potential capacity deficiencies in the LA Basin under single peak conditions and assess the impact of potential transmission development and regulatory risks in meeting the local N-1-1 contingency requirements.[9]

9 N-1-1 refers to a contingency condition in which the local reliability area or sub-area operating in a nominal or normal state experiences the loss of a critical element, adjusts, and then suffers the loss of a second critical element.

The stack analysis focused on identifying the potential capacity shortfall that the LA Basin and its three subareas (Western LA Basin, Eastern LA Basin, and El Nido) could experience under a series of potential conditions representing regulatory, transmission, and retirement risks over the 2021-2031 timeframe, including:

+ 1. **Regulatory Risks:** Scenarios considering changes in the capacity counting mechanisms used in California's RA framework;
+ 2. **Transmission Development Risks:** Scenarios in which transmission projects forecasted to be completed in the 2022-2031 period were delayed; and
+ 3. **Asset Retirement Risks:** Scenarios modeling aged-based retirements and efficiency-based retirements.

Regulatory Risks: Changes to Capacity Valuation Methodologies

Since 2020, the CPUC and CAISO have been considering transitioning from a Net Qualifying Capacity (NQC) framework to an Unforced Capacity (UCAP) framework for capacity counting.

> Under the NQC framework, the countable capacity from dispatchable resources is based on available capacity, with this value equivalent to the maximum power output (Pmax). The UCAP framework incorporates forced outage rates into the capacity valuation, providing a more accurate representation of a resource's capabilities.

The CAISO has previously proposed to determine an asset's capacity contributions based on a UCAP methodology that considers asset performance during the top 20% of hours of the year with the tightest supply conditions (i.e. the tightest RA supply cushion hours in each season). Preliminary UCAP data reveals that natural gas assets have higher outage rates than storage, reducing expected capacity contributions for fossil generators with the transition to the UCAP framework. Although the CPUC and the CAISO have not yet implemented such changes, they have agreed to continue exploring a UCAP framework together under the CPUC's RA proceeding.

To model the potential impacts of a transition to UCAP, Strategen assumed UCAP values in line with those reported in the CAISO's RA Enhancements initiative.[10] To assess whether this transition could surface capacity deficiencies in the LA Basin and its subareas, the analysis relied on the CAISO's Local Capacity Technical Study (LCTS) for 2022. This is the most recent data at the time of the analysis, which estimates capacity needs for each Local Reliability Area (LRA) and subarea one and five years in advance. The LCTS focuses on outlier load conditions under 1-in-10 load assumptions,[11] an N-1-1 contingency scenario, and assumes limited energy efficiency and local PV assets. According to the LCTS, CAISO estimated approximately 19 GW of peak load and 12 GW of import capability in the LA Basin, requiring 7 GW of local capacity for reliability during an N-1-1 contingency. As such, the first stack analysis assessed if a transition to UCAP would materially decrease local capacity's value (i.e., countable contribution), thus surfacing shortfalls in the 2022-2031 period.

10 California ISO, Resource Adequacy Enhancements Final Proposal - Phase 1, February 17, 2021, http://www.caiso.com/InitiativeDocuments/ResourceAdequacyEnhancements-Phase1FinalProposal.pdf

11 1-in-10 load conditions refer to outlier load forecasts. A 1-in-10 load forecast is equivalent to saying that the ISO is planning for load conditions that historically manifest once every ten years or for a load forecast that has a 10% probability of manifesting in any given year. Planning for 1-in-10 load is thus more conservative than planning for 1-in-2 load, for example, as 1-in-2 load forecasts historically manifest once every two years or have a 50% probability of manifesting in a given year.

Figure 4 shows the stack of existing resources that are able to contribute to LA Basin capacity requirements, with thermal resources represented as "Market," consistent with CAISO convention. Figure 5 shows the difference between available and needed capacity, with positive values indicating a capacity surplus and negative values indicating a capacity shortfall. As shown in these figures, with a UCAP methodology, the LA Basin would expect to see capacity shortfalls of at least 100 MW by 2030.

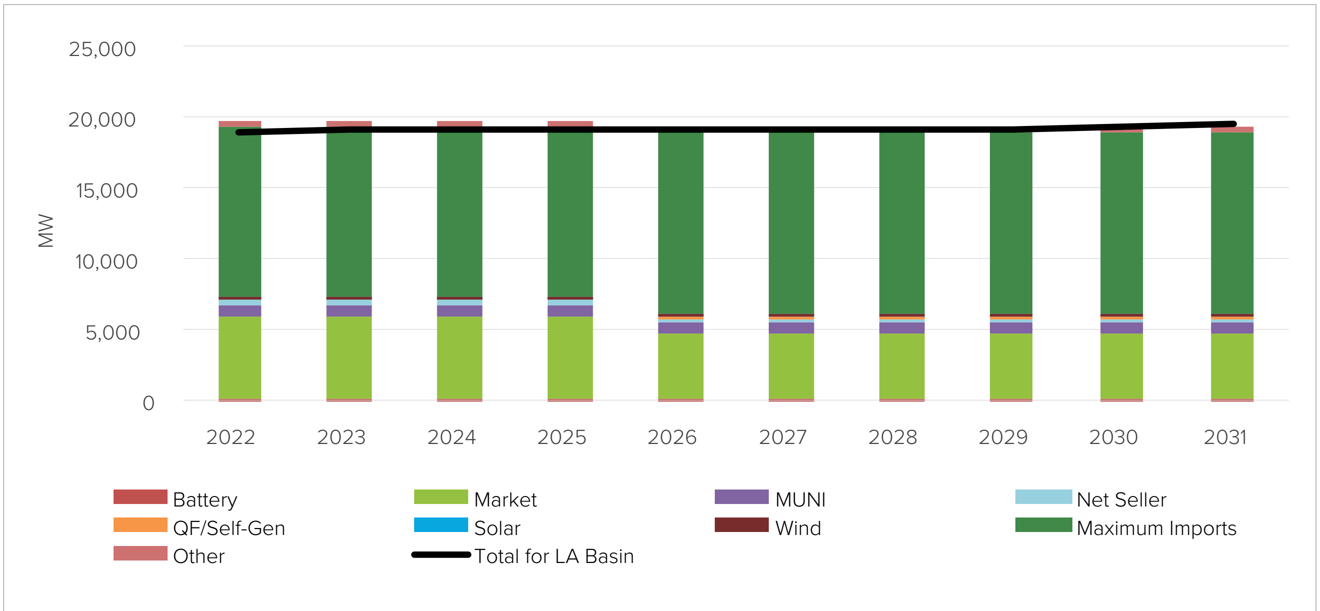

FIGURE 4: Capacity in LA Basin (UCAP)

Source: Strategen analysis of data from the CAISO

The UCAP framework reduces the capacity expected from all resources, with fossil assets hit the hardest. While the CAISO has previously noted that a shift to UCAP would not necessarily affect their LCR methodologies, the potential deficiencies found in Strategen's analysis indicate that current counting practices overestimate the reliability value provided by fossil-fueled resources.

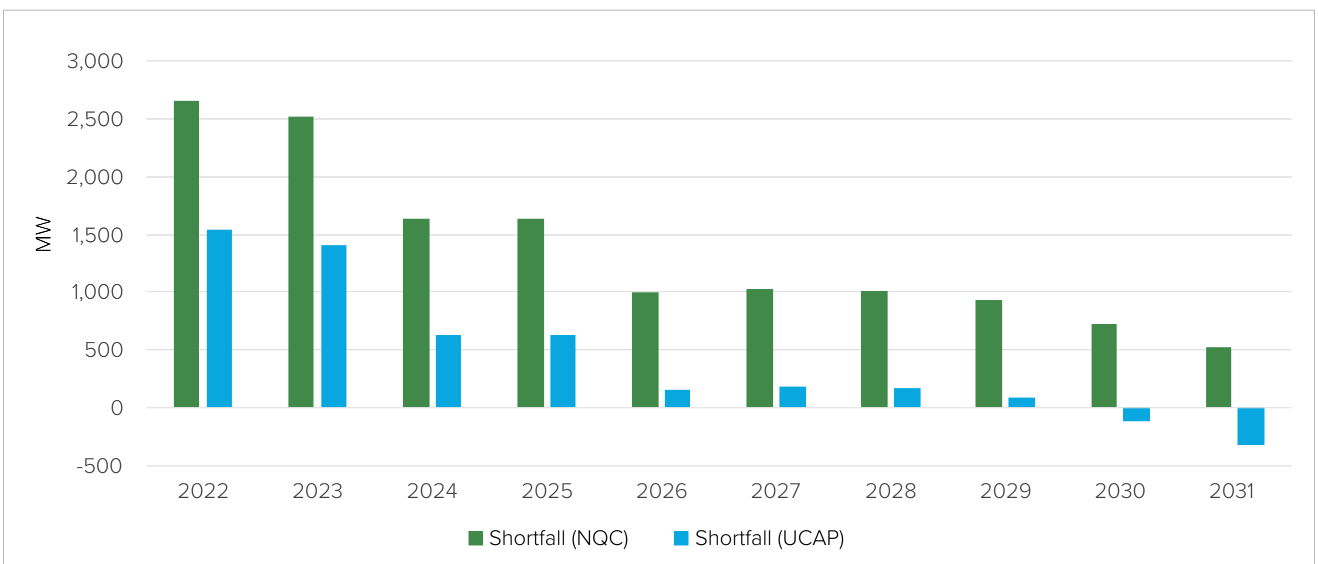

FIGURE 5: Potential Capacity Shortfall under NQC and UCAP (MW)

Source: Strategen analysis of data from the CAISO

Transmission Risks: Delays in Transmission Development

While the regulatory risk presented by UCAP is relevant, other significant investments are planned and in development in the LA Basin that could also affect the availability of local capacity in the region. For example, in the 2022 LCTS, the CAISO noted a series of transmission projects that would materially increase transfer capability into the LA Basin, effectively reducing the local capacity requirements. These projects include the Mesa Loop-In Project and the Laguna Bell Corridor, the Delaney-Colorado River Line, and the West of Devers upgrade. Collectively, these expected transmission upgrades would increase the LA Basin's transmission capability by 750 MW by 2026. All projects are assumed to have successful and on-time online dates in CAISO's LCTS analysis. Any delay or postponement of these projects would jeopardize capacity sufficiency. Therefore, Strategen performed additional analysis to determine the impacts of both a transition to UCAP and the potential delay of these transmission projects.

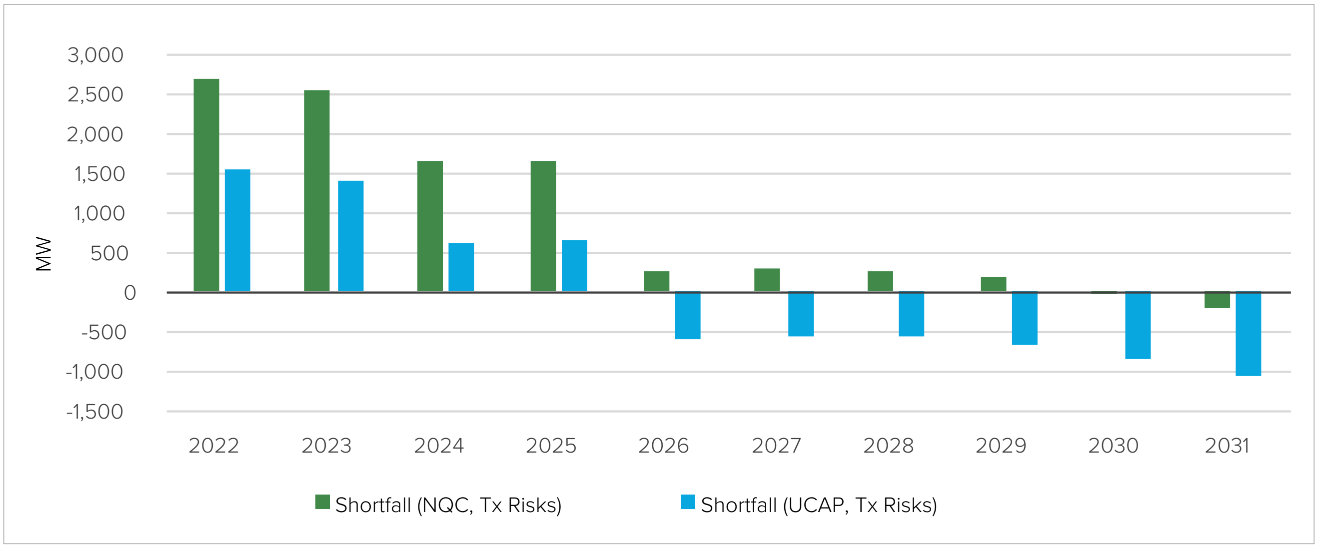

FIGURE 6: Potential Capacity Shortfall under NQC and UCAP, assuming Transmission Delays beyond 2031 (MW)
Source: Strategen analysis of data from the CAISO

As shown in Figure 6, if transmission projects get delayed beyond 2031, the LA Basin will experience a local capacity shortfall by 2026 under UCAP (549 MW) and by 2030 under NQC (24 MW). While this result underscores the importance of the transmission upgrades the CAISO has approved and that Participating Transmission Owners (PTOs) are diligently working towards, it also exposes how impactful potential delays would be to the region.

Retirement Risks: Age-Based Retirements

Given these conditions and California's climate imperative stated in Senate Bill (SB) 100, Strategen sought to understand the potential impacts of age-based retirements in the LA Basin's system. Within the IRP proceeding, the CPUC has assumed that aging thermal resources would be retired 40 years after their commercial operation date (COD). This assumption allowed the capacity expansion model used in the IRP process to identify potential resources that could replace contributions from retiring capacity, while meeting state policy goals, including preference for preferred resources and compliance with the state's emissions targets. Modeling age-based retirements in the LA Basin is critical given the region's dependence on "Once Through Cooling" (OTC) power plants, which use large amounts of water to cool their machinery and then discharge the heated water back into the environment. In the LA Basin, these include assets like Redondo Beach, Alamitos, and Huntington Beach. Most OTC plants are aging and are required to retire or modify operations due to their environmental impact. However, California has had significant challenges in retiring them due to the lack of a clear and consistent policy framework for phasing out these and other aging facilities in the region. Considering this, Strategen sought to identify the potential capacity effects of retiring all fossil-fueled power plants in the LA Basin that are at least 40 years old. Table 2 shows all OTC plants in the LA Basin that should be considered for age-based retirements.

Name	Current Age	Operating Capacity (MW)	Expected Retirement Date (as of Q2 2022)	Retirement Date (based on 40-year life)
Alamitos	67	1,152	2026	1996 (2022)
Redondo Beach	69	841	2024	1994 (2022)
Huntington Beach	65	226	2026	1998 (2022)
El Segundo Refinery	48	172	None	2015 (2022)
Glenarm	47	152	None	2016 (2022)
Watson Cogeneration	36	398	None	2027
Habor Cogeneration	35	106	None	2028
	TOTAL (MW)	**3,047**		

TABLE 2: Potential Aged-Based Retirements in the LA Basin (as of Q2 2022

Source: S&P Global and California Department of Water Resources

As shown above, the LA Basin is largely dependent on aging, inefficient generation. If the LA Basin commenced retirement of 40-year plus generation (as assumed in the IRP process), the area would immediately be deemed insufficient, as shown in Figure 7. The IRP age criteria would immediately accelerate the retirement of Redondo, Alamitos, and other generators. Figure 7 shows the effects of age-based retirements on top of the two previously analyzed risks: a transition to UCAP and the delay of transmission upgrades beyond 2031. If the IRP assumption was enforced, and assuming other risks materialized, the LA Basin overall would see capacity shortfalls of approximately 800 MW by 2022 and 2.6 GW by 2031. Of this shortfall, about 1.2 GW would be in the Western LA Basin sub-area.

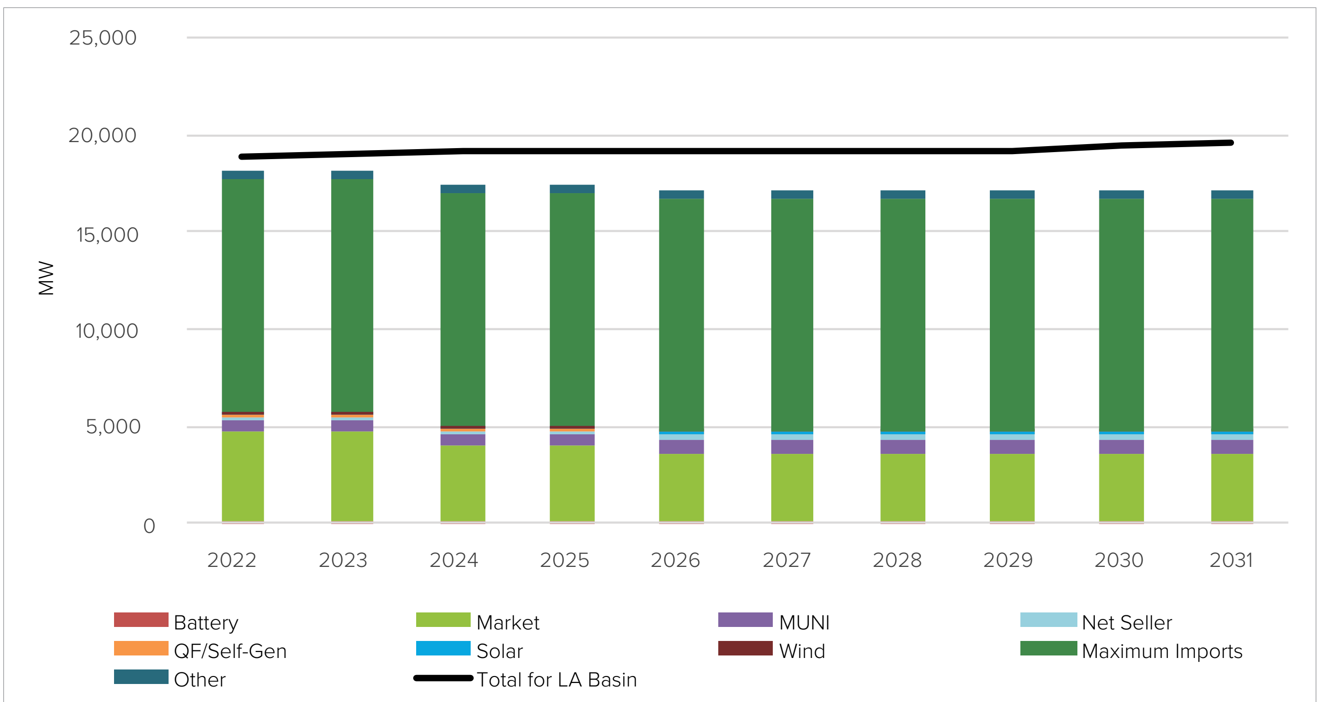

FIGURE 7: Assuming Retirement at 40 Years (UCAP)

Source: Strategen analysis of data from the CAISO

Given these shortfall expectations, it is clear that the material enforcement of the CPUC's IRP modeling assumption is unlikely and undesirable, given the imperative to preserve reliability and fair and reasonable rates. Nevertheless, this scenario shows what environmental and community advocates have noted for years: the LA Basin's electric needs are being met by plants on borrowed time, aging assets that materially worsen the lives of the communities around them.

Energy Storage is a Cost-Effective Alternative

To further examine the potential for energy storage to replace peaker plants in the LA Basin, Strategen assessed the cost-effectiveness of new 4-hour energy storage resources relative to the existing peaker fleet in the region. For this analysis, peaker plants were defined as natural gas plants in the LA Basin with a capacity factor of less than 15% based on actual historical utilization.

The analysis focused on a comparison of the net costs associated with both technologies to provide equivalent capacity.[12] The net cost was calculated as the difference between the costs of producing energy (capital, operating, and maintenance costs)[13] and the potential revenues in the CAISO day-ahead energy and ancillary service markets for each technology. For the incumbent peaker fleet, the net cost was approximated assuming that plants have already been paid off and therefore incur no additional capital costs and that the plants would run economically, meaning during hours when the wholesale-energy prices are higher than the cost of energy dispatch.[14] A charge and discharge schedule was set for energy storage resources, allowing one daily 4-hour cycle.[15] When not participating in the energy market, both peakers and energy storage were able to earn additional revenues from the ancillary services market in the form of non-spinning reserves for gas plants, and spinning reserves and regulation for energy storage.

Strategen performed the net cost analysis for both a Base Case and an Advanced Policy Case. In the Base Case, energy storage costs reflect NREL's "moderate" price decline scenario and a 30% Investment Tax Credit (ITC) consistent with base benefits from the Inflation Reduction Act of 2022 (IRA).[16] The Base Case also included natural gas price projections from the reference scenario in EIA's 2022 Annual Energy Outlook[17] and current CO2 costs from California's Cap-and-Trade Program.[19] The Advanced Policy Case included a faster decline in the cost of energy storage based on NREL's "advanced" price decline scenario, reflecting more investment in research and development and supply competition. For the peaker plants, the Advanced Policy Case assumed that natural gas prices would increase as a result of a stricter carbon policy or reduced natural gas supply.[20]

12 Equivalent capacity was determined based on the Net Qualifying Capacity of each resource in the CAISO. The weighted seasonal average availability factor for a natural gas peaker is 87.5% and the factor for energy storage is 96.4%.

13 Capital costs, fixed annual costs, and variable costs were sourced from the NREL Annual Technology Baseline for 2021. Accessible at: https://atb.nrel.gov/electricity/2021/data

14 Operating costs were determined by the heat rate for each unit, the annual projected price of natural gas, and expect operation and maintenance costs. The energy prices were based on historical local marginal prices (LMPs) from 2019, adjusted for inflation. To reduce complexity, associated revenues were estimated only for day-ahead markets under the assumption that peakers would not deviate from their day-ahead schedule.

15 It was assumed that energy storage resources would not have perfect foresight of market prices and that they would focus on arbitrage for the day-ahead energy market. Therefore, the daily charge and discharge cycle was set for every month based on historical 2019 LMPs in blocks of four consecutive hours.

16 The Inflation Reduction Act provides a 30% ITC benefit for energy storage, assuming sourcing and labor requirements are fulfilled.

17 U.S. Energy Information Administration, 2022, 2022 Annual Energy Outlook, https://www.eia.gov/outlooks/archive/aeo22/

18 California Air Resources Board (CARB), Cap and Trade Program Auction Results, Accessed May 1, 2023, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/auction-information

19 CO2 costs were based on the social cost of carbon developed by the Interagency Working Group on the Social Cost of Greenhouse Gases, using a 3% discount rate. See: The U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990.

20 Natural gas price projection was based on EIA's Low Oil & Gas Supply scenario from the 2022 Annual Energy Outlook. Available at: https://www.eia.gov/outlooks/archive/aeo22/

The analysis found that energy storage is cost-effective relative to local capacity prices in the LA Basin in both modeled cases. That is, after considering all costs and revenues, capacity from energy storage would be available at a lower cost than existing capacity resources like peakers, potentially bringing savings to the system by replacing the most expensive sources of capacity.[21]

The study also shows that energy storage is already a cost-effective resource to ensure reliability and enable the retirement of peakers. Strategen compared the levelized costs and market revenues of the LA peaker fleet to those of potential energy storage replacement deployed in different years under two scenarios, the first showing the current market landscape and the second including an increase of carbon costs and a faster price decline of battery storage. The analysis showed that starting in 2026, it will be cost-effective to deploy energy storage to replace the existing peaker fleet (represented by the average peaker in LA and considering its lack of capital expenditures) at about $1.5/kW-month and that this replacement would already be economical if the planning process were to consider the social cost of carbon included in the Advanced Policy Case. Additionally, energy storage is already a viable option to replace the oldest and most inefficient portion of the fleet.

