Los Angeles LA DWP Department of Water & Power

LA100 PLAN

Achieving A Clean Energy Future for Los Angeles













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LA100 PLAN – *Preface*

This LA100 Plan marks a decisive step forward in Los Angeles' journey toward a carbon-free future. Building on the foundation laid by the 2022 Strategic Long-Term Resource Plan (SLTRP), the LA100 Plan reflects our unwavering commitment to achieving 100% carbon-free electricity by 2035. Unlike the 2022 SLTRP—which evaluated a range of future scenarios and ultimately recommended one for adoption—the LA100 Plan centers on a single primary pathway to achieve 100% carbon-free electricity by 2035. This "LA100 Pathway" builds directly on the Recommended Case from the 2022 SLTRP and serves as the central reference case for this plan, alongside additional sensitivities and the SB100 Benchmark. It serves as the City's official blueprint to reach a decarbonized energy future, informed by state-of-the-art modeling and rigorous analysis across engineering, environmental, and economic dimensions.

The LA100 Pathway updates and expands upon the 2022 SLTRP Recommended Case, incorporating the most current information available on load forecasts, distributed energy resources, transmission constraints, fuel availability, technology cost curves, and policy targets. While the core pathway remains fixed, the LA100 planning process introduced a broader range of sensitivities to explore uncertainties and better understand potential risks—from extreme weather and fuel supply issues to emerging clean technologies and load growth. This more expansive risk lens reflects our recognition that building a reliable, equitable, and clean energy future will require resilience in the face of a rapidly changing energy landscape.

At its heart, the LA100 Plan is a systems-level transformation strategy. It replaces fossil fuels with a diverse portfolio of carbon-free energy resources—solar, wind, geothermal, energy storage, and in-basin carbon-free dispatchable resources such as green hydrogen—while modernizing grid infrastructure and scaling energy programs to meet customer needs. The pathway targets complete coal retirement by 2025 and full natural gas phaseout or conversion by 2035. It is ambitious by design and reflects the will of the City and its residents to meet the climate crisis with urgency and resolve.

Still, the challenges ahead are substantial. Achieving a fully carbon-free power system will require large-scale investment, bold innovation, and coordination across regulatory, political, technical, and community fronts. The transition must remain reliable, equitable, and financially sustainable for all Angelenos—especially those historically underserved or energy-burdened. This document is both a plan and a call to action, grounded in the best analysis available today and intended to be updated as new technologies, partnerships, and policies continue to evolve.

To that end, LADWP is already planning for the next iteration of this work—the 2026 LA100 Plan—which will revisit key assumptions, refine implementation timelines, and incorporate the latest research and stakeholder input. The LA100 Plan is not the final word—it is the foundation of an ongoing transformation. With every update, Los Angeles reaffirms its commitment to lead with innovation, equity, and resolve, ensuring a resilient, carbon-free power system for all Angelenos by 2035.

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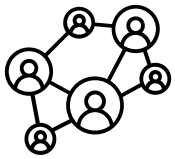
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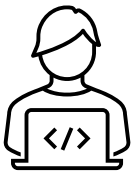
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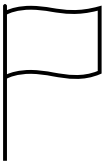
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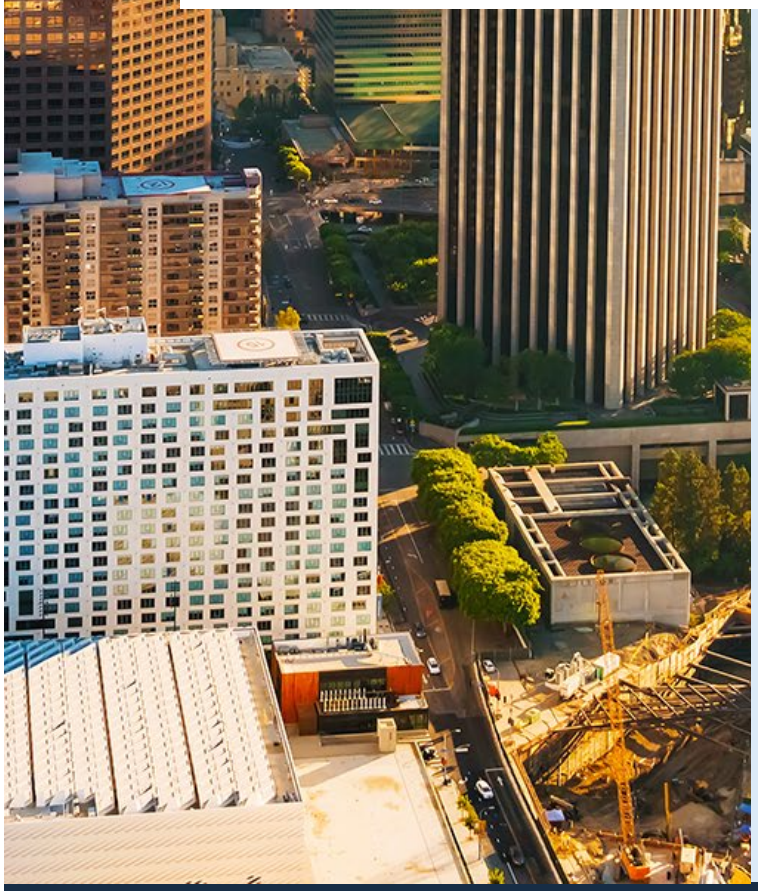
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Executive Summary



Key Highlights

- Goals: The LA100 Pathway commits LADWP to delivering 100% carbon-free energy by 2035
- Scenario: Eleven sensitivity model runs were conducted to assess the robustness of LADWP's decarbonization pathway under different risk factors
- Energy Burden: LADWP acknowledges that ensuring equitable outcomes across all neighborhoods requires more than just system-wide emissions reductions, but efficient monitoring and mitigation.



ES.1 Power System Overview

The Los Angeles Department of Water and Power (LADWP) is the nation's largest municipal utility with a net maximum plant capacity of 10,988 megawatts ("MW") and net dependable capacity of 7,965 MW as of December 31, 2024. The Power System's highest instantaneous peak demand registered 6,502 MW on August 31, 2017. We are responsible for meeting the electricity and water requirements of our service area and provide service almost entirely within the boundaries of the City of Los Angeles (LA). This service area encompasses approximately 473 square miles and is populated by approximately 4.0 million residents. In Fiscal Year 2021-2022, LADWP supplied 25,517 gigawatt-hours ("GWh") to more than 1.55 million residential and business customers, in addition to more than 5,100 customers in California's Owens Valley. Commercial, industrial, and governmental customers consumed about 61% of the electricity in Los Angeles. As of Fiscal Year 2024-2025, LADWP had an approved total Power System budget of $5.8 billion, comprised of $2.4 billion for capital projects, $1.8 billion for operations and maintenance, and $1.6 billion for fuel and purchased power.

LADWP also has vertically integrated power generation, transmission, and distribution systems that span over five Western U.S. states. As shown in Figure 1, within the Los Angeles Basin, LADWP currently owns and operates four natural gas-fired generating stations (often referred to as the "in-basin" power plants):

- Harbor Generating Station, located near the Port of Los Angeles
- Haynes Generating Station, located in Seal Beach
- Scattergood Generating Station, located near Los Angeles International Airport
- Valley Generating Station, located in the San Fernando Valley



Figure 1. LADWP's four "in-basin" generating stations.

LADWP owns and operates the Castaic Power Plant, a 1,250 MW pumped-storage hydroelectric generation facility located in Castaic, California. Additionally, as of 2024, LADWP has over 760 MW of total installed local solar (Figure 2).



Figure 2. Installation of local rooftop solar.

LADWP also has out-of-state contracts for a portion of the generating capacity from the Intermountain Power Project—a coal-fired power plant located in Delta, Utah set for retirement in 2025, the Hoover Dam hydroelectric power plant in Nevada, and the Palo Verde Generating Station, a nuclear power plant located in Arizona (Figure 3).



Figure 3. Palo Verde Nuclear Generating Station, located in Arizona.

On the renewable energy front, LADWP owns and has power purchase agreements for a diverse number of renewable energy generating facilities, including several solar, wind, and small hydroelectric facilities in California's Owens Valley, wind facilities located in Utah, New Mexico, Oregon, Wyoming, and Washington State, and geothermal and solar facilities in California and Nevada (see Figure 4 and Figure 5).



Figure 4. Red Cloud Wind Project, located in New Mexico.



Figure 5. LADWP's generation and transmission resources.

Combined with the in-basin renewable energy generation resources, an estimated 39.5% of LADWP's power resources in the year 2023 were eligible renewable energy resources, as shown in

Figure 6.

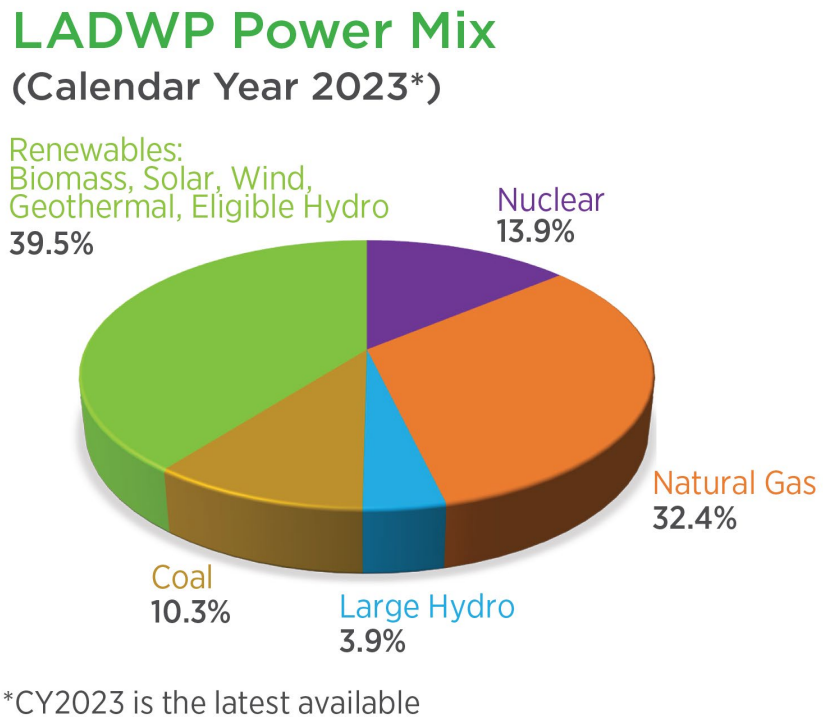


Figure 6. LADWP's power supply mix for calendar year 2023. Renewable resources—including biomass, solar, wind, geothermal, and eligible hydro—comprised the largest share at 39.5%, followed by natural gas at 32.4%, nuclear at 13.9%, coal at 10.3%, and large hydro at 3.9%.

Furthermore, that number increased to 57.3% when eligible hydroelectric and nuclear energy were included as part of a broader carbon-free energy category. LADWP has made these substantial achievements in renewable energy procurement in just under two decades and is accelerating the rate of renewable energy adoption.

As shown in Figure 7, LADWP has achieved significant reductions in reducing greenhouse gas (GHG) emissions through a combination of replacing coal-fired generation, adding more efficient gas generation, expanding energy efficiency, and integrating renewable energy. For example, LADWP achieved and exceeded the GHG emission reduction target set by California Senate Bill 32 to reduce GHG emissions to 40% below 1990 levels by 2030 in 2016, 14 years ahead of schedule. As of 2023

LADWP's GHG emissions were approximately 5.8 million metric tons (MMT), nearly 68% below the 1990 emissions baseline of 17.9 MMT.

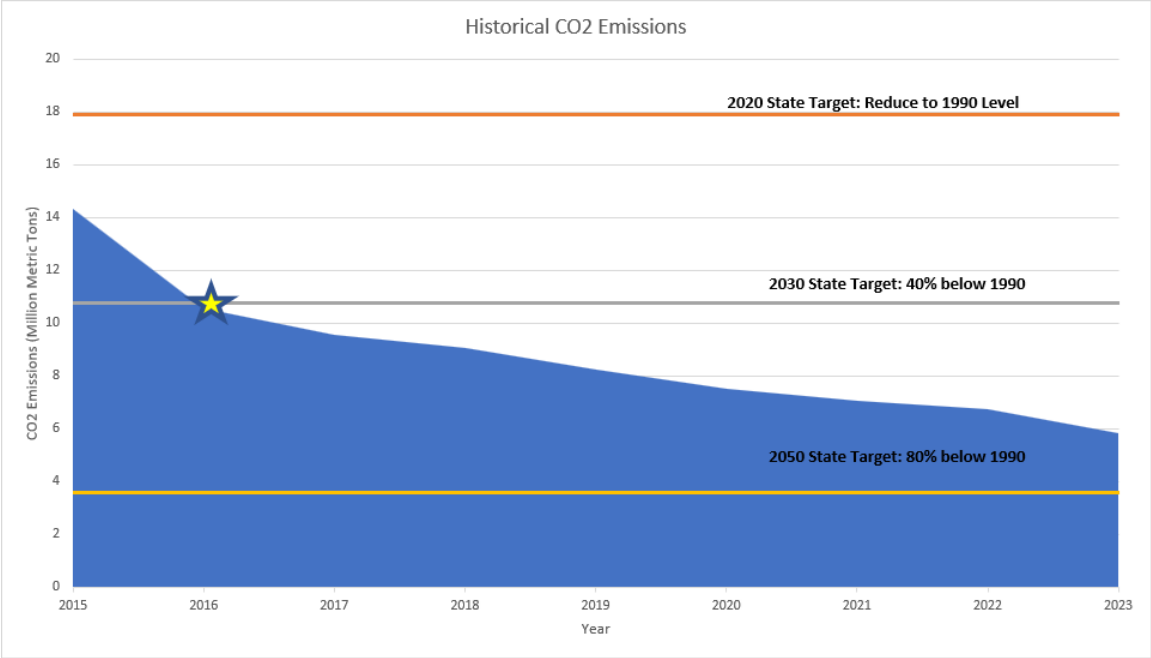


Figure 7. Historical LADWP GHG Emissions.

With respect to transmission, LADWP has 4,081 miles of overhead transmission circuits (alternating current and direct current) and 135 miles of underground transmission circuits. On the distribution side, LADWP has 7,380 miles of overhead distribution lines, 3,883 miles of underground distribution cables, and 178 distribution substations. In terms of collaboration with neighboring utilities and system operators, LADWP serves as a balancing authority for the City of Glendale's and City of Burbank's electric utilities, helping balance generation, power flows, and demand across the interconnected systems in real-time. LADWP is also a participant in the California Independent System Operator's Western Energy Imbalance Market (WEIM), which helps electric grid operators in the region share energy reserves and optimize renewable energy resources, helps ensure reliability, lowers costs, and lowers greenhouse gas emissions.

ES.2 Background and Timeline

Several developments occurring over the last several years have culminated in this LA100 Plan, which serves as LADWP's comprehensive roadmap for meeting LA's future energy needs, regulatory mandates, and carbon-free energy goals while maintaining reliable and affordable power for its customers. In 2018, California legislators passed Senate Bill 100 (SB 100) which set forth, among other requirements, a goal of achieving 100% carbon-free electricity to supply all retail sales in California by the year 2045. In 2019, the Mayor of Los Angeles, Eric Garcetti, and the Los Angeles City Council (City Council), announced the LA Green New Deal which established a goal of attaining 100% renewable energy by 2045. In parallel, LADWP partnered with the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) to create the Los Angeles 100% Renewable Energy Study (LA100 Study). This study analyzed multiple pathways of achieving 100% carbon-free energy, but only one scenario, the "Early and No Biofuels Scenario", met this goal by 2035—10 years ahead of the mandate established in SB 100. In 2021, the LA100 Study was completed, and the Los Angeles City Council then passed a motion instructing LADWP to create a plan to achieve 100% carbon-free energy by 2035. Based on the results of the LA100 Study, LADWP developed the 2022 Power Strategic Long-Term Resource Plan to establish several cases that achieve 100% carbon-free energy, pursuant to the City Council motion. The 2022 SLTRP examined three primary scenarios achieving 100% carbon-free energy by 2035 and designated one of those scenarios as the Recommended Case. The following iteration of the 2022 SLTRP—this LA100 Plan—uses the Recommended Case from the 2022 SLTRP as its primary scenario, and updates various assumptions, including, but not limited to, capital costs for new generation including renewables, fuel pricing, carbon pricing, electrification, and distributed energy resources. The LA100 Plan reaffirms LADWP's commitment to 100% carbon-free energy by 2035 and serves as a high-level Power System roadmap, while also examining several sensitivities that quantify the impacts of certain risks, such as climate change.

ES.2.1 California Senate Bill 100

In 2018, California passed Senate Bill 100 (SB 100). SB 100 requires that all retail electricity sold in California is supplied by renewable and zero-carbon resources by the year 2045. Renewable energy resources include wind, solar, geothermal, and small hydroelectric technologies, while zero-carbon resources include large hydroelectric and nuclear technologies. While not specified in SB 100, it is assumed that combustion resources fueled by biofuels or hydrogen derived from renewable energy resources are

also considered zero-carbon resources. It is important to note that while all retail electricity sales in California must be served by renewable and zero-carbon resources by 2045, power losses, mostly in the form of resistive heat from transmission and distribution lines, can still be served by fossil-fired generation.

Along with the 2045 goal of achieving 100% carbon-free electricity, SB 100 also sets forth a 60% renewable portfolio standard (RPS) by the year 2030. This percentage of renewables must be maintained at or above 60% from the year 2030 onward.

The SB 100 Joint Agencies, comprised of the California Air Resources Board (CARB), California Energy Commission (CEC), and the California Public Utilities Commissions (CPUC), conducted computer simulations that revealed several key takeaways:

- The goals set forth in SB 100 are achievable from a technical standpoint through multiple pathways.
- The procurement and construction of clean electricity generation facilities such as solar, wind, geothermal, small hydroelectric, and biofuels along with energy storage technologies such as batteries, compressed air energy storage, and pumped-hydroelectric energy storage must be sustained at record-setting build rates.
- Geographic and technological diversity of zero-carbon energy resources lowers overall costs and enhances system reliability.
- Natural gas combustion turbines and combined-cycle facilities can act as a bridge to achieving 100% zero-carbon energy by 2045 and help minimize overall costs during the transition.
- Increased use of energy storage can reduce natural gas capacity needs.
- Transitioning to 100% carbon-free energy would have benefits above and beyond the mitigation of greenhouse gasses including:
    - Public health improvement
    - Energy equity advancement
    - Clean energy economy growth

After recognizing that the SB 100 Joint Agency Report was an initial analysis, theJoint Agencies recommended further analysis which includes:

- Verifying that scenario results satisfy the state's grid reliability requirements
- Evaluating the potential effects of emerging resources, such as offshore wind, long-duration energy storage, green hydrogen technologies, and demand flexibility
- Assessing the costs and benefits for environmental, social, and economic factors associated with the additional clean electricity generation capacity and storage needed to implement SB 100
- Supporting the alignment among the joint agencies and continuity between SB 100 reports by holding annual workshops.

ES.2.2 City of Los Angeles Green New Deal

In 2019, Mayor Eric Garcetti announced the LA Green New Deal. This plan established a goal of achieving 100% renewable energy for the City of Los Angeles by the year 2045. Additionally, this plan called for several interim renewable energy targets for Los Angeles, including a 55% RPS by 2025 and 80% RPS by 2036.

The LA Green New Deal also set forth several goals affecting local generation, energy storage, and behind-the-meter resources:

- Achieve 900 to 1,500 MW of local solar by 2025, 1,500 to 1,800 MW by 2035, and 1,950 MW by 2050
- Achieve 1,654 to 1,750 MW of local energy storage capacity by 2025, 3,000 MW by 2035, and 4,000 MW by 2050
- Expand demand response (DR) programs to 234 MW by 2025 and 600 MW by 2035.

The LA Green New Deal also established goals for transportation electrification, which would have the effect of increasing LADWP's total customer demand for electricity while simultaneously reducing emissions. The plan called for:

- Increasing the percentage of zero-emission vehicles in Los Angeles to 25% by 2025, 80% by 2035, and 100% by 2050
- Electrifying 100% of Metro and Los Angeles Department of Transportation (LADOT) buses by 2030

- Reducing GHG emissions associated with the Port of Los Angeles (POLA) by 80% by 2050.

The LA Green New Deal presented a comprehensive set of environmental goals, with a scope that reached beyond LADWP's Power System. Additional goals set forth also included, but were not limited to:

- Increasing the landfill diversion rate to 90% by 2025, 95% by 2035, and 100% by 2050
- Reducing industrial emissions by 38% by 2035 and 82% by 2050
- Increasing the percentage of all trips made by walking, biking, ride sharing, and public transportation to at least 35% by 2025 and 50% by 2035
- Ensuring 57% of new housing units are built within 1,500 feet of transit by 2025 and 75% by 2035
- Ensuring all new buildings will be net zero-carbon by 2030 and 100% of all buildings will be net zero-carbon by 2050
- Reducing potable water use per capita by 22.5% by 2025 and 25% by 2035
- Creating 300,000 green jobs by 2035 and 400,000 green jobs by 2050.


San Pedro
Wilshire Blvd

ES.2.3 The LA100 Study

LADWP partnered with the National Renewable Energy Laboratory to compile the LA100 Study which was released in 2021. The LA100 Study presented several pathways outlining how LADWP could technically achieve 100% carbon-free energy.

The LA100 Study was unprecedented in terms of its scope and objectives. Using a supercomputer, millions of simulations were conducted to examine how adoption of new design elements, appliances, and other electrical equipment would affect how and when people consume electricity. Opportunities to electrify different modes of transportation were explored along with concomitant impacts of electric vehicle (EV) charging on LADWP's electric grid. Aerial LiDAR surveys and computer simulations were used to estimate the power output from potential rooftop photovoltaic systems built throughout the City of Los Angeles.

Utility planning tools were deployed at an unprecedented scale while conducting analysis for the LA100 Study. Stochastic production cost models were run, and the potential portfolios of a wide range of technologies including solar photovoltaics, wind, concentrating solar, geothermal, biofuels, batteries, hydrogen storage, and demand response were built by capacity expansion models as shown in Figure 10. A detailed analysis of both LADWP's transmission network as well as distribution network were conducted to ensure power flow requirements were satisfied.

A local air quality analysis was also conducted as part of the LA100 Study. The concentrations of various local criteria air pollutants were determined as well as their associated health impacts.

Furthermore, the LA100 Study was unprecedented for LADWP regarding the level of depth and breadth of stakeholder engagement, outreach, and feedback obtained through over 30 total advisory group (AG) and public community outreach meetings, as well as dozens of internal subject-matter expert meetings over the course of five years.

Across several pathways to 100% carbon-free energy, the LA100 Study revealed several key insights:

- **Elimination of GHG emissions:** LADWP's GHG emissions from power plant operations would decline by 76% to 100% when compared to GHG emissions in 2020. This is because significant quantities of renewables and zero-carbon energy

resources would need to be deployed by 2045 to meet California's 100% carbon-free energy goal.

- **Managing increased electric demand:** Electricity demand is expected to continuously grow, due to an increasing population, a warming climate, and electrification. High levels of energy efficiency are needed to offset this projected demand.
- **Robust growth in distributed solar:** Customers are likely to drive significant growth in rooftop solar. The LA100 Study forecasts that 3 to 4 gigawatts of rooftop solar will be installed by 2045.
- **Electrification is key to local community health benefits:** Electrification of buildings and the transportation sector will lead to significant improvements in local air quality and associated health benefits.
- **Clean energy jobs and the economy:** Economic impacts to the City of Los Angeles will be small relative to the overall size of its economy, but the transition to carbon-free energy is anticipated to create thousands of clean energy jobs.
- **Firm dispatchable electric generation is critical**: A significant amount of firm, dispatchable generation is needed within the Los Angeles Basin to ensure reliability. Such capacity will be used infrequently, primarily during times of insufficient energy production from intermittent renewables such as wind and solar.
- **Electrification is also key to affordable rates:** To achieve 100% carbon-free energy with sustainable electricity rate impacts, significant increases of electricity sales are required. This can be achieved through both transportation and building electrification.

The LA100 Study also examined pathways in which 100% carbon-free energy is attained by the year 2035—10 years ahead of California's 2045 mandate. An earlier target would mean LADWP would need to make additional necessary investments earlier and more quickly. This would result in more debt accumulation and greater costs overall; however, certain benefits, such as reduced GHG emissions would be realized more quickly.

In developing the LA100 Plan, LADWP's Resource Planning team incorporated key insights from both the original LA100 Study and the 2022 Strategic Long-Term Resource Plan (SLTRP). The team also drew on substantial input from the LA100 Plan Advisory Group, which includes a broad cross-section of stakeholders representing LADWP's diverse customer base.

The original LA100 Study assumed high levels of customer adoption of rooftop and other distributed solar resources and excluded the use of biofuels due to sustainability concerns. Instead, it relied on significant investments in clean hydrogen infrastructure, designed to serve as backup generation during stressed grid conditions such as wildfires. To reduce reliance on clean hydrogen during normal operations, the LA100 Early & No Biofuels scenario also incorporated substantial geothermal capacity, providing firm, baseload renewable generation.

As illustrated in Figure 8 and Figure 9, the original LA100 Study further envisioned large-scale deployment of standalone energy storage, as well as extensive buildout of utility-scale solar facilities paired with energy storage, to enhance reliability and support the transition to a fully carbon-free power system.

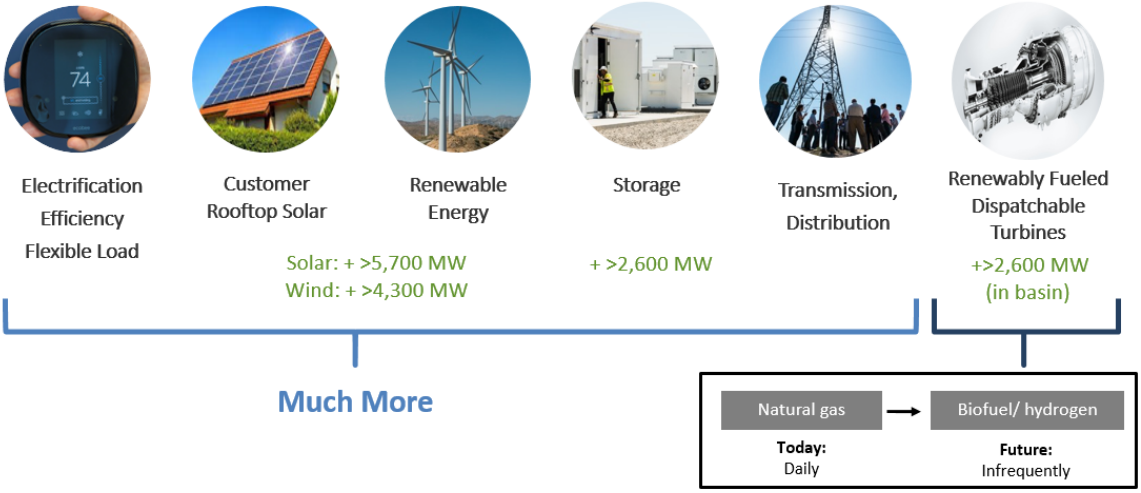


Figure 8. Common investments across all LA100 Study scenarios.

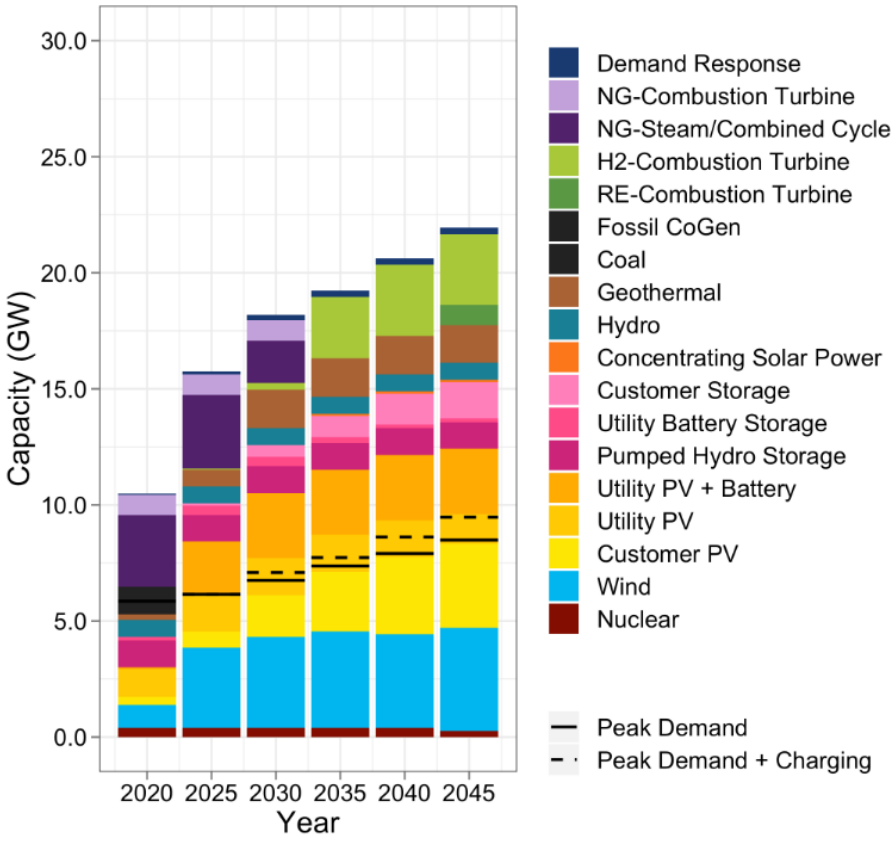


Figure 9. The original LA100 Study Early & No Biofuels (Moderate Load) Capacity Mix, 2020-2045.

ES.2.4 LA100 Equity Strategies

In 2023, the groundbreaking LA100 Equity Strategies initiative concluded after two years of unprecedented research and community engagement. This in-depth analysis examined energy-related inequities that have long impacted underserved communities in Los Angeles. Conducted under the leadership of the Board of Water and Power Commissioners, the effort involved collaboration with UCLA, and the US Department of Energy's National Renewable Energy Laboratory (NREL), which authored the original LA100 Study. The initiative aimed to inform the design of programs and policies that ensure underserved communities are not further burdened but instead equitably benefit from Los Angeles' transition to 100% clean energy.

The project centered on priorities identified by frontline communities, represented by a diverse Steering Committee and engaged through surveys, meetings and in-person listening sessions. Key focus areas included:

- Affordability and burdens
- Access to and use of energy technologies, programs, and infrastructure
- Health, safety, and community resilience
- Jobs and workforce development
- Inclusive community involvement

The report highlighted significant disparities in clean energy access, such as solar incentives and electric vehicle charging infrastructure disproportionately favoring affluent areas over disadvantaged neighborhoods. It also revealed that approximately 230,000 low-income households in Los Angeles currently lack access to cooling and could face more than two months of dangerous indoor temperatures annually by 2035. Residents of multifamily buildings are particularly vulnerable to extreme heat exposure. To address these inequities, the report proposed 50 targeted strategies, paving the way for a more equitable future in Los Angeles.

Building on the findings of the LA100 Equities Strategies Study, LADWP is now initiating the next phase: developing and implementing a LADWP Equity Action Plan to translate the report's recommendations into clear tangible actions with a plan to monitor results over time. This plan will focus on addressing gaps in existing approaches, prioritize historically underserved communities, and ensure equitable access to clean energy benefits. The plan will include a structured roadmap for short, medium, and long-term strategies, emphasizing inclusivity by tailoring programs and offerings to meet diverse needs, including those of vulnerable populations.

To ensure transparency, LADWP will track progress with clear goals and metrics while leveraging external funding to expand participation in disadvantaged communities. This plan aims to deliver tangible, equitable outcomes and address systemic disparities, creating a cleaner fairer energy future for all Angelenos in a fiscally responsible manner.

ES.2.5 The Los Angeles City Council Motion

In September 2021, the Los Angeles City Council passed a Motion (Council File No. 21-0352) instructing LADWP to create a Strategic Long-Term Resource Plan that would achieve 100% carbon-free energy by 2035 based on the findings of the LA100 Study. The City Council motion noted the "opportunity to re-create its utility in a way that recognizes the potential for a fossil-free future, demonstrates global leadership in its commitment to clean energy, and protects ratepayers from the increasing costs of carbon-based fuels."

The Motion further noted the benefits outlined in the LA100 Study of transitioning to a clean energy future, including:

- Improvements to local air quality and associated health benefits
- The creation of thousands of jobs
- The opportunity to reverse decades of environmental injustice by replacing gas-fired power plants in working class neighborhoods with carbon-free energy
- A reliable and resilient grid capable of adapting to a changing climate and shocks caused by natural disasters.

Additionally, the Motion noted then-President Joe Biden's commitment to decarbonizing the nation's electric power sector by 2035 and the prospect of federal funding in support of this goal.

In light of the findings from the LA100 Study and the federal government's goal of decarbonizing the nation's electric grid, the City Council motion set forth the following language:

> "I THEREFORE MOVE that the Council INSTRUCT the Department of Water and Power to prepare a Strategic Long-Term Resource Plan that achieves 100% carbon-free energy by 2035, in a way that is equitable and has minimal adverse impact on ratepayers."

In response to this motion from the Los Angeles City Council, LADWP began work on the 2022 Power Strategic Long-Term Resource Plan that would present several scenarios achieving 100 % carbon-free energy by 2035. This LA100 Plan further updates, refines, and expands on the findings of the 2022 SLTRP.

ES.2.6 California Senate Bill 1020

In September 2022, California Senate Bill 1020 (SB 1020) was enacted. SB 1020 added interim goals to the mandates already established in SB 100. Under SB 1020, at least 90% of all retail sales of electricity in California must be supplied by eligible renewable and carbon-free energy resources by December 31, 2035. By December 31, 2040, 95% of all retail electricity sales must be supplied by eligible renewable and carbon-free energy resources. Additionally, all electricity procured to serve California state agencies must be supplied by renewable or carbon-free energy resources by the end of 2035.

ES.2.7 2022 Power Strategic Long-Term Resource Plan

In response to the Los Angeles City Council's motion instructing LADWP to prepare an SLTRP that achieves 100% carbon-free energy by 2035, we initiated the 2022 SLTRP process in September 2021. The LADWP Integrated Resource Planning (IRP) Group took the lead in compiling the 2022 SLTRP, including gathering stakeholder input and assumptions, interfacing with consultants providing computer modeling and simulation support, participating in public outreach, and writing the 2022 SLTRP document.

LADWP's 2022 SLTRP provided a comprehensive roadmap for meeting LA's future energy needs, regulatory mandates, and carbon-free energy goals while maintaining reliable and affordable power for its customers. The planning process included an Advisory Group to ensure LADWP's plans reflect the input of the communities and customers it serves. The 2022 SLTRP was an essential part of LADWP's budget process that provides updated assumptions and a recommended optimal pathway to achieve 100% carbon-free energy by 2035, while addressing technological risk, minimizing adverse rate impacts, and ensuring an equitably just transition.

ES.2.8 The LA100 Plan

The LA100 Plan is LADWP's officially adopted pathway to achieve 100% carbon-free electricity by 2035—ten years ahead of California's Senate Bill 100 mandate of 2045. Based on the Recommended Case from the 2022 Strategic Long-Term Resource Plan, the LA100 Pathway scenario requires that all generation, including energy used to cover transmission and distribution losses, come from carbon-free sources. It incorporates updated assumptions for load growth, electrification, distributed energy resource adoption, technology costs, and transmission availability, while balancing reliability,

affordability, and equity. The plan is supported by ten targeted sensitivities that examine potential risks—such as fuel cost changes, technology availability, and market constraints—along with an SB 100 Reference Case and one SB 100 Price Sensitivity for benchmarking purposes. Together, these analyses provide a comprehensive view of how LADWP can reliably and equitably transition to a carbon-free power supply.

To maintain clarity throughout this document, the following naming convention is used to distinguish between the overall planning effort, the primary model run, and the benchmark scenario:

- **LA100 Plan**: Refers to this comprehensive planning document. It includes all model runs, assumptions, sensitivity analyses, and supporting narrative associated with LADWP's commitment to achieving 100% carbon-free electricity by 2035. This includes the LA100 Pathway, multiple sensitivities, and the SB100 Benchmark.
- **LA100 Pathway**: Refers specifically to the primary model run analyzed in this plan. It is based on Case 1—the Recommended Case from the 2022 Strategic Long-Term Resource Plan (SLTRP)—but incorporates updated assumptions, cost trajectories, and modeling refinements. The LA100 Pathway is the trajectory LADWP is actively pursuing to reach 100% carbon-free electricity by 2035.
- **SB100 Benchmark**: Refers to a separate model run aligned with the statewide SB 100 target. It is included for informational and benchmarking purposes only and does not represent a viable planning option for LADWP.

ES.2.8.1 Stakeholder Engagement, Outreach, and Feedback

The first step of the LA100 Plan process is to gather stakeholder input. There are numerous stakeholder groups, both internal and external to LADWP, that are consulted for the purposes of setting goals and objectives, as well as establishing input assumptions and operational parameters for each scenario and sensitivity considered in the LA100 Plan.

A major component in the process of gathering stakeholder input is the LA100 Plan Advisory Group. The LA100 Plan Advisory Group was comprised of over 90 stakeholders representing Neighborhood Councils, Academia, Community Organizations, Existing Customers, and City and Local Government, among others. The Advisory Group was designed to reflect the diverse perspectives and expertise necessary to understand the challenges and possibilities for achieving a 100% carbon-free power supply by 2035.

In addition to meeting with the LA100 Plan Advisory Group, LADWP held four public outreach meetings in June of 2025. These meetings were held virtually and were open to the general public. LADWP presented information on the sensitivities considered in the LA100 Plan as well as their benefits and trade-offs. Preliminary results from computer modeling and simulations were also presented. LADWP solicited feedback from the public during these outreach meetings.

Based on feedback provided by the LA100 Plan Advisory Group and the feedback provided during the public outreach process, the IRP Group was able to categorize most of the feedback into several broad themes. Feedback themes included, but were not limited to, examining a "no in-basin combustion" case that employed green hydrogen fuel cells instead of combined-cycle and combustion turbine generation units, ensuring affordable electricity rates, addressing the overall feasibility and constructability of the LA100 scenario, ensuring reliability, and encouraging local, behind-the-meter assets such as rooftop solar, energy efficiency, and demand response.

Stakeholders consistently raised three primary concerns throughout Advisory Group meetings and public outreach: equity and affordability, rates and cost transparency, and system reliability and resiliency.

First, there was strong emphasis on ensuring a just transition to a carbon-free future, with particular concern about the potential rate impacts on low-income and disadvantaged communities. To directly address this, LADWP partnered with UCLA to develop an Energy Burden Tool. This software projects the share of household income spent on energy (including electricity, natural gas, and gasoline) across LADWP's service territory, down to the level of zip code and census tract. By integrating this tool into the planning process, LADWP is able to better evaluate how different pathways affect vulnerable customers and design programs to reduce disproportionate impacts.

Second, stakeholders were concerned that achieving 100 percent carbon-free power by 2035 could drive significant rate increases, and requested greater financial transparency around assumptions such as inflation, incremental versus budgeted costs, and financing. In response, LADWP employed capacity expansion software to develop a least-cost, best-fit portfolio. This approach evaluates thousands of potential resource combinations, ensuring that the selected portfolio minimizes costs while maintaining system reliability and meeting policy goals. By grounding the plan in this modeling, LADWP can provide a transparent framework for assessing rate impacts and demonstrate how affordability considerations are incorporated into decision-making.

Finally, participants repeatedly underscored the importance of maintaining grid reliability during the transition, particularly given climate-driven risks such as extreme heat, wildfires, and aging infrastructure. In response, LADWP conducted extensive reliability sensitivities, testing system performance under a range of stress conditions including high and low load growth, varying levels of distributed energy resources, and extreme climate scenarios. This work informed contingency planning and highlighted the role of distributed energy resources and battery storage as critical tools for enhancing local resilience.

ES.2.8.2 The LA100 Pathway and Sensitivities

The LA100 Pathway is based on the Recommended Case from LADWP's 2022 Strategic Long-Term Resource Plan (SLTRP), which has been adopted as the City's official pathway to achieve 100% carbon-free electricity by 2035. This pathway—referred to simply as the LA100 Pathway—requires that all generation, including energy used to cover transmission and distribution losses, come from carbon-free sources. It reflects updated assumptions for load growth, electrification, distributed energy resource (DER) adoption, technology costs, and transmission availability, and is designed to balance reliability, affordability, and equity.

For benchmarking purposes, the plan also includes a Senate Bill 100 (SB 100) Benchmark, which represents the minimum compliance pathway under state law (100% carbon-free electricity by 2045, measured on a retail sales basis), and one SB 100 Price Sensitivity, which serves as a lower-cost "bookend" for technology price assumptions.

To test the robustness of the LA100 Pathway, 11 sensitivities were modeled:

- **High Price Sensitivity**: Assumes higher-than-anticipated costs for renewables and storage, but lower costs for green hydrogen—altering the relative economics of decarbonization pathways.
- **Low Price Sensitivity**: Assumes lower-than-anticipated costs for renewables and storage, but higher costs for green hydrogen—potentially shifting the technology mix and investment strategies.
- **Low Load**: Models lower net load and higher DER adoption, reducing the amount of utility-scale renewables needed and lowering costs.
- **High Load**: Models higher net load, higher peaks, and lower DER adoption, increasing reliance on dispatchable resources and raising costs.

- **Low DER**: Assumes less rooftop solar, storage, and other DER adoption than LA100, requiring greater investment in centralized resources.
- **High DER**: Assumes greater customer adoption of rooftop solar, storage, and other DERs, reducing the need for centralized generation but increasing operational complexity; adoption levels largely depend on customer choice, which LADWP cannot directly control.
- **No In-Basin Combustion**: Replaces in-basin hydrogen combustion turbines with hydrogen fuel cells, which was found to be infeasible due to cost, space requirements, manufacturing constraints, and operational limitations.
- **No In-Basin Hydrogen Supply**: Assumes no green hydrogen availability for in-basin generation, requiring limited natural gas backup and relying on IPP (operating at 30% hydrogen through 2045) for the only hydrogen-fueled generation.
- **Limited Hydrogen Supply**: Assumes only half the hydrogen supply available in LA100; reduces turbine capacity factors (already low in LA100) by half and compensates with additional renewables and storage, increasing costs.
- **Resource-Constrained**: Limits annual renewable and storage buildout to half the LA100 rate and delays hydrogen turbine deployment, pushing the 100% carbon-free goal to 2040.
- **Climate Change Sensitivity**: Examines the impact of warmer temperatures on load and resource performance, providing insight into how climate shifts could affect reliability and planning.

Table 1 provides a summary of the models runs examined in this LA100 Plan, including the LA100 Pathway, SB 100 Benchmark, and associated sensitivities.

Table 1. Model runs examined in the LA100 Plan.

Scenarios/Sensitivities*	Year 100% Carbon-Free Energy Is Reached**	Description	Risks Addressed
LA100 Pathway	**2035**	**Main scenario, local policy mandate**	**N/A; risks were assessed via sensitivities**
1. LA100 - Price Sensitivity	2035	High renewable energy, energy storage, and green H_2 costs; low natural gas and CO_2 allowance costs	Impact of higher cost of clean energy and lower cost of fossil fuels
2. LA100 - Low Load Sensitivity	2035	Load growth is lower than expected	Impact of lower-than-expected customer load growth
3. LA100 - High Load Sensitivity	2035	Load growth is higher than expected	Impact of higher-than-expected customer load growth
4. LA100 - Low Distributed Energy Resource (DER) Sensitivity	2035	DER adoption is lower than expected	Impact of customers adopting fewer DERs than anticipated
5. LA100 - High Distributed Energy Resource (DER) Sensitivity	2035	DER adoption is higher than expected	Impact of customers adopting more DERs than anticipated
6. LA100 - No In-basin Combustion Sensitivity	2035	Replacement of green H_2-capable combustion turbines with green H_2-capable fuel cells, in-basin	Impact of green H_2-capable fuel cells, in place of in-basin green H_2-capable combustion turbines
7. LA100 - No In-basin Hydrogen (H_2) Supply Sensitivity	N/A (97% by 2035)	Maintaining of natural gas-fueled generation online, in lieu of green H_2-capable generation in-basin	Impact of green H_2 commodity market failing to reach commercial maturity at scale
8. LA100 - Limited In-basin Hydrogen (H_2) Supply Sensitivity	2035	Limited H_2 fuel supply available for in-basin generation	Impact of green H_2 commodity market supplying less in-basin fuel than anticipated
9. LA100 - Resource Constrained Sensitivity	2040	New renewable energy and energy storage procurement capped at 500 MW/year. Green H_2-capable generation in-basin is not fully built out until 2040	Impact of undersupplied market for renewable energy and energy storage, in addition to delays in H_2 technology maturity
10. LA100 - Climate Change Sensitivity	2035	Base customer load is higher than expected	Impact of climate change
SB 100 Benchmark	**2045**	**Benchmark scenario, state policy mandate**	**N/A; risks were assessed via sensitivities**
11. SB 100 Price Sensitivity Sensitivity	2045	Lower renewable energy, energy storage, and green H_2 costs; Higher natural gas and CO_2 allowance costs	Impact of lower cost of clean energy and lower cost of fossil fuels

**Developed with input from the LA100 Advisory Group*
***LA100 reaches 100% carbon-free energy by 2035, as a percentage of all electric generation (including losses). SB 100 reaches 100% clean energy by 2045, as a percentage of electric retail sales (excluding losses).*

ES.2.8.3 Modeling

A major component of the LA100 Plan process is the modeling of LADWP's Power System using computer models. For long-term planning, computer modeling involves simulating aggregate customer demand, the dispatch of LADWP's various electricity generating assets and energy storage assets, and power flows through the high-voltage transmission system. Such modeling typically does not involve simulating the flow of electricity on LADWP's lower voltage distribution system.

For this LA100 Plan, the planning horizon was chosen to span between the years 2024 and 2045 to align with California policy objectives. As mentioned previously, high-level assumptions need to be made about which generation, storage, and transmission resources are expected to be available along with their various projected costs.

The LA100 Plan utilized the same modeling methodology and approach as the LA100 Study and 2022 SLTRP. Computer modeling is a two-step process. The first step involves running a capacity expansion model. A capacity expansion model determines which generation and storage resources should be built and in what quantities, and when and where to build them. As shown in Figure 10, the LA100 Plan used *Automated Resource Selection* (ARS), a proprietary software package provided by LADWP's consultant, Ascend Analytics, for capacity expansion modeling.

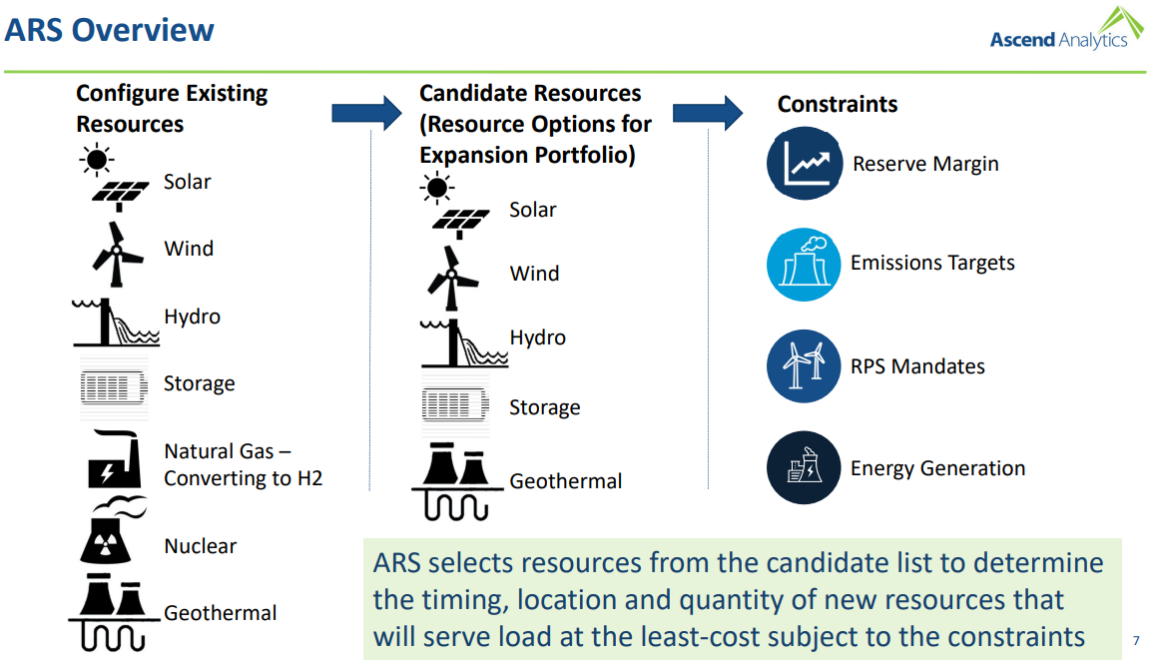


Figure 10. The ARS software package was used for capacity expansion modeling for the LA100 Plan.

The next step in the computer modeling process is running production cost models on the portfolios built by the capacity expansion model. Production cost models use the principle of economic dispatch, which uses the current marginal cost of each generation resource to make dispatch decisions.

Production cost models also take into consideration various operational constraints, as illustrated in Figure 11. For example, to ensure reliability, LADWP requires a minimum quantity of firm, dispatchable, and readily available generation to support transmission reliability. This dispatchable generation must withhold the ability to ramp up power output on short notice to mitigate any contingencies such as an unexpected outage of a major transmission line. The production cost model ensures such constraints are always met.

As with the 2022 SLTRP, the LA100 Plan employs stochastic Monte Carlo simulation. Several years of historical hourly weather data from various weather stations within LADWP's service territory as well as data from weather stations near its renewable generation assets were gathered. This hourly weather data was then correlated to historical customer load data and the output from intermittent renewable solar and wind generating stations. Numerous iterations called simulation repetitions (sim reps) were run using varied forecasted weather data. Some sim reps tended to have higher average temperatures, which resulted in higher customer demand, while other sim reps tended to have lower average temperatures, resulting in lower customer demand. Weather also affects production from wind and solar generating stations. For instance, it was determined that the spread between the high and low temperature of the day was highly correlated to wind energy production. By running multiple sim reps with differing weather, each resource portfolio built by the capacity expansion model could be tested against a wide range of conditions.

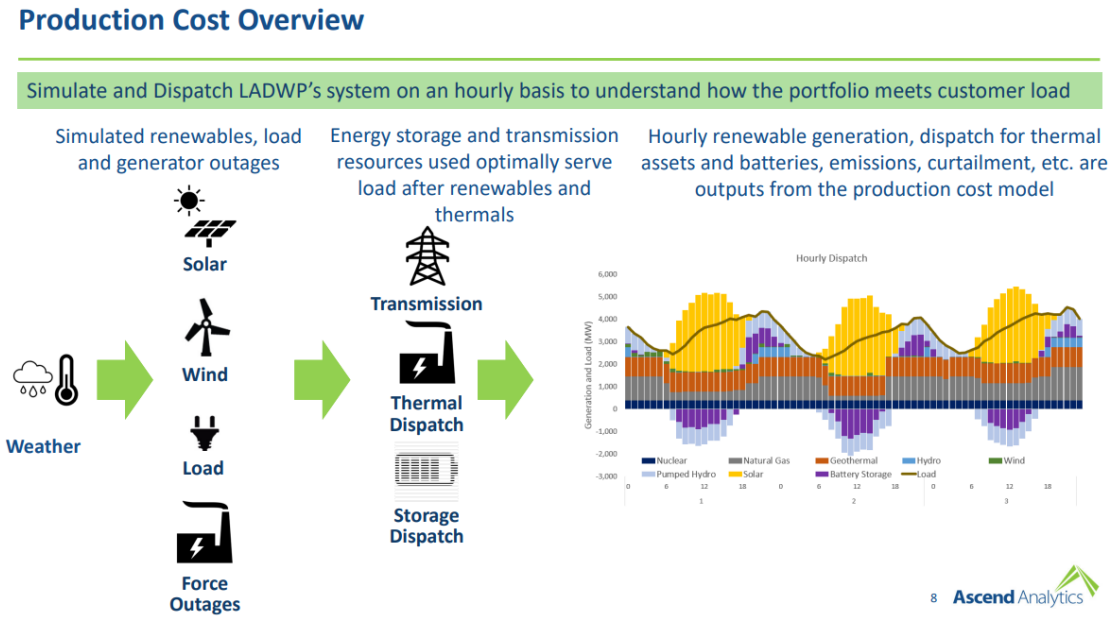


Figure 11. The production cost modeling process used for the LA100 Plan.

ES.3 Results

The LA100 Plan—based on Case 1 from LADWP's 2022 Strategic Long-Term Resource Plan—is the adopted pathway to meet the Los Angeles City Council's goal of 100% carbon-free electricity by 2035. This commitment exceeds California's SB 100 requirement by both timeline and scope, mandating that all generation, including those used to serve transmission, distribution, and future energy storage losses, be carbon-free. It also sets an interim target of 80% renewable portfolio standard (RPS) by 2030.

By 2035, the LA100 Pathway calls for 1,898 MW of local distributed solar, 3,794 GWh of cumulative energy efficiency savings (relative to 2023), 331 MW of distributed energy storage, and 815 MW of demand response. These targets advance a reliable, equitable, and locally focused transition to a carbon-free power system.

The following sections present the results of the computer modeling for the LA100 Pathway, summarizing key findings on resource mix, costs, reliability, and emissions.

ES.3.1 Resource Buildout

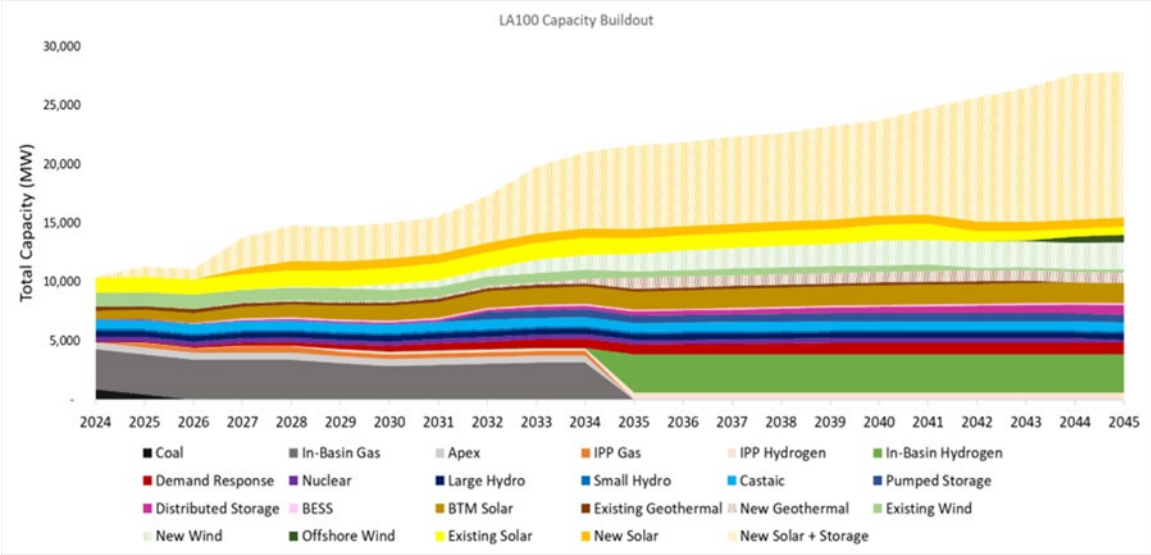


Figure 12. The LA100 Pathway achieves 100% carbon-free electricity by 2035 through major additions of solar with storage, green hydrogen, and wind (including offshore), complemented by geothermal and other firm renewables. Coal is retired by 2025, and natural gas units are retired or converted to hydrogen by 2035.

To reach 100% carbon-free electricity by 2035, the LA100 Pathway calls for major additions of solar with storage, green hydrogen, and wind (onshore and offshore), supported by geothermal and other firm renewables for reliability (Figure 12). Coal is retired by 2025, and all natural gas generation is retired or converted to green hydrogen by 2035, including in-basin thermal units. This balanced portfolio, informed by the NREL LA100 Study, ensures reliability even during periods of low wind and solar output.

ES.3.2 Generation Dispatch

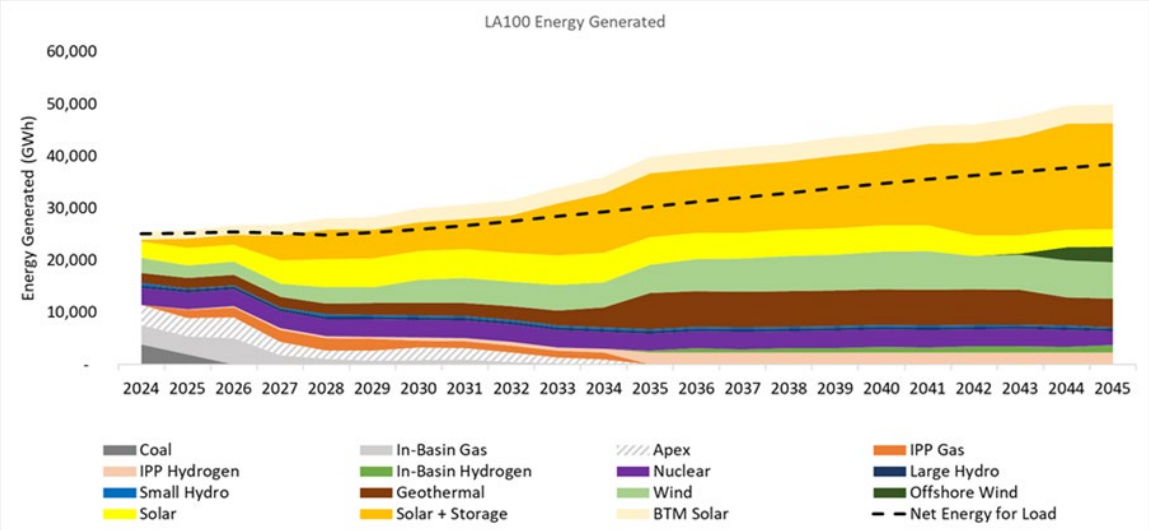


Figure 13. Under LA100 Pathway, the energy mix transitions from fossil fuels to a diverse portfolio of carbon-free resources, reaching 100% by 2035. Coal is retired by 2025, and natural gas is phased out or converted to green hydrogen by 2035. Growing contributions from solar, solar + storage, wind, geothermal, and in-basin hydrogen highlight the system's diversification and decarbonization.

Under the LA100 Pathway, all fossil-fueled generation—coal and natural gas—is eliminated by the end of 2034 to meet the City's 2035 carbon-free goal. The portfolio is anchored by solar PV (both utility-scale with storage and rooftop), wind, offshore wind, and geothermal, with additional contributions from hydro, nuclear, and thermal generation fueled by green hydrogen produced from carbon-free sources (Figure 13). By 2035, all remaining thermal generation uses this dispatchable, carbon-free fuel to help balance variable renewables. At times, generation exceeds net load, which may lead to curtailment or exports, though LADWP seeks to minimize curtailment due to financial and contractual constraints

ES.3.3 Customer Load With Load Modifiers

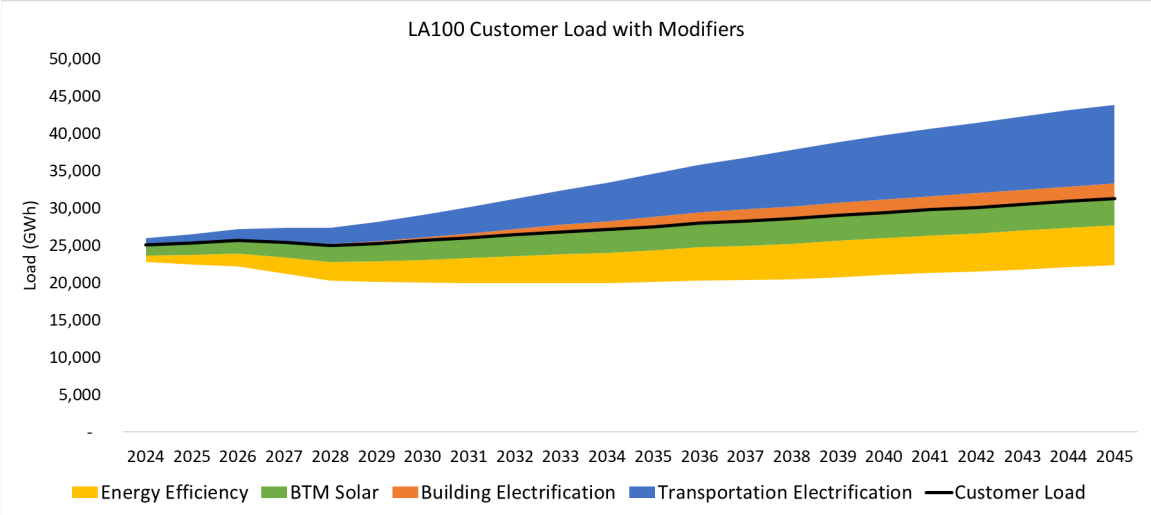


Figure 14. LA100 Pathway customer load with modifiers. While energy efficiency and behind-the-meter solar reduce demand, growth from building and especially transportation electrification drives a steady net increase in load—underscoring the need for proactive planning to deliver reliable, carbon-free power in an electrified future

Projected customer load under the LA100 Plan reflects the combined impacts of energy efficiency, behind-the-meter solar, and growing electrification (Figure 14). Early load reductions from efficiency and rooftop solar are eventually outweighed by demand growth from building and, especially, transportation electrification, driving a steady net increase through the mid-2030s. Managing this evolving load profile will be critical to ensuring reliable, carbon-free electricity delivery.

ES.3.4 In-Basin Capacity Factors

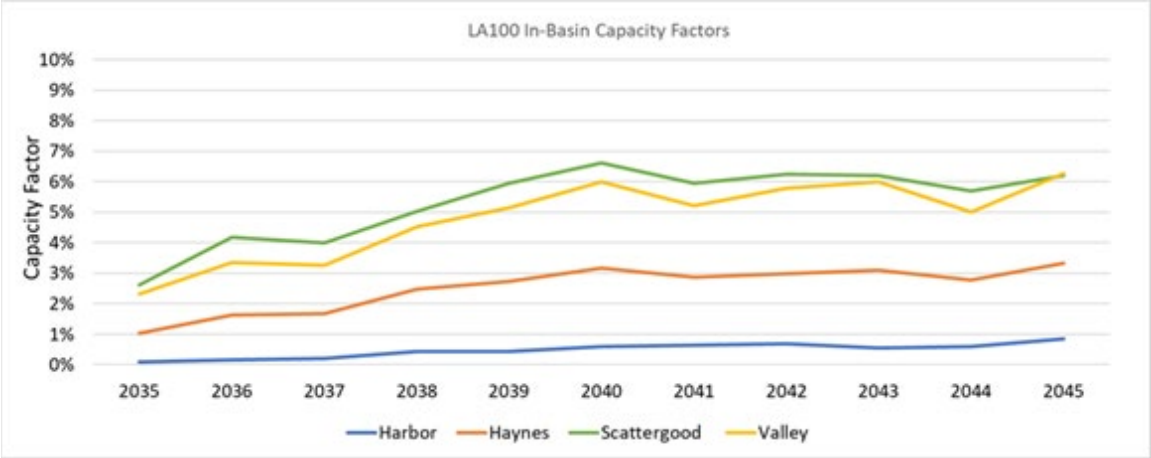


Figure 15. Projected capacity factors for LADWP's in-basin thermal plants under the LA100 Pathway—operating solely on green hydrogen from 2035—remain below 10%, reflecting their role as low-utilization, dispatchable resources for balancing the grid.

By 2035, all LADWP in-basin thermal units are converted to operate solely on green hydrogen from carbon-free sources, maintaining local dispatchable capacity without fossil fuels. These units—projected to operate at capacity factors between 2% and 9% through 2045—serve primarily as reliability reserves, running infrequently to balance variable renewable generation or meet peak demand (Figure 15). Higher utilization is expected for the Scattergood combined-cycle unit, reflecting its efficiency, while smaller combustion turbines remain in reserve for rare contingencies. This approach preserves firm, flexible capacity essential for a resilient, carbon-free grid.

ES.3.5 Renewable and Clean Generation

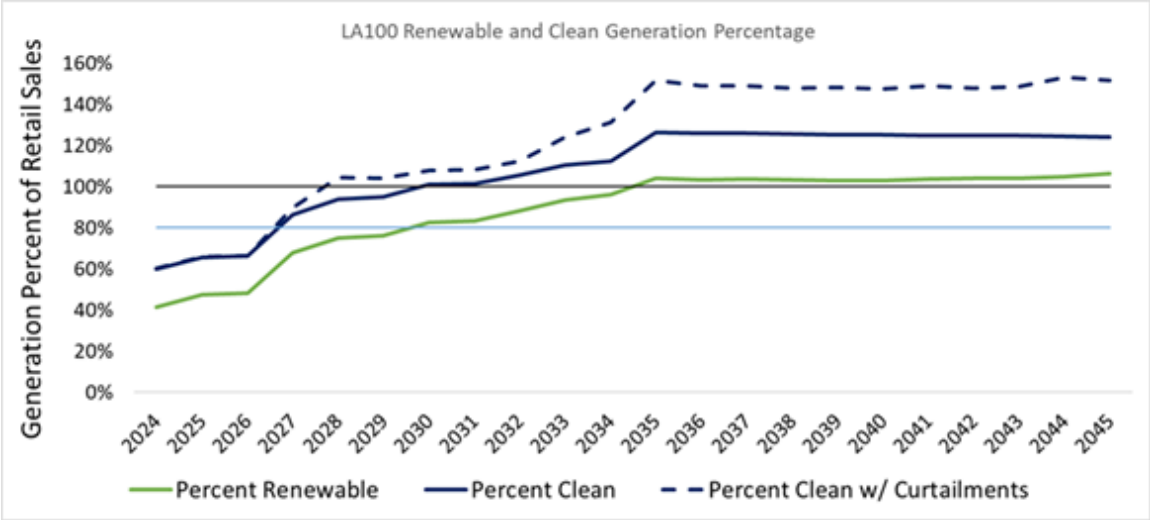


Figure 16. LA100 Pathway renewable and clean energy share as a percentage of LADWP's retail electricity sales. The green line shows renewables (solar, wind, geothermal, small hydro), while the dark blue line includes renewables plus large hydro and nuclear. The dashed blue line shows clean energy including curtailed generation. The black line marks 100% of retail sales, and the light blue line indicates the interim target of 80% renewables by 2030.

Figure 16 shows renewable and clean energy shares as a percentage of LADWP's retail electricity sales under LA100. Renewables (green) reach 80% by 2030; clean energy (dark blue)—renewables plus large hydro and nuclear—hits 100% in the early 2030s. The dashed line includes curtailed clean generation and exceeds 100% in every year after 2030, reflecting periods when total generation from the portfolio exceeds customer demand, requiring curtailment of some renewable output. Under LA100 policy, all generation used to serve losses must also be carbon-free by 2035.

ES.3.6 Greenhouse Gas Emissions

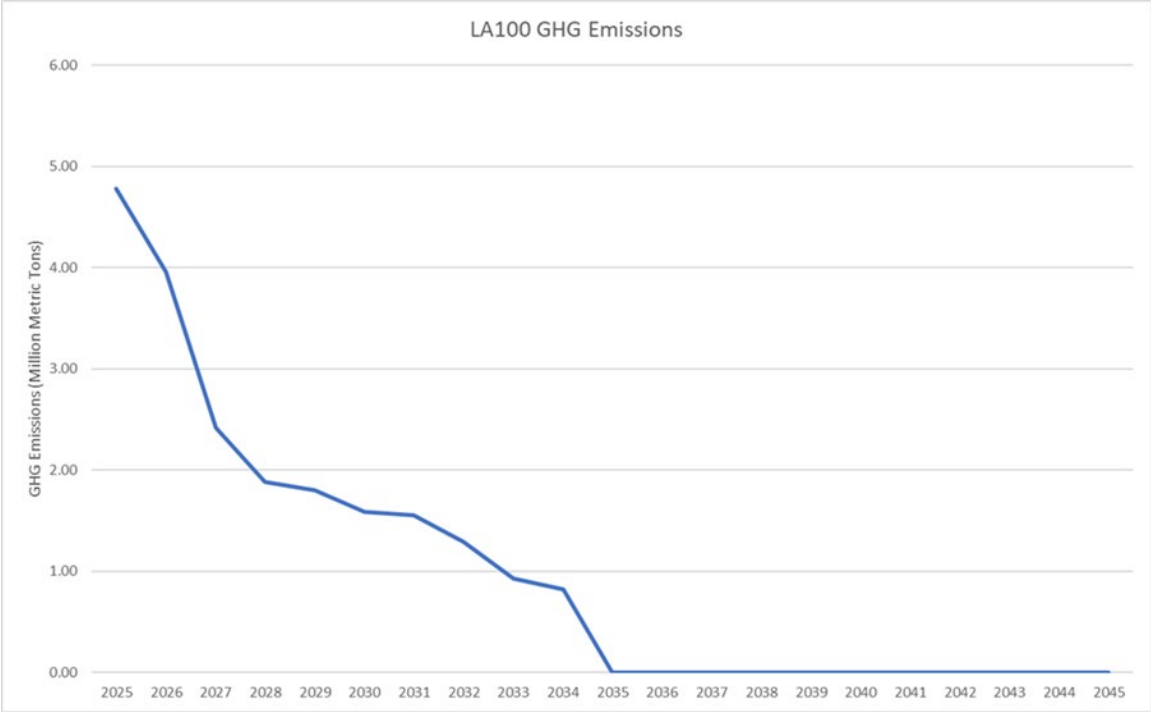


Figure 17. Annual GHG emissions from electricity generation (million metric tons) drop sharply from 2025 to 2035 as LADWP phases out coal and natural gas under the LA100 Pathway, reaching zero in 2035 and remaining at zero through 2045.

GHG emissions from LADWP's power supply fall from just under 5 million metric tons in 2025 to zero by 2035, driven by retiring coal, reducing fossil gas, expanding renewables, improving efficiency, and converting in-basin thermal generation to green hydrogen (Figure 17). From 2035 onward, LADWP sustains zero emissions, meeting all load, losses, and storage needs with carbon-free energy.

ES.3.7 Reliability

Loss of Load Expectation (LOLE) is a key metric used in long-term electric system planning to evaluate system reliability. It represents the expected number of events per year in which aggregate customer demand exceeds the available generation supply or capacity. These system-level shortfalls may result from extreme weather, generation outages, or transmission constraints.

Utilities typically plan their systems to achieve a LOLE of 0.1 or less, meaning no more than one loss of load event every ten years. To estimate LOLE, production cost modeling software performs hundreds of Monte Carlo simulations, each representing a different combination of weather conditions, customer demand, and resource availability. For example, if 100 simulations are run for a given year and 10 of them experience one event where demand exceeds supply, the LOLE would be 0.1—indicating that the system meets the planning standard.

Table 2. LOLE for 2030, 2035, 2040, and 2045 for the LA100 Pathway. The LA100 Pathway consistently achieves LOLE values well below 0.1, indicating an exceptionally reliable system.

LA100 Loss of Load Expectation (LOLE)			
2030	**2035**	**2040**	**2045**
0.02	0.02	0.04	0.00

Table 2 shows the LOLE for the LA100 Pathway for the years 2030, 2035, 2040, and 2045. The LA100 Pathway consistently achieves LOLE values well below 0.1, indicating an exceptionally reliable system.



ES.3.8 Cost

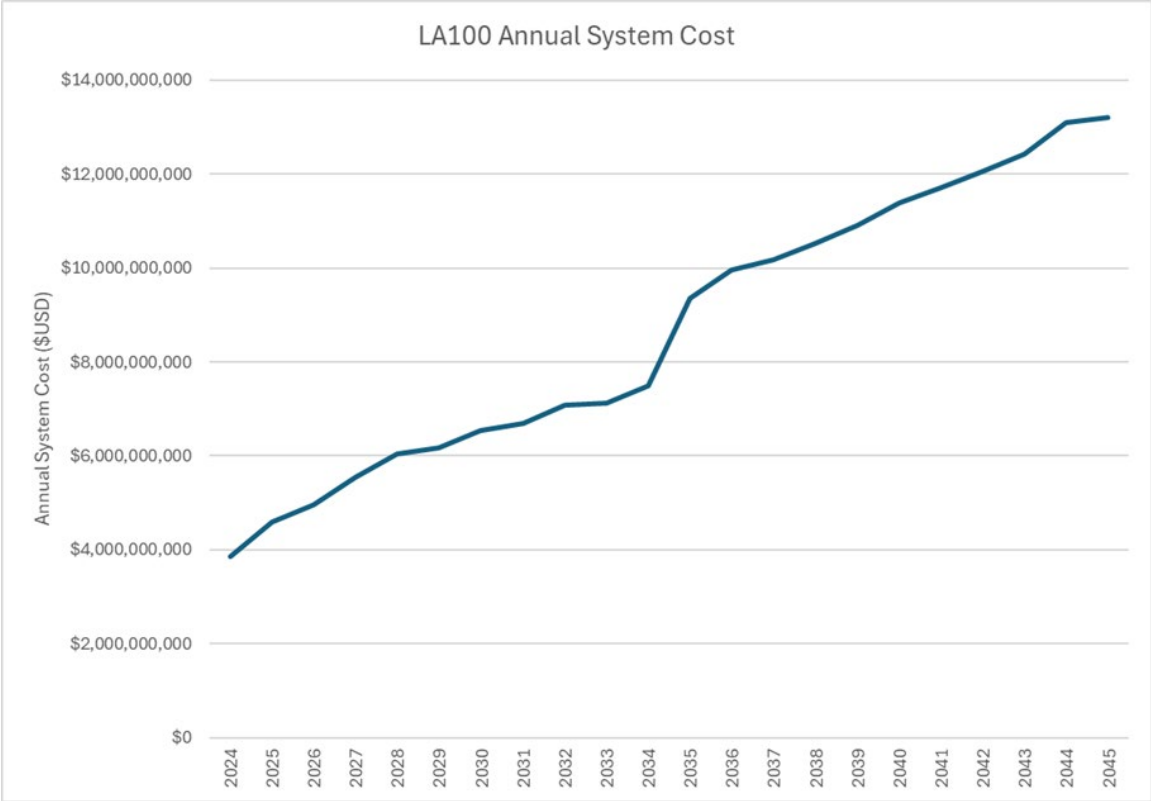


Figure 18. LA100 Pathway annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (such as eHubs).

Annual system costs rise steadily through the 2020s as LADWP invests in renewables, storage, and grid modernization, with a sharper increase around 2035 driven by major infrastructure to achieve 100% carbon-free energy, reliability upgrades, and EV charging deployment (Figure 18). Costs continue to grow at a slower pace into the 2040s, reflecting ongoing maintenance and asset replacement in a modern, electrified grid.

ES.3.9 Rates

LADWP's Financial Services Organization (FSO) performed an electric rate estimate analysis for the LA100 Plan and the SB 100 Reference Scenario, as shown in Figure 19.

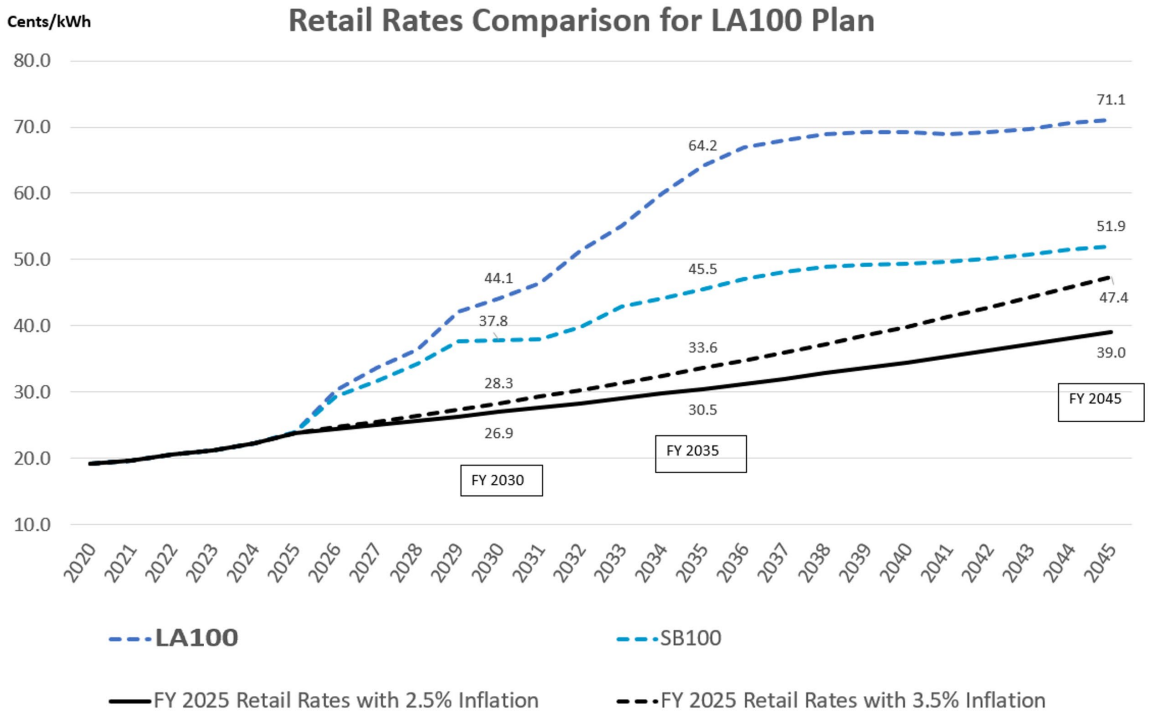


Figure 19. Projected retail electricity rates (in cents per kWh) under the LA100 Pathway and SB100 Benchmark scenarios through 2045. The LA100 scenario assumes accelerated investments to reach 100% renewable energy by 2035, resulting in steeper rate increases compared to the SB100 Benchmark, which targets 100% clean electricity by 2045. For context, the chart also includes inflation-adjusted projections of FY 2025 retail rates under 2.5% and 3.5% annual inflation assumptions.

Retail electricity rates for the LA100 Pathway begin to diverge significantly from those of the SB100 Benchmark starting in 2030, reflecting the accelerated investment trajectory required to achieve 100% renewable energy by 2035. At that point, LA100 rates are projected to be approximately 6.3 cents/kWh higher than SB100. This gap widens rapidly, reaching 18.7 cents/kWh by 2035 and 19.2 cents/kWh by 2045.

The analysis highlights that the most significant rate impacts are front-loaded, with steep increases occurring prior to 2035 due to the early infrastructure and resource investments needed for LA100 compliance. After 2035, rates stabilize as the system

transitions into a lower capital-spending phase. Over the long term, increased electrification presents a key opportunity to grow retail load and mitigate upward rate pressure by spreading fixed costs across a broader consumption base.

ES.3.10 Energy Burden

To better understand how the LA100 Plan impacts customers at the household level, LADWP partnered with UCLA researchers to develop the Los Angeles Residential Energy Transition (RESET) Tool, also called the Energy Burden Tool.

ES.3.10.1 Purpose

The tool projects how LADWP's future revenue requirements and clean energy transition may affect households across the service territory. It measures *energy burden*—the percentage of household income spent on electricity, natural gas, and transportation fuels. A household with an energy burden above 6% is considered to face high energy costs.

ES.3.10.2 How The LA RESET Tool Works

The tool allows LADWP to evaluate customer energy burden under different clean energy pathways by simulating different household profiles. Key attributes of a household's profile include:

- Geography (census tract, zip code, council district, DAC vs. non-DAC)
- Building type (single-family, multi-family, mobile home)
- Upgrade scenarios (energy efficiency or electrification measures)
- Customer programs (EZ-Save, Lifeline, NEM, etc.)
- Energy system assumptions (electric rate cases, natural gas price scenarios, EV charging types)

By adjusting these factors, LADWP can estimate how different decarbonization strategies affect customers across diverse circumstances.

ES.3.10.3 RESET Tool Outputs

The RESET Tool generates annual projections from 2024 to 2045 and produces maps at milestone years (2025, 2030, 2035, 2040, 2045). These maps show geographic variations in projected energy burden, with darker shades highlighting areas of higher household energy burden (see Figure 20, Figure 21, Figure 22, Figure 23, and Figure 24).

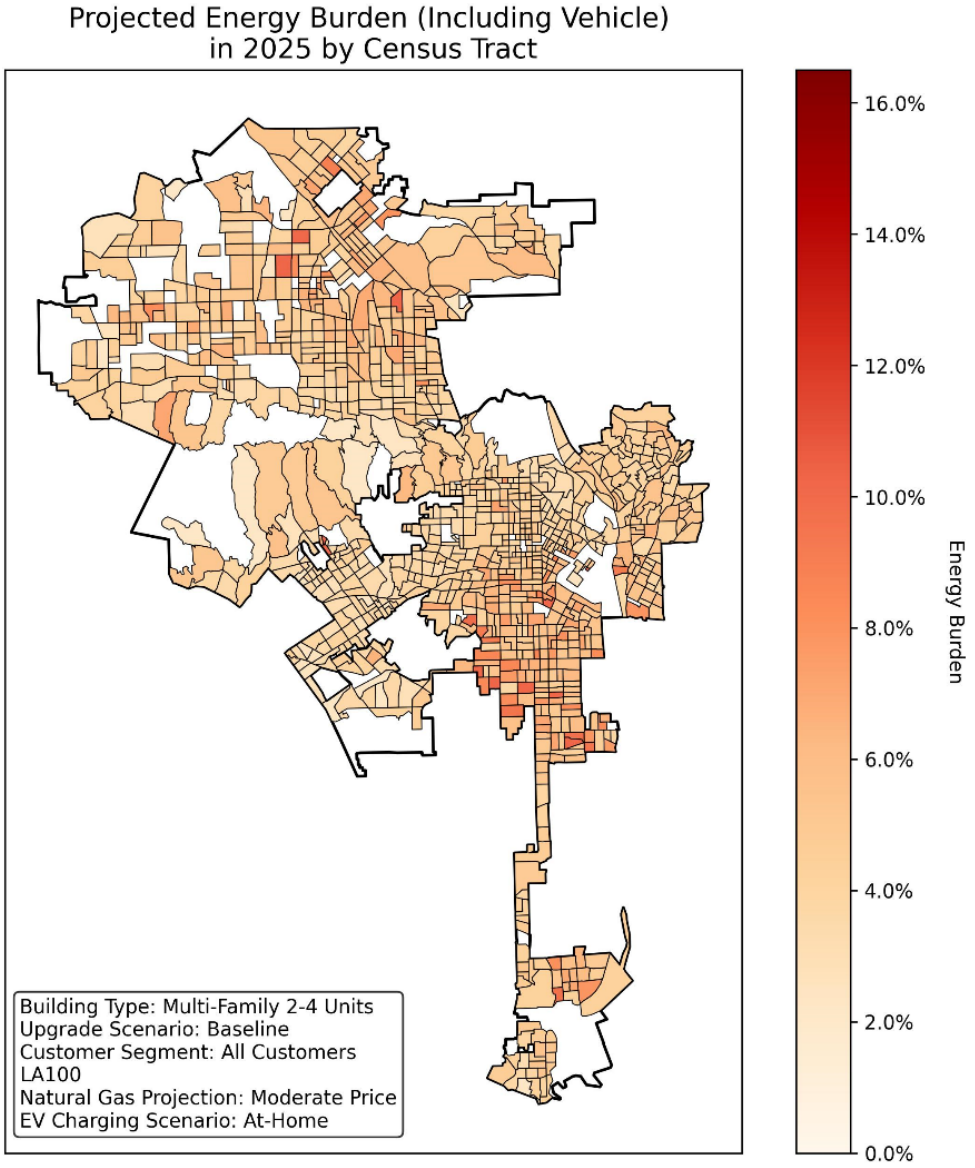


Figure 20. Projected 2025 Energy Burden by Census Tract. Darker areas indicate higher burden; blank tracts lack matching customer profiles. Some areas already exceed the 6% high-burden threshold, though outcomes vary by profile and may improve with customer programs and electrification.

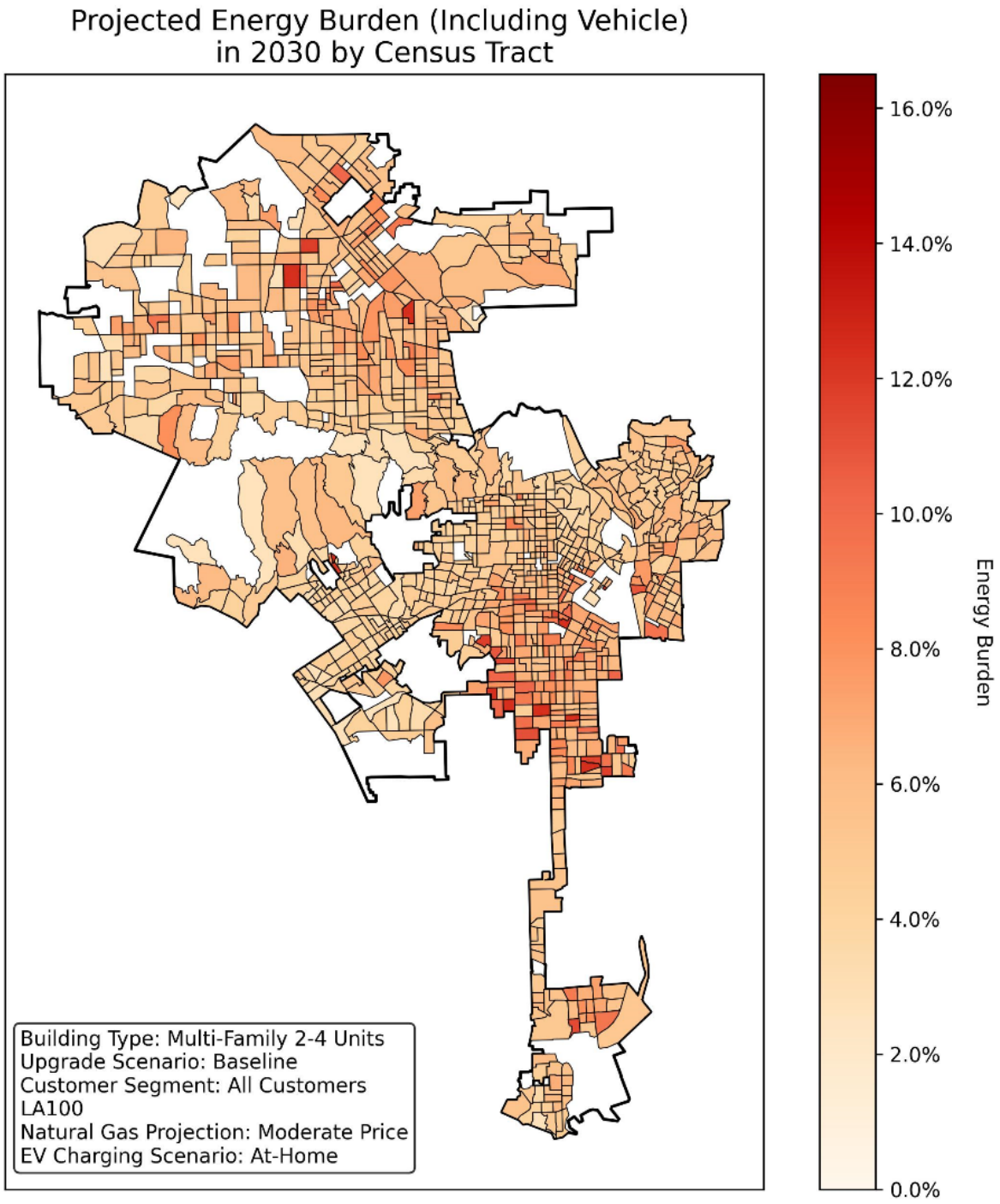


Figure 21. Projected 2030 Energy Burden by Census Tract. Darker colors indicate higher burden; blank tracts lack matching profiles. Energy burden increases in many areas compared to 2025 projections.

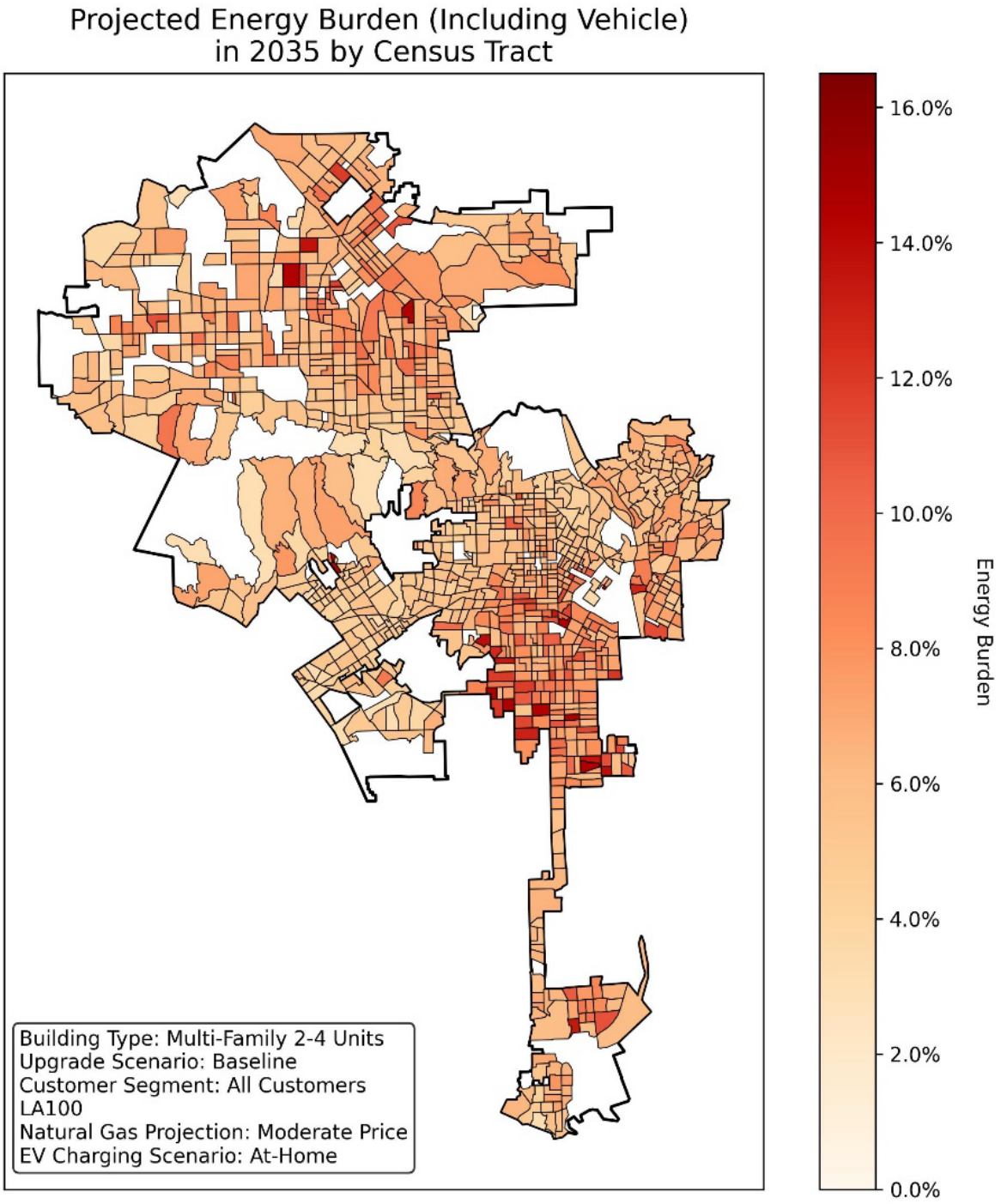


Figure 22. Projected 2035 Energy Burden by Census Tract. Darker areas show higher burden; blank tracts lack matching profiles. Many tracts show increased burden compared to 2030.

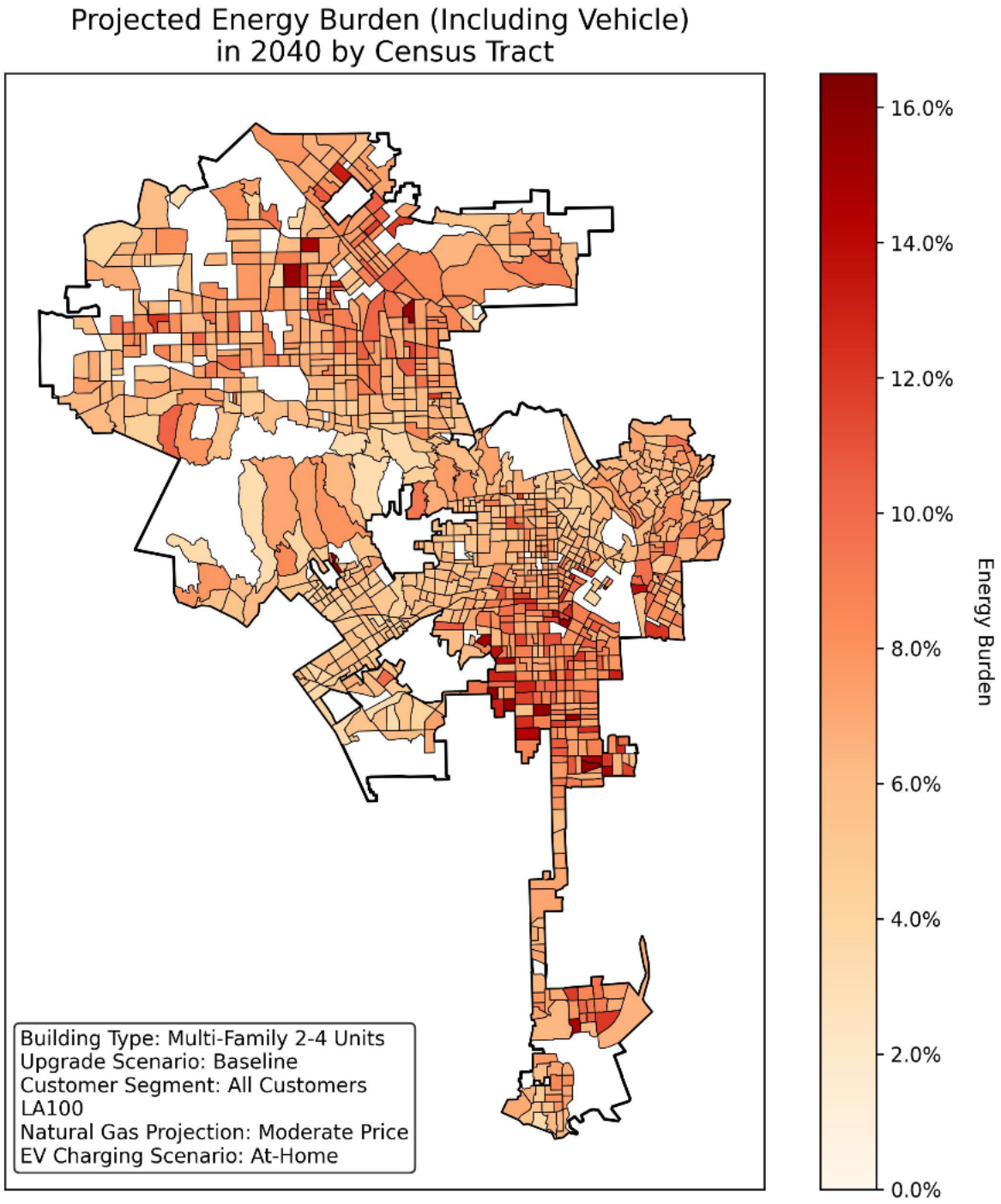


Figure 23. Projected 2040 Energy Burden by Census Tract. Darker shades indicate higher burden; blank tracts lack matching profiles. Burden continues to rise in many areas compared to 2035.

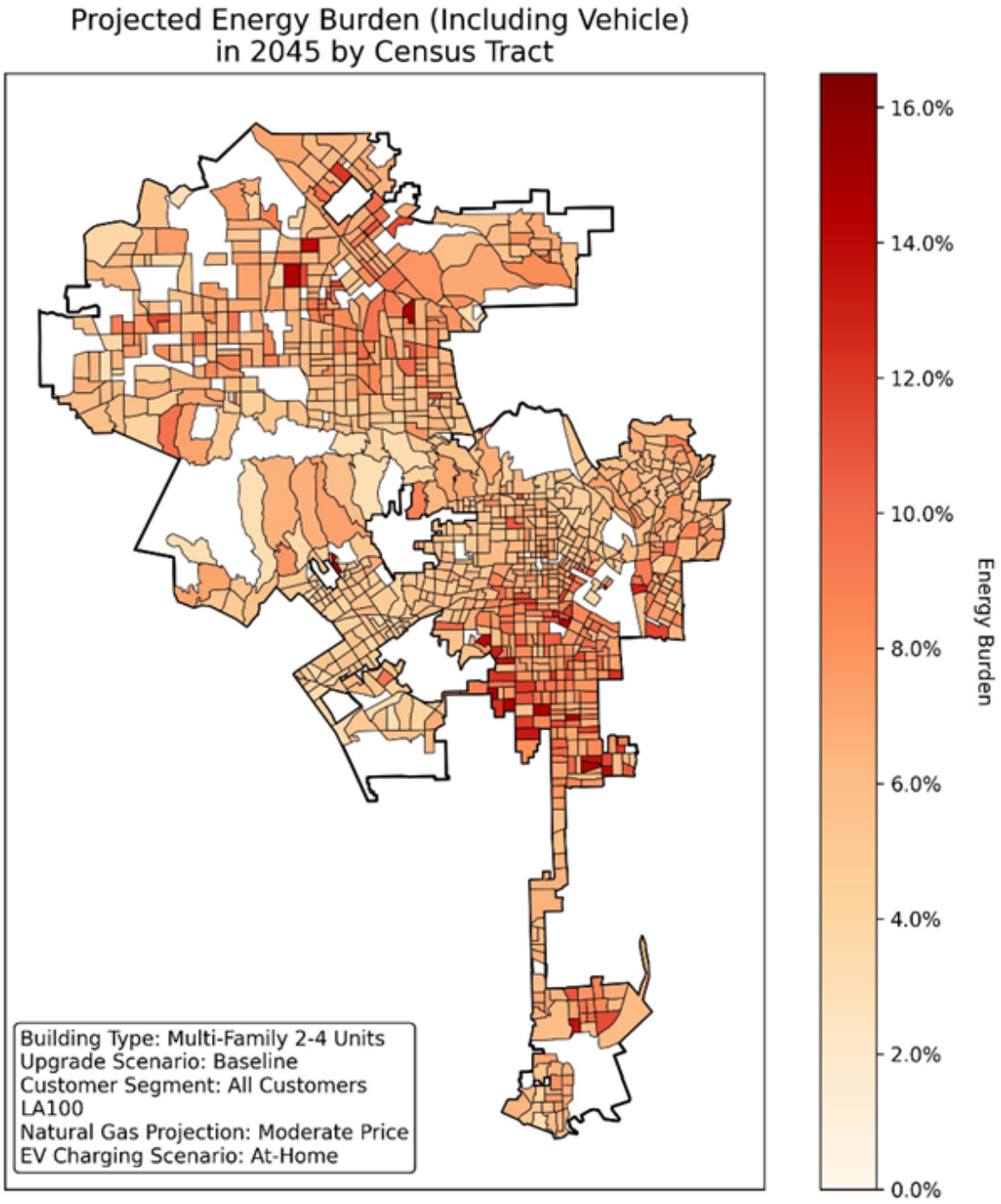


Figure 24. Projected 2045 Energy Burden by Census Tract. Darker colors reflect higher burden; blank tracts lack matching profiles. Slight decrease in burden seen compared to 2040.

ES.3.10.4 Value to LADWP and Customers

The Energy Burden Tool provides:

- A clearer view of the economic impacts of the clean energy transition.
- The ability to identify vulnerable populations at risk of high energy burdens.
- Insight into which programs and technology pathways deliver the most customer savings.

This tool helps ensure LADWP's path to 100% clean energy remains both technically feasible and economically equitable for Los Angeles residents.

ES.4 Long-Term Planning and Next Steps

As mentioned previously, the Los Angeles City Council passed a Motion instructing LADWP to prepare a Strategic Long-Term Resource Plan that achieves 100% carbon-free energy by 2035 in a way that is equitable and has minimal adverse impact on ratepayers.

To that end, LADWP created this LA100 Plan, taking into consideration five primary metrics: cost, emissions, reliability, local air pollutants, and renewable energy curtailments.

ES.4.1 Long-Term Planning Considerations

As the State of California advances toward full decarbonization, LADWP has assumed a leadership role in charting a pathway to achieve 100% carbon-free energy by 2035. This accelerated transition presents significant challenges that must be carefully evaluated and addressed for success. These include implementation feasibility, ensuring affordability and reducing energy burden, overcoming transmission constraints and permitting hurdles, and meeting workforce and human resource needs, among other considerations.

For LADWP to remain a leader in clean energy transformation, it must deliver this transition in a way that preserves both system reliability and affordability for customers. Developing a long-term Power System plan that balances reliability, competitive rates, and environmental stewardship is a complex and ongoing challenge.

This LA100 Plan presents an ambitious strategy to meet the goals set forth by the Los Angeles City Council. It is designed to ensure compliance with regulatory mandates and to provide adequate resources through 2045 based on current information. Achieving these objectives will require success across several major strategic initiatives and goals, including those outlined below:

- Eliminate coal from LADWP's Power Supply by replacing IPP by 2025 with green hydrogen-ready units
- Reach 55% RPS by 2025, 80% RPS by 2030, and 100% carbon-free energy by 2035, including a goal of nearly 1,500 MW of local solar by 2030 and nearly 2,000 MW of local solar by 2035
- Implement several transmission projects and upgrades by 2030 to accommodate the ramp up in renewable energy
- Eliminate the use of Once-through Cooling by 2029 and preserve reliability and resiliency by transforming in-basin generation to carbon-free fuel
- Invest in the Power System Reliability Program to address existing overloads and prepare the grid for future electrification and load growth
- Promote charging infrastructure to support high levels of transportation electrification, which is the key to affordability.

The analysis and conclusions in this LA100 Plan rely on numerous assumptions, including projected fuel and purchased power costs, renewable generation costs, proposed state and federal mandates, and greenhouse gas emissions costs. Beyond these, other risks—such as implementation challenges, workforce availability, permitting requirements, and factors outside LADWP's direct control—could significantly influence outcomes.

If any of these underlying assumptions change, LADWP's long-term strategies will need to be adjusted accordingly. Long-term resource planning is inherently an ongoing, iterative process. As uncertainties are better understood and as policy direction and requirements become more defined, LADWP will continue to adapt and refine the LA100 Plan.

The recommendations in this and future iterations may need to be updated as new programs are developed and implemented, especially in response to changing economic conditions, technological advancements, and other unforeseen factors. LADWP remains committed to working collaboratively with research organizations, customers, and key

stakeholder groups to evolve the LA100 Plan and deliver successful projects and programs that advance the City's clean energy transition.

ES.4.2 Next Steps

As previously noted, the LA100 Plan is an iterative process that will continue to evolve through periodic updates informed by technical findings, stakeholder input, and emerging policy or operational considerations. LADWP will maintain regular communication with the Los Angeles City Council on the progress of LA100 Plan implementation. These updates include a semi-annual "report card" to the Council's Energy, Climate Change, Environmental Justice, and River (ECCEJR) Committee, providing a transparent accounting of progress made, challenges encountered, and risks identified across major categories essential to achieving the LA100 goals.

With the approval of LADWP Power System Division Directors and Executive Management, this iteration of the LA100 Plan is being formally released. Immediately following its release, work will commence on the next version, which will integrate lessons learned, new modeling insights, stakeholder feedback, and any relevant developments in technology, regulation, and market conditions.

In parallel, LADWP's Financial Services Organization will review the LA100 Plan in detail to assess any implications for rates. Should a rate action be deemed necessary, it will be subject to the formal approval process by the LADWP Board of Commissioners and the Los Angeles City Council. This coordinated approach ensures that the LA100 Plan remains both technically feasible and financially responsible, while aligning with the City's broader energy transition objectives.

ES.4.3 Caveats

This LA100 Plan serves as a conceptual framework rather than a definitive, prescriptive roadmap. Its projections and strategies are subject to a wide range of uncertainties, including the availability and maturity of emerging technologies, the feasibility of large-scale implementation, and potential impacts on system reliability and affordability. These challenges represent key risks that could delay or alter LADWP's transition to 100% carbon-free energy.

Future iterations of the LA100 Plan will need to account for these constraints in greater detail, assessing how they may influence assumptions, modeling approaches, and projected clean energy outcomes. As LADWP continues to refine and optimize the buildout of its Power System resource portfolio, careful consideration will be given to balancing reliability and resilience, environmental stewardship, and cost-effectiveness.

The ongoing nature of this process underscores that the LA100 Plan is a living document—one that will evolve in response to new data, policy developments, stakeholder input, and advances in technology. This adaptive approach will help ensure that the plan remains both aspirational and achievable while aligning with LADWP's core mission of delivering safe, reliable, and affordable power to the people of Los Angeles.

To help mitigate the risks associated with long-range planning and evolving external conditions, LADWP maintains a proactive focus on contingency planning and near-term execution through its Power System Top 10 Initiatives. These initiatives represent critical infrastructure and operational priorities designed to reinforce system reliability, improve public safety, support economic vitality, and bolster climate resilience—regardless of uncertainties such as distributed energy resource (DER) adoption rates, supply chain constraints, or the pace of hydrogen cost reductions. The current Top 10 Initiatives are: (1) Scattergood Generating Station Modernization, (2) Wildfire Mitigation, (3) Pacific Palisades Fire Hardening, (4) Outage Management System Modernization, (5) New 34.5 kV Subtransmission and 4.8 kV Feeder Upgrades, (6) New Business Support, (7) Tarzana–Olympic Transmission Line Upgrade, (8) Sylmar Converter Station Bank E/F/G Upgrades, (9) Renewable Resources Procurement, and (10) New Business Concierge Services.

These initiatives complement the longer-term strategic direction of the LA100 Plan by ensuring that foundational grid visibility, reliability, and customer service improvements are being addressed in parallel with transformational decarbonization. For example, wildfire mitigation and subtransmission upgrades directly reduce outage risks during extreme weather events, while modernization efforts at Scattergood provide firm, local generation to support system reliability during high-stress conditions. In parallel, LADWP continues to invest in critical modeling and sensitivity analyses. These "what-if" stress tests examine potential deviations from baseline assumptions—such as slower EV adoption, lower building electrification uptake, or lagging technology readiness—and help inform resource planning strategies that are robust across a broad range of future scenarios.

The implementation of Advanced Metering Infrastructure (AMI) and Distribution Automation (DA) is an essential foundation for many of the Power System Top 10 Initiatives and for the long-term goals and implementation of LA100. Together, AMI and DA provide the real-time granular operational data, and automated field capabilities required to support a clean, flexible, but most importantly safe and reliable power grid. These technologies increase the operational visibility of the distribution system at a scale unmatched by legacy infrastructure, enabling LADWP to more precisely forecast demand, manage variability from renewable resources, and respond to emerging reliability risks.

Collectively, AMI and DA form the infrastructure and digital backbone that connects customers, field devices, planning tools, and operational systems. By embedding automation, and data analytics into the grid, these investments ensure that LADWP can navigate evolving technology landscapes, respond to emerging risks, and sustain progress toward achieving 100% carbon-free energy.

Overall, these combined efforts underscore that the LA100 Plan is not a rigid prescription, but rather a flexible and adaptive framework designed to evolve in response to new information, stakeholder input, and real-world developments. By integrating both high-level strategy and boots-on-the-ground implementation, LADWP is better equipped to deliver a clean, resilient, and affordable energy future for all Angelenos—even amid deep uncertainty.

ES.4.4 Change in Law

Since the transition to the current presidential administration, notable policy changes related to energy and utilities have been announced, including executive orders and legislation. LADWP is actively monitoring these developments, which include potential impacts to funding available for clean energy projects.

ES.4.4.1 Implications of the One Big Beautiful Bill (OBBB) Act

In addition to executive actions, federal legislative changes can significantly influence LADWP's long-term planning and investment strategies. On July 4, 2025, President Trump signed the One Big Beautiful Bill Act (H.R. 1) into law. This legislation introduces sweeping changes to clean energy tax policy, including the phase-out of the Section 45Y Production Tax Credit (PTC) and Section 48E Investment Tax Credit (ITC) for wind and solar projects. These changes are expected to have a substantial impact on renewable

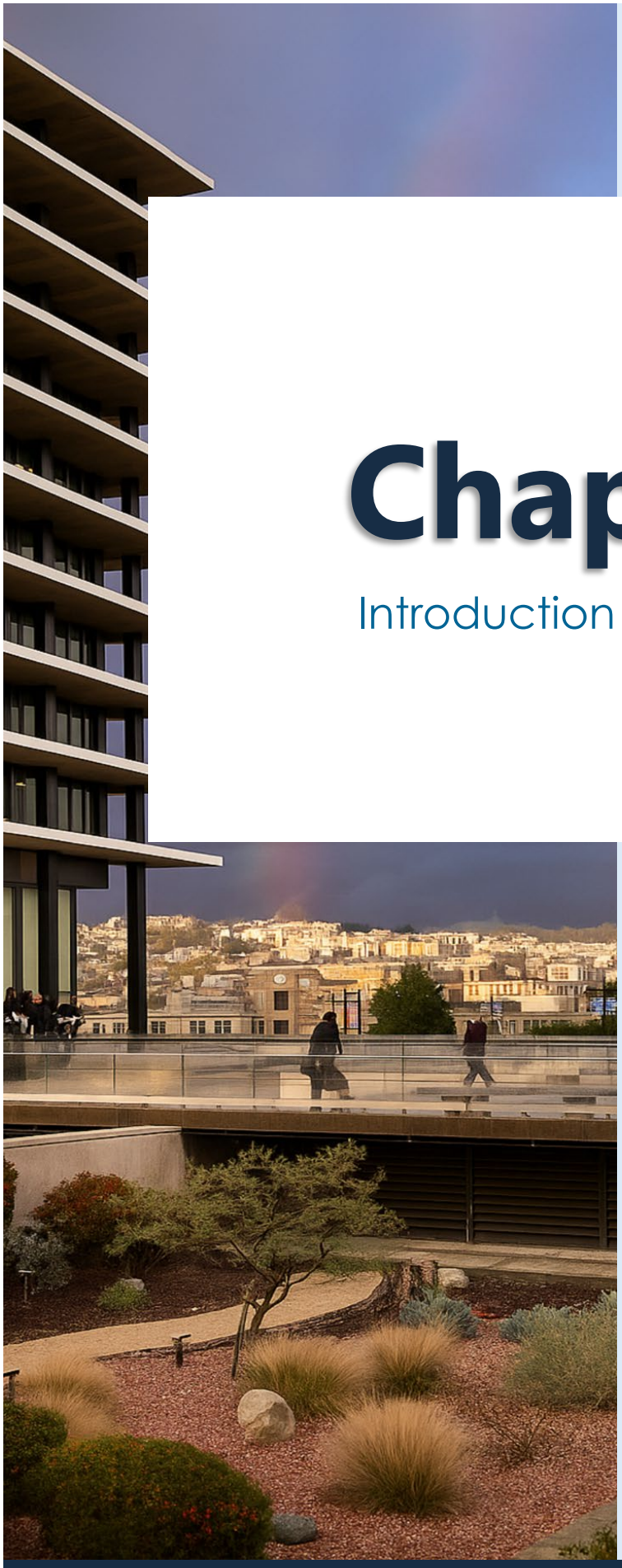
energy project pricing, financeability, and overall viability, not just for LADWP, but for utilities nationwide. The OBBB was enacted after the modeling for the current LA100 Plan was nearly complete, meaning its effects are not fully reflected in the current analysis. The next iteration of the LA100 Plan will explicitly incorporate the implications of the OBBB, including updated assumptions around project economics, market dynamics, and procurement strategies. This will ensure LADWP's planning remains responsive to evolving federal policy and continues to support a reliable, affordable, and sustainable transition to 100% carbon-free energy.

ES.4.4.2 Termination of Federal Funds for California Hydrogen Hub

In October 2025, the U.S. Department of Energy (DOE) rescinded its $1.2 billion award to the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES), which had been designated in 2023 as one of seven regional hydrogen hubs under the Bipartisan Infrastructure Law. As a subrecipient, LADWP had anticipated receiving federal funding through ARCHES to support the Scattergood Generating Station Units 1 & 2 Green Hydrogen-Ready Modernization Project. Following the cancellation, the Governor's Office of Business and Economic Development (GO-Biz) plans to continue to develop California's Hydrogen Market Development Strategy; they will work closely with ARCHES founding members, partners, and interested parties to establish a shared foundation for robust market development.



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Chapter 1

Introduction & Background

Key Highlights

- Roadmap: Defines LADWP's official pathway to achieve 100% carbon-free energy by 2035, ensuring reliability, affordability, and equity.
- Foundation: Builds on the LA100 Study and 2022 SLTRP Recommended Case, translating technical findings into actionable strategies.
- Investments: Focuses on key "no-regrets" investments, renewables, green hydrogen, energy storage, and transmission upgrades, to accelerate progress.

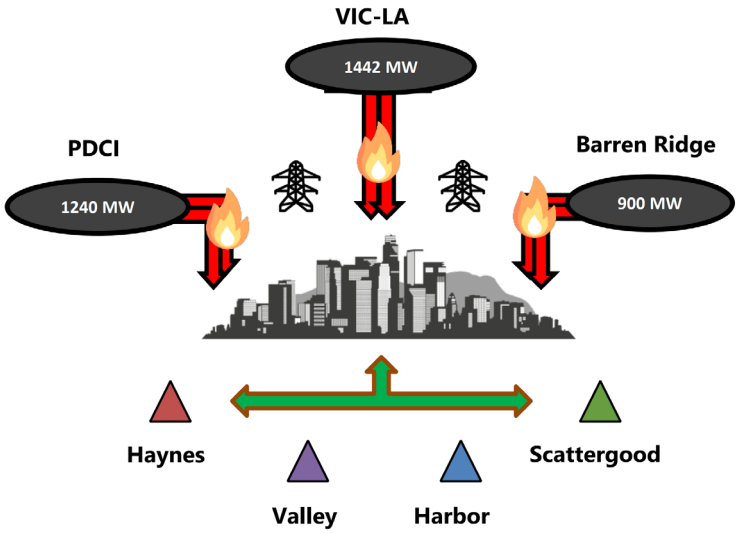


1.1 Introduction and Background

The LA100 Plan developed by the Los Angeles Department of Water and Power (LADWP) provides a comprehensive roadmap for meeting the future energy needs, regulatory mandates and clean energy goals for the City of Los Angeles (LA). At LADWP, we strive to achieve all our planned goals while providing affordable, safe, and reliable power to all our customers. To ensure that our plans reflect the values and needs of the communities and customers we serve, the process for developing the LA100 Plan includes an Advisory Group (AG) where stakeholders and community members can provide us with feedback and additional recommendations. Throughout the planning process, LADWP staff considered all technical requirements, regulatory mandates, and community feedback to present a comprehensive and robust long-term plan. The LA100 Plan will synchronize with the annual budget process, which will allow us to update the plan's assumptions and recommend the optimal pathway for achieving 100% carbon-free energy by 2035 with minimal adverse rate impacts. This LA100 Plan sets up a framework for LADWP to address key opportunities and risks to ensure an effective and equitable clean energy transformation for the City of LA.

1.2 The Power System

LADWP's Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,988 megawatts ("MW") and net dependable capacity of 7,965 MW as of December 31, 2024. The Power System's highest load registered 6,502 MW on August 31, 2017. LADWP provides electric and water service almost entirely within the boundaries of the City of LA, an area covering approximately 473 square miles, where it serves over 1.5 million customers, and serves approximately 5,214 customers in certain areas of Inyo and Mono Counties in the State of California. To provide Angelenos with a safe, reliable, and resilient electric grid, LADWP maintains a vast network of overhead transmission and distribution lines, transmission towers, underground cables, power poles, crossarms, transformers, and vaults.



Additionally, LADWP currently owns and operates four natural gas-fired generating stations located within the Los Angeles Basin (often referred to as the "in-basin" power plants), which are shown in Figure 1-1:

- Harbor Generating Station, located near the Port of LA
- Haynes Generating Station, located in Long Beach and Seal Beach
- Scattergood Generating Station, located near Los Angeles International Airport (LAX)
- Valley Generating Station, located in the San Fernando Valley.



Valley Generation Station



Haynes Generation Station



Harbor Generation Station



Scattergood Generating Station



Figure 1-1 LADWP "in-basin" generating stations.

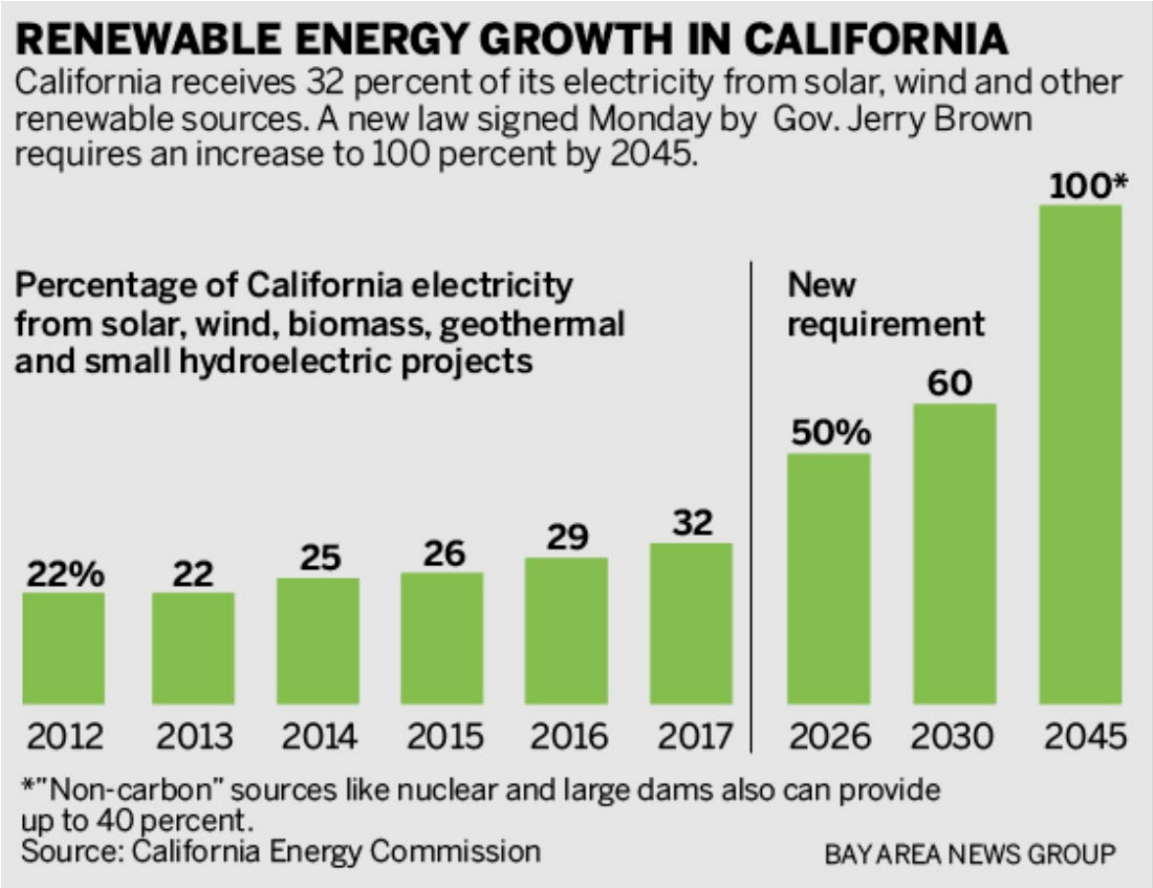
LADWP owns and operates the Castaic Power Plant, a pumped-storage hydroelectric generation facility located in Castaic, California. LADWP also has contracts for a portion of the generating capacity from the Intermountain Power Project (IPP)—a coal-fired power plant located in Delta, Utah set for retirement in 2025, Hoover Dam hydroelectric power plant in Nevada, and the Palo Verde Generating Station, a nuclear power plant located in Arizona.

LADWP also owns or has power purchase agreements for several renewable energy generating facilities, including several solar, wind, and small hydroelectric facilities in California's Owens Valley, wind facilities located in Utah, New Mexico, Oregon, Wyoming, and Washington State, and geothermal and solar facilities in California and Nevada.

1.3 California Senate Bill 100

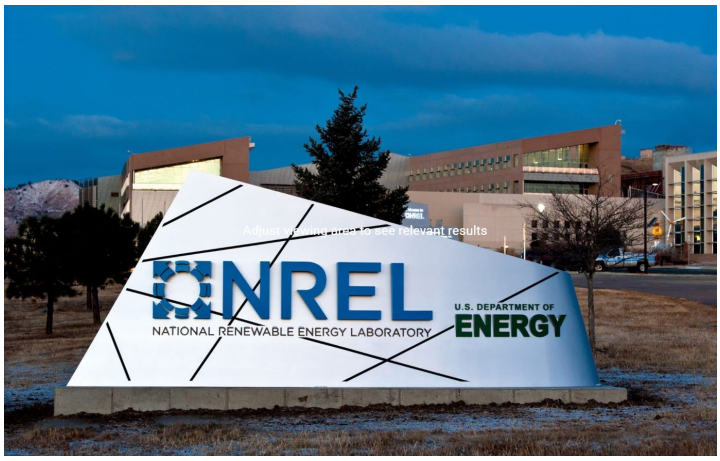
California Senate Bill 100 (SB 100), or the "100 Percent Clean Energy Act of 2018", sets a 2045 goal of powering all retail electricity sold in California with zero-carbon resources, such as solar, wind, hydroelectric, and nuclear power. Additionally, SB 100 mandates that California utilities achieve at least 60% renewable portfolio standard (RPS) by 2030.

Computer modeling conducted by the Joint Agencies (CEC, CPUC, and CARB) and their consultants suggests that SB 100 is technically achievable through multiple pathways; however, construction of clean electricity generation and storage facilities must be sustained at record-setting rates. Additional findings indicate that retaining some firm, dispatchable generation capacity such as natural gas-fired power plants may minimize costs and ensure uninterrupted power supply during the transition to 100% carbon-free energy.



1.4 National Renewable Energy Laboratory Study

In 2016, the LA City Council approved a Motion instructing LADWP to develop a partnership with the US Department of Energy and other entities to determine what investments must be made to achieve a 100% carbon-free portfolio. This project is known as the LA100 Study.



As a result of the Council's Motion, LADWP entered into an innovative partnership with the US Department of Energy's National Renewable Energy Laboratory (NREL) to study the technical feasibility of achieving a 100% clean energy grid.

The LA100 Study found that decarbonizing LADWP's electric grid could have several potential benefits, including:

- Improvements in local air quality and reduced hospitalization and death from respiratory ailments.
- The creation of local jobs, such as for the maintenance of clean energy systems and the construction of new transmission and distribution lines.
- The improvement of LADWP's grid to enhance reliability and resiliency and the ability to adapt to changing climate shocks caused by natural disasters.

Based on the findings of the LA100 Study, in 2021 the Los Angeles City Council instructed LADWP to prepare a strategic long-term resource plan (SLTRP) that achieves 100% carbon-free energy by 2035 in an equitable manner, with minimal adverse impact on ratepayers. In response, LADWP compiled the 2022 SLTRP with the Recommended Case achieving 100% carbon-free energy by 2035. The successor to the 2022 SLTRP is this LA100 Plan, whose primary pathway to 100% carbon-free energy by 2035 is based on the 2022 SLTRP's Recommended Case.