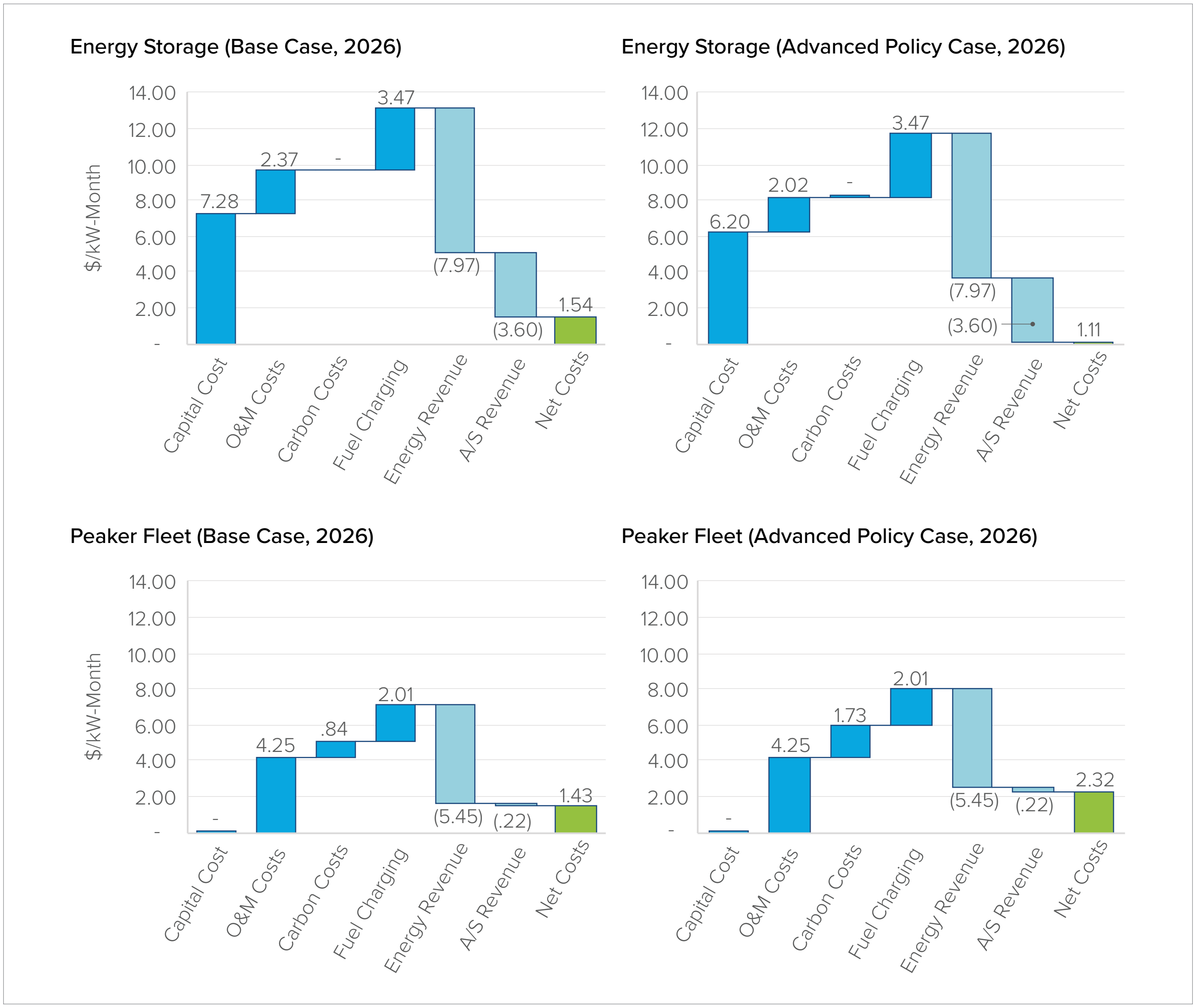

FIGURE 8: Net Cost Comparison of New Storage Resources vs. Incumbent Peaking Plants

Source: Strategen analysis of data from NREL, the CAISO and EIA

21 California Public Utilities Commission, 2020 Resource Adequacy Report, December 2021, Table 7, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2020_ra_report.pdf

Notably, the analysis compares new energy storage systems with an average representation of the entire peaker fleet in the LA Basin, and therefore the older and more inefficient plants could likely be economically replaced even earlier. In this region, 60% of the peaking capacity is at or past its expected useful life of 40 years.

The net cost analysis points to the tremendous opportunity for energy storage resources to economically displace fossil resources in the LA Basin, leading to improvements in local air quality and reduced health impacts in DACs. However, given its limited duration, 4-hour storage may not be sufficient for maintaining reliability in this constrained urban area, and further analysis is required to examine the appropriate mix of renewable resources and storage technology options necessary to enable this transition and overcome potential capacity shortfalls.

Fossil Fuel Retirement and Replacement

In partnership with Strategen, PNNL conducted long-term analysis of the future role of energy storage as the LA Basin transitions away from aging fossil plants. PNNL's objective was to develop a long-term assessment of the resource and capacity needs in the LA Basin and identify ways for clean energy resources, in particular energy storage and LDES, to replace fossil fuel generation capacity. This analysis was intended to closely replicate the analysis already undertaken by the state and to be consistent with California policy, with the added consideration of local reliability constraints. Overall, the analysis provides the following directional insights:

+ **1.** There is a need for significant deployment of energy storage to replace the generation capacity historically provided by fossil peakers.
+ **2.** Driven by the lack of transmission capacity, energy storage sited in the LA Basin itself is particularly valuable, and California's reliability and clean energy goals will benefit from maximizing potential in-Basin deployment.
+ **3.** Development of increased transmission capacity between the LA Basin and the rest of the CAISO will help to reduce overall resource costs and accelerate the retirement of fossil assets, as well as alleviate land use concerns for in-Basin resource deployment.
+ 4. Availability of out-of-Basin renewables or other clean energy resources is critical for charging in-Basin energy storage during off-peak hours, but will contribute to transmission congestion, further increasing the need for either incremental transmission investments or in-Basin generation assets.
+ **5.** Longer-duration storage assets will be required to retire fossil assets while maintaining local reliability; 10-hour storage can create value as soon as 2035, and storage with as much as 100 hours of dispatch capability could be valuable to retire all fossil assets.

Modeling Approach & Methodology

For this analysis and the resulting report, *Capacity Expansion Planning for LA Basin: The Role of Energy Storage*,[22] PNNL employed GridPath, a capacity expansion tool from Blue Marble,[23] to model the LA Basin and its relationship with the more extensive California system. Specifically, the analysis was built upon the existing CPUC 2019 Planning Model, the RESOLVE model from E3,[24] which is used to develop a long-term plan for the implementation of both transmission and generation resources across the state. The CPUC's approach, while useful for directional guidance in resource planning, is limited in its ability to provide detailed recommendations for planning of generation capacity and resource options and does not provide any guidance on local reliability.

22 Pacific Northwest National Laboratory, 2023, Capacity Expansion Planning for LA Basin: the Rose of Energy Storage, https://www.pnnl.gov/publications/capacity-expansion-planning-la-basin-role-energy-storage

23 Blue Marble Analytics, GridPath: Advanced Software for Power-System Planning, Accessed May 1, 2023, https://www.bluemarble.run/gridpath

24 Energy + Environmental Economics, Resolve: Renewable Energy Solutions Model, Accessed May 1, 2023, https://www.ethree.com/tools/resolve-renewable-energy-solutions-model/

Modeling transmission congestion and local load balancing is necessary for understanding regional reliability and thus how much local generation and storage is required.

PNNL's analysis in GridPath expanded upon the CPUC's approach by including the LA Basin as a new 3-bus model connected to the original 7-bus model used by the Commission to represent the state of California and key import/export partners. Each "bus" represents an aggregated load and generation region of California, connected to other regions by transmission lines. The addition of three buses for Eastern Los Angeles, Western Los Angeles, and the El Nido subzones allowed the analysis to specifically focus on local impacts and consider more granular geographic constraints of deploying resources in-Basin. The newly incorporated transmission lines (labeled as I, J, M, N, O, P in Figure 9) explicitly modeled power imports and exports from the LA Basin to add the granularity necessary to assess local transmission constraints.

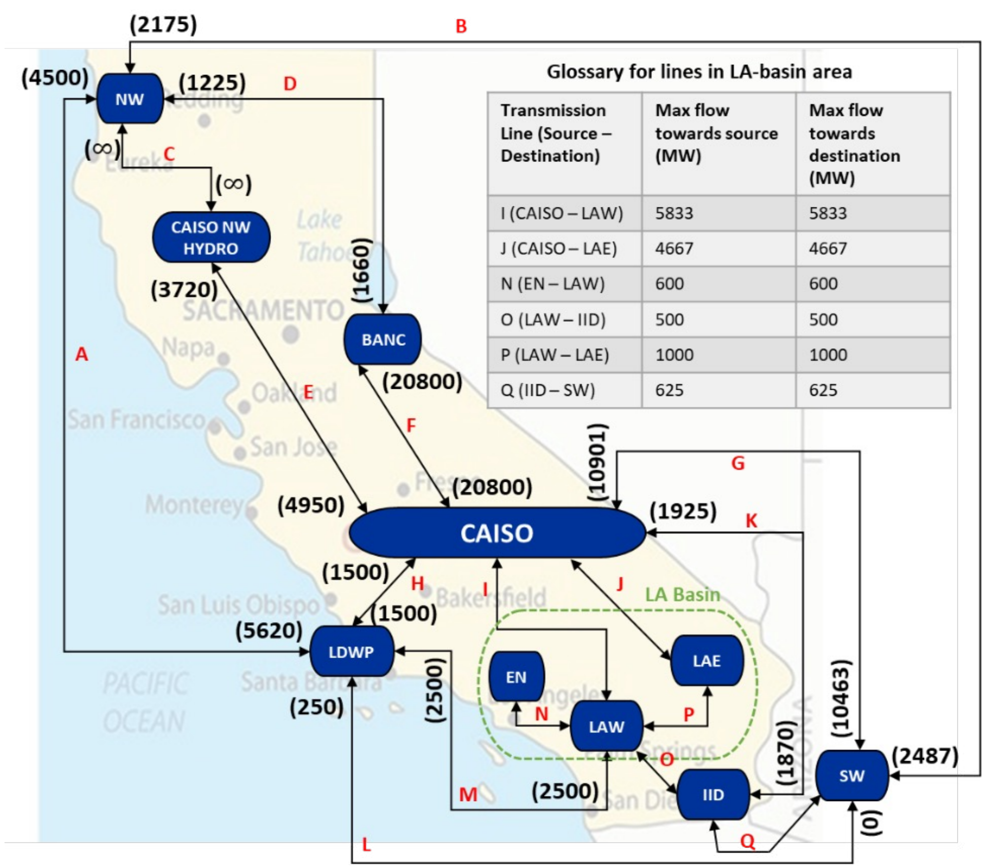

FIGURE 9: 10-Bus System Schematic, with Three Buses Representing the LA Basin
Source: PNNL

To determine the appropriate resource mix to potentially replace the region's fleet of natural gas plants, PNNL made significant modifications to the CPUC's existing dataset of candidate resources. Importantly, no new natural gas resources were allowed in either the LA Basin or the state at large. The clean energy resources selected to replace the natural gas peaker units were required to address both energy needs and local grid reliability, while meeting future decarbonization targets.

Further, to account for urban density planning concerns, PNNL limited new solar capacity in the LA Basin to approximately 35 MW per year, or 1,000 MW cumulatively during the planning horizon, to avoid possible overbuild. Likewise, the buildout for each storage technology option was limited to 1,000 MW per year, acknowledging supply chain limitations and other real-world factors. Considering the lack of land availability in the LA Basin, this constraint may still be too high for real-world resource deployment, but it was used to enable the modeling to provide directional guidance on the order of magnitude of energy storage resources necessary to replace all fossil peakers.

PNNL's analysis also aimed to understand what storage operational and performance characteristics will be needed to facilitate the mass retirement of fossil fuel resources in the LA Basin. The analysis covered a time horizon of 2022-2049 to determine how quickly these retirement goals can be achieved and whether it is feasible under California's decarbonization timeline. Table 3 lists the candidate technologies included in PNNL's analysis.

Technology	Roundtrip Efficiency	Minimum Duration	Maximum Duration	Power Cost[25,26] ($/MW)	Energy Cost ($/MWh)
4-hour battery	84.60%	1	4	Base ($109)	Base ($15,742)
10-hour battery	72.00%	10	24	x6	x0.25
100-hour battery	64%	100	200	x7.5	x0.125
8-hour/Flow battery	70%	1	8	x8	x0.62
Pumped Storage	81%	12	48	x10.1	x0.39

TABLE 3: Storage Technologies and Parameters included in PNNL Study. Costs are reflected as multipliers off the "Base" storage cost for a 4-hour battery.
Source: PNNL

To determine the optimal resource mix, the model simulated 37 representative days in each of the 11 "investment period" years[27] over the planning horizon. This approach was chosen to limit the computational intensity of the modeling process, and to maintain consistency with the CPUC's planning approach.

PNNL's modeled scenarios all adhered to the following constraints, in alignment with California policies:

+ 1. **California Carbon Cap:** By 2045, 90% of retail sales must be sourced from zero-carbon resources, based on California's Senate Bill 100 (CA SB 100).[28] Requiring 100% carbon-free electricity by 2045 was also considered in an Accelerated Decarbonization scenario, as described below.
+ 2. **Renewable Portfolio Standard:** The percentage of retail sales from qualifying renewable energy resources must meet the minimum annual targets set by California Senate Bill 350 (CA SB 350),[29] reaching 50% by 2030. An Accelerated Decarbonization scenario also considered the CA SB 100 target of reaching 60% renewable resources by 2030.
+ 3. **Planning Reserve Margin (PRM):** Resulting resource portfolios must meet CPUC's PRM of 14.9%, increasing to 22.55% in 2024.

25 Base Power and Energy costs are taken from National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB), 2021. Accessible at: https://atb.nrel.gov/electricity/2021/data
26 Strategen Consulting, 2020. Long Duration Energy Storage For California's Clean Reliable Grid.
27 "Investment period" years included 2022, 2023, 2024, 2025, 2026, 2028, 2030, 2032, 2035, 2040, and 2045.
28 California Senate Bill 100, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100
29 California Senate Bill 350, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

With these guiding constraints, PNNL developed several unique scenarios to assess a wide range of possible futures. The sensitivities address different retirement dates for gas plants, accelerated decarbonization from CA SB 100, the prospect of Diablo Canyon Nuclear Power Plant continuing operation, alternative cost assumptions, and potential transmission derates due to resiliency events.

+ 1. **Base Case:** All 8 GW of natural gas capacity in the LA Basin is scheduled to retire linearly between 2022 and 2045, with retirement dates included as an input to the model
+ 2. **Economic Retirement:** Retirement dates are decision variables, determined within the model based on economics
+ 3. **Accelerated Decarbonization:** Adjusts the Base Case to include more aggressive and earlier carbon constraints following CA SB 100
+ 4. **Diablo Canyon Remains Online:** Incorporates Base Case assumptions, but the 2300 MW nuclear plant in California continues operation through the entire study horizon
+ 5. **Alternative Storage Costs:** Explores alternative resource cost sensitivity scenarios, assuming storage costs are 25%, 50%, and 150% of those assumed in the Base Case 25%, 50%, and 150% of S1 costs.
+ 6. **Resilience Event:** With Base Case assumptions, models the impact of potential wildfires or related events using line deratings to reduce transmission line power carrying capability, altering import/export capability in the LA Basin

PNNL performed one additional scenario, modeling all 8760 hours in years 2022 and 2035, in contrast to the representative 37-day approach taken for the other cases, to understand how the hourly variability in load and renewable generation impacts the build-out of various storage technologies. However, PNNL's work to produce successful simulation runs for this scenario remains ongoing, due in part to the computational intensity and temporal requirements necessary to complete hourly simulation runs with multiple buses. While analysis of this scenario is thus far inconclusive with respect to the impact on determining the ultimate storage needs in the LA Basin, the lack of result is valuable from a planning perspective. Many planning processes today do not appropriately incorporate or model the role that LDES can play as a flexible capacity resource. In many instances, this limited representation of LDES is due to modeling complexities, and specifically, longer dispatch optimization horizons which can significantly increase the required computing power. As Commissions and utilities begin incorporating these technologies into their modeling practices, they will need to assess whether their software tools are sufficient from a computational, temporal, and analytical perspective

Modeling Results & Findings

PNNL's modeling analysis found that, in all completed scenarios, significant build-out of 45 GW of 4-hour storage, between 39-45 GW of 10-hour storage, up to 15 GW of 8-hour storage, and up to 13 GW of 100-hour energy storage is required to replace the energy and capacity shortfalls that would exist in the LA Basin if all natural gas resources are retired. In addition to storage, the model called for an increase of up to 5.5 GW of transmission capacity and an increase of 3 GW of solar capacity to ensure that sufficient energy is available to charge storage resources. The transmission capacity upgrades would likely be even higher if the amount of in-Basin storage was reduced due to land availability constraints.

Across all scenarios, the model used by PNNL selected both 4- and 10-hour storage at high rates, maxing out the total capacity of 1 GW per in-Basin sub-region per year for 4-hour storage, for a total of 45 GW in-Basin in every scenario. Four-hour storage alone is insufficient to replace all natural gas generation in the LA Basin, and

10-hour storage was the most economical option to serve load beyond what 4-hour storage could provide. Ten-hour storage was built nearly as much, in most years building 1 GW per sub-region for at least 39 GW total in-Basin in every scenario. The model tended to prefer these two technologies compared to 8- and 100-hour storage, primarily due to the lower cost of 4- and 10-hour options relative to alternative durations.[30] Importantly, these results also suggest that maximum durations of 10 hours may be sufficient for replacing aging, polluting fossil resources.

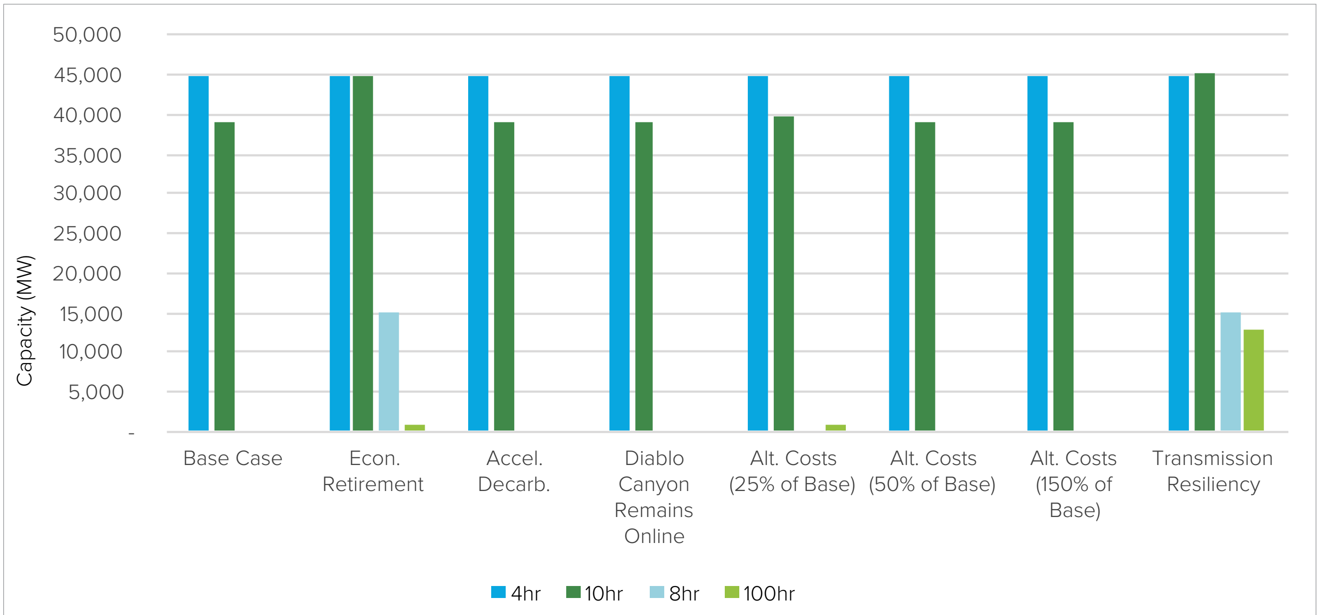

FIGURE 10: Total Storage Capacity installed in the LA Basin by Technology Type across each Scenario
Source: PNNL

The Base Case resulted in the total in-Basin deployment of 45 GW of 4-hour storage and 39 GW of 10-hour storage. These results were mirrored in the Accelerated Decarbonization scenario, as the Base Case already achieved the targets from SB 100. Similarly, the results in the Diablo Canyon Remains Online scenario were identical to the Base Case. This appears counterintuitive; however, it highlights the extent to which transmission constraints determine resource needs in the LA Basin, resulting in limited impact on in-Basin resource needs from the deployment of out-of-Basin resources. While energy storage deployment remained the same in-Basin, keeping Diablo Canyon online through 2045 resulted in approximately 10 fewer GW of energy storage required throughout the rest of CAISO.

The Economic Retirement scenario led to an additional 5 GW of 10-hour storage and 15 GW of 8-hour storage compared to the Base Case. When allowed to retire based on economics, inefficient gas plants are replaced earlier than in the Base Case, leading to some early additional storage build. Approximately 1 GW of natural gas capacity remains online at the end of the modeled period because those units have high efficiencies, which make them more cost-effective for serving load in the region. Interestingly, retaining this last GW of efficient natural gas capacity leads to an influx in additional 8-hour and 100-hour storage in 2045 as low-cost power from natural gas plants is available to generate and store more energy in the LA Basin.[31]

In PNNL's Alternative Storage Cost scenario, the 25% cost assumption led to the selection of substantially more 100-hour storage. This points to the prominent role that resource costs play in technology selection and reflects a more significant impact for certain technologies compared to others. However, the 50% cost scenario did not

30 It should be noted that the 8-hour storage assessed in the model was a flow battery, which is more expensive than other potential technologies with similar duration.

31 In this case, the longer 8-hour and 100-hour storage options are selected, because the model has already hit its limit for maximum buildout of the other durations. For more information, please refer to the Technical Appendix.

substantially change the selections relative to the Base Case, which indicates that longer-duration resources with lower round-trip efficiencies (RTEs) must achieve significantly lower costs to become competitive relative to shorter-duration resources with higher RTEs. As technologies continue to advance and costs decrease in the future, longer-duration options may have a larger role as part of an optimal portfolio of resources.

FIGURE 11: When transmission into LA Basin is further constrained, 100-hour storage is built in early years to provide added resiliency, along with new 8-hour storage and additional 10-hour storage
Source: PNNL

In the rest of the CAISO, storage build-out reaches an additional 35 GW in nearly every scenario. Broken down by technology, the analyses resulted in 10 GW of 4-hour storage, 5 GW of 10-hour storage, 15 GW of 100-hour storage, and 3 GW of 8-hour pumped hydro. In the scenario where Diablo Canyon does not shut down, this number drops to 27 GW overall due to the remaining nuclear capacity supporting energy and reliability. This scenario resulted in no change to storage deployment within the LA Basin. The stark difference in results when viewed at the state-level compared to the local-level further highlights the need for local granularity in the planning process.

Overall, PNNL's analysis highlights the need for a massive deployment of energy storage to replace fossil peakers in the LA Basin. While the exact level of deployment needed is tied closely to both transmission capacity and land availability, it is clear that significant capacity deployment of both short and long-duration storage technologies is critical to achieve California's clean energy and reliability goals. As shown through the sensitivities, transmission capacity plays a major role in the level of storage deployment. In resilience events with reduced transmission, even more storage is needed, while increasing the total transmission capacity may provide an alternative path to serving resource adequacy with fewer in-Basin resources.

The Challenge with California's Planning Paradigm

The series of analyses presented in the previous section illustrates how energy storage can support energy reliability and decarbonization in the LA Basin, one of California's most constrained areas. However, the current statewide planning process does not sufficiently account for these local reliability needs and transmission constraints, making it challenging to achieve renewable energy and equity goals while ensuring resilience in the region.

Limitations in California's IRP Process

One key limitation of the IRP process is that it is typically focused on the needs of the system as a whole with little consideration of local reliability area (LRA) needs. Because LRAs are geographic regions within the Commission's jurisdiction that are transmission and/or generation constrained, the needs for these areas may therefore differ from the overall needs of the system, requiring additional, targeted investment. As stated previously in this report, the LA Basin, including its three subareas, is one of the many LRAs within CAISO's footprint. Although the LA Basin faces unique challenges due to population density, urbanization, and economic scale, many of the decarbonization and reliability challenges identified in this analysis are common to other CAISO LRAs.

The reliability and decarbonization challenges laid out in this report highlight the importance of planning for local reliability and furthering decarbonization and pollution reduction in DACs, many of which are within LRAs. However, since the establishment of the IRP process in 2017, the Commission has refrained from studying specific LRA needs within the IRP's Planning Track, a decision that has affected procurement orders derived from the planning process. In 2021, the Commission issued Decision (D.) 21-06-035, which directed jurisdictional LSEs to procure 11,500 MW of incremental capacity, mainly from preferred resources, by 2028 to cure the shortfalls identified within the IRP process. The reach of this momentous order was unfortunately limited by the Commission's determination to solely require assets deliverable to the broader system (known as "System resources"), rather than direct a share of the assets to provide local benefits as "Local resources." In 2023, the Commission issued yet another Supplemental Mid-Term Reliability procurement order that adds an additional 4,000 MW of incremental capacity to be procured by jurisdictional LSEs. Due to the limitations of the Commission's modeling, this decision once again declined to order any form of locationally-specific procurement.

The lack of consideration of LRA needs within the IRP's planning and procurement activities can result in significant misalignments between the resources and infrastructure that are planned and deployed, and the opportunities for decarbonization in LRAs, leading to potential reliability issues and potentially higher costs for customers. Ignoring the needs of local reliability areas in long-term planning processes may also discourage the development of local generation resources, such as community solar projects, small-scale renewable energy projects paired with energy storage, and emerging technologies capable of providing firm power. Instead, this long-term planning omission leaves it up to other markets and regulatory frameworks to provide economic incentives for curing LRA deficiencies. In California, this responsibility falls squarely within the RA framework.

Another key limitation related to the current IRP modeling process stems from the temporal horizon used for optimizing new build decisions within the capacity expansion model. Today, RESOLVE co-optimizes new resource investment and dispatch for 37 independent days over a multi-year horizon to identify least-cost portfolios. This is inherently problematic to the valuation of storage, particularly LDES, which has the capability to move energy through storage over extended time periods, potentially across multiple days. RESOLVE's 37 representative days are not intertemporally linked with each other and are not modeled in chronological order. Therefore, storage balancing decisions are limited to a horizon of a single day. Given the model's current architecture, capacity additions are based on a simplistic dispatch schedule with no intra-hour or multi-day optimization. This severely limits the potential benefits to the grid that energy storage technologies would provide, as it excludes several of the intrinsic benefits of LDES that set it apart from other clean, firm resources. This is noted in research from the University of California (UC) Merced, which demonstrated that "the number of consecutive days for energy arbitrage changes the operation of storage."[32] The UC Merced study found that modeling longer time horizons, referred to as storage balancing horizons (SBHs), changes the role of low-cost LDES in CEM formulation.

A final challenge related to the CEM approach currently used by California agencies relates to the suite of solutions available for selection within RESOLVE. Currently, the only storage technologies modeled as candidate resources in RESOLVE are pumped storage hydropower (PSH), flow batteries, and lithium-ion batteries, with PSH being the only proxy of LDES. This constrained set of candidate resources is not representative of the diversity of the storage resource class, and it severely limits the potential benefits to the grid that would be provided by energy storage.

Fragmentation in the LSE Landscape

Just as planning methods and goals have become more complex, California's LSE landscape has also changed dramatically in recent years. In the past, most of California's load was served by the three major investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). These corporations owned and operated both the generation and distribution assets needed to serve their customers.

In recent years, there has been an increasing fragmentation of the LSE market in California due to the growth of community choice aggregators (CCAs), which are local government entities within IOU service areas that have formed to aggregate the electricity demand of their constituents and negotiate the procurement of electricity on their behalf.[33] Although IOUs are still responsible for the transmission and distribution of electricity, CCAs have the option to either purchase power from the wholesale market or develop their own generation resources, and they can offer customers a choice of electricity suppliers. The growth of CCAs has led to a shift in the LSE market in California, with more customers now being supplied by non-utility LSEs. This has resulted in a more complex and diverse market with multiple LSEs procuring power for customers within a single service territory. The increasing fragmentation of the LSE market and the growth of CCAs has made the Commission reevaluate several components of its RA framework, particularly as it relates to local RA.

Planning Inefficiencies in the RA Framework

Historically, procurement of Local resources has been costlier than System resources. In the current RA program, all resource characteristics are bundled, meaning that an LSE that contracts a given asset will be entitled to both its System and Local RA value. This element of the program presented few challenges in the 2000s and early 2010s, but in recent years IOUs noted that the expansion of CCAs has introduced new risks associated with this framework. Namely, IOUs were concerned that load migration might severely affect their RA requirements, thus creating significant risks for entering into long-term investments in LRAs. This issue is further exacerbated by the fact that, recognizing the difficult nature of procuring Local resources, Local RA requirements are set on a three-year forward basis, increasing the risk of stranded investments.

32 P.A. Sánchez-Pérez et.al. UC Merced, 2022, Effect of Modeled Time Horizon on Quantifying the Need for Long-Duration Storage, https://www.sciencedirect.com/science/article/pii/S0306261922004275#fig531

33 CCAs may be run by city or county governments directly or by third parties through contractual agreements.

In an attempt to mitigate these risks, the Commission instituted the Central Procurement Entity (CPE) framework.[34] The CPE framework designates PG&E and SCE as the central buyers of Local RA through their Transmission Access Charge (TAC) areas. The Commission adopted this framework as a means to facilitate the procurement of Local RA despite market fragmentation. As a result, SCE and PG&E, in their roles as CPEs, are responsible for coordinating the procurement of Local RA products on behalf of all of the LSEs that serve load in LRAs within the utilities' respective TAC areas. Critically, the CPE framework is also intended to help ensure that Local RA resources are procured at the lowest cost to consumers.

Although the CPE process was established to improve the efficiency and transparency of the RA procurement process in California, and to provide a more level playing field for all resources competing to provide RA products, it has significant limitations regarding both scope and authority. For example, the CPE framework currently only applies to the two largest utilities in the state and does not cover other LSEs, such as CCAs or municipal utilities. This means these LSEs are not subject to the same procurement process and may have more flexibility in procuring RA products. Another limitation is that, within this framework, PG&E and SCE do not have the authority to directly develop new resources or to make decisions about which resources should be procured. Rather, their role as CPEs is limited to coordinating the procurement process and aggregating the procured products into a single portfolio. This means that there is limited opportunity for PG&E and SCE, or other LSEs, to identify opportunities to retire and replace existing fossil assets with cleaner capacity resources.

Centralized procurement, through the RA process and the CPE framework, ultimately results in significant planning inefficiencies. Due to the limitations of these mechanisms, the current process has a tendency to encourage duplicative resource development at both the system and local levels, leading to a suboptimal portfolio of resources and missed opportunities to replace local polluting resources with cleaner options.

OTC Extensions

California has faced a number of challenges in retiring OTC power plants. Several of the aging fossil assets discussed in prior sections of this report are OTC plants, including Redondo Beach, Alamitos, and Huntington Beach, which are all more than 60 years old. OTC power plants can have significant environmental impacts, including the destruction of marine habitats, the entrainment and impingement of fish and other aquatic species, and the release of thermal pollution into waterways.

One of the primary challenges that California has faced in retiring OTC power plants is the lack of a clear and consistent policy framework for phasing out these facilities. While the state has adopted a number of policies and programs that aim to reduce the use of OTC power plants, there has been a lack of coordination and consistency in implementing these policies, leading to delays in the retirement of OTC facilities. Additionally, some of these facilities are owned by large, well-established utilities or other companies that have the resources to challenge retirement decisions in court or through regulatory processes.

Further, many OTC plants provide a significant portion of generation capacity in the state, and retiring them would require adequate flexible replacement resources, such as energy storage, to ensure reliability. Out of the nine OTC plants operating in California, six are located within the LA Basin local planning area, with five located directly in Los Angeles.[35] These plants are needed for local capacity, and their operations are limited to the hours of highest demand, yet they have disproportionate impacts on local air quality, especially in DACs.

34 Ellison Schneider Harris Donlan, 2022, CPUC Issues Decision Modifying the Central Procurement Entity Structure, http://eslawfirm.com/blog/cpuc-issues-decision-modifying-central-procurement-entity-st

35 California ISO, Local Capacity Technical Study, Page 2, 2022, http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf

Overview of the efforts to retire OTC power plants in California:

- **1970s:** The State Water Resources Control Board (SWRCB) began issuing National Pollutant Discharge Elimination System (NPDES) permits to OTC power plants, setting limits on the amount of water that could be withdrawn and the temperature of the discharged water.
- **1980s:** The SWRCB began requiring OTC power plants to conduct studies to evaluate the impacts of their operations on aquatic life.
- **1990s:** The CEC began requiring OTC power plants to demonstrate that they had considered alternative cooling technologies as part of the permitting process.
- **2002:** The California legislature passed SB 1078, which established a goal of reducing the use of OTC power plants in the state by 50% by 2020.
- **2009:** The CPUC adopted a rule requiring utilities to phase out the use of OTC power plants by 2020, unless the plants could demonstrate that they were using the “best available technology” to minimize their environmental impacts.
- **2018:** The CPUC adopted a rule requiring utilities to retire all OTC power plants by 2029, unless the plants could demonstrate that they were using the “best available technology” to minimize their environmental impacts.
- **2023:** The State Water Resources Control Board extended the compliance date for Alamitos Generating Station (Alamitos) Units 3, 4, and 5; Huntington Beach Generating Station (Huntington Beach) Unit 2; and Ormond Beach Generating Station (Ormond Beach) Units 1 and 2 for three years, from December 31, 2023, to December 31, 2026, to support system-wide grid reliability. The compliance date for Scattergood Generating Station (Scattergood) Units 1 and 2 was extended by five years, from December 31, 2024, to December 31, 2029, to support local system reliability.

IMAGE 1: Diablo Canyon Nuclear Power Plant
Source: http://calenergycommission.blogspot.com/2017/05/phase-out-looms-for-power-plants-that.html

Recommendations

This section focuses on recommendations for coordinating regulatory, modeling, and planning proceedings and initiatives across the State. In addition, this section provides actionable recommendations suited to address the challenges related to the lack of consideration of local reliability needs in the CPUC's IRP proceeding.

The CPUC IRP Process and the CAISO TPP Should be Further Integrated

From long-term planning for future resources in the CPUC's IRP proceeding, to identifying future transmission investments in the CAISO's TPP, California has sought to meet its State-level decarbonization goals by tasking different agencies with different facets of long-term planning. While this approach has worked for some cycles, the fragmented nature of the current framework allows for several opportunities for efficiency and improvement to go unnoticed. Tighter integration across the CPUC and CAISO planning processes is necessary to ensure that both energy resources and transmission resources are appropriately incorporated into planning processes. Today, the outputs of the CPUC's IRP proceeding are used to inform the CAISO's TPP. Each year, the CPUC communicates IRP-derived portfolios to the CAISO to perform their annual TPP. Despite existing linkages, once the CAISO completes their TPP assessments and identifies least-regrets transmission upgrades, the CPUC is once more tasked with finally approving these investments, resulting in significant delays due to this duplicative regulatory process. In this context, considering ways to minimize the administrative and regulatory back and forth of approving needed transmission investments could materially improve local reliability and local development of both generation and transmission assets. Moreover, this would help to increase focus on local reliability needs within the state's planning and procurement activities which could support the alignment between resources and infrastructure that are planned and deployed and opportunities for decarbonization in local areas.

The CPUC IRP Process Should Incorporate Local and System Planning

To date, one key limitation of the IRP process is that it is typically focused on the needs of the system as a whole, with little consideration of local reliability area needs. The IRP process must be able to plan for both system and local reliability needs, with collaboration from relevant stakeholders, mainly the LSEs and the CAISO. To this end, Strategen recommends that the CPUC improve the geographic granularity of CEM modeling to ensure that local decarbonization is done in a cost-effective manner. This is especially important as we enter the beginning stages of the CPE framework. Explicit modeling of LRAs will enable the CPUC to develop a portfolio that is sufficient to cost-effectively attain decarbonization goals at both a system and local level, as well as identifying investments needed to transition local reliability areas away from carbon-emitting capacity.

This modification would be highly beneficial for the planning of the future grid. By creating synergies between system and local planning within the IRP proceeding and with the RA proceeding, the CPUC could provide further certainty to stakeholders and systematically improve the modeling work done for both short- and long-term planning. In making this change, consistent assumptions and datasets should be leveraged by California's state-level planning agencies, including inputs and assumptions on power plant and system characteristics and operations, as well as data inputs or model constraints to accurately represent policy, utility plans, and industry trends at the state and regional level. The modeling tools leveraged by California's state-level planning agencies, which could include capacity expansion and production cost models, will only be as useful as the inputs and assumptions included in their analyses, making a thorough understanding of California's need and the broader energy ecosystem critical for the success of this process.

The CPUC IRP Process Should Model a More Comprehensive Portfolio of Storage Solutions

The CPUC should reassess the suite of solutions available to the grid and utilize an attribute-based approach to the different storage solutions that are deployable rather than simply expanding the list of storage technologies modeled as candidate resources. As noted previously, today the only storage technologies modeled are PSH, flow batteries, and lithium-ion batteries, with PSH being the only proxy of LDES. In order to expand the solution set without explicitly modeling each of the possible storage technologies, Strategen believes the CPUC could model storage solutions based on different durations, RTEs, and levelized costs, similar to the approach utilized in this report. Notably, this method allows for a technology-neutral variable-cost analysis of storage options, akin to research performed by UC Merced in 2022.[36] Strategen highly encourages the exploration of technology-neutral modeling since it is unclear which specific storage technologies will achieve the most significant cost and performance improvements in a market currently dealing with supply chain issues, interconnection woes, and support from the IRA. Ultimately, this approach can provide important insights for both public and private investments regarding the price points technologies like LDES should strive for in the coming years.

The CPUC IRP Modeling Methodology Should Incorporate Longer Optimization Horizons

As noted previously, research from UC Merced has demonstrated that "the number of consecutive days for energy arbitrage changes the operation of storage."[37] They found that modeling longer time horizons in CEM changes the role of low-cost LDES: the UC Merced model (SWITCH) selected storage assets with up to 10 hours of duration when allowed to optimize over a period of 7 consecutive days. When researchers increased the time horizon to 60 consecutive days, storage duration jumped to 200 hours. A time horizon of 365 consecutive days (8,760 hours) yielded storage selections of up to 630 hours in duration. Given these findings and considering the efforts Strategen and PNNL have put into developing an 8,760-hour CEM, we urge the CPUC to consider expanding the time horizon of RESOLVE to model 365 conservative days, in a concentrated effort to better understand the storage needs of the state.

The CPUC IRP Process Should Incorporate Improved Stakeholder Engagement

Regulators have an opportunity to incorporate stakeholder-driven modeling in their decision-making to ensure more robust planning that accounts for community needs and local development challenges. The following actions could empower stakeholders to complement utility-led modeling:

+ Making tools and data sets transparent and accessible, for example, by establishing data-access standards so that inputs and assumptions used in utility modeling can be easily reviewed and analyzed;
+ Establishing IRP rules that allow for stakeholder review and comment on the inputs and assumptions as early as possible in the planning process; and
+ Reducing cost barriers to stakeholders by requiring utilities to fund stakeholder licenses for their proprietary models, or by switching to free open-source models.

In particular, the CPUC should include and actively support greater participation from members of disadvantaged communities in the planning process. As discussed throughout this report, residents in disadvantaged communities are disproportionately impacted by the environmental and public health impacts from energy supply and use, and thus are significantly affected by energy policy and resource planning. Several states have developed programs and procedures to support the active participation of representatives in disadvantaged communities to improve regulatory decision-making, many of which could be replicated in California.

36 UC Merced, Materials for Long Duration Energy Storage Public Workshop #3, July 2022, https://efiling.energy.ca.gov/GetDocument.aspx?tn=244120

37 P.A. Sánchez-Pérez et.al. UC Merced, 2022, Effect of Modeled Time Horizon on Quantifying the Need for Long-Duration Storage, https://www.sciencedirect.com/science/article/pii/S0306261922004275#fig5

37 For example, see: Sec. 22a-20a. Environmental justice community, Connecticut Department of Energy and Environmental Protection, available at https://www.cga.ct.gov/current/pub/chap_439.htm#sec_22a-20a.

The CAISO and the CPUC Should Strive to Implement a Capacity Valuation Methodology That Captures Forced Outage Rates.

As noted previously in this report, since 2020, the CPUC and CAISO have been considering transitioning to an UCAP framework for capacity counting, which, contrary to the current NQC framework, would incorporate forced outage rates into the capacity valuation. This modification is desirable as it would provide a more accurate representation of a resource's capabilities. This type of analysis is particularly impactful for aging, inefficient, and unreliable fossil-fueled assets whose operational realities are far from what can be inferred based only on their nameplate capacity. The CAISO has previously proposed to determine an asset's capacity contributions based on a UCAP methodology that considers asset performance during the top 20% of hours of the year with the tightest supply conditions. While there is still opportunity to further revise this methodology since, for example, considering such a high number of hours per year (about 1,752) is uncommon across other U.S. markets, the development of a UCAP methodology is still desirable as it would alleviate regulatory risks associated with current counting practices that overestimate the reliability value provided by fossil-fueled resources.

The CEC Should Collaborate with the CPUC and the CAISO to Identify Local Areas Where Pilot, Demonstration, and Commercialization Efforts Related to LDES and Other Emerging Technologies Can Advance Replacement of Aging, Polluting Assets.

As the CPUC works on improving modeling and planning tools to effectively coordinate the decarbonization of local areas, the work of other agencies to build the operational experience and confidence in emerging technologies such as LDES will be equally important. As of 2023, the CEC has been tasked with considering ways to deploy over $350 million to spur the development and commercialization of LDES assets across the state. Deployment of these funds should be aligned with the goals of allowing LDES to demonstrate peaker replacement capabilities, particularly in transmission and/or generation-constrained settings. This can be achieved through proactive coordination between the CEC, CPUC, and CAISO, as well as the LSEs involved.

Pacific Northwest NATIONAL LABORATORY

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LA Basin Storage Scenarios

November 2022

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Abstract

This study constructs a 10-bus electric power system representing California and its major import/export neighbors based on data from the CPUC IRP Inputs to the 2021-2022 Transmission Planning Process[1]. The model is then studied using the Gridpath capacity expansion planning software to investigate investments across California, with specific interest in the LA Basin, over a 2022-2049 planning horizon. A primary focus of this study is to better understand the role of energy storage, as well as other generation resources, for high natural gas plant retirements in the LA Basin. To achieve this, seven different scenarios are developed, each testing the model's sensitivity to different parameters. Results for each scenario are reported with particular emphasis on storage investment and operations.

[1] (Commission, California Public Utilities Commission, 2021)

Summary

This analysis is built on the expansion planning model, GridPath by Blue Marble. GridPath is a versatile power system planning tool, incorporating capabilities including production cost modeling, capacity expansion modeling, asset valuation, and energy market modeling (Analytics, 2022). Within the GridPath toolset, the authors have built out a detailed nodal-zonal model for the state of California with a particular focus on the Los Angeles Basin (LA Basin). The model also incorporates nearby regions, effectively a zonal model of the Western Electricity Coordinating Council territory, with a more detailed representation of specific regions in California (i.e. the Los Angeles Basin).

The zonal-nodal model is based on the California Public Utilities Commission (CPUC) 2019 Planning Model. This is an expansion model developed by the CPUC using the RESOLVE toolset from E3[1]. The 2019 Planning Model is developed through a detailed and long-term stakeholder process to incorporate the existing system representation and develop realistic and stakeholder supported generation and transmission candidates across the state of California. It simplifies and aggregates generation across the areas of interest (California and the surrounding WECC regions), as well as transmission given it is a zonal model. A detailed characterization of the LA Basin in the model is built from information supplied by the California Independent System Operator (CAISO) in its transmission reliability planning documents. These documents include transmission system details as well as identification of specific generation resources within the LA Basin.

The driving function behind this analysis is the identification of clean energy resources, and in particular, energy storage and long-duration energy storage, to replace fossil infrastructure in the LA Basin over the time horizon 2022-2049. Much of this fossil infrastructure, almost exclusively natural gas, is relatively low-efficiency peaking units that are expensive and polluting. A significant component of them are located in disadvantaged and underserved communities, exacerbating pollution and other development issues in those areas.

High-level findings of this work include the following:

- The LA Basin, modeled with aggressive policy goals and is transmission constrained, will likely need significant investment in some combination of transmission, solar, and storage, if LAB gas is fully retired by 2045

- With lower storage costs, there is earlier energy storage buildout, and a preference to longer duration energy storage relative to shorter durations.

- Economic retirement for the scenarios under study results in significant retirement of natural gas units in the LAB.

- Explicitly modeling scenarios that would benefit from greater system resilience within the expansion planning incentivizes earlier storage investment.

- Extending the Diablo Canyon Nuclear plant lifespan when the LAB is transmission congested primarily affects investments outside of the LAB.