1.4.1 The LA100 Study

The LA100 Study was an unprecedented effort led by the National Renewable Energy Laboratory, with the support of a community-based advisory group, energy experts and researchers. The study identified multiple investment pathways for LADWP to provide reliable and affordable carbon-free energy by 2045, and as early as 2035. Each pathway analyzed impacts related to power reliability, job creation, environmental benefits, equity and environmental justice implications, costs, and rate impacts. The study was guided by an Advisory Group representing a diverse cross-section of stakeholders. The LA100 Study resulted in several key findings:

- The LA100 Study determined several investment pathways to achieve the 100% carbon-free energy target while remaining true to the core principles of reliability, environmental stewardship, environmental justice, resiliency, and affordability. With the LA100 Study completed, LADWP now has the tools and roadmap to continue on the path to 100% carbon-free energy.
- Creating a carbon-free energy supply is unprecedented for a power grid as large and complex as LA's and will require additional study and planning, followed by action.
- Prior to the LA100 Study, LADWP had already begun laying the groundwork to deeply decarbonize its power grid while continuing to maintain reliable energy for LA . Examples of plans and targets by 2030 include: 1,000 MW of new energy storage and electric vehicle (EV) charging infrastructure targets, including commercial charging stations (120,000) and EV adoption (750,000 light-duty EVs and 12,000 medium-and heavy-duty EVs).
- LADWP should approach its 100% carbon-free energy target through a multi-pronged effort that incorporates public input at every level.

Across all LA100 Study scenarios, there is also a need for new transmission to accommodate future growth in renewables and meet increased demand. LADWP has identified 10 critical transmission projects to complete over the next 10 years. This requires an unprecedented deployment of transmission infrastructure. These critical transmission projects will ensure grid reliability to meet growing electricity demand due to expanding EV adoption, building electrification and electrification of the Port of LA. Additionally, these transmission projects will support future conversion of LADWP's in-basin generating stations to green hydrogen power and storage, starting with Scattergood Generating Station.

To facilitate the completion of these transmission projects by 2035, LADWP will need reliable flexible generation capacity within the LA Basin. Permitting, upgrading, and building transmission capacity is a lengthy process. A recent in-basin underground transmission line stretching 11.5 miles through the busy West LA area took 12 years to complete.

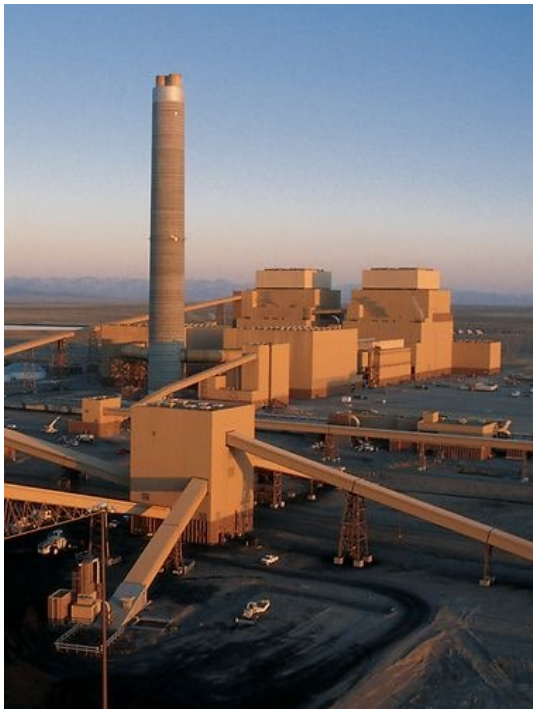


As LADWP builds the necessary infrastructure, procures new generation and storage technologies, and develops effective customer programs, LADWP is committed to working with communities to promote a just and equitable transition to a 100% carbon-free power supply for LA.

The LA100 Study also provided LADWP's power engineers and grid operators with tools to model scenarios to determine the path to 100%, evaluate tradeoffs and costs and take the next steps to keep LA on track to not only achieve, but to accelerate its path to 100% renewable energy.

During the LA100 Study process, LADWP made significant progress in continuing to green its grid and accelerate LA's clean energy transformation. Since the study began LADWP has made major renewable energy commitments to:

- Achieve LA's Green New Deal renewable energy targets.
- Invest in and commit to using green hydrogen at Intermountain Power Project, a key source of power generation for LA, which is expected to reach commercial operation in Quarter 4, 2025.
- Approve several large-scale solar-with-storage and wind projects.

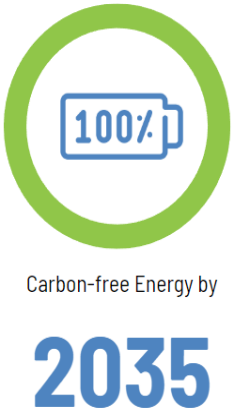


- Eland Solar & Storage Center, Phase 1 and 2 (400 MW solar + 1,200 MWh BESS) at Barren Ridge, Eland 1 reached commercial operation in 2024, and Eland 2 reached commercial operation in 2025Red Cloud Wind (331 MW) at Navajo, 12/22/2021 commercial operation date
- Milford Solar Phase 2 (300 MW) at Utah, estimated Quarter 4 2026 commercial operation date

- Launch several new distributed energy resource (DER) programs.
  - Expanded solar feed-in tariff program
  - Advertised a DER Request for Proposal for approximately 30 MW
  - Expanded commercial demand response program and launched a Power Savers program and will expand the Power Savers program
  - Launched a feed-in tariff+ and virtual net metering pilot program.

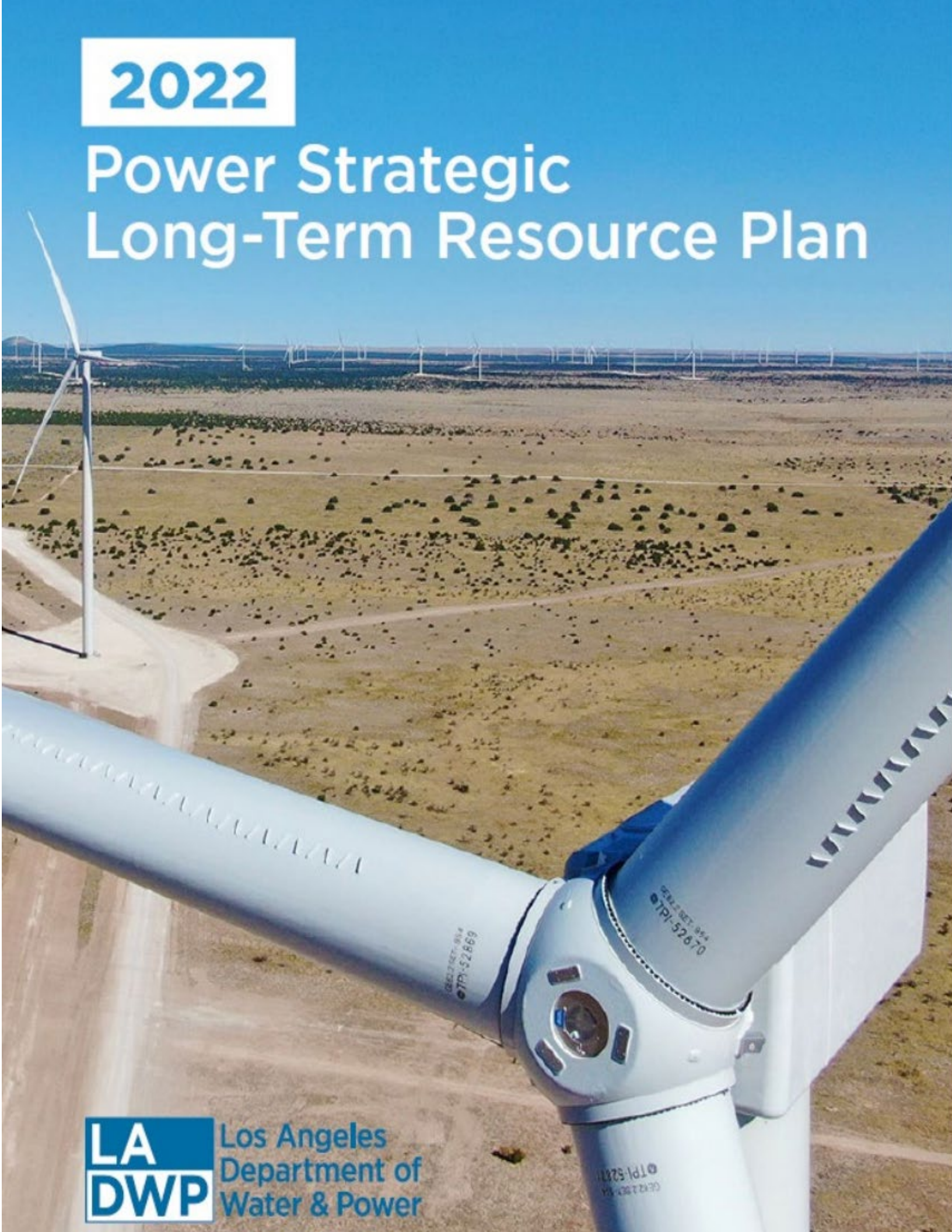
1.4.1.1 The 2022 Strategic-Long Term Resource Plan

In response to the LA100 Study, LADWP developed the 2022 Strategic Long-Term Resource Plan (2022 SLTRP) to translate the study's insights into actionable, utility-driven strategies. The 2022 SLTRP evaluated multiple scenarios to reach 100% carbon-free energy and ultimately recommended Case 1 as the most balanced and feasible option. This case aligned closely with the LA100 Study's "Early and No Biofuels" scenario, which had already been endorsed by then-Mayor Eric Garcetti and the LA City Council as a preferred pathway. Case 1 of the 2022 SLTRP achieves 100% carbon-free energy by 2035, in line with the City's accelerated goals and became the official Recommended Case. The 2022 SLTRP Recommended Case would serve as the primary pathway for achieving 100% carbon-free energy by 2035 for this LA100 Plan.



The framework for the 2022 SLTRP was guided by the findings of the LA100 Study as well as policy direction from the Mayor and City Council. The LA100 Study identified nine distinct pathways to reach 100% carbon-free energy by 2045 or sooner, analyzing tradeoffs in reliability, affordability, equity, environmental benefits, and job creation. Upon completion of the study in March 2021, Mayor Garcetti committed LADWP to achieving 80% renewables by 2030 and 100% carbon-free energy by 2035.

2022
Power Strategic Long-Term Resource Plan



LA DWP Los Angeles Department of Water & Power

In September 2022, the LA City Council reaffirmed this commitment through Motion No. 21-0352, which formally directed LADWP to develop the 2022 SLTRP based on these accelerated targets. The motion also emphasized environmental justice, equitable outcomes, and community engagement throughout the planning process.

The 2022 SLTRP was presented to LADWP's Board of Water and Power Commissioners and released to the public in 2023.

1.4.1.2 The LA100 Plan

Originally, the next planning cycle was intended to produce the 2024 SLTRP. However, to better reflect LADWP's full commitment to the City Council's motion and to build on the foundational work of the LA100 Study, management rebranded this effort as the LA100 Plan. The LA100 Plan takes the 2022 SLTRP's Case 1 as its primary planning case—referred to as the "LA100 Pathway" throughout this document—to signify that this is no longer one of many hypothetical options, but rather the officially adopted path forward. In doing so, LADWP has solidified its commitment to the infrastructure investments, programmatic initiatives, and policy priorities needed to achieve a 100% carbon-free energy supply by 2035.

1.4.1.3 Next Steps

The LA100 Study reaffirmed that achieving a 100% renewable power system requires sustained deployment of renewables like wind and solar, overnight and seasonal storage, in-basin transmission investments, and reliable "always on" power generation technologies, especially in the LA basin. It also made clear that it is possible to achieve our goal while remaining true to the core principles of reliability, environmental stewardship, environmental justice, resiliency, and affordability. With LA100, LADWP now has the tools and roadmap to continue on the path to 100% renewables.

As a result of the LA100 study, LADWP has identified five key elements that should be implemented now to pursue environmental justice and equity goals and keep LA on the path to 100% renewable energy. These elements are:

- Accelerating to 80% renewables and 97% carbon-free energy by 2030
- Transforming local generation
- Accelerating energy storage
- Accelerating distributed energy resources equitably
- Accelerating local transmission upgrades

By immediately accelerating investments in infrastructure projects that are common across all scenarios and in essential customer programs, LADWP will be able to accomplish its renewable energy and GHG emission reduction goals. Such investments are crucial to achieving 100% renewable energy for the City of LA. Delaying these projects puts the goal of achieving 100% zero-carbon energy at risk and would cost customers more in the long run, both in terms of environmental justice and costs. As LADWP undertakes an unprecedented grid transformation, it is committed to providing reliable and cost-effective service to its customers over the next decade. The aforementioned "no-regrets" project and program investments ensure that LADWP remains on track to reach the 100% zero-carbon energy goal in a timely manner. Furthermore, these investments provide flexibility to build out the backbone for a 100% zero-carbon energy future that reduces emissions at in-basin power plants located in disadvantaged communities, like Valley Generating Station.



1.4.1.4 Staying on Track to 100% Carbon-Free Projects and Initiatives

The following projects and initiatives outline the necessary steps needed to achieve 100% zero-carbon energy:

1.4.1.4.1 Accelerate Local Transmission Upgrades

To support increased penetration of renewables, LADWP has identified several "no regrets" transmission projects that will be required. These projects will increase LA basin

transmission capabilities to improve the reliability of renewable energy imports. LADWP will need support from the State to fast-track the California Environmental Quality Act process to renew the aging transmission system—that is 30 to 60 years old—by staggering scheduled upgrades to maintain power flow to customers. Sufficient in-basin capacity will afford LADWP the flexibility necessary to upgrade transmission infrastructure.

1.4.1.4.2 Accelerate to 80% Renewable Energy and 97% GHG-Free by 2030

Increased renewable energy is a key driver for reducing GHG emissions. While the State of California's mandate for renewables is only 60% by 2030, LADWP plans to add approximately 1,900 MW of *additional* renewable projects to accelerate its renewable energy target to 80% renewables and 97% zero-carbon resources by 2030. Through a combination of renewables-ready local generation and an accelerated local transmission system buildout, 80% renewable energy can be achieved by 2030. LADWP's renewable goals will be achieved in a way that benefits all Angelenos, but especially those located in lower-income and/or disadvantaged communities.



1.4.1.4.3 Transform Local Power Generation

LADWP continues to make significant progress toward a clean-energy future, but reliability and affordability remain key factors in how we get there. As LADWP increasingly relies on renewables—such as solar, wind, and geothermal supported by energy storage– the utilization of local, firm power generation will decline under normal conditions. However, these local generators are critical for ensuring grid reliability and resiliency, especially during stress-grid conditions when renewables or transmission are unavailable.

Accordingly, in-basin, local power generation will continue to play a critical role in completing LADWP's transition to a 100% carbon-free system. The LA100 Study by NREL, along with several internal and third-party studies, have continued to demonstrate the need for in-basin generation capacity across all modeled scenarios even in a 100% carbon-free future. The LA100 Study found that, in addition to renewables, energy

storage, and other critical investments, LADWP needs firm, dispatchable, carbon-free power at the existing generating stations that can serve as backup during extreme events, such as wildfires and earthquakes, and to decarbonize the final, most challenging portion of the electric system.

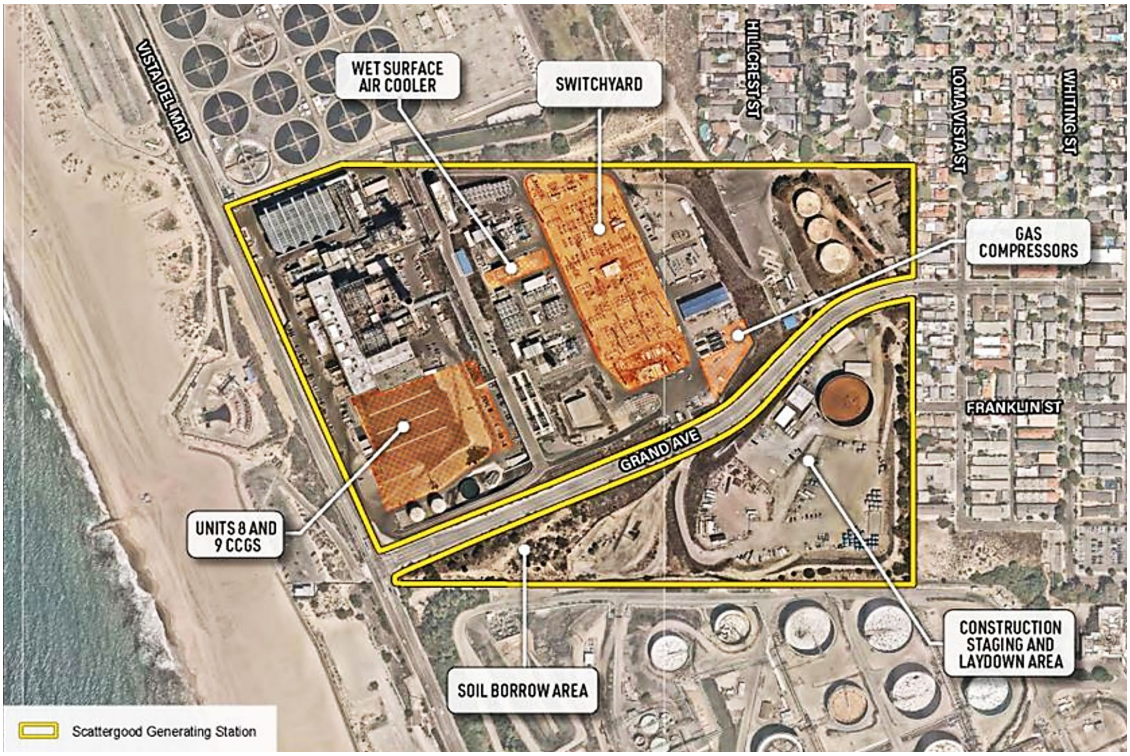
From a broader energy systems perspective, electrification is essential to achieving economy-wide decarbonization and improving local air quality; a reliable and resilient electric grid is the backbone of a clean-energy economy. Without it, progress toward reducing greenhouse gas emissions and cutting local air pollutants—such as nitrogen oxides (NO_x) from buildings, light-duty vehicles, and other mobility sources—will be significantly hindered. Ensuring the reliability and resiliency of the electric grid is therefore fundamental to meeting climate goals and securing a sustainable, healthy future for all communities.

LADWP has identified projects to address three converging drivers:

- Statewide once-through cooling (OTC) policy which requires the cessation of ocean-water OTC by December 31, 2029.
- Electric-grid reliability needs as required by regulatory standards.
- 100% carbon-free energy goals.

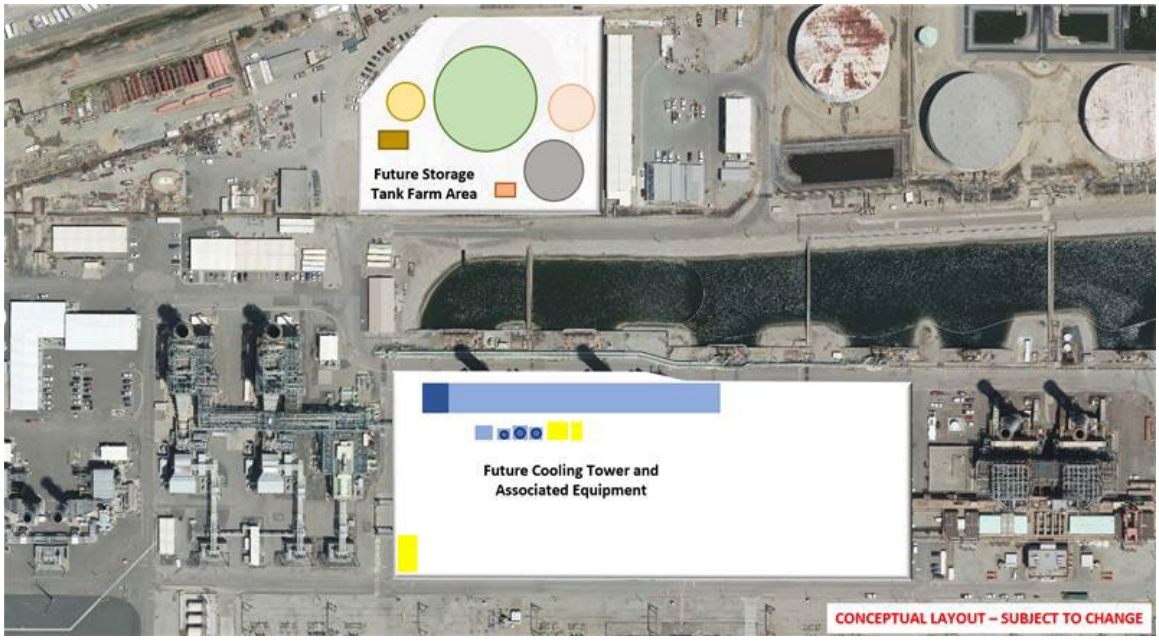
Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project

The proposed project is essential to maintaining the reliability of LADWP's power grid, particularly on the Westside, which serves critical facilities such as Los Angeles International Airport and the Hyperion Water Reclamation Plant. The proposed project would result in a rapid-response combined-cycle generating system (CCGS) at Scattergood Generating Station. The project would replace the generation capacity of existing Scattergood Units 1 and 2, which are conventional natural-gas-fired steam-boiler generators that would be removed from service, with a CCGS capable of operating on a fuel mixture of natural gas and hydrogen. NREL's independent 2025 analysis following the original LA100 Study re-evaluated the need for firm capacity at Scattergood. It confirmed that no fundamental changes to the LADWP power system have altered their conclusion that new, dispatchable capacity is needed to replace the retiring Scattergood Units 1 & 2.



Haynes Generating Station Unit 8 Cooling System Retrofit Project

Built in 2005, the combined-cycle generation system at LADWP's Haynes Generating Station—comprising Units 8, 9, and 10—is one of the most efficient assets in LADWP's generation fleet. The Haynes Unit 8 Cooling System Retrofit Project will convert the existing once-through cooling (OTC) system to a recycled-water wet-cooling tower. This upgrade delivers significant environmental justice benefits and contributes to reducing in-basin natural gas combustion, which in turn lowers overall greenhouse gas (GHG) emissions and decreases criteria air pollutants.



Harbor Generating Station Unit 5 Cooling System Retrofit Project

Harbor Generating Station, located in the Wilmington neighborhood of the City of Los Angeles, is situated in a predominantly industrial area due to its proximity to the Port of Los Angeles (POLA) and nearby freight rail lines that support port operations. The plant's combined-cycle steam turbine currently relies on once-through cooling (OTC). Converting this unit to use recycled-water wet-cooling will preserve its firm capacity—an essential asset for maintaining grid reliability during the clean-energy transition—

especially as POLA electrifies its operations, driving increased electricity demand in the surrounding area.



1.4.1.4.4 Accelerate Energy Storage

LADWP plans to build over 1,000 MW of energy storage in-basin and out-of-basin by 2030. As of Q4 2024, LADWP deployed 1,505 MW of energy storage. LADWP continues to issue an annual Rolling Request for Proposal to evaluate energy storage projects proposals. To allow for further integration in intermittent renewable energy into LADWP's grid, Haynes Units 3 through 6 have been demolished, and Valley Units 1 through 4 are being demolished, to make room for future energy storage.

1.4.1.4.5 Accelerate Distributed Resources Equitably

LADWP continues to ramp up distributed resources programs, with goals of deploying approximately 1,500 MW of local solar and 500 MW of demand response, doubling energy efficiency, and supporting 3,000 GWh of EV charging by 2030. As we design new programs to attract customers, our priority will be to place an increased focus on disadvantaged communities and low-income customers. To that end, we expanded our solar feed-in tariff program, advertised a Distributed Energy Resources RFP, expanded the commercial demand response program, and launched a Power Savers program. In 2021, LADWP launched the Feed-in Tariff+ and Virtual Net Energy Metering Pilot Programs and is continuing to expand the Power Savers program.

1.4.1.5 Impacts of Delay or Inaction

Delaying these key projects and initiatives would threaten LADWP's grid reliability and resiliency in the near term, risk customer outages, and limit local transmission upgrades.

These key initiatives are required to keep LA on the path to ensure a 100% carbon-free energy future. In the medium and longer terms, inaction risks not only non-compliance with the State's renewable and zero-carbon resource requirements by 2045 but would also put out of reach LADWP's ability to reach even more aggressive renewable goals should the Board, City, State, or Federal Government mandate it.

While the LA100 Study included a scenario, Early and No Biofuels, that could theoretically achieve 100% carbon-free energy by 2035, the study indicated several caveats in the Final Report (www.la100study.com). As part of this LA100 Plan, LADWP has updated key assumptions and vetted various challenges and risk factors to re-evaluate the investments required to achieve a 100% carbon free energy future by 2035. For this LA100 Plan, we have evaluated the major caveats from the LA100 Study, which are summarized as follows:

- Scenarios to achieve 100% carbon-free energy by 2035 assume the ability to quickly scale up green hydrogen infrastructure.
- Major new and expanded transmission are among the most uncertain inputs to modeling the pathways to 100% renewable energy.
- The evolution of the power system outside of LADWP could impact LADWP's opportunities.
- Climate change could impact the ability of LADWP to maintain resource adequacy.
- The original LA100 Study did not fully assess the feasibility of the accelerated deployment; in particular, the study does not evaluate the availability of manufacturing supply chains and labor forces or detailed construction schedules for the resources identified in each scenario.
- The study assumed that upgrades to LADWP's distribution system had been completed to alleviate existing overloads at the start of the study.

1.5 The LA100 Plan Process

LADWP's LA100 Plan provides a comprehensive roadmap for meeting LA's future energy needs, regulatory mandates and carbon-free energy goals, while maintaining reliable and affordable power for our customers. To ensure that our plans reflect the input of the communities and customers we serve, the planning process includes an advisory group comprised of various community members and stakeholders. The LA100 Plan will sync with LADWP's budget process with updated assumptions and recommend the optimal

pathway to achieve 100% carbon-free energy by 2035 while also addressing technology risk, minimizing adverse rate impacts, and ensuring an equitable transition to carbon-free energy.

1.5.1 Gathering Stakeholder Input



LADWP holds meetings with stakeholder groups to discuss the key strategic planning issues and to gather input. This is done early in the process to ensure that in the establishment of our goals and objectives, and in the development of the alternative cases for study and analysis, we give all expressed concerns due consideration. The LA100 Plan Advisory Group meetings included 11 meetings with over 25 presentations to provide transparency to our community and to guide the development of the final LA100 Plan.

1.5.1.1 Advisory Group and Public Outreach Community Feedback

The LA100 Plan Advisory Group was comprised of over 90 stakeholders spanning representation from neighborhood councils, academia, community organizations, existing customers, City and local government, and various other groups. The Advisory Group's valuable feedback, questions, and participation during the AG meetings helped inform our rigorous modeling efforts, wider-scale community outreach, and various strategies to identify the optimal pathway and resource combination to reach the City's 100% carbon-free energy goals. The Advisory Group is designed to reflect the diverse perspectives and expertise necessary to understand the challenges and opportunities for achieving a 100% carbon-free power supply by 2035.

In addition to engaging with the Advisory Group, LADWP held several public outreach meetings, guided by input from the Advisory Group. During the first half of 2025,

LADWP hosted public outreach meetings to share information on the LA100 Plan. Through these meetings we gained valuable community input. Major themes discussed in the public outreach meetings included but were not limited to:

- Rates and Energy Burden
- Green Hydrogen and Emissions
- Clean Energy Policy



1.6 LA100 Pathway Overview & Assumptions

The LA100 Plan's pathway to 100% carbon-free energy by 2035 is based on the Recommended Case from the 2022 Strategic Long-Term Resource Plan (SLTRP). This case—referred to in this document as the "LA100 Pathway"—was modeled with updated input assumptions to reflect the latest expectations for load growth and electrification, customer adoption of distributed energy resources (DERs), technology costs and availability (renewables, storage, and hydrogen-fueled resources), and transmission and siting considerations. The LA100 Pathway retains the policy directive that all generation, including those used to cover transmission and distribution losses, must be carbon-free.

The modeling scope for the LA100 Plan consists of:

- The LA100 Pathway (the adopted pathway),
- Ten targeted sensitivities run on LA100 to evaluate the impacts of key uncertainties and risks, and
- An SB 100 Benchmark (for benchmarking purposes only) along with one SB 100 Price Sensitivity serving as a lower cost "bookend."

The SB 100 Benchmark and its sensitivity are not proposed pathways for LADWP; they are included solely for comparison with the adopted LA100 Pathway. Together, they provide a comprehensive view of potential future conditions, allowing LADWP to assess the robustness, flexibility, and resilience of its chosen pathway under a range of plausible scenarios.

Once these scenarios were established, the next step in the LA100 Plan process is to gather various assumptions to be used as inputs to the computer modeling process. The Integrated Resource Planning (IRP) Group gathers assumptions from many subject matter experts within LADWP as well as from outside consultants and governmental agencies such as NREL. Assumptions include, but are not limited to the following:

- *Customer demand* – The IRP Group uses a customer demand forecast provided by the LADWP Load Forecasting Group.
- *Fuel Prices* – Natural gas price forecasts spanning several decades into the future are provided by an outside consultant. Coal prices for the Intermountain Power Project, set to retire in 2025, are provided by the LADWP Power Capital Projects and External Generation Division.
- *Power Plant Generation Ratings* – Power plant characteristics including megawatt capacity are provided by LADWP Generating Stations and Facilities Engineering.

- *Candidate Resource Pricing* – The IRP Group runs a capacity expansion model that builds out LADWP's future portfolio of generation resources subject to constraints such as RPS goals and reliability metrics while attempting to minimize overall cost. The pricing of future generation resources, such as solar, wind, and geothermal, which are provided as candidate resources from which the capacity expansion model can choose, is provided by NREL's Annual Technology Baseline.
- *Energy Efficiency* – Assumptions regarding the adoption and uptake of energy efficiency measures is provided by the LADWP Efficiency Solutions Group.
- *Building Electrification* – Several scenarios for the adoption of building electrification measures (e.g., converting from gas to electric water heating) are provided by the LADWP Efficiency Solutions Group.
- *Transportation Electrification* – Assumptions regarding the adoption of electric vehicles by customers within LADWP's service territory are provided by the LADWP Electric Transportation Programs Group.
- *Power System Reliability Program* – LADWP is expected to update and upgrade its current distribution system, replacing aging transformers, power poles, and other equipment. These upgrades fall under the Power System Reliability Program. Costs associated with this program are provided by LADWP Power System Engineering. Whereas the original LA100 Study assumed that all existing overloads are addressed by LADWP before any investments are made, LADWP has incorporated the additional cost in the LA100 Plan to address existing overloads and prepare the grid for future load growth due to electrification.
- *Transmission* – Assumptions regarding transmission line upgrades are provided by LADWP Transmission Engineering.
- *Greenhouse Gas Allowance Pricing* – Pursuant to California law, LADWP participates in the California Cap and Trade Program. Under this program, participants are required to have one greenhouse gas allowance for each metric ton of greenhouse gas emitted. Pricing forecasts for these allowances is provided by the LADWP Air Quality Group based on CARB's forecast.
- *Green Hydrogen* – Price forecasts for green hydrogen fuel are provided by various sources including external consultants and NREL.

The key objectives of LADWP's long term planning efforts, shown in Figure 1-2, are: (1) maintaining a high level of electric service reliability, (2) exercising environmental stewardship, and (3) maintaining competitive energy rates.

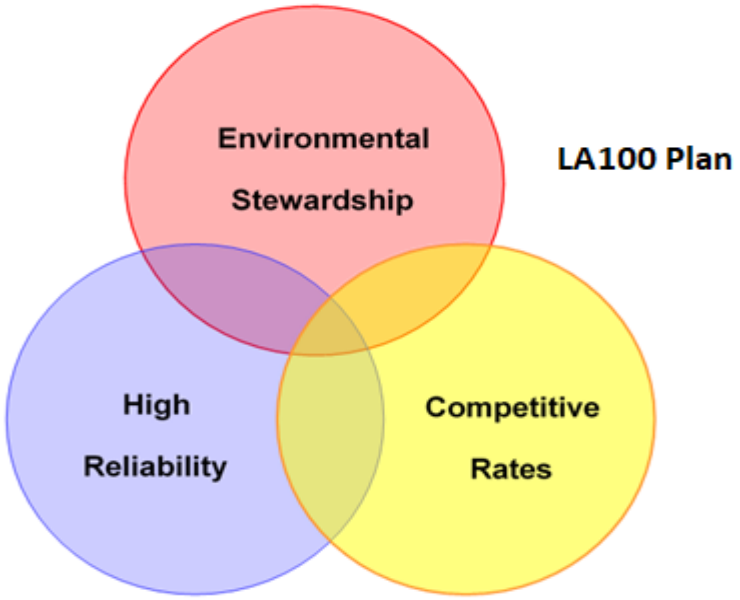


Figure 1-2 Objectives of this LA100 Plan.

Providing reliable electric service to the residents and businesses of LA has always been a cornerstone of LADWP. Some of the key principles, policies and program areas related to reliability are listed in the following subsections.

1.6.1 Reliability Standards

LADWP continues to follow all applicable Federal Energy Regulatory Commission (FERC)-approved reliability standards regarding bulk power system reliability. With the enactment of the Energy Policy Act of 2005, FERC granted North American Electric Reliability Corporation (NERC) the legal authority to enforce reliability standards with all users, owners and operators of the bulk power system in the United States. NERC is divided into eight regional electric grids in the United States. The Western Electricity Coordinating Council (WECC) (Figure 1-3), under the delegated authority of NERC, is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which LADWP is a part of. Both regulatory agencies enforce reliability standards on owners, operators and users of the bulk power system.

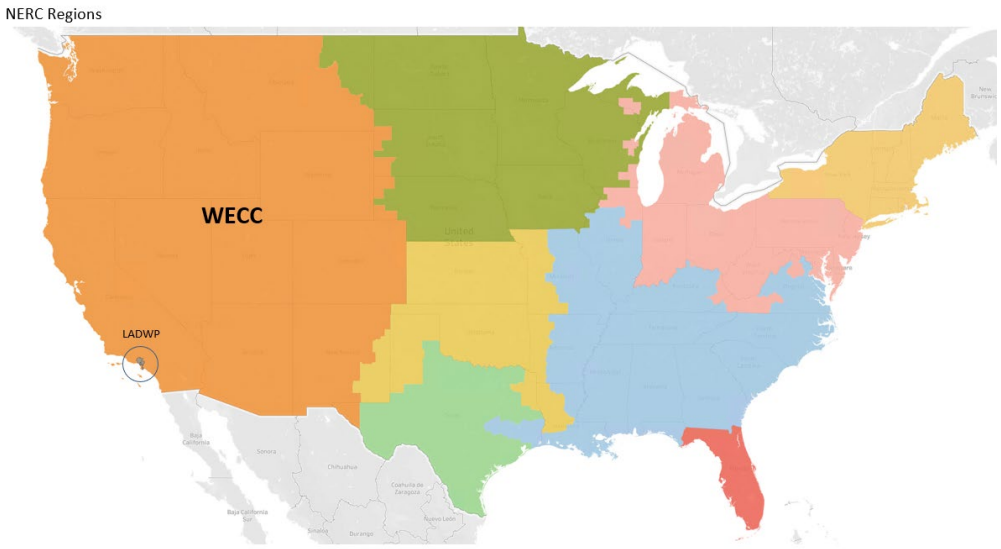


Figure 1-3 Map of NERC Regions, WECC, and LADWP.

In November 2012, NERC drafted a white paper outlining the need to incorporate risk concepts into the implementation of compliance and enforcement. In the white paper, NERC highlighted that the Electric Reliability Operator (ERO) Enterprise, comprising of NERC and the Regional Entities, must abandon its "zero tolerance" compliance monitoring and enforcement because it is neither effective nor sustainable. The "zero tolerance" compliance monitoring programs were centered around documenting compliance rather than reducing risk and improving reliability of the bulk electric system. As a result, the ERO Enterprise and industry collaborated to create the Reliability Assurance Initiative (RAI) to identify and implement changes to enhance the effectiveness of the Compliance Monitoring and Enforcement Program (CMEP).

On February 19, 2015, FERC approved the RAI program. The program's transformation for compliance monitoring involves the use of the Risk-Based Compliance Oversight Framework (Framework). The Framework focuses on identifying, prioritizing, and addressing risks to the bulk electric system, which enables NERC and regional entities to focus resources where they are most needed and effective. Regional entities are responsible for tailoring their approach to compliance monitoring in their specific region in accordance with the processes described in the RAI program.

1.6.2 CAISO

The California Independent System Operator (CAISO) was established in 1998 as part of California's electric utility restructuring effort. CAISO was established as a non-profit public benefit corporation charged with operating the majority of California's high-voltage wholesale power grid and providing equal access to the grid for all qualified users. LADWP is not a member of CAISO but was certified by CAISO to be a scheduling coordinator in 2012. That certification authorizes LADWP to buy and sell energy and ancillary services directly with CAISO.

In 2019, NERC approved CAISO's registration as reliability coordinator under the name RC West. RC West provides reliability coordinator services to balancing authorities and transmission operators in the Western United States, including to LADWP.

1.6.3 CAISO Western Energy Imbalance Market

The CAISO Western Energy Imbalance Market (WEIM) was launched in 2014 to allow non-ISO members in the western region voluntary access to their real-time grid management system, leveraging the power of geographic diversity. In April 2021, LADWP began participating in CAISO's WEIM market, and are presently full participants in the WEIM.

1.6.4 CAISO Extended Day Ahead Market

CAISO has launched its Extended Day Ahead Market (EDAM) to allow non-ISO members in the western region to voluntarily participate in their Day-Ahead Market system. The EDAM will launch in 2026, with its first participants being PacifiCorp and Portal General Electric (PGE). LADWP's Board of Water and Power Commissioners approved LADWP's Implementation Agreement to participate in EDAM at the December 10th, 2024 Board Meeting. LADWP currently plans to join the EDAM in 2027. Balancing Authority

LADWP is a registered balancing authority with NERC and is responsible for coordinating and balancing the load, generation, and delivery of electricity through its balancing authority area which includes the Burbank and Glendale power systems. LADWP will continue to serve as a balancing authority in the City of LA, as well as Burbank Water and Power, and Glendale Water and Power.

1.6.5 Self-Sufficiency

At LADWP, we maintain a policy of owning and controlling its transmission and generation resources independently to serve our native load customers. Augmenting LADWP's self-sufficiency, from time to time, a limited amount of firm energy is purchased from western energy market sellers to bolster LADWP's energy resources during stressed system conditions including those arising from gas curtailments related to Aliso Canyon or extreme weather events.

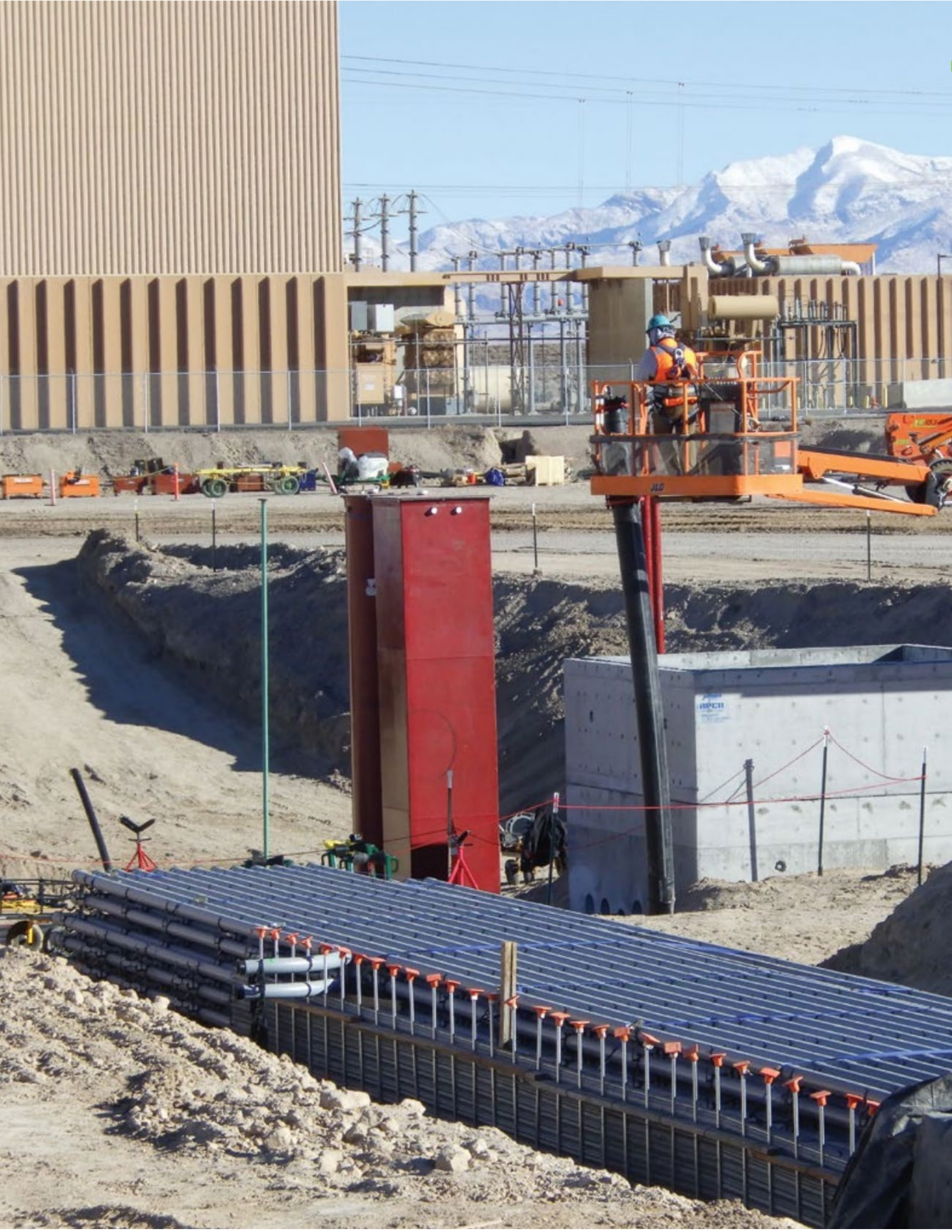
1.6.6 Coastal Power Plants



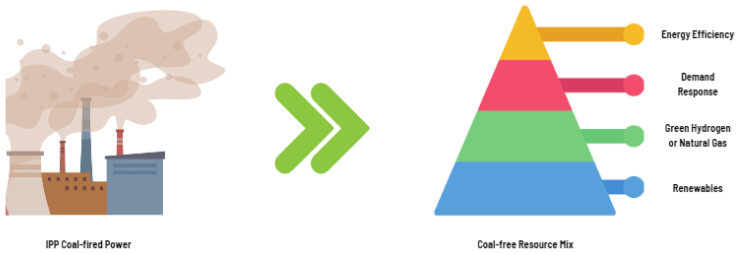
Figure 1-4 Scattergood Coastal Generating Station.

LADWP owns and operates three coastal natural gas-fired power plants (Haynes, Harbor, and Scattergood (see Figure 1-4)) that are critical to its operations. These plants were built beginning from the 1940s up until the 1970s. One of these plants, Harbor Generating Station, was modernized in the 1990s, resulting in increased efficiency and reliability. As a result, LADWP was able to reduce emissions and overall maintenance costs. The modernization of the remaining generation units is a long-term program. We are currently studying various hybrid clean energy options and working to modernize these plants for compliance with environmental regulations, improvements to efficiency, better integration of renewable resources, and expanded transmission import capability.

LA100 assumes the use of green hydrogen-powered in-basin combustion, beginning with the construction of a new combined-cycle generating unit located at the Scattergood Generating Station in 2030. The LA100 Plan assumes the buildout of several additional green hydrogen-powered generating units in the 2030s and into the 2040s. The green hydrogen-powered units are planned to be situated at the Harbor, Haynes, Scattergood, and Valley Generating Stations. The firm, dispatchable generation provided by green hydrogen is essential for maintaining LADWP's grid reliability and resiliency as an increasing proportion of intermittent renewables are integrated into our generation portfolio.



1.6.7 Intermountain Power Project Replacement



LADWP is committed to a strategy of complete divestment from coal-fired resources by 2025. As a result, we identified various alternative energy sources as critical for replacing the coal-fired capacity that the Intermountain Power Project provides. Power System staff have determined that a mix of energy efficiency, demand response, renewable resources (wind, solar and geothermal), and energy from a combined-cycle natural gas or green hydrogen generating facility will be sufficient to replace IPP's capacity. The goal of converting IPP from a coal-fired to combined-cycle natural gas or green hydrogen generating facility is to accelerate LADWP's coal divestiture by two years. In 2015, all 36 IPP participants, including several municipal utilities located in Southern California and Utah, approved an amendment to advance the IPP replacement date to 2025—two years ahead of the existing power purchase contract's June 2027 expiration date. To achieve the accelerated goal, IPP will be repowered with two combined-cycle natural gas generating units totaling 840 MW. The flexible capacity from the repowered IPP units will firm and back up renewable resources and provide a mechanism to reliably integrate renewable resources into LADWP's grid.

For this LA100 Plan, the combined-cycle units replacing IPP are assumed to be green hydrogen-ready, with the capability to use a blend of 30% green hydrogen and 70% natural gas, by volume. Under the LA100 Plan, the proportion of green hydrogen used will increase over several years until LADWP's portion of the project uses 100% green hydrogen to produce electricity—a milestone that we expect to achieve by 2035.

1.6.8 Transmission Planning

The Los Angeles Department of Water and Power (LADWP) Transmission Planning team conducts a comprehensive transmission assessment that occurs on an annual basis. The objective of the assessment is to ensure that LADWP's Bulk Electric System (BES) is planned such that the interconnected transmission system can be operated reliably over a wide range of system conditions throughout the Long-Term horizon, which aligns with

complying to North American Electric Corporation (NERC) reliability performance requirements (TPL-001-5.1)[1].

Figure 1-5 below illustrates the transmission planning process that is simplified to four (4) main stages. (1) Various datasets are provided as critical inputs from stakeholders to perform the analysis, which are discussed and shared with both internal and external stakeholders to collect any feedback prior to starting the analysis.

(2) The results of the study would identify any reliability issues that were observed, develop corrective action plans per the NERC TPL standard such as proposed transmission projects, Remedial Action Schemes or operational limitations. (3) The planning team works with various groups[2] to determine the feasibility of the proposed project and identify the scope, schedule, and budget. When the project has been refined up to the point of viability from all stakeholders, the project will be presented for approval with Power System management. (4) Lastly, the project is executed by the project manager elected, where planning continues to monitor and track the progress and status of the project throughout its life cycle until completion.

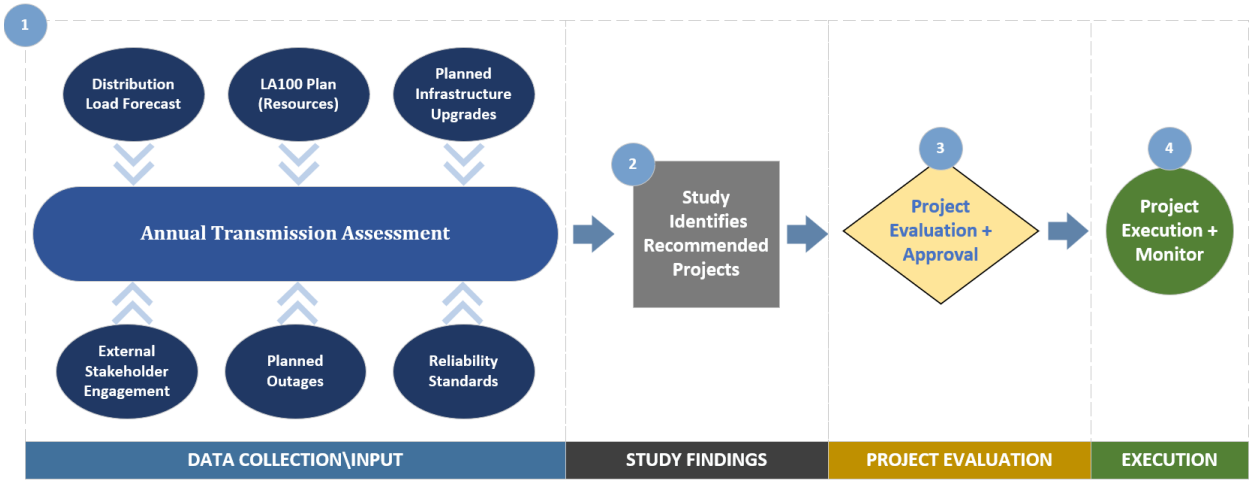


Figure 1-5 The transmission planning process

Some of the most critical data sets include the LA100 resource plan, the distribution load forecast and transmission project in service dates.

The resources determined by the LA100 resource plan are modeled to the best information available at various locations determined by the resource plan. The

[1] https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf

[2] Various groups included but not limited to Station Engineering Design, Overhead Engineering Design, Underground Cable Design, Real Estate, and Right-of-Way

distribution load forecast is used to model the load at each load bank for each receiving station in the LADWP transmission system. Lastly, only approved and planned transmission upgrades are modeled based on their latest estimated in-service date at the start of the study.

The modeling performed in the study looks at many different reliability-based events for a snapshot of time and compares the system changes against LADWP and NERC reliability criteria at different time periods. For example, typically a 2-year, 5-year and 10-year case are studied in accordance with TPL-001. However, additional sensitivities to look at longer term scenarios are also sometimes included if deemed beneficial. This analysis is completed at the end of each calendar year so the resulting recommended transmission projects can be utilized in the next LA100 resource planning cycle to determine if changes in resource location should be considered.

1.6.9 Distribution Planning

Distribution planning plays a vital role in ensuring that the electric grid can safely and reliably serve growing and evolving customer needs at the local level. This discipline focuses on the infrastructure that delivers electricity from substations to end-use customers and includes strategic evaluation of circuits, substations, transformers, and other assets to determine where upgrades, expansions, or new investments are needed.

Unlike transmission or bulk system planning, distribution planning must account for highly localized patterns of load growth, electrification, distributed energy resources (DERs), and customer behavior. As such, it requires a detailed, bottom-up approach grounded in granular data and engineering expertise.

1.6.9.1 Independent Load Forecasting for Distribution

To support this effort, LADWP's distribution planning team develops its own detailed load forecasts, distinct from system-wide forecasts used in integrated resource planning. These forecasts are tailored to the unique characteristics and demands of specific circuits, feeders, and substations across the service territory. They incorporate a wide range of "load modifiers," including:

- **Transportation and Building Electrification** – Expected increases in electricity demand from electric vehicles and heat pumps.
- **Photovoltaic (PV) Systems** – Local generation that reduces net load on the grid.
- **Energy Efficiency Measures** – Programmatic and behavioral reductions in energy usage.

- **Urban Densification** – Population growth and construction activity that affect load density and timing.
- **Weather and Climate Change Impacts** – Long-term shifts in temperature patterns that affect cooling and heating loads.

These forecasts are a critical input to identifying where capacity constraints, voltage issues, or asset deterioration may occur and help prioritize where investment is needed to maintain service quality.

1.6.9.2 Collaborative and Data-Driven Approach

To ensure robust and well-informed assumptions, LADWP's distribution planners regularly engage with internal experts across departments such as Integrated Resource Planning, DER Planning, Energy Efficiency, and Rate Design. Dedicated working groups help guide assumptions related to load modifiers, drawing on up-to-date industry research, such as studies from the Electric Power Research Institute (EPRI) and other relevant sources. These groups regularly review emerging trends, new technologies, policy developments, and local deployment patterns to ensure forecasts remain aligned with real-world dynamics.

1.6.9.3 Strategic Purpose

Ultimately, the purpose of distribution planning is to ensure that the grid evolves in lockstep with customer needs, climate and clean energy goals, and technological change. Through careful forecasting, scenario analysis, and cross-departmental coordination, LADWP aims to deliver cost-effective and forward-looking infrastructure solutions that support reliability, customer equity, and the city's long-term sustainability.

1.6.10 Climate Change Planning



As part of the comprehensive LA100 planning process, Climate Change Planning was conducted to evaluate how rising temperatures driven by global climate change could impact LADWP's future electricity demand and resource needs. This analysis is embedded within the broader modeling framework to ensure that long-term decarbonization pathways remain robust and adaptable under different climate futures.

To this end, a Climate Change Sensitivity study was performed, beginning with forward-looking projections of Heating Degree Days (HDD) and Cooling Degree Days (CDD) through 2045. Two standardized climate scenarios were used to capture a range of future possibilities:

- RCP 4.5, representing a moderate-emissions trajectory with stabilization by 2100
- RCP 8.5, representing a high-emissions scenario with minimal mitigation and more severe climate impacts.

These scenarios are based on Representative Concentration Pathways (RCPs) commonly used in global climate modeling.

To model local effects, the analysis incorporated ten years of historical HDD and CDD data from multiple sites within LADWP's service territory, including Downtown Los Angeles, LAX, Woodland Hills, and Van Nuys. Using this dataset, correlations were developed between temperature-sensitive metrics and historical customer electricity demand.

Several machine learning techniques were evaluated to capture these relationships. The best-performing methods—Locally Weighted Learning (LWL), linear nearest neighbor search, and linear regression—were used to train predictive models. LWL, in particular, was well-suited to this application due to its ability to create localized models that give

more weight to data points closer to the conditions being predicted. Alternative methods, including decision trees and neural networks, were considered but found to be less effective in this context.

The trained models were then applied to future HDD and CDD projections under each climate scenario to produce adjusted load forecasts that reflect climate-driven demand changes.

1.6.10.1 Key Findings

Results from the Climate Change Sensitivity indicate that rising temperatures will increase electricity demand, particularly from higher cooling loads. However, even under these more challenging conditions, LADWP can still achieve its 100% carbon-free energy goal by 2035 under the LA100 Pathway portfolio while maintaining system reliability.

These findings underscore two important points:

- The resilience of the LA100 Plan resource mix under a range of future climate conditions.
- The strategic importance of continued investment in flexible, clean energy resources to accommodate accelerated electrification and climate-related shifts in load patterns.

1.7 The Advisory Group and Public Outreach



The AG plays a critical role in shaping key assumptions and by informing our key strategic decisions. After the 2017 SLTRP was completed, we expanded the Advisory Group for the 2022 SLTRP and subsequent LA100 Plan. In order to maintain continuity with the original LA100 Study, the expanded Advisory Group includes all the members that participated in the original LA100 Study. The Advisory Group allows LADWP to reinforce full transparency in the planning process and build on the collaborative dialog that has guided past IRP and SLTRP processes. LADWP staff presented AG members with the major challenges facing LADWP, allowing them to weigh in on how specific challenges should be addressed in a community-focused manner.

While the Advisory Group does not have any approval authority for the LA100 Plan, it helped determine the strategic decisions that were considered. Input from AG members influenced the assumptions that we used in the model runs. The Advisory Group contributed to the process in a constructive manner, mutually exchanging information with LADWP for the betterment of the entire Power System, the ratepayers, and the environment.

Through the Advisory Group, LADWP obtained stakeholder feedback on several specific power-related issues, such as the pace of renewable energy deployment, distributed energy resource levels, and in-basin generation strategies for achieving a 100% carbon-free resource portfolio by 2035. The Advisory Group also provided an opportunity for stakeholders to fully understand and appreciate the diverse viewpoints among the various stakeholder groups.

The Advisory Group represents a range of stakeholder representatives, including neighborhood councils, business customer representatives, environmental representatives, the LA City Council and Mayor's Office, utilities, academia, and others. The Advisory Group met eleven times throughout the LA100 Process.

In addition to the LA100 Advisory Group, three virtual public outreach workshops were held in June of 2025. These public meetings were an opportunity to provide an overview of the LA100 Plan and to collect comments from the public.



Some of the LA100 AG members

1.8 Computer Simulation



Creating a robust computer model of LADWP's Power System is a crucial component of the LA100 Plan process. For long-term planning, computer modeling involves simulating aggregate customer demand, the dispatch of LADWP's various generation and energy storage assets, and our expansive high-voltage transmission system. Typically, such modeling does not involve simulating the flow of electricity on LADWP's relatively low-voltage distribution system.

For this LA100 Plan, the planning horizon was chosen to span between 2024 and 2045. As mentioned previously, the modeling process requires us to make high-level assumptions about which generation, storage, and transmission resources are expected to be available. Additionally, certain assumptions must be made regarding various projected costs.

Computer modeling is a two-step process. The first step involves running a *capacity expansion model*. This model determines which generation and storage resources should be built, as well as where, when, and to what capacities those resources should be built. Many candidate generation and storage resources are provided as inputs to the capacity expansion model, along with their projected costs. These candidate resources reflect what the IRP Group reasonably believes will be available for development. Our high-

voltage transmission system spans several states in the western United States, passing through various regions with, due to their geography, favorable conditions for solar, wind, and geothermal energy production. Candidate solar, wind, and geothermal resources are then provided to the model and situated near these geographical locations within the model. Generally, LADWP prefers to have generation and storage assets located near existing transmission infrastructure to reduce costs and minimize environmental impacts. Efficiently sited resources reduce the need to build additional transmission capacity. LADWP's existing generation, storage, and transmission assets are also included as input to the capacity expansion model.

Once all assumptions have been submitted into the capacity expansion software, the computer builds a model of LADWP's generation and storage portfolio, all the way up to the 2045 planning horizon. There are several key constraints the model must adhere to:

- ***Customer demand*** – The capacity expansion model must ensure enough generation and storage assets are built each year over the planning horizon to guarantee adequate electricity generating capacity to serve aggregate customer demand. If any year in the planning horizon falls short, the model must build additional generation capacity in that year or prior to that year to mitigate the shortfall.
- ***RPS and clean energy goals and mandates*** – The capacity expansion model must also ensure enough renewable and carbon-free resources are built to meet any RPS and clean energy goals and mandates. For example, the LA100 Plan stipulates achieving an 80% RPS by 2030. The capacity expansion model must ensure enough solar, wind, and geothermal resources are built by 2030 so that this constraint is met and that enough of these resources are built in subsequent years to guarantee LADWP maintains at least an 80% RPS throughout the planning horizon.
- ***Reliability*** – To ensure customers' lights turn on as expected with the flip of a switch, the capacity expansion model must build out enough generation and storage resources to meet an expected loss of load expectation (LOLE) metric. As discussed previously, capacity expansion must guarantee enough generation and storage resources are built to satisfy customer demand every year; however, customer demand itself can fluctuate, and is highly dependent on weather conditions. Several hundred weather conditions are simulated along with their effect on customer demand. Hot weather conditions tend to increase customer load due to increased demand for air conditioning, while mild weather reduces demand. A single portfolio must be built by the capacity expansion model that

allows for no more than an expected 0.1 LOLE for each year, which is equivalent to NERC's 1-in-10-year industry standard. A loss of load event is any instance in which customer demand exceeds LADWP's total generation capacity. For example, on a typical hot summer day, LADWP's total aggregate customer demand may reach 6,000 MW during the peak hour of that day. If, for any reason, LADWP did not have 6,000 MW of total generating capacity (e.g., due to a power plant or transmission line outage), then this would count as one loss of load event. The industry standard is to plan for an expected LOLE of 0.1 or less.

- ***Cost*** – While adhering to the constraints mentioned above, the capacity expansion model attempts to build a portfolio that minimizes the total cost. Costs include not only capital and construction costs, but also operational costs such as fuel and maintenance.

Once the capacity expansion model creates a resource portfolio, the second step is to run the portfolio through a *production cost model*. The production cost model simulates the dispatch of the generation resources in the capacity model's resource portfolio. Typically, a production cost model uses hourly resolution to simulate dispatch decisions; however, five- and 15-minute resolution can be used as well. The production cost model uses the marginal cost of each resource to determine which resources to dispatch first. The most inexpensive resources are dispatched first, with more expensive resources dispatched subsequently. The model ensures that enough generation resources are dispatched to meet the assumed aggregate customer demand in each hour. The production cost model can determine total fuel consumed, emissions produced, and overall system cost, among many other output metrics. The production cost model also simulates planned and unplanned outages for LADWP's generation assets.

1.9 LA100 Pathway Key Metrics Considered

The LA100 Pathway builds upon the foundation established by the Recommended Case from LADWP's 2022 Strategic Long-Term Resource Plan (SLTRP). While the SLTRP included multiple planning cases with a formal recommendation process, the LA100 Plan reflects a shift in approach: it adopts the LA100 Pathway as the committed course of action, rather than offering alternative cases for consideration.

The original Recommended Case from the SLTRP was selected based on detailed modeling and analysis, with LADWP executive management evaluating a broad set of performance metrics, including:

- Cost

- Electricity rates and customer bill impacts
- Greenhouse gas emissions and local air pollutants
- Reliability
- Curtailment
- Risk
- Resiliency

The LA100 Pathway updates and expands on that Recommended Case, incorporating improved assumptions, new data, and enhanced modeling to support LADWP's commitment to delivering 100% carbon-free electricity by 2035.

1.9.1 Cost



Costs assessed in the LA100 Plan are split into fixed costs and variable costs. Fixed costs do not vary with the utilization of an asset. These could be capital costs spent on power plant development and construction (including equipment, permitting, and construction labor), fixed operations and maintenance costs (including routine maintenance, inspection, and monitoring), and costs associated with fixed power purchase agreements, for which LADWP is obligated to purchase a minimum quantity of energy annually. Variable costs are proportional to the quantity of energy generated. The production cost modeling stage of the LA100 Plan provides insight into these costs through hourly simulations of Power System dispatch. Variable costs include costs for fuel (such as coal, natural gas, green hydrogen), greenhouse gas allowances and emission reduction credits (such as those for carbon dioxide and nitrogen oxides), as well as variable operations and maintenance (such as more maintenance and repair of generating units that are used more frequently). Overall, fixed and variable costs are aggregated in the LA100 Plan into total portfolio costs. The annual cash flows are discounted through a net present value methodology, which more accurately compares costs among the different model runs.

1.9.2 Rate and Bill Impacts

The estimated electric retail rate ($/kWh) and consequent bill impacts ($) in the SLTRP are preliminary averages and subject to ongoing budget estimate and future rate reviews. The preliminary numbers do not yet reflect the potential cost savings from

additional funding sources such as the federal government's Inflation Reduction Act and Bipartisan Infrastructure Law, among others.

The IRP Group worked closely with LADWP's Financial Services Organization to determine the volumetric electric retail rate estimates per unit of power sold. We derived estimates for key years such as 2030 and 2035 using the existing LADWP rate structure. The overall total portfolio costs are a key factor in determining rates, as are electric customer retail sales. Building and transportation electrification are examples of negative rate drivers that will help make the per unit cost of power less expensive by increasing the volume of overall retail sales. Examples of positive rate drivers—which make the cost per unit of power more expensive—are programs that reduce overall retail sales such as net-metered solar and energy efficiency.

We recognize that LADWP customers may currently receive utility bills every other month for electric service combined with charges for water service, sewage, and waste disposal. With respect to average monthly electric retail bill estimates, the values presented in the LA100 Plan are for electric service only and are averaged out over each month. Using this method, we generate an average monthly electric retail bill estimate.

1.9.3 Emissions

Greenhouse gas (GHG) emissions—often cited in units of million metric tons—as well as emissions from nitrogen oxides (NOx)—often cited in units of tons—are estimated in the LA100 Plan at a high-level, through production cost modeling. Power plant emissions resulting from the generation process are largely a result of generation efficiency, as well as emissions intensities of the fuel sources. As an example, for a given quantity of energy produced, natural gas emissions are substantially lower than coal emissions. LADWP will fully divest from all coal resources by 2025. Older generating units are less efficient and produce more GHG emissions per unit of energy produced when compared to newer units, which have greater generating efficiencies as a result of technological advances, among other factors.



For the LA100 Plan, the supply resource mix is largely driven by modeling constraints imposed as a result of the 2035 100% carbon-free energy goal established by the Los Angeles City Council. It is assumed that all remaining power generation turbines in LADWP's generation fleet are completely fueled using 100%

green hydrogen beginning the year 2035, and that the green hydrogen used has no associated GHG emissions as it is produced via a renewable energy powered electrolysis process (either by LADWP or an outside supplier).

To quantify the effects of local pollutants, like NOx and particulate matter, we have partnered with the National Renewable Energy Laboratory to conduct an in-depth local emissions and air quality analysis for the City of LA.

1.9.4 Reliability



Reliability in the LA100 Plan is quantified by using a metric called *loss of load expectation (LOLE)*. LOLE quantifies the number of expected loss-of-load events during which aggregate customer demand exceeds LADWP's total generation and energy import capacity. Electric utility companies typically plan for no more than 1 loss-of-load event every 10 years, or 0.1 loss of load events annually Due to this reliability constraint, the resource portfolio for this LA100 Plan is built to ensure an LOLE at or below 0.1 for each year in the study horizon. Because LADWP is a balancing authority that includes Burbank and Glendale, it is imperative that we not only remain below a 0.1 LOLE, but also strive to maintain the same, exceptional level of reliability we have today.

In the LA100 Plan, large quantities of non-dispatchable, variable energy resources such as solar and wind are built. This is due to their declining effective load carrying capability (ELCC), or effective system value, as those types of resources start to become oversaturated in the system. The oversaturation of a resource on the system results in a declining ELCC for these resource types, which indicates that the value to the Power System of each additional unit of capacity (MW) from such a resource decreases. One notable example of a resource with declining ELCC in the LADWP system is solar energy, which tends to produce maximum output around the middle of the day and during the spring season in California. Solar energy is often available in abundance during the middle of the day such that its market price in the real-time market becomes negative;

that is, power producers will pay others to use or "off-take" the excess solar energy they produce. Conversely, as solar energy output drops during the darker evening hours, there is a premium price for dependable and dispatchable energy resources that can fill in the supply gap left by low solar generation. We place a high value on flexible resources that can ramp up or down to meet variable demand through the evening hours—something that solar and energy storage assets cannot do.

In order to adhere to rigorous reliability criteria while also complying with the constraints of our 100% carbon-free energy target, long-duration, dispatchable green hydrogen turbines are assumed to be deployed. These dispatchable resources have zero carbon emissions when fueled entirely with green hydrogen, which LADWP will begin to do in 2035.

1.9.5 Curtailment



Energy (GWh) curtailment, which, in the LADWP Power System, most commonly applies to renewable energy—occurs when system constraints do not allow LADWP to take delivery of and integrate all possible renewable energy output. Curtailment can occur due to technical constraints, or when there is an oversupply of renewable energy (renewable energy supply is greater than customer demand).

For our Power System, this phenomenon most often occurs with solar energy resources during the spring season, when high solar energy generation during the

middle of the day coincides with low electricity demand. It is important to note that in order to get the best possible prices, many of LADWP's renewable energy projects are power purchase agreements (PPAs) with third-party renewable energy suppliers (as opposed to more expensive, LADWP built capital projects), for which LADWP must pay a fixed price, whether or not we are able to accept all renewable energy production from a given facility. While some PPAs do include clauses allowing a small amount of renewable energy curtailment, as more variable energy resources are interconnected onto the system, the frequency of renewable energy curtailment is expected to increase.

Our goal is to keep renewable energy curtailment to a minimum. To reduce curtailment from variable energy resources, namely solar and wind, we look to employ strategies such as increased energy storage deployment. Energy storage resources allow us to capture and store renewable energy that cannot immediately be absorbed by system demand. LADWP can then dispatch energy from energy storage resources when the system requires it. Another potential use of normally curtailed renewable energy is electrolytic green hydrogen production, where surplus renewable energy can be used to power an electrolyzer that splits water molecules into oxygen and hydrogen. This green hydrogen, produced entirely using renewable energy, has no carbon emissions and can be stored for long durations (i.e. weeks or months) until needed. Effectively, using green hydrogen, we can deploy a form of "seasonal" energy storage to better take advantage of all our renewable energy resources.

1.9.6 Risks

Many potential risks could affect the implementation of the LA100 Plan. Some of the main risks that we considered during the LA100 Plan development process are:

- Required resource build rates (MW/year)
- Required customer resource build rates (MW/year dependent on customer participation)
- Required number of transmission builds
- Technological readiness of resources
- Sufficiency of capable workforce and human resources for implementation
- Operations and maintenance personnel required
- Availability of required materials and assets in the market via stable and reliable supply chains
- Streamlining project permitting for timely completion

- Carefully staging sequence of required outages for system upgrades (critical path/predecessor sequencing, limit of power system elements that can be scheduled for outages at a given time without compromising reliability)
- Maintaining financial health (required capitalization ratios, borrowing ratios, bond ratings, cash-on-hand, etc.)
- Bolstering the Power System to withstand extreme weather events because of climate change (black start capability and response time, loss of load hours, geographical diversity of resources, diversity of resource capabilities and characteristics)
- Mitigate cybersecurity threats
- Potential for high or low loads (impact to rates and number of required resources to meet demand while maintaining reliability)

Our IRP Group works in constant collaboration with other LADWP staff to measure and analyze various metrics to assess the aforementioned risks throughout the planning process.

1.9.7 Resilience



Along with reliability, our top priority is to maintain grid resilience amidst increasing extreme weather events—a result of climate change. While grid reliability is centered around having sufficient resources to adequately meet load while accounting for commonly expected events (e.g. equipment failure or short-duration outages), resilience

focuses on high-impact, low-frequency (HILF) events that are often unexpected and can result in long-duration outages. Examples of HILF events include, but are not limited to, wildfires, earthquakes, extreme heat storms (projected to be far more frequent and extreme due to climate change), and even acts of terrorism (both physical and cyber security threats).

Electric grid reliability has widely adopted, industry-approved metrics and requirements that are often overseen by regulatory governing bodies at various levels of government. However, definitions, metrics, and guidelines for grid *resilience* have not been widely adopted or standardized across the utility industry at present day. Often, defined resilience standards and metrics are up to each specific organization. Here at LADWP, our working definition of resilience for the Power System is as follows:

The ability of a power system to anticipate, absorb, adapt, and rapidly recover from a certain set of high-impact, low-frequency events, and to supply sufficient capacity, energy, and services to its customers at all times of the year while managing societal impacts and meeting policy objectives.

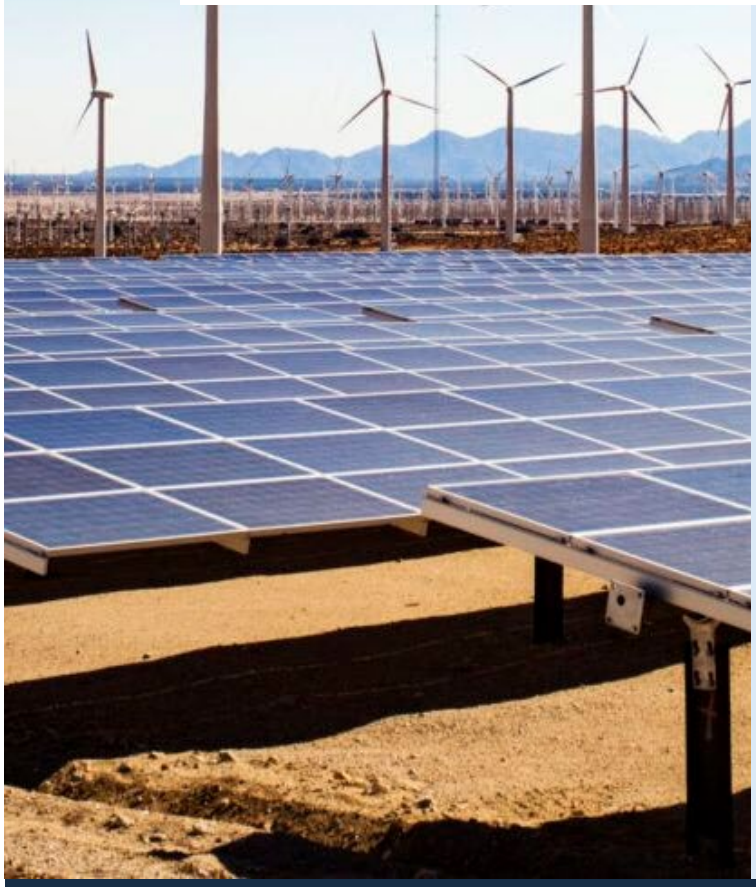
LADWP has experienced multiple HILF events that have put our grid resilience capabilities to the test. In 1994, the Northridge Earthquake caused widespread damage and power outages across the City of Los Angeles and required the use of black start generators to restore power after widespread outages. The recent California wildfires have also stressed the LADWP grid. The 2019 Saddleridge Fire and 2025 Pacific Palisades fire caused the temporary derating of several critical power transmission paths into the LA basin during a time where several power plants were out-of-service for maintenance. To continue meeting the City's electric demand, LADWP needed to ramp up generation at the remaining in-basin units.

Events that stress the resilience of the grid can be measured using a variety of metrics such as de-rate factors, outage occurrences, and outage durations for critical power system elements such as high voltage transmission. Other potential metrics include the number of customers affected during load shedding or capacity factors of generators during emergency periods with loss of major transmission. Potential future strategies that can help us quantify resilience include assigning monetary values to lost load (VoLL) to calculate cost-benefit of grid investments or calculating the social burden on communities impacted by potential power outages. These methods can be used to evaluate the costs and benefits of community resilience plans and for physical systems such as microgrids.

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Chapter 2

LA100 Plan Case, Sensitivities, and LADWP Programs and Initiatives



Key Highlights

- Energy Efficiency Leadership: LADWP targets 3,400 GWh in additional savings by 2035 through cost-effective programs like BOSS and CAMR
- DER Warehouse Innovation: Centralized data platform improving DER forecasting, grid visibility, and equity analysis across LA
- Demand Response Expansion: New DRMS will integrate EVs and smart devices to cut peak demand and boost reliability



2.1 LA100 Plan Case and Sensitivities

The LA100 Plan is LADWP's official long-term roadmap to achieving a 100% carbon-free power system by 2035—ten years ahead of California's SB 100 legal mandate. Built upon the Recommended Case from the 2022 Strategic Long-Term Resource Plan (SLTRP), the LA100 Pathway not only accelerates the decarbonization timeline but also exceeds the minimum legal requirements by eliminating all fossil fuel-based generation, including generation to cover system losses. In addition to the LA100 Pathway, the plan includes a reference SB100 Benchmark representing compliance with state law, as well as a suite of sensitivity cases that assess key risks and uncertainties.

2.2 LA100 Plan Case & Sensitivities Overview

The primary scenario in the LA100 Plan—referred to as the "LA100 Pathway"—serves as LADWP's approved and adopted pathway for reaching 100% carbon-free electricity by 2035. This scenario is based on the Recommended Case from the 2022 SLTRP and is designed to be more ambitious than California's SB 100 requirement. While SB 100 mandates that all retail sales be served with carbon-free resources by 2045, the LA100 Pathway requires that all generation, including those used to cover system losses, be

carbon-free by 2035. As such, the LA100 Pathway represents a more stringent and proactive commitment to decarbonization.

To understand potential risks to the LA100 Pathway, the plan evaluates ten sensitivity cases, each designed to test the robustness of the scenario against specific uncertainties. These include economic factors (e.g., higher clean energy costs), demand uncertainties (e.g., lower or higher load growth), technology adoption risks (e.g., greater-than-expected customer adoption of distributed energy resources), and resource technology uncertainties (e.g., replacing in-basin thermal plants with green hydrogen fuel cells rather than turbines). Additional sensitivities address market risks, such as limited or nonexistent availability of green hydrogen, and broader supply chain challenges, such as delays in renewable and storage procurement alongside hydrogen technology maturity. The potential impacts of climate change, particularly warmer temperatures, —are also modeled as a dedicated sensitivity.

For comparison, the SB100 Benchmark is included in the plan strictly as a reference case and reflects the minimum level of action required by state law. It also includes one sensitivity exploring the implications of lower clean energy costs.

2.3 LA100 Plan Case & Sensitivities Descriptions

The LA100 Plan includes a comprehensive set of models to evaluate the transition to a 100% carbon-free power system. The core model—the LA100 Pathway—serves as the primary planning case and reflects LADWP's local policy commitment to achieve 100% carbon-free electricity by 2035. It builds upon the Recommended Case from the 2022 Strategic Long-Term Resource Plan (SLTRP), updated with the latest technology assumptions and market data.

To assess uncertainty and manage risk, ten sensitivity analyses were conducted around the LA100 Pathway. These explore a range of plausible variations, including changes in customer demand, technology adoption, resource availability, and cost trajectories. Each sensitivity isolates specific risk dimensions such as low or high load growth, variation in distributed energy resource (DER) adoption, hydrogen market uncertainties, resource procurement caps, and climate change impacts.

In addition to the LA100 Pathway and its sensitivities, the SB100 Benchmark was modeled to align with California's statewide mandate for 100% clean electricity by 2045.

This scenario is included for informational and benchmarking purposes only—it is not under consideration as a potential pathway for LADWP.

A single sensitivity was also run on the SB100 Benchmark to evaluate the implications of a high-cost trajectory for renewables and storage, combined with lower natural gas prices.

Together, this suite of scenarios provides a robust analytical foundation for understanding the potential challenges and tradeoffs associated with the transition to a reliable, affordable, and fully decarbonized grid.

Table 2-1 LA100 model runs

Scenarios/Sensitivities*	Year 100% Carbon-Free Energy Is Reached**	Description	Risks Addressed
LA100 Pathway	**2035**	**Main scenario, local policy mandate**	**N/A; risks were assessed via sensitivities**
1. LA100 - Price Sensitivity	2035	High renewable energy, energy storage, and green H_2 costs; low natural gas and CO_2 allowance costs	Impact of higher cost of clean energy and lower cost of fossil fuels
2. LA100 - Low Load Sensitivity	2035	Load growth is lower than expected	Impact of lower-than-expected customer load growth
3. LA100 - High Load Sensitivity	2035	Load growth is higher than expected	Impact of higher-than-expected customer load growth
4. LA100 - Low Distributed Energy Resource (DER) Sensitivity	2035	DER adoption is lower than expected	Impact of customers adopting fewer DERs than anticipated
5. LA100 - High Distributed Energy Resource (DER) Sensitivity	2035	DER adoption is higher than expected	Impact of customers adopting more DERs than anticipated
6. LA100 - No In-basin Combustion Sensitivity	2035	Replacement of green H_2-capable combustion turbines with green H_2-capable fuel cells, in-basin	Impact of green H_2-capable fuel cells, in place of in-basin green H_2-capable combustion turbines
7. LA100 - No In-basin Hydrogen (H_2) Supply Sensitivity	N/A (97% by 2035)	Maintaining of natural gas-fueled generation online, in lieu of green H_2-capable generation in-basin	Impact of green H_2 commodity market failing to reach commercial maturity at scale
8. LA100 - Limited In-basin Hydrogen (H_2) Supply Sensitivity	2035	Limited H_2 fuel supply available for in-basin generation	Impact of green H_2 commodity market supplying less in-basin fuel than anticipated
9. LA100 - Resource Constrained Sensitivity	2040	New renewable energy and energy storage procurement capped at 500 MW/year. Green H_2-capable generation in-basin is not fully built out until 2040	Impact of undersupplied market for renewable energy and energy storage, in addition to delays in H_2 technology maturity
10. LA100 - Climate Change Sensitivity	2035	Base customer load is higher than expected	Impact of climate change
SB 100 Benchmark	**2045**	**Benchmark scenario, state policy mandate**	**N/A; risks were assessed via sensitivities**
11. SB 100 Price Sensitivity Sensitivity	2045	Lower renewable energy, energy storage, and green H_2 costs; Higher natural gas and CO_2 allowance costs	Impact of lower cost of clean energy and lower cost of fossil fuels

**Developed with input from the LA100 Advisory Group*

***LA100 reaches 100% carbon-free energy by 2035, as a percentage of all electric generation (including losses). SB 100 reaches 100% clean energy by 2045, as a percentage of electric retail sales (excluding losses).*

2.3.1 LA100 Pathway

The LA100 Pathway—originally identified as Case 1 in LADWP's 2022 Strategic Long-Term Resource Plan (SLTRP)—was adopted by the LADWP Board as the official pathway to achieving the Los Angeles City Council's directive for 100% carbon-free energy by 2035. This directive exceeds the requirements of California's SB 100 by mandating that all electricity, including energy used to cover transmission and distribution losses, must be sourced from carbon-free resources. By contrast, SB 100 applies only to retail electricity sales and sets a compliance deadline of 2045.

The LA100 Pathway establishes a more aggressive timeline and a broader scope. It commits LADWP to delivering 100% carbon-free electricity by January 1, 2035—ten years ahead of the state mandate—and sets an interim goal of reaching an 80% renewable portfolio standard (RPS) by 2030. The plan also emphasizes local investment in distributed solar, energy efficiency, distributed storage, and demand response to help achieve these targets. Together, these elements represent a comprehensive, community-centered approach to decarbonizing Los Angeles' electricity system while supporting grid reliability, environmental equity, and long-term resilience.



2.3.1.1 LA100 Sensitivities

To assess the resilience of the LA100 Plan under a range of uncertain future conditions, LADWP developed a suite of sensitivity cases based on input received from the LA100 Plan Advisory Group. These sensitivities examine how variations in key assumptions—such as energy costs, load growth, customer adoption of distributed energy resources (DERs), green hydrogen availability, and climate impacts—could affect the performance, costs, and implementation of the LA100 pathway. By stress-testing the plan against these risks, LADWP aims to identify potential challenges early and ensure the plan remains achievable, flexible, and reliable as conditions evolve.

2.3.1.1.1 LA100 Price Sensitivity

The LA100 Price Sensitivity is derived from the LA100 Plan but reflects a scenario in which renewable energy and hydrogen costs are higher than anticipated, while natural gas prices are lower than anticipated. Like the core LA100 Pathway, this sensitivity requires that all electricity—including that used to cover transmission and distribution losses—must come from carbon-free sources by January 1, 2035. It also retains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

Although the policy objectives remain the same, this sensitivity yields different outcomes due to the altered cost assumptions. Higher-than-anticipated costs for renewable energy, energy storage, and green hydrogen—combined with lower-than-anticipated dispatch costs for natural gas—affect portfolio composition and overall system costs.

By 2035, the LA100 Price Sensitivity includes the deployment of:

- 853 MW of local distributed solar
- 3,346 GWh of cumulative energy efficiency savings
- 277 MW of distributed energy storage
- 729 MW of demand response capacity

These targets support a comprehensive and locally focused approach to decarbonizing Los Angeles' electricity supply while maintaining system reliability, equity, and long-term resilience.

2.3.1.1.2 LA100 Low Load Sensitivity

The LA100 Low Load Sensitivity is based on the core LA100 Pathway but assumes a lower net load than anticipated in the main scenario. As with the LA100 Pathway, this sensitivity requires that all electricity, including energy used to cover transmission and distribution losses, must be sourced from carbon-free resources by January 1, 2035. It also maintains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

This sensitivity diverges from the base model in several key outcomes. Lower overall customer load, combined with increased adoption of distributed energy resources (DERs), reduces the amount of utility-scale renewable procurement needed to meet carbon-free targets. As a result, the sensitivity achieves significant cost savings and a lower total system cost, while still meeting all clean energy milestones.

By 2035, the LA100 Low Load Sensitivity includes the deployment of:

- 1,017 MW of local distributed solar,
- 3,346 GWh of cumulative energy efficiency savings,
- 376 MW of distributed energy storage, and
- 862 MW of demand response capacity.

These investments support a localized, cost-effective approach to decarbonization while maintaining system reliability, equity, and long-term resilience.

2.3.1.1.3 LA100 High Load Sensitivity

The LA100 High Load Sensitivity is derived from the core LA100 Pathway but assumes a higher net load than anticipated in the main scenario. As with the LA100 Pathway, this sensitivity requires that all electricity—including energy used to cover transmission and distribution losses—must come from carbon-free sources by January 1, 2035. The interim target of achieving an 80% renewable portfolio standard (RPS) by 2030 is also retained.

This sensitivity diverges from the base model in several key areas. Higher overall electricity demand, elevated peak loads, and lower-than-expected adoption of distributed energy resources (DERs) place increased pressure on system reliability and flexibility. As a result, the system relies more heavily on dispatchable carbon-free resources and incurs higher overall costs to maintain reliability and meet clean energy goals.

By 2035, the LA100 High Load Sensitivity includes the deployment of:

- 1,424 MW of local distributed solar,
- 3,434 GWh of cumulative energy efficiency savings,
- 331 MW of distributed energy storage, and
- 615 MW of demand response capacity.

These investments reflect a comprehensive and locally targeted approach to meeting clean energy objectives while ensuring the grid remains reliable and resilient under high-demand conditions.

2.3.1.1.4 LA100 Low DER Sensitivity

The LA100 Low DER Sensitivity examines a future in which customer adoption of distributed energy resources (DERs)—such as rooftop solar, behind-the-meter storage, and flexible building loads—is lower than anticipated in the core LA100 Pathway. This outcome reflects potential barriers such as policy limitations, lack of incentives, equity challenges, market constraints, or slower consumer uptake.

As with the LA100 Pathway, this sensitivity requires that all electricity—including energy used to cover transmission and distribution losses—must come from carbon-free resources by January 1, 2035, and it retains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

Lower levels of DER adoption increase reliance on the central grid, requiring greater investment in utility-scale generation, transmission infrastructure, and firm clean capacity. This sensitivity highlights the critical role of centralized resources in achieving decarbonization under constrained customer participation and raises important considerations around cost, equity, and grid design.

2.3.1.1.5 LA100 High DER Sensitivity

The LA100 High DER Sensitivity explores a future in which customer adoption of distributed energy resources (DERs), including rooftop solar, behind-the-meter storage (BESS) paired with photovoltaic systems, and other customer-sited distributed generation—grows significantly beyond levels assumed in the core LA100 Pathway. As with the LA100 Pathway, this sensitivity requires that all electricity, including energy used to cover transmission and distribution losses, must come from carbon-free resources by

January 1, 2035. It also maintains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

This sensitivity represents a highly decentralized, flexible, and consumer-driven approach to decarbonization. High DER adoption reduces dependence on centralized utility-scale generation and limits the need for major new transmission infrastructure. While it accelerates the transition away from fossil fuels, it also presents new challenges for grid operations, planning, and coordination due to the increased complexity of managing large volumes of distributed generation and storage.

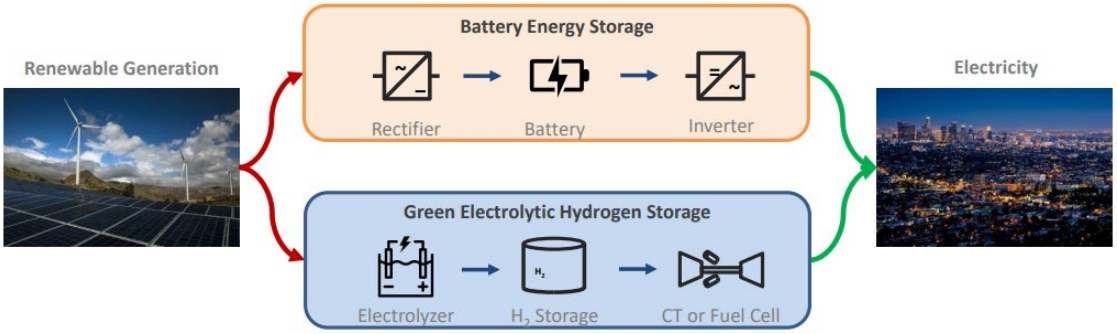
Importantly, outcomes in this sensitivity are largely shaped by customer behavior, market forces, and broader policy conditions. As such, LADWP has limited direct control over the level and pace of DER adoption, making it a key area of uncertainty in long-term resource planning.

The High DER Sensitivity highlights the potential for customer participation to play a transformative role in achieving a carbon-free electricity system while reshaping the grid into a more localized and dynamic network.

2.3.1.1.6 LA100 No In-Basin Combustion Sensitivity

The LA100 No In-Basin Combustion Sensitivity explores a future in which LADWP eliminates all in-basin combustion-based generation—even when fueled by green hydrogen—and instead relies on hydrogen-powered fuel cells for local firm capacity. This sensitivity is based on the broader LA100 Pathway framework and was designed to evaluate a non-combustion pathway for meeting reliability needs within the LA Basin, where local generation plays a critical role in maintaining grid stability.

To replace green hydrogen-fueled combustion turbines, the sensitivity models the deployment of in-basin green hydrogen fuel cells as an alternative source of dispatchable carbon-free capacity. While this approach aligns with the goal of eliminating all combustion technologies, it was ultimately determined to be infeasible for several reasons.



First, fuel cell technology at the scale required by LADWP is not commercially available today, and there are substantial concerns about future manufacturing capacity being able to meet the volume needed. In addition, fuel cells are significantly more expensive than combustion turbines, both in terms of capital cost and operational complexity. Their physical footprint is also a major concern in the densely populated and space-constrained LA Basin, where available land for large-scale infrastructure is extremely limited. Moreover, unlike turbines, fuel cells are limited in their ability to rapidly ramp output up or down in response to fluctuating grid conditions, making them less suitable for the type of flexible, firm capacity that LADWP requires to support reliability in a high-renewables system.

While the No In-Basin Combustion Sensitivity provided useful insight into alternative clean energy configurations, it highlighted serious technical, economic, and operational challenges that make this approach impractical under current and projected future conditions.

2.3.1.1.7 LA100 No In-Basin H2 Supply Sensitivity

The LA100 No In-Basin Hydrogen Supply Sensitivity explores a scenario in which no green hydrogen is available for in-basin power generation at any point during the study period. Based on the core LA100 Pathway, this sensitivity assesses the impact of a complete failure of the green hydrogen commodity market to deliver fuel for LADWP's planned hydrogen-fueled combustion turbines within the LA Basin. This could result from a range of factors, including stalled technology development, lack of infrastructure investment, policy or market failures, or an inability to scale green hydrogen production and delivery systems to utility levels.



With no in-basin hydrogen-fueled generation available, the model retains a limited amount of natural gas-fueled capacity within the basin to provide backup generation during periods of high demand or system stress. This natural gas generation is assumed to be used sparingly and only when necessary to maintain reliability. The only hydrogen-fueled generation in this sensitivity comes from the Intermountain Power Project (IPP) in Delta, Utah, which is assumed to operate on a constant 30% green hydrogen by volume blend from 2025 through 2045. This assumption differs from the LA100 Pathway, where IPP ramps up to 100% green hydrogen by 2035.

All other assumptions from the LA100 Pathway—including distributed energy resource adoption, energy efficiency levels, and demand response—remain unchanged. This sensitivity isolates the consequences of a total lack of hydrogen fuel availability for in-basin use and highlights the critical dependency of the LA100 Pathway on the emergence of a viable, large-scale green hydrogen market. It also underscores the importance of contingency planning for firm, dispatchable, carbon-free resources in the event hydrogen infrastructure and supply chains fail to develop as anticipated.

2.3.1.1.8 LA100 Limited H2 Supply Sensitivity



The LA100 Limited Hydrogen Supply Sensitivity explores a future in which green hydrogen is available for in-basin power generation, but only at approximately half the volume assumed in the LA100 Pathway. This sensitivity was designed to assess the impact of constrained hydrogen availability—reflecting potential market limitations in fuel production, infrastructure development, and delivery—on the reliability and cost of achieving a carbon-free electricity system by 2035.

To model this sensitivity, the capacity factors of in-basin hydrogen-fueled combustion turbines were reduced by approximately 50% relative to LA100 Pathway assumptions. However, it is important to note that under the LA100 Pathway, these turbines already operated at consistently low capacity factors—in the single digits—due to their intended role as firm, dispatchable backup resources. Further reducing their utilization significantly increased the challenge of maintaining system reliability without the full availability of carbon-free, flexible generation.

To compensate, the model added substantial amounts of renewable energy—primarily wind and solar—along with a corresponding increase in energy storage. While renewables are variable, layering additional resources and pairing them with storage can enhance reliability across a range of operating conditions. However, this approach comes at a cost.

The additional buildout of renewables and storage required to offset limited hydrogen supply results in higher total system costs compared to the core LA100 Pathway. This sensitivity highlights the critical trade-off between reliability and affordability when firm, carbon-free fuels are constrained, and underscores the importance of both securing a robust green hydrogen supply and maintaining flexibility in long-term planning.

2.3.1.1.9 LA100 Resource-Constrained Sensitivity

The LA100 Resource-Constrained Sensitivity evaluates the risk that market conditions, supply chain disruptions, permitting delays, or other external barriers may limit LADWP's ability to deploy the carbon-free resources needed to meet its decarbonization goals on schedule. While this sensitivity maintains the same foundational objectives as the LA100 Pathway—including reaching 100% carbon-free electricity and eliminating fossil fuel use for all generation, including line losses—it reflects a scenario in which the buildout of key technologies does not proceed as planned. As a result, the 100% carbon-free target is delayed from 2035 to 2040—still ahead of California's SB 100 mandate of 2045.

To simulate these constraints, the model limits the pace at which carbon-free resources can be added to the system. For renewable energy resources, only half of the annual buildout assumed in the LA100 Pathway is allowed in any given year. This effectively "spreads out" the deployment of new solar and wind generation over a longer period, resulting in a slower transition to a high-renewables grid. Similar constraints are applied to energy storage technologies, limiting the availability of capacity needed to firm intermittent resources.

In addition, this sensitivity assumes a delayed buildout of in-basin hydrogen-fueled combustion turbines, which are a critical source of firm, carbon-free dispatchable generation in the LA100 Pathway. The delay reflects potential barriers such as limited manufacturing capacity, infrastructure siting challenges, or slow development of a scalable green hydrogen supply chain.



Scattergood Generating Station Repowering

The Resource-Constrained Sensitivity illustrates how delays in the availability of carbon-free technologies can impact the timing, cost, and operational reliability of the clean energy transition. While the ultimate goal of a 100% carbon-free grid remains technically feasible, achieving it under these constrained conditions requires greater planning flexibility, increased reliance on transitional resources, and potentially higher system costs. This scenario underscores the need for risk-aware implementation strategies, robust contingency planning, and strong coordination with industry partners and policymakers to mitigate external bottlenecks.

2.3.1.1.10 LA100 Climate Change Sensitivity

The LA100 Climate Change Sensitivity evaluates how rising temperatures driven by climate change could affect future electricity demand and resource needs for LADWP. This analysis began with forward-looking projections of Heating Degree Days (HDD) and Cooling Degree Days (CDD) through 2045, based on two climate scenarios: RCP 4.5 and RCP 8.5. Representative Concentration Pathways (RCPs) are standardized greenhouse gas concentration trajectories used in global climate modeling. RCP 4.5 assumes moderate emissions with stabilization by 2100, while RCP 8.5 represents a high-emissions scenario with minimal mitigation, resulting in more severe climate impacts.

We combined these forward-looking projections with ten years of historical HDD and CDD data for key locations across LADWP's service territory, including Downtown Los Angeles, LAX, Woodland Hills, and Van Nuys. Using this historical dataset, we developed correlations between temperature-sensitive metrics and historical customer electricity demand. To model this relationship, we applied several machine learning techniques, including Locally Weighted Learning (LWL)—an algorithm that predicts outcomes by creating localized models for each prediction, giving more weight to nearby data points. LWL, along with linear nearest neighbor search and linear regression, delivered the most accurate results for our application. Alternative methods such as decision trees and neural networks were evaluated but provided less reliable correlations.

The trained model was then applied to forward-looking HDD and CDD projections to adjust LADWP's load forecast under future climate conditions. Results indicate that while rising temperatures significantly increase electricity demand—primarily due to higher cooling loads—LADWP can still achieve its 100% carbon-free energy target by 2035 under the LA100 Pathway portfolio while maintaining system reliability. These findings highlight both the resilience of the LA100 Pathway resource mix and the importance of

ongoing investment in flexible, clean energy resources as climate change accelerates electrification and cooling demand.

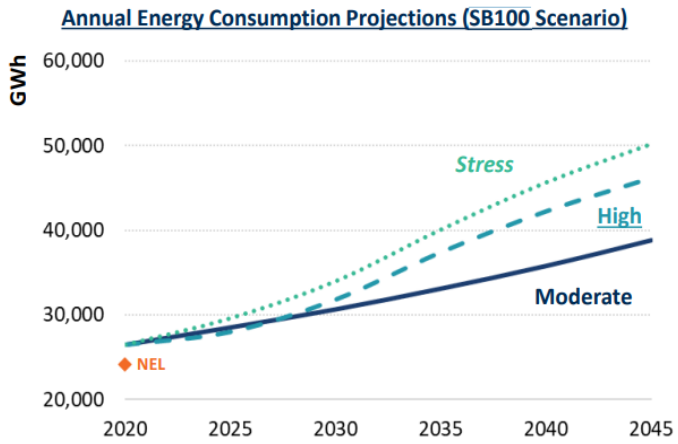
2.3.2 SB 100 Benchmark Reference Case

The SB100 Benchmark represents a compliance-oriented pathway developed solely for comparison purposes. It models the minimum level of transition LADWP would need to pursue in order to meet the clean energy mandates established by Senate Bill 100 (SB 100) and subsequent legislation, including Senate Bill 1020. SB 100 requires all California utilities to supply 60% of retail electricity sales from renewable resources by 2030 and to achieve 100% carbon-free electricity by 2045. SB 1020 adds interim targets of 90% carbon-free electricity by 2035 and 95% by 2040, further reinforcing the state's decarbonization trajectory.

This analysis is included in the LA100 Plan strictly as a reference case and does not represent LADWP's adopted or preferred path forward. It serves as a benchmark for evaluating trade-offs related to timing, resource mix, cost, emissions, and grid operations when compared to the more ambitious LA100 Pathway.

Under the SB100 Benchmark, the transformation of LADWP's power supply occurs at a more gradual pace. Coal-fired generation is retired by 2025, but natural gas resources—both in-basin and out-of-basin—continue operating through 2045, albeit with significantly reduced utilization. This reflects the compliance structure of SB 100, which allows fossil generation to remain on the system as long as carbon-free resources are sufficient to offset retail electricity sales on an annual basis.

To meet renewable and clean energy targets, LADWP adds substantial solar generation paired with energy storage, along with new wind capacity, battery storage systems, and modest contributions from geothermal and offshore wind in later years. Emerging technologies, such as green hydrogen, appear only in limited volumes beginning in the 2030s and are not a central component of the resource mix.



Customer load in this analysis grows steadily over time due to widespread electrification of buildings and transportation, partially offset by energy efficiency and early adoption of behind-the-meter solar. Operationally, thermal units continue to play a key role in maintaining grid reliability and stability, resulting in moderate greenhouse gas (GHG) and nitrogen oxide (NO_x) emissions throughout the planning horizon.

2.3.2.1 SB 100 Sensitivity

Although the SB100 Benchmark serves only as a reference case to illustrate compliance with California's minimum legal requirements, a sensitivity was developed to explore the potential impact of lower-than-anticipated clean energy costs. This analysis provides insight into how cost reductions could influence resource decisions and overall system performance under a less aggressive decarbonization pathway. While not the adopted strategy, the SB100 Price Sensitivity helps to contextualize cost risks and opportunities in relation to the state-mandated target.

2.3.2.1.1 SB 100 Price Sensitivity

The SB 100 Price Sensitivity explores how LADWP's compliance with Senate Bill 100 (SB 100)—which mandates 100% carbon-free electricity by 2045, measured on a retail sales basis—could be affected under assumptions of significantly lower clean technology costs. This sensitivity models reduced costs for key resources, including renewable energy, energy storage, and hydrogen-fueled generation, while keeping all other policy requirements and timelines consistent with the SB100 Benchmark.

This scenario is not intended as an actionable or preferred pathway for LADWP. Rather, it serves as an analytical bookend representing the lower-cost extreme of the technology cost spectrum. By doing so, it provides insight into how improved market conditions could shift resource planning decisions, reduce system costs, and affect generation dispatch—within the context of a more gradual, compliance-focused transition.

The SB 100 Price Sensitivity also helps to illuminate cost-driven trade-offs and operational dynamics across the portfolio and serves as a useful benchmark for comparing other LA100 Plan models, such as those involving high electrification or differing levels of distributed energy resource adoption.

2.4 Load Forecasting

Utilities are required to forecast energy demand and determine viable methods to satisfy that demand. Planning the buildout of electricity generating ("supply-side") resources in order to meet forecasted demand is a vital component of the LA100 process and LADWP responsibilities. Another key element in our planning process is determining methods and technologies that help us reduce or control energy demand and increase the efficiency of our customers' electricity use. This process is known as "demand-side resource" planning.

This section and subsequent sections of the LA100 Plan address the following:

- Forecasts of future energy demand, including transportation electrification
- Demand-side resources (DSR), including energy efficiency and demand response
- Distributed generation
- Supply-side resources
- Transmission and distribution information, including grid reliability
- Advanced technologies, including Smart Grid and energy storage
- Climate change effects on power generation
- Reserve requirements

The discussions include the technical, regulatory, and economic factors that influence LADWP's planning process and execution of programs and projects.

Data for this analysis comes from publicly available reports from organizations such as the California Energy Commission (CEC), California Public Utilities Commission (CPUC), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), other industry forecasts, and internal LADWP sources. In this LA100 Plan, we have also highlighted additional studies that are either underway or will be performed in the near future to provide additional clarity regarding the boundaries and needs of the Power System.

2.4.1 Forecasting Future Energy Needs

The LA100 Plan utilizes LADWP's official 2023 Load Forecast—dated December 22, 2023—of customer demand for electricity over the next 20 years (the complete 2023 Load Forecast will be included in an appendix). The 2023 Load Forecast divides customer sales into six separate classes.

The information provided below includes information on sales classes and trend influences.

- Econometric models are used to forecast sales in the Residential, Commercial, and Industrial classes. Trend models are used to forecast sales in the Streetlight and Owens Valley classes.
- For the Transportation Electrification (TE) sales class, LADWP's Distribution Planning Group's electric vehicle (EV) forecast from their 2023 Distribution Load Forecast is adopted.
- The drivers in the retail sales models include normalized weather, population, employment, construction activity, and personal consumption and income.
- The retail sales forecasted from the class models are adjusted for LADWP programs that affect consumption behind-the-meter such as energy efficiency and net-metered solar generation as well as known state regulations, most notably the Huffman Bill.
- From the sales forecast, a net energy for load (NEL) forecast is developed by applying a normalized loss factor of 12%. NEL is defined as the energy production necessary to serve retail sales. Losses can vary in a given year depending on the sources of energy production and other factors. An econometric model is also used to develop weather response functions to forecast peak demand.
- The weather response model includes temperature, heat buildup, and time of the summer, as drivers. Peak demand grows over time as a function of the NEL forecast adjusted for energy efficiency, net-metered solar, residential lighting, and charging of electric vehicles. The NEL forecast is allocated into an hourly shape using the Loadfarm algorithm developed by Global Energy. The inputs into the algorithm are forecasted NEL, peak demand, minimum demand, and historical system average load shape in monthly intervals.

2.4.2 2023 Retail Electrical Sales and Demand Forecast

The COVID-19 public health crisis began affecting electricity sales in the third quarter of FY19/20. Sales for FY21/22 were 21,309 Gigawatt-hours (GWh), which is 3.0% below recorded sales in the last pre-COVID-19 year, FY18/19, which totaled 21,961 GWh. The compounded growth rate for sales is estimated to be only 0.07% over the five-year forecast period. Persistent higher vacancy rates in the commercial sector is the predominant reason for the change. With higher vacancy rates, the economy will muddle along until the vacant commercial spaces are repurposed. Improving technology in electric transportation and building electrification is a source of additional electricity sales. Electricity sales growth will be restrained by accelerated incremental savings from LADWP's energy efficiency and solar distributed generation programs. Electricity price increases may lead customers to change their consumption behavior, with a tendency toward greater conservation.

The five-year budget period is one of great uncertainty. LADWP is monitoring the sales and load data weekly and will make necessary adjustments for immediate forecast needs. Figure 2-1 shows LADWP's historical retail sales net of energy efficiency and distributed generation.

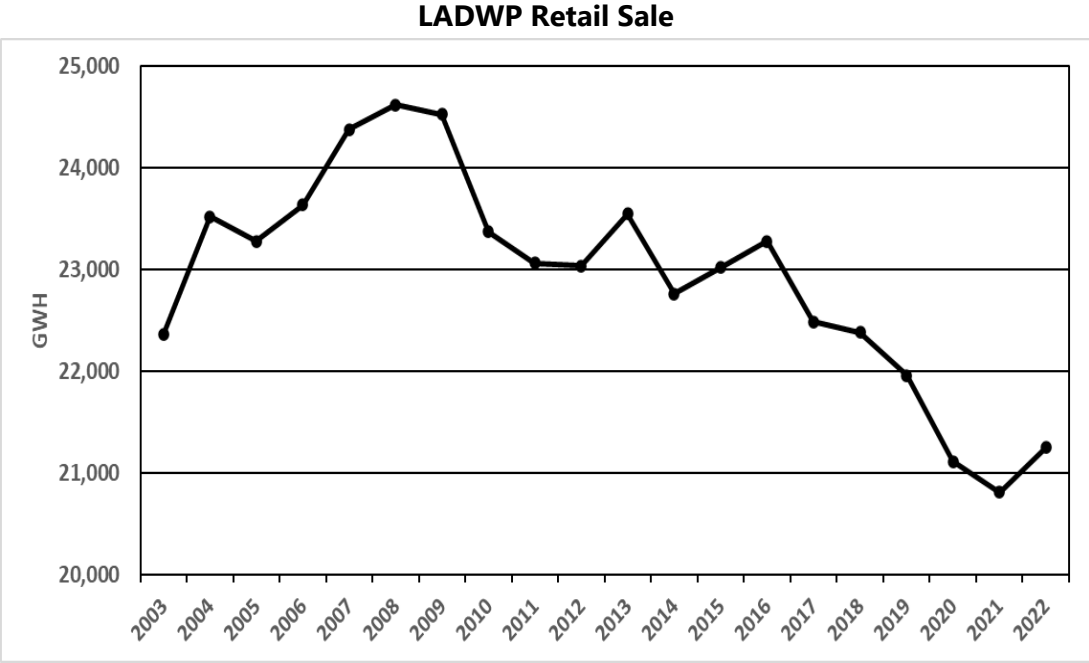


Figure 2-1 Retail sales net of energy efficiency and distributed generation.

2.4.3 Electrical Losses

The average electrical loss factor for LADWP for the period of 2001 through 2022 is 12.4% with a standard deviation of 1.2%. Loss factor in 2022 was 11.2%. LADWP uses the loss factor of 12% for forecasting purposes. Figure 2-2 shows historical electrical losses as percentage of total generation. Such losses primarily arise from resistive heating in transmission and distribution lines.

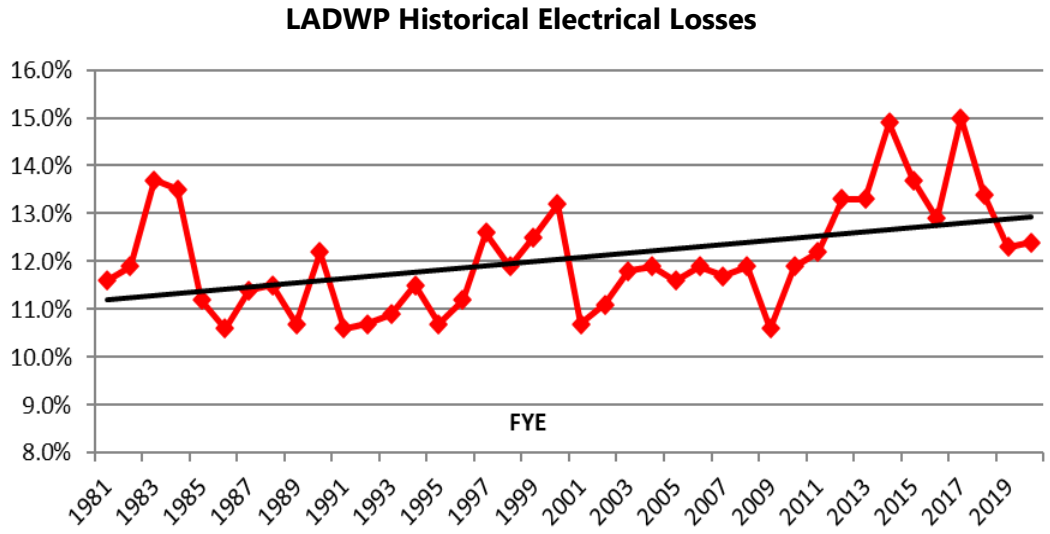


Figure 2-2 Historical percentage losses by fiscal year.

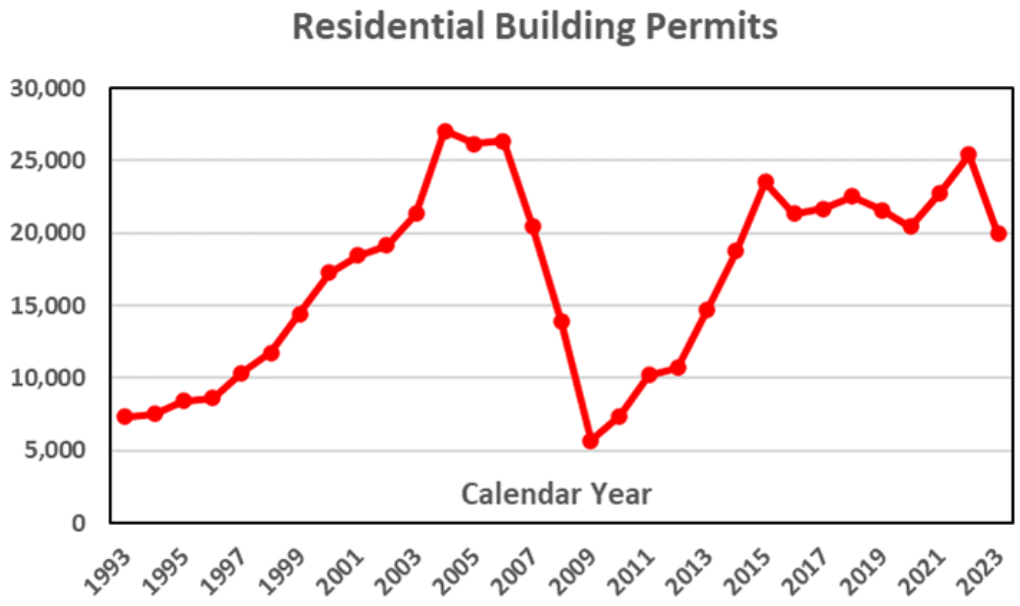
2.4.4 Economics

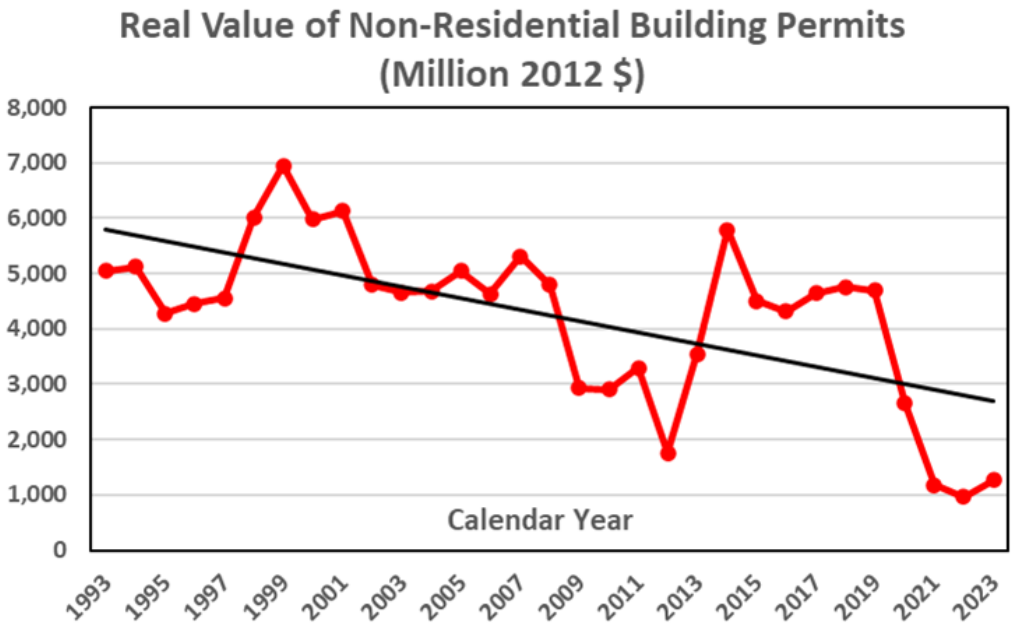
The population and its growth have a direct impact on the economy of a city or county. The total net migration for Los Angeles County in 2023 was negative 9,000 people, signaling a loss of residents versus the influx of new residents, however at a slower rate compared to the pandemic years. The last positive year for net migration in Los Angeles County was 2001. Recently, the Los Angeles County population growth can be attributed to natural increase (the difference between the number of live births and the number of deaths), rather than migrants. The LADWP service area is most commonly modeled as having a significant share of Los Angeles County population.

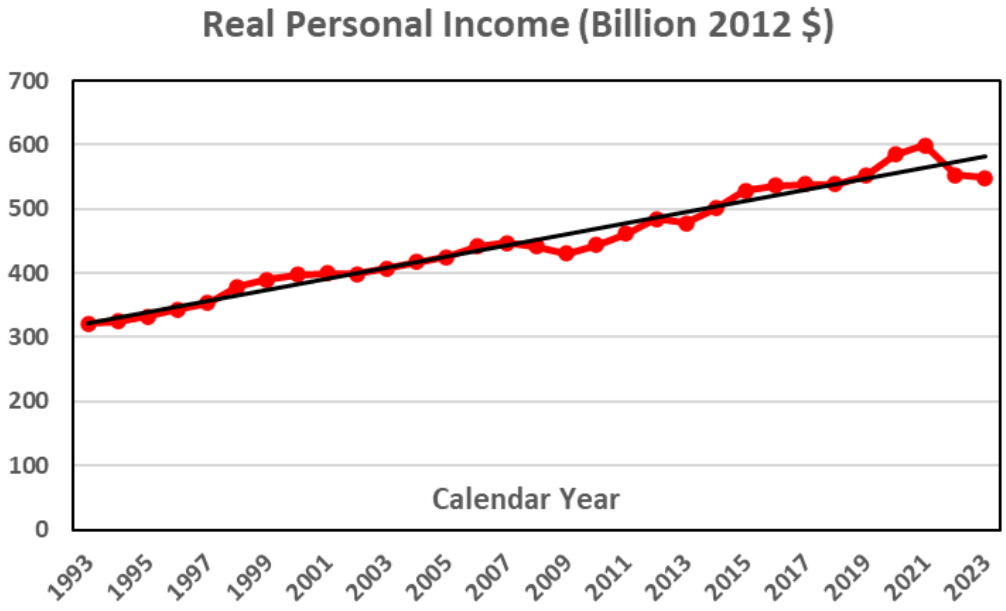
The electricity consumption within LADWP's service territory is forecasted to increase 0.07% over the next five years as stagnant population growth, energy efficiency, customer-installed solar photovoltaic (PV) expansion offsets growth from economic

activity. The growth in annual peak demand over the next ten years is predicted to be about a 1% combined effect due to the steady growth of energy efficiency, solar PV programs, transportation electrification and building electrification. Also, the implementation of the demand response program may lead to load reduction although the demand response program was not factored into our peak demand forecast. Despite its exclusion from the forecast, it has been considered as a resource to serve peak demand in this LA100 Plan.

All the data and forecasts in Figure 2-3 below are taken from the 2023 UCLA Anderson Forecast.




Real Value of Non-Residential Building Permits
(Million 2012 $)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Calendar Year
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023


Real Personal Income (Billion 2012 $)
700
600
500
400
300
200
100
0
Calendar Year
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

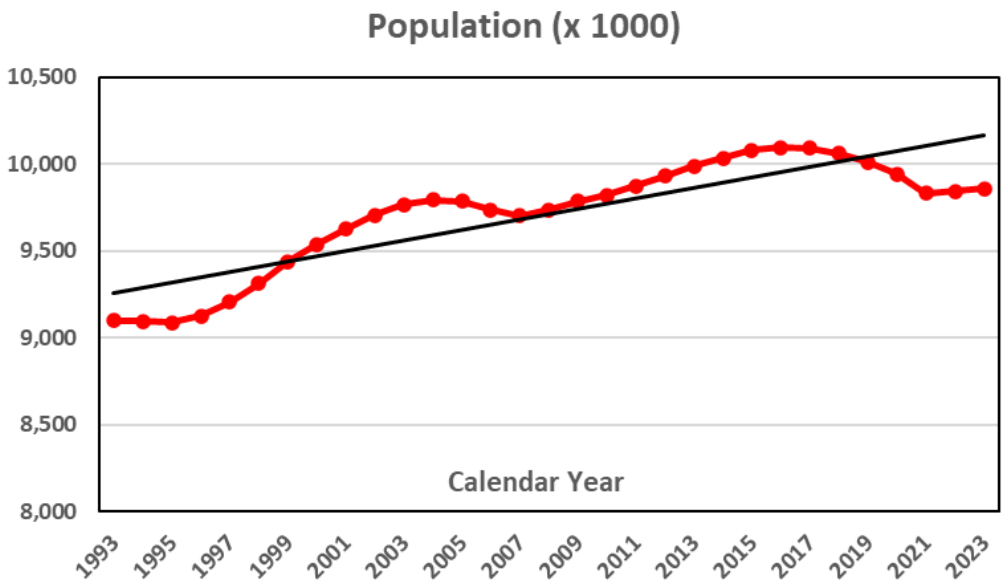


Figure 2-3 2023 UCLA Anderson historical inputs for residential building permits, real value of non-residential building permits, real personal income, and population by calendar year.

2.4.5 Forecast Data Sources

The 2023 Load Forecast serves as LADWP's official Power System load forecast and is utilized as the foundation for LADWP Power System planning activities. These activities include, but are not limited to, Strategic Long-Term Resource Planning, transmission and distribution planning, and wholesale marketing. The forecast is a public document that uses only publicly available information.

Table 2-2 summarizes the data sources used to develop the forecast and source updates.

Table 2-2 Load forecast data sources.

Data Sources	Updates
1. Historical Sales through December 2022 were reconciled to the General Accountings Consumption and Earnings Report.	Historical Sales, Net Energy for Load and weather data are updated through December 2022.
2. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2022 benchmark.	Employment data is updated through December 2022 using the March 2022 benchmark.
3. The Transportation Electrification Forecast is based on LADWP's Distribution Planning Group's electric vehicle (EV) forecast from their 2023 Distribution Load Forecast.	
4. The LADWP program energy efficiency forecast is based on the AB 2021 goals adopted by Board Resolution on August 5, 2014 and is consistent with the LA100 Plan. Historical installation rates are provided by the Energy Efficiency group.	
5. Projected solar rooftop installations are consistent with the LA100 Plan. Historical installations are provided by the Solar Programs Development Group.	
6. Electric prices are based on approved FY22/23 Final Budget Financial Plan Case-3 developed by the Financial Services Organization.	

2.4.6 Five-year Sales Forecast

The 2023 Load Forecast represents total sales that will be realized at the meter while incorporating future impacts from known energy efficiency technologies and distributed generation. However, it does not include changes in sales that may result from emerging technologies. The historical accumulated energy efficiency and solar savings reported in the forecast are from 1999 and onwards. Historical codes and standard savings for the years 1999 through 2011 are based on a California Energy Commission analysis. Starting after 2011, LADWP began calculating its share of total savings from codes and standards

from reported California savings. While true accumulated energy efficiency data can be traced to 1974 (the enactment of the Warren-Alquist Act), accurate records are not available. The 2023 Load Forecast assumes that the projected energy efficiency and customer-sided solar savings occur uniformly as a simplification.

Table 2-3 shows projections for short-term retail sales and energy efficiency growth.

Table 2-3 Short-term retail sales and energy efficiency growth.

Fiscal Year	***Retail Sales***		***Additional Load if not for EE & Solar Savings***
Ending June 30	(GWh)	Growth Rate (Year-Over-Year)	(GWh)
2022-23	21,611	1.4%	4,483
2023-24	21,734	0.6%	4,841
2024-25	21,574	-0.7%	5,372
2025-26	21,635	0.3%	5,922
2026-27	21,380	-1.2%	6,456

Adjustments were made to the approved load forecast to account for the alternative energy efficiency targets and customer net-metered solar projections during LA100 Plan modeling and analysis.

Our estimated sales for FYE 2023 were 300 GWh, or 1.4% above recorded sales in FYE 2022. The compounded growth rate for sales is estimated to be 0.07% over the five-year budget period. This result is mainly attributed to accelerated incremental savings from LADWP's energy efficiency and solar distributed generation programs and expected increases in real electric rates. In the 2023 Load Forecast, electric rate increases are lagged one year to allow for customer behavior to change.

Historical and future retail sales would be significantly higher absent LADWP energy efficiency and solar distributed generation programs. Total sales have been reduced by 4,208 GWh since FYE 2000 through LADWP-sponsored programs. LADWP is accelerating

these savings programs and retail sales are expected to be reduced by another 2,247 GWh over the next five years.

2.5 LADWP Programs and Initiatives

The following subsections describe the various LADWP programs and initiatives included in the LA100 Plan.



2.5.1 Energy Efficiency

Energy Efficiency (EE) is a key strategic element in LADWP's resource planning efforts. EE serves an important and multi-faceted role in meeting customer demand. A common example of a successful EE measure is the replacement of compact fluorescent lamps (CFLs) with light-emitting diode (LED) lamps. LEDs consume up to 60% less energy than CFLs while producing an equivalent amount of illumination and lasting up to seven times longer.

EE programs have reduced consumption by approximately 327.5 GWh/yr. LADWP is committed to implementing comprehensive energy efficiency programs with measurable, verifiable goals as well as maintaining an overall cost-effective energy efficiency portfolio.

Under Assembly Bill 2021 (AB 2021), publicly owned utilities such as LADWP, must identify, develop and implement programs for all potentially achievable, cost-effective EE savings and establish annual targets of no less than 10%.

Furthermore, utilities are required to conduct periodic EE potential studies to update their forecasts and targets. LADWP completed and finalized the 2013 EE Potential Study in 2014. The revised energy savings and demand reduction targets, based on the EE Potential Study, were recommended and adopted by the Board of Water and Power Commissioners on August 5, 2014. The next EE Potential study was conducted in 2017, which concluded that LADWP could cost effectively achieve another 15% energy efficiency from 2017 through 2027 in addition to the previously committed 15% from 2010 through 2020. LADWP achieved its 2020 15% goal, equivalent to a cumulative 3,122 GWh. Currently LADWP is aiming to keep up with the same pace in years past with an additional 3434GWh savings by 2035. This surpasses the projections from the LA100 Study.