[1] (Commission, California Public Utilities Commission, 2021)

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1.0 Methodology Overview

The system under study is primarily based on the CPUC IRP Inputs to 2021-2022 Transmission Planning Process (TPP) (Commission, California Public Utilities Commission, 2021). The CPUC IRP inputs are typically run in the Renewable Energy Solutions Model (RESOLVE) developed by E3 (E3, 2022). RESOLVE is a Capacity Expansion Planning Software capable of both generation and transmission expansion but typically only used for Generation Expansion by the CPUC. The CPUC IRP Inputs represent the State of California and key import/export partners such as the Northwest and Southwest regions of the United States as a 7-bus system. This work enhances this model by including the Los Angeles Basin (LAB) as a new 3-bus model connected to the original 7-bus model though additional transmission representation bring the granularity of the California model up to 10 buses. The intent of this modification is to better represent a key load pocket of the California electric power grid with ageing gas plants.

The system is modeled in the Gridpath (Analytics, 2022) planning software as a linear program (LP) and solved using CPLEX version 22.1.0.0. GridPath is a versatile grid-analytics platform developed by Blue Marble Analytics. The platform integrates several power-system planning approaches -- including production-cost, capacity-expansion, and reliability modeling -- within the same software ecosystem. Gridpath can capture the effects on operations and the optimal resource portfolio, provision of ancillary grid services, interconnection, reliability requirements such as a planning reserve margin or local capacity requirements, and policies such as a renewables portfolio standard (RPS) or a carbon cap (Mileva, 2022).

The 10-bus California model considers both generation expansion and a limited amount of transmission expansion inside of the LAB basin and connecting the LAB to the rest of the California system. Of particular interest in this work is modeling the retirement of natural gas plants in the LA Basin over the 2022-2049 planning horizon. Additionally, both short, medium, and long-duration storage options are modeled to better understand how they might augment system operations if gas plant capacity is reduced through retirement in the future. The following sections will elaborate on many of the modeling details and assumptions briefly mentioned here.

1.1 Storage Candidates

Candidate storage technologys' efficiency, durations, power costs, and energy costs are listed in **Error! Reference source not found.**. Base power and energy costs are taken from (National Renewable Energy Laboratory, 2021) while multipliers of those costs come from (Strategen, 2020). 2022 30-year annualized base costs in **Error! Reference source not found.** are (17,109 $/MW, 15,742 $/MWhr).

Table 1: Battey Storage Parameters

Technology (Names in parenthesis indicate simulation names mapping to each technology)	Efficiency	Minimum Duration	Maximum Duration	$/MW	$/MWh
4 hour battery (BTM_Li_Battery,BatLi4, Battery, Li_Battery)	84.60%	1	4	Base	Base
10 hour battery (ES10)	72.00%	10	24	x6	x0.25
100 hour battery (ES100)	64%	100	200	x7.5	x0.125
Flow battery (ESFlow8, Flow_Battery)	70%	1	8	x8	x0.62
Pumped Storage (PSH12, Pumped_Storage)	81%	12	48	x10.1	x0.39

1.2 Retirements

For most scenarios retirements of gas plants are parameterized, meaning chosen exogenously by the user. In these scenarios, all LA Basin gas plants are linearly retired throughout the planning horizon. It is noted that the retirement decisions for this capacity type are 'linearized,' i.e. the optimization may retire generators partially (e.g. retire only 200 MW of a 500-MW generator). If retired, the annual fixed O&M cost of these projects is avoided in the objective function.

Additionally, a linear economic retirement is tested on all gas plants in the LAB, meaning they are retired endogenously. When modeling this way Gridpath makes the decision to retire generation in each study period based on their operational costs. Retirement decisions for this capacity type are 'linearized,' i.e. the optimization may retire generators partially (e.g. retire only 200 MW of a 500-MW generator). If retired, the annual fixed O&M cost of these projects can be avoided in the objective function.

1.3 Generation

The generation fleet representation outside of the LAB is an aggregation primarily based on the CPUC IRP Inputs to 2021-2022 Transmission Planning Process (TPP) (Commission, California Public Utilities Commission, 2021). Generation parameters are primarily based on the CPUC resolve dataset and where applicable the NREL 2021 ATB, particularly for cost data. Disaggregated LAB generation capacities are estimated from the Net qualifying Capacities listed in the 2022 LCTS Attachment A, and their capacity is subtracted out of the CAISO region in the CPUC IRP inputs.

Significant modifications beyond the CPUC dataset include the following:

- Natural gas generation candidates are not allowed in either the LAB or greater CA model. Within the LAB only, solar and storage candidates are allowed.

- Annual LAB investible solar capacity is limited to ~35 MW per year per area (1000 MW per area cumulative during the horizon). Given the LAB is an urban area, a low MW capacity limit for solar was chosen, however, greater consideration of space constraints and land use might be utilized to improve upon this estimate.

- Each storage candidate in the LAB is limited to 1000 MW of capacity per year at each bus.

- Li-Ion candidates provided by the CPUC and attached to CAISO are removed and replaced by a single battery candidate with 2000 MW of capacity allowed per year.

- Candidate technologies in CAISO are capped at 1000 MW of investment per year if the CPUC dataset indicates their resource capacity is less than 10,000 MW. Candidate technologies in CAISO are capped at 2000 MW of investment per year if the CPUC dataset indicates their resource capacity is greater than 10,000 MW.

- The purpose behind adding annual capacity limits to the data was that initially results indicated significant investment in the final time period. However, while the Gridpath optimization may consider this the most economic solution, the reality of supply chain limitations would likely never let this happen. Thus, capacity limits were developed not necessarily to limit the total capacity of the generation technologies but rather to cap the annual investment allowed to avoid large investments in the final time period of the simulation.

1.4 Transmission

The transmission model for this analysis has been developed largely from CPUC (Commission, California Public Utilities Commission, 2021). Modifications have been incorporated to expand the network in a manner such that the LAB region is segregated from the CAISO zone. The LAB area is further disaggregated into three separate nodes – (a) Los Angeles West (LAW), (b) Los Angeles East (LAE) and (c) the El Nido area (EN). The assumed transmission topology is given in the figure given below.

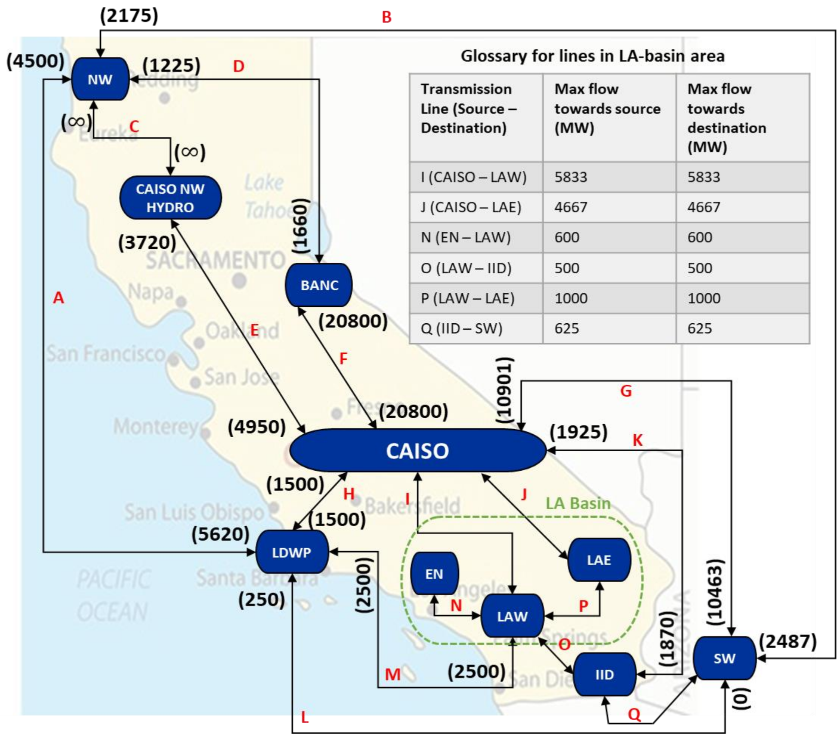

Figure 1: Schematic representation of the assumed transmission network

The connectivity model (through transmission lines) has also been retained largely from the CPUC RESOLVE model, with some minor modifications made, which are necessitated by the disaggregation of the CAISO node, as explained earlier. The newly added transmission lines (I, J, M, N, O, P) explicitly model power imports and exports from the LAB area. The lengths and electrical characteristics of all transmission lines in our model are approximated based on their rough geographic locations and standard per unit impedance values for 345 kV lines (Kundur & Malik, 2022), respectively. The assumed cost for Candidate lines is 2 Million USD/mile (WECC report , 2022)while the operations and maintenance (O&M) cost is 10,000 USD/mile (Council, 2017). For the transmission lines, we assume an overall lifetime of 35 years and the costs for transmission build and O&M are annualized for the analysis, assuming a 5% annual discount rate.

1.5 Temporal Modeling

All scenarios modeled in this study, with the exception of S5 (8760-hour model), use a 37-day,11-year model. A planning horizon of 2022 to 2049 is considered, with the 11 investment periods chosen being 2022, 2023, 2024, 2025, 2026, 2028, 2030, 2032, 2035, 2040 and 2045.

Although modeling all 365 days for each of the 11 years would yield the best temporal modeling fidelity, it would also be computationally intractable. In the interest of balancing computational complexity with modeling fidelity, 37 representative days are chosen for each year based on the 37 days in the RESOLVE dataset. 24 hours are modeled for each day, with each hour considered as a timepoint modeling multiple hours of the year. Load and renewable generation profiles are obtained from the RESOLVE dataset to reasonably represent conditions at each timepoint.

The 8760-hour model in S5 is an attempt at modeling load and renewable generation hourly for all 365 days in a year, with only two years (2022 and 2032) modeled in order to maintain reasonable simulation runtimes. This scenario is described in detail in section 3.5 of this report.

1.6 Policy Constraints

Carbon policy constraints are applied to the model based on carbon legislation in the state of California. These are modeled as hard constraints, that is, they cannot be violated. The implemented policy constraints take two forms:

1. Carbon cap: A limit to 90% of retail sales being from zero-carbon resources by 2045 (AB 32 and following executive orders).

2. Renewable Portfolio Standard: Minimum retail sales requirements by year from qualifying renewable energy resources, 50% renewables by 2030 (CA SB 350).

A second, more limiting scenario, is also modeled which builds on California legislation SB100.[1] This requires:

1. Carbon cap: 100% carbon-free electricity by 2045.

2. Renewable Portfolio Standard: 60% from renewable resources by 2030.

In addition, carbon limits are applied to the Northwest based on state policies in Washington and Oregon, and a transmission imports carbon intensity is applied to imports from the Southwest (e.g., AZ, NM, NV).

1. Carbon cap for the NW: 100% carbon-free electricity by 2045 (can be violated by paying penalties)

2. Transmission imports intensity from the SW of 0.6 tons/MWh[2]

These constraints are implemented in GridPath's policy module. Additional details about the policy module can be found in GridPath user documentation.[3]

1.7 Reserves

1.7.1 System Planning Reserve Margin

System Planning Reserve Margin in Resolve database in CAISO is applied to our base case. The System Planning Reserve Margin requirements are given in the table below. Many other areas will use the CAISO system PRM requirement. It is noted that the Reserve Margin Requirement in resolved database is based on the CPUC IRP Inputs to 2021-2022 Transmission Planning Process (TPP).

[1] https://focus.senate.ca.gov/sb100/faqs and https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100
[2] Based on emissions intensities as reported by the Electricity Information Administration https://www.eia.gov/environment/emissions/state/
[3] https://gridpath.readthedocs.io/en/stable/

Table 2: Planning Reserve Margin Requirements

Reliability_constraint	Period	Period planning reserve margin (%)
CAISO_PRM	2022	0.149
CAISO_PRM	2023	0.149
CAISO_PRM	2024	0.225467759
CAISO_PRM	2025	0.225467759
CAISO_PRM	2026	0.225467759
CAISO_PRM	2028	0.225467759
CAISO_PRM	2030	0.225467759
CAISO_PRM	2032	0.225467759
CAISO_PRM	2035	0.225467759
CAISO_PRM	2040	0.225467759
CAISO_PRM	2045	0.225467759

1.7.2 System Operational Reserve

System operational Reserve in Resolve database in CAISO is applied to our base case. The system Operational Reserve includes regulation up/down service and system frequency response service. All natural gas generation candidates in CAISO are used to participate and provide system Operational Reserve.

2.0 Simulation Scenarios

In this work, we evaluate the following different scenarios:

S1 (Base Case): Scheduled retirements

- All gas in the LAB is retired linearly between 2022 and 2045 ~ 8GW
- All retirements are parameterized

S2: Economic Retirement

- Same as S1 except for retirement schedule between 2022-2045 based on economics
- Retirements are decision variables

S3: Accelerated Decarbonization

- Same as S1 except for more aggressive and earlier carbon constraints

S4: Diablo Canyon never retires

- Same as S1 except 2300 MW nuclear plant in California never retires in this scenario.

S5: 1-2 year, 8760-hour per year expansion plan (only scenario incomplete)

- Same as S1 except the intra-year time horizon has significantly more resolution Load/renewable profiles that come from a different source than S1

S6: Alternate cost assumptions

- Same as S1 except battery costs modified to 25%, 50%, and 150% of S1 costs.

S7: Resilience Event

- Same as S1 except models impact for wildfires using reduced transmission line power carrying capability (derated lines).
- Line deratings impacting LAB import/export capability

2.1 S1: Base Case

Table 3: Investment and durations by year and location and technology

		mw											hours										
	vintage	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
technology	load_zone																						
Biomass	CAISO	1000	146.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Advanced_CCGT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Aero_CT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Reciprocating_Engine	CAISO	255.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	CAISO	0	100	0	0	0	1955.1	277	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore_Wind	CAISO	0	0	0	0	0	195	3607	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	CAISO	2216.6	1672.2	3454.8	11678	0	1315.6	6259.7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	35.7	35.7	35.7	35.7	71.4	71.4	71.4	107.1	178.6	178.6	178.6	0	0	0	0	0	0	0	0	0	0	0
	LAE	35.7	35.7	35.7	35.7	71.4	71.4	71.4	107.1	178.6	178.6	178.6	0	0	0	0	0	0	0	0	0	0	0
	LAW	35.7	35.7	35.7	35.7	71.4	71.4	71.4	107.1	178.6	178.6	178.6	0	0	0	0	0	0	0	0	0	0	0
Wind	CAISO	902.8	95.7	3170.5	1149.9	3000	0	0	12000	17351.6	16090.4	20000	0	0	0	0	0	0	0	0	0	0	0
BTM_Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BatLi4	CAISO	0	0	0	0	0	0	0	0	0	0	10000	0	0	0	0	0	0	0	0	0	0	4
Battery	EN	0	0	0	0	0	0	0	0	5000	5000	5000	0	0	0	0	0	0	0	0	4	4	4
	LAE	0	0	0	0	0	0	0	0	5000	5000	5000	0	0	0	0	0	0	0	0	4	4	4
	LAW	0	0	0	0	0	0	0	0	5000	5000	5000	0	0	0	0	0	0	0	0	4	4	4
ES10	CAISO	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	24
	EN	0	0	0	0	0	0	0	0	0	5000	5000	0	0	0	0	0	0	0	0	0	24	24
	LAE	0	0	0	0	0	0	0	0	5000	5000	5000	0	0	0	0	0	0	0	0	24	24	24
	LAW	0	0	0	0	0	0	0	0	4000.7	5000	5000	0	0	0	0	0	0	0	0	24	24	24
ES100	CAISO	0	0	0	0	0	818.9	2000	0	2002.8	5000	5000	0	0	0	0	0	100	134.6	0	65.4	100	150.4
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESFlow8	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flow_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSH12	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumped_Hydro	CAISO	0	0	0	0	0	0	0	0	0	0	2900	0	0	0	0	0	0	0	0	0	0	48
trans	CAISO_LAE_NEW	0	0	0	0	0	0	2000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAISO_LAW_NEW	0	0	0	0	0	0	2000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN_LAW_NEW	0	0	0	0	0	0	147.6	0	0	0	466.5	0	0	0	0	0	0	0	0	0	0	0
	LAW_LAE_NEW	0	0	0	0	0	0	863.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

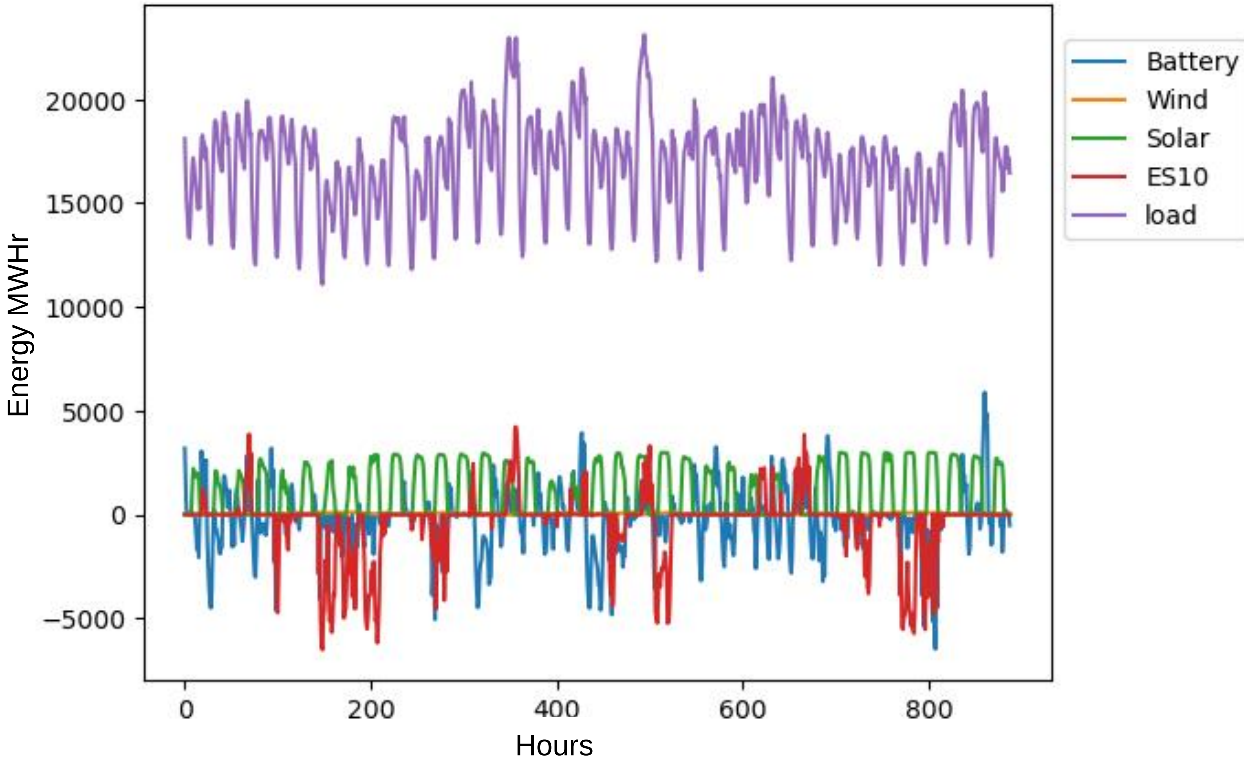

Figure 2: LAB dispatch by technology in 2045

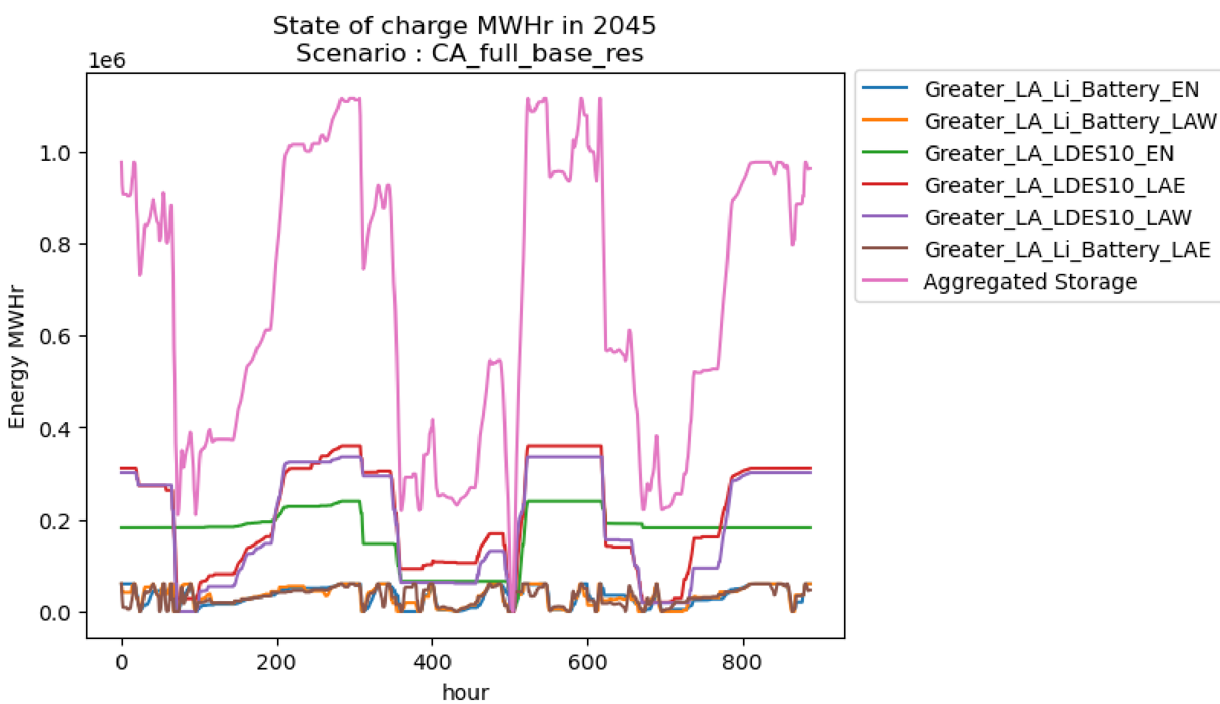

Figure 3: Battery State of Charge, aggregated and by technology & area in LAB

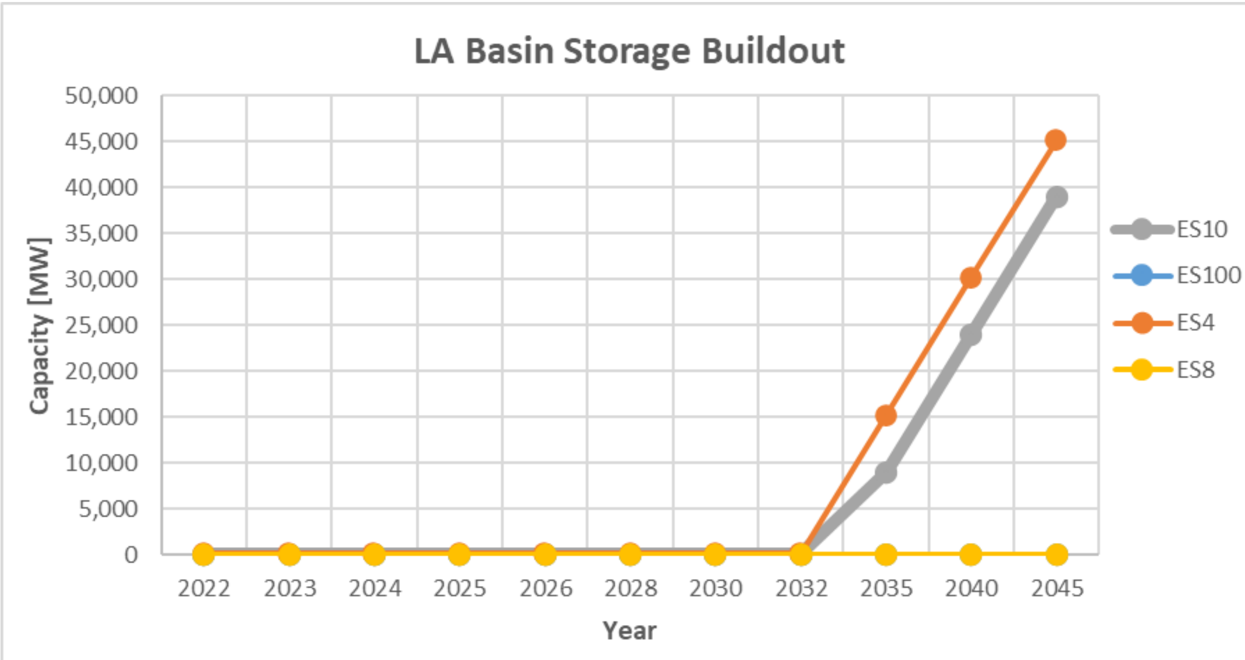

Figure 4: Cumulative Storage by area in and year.

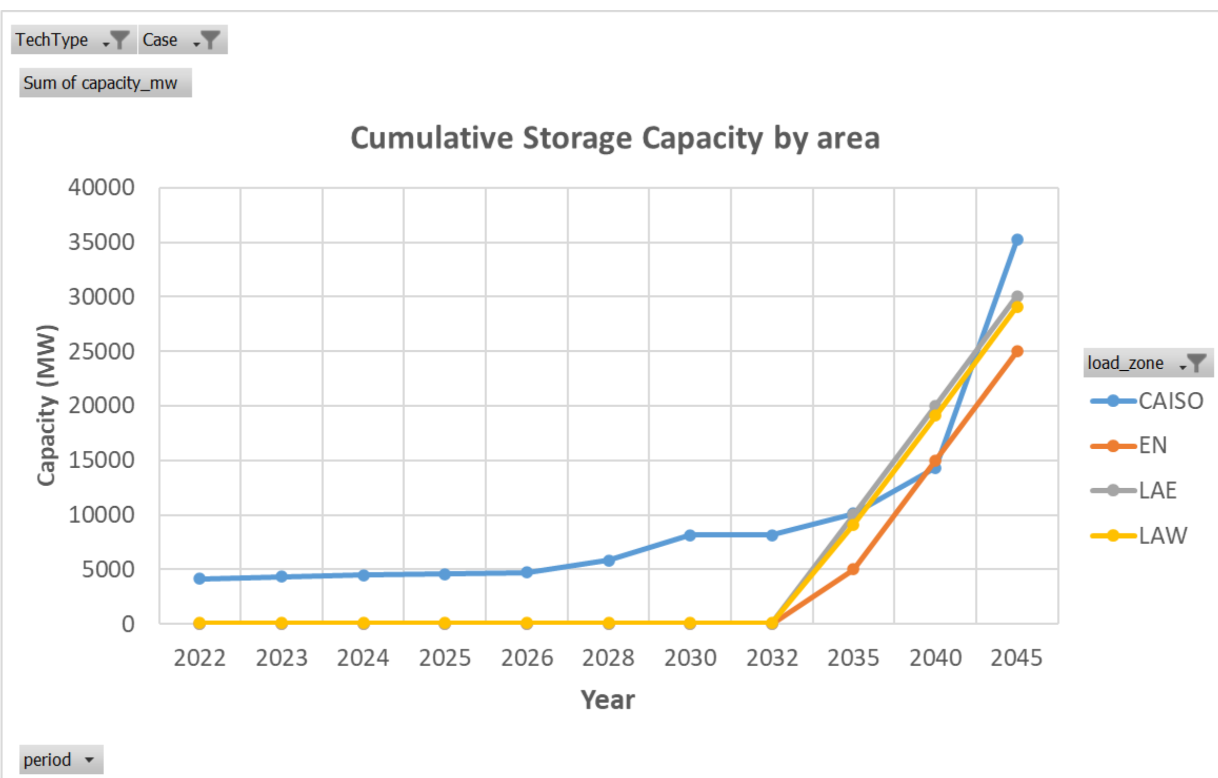

Figure 5: Cumulative Storage in LAB by year and technology

S1 is the base case scenario to which all other scenarios are compared. In S1 we observe significant 4-hour and 10-hour storage in the LAB. Furthermore, each LAB area hits its 1,000 MW capacity limit. In terms of transmission, both lines connecting the LAB to the rest of California hit their maximum capacity limit indicating that LAB, for the chosen model parameters, is significantly constrained by 2045 in serving load.

2.2 S2: Economic Retirement

Table 4: Investment Comparison of Scenario 2 and Scenario 1.

		mw											hours										
	vintage	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
technology	load_zone																						
Biomass	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Advanced_CCGT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Aero_CT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Reciprocating_Engine	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	CAISO	0	0	0	0	0	-21.8	21.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore_Wind	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	CAISO	0	0	-37.5	-188.7	0	69	207.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	CAISO	0	0	0	0	0	0	0	0	344.6	-344.6	0	0	0	0	0	0	0	0	0	0	0	0
BTM_Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BatLi4	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battery	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ES10	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	24	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	999.3	0	0	0	0	0	0	0	0	0	0	0	0	0
ES100	CAISO	0	0	0	0	0	-24.6	0	0	-2.3	0	0	0	0	0	0	0	0	0.1	0	-0.1	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	243.8	0	0	0	0	0	0	0	0	0	0	200
	LAW	0	0	0	0	0	0	0	0	0	0	665.4	0	0	0	0	0	0	0	0	0	0	200
ESFlow8	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	8
	LAE	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	8
	LAW	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	8
Flow_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSH12	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumped_Hydro	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans	CAISO_LAE_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAISO_LAW_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN_LAW_NEW	0	0	0	0	0	0	21.6	0	0	0	-54.6	0	0	0	0	0	0	0	0	0	0	0
	LAW_LAE_NEW	0	0	0	0	0	0	0	0	0	0	77.3	0	0	0	0	0	0	0	0	0	0	0

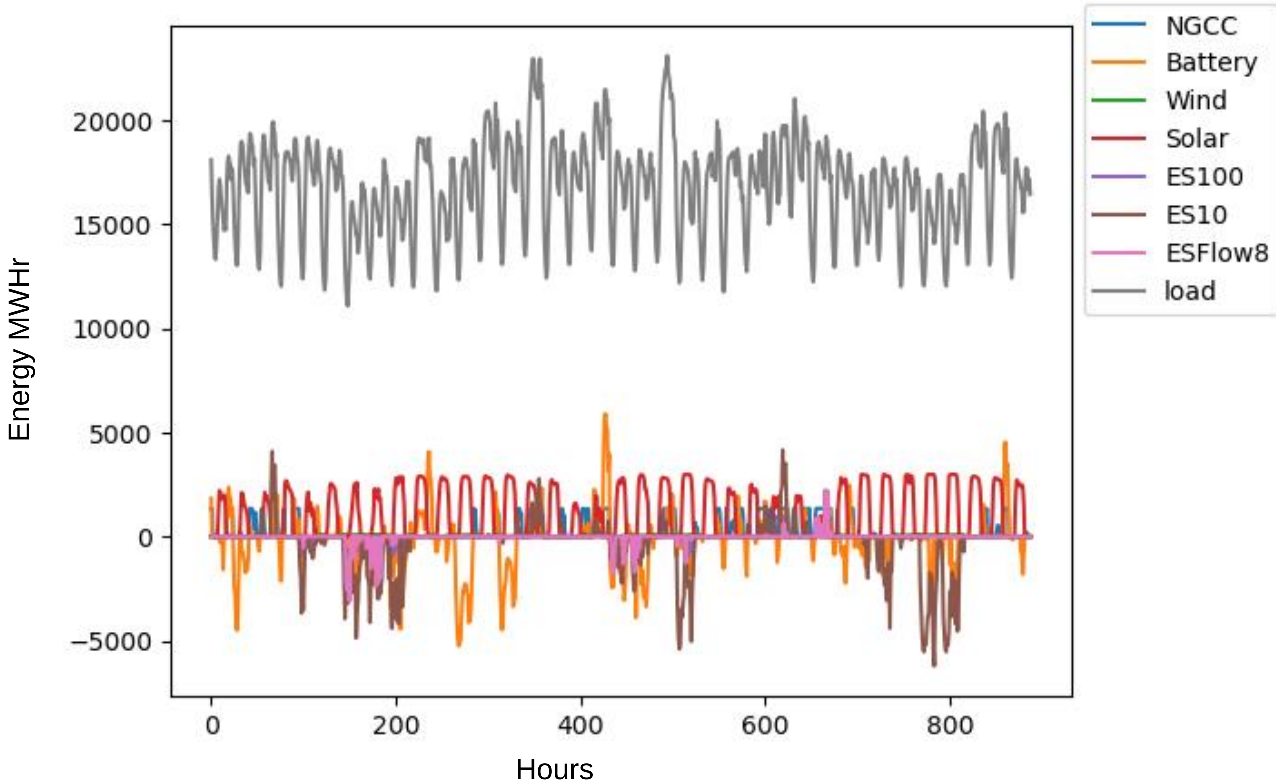

Figure 6: LAB dispatch by technology in 2045

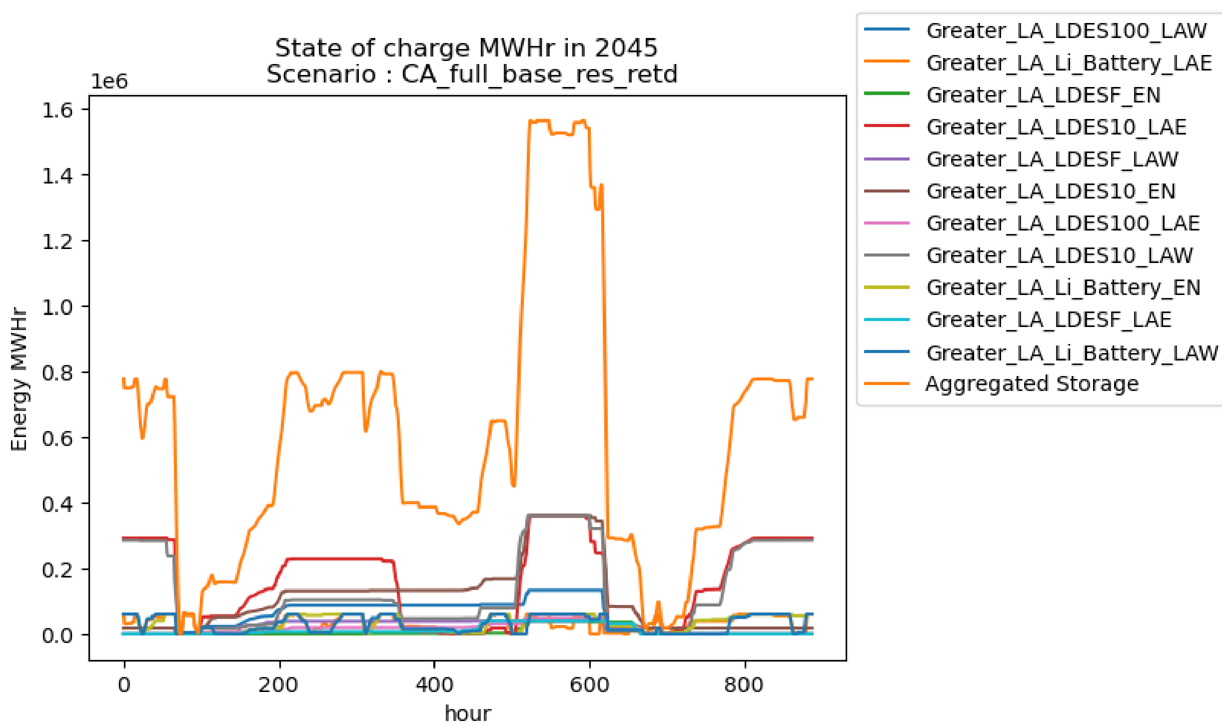

Figure 7: Battery State of Charge, aggregated and by technology & area in LAB

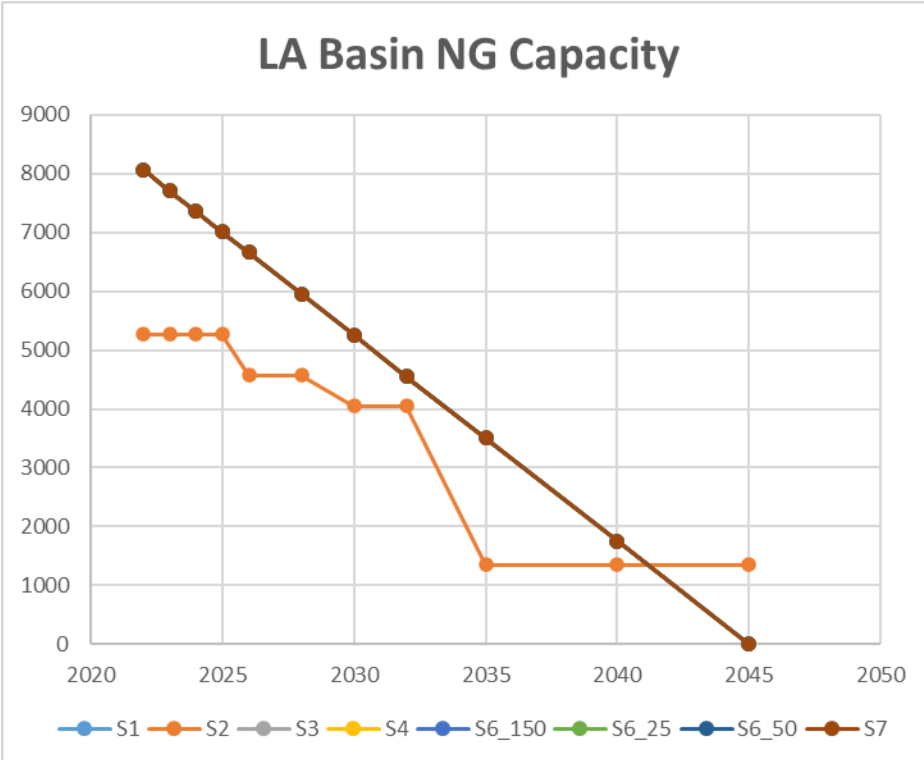

Figure 8: Retirements of S2 vs S1, S3-S7 (represented by straight line as they identical).

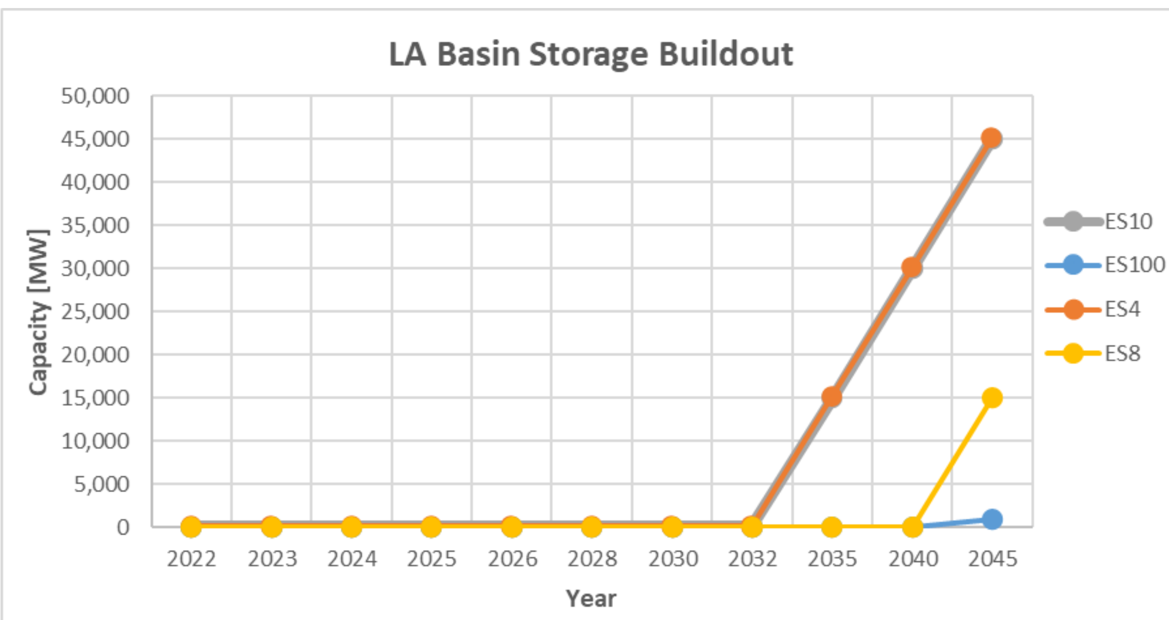

Figure 9: Storage buildout by technology types in LAB, across the years (2022-2045)

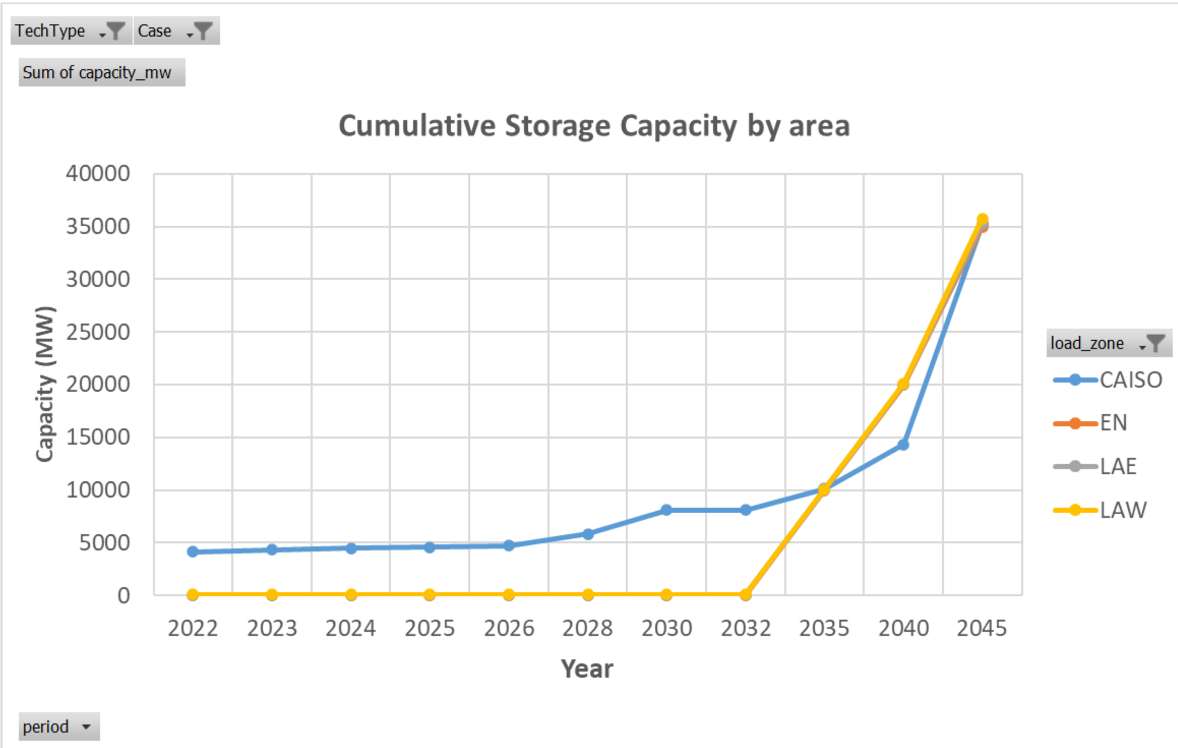

Figure 10: Storage buildout by area across the years (2022-2045)

In S2, it is observed that retirements occur faster than in the base case initially but not as much gas retires by the end of the planning horizon. Over a GW of gas plants do not retire by 2045. The earlier retirement of gas plants likely results in the earlier 2035 storage investment with respect to the base case. Furthermore, the late 2045 surge of storage investments with respect to the base case may be taking advantage of the efficient heat rate gas plants that are not retired in the LAB system.