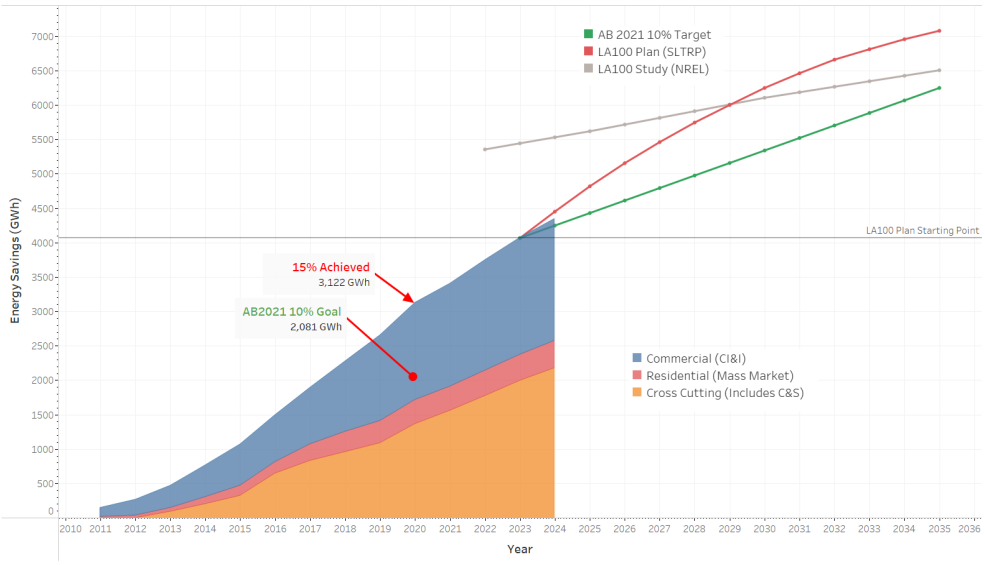


Figure 2-4 Cumulative energy efficiency savings.

The historical performance and current portfolio plan cost effectiveness has consistently ranged from $0.04 -$0.05/kWh Levelized Cost of Energy (LCOE) for each year-to-year activities. This further reinforces energy efficiency as a long-term, cost-effective alternative solution to avoid and defer the most costly supply resources of the future.

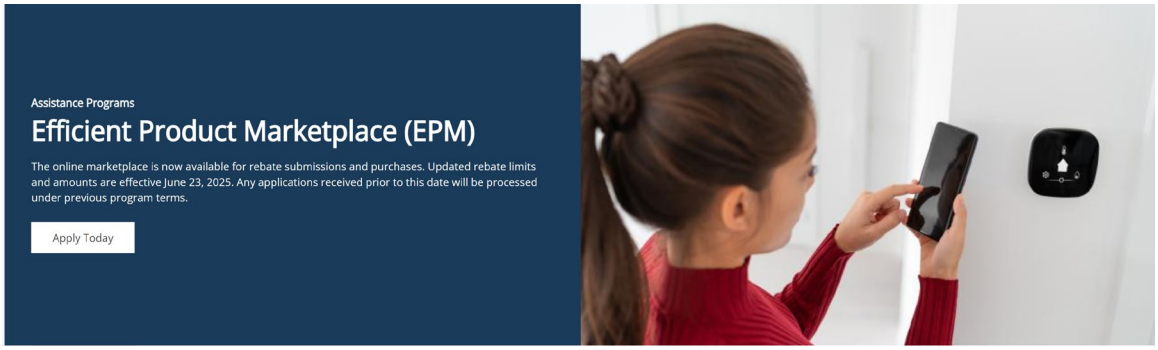
The following subsections highlight some of LADWP's EE programs.

2.5.1.1 Comprehensive Affordable Multifamily Retrofits



The Comprehensive Affordable Multifamily Retrofits (the "CAMR") program provides low-income tenants and affordable housing property owners access to energy efficiency retrofits, building electrification measures, and on-site solar installation. The participating housing providers receive free energy assessments and assistance in scoping retrofit projects based on opportunities for energy savings, cost reductions, and GHG emissions reduction. Participating properties must meet affordability requirements of at least 66% of households at or below 80% of the area median income, consist of five or more units, and install energy improvements that equate to at least 10% in energy savings.

2.5.1.2 Efficient Product Marketplace



The Efficient Product Marketplace (the "EPM") program provides customers an opportunity to research, locate, and purchase energy efficient products from a single website. It offers a point-of-sale credit option to customers during their online purchases, eliminating the need for completing a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare and choose offers from a list of local third-party vendors.

2.5.1.3 Food Service Program

For in-store purchases, the Food Service Program offers an instant rebate as a line-item discount directly on their sales invoice for eligible equipment. The Food Service Program is intended to influence commercial food service vendors to stock and sell energy-efficient equipment. Beginning in 2024, the Food Service Program started offering electrification incentives for all electric commercial cooking equipment and appliances.



2.5.1.4 Custom Performance Program/Business Offerings for Sustainable Solutions

As initially established, the Custom Performance Program (the "CPP") provided cash incentives for energy savings achieved through the implementation and installation of various energy efficiency measures and equipment that meet or exceed Title 24 or industry standards. Measures may include but are not limited to equipment controls, industrial process, retro-commissioning, chiller efficiency, and/or other innovative energy savings strategies.

Beginning July 1, 2024, the CPP was rebranded as the Business Offerings for Sustainable Solutions ("BOSS") Program. The BOSS Program continues to fast-track smaller, less energy-intensive projects through its "Custom Express" service, which offers energy savings projections to expedite application processing and faster payments to customers. Additionally, the Custom Calculated service provides in-depth analyses to calculate the energy savings of individual efficiency projects. Since 2007, the CPP/BOSS

Program has achieved over 614 GWhs of energy savings and introduced electrification incentives for space and water heating end uses.

2.5.1.5 Commercial Lighting Incentive Program

The Commercial Lighting Incentive Program ("CLIP") offers customers incentives to install newly purchased and installed energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilowatts (kW). CLIP's calculated savings approach allows customers to tailor their lighting efficiency upgrades to better meet their lighting needs, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 826 GWhs of energy savings since 2000.



2.5.1.6 Commercial Direct Install Program

The Commercial Direct Install ("CDI") Program is a free direct-install program that targets small, medium, and large business customers in the Department service territory. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less; CDI has achieved over 528 GWhs of energy savings since its inception in 2008.

2.5.1.7 Home Energy Improvement Program

The Home Energy Improvement Program ("HEIP") is a comprehensive direct install whole-house retrofit program that offers residential customers a full suite of free products and services to improve the home's energy and water efficiency by upgrading/retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the neediest customers.

2.5.1.8 Refrigerator Exchange Program

The Refrigerator Exchange Program ("REP") is a free refrigerator replacement initiative targeting customers who qualify under the Department's Low-Income or Senior Citizen/Disability Lifeline Rates, as well as multi-residential and non-profit customers. The program has expanded to include multi-family and mobile home communities, civic, community, faith-based organizations, and educational institutions. Currently, the REP is suspended while the program seeks a new third-party contractor to administer the program and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Since 2007, REP has achieved over 106 GWhs of energy savings.



Description

The Los Angeles Department of Water and Power's (LADWP) Refrigerator Exchange Program provides new energy-saving, Energy Star® rated refrigerators in exchange for qualified older model refrigerators, **FREE** of charge.

When the new refrigerator is delivered, the old unit will be removed and recycled in an environmentally friendly manner.

Saves

- **Money** – Estimated savings of $60 annually on refrigerator operating costs
- **Energy** – Energy Star® rated refrigerators use half the electricity of non-Energy Star® rated models
- **Environment** – Using less electricity reduces the emission of greenhouse gases

2.5.1.9 LED Streetlight Program

The LED streetlight program provided a $48 million loan to the City of Los Angeles to enable it to ultimately install over 180,000 highly energy efficient LED streetlights and reduce its consumption of electricity as a result. This program is now completed, and the loan has been repaid by the City. As a result, this model is being expanded with a new $24 million loan to retrofit decorative street lighting with LED streetlights throughout the City.

2.5.1.10 Program Analysis and Development Program

The Program Analysis and Development Program is a non-resource program that covers support activities related to the energy efficiency portfolio that are not included in the individual programs. These activities include but are not limited to, developing new programs, conducting special studies and pilot programs, participation in technical professional groups, and the investment in external studies. The Department has contributed to several research studies as it relates to building electrification, including NBI's Building Electrification Technology Roadmap and E3's Residential Building Electrification in California. Since the results of the studies, the Department has been crafting incentives for customers to electrify building end uses leveraging existing

program delivery mechanisms to promote electric space and water heating, cooking and drying that have traditionally used natural gas as a fuel. While building electrification presents an opportunity to produce additional revenue, the Department's activities have focused on promoting measures that effectively result in net utility bill reduction (including gas and electricity). This is directed towards maintaining a high level of customer benefit and satisfaction.

2.5.2 Building Electrification

Starting in 2018, California established several bills such as AB 3232 and SB 1477 that aim to reduce carbon emissions in the building sector. These policies did not create mandates for any local entity but rather set emission reduction goals for the CEC and CARB. Specifically, the goals encourage both entities to focus on lowering overall building sector carbon emissions to below 40% of 1990 carbon levels. In 2019, sitting Mayor Eric Garcetti released the Green New Deal, setting local targets to reduce carbon emissions within the building sector. Specifically, it aims to establish zero-carbon requirements for new buildings by 2030 and all buildings by 2050. In 2023, Los Angeles adopted the all-electric buildings ordinance, that effectively requires all new construction building permits to be all-electric with a few exceptions. These state and local policies push the market to decarbonize in the building sector and have driven adoption in large established institutions in that direction, while LADWP introduces customer incentives to support the market transformation and relieve the initial financial burdens of decarbonizing.

2.5.2.1 LADWP's Efforts and Considerations

In 2018, LADWP participated in a joint study with SCE, SMUD, and E3 to determine the impacts of residential electrification. This study provided valuable information that provided a foundational assessment of the impacts that can be expected from building electrification in the state.

Following the joint study, LADWP collaborated with CMUA to commission GDS Associates. They were tasked with expanding upon the Energy Efficiency Potentials forecast by incorporating feasible levels of building electrification to the scope. This forecast effort included residential and small- medium sized commercial applications, which covers the vast majority of the decarbonization potential in the building sector. The electrification studies have ignored large commercial and industrial electrification opportunities because of the diversity and complexity of this sector. The potential

electrification applications require a more advanced level of analysis and scenario building. It also accounts for the smallest proportion of natural gas consumption in the building sector. Additional studies will be required to identify opportunities for these customer segments.

2.5.2.2 Load Growth Potential

The scenarios considered in the Building Electrification (BE) potential forecast conducted by GDS follow the same general methodology used within the Energy Efficiency Potentials. The model is limited in consideration for electrification opportunities for Residential Sector and Small Medium Businesses but does not cover Large Commercial or Industrial sectors due to their diverse & bespoke equipment types and lack of electric alternatives available in the market. Another key distinction is that the BE model had additional considerations for consumer adoption such as comparing life cycle costs of gas appliances to fuel-switching electric measures. Some factors included in measuring life cycle costs are the retail price, effective useful life, and gas/electric billing impact costs. Gas rates data was taken from EIA projections while the electric rates data was taken from rate scenarios developed in the LA100 Study. Incentive rates from electric products and SoCal Gas programs were applied to the measures to decrease (Table 2-4).

Table 2-4 Percentage of retail price covered by various building electrification incentives.

	End Use			
Sector	Water Heating	Space Heating	Clothes Drying	Cooking
Residential	40% coverage	25% coverage	40% coverage	35% coverage
Commercial	30% coverage	10% coverage	N/A	N/A

These incentive rates were selected, as they were shown to be the optimal incentives LADWP could provide while balancing electric sales and avoided costs for a net benefit.

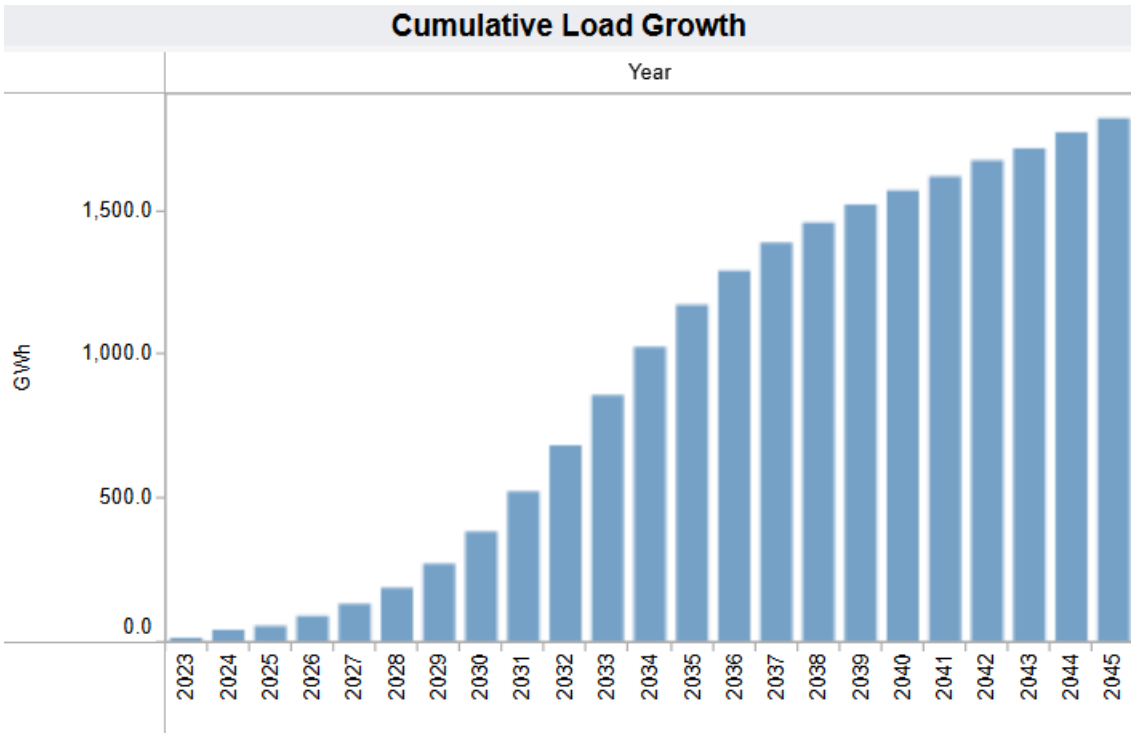


Figure 2-5 Forecasted load growth for building electrification in commercial and residential sectors.

The results of the study indicate that both residential and commercial building electrification adoption begins gradually but starts rapidly increasing after 2030 (Figure 2-5). This pattern occurs due to a predicted rapid increase in gas rates after 2030. The operation of gas products may begin to become noticeably more expensive than their electric counterparts. The residential sector has a much larger share of gas consumption compared to the commercial sector which the building electrification model considers when calculating electric consumption potential. In addition, the electricity usage for commercial space conditioning measures is dampened by the space cooling savings incurred by heat pumps.

2.5.2.3 Peak Impact Analysis

As part of the Building Electrification Potential Forecast study, LADWP developed models to predict demand impacts, specifically focusing on LADWP's peak period. The model demonstrated that the load growth during the peak period is largely mitigated by the countering effects of space cooling energy efficiency impacts. When space heating is converted to a heat pump system, energy efficiency also improves for the air conditioning system. Also, it's important to note that the space heating load increase

does not produce a winter peak. Figure 2-6 shows the hourly load profile of building electrification consumptions for 2035 for illustrative purpose.

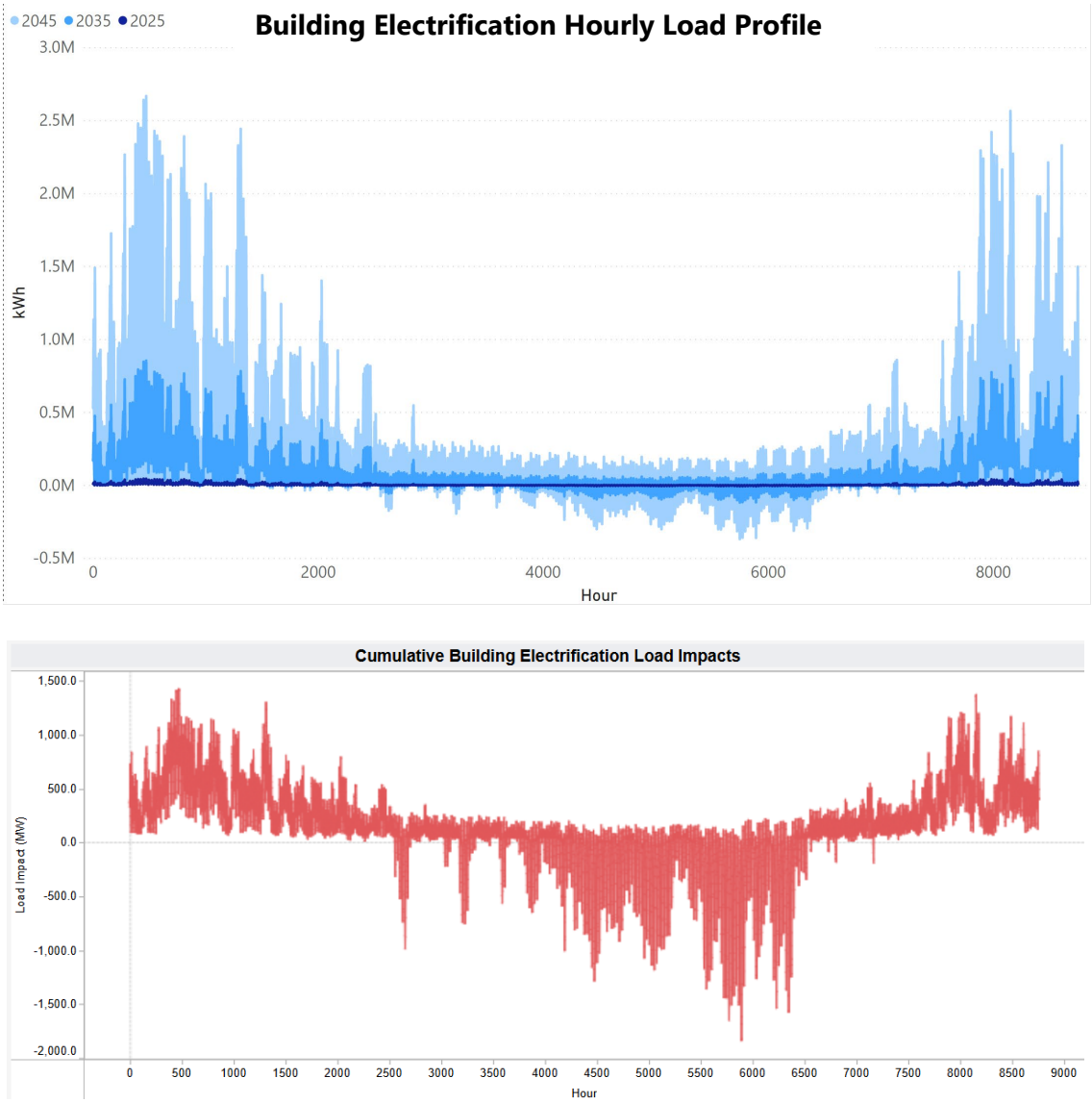


Figure 2-6 Hourly Load Profile of building electrification consumption for 2035.

Once the building electrification consumption and energy efficiency profiles are combined, the net profile shows that improvements in energy efficiency offsets the increasing energy consumption from electrification. As stated above in Section 2.5.2.2 on Load Growth Potential, building electrification adoption rates begin to ramp up past 2030, however, the effects of electrification on energy savings diminish by 2035. By 2045, electricity consumption from end uses such as space heating and water heating become greater than energy savings, especially during winter. During summer and the system's peak time frame, energy savings greatly outweigh electrification consumption.

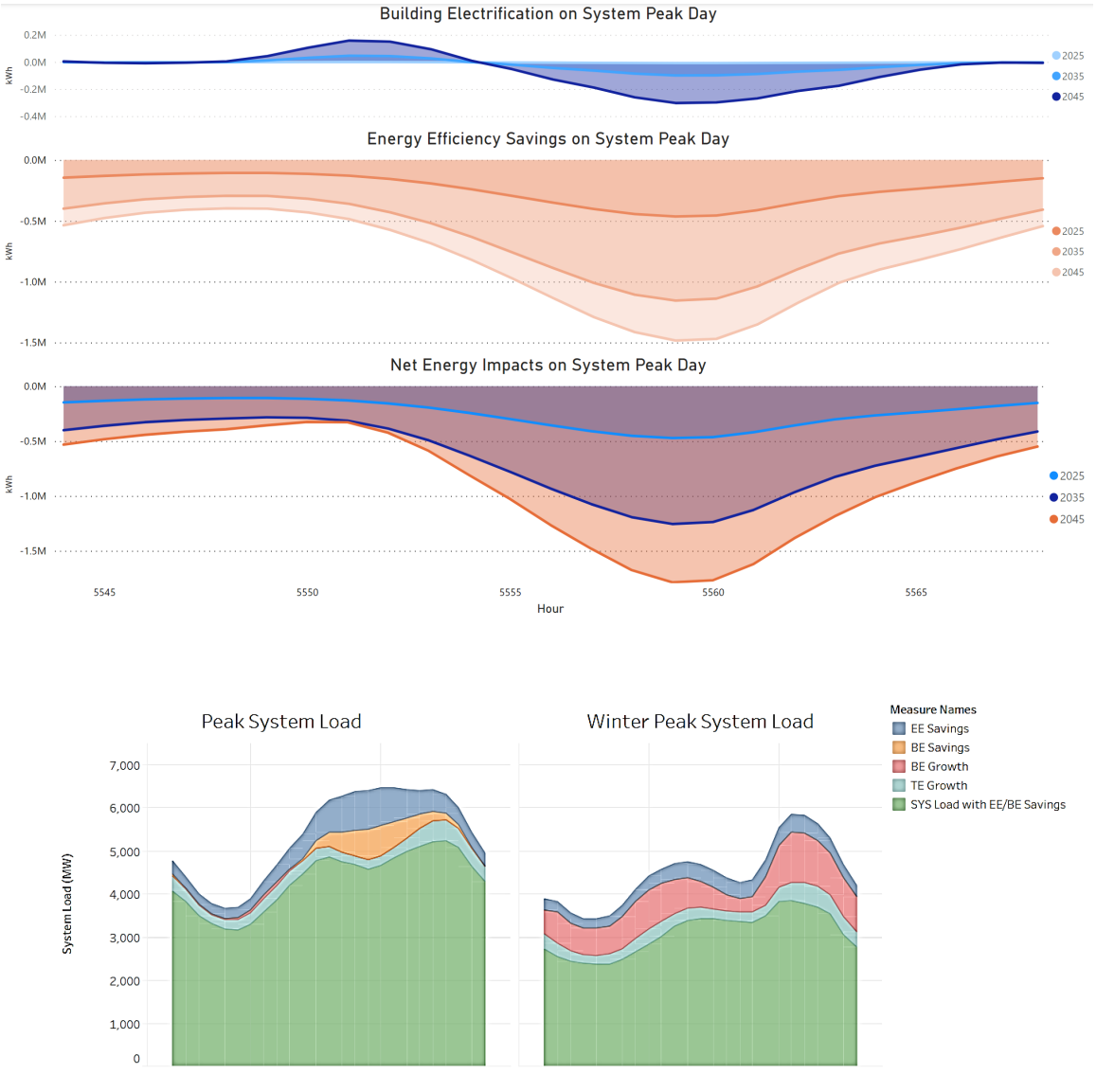


Figure 2-7 Building electrification, energy efficiency, and net energy impacts on system summer & winter peak days.

On the projected system peak day, Figure 2-7 shows energy efficiency savings surpassing the increased electrification consumption loads. The building electrification consumption peaks around 10:00 AM followed by the energy efficiency savings load profile peak around 3:00 PM. From 4:00 – 9:00 PM, the net energy savings profile decreases, yet provides a considerable amount of system peak demand reduction.

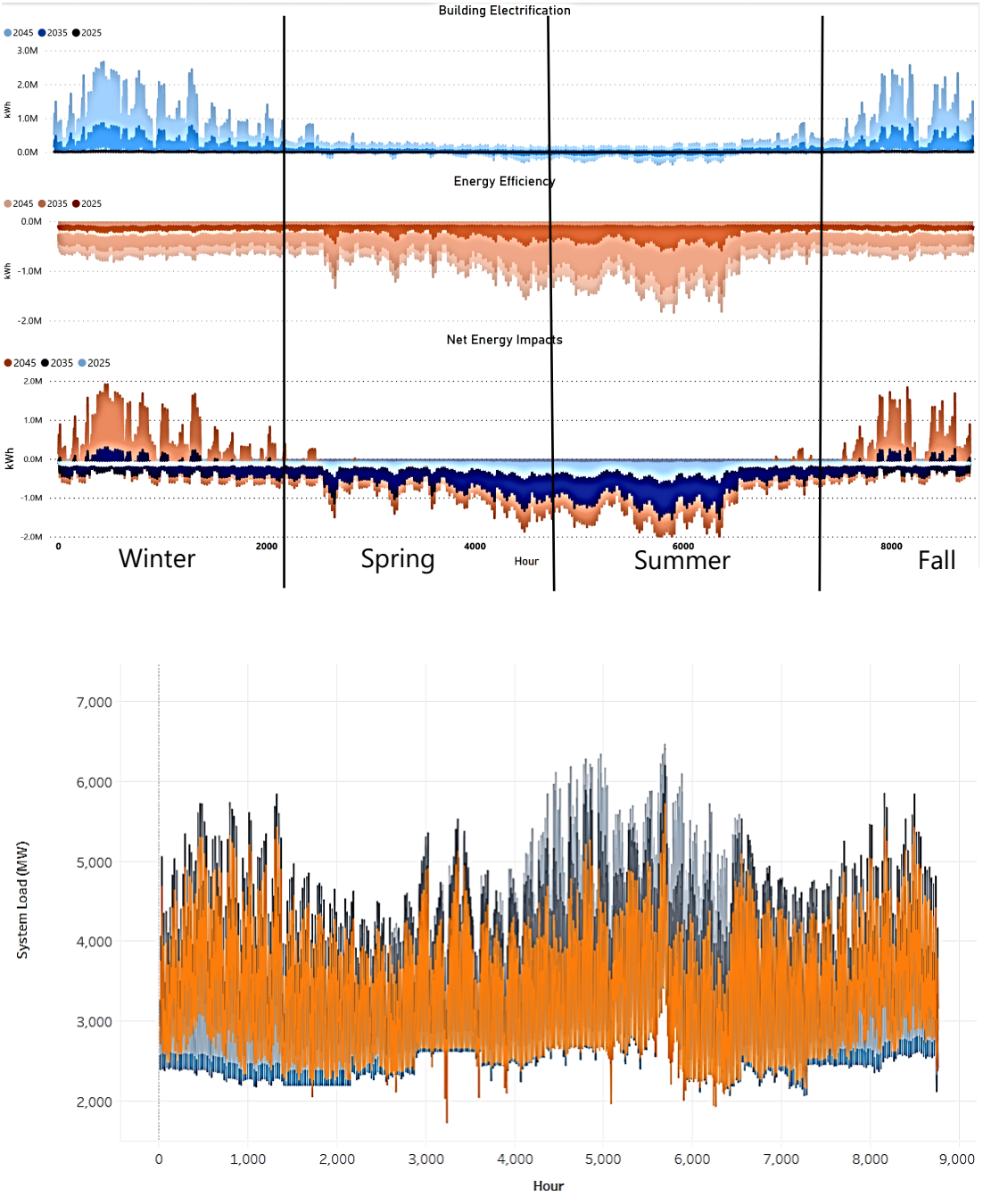


Figure 2-8 Hourly profile of combined EE and BE net energy impacts by 2035.

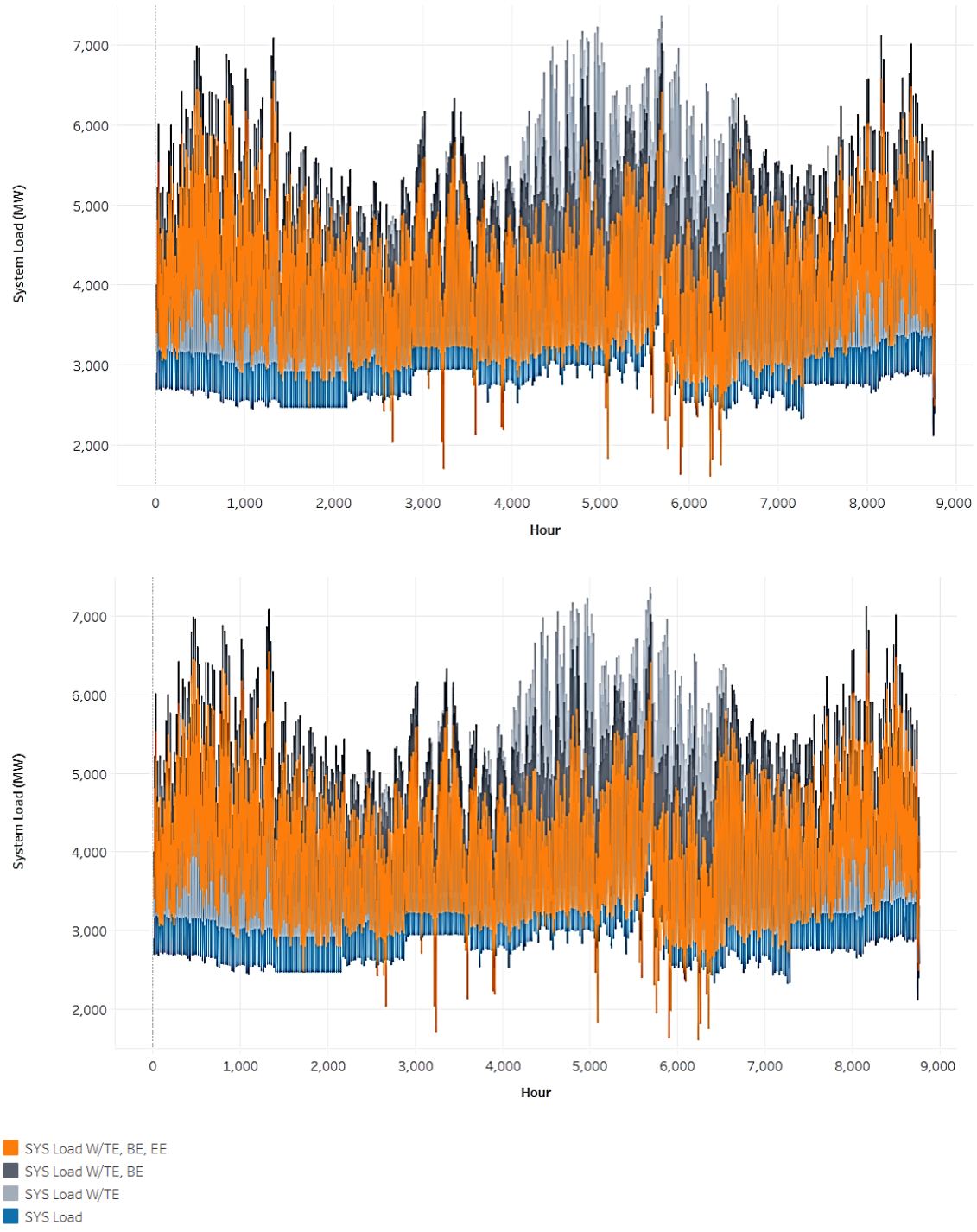


Figure 2-9 Hourly profile of combined EE and BE net energy impacts by 2045.

The combined EE and BE net energy impact profiles illustrate the increase in electricity consumption in fall and winter seasons on an annual timeframe (Figure 2-8 and Figure 2-9). In the spring, the effects of energy efficiency savings become more pronounced, and by summer, the grid will be experiencing a net decrease in consumption during most of the season. The projected system peak does not perfectly align with the combined BE and EE net energy impacts peak; however, BE and EE provide substantial system demand savings throughout summer.

2.5.2.4 Building Electrification Programs Projected Cost and Cost Effectiveness of Investment

The LA100 Plan considers LADWP's economic market intervention with incentives for building electrification. As discussed previously, the general assumptions included the specified incentives that cover a percentage of measured installation costs. Considerations were also made for the potential administrative costs that LADWP may incur for the delivery of incentives to customers. Figure 2-10 show annual incremental building electrification program costs, while Figure 2-11 shows cumulative annual costs.

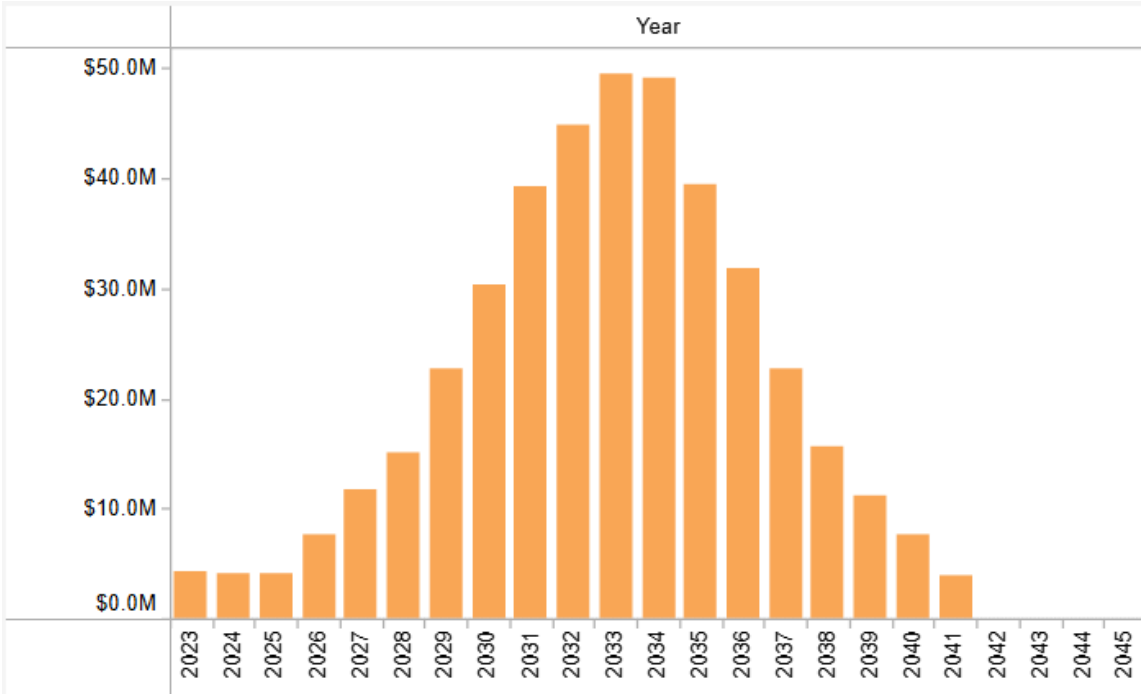


Figure 2-10 Incremental building electrification program costs.

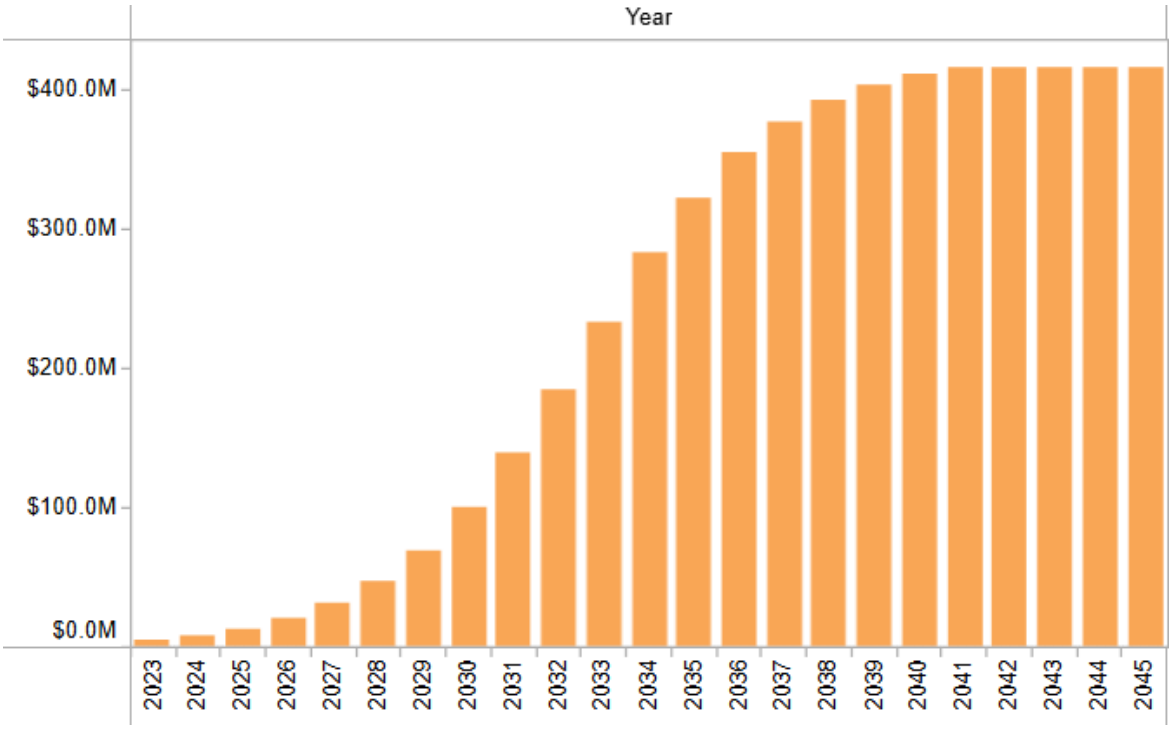


Figure 2-11 Cumulative building electrification costs.

BE cost effectiveness analysis identified two benefit streams:

- Potential future revenue from increased consumption due to electrifying building end uses.
- Hourly utility avoided costs that are traditionally used to determine EE benefits, can be used as a proxy for determining required grid infrastructure upgrades as a result of increased BE loads.

Figure 2-12 positive values represent dollars spent by LADWP as a result of increased load and negative values represent dollars saved by LADWP from load decreases.

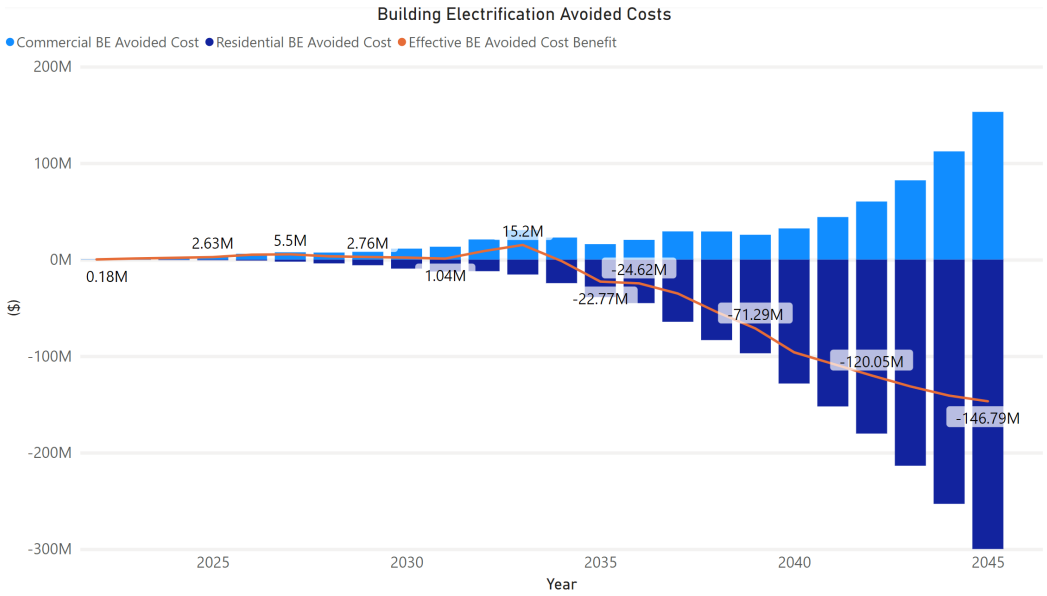


Figure 2-12 Building electrification avoided costs under the LA100 case. Positive values indicate additional grid operation costs incurred by LADWP due to increased electricity consumption, while negative values represent savings from reduced loads.

Early in the study period, commercial building electrification results in net operational savings due to reduced natural gas cooling loads. However, after 2035, growing residential electrification outpaces commercial savings, leading to a net increase in system operating costs.

LADWP saves on grid operation costs up until 2035 since the space cooling energy savings from the commercial sector electrification offsets the consumption increases from the residential sector. After 2035, electricity usage in the residential sector surpasses the savings incurred by the commercial space cooling and results in an overall cost detriment to the utility. Figure 2-13 shows the cumulative building electrification revenue under the LA100 case, while Figure 2-14 shows cumulative cost and benefits.

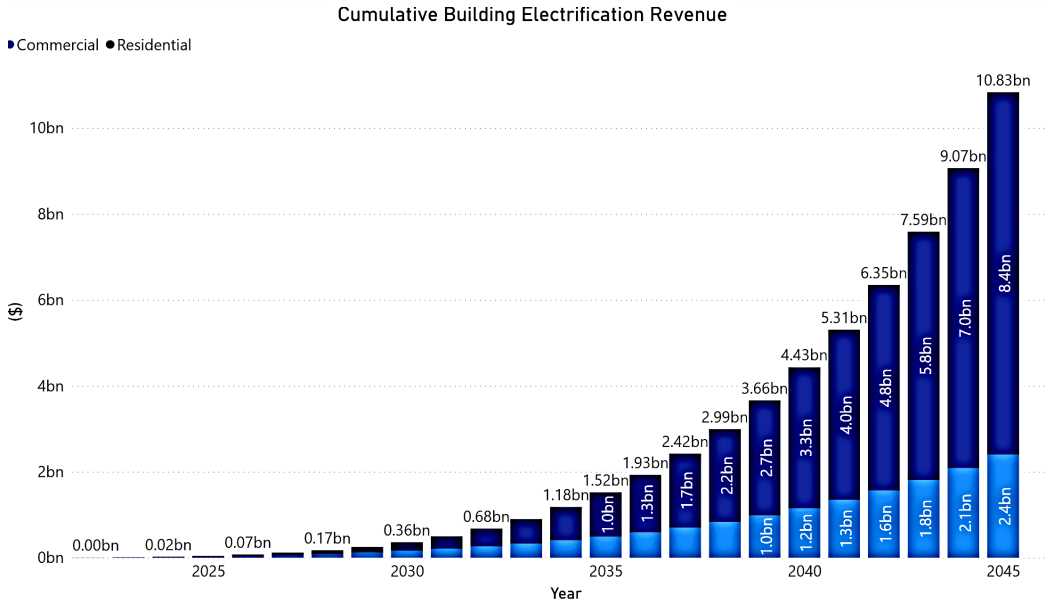


Figure 2-13 Cumulative building electrification revenue under the LA100 case. Residential adoption drives most of the growth, with total revenue reaching about $10.8 billion by 2045

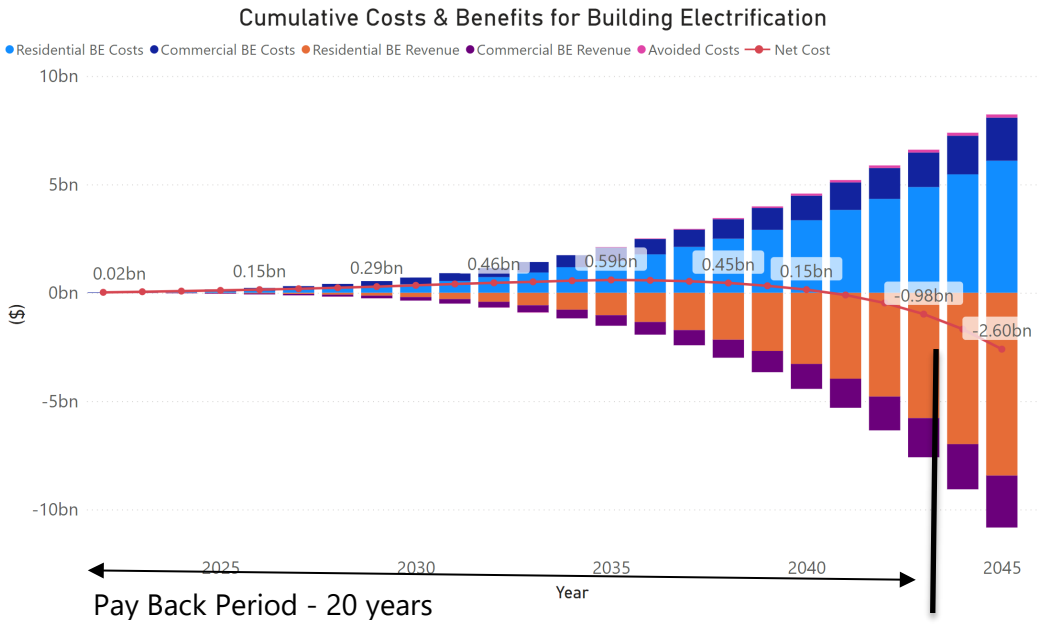


Figure 2-14 Cumulative costs and benefits of building electrification under the LA100 case. Revenues and avoided costs grow, especially in the residential sector, but do not fully offset rising costs, resulting in a net cumulative cost of about $2.6 billion by 2045

2.5.3 Distributed Energy Resources

Distributed energy resources are the aggregation and management of smaller demand-side resources that are able to provide utility-scale services. LADWP is evaluating the integration of DERs, such as rooftop solar PV, demand response, energy storage, electric vehicle charging, enhanced energy efficiency technologies, and other modernized smart grid infrastructure.

Each DER has unique operational characteristics that have distinct impacts to power flow. For instance, excess rooftop and distributed solar generation may result in reverse power that can potentially damage distribution equipment designed for one-way flow. The near-term solution would be to offset the solar generation with energy storage or electric vehicle charging, creating an electrical load to absorb excess energy for later use. Communications and intelligent controllers are necessary in order to provide resources like the PV system, the energy storage system, and the electric vehicle charger the appropriate signals to switch on and off. LADWP is currently investigating microgrid control solutions and their potential to demonstrate their ability to provide grid operators with more data visibility and control of DERs, while simultaneously acting as a demand response asset.

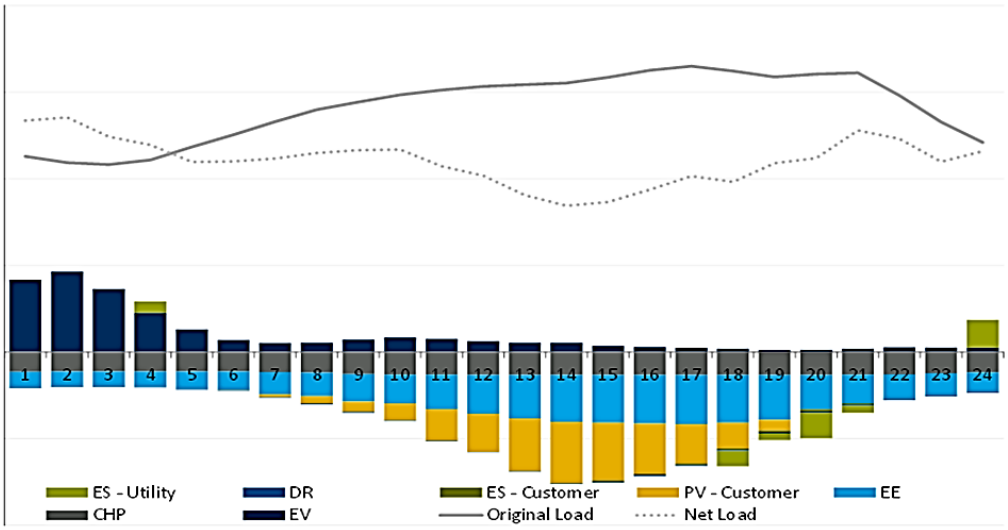


Figure 2-15 Aggregate DER impact on net load.

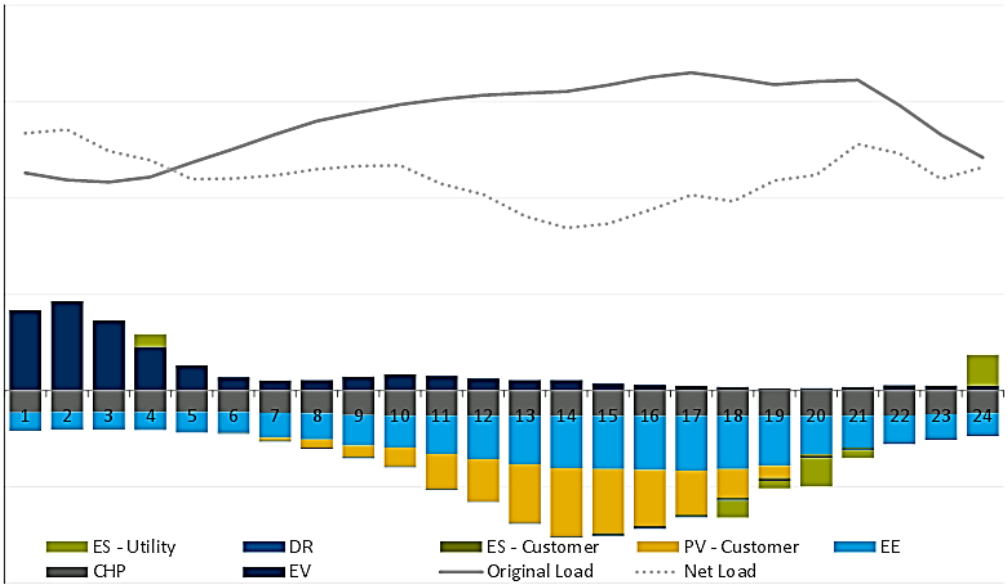


Figure 2-16 Aggregate DER impact on net load.

The logic required to manage a single location's DERs may be relatively simple, but every device's activation and deactivation leaves a small ripple in the power flow. This ripple effect can be amplified by the hundreds of devices on a circuit, or the millions installed across the LADWP Power System. The amplified effect can cause grid disturbances, transients, and deteriorating power quality and reliability. LADWP is investigating potential solutions to prevent cascading reliability events before DER adoption reaches critical levels.

LADWP's Energy Control Center (ECC) has already implemented a Distributed Energy Resource Management System (DERMS) and is currently positioned to control distributed energy assets as they come online. A range of DERs—such as solar photovoltaic (PV) systems and battery energy storage systems (BESS)—are already being controlled at grid scale, demonstrating technical readiness for large-scale deployment. However, some DER programs, such as managed electric vehicle (EV) charging, remain relatively new. One persistent challenge is the lack of standardization across DER manufacturers, which complicates integration. The most effective DERMS deployments to date have involved close partnerships with original equipment manufacturers (OEMs), a practice that differs from LADWP's traditional procurement processes. Additionally, LADWP's current Net Energy Metering (NEM) rate structure provides generous compensation for solar exports, which reduces customer incentives to participate in dispatch or demand response programs. This issue is less prevalent in other California Independent System Operator (CAISO) jurisdictions, where different rate designs better

support DER coordination. The DERMS utilized by LADWPs ECC is the first step to aggregating, managing, and dispatching precise commands by leveraging circuit topology, system health, and resource availability.

A primary focus of LADWP's Distributed Energy Resource (DER) portfolio is to evaluate the full range of potential system impacts—both benefits and challenges—associated with DER deployment. By identifying how and where these technologies can support grid operations and provide value to customers, LADWP aims to align DER incentive programs with power system planning, engineering, and operational strategies. When properly coordinated, DERs have the potential to defer capital infrastructure investments, reduce generation and transmission operating costs, and enhance the integration of renewable distributed generation. However, the lack of visibility and situational awareness at the distribution level currently limits LADWP's ability to fully leverage the benefits of dispatchable DERs. Improving distribution system data and monitoring will be critical to realizing the full potential of these resources. Figure 2-17 depicts the various types of DERs that can be deployed.



Figure 2-17 Components of distributed energy resources.

2.5.3.1 The California Energy Commission Demand Side Grid Support Program

The California Energy Commission (CEC) Demand Side Grid Support (DSGS) Program offers incentives to electric customers that provide load reduction and backup generation to support California's electrical grid during extreme events, reducing the risk of blackouts. As of Summer 2025, the CEC offers four options to incentivize the load reduction or backup generation. Each option targets specific device types or customer categories.

CEC DSGS Guidelines 4th Edition

Option 1: Emergency Dispatch	Option 2: Market Integrated Demand Response	Option 3: Market-Aware Behind-the-Meter (BTM) Battery Storage	Option 4: Emergency Load Flexibility

• Allows renewable and combustion resources
• Enabled only through Energy Emergency Alerts (EEAs) during the following dates:
  • May 1st – Oct 31st
• Large customers such as UCLA eligible
	• Limited to CAISO Proxy DR Resources
	• LADWP does not do CAISO Proxy DR
		• POUs may serve as DSGS BTM battery VPP aggregators
		• Tesla is participating with LADWP
			• Load flexibility devices
			  • Smart Thermostats
			  • Water Heaters
			  • EVSE
			  • BTM batteries
			  • Smart Electrical Panels

Figure 2-18 DSGS Options

Option 1 targets large cogeneration customers, both renewable and combustion. Option 2 targets CAISO Proxy Demand Response resources, which LADWP does not currently participate in. Option 3 targets battery energy storage system (BESS) aggregators, and Option 4 targets load flexibility devices such as thermostats, water heaters, and electric vehicle chargers. LADWP is currently participating in Option 3.

The CEC DSGS Program has an allocated budget of about $200 million and a five-year program duration until approximately 2027 or whenever CEC funding is depleted. The Option 3 program season runs from May 1st to October 31st each year with the incentive structure shown in Table 2-5.

Table 2-5 Storage incentives by duration

Storage Incentives by Duration ($/kW)

Month	4-Hour	3-Hour	2-Hour
May	$9.00	$8.10	$6.75
June	$9.30	$8.37	$6.98
July	$16.80	$15.12	$12.60
August	$18.00	$16.20	$13.50
September	$19.20	$17.28	$14.40
October	$10.50	$9.45	$7.88
Season	**$82.80**	**$74.52**	**$62.10**

The DSGS Program provides load reduction through BESS discharges during LADWP's extreme events. Whenever LADWP's Net Power for Load reaches a certain pre-determined threshold that has been agreed upon with the CEC, LADWP ECC can choose to dispatch a DSGS event. This dispatch is an email notification that LADWP ECC sends to the CEC's contractor, Olivine, who in turn dispatches aggregators of residential BESS to discharge over a two-hour period. Figure 2-19 an illustrative example:

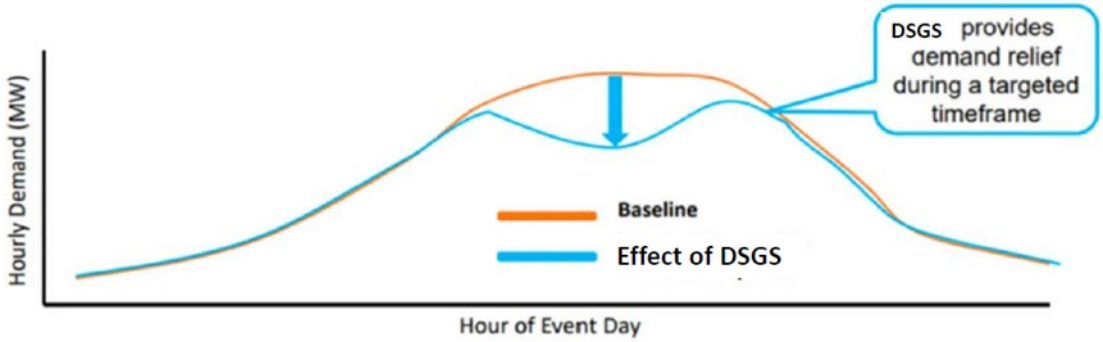


Figure 2-19 Illustrative example of load reduction via the DSGS Program.

LADWP ECC can also choose to dispatch DSGS resources when the LADWP Balancing Authority has an Energy Emergency Alert (EEA). EEAs can occur when all of LADWP's resources are already in use or committed for use, and energy deficiencies are expected. This can happen a day ahead or the same day.

LADWP's DSGS Program has been active since October of 2024. LADWP ECC dispatched the aggregation on 10/31/24 and reached 1MW (141 customers) for a two-hour duration.

LADWP will continue to dispatch at least one event per summer month so long as the CEC funding exists. The DSGS Program Option 3 can dispatch 35 events per season. The DSGS Program enrollment almost doubled during the summer months of 2025 (Figure 2-20).

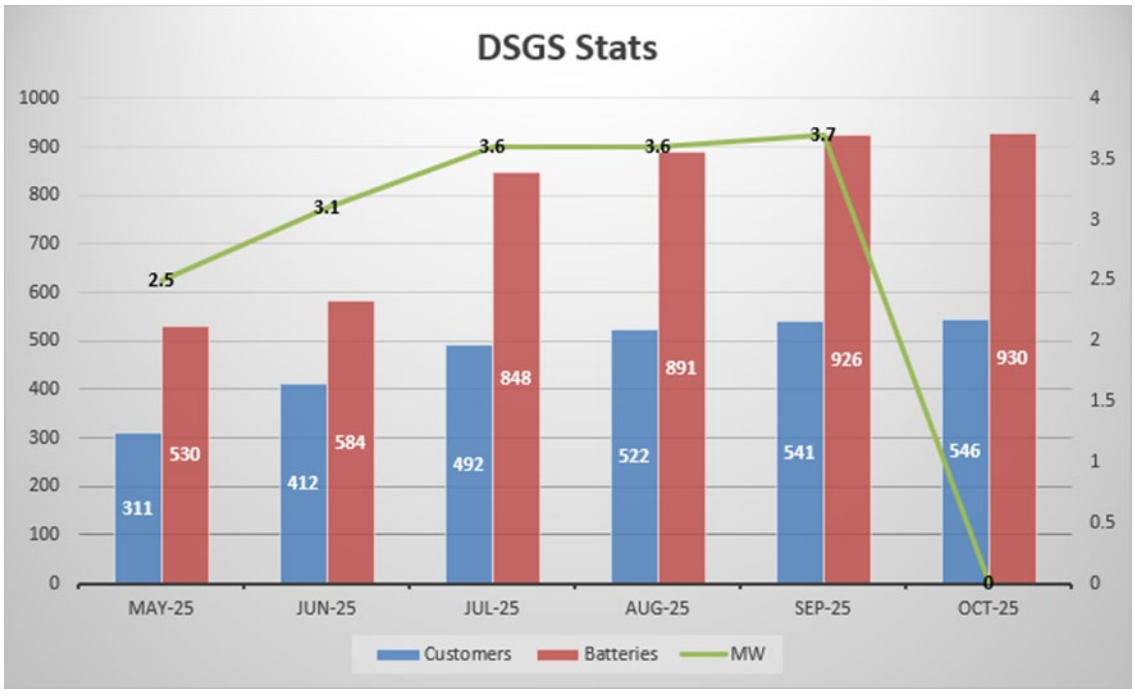


Figure 2-20 DSGS enrollment

Program enrollment also grew from residential customers that already owned or leased batteries (Figure 2-21).

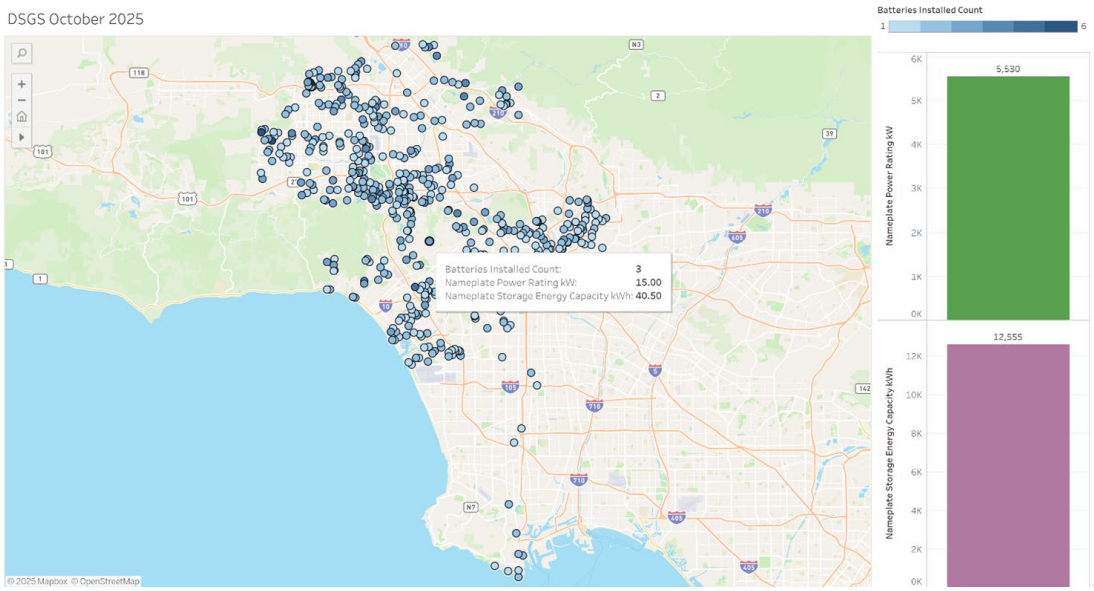


Figure 2-21 Batteries installed under the DSGS Program.

As this DSGS Program proves itself to be a firm dispatchable resource, the ECC may come to treat this as a more dependable source of power plant capacity.

Since BESS aggregators are willing to accept $62.10 per kW of two-hour capacity here in California, LADWP would assume that these market prices would support future growth of the DSGS Program through BESS aggregators. As residential BESS is forecasted to continue growing for customer resiliency, this DSGS Program will continue to provide reliability to LADWP's grid during extreme events and may even help defer distribution upgrades in the future as DER Planning tracks BESS adoption on feeders and substations.

2.5.3.2 The Distributed Energy Resource Warehouse

The Distributed Energy Resource Warehouse (DER Warehouse) is a centralized database repository designed to store, manage, and provide access to datasets that support the planning and integration of distributed energy resources (DERs) across the LADWP service territory. Maintained by the Power System Planning Division's DER Planning Group, this warehouse consolidates data from a variety of internal and external sources.

The DER Warehouse is central to support data-driven decision-making for grid planning, DER forecasting, and customer program analysis. Its value is reflected in the following key contributions:



- Feeder-level DER Forecasts: The DER Warehouse enables forecasting of distributed energy resources, such as rooftop solar, behind-the-meter battery storage, and electric vehicles at the feeder level.
- Loading and Capacity Analysis: By linking customer DER installations to their associated service transformers and feeders to assess loading and capacity impacts.
- Customer Profiling and Segmentation: Provide insights into customer characteristics and energy usage patterns in relation to DER adoption.

The DER Warehouse currently serves as the central data infrastructure for a wide range of planning, analysis, and reporting functions within the Power System Planning Division. It supports both monthly and annual planning deliverables, including forecasts for photovoltaic systems (PV), electric vehicles (EVs), and battery energy storage systems (BESS). Its current applications include the following:

- Forecasting and Planning Deliverables: The DER Warehouse enables the development of annual forecasts for DER adoption across the service territory, which feed into the Distribution Load Forecast
- Data Reconciliation and Quality Assurance: The warehouse plays a key role in validating and reconciling DER data to ensure consistency across planning and reporting.
- Address Standardization and Feeder Mapping: One of the core functions of the warehouse is to standardize customer addresses and accurately assign them to their respective circuit feeders that improves the accuracy of grid impact assessments and planning models
- Internal Dashboards and Visualizations: The warehouse supports internal dashboards and Tableau visualizations used by engineers, planners, and analysts that track DER adoption trends and provide customized extracts for analysis and reporting.

As LADWP advances toward a carbon-free energy future, the DER Warehouse must evolve into a more intelligent, responsive, and collaborative system. This transformation will enable real-time insights, greater cross-departmental integration, and improved decision-making. The future vision includes the following key developments:

- Enhanced Accessibility and Platform Integration: Future enhancements will include building programmatic access to DER datasets. This will allow seamless

integration with dashboards, modeling tools, and internal documentation platforms. Improved accessibility will reduce reliance on manual data extraction and help break down data silos across LADWP groups, divisions, and departments.

- Automated, Real-Time Data Pipelines: The implementation of automated pipelines will support continuous updates of records that ensure timely availability of DER information for planning and analysis.
- AI-Powered Anomaly Detection and Predictive Analytics: By incorporating artificial intelligence and machine learning techniques, the DER Warehouse will be able to detect inconsistencies and report anomalies more efficiently. These tools will also support predictive analytics to identify potential DER adoption hotspots and inform proactive grid planning.
- Integration with AMI and Interval Data: Future integration of DER data with Advanced Metering Infrastructure (AMI) and SCADA systems will provide deeper visibility into real-time grid conditions and DER performance. This will enable improved load-shape analysis for PV, BESS and EVs, better monitoring of behind-the-meter resources during peak events, and more accurate forecasting of feeder-level demand.
- Expanding Equity and Program Transparency: The DER Warehouse will support
- equity-focused planning by enabling analysis of DER adoption by income, race, and disadvantaged community status since US Census data is already included. It will also help track program participation rates and incentive effectiveness, ensuring that clean energy benefits are equitably distributed across all customer segments.

The continued development of the DER Warehouse represents more than just a technical upgrade or stranded asset. It is a strategic investment that will bring measurable improvements across grid planning, customer engagement, and eventually operations. Key benefits include:

- Proactive and Data-Driven Grid Planning: With more timely, accurate DER data, planners will be able to anticipate localized grid impacts, optimize capital investment by targeting upgrades only where needed, and model a wider range of DER growth scenarios.
- Accurate and Effective DER Program Development: DER adoption patterns based on customer type and geography can be matched with localized distribution grid

needs. DER devices and technologies can be targeted to appropriate customer segments and achieve LADWP's needed grid or energy impacts.

- Streamlined Workflows and Improved Internal Collaboration: Through automation, standardized data, and API access, the manual burden on engineers will be reduced while ensuring data consistency across departments, supporting faster turnaround for external reporting and internal requests, and enabling self-service analytics for non-technical users across planning, operations, and program teams.

2.5.4 Demand Response

Demand Response (DR) is an important energy management tool that facilitates the reduction of energy-use over a given time period. These events could be in response to a price signal, financial incentive, or other triggering mechanism. The key objective of DR is to cost-effectively reduce the summertime system peak by deferring and/or dampening long-term investments in expensive dispatchable power plants (e.g. natural gas and hydrogen) and energy storage assets (e.g. batteries). To meet this objective, customers are incentivized to reduce energy usage at critical peak demand periods in a manner that decreases overall system costs. LADWP's DR programs are based on incentives to encourage customer participation, including reduced rates, rebates, or other financial incentives. The permanent load impacts of EE and temporary load impacts of DR are compared in Figure 2-22. The Demand Response (DR) Development team is currently managing two DR programs, the Commercial and Industrial (C&I) Program for commercial and industrial customers and the Power Savers Program (PSP) for residential and small business customers. The C&I Program was launched in 2015 with the supports from a contractor and transfer the program management to the in-house team starting 2017. LADWP began offering PSP to the customers in 2020 and the program used bring-your-own-thermostat (BYOT) approach. In addition to these existing programs, the DR team is working on a DR Request-for-Proposal (RFP), which will acquire a demand response management system (DRMS) and develop new programs leveraging electric vehicles (EVs), EV supply equipment (EVSE), Internet-of-things (IoTs) devices, and connected appliances. The RFP was advertised on April 26, 2024, and proposals were due on June 25, 2024. The contracts are expected to be finalized in the third quarter of 2025. The contract term is for five years, emphasizing LADWP's long-term commitment to DR enhancements.

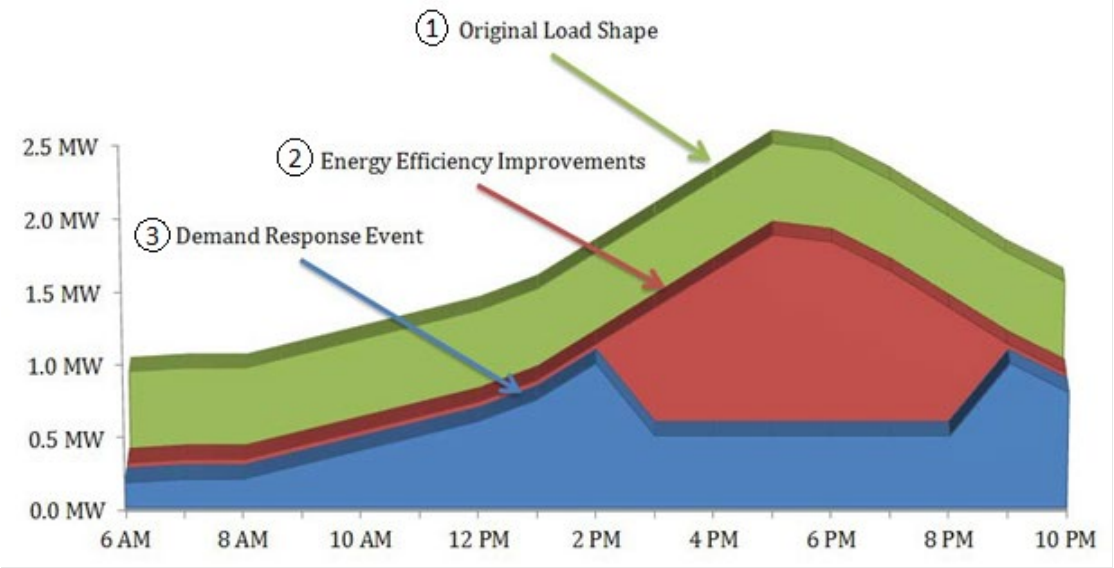


Figure 2-22 Impacts of energy efficiency and demand response on load.

Figure 2-22 illustrates the impact of energy efficiency improvements (2) on the original load shape (1). Energy efficiency improvements reduce the overall original load shape without targeting specific periods of time. In contrast, demand response is effective in reducing energy usage over specific periods of time and can assist in targeting the peak hours of the energy load shape. The resulting load shape from a demand response event (3) is shown in Figure 2-22. It has a flattening effect on the load shape during the peak period. The combination of demand response and energy efficiency can be an essential strategy in reducing overall peak load because of their complementary effects.

A well designed and cost-effective set of DR programs will benefit both LADWP and its customers through:

- *Reduced System Costs* - DR eliminates or defers the need to build additional power plants, energy storage assets, and the associated transmission and distribution infrastructure. Additionally, DR may reduce purchased energy costs by reducing the amount of energy that must be purchased to meet load, especially during the expensive peak demand periods. The overall effect of the cost savings helps maintain low rates for customers.
- *Reduced Customer Bill* - Customers who participate in DR programs will enjoy either reduced rates, rebates, or other financial incentives for reducing energy consumption during peak periods or emergency situations. In addition, cost-

effective DR also benefits customers who do not participate through DR's potential of reducing purchased energy costs and energy investment costs.

- *Increased Reliability* - The ability to strategically lower energy consumption is one way to help overcome supply-demand constraints and reduce the chance of overload and power failure. This is especially important during those few critical peak times each year when demand is at its highest or when generation units are offline.
- *Reduced Environmental Impact* - By eliminating or deferring the need to build additional infrastructure, the associated construction and operational impacts are also eliminated or deferred. Furthermore, the reduction in energy usage results in fewer operational impacts (fuel consumption, carbon emissions, transmission use).
- *Integrating Renewables* - Advanced Automated DR can balance customer loads with generation fluctuations from wind and solar power. Additionally, as renewable energy continues to become a larger percentage of LADWP's generation portfolio, there may be times when DR events are initiated to increase demand and absorb the renewable energy, reducing overall system costs.

The updated Title 24 standard that took effect on July 1st, 2014, includes an updated requirement for Automated Demand Response (Auto DR) readiness. New buildings larger than 10,000 square feet and any existing building replacing 10% or more of existing luminaries must implement a building management system capable of receiving Auto DR signals via the internet to control lighting fixtures. Additionally, HVAC in non-critical zones must also be responsive to Auto DR signals. This regulation is important for the development of the DR portfolio because it may assist LADWP in identifying potential customers who are already capable of participating in future DR programs. Furthermore, the Title 24 updates show a continued commitment by the federal government to promote DR readiness and participation.

The guiding principles for the development and operation of the DR portfolio are:

- DR will be operated by the Energy Control Center (ECC), managed by the Power System, integrated with billing and customer information systems (CIS), and aligned with Energy Efficiency and Premier Account activities.
- DR will be customer-friendly through ease of enrollment, flexible participation, incentives and rates transparency, and inclusivity.

- Prospective participants must agree to reduce 100kW of demand and choose either 24-hour (day-ahead) notification or 2-hour (same-day) notification.
- DR will be treated as a resource by LADWP and included in the annual resource planning process. DR goals will be revisited each year during the LA100 Plan update process and realigned with projections of supply and demand and changing strategic priorities at LADWP.

LADWP's focus is on DR resources that are cost-effective and proven. DR resources will be ranked by their cost-effectiveness when meeting future load growth projections, based on the most reliable information. Ramping the program in this manner—gradually and through internal programs—will promote the development of in-house expertise and allow time for the deployment of the supporting information infrastructure necessary to implement these DR systems successfully.

During spring 2013, LADWP hired Navigant Consulting to assist with developing a Demand Response Strategic Implementation Plan. The strategic implementation plan serves as LADWP's near-term and long-term plan for developing a measurable, cost-effective, and customer-friendly DR portfolio. The DR implementation plan provides in-depth details on items such as the estimated DR resources, measurement and verification methods for load and billing impacts, and other requirements. The DR implementation plan is updated annually and is incorporated into LADWP's LA100 Plan. All customer classes and sizes will be eligible to participate in some form of demand response, while the principal sources of load curtailment are provided by the following customers and programs:

- Commercial, Industrial, and Institutional (CII) Curtailable – Participants receive monthly capacity payments in return for providing guaranteed load reductions of at least 100 kW when requested by LADWP. Additional incentives are provided based on energy reduced during DR events.
- Residential and Small Commercial Direct Load Control (DLC) – Participants with less than 30 kW peak load receive an annual payment that varies based on their ability and willingness to reduce power consumption from equipment. These may include central air-conditioning units, wall-mounted air-conditioning units, pool pumps, and other equipment.
- Critical Peak Pricing – Residential, small commercial, large commercial, and industrial participants of all sizes will be given a dynamic Time-of-Use (ToU) rate

that includes a high "critical peak" price in effect during periods of high energy prices, exceedingly high customer demand, or emergency situations.

- Electric Vehicle Rider – Participants will have an EV charging station with a separate meter installed. During a DR event, their usage may be curtailed in exchange for a discounted rate while using the charging station.



- Alternative Maritime Power (AMP) – The California Air Resources Board (CARB) is requiring large vessels docked at the Port of Los Angeles be connected to electric power through LADWP's grid to reduce the emissions caused by on-ship diesel generation. In cases of system-wide emergencies, LADWP system operators may temporarily disconnect AMP customers in order to maintain grid reliability.

2.5.4.1 Implementation Schedule

The initial vision for DR extends through 2026, with the steady growth of CII and mass market load curtailment capability that began in 2014. Early pilot programs have provided real DR capacity and built confidence in the resource, while also refining LADWP's choice of technologies, program designs, and outreach strategies. The first new offerings extended new DR opportunities to large CII customers. Future phases will extend to residential customers with central air conditioning. Once advanced metering infrastructure (AMI) is established within the service territory, residential customers will have additional options via an expanded TOU rate offering and new Critical Peak Pricing (CPP) options.



With the elimination of coal - fired power plants and the influx of renewable energy, particularly solar photovoltaic, LADWP predicts there will soon be periods where generation will exceed customer demand. Since many utilities are likely to encounter similar imbalances between generation and demand, it is unlikely that LADWP will be able to sell excess generation to neighboring utilities. Furthermore, curtailing renewable generation is costly and wastes clean energy, and the cost - effectiveness of utility energy storage is still unknown. Thus, in the near term, LADWP will study the feasibility of demand response programs to encourage consumption during periods of overgeneration.

As LADWP investigates opportunities to address the over - generation challenges described above, customers with significant co - generation capabilities will be engaged to determine capabilities to ramp - up and ramp - down co - generation in response to future periods of over-generation.

Assembly Bill 2514 requires investor-owned utilities (IOUs) procure cost - effective energy storage systems in accordance with CPUC rulemaking. LADWP and other publicly owned utilities will be required to adopt their own energy storage goals and report progress to the California Energy Commission. As details of LADWP's Energy Storage goals develop, staff will identify any coordination opportunities and potential synergies between DR and Energy Storage programs.

2.5.5 Transportation Electrification



State legislation such as AB 32, SB 350, AB 2127, and CARB's Mobile Source Strategy development facilitates increased electrification across various sectors. These initiatives aim to reduce overall GHG emissions in California and help meet federal air quality standards. This has added a degree of uncertainty to the forecast of future electricity needs in terms of additional resulting load and the speed of implementation of electrification programs.

In the transportation sector, switching from fossil fuels to clean electric power can result in air quality improvements. To support the adoption of electric vehicles, LADWP launched a pilot program in May 2011 that provided 1,000 customers with a rebate of up to $2,000 towards the purchase and installation of electric vehicle home charging systems. The pilot program resulted in over 500 residential charger installations in Los Angeles. Building from the success of the initial Electric Vehicle Charger rebate program, LADWP implemented the "Charge Up L.A." Rebate Program in 2013. It introduced commercial charger rebates and issued over $2.5 million in electric vehicle charging station rebates for large businesses, small businesses, multi-family buildings, single family houses, and public use. The rebate program was further expanded in 2018 to introduce new rebate segments for DC fast chargers and medium- and heavy-duty electric vehicle chargers. We use proceeds from the sales of Low Carbon Fuel Standard

(LCFS) credits and California Carbon Allowances (CCA) to fund the rebate programs. Program funding is subject to budget appropriations and availability. As of April 2025, the rebate program has provided 8,146 residential and 30,179 commercial charging station rebates and 4,936 used electric vehicle rebates, totaling over $168 million to customers since the program's inception. To support the City's electric vehicle fleet, LADWP installed 1,348 chargers on LADWP properties and supported the installation of over 2,500 chargers on other City properties. Figure 2-23 shows the forecasted energy growth attributed to plug-in electric vehicles.

Plug-In Electric Vehicles

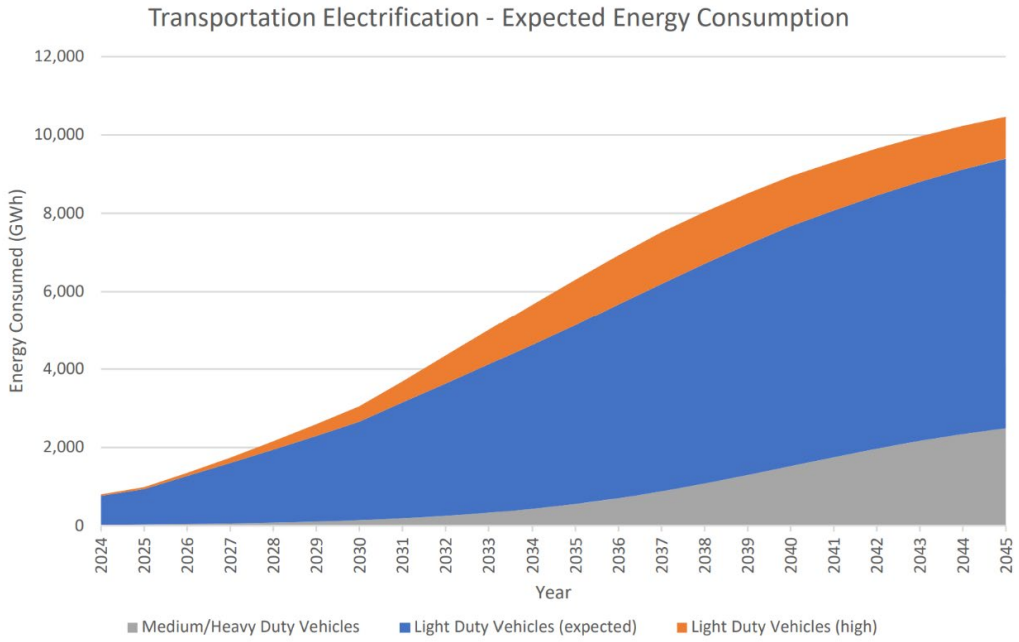


Figure 2-23 Forecasted energy growth in GWh attributed to plug-in electric vehicles.

CARB developed the Advanced Clean Fleets regulation, a medium and heavy-duty zero-emission fleet regulation with the goal of achieving zero-emission truck and bus fleets by 2045 wherever feasible for public fleets. Other agencies in the L.A. air basin are currently implementing their own initiatives for electrification as they shift towards electrifying fleets and passenger vehicles. In addition, expansions planned for public transportation railways and bus fleets would add additional electric load to the system. Another example of transportation sector electrification is the Clean Air Action Plan developed jointly by the Port of Los Angeles and the Port of Long Beach to reduce air pollution from their mobile and fixed sources. This includes trucks, locomotives, ships, harbor craft,

Plug-in Electric Vehicles (PEVs)

Large scale deployment of electric vehicles will significantly affect the way electricity is consumed. It is estimated that by 2030, California will have seven and a half million EVs in deployment, 10% of which are expected to be in the City of Los Angeles. The introduction of electric vehicles in Southern California brings a challenging set of planning, regulatory and cost issues. Because EVs require a unique infrastructure, including specialized charging equipment and adequate electric service, it is essential to anticipate and predict the grid impact in Southern California from the EV deployment.

Regulated utilities in California are now responding to regulatory direction to submit plans for a large-scale EV initiative with full delineation of costs and benefits. This regulatory initiative is an aggressive step, seeking to promote accelerated adoption of EVs. The EV deployments and the associated utility customer features are proceeding throughout the State of California. Energy needed for PEVs will come partially from the utility electric grid. It is expected that the "fuel shift" from traditional transportation fuels will increase customers' demand for electricity from the electric grid.

PEVs also present an opportunity to influence charging patterns by incentivizing charging during off-peak time periods, resulting in better system load factors or as a targeted load participation program to maximize the use renewables that might otherwise be curtailed due to over generation.

cranes, transportation refrigeration units, and various types of cargo handling equipment. One of the programs, Alternative Marine Power, allows AMP-equipped container vessels docked in-port to "plug-in" to shore-side electrical power instead of running on diesel power while at berth.

2.5.5.1 LADWP Electric Transportation Program

LADWP has updated its electric transportation program in alignment with the electrification goals detailed in the California Energy Commission's AB 2127 Electric Vehicle Charging Infrastructure Assessment. A couple of benefits include the overall reduction of GHG emissions and increased electric sales.



These new goals seek to achieve 250,000 EVs in L.A. by 2025 and 750,000 by 2030. Additionally, Governor Newsom's Executive Order N-79-20 requires all new vehicles sold in California to be zero-emission vehicles (ZEVs) starting in 2035. To support the charging needs of these vehicles, LADWP is targeting 45,000 and 120,000 commercial charging stations by 2025 and 2030, respectively. To reach these aggressive targets, key stakeholders must collaborate in reducing the barriers to charging accessibility. Various policies, programs, and initiatives must be implemented on a federal, statewide, and local level to contribute towards ensuring L.A. is well-positioned to maximize the use of electric transportation for Angelenos and visitors during the planned 2028 Olympic Games and beyond.

The Electric Transportation Program is outlined by the following elements:

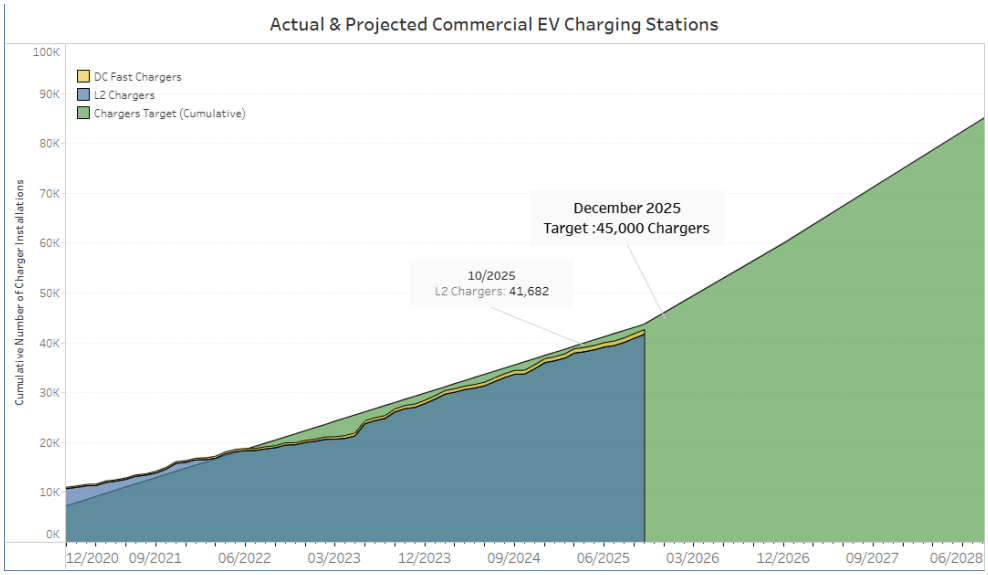
- *Program Development* - Develop and implement overall electric transportation program strategies. Assess electrification grid impact and mitigation solutions such as charging management and Vehicle-to-Grid integration. Track EV charging adoption and consumption and report to Sustainability Affairs and various state, federal, and local entities. Launch Managed Charging program for managed EV charging with residential and commercial customers.
- *Education and Outreach* - Increase the percentage of zero-emission vehicles in the city to 25% by 2025, 80% by 2035, and 100% by 2050 in accordance with L.A.'s Green New Deal Sustainability Plan 2019 through increased ride and drive events, social media, and a joint program with other utilities and car dealers.
- *Electrify LADWP and L.A. City Fleet* – 100% of new L.A. City light duty and transit vehicles to be electric by 2028 where technically feasible.
- *Residential Charging Rebates* - Continue LADWP's "Charge Up L.A.!" residential rebates.
- *Commercial Charging Rebates* - Provide rebates for multi-unit dwelling, workplace, and public charging. This includes installation costs that go beyond the compliance requirements of the Green Building Ordinance. This ordinance

requires newly constructed buildings to supply electric vehicle charging infrastructure.

- *Equitable Transportation Electrification* - Ensure at least 30% (increasing to 50% in 2024) of LCFS holdback credits are used in disadvantaged communities (DAC) and/or low-income communities (LIC). LADWP offers additional used EV and EV charging station rebates to low-income residential customers to address barriers for EV adoption and increase participation within these communities.
- *City EV Charging Infrastructure* - Install curbside and parking lot public chargers, City Fleet Chargers, City DC Fast Chargers, and City workplace chargers throughout Los Angeles. Develop partnerships with State, City, county agencies, and other utilities for a swift rollout.
- *Medium- and Heavy-Duty Fleet Charging* - Electrify Port of Los Angeles fleets, Los Angeles World Airports fleets, forklifts, rail, and school and transit busses.

LADWP's Electric Transportation Program clearly illustrates LA's visible support for EV technology through:

- 45,000 City and private commercial chargers for the public, workplace, and City vehicles
- Residential charging support
- Assisting in meeting LADWP's goals of GHG reductions, integration of renewables, better utilization of assets, and customer savings



2.5.6 Power System Reliability Program

To ensure system reliability, LADWP initiated a new multi-year Power System Reliability Program (PSRP) in 2014 to expand the scope of the previous Power Reliability Program (PRP). This includes the establishment of metrics and indices to prioritize infrastructure replacement expenditures from all major sectors of the Power System – Generation, Transmission, Substation, and Distribution (see Figure 2-24). The PSRP assesses all power system assets affecting reliability and proposes corrective actions designed to minimize future outages. As funding priorities constantly shift, especially from the demands of regulatory mandated programs, competition for the remaining limited pool of resources necessitates an expanded Power System Reliability Program and planning process. LADWP must also evaluate and increase its distribution system expansion targets in order to meet Electrification and LA100 Study goals.

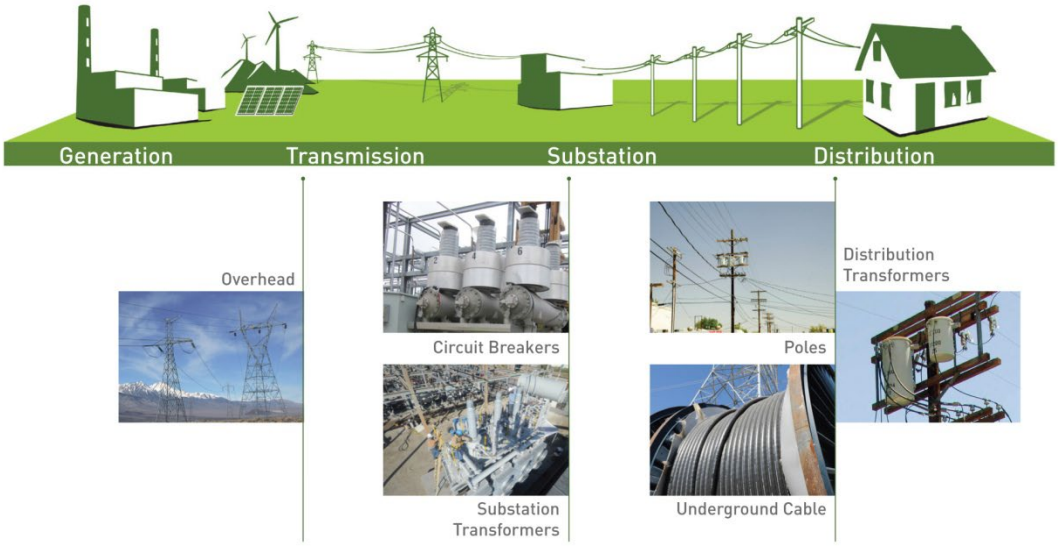


Figure 2-24 Power System infrastructure assets that provide electricity to customers.

The PSRP is a comprehensive, long-term power reliability program with the following goals:

- Address overloaded circuits and stations based on the types of outages and equipment failures specific to the facility

- Expedite restoring temporary repairs of equipment failures and target circuits that contribute heavily to LADWP's reliability indices
- Commit to proactive maintenance and effective capital improvements needed to expand system capacity and ensure continuance of service
- Achieve replacement cycles that align with the assets' respective life cycles, including the replacement of overloaded distribution transformers, aged underground cables, deteriorated overhead poles, and fatigued substation equipment.

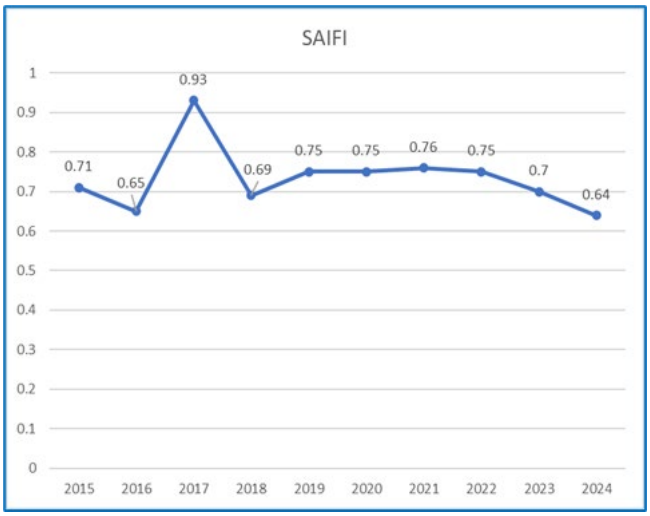
The 2024 PSRP Recommended Asset Replacement (Table 2-6) lists the assets that are prioritized. PSRP targets are expected to be updated on a fiscal-year basis in order to adjust for varying Power System needs, material supply constraints, and human and resource allocations.

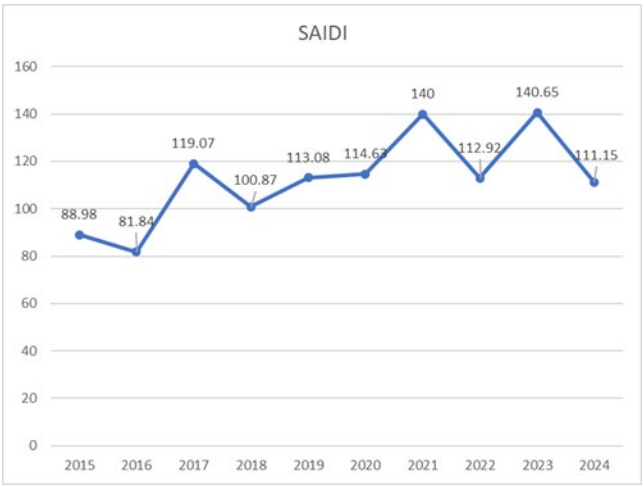
Table 2-6 The 2024 PSRP Report Asset Recommended Replacement List.

2024 PSRP Asset Replacement Categories	
GENERATION	Generation Transformers (GSU & AUX) Major Inspections (Hydro, Pumps, and Thermal)
TRANSMISSION	Transmission Tower Painting
SUBSTATION	Extra High Voltage Transformers (high side >230-kV) High Voltage Transformers (high side 100-kV to 230-kV) Medium Voltage Transformers (high side <100-kV) Transmission Circuit Breakers (>100-kV) Sub-Transmission Circuit Breakers (34.5-kV) Distribution Circuit Breakers (4.8-kV)
DISTRIBUTION	Cables (34.5-kV & 4.8-kV) Crossarms Poles Substructures Transformers

2.5.6.1 Ongoing Reliability Challenges

As shown in Figure 2-25, the number of customers experiencing outages (SAIFI) has been relatively stable and even trended down in recent years. However, even when Major Event Days (MEDs) are not counted for, there has been an upward trend in the outage duration (SAIDI) and outage restoration (CAIDI) times. Extreme weather conditions and aging infrastructure can be attributed as aggravating factors in recent years. Rain, windstorms, and a station outage contributed to increased SAIFI and SAIDI in 2017. Rain and windstorms contributed to increased SAIDI and CAIDI in 2021. A historic atmospheric river brought rain and windstorms which led to increased SAIDI and CAIDI in 2023.





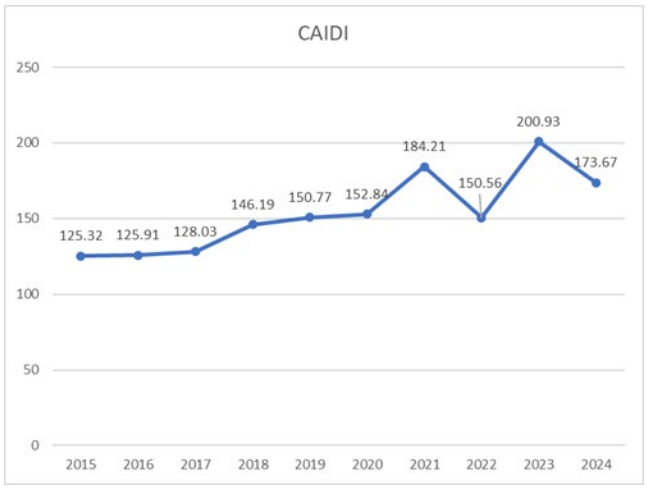


Figure 2-25 SAIFI, SAIDI, & CAIDI Jan 2015- Dec 2024 (Excluding MEDs)

2.5.7 Transmission



Electricity from LADWP's generation sources is delivered to customers over an extensive transmission system. To deliver energy from generating plants to customers, LADWP owns and/or operates approximately 15,000 miles of alternating current (AC) and direct current (DC) transmission and distribution circuits. These transmission and circuit facilities operate at voltages ranging from 120 volts to 500 kilovolts (kV).

In addition, we arrange for the transmission of energy to other market participants and balancing authorities through our Open Access Same-Time Information System (OASIS) when surplus transmission capacity is available and saleable. LADWP uses its extensive transmission network to economically buy and sell wholesale energy products in the California, Northwest, and Southwest energy markets. Revenues from these economic energy transactions are used to reduce costs for customers and for capital improvements.

In critical times, neighboring utilities look to LADWP's surplus energy and transmission resources to bolster their power system and avoid blackouts. For example, as a result of the nearby San Onofre Nuclear Generating Station retirement, the California Independent System Operator (CAISO) has been attempting to secure the delivery of replacement energy from other potentially available generation sources.

Additionally, LADWP annually performs a Long-Term Transmission Assessment in compliance with the North American Electricity Reliability Corporation (NERC) Compliance Enforcement Program. LADWP's 2024 Long-Term Transmission Assessment identified a number of transmission improvements that are required to maintain reliability.

2.5.7.1 Transmission for Renewable Energy

Renewable resources are often located in areas that lack transmission facilities and in areas that are far from the City of Los Angeles. Therefore, reliably accessing future renewable resources will require extensive infrastructure improvements including the construction of new transmission lines, upgrades to existing out-of-basin and local transmission lines, and improvements at transmission facilities and stations to increase their transfer capability.



2.5.7.2 Barren Ridge Renewable Transmission

The Barren Ridge Renewable Transmission Project, completed in 2016, increased the capacity of the existing 230-kV Barren Ridge-Rinaldi transmission segment. In February 2025 the Barren Ridge Haskell Line 1 was upgraded to allow for an additional 400 MW of energy from Eland I and II solar projects to be reliably transferred to the LA Basin. Barren

Ridge provides customers access to approximately 1,300 MW of wind and solar power. The resources include, but are not limited to:

- 400 MW from Eland I and Eland II solar projects combined
- 250 MW from the Beacon solar project
- 60 MW from RE Cinco solar
- 350 MW from the Springbok 1,2, and 3 solar projects
- 143 MW from the combination of Pine Tree solar and Pine Tree wind facility
- Over 100 MW from several of LADWP's hydroelectric plants in the north.



2.5.7.3 The Haskell Canyon-Olive Transmission Line Project

LADWP has reconnected the existing Power Plant 115-kV Transmission Lines 2 to the new Haskell Canyon Switching Station. Line 1 is currently in progress. The double-circuit 115-kV towers have been replaced with new 230-kV towers from the new Haskell Canyon Switching Station to the north side of the Los Angeles Basin transmission system. This allowed for an additional 230-kV circuit to a new position at the existing Sylmar Switching Station. This project will maintain system reliability and increase the transfer capability from the new Haskell Canyon Switching Station to the Los Angeles Basin transmission system. It will also assist with supporting the 1,300 MW of renewables coming from Owens Valley.



2.5.7.4 The Victorville-Los Angeles (Vic-LA) Project

The Vic-LA Projects involve infrastructure and operational improvements between the Victorville area and the Los Angeles Basin. These projects will allow us to add up to 500 MW of transfer capacity, subject to operational requirements. The upgrade work to be performed and scheduled will be determined by a joint Grid Planning and Development Section. The upgrade work could include, but not be limited to, the following work activities:

- Completed:
  - Replaced Transformer Bank K
  - Replaced Toluca Bank H

        - Replaced the 230 kV circuit breakers and the disconnect switches at the Rinaldi Receiving Station
        - Reconductored Valley- Rinaldi 230 kV circuits
    - In progress:
        - Upgrading equipment at Victorville, Mead, and Century Substation including wave traps and capacitor voltage transformers to raise the operating voltage from 287 kV to 300 kV
        - Relocate Transformer Bank K to a new position at Victorville Switching Station
        - Installing shunt capacitors at different strategic locations to improve the Los Angeles Basin load power factor
    - Replacing Toluca Bank H
    - Replacing the 230 kV circuit breakers and the disconnect switches at the Rinaldi Receiving Station
        - Reconductoring Valley-Toluca 230 kV circuits.

2.5.7.5 Los Angeles Basin Projects

The annual Long-Term Transmission Assessment consistently identified the Rinaldi-Tarzana 230 kV lines as an essential upgrade. Every year that passed exposed the increasing urgency for the installation as temporary improvements had decreasing benefits. LADWP was able to move forward with the project and complete the reconducting and terminal equipment upgrade in April 2025.

Other recently completed projects in Los Angeles Basin projects include:

- Upgraded disconnects and circuit breakers at Receiving Station-U and Receiving Station J.
- Replaced Transformer Banks E and F at Receiving Station K
- Installed 90 MVAR Reactors at RS-D
- New 230 kV Pershing Station to support increasing LAX load
- New underground 230 kV cable and re-termination of the Scattergood Olympic Cable A to Pershing Station

These infrastructure improvements are critical to avoid potential overloads and over-voltage violations on key segments of the Los Angeles Basin transmission system.

2.5.7.6 FERC Order 1000 – WestConnect Regional Transmission Planning

On July 21, 2011, the FERC issued its order on transmission planning and cost allocation (Order 1000). On May 17, 2012, FERC issued Order 1000 A, stating that non-jurisdictional entities (such as LADWP) must formally enroll in a transmission planning region before its costs can be assessed under the regional cost allocation methodology. FERC also stated that non-jurisdictional entities must have a right to withdraw and avoid cost allocations from the region.

However, Orders 1000 and 1000A contain language that would significantly broaden FERC's authority to allocate transmission costs. FERC takes the unprecedented position that transmission costs may be allocated to entities in the absence of a contract or service relationship.

Most jurisdictional transmission providers filed their compliance filings to amend their tariffs for the inclusion of a regional planning process in October 2012. FERC has recently issued orders detailing that many of the compliance filings in planning regions did not meet the requirements of Order 1000 with respect to cost allocation. LADWP, as a non-jurisdictional entity, was not required to make a filing.

The Final Rule urges, but does not require, government owned utilities such as LADWP and cooperative utilities to participate in regional transmission planning and cost allocation. FERC indicates that if "non-jurisdictional" transmission owners do not comply with Order No. 1000, they may not meet reciprocity requirements and thus may have limited access to third party transmission services.

Even though Order 1000 does not require non-public transmission operators to enroll in a region, we decided to enroll in WestConnect as a Coordinated Transmission Owner (CTO). We proceeded with voluntary enrollment due to a potential to benefit from the regional planning process which can identify transmission regional needs. A board package to enroll into WestConnect was compiled and presented in the November 2015 board meeting and was approved. LADWP officially joined WestConnect on May 1, 2016.

U.S. 5th Circuit Court of Appeals Ruling in 2023 required FERC to make changes that ultimately resulted in removing CTO member sector since project costs were non-binding for CTO Members. On April 24, 2025, FERC accepted WestConnect's Tariff and

PPA changes filed by ETOs to FERC on December 16, 2024. The effective date for the changes is December 17, 2024. LADWP is currently not a member of WestConnect or any other regional planning organization and is in the process of evaluating potential regional planning options.

Figure 2-26 shows our major out-of-basin generation resources. LADWP serves approximately 10% of California's electric load yet owns roughly 25% of the state's total transmission capacity—highlighting our outsized role in California's energy infrastructure. Unlike many other utilities, LADWP continues to operate as a fully vertically integrated electric utility. This means we own and manage our generation, transmission, and distribution systems directly, rather than functioning as a holding company with separate subsidiaries performing these roles. This structure enhances our ability to plan, invest, and operate holistically across the entire power supply chain.



Figure 2-26 Major in-basin and out-of-basin generating stations and major transmission lines.

2.5.8 IPP Coal-to-Hydrogen Transition

LADWP's coal generating capacity comes from the Intermountain Generating Station (IGS). IGS is also referred to as the Intermountain Power Project (IPP). The amount of capacity available to us from IPP is up to 1,202 MW.

The original contractual arrangements for power from IPP will expire on June 15, 2027, at which point the renewal contracts (which were executed in 2017) will immediately take operational effect and continue for a term ending in 2077. LADWP and the other participants at IPP plan to replace the existing coal-powered units with new efficient units capable of operation on a fuel mixture of green hydrogen and natural gas, a project that is anticipated to be completed in 2025.

Effective July 01, 2016, the Department divested its 21.2% generation share (equivalent to 477 MW) from the coal-fired Navajo Generation Station. The divestment was pursuant to the Salt River Project (SRP) Asset Purchase and Sale Agreement (the "Navajo Sale Agreement"). Power instead comes from renewable resources and energy efficiency programs that are backed by natural gas. The backup resource utilizes natural gas and is located outside the L.A.-basin. Therefore, it is not affected by problems associated with the Aliso Canyon Natural Gas Storage Facility. With the completion of the Navajo transaction, we have reduced coal generated power from 39% to 19% of the City's energy portfolio.



2.5.9 Palo Verde Nuclear Generating Station

LADWP has contractual entitlements totaling approximately 387 MW of capacity from the Palo Verde Nuclear Generating Station (PVNGS). PVNGS, located approximately 50 miles west of Phoenix, Arizona, consists of three generating units. Of the 387 MW capacity available to LADWP, approximately 159 MW are available through a power sales agreement with the Southern California Public Power Authority (SCPPA).

2.5.10 Hydropower

LADWP's large hydroelectric facilities include the Castaic Pumped-storage Hydroelectric Plant and a portion of the capacity of Hoover Dam. The Castaic Pumped-storage Hydroelectric Plant, located in Castaic, California, is our largest source of hydroelectric capacity and consists of seven units. Hoover Dam, located on the Arizona-Nevada border, consists of seventeen units.

A distinction is made between "large hydro" and "small hydro." According to a provision of SB 2 (1X), small hydroelectric facilities are those that consist of generating units with a nameplate capacity maximum of 40 MW per unit operated as part of a water supply or conveyance system. LADWP's small hydro units are located along the Los Angeles Aqueduct. These units qualify as renewable resources for electricity generation.

2.5.11 Current Renewable Energy Projects

As of 2025, LADWP's renewable energy portfolio includes over 4,000 MW of existing and near-term planned capacity. These resources span wind, small hydro, solar, geothermal, and biomass, and reflect LADWP's ongoing commitment to transitioning toward a fully carbon-free power supply under the LA100 Plan. Additional renewable energy is also procured through market purchases to support seasonal variability and grid reliability.

Below is an outline of LADWP's current renewable energy projects by resource type:

Wind

- SW Wyoming Wind
- Pebble Springs
- Willow Creek
- Pine Tree Wind Power Project
- Milford Wind Phase I
- Windy Point Phase II
- Linden Wind Energy Project
- Red Cloud



Small Hydro

- Aqueduct, Owens Valley, and Owens Gorge Projects
- North Hollywood
- Sepulveda



Solar



- Community Solar / Utility-Built Solar In-Basin / Net Energy Metered (NEM) Solar
- Feed-in-Tariff Projects
- Adelanto Solar
- Pine Tree Solar
- Copper Mountain 3
- Moapa Southern Paiute Solar
- Beacon Solar 1, 2, 3, 4, and 5
- Springbok Solar 1, 2, and 3
- RE Cinco
- Eland 1 and 2 Solar-plus-Storage Center

Geothermal and Biomass

- Don A. Campbell I and II
- Heber-1
- NV Geothermal Portfolio
- Ormesa
- Imperial Valley Biomass













2.6 Distribution

As LADWP transitions toward a 100% carbon-free power system under the LA100 Pathway, the role of the distribution system becomes increasingly critical. Electrification of buildings and transportation, coupled with the rapid growth of distributed energy resources (DERs), is placing unprecedented demands on LADWP's local grid infrastructure. While transmission investments enable the delivery of renewable energy from remote generation sites, the distribution system is where decarbonization meets the customer—supporting reliability, resilience, and equitable access to clean energy.

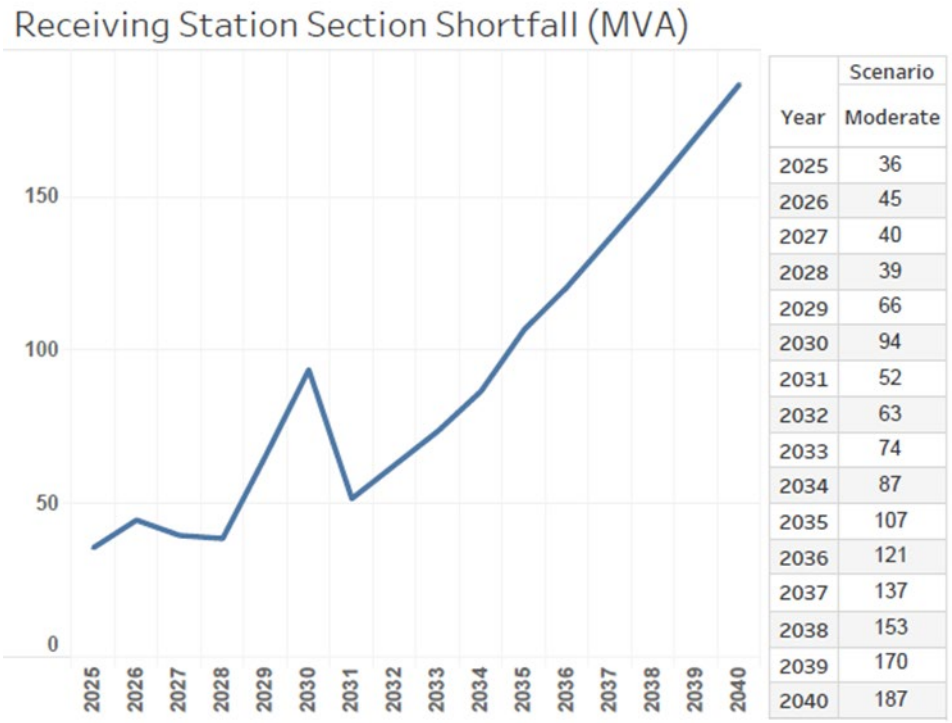


This section outlines LADWP's capital investment strategy for key distribution assets, including Receiving Stations (RS), Distributing Stations (DS), 34.5 kV circuits, and 4.8 kV feeders. These investments are informed by the 2025 Distribution Load Forecast (DLF), which models future demand growth, DER adoption, and electrification trends across LADWP's service territory. The DLF Moderate Scenario—selected as the planning basis—reveals that many distribution assets are already operating near or above their rated capacity. Without proactive upgrades, hundreds more are projected to exceed capacity by 2035. Additional distribution system investments are required to address both existing constraints and anticipated future shortfalls.

To ensure that the distribution system can support the LA100 goals, LADWP is prioritizing targeted infrastructure upgrades, capacity relief projects, and system modernization efforts. The following subsections detail the investment needs and planned actions for each major asset class to increase system capacity.

2.6.1 Receiving Stations

Receiving Stations step down transmission-level voltage to 34.5 kV, supplying power to Distributing Stations and large customers. As decarbonization accelerates across the City of Los Angeles, Receiving Station capacity must be expanded to meet growing demand from building electrification, electric vehicles, and other DERs. Additional capacity is required to support major initiatives such as Port of Los Angeles (POLA) electrification and to accommodate energy intensive developments like data centers. As shown in Figure 2-27, LADWP faces capacity shortfalls across its Receiving Station transformers.



Year	Scenario: Moderate
2025	36
2026	45
2027	40
2028	39
2029	66
2030	94
2031	52
2032	63
2033	74
2034	87
2035	107
2036	121
2037	137
2038	153
2039	170
2040	187

Figure 2-27 Forecasted Capacity Shortfall Across RS Sections (Transformers)

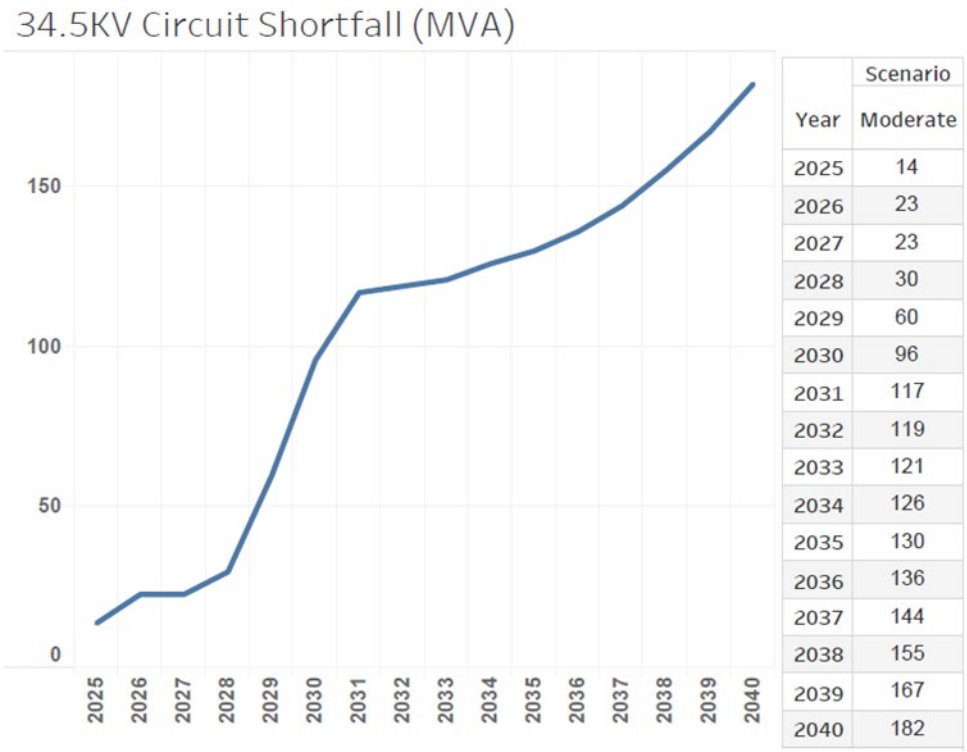
To address these shortfalls, LADWP is implementing a series of Receiving Station expansion projects, listed below. As electrification accelerates and system demand grows, LADWP will continue to evaluate and implement additional Receiving Station

projects to ensure long-term reliability, capacity, and operational flexibility. These efforts are critical to enabling the infrastructure needed to achieve LA100 goals and objectives.

- Wilmington RS-C – Build a new rack to increase capacity and support load growth in the Wilmington area of Los Angeles.
- Harbor RS-Q – Build a new rack to increase capacity and support POLA electrification.
- St. John RS-A – Build a new receiving station to replace and modernize existing RS, relieve 34.5kV network congestion, and support load growth in Downtown area of Los Angeles.
- Valley RS-M – Build a new rack and upgrade existing equipment to relieve 34.5 kV network congestion and increase operational flexibility.
- Century RS-B – Build a new rack to increase capacity and relieve 34.5kV network congestion.

2.6.2 Circuits (34.5 kV)

34.5 kV circuits supply power to Distributing Stations and large customers. Capacity shortfalls are beginning to emerge within the 34.5 kV network and are expected to increase, as shown in Figure 2-28. To maintain operational flexibility and support timely interconnection of new large loads, circuit loading must be reduced to their planning capacity of 80% or less.



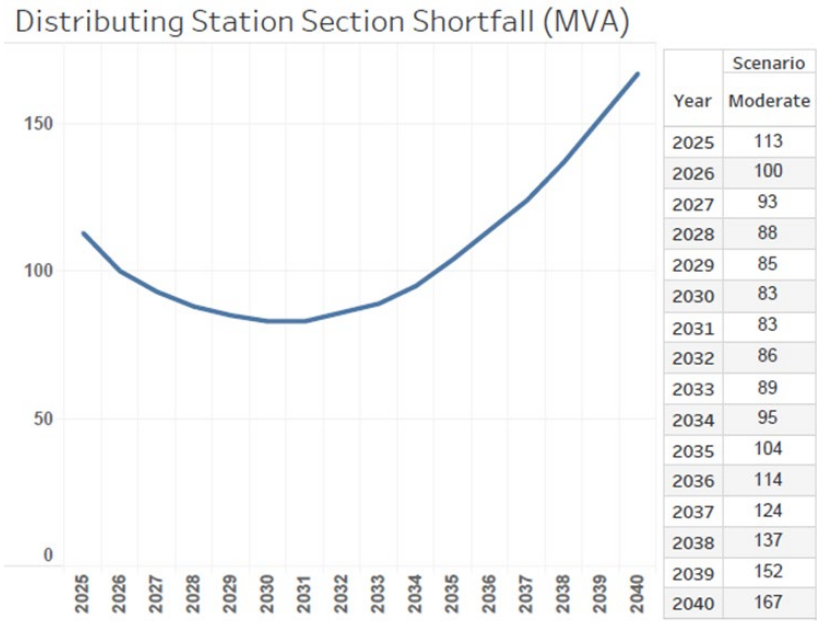
Year	Scenario Moderate
2025	14
2026	23
2027	23
2028	30
2029	60
2030	96
2031	117
2032	119
2033	121
2034	126
2035	130
2036	136
2037	144
2038	155
2039	167
2040	182

Figure 2-28 Forecasted Capacity Shortfall Across 34.5 kV Circuits per 2025 Distribution Load Forecast.

Over 20 projects are currently underway to address 34.5 kV system needs. LADWP is actively developing additional plans to meet growing demand and support the LA100 initiative.

2.6.3 Distribution Stations

Distributing Stations step down voltage from 34.5 kV to 4.8 kV, which is more suitable for power delivery to residential areas, as well as small commercial and industrial customers. Many of these substations operate above their rated capacity, and more are projected to do so in the near future. The projected capacity shortfall across Distributing Station transformers is shown below in Figure 2-29.



Year	Scenario Moderate
2025	113
2026	100
2027	93
2028	88
2029	85
2030	83
2031	83
2032	86
2033	89
2034	95
2035	104
2036	114
2037	124
2038	137
2039	152
2040	167

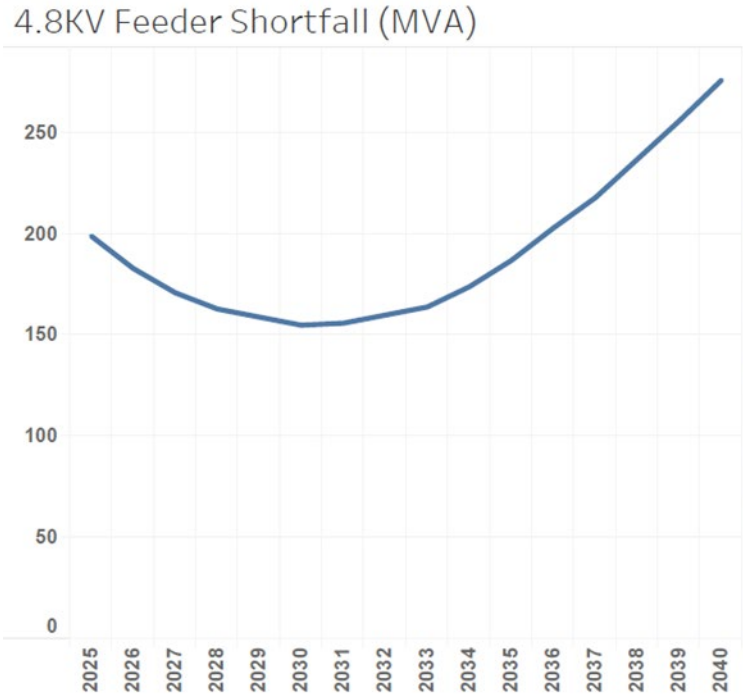
Figure 2-29 Forecasted Capacity Shortfall Across DS Sections (Transformers) per 2025 Distribution Load Forecast.

LADWP currently has over 60 capacity expansion projects for Distributing Stations. Additional plans are being developed to meet existing and future demand and support the goals of the LA100 initiative. Among these efforts, three major initiatives stand out for their scale and strategic importance:

- DS-29 Rebuild, 12kV, Palisades Underground – Following damage from the January 2025 wildfires, LADWP proposes rebuilding Distributing Station 29 in Pacific Palisades as a modern 12.47 kV, 75 MVA facility. This project will improve reliability, support future load growth, and enhance system resiliency through an underground distribution network.
- Four New Distributing Station – LADWP has identified four priority areas to construct new Distributing Stations. In line with LA100 goals, these new substations will enhance system reliability and resiliency by relieving overloaded assets, modernizing aging infrastructure, and adding capacity to meet growing demand.
- Relocate and Rebuild DS-1 – LADWP plans to relocate and reconstruct Distributing Station 1, increasing its capacity to 80 MVA. This project will modernize one of the utility's oldest facilities and ensure reliable power supply for the area well into the future.

2.6.4 Feeders (4.8 kV)

4.8 kV feeders supply power to residential areas, as well as small commercial and industrial customers. They have historically been the most frequently and severely overloaded assets within the distribution system. Projected capacity shortfalls across 4.8 kV feeders are shown below in Figure 2-30. Feeder load relief is essential to meeting growing demand and mitigating reliability and resiliency risks associated with sustained overloading.



Year	Scenario: Moderate
2025	199
2026	183
2027	171
2028	163
2029	159
2030	155
2031	156
2032	160
2033	164
2034	174
2035	187
2036	203
2037	218
2038	237
2039	256
2040	276

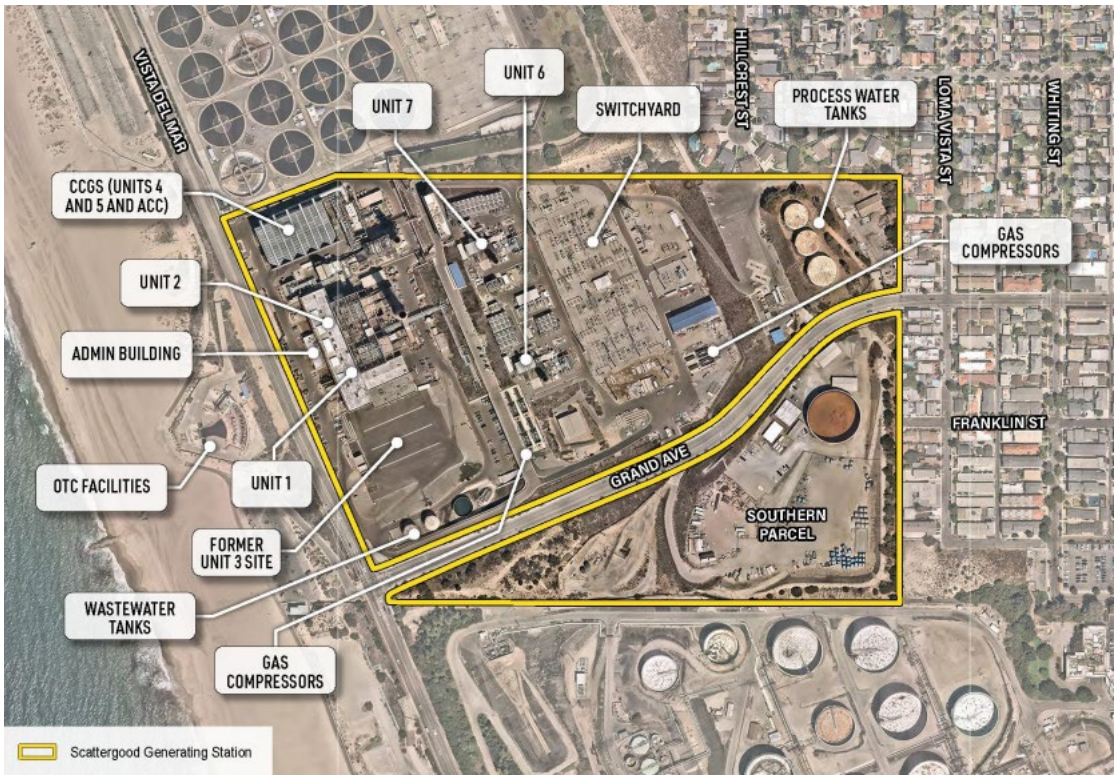
Figure 2-30 Forecasted Capacity Shortfall Across 4.8 kV Feeders per 2025 Distribution Load Forecast

To address 4.8 kV system needs, LADWP has over 200 plans in the pipeline and is actively developing additional plans that will support LA100 goals and objectives.

2.7 Transformation of Local Power Generation

In-basin, local power generation is at the crux of LADWP's transition to 100% renewable energy and must be built in a forward-looking, environmentally conscious, and just manner. The LA100 Study, along with several internal and third-party studies, have clearly demonstrated the need for significant additional in-basin generation capacity—between 2,280 MW and 3,620 MW. In all of the modeled scenarios, the LA100 Study shows a need for in-basin capacity as part of LADWP's clean energy future. To meet this need in both the near and long-term and in a just and environmentally sensitive way, LADWP plans to build renewable hydrogen-ready generation units at local power plants. This increased in-basin capacity will help meet the growing demand for electricity due to the growth in ownership of electric vehicles, greater building electrification, and growing demand from large customers such as POLA and Los Angeles International Airport (LAX). Renewable hydrogen-ready in-basin capacity also ensures resiliency in the face of the growing threat of wildfire and will help LADWP provide reliable service to its customers. LADWP will begin to transform its in-basin generation fleet to 100% carbon-free energy via significant infrastructure upgrades, including investments in green-hydrogen.

Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project. LADWP's Scattergood Generating Station Units 1 and 2 Green Hydrogen ‐ Ready Modernization Project would allow the generation capacity of existing Scattergood Units 1 and 2, which are conventional natural-gas-fired steam boiler generators, to be replaced with a rapid-response combined-cycle generation system capable of operating on a fuel mixture of natural gas with a minimum of 30% hydrogen by volume. The existing ocean-water OTC system at Scattergood would no longer be used once Units 1 and 2 are removed from service concurrent to the commissioning of the project. By ceasing use of the remaining OTC system at Scattergood by December 31, 2029, LADWP will comply with the statewide Water Quality Control Policy on the use of Coastal and Estuarine Waters for Power Plant Cooling.



Haynes Generating Station Unit 8 Cooling System Retrofit Project. Built in 2005, the relatively new combined-cycle generation unit at LADWP's Haynes Generating Station, which consists of Haynes Units 8, 9 and 10, is the second most efficient generation asset in LADWP's fleet. The Haynes Generating Station Unit 8 Cooling System Retrofit Project aims to convert the existing OTC system to a recycled-water wet-cooling tower. This has significant environmental justice benefits ensuring an equitable implementation of the Mayor's February 2019 OTC commitment and reducing in-basin natural gas combustion which will lower GHG emissions and reduce criteria pollutants. This strategy avoids displacing needed generation to other less efficient in-basin generation assets like the Valley Generating Station combined cycle.

Harbor Generating Station Unit 5 Cooling System Retrofit Project. Harbor Generating Station, located in the Wilmington neighborhood within the City of LA, is surrounded by largely industrial operations due to its proximity to POLA and local train routes facilitating shipments to and from the port. Currently, the steam turbine of the combined cycle utilizes OTC. Converting this unit to use recycled-water wet-cooling preserves firm capacity which is critical for the clean-energy transition as the co-located POLA electrifies its operations, increasing load in the area.

2.7.1 Power System Background

LADWP owns and operates four generating stations within the LA Basin: Scattergood Generating Station located in the Playa del Rey community in LADWP's western service territory, Harbor Generating Station in the Wilmington community in LADWP's southern service territory, Valley Generating Station in the Sun Valley community in LADWP's northern service territory, and Haynes Generating Station located primarily within the City of Long Beach. Additionally, there is an extensive network of customer and commercial solar installations within LADWP's service territory that provide power both to LADWP and directly to customers.

LADWP's Power System was designed and has continued to rely upon its four foundational in-basin generating stations: Harbor, Haynes, Scattergood, and Valley. These stations ensure the system remains reliable and resilient while also enabling the import of renewable energy from outside the LA Basin. Three out of the four in-basin generating stations are located on the coast in the southern and western boundaries of the system. These facilities were sited along the coast for accessibility to ocean water which has traditionally been used to cool various processes across the thermal power generation cycle. The southern and western portion of LADWP's service territory form transmission cul-de-sacs, while electricity imports from outside the LA Basin predominantly flow in from the north. Put simply, this means that renewable power flows from the north and dispatchable, natural gas-fired generation flows from the south.

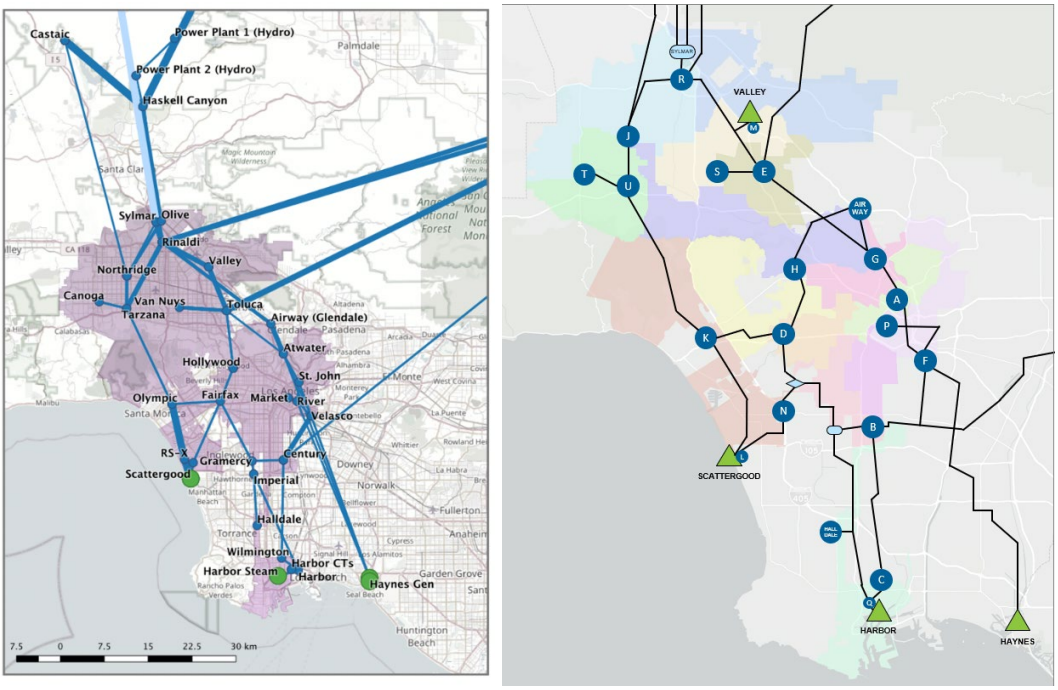


Figure 2-31 Simplified LADWP Power System with in-basin generating stations.

The need to retain firm in-basin capacity, particularly at the coastal generating stations (Scattergood, Harbor, and Haynes), is paramount to meet reliability criteria, resource adequacy, contingency reserves, replacement reserves, customer demand, and system stability.

This requirement was affirmed in the LA100 Study. The loss of local, firm capacity would put LADWP in violation of the North American Electric Reliability Corporation requirements since we would not be able to fulfill its reliability must run (RMR) obligations. Construction of new transmission lines sited within LA Basin would satisfy the in-basin generation capacity requirements. However, due to dense urbanization local transmission lines are largely locked into their current rights-of-way and there is minimal real estate for adding or moving transmission lines. LADWP is planning multiple upgrades to the local transmission system to reduce the necessary in-basin generation capacity while meeting all reliability requirements. These transmission projects require coordination with numerous entities and face significant environmental hurdles which make the projects lengthy and complex. In addition, maintaining the in-basin generation capacity during the planned upgrades is extremely important since the transmission upgrades will require scheduled outages of transmission infrastructure. Fortunately, LADWP will utilize local generation to maintain reliability. Upon completion, these

planned upgrades will relieve some of the transmission stresses on the system, but continuing to develop local capacity will remain a priority to preserve system resiliency reliability.

2.7.2 Need for Firm Capacity

The LA100 Study found that significant amounts of firm capacity will be required at all in-basin generating stations despite the rapid deployment of renewable generation, energy storage, and planned transmission upgrades. These renewable energy resources are largely located outside of the LA Basin and are dependent on corresponding increases to LADWP's transmission network to serve customer load. This increase in renewable generation results in a decrease in thermal generation which improves the air quality for the communities that LADWP serves. However, additional renewable generation capacity requires new or upgraded transmission networks. Additionally, renewable resources like wind and solar are weather-dependent and uncontrollable. In recent years, extreme weather events have shown that there may be future shortfalls in system reliability if these needs are unaddressed. Energy storage helps but needs to be located near load centers which makes it reliant on the same transmission networks as renewable energy resources. As a result, long-term, dispatchable power generation remains critical during stressed grid conditions that may be caused by low-probability, high-impact events. Stressed grid conditions may also result from sustained periods of low renewable generation or transmission line maintenance or upgrades that can worsen if they coincide with periods of high demand.

Saddleridge Fire

The Saddleridge Fire began on October 10, 2019, and occurred near the northern San Fernando Valley. Tragically, the wildfire resulted in one fatality, eight injuries, and burned 8,799 acres. During this event, LADWP's transmission network and its ability to import energy into the LA Basin were significantly impacted. LADWP lost all its transmission capacity on the Pacific DC Intertie and through the Barren Ridge Corridor. Additionally, LADWP lost two of the five lines on the Victorville-Los Angeles transmission path. As a result, LADWP dispatched 1,889 MW from its in-basin generating stations to compensate for this lost transmission capacity. Thankfully, the wildfire occurred on a relatively low-load day, and LADWP was able to rely on firm and dispatchable in-basin generation to stabilize its system. Customer blackouts would have likely occurred if the load was materially higher or if in-basin generation had been unavailable. The Saddleridge Fire is one recent example of a low-probability, high-impact event that resulted in stressed grid conditions. As the impacts of climate change make these events more frequent and more severe, it is important that LADWP adequately plan against high-impact outcomes.

In the LA100 Study, NREL confirmed that LADWP's in-basin generation fleet needs a significant amount of firm capacity to maintain a reliable power system. NREL defined firm-capacity resources as generation resources whose capacity credits (i.e., dependable capacity ratings) remain effectively constant, regardless of customers' demand patterns and the mix of technologies deployed on the grid. Firm-capacity resources can generate electricity on demand within minutes and run for uninterrupted periods ranging from hours to weeks.

To meet the local firm-capacity requirements, NREL's models deployed significant amounts of renewably-fueled gas turbines at LADWP's in-basin generating stations. These units are predicted to be used infrequently compared to today's usage of the natural-gas units and are meant to serve load during periods of peak demand and emergency events. They also provide valuable reserve capacity when they are not running.

Background on LADWP Wildfire Mitigation Measures

Since 2008, LADWP has put in place reliability standards for power equipment that helps mitigate wildfire risks in high-threat fire zones. In addition, the Department has aggressive vegetation management and Power System Reliability Programs, both of which serve to help mitigate wildfires.

LADWP has also worked with the Los Angeles Fire Department (LAFD) to put in place operating protocols and restrictions when working in designated fire threat and brush clearance areas, and during Red Flag warning periods. This includes suspending all non-essential work in Tier 2 and 3 zones. When work is completed in these areas, extra precautions are taken to ensure the work performed does not contribute to the risk of ignition.

In 2024, LADWP put additional protocols in place to further reduce the risk of wildfires, and more are in development under the Department's Wildfire Mitigation Plan. For example, during previous fires like the Saddleridge and Getty Fires, LADWP turned off automatic reclosers on its distribution lines. This step ensured that a power line that experiences a disruption does not automatically re-energize, substantially minimizing the potential for fire ignition. Crews also de-energized power lines directly impacted or threatened by the fire. This allowed staff to work closely with LAFD to eliminate electrical hazards in the path of the fires. LADWP plans to take further actions to strengthen its system against fire risks, this included installing more steel poles and covered wire that helps reduce the risk of wildfire.

The green hydrogen-fueled capacity requirements from the LA100 Study for each in-basin generating station are provided in Table 2-7 below. Effectively, these represent carbon-free capacity requirements for each facility to ensure system resiliency and reliability.

Table 2-7 Expected in-basin hydrogen-fueled capacity (MW)

Year	2030	2035
Harbor	0	257
Haynes	0	762
Scattergood	346	688
Valley	0	398
Total	346	2105

2.7.3 Green Hydrogen as a Renewable Fuel

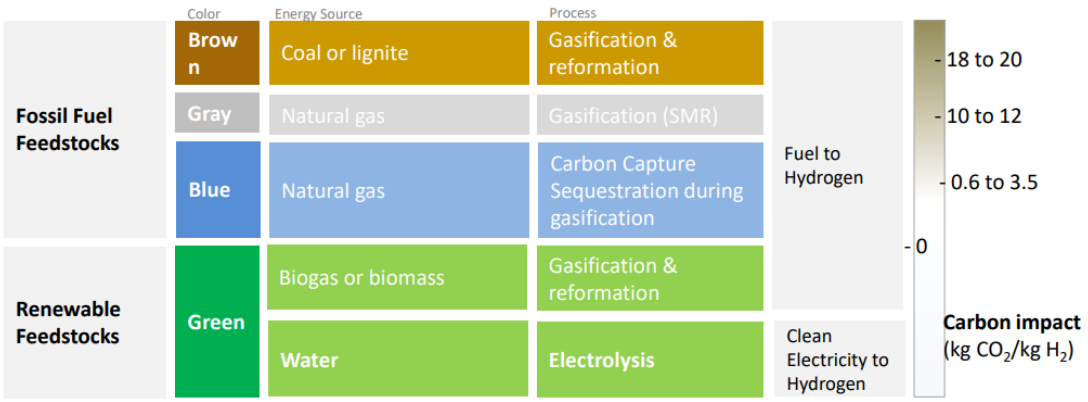
Green hydrogen continues to gain momentum as a key enabler towards the clean energy transition. It has the potential to displace significant amounts of fossil fuels—reducing overall carbon emissions—particularly for sectors and use-cases that are considered difficult to electrify. The potential of green hydrogen is evident within the rapidly evolving global policy landscape. In November 2021, the United States Congress passed the Infrastructure Investment and Jobs Act. This law allocates $8 billion for the creation of at least four regional hubs under the Clean Hydrogen Hubs (H2Hubs) Program, overseen by the DOE through the Office of Clean Energy Demonstrations. In August 2022, Congress passed the Inflation Reduction Act (IRA) which contains significant provisions related to climate and energy. Notably, the IRA includes provisions on production tax credits for clean hydrogen and expands the existing Clean Energy Tax Credit to clean hydrogen production facilities. These policies will catalyze and foster clean hydrogen markets across the country.

To support and manage the California hydrogen hub, the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) was formed. ARCHES is a public-private partnership organized to accelerate hydrogen projects on an industrial scale in California and LADWP is a subrecipient set to receive funds through ARCHES. The Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project is one of two large power projects set to receive federal funds through H2Hubs.

2.7.3.1 Colors of Green Hydrogen

There are many ways to produce hydrogen. The term green hydrogen typically refers to hydrogen that is produced through electrolysis using renewable energy. The energy

industry has traditionally used color codes to classify the feedstocks, energy sources, and production methods of hydrogen. However, there is a growing industry-wide interest to move away from the qualitative color-coding method. Instead, the industry wants to adopt a methodology based on carbon intensity which is defined as the total lifecycle greenhouse gas emissions in kilograms of CO2 equivalent per kilogram of hydrogen produced. Quantifying the carbon intensity of clean hydrogen is important since the IRA production tax credits are calculated on a sliding scale based on carbon intensity. For example, to be eligible for the full production tax credit, clean hydrogen needs to be produced with less than 0.45 kilograms of CO2 equivalent of lifecycle GHG emissions for every kilogram of hydrogen produced. At the direction of Los Angeles City Council, LADWP is only pursuing green, carbon-free, and electrolytically-produced hydrogen that meets these criteria.



2.7.3.2 Long-Duration Energy Storage



Green hydrogen can be used as a form of long-duration chemical energy storage. Excess renewable generation can be used to power electrolyzers that produce hydrogen, which helps to avoid renewable generation curtailments. This conversion is commonly referred to as power-to-gas (P2G). Electrolyzers produce green hydrogen by splitting molecules of water (H2O) into hydrogen (H2) and oxygen (O2) which can then be stored in various forms. When electricity generation is needed later—

perhaps months later—the hydrogen can be converted back to electricity using a combustion turbine or fuel cell. This constitutes a form of long-duration energy storage which is beneficial in systems with high amounts of variable energy generation like wind and solar. Hydrogen as a form of energy storage allows for geographic and technological diversity that compliments other forms of energy storage like batteries. Hydrogen's ability to be delivered via pipeline creates a new pathway that relies on other parties for storage and delivery and separates these parties from end users like LADWP. In the case of extreme weather, these separate pathways improve system reliability and resiliency. Additionally, by only acting as an off taker, LADWP preserves space at LADWP's existing generating stations, allowing LADWP to operate similarly to how it does now.

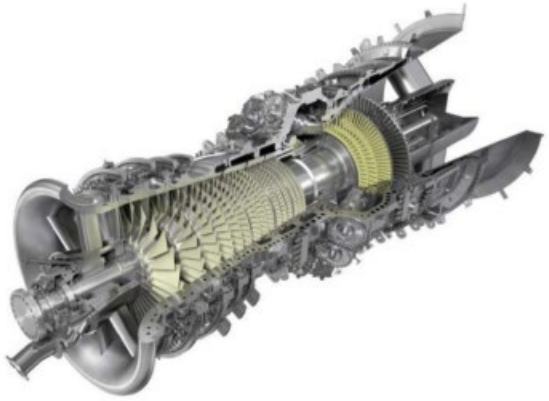
2.7.3.3 Fuel Cell Applications

An additional benefit of green hydrogen as a fuel is its flexibility. Aside from its use in gas turbines, green hydrogen can be used in low and high temperature fuel cells as a no in-basin combustion alternative. Low temperature fuel cells are useful for transportation applications, eliminating vehicle GHG and NOx emissions. High temperature fuel cells are most applicable to providing baseload power—power that does not follow changes in a utility's load. While hydrogen fuel cells are being considered for smaller-scale stationary power, hydrogen-fueled gas turbines are more applicable to LADWP's needs due to cost and technology development considerations. LADWP does not consider fuel cells to be viable for utility-scale, bulk power generation at the existing in-basin facilities. In February 2025, NREL completed the Scattergood Modernization Project Alternatives study. This study examined potential scenarios where LADWP installed non-combustion generation at Scattergood as an alternative to a hydrogen-ready combined cycle. This study acts as an extension and update of the original LA100 Study, which identified possible solutions that could replace the retiring capacity at Scattergood. The LA100 Study found that in most cases, renewably fueled combustion turbines similar to the proposed Scattergood Modernization Project turbines, were the most cost-effective technology to provide firm capacity. This supplemental study considers the changes in technology that have occurred since the completion of the LA100 Study analysis in late 2020. The Study reevaluated the need for firm capacity at Scattergood and compared the proposed hydrogen-ready combined cycle to four non-combustion alternatives. Key considerations in the study included constructability by 2029, the ability to be sited at or near Scattergood, and the contributions towards reliability, cost, safety, and emissions among other factors. Following the Scattergood Modernization Project Alternatives Study, it was determined that in 2030 both high and low temperature fuel cell options

resulted in a small increase—generally less than 1% —in systemwide CO2 emissions. Additionally, there are negligible changes in the in-basin NOx emissions when comparing the proposed hydrogen-ready combined cycle to fuel cells.

2.7.3.4 Hydrogen Turbine Developments

LADWP remains vigilant in monitoring and learning from contemporary hydrogen demonstrations. The Electric Power Research Institute (EPRI) has completed several demonstrations with partners including the New York Power Authority, Georgia Power, and Constellation Energy. In summary, EPRI and its partners have demonstrated the viability of using a blend of hydrogen and natural gas in several different combustion turbines. These demonstrations included an aeroderivative turbine using water injection to control NOx and two large, heavy-duty turbines both using dry low NOx technology to control NOx. In these demonstrations the existing NOx control methods successfully mitigated NOx emissions to below permit levels. Additionally, EPRI's demonstrations included hydrogen leak prevention and leak monitoring, with no leaks identified throughout these demonstrations. It was also noted that when hydrogen was introduced, carbon monoxide levels decreased rapidly which could enable greater operational flexibility when using hydrogen fueled turbines.



2.7.3.5 Additional Benefits of Hydrogen Infrastructure

NOx emissions come from several sources within LA. NOx is created when air containing nitrogen and oxygen is heated until the nitrogen becomes free to join with oxygen. As depicted in Figure 2-32, the primary source of NOx emissions in the LA Basin is the transportation sector. With the buildout of new hydrogen infrastructure and pipelines, hydrogen will become more readily available which will enable the reduction of NOx and CO2 emissions from the transportation sector. Although not shown in Figure 2-32, hydrogen will be particularly advantageous in decarbonizing medium- and heavy-duty vehicles where electrification is not feasible. LADWP's generation stations have a relatively small contribution to the city-wide production of NOx when compared to other sources. Furthermore, as new renewable resources are deployed, LADWP will decrease

the dispatch of thermal generation assets, resulting in the reduction of NOx and improved in-basin air quality.

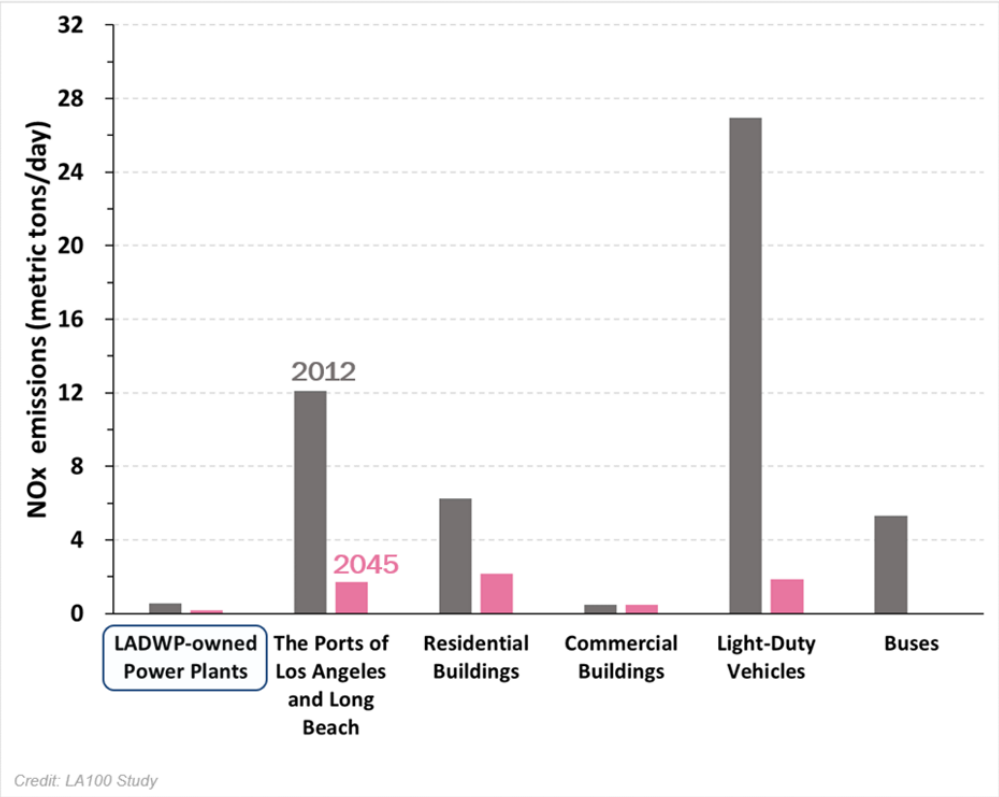


Figure 2-32 Sources of NOx Emissions in Los Angeles.

2.7.3.6 Alternative Renewable Fuels

While green hydrogen is the most promising renewable fuel to date, LADWP is also monitoring the development of other renewable fuels including renewable natural gas and biofuels, among others. The viability of these fuels—considering cost, logistics, and sustainability—remains uncertain and faces significant challenges. LADWP will continue to diligently monitor the development of alternative renewable fuels while developing its long-term strategy for decarbonization.

2.7.3.7 Implementation Challenges and Risks

Hydrogen is well suited to power generation. As shown by EPRI's blended hydrogen and natural gas fuel demonstrations, certain gas turbines can run on blends of hydrogen fuel with and without modifications to their combustors. As hydrogen is added to LADWP's resource mixture, there will be new challenges that arise from its implementation.

Table 2-8 Implementation challenges and risks associated with transforming LADWP's in-basin generation capacity to use green hydrogen fuel.

Area of Consideration	Description
Once-Through Cooling Retirements	Costal units must cease use of OTC no later than December 31, 2029. This regulatory deadline is firm and will result in up to 705 MW of lost capacity (Haynes Unit 8 and Harbor Unit 5 will be retrofitted to eliminate once-through cooling). LADWP is considering this significant loss of generation capacity and developing mitigative efforts to minimize the impacts on system reliability and resiliency.
Technology Maturity	The technology needed to operate a turbine on 100% hydrogen is not yet commercially available, specifically the type of generating unit and combustion system LADWP requires. Turbine manufacturers continue to develop the enabling technologies and expect that such units will become commercially available by 2035 or sooner.
Cost	Current methods of producing green hydrogen (e.g., electrolysis powered by renewable energy) are expensive, making hydrogen more costly than fossil fuels or other clean energy sources.
Infrastructure	As of right now, there is no green hydrogen infrastructure in LA. A significant amount of infrastructure will be required to support green hydrogen production, storage, and transportation. These projects will be capital intensive as hydrogen's low volumetric density makes most forms of transportation expensive and cumbersome in comparison to fossil fuels. In addition, the operations and logistics across the full value chain must be established to ensure that hydrogen can be reliably supplied to LADWP's generating stations. Through ARCHES, California is developing a clean, renewable hydrogen ecosystem connecting hydrogen suppliers with hydrogen off takers. The infrastructure ARCHES is supporting may enable LADWP to receive hydrogen by pipeline at LADWP generating stations, similarly to how these generating stations currently receive natural gas.

Environmental and Permitting Requirements	Hydrogen does not produce CO_2 when used, but there are other potential emissions that need to be monitored and recorded to comply with existing environmental permit limits. Additionally, there are unknowns involved in the permitting process given that hydrogen-fueled gas turbines for electricity generation are an emerging technology. LADWP is committed to working with regulatory agencies to ensure that future assets meet or exceed air permit standards.
Workforce and Labor	Transitioning the in-basin fleet to renewably-derived fuels will require more personnel—both within LADWP and through outside contractors—for successful execution of the projects. Given current economy-wide labor shortages, there is a risk that there will be insufficient personnel to support these transformative projects. While turbine technology exists at LADWP in-basin generating stations, hydrogen as a fuel for turbines is relatively new. Continued federal, state, and local investment is needed to support job training programs and workforce development in hydrogen and hydrogen-adjacent industries to ensure these is a skilled labor force for the growing market.
Space Constraints	Due to the dense urbanization in LA, all four in-basin generating stations are surrounded by residential communities and commercial properties with minimal room for future projects. Proper vetting of potential site configurations for new hydrogen-fueled capacity—with consideration of project sequencing—is required. The LADWP generating stations do not have the land needed to install an adequate number of electrolyzers or sufficient hydrogen storage without significant property expansion. This lack of available land due to the dense urban areas in the LA Basin means expanding LADWP's generating stations is not a practical or actionable solution.
Transmission Constraints	There are currently no practical means of transporting carbon-free electricity from LADWP's renewable resources outside of the LA Basin to the in-basin generating stations. The existing in-basin transmission and distribution networks are designed to supply electricity to LADWP ratepayers. These transmission networks cannot

	support the additional renewable energy needed for electrolysis without significant upgrades.
Outage Coordination	As LADWP increasingly relies on renewable resource located outside of the LA Basin, constrained transmission corridors will need to be upgraded. During these upgrades, transmission lines will need to become temporarily unavailable, requiring Grid Operations to rely on in-basin generating units to support the system. Aside from outages due to upgrades, both transmission lines and generating units will need to be taken out of service for periodic and routine maintenance. If LADWP's existing units are retrofitted to be capable of operating on hydrogen, the units will be temporarily unavailable as a part of the upgrade process. All of these outages require coordination in order to maintain system reliability.
Buildout Schedule and Sequencing	A significant buildout of hydrogen-fueled capacity will be required at all in-basin generating stations to achieve 100% carbon-free energy by 2035. Complex coordination between construction forces, engineering groups, and contractors is essential for a successful buildout. LADWP's buildout includes simultaneous generation projects, retrofits, and demolitions while maintaining the electricity system reliability. Additionally, project schedules will need to be accelerated in order to meet the rapidly approaching clean-energy targets.
Public Perception	The public has expressed concerns about the potential negative impacts of hydrogen, including concerns about NOx emissions during hydrogen combustion and the potential indirect greenhouse gas effect if hydrogen leaks. Safety risks are also a key concern. LADWP believes these concerns can be addressed through proper engineering and by applying the strictest engineering and safety codes & standards. Multiple industries have used hydrogen for over one hundred years, and proper safety designs, technologies, and procedures are well established. Additionally, groundbreaking demonstrations have been completed that show that hydrogen can be combusted safely in gas turbines with no impacts to emissions.

2.7.3.8 Operational Challenges and Risks

Hydrogen's ability to act as a fuel for dispatchable firm generation allows LADWP to operate hydrogen ready units at its existing generating stations. To ensure that this transition to hydrogen meets LADWP's needs, there are risks that need to be addressed before LADWP can fully transition to hydrogen.

Table 2-9 List of operational challenges and risks associated with green hydrogen.

Area of Consideration	Description
Fuel Supply and Storage	A continuous supply of green hydrogen will be necessary to operate generating units reliably. Onsite storage is impractical due to the low volumetric energy density of gaseous hydrogen and space constraints at existing facilities. As a result, LADWP will need to rely on hydrogen producers and distributors for its fuel supply.
Fuel Cost	Hydrogen is currently expensive to produce, transport, and store due to its low volumetric density. Renewable and low-carbon hydrogen currently cost more to produce than hydrogen produced using fossil fuels and much more expensive than traditional fossil fuels. The exact cost of hydrogen will depend on future market conditions and the cost of infrastructure. However, there are several federal and state policies in place that are intended to reduce the price of hydrogen, with green hydrogen receiving the largest incentives.
Backup Fuel	LADWP currently uses ultra-low sulfur diesel oil as an emergency backup fuel that is stored onsite at three of the existing in-basin generating stations. It is undetermined at this time whether diesel fuel may be used in hydrogen-optimized combustors. Natural gas may not be a suitable backup fuel since natural gas supplies and infrastructure will likely be vulnerable to the same risks as hydrogen supplies.
Safety	Hydrogen has unique properties that make its storage and handling different from traditional fossil fuels, but it is also non-toxic and does not directly contribute to GHG emissions. Hydrogen has been an industrialized product for over one hundred years and effective safety designs, technologies, and procedures have been established. LADWP has safely worked with hydrogen at all in-basin generating stations for decades, as hydrogen is used to cool existing electrical generators.

	LADWP personnel will be trained to safely handle increased quantities of hydrogen once it is used LADWP's generating stations.
Water Constraints	Due to frequent drought conditions and the increasing importance of water conservation, LADWP is looking to minimize the need for water at its generating stations wherever possible. Although electrolysis will not be located at the in-basin generating stations, LADWP recognizes that the production of electrolytic hydrogen requires significant amounts of water. However, hydrogen can be produced using municipal wastewater or recycled water. This challenge must be thoughtfully considered and addressed to ensure that the transition to green hydrogen is a viable and sustainable strategy for decarbonization.

2.7.3.9 Alternative Solutions

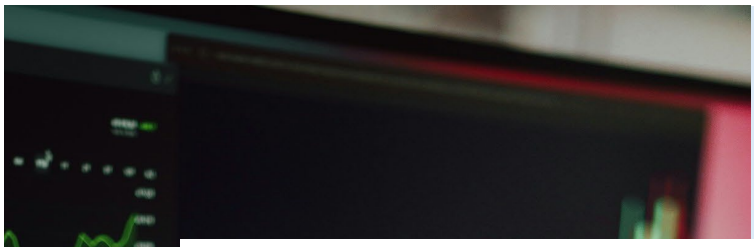
LADWP is aware of alternative solutions that would reduce the need to develop hydrogen-fueled gas turbines at each of the in-basin generating stations. A summary of some of these alternatives are described below.

- Retrofits to Existing Units – In lieu of building new hydrogen-fueled generation capacity, an alternative option is to modify existing, non-OTC, natural-gas units so that they may operate on hydrogen. Current available technology limits the modification of existing units to 15–35% hydrogen by volume, with the remaining balance being natural gas. The scope of the modifications includes but are not limited to upgrades to the turbine combustors, the addition of safety monitoring equipment, and the installation of a fuel-blending skid. These retrofits might be preferable for LADWP's newer generating units that have more of their original operational lifespan. LADWP will continue to evaluate the viability of modifications to best utilize existing assets. LADWP intends to utilize in-basin hydrogen-fueled generating capacity as a back-up resource to renewable energy and energy storage resources. The economics of retrofitting units versus building new units will need to be considered when selecting the best path forward.
- New Electric Transmission Corridors - The opportunity to develop new transmission lines over land in LA is extremely limited due to dense urbanization. Subsea transmission lines are a potential solution that are in service around the world and could expand available solutions. Adopting this technology would allow LADWP to add new transmission corridors along the coastal side of its

service territory which may alleviate the capacity requirements at each of the in-basin generating stations.

- New Generation Technologies - LADWP believes that hydrogen-fueled gas turbines will be a key technology that enables decarbonization at its in-basin generating stations. However, there might be other technologies in development that reduce the need for hydrogen-fueled gas turbines at LADWP's generating stations. Generation technologies that could potentially augment gas turbines in the foreseeable future include advanced hydrogen fuel cells and offshore wind turbines. LADWP will continue to monitor the development of these alternatives as part of its strategy for decarbonization.

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Chapter 3

Modeling Inputs, Assumptions, and Methodology



Key Highlights

- Analytical Framework: Lays out the data, forecasts, and reliability standards guiding LADWP's clean-energy modeling
- Scenario Testing: Examines diverse futures, from high electrification to hydrogen constraints, to gauge system resilience
- Modeling Platform: Uses PowerSIMM to optimize resources and simulate real-world operating and cost conditions

3.1 Model Input Assumptions

One of the critical components of the LA100 Plan is computer modeling. The LA100 Plan Assumptions Package establishes various inputs to the model, including, but not limited to, assumptions regarding customer demand, fuel costs, and capital costs.

The initial step in the modeling process involves running a capacity expansion model. Capacity expansion models build or procure sufficient generation resources to meet customer load over the entire planning horizon, subject to any given constraints. In the case of the LA100 Plan, the planning horizon stretches from 2024 to 2045. The primary constraints given to the capacity expansion model are annual renewable portfolio standard (RPS) targets and annual carbon-free energy targets. Our model seeks to minimize the total net present value (NPV) of capital costs and variable costs (e.g., fuel, operations and maintenance, and emissions) over the planning horizon, to select the least-cost and best-fit portfolio of generation resources.

The second step is transferring the buildout from the capacity expansion model into the production cost model. The production cost model then simulates the hourly dispatch of the generation portfolio built by the capacity expansion model. The model also performs Monte Carlo analyses, running up to 250 hourly simulations over the entire planning horizon. The simulations differ in terms of weather, with warmer weather resulting in higher loads and cooler weather resulting in lower loads. The weather simulation also drives the output of solar and wind resources. The Integrated Resource Planning (IRP) team, in collaboration with their consultant, ensures that enough generation resources are built or procured to guarantee no more than 0.1 days per year, on average, when customer demand exceeds generation. The 0.1 loss of load expectation (LOLE) per year target is the industry standard and is the threshold most utilities plan for.

The production cost model also provides numerous output metrics, including, but not limited to, total cost, fuel usage, and emissions. This chapter goes into more detail about how modeling assumptions were established and the reason behind their usage. Modeling results are presented in Chapter 4 of this document.

3.1.1 LA100 Plan Modeling Runs

In close coordination with the LA100 Advisory Group, LADWP developed a robust set of sensitivities to stress-test the LA100 Pathway and assess the system's resilience under a range of plausible futures. Over the course of multiple meetings, Advisory Group members participated in breakout sessions to discuss potential uncertainties that could materially impact the transition to 100% carbon-free energy. These sessions helped surface key areas of concern, including cost uncertainty, variable load growth, levels of customer adoption of distributed energy resources (DERs), hydrogen technology readiness, in-basin resource availability, and climate change impacts. The final list of sensitivities (see Table 3-1) reflects the Advisory Group's collective input and addresses the most salient risks identified by its diverse membership, ensuring the LA100 Plan remains grounded in stakeholder priorities and real-world complexities.

Table 3-1. List of Modeling Runs

Scenarios/Sensitivities*	Year 100% Carbon-Free Energy Is Reached**	Description	Risks Addressed
LA100 Pathway	**2035**	**Main scenario, local policy mandate**	**N/A; risks were assessed via sensitivities**
1. LA100 - Price Sensitivity	2035	High renewable energy, energy storage, and green H_2 costs; low natural gas and CO_2 allowance costs	Impact of higher cost of clean energy and lower cost of fossil fuels
2. LA100 - Low Load Sensitivity	2035	Load growth is lower than expected	Impact of lower-than-expected customer load growth
3. LA100 - High Load Sensitivity	2035	Load growth is higher than expected	Impact of higher-than-expected customer load growth
4. LA100 - Low Distributed Energy Resource (DER) Sensitivity	2035	DER adoption is lower than expected	Impact of customers adopting fewer DERs than anticipated
5. LA100 - High Distributed Energy Resource (DER) Sensitivity	2035	DER adoption is higher than expected	Impact of customers adopting more DERs than anticipated
6. LA100 - No In-basin Combustion Sensitivity	2035	Replacement of green H_2-capable combustion turbines with green H_2-capable fuel cells, in-basin	Impact of green H_2-capable fuel cells, in place of in-basin green H_2-capable combustion turbines
7. LA100 - No In-basin Hydrogen (H_2) Supply Sensitivity	N/A (97% by 2035)	Maintaining of natural gas-fueled generation online, in lieu of green H_2-capable generation in-basin	Impact of green H_2 commodity market failing to reach commercial maturity at scale
8. LA100 - Limited In-basin Hydrogen (H_2) Supply Sensitivity	2035	Limited H_2 fuel supply available for in-basin generation	Impact of green H_2 commodity market supplying less in-basin fuel than anticipated
9. LA100 - Resource Constrained Sensitivity	2040	New renewable energy and energy storage procurement capped at 500 MW/year. Green H_2-capable generation in-basin is not fully built out until 2040	Impact of undersupplied market for renewable energy and energy storage, in addition to delays in H_2 technology maturity
10. LA100 - Climate Change Sensitivity	2035	Base customer load is higher than expected	Impact of climate change
SB 100 Benchmark	**2045**	**Benchmark scenario, state policy mandate**	**N/A; risks were assessed via sensitivities**
11. SB 100 Price Sensitivity Sensitivity	2045	Lower renewable energy, energy storage, and green H_2 costs; Higher natural gas and CO_2 allowance costs	Impact of lower cost of clean energy and lower cost of fossil fuels

**Developed with input from the LA100 Advisory Group*
***LA100 reaches 100% carbon-free energy by 2035, as a percentage of all electric generation (including losses). SB 100 reaches 100% clean energy by 2045, as a percentage of electric retail sales (excluding losses).*

Table 3-1 describes an overview of energy planning modeling runs and associated risk assessment sensitivities for LADWP, focusing on future clean energy and carbon-free generation targets. There are two primary model runs presented:

LA100 Pathway (Local Policy: 100% Carbon Free by 2035): This is the intended path for achieving a carbon-free electric grid as identified in the 2022 Power Strategic Long-Term Resource Plan (SLTRP), featuring updated assumptions about load growth, cost, and technological advancements. The pathways trajectory entails that LADWP ramp up renewable energy to 80% renewable portfolio standard (RPS) by retail sales in 2030, and then to 100% carbon-free energy by generation by 2035, continuing to meet this target through 2045. It relies on adding major renewable and energy storage capacity and transforming the in-basin generating units, as well as the Intermountain Power Project (IPP), to fully operate off green hydrogen by 2035.

SB100 Benchmark (State Policy: 100% Clean Energy Sales by 2045): This model run aligns with California state law, setting a less aggressive pace than the LA100 Plan. It starts at 60% RPS by 2030 and aims for 90% clean energy by sales by 2035, reaching 100% clean energy with respect to sales, by 2045. It also uses in-basin unit transformations but allows for continued natural gas usage, including partial natural gas use at IPP, to serve losses.

There are also 11 sensitivities which alter the main model to assess how different risk factors impact the LA100 Plan. 10 sensitivities are derived from the LA100 Plan, and 1 sensitivity, the "SB100 Price Sensitivity", is derived from the Reference Case. They are summarized as follows:

LA100 Price Sensitivity: This sensitivity explores the impact of higher clean energy and energy storage costs, combined with lower fossil fuel prices and reduced CO_2 allowance costs. This scenario was designed to test how changes in market prices could affect the cost-effectiveness and pace of the clean energy transition. Despite these unfavorable price conditions, the LA100 modeling still achieved 100% carbon-free energy by 2035, though at a slightly higher total system cost relative to the core LA100 Pathway. This sensitivity helps illuminate the financial risks of delayed or less favorable market shifts, while demonstrating the robustness of the pathway under economic pressure.

LA100 Low Load Sensitivity: A sensitivity exploring how the system performs if customer electricity demand is lower than anticipated—due to factors such as increased energy efficiency, demand-side management, or slower electrification of buildings and transportation. In this scenario, the system requires fewer resources to meet energy needs, which can lower overall investment requirements. However, the sensitivity also evaluates the potential risk of under-utilizing infrastructure or overbuilding resources if demand projections were overestimated. Despite the reduced load, the system still

reaches 100% carbon-free energy by 2035, reinforcing the flexibility and resilience of the LA100 Pathway.

LA100 High Load Sensitivity: A sensitivity which explores the effects of higher-than-expected load growth on LA100 Pathway results. The High Load Sensitivity assumes higher overall customer load growth and increased electrification as well as lower distributed energy resource adoption which leads to higher peak loads and increased strain on system reliability compared to the original LA100 Pathway buildout.

LA100 Low Distributed Energy Resource (DER) Sensitivity: A sensitivity which explores the effects of lower-than-expected DER adoption. The Low DER Sensitivity assumes lower adoption by DWP customers of behind-the-meter resources such as rooftop solar and behind-the-meter storage compared to the LA100 Pathway which increases reliance on utility-scale resources for reliability.

LA100 High Distributed Energy Resource (DER) Sensitivity: A sensitivity which explores the effects of higher-than-expected DER adoption. The High DER Sensitivity assumes higher adoption by DWP customers of behind-the-meter resources such as rooftop solar and behind-the-meter storage compared to the LA100 Pathway which decreases reliance on utility-scale resources for reliability.

LA100 No In-Basin Combustion: A sensitivity which evaluates the viability of disallowing the use of combustion resources in the LA basin area. The No In-Basin Combustion Sensitivity explores the feasibility of replacing all dispatchable resources in-basin with green hydrogen fuel cells by 2035 instead of using green hydrogen combustion turbines per the LA100 Pathway. This sensitivity was developed with input from the Advisory Group stakeholders. In parallel to the LA100 Plan, LADWP contracted with NREL to conduct a Scattergood Alternatives Study, and the results show that there are currently no alternatives to the Scattergood Modernization Project.

LA100 No In-Basin Hydrogen Supply: This analysis assumes that LADWP is unable to bring online any hydrogen-fueled combustion generation located within the Los Angeles Basin. This sensitivity evaluates the impact of a situation where the hydrogen fuel supply chain fails to develop at the scale or pace necessary to support in-basin combustion, due to either technological, infrastructure, or market constraints. As a result, the system must rely more heavily on alternative resources—such as out-of-basin renewables, battery storage, and other forms of firm capacity—to ensure reliability. This case tests the resilience of the portfolio under a significant supply-side limitation and highlights the importance of a diversified set of solutions for achieving 100% carbon-free energy.

LA100 Limited In-Basin Hydrogen Supply: A sensitivity which explores the effects of hydrogen fuel shortages in the LA basin area. The Limited In-Basin Hydrogen Supply Sensitivity assumes lower than expected availability for hydrogen fuel, impacting the reliability of in-basin hydrogen turbines and overall system reliability.

LA100 Resource Constrained: This sensitivity seeks to evaluate the impact on LADWP's decarbonization timeline if resources remain a constraint.

LA100 Climate Change: This sensitivity tests the resilience of the LA100 Pathway under increasingly challenging weather conditions projected through 2045. These scenarios reflect the impacts of a warming climate, including higher peak temperatures, shifts in wind and solar patterns, and reduced availability of hydroelectric generation. As these weather conditions intensify over time, they place additional strain on the power system—raising electricity demand (particularly for cooling) and affecting the performance of renewable resources. This sensitivity helps assess whether the LA100 portfolio remains reliable under these more extreme and compounding climate stressors.

SB100 Price Sensitivity: This sensitivity was developed as a low-cost bookend to explore how more favorable cost assumptions might affect outcomes for the SB100 Benchmark portfolio. This sensitivity assumes lower costs for renewable generation, energy storage, and hydrogen fuel, along with higher natural gas prices. These assumptions reflect a scenario in which clean energy technologies become more affordable, while fossil fuel prices rise. Although the overall generation mix and emissions trajectory remain similar to the core SB100 case, the sensitivity results in a lower total system cost, helping to define the potential lower bound of long-term planning costs under optimistic market conditions.

3.1.2 Energy Load Forecast

Table 3-2. 2023 Energy and Demand Forecast

2023 ENERGY AND DEMAND FORECAST
NET ELECTRICITY SALES BY CUSTOMER CLASS AND SYSTEM PEAK DEMAND WITH REGULATORY IMPACTS

	Page 20	Page 21	Page 22			Page 19				Page 18			Page 16		
	SECTOR SALES					Total Sales	LOSSES			Net Energy	Customer	Service	Peak	Customer Self-Generation	Service
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	Electric Transportation (GWh)	to Ultimate Customers (GWh)	Total (GWh)	Percentage (%)	DC Line (GWh)	for Load (GWh)	Self-Generation (GWh)	Area Load (GWh)	Demand (MW)	Peak (MW)	Area Peak (MW)
2010-11	8,068	12,428	2,189	378		23,062	3,197	12.2%	598	26,258	1,111	27,370	6,142	194	6,336
2011-12	8,162	12,600	1,924	350		23,037	3,524	13.2%	886	26,561	1,137	27,699	5,907	201	6,108
2012-13	8,441	12,844	1,947	315		23,548	3,604	13.1%	888	27,152	1,173	28,324	5,782	210	5,991
2013-14	7,964	12,700	1,827	269		22,760	3,999	15.0%	836	26,759	1,249	28,008	5,862	230	6,092
2014-15	8,145	12,913	1,720	240		23,018	3,669	13.8%	506	26,688	1,307	27,995	6,343	240	6,583
2015-16	8,313	13,073	1,630	263		23,279	3,452	12.9%	615	26,731	1,358	28,089	6,234	253	6,487
2016-17	8,099	12,550	1,591	251		22,490	3,970	15.0%	1074	26,460	1,430	27,890	5,762	270	6,032
2017-18	8,076	12,563	1,501	243		22,383	3,474	13.4%	949	25,857	1,483	27,340	6,432	284	6,715
2018-19	8,160	12,350	1,225	227		21,961	3,085	12.3%	529	25,046	1,553	26,599	6,201	301	6,502
2019-20	8,020	11,645	1,240	223		21,127	2,968	12.3%	685	24,095	1,636	25,732	5,637	322	5,959
2020-21	8,523	11,074	1,031	210		20,838	2,943	12.4%	890	23,781	1,731	25,512	6,110	345	6,455
2021-22	8,185	11,724	1,185	215		21,309	2,686	11.2%	784	23,994	1,843	25,837	4,911	373	5,283
2022-23	8,443	11,763	1,122	219	65	21,611	3,072	12.4%	770	24,683	1,970	26,653	6,216	404	6,621
2023-24	8,309	11,639	1,153	219	414	21,734	2,864	11.6%	770	24,599	2,088	26,686	5,654	434	6,088
2024-25	8,239	11,397	1,149	221	569	21,574	3,034	12.3%	770	24,608	2,212	26,820	5,727	465	6,192
2025-26	8,255	11,252	1,145	222	761	21,635	2,898	11.8%	770	24,533	2,346	26,879	5,694	498	6,192
2026-27	8,138	10,887	1,143	223	990	21,380	2,853	11.8%	770	24,233	2,479	26,712	5,700	531	6,231
2027-28	7,833	10,228	1,135	224	1,212	20,632	3,018	12.8%	770	23,650	2,611	26,261	5,556	564	6,120
2028-29	7,727	9,880	1,127	225	1,448	20,406	2,827	12.2%	770	23,233	2,750	25,983	5,415	598	6,013
2029-30	7,738	9,780	1,123	226	1,669	20,537	2,802	12.0%	770	23,338	2,896	26,235	5,402	634	6,036
2030-31	7,766	9,686	1,119	227	1,927	20,726	2,843	12.1%	770	23,569	3,048	26,617	5,443	672	6,115
2031-32	7,804	9,604	1,116	228	2,247	20,999	2,926	12.2%	770	23,925	3,204	27,129	5,491	711	6,202
2032-33	7,863	9,546	1,112	229	2,521	21,272	2,901	12.0%	770	24,173	3,363	27,536	5,563	750	6,313
2033-34	7,930	9,494	1,109	231	2,826	21,590	2,899	11.8%	770	24,488	3,522	28,010	5,606	790	6,395
2034-35	7,969	9,425	1,105	232	3,096	21,826	3,023	12.2%	770	24,849	3,677	28,527	5,657	828	6,485
2035-36	8,147	9,475	1,102	233	3,395	22,352	3,054	12.0%	770	25,406	3,824	29,230	5,738	865	6,603
2036-37	8,219	9,446	1,098	234	3,671	22,667	3,139	12.2%	770	25,806	3,964	29,770	5,861	899	6,761
2037-38	8,341	9,470	1,094	235	3,974	23,114	3,118	11.9%	770	26,232	4,095	30,328	5,912	932	6,844
2038-39	8,448	9,490	1,090	236	4,268	23,532	3,245	12.1%	770	26,778	4,219	30,997	5,996	963	6,959
2039-40	8,652	9,600	1,087	238	4,578	24,154	3,338	12.1%	770	27,492	4,335	31,827	6,114	991	7,105
2040-41	8,820	9,690	1,083	239	4,889	24,722	3,373	12.0%	770	28,095	4,306	32,401	6,254	984	7,238
2041-42	9,019	9,813	1,080	240	5,215	25,367	3,418	11.9%	770	28,784	4,537	33,322	6,364	1,042	7,405
2042-43	9,205	9,915	1,076	241	5,547	25,984	3,571	12.1%	770	29,555	4,626	34,181	6,492	1,064	7,556
2043-44	9,498	10,101	1,073	242	5,890	26,804	3,699	12.1%	770	30,503	4,707	35,209	6,655	1,084	7,739
2044-45	9,774	10,270	1,069	244	6,244	27,600	3,757	12.0%	770	31,358	4,781	36,139	6,846	1,102	7,948
Annual Percent Change															
1996-2010	1.38%	0.68%	-1.43%	0.74%		0.69%				0.75%		0.58%	1.15%		1.09%
2012-22	0.03%	-0.72%	-4.73%	-4.77%		-0.78%				-1.01%		-0.69%	-1.83%		-1.44%
2022-27	-0.12%	-1.47%	-0.72%	0.73%		0.07%				0.20%		0.67%	3.03%		3.36%
2022-32	-0.48%	-1.97%	-0.60%	0.61%		-0.15%				-0.03%		0.49%	1.12%		1.62%
2022-45	0.77%	-0.57%	-0.45%	0.55%		1.13%				1.17%		1.47%	1.46%		1.79%

Table updated through December 2022
Electric Transportation Sales before January 2023 included in Residential and Commercial Sales
Intradepartmental sales, historically included in Miscellaneous, are now included in Commercial sector

*'Miscellaneous' includes Streetlighting, Owens Valley.

The Energy and Demand Forecast shown in Table 3-2 is the foundation of load projections made for all modeling conducted in the LA100 Plan. The forecast shows a breakdown of historical and expected energy demand within LADWP's service area. Energy demand is then summated with the expected losses incurred transmitting the energy to customers and with various "load modifiers" which are augmentations to the load depending on extrinsic factors. The final calculation of 'Net Energy for Load' is then used as the basis for load in the modeling process.

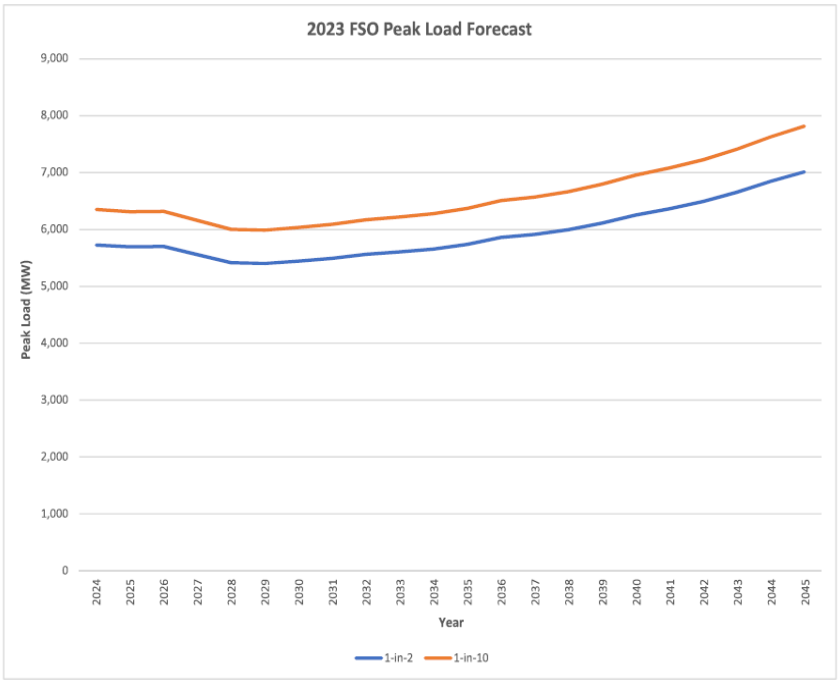
The load modifiers, such as Energy Efficiency (EE) in Figure 3-5, Distributed Energy Resources (DER) described in Figure 3-3, Figure 3-4, and Figure 3-7, Transportation Electrification (TE) in Figure 3-8, and Building Electrification (BE) in Figure 3-6, are pre-assumed in the above forecast. In the modeling process however, said load modifiers are applied to the load displayed, based on internally provided assumptions, to be re-added to the model in configurations for unique modeling sensitivities such as the "High DER" sensitivity (Table 3-1), which assumes increased Distributed Energy Resources such as local solar installations.

Also, in Table 3-2 is the Peak Demand, which represents the highest level of electricity consumption expected within LADWP's service area for each year forecasted. This value is utilized to assess reliability in the model, since LADWP's resource portfolio capacity in megawatts must always exceed this demand. Though a value for peak demand is provided in this sheet, the actual peak demand metrics used in the model are derived separate from this sheet as seen below in Table 3-3.

3.1.3 Peak Demand

Table 3-3. Peak Demand profiles utilized in LA100 Plan and sensitivities.

CY	1-in-2	1-in-10
2023	5,654	6,270
2024	5,727	6,351
2025	5,694	6,313
2026	5,700	6,319
2027	5,556	6,159
2028	5,415	6,003
2029	5,402	5,988
2030	5,443	6,034
2031	5,491	6,090
2032	5,563	6,170
2033	5,606	6,220
2034	5,657	6,279
2035	5,738	6,371
2036	5,861	6,510
2037	5,912	6,568
2038	5,996	6,665
2039	6,114	6,798
2040	6,254	6,957
2041	6,364	7,082
2042	6,492	7,228
2043	6,655	7,412
2044	6,846	7,628
2045	7,012	7,816
2046	7,029	7,834
2047	7,068	7,877
2048	7,119	7,934
2049	7,130	7,945
2050	7,146	7,963



Note:
For illustration purposes only. Production cost modeling software will create a unique annual peak during its Monte Carlo simulation process."

LADWP experiences its highest electricity demand during the summer months, particularly from June to September, when increased use of air conditioning significantly elevates energy consumption. LADWP uses 1-in-2 and 1-in-10 Peak Demand forecasts to ensure reliability in times of volatility, by controlling its own generation capacity. Historically, when LADWP performed IRP modeling deterministically, without incorporating randomness to represent outcome uncertainty, the 1-in-10 peak demand was used. Most recently, with the development of LADWP's IRP modeling capabilities to incorporate stochastics that account for randomness and uncertainty, a very important

factor when simulating future power systems that are heavily dependent on variable energy resources such as wind and solar, the 1-in-2 peak demand is used now, however each scenario and sensitivity is simulated hundreds of times, to ensure the reliability criterion is met across the entire range of possible outcomes.

3.1.4 Renewable Projects

Table 3-4. Existing, Planned, and Potential Renewable projects list

Current and Potential Renewable Projects									
			Ownership	Contract	LA's Share	GWh			
	Technology	COD	Option Date	End Date	MW	2024	2025	2026	2027
Projects In-service									
Small Hydro	Small Hydro	In service			247.0	522	301	301	301
DWP Built Solar	Solar	In service			6.8	11	11	11	11
Solar CNM (SB1)	Solar	In service			550.4	0	0	0	0
SW Wyoming Wind	Wind	7/1/06		6/30/25	82.7	0	0	0	0
Pebble Springs Wind	Wind	1/30/09		2/28/27	68.7	167	216	212	16
MWD Sepulveda	Small Hydro	In service		12/31/23	8.5	0	0	0	0
Willow Creek Wind	Wind	1/1/09		1/31/24	72	9	0	0	0
Pine Tree Wind Power Project	Wind	6/1/10			135	281	122	121	120
Milford Wind Phase I	Wind	11/16/09	5/16/29	11/15/29	185	374	336	331	325
Milford Wind Phase II	Wind	5/2/11	1/1/31	6/30/31	102	194	183	180	178
Windy Point Phase II	Wind	1/31/10	1/31/30	9/9/34	262.2	673	649	639	628
Linden Wind Energy Project	Wind	6/30/10			50	134	113	111	109
North Hollywood PS Power Plant	Small Hydro	In service			1	0	0	0	0
Adelanto Solar Facility	Solar	6/30/12			10.0	6	9	8	7
Pine Tree Solar Facility	Solar	3/15/13			8.5	14	10	9	9
Manzana Wind	Wind	12/20/12		7/18/23	39	0	0	0	0
Don Campbell I Geothermal	Geothermal	1/1/14		12/31/33	13.71	124	103	100	98
Feed-In-Tariff	Solar	In service			101.7	194	194	194	194
Copper Mountain Solar 3	Solar	4/8/15	4/8/25	4/8/35	210	512	742	675	611
Don Campbell II Geothermal	Geothermal	9/17/15		9/16/35	16.2	135	92	86	81
Heber 1 Geothermal	Geothermal	2/2/16		2/1/26	35.9	246	258	0	0
Springbok 1 Solar	Solar	7/11/16	7/10/31	7/11/41	105	296	295	292	289
Springbok 2 Solar	Solar	9/6/16	9/6/31	9/6/43	155	414	405	401	397
RE Cinco Solar	Solar	8/23/16	8/23/26	8/23/36	60	170	166	164	162
Beacon Solar Project Site 1	Solar	4/28/17	4/28/24	4/28/42	56	140	136	134	133
Beacon Solar Project Site 2	Solar	12/15/17	12/15/24	12/15/42	44.9	123.9	168	148	114
Beacon Solar Project Site 3	Solar	12/30/16	12/30/23	12/30/41	56	140	130	129	127
Beacon Solar Project Site 4	Solar	12/9/16	12/9/23	12/9/41	50	124	115	114	113
Beacon Solar Project Site 5	Solar	12/8/17	12/8/24	12/8/42	36.7	97	94	93	92
Moapa Southern Paiute Solar	Solar	12/8/16	12/8/26	12/8/41	250	618	615	609	603
Ormesa Geothermal	Geothermal	1/1/18		12/31/42	30	194	231	229	227
NNV Geothermal Portfolio	Geothermal	12/19/22		12/31/43	163.6	1,309	1,274	1,261	1,249
ARP Loyalton Biomass	Biomass	4/30/18		4/30/23	8.9	0	0	0	0
Springbok 3 Solar	Solar	7/19/19	7/19/34	7/20/46	90	223	236	233	231
Roseburg Biomass	Biomass	2/16/21		2/16/26	5.4	0	0	0	0
Red Cloud Wind	Wind	12/22/21	12/22/34	12/22/41	331	1,346	1,062	1,062	1,062
Projects Under Construction									
DWP Built Solar (In-Basin)	Solar	2023			33.2	44.8	58	58	57
Community Solar Program	Solar	2023-2029			3	5.3	5	5	5
Feed-In-Tariff	Solar	2023-2025			98.3	129.8	158	158	158
Eland Solar & Storage Center, Ph 1	Solar	9/22/24	9/22/39	9/22/49	175	367	751	751	751
Projects Planned									
Eland Solar & Storage Center, Ph 2	Solar	5/20/25	5/20/40	5/20/50	200	166	826	858	858
Potential Projects									
Feed-in-Tariff 300 Expanded	Solar	2023-2028			250	0	32	103	180
Solar PPA 2027 U	Solar	12/31/27			238	0	0	23	599
Solar + Storage PPA 2026 B	Solar	12/31/26			170	0	0	143	543
Solar PPA 2027 M	Solar	12/31/27			235	0	0	0	277
Solar + Storage PPA 2029 Navajo	Solar	13/31/29			400	0	0	0	0

Table 3-4 displays a list of all existing, planned, and potential renewable projects qualifying as RPS projects in LADWPs resource portfolio. In the figure, details of each project's commercial operation period and capacity estimations as of early 2024 are listed. A four-year forecast of energy produced by each project in GWh is also provided

predictions of annual energy produced for projects operating beyond the four-year forecast were extrapolated using the forecast and the RPS Master List as a basis when being input into the model.

3.1.5 Local Solar

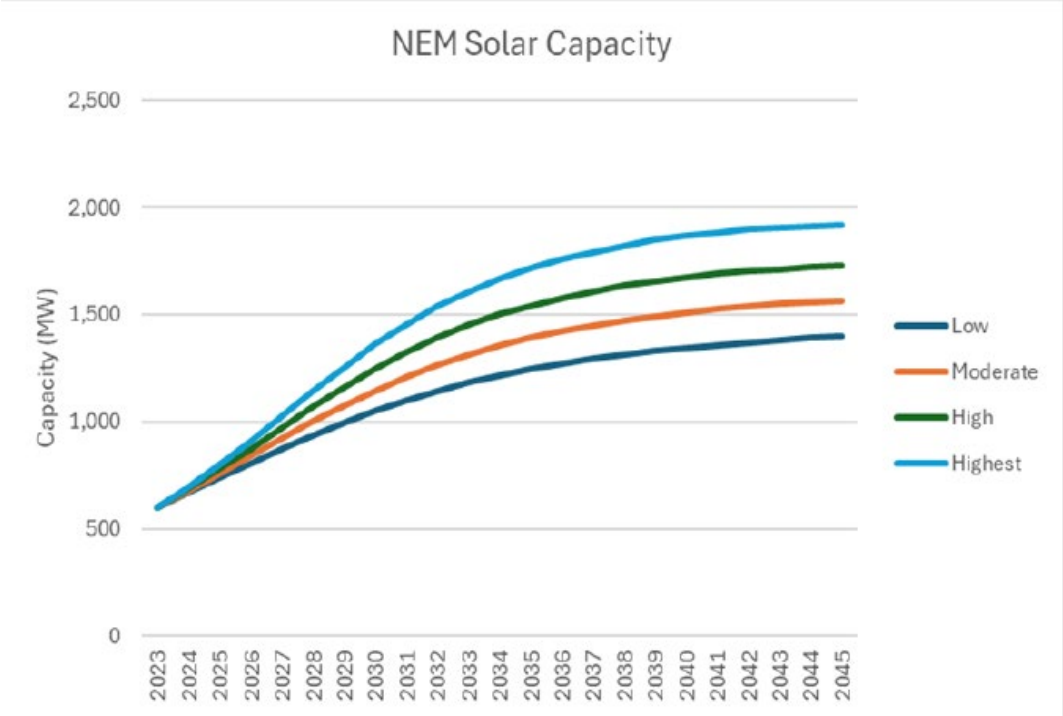


Figure 3-1. Forecasted growth of Net Energy Metered (NEM) Solar Capacity

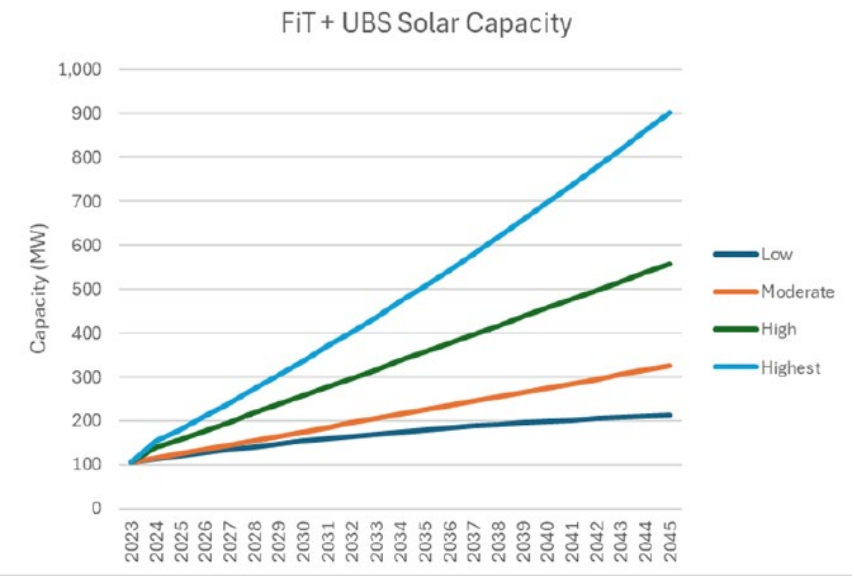


Figure 3-2. Forecasted Growth of Feed-in Tariff (FiT), and Utility-Built Solar (UBS) Capacity

LADWP offers several programs to promote local solar energy adoption among customers. Local solar aims to expand solar access, support green energy, create local jobs, and protect the environment.

Net energy metered solar (Figure 3-1), for example, allows customers to self-generate on site and provide any excess energy to LADWP in exchange for credits. Feed-in-Tariff (Figure 3-2), allows property owners and developers to sell the output of local eligible renewable energy projects directly to LADWP, while utility-built solar is built on City-owned rooftops and parking lots.

The LA100 Plan model runs assume different levels of local solar, per their definitions. The values shown above reflect cumulative total distributed solar capacity assumed for the LA100 Plan models, as provided by the LADWP Distributed Energy Resource Planning groups.



Table 3-5. Forecasted growth of Net Energy Metered, Feed-in Tariff, and Utility-Built Solar

NEM	Cumulative MW																						
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Highest*	600	698	802	912	1,027	1,141	1,254	1,359	1,455	1,536	1,607	1,666	1,715	1,756	1,792	1,822	1,847	1,867	1,883	1,896	1,906	1,914	1,919
High	600	688	779	875	972	1,067	1,161	1,247	1,325	1,392	1,451	1,500	1,541	1,577	1,607	1,633	1,655	1,674	1,689	1,702	1,712	1,720	1,727
Moderate	600	678	758	839	920	999	1,075	1,145	1,209	1,265	1,313	1,355	1,391	1,422	1,448	1,471	1,491	1,509	1,524	1,537	1,548	1,558	1,566
Low	600	669	737	805	871	934	994	1,049	1,099	1,143	1,182	1,215	1,245	1,271	1,293	1,312	1,329	1,344	1,358	1,370	1,381	1,390	1,398

FiT + UBS	Cumulative MW																						
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Highest*	105	155	180	210	240	271	303	335	368	402	437	472	507	544	581	618	657	696	736	776	817	859	902
High	105	139	157	177	197	217	237	257	277	297	317	337	357	377	397	417	437	457	477	497	517	537	557
Moderate	105	115	125	135	145	155	165	175	185	195	205	215	225	235	245	255	265	275	285	295	305	315	325
Low*	105	113	120	128	135	141	147	153	159	165	170	175	179	184	188	192	195	199	202	205	208	211	213

**Calculated by IRP Group*

3.1.6 Distributed Energy Storage

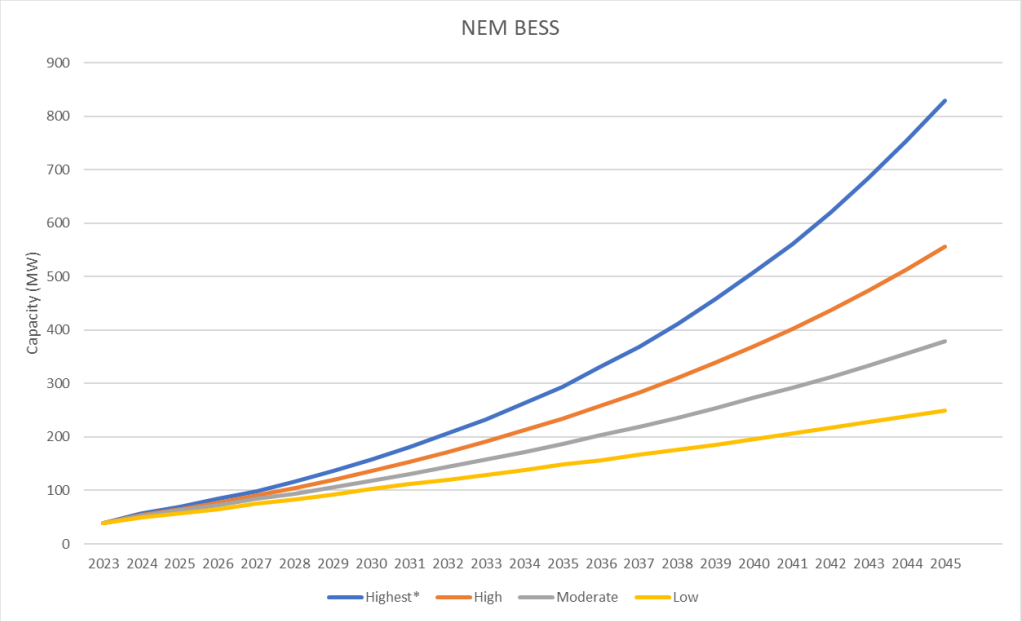


Figure 3-3. Forecasted Growth of Net Energy Metered Energy Storage Capacity

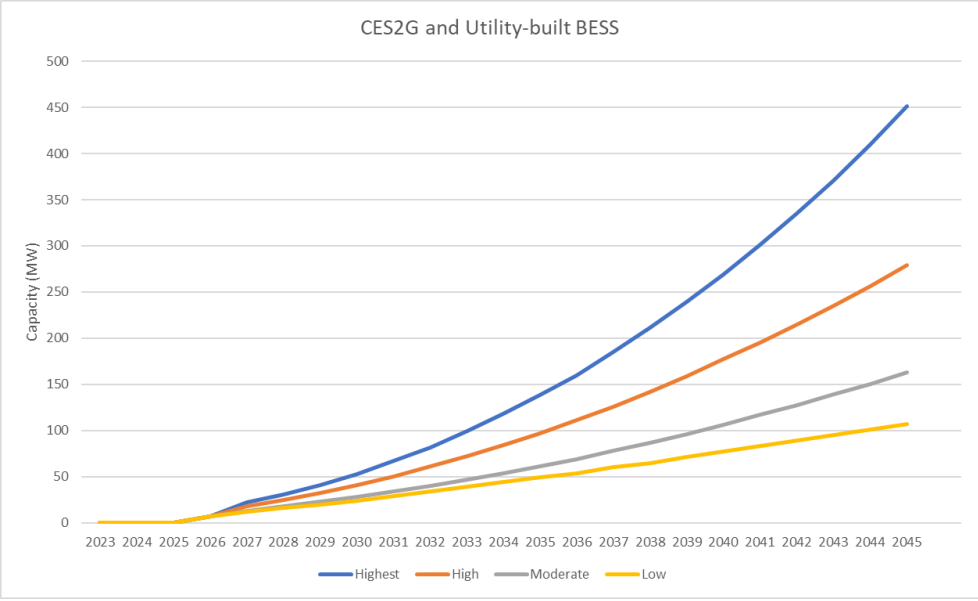


Figure 3-4. Forecasted Growth of Utility-built Energy Storage

The projections shown in Figure 3-3 and Figure 3-4 above forecast the anticipated additions of local battery energy storage system (BESS) capacity within LADWP's service area. The forecasts have multiple levels ranging from "Low" to "Highest" expected capacity additions for net energy metering and Utility Built BESS which were derived internally by subject matter experts within LADWP. In the modeling, the "Moderate" and "High" levels were used in the SB100 Benchmark and LA100 Pathway respectively, and all four levels were used diversely in the sensitivities modeled depending on established assumptions.

3.1.7 Hoover and Small Hydro

Table 3-6. Energy Projections of Hoover and Small Hydro Power Plants

	Hoover			Owens Gorge, Owens Valley, Aqueduct		
	Estimated GWh			Estimated GWh		
	Calendar Year	Calendar Year	Calendar Year	CY	Aqueduct	Owens Valley
Jan	35.96	28.27	21.07	2024	226	226
Feb	32.39	33.24	25.77	2025	130	130
Mar	58.01	55.36	39.62	2026	130	130
Apr	63.6	56.03	44.03	2027	130	130
May	58.79	54.64	45.87	2028	207	207
Jun	53.94	51.54	47.9	2029	207	207
Jul	49.27	45.43	41.14	2030	207	207
Aug	45.81	42.48	31.18	2031	178	234
Sep	40.8	37.61	27.21	2032	178	234
Oct	34.4	27.87	28.59	2033	178	234
Nov	38.32	34.03	34.59	2034	178	234
Dec	30.9	29.8	20.18	2035	178	234
	542.19	496.3	407.14	2036	178	234
				2037	178	234
				2038	178	234
				2039	178	234
				2040	178	234
				2041	178	234
				2042	178	234
				2043	178	234
				2044	178	234
				2045	178	234

The energy projections shown above in Table 3-6, are the estimated annual generation produced by LADWP's hydroelectric generating facilities located at Hoover Dam, the Owens Gorge and Owens Valley, as well as facilities along the Los Angeles Aqueduct. These projections are derived using historical facility averages as captured by LADWP subject matter experts. The latest information regarding ongoing drought conditions in the Western United States is also reflected.

3.1.8 IPP Hydrogen Usage

Table 3-7. (Top) IPP Hydrogen Usage by Year to achieve 100% Carbon-Free Energy, (Bottom) LADWP Share of IPP Generation

	IPP Renewed Green H2 Usage and Purchases								
	100% by 2035			100% by 2040			100% by 2045 (by Retail Sales)		
Year	% Volume	% Self-produced	% Market-purchased	% Volume	% Self-produced	% Market-purchased	% Volume	% Self-produced	% Market-purchased
2025	30%	100%	0%	30%	100%	0%	30%	100%	0%
2030	65%	100%	0%	30%	100%	0%	30%	100%	0%
2035	100%	50%	50%	30%	100%	0%	30%	100%	0%
2040	100%	50%	50%	100%	50%	50%	30%	100%	0%
2045	100%	50%	50%	100%	50%	50%	30%	100%	0%

LADWP Share of Generation (Base Shares Only)
2025-Mid-2027: 48.6% of 840 MW Plant Total **(~408 MW)**
Afterwards: 70.6% of 840 MW Plant Total **(~593 MW)**

Table 3-7 shows the three configurations of IPP Renewed based on the percentage of volumetric green hydrogen utilized by the plant in the model. For each model run conducted, a configuration among the three was utilized depending on the timeline for achieving 100% carbon-free energy. For example, model runs with the LA100 Pathway as their basis utilized the "100% by 2035" configuration of IPP Renewed to align with projections of achieving 100% carbon-free energy by 2035. The amount of hydrogen produced for use in IPP Renewed is affected significantly by changes in configuration.

IPP Renewed configurations also determine the procurement method of green hydrogen supply throughout the project's operation. The bottom table reflects whether hydrogen is procured via self-production or market-purchases and the weight for each procurement method. In cases where IPP Renewed is assumed to eventually operate at 100% green hydrogen, LADWP moves from producing hydrogen using solely LADWP-owned resources, to purchasing hydrogen from available markets. These assumptions are reflected in the model as changing fuel purchasing costs for IPP Renewed over time, depending on the configuration relevant to the scenario being run. Certain assumptions apply to all configurations of IPP Renewed. For example, the assumption of LADWP's share of generation is a constant between configurations.

There are several caveats surrounding the assumptions mentioned above that must be iterated to fully comprehend the modeling of IPP Renewed. The projected IPP Renewed hydrogen volumes stated are for modeling purposes only and strictly reflect the technical requirements for the fuel supply to IPP, that are required to achieve 100%

carbon-free energy in alignment with local mandates and state policies. Currently, there is low probability that the paths for achieving the goals stated, especially for the "100% by 2035" and "Limited Resource Availability" configurations, will be producible. Numerous challenges in the production, storage, and transportation of green hydrogen have reduced the prospect of providing sufficient volume to support operation at percentages above 30%. In addition, the available power generation technology has yet to demonstrate capabilities of burning hydrogen beyond the 30% by volume threshold, and turbine blade technology has not been developed to support 100% hydrogen combustion reliably. Even assumptions regarding operation at 30% volume are contingent on renewable energy availability for self-produced hydrogen generation, and currently, there are few renewables in LADWPs resource portfolio that can supply the renewable energy needed to generate hydrogen in support of operation at 30% hydrogen by volume. The contingencies for running IPP Renewed on 30% hydrogen by volume continue, with the availability of interconnections for the renewable resources, and the expansion of H2 production and storage capabilities also having heavy implications for the continued use of IPP renewed within intended specifications. To summarize, the future usage of IPP Renewed is largely dependent on factors external to LADWP's control, and LADWP must maintain caution and awareness of those factors if it is to operate IPP Renewed as intended.

3.1.9 In-Basin Generation Modeling Parameters + Apex

Table 3-8. Generation Modeling Parameters for In-Basin Units + Apex

Variable	Description
Unit	The name of the generating unit being referenced
Type	The type of turbine used for generation (i.e. Simple Cycle, Combined Cycle, Boiler, etc.)
Start Date	The date the unit began commercial operation
Retire Date	The date of the units intended retirement
Econ Max (MW)	The maximum capacity a unit is capable of generating
High Temp Econ (MW)	The maximum capacity of a unit during high temperatures conditions affecting unit operation
Econ Min (MW)	The minimum capacity a unit must generate when operating
Heat Rate (Btu/kWh) @ Econ Max	The heat rate of a unit operating at its econ max (MW)
Heat Rate (Btu/kWh) @ Econ Min	The heat rate of a unit operating at its econ min (MW)
Startup Cost ($)	The cost of starting up the unit from a 'cold' state
Min Up Time (Mins.)	The minimum amount of time the unit must operate upon starting
Min Down Time(Mins.)	The minimum amount of time the unit must rest after shutting down before starting again
Ramp Up (MW/min)	The rate at which the unit reaches can increase its capacity
Ramp Down (MW/min)	The rate at which the unit reaches can decrease its capacity
VOM ($/MWh)	Variable Operation & Maintenance Cost - $ cost of operating the unit for every MWh of energy produced by its operation
FOM ($/hr)	Fixed Operations & Maintenance Cost - $ cost of operating the unit for every hour it is online regardless of energy
EFOR (%)	Equivalent Forced Outage Rate - The % amount of time the unit is offline in a year due to unforseen outages
Maximum Startups per Day	The maximum number of startups the unit can make per day

The generation and modeling parameters for In-Basin units + Apex encompass the major parameters required in the standard operation of the thermal generating units listed in the Generation Ratings and Capabilities Table (Table 3-13 through Table 3-15). The data encompassing these assumptions is considered confidential, as it reflects the operating

parameters of existing thermal generation. However, a list of the variables provided through this is assumption is available in Table 3-8.

3.1.10 In-Basin Generation Transformation-100% by 2035

Table 3-9. Transformation Schedule of In-Basin Generating Units to achieve 100% Carbon-Free Energy by 2035

Expected in-basin green hydrogen-ready capacity (MW)				
Generating Station	**2030**	**2035**	**2040**	**2045**
Haynes	0	1,594	1,594	1,594
Scattergood	337	852	852	852
Harbor	0	460	460	460
Valley	0	576	576	576
Cumulative Total	**337**	**3,482**	**3,482**	**3,482**

LADWP is committed to transforming its in-basin generating units to achieve a 100% carbon-free energy system by 2035, as shown on Table 3-9. A key component of this strategy is the modernization of the Scattergood Generating Station and Haynes Generating Station Units 1 and 2. The proposed project involves constructing a rapid response combined-cycle generation system capable of operating on a fuel mixture of natural gas and at least 30% green hydrogen by volume, with the potential to transition to 100% green hydrogen in the future. This initiative aims to enhance fuel efficiency, reduce greenhouse gas emissions, and eliminate the use of ocean water for cooling.

The Scattergood modernization is integral to LADWP's broader plan to deploy firm capacity resources utilizing renewably derived hydrogen fuel, enabling LADWP to meet future peak demands and support the accelerated buildout of clean energy projects. These efforts are guided by the LA100 Plan, which outlines pathways for LADWP to achieve reliable 100% carbon-free energy as early as 2035.

3.1.11 In-Basin Generation Transformation-100% by 2040

Table 3-10. Transformation Schedule of In-Basin Generating Units to achieve 100% Carbon-Free Energy by 2040

Expected in-basin green hydrogen-ready capacity (MW)				
Generating Station	**2030**	**2035**	**2040**	**2045**
Haynes	0	444	1,594	1,594
Scattergood	337	337	852	852
Harbor	0	240	460	460
Valley	0	0	576	576
Cumulative Total	**337**	**1,021**	**3,482**	**3,482**

LADWP is pursuing a long-term transformation of its in-basin generating units as part of its commitment to achieving 100% carbon-free energy by 2035. As part of the LA100 Plan's exploration of potential risks to the clean energy transition, one sensitivity considered the possibility that renewable resource availability may fall short of the levels required to meet the accelerated 2035 target, resulting in a 5-year delay in fully decarbonizing the Power System.

In such a scenario, LADWP would likely need to extend the timeline for achieving a 100% carbon-free energy portfolio, potentially shifting the goal to 2040. The schedule for transforming in-basin generating units seen in Table 3-10, encompasses this extension, with modernized generating units coming online as late as 2040. The transformation logistics remain the same, involving retiring or repowering aging natural gas plants with cleaner, more flexible technologies that can support a renewable-heavy grid. Central to this effort is the shift toward green hydrogen-ready facilities, such as the planned modernization of the Scattergood, Haynes, Harbor, and Valley Generating Stations. These upgraded units will initially operate on a blend of natural gas and green hydrogen, with the goal of transitioning to 100% green hydrogen as the technology becomes more viable and supply scales up, in this instance, at a slightly slower pace than expected.

3.1.12 In-Basin Generation Transformation-100% by 2045

Table 3-11. Transformation Schedule of In-Basin Generating Units to achieve 100% Clean Energy by 2045

Expected in-basin green hydrogen-ready capacity (MW)				
Generating Station	**2030**	**2035**	**2040**	**2045**
Haynes	0	0	0	0
Scattergood	337	337	337	337
Harbor	0	0	0	0
Valley	0	0	2,037	2,037
Cumulative Total	**337**	**337**	**2,374**	**2,374**

While LADWP is committed to achieving a 100% carbon-free energy portfolio by 2035, it is important to evaluate this target against a baseline scenario. The SB100 Benchmark was modeled to reflect minimum compliance with California Senate Bill 100, which requires all retail electricity sales to be served by clean energy resources by 2045. This case serves as a benchmark for comparing key outcomes such as system costs, emissions, and reliability.

As detailed in Section 3.1.1, the SB100 Benchmark assumes that LADWP's in-basin generating units remain fueled by natural gas and are not converted to hydrogen. Table 3-11, shown above, presents the associated transformation schedule. Under SB 100, limited dispatch of natural gas resources is allowed to account for system losses during electricity delivery. As a result, the need for in-basin dispatchable generation buildout is significantly reduced, along with the corresponding capital costs and infrastructure requirements.

It should be noted that SB 100 allows for retaining natural gas capacity for back up purposes and to serve system losses.

3.1.13 In-Basin Generation Transformation-No Combustion

Table 3-12. Transformation Schedule of In-Basin Generating Units to achieve 100% Carbon-Free Energy by 2035 with No In-Basin Combustion

Expected in-basin green hydrogen-ready capacity (MW)				
Generating Station	**2030**	**2035**	**2040**	**2045**
Haynes	0	1,594	1,594	1,594
Scattergood	337	852	852	852
Harbor	0	460	460	460
Valley	0	576	576	576
Cumulative Total	**337**	**3,482**	**3,482**	**3,482**

LADWP has evaluated scenarios involving the elimination of in-basin combustion to achieve a 100% carbon-free energy system. The LA100 Plan explored "No In-Basin Combustion" alternatives, which would rely heavily on renewable energy sources, energy storage, green hydrogen fuel cells, and extensive transmission upgrades. Specifically, this sensitivity was modeled by replacing the green hydrogen-capable capacity that appears in the LA100 Pathway as combustion turbines, with fuel cells instead (Table 3-12). It must be emphasized however that currently, this technology is not available at scale. The No In-Basin Combustion sensitivity highlights the need for firm, dispatchable in-basin generation to ensure grid stability and the analysis underscores the importance of incorporating flexible resources, like green hydrogen-ready facilities, to support the transition to a carbon-free energy future while maintaining system reliability.

3.1.14 Power System Generation Ratings and Capacities

LADWP is the largest municipal utility in the United States, and its capacity is derived from a diverse portfolio of power sources, including natural gas-fired generating stations, hydroelectric facilities, and renewable energy projects. The LADWP Generation Ratings and Capacities of Power Sources document shows key information for LADWP-owned generating facilities of different types, including hydroelectric, pumped storage, in-basin thermal, external energy resources, wind, solar, and energy storage. Key information in this document includes names and generating unit numbers, the date that a facility first carried system load, generator nameplate ratings, net maximum unit capacities, net maximum plant capacities, and net dependable plant capacities, supported by detailed and individualized footnotes. This document was put together by LADWP's Generating Stations and Facilities Engineering section and is updated annually.

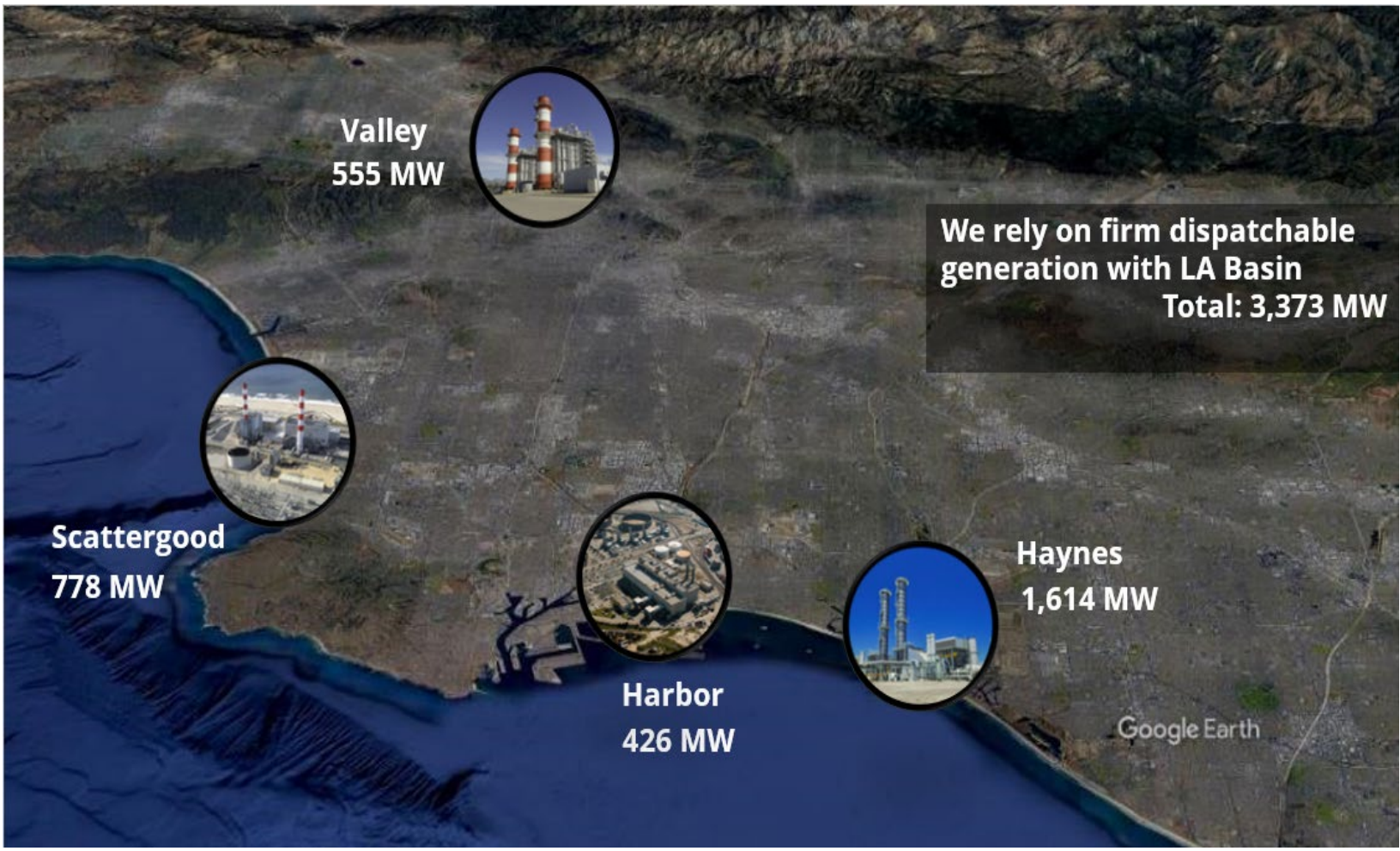


Table 3-13. 2024 LADWP Generation Ratings and Capacities of Power Sources chart (1 of 3)

Los Angeles Department of Water & Power

CITY OF LOS ANGELES - DEPARTMENT OF WATER AND POWER

GENERATION RATINGS AND CAPACITIES OF POWER SOURCES [1]

(Based on Information Available as of January 26, 2024)

HYDROELECTRIC							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Upper Gorge Power Plant	1	06/15/1953	37,500	37,500	36,500	[A] 110,500	32,267
Middle Gorge Power Plant	1	05/11/1952	37,500	37,500	37,500		
Control Gorge Power Plant	1	04/01/1952	37,500	37,500	37,500		
Pleasant Valley Power Plant	1	02/05/1958	4,000	3,200	2,700	2,700	[E][F] 2,563
Big Pine Power Plant	1	07/29/1925	4,000	3,200	3,050	[B] 3,050	
Division Creek Power Plant	1	03/22/1909	750	600	680	680	
Cottonwood Power Plant	1	11/13/1908	937	750	1,200	[C] 1,800	
	2	10/13/1909	937	750	1,200		
Haiwee Power Plant	1	07/18/1927	3,500	2,800	2,500	[D] 3,600	
	2	07/18/1927	3,500	2,800	2,500		
San Francisquito Power Plant 1	1A	12/10/1983	25,000	22,500	27,000	[G] [H] 61,000	[K] 29,473
	3	04/16/1917	11,720	9,962	11,000		
	4	05/21/1923	12,500	10,625	12,000		
	5A	04/09/1987	25,000	22,500	27,000		
San Francisquito Power Plant 2	1	07/06/1919	17,500	14,000	0		
	2	08/07/1919	17,500	14,000	14,400		
	3	12/02/2006	20,000	18,000	16,000		
San Fernando Power Plant	1	10/22/1922	3,500	2,800	3,250	[I] 6,000	
	2	10/22/1922	3,500	2,800	3,000		
Foothill Power Plant	1	10/06/1971	11,000	8,800	8,600	[J] 8,600	
Franklin Power Plant	1	06/03/1921	2,500	2,000	2,000	2,000	
Sawtelle Power Plant	1	06/05/1986	711	640	650	650	
North Hollywood Pumping Station	1PT2	01/01/1993	2,025	1,800	1,800	4,300	[L] 0
	1PT3	01/01/1993	2,025	1,800	1,800		
	3T1	01/01/1993	584	500	500		
	3T2	01/01/1993	231	200	200		
TOTAL HYDROELECTRIC						204,880	64,303

PUMPED STORAGE							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Castaic Power Plant	1	07/11/1973	287,500	271,000	270,500	[M] 1,265,000	[N] 1,265,000
	2	07/09/1974	287,500	271,000	270,500		
	3	07/13/1976	287,500	271,000	270,500		
	4	06/16/1977	287,500	271,000	270,500		
	5	12/16/1977	287,500	271,000	270,500		
	6	08/11/1978	287,500	271,000	270,500		
	7	01/27/1972	70,000	56,000	51,500		
TOTAL PUMPED STORAGE						1,265,000	1,265,000

Table 3-14. 2024 LADWP Generation Ratings and Capacities of Power Sources chart (2 of 3)

EXTERNAL ENERGY RESOURCES							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Intermountain Generating Station	1	06/09/1986	991,000	950,000	900,000	1,202,000	[V] 1,175,200
	2	04/30/1987	991,000	950,000	900,000		
Palo Verde Nuclear Generating Station	1	01/30/1986	1,559,100	1,413,190	1,333,000	386,690	[W] 380,300
	2	09/19/1986	1,559,100	1,413,190	1,336,000		
	3	01/19/1988	1,559,100	1,413,190	1,334,000		
Apex Generating Station	1A	03/28/2014	239,000	203,150	168,075	577,500	[X][Y] 482,600
	1B	03/31/2014	239,000	203,150	168,075		
	STG	03/28/2014	264,000	237,600	229,879		
Hoover Power Plant	(Energy purchased from WAPA through Sep 2067) [Z]					496,000	269,700
TOTAL EXTERNAL ENERGY RESOURCES						2,662,190	2,307,800

SYSTEM SUMMARY		
SYSTEM SUBTOTAL NET CAPACITY AND ENTITLEMENTS	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Subtotal Net Capacity of the System	7,505,520	6,828,103
California Department of Water Resources (CDWR) Entitlement [AA]	(120,000)	(47,974)
TOTAL NET CAPACITY OF THE SYSTEM	7,385,520	6,780,129

WIND, SOLAR, AND ENERGY STORAGE							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Linden Wind Power Plant	1-25	6/30/2010	2,189	2,080	2,000	50,000	12,000
Pine Tree Wind Power Plant	1-90	6/14/2009	1,739	1,565	1,500	135,000	32,400
Adelanto Solar Power Plant	1-13	06/30/2012	800	800	800	10,000	2,800
Pine Tree Solar Power Plant	1-17	03/15/2013	500	500	500	8,500	2,380
Beacon Battery Energy Storage System	1-13	08/01/2018	2,083	1,695	1,667	[AB] 20,000	[AB] 20,000
TOTAL WIND, SOLAR, AND ENERGY STORAGE						223,500	69,580

IN-BASIN THERMAL							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Harbor Generating Station	1	01/31/1995	100,400	85,340	73,000	[O] 426,000	422,000
	2	01/31/1995	100,400	85,340	73,000		
	5	01/31/1995	93,750	75,000	60,000		
	10	01/04/2002	71,176	60,500	44,000		
	11	01/04/2002	71,176	60,500	44,000		
	12	01/04/2002	71,176	60,500	44,000		
	13	01/04/2002	71,176	60,500	44,000		
	14	01/04/2002	71,176	60,500	44,000		
Haynes Generating Station	1	09/02/1962	270,000	229,500	222,000	[P] 1,614,200	[Q] [R] 1,507,000
	2	04/07/1963	270,000	229,500	222,000		
	8	01/25/2005	311,000	264,350	250,000		
	9	01/25/2005	215,000	182,750	162,500		
	10	01/25/2005	215,000	182,750	162,500		
	11	06/11/2013	127,282	108,190	99,200		
	12	06/12/2013	127,282	108,190	99,200		
	13	06/12/2013	127,282	108,190	99,200		
	14	06/19/2013	127,282	108,190	99,200		
	15	06/12/2013	127,282	108,190	99,200		
	16	06/12/2013	127,282	108,190	99,200		
Scattergood Generating Station	1	12/07/1958	192,000	163,200	105,000	[S] 778,250	[T] 734,000
	2	07/01/1959	192,000	163,200	156,250		
	4	10/09/2015	255,200	216,920	206,000		
	5	11/15/2015	139,882	118,900	107,000		
	6	08/09/2015	125,765	106,900	102,000		
	7	09/23/2015	125,765	106,900	102,000		
Valley Generating Station	5	08/17/2001	71,176	60,500	44,000	555,000	[U] 528,000
	6	09/04/2003	215,000	182,750	155,000		
	7	09/09/2003	215,000	182,750	155,000		
	8	11/13/2003	311,000	264,350	201,000		
TOTAL IN-BASIN THERMAL (Based on natural gas fuel ratings)						3,373,450	3,191,000

Table 3-15. 2024 LADWP Generation Ratings and Capacities of Power Sources chart (3 of 3)

(1) Power sources included are LADWP's wholly-owned and operated in-basin gas-fired thermal, pump storage, small hydro (including North Hollywood Power Plant), wind (Pine Tree), solar (Pine Tree, Adelanto) generation, and battery storgage (Beacon). Also included are the following specific jointly-owned and operated power sources acquired through power purchase agreements (PPAs) or entitlements: coal-fired (Intermountain), nuclear-fueled (Palo Verde), gas-fired (Apex) thermal generation, large hydro generation (Hoover), and wind (Linden).

(2) Net Maximum Unit Capacity can be attained only when the weather and equipment are simultaneously at optimum conditions. Hydro power plants' Net Maximum Unit and Net Plant Capacity are values based on historical data, or benchmarking values based on water flow through the turbine. Net Maximum Unit and Plant Capacities for thermal units was determined from respective Unit Guide Sheets unless otherwise stated.

(3) Net Maximum Plant Capacity for hydro power plants is limited by water flow limits; for in-basin thermal generation and wind power plants, it is determined by the sum of the plant's Net Maximum Unit Capacity; and for external generation it is determined by LADWP's power purchase entitlement share.

(4) The Plant Net Dependable Capacity (NDC) reflects year-round output capability. The NDC for small hydro units are calculated from the last five years of net actual generation over the units' available hours. The NDC for the In-Basin generating stations are calculated from the top five highest peak load days for the years 2019-2023 where ambient temperatures exceeded 80 degrees Fahrenheit. The NDC for Scattergood Generating Station (SGS), Unit 2 and Haynes Generating Station (HnGS), Unit 1 was determined by the load limits placed on the units by the Energy Control Center/Plant Engineers due to equipment limitations. The NDC for SGS, Unit 1 was calculated utilizing available data during peak day conditions from 2019-2023. The NDC for HnGS, Unit 2 was derived from data following a major rotor repair completed in November 2019. The NDC for Apex Generating Station was determined from the latest Unit Guide Sheet (2021) for Summer. The NDC for Intermountain Generating Station (IGS) was determined by LADWP's historical share from the past five fiscal years. The plant NDC for the remaining External Generation PPAs reflect their associated agreements with LADWP. The plant NDC for the Wind, Solar, and Energy Storage reflect the resource assumptions provided by the 2017 Strategic Long-term Resource Plan (SLTRP). Wind and solar generation are not considered to be dispatchable and dependable. Net Dependable Plant Capacity reflects the amount of generating capacity that can be depended on during the peak demand hours of a day. Dependable capacity of a plant using a specific renewable technology is estimated by applying a Dependable Capacity Factor (DCF) to the plant nameplate capacity. Per the 2017 LADWP SLTRP, the DCF is 24% for wind and 28% for solar. Black start capability is not applicable for wind power

[A] Upper Gorge (UG) Power Plant is limited to 36.5 MW due to penstock losses. Owens Gorge Power Plants' Net Maximum Plant Capacity of 110.5 MW reflects a maximum generation output at UG of 35.5 MW, and 37.5 MW at Middle and Control Gorge Power Plants each when all three units are running. This is due to a lower effective head from a longer tunnel and venturi losses at UG to which the other two plants are not subjected. All the Owens Gorge Power Plants have black start capability, but cannot send power to the LA basin if the system was in a black out condition.

[B] Big Pine Power Plant's Net Maximum Unit Capacity is limited to a maximum flow through penstock.

[C] Cottonwood Power Plant, Units 1 and 2 were rewound to a higher Net Maximum Unit Capacity of 1.2 MW each. Net Maximum Plant Capacity is 1.8 MW due to limited maximum flow through the penstock.

[D] Net Maximum Unit Capacity for Haiwee Power Plant, Units 1 and 2, is 2.5 MW each when only one unit is running. However, when both units are running and feed is taken from North Haiwee Reservoir, the Net Maximum Plant Capacity is 3.6 MW. Haiwee Power Plant's Net Dependable Capacity is limited by Division of Safety of Dams (DOSD) reservoir level.

[E] Division Creek is out of service due to damage caused by a flash flood. Haiwee, Units 1 and 2 are on an outage for overhauls, inspections, and repairs. The Estimated Time of Restoration (ETR) for Haiwee, Unit 2 is June 2024. The ETR for Haiwee, Unit 1 is yet to be determined.

[F] Maximum unit and plant capacities are provided by Owens Valley Operations. None of the Haiwee, Cottonwood, Division Creek, Big Pine, and Pleasant Valley Power Plant units have black start capability.

[G] San Francisquito Power Plant 1 (PP1), Unit 3 rating is 60 Hz and 11,720 kVA instead of 50 Hz and 9,375 kVA as indicated on original nameplate. Unit 3 was rewound in 1980. Units 3 and 4 have black start capability. PP1 and San Francisquito Power Plant 2 (PP2) have a combined maximum net capacity of 61 MW due to downstream flow constraints.

[H] PP2, Unit 1 has been out of service since 1996. PP2, Unit 3 has a new generator rated at 18 MW with a refurbished turbine as of December 2, 2006. PP2, Unit 2 has black start capability. PP2 penstock is limited to 400 cfs. Due to penstock limitations, only Unit 3 is operated. Unit 2 is operated as a back-up to Unit 3.

[I] Net Maximum Plant Capacity for San Fernando Power Plant is 3.5 MW due to the main transformer being placed in open-delta configuration. One of the three transformers was removed because dissolved gases were detected. Plant has no black start capability.

[J] Foothill Power Plant Rated Output is 8,800 kW but is limited to 8,600 kW due to maximum flow through the penstock of 275 cfs. Plant has no black start capability.

[K] PP2, Unit 2 is on an outage due to broken windings. San Fernando, Unit 2 is on an outage for a major generator overhaul. Franklin is on an outage due to load controller problems. Sawtelle is on an outage due a dirty rotor.

[L] North Hollywood Pump Station (NHPS), Turbine 3T1 is rated for two different speeds (500kW and 200kW). NHPS has not generated since 2014, Water System is making future improvements/changes to the units, and plan to keep them in operation.

[M] Castaic Power Plant's Net Maximum Plant Capacity is limited by the maximum flow through Angeles Tunnel. Based on the latest test conducted in November 2011, Net Maximum Plant Capacity was rated at 1,265 MW at nominal hydraulic head of 1060 ft. Net Dependable Plant Capacity varies based on the Elderberry and Pyramid Lake water levels. The Castaic Power Plant units have completed modernization improvements as follows: Unit 2 in September 2004, Unit 6 in December 2005, Unit 4 in June 2006, Unit 5 in July 2008, Unit 3 in July 2009, Unit 1 in October 2013, and Unit 7 in August 2016. CPP Units 1-6 have black start capability.

[N] Castaic Power Plant's Net Dependable Plant Capacity is limited by the flow through Angeles Tunnel. Unit 7 is unavailable as a generator and synchronous condenser, and is used for pump start and station service power supply. Unit 5 is unavailable until April 2024 due to a major overhaul.

[O] Harbor Generating Station (HGS), Units 1 and 2 Net Maximum Capacity is approximately 73 MW each due to gas turbine wear. Units 12 and 13 have black start capability.

[P] Per the Unit Guide Sheet, HnGS, Units 11-16 can each attain a Net Maximum Unit Capacity of 99.2 MW when all six units are operating simultaneously, as this creates the lowest average auxiliary power being drawn per unit. HnGS, Units 3 and 4 were decommissioned in September 2004 and November 2003, respectively. HnGS, Units 5 and 6 were decommissioned in June 2013. None of the HnGS units have black start capability.

[Q] The NDC for HnGS, Unit 1 currently has a limit of 200 MW due to high stator temperatures on the boiler feed pumps. Unit 2 is currently out of service for a turbine blade repair with an ETR

[R] HnGS Net Dependable Plant Capacity includes operating Units 9 and 10 with duct burners running.

[S] SGS, Unit 1 was derated to a gross capacity of 111.8 MW as part of the Unit 3 Repowering Project, and operates at a net maximum capacity of 105 MW. The Net Max Capacity of the combined cycle is reduced by 2 MW when Unit 4 is run in a 1+1 configuration with Unit 5. None of the SGS units have black start capability.

[T] The NDC for SGS, Unit 2 is limited due to low forced draft air fan flow.

[U] Valley Generating Station (VGS) Net Dependable Plant Capacity includes operating Units 6 and 7 with duct burners running. Unit 5 has black start capability.

[V] The LADWP entitlement for Intermountain Generating Station (IGS) is 44.617% direct ownership, plus a 4% purchase from Utah Power & Light Company (UP&L), plus 86.281% of up to 21.057% of muni's and co-op's recallable entitlement, which can vary. IGS Net Dependable Plant Capacity is determined by applying the average historical share from the past five fiscal years to the actual net max plant capacity (1,800,000 kW). None of the Intermountain Generating Station's units have black start capability.

[W] LADWP's entitlement is 9.66% of generation comprised of 5.7% direct ownership in Palo Verde Nuclear Generating Station and another 67% power purchase of Southern California Public Power Authority's (SCPPA's) 5.91% ownership of Palo Verde. Units 1, 2, and 3 Design Electrical Rating is used for Net Maximum Unit Capacity.

[X] Apex Generating Station's Net Dependable Plant Capacity includes operating Units 1A and 1B with duct burners running. Units 1A and STG were originally placed in-service by the original owner on January 13, 2003, and Unit 1B on January 20, 2003. None of the Apex Generating Station's units have black start capability.

[Y] SCPPA took ownership of Apex Generating Station on March 26, 2014 and maintains a sales agreement for the station's generated power. LADWP's entitlement is 100% of Apex Generating Station's power produced.

[Z] LADWP has a power purchase agreement with the United States Department of Energy Western Area Power Administration (WAPA), the Balancing Authority, for Hoover Power Plant. LADWP's entitlement through September 2067 is 23.9% of the total contingent capacity (2,074 MW) and 14.7% of Firm Energy (approximately 663,283 kWh). Hoover Power Plant output constantly varies due to lower water levels at Lake Mead resulting from the drought conditions.

[AA] The maximum California Department of Water Resources (CDWR) Entitlement from Castaic Power Plant is 120 MW. This amount varies weekly. The average for FY22-23 was approximately 47.97 MW.

[AB] Beacon Battery Energy Storage System (BESS) provides frequency support and can discharge 10 MWh, therefore, 20 MW can only be achieved for 30 minutes. Per warranty guidelines, Beacon BESS can fully charge and discharge once per day. The charge/discharge schedule is set by the Energy Control Center. Of the 13 units at Beacon BESS, 12 units regularly operate, and one unit is a reserve. When the reserve unit is in operation, the net maximum plant capacity does not increase.

3.1.15 Energy Efficiency

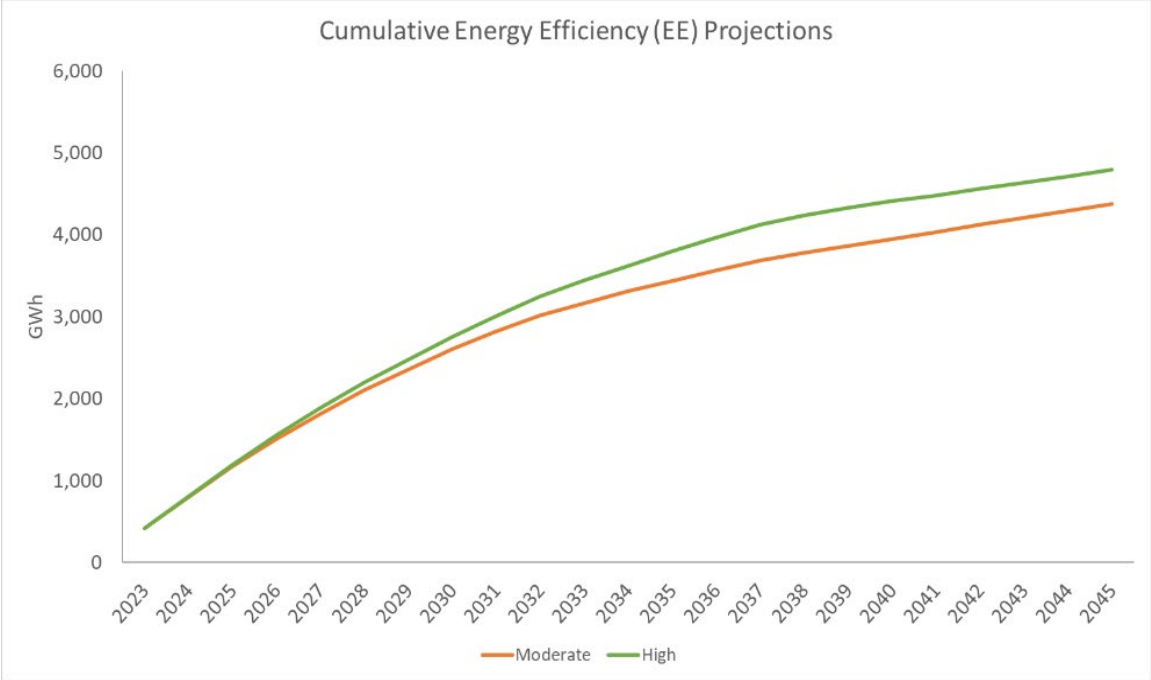


Figure 3-5. Forecasted Energy Efficiency Growth (in GWh)

The projections shown above (Figure 3-5) forecast the cumulative levels of energy savings in LADWP's service area due to energy efficiency programs. The projections have two levels of cumulative energy efficiency, "Moderate" and "High", which were determined by subject matter experts internally. The "Moderate" projection assumes that LADWP only offers currently existing and planned energy efficiency incentives throughout the forecasted period. The "High" projection assumes that the number of planned energy efficiency incentives and programs increases beyond current estimates to maximize peak demand reduction. In the modeling, the "Moderate" and "High" projection were used in the SB100 Benchmark and LA100 Pathway scenarios respectively, while being used more diversely in the sensitivities modeled depending on established assumptions.

3.1.16 Building Electrification

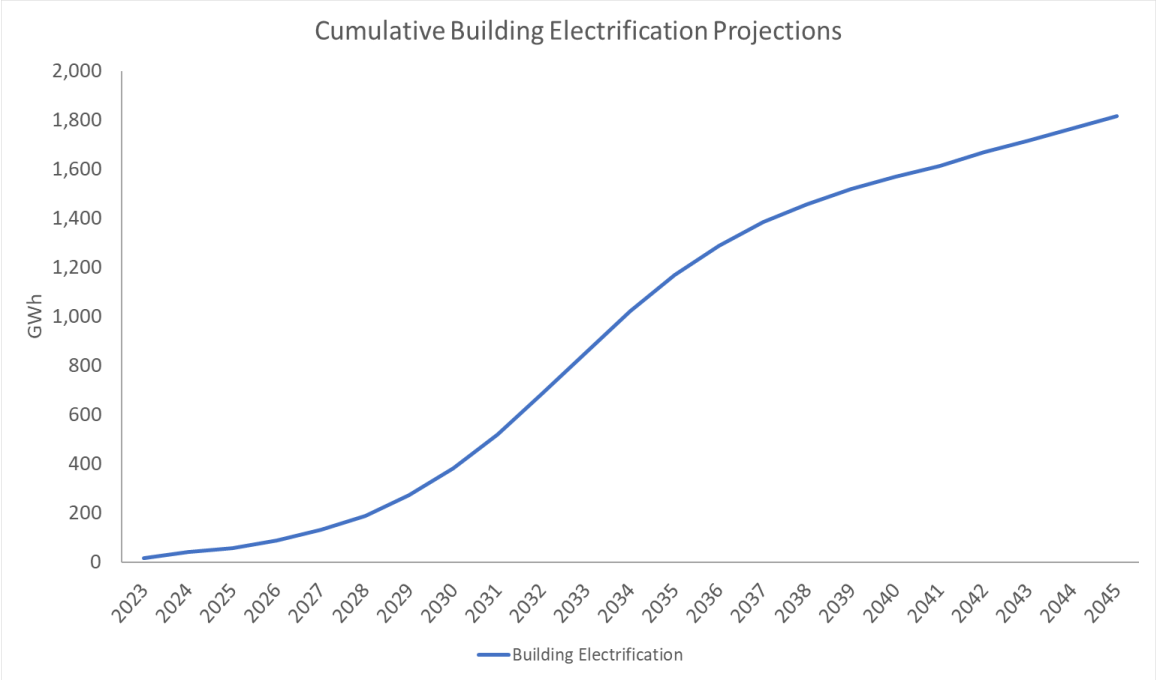


Figure 3-6. Forecasted Building Electrification Growth (in GWh)

The projection shown above (Figure 3-6) forecasts the cumulative yearly load growth in LADWP's service area due to building electrification. In this LA100 Plan, only one projection for building electrification was forecasted based on assumptions calculated by subject matter experts internally. The forecast assumes building electrification will increase substantially over the study horizon.

3.1.17 Demand Response

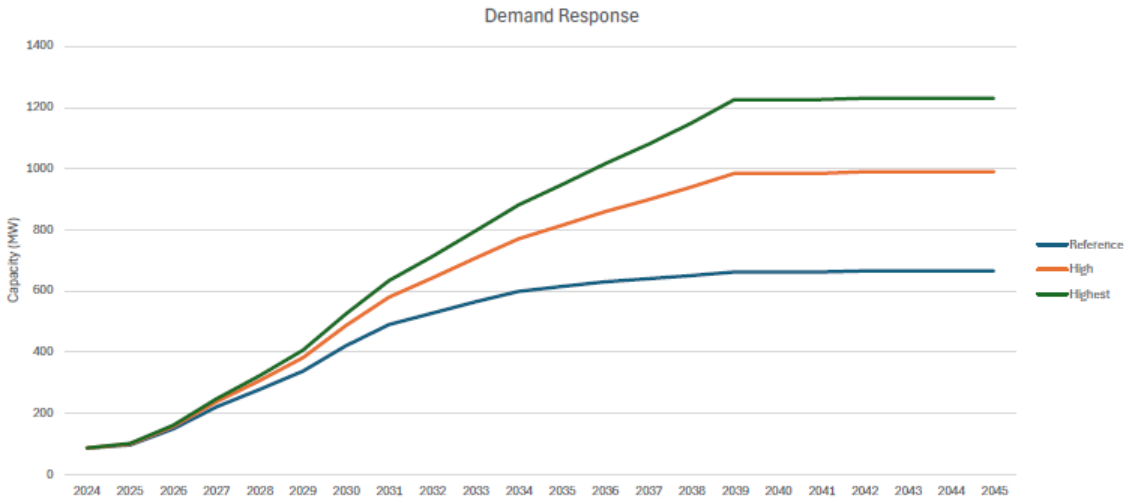


Figure 3-7. Forecasted Demand Response Capacity Growth (in MW)

LADWP offers a Demand Response (DR) Program, an incentive-based, voluntary energy management initiative designed to help commercial and industrial customers reduce their electricity usage during peak demand periods, thereby enhancing grid reliability and lowering utility bills. Participation in the DR Program not only yields cost savings but also contributes to environmental sustainability by reducing greenhouse gas emissions and supporting the integration of renewable energy sources. The levels of demand response (Reference, High, and Highest) shown above (Figure 3-7) cumulatively reflect both the existing and planned capacities. It must be noted that DR operates under specific criteria; therefore, it may not be available at all hours of the year as a resource. Like other DERs, DR also depends on customer participation.

3.1.18 Transportation Electrification

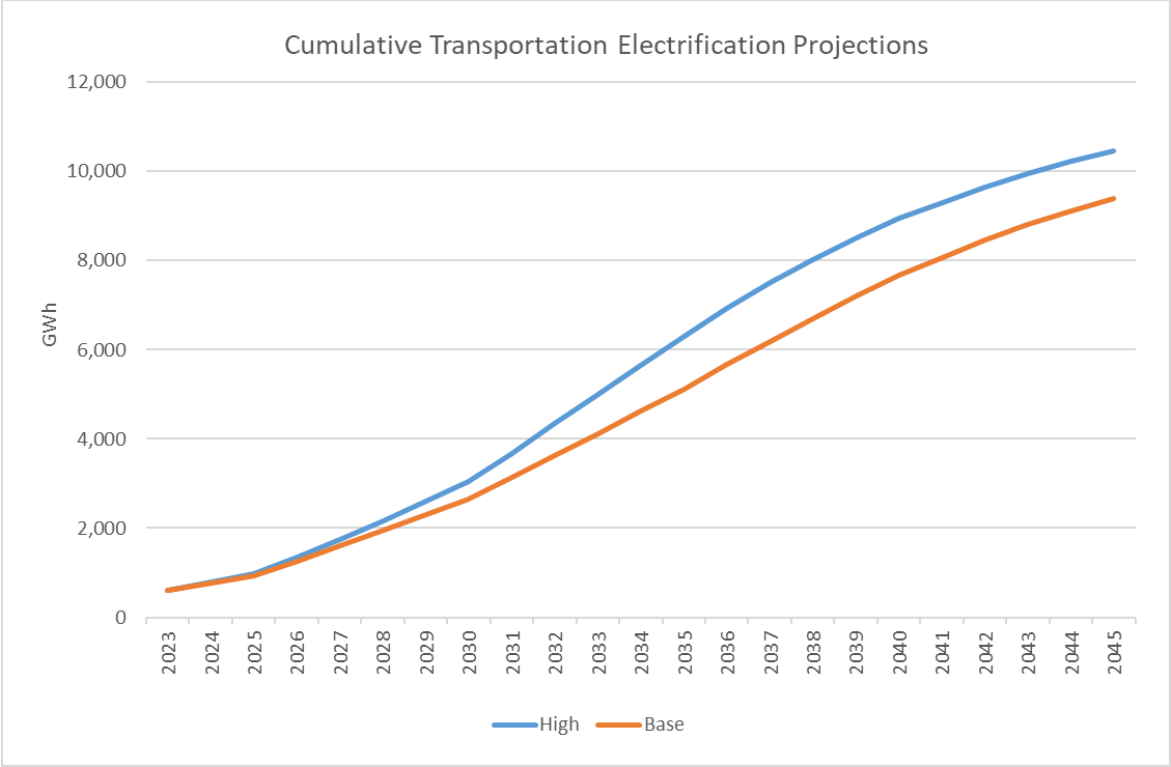


Figure 3-8. Forecasted Transportation Electrification Growth (in GWh)

The projection shown above (Figure 3-8) forecasts the cumulative yearly load growth in LADWP's service area due to transportation electrification. The "Base" projections were used for the LA100 Pathway and most of the sensitivities, with the exception of the "High Load" sensitivity which used the "High" projections for transportation electrification, based on assumptions made by subject matter experts internally. The forecasts assumes that transportation electrification will increase gradually due to the increased use of Light, Medium, and Heavy-Duty electric vehicles.

3.1.19 Renewable Energy & Energy Storage Price Forecast

Table 3-16. Forecasted Renewable Energy and Energy Storage Prices

All values in nominal $; Assume 3% annual inflation

Solar + Storage (50%)	Units	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Low	$/MWh	$71	$70	$69	$68	$67	$66	$65	$64	$64	$63	$62	$61	$62	$63	$65	$66	$67	$68	$69	$71	$72	$73
Base		$81	$79	$79	$79	$79	$79	$79	$79	$79	$79	$79	$79	$80	$82	$83	$85	$86	$87	$89	$90	$92	$93
High		$91	$92	$94	$95	$96	$97	$98	$99	$101	$103	$105	$107	$109	$111	$113	$115	$117	$119	$121	$123	$125	$127
Land-Based Wind		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Low	$/MWh	$46	$46	$46	$45	$45	$45	$44	$45	$46	$47	$47	$48	$49	$49	$50	$51	$52	$52	$53	$54	$55	$55
Base		$48	$49	$49	$50	$50	$51	$51	$52	$53	$54	$55	$57	$58	$59	$60	$61	$62	$63	$65	$66	$67	$68
High		$50	$51	$52	$54	$55	$56	$57	$59	$60	$61	$63	$64	$66	$67	$69	$70	$72	$73	$75	$77	$78	$80
Off-Shore Wind		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Low	$/MWh	$84	$83	$83	$82	$82	$82	$82	$83	$84	$84	$85	$86	$88	$89	$90	$91	$93	$94	$96	$97	$99	$101
Base		$94	$93	$93	$93	$94	$94	$95	$96	$97	$99	$100	$102	$103	$105	$107	$109	$110	$113	$115	$117	$119	$121
High		$116	$117	$118	$120	$122	$124	$126	$129	$131	$134	$137	$140	$143	$146	$149	$153	$156	$160	$164	$168	$172	$176
Geothermal		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Low	$/MWh	$96	$95	$95	$95	$95	$95	$95	$96	$96	$97	$97	$98	$100	$103	$105	$108	$111	$114	$117	$120	$123	$126
Base		$98	$99	$100	$101	$103	$104	$105	$107	$109	$111	$113	$115	$118	$121	$124	$127	$130	$134	$137	$141	$144	$148
High		$103	$106	$108	$111	$114	$117	$120	$123	$126	$130	$133	$136	$140	$144	$147	$151	$155	$159	$163	$167	$172	$176
4-Hr BESS (Li-Ion)		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Low	$/kW	$1,429	$1,397	$1,378	$1,356	$1,332	$1,305	$1,276	$1,291	$1,306	$1,321	$1,335	$1,349	$1,363	$1,376	$1,389	$1,402	$1,414	$1,425	$1,436	$1,447	$1,456	$1,465
Base		$1,933	$1,745	$1,739	$1,732	$1,722	$1,710	$1,696	$1,720	$1,744	$1,767	$1,791	$1,814	$1,837	$1,860	$1,883	$1,905	$1,927	$1,949	$1,970	$1,991	$2,011	$2,031
High		$2,198	$2,232	$2,213	$2,190	$2,165	$2,136	$2,103	$2,151	$2,200	$2,251	$2,302	$2,354	$2,408	$2,462	$2,518	$2,575	$2,633	$2,692	$2,752	$2,813	$2,876	$2,940
8-Hr BESS (Li-Ion)		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Low	$/kW	$2,589	$2,532	$2,497	$2,457	$2,413	$2,364	$2,311	$2,339	$2,367	$2,392	$2,418	$2,446	$2,469	$2,494	$2,517	$2,540	$2,560	$2,581	$2,604	$2,623	$2,638	$2,654
Base		$3,488	$3,140	$3,117	$3,089	$3,057	$3,020	$2,977	$3,016	$3,054	$3,091	$3,129	$3,165	$3,201	$3,236	$3,271	$3,305	$3,338	$3,370	$3,401	$3,431	$3,459	$3,487
High		$3,982	$4,042	$4,000	$3,951	$3,896	$3,834	$3,765	$3,851	$3,940	$4,030	$4,121	$4,215	$4,311	$4,408	$4,508	$4,610	$4,713	$4,819	$4,927	$5,037	$5,149	$5,263

Notes:
Prices from NREL's 2023 Electricity Annual Technology Baseline (ATB), with adjustments made to convert from 2021 $ to nominal $
Prices assumed from NREL ATB levelized cost of energy (LCOE) values, assuming the following resource "classes": Solar + Storage (50%) from Class 1, Land-based wind from Class 9, Off-shore Wind from Class 5
Geothermal prices calculated from an average LCOE of the Hydro/Flash and Hydro/Binary technologies
4-hr Battery Energy Storage System (BESS) (Li-Ion) derived from utility scale battery storage (4 hour) category
8-hr Battery Energy Storage System (BESS) (Li-Ion) derived from utility scale battery storage (8 hour) category

LADWP is actively planning for a transition to 100% carbon-free energy by 2035. The LA100 Plan serves as a comprehensive roadmap through 2035 that guides LADWP's efforts in this transition. While specific price forecasts for renewable energy and storage technologies are detailed in the document, the LA100 Plan incorporates cost projections and market dynamics (Table 3-16) to evaluate various strategies for achieving a clean energy future. These efforts aim to balance environmental goals with maintaining low and stable electric rates for customers.