2.3 S3: Accelerated Decarbonization

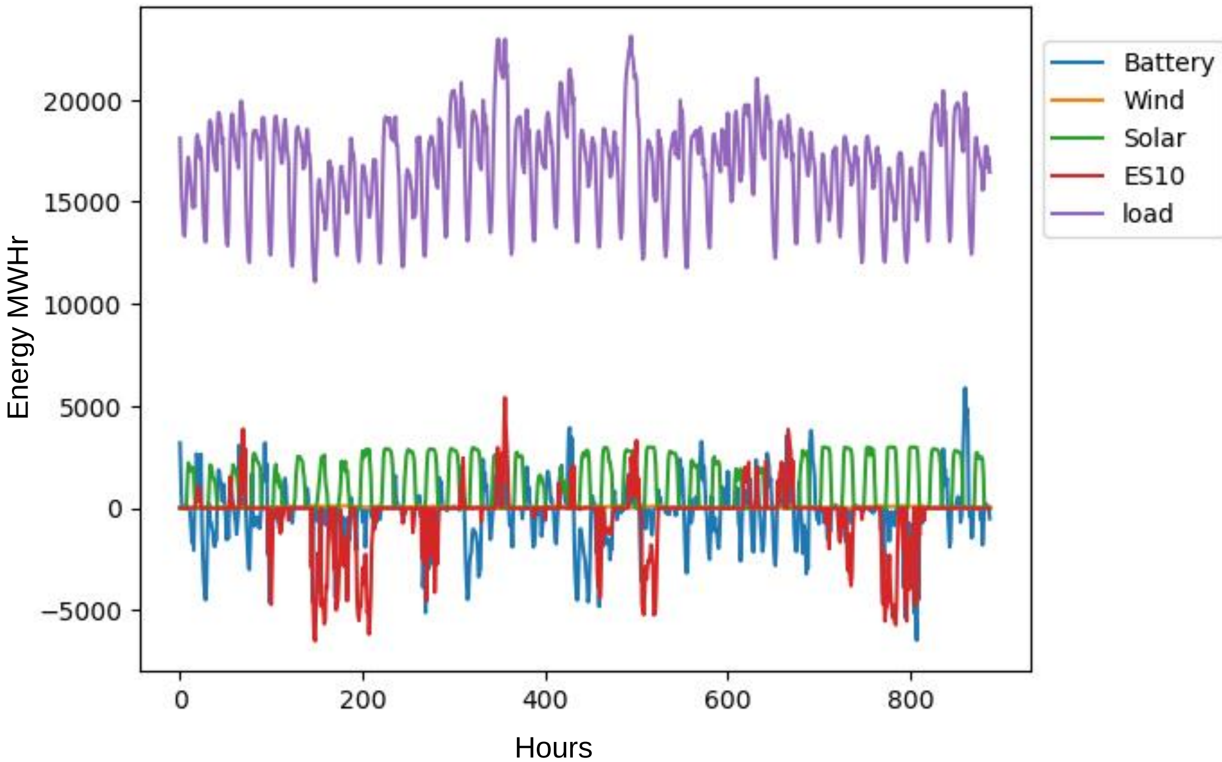

Figure 11: LAB dispatch by technology in 2045

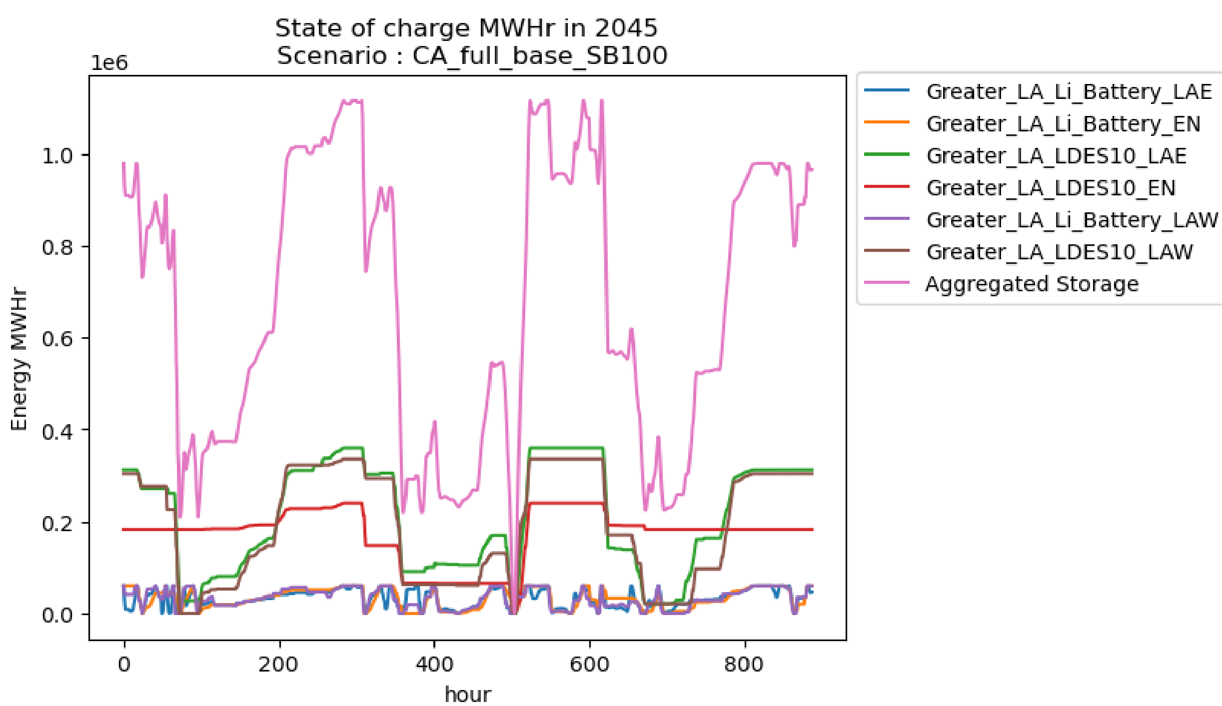

Figure 12: Battery State of Charge, aggregated and by technology & area in LAB

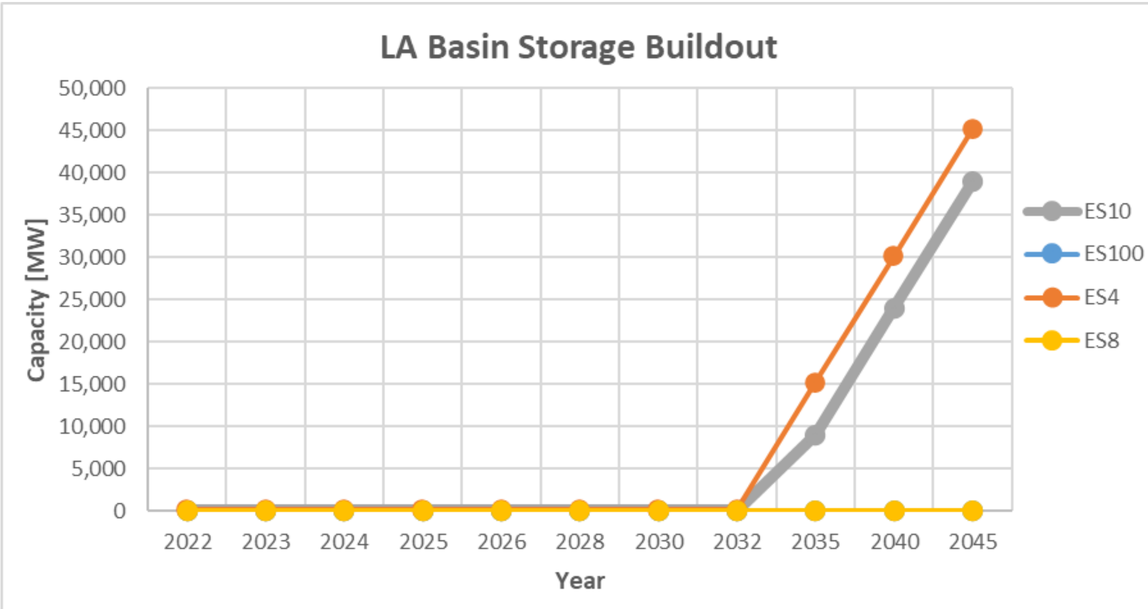

Figure 13: Storage buildout by technology types in LAB, across the years (2022-2045)

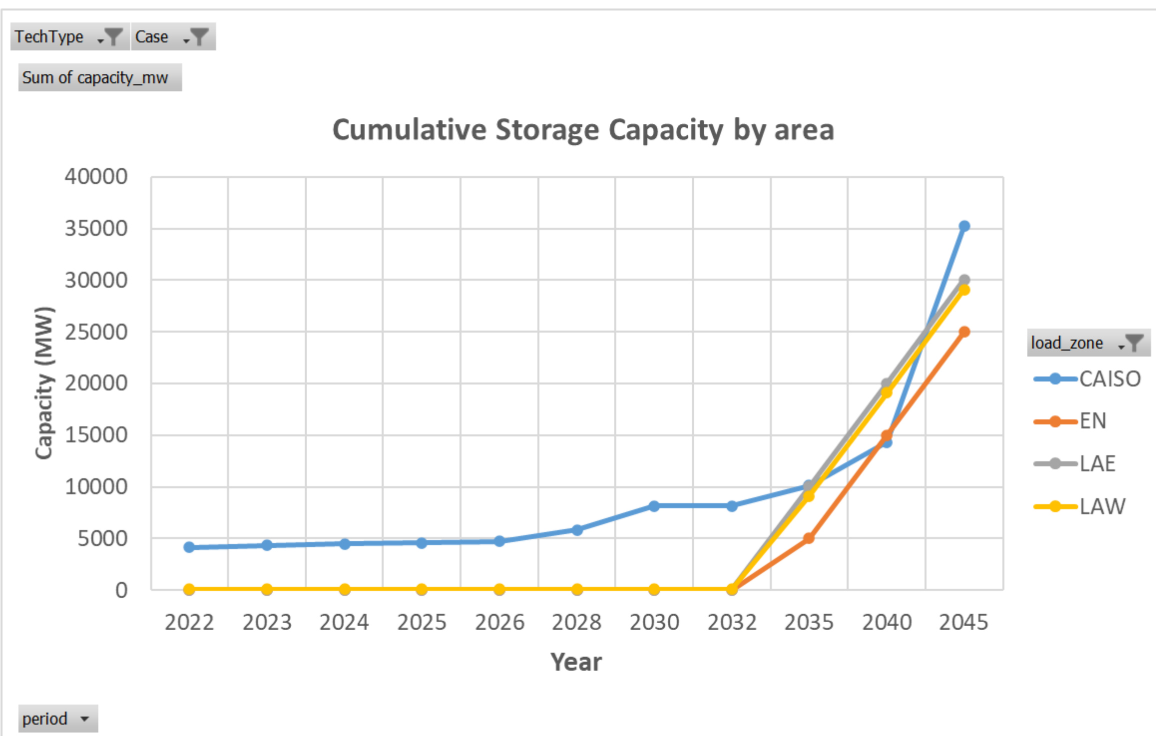

Figure 14: Storage buildout by area across the years (2022-2045)

The scenario 3 is the accelerated decarbonization scenario from “SB 100” policy. SB 100 would accelerate the state’s current RPS program to 50% by 2025, 60% by 2030. In addition, SB 100 sets a 100% clean, zero carbon, and renewable energy policy for California’s electricity system by 2045. It further requires state agencies regulating energy, clean air, and climate to implement the policy in all proceedings authorized under law. The Scenario 3 represents a scenario with much more aggressive decarbonization target than the base case scenario 1.

In terms of the simulation, we see similar investment and durations by year in scenario 1 and scenario 3 as we shown in Table 3. The reason is because the investment and duration in scenario 1 already meet the “SB 100” policy requirement in period energy target.

2.4 S4: Diablo Canyon

Table 5: Investment Comparison of Scenario 4 and Scenario 1.

		mw											hours										
	vintage	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
technology	load_zone																						
Biomass	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Advanced_CCGT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Aero_CT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Reciprocating_Engine	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	CAISO	0	0	0	0	0	-1787	1787	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore_Wind	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	CAISO	0	0	-2476.2	-10764.6	9	9088.9	-3881.2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	CAISO	0	0	-1605.8	400.5	0	1205.3	0	0	-133.1	133.1	0	0	0	0	0	0	0	0	0	0	0	0
BTM_Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BatLi4	CAISO	0	0	0	0	0	0	0	0	0	0	-6300.8	0	0	0	0	0	0	0	0	0	0	0
Battery	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ES10	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ES100	CAISO	0	0	0	0	0	-818.9	-2000	0	-2002.8	0	0	0	0	0	0	0	-100	-134.6	0	-65.4	0	-20
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESFlow8	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flow_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSH12	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumped_Hydro	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans	CAISO_LAE_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAISO_LAW_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN_LAW_NEW	0	0	0	0	0	0	-9.2	0	0	0	9.2	0	0	0	0	0	0	0	0	0	0	0
	LAW_LAE_NEW	0	0	0	0	0	0	-35.8	0	0	0	28.5	0	0	0	0	0	0	0	0	0	0	0

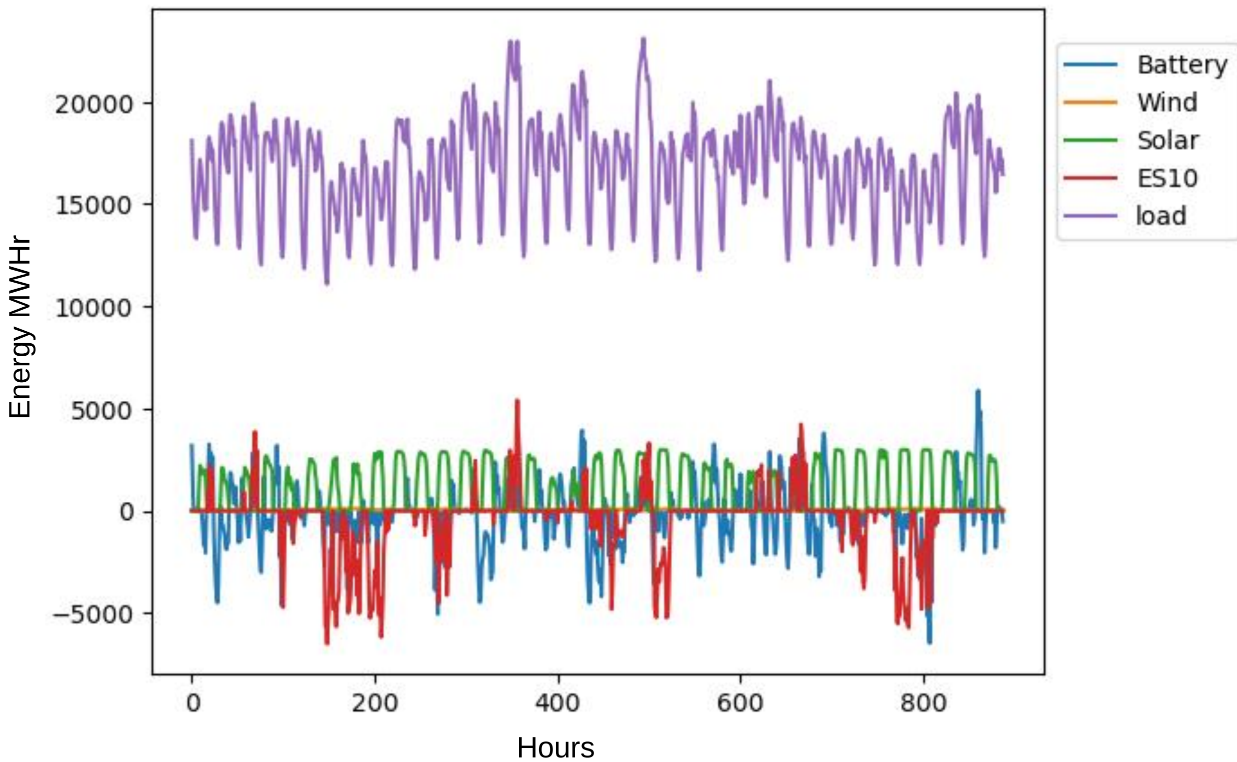

Figure 15: LAB dispatch by technology in 2045

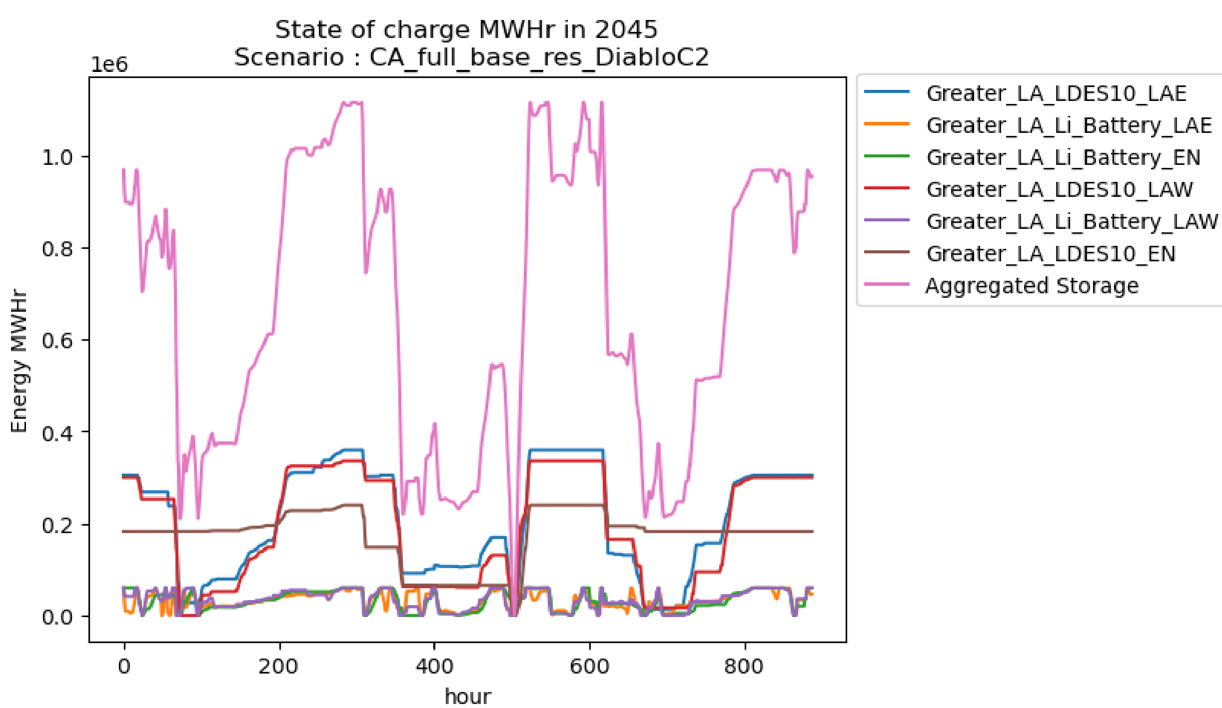

Figure 16: Battery State of Charge, aggregated and by technology & area in LAB

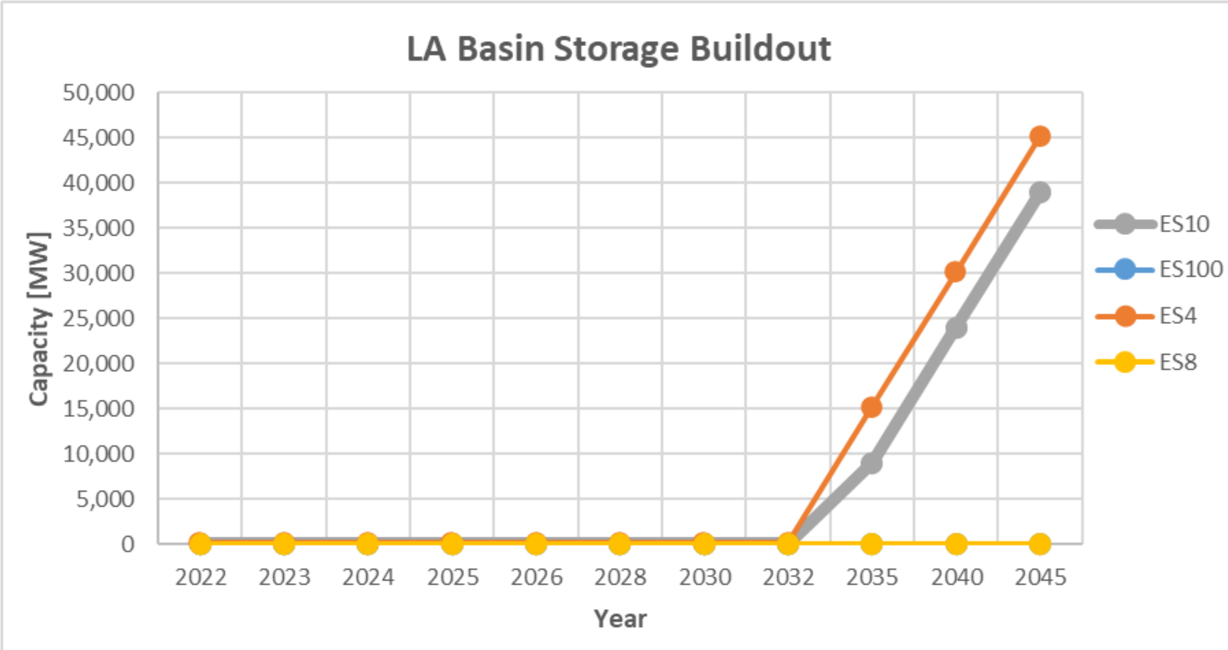

Figure 17: Storage buildout by technology types in LAB, across the years (2022-2045)

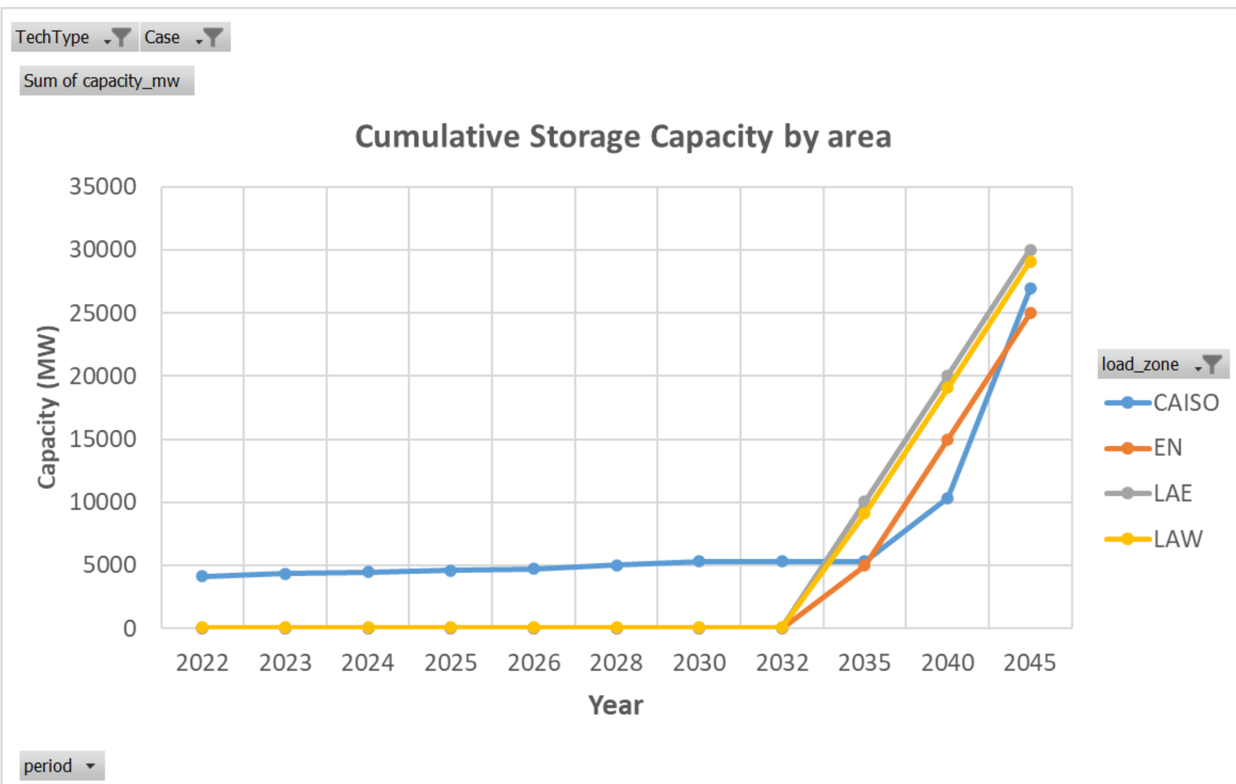

Figure 18: Storage buildout by area across the years (2022-2045)

While originally scheduled for retirement by 2025, California lawmakers recently extended the lifespan of the 2,300 MW Diablo Canyon Nuclear power plant in California by another 5 years (National Public Radio, 2022). Given the size of the Diablo Canyon Nuclear power plant, it has historically played a significant role in the dispatch of power in California and the WECC system. However, rather than simply extending the lifespan of the Diablo Canyon plant by another 5 years through 2030 as currently planned, which may only temporarily shift investment decisions by a few years, this scenario seeks to understand how extending the lifespan of Diablo Canyon through the end of the planning horizon (2049) would impact the investment decisions.

In terms of the simulation, the largest changes with respect to the base case occur in avoided investments in 4-hour and 100-hour storage in CAISO. However, the LAB investments do not appear to be significantly impacted. This is likely because the transmission to the LAB and generation contained within the LAB are already very constrained.