3.1.20 Greenhouse Gas Emissions Allowance Prices

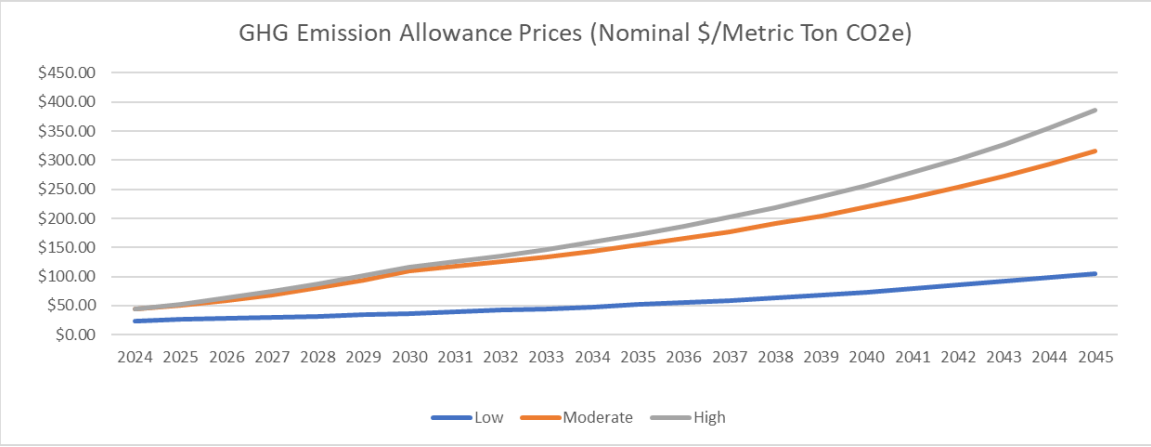


Figure 3-9. Forecasted Greenhouse Gas Emissions Allowance Prices

The price projections shown above in Figure 3-9 are the forecasted price of GHG emission allowances administered through the California Air Resources Board's (CARB) Cap-and-Trade Program. The allowances are used to regulate the emissions that any California utility emits in their operation by requiring that they purchase an allowance from a limited pool for every metric ton of CO_2 they release. The prices used in the model are based on forecasts developed by the California Energy Commission as a part of their Integrated Energy Policy Report (IEPR). IEPR forecasts presented a "Price Floor" and "Mid Price" scenario which have been approximated to the "Low" and "Moderate" level price growth in the LA100 Plan. Both the LA100 Pathway and SB100 Benchmark utilized the "Moderate" level price growth in the model. LADWP also developed a "High" price scenario derived from the IEPR which was used diversely in the sensitivities alongside the "Low" price scenario depending on sensitivity assumptions.

3.1.21 Natural Gas Price Forecast

LADWP utilizes natural gas price forecasts (Table 3-17 through Table 3-20) to inform its strategic planning and ensure cost-effective operations. LADWP incorporates these projections for gas prices into the LA100 Plan to evaluate various strategies for achieving a clean energy future while maintaining low and stable rates for customers. These efforts aim to balance environmental goals with economic considerations, ensuring reliable and affordable energy for LADWP customers.

Table 3-17. Natural Gas Price Forecast, In-Basin Monthly Cost in $/MMBTU (1 of 2)

SoCal Year	January	February	March	April	May	June	July	August	September	October	November	December
2024	5.90	5.61	4.80	4.49	3.20	3.66	5.09	5.82	5.34	4.97	6.59	8.55
2025	8.78	7.64	5.21	4.76	4.65	4.99	6.84	7.07	6.81	5.22	7.41	9.77
2026	8.47	7.77	5.90	5.05	5.05	5.23	6.76	6.81	6.64	5.84	7.81	9.17
2027	9.57	8.37	6.88	5.47	5.48	5.63	6.59	6.61	6.45	5.86	7.72	8.91
2028	9.11	8.46	7.04	5.47	5.48	5.62	6.36	6.39	6.23	5.69	6.97	7.58
2029	8.41	8.17	7.42	5.20	5.21	5.36	6.00	6.08	5.92	5.40	5.92	6.50
2030	8.23	8.04	7.24	5.13	5.13	5.29	5.82	5.91	5.74	5.29	5.92	6.51
2031	8.23	8.04	7.29	5.23	5.22	5.35	5.84	5.92	5.79	5.29	5.89	6.48
2032	8.14	7.93	7.18	5.16	5.15	5.30	5.83	5.91	5.78	5.27	5.76	6.33
2033	8.01	7.82	7.29	5.37	5.37	5.40	5.80	5.88	5.76	5.26	5.74	6.28
2034	7.94	7.78	7.39	5.49	5.49	5.52	5.92	6.00	5.88	5.38	5.82	6.20
2035	7.82	7.75	7.51	5.72	5.71	5.75	6.14	6.22	6.10	5.61	5.96	6.25
2036	7.90	7.84	7.59	5.82	5.81	5.84	6.24	6.32	6.20	5.71	6.05	6.35
2037	7.99	7.92	7.68	5.49	5.46	5.53	5.95	6.07	5.97	5.55	5.97	6.48
2038	8.43	8.27	7.85	5.72	5.68	5.76	6.17	6.29	6.20	5.81	6.18	6.67
2039	8.58	8.42	8.02	5.87	5.84	5.92	6.31	6.43	6.35	5.99	6.40	6.97
2040	9.02	8.83	8.36	6.36	6.33	6.39	6.75	6.86	6.77	6.41	6.80	7.37
2041	9.40	9.21	8.73	6.66	6.62	6.70	7.07	7.20	7.12	6.80	7.07	7.64
2042	9.63	9.44	8.96	6.74	6.68	6.79	7.19	7.35	7.29	7.01	7.20	7.83
2043	9.92	9.70	9.17	6.97	6.92	7.02	7.40	7.55	7.49	7.24	7.42	8.22

Table 3-18. Natural Gas Price Forecast, In-Basin Monthly Cost in $/MMBTU (2 of 2)

Opal-SoCal

Year	January	February	March	April	May	June	July	August	September	October	November	December
2024	5.33	5.10	3.88	3.60	2.68	2.94	3.60	3.78	3.63	3.54	5.34	8.32
2025	8.35	7.20	4.82	4.08	3.91	4.16	4.89	4.97	4.82	4.47	6.26	8.28
2026	8.20	7.66	5.42	4.34	4.05	4.30	5.17	5.27	5.08	4.63	6.26	7.99
2027	8.00	7.52	5.47	4.34	4.02	4.27	5.18	5.27	5.06	4.56	6.16	7.78
2028	7.79	7.32	5.39	4.30	4.00	4.23	5.08	5.15	4.96	4.50	5.97	7.47
2029	7.48	7.06	5.25	3.98	3.50	3.79	5.09	5.23	4.96	4.19	5.85	7.27
2030	7.33	6.94	5.21	3.91	3.38	3.69	5.07	5.21	4.93	4.17	5.83	7.18
2031	7.29	6.91	5.31	3.99	3.44	3.72	5.11	5.25	5.00	4.14	5.76	7.04
2032	7.13	6.74	5.21	3.92	3.34	3.66	5.15	5.29	5.04	4.11	5.59	6.81
2033	6.91	6.57	5.30	4.18	3.60	3.80	5.15	5.29	5.04	4.13	5.59	6.81
2034	6.88	6.55	5.41	4.30	3.74	3.93	5.27	5.41	5.16	4.26	5.65	6.67
2035	6.73	6.50	5.56	4.64	4.38	4.49	5.08	5.16	5.06	4.71	5.80	6.70
2036	6.81	6.59	5.66	4.70	4.45	4.55	5.14	5.23	5.13	4.77	5.88	6.77
2037	6.89	6.68	5.77	4.38	4.10	4.24	4.87	5.00	4.92	4.61	5.80	6.86
2038	7.35	7.05	6.00	4.57	4.29	4.44	5.07	5.21	5.13	4.82	5.60	7.56
2039	7.84	7.36	5.36	4.76	4.48	4.63	5.27	5.40	5.32	5.02	5.76	7.80
2040	8.22	7.70	5.63	5.35	5.08	5.21	5.83	5.94	5.86	5.54	6.13	8.19
2041	8.61	8.09	6.01	5.56	5.28	5.43	6.07	6.21	6.13	5.84	6.35	8.41
2042	8.84	8.32	6.24	5.62	5.32	5.50	6.18	6.35	6.28	6.03	6.45	8.56
2043	9.09	8.55	6.41	5.88	5.58	5.76	6.43	6.60	6.53	6.27	6.67	8.96

Table 3-19. Natural Gas Price Forecast, Out-Of-Basin Monthly Cost in $/MMBTU (1 of 2)

Apex

	January	February	March	April	May	June	July	August	September	October	November	December
2024	4.11	3.85	2.70	2.65	1.53	1.91	2.85	3.60	3.03	2.71	4.24	6.72
2025	6.92	5.84	3.53	2.79	2.70	3.06	4.95	5.22	4.90	3.40	5.17	6.95
2026	6.62	5.99	4.21	3.17	3.15	3.35	5.00	5.05	4.88	3.97	5.22	6.49
2027	6.69	6.05	4.31	3.49	3.48	3.65	4.67	4.71	4.55	3.87	5.19	6.29
2028	6.41	5.86	4.42	3.54	3.54	3.69	4.47	4.51	4.35	3.74	5.11	5.76
2029	5.92	5.68	4.89	3.28	3.27	3.44	4.32	4.39	4.25	3.83	5.05	5.65
2030	5.96	5.71	4.88	3.25	3.23	3.41	4.28	4.34	4.21	3.69	5.07	5.67
2031	5.97	5.71	4.94	3.35	3.32	3.48	4.31	4.36	4.26	3.69	5.06	5.67
2032	5.90	5.63	4.84	3.31	3.27	3.45	4.32	4.38	4.28	3.68	4.62	5.21
2033	5.72	5.48	4.91	3.55	3.51	3.58	4.33	4.39	4.29	3.69	4.04	4.60
2034	5.62	5.40	4.98	3.67	3.63	3.70	4.45	4.50	4.41	3.80	4.12	4.52
2035	5.46	5.34	5.07	3.89	3.85	3.92	4.63	4.69	4.60	4.03	4.26	4.56
2036	5.54	5.42	5.16	3.99	3.95	4.02	4.69	4.74	4.66	4.13	4.34	4.64
2037	5.57	5.45	5.19	3.69	3.63	3.73	4.35	4.44	4.39	3.99	4.28	4.79
2038	6.04	5.84	5.40	3.93	3.86	3.96	4.49	4.59	4.55	4.24	4.48	4.96
2039	6.17	5.97	5.55	4.13	4.07	4.17	4.69	4.79	4.75	4.46	4.66	5.21
2040	6.46	6.24	5.77	4.66	4.61	4.70	5.24	5.32	5.27	4.92	5.08	5.63
2041	6.89	6.67	6.19	4.97	4.90	5.01	5.51	5.61	5.58	5.31	5.36	5.91
2042	7.12	6.90	6.43	5.06	4.97	5.11	5.64	5.78	5.76	5.53	5.48	6.08
2043	7.36	7.11	6.60	5.34	5.26	5.39	5.89	6.01	6.00	5.79	5.73	6.50

Table 3-20. Natural Gas Price Forecast, Out-Of-Basin Monthly Cost in $/MMBTU (2 of 2)

Opal-Apex

Year	January	February	March	April	May	June	July	August	September	October	November	December
2024	4.14	3.91	2.69	2.41	1.49	1.75	2.41	2.59	2.44	2.35	4.14	7.11
2025	7.15	5.99	3.62	2.89	2.72	2.96	3.69	3.78	3.62	3.27	5.06	7.07
2026	7.00	6.45	4.23	3.15	2.86	3.11	3.98	4.07	3.89	3.44	5.06	6.79
2027	6.80	6.32	4.28	3.15	2.83	3.08	3.99	4.07	3.86	3.37	4.96	6.57
2028	6.58	6.12	4.20	3.11	2.81	3.04	3.88	3.96	3.76	3.31	4.77	6.26
2029	6.27	5.85	4.05	2.79	2.31	2.60	3.89	4.03	3.76	3.00	4.66	6.07
2030	6.13	5.73	4.02	2.72	2.19	2.50	3.87	4.01	3.74	2.98	4.63	5.98
2031	6.08	5.70	4.11	2.80	2.25	2.53	3.92	4.06	3.81	2.95	4.56	5.84
2032	5.92	5.54	4.02	2.73	2.16	2.47	3.95	4.10	3.84	2.92	4.39	5.61
2033	5.71	5.36	4.11	2.99	2.41	2.61	3.95	4.10	3.85	2.94	4.39	5.61
2034	5.68	5.35	4.21	3.11	2.55	2.74	4.07	4.22	3.96	3.06	4.46	5.47
2035	5.52	5.30	4.36	3.44	3.19	3.29	3.88	3.97	3.87	3.51	4.60	5.50
2036	5.61	5.39	4.47	3.51	3.26	3.36	3.95	4.03	3.94	3.58	4.69	5.57
2037	5.69	5.47	4.57	3.18	2.91	3.05	3.68	3.80	3.72	3.42	4.60	5.66
2038	6.15	5.85	4.80	3.38	3.10	3.24	3.88	4.01	3.93	3.63	4.41	6.36
2039	6.64	6.16	4.17	3.57	3.29	3.43	4.07	4.20	4.13	3.83	4.57	6.60
2040	7.01	6.49	4.43	4.15	3.88	4.01	4.63	4.74	4.66	4.34	4.94	6.98
2041	7.40	6.88	4.82	4.36	4.08	4.23	4.87	5.01	4.93	4.64	5.15	7.20
2042	7.63	7.11	5.04	4.42	4.12	4.30	4.98	5.15	5.08	4.83	5.25	7.35
2043	7.88	7.34	5.21	4.68	4.39	4.56	5.23	5.40	5.33	5.07	5.47	7.75

3.1.22 Green Hydrogen Price Forecast

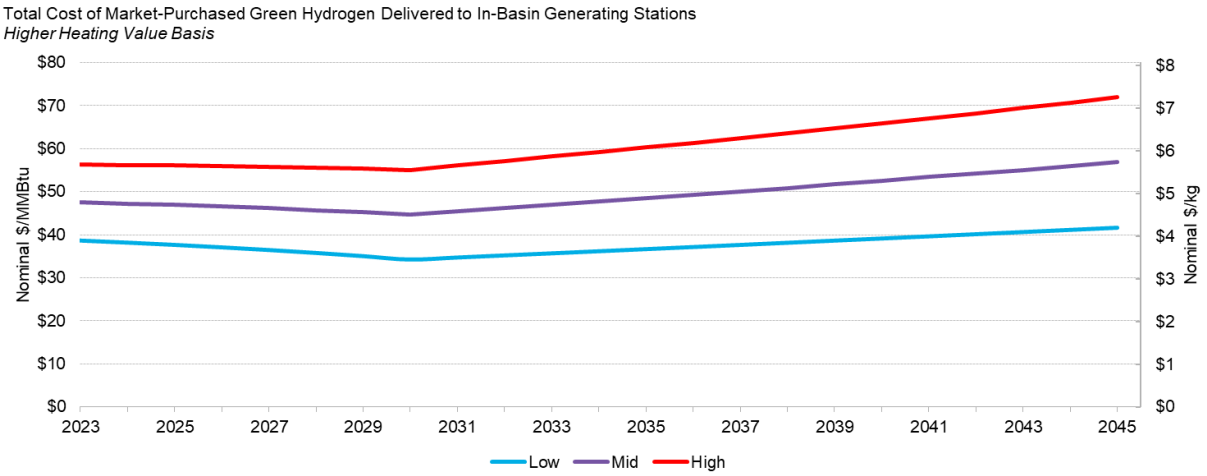


Figure 3-10. Forecasted Green Hydrogen Price

The price projections shown in Figure 3-10 reflect cost estimates for the purchase, storage, and delivery of market-supplied green hydrogen fuel to the in-basin hydrogen-capable gas turbines. The prices were derived from the assumption that green hydrogen for the in-basin generating units would need to be purchased from the market due to continuing investigation of the technical details for in-basin storage and production.

As highlighted in the previous section, Section 3.1.8 IPP Hydrogen Usage, certain configurations of IPP Renewed would also need to purchase hydrogen fuel from the market and utilize the same price forecast for those assumptions. The forecasts pricing ranges from "Low" to "High" price, but the "Mid" price is used for the LA100 Pathway and SB100 Benchmark while the former prices are used diversely among the sensitivities.

3.2 Modeling Methodology & Simulation In-Depth

LADWP contracted with a consultant, Ascend Analytics, to augment its existing computer modeling and simulation capabilities for this LA100 Plan. The primary software tool provided by Ascend Analytics is called PowerSIMM. This section describes in detail how PowerSIMM is used to inform stakeholders in the decision-making process.

PowerSIMM is a software program used for simulating the performance of an electric power system with high spatial and temporal granularity. PowerSIMM's three main

applications are for production cost modeling, capacity expansion optimization, and resource adequacy analyses. The PowerSIMM suite of software can be used to inform decision-making over a range of time-steps, from near-immediate decisions on bidding strategies and risk management to long-term resource planning and investment decisions about generation assets.

The overall modeling process is explained below (Figure 3-11).

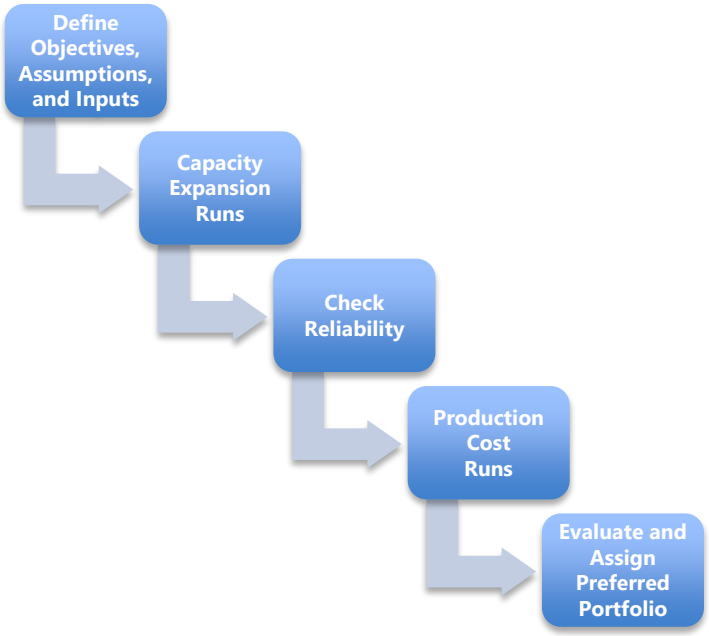


Figure 3-11. LA100 Plan Modeling Process.

3.2.1 Capacity Expansion

For the LA100 Plan, LADWP developed the forecasted resource portfolios to provide LADWP customers 100 percent carbon-free energy by 2035 using capacity expansion, resource adequacy, and production cost models in PowerSIMM. The three types of models play an important role in creating least-cost, reliable resource portfolios.

The process of developing resource portfolios for the LA100 Plan starts by defining the objectives, assumptions, and inputs for the capacity expansion model. Primary inputs for the capacity expansion model include the candidate resource options, price forecasts (power, natural gas, coal, carbon), and model constraints such as capacity needs, energy

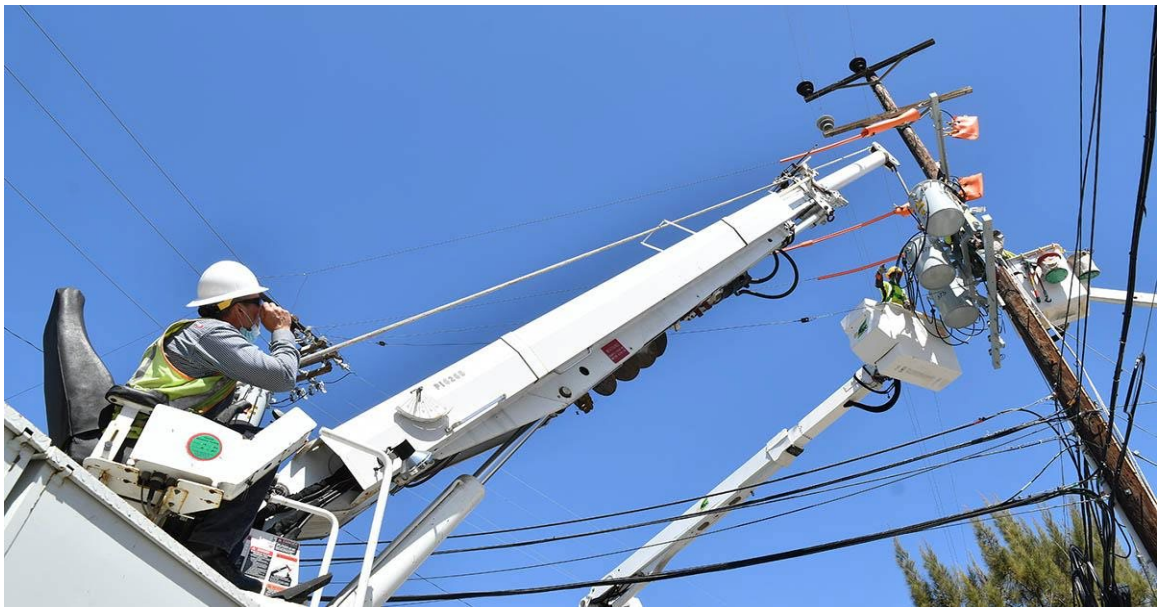
needs, and resource build limitations. The objective of capacity expansion modeling is to select a set of future resources which are capable of meeting the interim renewable portfolio standard targets and reaching 100 percent carbon-free energy by 2035.

Capacity expansion models provide a least-cost set of resources that meet the constraints defined in the model. Portfolio outputs from the capacity expansion models are then analyzed for resource adequacy. If a portfolio cannot adequately serve load, additional resources must be added. Finally, if portfolios are resource adequate, they are evaluated in a production cost model where they are analyzed to determine production costs and emissions, among other outputs.

The key inputs to the capacity expansion model are capacity values for renewable generation and duration-limited resources such as energy storage, the cost to build new resources, forecast of load, and constraints on carbon emissions. The effective load carrying capability (ELCC) is a measure of the contribution of a power generation asset to serving customer load. ELCC is used in capacity expansion models to adjust the capacity of renewable generation and storage, in order to reflect its ability to improve the reliability of the LADWP Power System. The capital cost to build new resources was developed using the 2023 NREL Electricity Annual Technology Baseline. The expected cost to build new resources is a significant factor in determining the least-cost portfolio. Expected customer load, electrification load, and demand side management programs were forecasted by LADWP and subsequently programmed as inputs for the capacity expansion model. For carbon emissions, there were two sets of constraints used: for the SB100 Benchmark, our system needed to meet 100% clean energy by 2045, and in the LA100 Pathway, our system needed to reach 100% carbon-free energy by 2035. The capacity expansion model takes this set of inputs and optimizes the least-cost portfolio to meet the goals of the LA100 Plan and to reliably serve customer load with 100% carbon-free energy by 2035. To achieve these goals, the LA100 Plan capacity expansion models set constraints on the capacity requirements of the overall generation portfolio, renewable generation, and clean energy. The capacity requirements ensure that the LADWP has sufficient capacity to meet customer load, even during extreme events. The renewable generation and clean energy constraints target the 2030 RPS goals and 100% carbon-free energy by 2035. After selecting the least-cost portfolio for the LA100 Pathway and SB100 Benchmark, the portfolios are assessed for resource adequacy.

3.2.2 Reliability

Resource adequacy models are used to understand a power system's ability to meet demand. To meet the LA100 Plan goal of maintaining reliability though the transition to 100% carbon-free energy, a baseline of the current reliability metrics for LADWP needed to be set. The resource adequacies of the LA100 Plan were modeled for every fifth year starting with 2025. Through resource adequacy modeling, LADWP showed that the LA100 Plan was able to maintain reliability while transitioning to 100% carbon-free energy. Understanding that the LA100 Plan achieved sufficient reliability, the final phase of the analysis moved to running the production cost models.



3.2.3 Production Cost Modeling

The production cost modeling phase of the LA100 Plan was used to quantify how the LADWP Power System was dispatched hourly to serve customer load, as well as assess the costs associated with operating our existing and future Power System. The outputs from the production cost models were used to calculate metrics such as the total system cost, renewable generation, clean energy generation, carbon emissions, and other figures. In addition to running models for the LA100 Pathway and SB100 Benchmark, sensitivities were considered such as high and low load, as well as no in-basin hydrogen supply, among others. These sensitivities investigated the dispatch of potential LADWP generation changes in order to meet the demands of our system during different load

futures, or circumstances where green hydrogen is not available in-basin to be used as a carbon-free fuel.

A key feature of the PowerSIMM platform is its simulation engine—the bedrock of any power system model—which explicitly captures the relationships observed in historical data and the correlations among key variables, including geographic and temporal relationships (autocorrelation). The PowerSIMM simulation engine first trains its models on historical data for key variables—weather, loads, renewable generation, and power and fuel prices—using time-series regression techniques. The models use relevant inputs, such as weather for load or renewables, to simulate future values with added calibrated, stochastic terms that create a realistic range of future conditions. This method produces simulations of future conditions whose variation and correlations are meaningful because they are based on information from historical conditions but are not limited to historical data. The objective of simulating future conditions that fall outside of historical observations (hotter days in the summer, colder days in the winter) allow for power system models that include events and conditions that have not occurred before.

The PowerSIMM platform applies the regression techniques described above to simulations at hourly and sub-hourly time-steps. Simulations of load, renewables, and prices that maintain key structural relationships provide an understanding of the operating characteristics of the types of generation resources that are increasingly common—resources like wind and solar whose variable output is driven by the weather, and flexible resources like battery energy storage that can respond rapidly to changing system conditions.



Chapter 4

Modeling Results

Key Highlights

- Accelerated Decarbonization: Establishes LADWP's roadmap to achieve a fully carbon-free power system by 2035, surpassing state mandates by ten years
- Balanced Investments: Expands renewables, storage, transmission, and distributed energy to ensure reliability and equity
- Resilient Strategy: Modeling shows the plan remains reliable and cost-effective across economic, load, and climate scenarios


JOHN FERRARO
BUILDING

4.1 LA100 Modeling Results

The LA100 Pathway—originally identified as Case 1 in LADWP's 2022 Power Strategic Long-Term Resource Plan (SLTRP)—was approved by Power System Management and presented to the LADWP Board of Commissioners as the official pathway to achieving the Los Angeles City Council's directive for 100% carbon-free energy by 2035. This directive goes beyond the requirements of California's SB 100 by mandating that all electricity, including that used to cover transmission and distribution losses (line losses), must come from carbon-free sources. In contrast, SB 100 applies only to retail electricity sales and allows for compliance by 2045.

The LA100 Pathway sets a more aggressive timeline and broader scope. It commits LADWP to delivering 100% carbon-free energy by January 1, 2035, a full decade ahead of SB 100's deadline. In addition, the pathway establishes an interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

By 2035, the LA100 Pathway also aims to deploy:

- 1,898 MW of local distributed solar,
- 3,794 GWh of cumulative energy efficiency savings (relative to 2023 base year),
- 331 MW of distributed energy storage, and
- 815 MW of demand response capacity.

These targets represent a comprehensive and locally focused approach to decarbonizing Los Angeles' electricity supply while enhancing system reliability, equity, and resilience.

4.1.1 Capacity Expansion

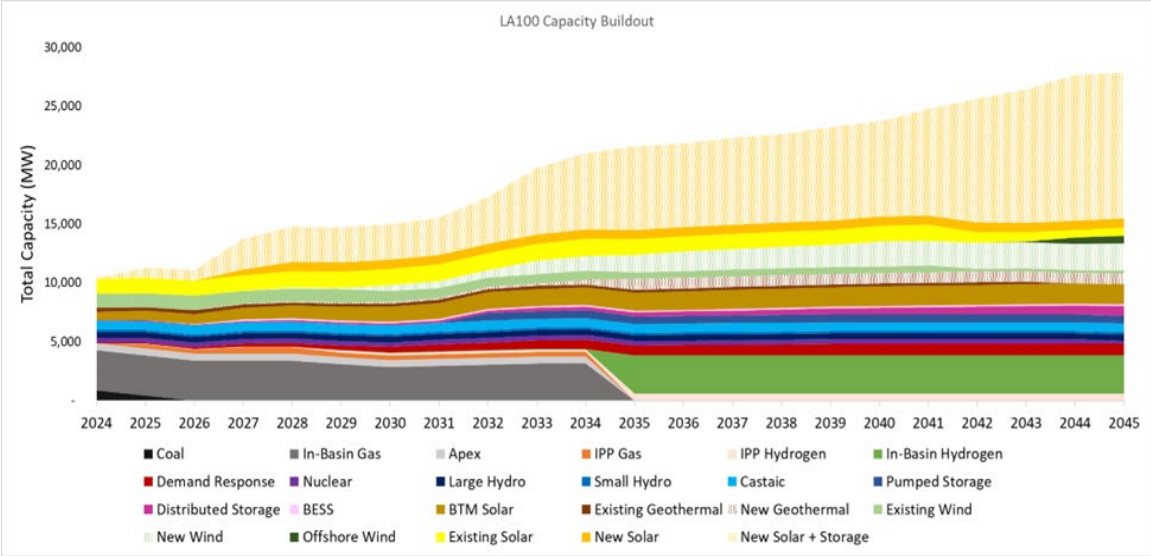


Figure 4-1. The LA100 Pathway requires significant additions of new solar paired with storage, green hydrogen, and wind resources (including offshore) to achieve 100% carbon-free electricity by 2035. Coal generation is fully retired by 2025, and all natural gas-fueled generation is either retired or converted to green hydrogen by 2035. The buildout also includes incremental additions of geothermal and other firm renewable resources to provide reliability and balance variable renewable generation.

The LA100 Pathway requires a substantial buildout of clean energy resources to meet Los Angeles' goal of delivering 100% carbon-free electricity by 2035. As shown in Figure 4-1, the transition is driven by major additions of new solar paired with storage, green hydrogen, and wind power, including both onshore and offshore resources. LADWP's coal-fired generation is fully retired by 2025, marking a critical early milestone.

By 2035, all natural gas-fired generation is either retired or converted to operate entirely on green hydrogen, a zero-emission fuel. In-basin thermal generation is fully transitioned to green hydrogen by this date, ensuring compliance with the City's directive for emissions-free electricity, even accounting for system losses.

Figure 4-1 also shows a moderate but strategic expansion of long-duration renewable technologies such as geothermal. These resources offer higher effective load carrying

capability, contributing essential dispatchable capacity to balance variable wind and solar.

Finally, the LA100 Pathway reflects insights from the LA100 Study conducted by the National Renewable Energy Laboratory (NREL) in 2021, which emphasized the need for a portfolio that includes firm, dispatchable resources to ensure system reliability, especially during periods of low solar and wind generation.

4.1.2 Generation Dispatch

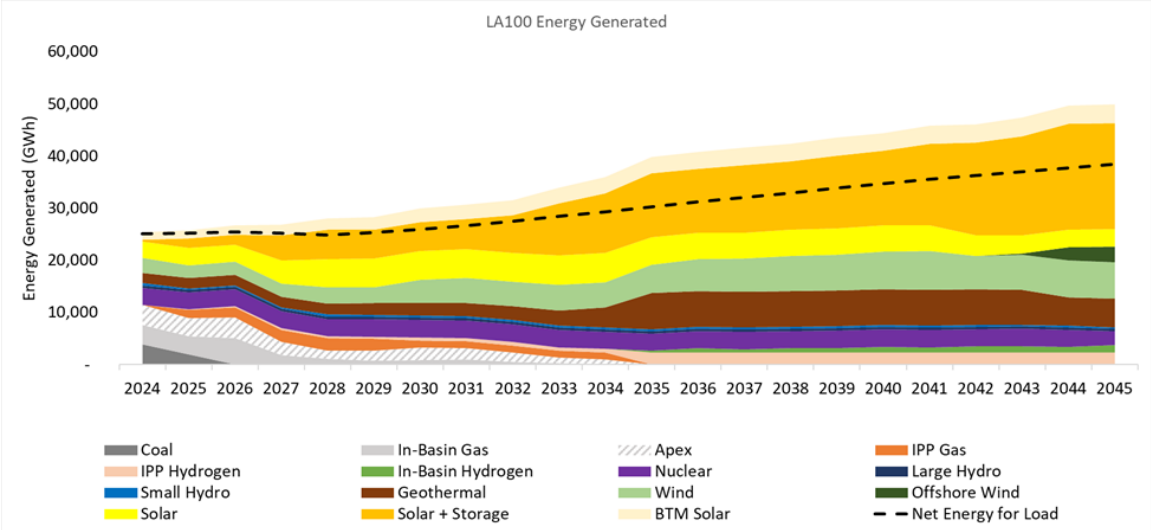


Figure 4-2. Projected energy generation mix under the LA100 Pathway. The LA100 Pathway achieves 100% carbon-free electricity by 2035 through a phased transition from fossil fuels to clean energy resources. Coal is fully retired by 2025, and all natural gas-fueled generation is either phased out or converted to green hydrogen by 2035. The increasing contributions from solar, solar + storage, wind (onshore and offshore), geothermal, and in-basin hydrogen generation reflect the diversification and decarbonization of LADWP's supply portfolio. The dashed line represents net energy required to meet load, highlighting how renewable generation scales to meet demand over time.

Figure 4-2 illustrates the projected energy generation mix under the LA100 Pathway. To meet the City Council's directive of achieving 100% carbon-free electricity by January 1, 2035, the pathway transitions away from all fossil-fueled generation—including both coal and natural gas—by the end of 2034.

The LA100 Pathway relies heavily on solar photovoltaics (PV)—including utility-scale solar + storage projects and behind-the-meter (BTM) rooftop solar—as well as

increasing contributions from wind, offshore wind, and long-duration renewable resources such as geothermal. The generation mix is further diversified with contributions from small and large hydro, nuclear, and hydrogen-fueled thermal generation (converted from existing natural gas assets).

By 2035, all thermal resources still in operation are fueled by green hydrogen, enabling dispatchable, zero-carbon generation to help balance variable solar and wind output.

As shown by the dashed black line, projected energy generation eventually exceeds net load in some years—highlighting potential curtailment during periods of oversupply. In practice, excess generation may be curtailed or exported to other utilities, though LADWP aims to minimize curtailment wherever possible due to the financial and contractual constraints of power purchase agreements (PPAs), which often include minimum annual purchase obligations regardless of energy delivery.

4.1.3 Customer Load with Modifiers

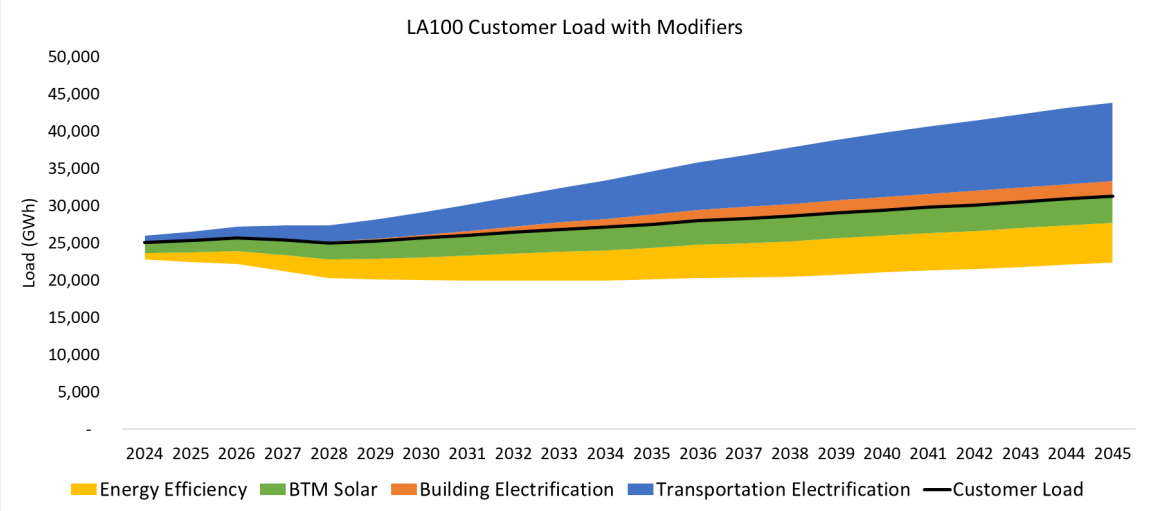


Figure 4-3. LA100 customer load with modifiers. While energy efficiency and behind-the-meter (BTM) solar reduce overall load, building electrification and especially transportation electrification significantly increase demand over time. Despite these competing forces, net customer load grows steadily, highlighting the importance of proactive planning to ensure reliable, carbon-free electricity delivery in a more electrified future.

Figure 4-3 illustrates projected customer electricity load through 2045 under the LA100 Pathway, incorporating major demand-side modifiers that influence net load. The black

line represents total customer load after accounting for the combined impacts of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification.

In the early years, energy efficiency programs and increasing adoption of BTM solar generation reduce net electricity demand, helping to partially offset load growth. However, as Los Angeles accelerates its transition toward an electrified economy, rising electricity consumption from building electrification (e.g., electric heat pumps, water heating, and cooking) and especially transportation electrification (e.g., electric vehicles and charging infrastructure) begins to outpace these savings. By the mid-2030s, these upward pressures on demand become the dominant trend, driving a steady increase in total customer load.

This forecast highlights the critical importance of integrating both supply-side planning and demand-side strategies to achieve a reliable, fully decarbonized electric grid. As Los Angeles pursues its climate goals, managing this evolving load profile—while maintaining affordability and equity—will be essential to the successful implementation of the LA100 Pathway.

4.1.4 In-Basin Capacity Factors

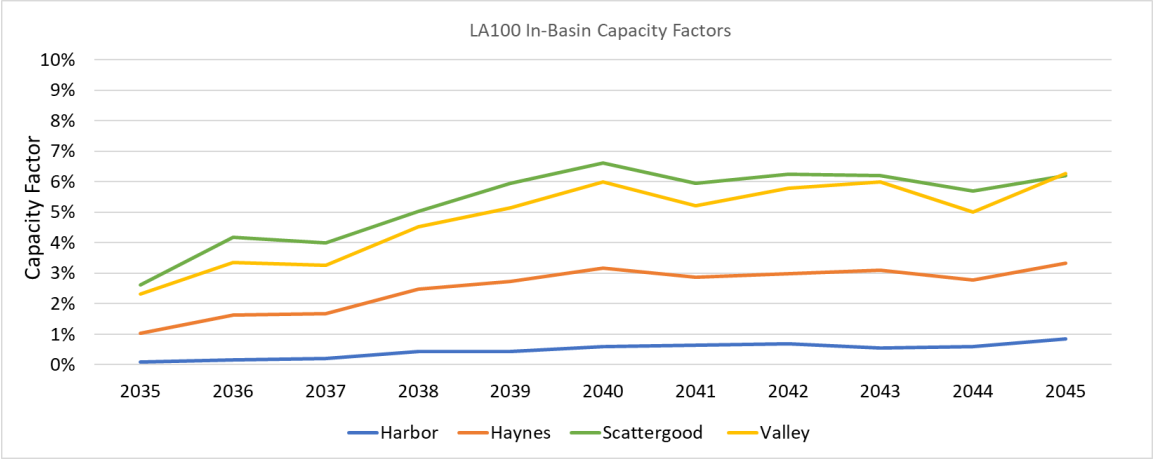


Figure 4-4. LA100 Pathway in-basin capacity factors. Projected capacity factors for LADWP's in-basin thermal generation facilities, beginning in 2035—the first year all units are expected to operate exclusively on green hydrogen—remain well below 10%. Capacity factor is defined as the actual energy produced by a generating unit over a period of time, divided by the maximum possible energy it could have produced if operated at full output continuously over that same period.

Under the LA100 Pathway, LADWP transitions all of its fossil-fueled thermal generation units to run exclusively on green hydrogen by 2035, eliminating fossil fuel use while preserving local dispatchable generation. As shown in Figure 4-4, projected capacity factors for these facilities remain low throughout the 2035–2045 period—typically between 0% and 7%—indicating that while these facilities are vital for reliability, they are not expected to operate frequently or at high output for extended periods.

The Scattergood green hydrogen-capable combined-cycle (CC) unit in 2029, exhibits the highest capacity factor across the in-basin portfolio. This reflects its efficiency and likely role in meeting load during periods of low renewable generation. Other combined cycle units—such as those at Haynes and Valley —also show modest utilization, consistent with their deployment as balancing resources. By contrast, smaller combustion turbines at Valley, Haynes, Harbor, and Scattergood show minimal capacity factors, showing they will be held in reserve for rare events such as extreme weather or grid contingencies. It is important to note that the forecasted capacity factors are based on the LA100 Plan assumptions, which include the timely procurement of renewable energy resources, transmission expansion, and local distributed energy resources. As such, these values

represent a best-case planning scenario, and actual capacity factors may vary depending on system conditions and operational needs.

These projections reinforce a key conclusion from the LA100 Study (2021): achieving a reliable, fully carbon-free power system requires firm, flexible, dispatchable capacity, even if such resources are seldom used. The strategic use of green hydrogen in LADWP's in-basin fleet allows the utility to meet peak demand, respond to renewable variability, and ensure operational resilience—without emitting greenhouse gases.

4.1.5 Renewable and Clean Generation

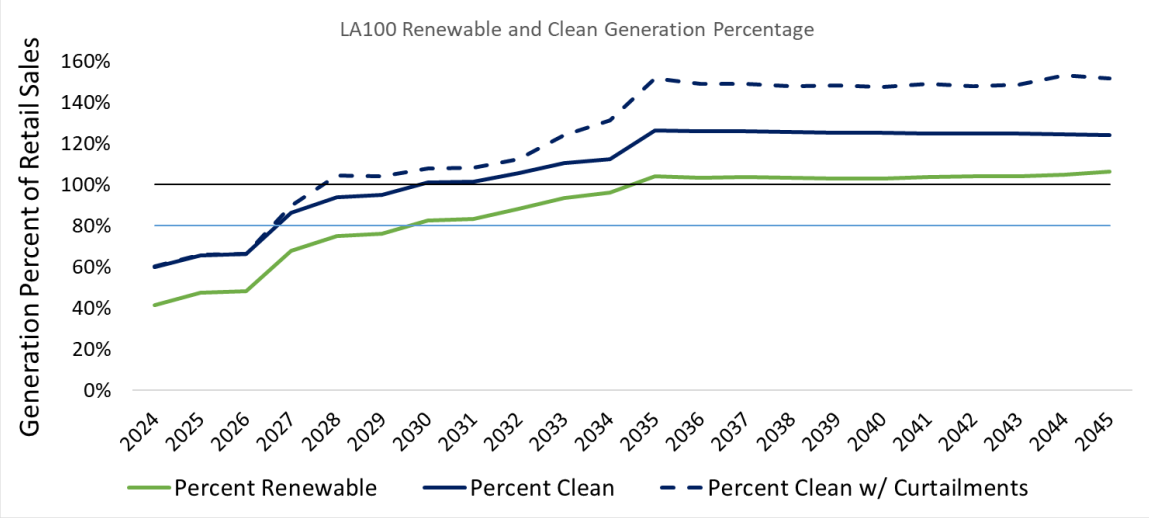


Figure 4-5. LA100 renewable and clean generation percentage is expressed as a share of LADWP's retail electricity sales. The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro), while the solid dark blue line represents clean energy, which includes renewables along with large hydro and nuclear. The dashed blue line reflects clean energy including curtailed generation—energy produced but not used. The horizontal black line represents 100% of retail sales, and the light blue line marks the interim target of 80% renewable energy by 2030.

LA100's renewable and clean generation percentage reflects LADWP's path toward meeting the City Council's goal of providing 100% carbon-free electricity by 2035. All values are shown as a percentage of retail sales (see Figure 4-5), which refer to the electricity actually delivered to customers (excluding losses).

The renewable portion, shown in green, increases steadily to meet the 80% target by 2030 and continues climbing gradually through 2045. The clean energy share, depicted

in solid dark blue, includes additional zero-carbon sources such as large hydro and nuclear, enabling LADWP to meet 100% of retail sales with clean energy by 2035.

The dashed line, which includes curtailed clean energy, rises above 100% starting in the early 2030s. This reflects the need to generate additional clean electricity to compensate for system losses, particularly those associated with the round-trip inefficiencies of energy storage technologies like batteries. Under Los Angeles' stricter requirements—unlike California's SB 100—even these losses must be served with carbon-free energy.

Altogether, the LA100 Pathway ensures that not only customer demand, but also the full operational footprint of the electric system, is met with zero-carbon resources.

4.1.6 Renewable Curtailment

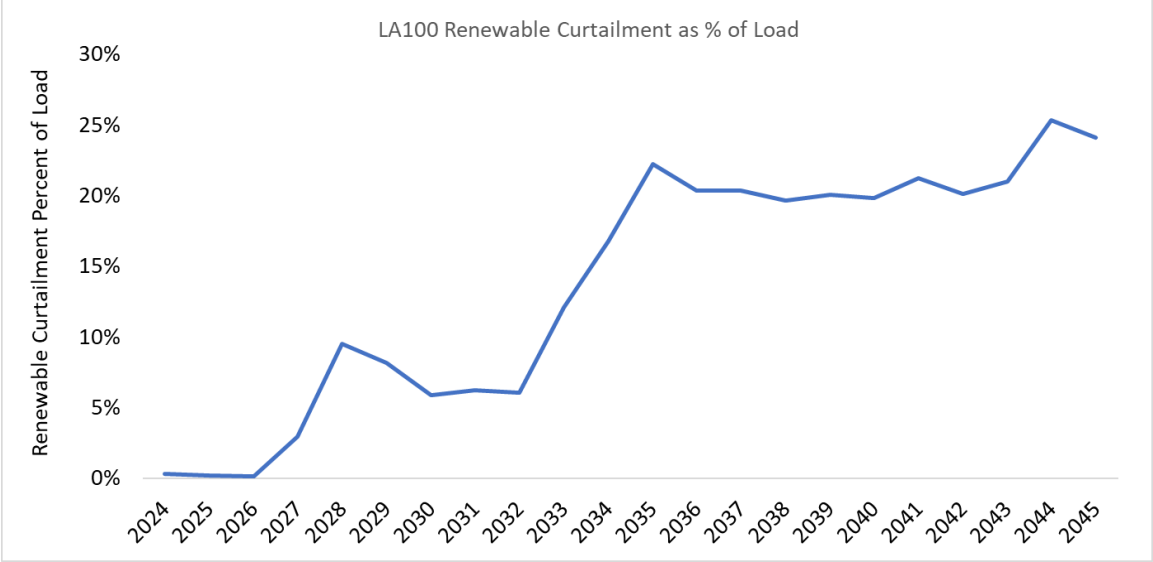


Figure 4-6. LA100 renewable curtailment as a percentage of net load represents the share of renewable energy that is generated but not ultimately used to serve customer demand. Curtailment levels increase in the early 2030s, peaking around 2035, as LADWP expands renewable energy deployment to meet carbon-free energy targets. Some curtailment is a planned and cost-effective outcome of a strategy that prioritizes broad renewable deployment over more expensive alternatives like green hydrogen for routine energy delivery.

LA100 renewable curtailment as a percentage of retail load reflects the portion of renewable electricity generated but not used due to a combination of system conditions and intentional resource planning decisions (see Figure 4-6). While curtailment can occur

because of grid constraints, storage limitations, or periods of excess generation, the LA100 Pathway also incorporates a deliberate strategy of developing a robust portfolio of renewable resources—even if not all generated energy is utilized at all times.

As Figure 4-6 shows, curtailment begins to rise in the late 2020s and climbs significantly through the early 2030s, reaching a peak around 2035, when LADWP achieves its 100% carbon-free electricity goal. Rather than relying heavily on green hydrogen, which remains costly for routine generation, the plan opts to deploy a broad and abundant mix of renewable resources. This approach ensures system reliability and cost-effectiveness, even if it results in some excess generation being curtailed.

This planned curtailment is a strategic tradeoff—allowing LADWP to reduce dependence on high-cost dispatchable fuels while still ensuring that all customer load (including line losses and storage inefficiencies) is served by clean, carbon-free energy. Curtailment is expected to remain a manageable and accepted component of system operations in a high-renewable future.

4.1.7 Greenhouse Gas Emissions

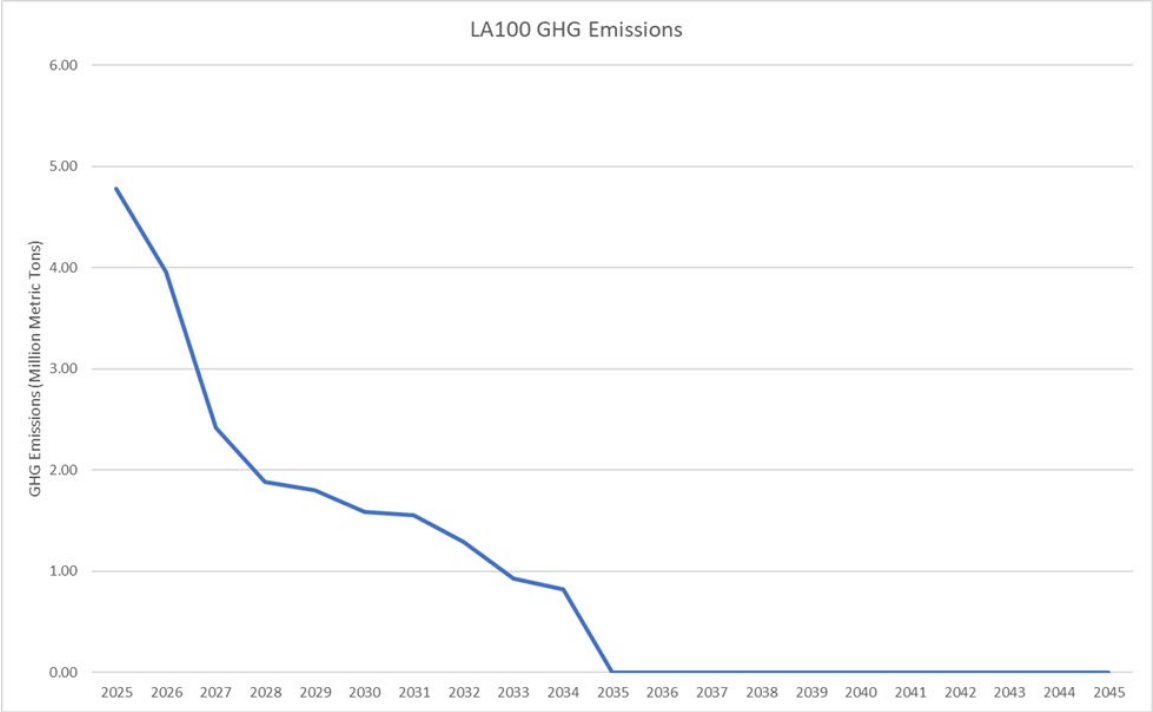


Figure 4-7. LA100 GHG emissions represent annual greenhouse gas emissions associated with electricity generation, measured in million metric tons. Emissions decline steeply from 2025 through 2035 as LADWP phases out coal and natural gas and transitions to a 100% carbon-free energy portfolio. Beginning in 2035, emissions reach effectively zero and remain at that level through 2045.

LA100 GHG emissions reflect LADWP's projected progress in eliminating carbon emissions from its power supply (see Figure 4-7). Emissions begin at just under 5 million metric tons in 2025 and decline sharply over the next decade as coal-fired generation is fully retired and fossil gas use is steadily reduced. The most significant drops occur between 2025 and 2035, driven by expanded deployment of renewable energy, increased energy efficiency, and the conversion of in-basin thermal generation to green hydrogen.

By 2035, LADWP achieves net-zero operational emissions, meaning no fossil fuels are used for electricity generation. This marks the fulfillment of the Los Angeles City Council's directive to provide 100% carbon-free electricity—not only to meet customer load, but also to serve transmission losses and storage inefficiencies with clean energy.

From 2035 onward, emissions remain flat at zero, demonstrating sustained carbon-free operation through 2045.

This rapid and permanent decline in GHG emissions underscores the transformative nature of the LA100 Pathway and its contribution to meeting both local climate commitments and broader state and national decarbonization goals.

4.1.8 NOx Emissions

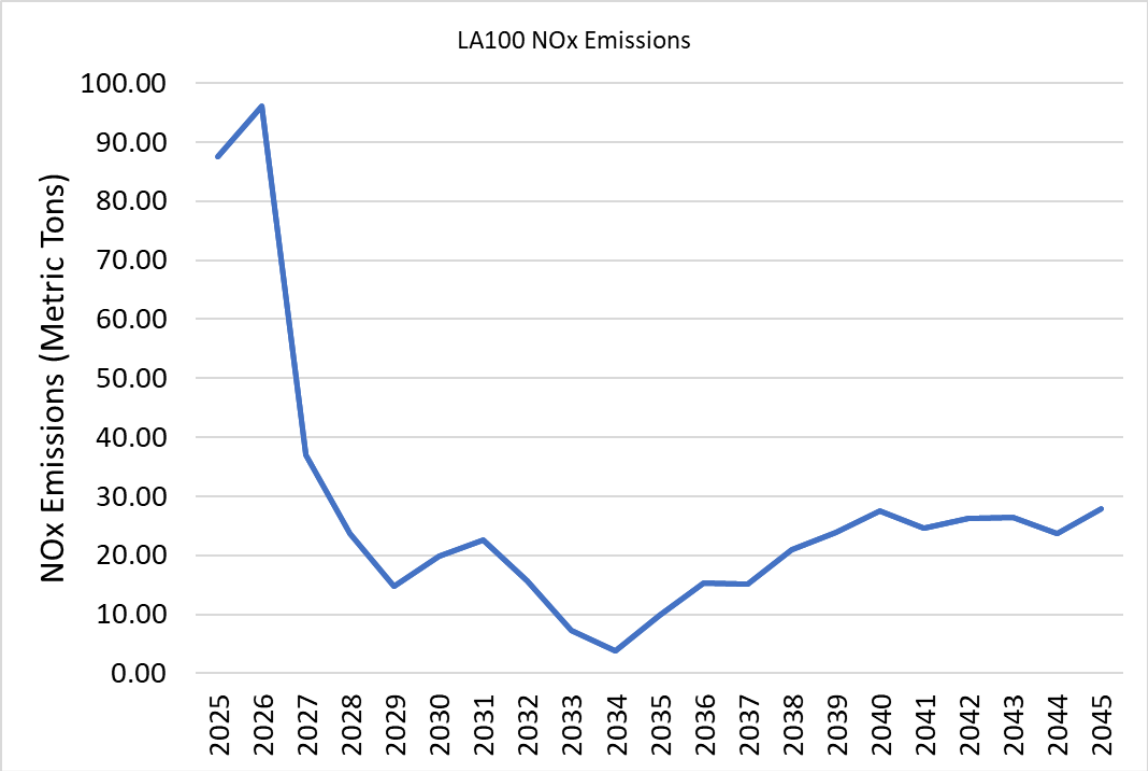


Figure 4-8. LA100 NOx emissions refer specifically to nitrogen oxides released from LADWP's in-basin power plants, which are located within a federally designated nonattainment area regulated by South Coast Air Quality Management District (AQMD). Emissions decline sharply through the late 2020s as fossil fuel use is reduced, then reach minimal levels by the early 2030s. A slight rebound occurs in later years due to infrequent dispatch of hydrogen-fueled units during periods of high system need.

LA100 NOx emissions track the projected nitrogen oxide emissions from LADWP's in-basin generation facilities, which are located within a federally designated nonattainment area regulated by South Coast AQMD. These emissions are of particular interest because

NOx contributes to the formation of smog and ground-level ozone, which are broader regional air quality concerns—especially in densely populated urban areas.

Figure 4-8 shows a sharp decline in NOx emissions beginning in 2026, as LADWP retires or reduces operation of natural gas combustion turbines and combined-cycle units. By the early 2030s, emissions drop to very low levels due to the transition of in-basin thermal plants to green hydrogen, which can be combusted with minimal NOx output when properly managed.

After 2035, there is a modest rise in emissions, reflecting occasional use of hydrogen-fueled units for system balancing and reliability purposes. However, even in these years, emissions remain well below historical levels, representing a significant and sustained improvement in local air quality. It is important to note that these projections are based on modeling results that assume LADWP successfully procures and deploys all necessary clean energy resources—such as renewables, transmission upgrades, and distributed energy resources—consistent with the LA100 Plan assumptions. As such, these represent a best-case scenario, and actual in-basin NO_x emissions may vary depending on operational needs, system reliability requirements, and the timing of clean energy resource availability.

This trajectory underscores how the LA100 Pathway delivers not only on climate goals, but also contributes to broader efforts to reduce regional air pollution and improve environmental outcomes in overburdened communities.

4.1.9 Fuel Burn

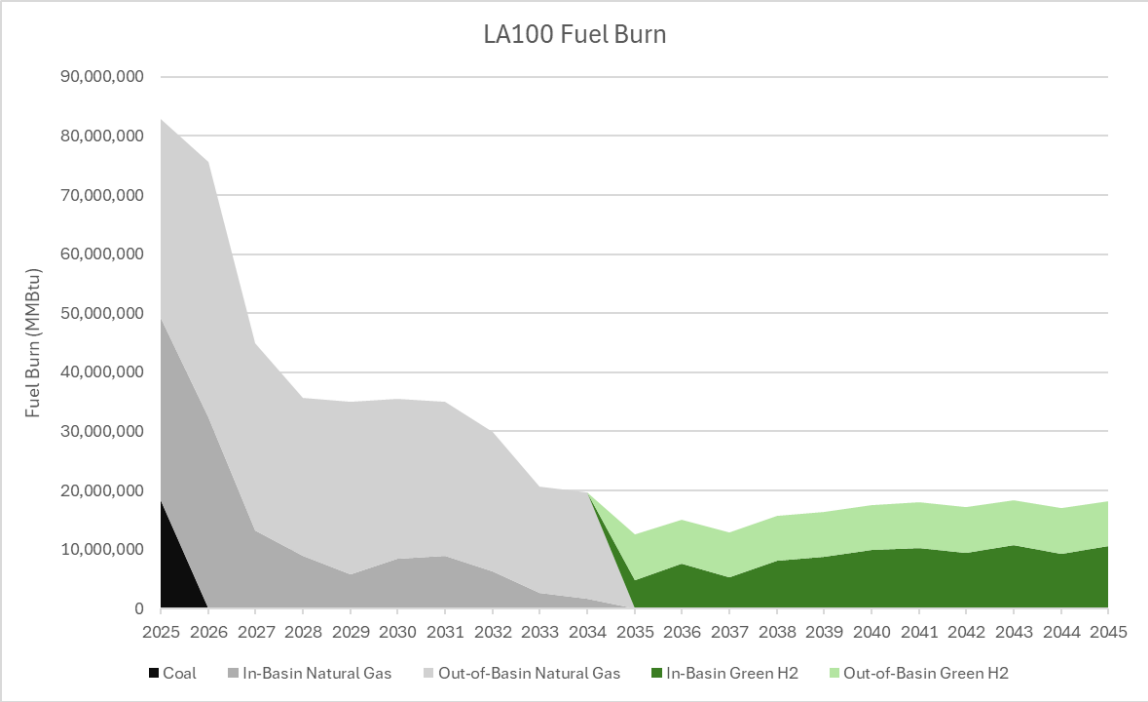


Figure 4-9. LA100 fuel burn shows projected consumption of purchased fuels used in LADWP's power generation portfolio, measured in millions of British thermal units (MMBtu). The chart illustrates the complete phase-out of coal by 2025 and natural gas by 2035. By 2035, green hydrogen—both in-basin and out-of-basin—is fully introduced in limited quantities to support dispatchable, carbon-free generation needed to maintain system reliability.

LA100 fuel burn reflects the transition of LADWP's generation portfolio from fossil fuels to carbon-free resources in support of the City's 2035 carbon-free energy goal. Early in the timeline, Figure 4-9 shows the retirement of coal by 2025, followed by a gradual reduction and complete elimination of both in-basin and out-of-basin natural gas use by 2035.

By 2035, the LA100 Pathway incorporates the use of green hydrogen—a carbon-free fuel—at both in-basin and out-of-basin thermal generation sites. The use of hydrogen enables LADWP to maintain reliable, dispatchable capacity for grid stability, while still meeting the City's requirement that all electricity, including for system losses and inefficiencies, be supplied from non-emitting sources. In-basin hydrogen use is limited and primarily reserved for periods of high system need.

The fuel consumption after 2035 does not indicate a return to high-carbon operations but rather reflects the role of hydrogen-fueled units as a reliability backstop in a system otherwise dominated by variable renewable resources. The LA100 Pathway minimizes combustion overall but includes strategic use of clean fuels to preserve operational flexibility as part of a fully decarbonized system.



4.1.10 Annual System Cost

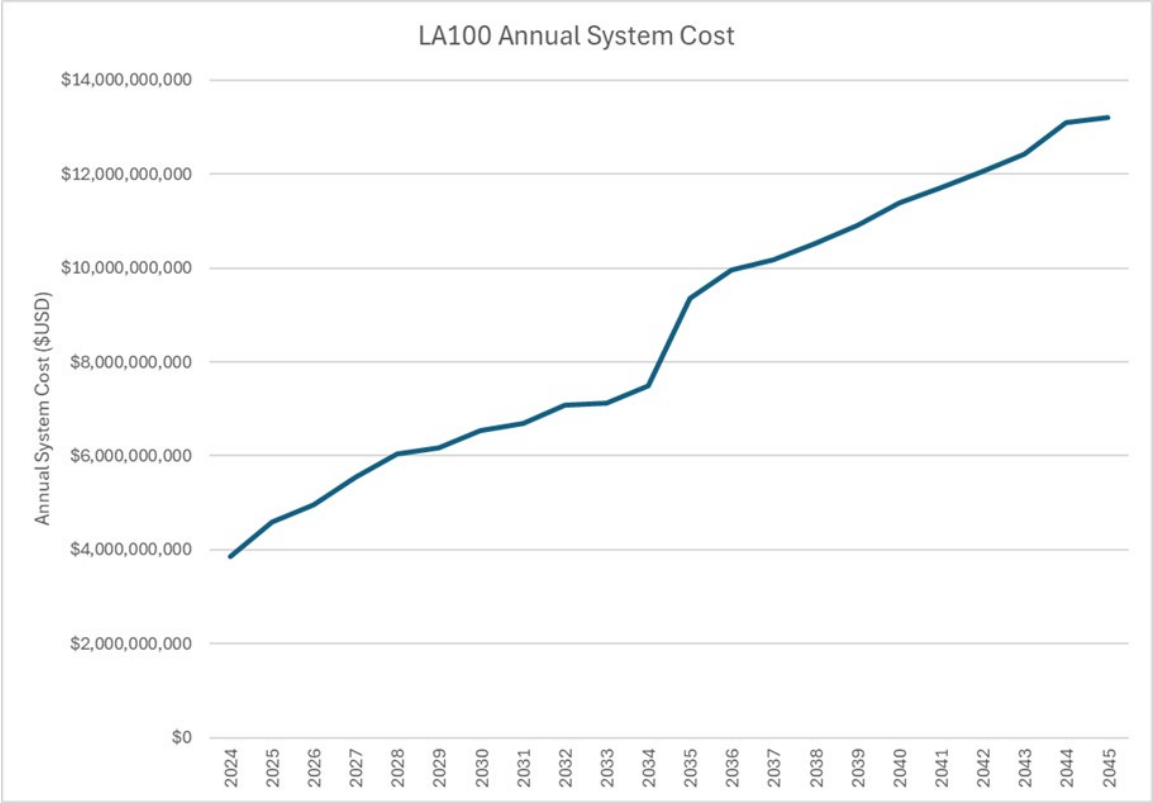


Figure 4-10. LA100 annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (eHubs).

LA100 annual system cost represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway through 2045 (see Figure 4-10). The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, transmission, and distribution investments.

In the near term, costs rise steadily as LADWP begins investing in renewable energy, storage, and grid modernization. A more noticeable increase occurs around 2035, corresponding with large-scale infrastructure development to meet the City's 100% carbon-free energy goal. This includes not only generation and storage projects, but also

grid upgrades tied to the Power System Reliability Plan, which replaces aging infrastructure, and the rollout of eHub electric vehicle charging centers to support transportation electrification.

By the late 2030s and into the 2040s, system costs continue to grow but at a more moderate pace, reflecting the sustained need for maintenance, upgrades, and replacement of long-lived assets in a modern, electrified grid. This all-in cost view offers a comprehensive picture of the financial requirements to maintain reliability and support a decarbonized, electrified future for Los Angeles.



4.2 LA100 Price Sensitivity

The LA100 Price Sensitivity is derived from the LA100 Pathway but reflects a scenario in which renewable energy, energy storage, and green hydrogen costs are higher than anticipated, while natural gas prices and greenhouse gas emissions allowances are lower than anticipated. Like the core LA100 Pathway, this sensitivity requires that all electricity—including that used to cover transmission and distribution losses—must come from carbon-free sources by January 1, 2035. It also retains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

The LA100 Price Sensitivity explores a future in which the costs of renewable energy, energy storage, and green hydrogen are higher than anticipated, while fossil fuel prices—particularly natural gas and CO_2 allowance costs—are lower. This scenario was designed to assess the potential challenges of transitioning to clean energy under less favorable economic conditions. By modeling a world where clean resources are more expensive and fossil fuels remain relatively cheap, LADWP can better understand the cost and system impacts of delayed cost reductions or policy shifts and prepare accordingly.

Although the policy objectives remain the same, this sensitivity yields different outcomes due to the altered cost assumptions. Higher-than-anticipated costs for renewable energy, energy storage, and green hydrogen—combined with lower-than-anticipated dispatch costs for natural gas—affect portfolio composition and overall system costs.

By 2035, the LA100 Price Sensitivity includes the deployment of:

- 1,898 MW of local distributed solar,
- 3,794 GWh of cumulative energy efficiency savings (relative to 2023 base year),
- 331 MW of distributed energy storage, and
- 815 MW of demand response capacity.

These targets support a comprehensive and locally focused approach to decarbonizing Los Angeles' electricity supply while maintaining system reliability, equity, and long-term resilience.

4.2.1 Capacity Expansion

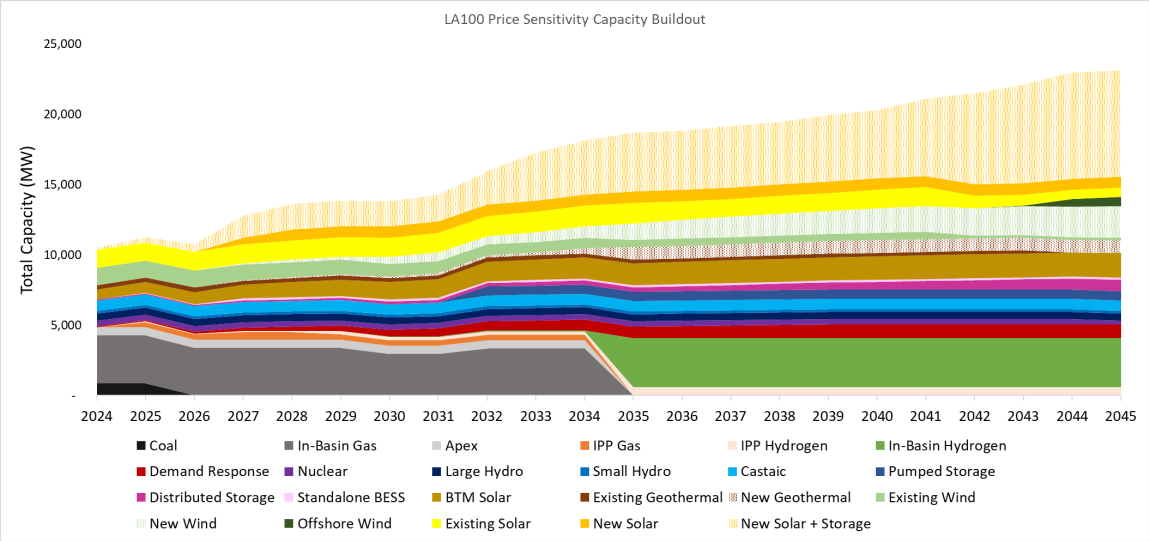


Figure 4-11. LA100 Price Sensitivity capacity buildout.

The LA100 Price Sensitivity assumes the same buildout of clean energy resources as the LA100 Pathway to meet Los Angeles' goal of delivering 100% carbon-free electricity by 2035. As shown in the chart in Figure 4-11, the transition is driven by major additions of new solar paired with storage, green hydrogen, and wind power, including both onshore and offshore resources.

The LA100 Price Sensitivity also assumes LADWP's coal-fired generation is fully retired by 2025, and the retirement or conversion of all natural gas-fired generation to green hydrogen, a carbon-free fuel, by 2035. Long-duration renewable technologies such as geothermal are also employed in the portfolio, ensuring that, like the LA100 Pathway, the LA100 Price Sensitivity complies with the City's directive for emissions-free electricity, while remaining reliable throughout the study horizon.

4.2.2 Generation Dispatch

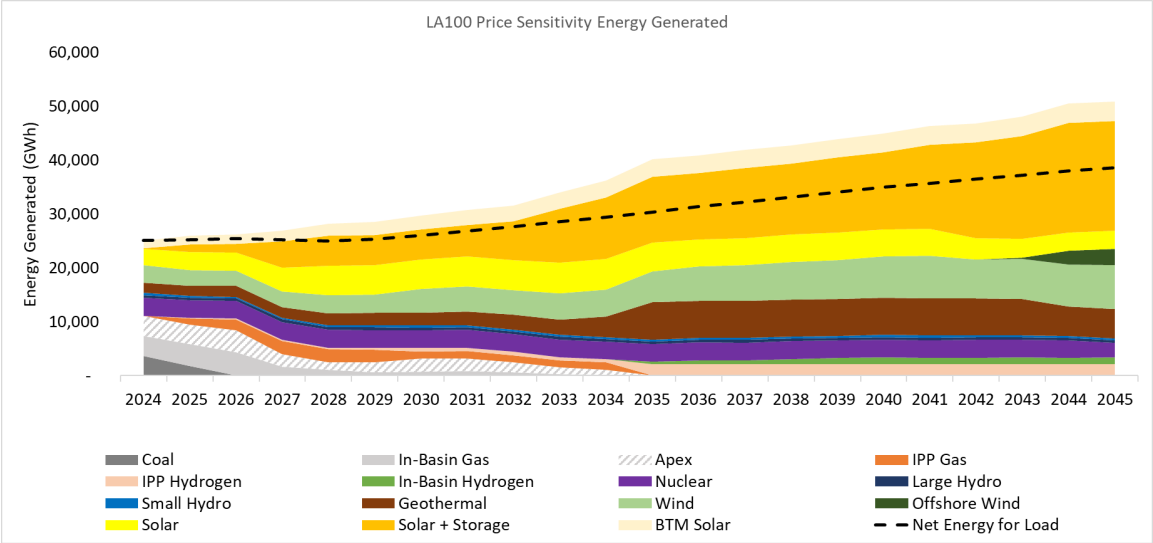


Figure 4-12. Projected energy generation mix under the LA100 Price Sensitivity.

Figure 4-12 illustrates the projected energy generation mix under the LA100 Price Sensitivity which meets the City Council's directive of achieving 100% carbon-free electricity by January 1, 2035.

Like the LA100 Pathway, the LA100 Price Sensitivity relies heavily on solar photovoltaics (PV)—including utility-scale solar + storage projects and behind-the-meter (BTM) rooftop solar—as well as increasing contributions from wind, offshore wind, and long-duration renewable resources such as geothermal. The generation mix is further diversified with contributions from small and large hydro, nuclear, and hydrogen-fueled thermal generation (converted from existing natural gas assets).

By 2035, all thermal resources still in operation are fueled by green hydrogen, enabling dispatchable, zero-carbon generation to help balance variable solar and wind output. While the LA100 Price Sensitivity employs different costs for renewable generation and natural gas purchases, these variables lead to only slight change in the generation mix overall due to the consistency of demand and renewable generation between the sensitivity and the main LA100 Pathway.

As shown by the dashed black line, projected energy generation eventually exceeds net load in some years—highlighting potential curtailment during periods of oversupply. In

practice, excess generation may be curtailed or exported to other utilities, though LADWP aims to minimize curtailment wherever possible due to the financial and contractual constraints of power purchase agreements (PPAs), which often include minimum annual purchase obligations regardless of energy delivery.

4.2.3 Customer Load with Modifiers

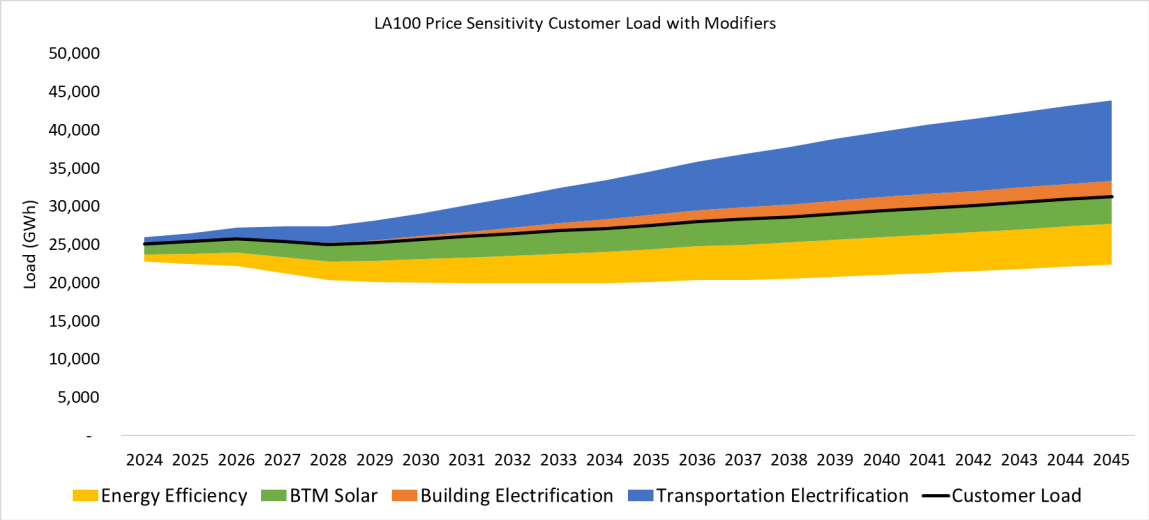


Figure 4-13. LA100 Price Sensitivity customer load with modifiers. While energy efficiency and behind-the-meter (BTM) solar reduce overall load, building electrification and especially transportation electrification significantly increase demand over time. Net customer load grows steadily, highlighting the importance of proactive planning to ensure reliable, carbon-free electricity delivery in a more electrified future.

Figure 4-13 illustrates projected customer electricity load through 2045 under the LA100 Price Sensitivity, incorporating major demand-side modifiers that influence net load. The black line represents total customer load after accounting for the combined impacts of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification.

Like the LA100 Pathway, early years in the LA100 Price Sensitivity show an influx of energy efficiency programs and increasing adoption of BTM solar generation reduce net electricity demand, helping to partially offset load growth. However, rising electricity consumption from building electrification (e.g., electric heat pumps, water heating, and cooking) and especially transportation electrification (e.g., electric vehicles and charging infrastructure) begins to outpace these savings.

By the mid-2030s, these upward pressures on demand become the dominant trend, driving a steady increase in total customer load.

4.2.4 Renewable and Clean Generation

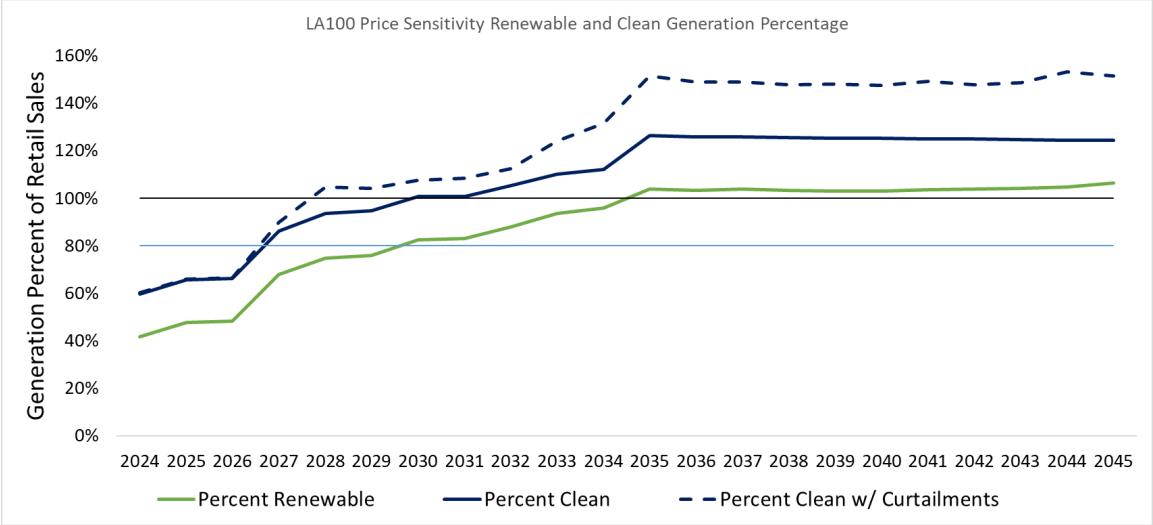


Figure 4-14. LA100 Price Sensitivity renewable and clean generation percentage is expressed as a share of LADWP's retail electricity sales. The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro), while the solid dark blue line represents clean energy, which includes renewables along with large hydro and nuclear. The dashed blue line reflects clean energy including curtailed generation—energy produced but not used. The horizontal black line represents 100% of retail sales, and the light blue line marks the interim target of 80% renewable energy by 2030.

LA100's renewable and clean generation percentage reflects LADWP's path toward meeting the City Council's goal of providing 100% carbon-free electricity by 2035. All values are shown as a percentage of retail sales, which refers only to the electricity delivered to customers (excluding losses). The LA100 Price Sensitivity retains the resource buildout of the LA100 Pathway, so the renewable and clean generation percentage grows at nearly the same rate.

The renewable portion, shown in green in Figure 4-14, increases steadily to meet the 80% target by 2030 and continues climbing gradually through 2045. The clean energy share, depicted in solid dark blue, includes additional zero-carbon sources such as large hydro and nuclear, enabling LADWP to meet 100% of retail sales with clean energy by 2035.

The dashed line, which includes curtailed clean energy, rises above 100% starting in the early 2030s. This reflects the need to generate additional clean electricity to compensate for system losses, particularly those associated with the round-trip inefficiencies of energy storage technologies like batteries. Under Los Angeles' stricter requirements—unlike California's SB 100—even these losses must be served with carbon-free energy.

Altogether, the LA100 Pathway ensures that not only customer demand, but also the full operational footprint of the electric system, is met with zero-carbon resources.



4.2.5 Renewable Curtailment

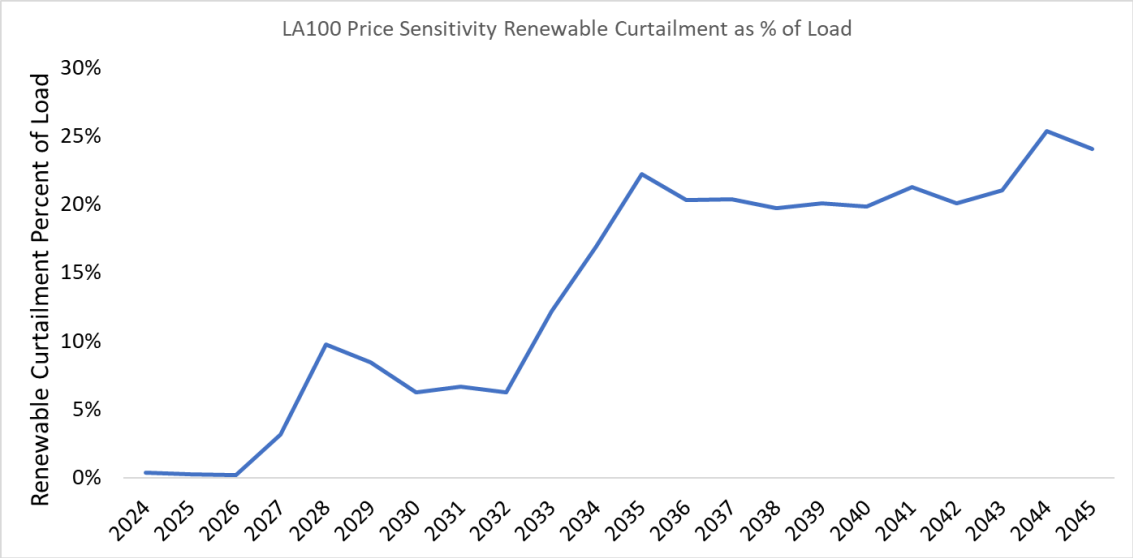


Figure 4-15. LA100 Price Sensitivity renewable curtailment as a percentage of net load represents the share of renewable energy that is generated but not ultimately used to serve customer demand. Curtailment levels increase in the early 2030s, peaking around 2035, as LADWP expands renewable energy deployment to meet carbon-free energy targets. Some curtailment is a planned and cost-effective outcome of a strategy that prioritizes broad renewable deployment over more expensive alternatives like green hydrogen for routine energy delivery.

LA100 renewable curtailment as a percentage of retail load (Figure 4-15) reflects the portion of renewable electricity generated but not used due to a combination of system conditions and intentional resource planning decisions. While curtailment can occur because of grid constraints, storage limitations, or periods of excess generation, the LA100 Pathway also incorporates a deliberate strategy of developing a robust portfolio of renewable resources—even if the generated energy is not utilized at all times.

The LA100 Price Sensitivity retains the resource buildout of the LA100 Pathway, so the renewable curtailment percentage grows at nearly the same rate, displaying a substantial increase in the 2030s which peaks around 2035 as the resource portfolio becomes significantly saturated with renewable energy.

This planned curtailment is a strategic tradeoff—allowing LADWP to reduce dependence on high-cost dispatchable fuels while still ensuring that all customer load (including line losses and storage inefficiencies) is served by clean, carbon-free energy. Curtailment is

expected to remain a manageable and acceptable component of system operations in a high-renewable future.

4.2.6 Greenhouse Gas Emissions

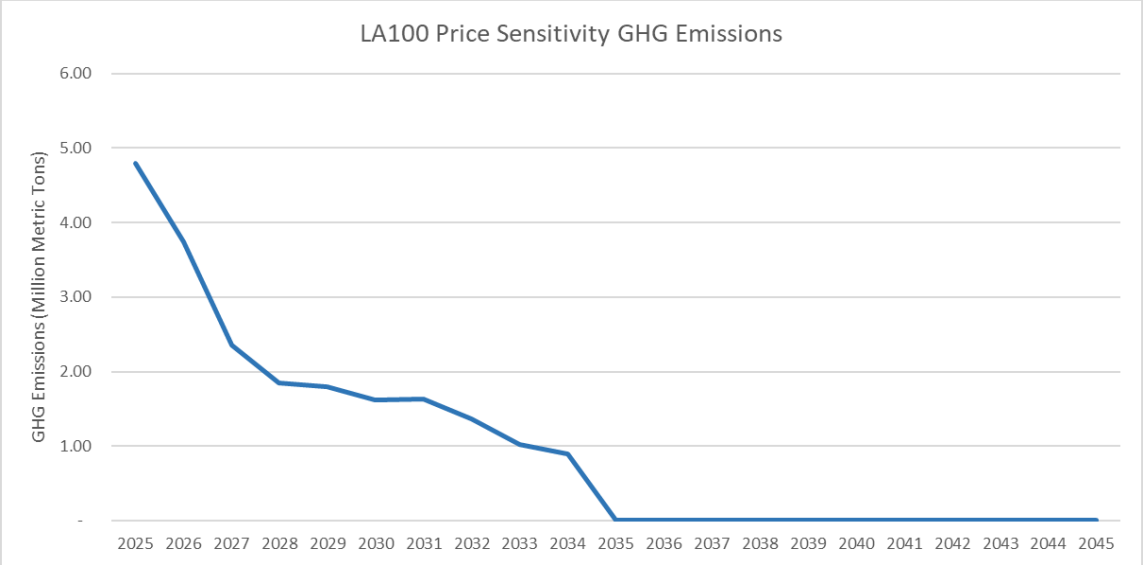


Figure 4-16. LA100 Price Sensitivity GHG emissions represent annual greenhouse gas emissions associated with electricity generation, measured in million metric tons. Emissions decline steeply from 2025 through 2035 as LADWP phases out coal and natural gas and transitions to a 100% carbon-free energy portfolio. Beginning in 2035, emissions reach effectively zero and remain at that level through 2045.

LA100 GHG emissions in Figure 4-16, reflect LADWP's projected progress in eliminating carbon emissions from its power supply. The LA100 Price Sensitivity differs from the LA100 Pathway in emissions progress by a notable amount. Emissions in the LA100 Price Sensitivity begin at under 5 million metric tons in 2025 but are slightly lower than the LA100 Pathway when compared. Natural gas costs are lowered in this sensitivity, incentivizing the use of gas in favor of more carbon-intensive coal when both are available. However, as coal is retired in 2025, the LA100 Price Sensitivity sees slightly higher natural gas usage and higher emissions each year until it is replaced fully by clean hydrogen in 2035. The increase can be attributed to a redistribution of gas usage from in-basin to out-of-basin natural gas, which is incrementally cheaper to dispatch when all natural gas prices are lowered, but slightly more emitting due to having a higher heat

rate than the in-basin units being tapered. When measured by capacity factor, though, the overall usage of natural gas resources remains the same as in LA100 Pathway.

By 2035, LADWP achieves zero operational emissions, meaning no fossil fuels are used for electricity generation. This marks the fulfillment of the Los Angeles City Council's directive to provide 100% carbon-free electricity—not only to meet customer load, but also to serve transmission losses and storage inefficiencies with clean energy. From 2035 onward, emissions remain flat at zero, demonstrating sustained carbon-free operation through 2045.

4.2.7 Annual System Cost

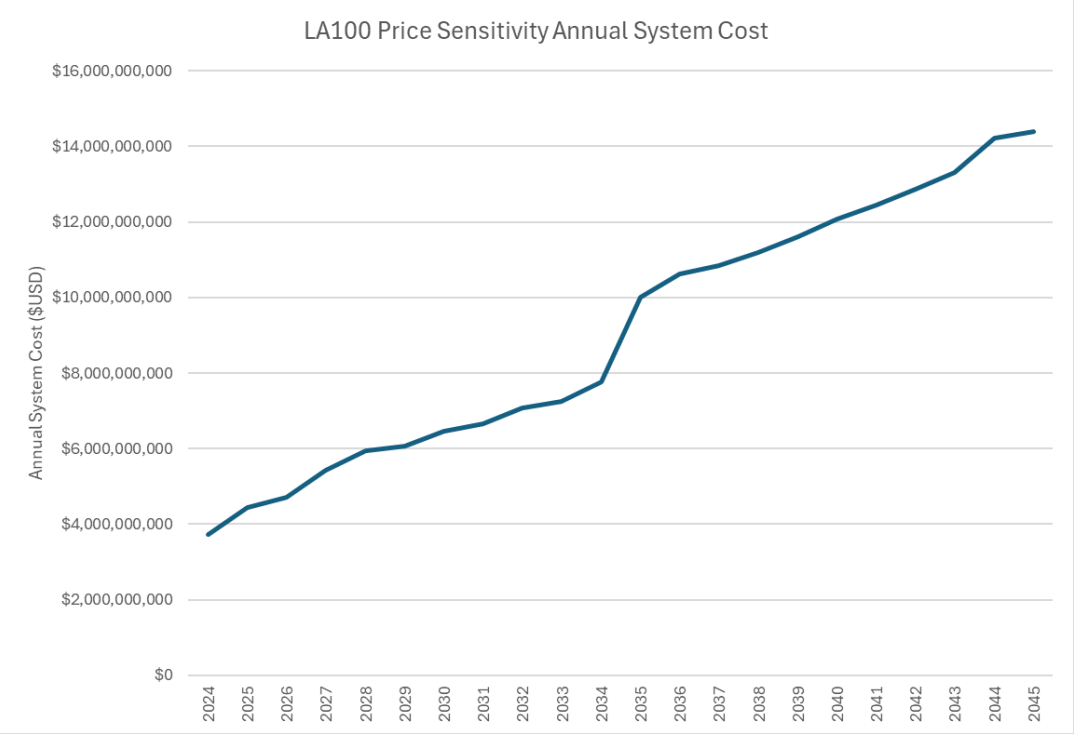


Figure 4-17. LA100 Price Sensitivity annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (eHubs).

The LA100 Price Sensitivities annual system cost in Figure 4-17, represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy

pathway through 2045. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, transmission, and distribution investments.

The cost of the LA100 Price Sensitivity grows at the same trajectory and rate as the LA100 Pathway due to the same factors of rising renewable, storage, and grid stabilizing purchases; as well as the influx of infrastructure necessary to meet the City's 100% carbon-free energy goal.

Due to the increased costs of purchasing renewable resources such as solar and energy storage, energy storage, and of purchased hydrogen, the LA100 Price Sensitivity is more expensive annually than the LA100 Pathway. The sensitivity exemplifies that the price of these resources should be monitored carefully as LADWP continues to strive toward a 100% carbon-free energy future while maintaining reliable, sustainable, and cost-effective services.

4.2.8 Key Takeaways

Under the Price Sensitivity, higher costs for renewables and storage—paired with lower assumed prices for natural gas and GHG allowances—led to a slight increase in average annual carbon emissions between 2025 and 2034 (2.19 $MMTCO_2$ compared to 2.10 $MMTCO_2$ in the LA100 Pathway). This outcome reflects a modest shift in the model's dispatch decisions, slightly favoring natural gas generation in the early years. Despite this, the total system cost from 2025 to 2045 ($105.6 billion) is only 3% higher than the LA100 Pathway, suggesting that even under less favorable clean energy pricing assumptions, the portfolio remains cost-effective. In-basin dispatchable resources continue to play a marginal operational role in the long term, with an average capacity factor of just 3% from 2035 to 2045.

4.3 LA100 Low Load Sensitivity

The LA100 Low Load Sensitivity is based on the core LA100 Pathway but assumes a lower net load than anticipated in said pathway. As with the LA100 Pathway, this sensitivity requires that all electricity, including energy used to cover transmission and distribution losses, must be sourced from carbon-free resources by January 1, 2035. It also maintains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

The LA100 Low Load Sensitivity examines a future where electricity demand grows more slowly than expected. This scenario was developed to understand the implications of lower-than-anticipated customer load growth—whether due to slower electrification of buildings and transportation, improved energy efficiency, or economic and behavioral factors. By modeling a reduced demand trajectory, LADWP can evaluate how lower load growth would affect clean energy investments, resource utilization, and overall system planning, helping ensure flexibility under a range of future conditions.

This sensitivity diverges from the base LA100 Pathway in several key outcomes. Lower overall customer load, combined with increased adoption of distributed energy resources (DERs), reduces the amount of utility-scale renewable procurement needed to meet carbon-free targets. As a result, the sensitivity achieves significant cost savings and a lower total system cost, while still meeting all clean energy milestones.

By 2035, the LA100 Low Load Sensitivity includes the deployment of:

- 2,072 MW of local distributed solar,
- 3,794 GWh of cumulative energy efficiency savings,
- 432 MW of distributed energy storage, and
- 948 MW of demand response capacity.

These investments support a localized, cost-effective approach to decarbonization while maintaining system reliability, equity, and long-term resilience.

4.3.1 Capacity Expansion

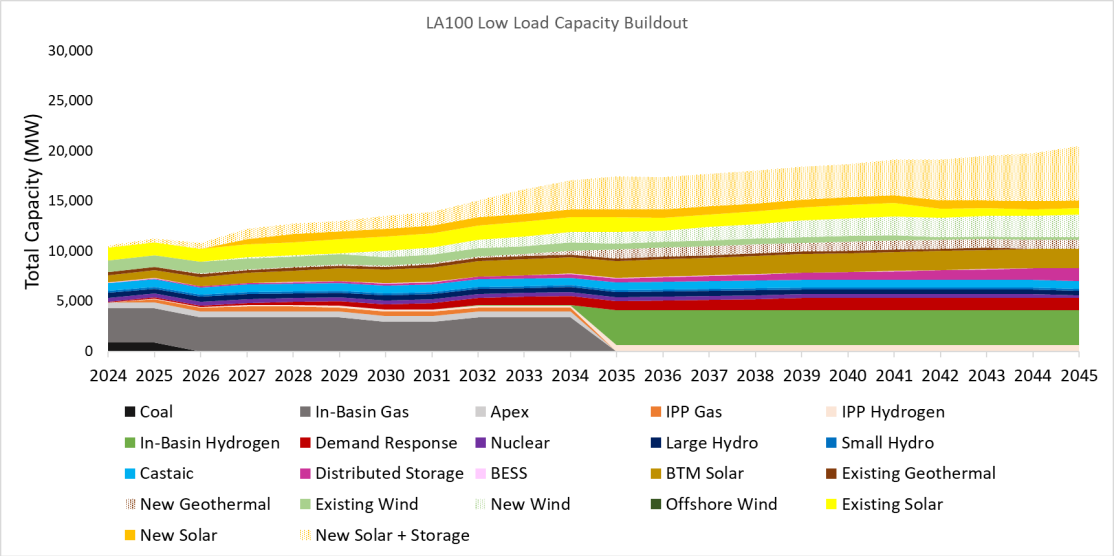


Figure 4-18. LA100 Low Load Capacity Buildout.

The LA100 Low Load Sensitivity assumes an overall lower buildout of clean energy resources compared to the LA100 Pathway to meet Los Angeles' goal of delivering 100% carbon-free electricity by 2035. As shown in the chart in Figure 4-18, the transition is driven by major additions of new solar paired with storage, green hydrogen, and wind power, but deviates from the LA100 Pathway by employing less solar and storage resources, and foregoing the use of new pumped hydro and offshore wind resources entirely. The sensitivity also employs increased behind the meter solar and higher demand response, which serve as load modifiers driving the net load lower. Overall, these changes lead to a substantial decrease in the total capacity of the resource portfolio by 2045, matching the decreased need for said resources in accordance with the sensitivity.

Major milestones such as the retirement of coal-fired generation in 2025, and the transition of in-basin thermal generation to green hydrogen by 2035, remain the same as the LA100 Pathway within this sensitivity. Long-duration renewable technologies such as geothermal are still employed in the sensitivity, contributing further dispatchable capacity to balance variable wind and solar. These resource additions reflect the insights derived from the LA100 Study conducted by the National Renewable Energy Laboratory

(NREL), which emphasized the need to have firm dispatchable resources within the resource portfolio, even with a lower net load.

4.3.2 Generation Dispatch

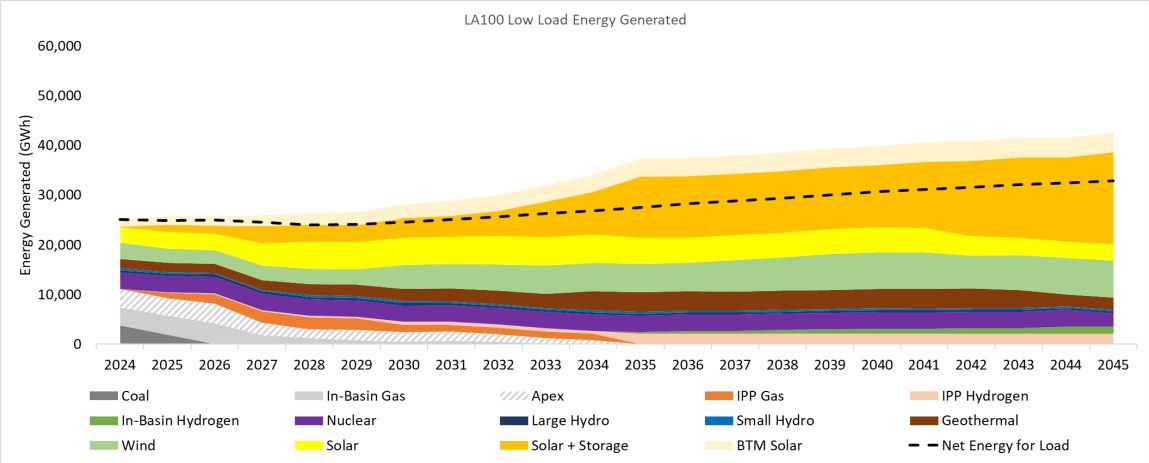


Figure 4-19. Projected energy generation mix under the LA100 Low Load Sensitivity. The sensitivity achieves 100% carbon-free electricity by 2035 through a phased transition from fossil fuels to clean energy resources. Coal is fully retired by 2025, and all natural gas-fueled generation is either phased out or converted to green hydrogen by 2035. The increasing contributions from solar, solar + storage, wind (onshore and offshore), geothermal, and in-basin hydrogen generation reflect the diversification and decarbonization of LADWP's supply portfolio. The dashed line represents net energy required to meet load, highlighting how renewable generation scales to meet demand over time.

Figure 4-19 illustrates the projected energy generation mix under the LA100 Low Load Sensitivity. To meet the City Council's directive of achieving 100% carbon-free electricity by January 1, 2035, the sensitivity transitions away from all fossil-fueled generation—including both coal and natural gas—by the end of 2034.

The LA100 Low Load Sensitivity is similar to the LA100 Pathway in its reliance on utility-scale solar + storage projects and behind-the-meter (BTM) rooftop solar—as well as increasing contributions from wind, and long-duration renewable resources such as geothermal. The generation mix is further diversified with contributions from small hydro, nuclear, and hydrogen-fueled thermal generation (converted from existing natural gas assets).

Unlike the LA100 Pathway, the LA100 Low Load Sensitivity has a lower net load and an altered resource portfolio to match decreased demand, which results in notable differences for the energy generation profile. The clearest disparity between the main pathway and sensitivity is the lower total expected energy generation by 2045, a direct

result of the lower total capacity of renewable resources in the portfolio. The lack of offshore wind energy in later years of the study due to such resources being left unselected, also contributes substantially to the lower energy generation in the sensitivity. As a result of lowering renewable purchases to align with lower load, the usage of dispatchable resources remains largely the same as the LA100 Pathway, especially after 2035, when all dispatchable thermal generation is replaced by green hydrogen.

As shown by the dashed black line, projected energy generation eventually exceeds net load in some years—highlighting potential curtailment during periods of oversupply. However, curtailment in the Low Load Sensitivity is much lower annually compared to curtailment in the LA100 Pathway, especially in the latter years of the study.

4.3.3 Customer Load with Modifiers

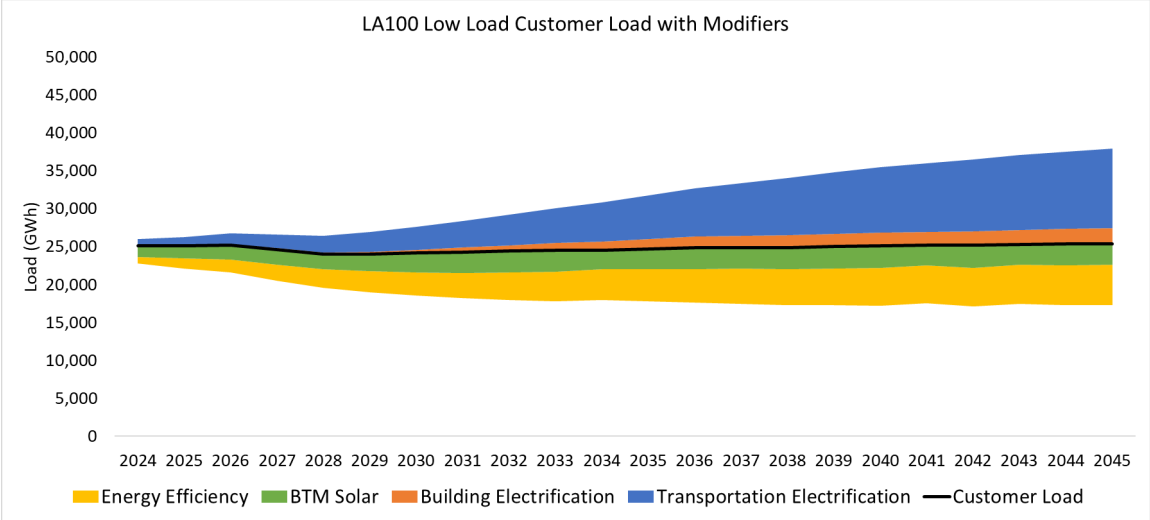


Figure 4-20. LA100 Low Load customer load with modifiers. While energy efficiency and behind-the-meter (BTM) solar reduce overall load, building electrification and especially transportation electrification significantly increase demand over time. Despite these competing forces, net customer load grows steadily, highlighting the importance of proactive planning to ensure reliable, carbon-free electricity delivery in a more electrified future.

Figure 4-20 illustrates projected customer electricity load through 2045 under the LA100 Low Load Sensitivity, incorporating major demand-side modifiers that influence net load. The black line represents total customer load after accounting for the combined impacts

of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification.

Compared to the LA100 Pathway, the Low Load Sensitivity has fairly low load growth when broken down to its modifiers. Like the LA100 Pathway, the sensitivity begins with an influx of load reducing energy efficiency programs and BTM solar adoption, but eventually steady building electrification and rapid transportation electrification promote higher load growth year over year. The key differences in the sensitivity are that a lack of "baseline" customer load growth ensures that growth is largely dependent on electrification which is more effectively balanced by the forecasted increase in BTM solar adoption compared to the LA100 Pathway.

4.3.4 Renewable and Clean Generation

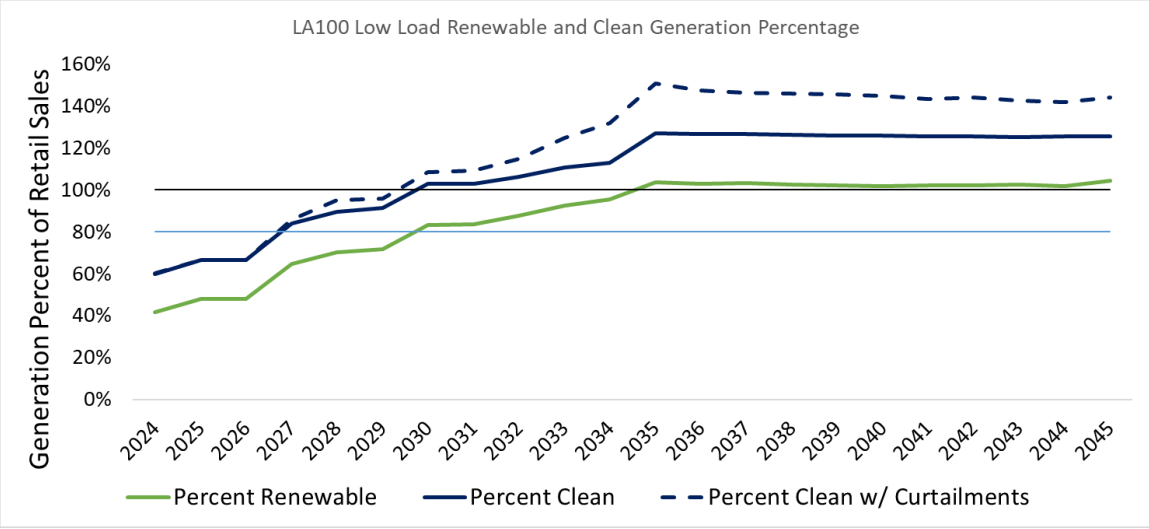


Figure 4-21. LA100 Low Load's renewable and clean generation percentage is expressed as a share of LADWP's retail electricity sales. The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro), while the solid dark blue line represents clean energy, which includes renewables along with large hydro and nuclear. The dashed blue line reflects clean energy including curtailed generation—energy produced but not used. The horizontal black line represents 100% of retail sales, and the light blue line marks the interim target of 80% renewable energy by 2030.

The LA100 Low Load Sensitivity mostly (Figure 4-21) mimics the trajectory of the LA100 Pathway as far as renewable growth. In the chart, the renewable portion, shown in green, increases steadily to meet the 80% target by 2030 and continues climbing gradually through 2045. The clean energy share, depicted in solid dark blue, includes additional

zero-carbon sources such as large hydro and nuclear, enabling LADWP to meet 100% of retail sales with clean energy by 2035.

The dashed line, which includes curtailed clean energy, rises above 100% starting in the early 2030s. This reflects the need to generate additional clean electricity to compensate for system losses, particularly those associated with the round-trip inefficiencies of energy storage technologies like batteries. Though the Low Load Sensitivity boasts slightly lower curtailment rates than the LA100 Pathway, curtailment is still expected to be a continuous factor in the sensitivity.

Altogether, the LA100 Low Load Sensitivity ensures that not only customer demand, but also the full operational footprint of the electric system is met with zero-carbon resources.

4.3.5 Renewable Curtailment

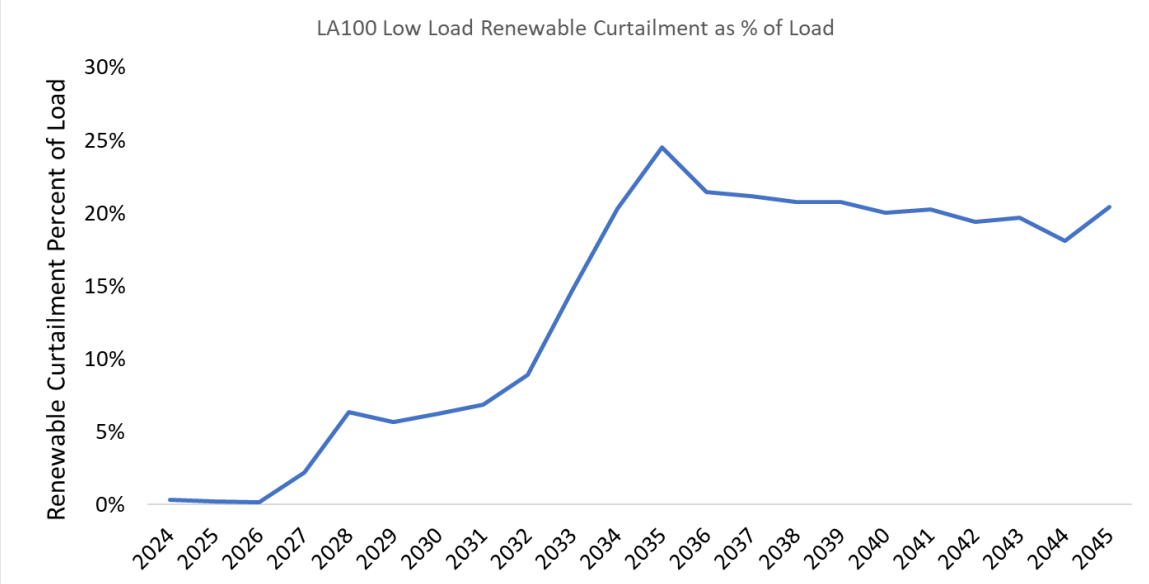


Figure 4-22. LA100 Low Load renewable curtailment as a percentage of net load represents the share of renewable energy that is generated but not ultimately used to serve customer demand. Curtailment levels increase in the early 2030s, peaking around 2035, as LADWP expands renewable energy deployment to meet carbon-free energy targets. Some curtailment is a planned and cost-effective outcome of a strategy that prioritizes broad renewable deployment over more expensive alternatives like green hydrogen for routine energy delivery.

Like the LA100 Pathway, curtailment in LA100 Low Load (Figure 4-22) begins to rise in the late 2020s and climbs significantly through the early 2030s, reaching a peak around 2035, when LADWP achieves its 100% carbon-free electricity goal. Rather than relying heavily on green hydrogen, which remains costly for routine generation, the sensitivity opts to deploy a broad and abundant mix of renewable resources. This approach ensures system reliability and cost-effectiveness, even if it results in some excess generation being curtailed.

This planned curtailment is a strategic tradeoff—allowing LADWP to reduce dependence on high-cost dispatchable fuels while still ensuring that all customer load (including line losses and storage inefficiencies) is served by clean, carbon-free energy. Curtailment is expected to remain a manageable and an accepted component of system operations in a high-renewable future.

4.3.6 Greenhouse Gas Emissions

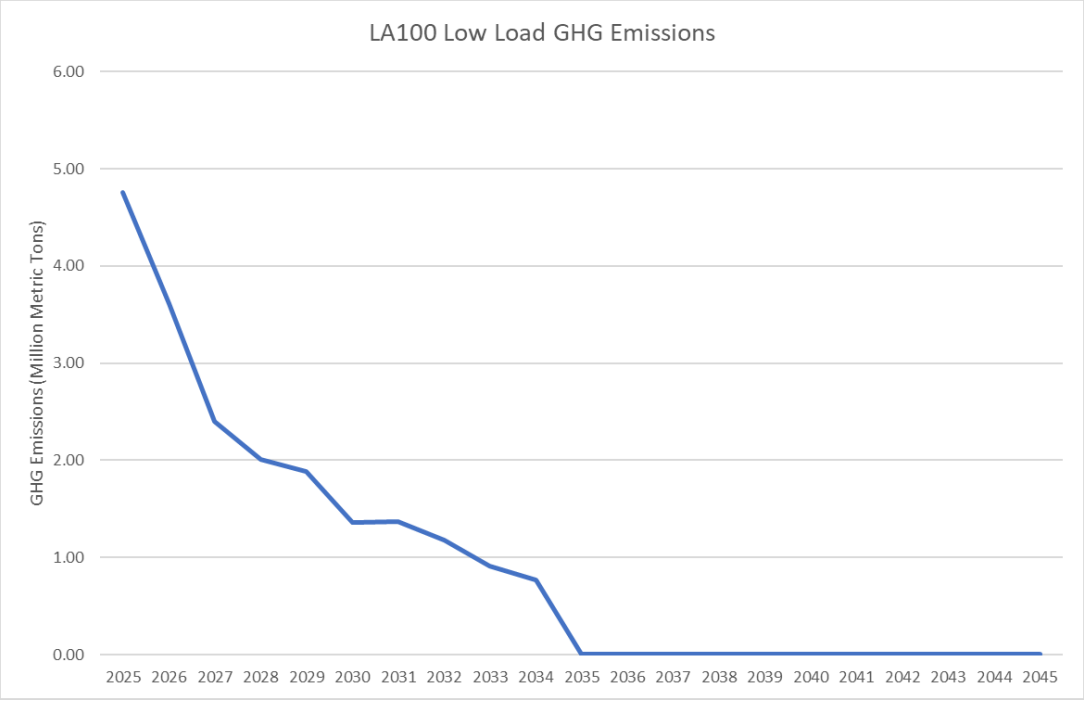


Figure 4-23. LA100 Low Load GHG emissions represent annual greenhouse gas emissions associated with electricity generation, measured in million metric tons. Emissions decline steeply from 2025 through 2035 as LADWP phases out coal and natural gas and transitions to a 100% carbon-free energy portfolio. Beginning in 2035, emissions reach effectively zero and remain at that level through 2045.

GHG emissions in the Low Load Sensitivity, as shown in Figure 4-23, mirror the LA100 Pathway and reflect LADWP's projected progress in eliminating carbon emissions from its power supply. Emissions begin at just under 5 million metric tons in 2025 and decline sharply over the next decade as coal-fired generation is fully retired and natural gas use is steadily reduced. The most significant drops occur between 2025 and 2035, driven by expanded deployment of renewable energy, increased energy efficiency, and the conversion of in-basin thermal generation to green hydrogen.

By 2035, LADWP achieves zero operational emissions, meaning no fossil fuels are used for electricity generation. This marks the fulfillment of the Los Angeles City Council's directive to provide 100% carbon-free electricity—not only to meet customer load, but also to serve transmission losses and storage inefficiencies with clean energy. From 2035 onward, emissions remain flat at zero, demonstrating sustained carbon-free operation through 2045.

This rapid and permanent decline in GHG emissions underscores the transformative nature of the LA100 Pathway and its contribution to meeting both local climate commitments and broader state and national decarbonization goals.

4.3.7 Annual System Cost

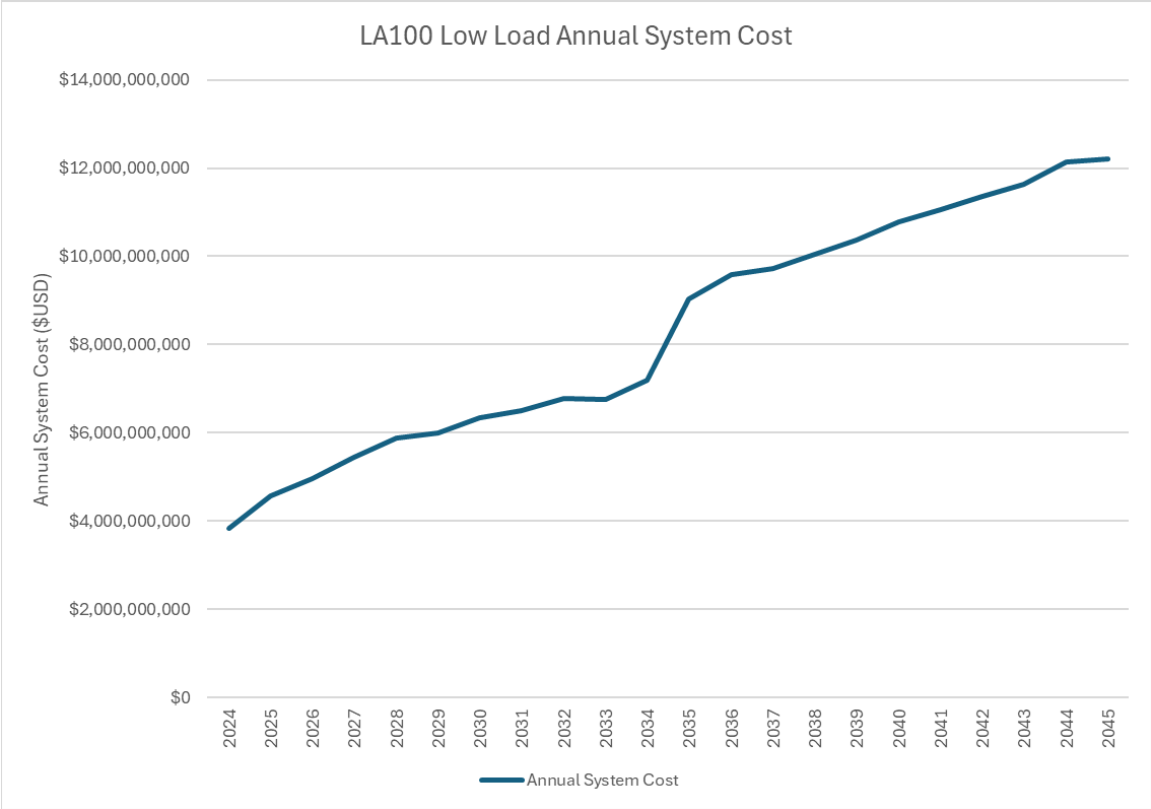


Figure 4-24. LA100 Low Load's annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (eHubs).

The LA100 Low Load Sensitivities annual system cost, shown in Figure 4-24, represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway through 2045. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, transmission, and distribution investments.

The cost of LA100 Low Load grows at a similar trajectory and rate as the LA100 Pathway due to similar factors of rising renewable, energy storage, and grid stabilizing purchases; as well as the influx of infrastructure necessary to meet the City's 100% carbon-free energy goal.

However, the lower load of the sensitivity allows for significant cost savings from purchasing lower amounts of renewable resources to align with the decreased load requirements of the portfolio. This leaves the Low Load Sensitivity at a lower year by year cost starting in the late 2020s, where renewables for the portfolio are most likely to be purchased en masse. Overall, The LA100 Low Load Sensitivity results in a lower total cost than the LA100 Pathway.

4.3.8 Key Takeaways

In evaluating how lower than expected load growth and a subsequent lower resource buildout would affect LADWP operations; the Low Load Sensitivity exhibited a few key discrepancies from the LA100 Pathway results. The reduction in hourly customer demand resulted in less periods of system strain, and less need by the model to supplement those periods with in-basin natural gas generation. Annual carbon emissions between 2025 and 2034 decreased slightly as a result (2.06 $MMTCO_2$ compared to 2.10 $MMTCO_2$ in the LA100 Pathway). With less load to serve and less resources built, the cost of the Low Load Sensitivity ($98.5 billion) is 4% lower than the LA100 Pathway, making it the second lowest-cost sensitivity based on the LA100 Pathway. It is important to note that a decreased total cost will not necessarily lead to lower electric rates. In the case of a lower overall load, the costs incurred must be spread over a smaller customer base, which may instead necessitate an increase in rates. Actual rate changes that may be enacted are uncertain and subject to more detail.

4.4 LA100 High Load Sensitivity

The LA100 High Load Sensitivity is derived from the core LA100 Pathway but assumes a higher net load than anticipated in the main pathway. As with the LA100 Pathway, this sensitivity requires that all electricity—including energy used to cover transmission and distribution losses—must come from carbon-free sources by January 1, 2035. The interim target of achieving an 80% renewable portfolio standard (RPS) by 2030 is also retained.

The LA100 High Load Sensitivity explores a future in which electricity demand grows faster than expected. This scenario evaluates the impacts of accelerated customer load growth—potentially driven by rapid electrification of buildings and transportation, population growth, or increased economic activity. Modeling this high-demand future allows LADWP to assess how more aggressive load growth could affect the scale and timing of clean energy investments, infrastructure needs, and system reliability. It also

helps ensure that resource planning remains resilient if energy demand surges beyond baseline expectations.

This sensitivity diverges from the LA100 Pathway in several key areas. Higher overall electricity demand, elevated peak loads, and lower-than-expected adoption of distributed energy resources (DERs) place increased pressure on system reliability and flexibility. As a result, the system relies more heavily on dispatchable carbon-free resources and incurs higher overall costs to maintain reliability and meet clean energy goals.

By 2035, the LA100 High Load Sensitivity includes the deployment of:

- 1,424 MW of local distributed solar,
- 3,434 GWh of cumulative energy efficiency savings,
- 331 MW of distributed energy storage, and
- 615 MW of demand response capacity.

These investments reflect a comprehensive and locally targeted approach to meeting clean energy objectives while ensuring the grid remains reliable and resilient under high-demand conditions.

Higher electric load has the potential to improve rate affordability by increasing total retail electricity sales, which can help offset system costs and support key financial metrics such as debt service coverage ratios. In this way, increased load can spread fixed costs across a larger base of customer usage, mitigating upward pressure on rates. However, while future load growth could provide these benefits, it depends on a range of factors—including economic trends, electrification of buildings and vehicles, and customer behavior—and should not be assumed as a given when planning for affordability.

4.4.1 Capacity Expansion

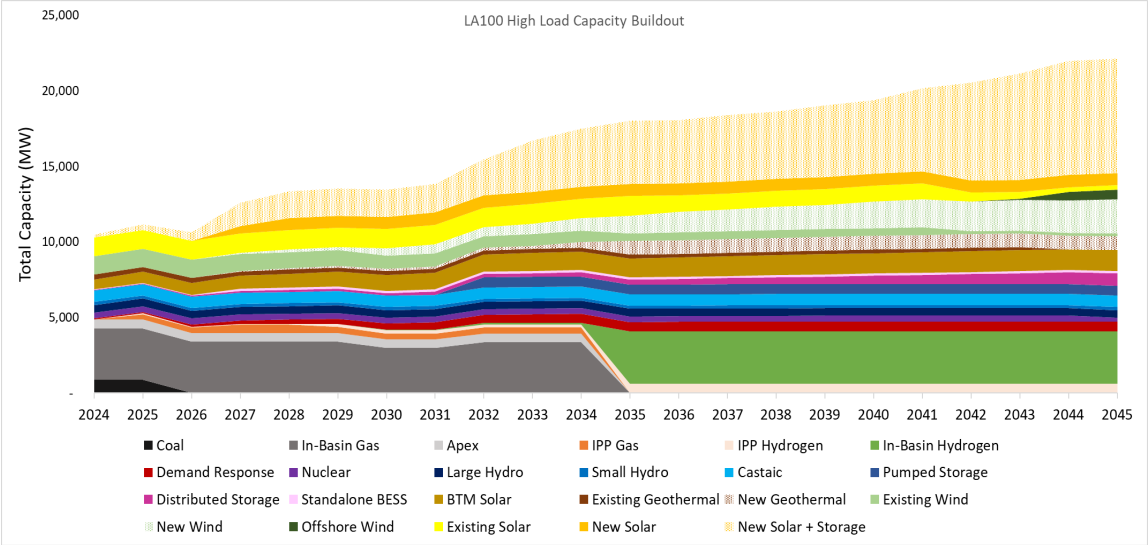


Figure 4-25. LA100 High Load Capacity Buildout.

The LA100 High Load Sensitivity assumes the same buildout of clean energy resources as the LA100 Pathway to meet Los Angeles' goal of delivering 100% carbon-free electricity by 2035. As shown in the chart in Figure 4-25, the transition is driven by major additions of new solar paired with storage, green hydrogen, and wind power, including both onshore and offshore resources.

Major milestones such as the retirement of coal-fired generation in 2025, and the transition of in-basin thermal generation to green hydrogen by 2035, remain the same as the LA100 Pathway within this sensitivity. Long-duration renewable technologies such as geothermal are also employed in the sensitivity, contributing further dispatchable capacity to balance variable wind and solar. These resource additions reflect the insights derived from the LA100 Study conducted by NREL, which emphasized the need to have firm dispatchable resources within the resource portfolio.

With this resource portfolio, the sensitivity continuously complies with the City's directive for emissions-free electricity, while remaining reliable and resilient throughout the study horizon.

4.4.2 Generation Dispatch

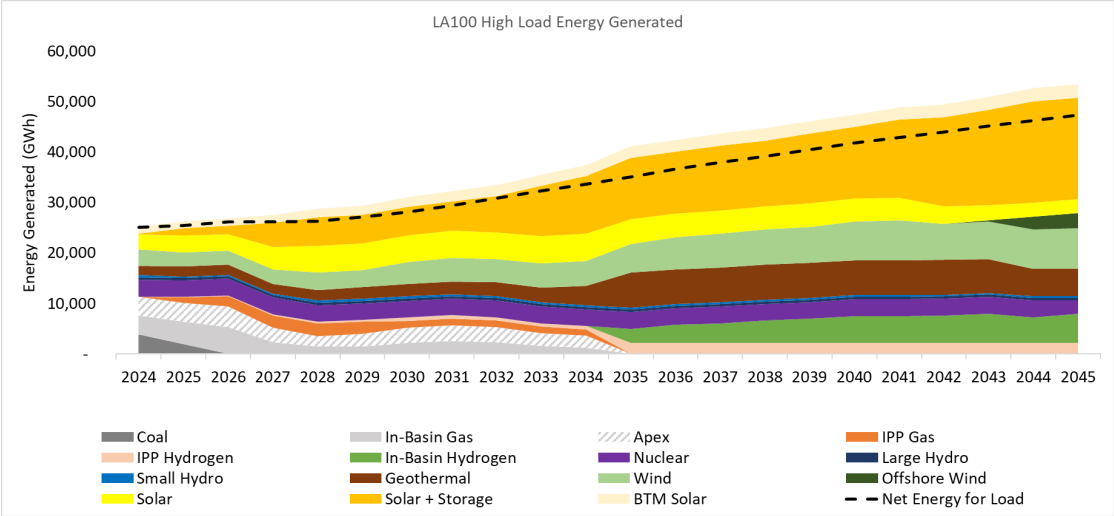


Figure 4-26. Projected energy generation mix under the LA100 High Load Sensitivity. LA100 High Load achieves 100% carbon-free electricity by 2035 through a phased transition from fossil fuels to clean energy resources. Coal is fully retired by 2025, and all natural gas-fueled generation is either phased out or converted to green hydrogen by 2035. The increasing contributions from solar, solar + storage, wind (onshore and offshore), geothermal, and in-basin hydrogen generation reflect the diversification and decarbonization of LADWP's supply portfolio. The dashed line represents net energy required to meet load, highlighting how renewable generation scales to meet demand over time.

Figure 4-26 illustrates the projected energy generation mix in the LA100 High Load Sensitivity. To meet the City Council's directive of achieving 100% carbon-free electricity by January 1, 2035, the sensitivity transitions away from all fossil-fueled generation—including both coal and natural gas—by the end of 2034.

The High Load Sensitivity is similar to the LA100 Pathway in its reliance on utility-scale solar + storage projects and behind-the-meter (BTM) rooftop solar—as well as increasing contributions from wind, offshore wind, and long-duration renewable resources such as geothermal. The generation mix is further diversified with contributions from small and large hydro, nuclear, and hydrogen-fueled thermal generation (converted from existing natural gas assets).

Unlike the LA100 Pathway, The High Load Sensitivity has a much higher net load which results in notable differences for the energy generation profile. For instance, the sensitivity shows much higher usage of in-basin dispatchable hydrogen compared to the

LA100 Pathway. This increased dispatch is necessary to make up for energy deficits that occur in certain instances of high demand or low renewable generation. There are regular periods in the sensitivity where variable energy resources such as wind and solar cannot match the increased demand on their own. This has a cascading effect, where energy generated by renewables must be contributed directly to the load during high demand periods instead of being used to charge energy storage resources, which could serve to alleviate demand when those renewables are unavailable. As such, dispatchable generation becomes prudent to fill in the gaps created and ensure that demand is met in these instances and even more so during peak demand events or emergency outages.

Another notable effect of the higher net load is a significant reduction in the curtailment of renewable energy resources in the portfolio which will be discussed in greater detail throughout the section. There is also a decrease in energy provided by BTM solar resources due to an assumed lower total capacity of the resource. Though, relative to the whole portfolio, the decreased availability of BTM Solar does not have a significant effect on the outcome of energy dispatch.

4.4.3 Customer Load with Modifiers

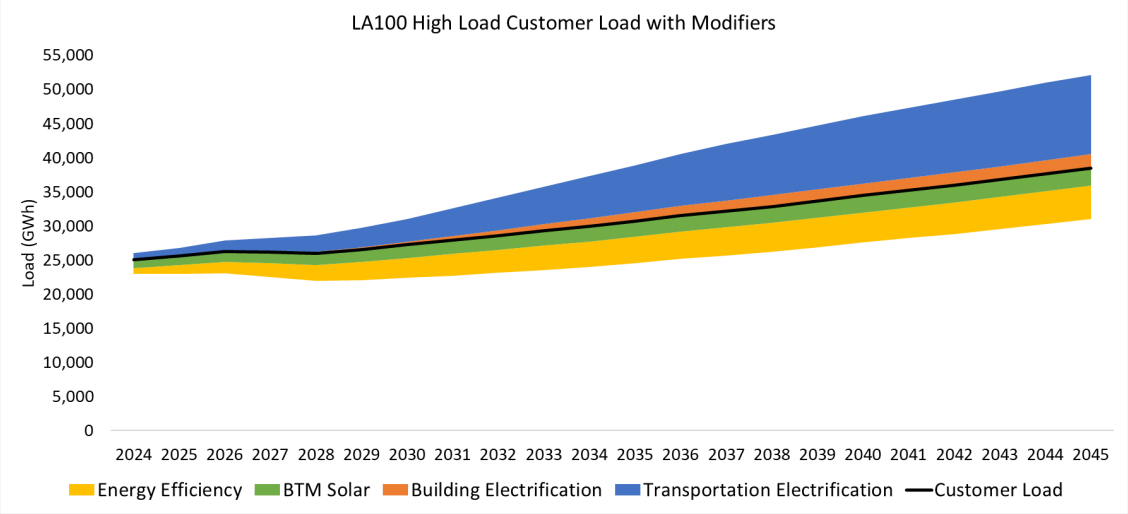


Figure 4-27. LA100 High Load customer load with modifiers. While energy efficiency and behind-the-meter (BTM) solar reduce overall load, building electrification and especially transportation electrification significantly increase demand over time. In the High Load sensitivity, net customer load grows rapidly, highlighting the importance of proactive planning to ensure reliable, carbon-free electricity delivery in a more electrified future.

Figure 4-27 illustrates projected customer electricity load through 2045 under the LA100 High Load Sensitivity, incorporating major demand-side modifiers that influence net load. The black line represents total customer load after accounting for the combined impacts of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification.

The High Load Sensitivity sees much higher growth rates for transportation electrification and slower growth for BTM solar and energy efficiency compared to the LA100 Pathway. These changes alongside much steeper "baseline" customer load growth, lead to much greater increases in the total load year over year and a much higher total load overall.

4.4.4 Renewable and Clean Generation

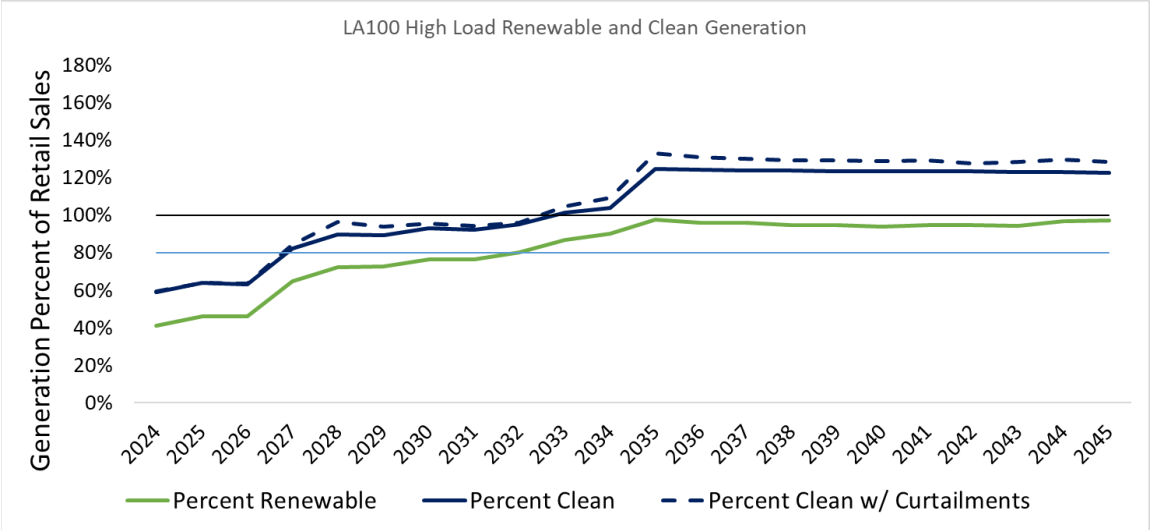


Figure 4-28. LA100 High Load renewable and clean generation percentage is expressed as a share of LADWP's retail electricity sales. The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro), while the solid dark blue line represents clean energy, which includes renewables along with large hydro and nuclear. The dashed blue line reflects clean energy including curtailed generation—energy produced but not used. The horizontal black line represents 100% of retail sales, and the light blue line marks the interim target of 80% renewable energy by 2030.

The LA100 High Load Sensitivities renewable and clean generation percentage reflects LADWP's path toward meeting the City Council's goal of providing 100% carbon-free electricity by 2035. All values are shown as a percentage of retail sales, which refer to the electricity actually delivered to customers (excluding losses).

The renewable portion, shown in green in Figure 4-28, increases steadily but falls short of the 80% RPS target by 2030, instead reaching 80% RPS by 2032 due to the increased load being forecasted. It continues to climb until it peaks just under 100% in 2035. The clean energy share, depicted in solid dark blue, includes additional zero-carbon sources such as large hydro and nuclear, and comprises 100% of generation by 2033, enabling LADWP to meet 100% of retail sales with clean energy by 2035.

The dashed line, which includes curtailed clean energy, rises above 100% starting in 2033 in line with the clean energy share. As previously mentioned, the percent curtailed is much lower in the High Load Sensitivity, only rising slightly above the actual clean energy share through 2045. This reflects that the excess clean electricity produced by renewable resources is aptly utilized under the higher load projections of the sensitivity, rather than being curtailed as is common in the LA100 Pathway. Altogether, the LA100 Pathway ensures that not only customer demand, but also the full operational footprint of the electric system, is met with zero-carbon resources.



4.4.5 Renewable Curtailment

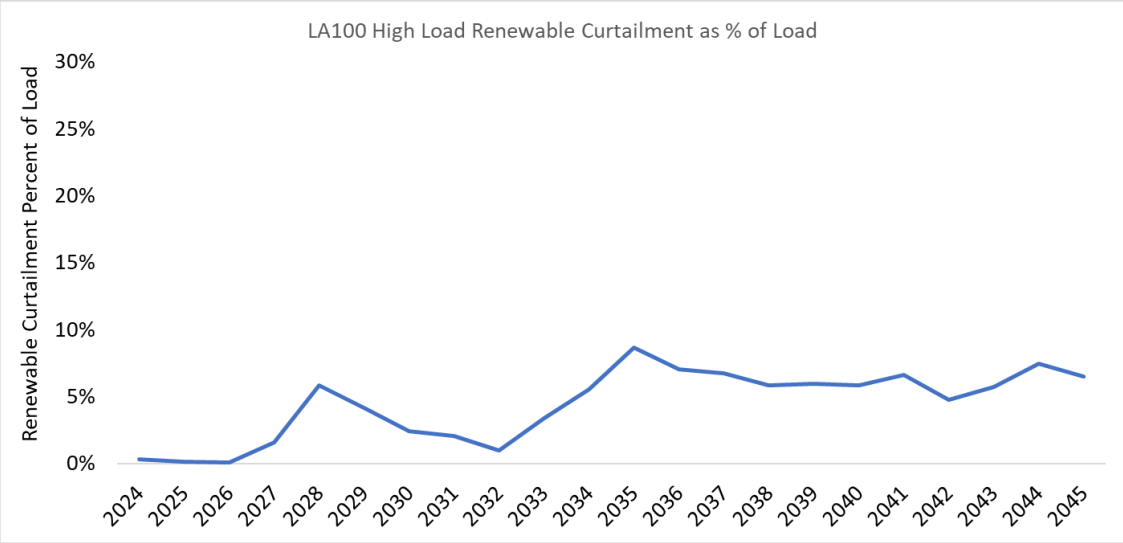


Figure 4-29. LA100 High Load renewable curtailment as a percentage of net load represents the share of renewable energy that is generated but not ultimately used to serve customer demand. Curtailment levels increase in the early 2030s, peaking around 2035, as LADWP expands renewable energy deployment to meet carbon-free energy targets. Some curtailment is a planned and cost-effective outcome of a strategy that prioritizes broad renewable deployment over more expensive alternatives like green hydrogen for routine energy delivery.

In the High Load Sensitivity, curtailment fluctuates between fairly low percentage values which are significantly lower than those seen in the LA100 Pathway as seen in Figure 4-29. As explained in previous sections, curtailment can occur because of grid constraints, storage limitations, periods of excess generation, or from intentional resource planning decisions. Curtailment from excess generation is especially prudent in explaining this sensitivity, as more curtailment becomes necessary in later years of the LA100 Pathway due to renewables generating energy during certain hours at a magnitude that often exceeds the expected load. The higher load in this sensitivity means that high instantaneous renewable generation comes much closer to meeting load expectations exactly, rather than exceeding them like in the LA100 Pathway. This ensures that energy purchased by LADWP will be used by LADWP, with less of it being 'wasted' or sold off at a lower price than the purchasing value.

Even with the resulting cost savings from lower curtailment, the LA100 High Load Sensitivity still results in higher cost than the LA100 Pathway due to the need to utilize

more high-cost dispatchable fuels in the resource portfolio to meet higher demand.

4.4.6 Greenhouse Gas Emissions

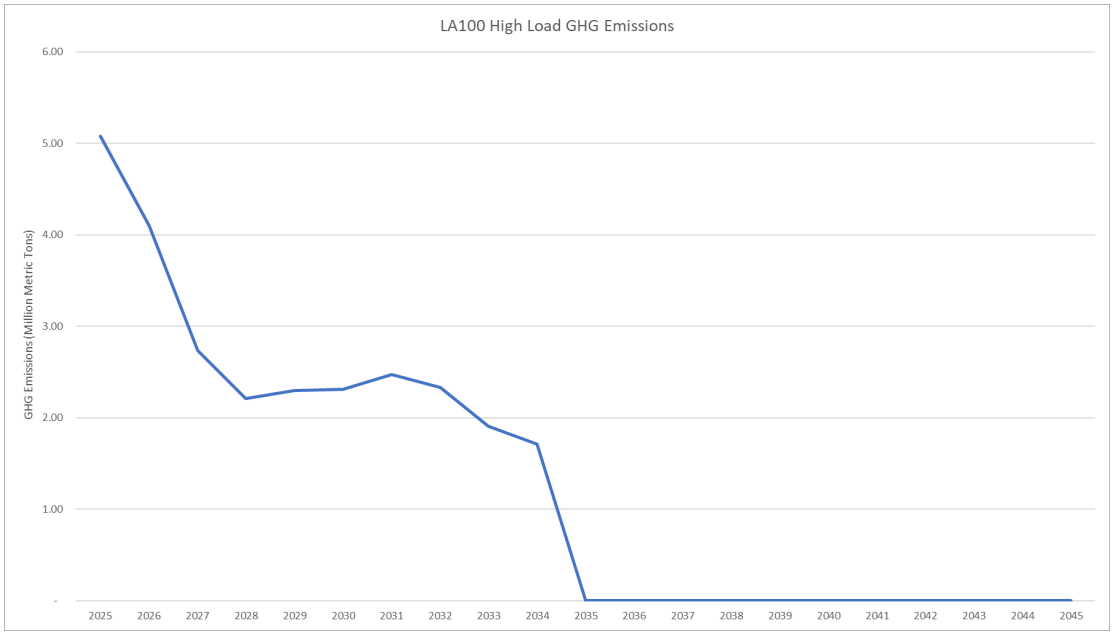


Figure 4-30. LA100 High Load GHG emissions represent annual greenhouse gas emissions associated with electricity generation, measured in million metric tons. Emissions decline steeply from 2025 through 2035 as LADWP phases out coal and natural gas and transitions to a 100% carbon-free energy portfolio. Beginning in 2035, emissions reach effectively zero and remain at that level through 2045.

GHG emissions from the LA100 High Load Sensitivity, shown in Figure 4-30, reflect LADWP's projected progress in eliminating carbon emissions from its power supply. Emissions begin at slightly above 5 million metric tons in 2025 and decline sharply through 2028 as coal-fired generation is fully retired and fossil gas use is steadily reduced. From 2028 to 2035 emissions raise then slightly decrease, driven by higher customer loads necessitating higher dispatch of the natural gas units.

By 2035, LADWP achieves zero operational emissions, meaning no fossil fuels are used for electricity generation. This marks the fulfillment of the Los Angeles City Council's directive to provide 100% carbon-free electricity—not only to meet customer load, but also to serve transmission losses and storage inefficiencies with clean energy. From 2035 onward, emissions remain flat at zero, demonstrating sustained carbon-free operation through 2045

4.4.7 Annual System Cost

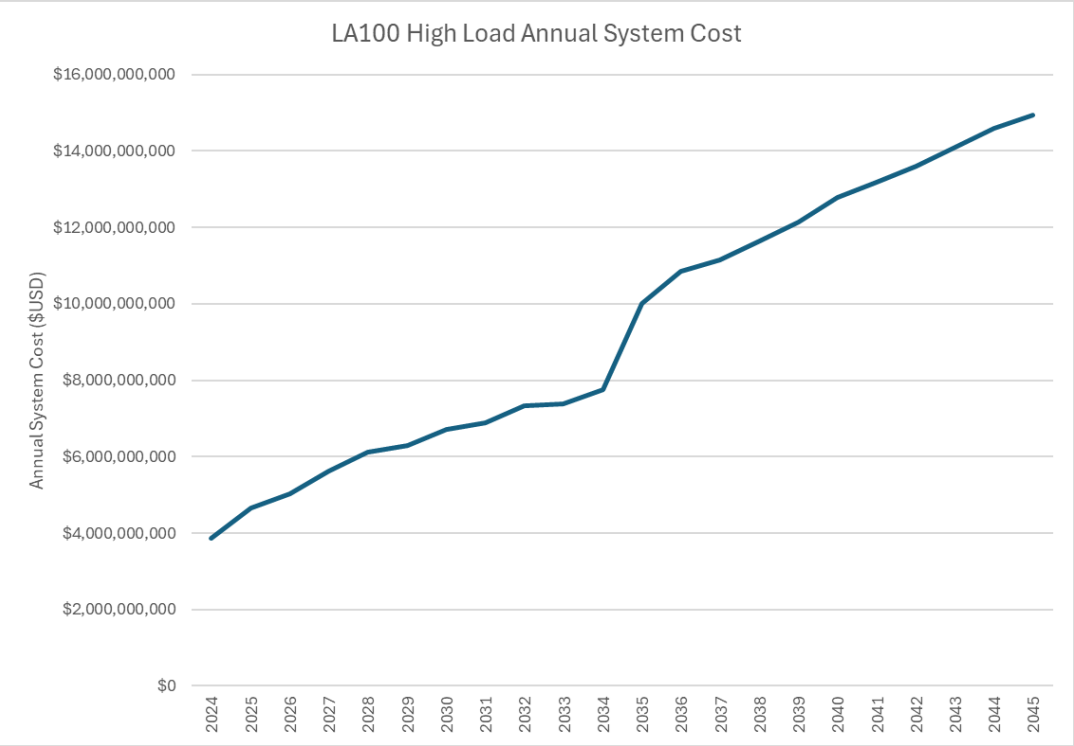


Figure 4-31. LA100 High Load annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (eHubs).

LA100 High Loads annual system cost (Figure 4-31) represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway through 2045. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, transmission, and distribution investments.

The cost of the LA100 High Load Sensitivity grows at the same trajectory and rate as the LA100 Pathway due to the same factors of rising renewable, energy storage, and grid stabilizing purchases; as well as the influx of infrastructure necessary to meet the City's 100% carbon-free energy goal.

However, due to increased load growth, and the subsequent higher costs incurred to meet increased demand, such as fuel costs from increased dispatchable unit operations, the annual cost is much higher than the LA100 Pathway, and its total cost is the highest among all sensitivities explored during modeling.

4.4.8 Key Takeaways

Under the High Load Sensitivity, the load growth increase was evaluated for its impact on reliability and led to an increase in annual carbon emissions between 2025 and 2034 (2.78 $MMTCO_2$ compared to 2.10 $MMTCO_2$ in the LA100 Pathway). The outcome reflects a shift in the model's dispatch decisions, favoring natural gas generation for the increased load. With the increase in load, the total system cost from 2025 to 2045 ($104.4 billion) is 7% higher than the LA100 Pathway. Customer demand increases at 2.06% annually on average versus 1.06% for LA100. In-basin dispatchable resources will run at an average 17% capacity factor from 2035 to 2045, however if load trends are higher than expected, additional renewable energy would be planned to meet the demand. The system will maintain reliable operations and achieve the clean energy target by 2035, and increased load may put downward pressure on rates.

4.5 LA100 Low DER Sensitivity

The LA100 Low DER Sensitivity models a future where customers adopt fewer distributed energy resources (DERs)—such as rooftop solar, battery storage, and other behind-the-meter technologies—than anticipated. This sensitivity explores the implications of reduced customer-side participation in the energy transition, whether due to financial, regulatory, or behavioral barriers. By examining this lower-DER future, LADWP can better understand how shortfalls in DER deployment might affect system-wide resource needs, utility-scale investment strategies, and overall grid flexibility. This analysis helps ensure that long-term plans remain robust even if customer adoption of clean energy technologies falls short of projections.

As with the LA100 Pathway, this sensitivity requires that all electricity—including energy used to cover transmission and distribution losses—must come from carbon-free resources by January 1, 2035, and it retains the interim target of achieving an 80% renewable portfolio standard (RPS) by 2030.

Lower levels of DER adoption increase reliance on the central grid, requiring greater investment in utility-scale generation, transmission infrastructure, and firm clean

capacity. This sensitivity highlights the critical role of centralized resources in achieving decarbonization under constrained customer participation and raises important considerations around cost, equity, and grid design.

4.5.1 Capacity Expansion

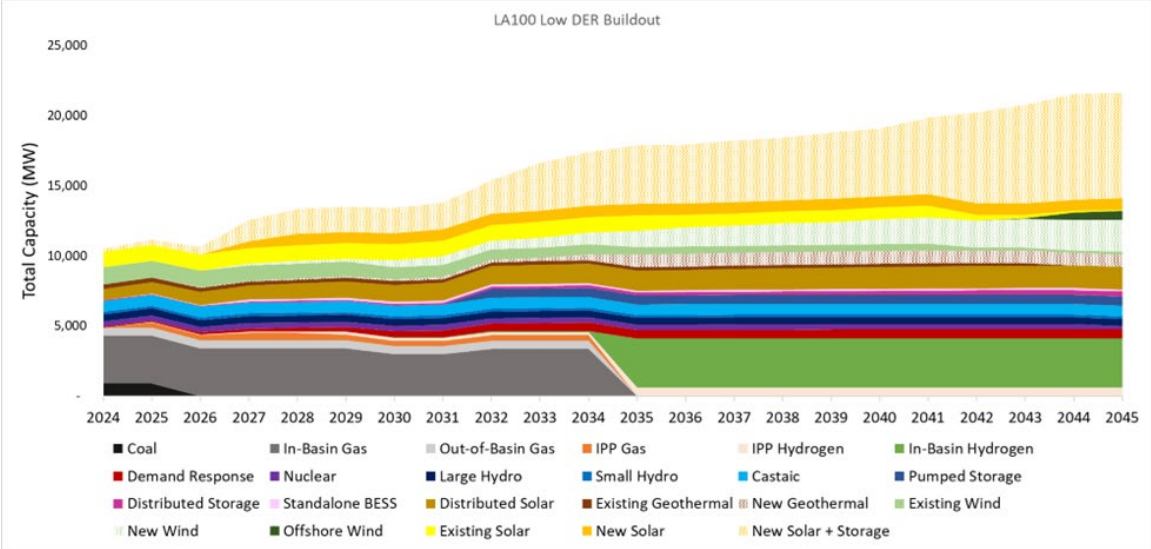


Figure 4-32. LA100 Low DER buildout. In alignment with LA100 Pathway goals to eliminate fossil fuels and decarbonize fully by 2035, coal is fully retired by 2025, followed by dramatic drops in In-Basin Gas and IPP Gas (natural gas) by 2035. In-Basin Hydrogen begins appearing around 2030 and rapidly increases starting 2035 with the intent of replacing retiring natural gas-fueled power plants. The LA100 Pathway also requires a substantial buildout of clean energy resources to meet Los Angeles' goal of delivering 100% carbon-free electricity by 2035. Solar + Storage grows dramatically post-2030, becoming the largest capacity contributor by 2045. Wind has moderate growth and steady increases after 2035. The chart also shows a gradual increase in geothermal, which offers essential dispatchable capacity to balance variable wind and solar. Distributed Solar & Storage shows little to no growth.

In Figure 4-32, the resource mix shifts dramatically from fossil fuels toward large-scale renewables and firm zero-carbon solutions. Low DER participation leads to significantly higher reliance on utility-scale resources such as New Solar + Storage and green-hydrogen capable resources. Demand Response and Distributed Storage remain small, showing LADWP's grid must rely more on large centralized systems for reliability and flexibility. On average, DER adoption grows at 5.24% annually versus 6.85% for the LA100 Pathway.

4.5.2 Generation Dispatch

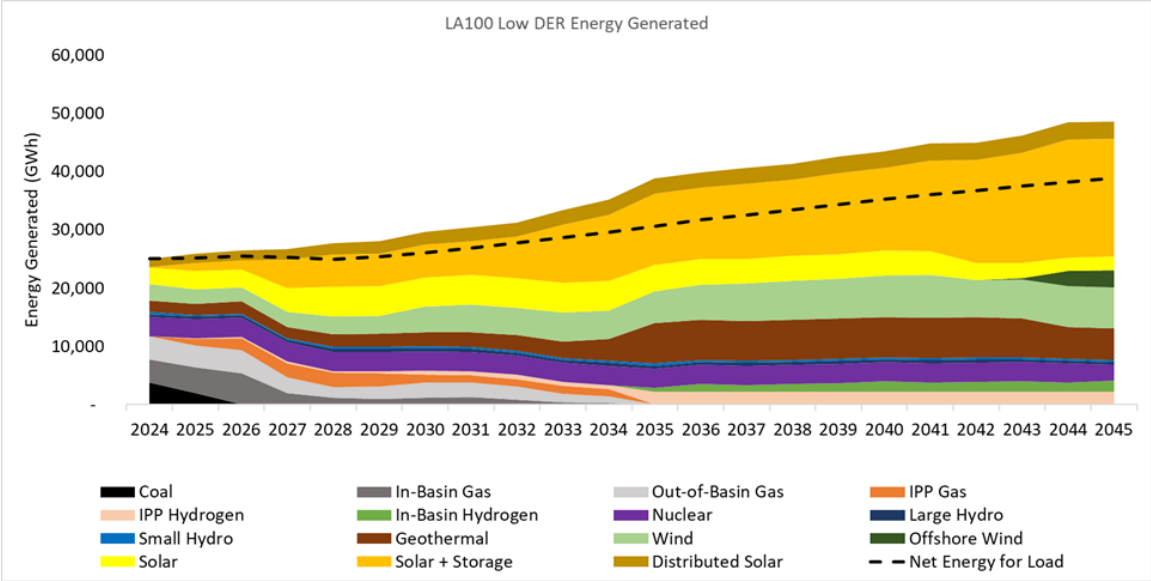


Figure 4-33. LA100 Low DER energy generated. With low DER generation, the decline of fossil fuels (Coal, IPP Gas, and In-Basin Gas) continues from 2024-2035. This reflects LADWP's effort to decarbonize and comply with SB 100 and LA100 targets. Similarly, the rise of renewable generation continues to rise with solar+ storage becoming the largest source of energy by 2035 and wind gradually increasing and stabilizing after 2035. However, distributed solar is lower in total contribution, which is consistent with assumptions for the Low DER Sensitivity. Geothermal and nuclear remain relatively stable. Reliance on in-basin hydrogen grows steadily and fills the gap left by retiring natural gas-fueled resources, with IPP Hydrogen playing a supplementary role. The dashed line represents net energy required to meet load, highlighting how renewable generation scales to meet demand over time.

Figure 4-33 shows annual electricity generation by resource (in GWh) under the Low DER Sensitivity based on the LA100 Pathway modeling. The dashed black line represents net energy for load—the total electricity demanded after offsets from DERs and increased electrification. Due to the decrease in distributed energy resources, the net load observed is higher than the LA100 Pathway load by a notable margin. The Low DER Sensitivity places a greater burden on LADWP to build out utility-scale renewable and firm generation, which leads to higher energy generation from these resource types. The limited role of customer-owned resources means the clean energy transition in the Low DER Sensitivity relies more heavily on centralized energy systems and large-scale infrastructure development.

4.5.3 Customer Load with Modifiers

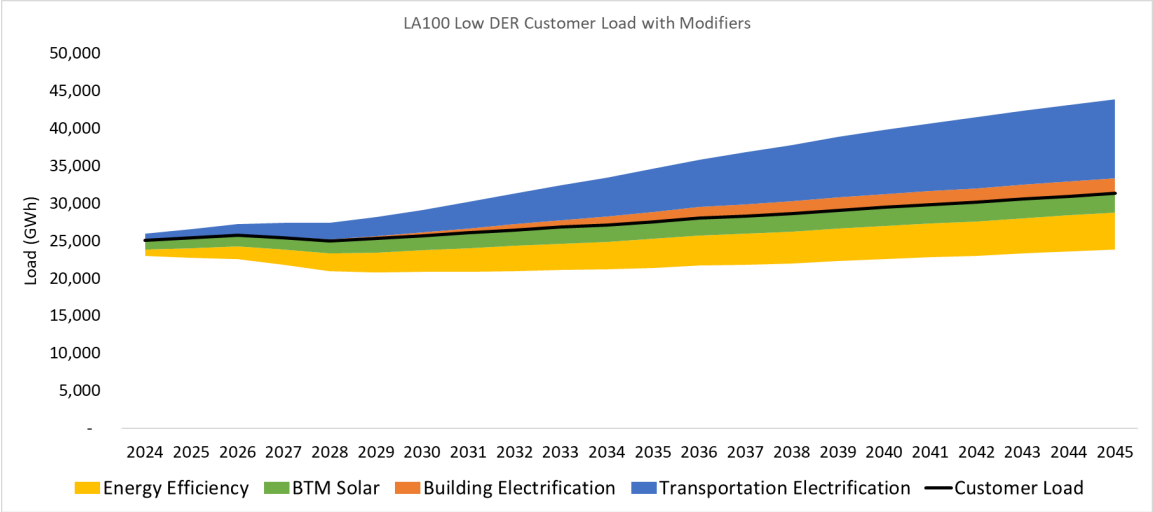


Figure 4-34. LA100 Low DER customer load with demand-side modifiers. Although energy efficiency and behind-the-meter (BTM) solar help decrease overall electricity demand, building electrification—and particularly transportation electrification—drive a substantial increase in load over time.

Figure 4-34 displays projected customer electricity load through 2045 under the LA100 Low DER sensitivity, factoring in major demand-side modifiers that influence net load. The black line represents total customer load after accounting for the combined impacts of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification. With Low DER adoption, BTM solar continues to contribute to load reduction, however at much lower capacities than the baseline LA100 Pathway. DERs play a critical role in mitigating peak loads, but are not as effective in eliminating overall load growth.

4.5.4 Renewable and Clean Generation

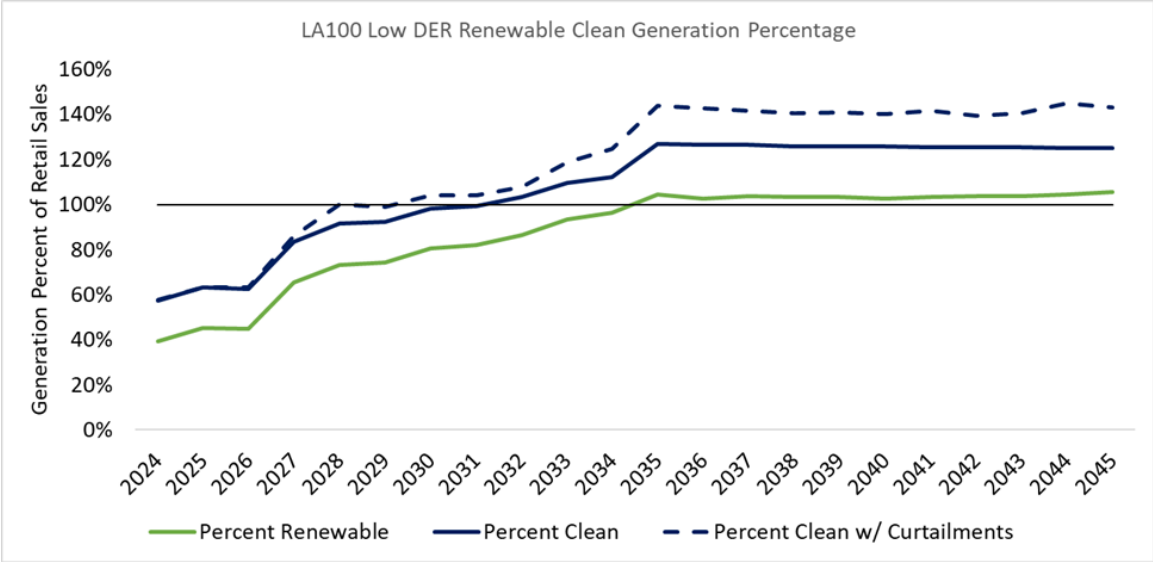


Figure 4-35. LA100 Low DER renewable and clean generation percentage is expressed as a share of LADWP's retail electricity sales. The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro), while the solid dark blue line represents clean energy, which includes renewables along with large hydro and nuclear. The dashed blue line reflects clean energy including curtailed generation—energy produced but not used. The horizontal black line represents 100% of retail sales.

In Figure 4-35, all metrics—renewable and clean generation—increase steadily from 2024 through 2035, with flattening trends beyond 2035. This reflects early investments and transitions, followed by a plateau likely due to system saturation or diminishing marginal returns. Exceeding 100% of retail sales means LADWP is generating surplus clean energy, which could be stored, exported, or curtailed. High curtailments post-2035 implies a need for enhanced grid flexibility such as demand response, energy storage, transmission upgrades, and greater DER integration. Compared to the LA100 Pathway, with lower DER implementation the gap between the dashed and solid blue lines (particularly from 2030 onward) is closer, representing a decrease in clean energy curtailment.

4.5.5 Renewable Curtailment

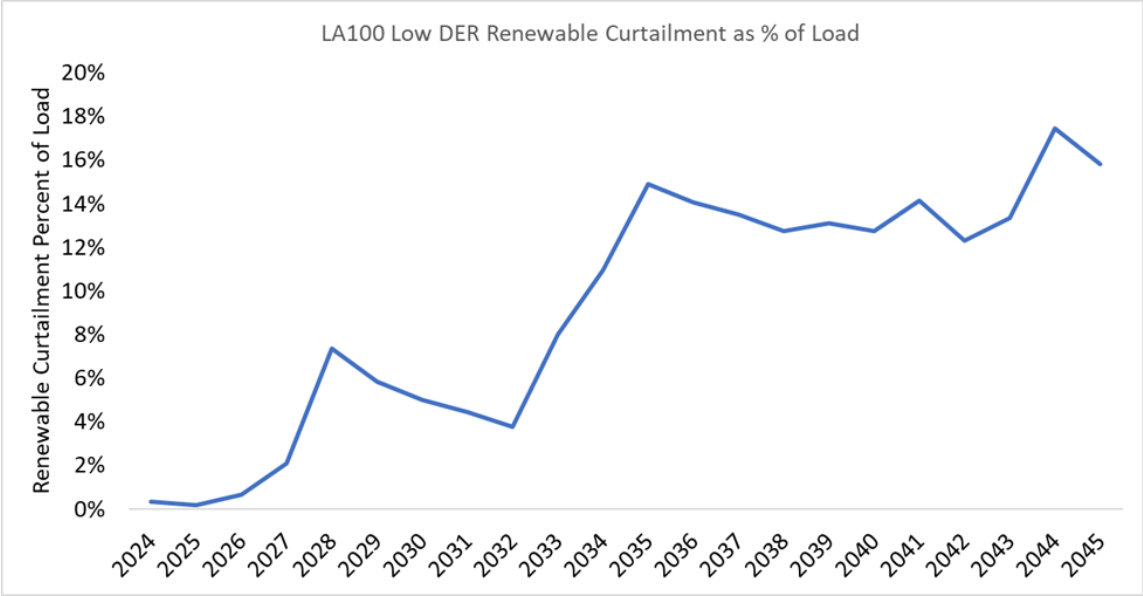


Figure 4-36. LA100 Low DER renewable curtailment as a percentage of net load represents the share of renewable energy that is generated but not ultimately used to serve customer demand. Curtailment levels increase in the early 2030s, peaking around 2035, as LADWP expands renewable energy deployment to meet carbon-free energy targets.

Figure 4-36 displays how low levels of distributed energy resources affect renewable energy curtailment within LADWP service territory. Curtailment occurs when available renewable energy cannot be utilized due to system constraints such as transmission limitations or low demand during periods of high generation. DERs—including rooftop solar photovoltaics, behind-the-meter energy storage, and demand-side management technologies—can also play a key role in shaping load profiles and influencing curtailment patterns. Compared to the LA100 Pathway where curtailment reaches a peak of 21% when LADWP achieves its 100% carbon-free electricity goal in 2035, in the LA100 Low DER sensitivity, it is 17%. This shows that if DER levels are low, curtailment of renewable energy is lower. This is because energy demand that would otherwise be met by customers through their own BTM resources must instead be filled from the grid via utility-scale renewables. Also, utility-scale solar and wind have more space on the electric grid to integrate without being displaced by customer-sited solar (e.g., rooftop PV). In other words, the centralized grid can be more easily controlled than scattered DERs.

4.5.6 Greenhouse Gas Emissions

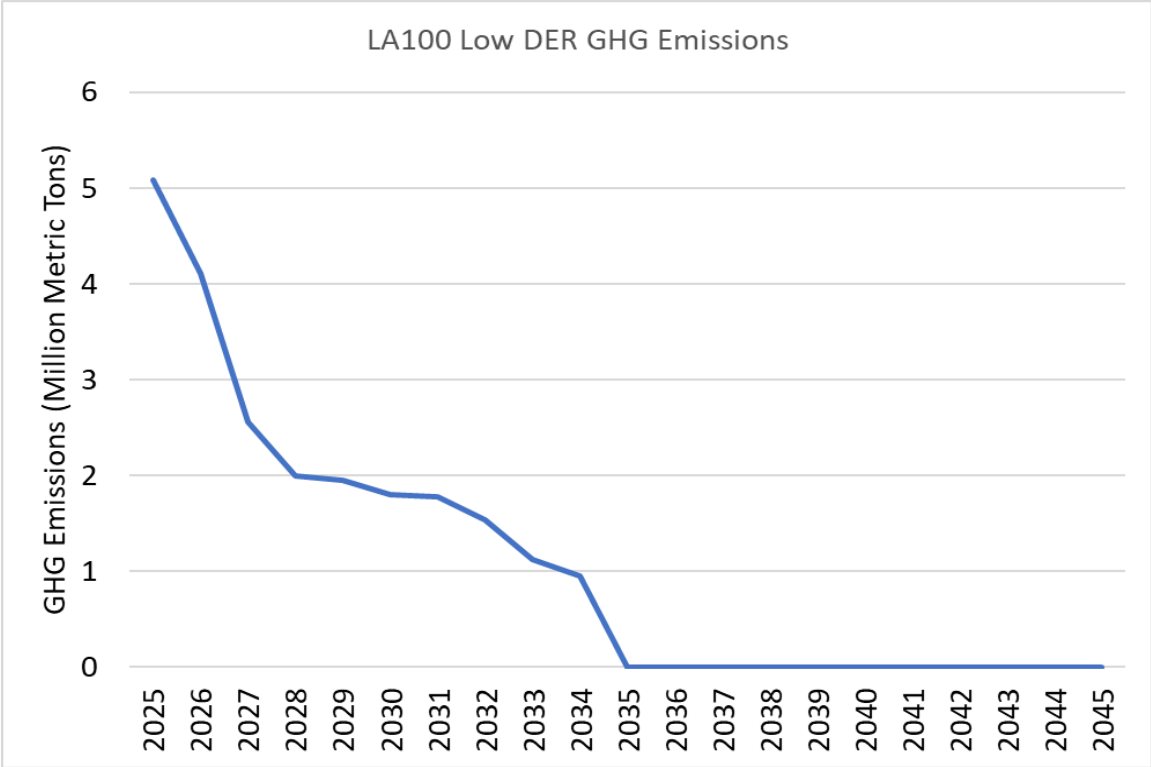


Figure 4-37. LA100 Low DER GHG emissions represent annual greenhouse gas emissions associated with electricity generation, measured in million metric tons. From 2025 through 2035, modest GHG reductions occur primarily through retirement of some fossil assets and increased utility-scale renewables. From 2035–2045, major GHG reductions are achieved through conversion of in-basin thermal units to green hydrogen and expanded utility-scale clean energy with zero emissions reached by 2035 and continuing through 2045.

Figure 4-37 highlights that even with low DER adoption, LADWP can achieve deep decarbonization. Like the LA100 Pathway, GHG emissions drop to 0% by 2035 and remain there through 2045. Progressively, utility-scale renewables fill the bulk of energy demand and fossil fuel generation declines, being replaced with green hydrogen, energy storage, and transmission expansion to ensure reliability. However, achieving decarbonization with low DER adoption will require more investment in utility-scale infrastructure and a higher total generation capacity to meet demand. While the trajectory of the sensitivity is similar to the LA100 Pathway, near-term reductions are slightly lower and cumulative emissions are greater due to increased natural gas usage prior to 2035.

4.5.7 Annual System Cost

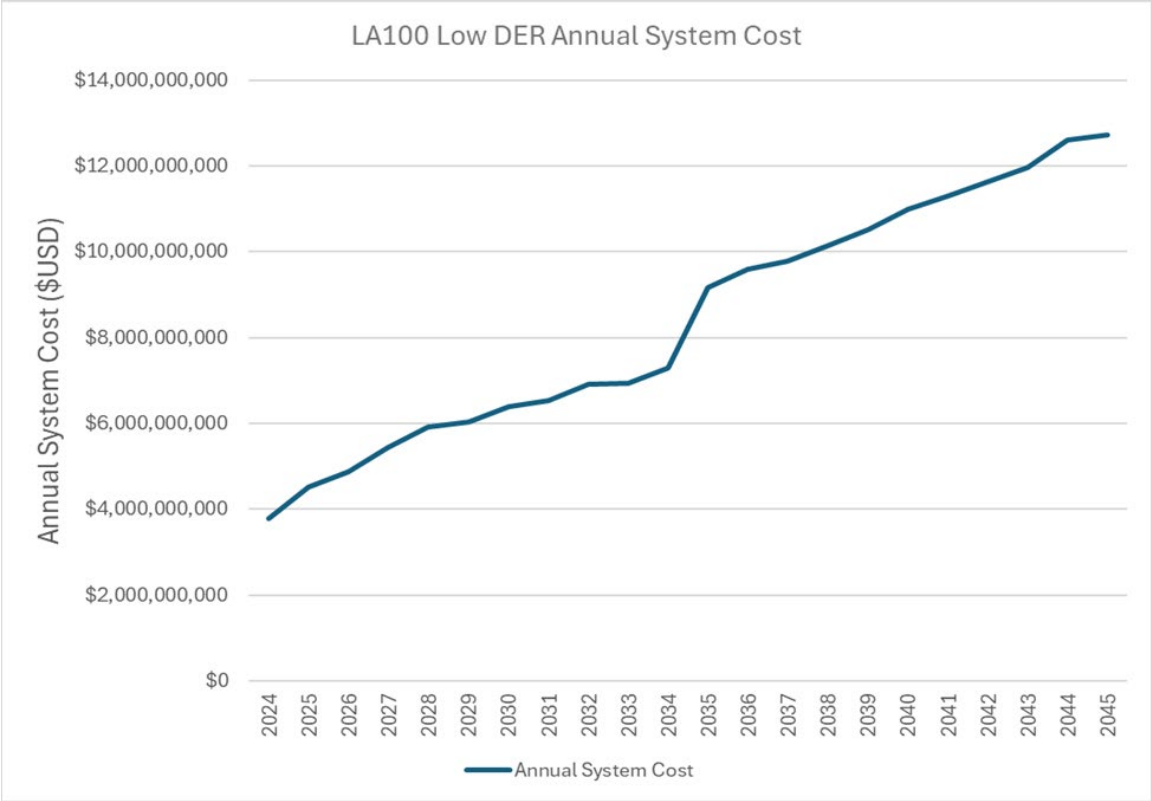


Figure 4-38. LA100 Low DER annual system cost. Annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (eHubs).

In Figure 4-38, lower customer participation in distributed energy solutions leads to steadily rising annual system costs, driven by utility capital investments, fuel and operational expenditures, and the scale of hydrogen infrastructure needed. As distributed flexibility is limited, more green hydrogen is required post-2035 to maintain reliability with low-capacity-factor thermal plants. The production, storage, and use of green hydrogen significantly raise the annual operating costs in the Low DER sensitivity. Costs decrease slightly driven by less spending on Net Energy Metered (NEM) solar, Feed-in Tariff (FiT), and DWP-built solar, which have a cost premium. Low DER buildouts are simpler and cheaper in the short term but may miss key opportunities for modernization, resilience, and decarbonization. Although LA100 Plan modeling does not

directly model electricity rates, the higher utility-side costs in the Low DER Sensitivity could also put upward pressure on customer rates, especially without distributed cost-sharing or subsidies.

4.5.8 Key Takeaways

Distributed energy resources (DER) such as rooftop solar bring many local community benefits, including lower local emissions and less dependence on transmission. The LA100 Pathway seeks to maximize these investments, including $1.9 billion in investment in expanding DERs. However, because DER adoption is extremely dependent on community cooperation, in the case of less participation, analysis included a Low DER Sensitivity to evaluate potential risks. This analysis explored a situation in which DER adoption grows at 5.24% annually on average instead of the target of 6.85%. In this scenario, emissions during the 2025-2034 transition period to clean energy marginally increase from 2.10 million metric tons of carbon emissions up to 2.27 million metric tons of carbon emissions. The increase is caused by a slightly higher frequency in the dispatch of in-basin generation. Additionally, the average capacity factor of in-basin dispatchable units is expected to be 5% beyond 2035. While emissions increase, less spending on rooftop solar, Feed-in-Tariff (FiT), and DWP-built solar projects also slightly reduces total system cost from 2025 to 2045 ($99.5 billion) by 3% compared to the LA100 Pathway. Reliability is expected to be maintained throughout the modeling horizon.

4.6 LA100 High DER Sensitivity

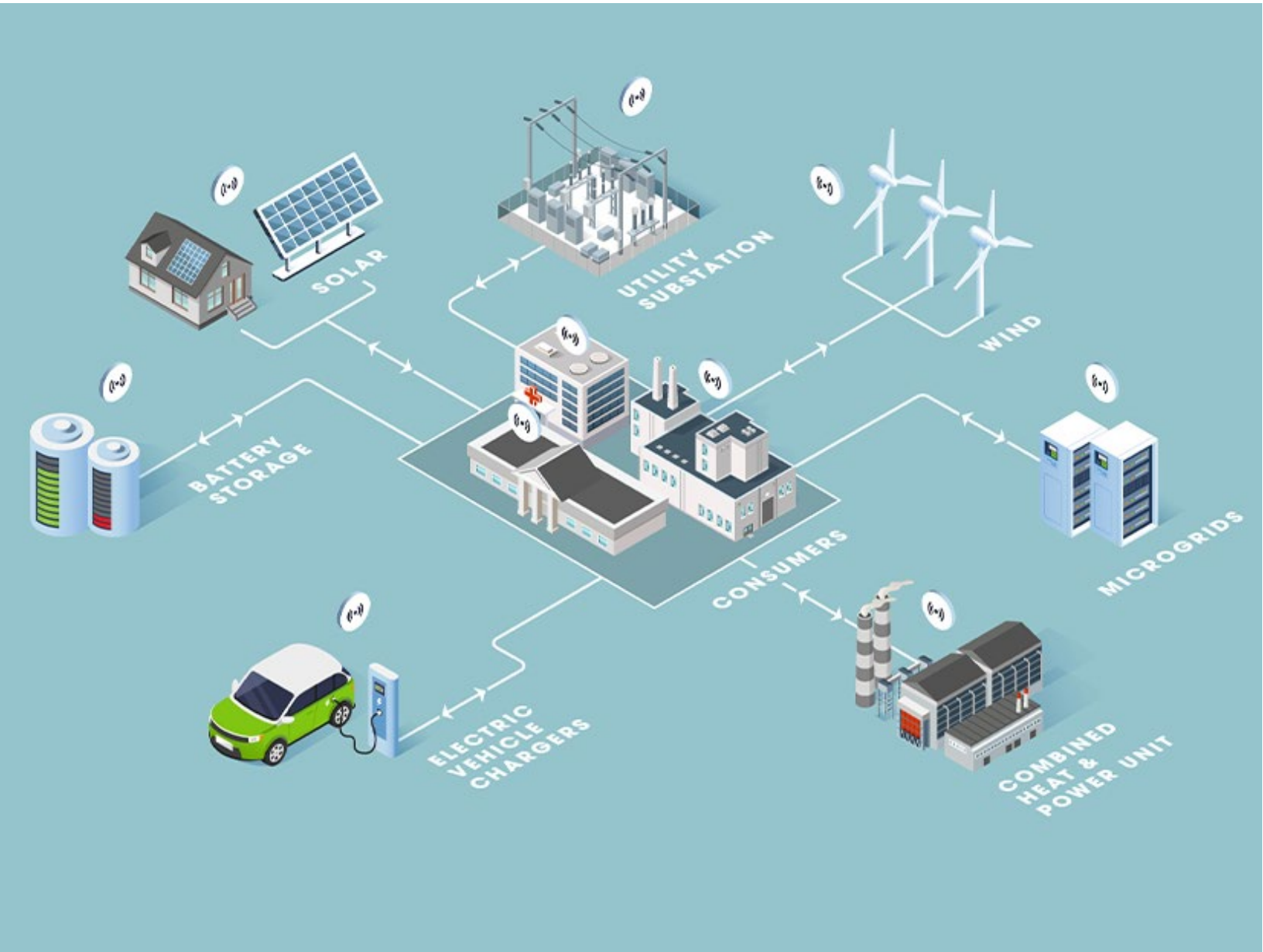
The LA100 High DER Sensitivity explores a future in which customer adoption of distributed energy resources (DERs)—such as rooftop solar, behind-the-meter batteries, and smart home technologies—exceeds expectations. This scenario allows LADWP to assess how widespread and accelerated deployment of customer-sited clean energy could impact utility-scale resource planning. Higher DER uptake may reduce net system load, shift peak demand, and increase local generation and flexibility, potentially deferring or displacing the need for some centralized infrastructure.

This sensitivity was developed in consultation with the LA100 Advisory Group to reflect stakeholder interest in understanding the implications of a more decentralized grid. Modeling this scenario helps LADWP evaluate the benefits and operational challenges of high DER adoption, and ensures system reliability and cost-effectiveness across a range of potential future pathways.

This sensitivity represents a more decentralized, flexible, and consumer-driven approach to decarbonization. High DER adoption reduces dependence on centralized utility-scale generation and limits the need for major new transmission infrastructure. While it accelerates the transition away from fossil fuels, it also presents new challenges for grid operations, planning, and coordination due to the increased complexity of managing large volumes of distributed generation and storage.

Outcomes in this sensitivity are more shaped by customer behavior, market forces, and broader policy conditions. LADWP has limited direct control over the level and pace of DER adoption, making it a key area of uncertainty in long-term resource planning.

The High DER Sensitivity highlights the potential for customer participation to play a transformative role in achieving a carbon-free electricity system while reshaping the grid into a more localized and dynamic network.



4.6.1 Capacity Expansion

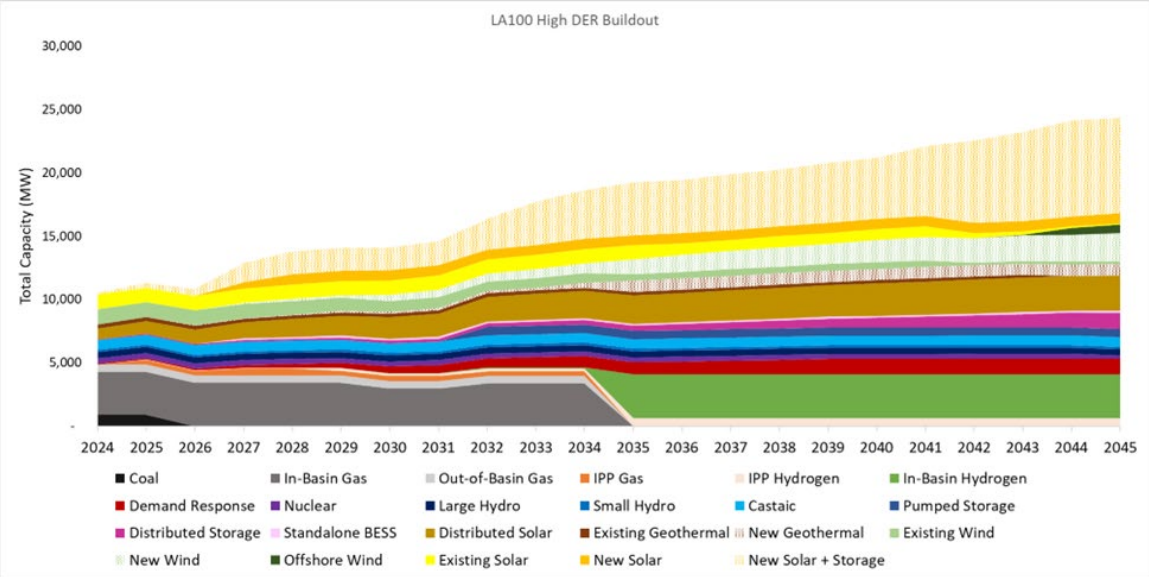


Figure 4-39. LA100 High DER buildout. In alignment with the LA100 Pathway intent to eliminate fossil fuels and decarbonize fully by 2035, coal is fully retired by 2025, followed by dramatic drops in In-Basin Gas and IPP Gas by 2035. In-Basin Hydrogen begins appearing around 2030 and rapidly increases starting 2035, to replace retiring natural gas plants. The LA100 Pathway also requires a substantial buildout of clean energy resources to meet Los Angeles' goal of delivering 100% carbon-free electricity by 2035. Solar + Storage grows dramatically post-2030, becoming the largest capacity contributor by 2045. Wind has moderate growth and steady increases after 2035. The chart also shows a gradual increase in geothermal, which offers essential dispatchable capacity to balance variable wind and solar. Lastly, Distributed Solar & Storage gradually grow as DER implementation increases.

In the LA100 High DER Sensitivity (Figure 4-39), the energy system undergoes a significant transition from fossil fuels to various renewables. DER adoption grows at an average annual rate of 8.45% in the High DER Sensitivity, versus 6.85% in the LA100 Pathway. New Solar + Storage significantly rises post-2035, becoming the dominant capacity resource by 2045. This reflects an increase in reliance on hybrid PV+BESS installations, which meet evening load and reliability targets that standalone solar often falls short of. In addition, distributed solar and BESS steadily grows from 2025 onward due to increased rooftop PV adoption by residents and businesses.

4.6.2 Generation Dispatch

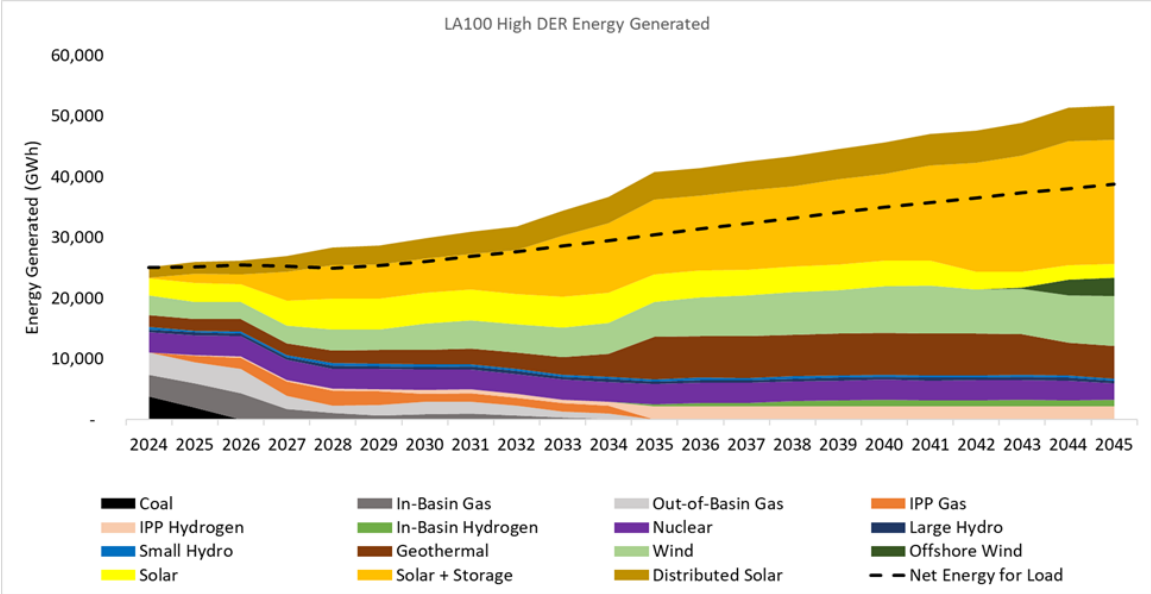


Figure 4-40. The graph shows the projected annual energy generation (GWh) in the LA100 High DER sensitivity from 2024 to 2045, broken down by source. With high DER energy generation, the decline of fossil fuels (Coal, IPP Gas, and In-Basin Gas) continues from 2024-2035. This reflects LADWP's effort to decarbonize and comply with SB100 and LA100 Pathway targets. Similarly, the rise of renewable generation continues to rise with solar + storage becoming the largest source of energy by 2035 and wind gradually increasing and stabilizing after 2035. Distributed solar increases in total contribution, which is consistent with the High DER sensitivity. Geothermal and nuclear remain relatively stable. Reliance on In-Basin Hydrogen grows steadily and fills the gap left by retiring gas resources with IPP Hydrogen playing a supplementary role. The dashed line represents net energy required to meet load, highlighting how renewable generation scales to meet demand over time.

Figure 4-40 illustrates the projected energy generation mix under the LA100 High DER sensitivity from 2024 to 2045. The High DER sensitivity delivers a high-renewable, low-emissions future with early fossil fuel phase-outs and growing integration of clean firm capacity. By 2045, the system is dominated by solar, wind, and hydrogen, with sufficient generation to meet or exceed demand, highlighting the importance of storage, flexibility, and planning for reliable operations. With high DER adoption, energy generation continues to exceed net load from around 2027 onward, which is represented by the black dash line. This represents a surplus in renewable generation available to make up for system losses and for export, storage, or conversion (e.g., to hydrogen).

4.6.3 Customer Load with Modifiers

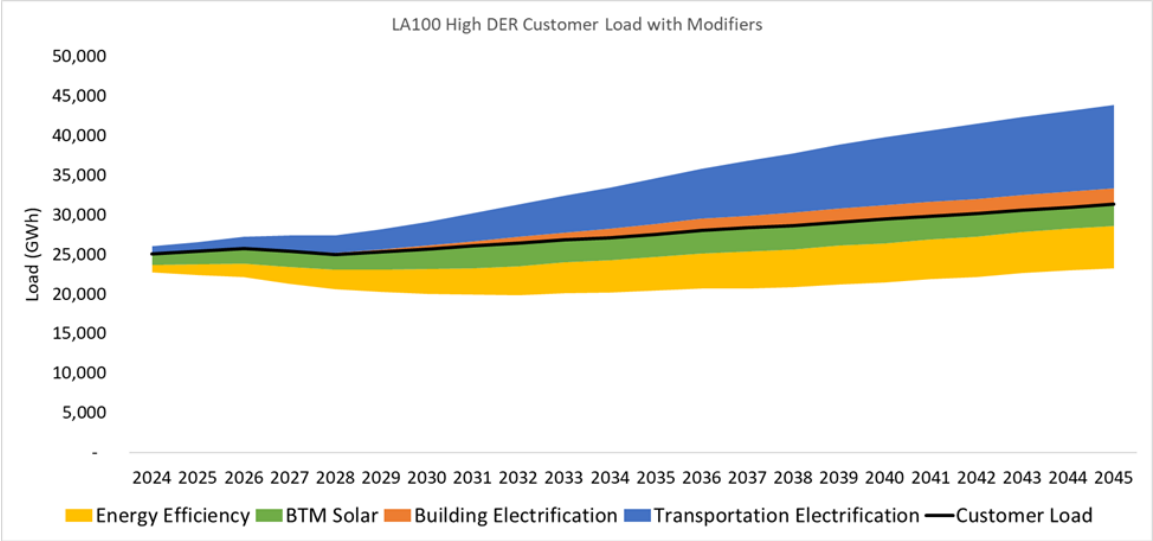


Figure 4-41. LA100 High DER customer load with demand-side modifiers. Although energy efficiency and behind-the-meter (BTM) solar help decrease overall electricity demand, building electrification—and particularly transportation electrification—drive a substantial in load over time.

Figure 4-41 displays projected customer electricity load through 2045 under the LA100 High DER sensitivity, factoring in major demand-side modifiers that influence net load. The black line represents total customer load after accounting for the combined impacts of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification. With high DER adoption, BTM solar contributes to load reduction at greater quantities compared to the LA100 Pathway. DERs play a critical role in mitigating peak loads, but are not as effective in eliminating overall load growth.

4.6.4 Renewable and Clean Generation

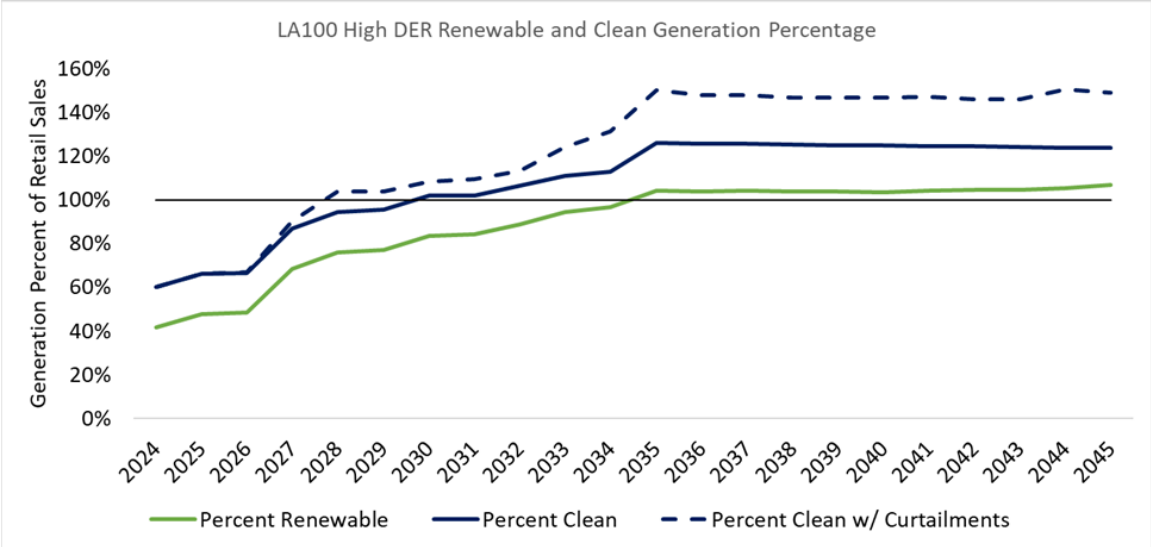


Figure 4-42. LA100 High DER renewable and clean generation percentage is expressed as a share of LADWP's retail electricity sales. The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro), while the solid dark blue line represents clean energy, which includes renewables along with large hydro and nuclear. The dashed blue line reflects clean energy including curtailed generation—energy produced but not used. The horizontal black line represents 100% of retail sales.

In Figure 4-42, all metrics—renewable and clean generation—increase steadily from 2024 through 2035, with flattening trends beyond 2035. This reflects early investments and transitions, followed by a plateau likely due to system saturation or diminishing marginal returns. Exceeding 100% of retail sales means LADWP is generating surplus clean energy, which could be stored, exported, or curtailed. High curtailments post-2035 implies a need for enhanced grid flexibility such as demand response, energy storage, transmission upgrades, and greater DER integration. Compared to the LA100 Pathway, with high DER implementation the gap between the dashed and solid blue lines (particularly from 2030 onward) increases, representing clean energy curtailment increases.

4.6.5 Renewable Curtailment

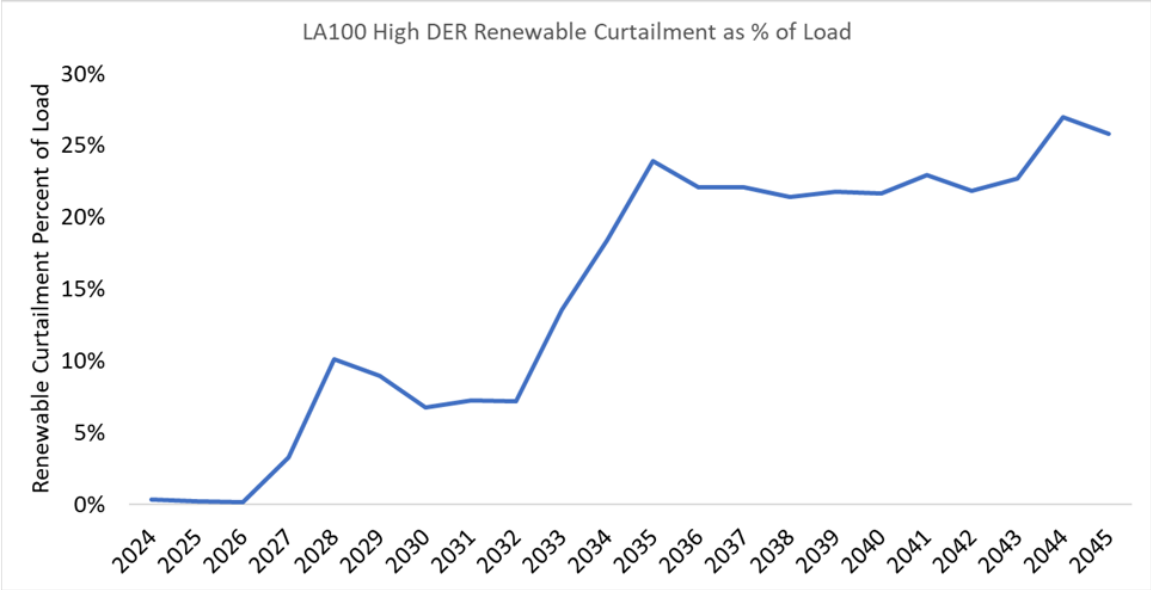


Figure 4-43. LA100 High DER renewable curtailment as a percentage of net load represents the share of renewable energy that is generated but not ultimately used to serve customer demand. Curtailment levels increase in the early 2030s, peaking around 2035, as LADWP expands renewable energy deployment to meet carbon-free energy targets. The graph highlights a core challenge of the high DER sensitivity: while DERs enable high renewable penetration, without parallel investments in grid flexibility, load shaping, and energy storage, significant portions of clean energy will go unused.

Figure 4-43 reflects the share of renewable energy output curtailed—i.e., produced but not consumed. The High DER Sensitivity incurs significantly higher renewable curtailment (up to 27% of annual load by 2045) compared to the LA100 Pathway (peaking at 23%). This gap stems primarily from aggressive rooftop solar growth, and limited grid visibility/control over DER. Persistent curtailment above 20% of load is operationally inefficient and economically suboptimal. To reduce the renewable energy "spillage" in high DER futures, flexibility solutions (smart charging, long-duration storage, flexible demand incentives, and DER aggregation) must be accelerated alongside DER adoption.

4.6.6 Greenhouse Gas Emissions

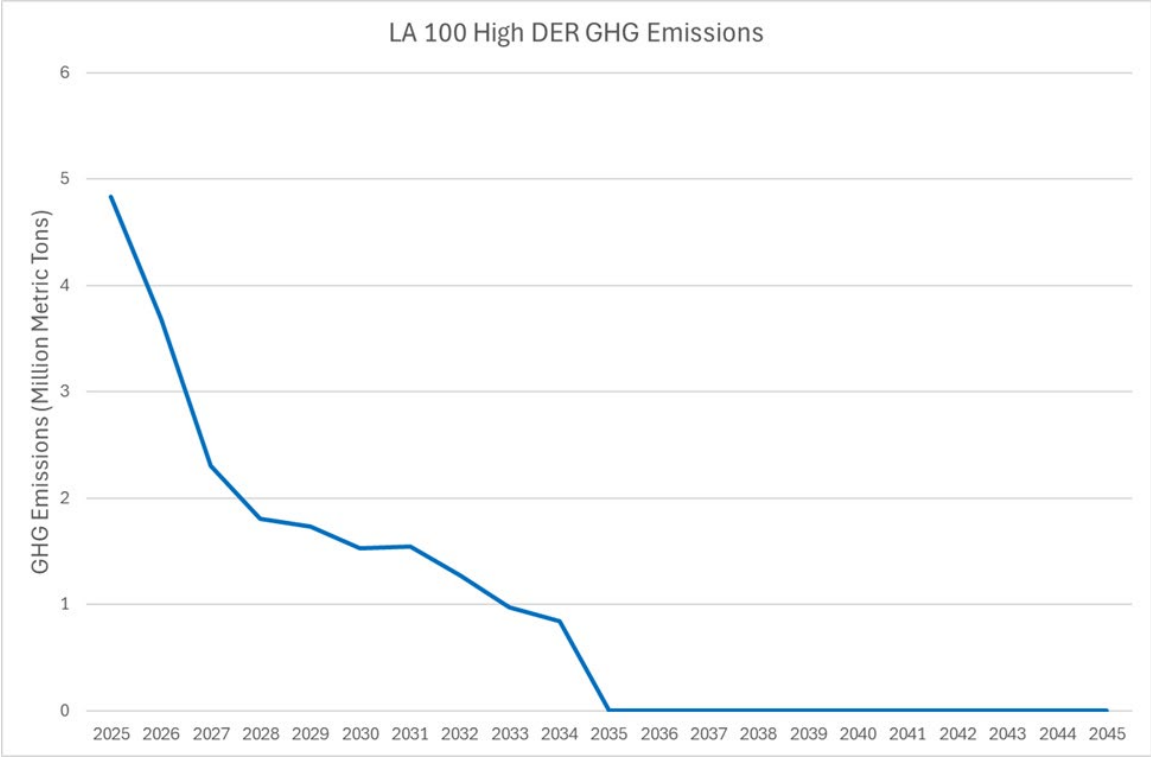


Figure 4-44. LA100 High DER GHG emissions represent annual greenhouse gas emissions associated with electricity generation, measured in million metric tons. From 2025 through 2035, modest GHG reductions occur primarily through retirement of some fossil assets and increased utility-scale renewables. From 2035–2045, major GHG reductions is achieved through conversion of in-basin thermal units to green hydrogen and expanded utility-scale clean energy with zero emissions reached by 2035 and continuing through 2045.

Figure 4-44 highlights that even with high DER adoption, LADWP can achieve deep decarbonization. Similarly, to the LA100 Pathway, GHG emissions drop to 0% by 2035 and remain there through 2045. Progressively, utility-scale renewables meet the bulk of energy demand and fossil fuel generation declines, being replaced with green hydrogen, energy storage, and transmission expansion to ensure reliability. While the trajectory of the sensitivity is similar to the LA100 Pathway, near-term reductions are slightly higher and cumulative emissions are lower due to decreased natural gas usage prior to 2035.

4.6.7 Annual System Cost

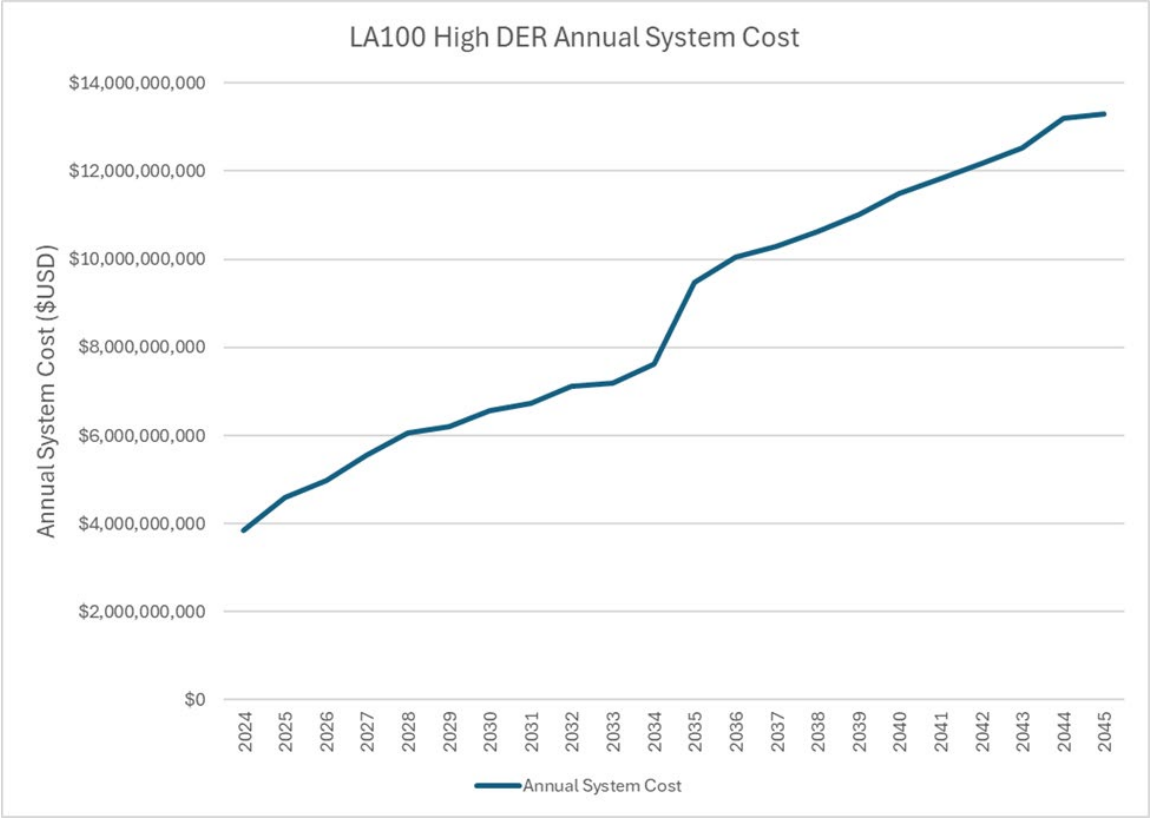


Figure 4-45. LA100 High DER Annual System Cost. Annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments), as well as spending associated with the Power System Reliability Plan (PSRP) and electric vehicle charging infrastructure (eHubs).

In the High DER Sensitivity, annual system cost (Figure 4-45) in absolute dollars is slightly higher compared to the LA100 Pathway by 2045. High DER implementation increases total annual system cost modestly, mainly due to higher capital investment in customer-sited technologies (e.g. smart meters, interconnection). Unmanaged DER growth may also lead to excess curtailment and higher system-wide cost per unit of useful energy delivered. However, some costs are offset by reductions in fossil fuel spending, centralized infrastructure, and enhanced system efficiency — especially when DERs are actively coordinated and paired with flexible demand and storage.

4.6.8 Key Takeaways

In the High DER Sensitivity, distributed energy resource (DER) adoption grows faster than in the LA100 Pathway—averaging 8.45% annually compared to 6.85%. This higher adoption modestly improves in-basin resiliency by reducing overall load, which slightly decreases emissions prior to 2035 due to reduced reliance on natural gas. Total system costs from 2025 to 2045 ($103.3 billion) rise by only 1% compared to the LA100 Pathway, driven primarily by increased investment in rooftop solar, Feed-in Tariff (FiT) programs, and DWP-built solar—each carrying a cost premium. The average capacity factor for in-basin dispatchable units remains at 3%, indicating no material change from the LA100 Pathway.

4.7 LA100 No In-Basin Combustion Sensitivity

The LA100 No In-Basin Combustion Sensitivity explores a future where in-basin green hydrogen–capable combustion turbines are replaced with green hydrogen–fueled fuel cells. This scenario was developed in direct response to interest from the LA100 Advisory Group, who expressed a desire to understand the implications of removing combustion-based generation from the Los Angeles basin.

By modeling a system that relies solely on non-combustion technologies—such as hydrogen fuel cells—for in-basin reliability, this sensitivity allows LADWP to evaluate how such a shift would affect system performance, cost, emissions, and local air quality. The scenario provides insight into the feasibility of a zero-combustion grid, particularly in dense urban areas where environmental justice and air quality concerns are prominent. It also tests how well fuel cells can support reliability during periods of low renewable generation or high demand without relying on traditional thermal peaking technologies.

To replace green hydrogen-fueled combustion turbines, the sensitivity models the deployment of in-basin green hydrogen fuel cells as an alternative source of dispatchable carbon-free capacity. While this approach aligns with the goal of eliminating all combustion technologies, it was ultimately determined to be infeasible for several reasons.

First, fuel cell technology at the scale required by LADWP is not commercially available today, and there are substantial concerns about future manufacturing capacity being able to meet the volume needed. In addition, fuel cells are significantly more expensive than combustion turbines, both in terms of capital cost and operational complexity. Their

physical footprint is also a major concern in the densely populated and space-constrained Los Angeles Basin, where available land for large-scale infrastructure is extremely limited. Moreover, unlike turbines, fuel cells are limited in their ability to rapidly ramp up or down in response to fluctuating grid conditions—making them less suitable for the type of flexible, firm capacity that LADWP requires to support reliability in a high-renewables system.

While the No In-Basin Combustion Sensitivity provided useful insight into alternative clean energy configurations, it highlighted serious technical, economic, and operational challenges that make this approach impractical under current and projected future conditions.

4.7.1 Capacity Expansion

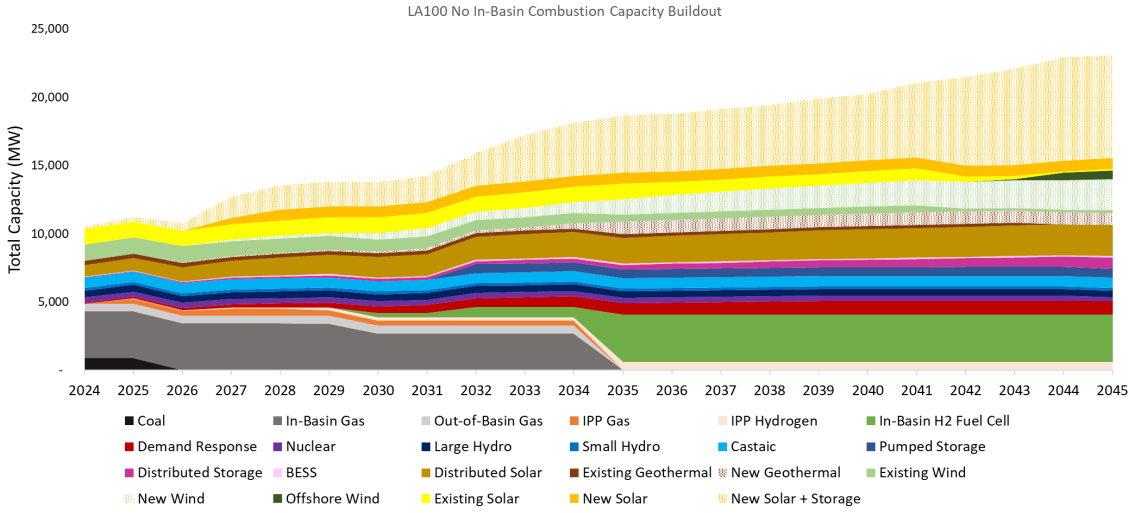


Figure 4-46. Total cumulative nameplate capacity for LA100 No In-Basin Combustion Sensitivity.

As shown in Figure 4-46, the No In-Basin Combustion Sensitivity retains the same renewable energy and energy storage portfolio buildout as the LA100 Pathway, however it replaces the in-basin green hydrogen-fueled combustion turbine capacity, in-kind, with in-basin green hydrogen-fueled fuel cells.

4.7.2 Generation Dispatch

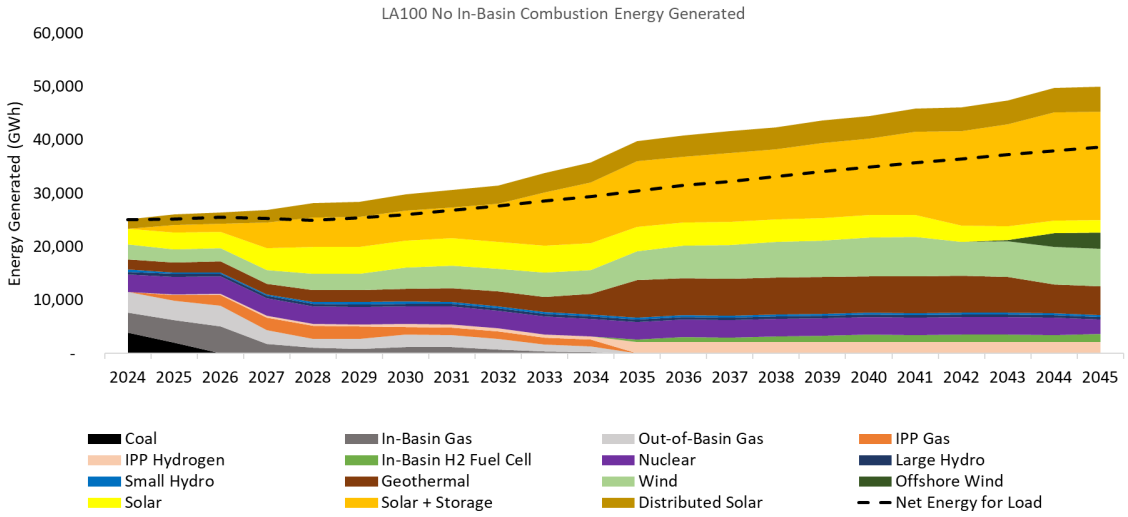


Figure 4-47. Projected energy generation mix under the LA100 No In-Basin Combustion Sensitivity.

Figure 4-47 illustrates the projected energy generation mix under the No In-Basin Combustion Sensitivity. As previously mentioned, this sensitivity retains the same renewable energy and energy storage portfolio as the LA100 Pathway, thus relying heavily on solar photovoltaics (PV)—including utility-scale solar + storage projects and behind-the-meter (BTM) rooftop solar—as well as increasing contributions from wind, offshore wind, and long-duration renewable resources such as geothermal. The generation mix is further diversified with contributions from small and large hydro, and nuclear, however instead of green hydrogen-fueled generation in-basin, green hydrogen-fueled fuel cells are used as backup, providing dispatchability to help balance variable solar and wind output.

4.7.3 Customer Load with Modifiers

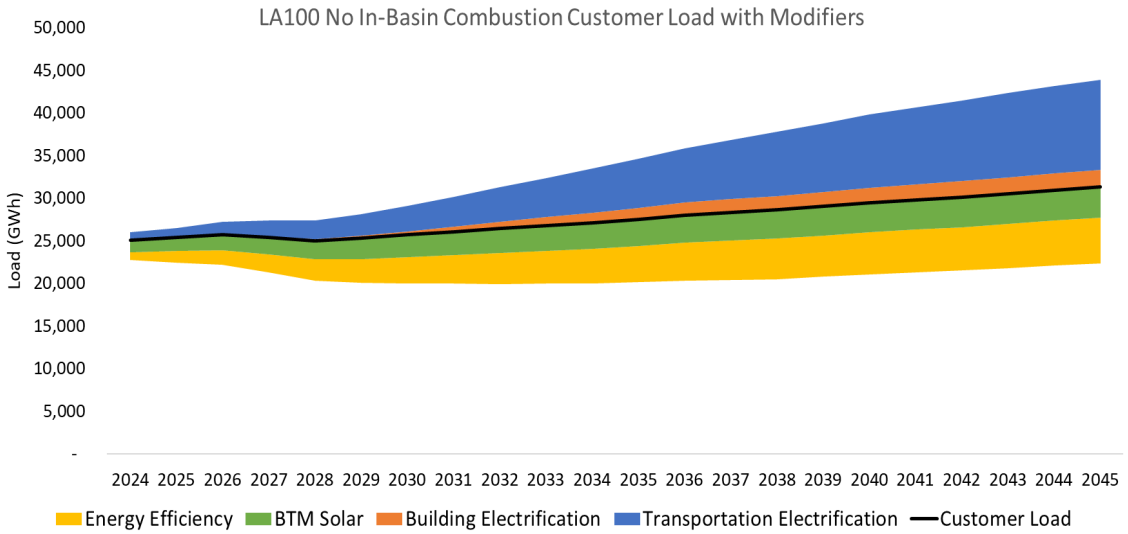


Figure 4-48. LA100 No In-Basin Combustion Sensitivity customer load with modifiers.

Figure 4-48 illustrates the same projected customer electricity load through 2045, as the LA100 Pathway.

4.7.4 Renewable and Clean Generation

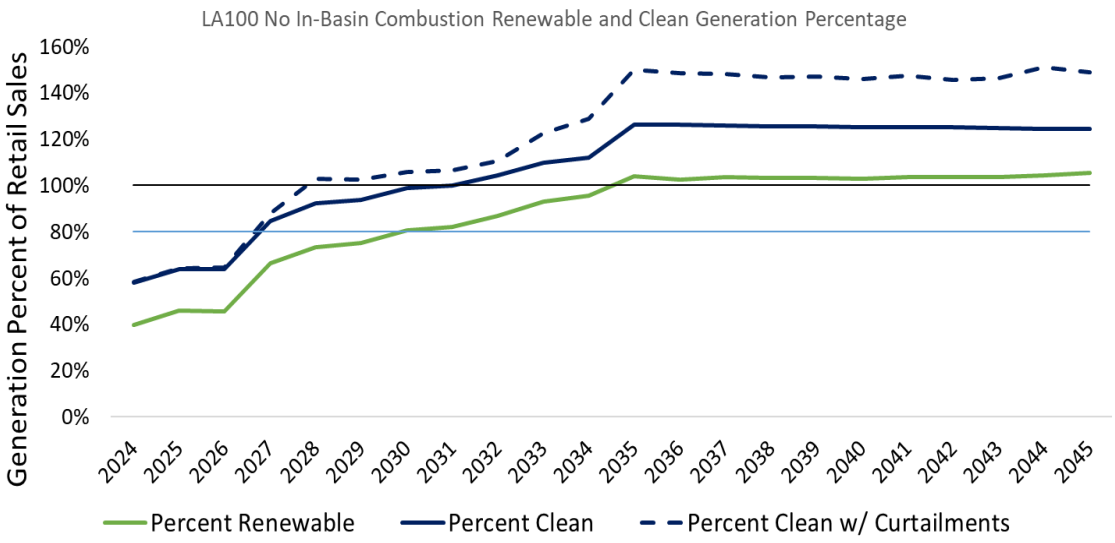


Figure 4-49. LA100 No In-Basin Combustion Sensitivity renewable and clean generation percentage.

The No In-Basin Combustion Sensitivity's renewable and clean generation percentage, shown in Figure 4-49, reflects LADWP's path toward meeting the City Council's directive of providing 100% carbon-free electricity by 2035. All values are shown as a percentage of retail sales, which refers to the electricity actually delivered to customers (excluding losses). Generally, the renewable and clean generation percentages for the No In-Basin Combustion Sensitivity are similar to those of the LA100 Pathway.

4.7.5 Renewable Curtailment

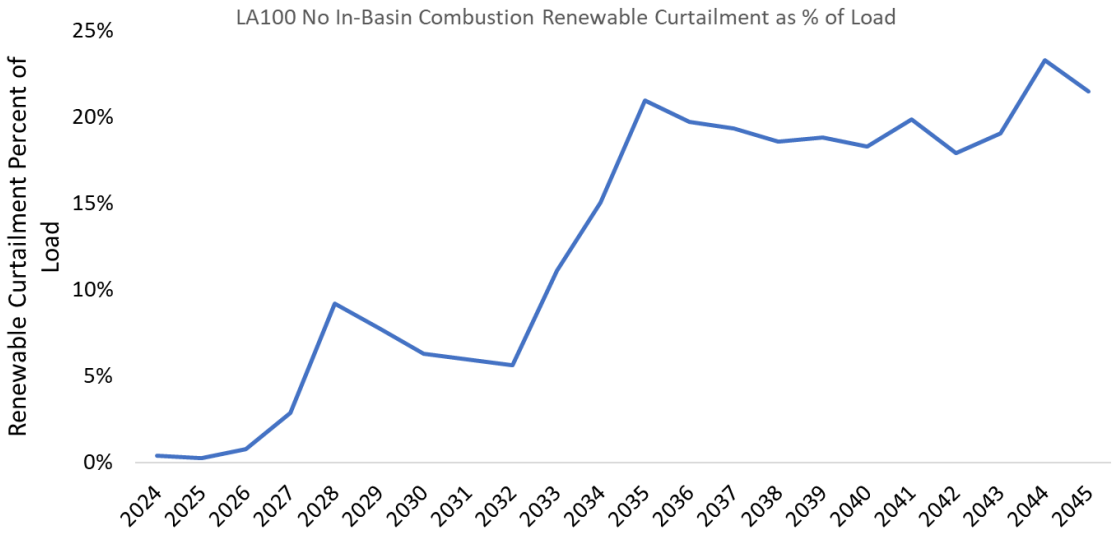


Figure 4-50. LA100 No In-Basin Combustion Sensitivity renewable energy curtailment.

Renewable curtailment as a percentage of net load in the No In-Basin Combustion Sensitivity, shown in Figure 4-50, reflects the portion of renewable electricity generated but not used due to a combination of system conditions and intentional resource planning decisions. Given that the renewable energy portfolio and the electrical load is the same as in the LA100 Pathway, the renewable curtailment figures follow a similar pattern as those in the LA100 Pathway.

4.7.6 Greenhouse Gas Emissions

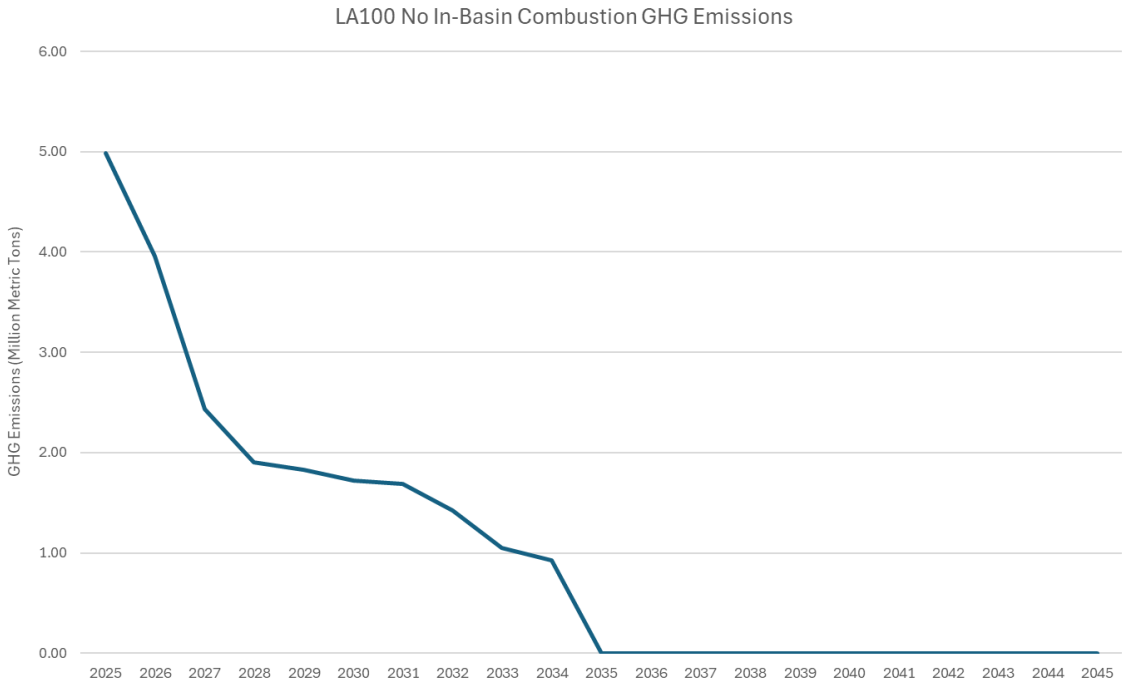


Figure 4-51. LA100 No In-Basin Combustion Sensitivity GHG emissions associated with electricity generation.

GHG emissions for the No In-Basin Combustion Sensitivity, shown in Figure 4-51, are very similar to those in the LA100 Pathway, beginning at just under 5 million metric tons in 2025 and declining sharply over the next decade as coal-fired generation is fully retired and fossil gas use is eventually phased out by 2035.

4.7.7 Annual System Cost

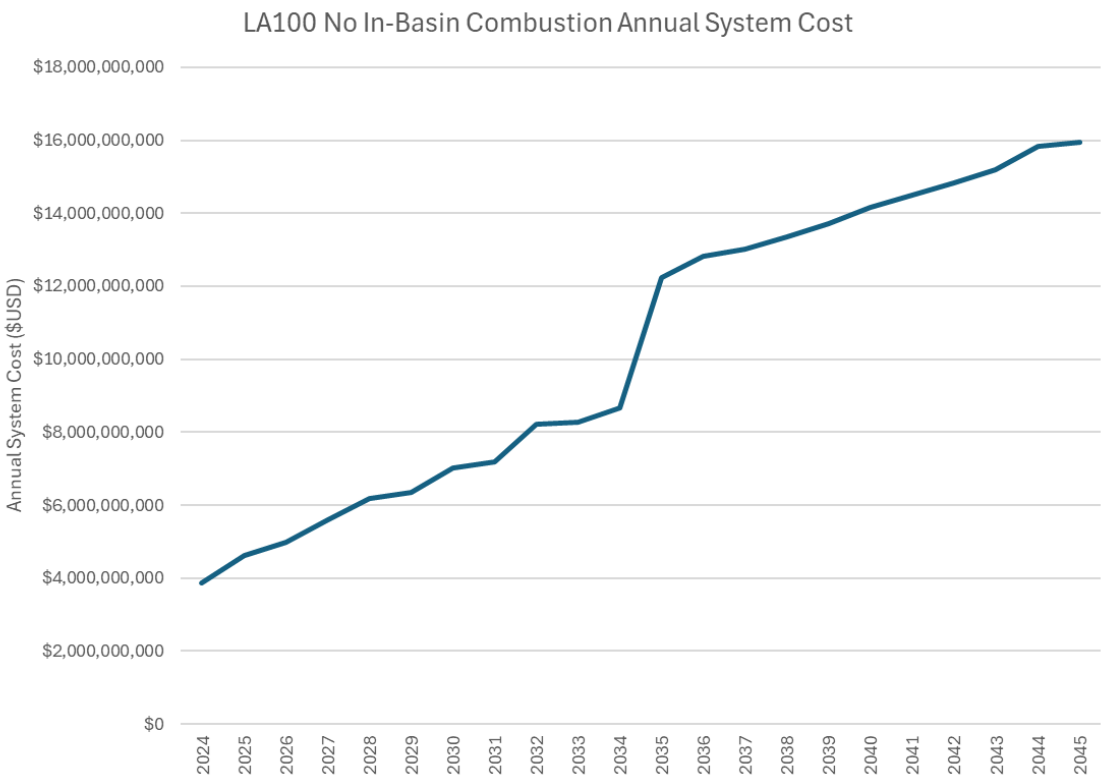


Figure 4-52. LA100 No In-Basin Combustion Sensitivity annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments).

The No In-Basin Combustion Sensitivity annual system cost, shown in Figure 4-52, represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway that uses green hydrogen-fueled fuel cells as backup, through 2045. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, transmission, and distribution investments. The costs for this sensitivity are significantly higher than those for the LA100 Pathway, by approximately $17B net present value, and are largely influenced by the expensive capital costs for green hydrogen-fueled fuel cells, as compared to green hydrogen-fueled combustion turbines. It must be noted that even if cost issues were addressed, the technology does not currently exist at the scale needed by LADWP.

4.7.8 Key Takeaways

In evaluating the use of non-combustion technologies in the LA basin, it was discerned that combustion alternatives, namely hydrogen fuel cells, cannot feasibly replace green hydrogen-fueled combustion turbines in the LA100 Plan. As previously stated, this conclusion was determined based on several factors, including a lack of observable potential for fuel cell production levels to reach the required scale by LA100 Plan deadlines, incompatibility with Los Angeles space constraints, and operational constraints affecting grid reliability. The results of the sensitivity also reveal that replacing in-basin combustion increases total costs dramatically. Driven by higher capital and maintenance costs, increased fuel needs, and the shorter life cycle of fuel cell technologies, the sensitivity sees a 16% increase in total system cost from 2025 to 2045 ($119.0 billion) compared to the LA100 Pathway. By eliminating in-basin combustion, in-basin NOx emissions from LADWP operations drop to near zero, removing the final 1/3 of LADWP-based NOx emissions that remain in the LA100 Pathway. However, NOx emissions from other sectors in LA remain and are subject to clean energy efforts by those sectors respectively. There is no discernable change in carbon emissions compared to the LA100 Pathway since carbon emissions are lowered in line with 2035 clean energy targets through green hydrogen combustion turbines.



4.8 LA100 No In-Basin H_2 Supply Sensitivity

The LA100 No In-Basin Hydrogen Supply Sensitivity explores a scenario in which zero green hydrogen is available for in-basin power generation at any point during the study period. Based on the core LA100 Pathway framework, this sensitivity models the consequences of a complete failure of the green hydrogen commodity market to materialize as anticipated—an outcome that could arise from stalled technology development, insufficient infrastructure investment, policy or regulatory breakdowns, or market limitations that prevent the scaling of green hydrogen production and delivery to utility scale.

This sensitivity was developed in consultation with the LA100 Advisory Group, who sought to understand the implications of a high-impact risk case in which green hydrogen does not become a viable or accessible resource for LADWP's planned hydrogen-capable thermal fleet. By removing all in-basin access to hydrogen, the scenario tests how the power system might compensate for this shortfall, whether through increased renewable overbuild, out-of-basin imports, enhanced energy storage, or alternative firm capacity solutions.

The results of this analysis provide insight into the resilience of the LA100 Pathway under technology or market constraints and help to quantify the value of in-basin hydrogen access as part of a broader clean energy portfolio.

With no in-basin hydrogen-fueled generation available, the model retains a limited amount of natural gas-fueled capacity within the basin to provide backup generation during periods of high demand or system stress. This natural gas generation is assumed to be used sparingly and only when necessary to maintain reliability. The only hydrogen-fueled generation in this sensitivity comes from the Intermountain Power Project (IPP) in Delta, Utah, which is assumed to operate on a constant 30% green hydrogen by volume blend from 2025 through 2045. This assumption differs from the LA100 Pathway, where IPP ramps up to 100% green hydrogen by 2035.

All other assumptions from the LA100 Pathway—including distributed energy resource adoption, energy efficiency levels, and demand response—remain unchanged. This sensitivity isolates the consequences of a total lack of hydrogen fuel availability for in-basin use and highlights the critical dependency of the LA100 Pathway on the emergence of a viable, large-scale green hydrogen market. It also underscores the

importance of contingency planning for firm, dispatchable, carbon-free resources in the event hydrogen infrastructure and supply chains fail to develop as anticipated.

4.8.1 Capacity Expansion

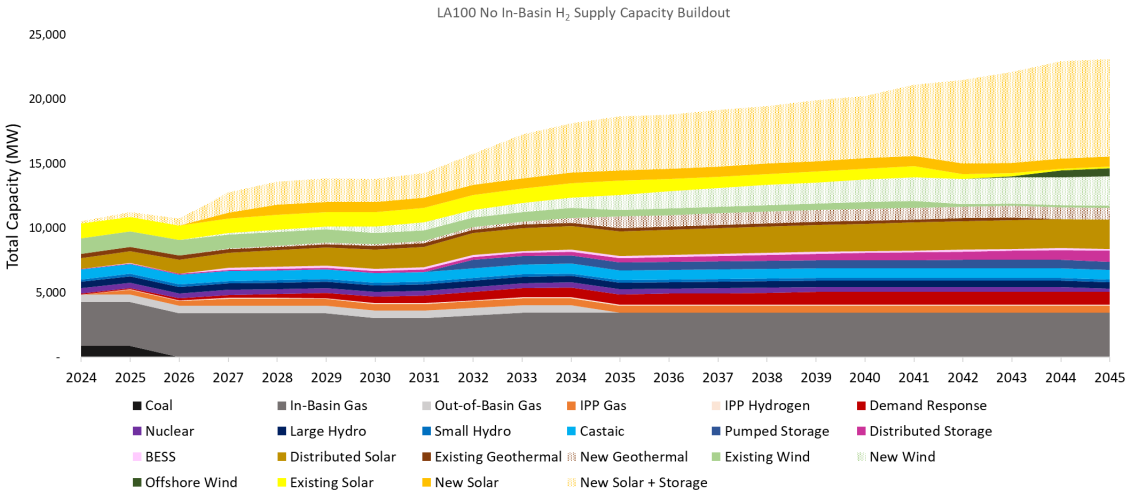


Figure 4-53. Total cumulative nameplate capacity for LA100 No In-Basin H_2 Supply Sensitivity.

As shown in the chart in Figure 4-53, the No In-Basin H_2 Supply Sensitivity retains the same renewable energy and energy storage portfolio buildout as the LA100 Pathway. This means the amounts of new solar (both standalone and paired with energy storage), wind, geothermal, and energy storage remain the same.

4.8.2 Generation Dispatch

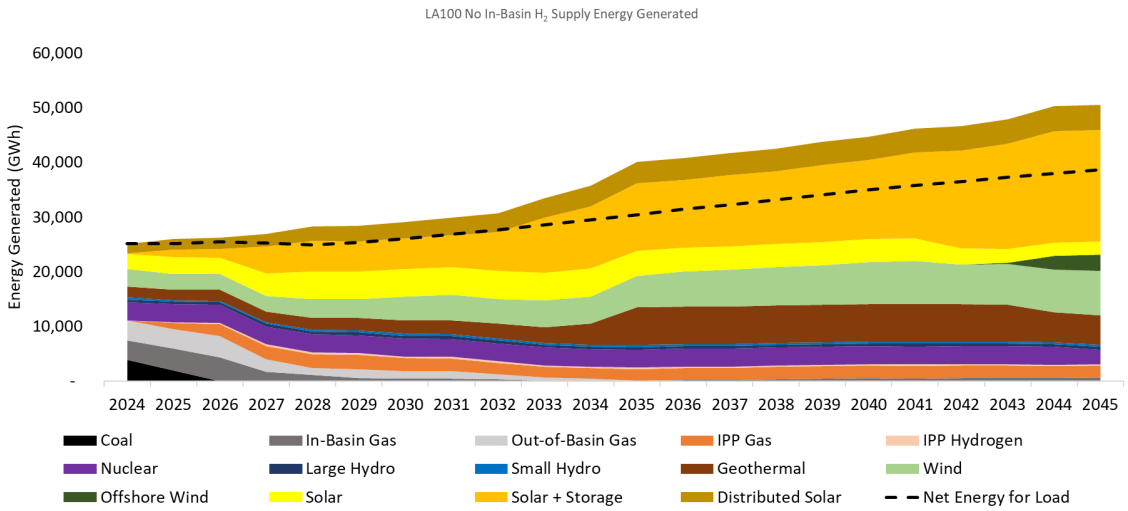


Figure 4-54. Projected energy generation mix under the LA100 No In-Basin H_2 Supply Sensitivity.

Figure 4-54 illustrates the projected energy generation mix under the No In-Basin H_2 Supply Sensitivity. As previously mentioned, this sensitivity retains the same renewable energy and energy storage portfolio as the LA100 Pathway, thus relying heavily on solar photovoltaics (PV)—including utility-scale solar + storage projects and behind-the-meter (BTM) rooftop solar—as well as increasing contributions from wind, offshore wind, and long-duration renewable resources such as geothermal. The generation mix is further diversified with contributions from small and large hydro, and nuclear, however instead of green hydrogen-fueled generation in-basin, natural gas-fueled generation is used as backup, providing dispatchability to help balance variable solar and wind output.

4.8.3 Customer Load with Modifiers

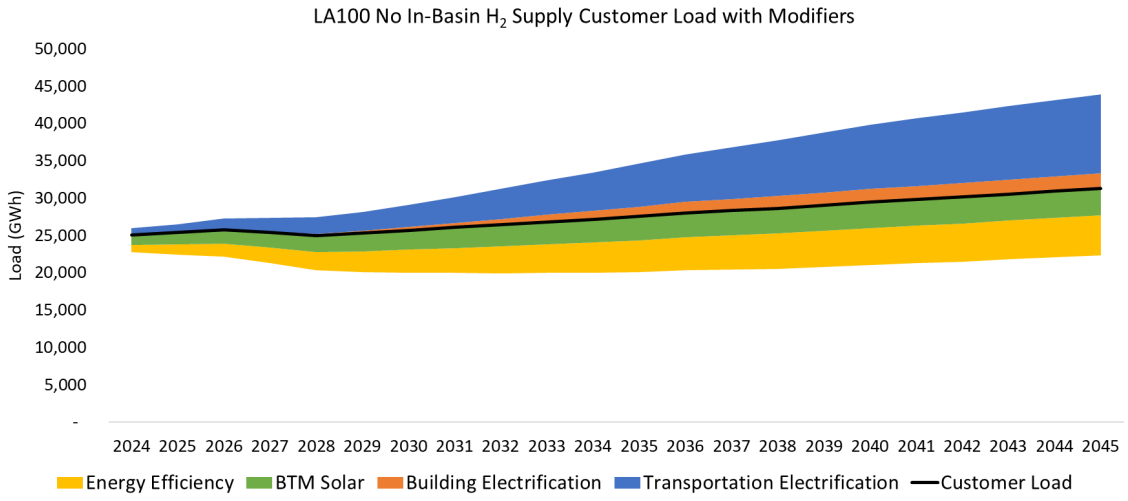


Figure 4-55. LA100 No In-Basin H_2 Supply Sensitivity customer load with modifiers.

Figure 4-55 illustrates the same projected customer electricity load through 2045, as the LA100 Pathway.

4.8.4 Renewable and Clean Generation

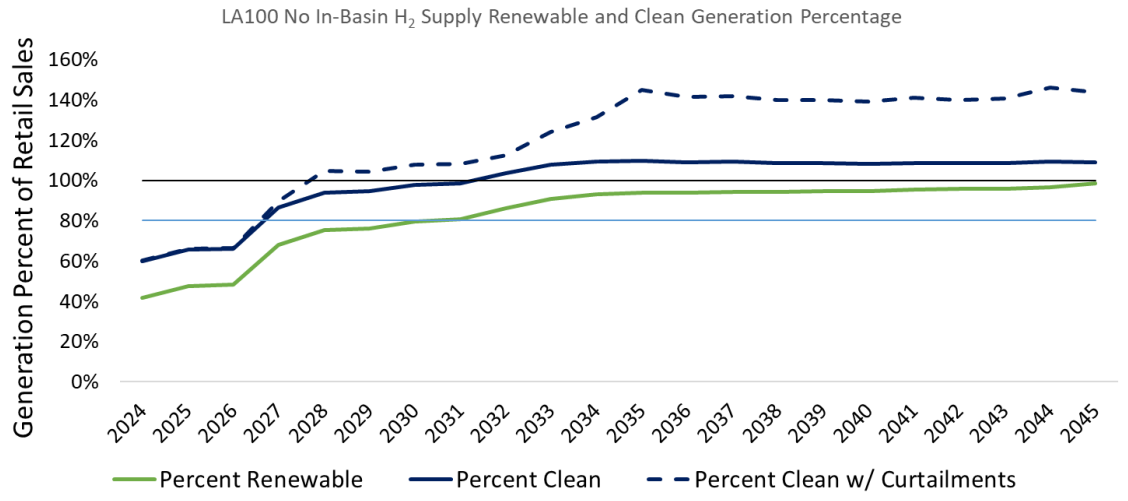


Figure 4-56. LA100 No In-Basin H_2 Supply Sensitivity renewable and clean generation percentage.

The No In-Basin H_2 Supply Sensitivity's renewable and clean generation percentage, shown in Figure 4-56, reflects LADWP's path toward meeting the City Council's directive of providing 100% carbon-free electricity by 2035. All values are shown as a percentage of retail sales, which refers to the electricity actually delivered to customers (excluding losses).

The renewable portion, shown in green, increases steadily in effort to meet the 80% target by 2030 and continues climbing gradually through 2045. The clean energy share, depicted in solid dark blue, includes additional zero-carbon sources such as large hydro and nuclear, enabling LADWP to meet 100% of retail sales with clean energy by 2035. While 100% of retail sales are met with carbon-free energy by 2035, when taken as a percentage of the net energy for load, which includes losses, this sensitivity reaches 97% carbon-free energy by 2035.

The dashed line, which includes curtailed clean energy, rises above 100% starting in the early 2030s. This reflects the need to generate additional clean electricity to compensate for system losses, particularly those associated with the round-trip inefficiencies of energy storage technologies like batteries.

4.8.5 Renewable Curtailment

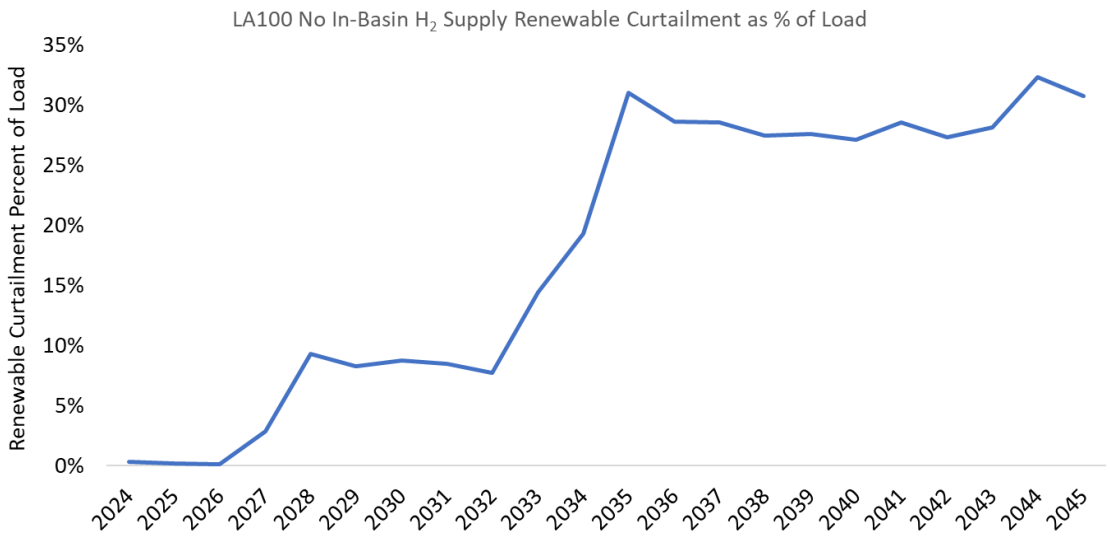


Figure 4-57. LA100 No In-Basin H_2 Supply Sensitivity renewable energy curtailment.

Renewable curtailment as a percentage of net load in the No In-Basin H_2 Supply Sensitivity, shown in Figure 4-57, reflects the portion of renewable electricity generated but not used due to a combination of system conditions and intentional resource planning decisions. Given that the renewable energy portfolio and the electrical load is the same as in the LA100 Pathway, the renewable curtailment figures follow a similar pattern as those in the LA100 Pathway. The magnitude of renewable curtailment appears to be higher in this sensitivity than in the LA100 Pathway, however, by approximately 9% in 2035 and 7% in 2044.

4.8.6 Greenhouse Gas Emissions

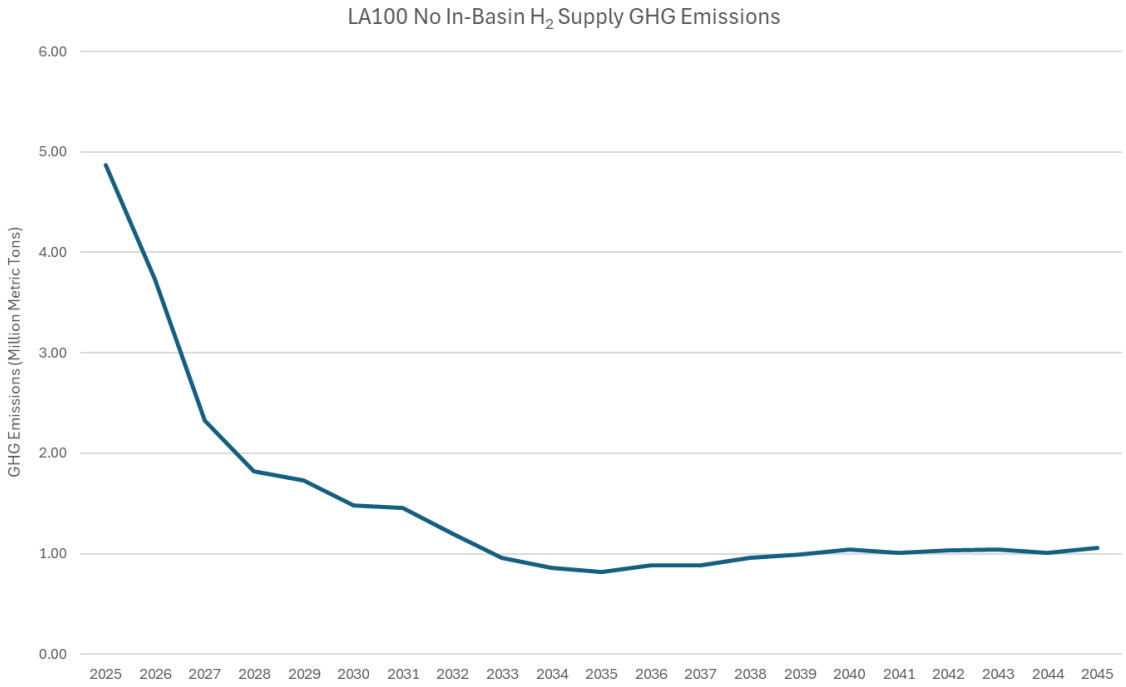


Figure 4-58. LA100 No In-Basin H_2 Supply Sensitivity GHG emissions associated with electricity generation.

GHG emissions for the No In-Basin H_2 Supply Sensitivity, shown in Figure 4-58, reflect similar trends to those seen in the LA100 Pathway, beginning at just under 5 million metric tons in 2025 and declining sharply over the next decade as coal-fueled generation is fully retired and natural gas use is steadily reduced.

Given this sensitivity retains natural gas-fueled generating units as backup, in lieu of green hydrogen fuel availability, GHG emissions do not drop to zero, however they do drop to below 1 million metric ton by 2035 and remain flat at that level through 2045.

4.8.7 Annual System Cost

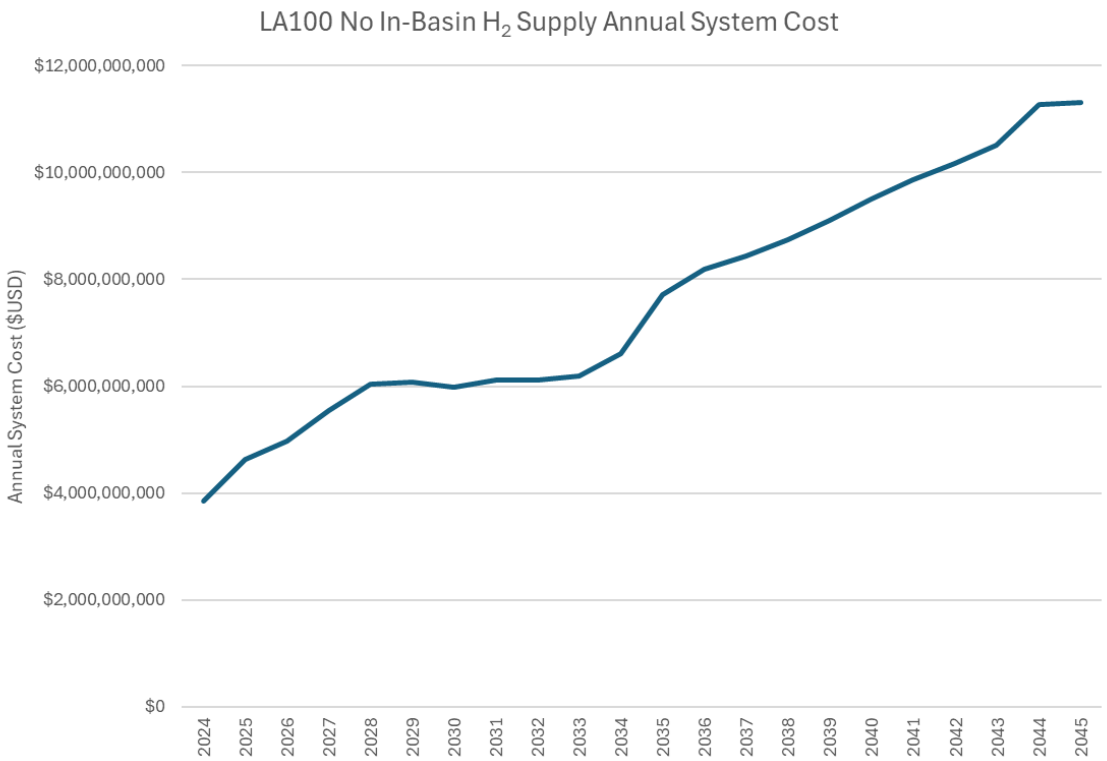


Figure 4-59. LA100 No In-Basin H_2 Supply Sensitivity annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments).

The No In-Basin H_2 Supply Sensitivity annual system cost, shown in Figure 4-59, represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway that retains natural gas-fueled generation as backup, through 2045. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, transmission, and distribution investments. Trends largely follow those of the LA100 Pathway, however with slightly smaller cost magnitudes due to not having to

modernize the entire in-basin power generation fleet to green hydrogen-capable generating units, and instead, retaining existing natural gas units and retrofits.

4.8.8 Key Takeaways

Under the No In-Basin H2 Supply Sensitivity, the market for H2 fuel does not exist, which kept natural gas generation online. Natural gas-fueled generators were kept online to be used as sparingly backup only. Emissions marginally decreased from 2025 to 2034 (2.08 $MMTCO_2$ compared to 2.10 $MMTCO_2$ for LA100 Pathway), however emissions increase between 2035-2045 (0.97 $MMTCO_2$ compared to 0.00 $MMTCO_2$ for LA100 Pathway). While GHG reduction targets were still achieved, total system costs from 2025 to 2045 ($91.4 billion) were 10% lower than the LA100 Pathway, as in-basin resources were not replaced with hydrogen-fueled generation for the last 5% of decarbonization. The average capacity factor for in-basin dispatchable units is 8% for 2035-2045.

4.9 LA100 Limited H_2 Supply Sensitivity

The LA100 Limited Hydrogen Supply Sensitivity explores a scenario in which green hydrogen is available for in-basin power generation, but at approximately half the volume assumed in the core LA100 Pathway. This sensitivity assesses the implications of constrained hydrogen availability—whether due to production shortfalls, underdeveloped infrastructure, policy delays, or supply chain bottlenecks—on the feasibility of achieving a reliable, carbon-free electricity system by 2035.

This scenario was developed in consultation with the LA100 Advisory Group, who recognized the importance of testing system resilience under more conservative hydrogen supply assumptions. While the LA100 Pathway assumes that green hydrogen becomes a scalable and dependable resource for firm capacity within the Los Angeles Basin, this sensitivity acknowledges the real-world uncertainties that could limit hydrogen's role, especially during the crucial buildout period through the early 2030s.

By halving the available hydrogen volume, this analysis helps explore how LADWP's power system might adapt—potentially through increased renewable capacity, deeper reliance on out-of-basin imports, greater energy storage deployment, or demand-side flexibility. It also provides insight into cost, emissions, and reliability tradeoffs when a key firm resource becomes constrained but not entirely unavailable.

To model this sensitivity, the capacity factors of in-basin hydrogen-fueled combustion turbines were reduced by approximately 50% relative to the LA100 Pathway. However, it is important to note that in the LA100 Pathway, these turbines already operated at consistently low capacity factors—in the single digits—due to their intended role as firm, dispatchable backup resources. Further reducing their utilization significantly increased the challenge of maintaining system reliability without the full availability of carbon-free, flexible generation.

To compensate, the model added substantial amounts of renewable energy—primarily wind and solar—along with a corresponding increase in energy storage. While renewables are variable, layering additional resources and pairing them with storage can enhance reliability across a range of operating conditions. However, this approach comes at a cost.

The additional buildout of renewables and storage required to offset limited hydrogen supply results in higher total system costs compared to the core LA100 Pathway. This sensitivity highlights the critical trade-off between reliability and affordability when firm, carbon-free fuels are constrained, and underscores the importance of both securing a robust green hydrogen supply and maintaining flexibility in long-term planning.

4.9.1 Capacity Expansion

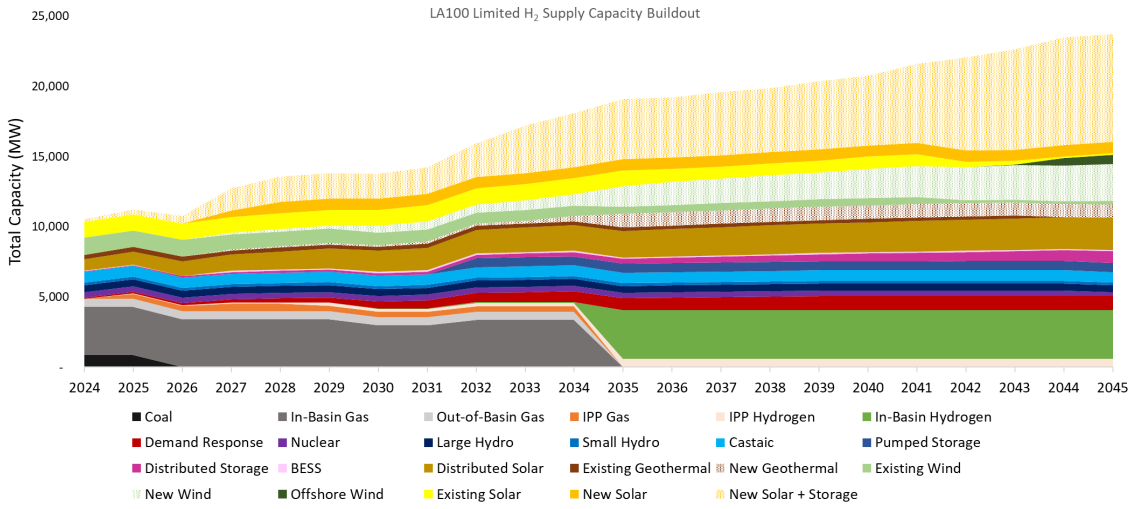


Figure 4-60. Total cumulative nameplate capacity for LA100 Limited H_2 Supply Sensitivity.

As shown in the chart in Figure 4-60, the Limited H_2 Supply Sensitivity retains nearly the same renewable energy and energy storage portfolio buildout as the LA100 Pathway, however it augments the amount of renewable energy capacity by 450 MW in 2035 and 575 MW (cumulatively) in 2045, to compensate for a reduction in more than 50% of the assumed in-basin green hydrogen fuel supply available.

4.9.2 Generation Dispatch

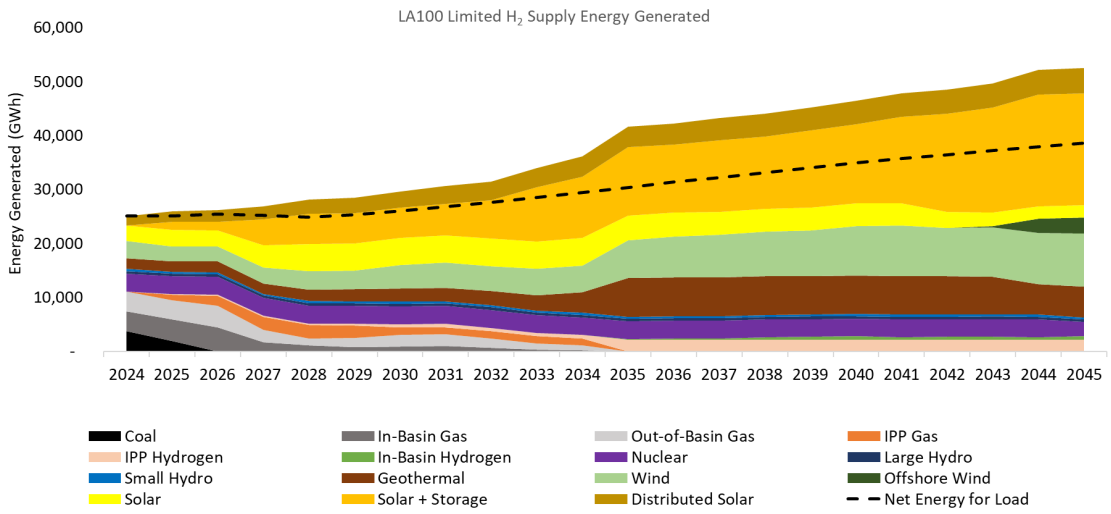


Figure 4-61. Projected energy generation mix under the LA100 Limited H_2 Supply Sensitivity.