2.5 S5: Modeling 8760 hours per year

Scenario 5 models similar assumptions as those in Scenario 1, but with increased temporal resolution such that all 8760 hours per year are modeled for two years – 2022 and 2032. Implementing this scenario requires load for all nodes, and renewable profiles for all renewable generators, to be developed again to capture every hour of each year that is modeled, and thus both load and renewable profiles come from different sources compared to all other scenarios in this report.

Load profiles for all 8 nodes which are within California are obtained from California Energy Demand Forecast data, which contains hourly load forecast results developed as part of the California Energy Commission's 2021 Integrated Energy Policy Report. Load Distribution Factors calculated from the 37-day 11-year RESOLVE dataset are used to distribute the load. For the two nodes external to California (NW and SW), hourly load data is extrapolated from a 2028 Hitachi ABB GridView case using the same year-on-year average load growth rate as that for the nodes in California.

Renewable profiles for all renewable generators in the model have been developed mostly using Hitachi ABB GridView data for 2028, using the generator names, where available, to find the approximate location of each generator. Where generator names are not available, the node at which each generator is connected is used as a proxy for developing the renewable profiles at that location. In cases where location-based profiles could not be found in the Hitachi ABB GridView data, the following sources were used, similar to the data used by the RESOLVE model:

- For solar data: NREL's PVWATTS calculator, available within the NREL System Advisor Model, using data from NREL National Solar Radiation Database (NSRDB)
- Onshore and offshore wind: NREL WIND Toolkit

Work to develop load and renewable profiles for this scenario is complete. Work is ongoing to integrate the data into GridPath and adjust various temporal requirements in the dataset to obtain successful simulation runs.

2.6 S6: Alternative costs

Table 6: Investment Comparison of Scenario 6 and Scenario 1.

		mw											hours										
	vintage	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
technology	load_zone																						
Biomass	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Advanced_CCGT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Aero_CT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Reciprocating_Engine	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	CAISO	0	0	0	0	0	-1954	-275.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore_Wind	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	CAISO	0	0	-1873.2	-3564.5	0	2439.5	10230.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	CAISO	0	0	1149.9	-1149.9	0	0	0	0	-651	-2088.9	0	0	0	0	0	0	0	0	0	0	0	0
BTM_Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BatLi4	CAISO	0	0	0	0	0	0	0	0	0	0	-8768.8	0	0	0	0	0	0	0	0	0	0	0
Battery	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ES10	CAISO	0	0	0	1000	2000	2000	2000	0	0	231	0	0	0	0	24	24	24	24	0	0	24	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	-263.5	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	999.3	0	0	0	0	0	0	0	0	0	0	0	0	0
ES100	CAISO	0	597.6	1000	1000	2000	1181.1	0	0	2997.2	0	0	0	100	100	100	150	100	65.4	0	-65.4	60	49.6
	EN	0	0	0	0	0	0	255.2	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0
	LAE	0	0	0	0	0	0	747.1	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESFlow8	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flow_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSH12	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumped_Hydro	CAISO	0	0	0	0	0	0	2900	0	0	0	-2900	0	0	0	0	0	0	48	0	0	0	-48
trans	CAISO_LAE_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAISO_LAW_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN_LAW_NEW	0	0	0	0	0	0	-66.4	0	0	0	7.8	0	0	0	0	0	0	0	0	0	0	0
	LAW_LAE_NEW	0	0	0	0	0	0	-118.5	0	0	0	111.2	0	0	0	0	0	0	0	0	0	0	0

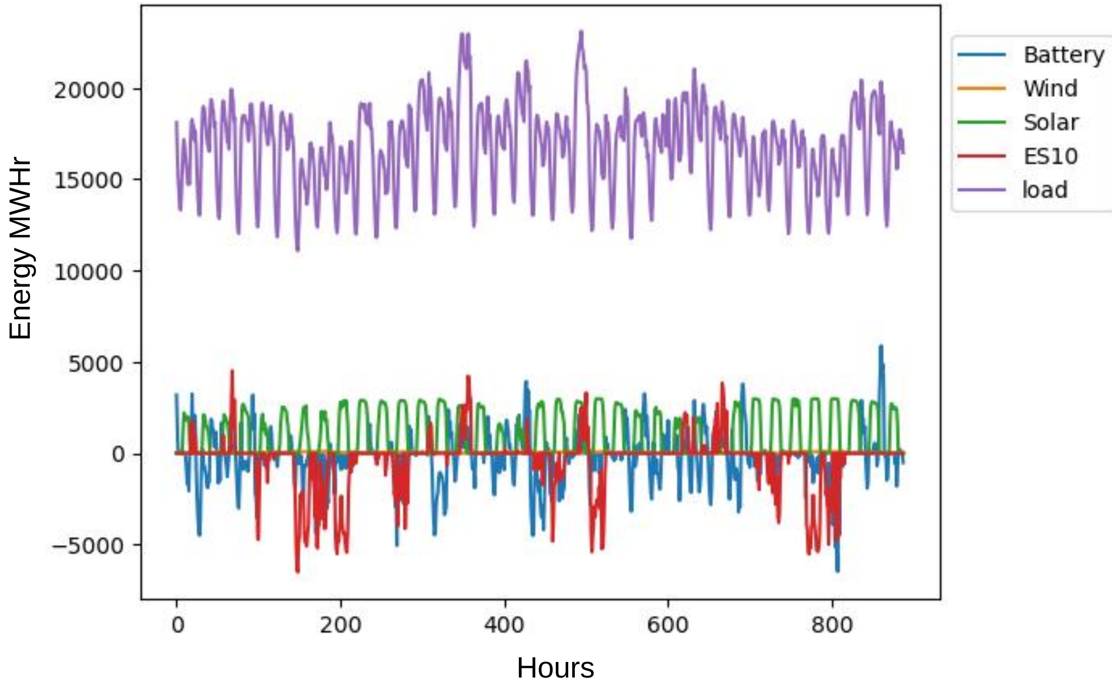

Figure 19: LAB dispatch by technology in 2045

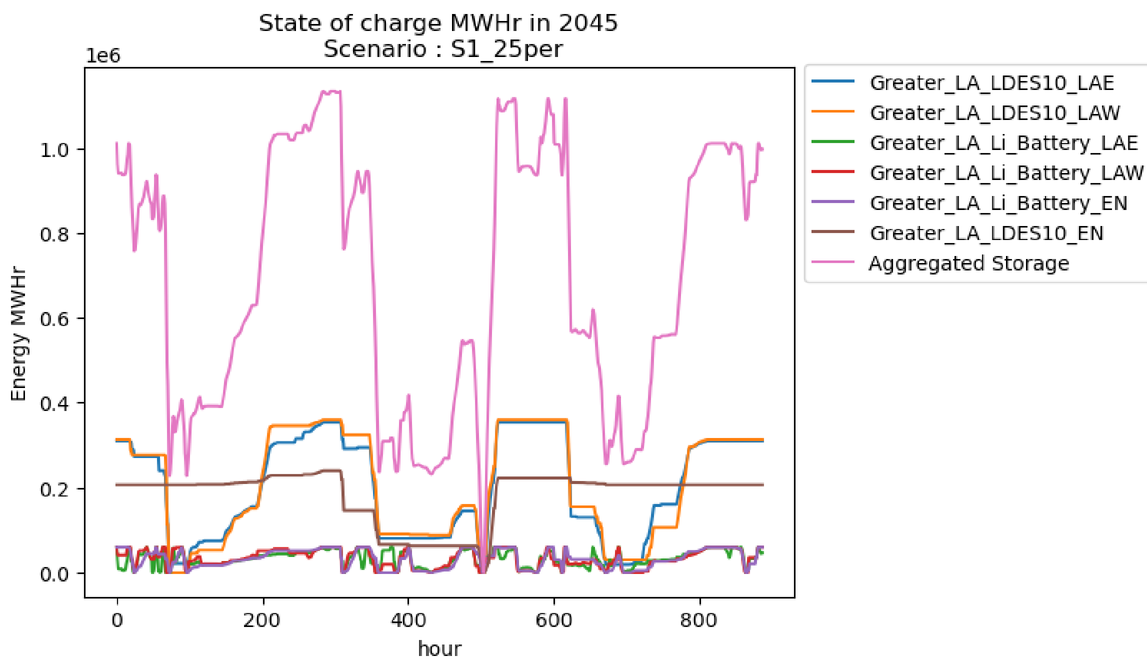

Figure 20: Battery State of Charge, aggregated and by technology & area in LAB

Scenario 6 considers different cost levels among energy storage candidate options. As discussed above, default costs are based on the prior Strategen California LDES study. These costs underlie the base case and all other scenarios. In scenario 6, PNNL evaluates three permutations of this base cost: (1) S6_25: 25% of the base energy and power cost; (2) S6_50: 50% of the base energy and power cost; and (3) S6_150: 150% of the base energy and power cost for each technology candidate being modeled.

First, we consider storage cost impacts across the LA Basin for all technologies. As is evident in Figure 21, across the cost permutation scenarios, there is little significant impact relative to the base case, although the 25% cost case sees a tiny bit more overall deployment in early stages of the simulation.

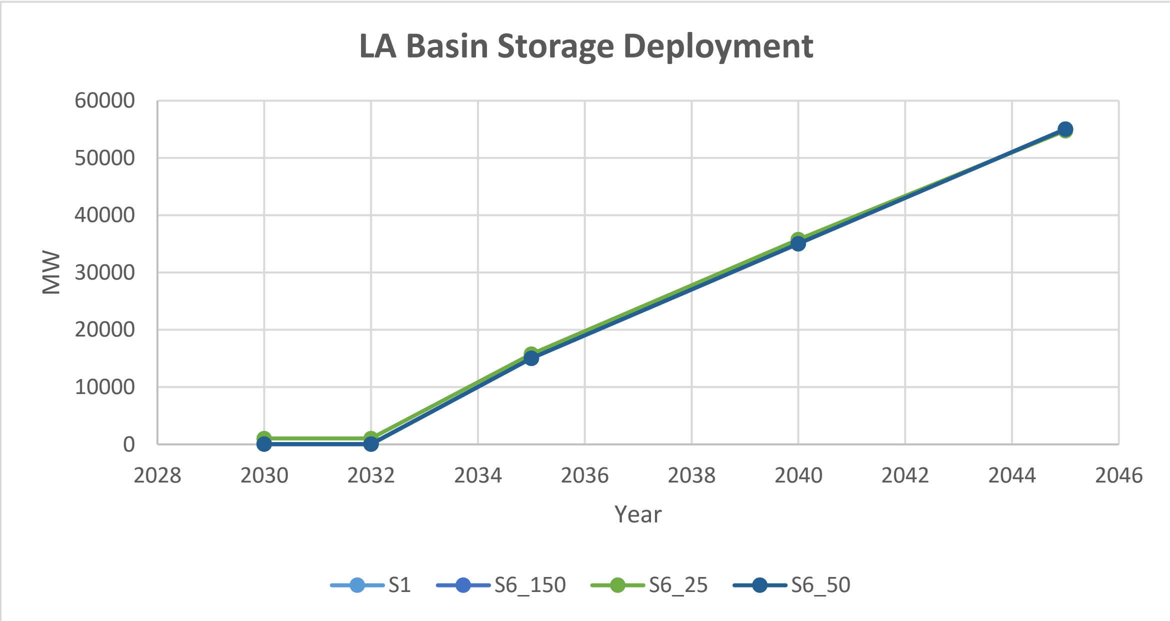

Figure 21: LA Basin Storage investments vs year

Digging down to a technology-specific analysis below, we see a variance with ES100 in the lowest cost (S6_25) scenario where ES 100 is built in the 2030 timeframe and operates through 2040, before being retired (due to lifetime limits). It is not rebuilt in 2045. Considering ES4 and ES10, we see basically identical buildout across all four scenarios e.g. (base case and cost permutations). This indicates that the LA Basin, with natural gas retirements and limited potential to build new transmission, is extremely capacity and transmission limited. Accordingly, despite costs varying dramatically, 25% to 150% of base, we see nearly identical buildout of storage resources, both ES4 and ES10. Seeing as we don’t see much, if any, ES100 buildout, this would suggest that the LA Basin is less energy limited than capacity limited.

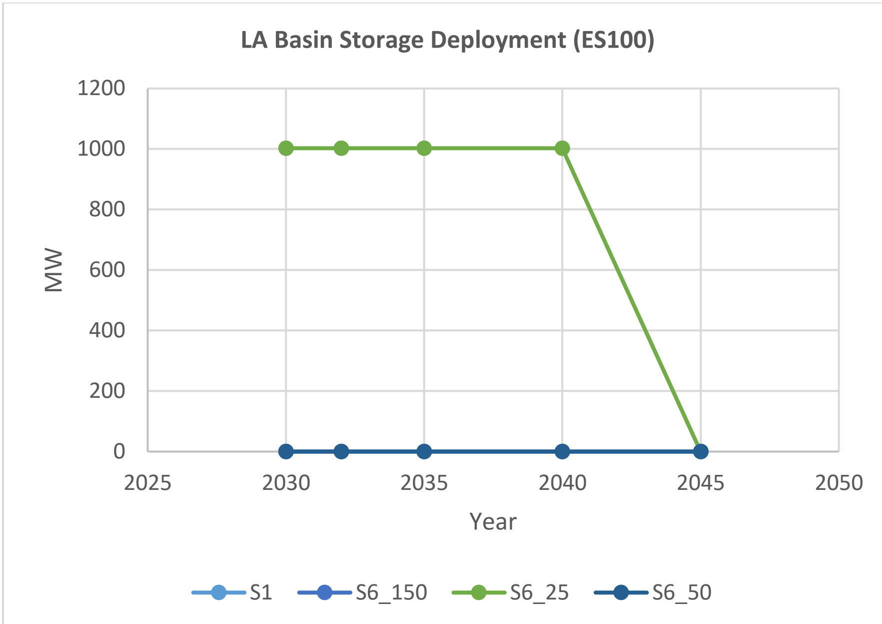

Figure 22: LAB S1 vs S6 100-hour storage deployment

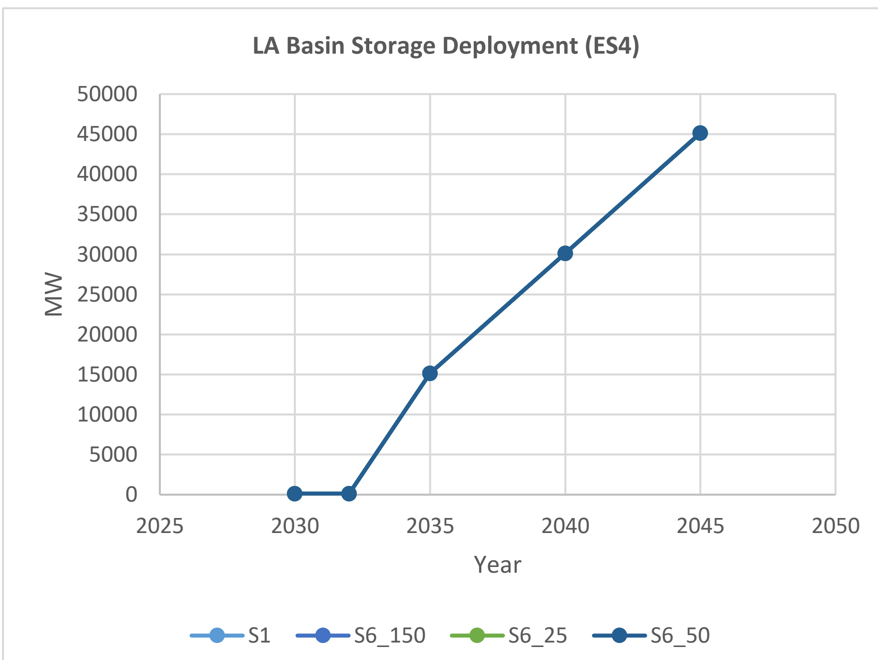

Figure 23: LAB S1 vs S6 4-hour storage deployment

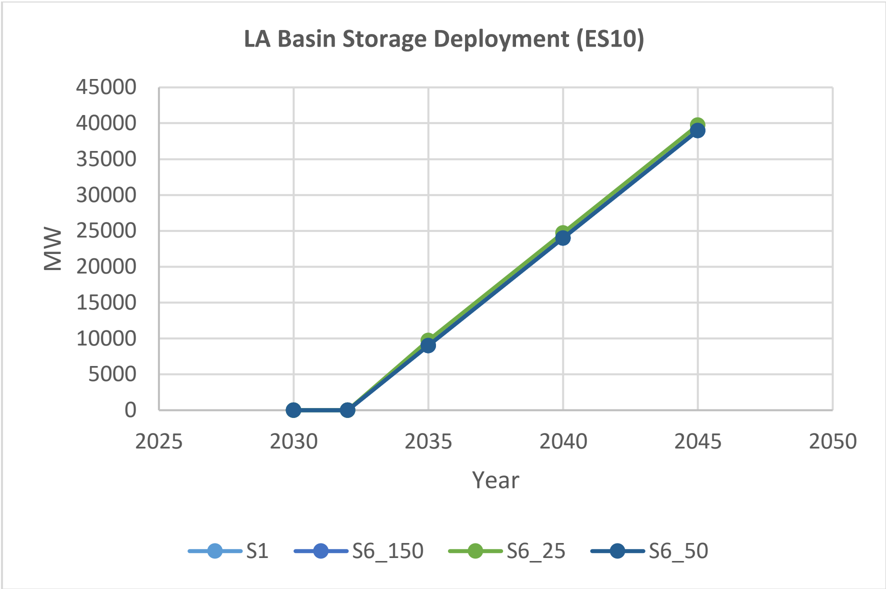

Figure 24: LAB S1 vs S6 10-hour Storage deployment

Moving to a CAISO-wide view (excluding the LA Basin) in Figure 25, we observe larger variances between the different scenarios, although, in aggregate, despite the large variance in energy storage capital costs, we do end up at nearly the same level of buildout by 2045. The variance arises more in the approach to deployment, that is, when energy storage costs are lower (scenarios S6_25 and S6_50) there is more storage buildout earlier. That said, in the lower cost case, S6_25, we see about 5 GW less total deployment relative to the other cases, when we see significantly more deployment earlier in the simulation horizon. This may be due to additional ES100 being deployed in the low-cost case. Interestingly, energy storage deployment numbers for the base case and a 50% cost increase (S6_150) are nearly identical.

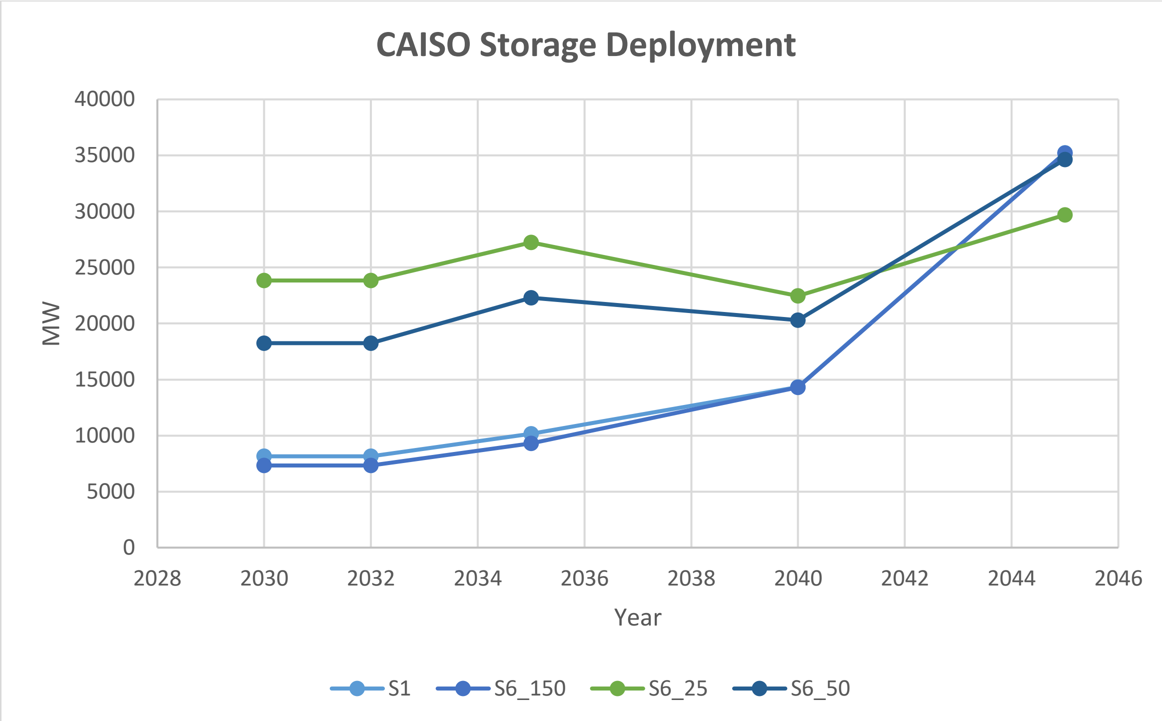

Figure 25: CAISO storage deployment

Diving into energy storage technology types in Figure 26-Figure 29 below, there is a little more variance between energy storage technology deployment relative to the results for the LA Basin. Starting with ES4, we see that at higher costs, up to 10GW additional ES4 is deployed by 2045 in the base case and S6_150 relative to the S6_25 scenario. We see no ES8 deployment. ES10 deployment follows aggregate results, with significantly more deployment in early years in the lower-cost cases, but by 2045, deployment reach the same level across all cases. With ES12 (pumped storage) deployment, again as with ES10, we see more deployment early in the lower cost cases (S6_25 and S6_50), but by 2045 deployment reaches the same level across all cases. Finally, looking at ES100, we again, as with ES10, see more deployment in the lower cost cases (though this variance is lower than with ES10), and deployment levels do not reach the same final level across the different cost scenarios, although they are close. The higher cost cases see more ES4 deployment and less ES100 deployment.

Although the cost variances are significant across the different scenarios, the amount of energy storage needed in CAISO is relatively similar. With lower costs, there is earlier energy storage buildout, and a preference for longer duration energy storage relative to shorter durations. That said, across all cost scenarios there remains a significant deployment of long-duration energy storage: 12-15 GW of ES100 and 5 GW of ES10.