Figure 4-61, illustrates the projected energy generation mix under the Limited H_2 Supply Sensitivity. As previously mentioned, this sensitivity largely retains the same renewable energy and energy storage portfolio as the LA100 Pathway, except for augmenting the amount of renewable energy capacity by 450 MW in 2035 and 575 MW (cumulatively) in 2045. These additional renewables are comprised of a diverse mix of geothermal, solar photovoltaic paired with battery energy storage, and wind. As a result, energy generated from in-basin green hydrogen units is slightly lower than in the LA100 Pathway.

4.9.3 Customer Load with Modifiers

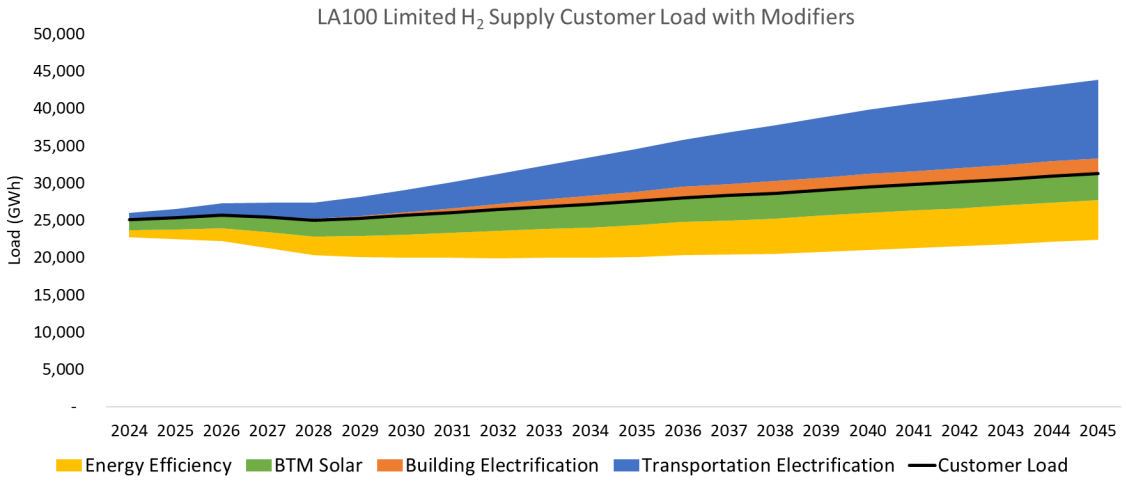


Figure 4-62. LA100 Limited H_2 Supply Sensitivity customer load with modifiers.

Figure 4-62, illustrates the same projected customer electricity load through 2045, as the LA100 Pathway.

4.9.4 Renewable and Clean Generation

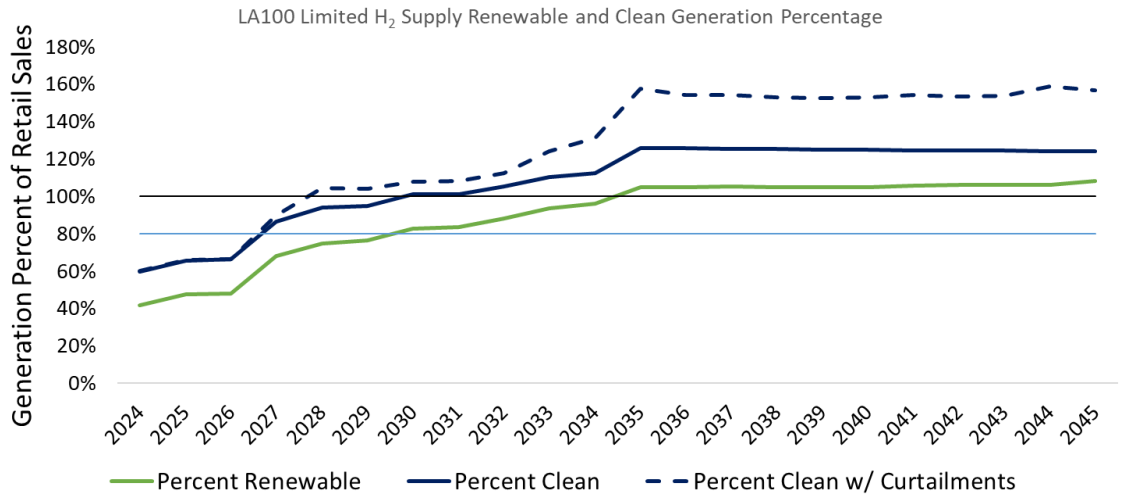


Figure 4-63. LA100 Limited H_2 Supply Sensitivity renewable and clean generation percentage.

The Limited H_2 Supply Sensitivity's renewable and clean generation percentage, shown in Figure 4-63, reflects LADWP's path toward meeting the City Council's goal of providing 100% carbon-free electricity by 2035. All values are shown as a percentage of retail sales, which refer to the electricity actually delivered to customers (excluding losses).

This sensitivity's renewable and clean generation percentages follow the general trends of the LA100 Pathway, except clean energy with curtailments is slightly higher, approximately 6% higher at its peak, as a result of the additional renewables added in this sensitivity.

4.9.5 Renewable Curtailment

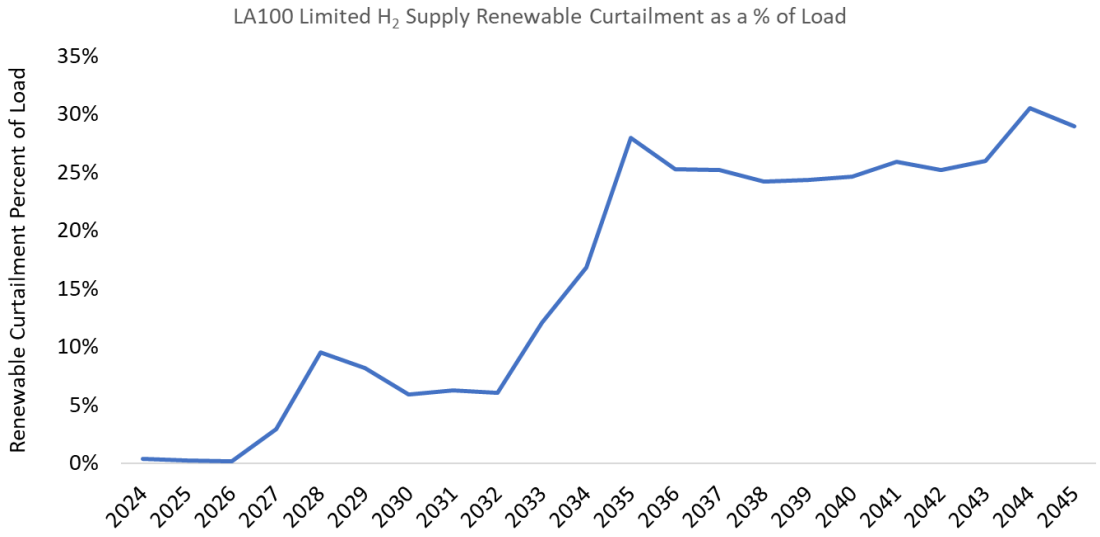


Figure 4-64. LA100 Limited H_2 Supply Sensitivity renewable energy curtailment.

Renewable curtailment as a percentage of net load in the Limited H_2 Supply Sensitivity, shown in Figure 4-64, reflects the portion of renewable electricity generated but not used due to a combination of system conditions and intentional resource planning decisions.

Curtailment trends are similar to those of the LA100 Pathway, but starting in 2035, become larger in magnitude due to the additional renewables in this sensitivity. At its peak, this sensitivity has approximately 6% more curtailment than the LA100 Pathway.

4.9.6 Greenhouse Gas Emissions

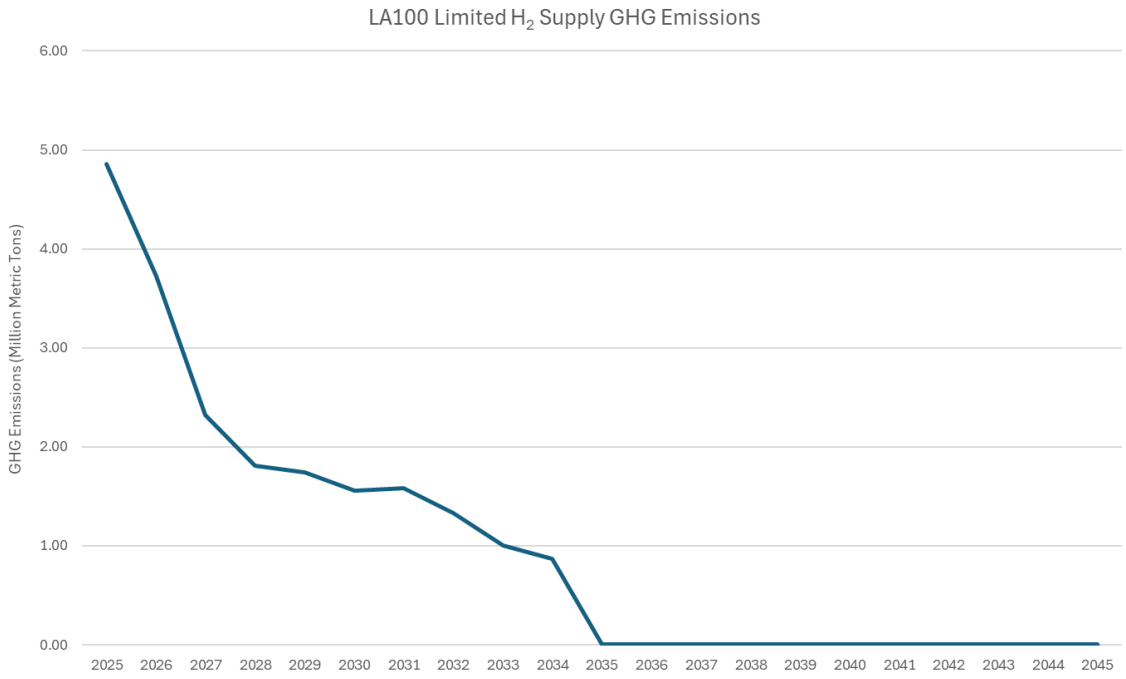


Figure 4-65. LA100 Limited H_2 Supply Sensitivity GHG emissions associated with electricity generation.

GHG emissions for the Limited H_2 Supply Sensitivity, shown in Figure 4-65, reflect similar trends to those seen in the LA100 Pathway, beginning at just under 5 million metric tons in 2025 and declining sharply over the next decade as coal-fired generation is fully retired and fossil gas use is steadily phased out by the start of 2035.

4.9.7 Annual System Cost

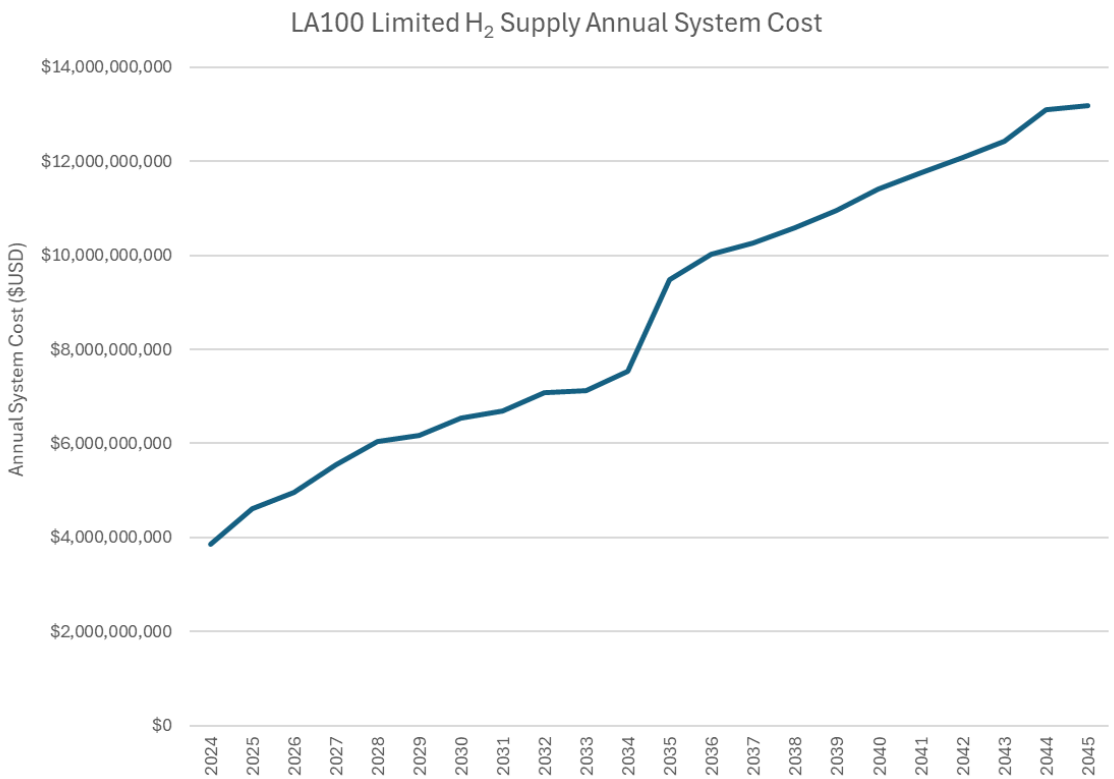


Figure 4-66. LA100 Limited H_2 Supply Sensitivity annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments).

The Limited H_2 Supply Sensitivity annual system cost, shown in Figure 4-66, represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway that assumes limited hydrogen supply available in-basin, and instead, builds out more renewables in its place. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, and transmission investments. Trends largely follow those of the LA100 Pathway, however with a very slight cost increase due to capital costs associated with increased amount of renewables overtaking cost savings from less usage of green hydrogen fuel.

4.9.8 Key Takeaways

With the collaboration across California to develop hydrogen infrastructure, one critical risk to evaluate is the possibility that less hydrogen than expected is available on the market. This would limit the availability of in-basin resources to about a 2% average capacity factor and require more acquisition of renewables and storage to maintain reliability throughout the study horizon. This is challenging with at least 3 years needed to secure a renewable project and would drive up costs by 3% compared to the LA100 Pathway, resulting in a total supply cost from 2025 to 2045 of $102.8 billion. Additionally, in the near term 2025-2034, carbon emissions would increase from 2.10 million metric tons of carbon emissions to 2.12 million metric tons.

4.10 LA100 Resource Constrained Sensitivity

The LA100 Resource-Constrained Sensitivity evaluates the risk that LADWP may be unable to deploy the full portfolio of clean energy resources on the schedule assumed in the LA100 Pathway. While the foundational goals of the LA100 Plan remain intact—including the achievement of 100% carbon-free electricity and the elimination of fossil fuel use for all generation, including line losses—this scenario examines what happens if external constraints hinder the timely buildout of key technologies.

These constraints may include market conditions such as cost escalations or resource shortages, supply chain disruptions affecting technology availability, and permitting or siting delays that slow construction timelines. The sensitivity provides a critical lens on the kinds of risks that can emerge from real-world implementation challenges outside of LADWP's direct control.

Developed in consultation with the LA100 Advisory Group, this sensitivity helps assess how the system might respond if renewables, storage, transmission, or green hydrogen infrastructure cannot be deployed at the pace assumed in the core pathway. It offers insights into the reliability, emissions, and cost tradeoffs associated with a slower-than-expected clean energy transition and highlights the importance of proactive planning, risk mitigation, and flexible resource strategies.

As a result, the 100% carbon-free target is delayed from 2035 to 2040—still ahead of California's SB 100 mandate of 2045. To simulate these constraints, the model limits the pace at which carbon-free resources can be added to the system. For renewable energy resources, only half of the annual buildout assumed in the LA100 Pathway is allowed in

any given year. This effectively "spreads out" the deployment of new solar and wind generation over a longer period, resulting in a slower transition to a high-renewables grid. Similar constraints are applied to energy storage technologies, limiting the availability of capacity needed to firm intermittent resources.

In addition, this sensitivity assumes a delayed buildout of in-basin hydrogen-fueled combustion turbines, which are a critical source of firm, carbon-free dispatchable generation in the LA100 Pathway. The delay reflects potential barriers such as limited manufacturing capacity, infrastructure siting challenges, or slow development of a scalable green hydrogen supply chain.

The Resource Constrained Sensitivity illustrates how delays in the availability of carbon-free technologies can impact the timing, cost, and operational reliability of the clean energy transition. While the ultimate goal of a 100% carbon-free grid remains technically feasible, achieving it under these constrained conditions requires greater planning flexibility, increased reliance on transitional resources, and potentially higher system costs. This sensitivity underscores the need for risk-aware implementation strategies, robust contingency planning, and strong coordination with industry partners and policymakers to mitigate external bottlenecks.

4.10.1 Capacity Expansion

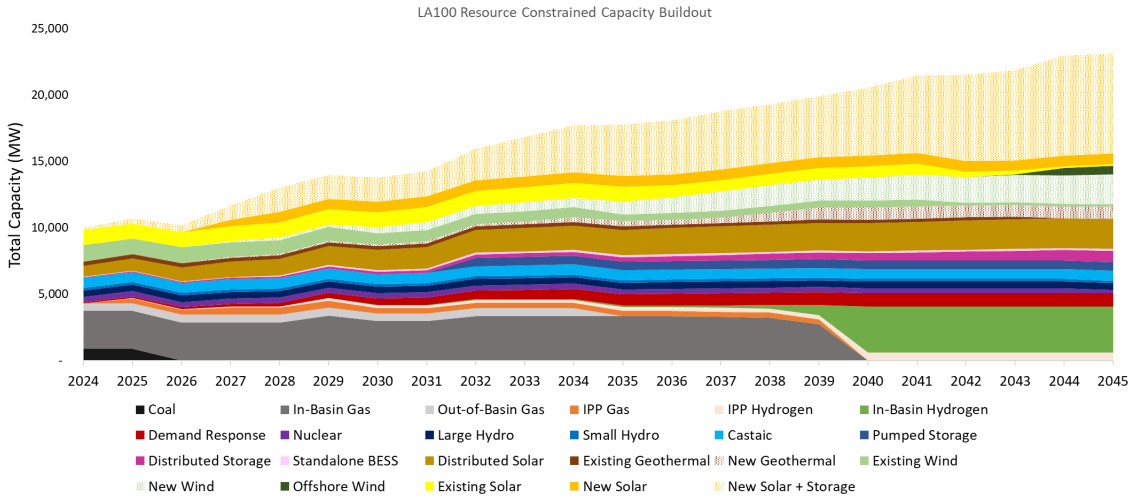


Figure 4-67. Total cumulative nameplate capacity for LA100 Resource Constrained Sensitivity.

As shown in the chart in Figure 4-67, the Resource Constrained Sensitivity slightly differs from the LA100 Pathway, due to market conditions and resource limitations delaying buildouts of renewable energy projects, energy storage, and clean, firm dispatchable generation units. Specifically for this sensitivity, the model was not allowed to build more than 500 MW of renewable energy projects in a given year, to simulate resource build rate constraints, and the commissioning of in-basin green hydrogen-fueled generating units was spread out to be fully in-service by 2040, rather than 2035 as assumed in the LA100 Pathway.

4.10.2 Generation Dispatch

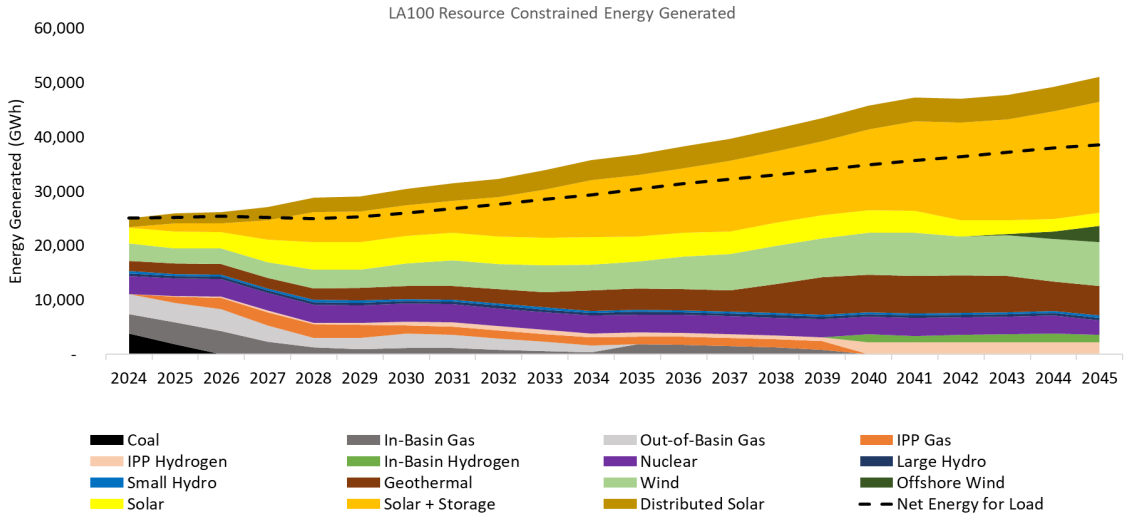


Figure 4-68. Projected energy generation mix under the LA100 Resource Constrained Sensitivity.

Figure 4-68 illustrates the projected energy generation mix under the Resource Constrained Sensitivity. Compared to the LA100 Pathway, the buildout of renewable energy, energy storage, and green-hydrogen generating units is spread out over a longer time horizon, 2040 as opposed to 2035, thus there is a more gradual buildout of resources throughout the study horizon. Natural gas-fueled generation slowly phases out over time, but it is retained until the end of 2039, until green hydrogen-fueled generation fully takes its place.

4.10.3 Customer Load with Modifiers

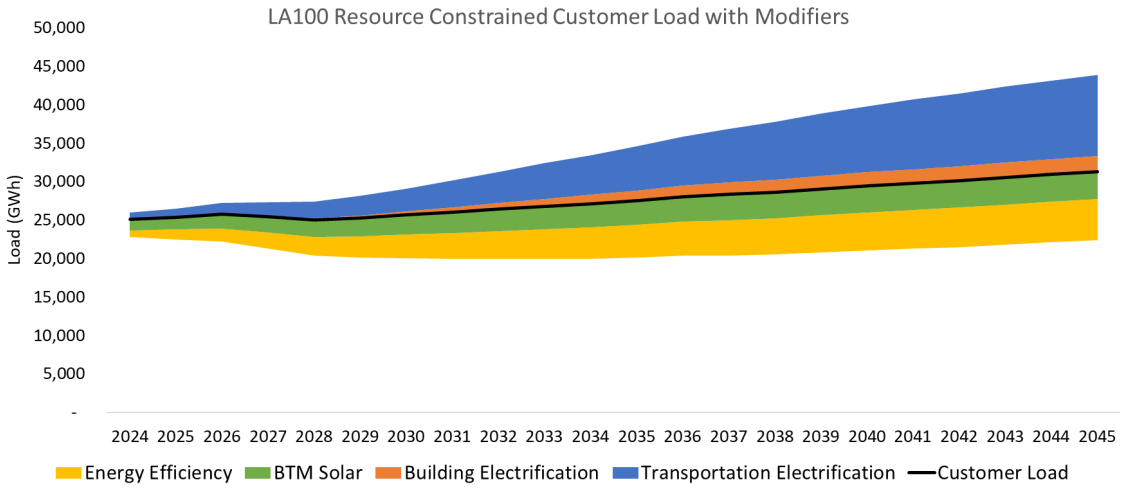


Figure 4-69. LA100 Resource Constrained Sensitivity customer load with modifiers.

Figure 4-69 illustrates the same projected customer electricity load through 2045, as the LA100 Pathway.

4.10.4 Renewable and Clean Generation

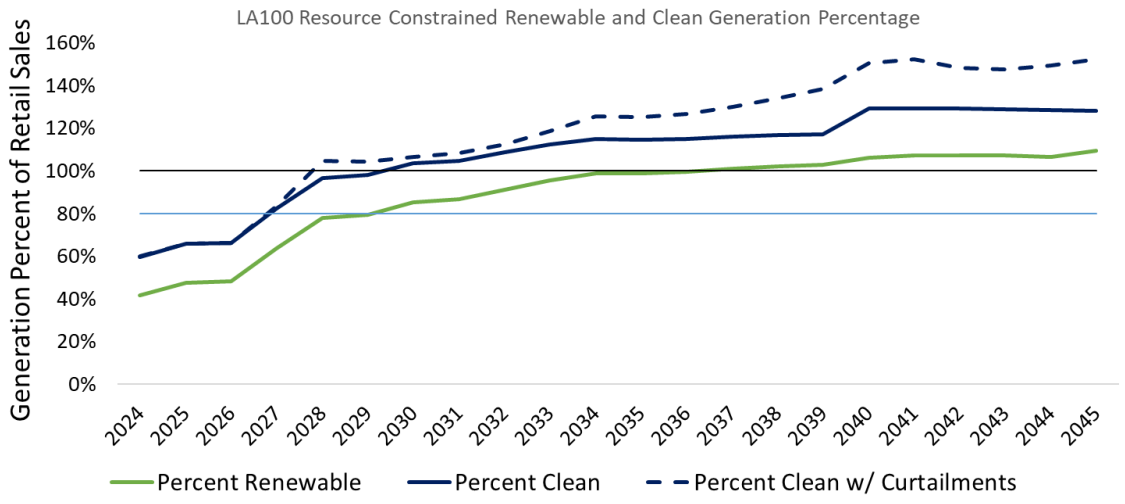


Figure 4-70. LA100 Resource Constrained Sensitivity renewable and clean generation percentage.

The Resource Constrained Sensitivity's renewable and clean generation percentage, shown in Figure 4-70, largely follows the trend shown in the LA100 Pathway, with the main difference being that renewable and clean energy generation percentages peak in 2040, as opposed to 2035, due to delayed clean energy resource builds.

4.10.5 Renewable Curtailment

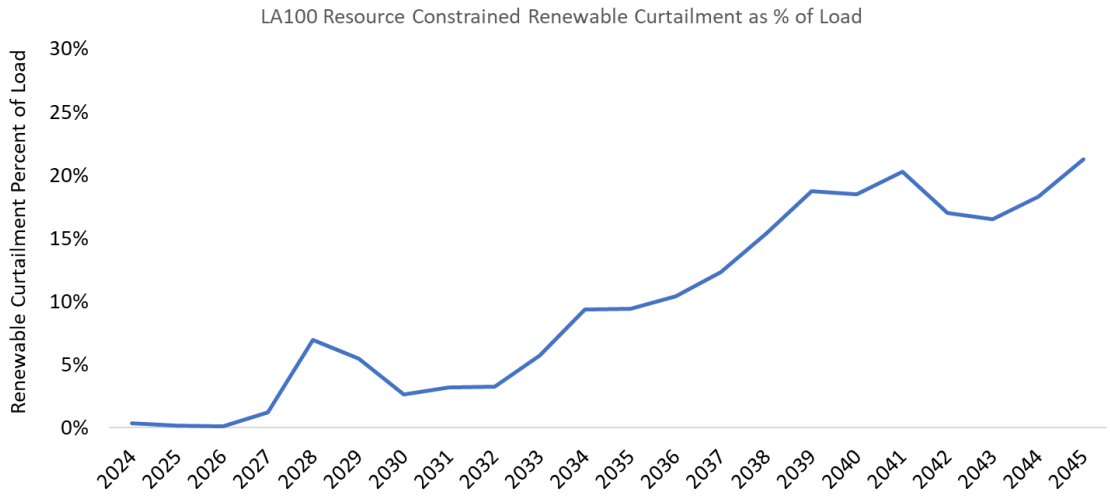


Figure 4-71. LA100 Resource Constrained Sensitivity renewable energy curtailment.

Renewable curtailment as a percentage of net load in the Resource Constrained Sensitivity, shown in Figure 4-71, reflects the portion of renewable electricity generated but not used due to a combination of system conditions and intentional resource planning decisions. Overall, curtailment is lower in this sensitivity, when compared to the LA100 Pathway, due to renewables coming online later in the study as opposed to earlier on. As a result, in some years in the mid-2030s, curtailment is reduced upwards of 50%, compared to the LA100 Pathway.

4.10.6 Greenhouse Gas Emissions

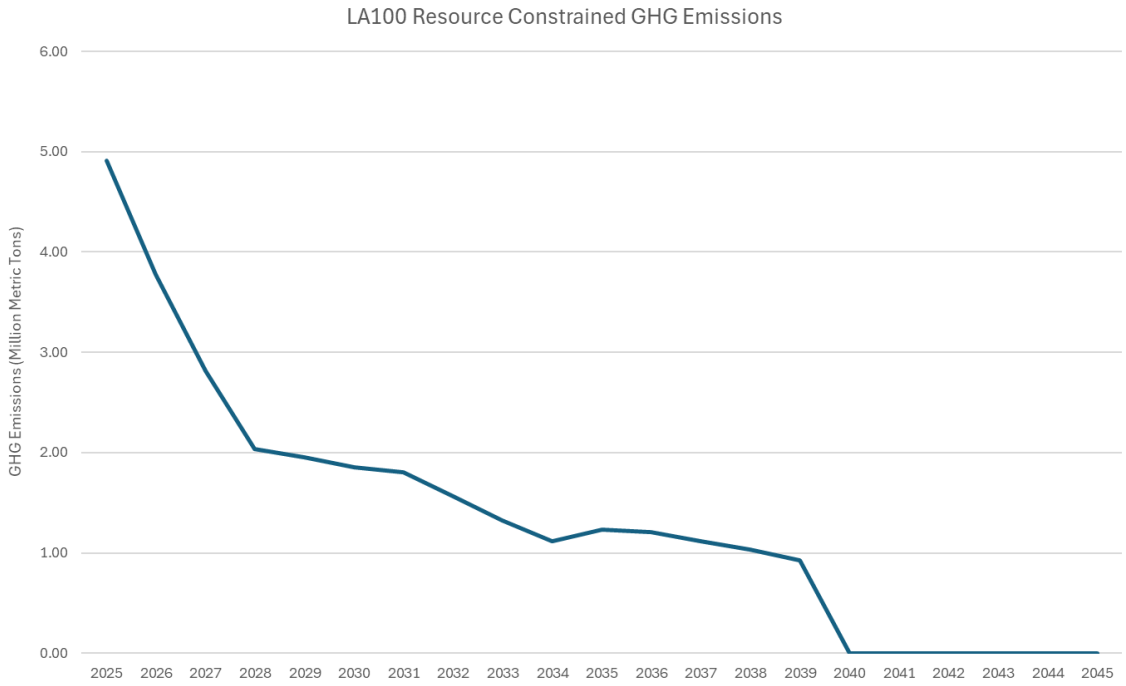


Figure 4-72. LA100 Resource Constrained Sensitivity GHG emissions associated with electricity generation.

GHG emissions for the Resource Constrained Sensitivity, shown in Figure 4-72, reflect similar trends to those seen in the LA100 Pathway, beginning at just under 5 million metric tons in 2025 and declining sharply over the next decade as coal-fired generation is fully retired, however emissions do not fully go to zero until 2040, due to keeping natural gas-fueled generating units online until that date.

4.10.7 Annual System Cost

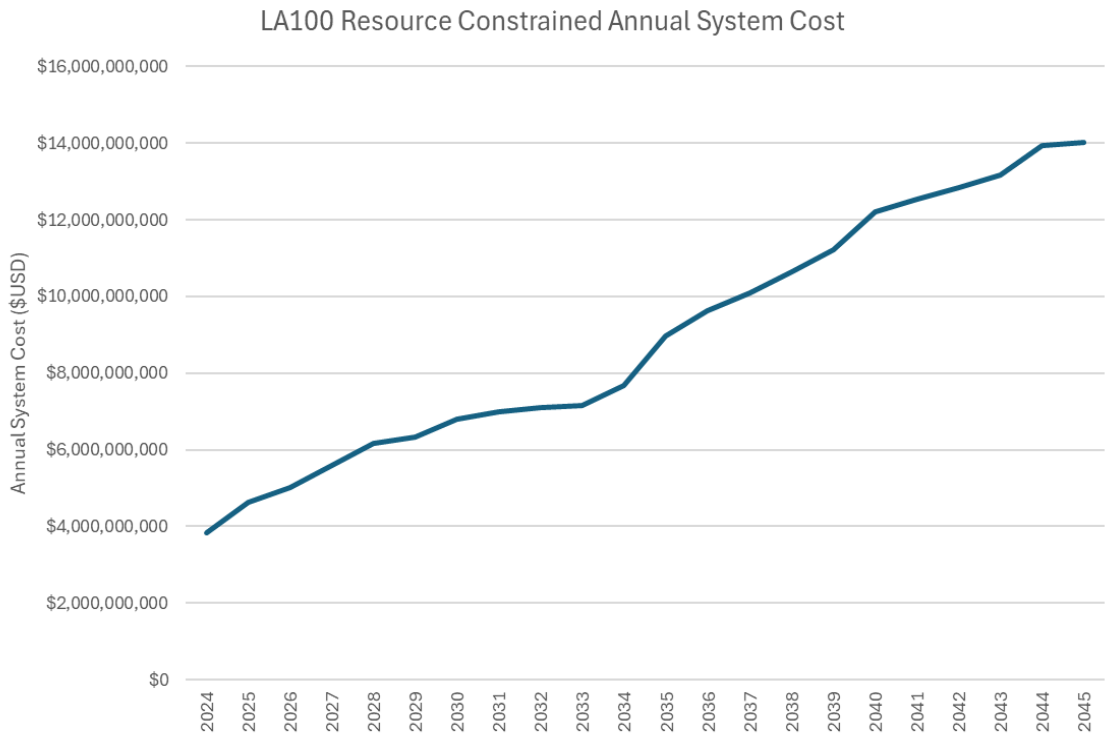


Figure 4-73. LA100 Resource Constrained Sensitivity annual system cost reflects the total cost of operating, maintaining, and expanding LADWP's power system each year. This includes both variable costs (e.g., fuel, wear and tear on equipment) and fixed costs (e.g., debt service for new infrastructure investments).

The Resource Constrained Sensitivity annual system cost, shown in Figure 4-73, represents the projected total cost to operate and build out LADWP's power system under a carbon-free energy pathway that retains natural gas-fueled generation as backup, through 2039. The cost includes both variable expenses, such as fuel and maintenance, and fixed costs, such as capital recovery for new generation, energy storage, and transmission investments. Trends largely follow those of the LA100 Pathway, however in the 2040s, there are slightly higher annual costs for the delayed renewable energy, energy storage, and green hydrogen-fueled generation projects as a result of inflation.

4.10.8 Key Takeaways

This sensitivity explores the implications of a constrained clean energy market, where the availability of renewables, storage, and hydrogen technology is limited. Under this scenario, LADWP assumes that no more than 500 megawatts of new resources can be procured each year, and hydrogen deployment is significantly delayed.

As a result of this limited procurement pace, the City's transition to carbon-free energy occurs more gradually. During the 2025 to 2034 period, emissions remain higher than those observed under the LA100 Pathway—averaging 2.37 million metric tons of CO_2 per year, compared to 2.10 million metric tons in the LA100 Pathway. However, emissions decline sharply in the 2035 to 2045 period, dropping to an average of 0.48 million metric tons annually as decarbonization efforts accelerate.

This delay in clean energy deployment also leads to a modest increase in total system costs. The cumulative total supply cost from 2025 to 2045 is estimated at $104.9 billion—approximately 2% higher than the LA100 Pathway. The cost premium is primarily driven by greater reliance on existing in-basin dispatchable units, which serve a more prominent role in maintaining grid reliability during the resource-constrained period. This is reflected in a higher average capacity factor of 7% for in-basin dispatchable units (2035–2045), more than double the 3% level projected under the LA100 Pathway.

Overall, the Resource Constrained Sensitivity highlights the importance of robust supply chains and a scalable hydrogen market. Delays in clean energy development pose risks to both emissions targets and cost containment, while increasing dependence on legacy in-basin generation for grid stability.

4.11 LA100 Climate Change Sensitivity

The LA100 Climate Change Sensitivity evaluates how rising temperatures driven by climate change could affect future electricity demand and resource needs for LADWP. This analysis began with forward-looking projections of Heating Degree Days (HDD) and Cooling Degree Days (CDD) through 2045, based on two climate scenarios: RCP 4.5 and RCP 8.5. Representative Concentration Pathways (RCPs) are standardized greenhouse gas concentration trajectories used in global climate modeling. RCP 4.5 assumes moderate emissions with stabilization by 2100, while RCP 8.5 represents a high-emissions scenario with minimal mitigation, resulting in more severe climate impacts.

We combined these forward-looking projections with ten years of historical HDD and CDD data for key locations across LADWP's service territory, including Downtown Los Angeles, Los Angeles International Airport (LAX), Woodland Hills, and Van Nuys. Using this historical dataset, we developed correlations between temperature-sensitive metrics and historical customer electricity demand. To model this relationship, we applied several machine learning techniques, including Locally Weighted Learning (LWL)—an algorithm that predicts outcomes by creating localized models for each prediction, giving more weight to nearby data points. LWL, along with linear nearest neighbor search and linear regression, delivered the most accurate results for our application. Alternative methods such as decision trees and neural networks were evaluated but provided less reliable correlations.

The trained model was then applied to forward-looking HDD and CDD projections to adjust LADWP's load forecast under future climate conditions. Results indicate that while rising temperatures significantly increase electricity demand—primarily due to higher cooling loads—LADWP can still achieve its 100% carbon-free energy target by 2035 under the LA100 Pathway portfolio while maintaining system reliability. These findings highlight both the resilience of the LA100 Pathway resource mix and the importance of ongoing investment in flexible, clean energy resources as climate change accelerates electrification and cooling demand.

4.11.1 Capacity Expansion

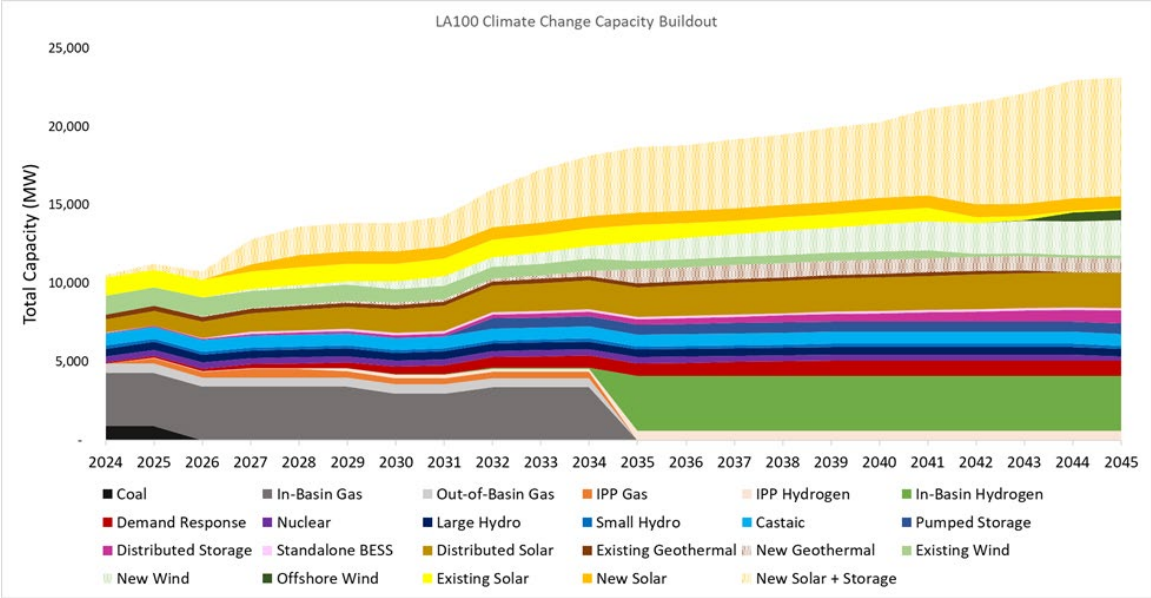


Figure 4-74. Projected capacity buildout under the LA100 Climate Change Sensitivity (2024–2045). This sensitivity assumes rising temperatures increase electricity demand, particularly for cooling. Compared to the core LA100 Pathway, additional clean generation and storage capacity is added to meet higher peak loads and annual energy needs.

The LA100 Climate Change Sensitivity explores how rising ambient temperatures may affect LADWP's future electricity demand and resource needs. This sensitivity builds on the LA100 Pathway but incorporates temperature projections from climate models, which were used to estimate increased building energy use—primarily for air conditioning—through a machine learning-based load forecasting approach.

As shown in Figure 4-74, total system capacity grows more rapidly in this sensitivity compared to the LA100 Pathway. While the mix of technologies remains broadly similar, higher peak and annual loads necessitate additional deployment of solar + storage, wind (onshore and offshore), geothermal, and hydrogen-fueled thermal generation to maintain reliability and meet the City's goal of achieving 100% carbon-free electricity by 2035.

To ensure system flexibility under more extreme temperature conditions, the sensitivity also includes expanded deployment of battery storage and in-basin dispatchable

capacity. These additions help LADWP respond to higher cooling loads and maintain system stability under potentially more variable demand profiles.

This iteration of the Climate Change Sensitivity focused solely on the demand-side impacts of rising temperatures. It does not evaluate how climate change may affect the supply-side—such as potential reductions in wind or solar resource availability due to shifting weather patterns or atmospheric conditions. These effects may be assessed in future modeling efforts.

Together, this sensitivity highlights the importance of planning for a changing climate, ensuring that the LA100 Pathway portfolio remains robust and reliable under a wide range of future conditions.

4.11.2 Generation Dispatch

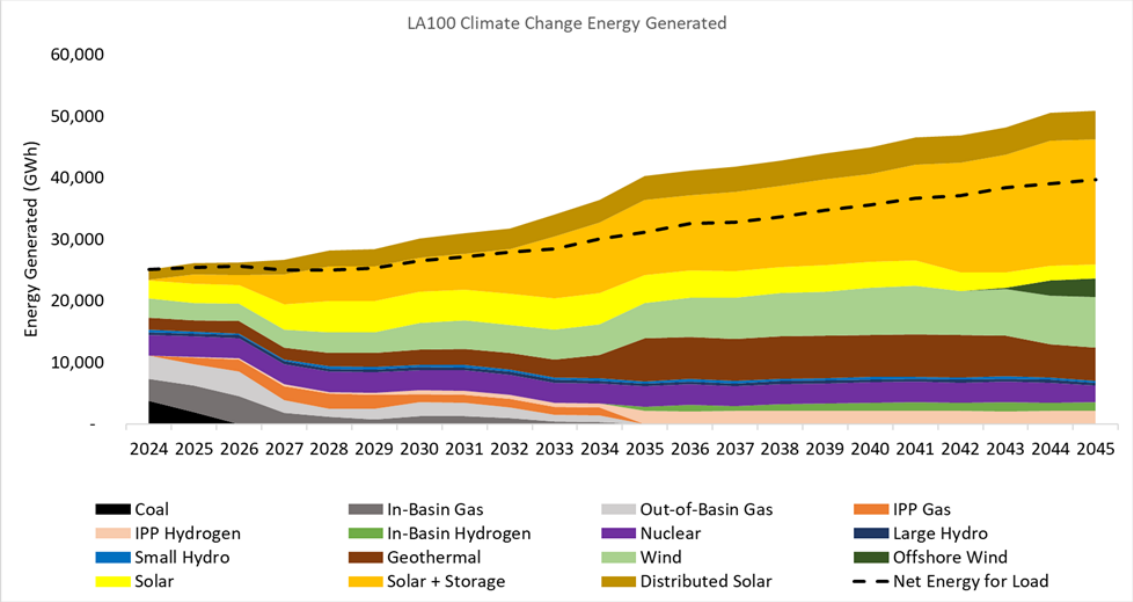


Figure 4-75. Projected energy generation under the LA100 Climate Change Sensitivity (2024–2045), measured in GWh. Compared to the LA100 Pathway, total generation increases to meet higher electricity demand resulting from rising temperatures. All energy is generated from carbon-free resources by 2035, consistent with the City's 100% carbon-free energy target.

Figure 4-75 illustrates projected electricity generation under the LA100 Climate Change Sensitivity, which models higher electricity demand based on temperature-driven increases in building energy use. As in the core LA100 Pathway, fossil fuel generation is

fully phased out by 2035 and replaced with a diversified portfolio of carbon-free resources.

The dashed black line represents net energy for load, which increases steadily through 2045 due to rising ambient temperatures and associated growth in air conditioning and other cooling-related demand. To meet this higher load, LADWP's generation portfolio expands accordingly, with additional contributions from solar (including solar + storage and distributed solar), wind (onshore and offshore), geothermal, and in-basin green hydrogen generation.

Although the resource mix remains similar to the LA100 Pathway, total generation volumes are higher in this sensitivity to ensure reliability and full compliance with the City's 100% carbon-free electricity requirement. By 2035, all delivered electricity—including that used for transmission losses and storage inefficiencies—is sourced from zero-emission resources.

This energy generation profile reflects LADWP's ability to scale a clean energy system to meet increased climate-driven demand while maintaining the integrity of the 2035 decarbonization goal. Future iterations of this sensitivity may explore how climate change could also affect renewable resource availability and generation patterns, which were not assessed in this modeling cycle.

4.11.3 Customer Load with Modifiers

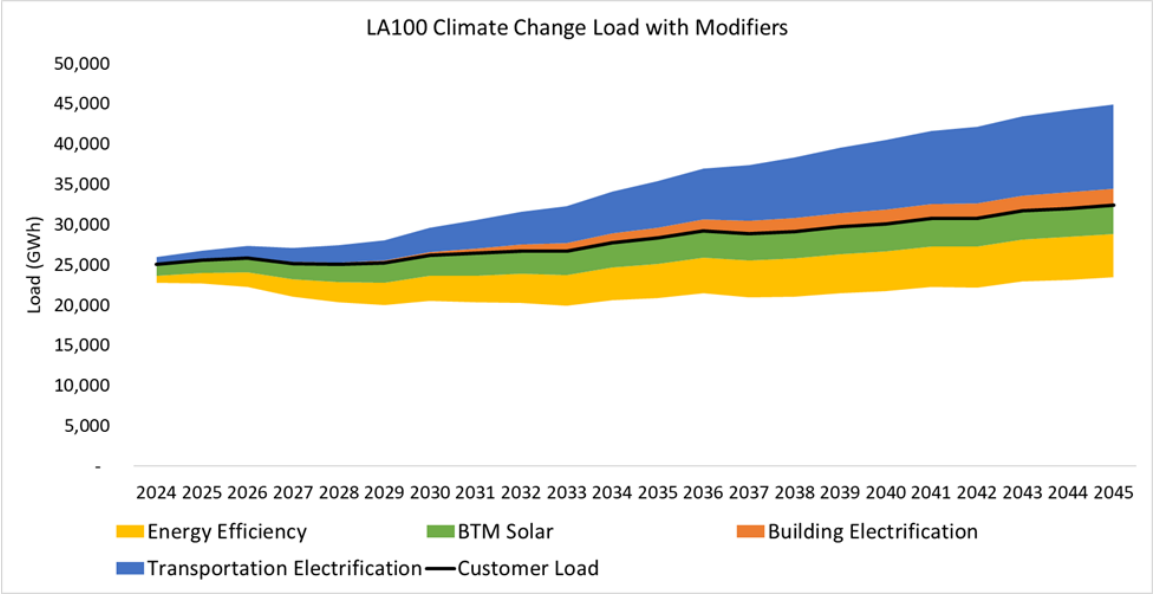


Figure 4-76. Projected customer electricity load under the LA100 Climate Change Sensitivity (2024–2045), incorporating major demand-side modifiers. The black line shows net customer load after accounting for energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification. Rising temperatures lead to higher baseline load compared to the LA100 Pathway.

Figure 4-76 shows projected customer electricity load under the LA100 Climate Change sensitivity, incorporating key demand-side modifiers. As in the LA100 Pathway, the analysis accounts for the effects of energy efficiency, behind-the-meter (BTM) solar adoption, building electrification, and transportation electrification. However, in this sensitivity, rising temperatures associated with climate change lead to higher baseline electricity use—particularly for air conditioning and other cooling loads.

The black line represents net customer load, which reflects the combined impact of all modifiers. Energy efficiency and BTM solar help reduce or offset load, while building and transportation electrification—driven by policy goals and technological adoption—contribute to steady growth in electricity demand through 2045.

The most notable change in this sensitivity is the elevated overall load level compared to the LA100 Pathway. This increase is a direct result of higher ambient temperatures

feeding into the machine learning-enhanced load forecast, which predicts greater electricity use across residential, commercial, and industrial sectors.

This sensitivity highlights the need to plan for rising energy demand in a warming climate and reinforces the importance of continued investment in demand-side measures to mitigate load growth while maintaining grid reliability and equity.

4.11.4 Renewable and Clean Generation

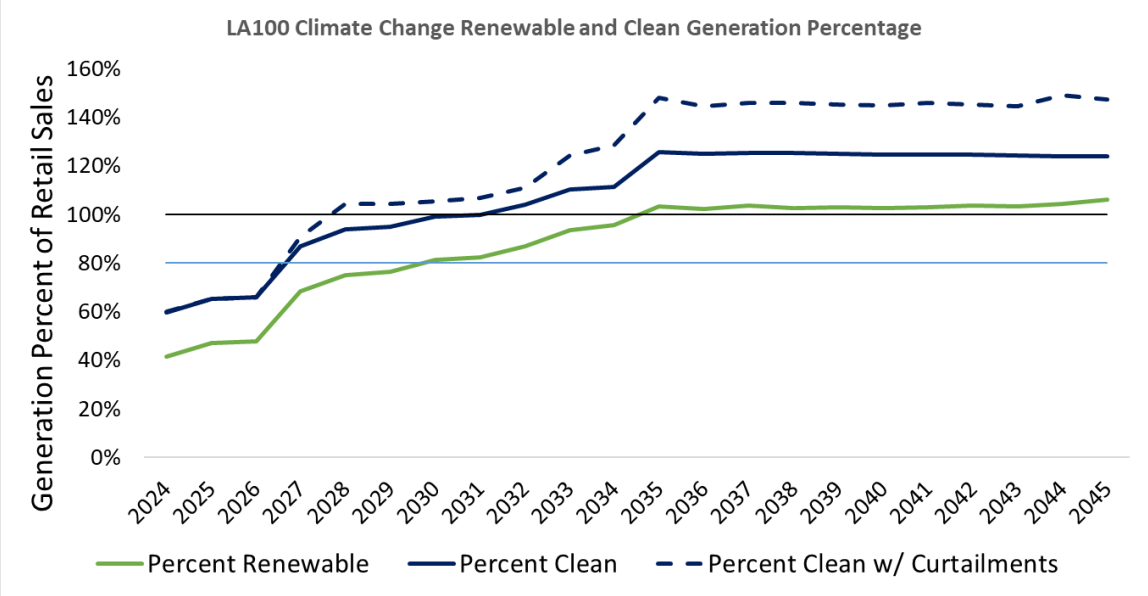


Figure 4-77. Projected renewable and clean energy generation as a percentage of retail sales under the LA100 Climate Change Sensitivity (2024–2045). The green line shows the share served by renewable energy, the solid blue line represents clean energy (including large hydro and nuclear), and the dashed blue line includes curtailed clean energy. While all values are expressed relative to retail sales for comparison, LADWP interprets the City Council's 2035 directive as requiring 100% carbon-free energy for all delivered electricity—including losses and storage inefficiencies.

Figure 4-77 shows projected progress toward 100% clean energy under the LA100 Climate Change Sensitivity, expressed as a percentage of retail electricity sales for comparability with state mandates. However, LADWP interprets the Los Angeles City Council's 2035 directive as requiring 100% carbon-free energy not just for retail sales, but for all delivered electricity—including transmission losses, energy storage inefficiencies, and other system needs.

The green line represents renewable energy (e.g., solar, wind, geothermal, and small hydro) as a share of retail sales. The solid blue line includes all clean resources—adding large hydro and nuclear to the renewable mix. The dashed blue line accounts for curtailed clean energy, which is generated but not ultimately delivered due to system constraints.

Despite increased customer demand driven by rising temperatures in this sensitivity, LADWP achieves 100% carbon-free energy by 2035 under the broader interpretation of "delivered electricity." Clean energy generation exceeds 100% of retail sales starting in the early 2030s and remains well above that level through 2045, providing the necessary margin to cover non-retail uses of electricity.

This trajectory demonstrates that even under a warming climate, LADWP can meet the full intent of the City's 2035 carbon-free directive—ensuring that all electricity used on the system, not just retail sales, is supplied from clean, zero-carbon resources.

4.11.5 Renewable Curtailment

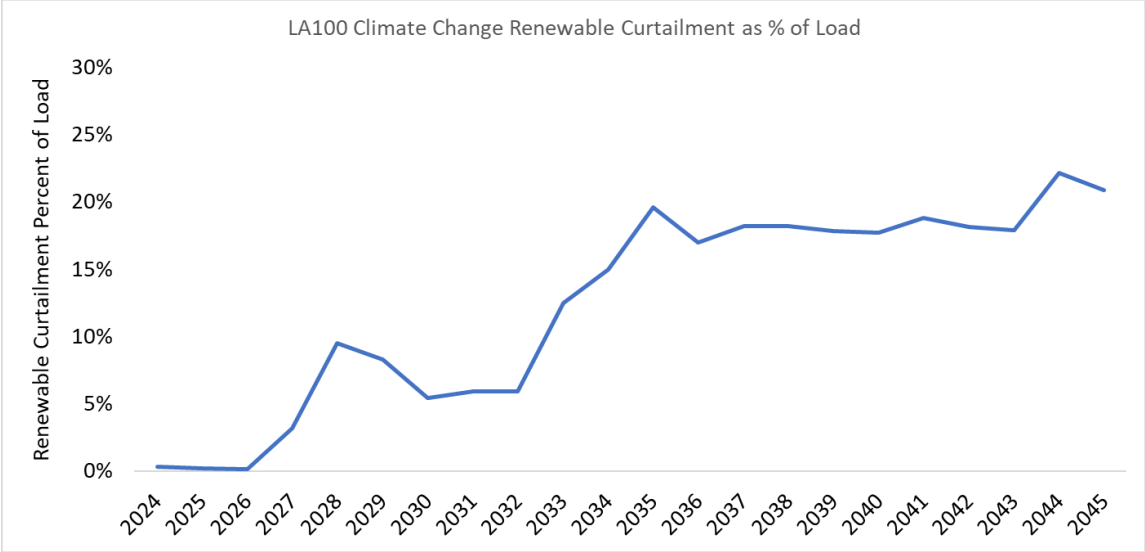


Figure 4-78. Projected renewable energy curtailment as a percentage of net load under the LA100 Climate Change Sensitivity (2024–2045). Curtailment rises in the early 2030s as renewable generation expands to meet higher load and reliability needs, then remains elevated as clean capacity continues to grow faster than load.

Figure 4-78 shows the share of renewable energy generation that is curtailed—generated but not used—expressed as a percentage of retail load under the LA100 Climate Change Sensitivity. Curtailment occurs when generation from solar, wind, or other renewables exceeds real-time system needs or available storage and transmission capacity.

In this sensitivity, renewable curtailment begins to rise meaningfully in the late 2020s and climbs more sharply through the early 2030s as LADWP scales up clean generation to meet rising electricity demand under higher temperature conditions. Curtailment peaks around 2035, coinciding with the achievement of 100% carbon-free energy delivery, and remains elevated throughout the 2035–2045 period.

The sustained level of curtailment reflects LADWP's strategy of building a robust and redundant portfolio of zero-carbon resources to ensure grid reliability, even during periods of high load or low renewable output. While some curtailment is a planned and cost-effective tradeoff in a high-renewables grid, it also highlights opportunities for future improvement through additional storage, flexible load, or regional coordination.

Under this climate-driven sensitivity, curtailment levels are somewhat higher than in the LA100 Pathway due to increased generation buildout needed to serve elevated customer demand—underscoring the importance of integrated planning across generation, storage, and grid operations in a warming climate.

4.11.6 Greenhouse Gas Emissions

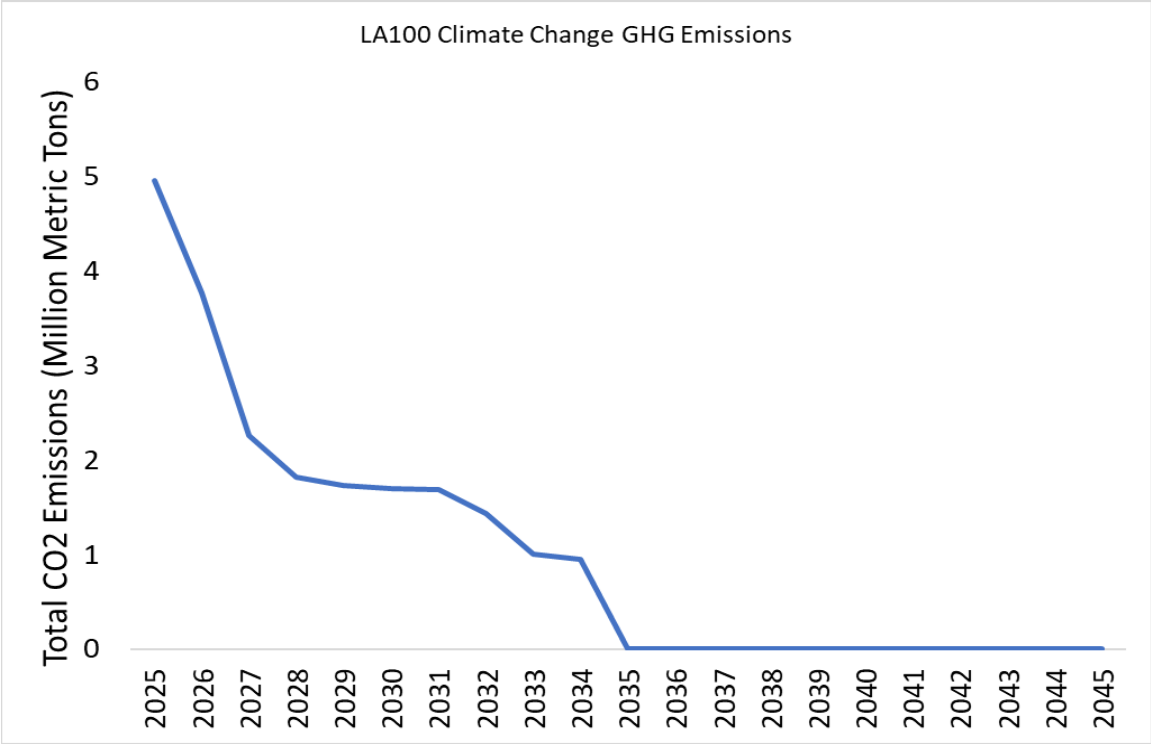


Figure 4-79. Projected greenhouse gas emissions under the LA100 Climate Change Sensitivity (2024–2045). Emissions decline steeply through 2035 as LADWP retires coal units, phases out natural gas, and transitions remaining natural gas-fueled thermal units to green hydrogen. From 2035 onward, emissions remain at zero, demonstrating compliance with the City's 100% carbon-free energy mandate despite increased load from climate-driven demand growth.

Figure 4-79 shows the trajectory of greenhouse gas emissions under the LA100 Climate Change Sensitivity. Emissions decrease significantly from 2024 through 2035 as major milestones are achieved, including the retirement of coal resources by 2025 and the conversion of all remaining in-basin and out-of-basin thermal generation to green hydrogen. While increased temperatures lead to higher projected demand compared to the LA100 Pathway, these changes do not delay the achievement of zero emissions by 2035.

After 2035, the system maintains zero emissions through the end of the planning horizon in 2045. This outcome confirms that LADWP can meet its clean energy mandate under more challenging load conditions without compromising system reliability. The result

underscores the importance of resource diversification, including renewable buildout, storage deployment, and dispatchable zero-carbon resources, to achieve and sustain deep decarbonization goals.

4.11.7 Annual System Cost

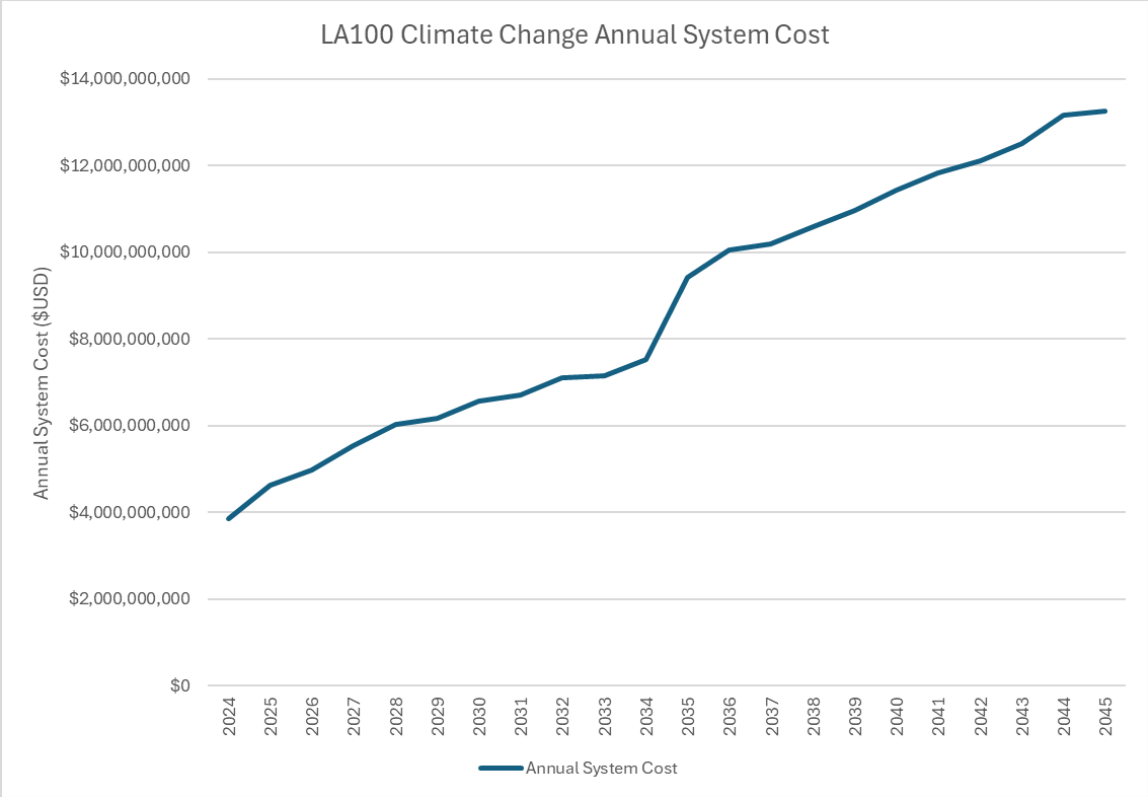


Figure 4-80. Projected annual system cost under the LA100 Climate Change Sensitivity (2024–2045). Costs rise steadily as the system transitions to 100% carbon-free energy by 2035 and continue increasing thereafter to maintain reliability under higher demand and climate-driven impacts.

Figure 4-80 shows the annual system cost trajectory for the Climate Change Sensitivity. Costs increase consistently throughout the planning period, reflecting the substantial capital investment required for renewable generation, storage, transmission, and distribution needed to support a carbon-free grid. The sharpest rise occurs in the early years as LADWP accelerates resource development and infrastructure upgrades to achieve the 2035 carbon-free energy target.

Following 2035, costs continue to climb gradually, driven by ongoing investments in system reinforcement, green hydrogen production and storage, and additional renewable capacity to meet increasing customer demand under climate change conditions. By 2045, annual system costs reach approximately $13 billion, underscoring the long-term financial implications of both achieving and sustaining a fully decarbonized and reliable power system.

4.11.8 Key Takeaways

The results of the LA100 Climate Change Sensitivity demonstrate that the LA100 Pathway resource portfolio remains reliable even in conditions of intensified climate change. The sensitivities high customer demand due to increased cooling loads is balanced by the portfolio's robust addition of utility-scale and demand side resources. Dispatchable units experience increased outage rates and worse operating parameters but still play a key role in mitigating the worst stress conditions that occur from intensified climate change. Even with increased usage and derated operating parameters by the dispatchable units, annual carbon emissions increase only slightly between 2025-2034 (2.18 $MMTCO_2$ compared to 2.10 $MMTCO_2$ in the LA100 Pathway). Overall, the LA100 Climate Change Sensitivity portfolio meets resource adequacy metrics at only a 3% increase to total supply cost from 2025 to 2045 ($105.6 billion) compared to the LA100 Pathway. As LADWP's understanding of climate change increases through its ongoing analyses, more detailed hazards, risks, and asset vulnerabilities may be assessed, which then alter the assumed reliability of LADWP resources and the system's overall reliability as a result. LADWP will maintain awareness and vigilance towards these risks in successive planning cycles and in its standard operations, in hopes of mitigating the effects of climate change as they become more prevalent.

4.12 SB 100 Benchmark

The LA100 Plan also ran a model aligned with the statewide SB100 target. Referred to in the LA100 Plan as the "SB100 Benchmark", the model represents a compliance-oriented pathway developed solely for comparison purposes. It models the minimum level of transition LADWP would need to pursue in order to meet the clean energy mandates established by Senate Bill 100 (SB 100) and subsequent legislation, including Senate Bill 1020. SB 100 requires all California utilities to supply 60% of retail electricity sales from renewable resources by 2030 and to achieve 100% carbon-free electricity by 2045.

SB 1020 adds interim targets of 90% carbon-free electricity by 2035 and 95% by 2040, further reinforcing the state's decarbonization trajectory.

This analysis is included in the LA100 Plan strictly as a reference case and does not represent LADWP's adopted or preferred path forward. It serves as a benchmark for evaluating trade-offs related to timing, resource mix, cost, emissions, and grid operations when compared to the more ambitious LA100 Pathway.

Under the SB100 Benchmark, the transformation of LADWP's power supply occurs at a more gradual pace. Coal-fired generation is retired by 2025, but natural gas resources—both in-basin and out-of-basin—continue operating through 2045, albeit with significantly reduced utilization. This reflects the compliance structure of SB 100, which allows fossil generation to remain on the system as long as carbon-free resources are sufficient to offset retail electricity sales on an annual basis.

To meet renewable and clean energy targets, LADWP adds substantial solar generation paired with energy storage, along with new wind capacity, battery storage systems, and modest contributions from geothermal and offshore wind in later years. Emerging technologies, such as green hydrogen, appear only in limited volumes and are not a central component of the resource mix.

Customer load in this sensitivity grows steadily over time due to widespread electrification of buildings and transportation, partially offset by energy efficiency and early adoption of behind-the-meter solar. Operationally, thermal units continue to play a key role in maintaining grid reliability and stability, resulting in moderate greenhouse gas (GHG) and nitrogen oxide (NO_x) emissions throughout the planning horizon.

In summary, the SB100 Benchmark illustrates a slower, compliance-driven pathway to decarbonization. While it meets all state mandates by 2045, it contrasts with the LA100 Pathway's accelerated timeline, earlier reductions in GHG and NO_x emissions, and deeper integration of zero-carbon technologies. As a benchmark, this analysis provides valuable context for understanding the implications of a more gradual energy transition.

4.12.1 Capacity Expansion

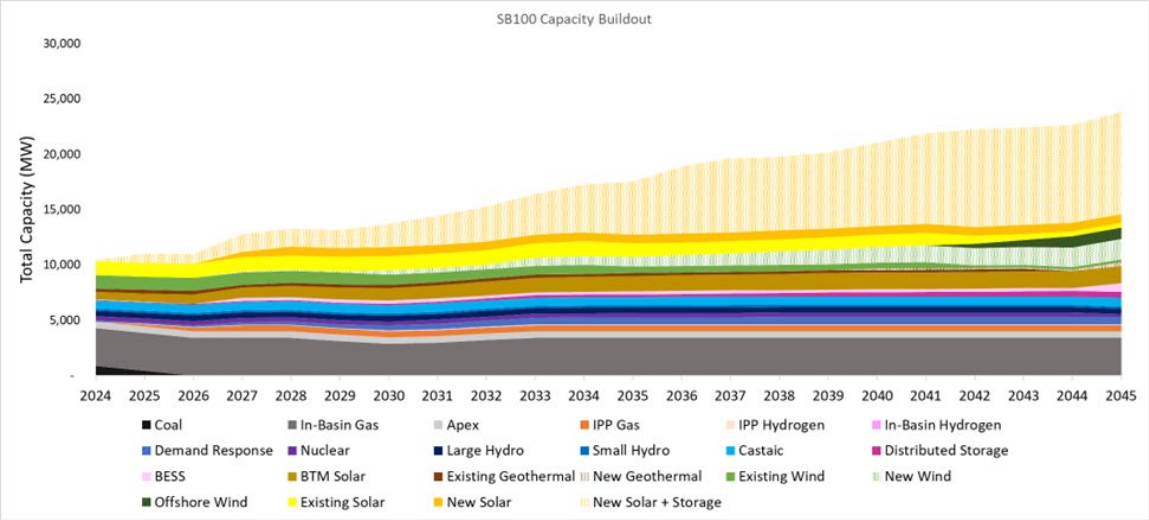


Figure 4-81. Projected capacity buildout under the SB100 Benchmark (2024–2045). SB 100 capacity buildout shows the evolution of LADWP's power system to meet the requirements of California Senate Bill 100, which mandates 60% renewable energy by 2030 and 100% carbon-free electricity by 2045 (based on retail sales). Coal is fully retired by 2025, while natural gas capacity remains online through 2045 under this benchmark. New capacity additions include solar + storage, wind, and battery energy storage, supporting the long-term transition to a carbon-free grid.

SB 100 capacity buildout reflects LADWP's baseline compliance pathway with California Senate Bill 100, which requires utilities to achieve a 60% renewable portfolio standard (RPS) by 2030 and provide 100% carbon-free electricity by 2045, as measured by retail sales. This analysis serves as a reference point for understanding the minimum effort needed to meet statewide legal obligations, in contrast to the accelerated, locally mandated targets in the LA100 Pathway.

Figure 4-81 illustrates a gradual transformation of LADWP's capacity mix over the next two decades. Coal is fully retired by 2025, while natural gas capacity, both in-basin and out-of-basin, is retained throughout the planning horizon, though its utilization is expected to decline over time. New additions include a steady deployment of utility-scale solar paired with storage, wind (both existing and new), and battery energy storage systems (BESS). Smaller but important contributions come from distributed resources, demand response, geothermal, and offshore wind in later years.

Because SB 100 does not require carbon-free generation for transmission losses or storage inefficiencies, the overall capacity expansion is more moderate than in the LA100 Pathway. As a result, some natural gas remains part of the resource mix to provide firm capacity and system flexibility, particularly during periods of low renewable output. This analysis assumes a slower phase-in of emerging technologies like green hydrogen and greater reliance on existing infrastructure for cost control and operational continuity.

While the SB100 Benchmark satisfies the letter of California law, it does not reflect the more ambitious goals adopted by the Los Angeles City Council. Nonetheless, it provides a useful benchmark for evaluating the tradeoffs between pace, cost, emissions, and reliability in the broader clean energy transition.

4.12.2 Generation Dispatch

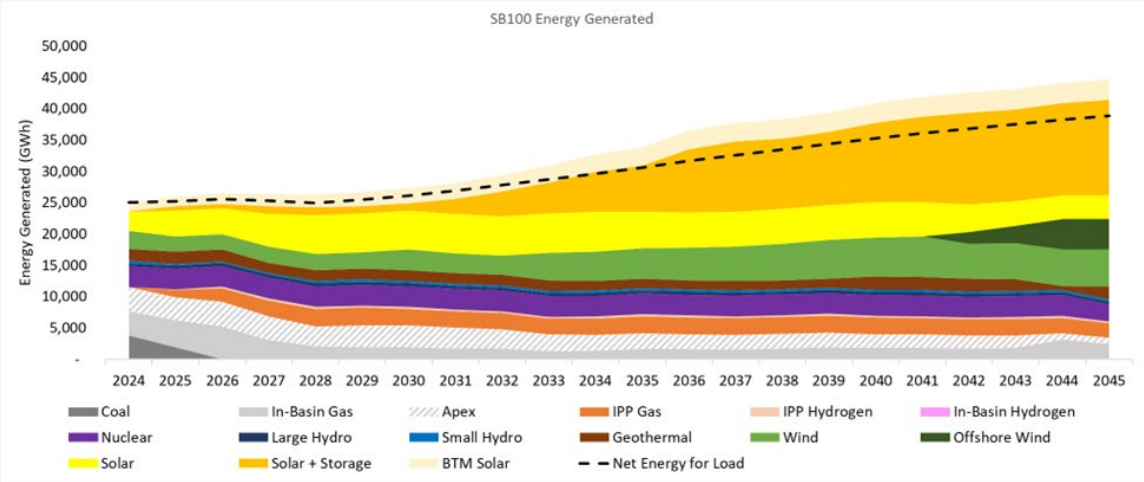


Figure 4-82. Projected energy generation mix under the SB100 Benchmark (2024–2045). SB 100 energy generated shows LADWP's projected electricity generation by fuel type to meet California's statutory clean energy requirements. Under Senate Bill (SB) 100, utilities must provide 60% of retail sales from renewables by 2030 and 100% from carbon-free resources by 2045. Senate Bill 1020 strengthens this trajectory by requiring 90% carbon-free energy by 2035 and 95% by 2040. Coal is fully phased out by 2025, and the generation mix gradually shifts toward solar, wind, and storage, while natural gas remains part of the portfolio to ensure reliability.

SB 100 energy generated illustrates LADWP's anticipated electricity generation mix under California's clean energy mandates. Senate Bill 100 requires utilities to meet a 60% renewable portfolio standard (RPS) by 2030 and provide 100% carbon-free electricity by 2045, based on retail sales. Senate Bill 1020, passed in 2022, adds interim targets of 90%

by 2035 and 95% by 2040, reinforcing the trajectory toward 100% carbon-free electricity by 2045.

As shown in Figure 4-82, coal-fired generation is fully eliminated by 2025, and renewable resources—particularly solar (including behind-the-meter and solar paired with storage) and wind—expand steadily over time. Geothermal and offshore wind contribute modestly to resource diversity, with offshore wind entering the mix later in the planning horizon. Despite the growth in clean energy, natural gas remains a component of LADWP's dispatchable capacity mix through 2045, primarily for grid balancing and reliability.

The dashed black line represents net energy for retail load. Unlike the LA100 Pathway, which requires all delivered electricity—including line losses and storage inefficiencies—to be carbon-free, the SB100 Benchmark reflects the retail-sales-based compliance framework of state law. As such, the total amount of carbon-free generation in this analysis generally tracks retail demand, with some buffer in later years.

The SB100 Benchmark reflects a compliance-oriented approach, meeting the legal floor established by the State of California. While less aggressive than the LA100 Pathway adopted by LADWP and the Los Angeles City Council, the SB 100 / SB 1020 model serves as an important reference for understanding the minimum trajectory and associated infrastructure implications for achieving statewide climate goals.

4.12.3 Customer Load with Modifiers

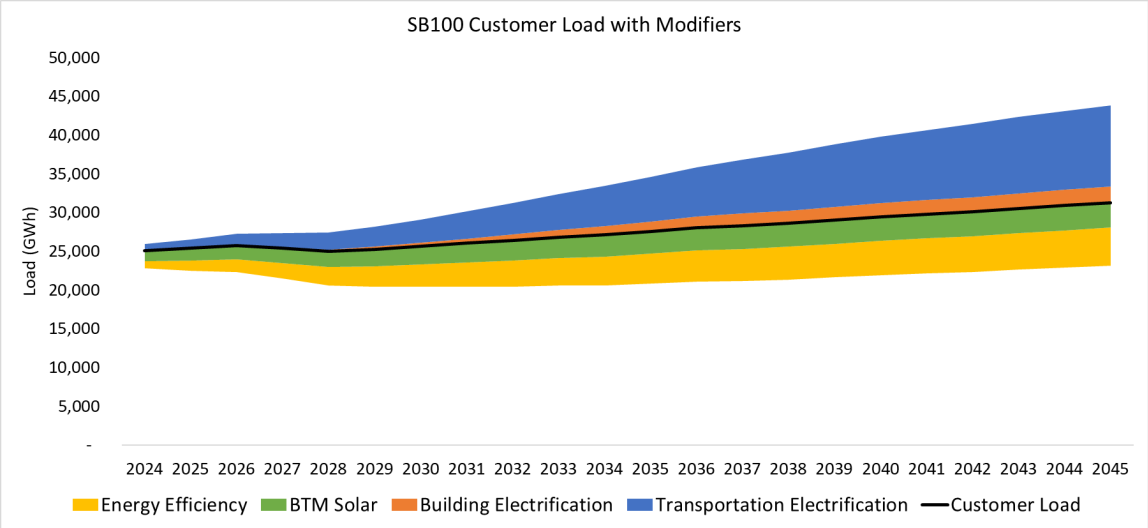


Figure 4-83. Projected customer load under the SB100 Benchmark, including demand-side modifiers (2024–2045). SB 100 customer load with modifiers shows LADWP's projected electricity demand over time, accounting for the effects of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification. While efficiency and BTM solar initially reduce net load, increased electrification of buildings and vehicles drives overall load growth—especially after 2030.

SB 100 customer load with modifiers illustrates the projected evolution of electricity demand on LADWP's system through 2045 (Figure 4-83). The black line represents net customer load, which reflects the combined impact of several key demand-side drivers: energy efficiency, behind-the-meter solar, and increased electricity use from buildings and transportation.

In the near term, energy efficiency and BTM solar reduce net load by lowering consumption and offsetting retail energy purchases. However, these effects are increasingly outweighed by rising electricity demand from building electrification (e.g., electric heating and appliances) and especially transportation electrification (e.g., electric vehicles and charging infrastructure), which become more prominent after 2030.

By the mid-2030s and beyond, total customer load increases significantly, reflecting the widespread adoption of electric technologies. This trend underscores the importance of coordinated planning between resource procurement and distribution system upgrades, particularly under SB 100's longer decarbonization timeline.

While the SB100 Benchmark allows for a more gradual transition to 100% carbon-free energy by 2045 (compared to LA100's 2035 target), it must still accommodate a steadily growing and evolving load profile shaped by state policies and customer behavior.

4.12.4 In-Basin Capacity Factors

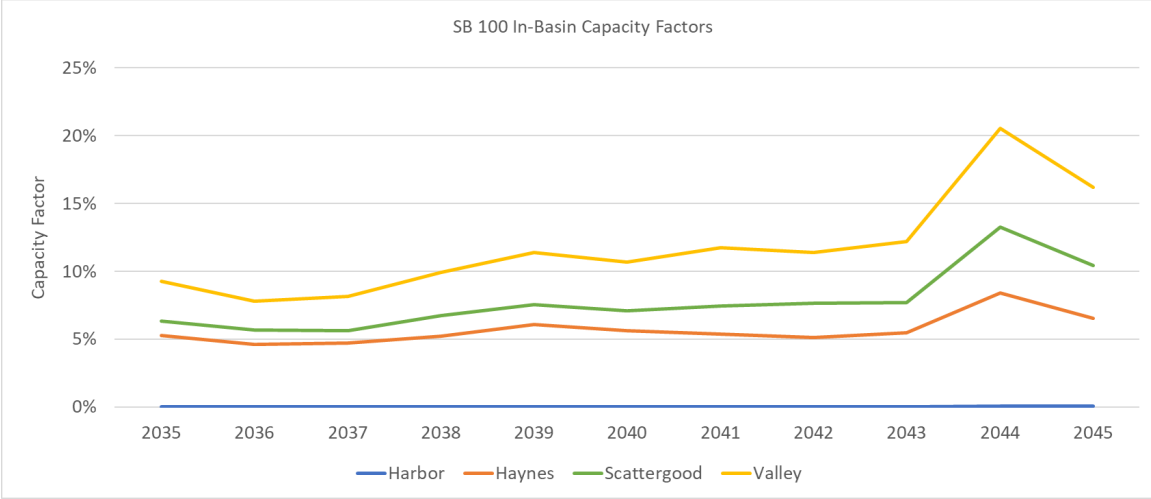


Figure 4-84. Projected capacity factors for LADWP's in-basin generation facilities under the SB100 Benchmark(2035–2045). SB 100 in-basin capacity factors reflect projected utilization levels for LADWP's in-basin thermal generation units, including combustion turbines (CTs) and combined-cycle (CC) plants. Under this analysis, natural gas continues to be used in several facilities beyond 2035, with the Scattergood Green-Hydrogen Capable Combined Cycle operating off a blend of 30% green hydrogen by volume (approximately 11% by energy content) starting in 2029.

SB 100 in-basin capacity factors illustrate the expected operational profile of LADWP's local thermal fleet from 2035 to 2045, under a compliance-based pathway aligned with Senate Bill 100 and Senate Bill 1020 clean energy mandates (Figure 4-84). These facilities, located within Los Angeles and surrounding areas, remain important for maintaining system reliability, especially as renewable integration and electrification increase.

In this model, natural gas remains in use across several in-basin facilities throughout the planning horizon, consistent with state policy that allows fossil fuel generation as long as it is balanced by carbon-free electricity to serve retail sales. Facilities such as the Haynes wet-cooled units, Scattergood CC, and Valley CC are expected to operate at modest capacity factors, consistent with their role as dispatchable backup during periods of high demand or limited renewable availability.

Beginning in 2029, the Scattergood Green-Hydrogen Ready Combined Cycle facility operates on a 30% green hydrogen blend by volume (approximately 11% by energy content). While not a full conversion, this represents an important early application of hydrogen fuel in LADWP's generation portfolio and a step toward reducing combustion-related emissions within the basin.

Other units, such as Valley, Harbor, and Haynes CTs, operate at very low capacity factors, largely serving as reserve capacity for grid contingencies. Overall, the SB100 Benchmark assumes a gradual operational transition, maintaining thermal capacity for reliability while integrating low-carbon fuels where feasible.

This contrasts with the more accelerated LA100 Pathway, which targets full in-basin decarbonization by 2035, and reflects LADWP's policy direction beyond minimum state requirements.

4.12.5 Renewable and Clean Generation

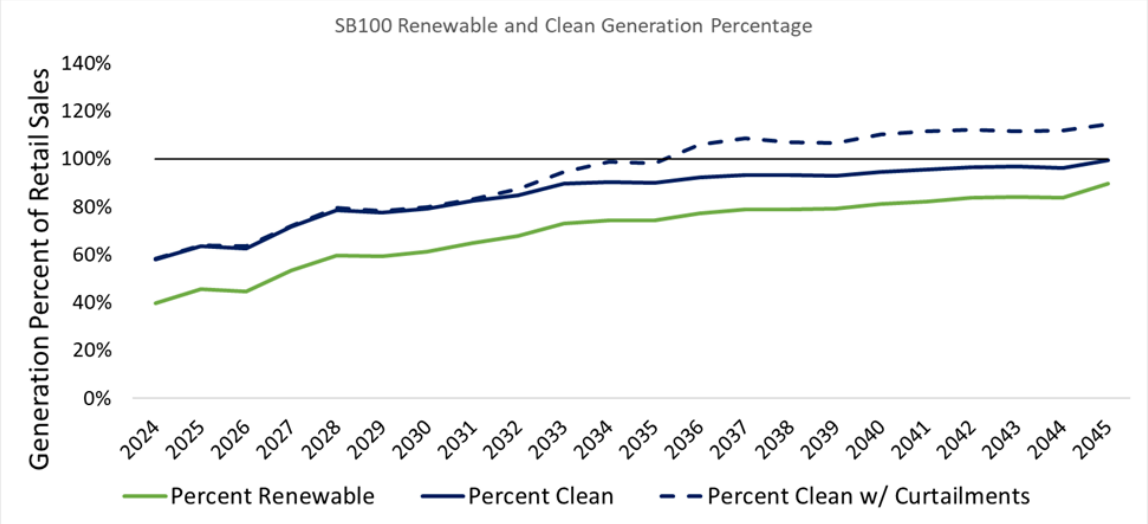


Figure 4-85. Projected renewable and clean energy generation as a percentage of retail sales under the SB100 Benchmark (2024–2045). SB100 renewable and clean generation percentage reflects LADWP's projected compliance with California's Senate Bill 100 and Senate Bill 1020 targets. The green line shows the share of retail sales served by renewable energy, while the solid blue line includes all clean energy sources (e.g., nuclear and large hydro). The dashed blue line includes clean energy generated but curtailed. All values are expressed as a percentage of retail electricity sales, consistent with the compliance framework established by state law.

SB100 renewable and clean generation percentage tracks LADWP's projected progress toward meeting California's clean energy mandates under Senate Bill 100 (SB 100) and Senate Bill 1020 (SB 1020) (Figure 4-85). These laws require utilities to serve 60% of retail sales with renewable resources by 2030, 90% with clean energy by 2035, 95% by 2040, and 100% by 2045. Unlike the LA100 Pathway and sensitivities, which require that all delivered electricity, including losses and storage inefficiencies, be carbon-free, the SB 100 / SB 1020 framework is based solely on retail sales.

The green line represents renewable energy (e.g., solar, wind, geothermal, small hydro), while the solid dark blue line reflects total clean energy, which includes renewables plus large hydro and nuclear. The dashed blue line captures clean energy that was generated but not used due to curtailment—typically caused by oversupply or limited grid flexibility.

By 2030, LADWP is on track to meet the 60% renewable target, and by 2035, clean energy generation exceeds 90% of retail sales, aligning with the SB 1020 interim requirement. Clean energy generation (including curtailments) exceeds 100% of retail sales beginning in the mid-2030s, providing margin to account for planning uncertainties and operational variability.

This trajectory demonstrates LADWP's ability to meet the state's legal requirements under a moderate pace of transition, even as retail load increases due to electrification. While SB 100 / SB 1020 provides a compliance-based path to decarbonization, it contrasts with the more aggressive LA100 Pathway, which imposes broader requirements and an earlier 2035 target for 100% carbon-free energy.

4.12.6 Renewable Curtailment

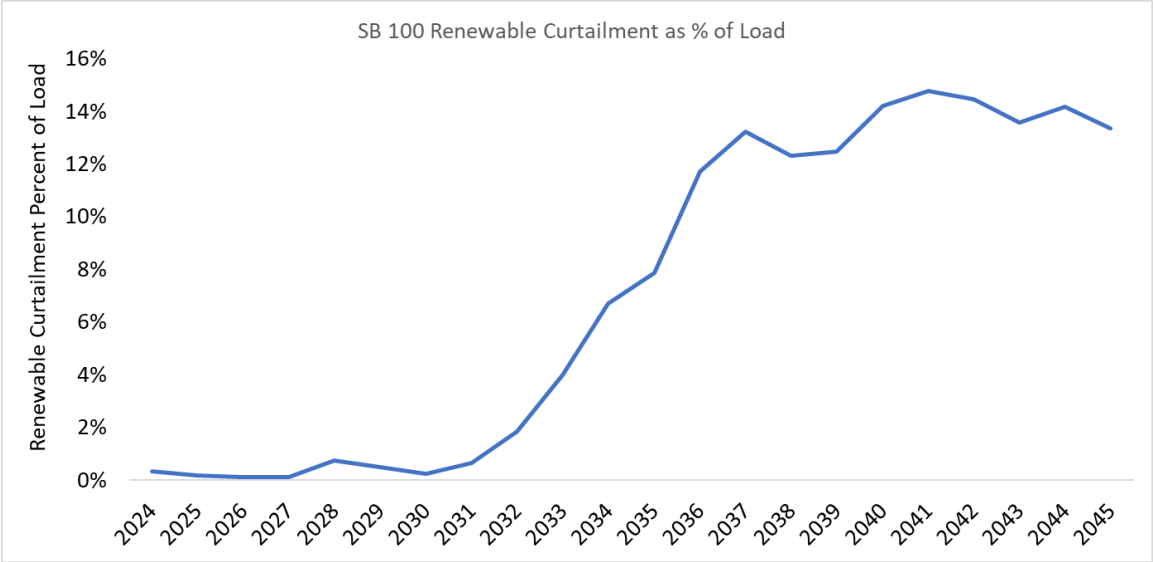


Figure 4-86. Projected renewable curtailment as a percentage of net load under the SB100 Benchmark (2024–2045). SB 100 renewable curtailment as a percentage of load shows the share of potential renewable generation that is not utilized due to system constraints or oversupply. Curtailment begins to rise meaningfully in the early 2030s and stabilizes between 10–14% of load through the 2035–2045 period, reflecting the growing share of variable renewables and limitations in storage, transmission, and grid flexibility.

SB 100 renewable curtailment as a percentage of load (Figure 4-86) illustrates the portion of renewable energy that is generated but not delivered to customers due to factors such as oversupply, limited transmission availability, or insufficient storage. As renewable penetration increases, particularly in the 2030s, curtailment becomes a more regular feature of grid operations.

In the SB100 Benchmark, curtailment remains minimal through the 2020s, then begins to rise sharply in the early 2030s as solar and wind capacity expands to meet state clean energy targets. By 2035, curtailment reaches approximately 13% of retail load, and remains in that general range through 2045. This level of curtailment reflects a combination of factors, including economic tradeoffs—it can be more cost-effective to build a surplus of renewables than to rely on expensive dispatchable technologies—and the inherent variability of renewable output.

Unlike the LA100 Pathway, which imposes a carbon-free requirement on all energy delivered, including losses and storage inefficiencies, the SB100 Benchmark is based strictly on retail sales, allowing some room for operational inefficiencies and excess generation. As a result, modest curtailment is expected and accepted within the compliance framework.

Going forward, curtailment levels may be reduced through increased regional coordination, storage deployment, flexible load, and market participation, but some degree of curtailment is anticipated in high-renewable portfolios.

4.12.7 Greenhouse Gas Emissions

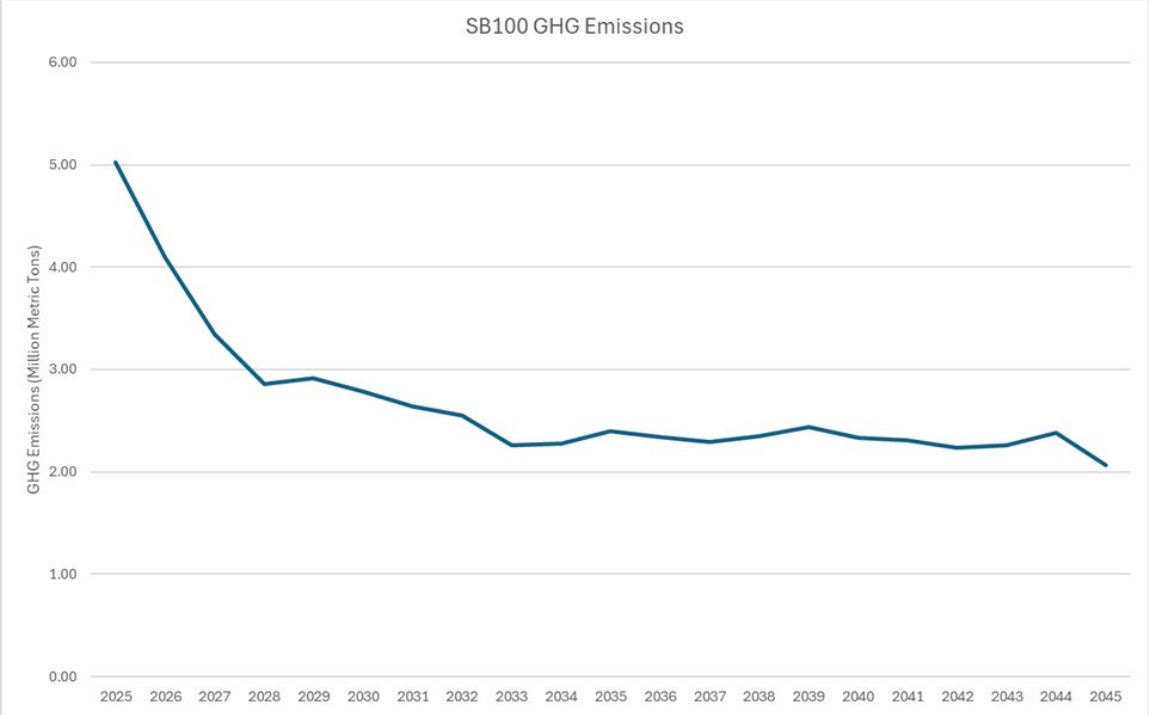


Figure 4-87. Projected greenhouse gas (GHG) emissions from LADWP's power system under the SB100 Benchmark (2025–2045). SB 100 GHG emissions reflect annual greenhouse gas emissions from LADWP's power generation portfolio. Emissions decline significantly through the late 2020s and early 2030s, then remain relatively stable at a reduced level through 2045, consistent with the compliance structure of SB 100, which allows fossil generation as long as retail sales are offset by clean energy.

SB 100 GHG emissions (Figure 4-87) track LADWP's anticipated carbon emissions in a model designed to comply with California Senate Bill 100, which mandates 100% clean

electricity by 2045, based on retail sales. Emissions fall sharply between 2025 and 2035, primarily due to the retirement of coal, reductions in natural gas use, and the increasing share of renewable and carbon-free generation.

After this initial decline, emissions stabilize at approximately 2 to 2.5 million metric tons per year through the 2040s. This is expected under SB 100's accounting rules, which allow fossil fuel use to continue as long as the equivalent volume of retail energy is supplied by carbon-free sources. Under this structure, LADWP retains the flexibility to utilize dispatchable fossil resources—particularly natural gas—to ensure reliability, manage variability, and respond to peak demand conditions.

While the SB100 Benchmark does not achieve zero GHG emissions from the power sector by 2035—as envisioned under the more aggressive LA100 Pathway—it represents a substantial and sustained reduction in emissions compared to historical levels. The long-term trend reflects meaningful progress toward decarbonization while maintaining operational flexibility under state policy.

Future GHG reductions beyond this analysis may be possible through the expanded use of clean fuels, enhanced energy storage, or broader adoption of non-combustion firm resources as technologies mature and become economically viable.

4.12.8 Fuel Burn

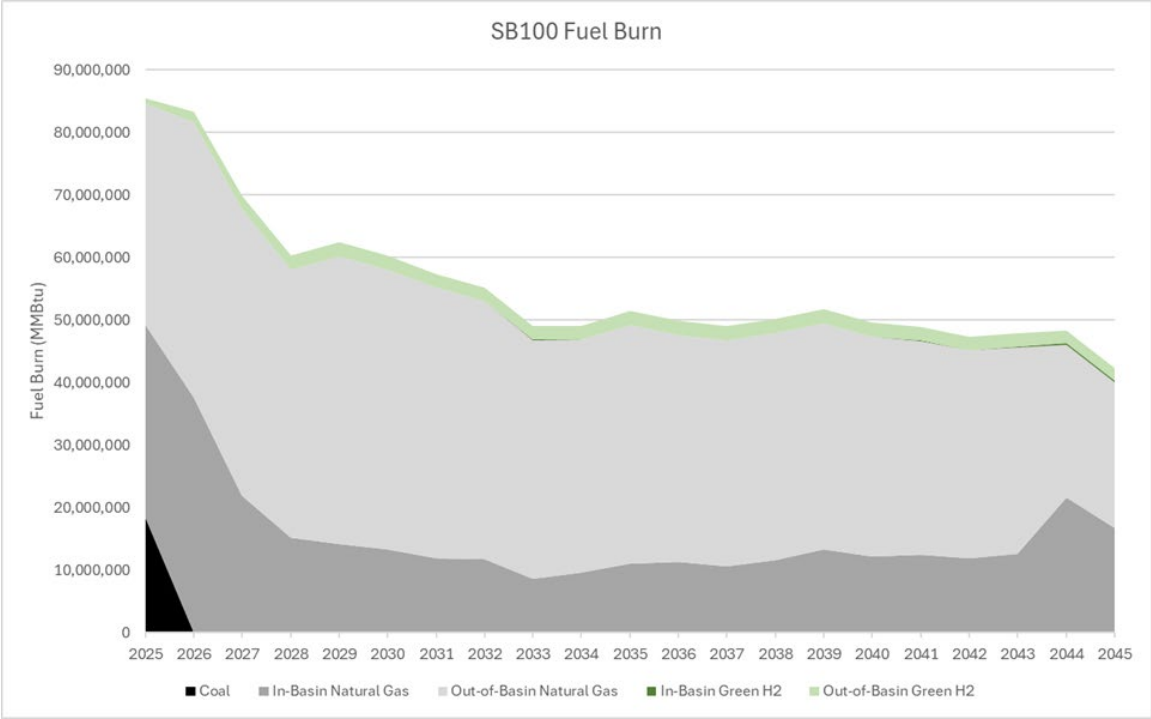


Figure 4-88. Projected purchased fuel consumption under the SB100 Benchmark (2025–2045), measured in million MMBtu. Coal is fully phased out by 2025. Natural gas use declines steadily through the 2030s and remains at reduced levels through 2045. Limited quantities of green hydrogen are introduced beginning in the early 2030s.

SB 100 fuel burn, as shown in Figure 4-88, reflects projected consumption of fuels used in LADWP's generation portfolio through 2045 under a compliance-based pathway consistent with California Senate Bill 100. As shown in Figure 4-88, total fossil fuel use declines significantly over time, with major reductions achieved by the early 2030s.

Coal is fully phased out by 2025, in line with LADWP's previously adopted commitments. Natural gas consumption—both in-basin and out-of-basin—declines steadily through the forecast period, reflecting reduced reliance on combustion-based generation as renewable energy, storage, and other clean resources are added to the system. While natural gas remains available through 2045 to support grid reliability, utilization is far lower than today's levels.

By the early 2030s, green hydrogen is introduced in limited volumes. Initially deployed at out-of-basin facilities, hydrogen use expands modestly to some in-basin units later in the planning horizon. These early applications support long-term decarbonization goals and provide operational flexibility in a high-renewables grid.

Overall, the SB100 Benchmark supports a major reduction in fossil fuel consumption while maintaining the ability to meet customer demand. This balanced approach allows LADWP to comply with state clean energy targets while transitioning the power system toward cleaner, more sustainable resources.

4.12.9 Annual System Cost

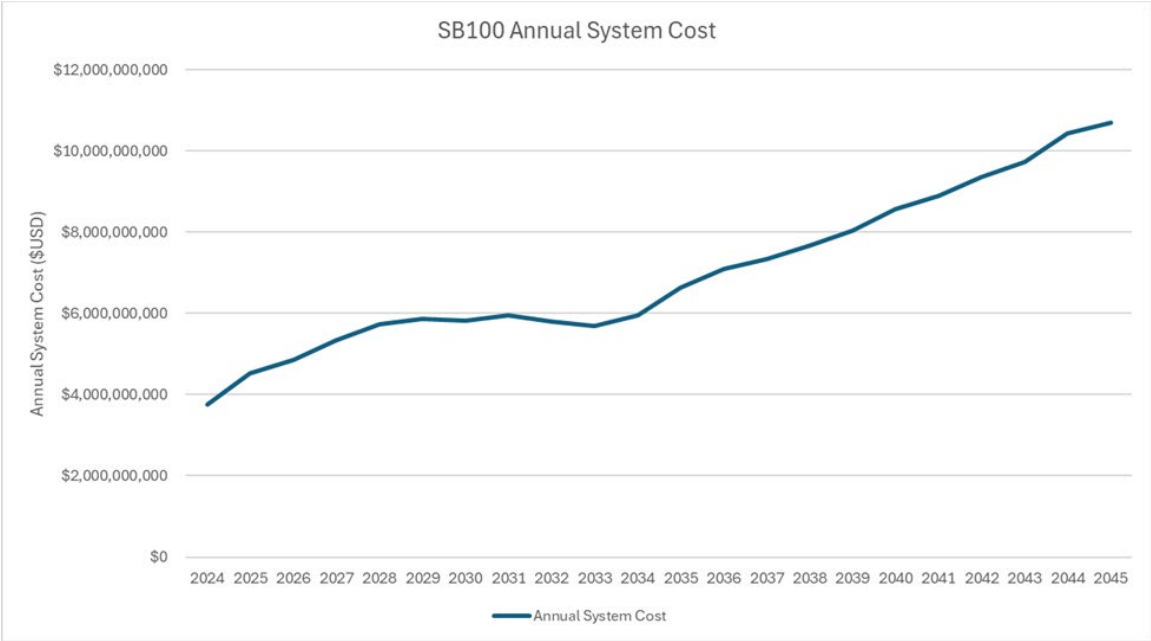


Figure 4-89. Projected annual system cost under the SB100 Benchmark (2024–2045), in nominal dollars. Costs include capital, operations and maintenance, fuel, and other system-wide expenses. System costs rise gradually through the 2030s, then increase more steadily in the 2040s as infrastructure investment and load growth continue.

SB 100 annual system cost reflects the projected cost of operating, maintaining, and expanding LADWP's electric power system through 2045 under a compliance pathway aligned with California Senate Bill 100. These costs include capital investment in new generation, energy storage, and transmission, as well as ongoing expenditures for operations and maintenance, fuel, and system support programs.

As shown in Figure 4-89, system costs increase moderately through the late 2020s, peaking around 2030 as initial infrastructure investments are made to support growing renewable deployment, storage, and electrification. In the early 2030s, costs level off temporarily as those investments are absorbed and early capital projects reach completion.

After 2035, costs begin rising more steadily. This increase is driven by sustained investments in clean energy infrastructure, continued electrification of buildings and transportation, and the need to modernize grid assets and accommodate higher system loads. By the 2040s, cost growth accelerates slightly, reflecting long-term upgrades and reinvestment in aging infrastructure.

While the SB100 Benchmark represents a moderate pace of transition compared to the LA100 Pathway, it still requires significant long-term investment to achieve the state's carbon-free energy goals. These projected costs provide a comprehensive view of the financial requirements associated with decarbonizing and modernizing LADWP's power system under a legally compliant, reliability-focused pathway.

4.13 SB 100 Price Sensitivity

The SB100 Price Sensitivity explores how LADWP's compliance with Senate Bill 100 (SB 100)—which mandates 100% carbon-free electricity by 2045, measured on a retail sales basis—could be affected under assumptions of significantly lower clean technology costs. This sensitivity models reduced costs for key resources, including renewable energy, energy storage, and hydrogen-fueled generation, while keeping all other policy requirements and timelines consistent with the SB100 Benchmark.

This sensitivity is not intended as an actionable or preferred pathway for LADWP. Rather, it serves as an analytical bookend representing the lower-cost extreme of the technology cost spectrum. By doing so, it provides insight into how improved market conditions could shift resource planning decisions, reduce system costs, and affect generation dispatch—within the context of a more gradual, compliance-focused transition.

The SB100 Price Sensitivity also helps to illuminate cost-driven trade-offs and operational dynamics across the portfolio and serves as a useful benchmark for comparing other LA100 Plan model runs, such as those involving high electrification or differing levels of distributed energy resource adoption

4.13.1 Capacity Expansion

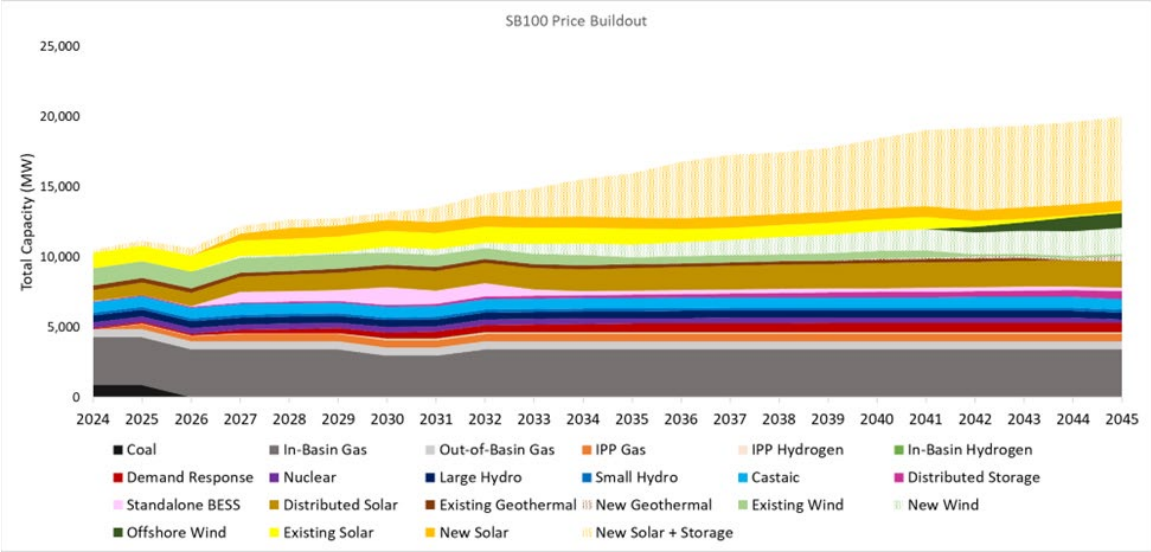


Figure 4-90. Projected resource capacity expansion under the SB100 Price Sensitivity (2024–2045). This chart presents the projected installed generation and storage capacity for the Los Angeles Department of Water and Power (LADWP) under the SB100 Price Sensitivity, as modeled in the LA100 Pathway analysis. The sensitivity evaluates resource buildout trajectories required to meet the mandates of Senate Bill 100 (SB 100)—which requires 60% renewable electricity by 2030 and 100% carbon-free electricity by 2045—while accounting for uncertainty in clean energy technology costs. The figure illustrates the stacked installed capacity by resource type from 2024 through 2045, highlighting the system's transition away from fossil fuels and toward a high-renewable, storage-integrated grid.

In Figure 4-90, the SB100 Price Sensitivity explores the same policy target as the SB100 Benchmark —reaching 60% renewable electricity by 2030 and 100% carbon – free electricity by 2045. However, this sensitivity models how lower costs in clean energy technologies (solar PV, battery energy storage, wind, and hydrogen) can influence resource choices, system cost, emissions reduction, and reliability strategies.

Coal is fully retired by 2025, while In-Basin Gas and IPP Gas remain until 2045, but stay flat or decline slightly. These are retained as dispatchable backup resources. Nuclear, geothermal, hydro, and demand response are existing resources which are largely static over time and intended to maintain grid stability but not contributing heavily to new growth. IPP Hydrogen and In-Basin Hydrogen are present in moderate amounts,

replacing some natural gas for firm capacity needs. Solar dominates growth in total capacity with a buildout in new solar and storage starting in 2028 and accelerating rapidly through 2045. Wind buildout also ramps up in later years with modest growth playing a supporting role in growing renewables. Standalone Battery Energy Storage Systems (BESS) and Distributed Storage see significant growth, particularly in the 2030–2045 period.

4.13.2 Generation Dispatch

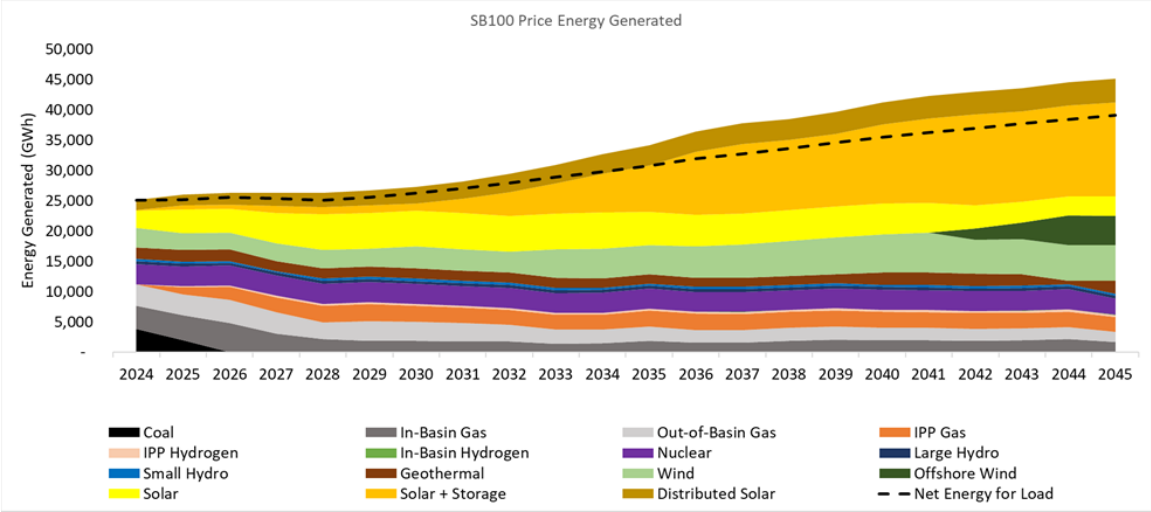


Figure 4-91. Annual energy generation mix (in GWh) for LADWP under the SB100 Price Sensitivity. This sensitivity models the evolution of energy production by resource type as the system transitions to meet the mandates of California Senate Bill 100 (SB 100), requiring 60% renewable electricity by 2030 and 100% carbon-free electricity by 2045, while accounting for uncertainties in future clean energy technology costs. The dashed black line indicates net energy for load, i.e., the total annual electricity demand after accounting for behind-the-meter consumption and demand-side management. Generation must meet or exceed this line to ensure resource adequacy.

Figure 4-91 projects a profound shift in LADWP's energy generation mix—away from fossil resources and toward a high-renewable, storage-integrated portfolio. Coal generation is eliminated by 2025, and lower capital costs for solar and wind lead to higher deployment and greater dispatch of renewables. From 2035 onward, total renewable generation begins to exceed net energy for load during some periods. The growing headroom above the demand line in later years highlights the importance of grid flexibility, regional coordination, and storage optimization. While solar resources

dominate the generation mix by 2045, firm low-carbon generation from natural gas, hydrogen, and legacy nuclear/hydro assets ensures grid reliability.

4.13.3 Customer Load with Modifiers

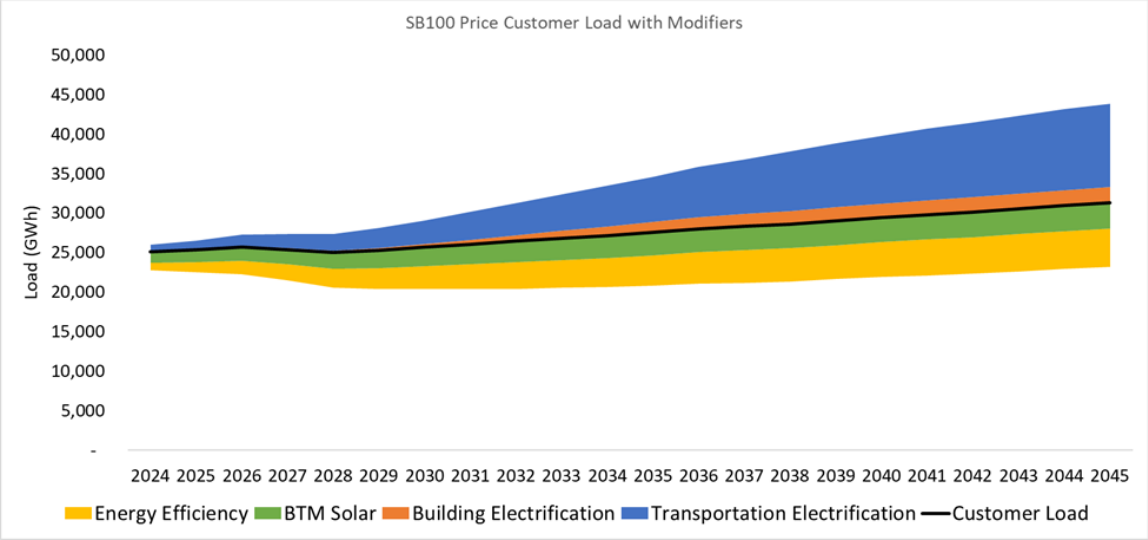


Figure 4-92. Projected customer load under the SB100 Price Sensitivity, including demand-side modifiers (2024–2045). SB100 Price Sensitivity customer load with modifiers shows LADWP's projected electricity demand over time, accounting for the effects of energy efficiency, behind-the-meter (BTM) solar, building electrification, and transportation electrification. While efficiency and BTM solar initially reduce net load, increased electrification of buildings and vehicles drives overall load growth—especially after 2030.

The SB100 Price Sensitivity customer load projection (Figure 4-92) shows how electricity demand on LADWP's system will change through 2045. Initially, energy efficiency and behind-the-meter (BTM) solar reduce net load. However, from the 2030s onward, growing demand from building and transportation electrification outweighs these reductions, leading to a significant increase in total load by the mid-2030s. Load modifiers enable modest demand flexibility, helping optimize use of low-cost renewables and storage. Although SB100 Price Sensitivity allows a slower shift to 100% carbon-free electricity by 2045 (versus LA100's 2035 target), it still requires managing a complex, rising demand shaped by customer behavior and state mandates.

4.13.4 In-Basin Capacity Factors

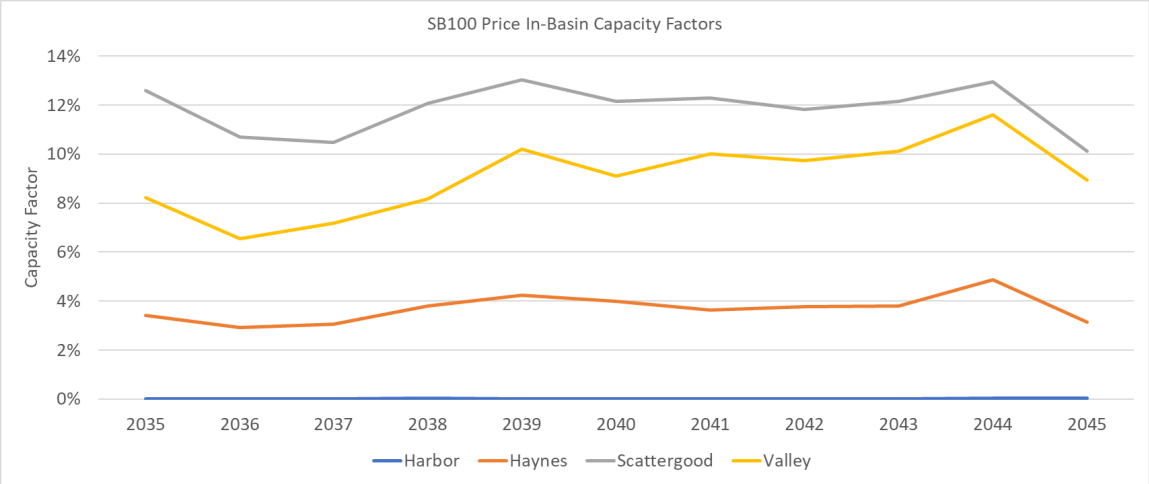


Figure 4-93. Projected capacity factors for LADWP's in-basin thermal generating facilities under the SB100 Price Sensitivity, which targets 100% carbon-free electricity by 2045. The capacity factor indicates how often a unit operates relative to its maximum output capacity — a key metric for understanding utilization and system role. Under this scenario, natural gas continues to be used in several facilities beyond 2035.

As seen in Figure 4-93, natural gas-fired generation continues to operate at multiple in-basin facilities through 2045 in the SB100 Price Sensitivity. This is consistent with California's compliance framework, which permits the use of fossil fuel resources provided that, on an annual basis, retail electricity sales are fully offset by carbon-free generation.

Scattergood is the most heavily relied upon in-basin dispatchable generation in this sensitivity. Its capacity factor gradually decreases as hydrogen fuel is adopted. Haynes is a prominent generation source in the SB100 Benchmark. In this sensitivity however, it has a lower utilization, but it still functions as a peaking resource. Valley continues to operate at consistent capacity factors and fulfill its roles as dispatchable backup during periods of high demand or limited renewable availability. Harbor operates at a very low-capacity factor, largely serving as reserve capacity for grid contingencies.

4.13.5 Renewable and Clean Generation

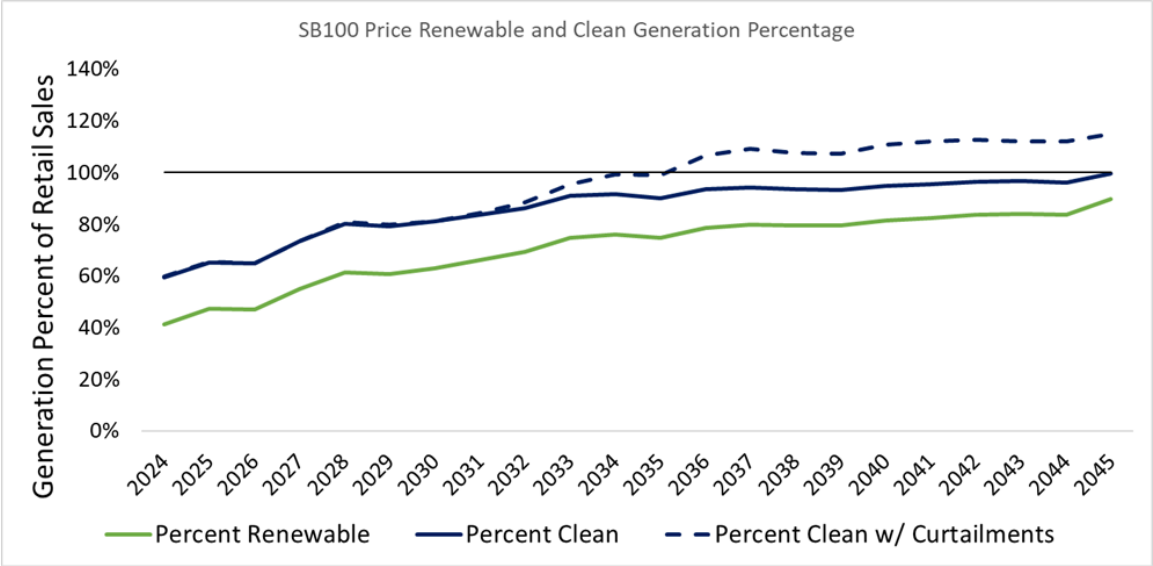


Figure 4-94. Projected share of renewable and clean energy generation as a percentage of LADWP's retail electricity sales under the SB100 Price Sensitivity from 2024 to 2045. The green line represents the portion of retail sales served by renewable energy resources, while the solid blue line encompasses all qualifying clean energy sources, including large hydroelectric and nuclear. The dashed blue line further incorporates clean energy that was generated but subsequently curtailed.

The SB100 Price Sensitivity models LADWP's projected compliance with California's statutory clean energy mandates established by Senate Bill 100 and Senate Bill 1020, which is based solely on retail electricity sales.

In Figure 4-94, the green line represents the portion of retail sales served by renewable energy sources such as wind, solar, geothermal, and small hydro. The solid blue line indicates total clean energy contributions, encompassing both renewable energy and additional zero-carbon resources including large hydroelectric and nuclear generation. The dashed blue line captures total clean energy produced, including energy curtailed due to oversupply conditions or limited grid flexibility.

LADWP is projected to meet the 60% renewable energy target by 2030 and to exceed the 90% clean energy requirement by 2035, consistent with the interim targets defined by SB 1020. Beginning in the mid-2030s, clean energy generation—including curtailed output—surpasses 100% of retail sales, providing an operational margin to account for planning uncertainties and system variability. This trajectory demonstrates LADWP's

ability to meet California's legal requirements under a compliance-based approach, even as retail load grows due to increased electrification.

4.13.6 Renewable Curtailment

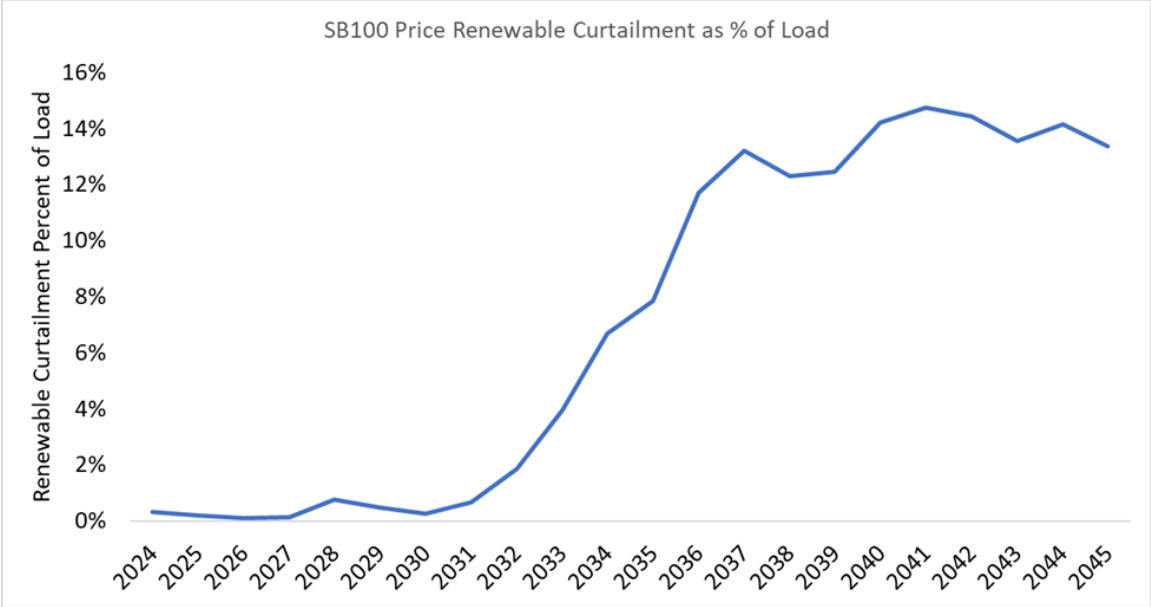


Figure 4-95. Renewable curtailment under the SB100 Price Sensitivity. The projected renewable curtailment, expressed as a percentage of LADWP's net load, quantifies the portion of available renewable energy generation that is not dispatched due to system constraints such as transmission limitations, insufficient storage capacity, or generation oversupply. Under the SB100 Price Sensitivity, curtailment levels remain minimal through the late 2020s but begin to increase significantly in the early 2030s. Between 2035 and 2045, curtailment stabilizes in the range of 12–15% of retail load. This trend reflects the growing integration of variable renewable energy resources and highlights the challenges associated with balancing supply and demand in a high-renewables grid environment.

Under the SB100 Price Sensitivity, renewable curtailment (Figure 4-95) remains low through the 2020s but increases significantly beginning in the early 2030s, driven by large-scale deployment of wind and solar to meet state mandates. Curtailment reaches approximately 12% of load by 2035 and remains within this range through 2045. This level of curtailment reflects economic optimization strategies (favoring overbuild of renewables over investment in costlier firm resources) and the variability inherent in renewable generation. Unlike the LA100 Pathway, the SB100 Price Sensitivity measures compliance based solely on retail sales, allowing for operational inefficiencies and some excess generation.