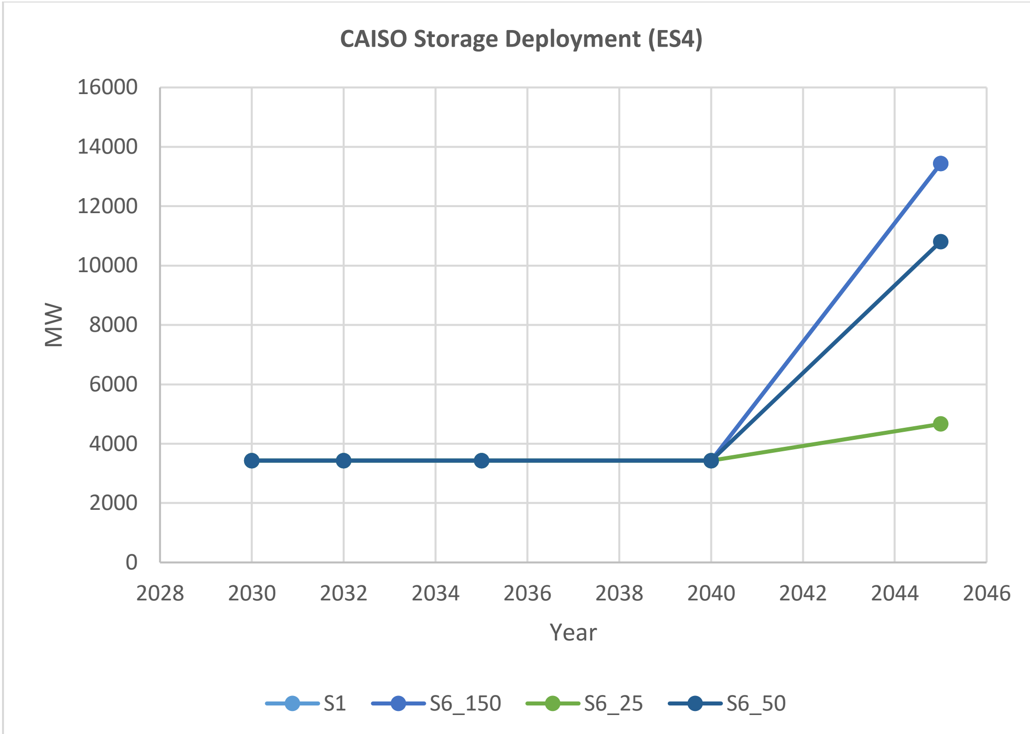

Figure 26: CAISO ES4 deployment

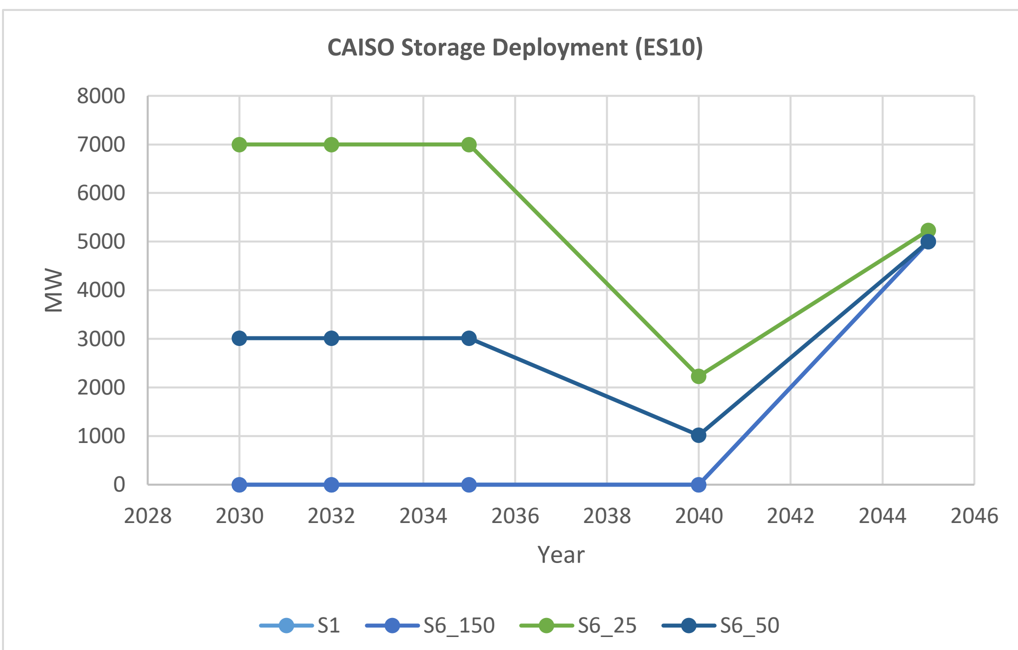

Figure 27: CAISO ES10 deployment

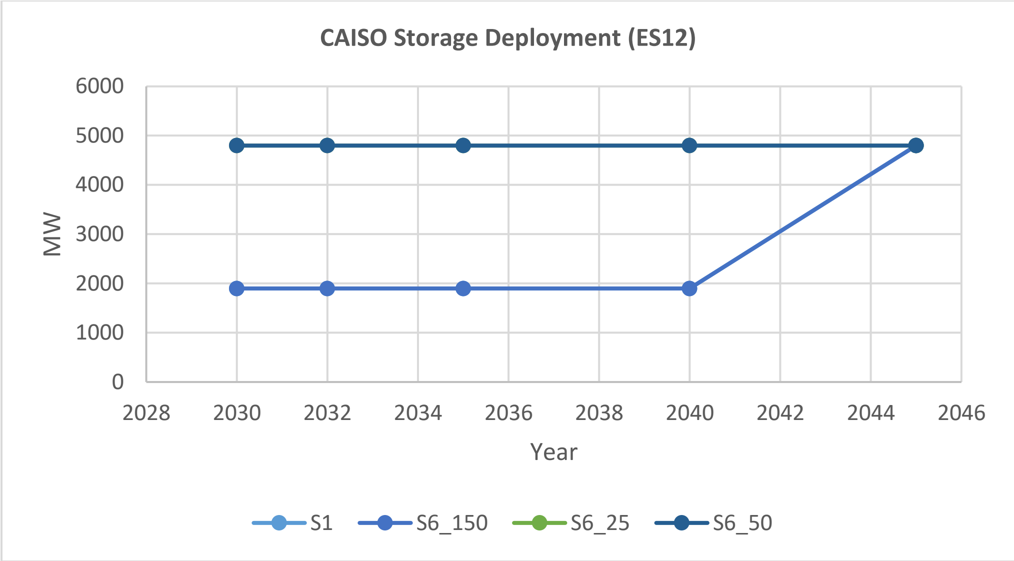

Figure 28: CAISO ES12 (pumped storage) deployment

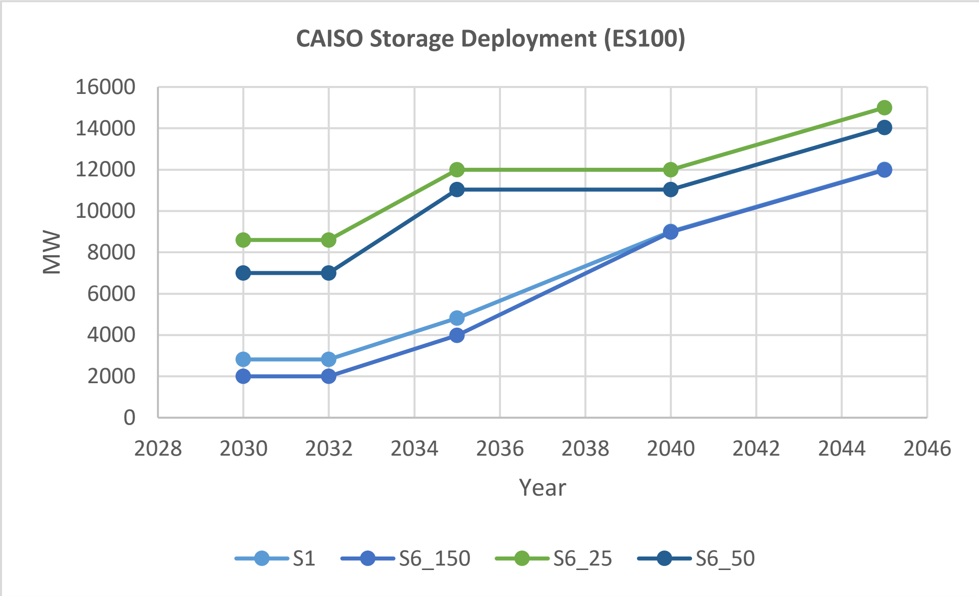

Figure 29: CAISO ES100 deployment

2.7 S7: Resilience

Table 7: Investment Comparison of Scenario 7 and Scenario 1.

		mw											hours										
	vintage	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
technology	load_zone																						
Biomass	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Advanced_CCGT	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Aero_CT	CAISO	0	0	0	0	0	503.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAISO_Reciprocating_Engine	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	CAISO	0	0	0	0	0	-66.9	66.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore_Wind	CAISO	0	0	0	0	0	0	0	0	0	0	905	0	0	0	0	0	0	0	0	0	0	0
Solar	CAISO	0	0	-1601.6	-2080.7	9	920.8	769.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	CAISO	-235	-22	562.7	-305.7	0	0	0	0	1289.2	-438.4	-850.7	0	0	0	0	0	0	0	0	0	0	0
BTM_Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BatLi4	CAISO	0	0	0	0	0	0	0	0	0	0	-8738.4	0	0	0	0	0	0	0	0	0	0	0
Battery	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ES10	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	79.8	44	0	0	0	0	0	0	5000	0	0	16.3	22.8	#VALUE!	0	0	0	0	0	24	0	0
	LAE	39.2	0	0	0	0	0	0	0	0	0	0	16.3	0	#VALUE!	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	999.3	0	0	0	0	0	0	0	0	0	0	0	0	0
ES100	CAISO	0	0	0	0	0	-818.9	-533.5	0	-2002.8	-3878.9	0	0	0	0	0	0	-100	-34.6	0	-65.4	0	-24.8
	EN	0	88.4	41.3	0	0	0	0	0	0	0	0	0	100	205.2	0	0	0	0	0	0	0	0
	LAE	0	912.4	121.8	277.7	208.9	518.6	0	0	247.7	3059.5	3478.3	0	100	291.4	318.9	349.8	171.5	0	0	0	216.2	200
	LAW	0	0	445.9	323.6	307.5	479	0	0	78.3	2478	1265	0	0	132.8	77.9	156.6	343	0	0	0	206.3	200
ESFlow8	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	8
	LAE	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	8
	LAW	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0	0	0	0	0	0	0	8
Flow_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Li_Battery	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSH12	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LAW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumped_Hydro	CAISO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans	CAISO_LAE_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAISO_LAW_NEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EN_LAW_NEW	0	0	0	0	0	0	-56.7	0	0	88.1	-349.6	0	0	0	0	0	0	0	0	0	0	0
	LAW_LAE_NEW	0	0	0	0	0	0	-202.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In this scenario, we considered the impact of potential wildfire events in and around the LAB region. Specifically, we assumed 1 wildfire event-driven day of operation (24 hours) in each of the 11 years that were modeled. For each of the 11 years modeled in our simulation, the day in the year that has the summer peak load (the summer peak load is also the annual peak load) was selected to be the event day in this scenario. During the event day, the transmission line capacities of three lines entering the LAB region from CAISO (namely CAISO → LAE, CAISO → LAW and CAISO → LDWP) were derated to model loss in transmission capability owing to wildfire-driven shutdowns. Note the optimization objective function remained the same as in S1. The rest of the setup remained the same as in S1. Note that the derating of the transmission lines was varied from 0.3 (30%) in 2022 to 0.6 (60%) in 2045, in monotonically increasing step size. This was done to model the fact that the probability of wildfire events increases from 2022 to 2045.

The main result from this simulation was the overwhelmingly high investment in all storage technologies (including100-hour storage) in EN, LAE and LAW, especially when compared to S1. This can be seen in Figure 32 as well as in **Error! Reference source not found.**. The overall high amount of storage buildout in LAB region, especially after 2032 can also be observed from Figure 33. This is done to ensure resource adequacy when transmission lines are unable to import power from CAISO into the LAB region during the wildfire event. Most of the discharge from these units are also coinciding with the wildfire period (to cater to demand and minimize load curtailment) as can be seen in
Figure 30 and Figure 31. Therefore, our results show that in order to make the LAB region resilient towards events such as wildfire, a greater amount of storage capacity buildout may be necessary. The amount of such additional buildout may be guided by additional simulation-driven assessments, whereby events that trigger such “resilient operations” mode are modeled with accuracy over the duration of the expansion planning problem.

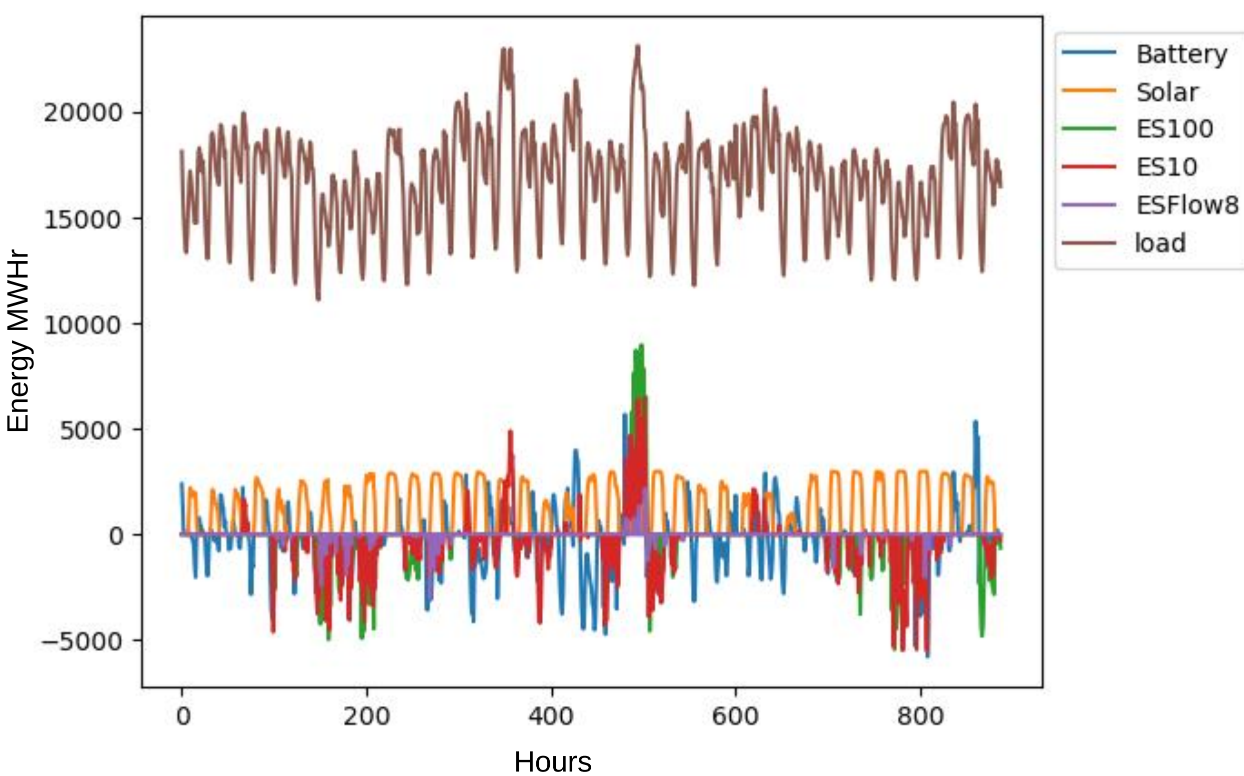

Figure 30: LAB dispatch by technology in 2045

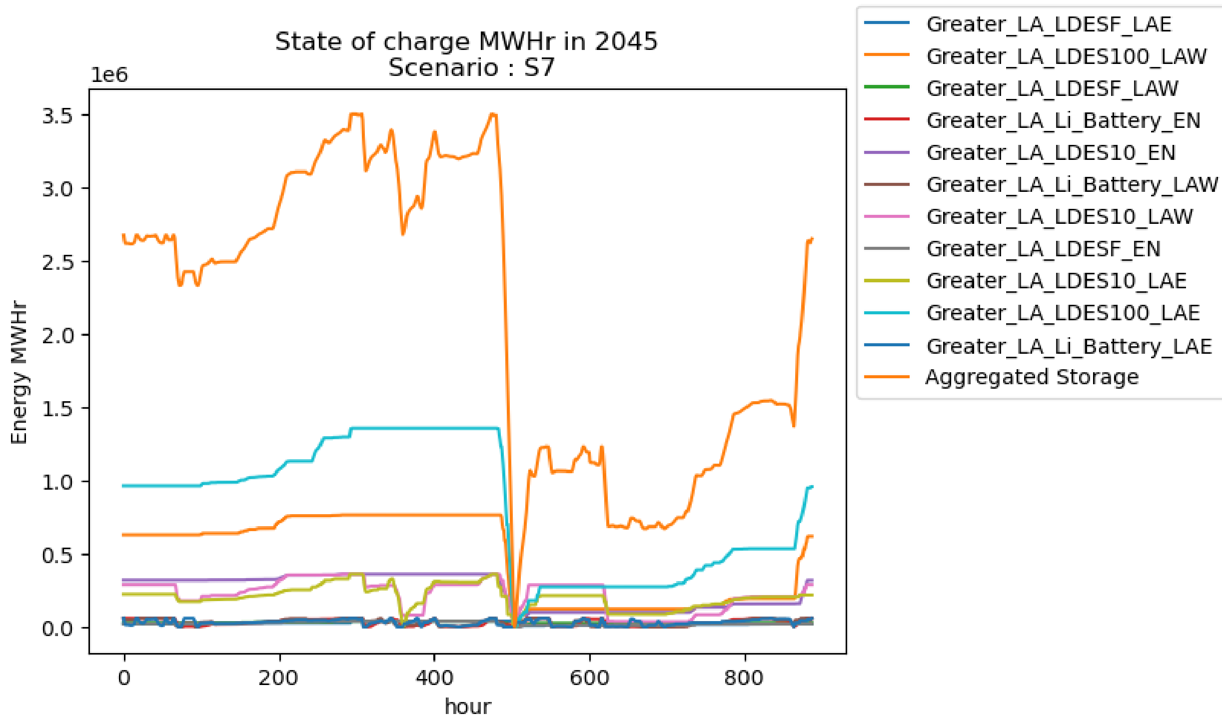

Figure 31: Battery State of Charge, aggregated and by technology & area in LAB

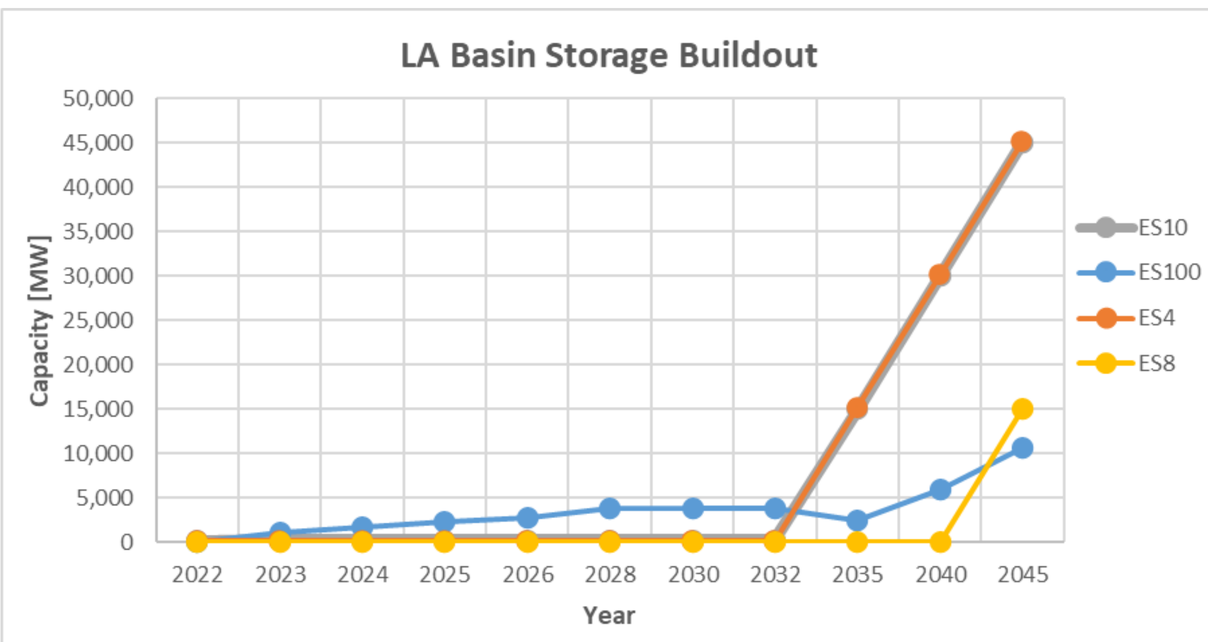

Figure 32: Storage buildout by technology types in LAB, across the years (2022-2045)

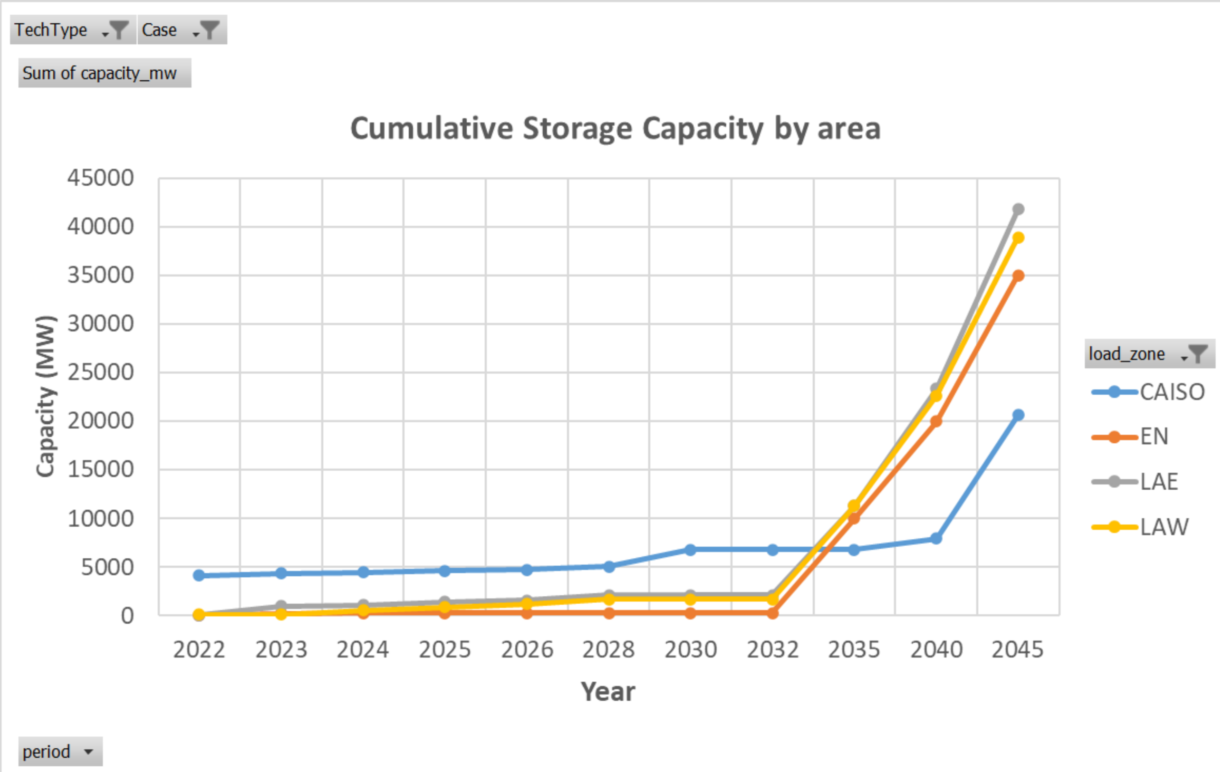

Figure 33: Storage buildout by area across the years (2022-2045)

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