4.13.7 Greenhouse Gas Emissions

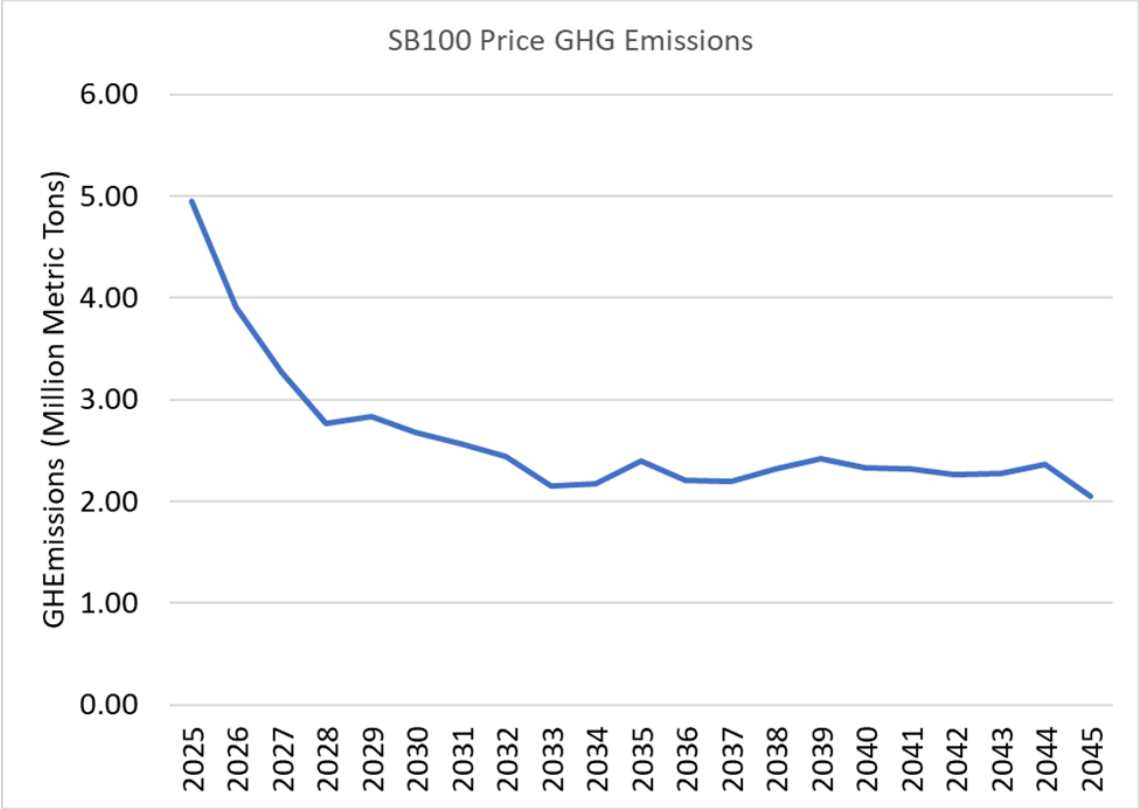


Figure 4-96. Projected annual greenhouse gas (GHG) emissions from LADWP's power generation portfolio under the SB100 Price Sensitivity. Emissions decline sharply through the late 2020s and early 2030s as fossil fuel use decreases in response to increasing renewable integration. Post-2035, emissions stabilize at a lower level and persist through 2045.

The SB100 Price Sensitivity models LADWP's projected GHG emissions (Figure 4-96) under a compliance framework aligned with California Senate Bill 100, which requires 100% clean electricity by 2045, measured on a retail sales basis. Emissions decline significantly between 2025 and 2035, driven by coal plant retirements, reduced reliance on natural gas, and increased deployment of renewable and carbon-free resources.

Following this period of rapid decline, emissions plateau at approximately 2.0–2.5 million metric tons annually through the 2040s. This outcome is consistent with SB 100's compliance methodology, which permits continued use of fossil-fueled generation provided that total retail sales are offset with clean energy. This approach enables

LADWP to retain dispatchable fossil capacity—primarily natural gas—for reliability, flexibility, and peak load management.

4.13.8 NOx Emissions

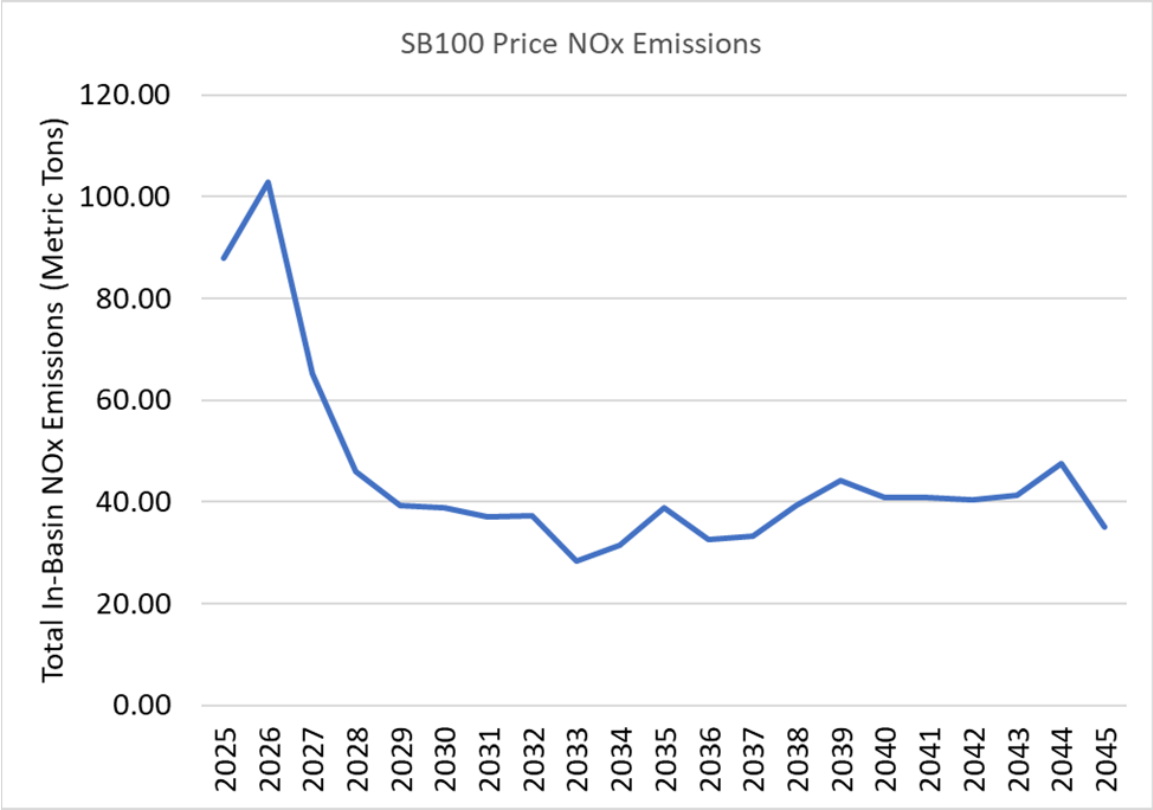


Figure 4-97. SB100 Price Sensitivity NOx emissions. LADWP's in-basin plants are located in a South Coast AQMD nonattainment area, and their NOx emissions decline sharply through the late 2020s as fossil fuel use decreases. By the early 2030s, emissions reach minimal levels, with a slight rebound later due to occasional dispatch of hydrogen-fueled units during high-demand periods.

Figure 4-97 shows a sharp decline in NOx emissions beginning in 2026, which is consistent with SB 100-driven decarbonization measures, such as coal phase-out and reduced gas generation. The mid-term stabilization with fluctuations indicates some level of continued reliance on dispatchable fossil or hydrogen-fueled resources, possibly triggered by cost-driven operational decisions in this price sensitivity. Despite SB 100 targets for clean retail energy by 2045, residual NOx emissions persist, reflecting continued in-basin combustion for non-retail needs (e.g., losses, storage charging, grid

support). These reductions support state and local clean air regulations, thus enhancing public health

4.13.9 Fuel Burn

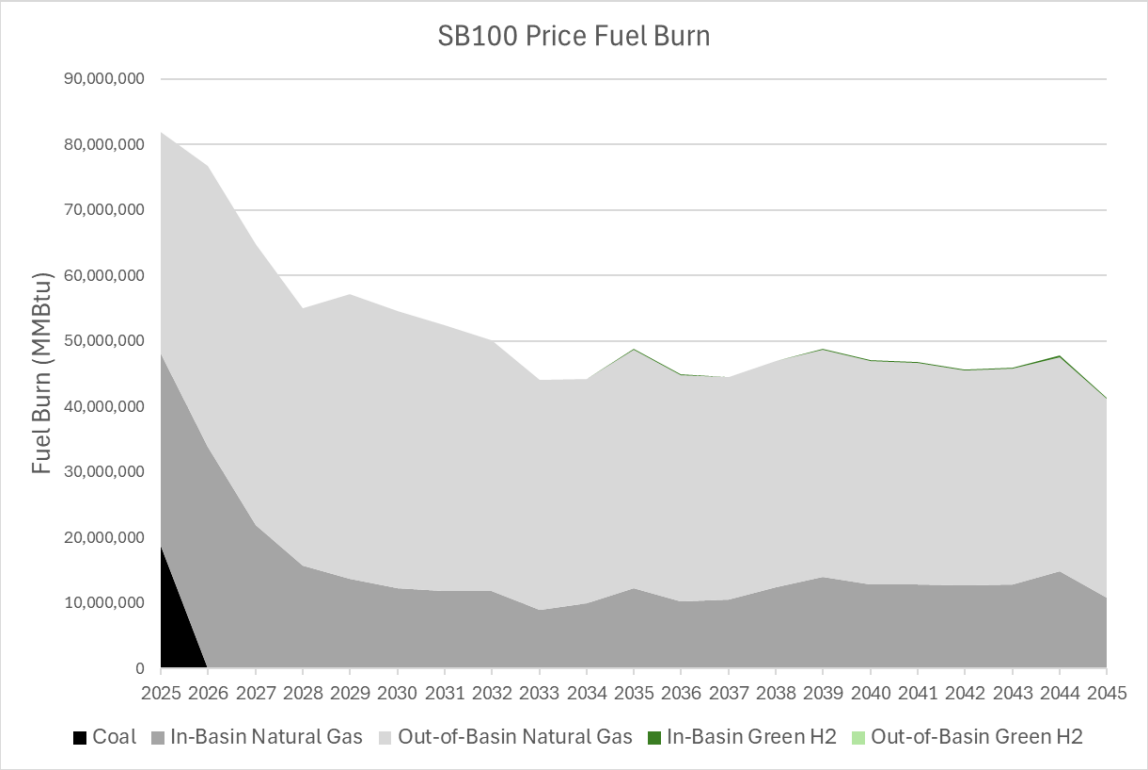


Figure 4-98. SB100 Price Sensitivity purchased fuel burn shows consumption of fuels used in LADWP's power generation portfolio, measured in millions of British thermal units (MMBtu). Total fuel burn decreases from 2025 -2032 due to the phaseout of coal and declining natural gas usage, consistent with early decarbonization and SB 100 compliance ramp-up. Post-2032, total fuel use plateaus, which suggests the system reaches a new operational baseline where combustion-based fuels are used intermittently to support grid needs. By 2030, green hydrogen is introduced to support dispatchable, carbon-free generation needed to maintain system reliability.

As shown in Figure 4-98, by 2026, coal is rapidly eliminated, which aligns with SB 100 decarbonization mandates. In-basin and out-of-basin natural gas takes a steep decline from 2025 to 2030, with In-Basin Natural Gas consumption remaining low post-2030, taking its role as a backup or reliability resource only. Out-of-Basin Natural Gas dominates residual fuel use, which shows continued reliance on external gas resources for dispatchable capacity. Limited adoption of In–Basin Green Hydrogen appears in 2030

but remains almost negligible compared to natural gas. This is due to renewables and storage being prioritized in terms of clean energy resources due to lower costs.

4.13.10 Annual System Cost

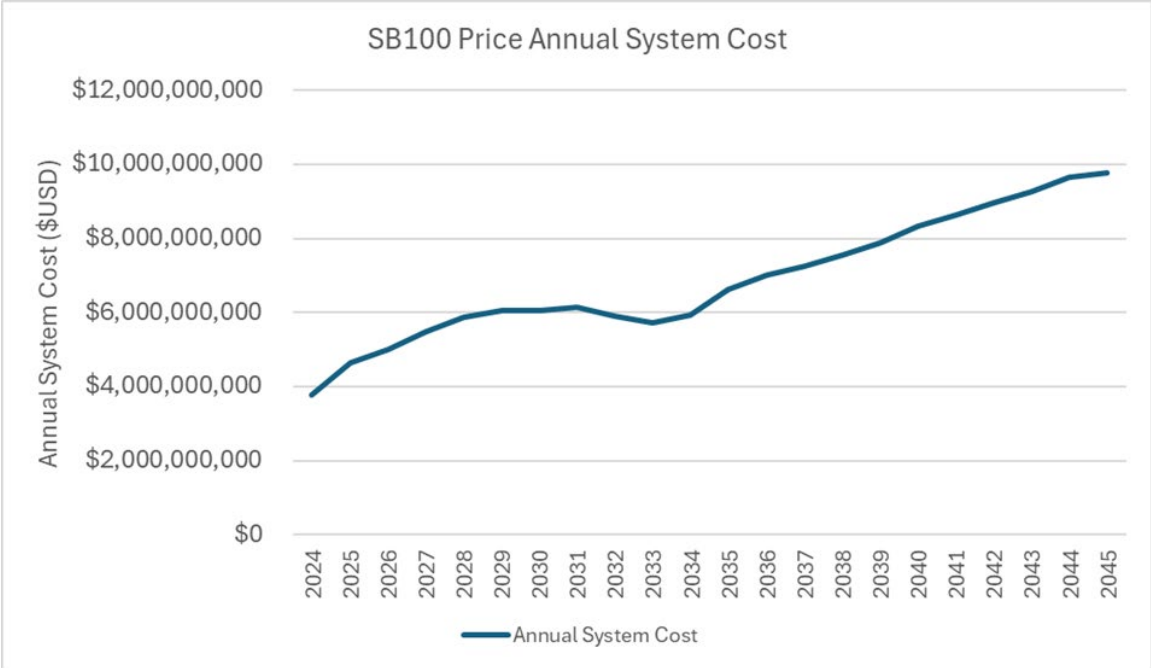


Figure 4-99. Annual system costs under the SB100 Price Sensitivity represent the total expenditures required to operate, maintain, and expand LADWP's power system. This includes both variable costs (such as fuel consumption and equipment degradation) and fixed costs (including capital recovery and debt service for infrastructure investments). The cost projection also incorporates expenditures related to the Power System Reliability Plan (PSRP) and deployment of electric vehicle charging infrastructure (eHubs).

The SB100 Price Sensitivity reduces costs by implementing less expensive renewables and storage, reducing fuel burn, and having a lower financing burden on capital-intensive projects. Compared to the SB100 Benchmark, the total annual system cost decreases ~9% by 2045 in the SB100 Price Sensitivity. In the early years of the planning horizon (Figure 4-99), system costs increase steadily as LADWP initiates investments in renewable generation, energy storage, and grid modernization. A more pronounced cost escalation is observed around 2035, driven by large-scale capital deployment required for expansion of clean generation and storage capacity, implementation of grid upgrades under the Power System Reliability Plan (PSRP) to replace aging infrastructure,

and the deployment of eHub electric vehicle charging infrastructure to enable transportation electrification. From the late 2030s through the 2040s, system costs continue to rise, though at a more gradual rate. This reflects ongoing expenditures for asset maintenance, system upgrades, and periodic replacement of long-lived infrastructure necessary to support a fully modernized and electrified grid.

4.13.11 Key Takeaways

Under the SB100 Price Sensitivity, lower costs for renewable and storage – paired with higher assumed prices for natural gas and GHG allowances- led to slight increase in average annual carbon emissions between 2025-2034 (3.11 $MMTCO_2$ in SB100 Price Sensitivity compared to 3.07 $MMTCO_2$ in the SB100 Benchmark), while there is a slight decrease between 2035-2045 (2.29 $MMTCO_2$ in SB100 Price Sensitivity compared to 2.31 $MMTCO_2$ in the SB100 Benchmark). Emissions for the SB100 Price Sensitivity is much higher when compared to the LA100 Pathway. This outcome reflects a modest shift in the model's dispatch decisions, slightly favoring renewable and storage in the later years, while slightly preferring natural gas generation in the early years when compared to SB100. The total system cost from 2025-2045 ($84.6 billion) was 17% lower than the LA100 Pathway and 1% lower than the SB100 Benchmark.

4.14 Sensitivity Comparisons

Across the LA100 Pathway, SB 100 Benchmark, and 11 sensitivities modeled, there are a number of metrics that can be evaluated to assess forecasted performance of one Power System resource portfolio over another, with respect to the specific risk factors driving each model run. Among others, the main metrics include reliability, cost, and emissions, which are presented in more detail below.

4.14.1 Reliability

Loss of Load Expectation (LOLE) is a reliability planning metric that represents the expected number of times per year a system may experience a loss of load event—defined as any instance when total customer demand exceeds available generation supply or capacity. LOLE does not account for localized distribution outages but focuses specifically on system-level shortfalls, which can be caused by factors such as extreme weather, generation outages, or transmission constraints. Utilities across the U.S. increasingly use LOLE in resource planning, targeting a threshold of 0.1 or fewer

expected events per year (i.e., one event every ten years) to maintain a high standard of reliability.

To assess LOLE, production cost modeling tools run hundreds of Monte Carlo simulations, capturing variability in load and renewable generation due to changing weather conditions. For example, if 10 out of 100 simulations in a given planning year experience at least one loss of load event, the calculated LOLE would be 0.1.

Table 4-1 summarizes the LOLE results for the LA100 Pathway, its various sensitivity runs, and the SB100 Benchmark. All scenarios demonstrate strong system reliability, with LOLE values well below the 0.1 threshold in most years. Even under more constrained or extreme assumptions—such as the Resource Constrained or No In-Basin Combustion sensitivities—LOLE remains within acceptable planning limits. This suggests that LADWP's portfolio designs are robust and capable of meeting customer demand reliably across a wide range of future conditions.

Table 4-1 Loss of Load Expectation (LOLE) results for the LA100 Pathway, associated sensitivities, and the SB100 Benchmark across planning years 2030, 2035, 2040, and 2045. All modeled scenarios remain within the industry standard target of ≤0.1 expected loss of load events per year, demonstrating high system reliability across a wide range of assumptions.

LA100 Plan Loss of Load Expectation (LOLE)				
Model Run	**2030**	**2035**	**2040**	**2045**
LA100 Pathway	0.020	0.020	0.040	0.000
LA100 - Price Sensitivity	0.044	0.000	0.002	0.000
LA100 - Low Load Sensitvity	0.000	0.000	0.000	0.000
LA100 - High Load Sensitivity	0.022	0.000	0.004	0.000
LA100 - Low DER Sensitivity	0.054	0.000	0.006	0.006
LA100 - High DER Sensitivity	0.022	0.000	0.000	0.000
LA100 - No In-Basin Combustion Sensitivity	0.040	0.002	0.012	0.016
LA100 - No In-Bas Hydrogen Supply Sensitvity	0.034	0.002	0.000	0.002
LA100 - Limited In-Basin Hydrogen Supply Sensitivity	0.028	0.000	0.000	0.000
LA100 - Resource Constrained Sensitivity	0.082	0.004	0.004	0.000
LA100 - Climate Change Sensitivity	0.046	0.000	0.006	0.010
SB 100 Benchmark	0.066	0.022	0.012	0.010
SB 100 - Price Sensitivity	0.056	0.016	0.016	0.010

4.14.2 Cost

The total system cost for each model run includes both fixed and variable costs, and is representative of the expenditures required to operate, maintain, and expand LADWP's Power System. Fixed costs include categories such as capital recovery and debt service for infrastructure investments, recurring costs for contractual agreements, and funding for customer programs, while variable costs represent generating unit variable operations and maintenance, which include components such as fuel costs, unit startup costs, emissions costs, and equipment degradation.

To properly compare total system cost across the different scenarios and sensitivities, the net present value of each portfolio cost is taken, which entails summing the fixed and variable costs for each portfolio across the entire modeling horizon (2024 through 2045), and discounting each portfolio cost to its present value.

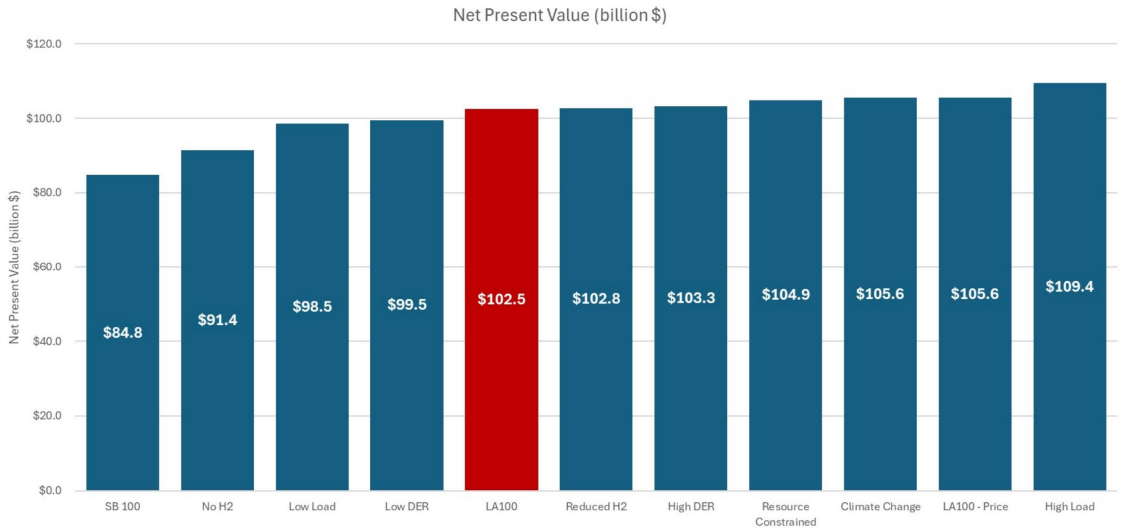


Figure 4-100. Total System Cost (in net present value) for the LA100 Plan Model Runs.

As shown in Figure 4-100, the Total System Cost for the model runs ranged from $84.8 billion to $109.4 billion. When comparing the LA100 Pathway ($102.5 billion) to the SB100 Benchmark ($84.8 billion), we see a difference of approximately $18 billion

The highest Total System Cost further increases to $119 billion when including estimated costs for the No In-Basin Combustion Sensitivity, which proved to be infeasible. Many factors outside of LADWP's control may influence the total cost, such as shown in the High Load Sensitivity at $109.4 billion. Under circumstances where the LA100 Pathway

investments in renewable energy are made but no hydrogen infrastructure is deployed in-basin and instead natural-gas fueled generating units are maintained as backup for reliability and resilience (i.e. No In-Basin Hydrogen Supply Sensitivity), the cost is $11 billion less than the LA100 Pathway with in-basin hydrogen infrastructure.

From the model outputs described above, additional metrics can be calculated such as the levelized cost of energy, levelized cost of carbon reduction, and marginal cost of carbon reduction, which can provide further insight on impacts to Power System decarbonization cost-effectiveness, when assessed under different risk factors.

The levelized cost of energy (LCOE) shown in Figure 4-101, shows the total supply cost per unit of net generation. As shown, the LCOE for the LA100 Pathway and its sensitivities range from approximately $225/MWh to $250/MWh, and the SB100 Benchmark and its sensitivity are around $200/MWh.

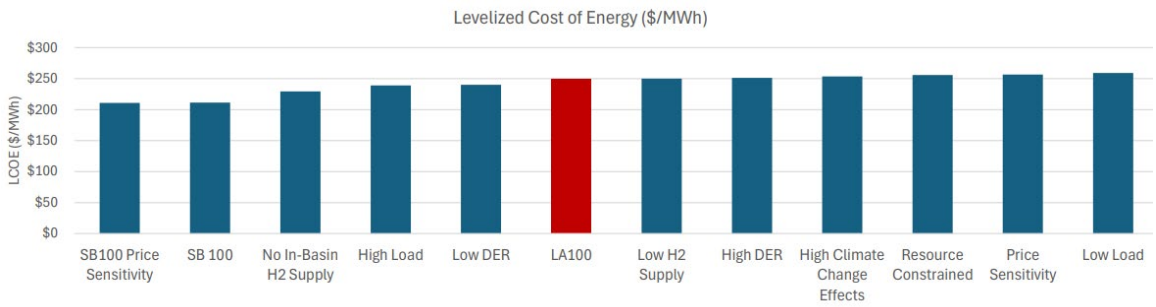


Figure 4-101. Comparison of levelized cost of energy.

The levelized cost of carbon reduction (LCOC) shown in Figure 4-102, compares the costs and emissions of the LA100 Pathway and its sensitivities, to the SB100 Benchmark. This metric is calculated by taking the cost difference between a given scenario or sensitivity and the SB100 Benchmark and dividing by the carbon reduction between the given scenario or sensitivity and the SB100 Benchmark.

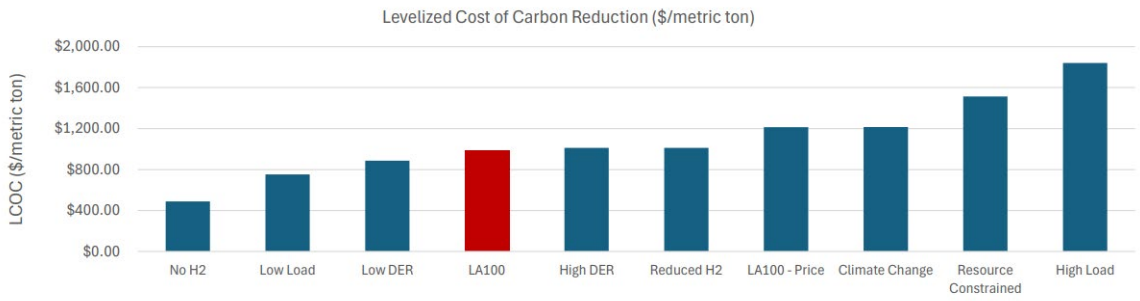


Figure 4-102. Comparison of levelized cost of carbon reduction.

Figure 4-102 shows LCOC ranging from about $490/metric ton to about $1,900/metric ton, with the LA100 No In-Basin Hydrogen Supply Sensitivity at the low end of that range, and the LA100 High Load Sensitivity at the high end of that range, respectively.

With respect to the LA100 Pathway, we see it has a LCOC roughly double that of the LA100 No In-Basin Hydrogen Supply Sensitivity, and each metric ton of carbon abatement above and beyond the carbon abated in the SB100 Benchmark, costs approximately $900.

Another metric, the marginal cost of carbon reduction, assesses the cost to reduce one additional metric ton of carbon, demonstrating how reducing carbon gets more expensive as emissions are reduced past a certain point.

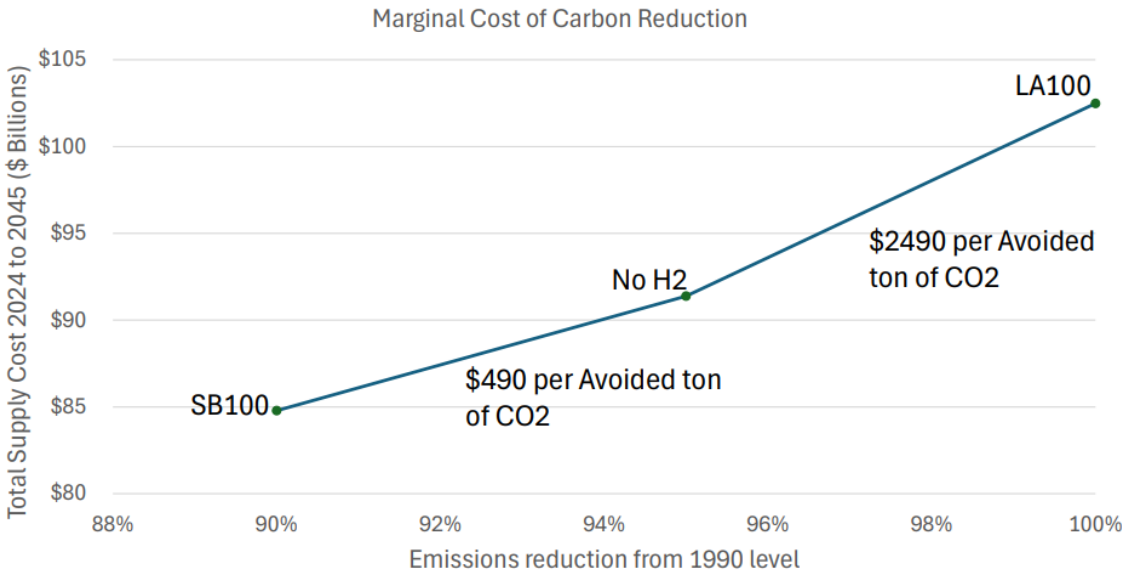


Figure 4-103. Marginal cost of carbon reduction.

As shown in Figure 4-103, there is a significant increase in the cost of reducing an additional metric ton of carbon, when comparing the LA100 Pathway to the SB100 Benchmark.

In the LA100 No In-Basin Hydrogen Supply Sensitivity ("No H2" on figure), transitioning to the LA100 Pathway's renewable energy portfolio while retaining the natural gas-fueled generating units for reliability and resilience (and forgoing their conversion to green-hydrogen capable), results in a marginal cost of carbon reduction of $490/metric ton.

When the in-basin thermal generation units are decarbonized as well (via conversion to green-hydrogen capable), as assumed in the LA100 Pathway, the cost to reduce an incremental ton of carbon above and beyond the LA100 No In-Basin Hydrogen Supply Sensitivity, dramatically increases to $2,490/metric ton.

4.14.3 Emissions

With respect to emissions, most LA100 sensitivities have cumulative carbon below 25 million metric tons, except for three exceptions.

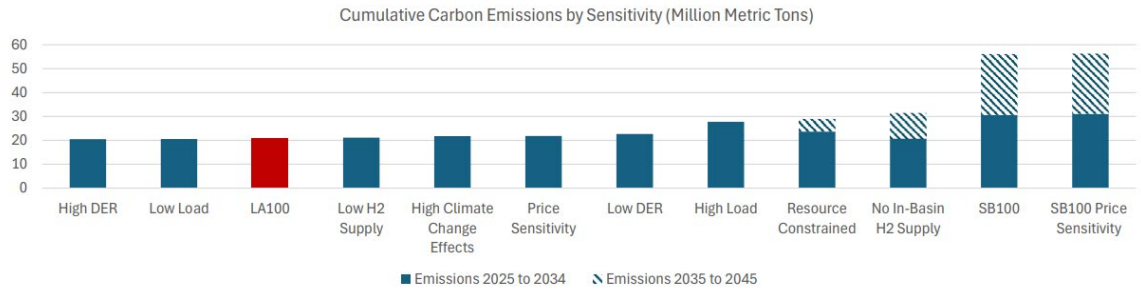


Figure 4-104. Comparison of cumulative carbon emissions.

Among the emissions shown in Figure 4-104, the "High Load" sensitivity requires most use of fossil fuels before the transition away from natural gas; the "No In-Basin Hydrogen Supply" sensitivity has higher emissions due to the continuation of in-basin natural gas; and the "Resource Constrained" sensitivity has higher emissions due to the slower growth of renewables and delayed transition away from natural gas.

4.14.4 In-Basin Capacity Factors

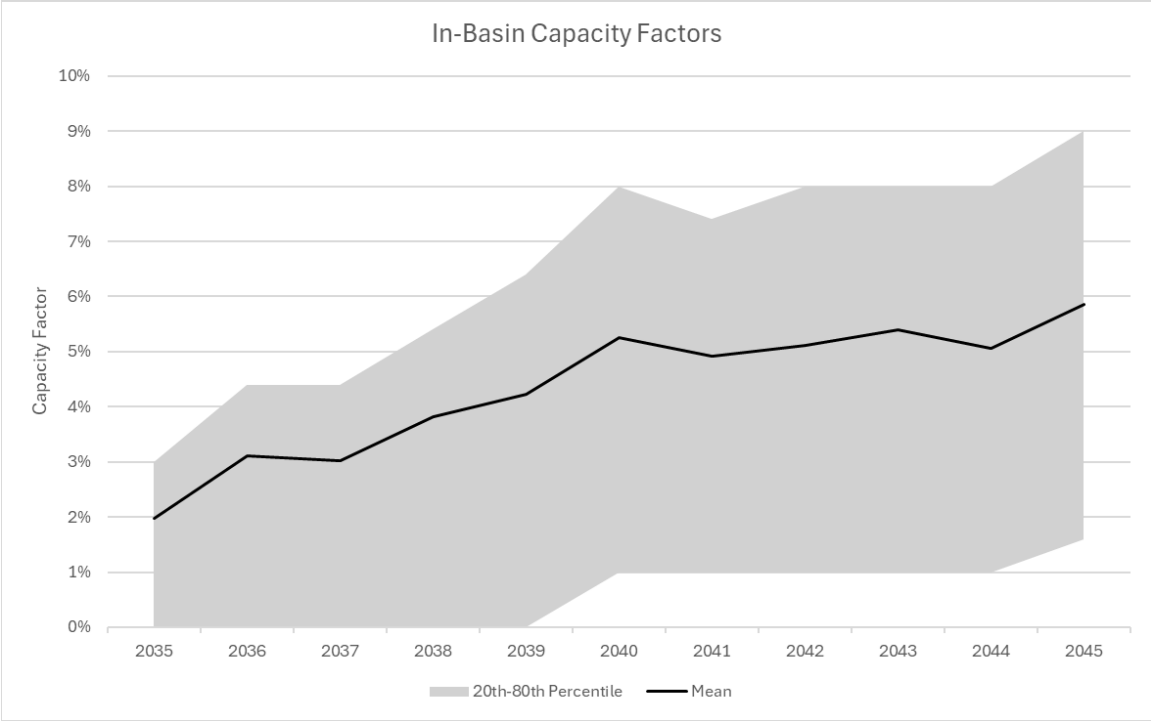


Figure 4-105 In-Basin Capacity Factors for LA100 Pathway Sensitivities (Average with 20th–80th Percentile Range). This chart presents the annual average capacity factor across all in-basin generating units for the suite of LA100 Pathway sensitivity cases. The solid black line represents the mean capacity factor in each year, while the shaded band reflects the 20th to 80th percentile range across all sensitivity cases for that year.

Figure 4-105 displays the average annual capacity factor of in-basin generation across all LA100 Pathway sensitivity scenarios, with the solid line representing the mean and the shaded band indicating the 20th to 80th percentile range. This percentile band captures the central spread of outcomes across scenarios such as Low DER Adoption, High Electrification, Low Load, and others.

Capacity factors remain low throughout the study period, reflecting the declining role of fossil-based in-basin generation as renewable penetration increases. Modest year-to-year variation is evident within the percentile band, showing how differences in electrification levels, load growth, and technology adoption can influence the residual need for in-basin dispatchable resources. In certain years, the tighter percentile band suggests convergence among scenarios, whereas wider spreads in others reflect

divergent assumptions—particularly in the pace of electrification and timing of hydrogen deployment.

This summary provides a high-level view of operational expectations for LADWP's in-basin generation fleet under a wide range of plausible futures modeled in the LA100 Plan.

4.14.5 Fuel Consumption

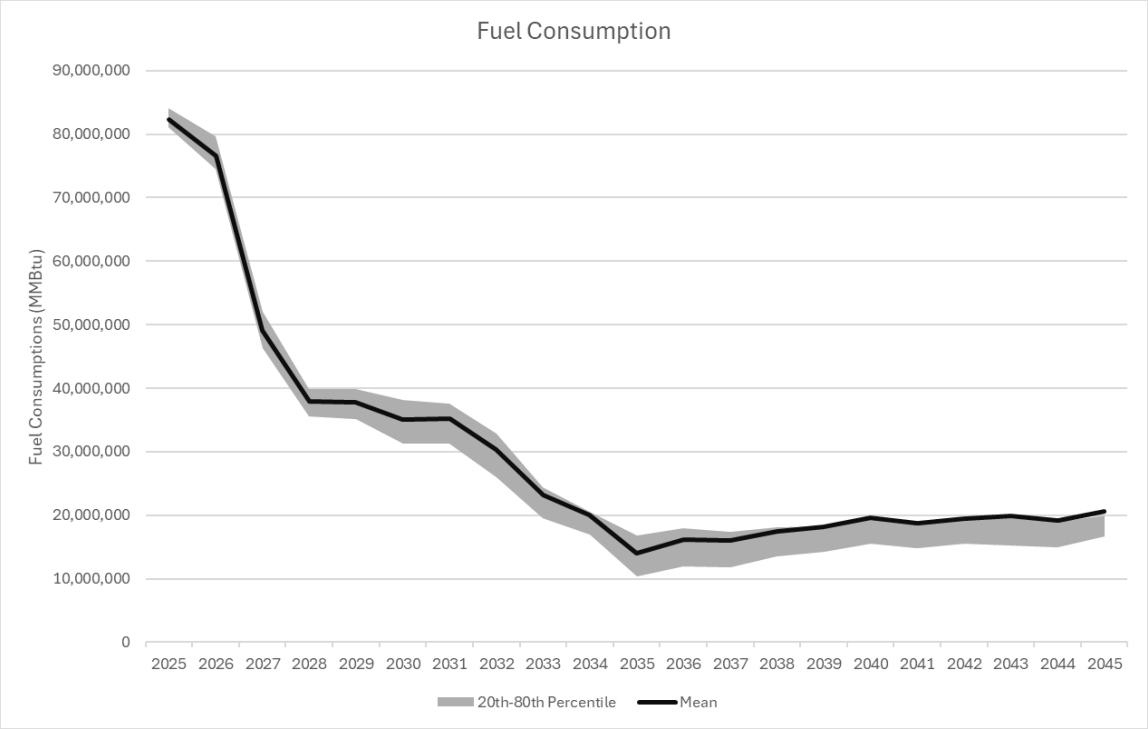


Figure 4-106 Total fuel consumption across all LA100 scenarios, expressed in MMBtu per year. The black line shows the mean value, while the shaded region indicates the 20th–80th percentile range. This aggregation includes all fossil and renewable fuels used for thermal generation (coal, natural gas, and green hydrogen).

Figure 4-106 illustrates total thermal fuel consumption—encompassing coal, natural gas, and green hydrogen—aggregated across all LA100 Pathway sensitivities. The bold black line represents the mean fuel consumption, while the shaded region captures the 20th to 80th percentile range of outcomes across sensitivities.

Fuel consumption declines sharply from 2025 through the early 2030s, reflecting early retirements of fossil-fueled generation and rapid deployment of clean energy resources. By the mid-2030s, the pace of decline slows and eventually levels off, with moderate increases observed in some scenarios during the 2040s. These later-year increases correspond to fuel consumption from dispatchable resources like green hydrogen, which begin to play a more prominent role as firm capacity sources in high-renewable systems.

The narrowing of the shaded percentile range after 2035 suggests increasing convergence in modeled outcomes, with a tighter spread across sensitivities. Nonetheless, some uncertainty remains, particularly in the final years of the study period, where technology mix and dispatch patterns may vary depending on system configuration and reliability needs.

4.14.6 NOx Emissions

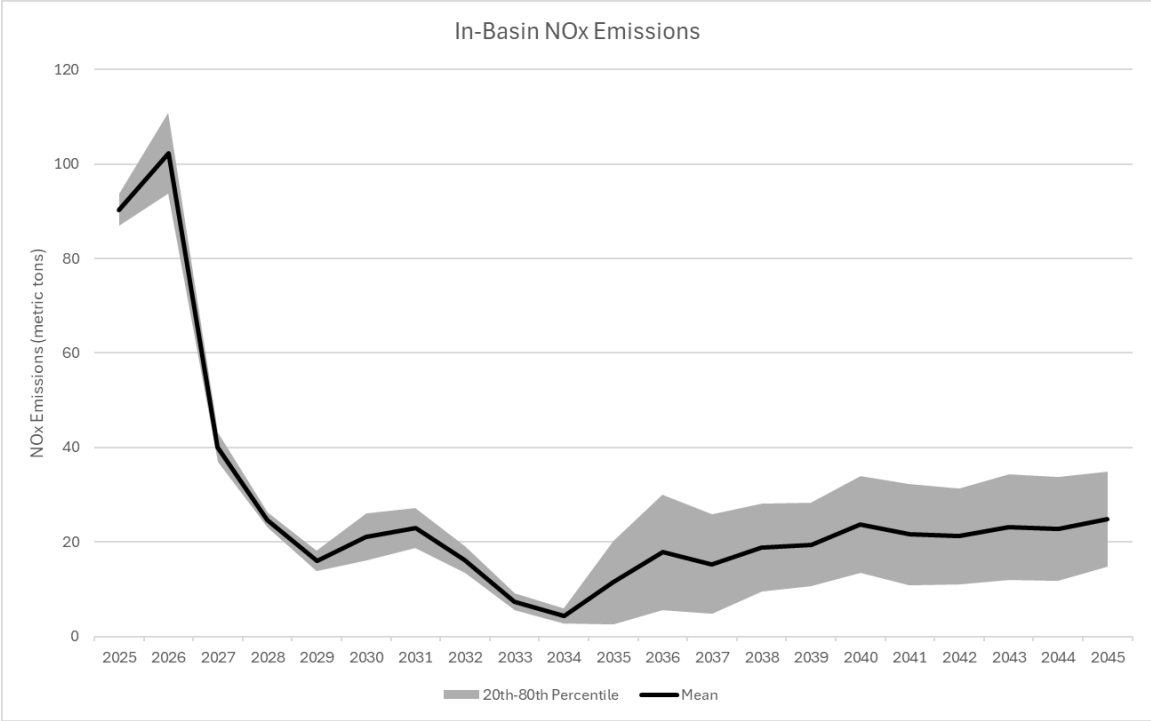


Figure 4-107 Projected in-basin NO_x emissions across LA100 Pathway sensitivities. The solid black line represents the mean of all LA100 Pathway sensitivities, while the shaded area shows the 20th–80th percentile range. Results indicate an initial sharp decline through 2030, followed by a modest increase and stabilization in the 2030s and 2040s. This increase is largely due to modeled thermal capacity additions required for reliability in scenarios with high electrification, limited imports, or constrained buildout of clean resources.

Figure 4-107 presents projected in-basin NOx (nitrogen oxides) emissions under the combined set of LA100 Clean Path sensitivities, offering insight into how emissions may evolve over the next two decades. The black line represents the mean across sensitivities, while the shaded region captures the 20th to 80th percentile range—illustrating the range of plausible outcomes based on varying assumptions for demand, clean energy buildout, DER adoption, and climate conditions.

A steep and immediate decline in NOx emissions is observed from 2025 through 2027, primarily reflecting the anticipated retirement of aging in-basin thermal generation units and the early deployment of large-scale clean energy resources. By 2028, emissions are

projected to fall to a fraction of their 2025 levels—dropping from over 100 metric tons to under 20 metric tons across all modeled sensitivities.

Between 2028 and 2034, emissions remain low and relatively stable, with only slight variation. However, from the mid-2030s onward, a gradual upward trend emerges in both the mean and percentile bands. This modest increase is driven by greater utilization of in-basin thermal resources across some sensitivities, often in response to higher net loads, limited transmission import capacity, or extended periods of low renewable output (e.g., during prolonged heatwaves). Despite this rise, emissions through 2045 remain far below historical levels.

The widening percentile band in the latter years of the planning horizon reflects growing uncertainty about how future operational, climate, and policy dynamics may affect in-basin generation and associated emissions. Still, even in the higher end of the range, NOx emissions never return to pre-2025 levels, underscoring the long-term benefits of early clean energy investments.

4.15 Electric Rate Estimates

LADWP's Financial Services Organization (FSO) performed an electric rate estimate analysis for the LA100 Pathway and the SB100 Benchmark, as shown in Figure 4-108.

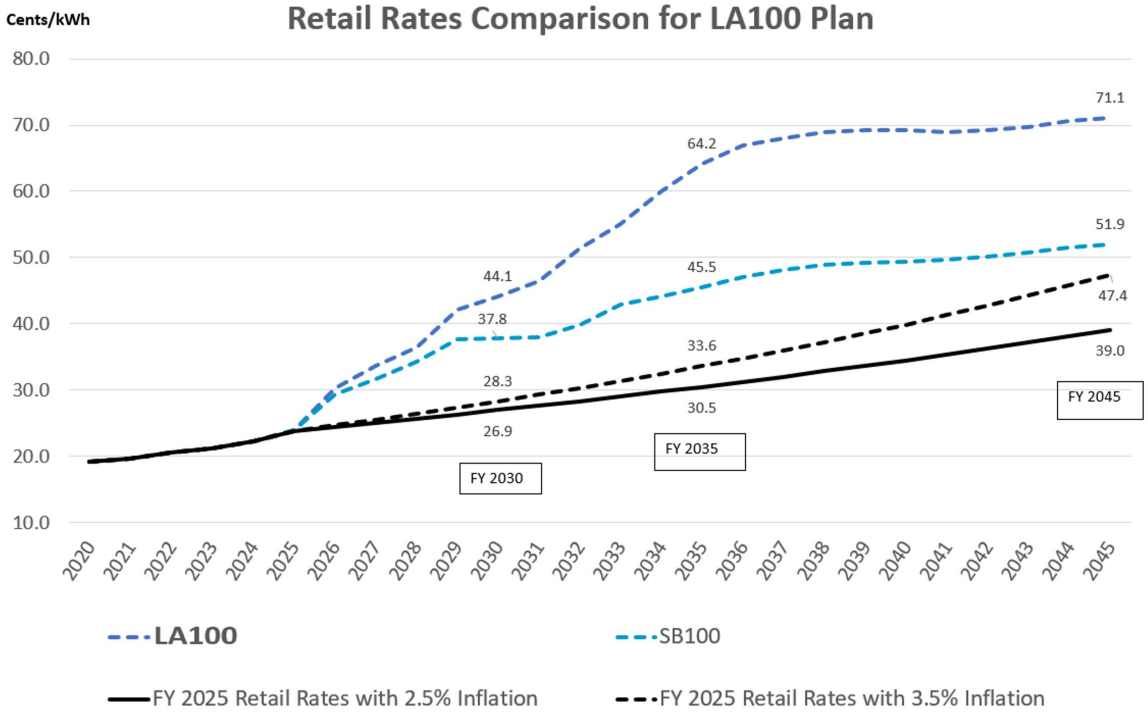
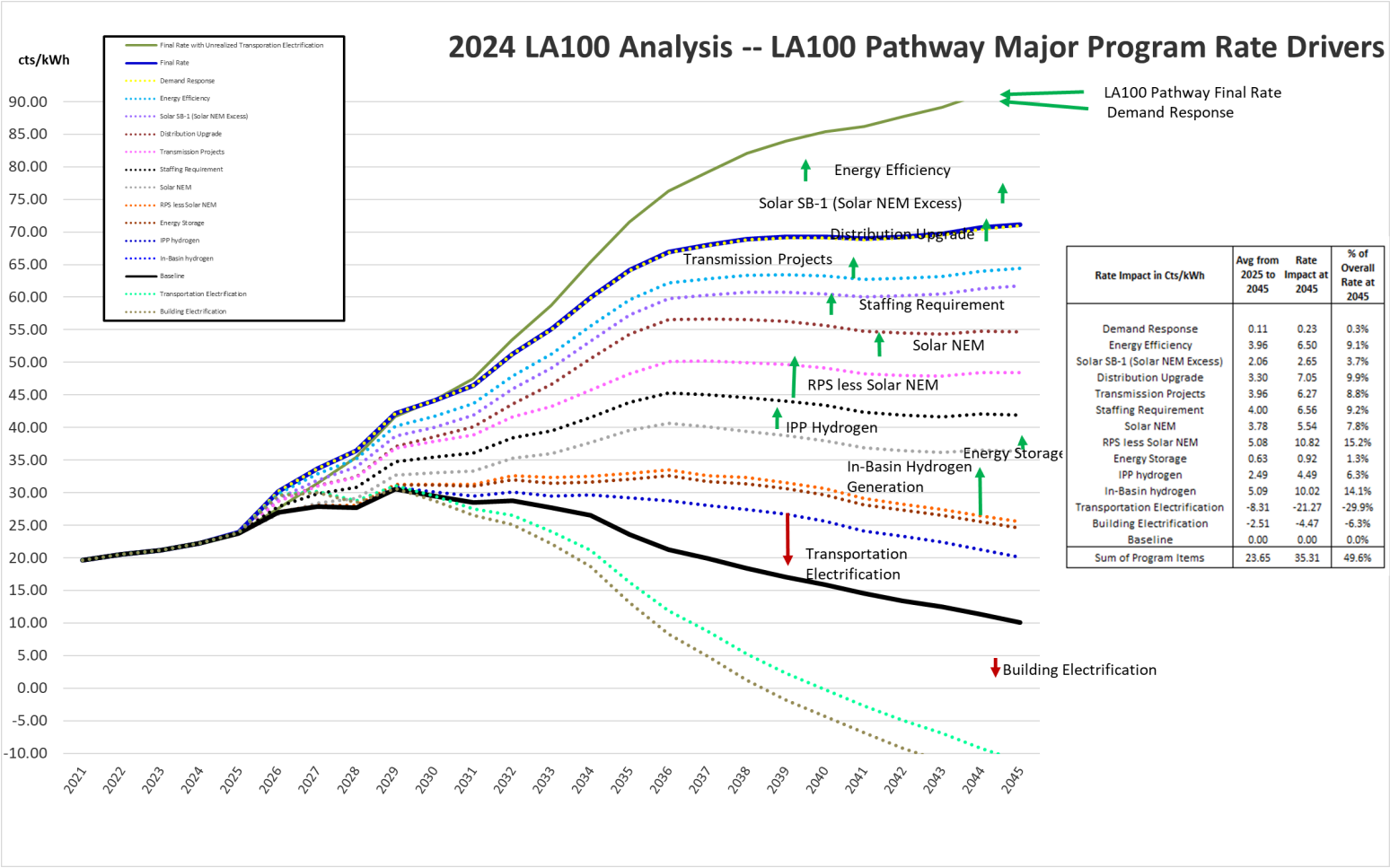


Figure 4-108. Comparison of electric rate estimates.

The rates begin to diverge in notably from 2030 onwards, where the difference in investments between the LA100 Pathway and the SB100 Benchmark are more notable (i.e. 80% RPS by 2030 vs 60% RPS by 2030). In 2030, the difference in estimated rates is approximately 6.3 cents/kWh, but that difference quickly grows to 18.7 cents/kWh in 2035, and culminates in a difference of 19.2 cents/kWh in 2045. From here it is evident that greatest rate impact is front loaded leading up to 2035 due to early investments required for the LA100 Pathway and stabilizes after that. Electrification offers an opportunity to increase retail load and drive rates lower.

When breaking down the different rate drivers for the LA100 Pathway and the SB100 Benchmark, to assess their impact on the overall estimated electric rate, we see various trends as shown in Figure 4-109 and Figure 4-110, below.



Rate Impact in Cts/kWh	Avg from 2025 to 2045	Rate Impact at 2045	% of Overall Rate at 2045
Demand Response	0.11	0.23	0.3%
Energy Efficiency	3.96	6.50	9.1%
Solar SB-1 (Solar NEM Excess)	2.06	2.65	3.7%
Distribution Upgrade	3.30	7.05	9.9%
Transmission Projects	3.96	6.27	8.8%
Staffing Requirement	4.00	6.56	9.2%
Solar NEM	3.78	5.54	7.8%
RPS less Solar NEM	5.08	10.82	15.2%
Energy Storage	0.63	0.92	1.3%
IPP hydrogen	2.49	4.49	6.3%
In-Basin hydrogen	5.09	10.02	14.1%
Transportation Electrification	-8.31	-21.27	-29.9%
Building Electrification	-2.51	-4.47	-6.3%
Baseline	0.00	0.00	0.0%
Sum of Program Items	23.65	35.31	49.6%

Figure 4-109. LA100 Pathway electric rate drivers.

For the LA100 Pathway, the most impactful electric rate drivers in the upward direction, meaning they contribute towards increasing rates, described as a percentage of overall rate in 2045, are as follow: “RPS less Solar NEM” (15.2%), “In-Basin Hydrogen” (14.1%), “Distribution Upgrade” (9.9%), “Staffing Requirement” (9.2%), and “Energy Efficiency” (9.1%).

Rate drivers in the downward direction, meaning they contribute towards reducing rates, are “Transportation Electrification” (-29.9%), and “Building Electrification” (-6.3%).

As mentioned before, the majority of the rate increases are front-loaded leading up to the year 2035 to fund early required investments for decarbonization, before stabilizing thereafter.

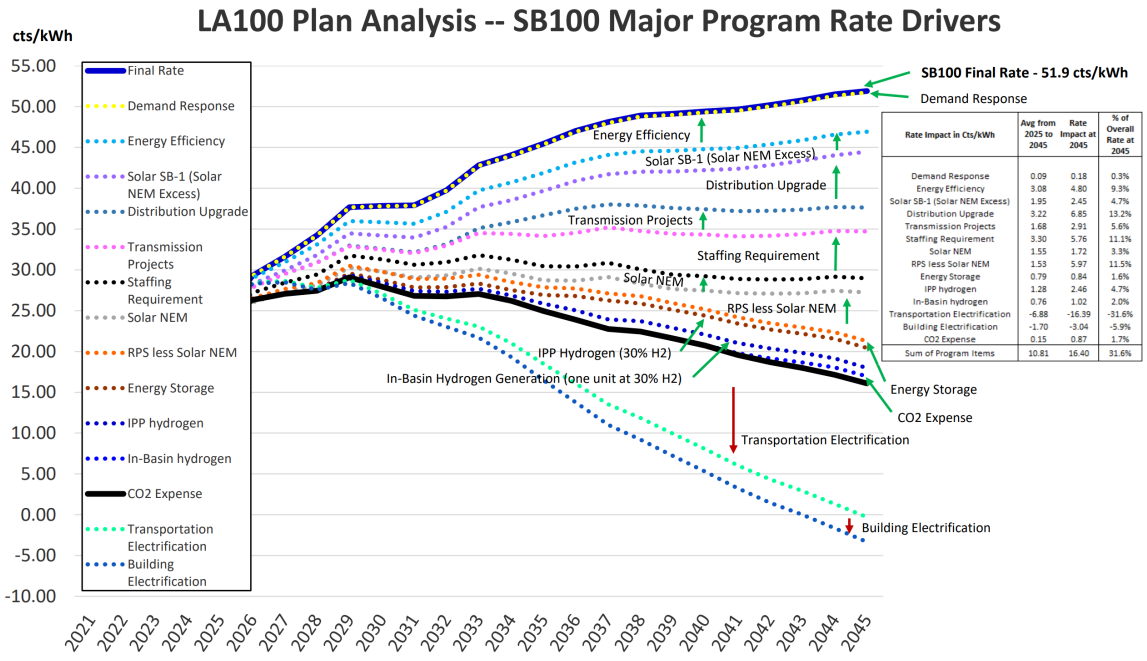


Figure 4-110. SB100 Benchmark electric rate drivers.

For the SB100 Benchmark, the most impactful electric rate drivers in the upward direction, meaning they contribute towards increasing rates, described as a percentage of the overall rate in 2045, are as follow: "Distribution Upgrade" (13.2%), "RPS less Solar NEM" (11.5%), "Staffing Requirement" (11.1%), "Energy Efficiency" (9.3%).

Rate drivers in the downward direction, meaning they contribute towards reducing rates, are "Transportation Electrification" (-31.6%), and "Building Electrification" (-5.9%).

In the SB100 Benchmark, rate increases are more spread out through 2045 as a result of less aggressive clean energy mandates (60% RPS by 2030, 100% clean energy with respect to electric sales by 2045).



4.16 Energy Burden

While the results of the LA100 Plan estimate the overarching costs of transitioning to a 100% carbon-free energy grid, there is a historical lack of methods to extrapolate the economic effects on LADWP customers in detail. To examine the impacts of the LA100 Plan on a residential scale, LADWP solicited UCLA researchers to create the LA Residential Energy Transition (RESET) Tool, also known as the Energy Burden Tool.

The LA RESET Tool is a modeling tool which can be used to project the potential impact of LADWPs increasing revenue requirements on households across LA's service territory using energy burden. *Energy burden* is defined as the percentage of household income that is being allocated towards home electricity, natural gas, and vehicle fuel spending, as denoted in Figure 4-111. A household whose energy burden is at 6% or above is considered a "high energy burden household", which may indicate energy insecurity, and other inequities.

$$Energy\ Burden\ (\%) = \frac{Spending\ on:\ Home\ Electricity,\ Natural\ Gas,\ and\ Vehicle\ Fuel}{Household\ Income}$$

Figure 4-111. Definition of energy burden.

In practice, energy burden calculations can serve to clarify the costs customers might incur on energy going forward and show LADWP more directly if the impacts of the clean energy transition are economically tenable. Furthermore, the LA RESET Tool can allow LADWP and its customers to discern programs and decarbonization approaches which lead to the most savings on customer bills.

The LA RESET Tool uses various energy attributes to distinguish LADWP customers. Energy attributes are variables which help to define a customer's unique energy use in the tool, such as:

- **Geography** – Customer location as denoted by a segment in LA's service territory. Segment types are divided into Census Tract, Zip Code, Council District, or Disadvantaged Community and Non-Disadvantaged Community segmentations. Based on the segment type selected, the tool extracts estimates of annual electricity and natural gas consumption, program enrollments, EV adoption percentage, annual miles driven, and median household income for each segment created.

- **Building Type** – Household type occupied by the customer. Configurations include attached or detached single-family homes (i.e., townhomes or row houses), small or large multi-family buildings (i.e., 2-4 units vs. 5+ units), and mobile homes. This attribute is used to amend electricity and natural gas consumption estimates, as well as energy load shapes.
- **Upgrade Scenario** – Prospective building electrification upgrades made by the customer. Ten scenarios are considered which vary on levels of insulation and home-sealing, inclusion of heat pumps or whole-home appliance electrification (e.g., heat pumps, dryers, ovens, stoves), and the efficiency of these installations. This attribute is used to amend the electricity and natural gas consumption estimates.
- **Customer Segment** – The specific sort of customer being served based on programs. Configurations include All Customers, Non-Discount Only, EZ-Save Only, Lifeline Only, EZ-Save and Lifeline, and NEM Only and serve to denote programs the customer utilizes if any. This attribute serves to weight the customers' median household income and amend electricity consumption for NEM Customers.
- **LA100 Plan Model Run** – The clean energy transition pathway followed by LADWP. Configurations include the LA100 Pathway and SB100 Benchmark. This attribute alters the electric rate projections significantly.
- **Natural Gas Projections** – Projections of Natural Gas Price and Supply to the LA-basin. Contains three cases for Low, Moderate, and High Price. This attribute is used to alter natural gas pricing assumptions.
- **EV Charging** – The type of EV Charging used by the customer. Configurations include At Home, Public Level 2, and Public DCFC (Direct Current Fast Charging). This attribute amends the expected electricity consumption for customers using EVs.

When using the tool, configurations of these attributes are selected to form a profile for a generalized LADWP customer. Depending on the profile, significant alterations are made to the existing projections of electric rates, fuel costs, and other metrics. With this, each segment defined under the geography variable is assigned an energy burden value applicable to households that fall under the profile formed.



The energy burden tool generates annual data for each year between 2024 and 2045 and is structured to create maps for 2025, 2030, 2035, 2040, and 2045 as key years in the timeframe. A map will display the projected energy burden for each segment identified in the year selected. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. The range of energy burden levels can change between maps and is indicated by a legend produced in each map. Finally, a segment in the map will not show up if the customer profile developed is not present in that segment. For example, if the tool is configured to display customers in mobile homes apart of the lifeline program, many parts of the map will be blank, indicating a lack of that sort of customer in most LA City areas.

4.16.1 LA RESET Tool Results

The following sections present the results of the LA RESET Tool applied to today's system, the LA100 Pathway, and SB100 Benchmark.

4.16.1.1 Current Energy Burden

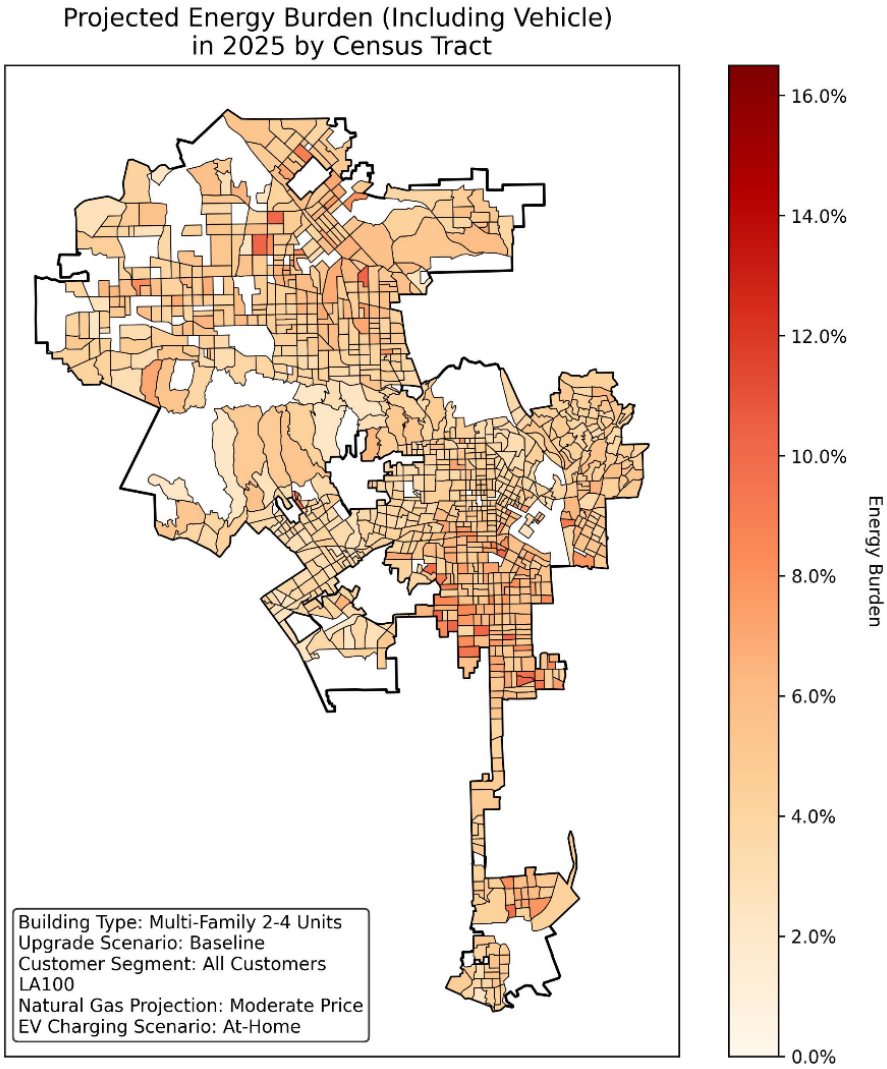


Figure 4-112 Projected Energy Burden in 2025 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Even in 2025, some census tracts under this trajectory already have an energy burden of 6% or higher. Though, energy burden may change drastically depending on customer profiles and may be lowered substantially through involvement in customer programs and energy efficient electrification.

Figure 4-112 illustrates notable spatial disparities in projected energy burden for customers living in 2–4 unit multifamily buildings in 2025. While many areas throughout the city maintain burdens under 6%, significant clusters—particularly in South Los Angeles, parts of the San Fernando Valley, and certain neighborhoods in the southeast—exceed this threshold, with some tracts approaching or surpassing 10%.

These variations are driven by multiple intersecting factors, including household income levels, building energy performance, and transportation energy needs. Even under moderate natural gas price assumptions and baseline building upgrade conditions, the results suggest that many communities may experience disproportionately high energy burdens unless further interventions are implemented.

This underscores the importance of targeted policy design and equity-focused investments. Energy burden is highly sensitive to building retrofits, electrification incentives, and distributed energy programs—particularly when coupled with tailored customer outreach and support. Identifying census tracts with high projected burden can help LADWP and the City of Los Angeles prioritize resources and better support the communities most at risk of economic energy insecurity during the clean energy transition.

4.16.1.2 LA100 Pathway

To better understand the potential impacts of pursuing the LA100 Pathway, the IRP Group utilized the LA RESET Tool to develop maps of projected energy burden throughout the City of Los Angeles. Electric rates were input based on the latest forecast by LADWP's Financial Services Organization derived from this latest iteration of the LA100 Plan. As explained in (section title), five maps were produced highlighting key years in the LA100 Plan study horizon, being: 2025, 2030, 2035, 2040, and 2045. The customer profile used covers small multi-family buildings with no building electrification upgrades, moderate natural gas pricing and at home EV charging. Given this profile, the resulting maps show that customers with these attributes will experience increasing energy burden over time in line with increasing rates.

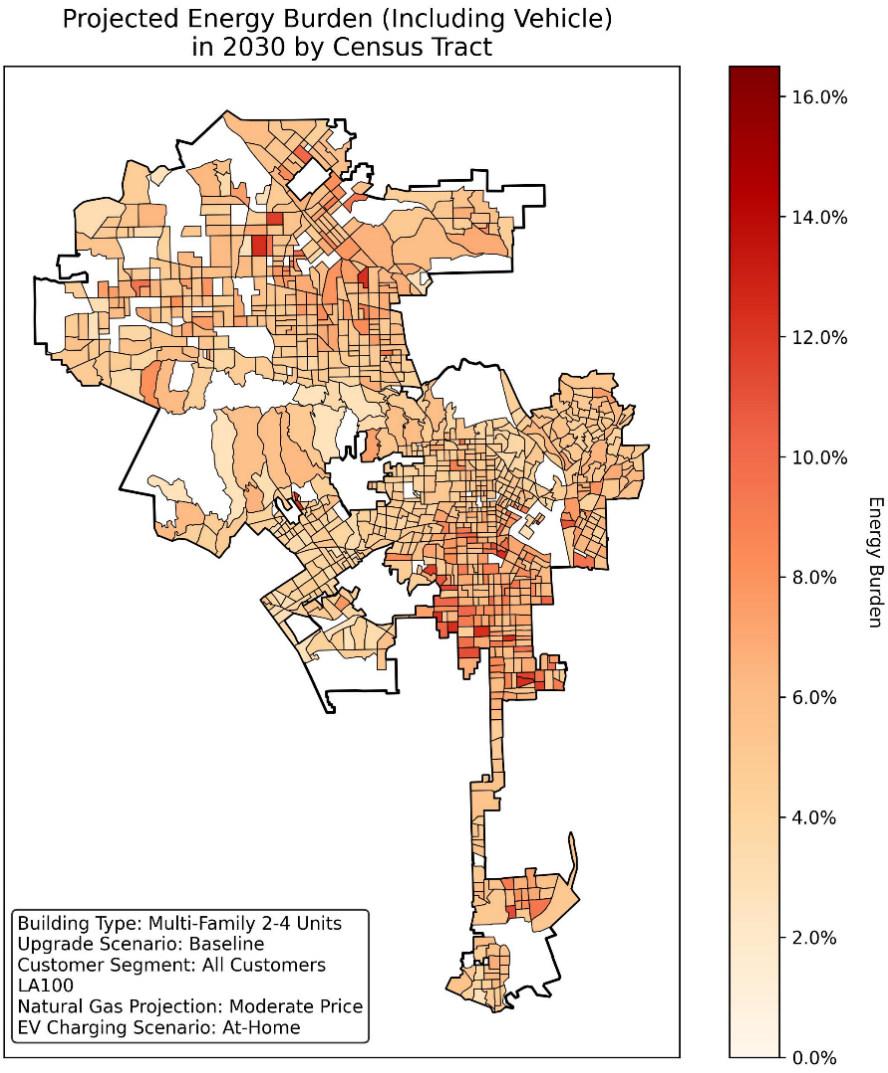


Figure 4-113 Projected Energy Burden in 2030 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see increased energy burden over 2025 projections.

In this 2030 projection under the LA100 Pathway (Figure 4-113), energy burden increases across many census tracts compared to 2025. Although the overall electrification of buildings and transportation is expected to reduce long-term energy costs, near-term transitions may lead to increased costs for some customers—particularly those in older, multi-family housing without access to energy-efficient upgrades.

The distribution of burden continues to vary significantly by geography, with certain neighborhoods in South and Southeast Los Angeles, and parts of the San Fernando

Valley, showing elevated energy burdens above 8% or even 10%. These disparities reflect the combined effects of building stock characteristics, income levels, and household energy use patterns, including transportation needs.

It is important to note that these results assume baseline levels of customer upgrades. Energy burdens could be significantly alleviated through equitable implementation of incentive programs, access to clean mobility options, and energy efficiency retrofits—especially in communities shown here to face the greatest challenges. Proactive investment and targeted outreach will be critical to ensure that the path to decarbonization also supports affordability and equity.

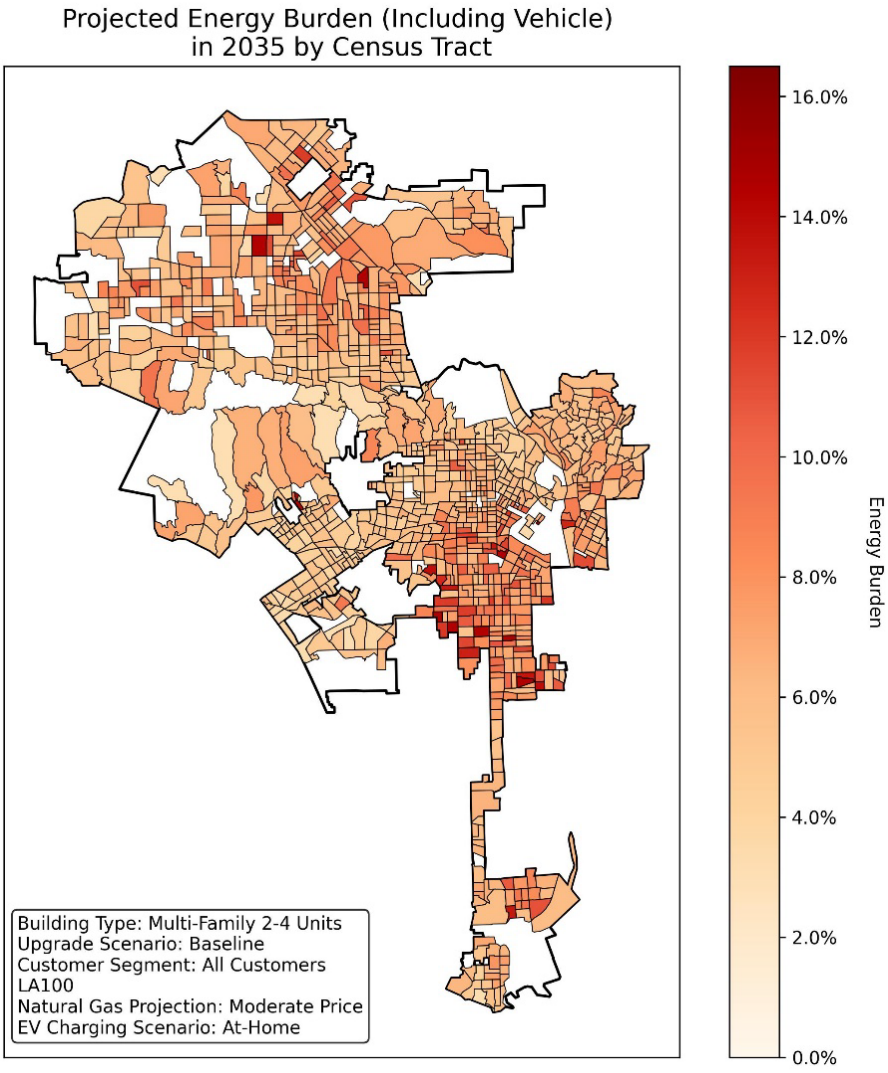


Figure 4-114 Projected Energy Burden in 2035 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see increased energy burden over 2030 projections.

In 2035, projected energy burdens under the LA100 Pathway show a further intensification of household energy costs for some census tracts across Los Angeles (Figure 4-114). Compared to 2030, more tracts surpass key threshold levels—such as 6% or 10% of household income—particularly in parts of South Los Angeles and the Harbor area. These areas already exhibit higher burdens in earlier years, and the increasing trend reflects compounding challenges tied to socioeconomic conditions, building stock, and electrification adoption.

The escalation seen in this year underscores the importance of targeted policy and programmatic interventions to reduce household energy burden. Without mitigating actions—such as expanded incentives for electrification upgrades, deeper customer assistance programs, and equitable rate design—high-burden communities may face growing affordability challenges, even under a fully decarbonized power system. The persistence and expansion of high-burden tracts in 2035 suggest that decarbonization efforts must be paired with robust equity strategies to ensure inclusive benefits across the city.

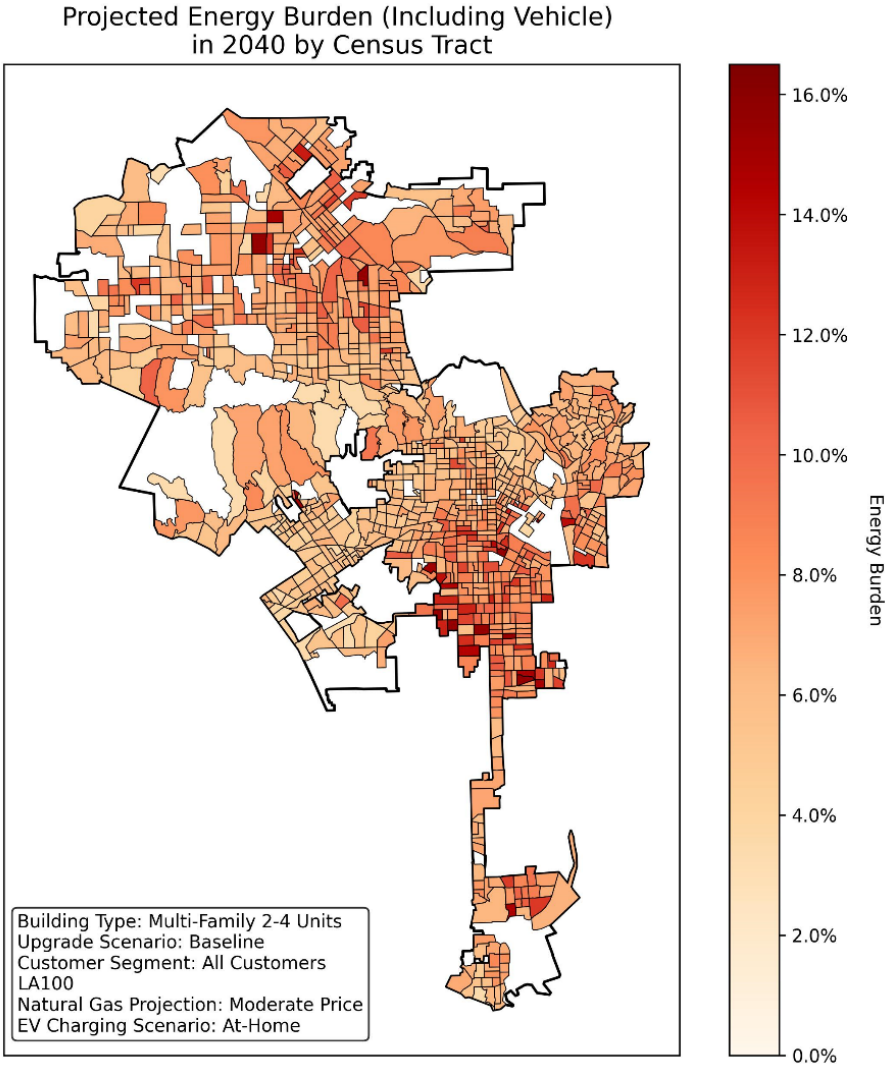


Figure 4-115 Projected Energy Burden in 2040 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see increased energy burden over 2035 projections.

Under the LA100 Pathway, energy burden continues to rise through 2040 for many parts of Los Angeles, particularly for multi-family 2–4 unit households (Figure 4-115). The map highlights a deepening of high energy burden areas compared to prior years, with more census tracts crossing the 6% threshold and some exceeding 10% or even 14%. These trends are visible across historically disadvantaged areas of South Los Angeles, the Harbor region, and parts of the Northeast San Fernando Valley.

This ongoing increase reflects the compounding impact of energy cost trajectories, household income growth assumptions, and electrification-related expenditures—including vehicle energy costs—under moderate natural gas price projections. Without targeted interventions, customers in these communities may face growing financial pressure to meet basic energy needs, raising equity concerns.

These findings reinforce the need for proactive investment in energy efficiency, supportive electrification programs, and targeted rate design. Absent such efforts, the benefits of decarbonization risk bypassing the communities already burdened with the highest energy costs relative to income.

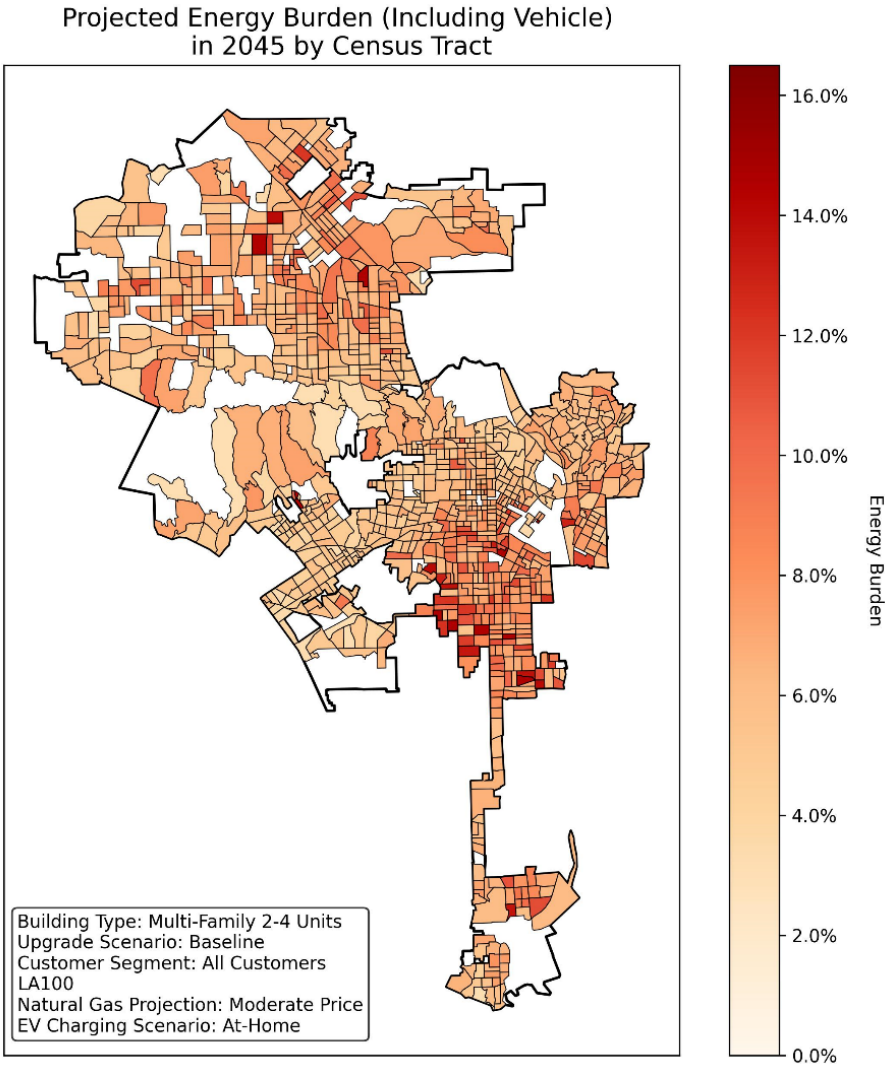


Figure 4-116 Projected Energy Burden in 2045 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see a slight decrease in energy burden figures compared to 2040 projections.

Despite a slight improvement over 2040 projections, the 2045 energy burden map continues to highlight enduring disparities across Los Angeles (Figure 4-116). Under this LA100 Pathway, many census tracts remain in the moderate to high energy burden range, with values exceeding 6% and, in some areas, rising above 12%–14%. These persistently high burdens are especially concentrated in South Los Angeles and parts of

the Eastside, where compounding socioeconomic factors and building stock characteristics may limit access to efficiency upgrades or customer programs.

Although energy burden slightly decreases in some tracts—likely due to assumed decarbonization efforts, vehicle electrification efficiency gains, or market stabilization—overall improvements remain modest. This underscores the importance of targeted interventions in historically underserved communities, even under a clean energy transition. It also signals that without proactive, equity-driven policy and program design, structural affordability challenges may persist or even intensify for vulnerable customers.

4.16.1.3 SB100 Benchmark

The IRP Group also utilized the LA RESET Tool to develop maps of projected energy burden under the SB100 Benchmark. This was done to create a reference for energy burden trajectories under the LA100 Pathway for comparison. Electric rates were input based on the latest forecast by LADWP's Financial Services Organization. Using the SB100 Benchmark as a basis, the electric rates increased by much lower margins, which affected the energy burden maps greatly. Five maps were produced highlighting key years study horizon: 2025, 2030, 2035, 2040, and 2045. The customer profile used covers small multi-family buildings with no building electrification upgrades, moderate natural gas pricing and at home EV charging. Given this profile, the resulting maps show that customers with these attributes will experience increasing energy burden over time, but to a lesser extent than in the LA100 Pathway.

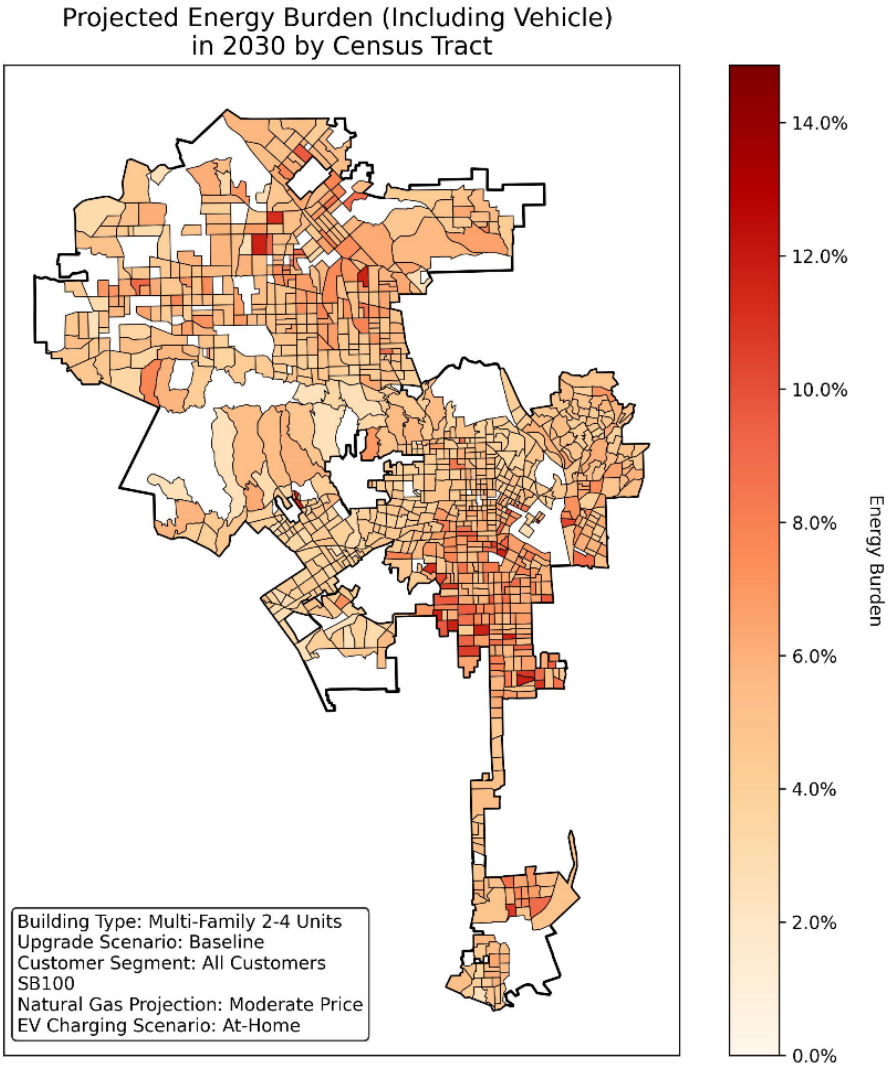


Figure 4-117 Projected energy burden for the SB100 Benchmark in 2030 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see increased energy burden over 2025 projections at a similar rate to the LA100 Pathway. Compared to the LA100 Pathway, energy burden remains lower overall.

Under the SB100 Benchmark scenario, projected energy burden in 2030 continues to increase across many areas of Los Angeles, following the upward trend observed between 2025 and 2030 (Figure 4-117). While many census tracts remain under the 6% energy burden threshold, several communities—particularly in the southern and eastern parts of the city—show elevated burden levels exceeding 8% or more. This scenario assumes more limited policy intervention and a slower pace of decarbonization

compared to the LA100 Pathway, and thus the overall energy burden remains slightly lower than in the LA100 case.

The spatial distribution of burden also differs modestly, with some high-burden tracts under the LA100 Pathway showing slightly reduced intensity in the SB100 Benchmark. This suggests that the more ambitious infrastructure investments required by the LA100 Pathway may increase costs in the near term for certain customers, unless accompanied by targeted affordability measures. These results underscore the importance of continued support for customer programs—especially in tracts already at or above high-burden thresholds—as energy system investments scale up across all scenarios.

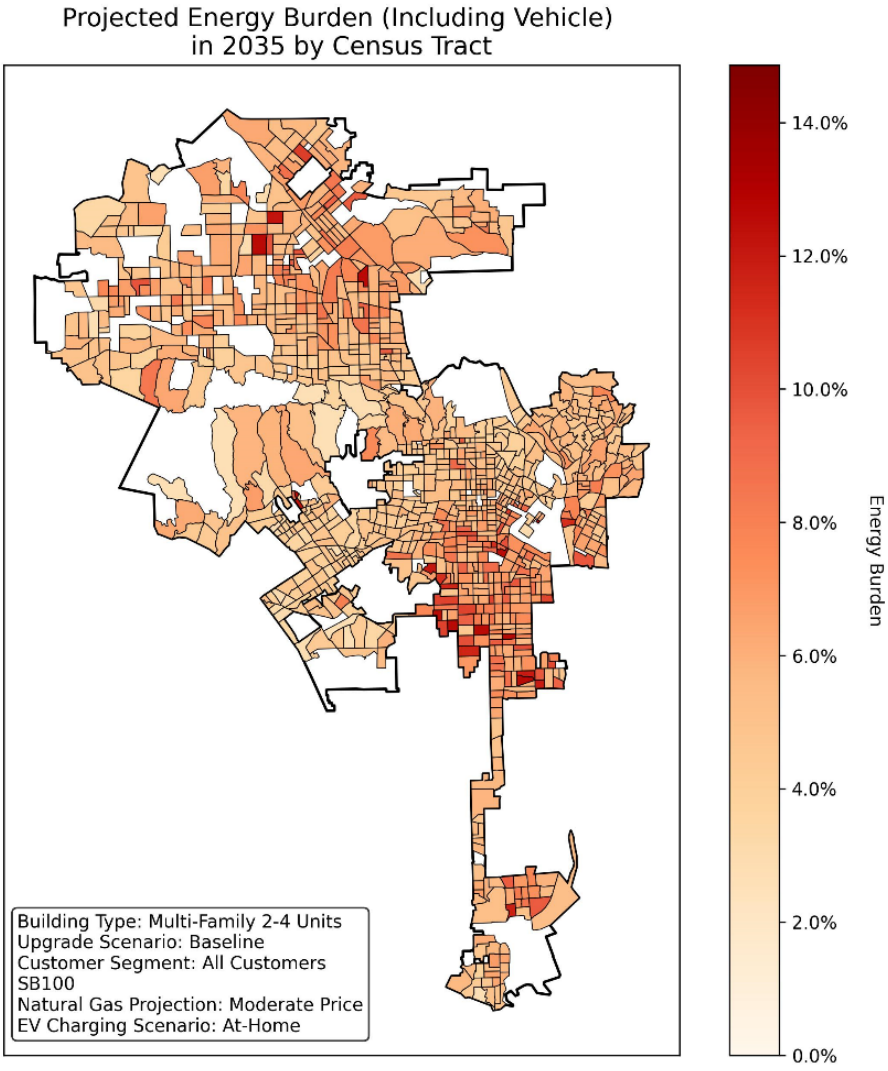


Figure 4-118 Projected energy burden for the SB100 Benchmark in 2035 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see increased energy burden over 2030 projections at a similar rate to the LA100 Pathway. Compared to the LA100 Pathway, energy burden remains lower overall.

Under the SB100 Benchmark scenario in 2035 (Figure 4-118), projected energy burden levels continue their upward trend across many parts of Los Angeles, following the trajectory observed from 2025 through 2030. While the SB100 scenario yields slightly lower energy burden levels than the LA100 Pathway, many census tracts—particularly in South Los Angeles, the Harbor area, and portions of the Eastside—still experience elevated burdens.

This map reveals that by 2035, the number of tracts experiencing energy burdens above 6% expands slightly, and some areas see burdens rise above 10% or even 14%. The distribution of higher burdens remains consistent with known patterns of income and housing type, disproportionately affecting communities already facing economic and environmental stress.

Although the SB100 scenario does not pursue the same scale of clean energy investment as the LA100 Pathway, the fact that energy burden remains significant even under this benchmark reinforces the need for targeted interventions—such as income-qualified customer programs, appliance upgrades, and EV incentives—that can reduce energy costs for the most impacted households.

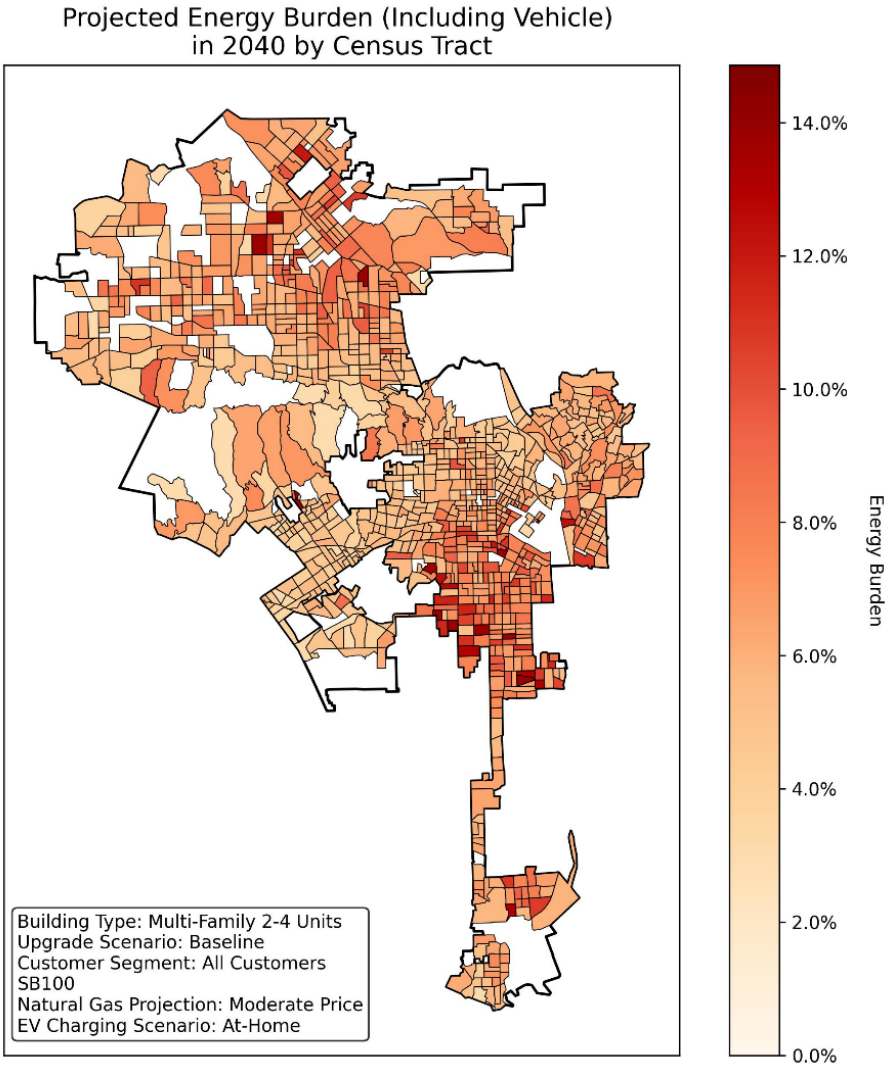


Figure 4-119 Projected energy burden for the SB100 Benchmark in 2040 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory see increased energy burden over 2035 projections at similar rate to the LA100 Pathway. Compared to the LA100 Pathway, energy burden remains lower overall.

Figure 4-119 illustrates the projected energy burden, including vehicle energy use, by Census Tract in 2040 under the SB100 Benchmark scenario. Each segment on the map is color-coded to reflect the anticipated percentage of household income spent on energy. Darker shades indicate higher energy burdens, while lighter shades indicate lower burdens. Segments with no shading represent areas where no customers match the specified profile—multi-family households in 2–4 unit buildings, under the baseline

upgrade scenario, with at-home electric vehicle (EV) charging and moderate natural gas price projections.

By 2040, energy burden is expected to increase compared to 2035 levels, continuing a trend observed in previous projections. However, the rate of increase closely tracks that of the LA100 Pathway scenario. Despite this similarity in trajectory, the overall energy burden under the SB100 Benchmark remains lower than that of the LA100 Pathway. This suggests that the SB100 trajectory may offer a more economically favorable path for affected customer segments, even as burden levels rise modestly over time.

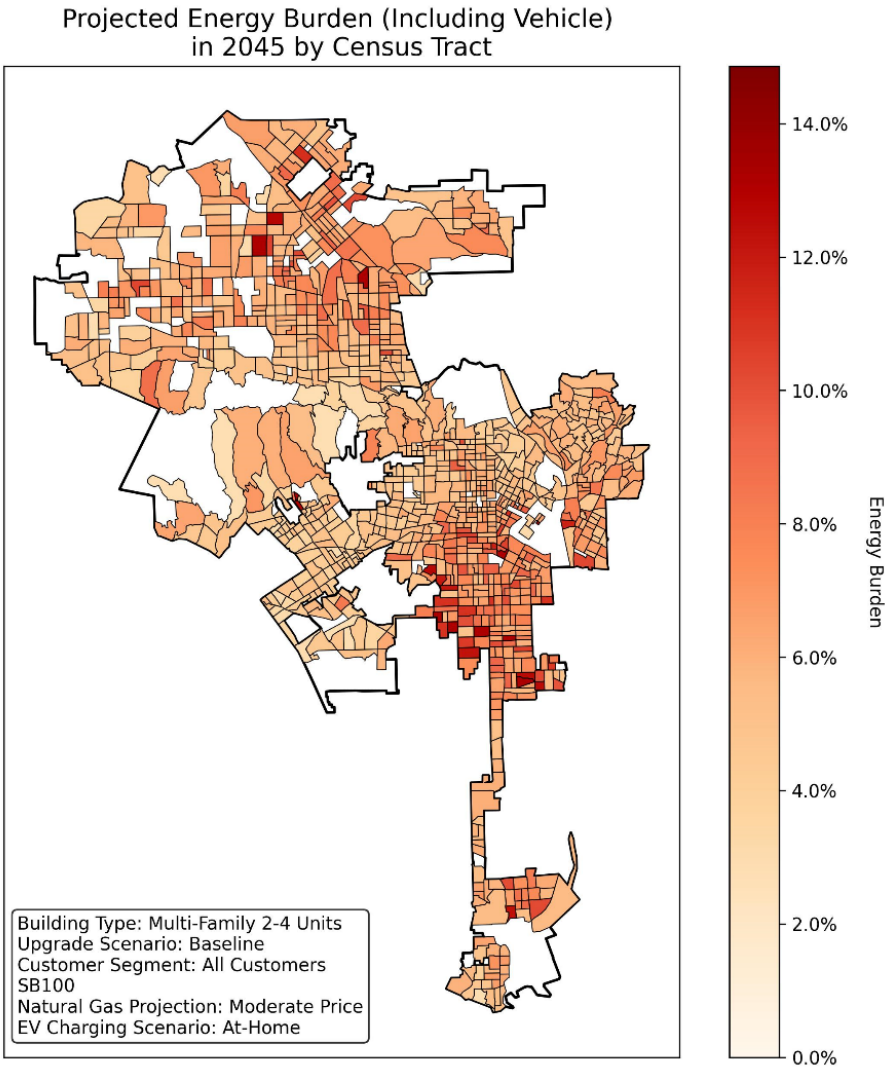


Figure 4-120 Projected energy burden for the SB100 Benchmark in 2045 by Census Tract. The level of energy burden in a mapped segment is represented by the color of the segment, where a darker hue signifies higher energy burden. Blank segments indicate a lack of customers in the segment who match the profile indicated in the bottom left. Census tracts under this trajectory show energy burden decreasing from 2040 projections at a similar rate to the LA100 Pathway while remaining lower overall.

In 2045, projected energy burdens across census tracts under the SB100 Benchmark scenario show modest improvement relative to 2040, with noticeable reductions in the most heavily burdened areas (Figure 4-120). While energy burden remains elevated in portions of South and Southeast Los Angeles, the overall intensity of darker red zones has softened, signaling a gradual easing of energy-related cost pressures. This trend aligns with the broader trajectory of the LA100 Pathway, in which energy burden also declines after peaking in 2040. However, SB100 continues to outperform LA100 on this

metric, maintaining lower average burdens across tracts. Blank tracts in the map indicate census segments without qualifying customers under the modeled profile (multi-family 2–4 unit households). Overall, the 2045 projection suggests that under the SB100 Benchmark, energy affordability slightly improves following 2040, with regional disparities persisting but beginning to moderate.

While the SB100 Benchmark scenario projects modest reductions in energy burden after 2040, the LA100 Plan anticipates a different trajectory—one in which energy burden may continue to increase in several areas of Los Angeles. This is particularly evident in historically overburdened communities such as South Los Angeles and portions of the San Fernando Valley, where the transition to a clean energy future may pose heightened affordability challenges.

LADWP acknowledges that ensuring equitable outcomes across all neighborhoods requires more than just system-wide emissions reductions. It requires intentional, sustained efforts to monitor and mitigate energy burden, especially where it intersects with existing social and economic vulnerabilities. As part of its long-term commitment to affordability and environmental justice, LADWP will continue to assess the distributional impacts of clean energy transitions and develop targeted strategies to address rising energy burdens in disproportionately affected communities.

These strategies will be informed by the LA100 Equity Strategies Action Plan and implemented through a combination of programmatic initiatives, customer support offerings, and thoughtful ratemaking processes. This may include expanding access to energy efficiency upgrades, targeted bill assistance, distributed energy resources, and electrification support in underserved areas. Additionally, LADWP will continue to engage with community stakeholders to co-develop solutions that are responsive to localized needs and priorities.

Through these efforts, LADWP reaffirms its commitment to delivering a just and affordable energy transition—one that ensures all Angelenos, regardless of income or location, are able to participate in and benefit from a clean energy future.



Chapter 5

Risks & Challenges



Key Highlights

- 100% Clean Energy by 2035: LADWP's LA100 Plan provides a flexible, data-driven roadmap to achieve a fully carbon-free power system
- Adaptive Risk Management: Uses modeling and risk tools to guide investments, manage uncertainty, and refine strategies over time
- System and Workforce Transformation: Modernizes infrastructure and expands staffing to support reliable, sustainable clean energy future



5.1 Risks and Challenges

With the completion of this LA100 Plan, the Los Angeles Department of Water and Power (LADWP) has firmly positioned itself as a vanguard of the utility industry regarding innovation, clean energy development, and holistic transformation. This rigorous and unprecedented level of resource planning has yielded a potential pathway to realizing the City of Los Angeles' goal of achieving 100% carbon-free energy by 2035. Although the LA100 Pathway is a foundational path forward, the critical process of iteration will continue to be refined as opportunities, risks, constraints, and innovations are made available and realized in the future. An example of the iterative nature of resource planning will be the incorporation of critical outcomes of the other critical Power System initiatives including, but not limited to, the Strategic Transmission Plan (STP), the Integrated Human Resource Plan (IHRP), the Power System Reliability Plan (PSRP), and the LA100 Equity Strategies (LA100 ES).

There are an array of potential risks that LADWP must consider in order to ensure reliability and resilience of the power grid in both the short-term and the long-term. In order to address these risks effectively, LADWP employs a systematic approach to prioritize risks, recognizing that not all threats are equal. Central to this strategy is the use of a risk matrix which provides a structured framework for ranking hazards based on critical factors like the likelihood of a risk event occurring and its potential impact or consequence on grid operations, public safety, and future plans or targets. This matrix categorizes risks into tiers based on potential adverse impacts, guiding LADWP's prioritization of risk-mitigating actions. This methodology allows LADWP to strategically

allocate finite financial and technical resources towards mitigating the most significant threats and subsequently building a grid that is not only robust against today's challenges but is also adaptable to future uncertainty.

To support robust decision-making in the face of uncertainty, LADWP evaluated a range of sensitivities through the LA100 Plan modeling effort. These sensitivities were designed to quantitatively assess how the power system might respond under varying conditions, such as higher or lower customer demand, evolving costs for key technologies, limited infrastructure availability, or challenges related to extreme weather and fuel supply. The scenarios were developed with extensive input from the LA100 Advisory Group and were intended to test the resilience of the LA100 Pathway across a wide spectrum of plausible futures. This structured exploration allowed LADWP to better understand key risks, identify potential tradeoffs, and ensure that the LA100 Plan remains adaptable as the transition to a clean energy future unfolds.

5.1.1 The Path Forward

A critical update to the traditional planning process will be to track and monitor critical risks sectors – first through qualitative understanding, and in subsequent updates, through expanded quantitative analysis to illuminate the implementation pathway. The level of difficulty in realizing 100% carbon-free energy by 2035 may present an ever-increasing challenge and it is paramount to the success of LADWP's carbon-free energy initiatives that we identify and mitigate risks and identify and realize opportunities.

The primary objectives for the LA100 Plan are to identify constraints and risks actively exerting pressure on LADWP, and to incorporate them into complex planning tools and models to determine how LADWP's goals may be affected by real-world limitations, such as federal legislation or supply chain and personnel constraints. This will provide the optimal environment to identify LADWP's gaps in processes, projects, programs, technologies, and capabilities. The results will provide a clear vision for accelerated implementation. In subsequent years, updates and revisions based on future capabilities with advancements in technology, financial products, and the global energy ecosystem will be implemented. LADWP's capabilities will additionally be updated as business strategies, corporate processes, and internal capabilities are enhanced and modernized. Lastly, pragmatic policies will continue to help bring about a carbon-free energy future and shape the regulatory forefront for utilities.

5.1.2 Mitigating Implementation Risks

Since the Industrial Revolution, humans have depended on fossil fuels, especially for electricity generation. The notion that this might change is hard to contemplate. LADWP must ensure adequate supplies of energy in the near term to meet today's needs, while dramatically accelerating a transition to clean energy and building new policy tools to facilitate investments that achieve 100% carbon-free energy by 2035. This grand adaptation needs to be piecemeal, even when well planned. Related clean energy risks and impacts must be addressed as early as possible.

A Power System risk is an uncertain event or condition that, if it occurs, has a positive or negative effect on one or more critical Power System objectives. Barriers are present in every organizational activity, especially across complex endeavors such as achieving 100% carbon-free energy by 2035. Organizational inertia is inherently risky because products, resources, and services become stale over time and may lose their competitive effectiveness due to dynamic changes internally and externally. In general, a Barrier Mitigation Matrix (BMM) will allow LADWP to enhance its planning process by:

- Anticipating and managing change
- Improving decision making
- Developing proactive preventative measures
- Avoiding potentially higher costs caused by reactive decision making
- Increasing the chances to realize opportunities for increased benefits
- Generating broad awareness of uncertainties and outcomes
- Supporting organizational agility and resilience

The most critical risks sectors to manage to ensure successful implementation will include, but not be limited to:

- Supply Chain and Commodity Volatility
- Technology Readiness
- Constructability and Outage Management
- Procurement Capabilities
- Distribution System Development
- Transmission System Development

- Generation System Development
- Electric Utility Rates
- Electrification
- LADWP Staffing

Due to existing constraints, only a limited number of topics have been studied at this time.



5.1.3 Legislative Changes

5.1.3.1 Executive Orders

Since the transition to the current presidential administration, there have been several executive orders related to energy and utilities that have been issued. LADWP is actively monitoring these developments, and as of the writing of this document, the following orders are of relevance:

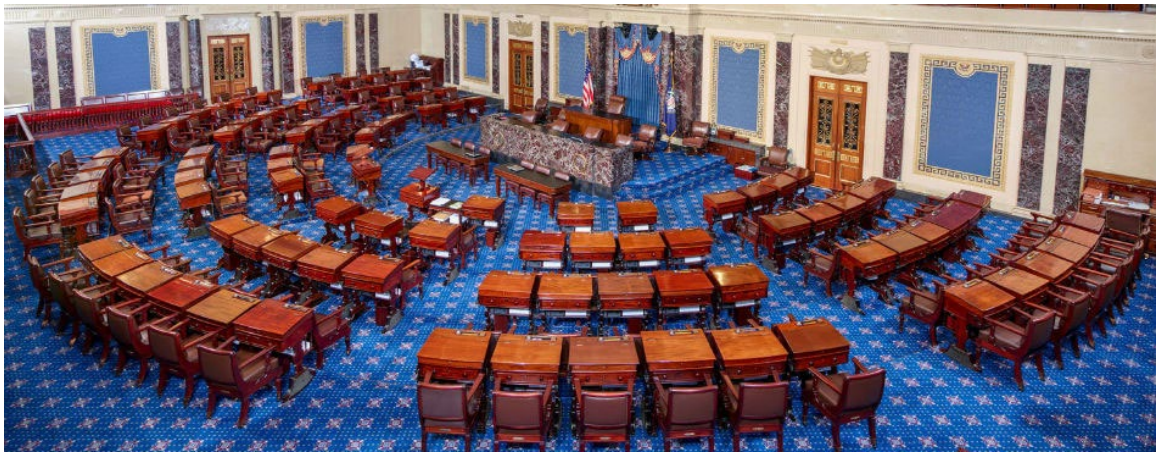
- **Unleashing American Energy (EO 14154)**: aiming to bolster the domestic energy production with an emphasis on oil, natural gas, coal, and nuclear power.
- **Protecting American Energy from State Overreach (EO 14260)**: aiming to remove barriers to domestic energy development to ensure energy affordability and national security.
- **Reinvigorating the Nuclear Industrial Base (EO 14302)**: increasing nuclear energy in America and reduces dependance on foreign supply chains. Accelerates licensing and deployment of advanced nuclear reactors and invests in developing a skilled U.S. nuclear workforce.
- **Ending Market Distorting Subsidies for Unreliable, Foreign Controlled Energy Sources (EO 12961):** eliminates federal subsidies for certain alternate energy sources including wind and solar.

These executive orders present potential hurdles for LADWP by pausing funding on some clean energy projects, phasing out green-energy tax credits, and eliminating major federal subsidies that have historically supported wind and solar projects. Language in the executive orders also raises questions about the legality of state and local renewable energy goals and policies that do not align with the goals of the current federal administration. While executive orders are not legislative acts and can be repealed by future administrations, LADWP continues to closely track all federal directives to assess potential impacts on projects, programs, and long-term planning timelines. Regardless of federal executive orders, LADWP remains firmly committed to advancing the City of Los Angeles' sustainability goals and delivering reliable, cost-effective and environmentally responsible services to its customers.

5.1.3.2 Legislation

In addition to executive actions, federal legislative actions can have significant implications for LADWP's internal planning process. On July 4, 2025, President Donald Trump signed the "One Big Beautiful Bill Act" (H.R. 1), which included provisions relating

to the United States energy sector. Notably, the bill phases out Biden-era Section 45Y (clean electricity Production Tax Credit) and 48E (clean electricity Investment Tax Credit) tax credits for wind and solar projects placed into service after 2027—unless construction begins by July 4, 2026.



5.1.4 Supply Chain and Commodity Volatility

As the world at large weans itself off fossil fuels, it must switch to cleaner energy sources. That translates into huge demand for metals, such as cobalt, copper, and nickel, that are vital for the technologies underpinning everything from electric cars to renewables. Specifically, Western countries will need to secure adequate supplies of these precious metals. However, even if adequate capacity for these metals is available, most refining of these metals occurs in foreign countries. LADWP is expected to rely on foreign suppliers for significant capacity to convert refined ores into the materials that go into these technologies. Such forecasts explain the frenzied activity up and down the electric battery value chain. Everywhere, supply chains are being transformed. Following the COVID-19 pandemic, supply chains are still volatile and dynamically adjusting to a new normal that is still being understood.



5.1.5 Technology Readiness

In the challenging process of transitioning to 100% carbon-free energy, additional technologies, tools, and unique innovations to accelerate the rate of carbon-free energy development will be required. LADWP must remain committed to the research, development, and growth of new emerging clean energy sectors. A firm, transparent technology readiness methodology must be established to ensure that updates to the LA100 Plan account for new innovations in the energy sector that are capable of scaling. An example of a theoretical potential could be nuclear fusion energy. To date, the process is unviable as an alternative to fossil fuels. However, recent developments in nuclear fusion suggest significant progress in this technological space could soon be achieved. LADWP must develop the appropriate litmus criteria to ensure rational processes filter and objectively identify optimal investment pathways.

5.1.6 Constructability and Outage Management

An unprecedented pace of generation, transmission, and distribution asset development will be required to achieve 100% carbon-free energy by 2035. The required increase in the total volume of generation, transmission, and distribution work will significantly complicate LADWP's project management and coordination efforts. To further increase the difficulty of this endeavor, LADWP does not have exclusive control over every project function. Regarding generation and transmission outages, available time windows are limited to specific low-load periods of the year and may be subject to regulatory oversight. Ensuring that resources are aligned to maintain coordination and timing, while developing an unprecedented number of like projects, will be critical to overall project efficiency and performance. Furthermore, the distribution system will need to appropriately manage parts of the system that are taken offline for maintenance or modernization efforts which will redirect electrical stresses to other circuits. Determining the optimal sequence of projects and timings will be a critical factor for implementation strategies.



5.1.7 Procurement Capabilities

It is expected that maturing renewable energy and energy storage technologies will continue to decrease in cost as global value chains evolve. For instance, the price of solar photovoltaic technologies has decreased by more than 90% over the last decade. LADWP must continue to make incremental investments into carbon-free energy projects and monitor market conditions to determine which projects provide the best fit at the least cost. In general, such projects have favorable market pricing and offer streamlined procurement capabilities. A focused optimization in this risk sector can have significant long-term benefits for LADWP's resource portfolio.

5.1.8 Generation System Development

As LADWP transforms its Power System to eliminate fossil-fired power generation resources, LADWP will need to continuously stay updated on the latest viable technologies that can be scaled in the required magnitude to continue to offer safe, reliable, and cost-effective electric service in an equitable manner. Such potential technologies include the use of green hydrogen as a renewable fuel, which would allow the conversion of critical firm and dispatchable capacity resources within the Los Angeles Basin, to carbon-free power generation resources. Challenges exist including technology maturity, space constraints, permitting requirements, and infrastructure requirements, among others. A significant number of personnel and coordination will be required to manage multiple parallel projects in order to achieve the accelerated 2035 target.

5.1.9 Transmission System Development

LADWP's transmission system will require significant upgrades to existing corridors and rapid development of new pathways for increased capacity to import carbon-free energy projects. Large-scale projects typically sited outside the Los Angeles Basin provide economies of scale, and geographical diversity. Efforts like the Strategic Transmission Plan will provide long-term transmission options for 2035 and 2045. The budgetary cost for the preliminary transmission system upgrades and new corridors has been captured during the planning process and include the potential options:



- Upgrade Century to Mead Corridor to 500 kV DC
- Fiber Optic Upgrade to Support Transmission Improvement
- Haynes to New Mexico Corridor 500 kV to DC and 500 kV AC Link
- LA Basin Transmission Upgrade
- STS Upgrade to 3,000 MW DC
- Marine DC cable from Haynes to Scattergood to Diablo Canyon

It is important to note that the abovementioned transmission projects are challenging and require a significant amount of coordination from other utilities.

5.1.10 Distribution System Development

To support the City's transition to a carbon-free future, LADWP's distribution system must undergo substantial modernization. Guided by the Power System Reliability Program (PSRP), these upgrades are essential to accommodate the growing demand from electrified homes, buildings, vehicles, and other end uses. As the grid evolves to become more decentralized and diverse, LADWP must invest in upgrading or replacing aging infrastructure, including substations, transformers, poles, voltage regulation equipment, and protection systems.

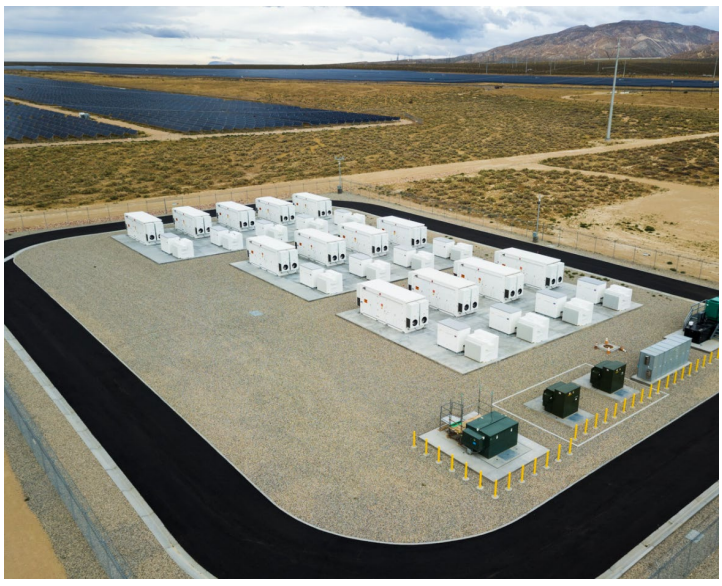
The increasing integration of behind-the-meter resources and the rapid growth of electric load from building and transportation electrification present new challenges to grid reliability and operational flexibility. These changes necessitate a more adaptive and resilient distribution network capable of managing bidirectional power flows and variable demand patterns. The financial requirements for addressing distribution system growth have been incorporated into the LA100 Plan. These investments will continue to be refined and evaluated in future planning cycles to ensure LADWP's distribution system remains reliable, resilient, and ready to meet the City's clean energy goals.

5.1.11 Electric Utility Rates

Significant investments must be made to achieve 100% carbon-free energy by 2035, and existing rate recovery mechanisms and methods may need to be adjusted to facilitate healthy financial growth and expand current capabilities to equitably provide enhanced programs and services to disadvantaged communities. The rigorous computational framework inherently built into the existing rate ordinances will need to be evaluated and optimized as LADWP closes the gap to 2035 and beyond. The rate comparisons in this LA100 Plan are subject to change as part of the budgetary review process but provides a sense of comparison among case scenarios and average retail electric rate increases year over year. The actual year to year increases may vary based on Power System expenditures.

5.1.12 Electrification

The main variable in setting electricity rates is the total number of sales in kilowatt-hours (kWh) to ultimate customers. There is an inherent inverse relationship with setting rates and the total number of retail electricity sales within the general process of fixed asset rate recovery. As electricity sales increase, the required unit cost of electricity to recover a fixed cost will decrease and vice versa. As electricity sales decrease, the required unit cost of electricity will increase. Considering this rudimentary example and relationship, it is



important that LADWP bolster its distribution system to foster and sustain healthy load growth. Although LADWP is planning for a high transportation electrification load growth, the actual realization of electrification and associated revenue recovery is an area of risk that needs careful consideration due to the uncertainty in customer adoption.

5.1.13 LADWP Staffing

LADWP will undergo an unprecedented transformation in infrastructure, technical resources, and human labor. Building the workforce of the future is actively underway. In the dynamic post pandemic (COVID-19) job market, it will be critical for LADWP to determine a competitive employee value proposition to hire, acquire, and retain talented, skilled workers. Additionally, LADWP must optimize the use of its labor resources and take advantage of growth opportunities through digital systems, modernized work processes, optimization technologies, and advanced tools (including both hardware and software). Preliminary budgetary estimates include approximately 2,500 to 3,000 additional positions to address existing system needs, PSRP revamp, load growth, and both LA100 and STP goals, which have been included in this LA100 Plan and will continue to be refined over time.

Another important risk to successful implementation of the LA100 Plan is the potential for workforce and staffing shortfalls. While the Resource Constrained Sensitivity did not explicitly model labor availability, it evaluated how delays in resource deployment—stemming from constraints in technology availability, permitting, or supply chains—could affect LADWP's ability to meet its clean energy targets. In this scenario, achieving 100% carbon-free energy was delayed from 2035 to 2040. A shortage of skilled staff to support planning, procurement, construction, and operations could lead to similar delays or cost overruns, effectively compounding these risks. This highlights the importance of aligning LADWP's workforce development strategies with the scale and urgency of the energy transition.


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Appendices

Appendix A - Load Forecast

Appendix A - Contents

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A.1 Overview

The 2023 Retail Sales and Demand Forecast (2023 Forecast) is a long-run projection of electrical energy sales, production, and peak demands for the City of Los Angeles (City) and Owens Valley. A flowchart of the forecast process is illustrated in Figure A-1. The following sections describe the four key components shown on the flow chart: data collection, sales and net energy for load (NEL) forecast, peak demand forecast, and hourly allocation.

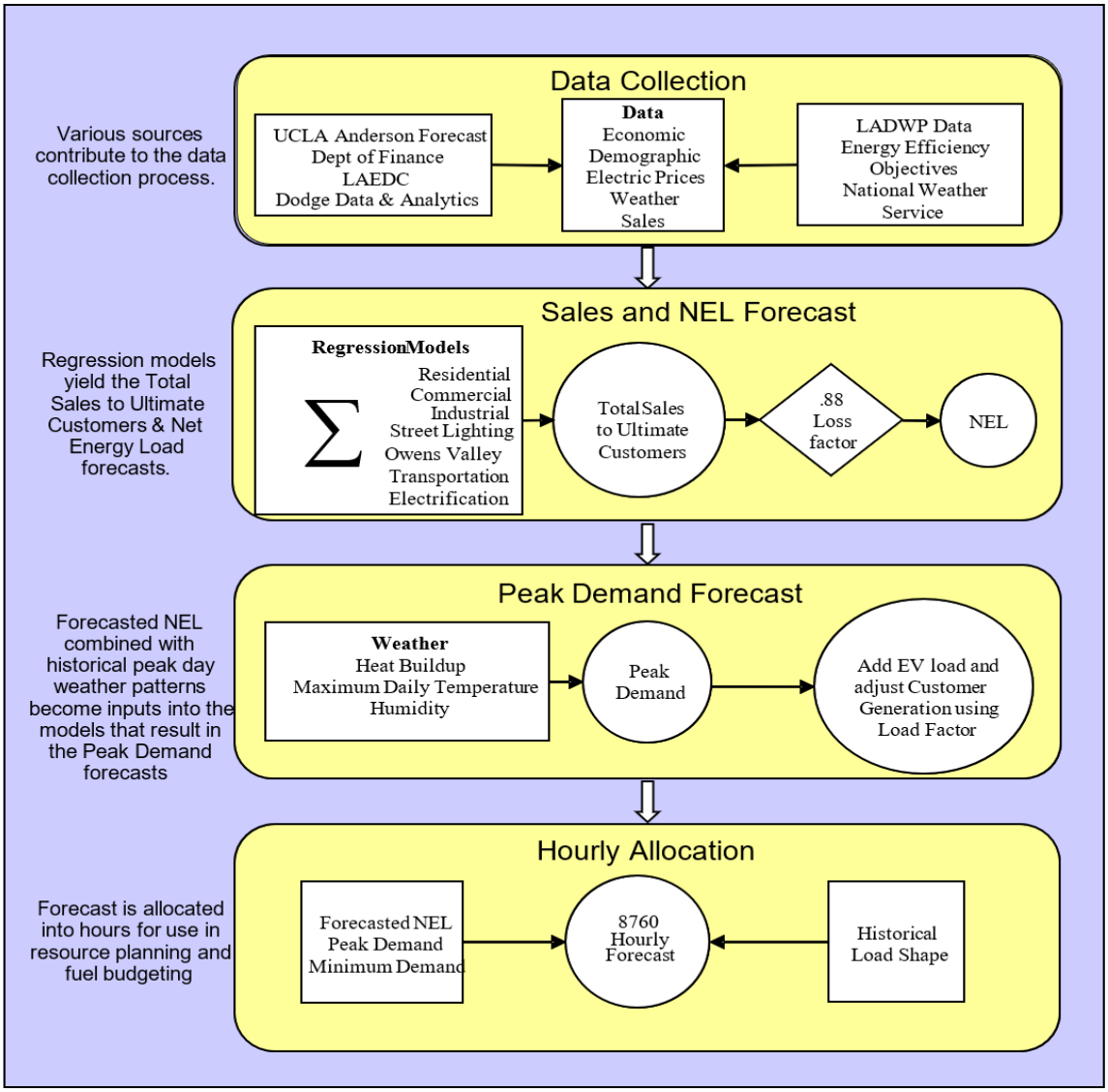


Figure A-1 Overview of the load forecasting process.

A.2 Data Collection

Data collection is the first step in the process. LADWP subscribes to an economic forecast of Los Angeles County from the Los Angeles Modeling Group of the University of California of Los Angeles (UCLA) Anderson Forecast Project. The Los Angeles County Forecast provides time series data for various demographic and economic statistics beginning with the year 1991 and continuing through the forecast horizon. For demographic history and projections, LADWP uses the State of California Department of Finance Demographic Research Unit. To gain further insight into development patterns, LADWP purchased a construction forecast from Dodge Data and Analytics, LLC (former McGraw-Hill Construction). The construction forecast gives a five-year view of construction projects detailed by building types. Weather also affects energy sales and demand. Weather data is collected from three key stations – Civic Center, Los Angeles Airport, and Woodland Hills. The other key components in the forecast are from LADWP's own internal data. Historical sales, net energy for load (NEL), billing cycles, electric price, and budget data are incorporated into the forecast. The economic, demographic, weather and electric price data provide key inputs to the models that forecast retail electric sales.

A.3 Sales and NEL Forecast

The Retail Sales Forecast is divided into six separate customer classes: residential, commercial, industrial, transportation electrification (TE), streetlight and Owens Valley. The residential, commercial, industrial, and streetlight classes are commonly used sales classes throughout the electric industry because they represent relatively homogeneous loads. In the past, we also had intradepartmental sales as a separate customer class. Intradepartmental sales are sales to the Water System and are primarily related to water pumping activities. Starting from the 2016 Forecast, intradepartmental sales are included in commercial sales due to Customer Care and Billing System (CCB) reclassification.
The California Energy Commission's 2013 Plug-in Electric Vehicle (PEV) forecast (with adjustment based on Power System's new electric vehicle input) has been adapted to the LADWP service area. Further, TE (former PEV) load is forecasted as a separate class, which will facilitate financial modeling due to the expected subsidies and production modeling as TE load has a unique load shape when compared to the residential class.

Owens Valley sales include all of the above sales classes. The Owens Valley service area is separate and discrete from the Los Angeles service area. Because of limited land available to be developed, Owens Valley sales exhibit very slow growth rates, and total sales are relatively small compared to total LADWP system sales. As a result, Owens Valley sales are rolled into a single class and forecasted separately.

The forecast model consists of five single equations plus the adapted TE forecast. For the residential, commercial, and industrial sales classes, the equations are estimated using generalized least squares regression techniques. Historical sales for each customer class are the dependent variables. Sales are regressed against a combination of the demographic, economic, weather, and electric price variables. Binary variables are used to account for extraordinary events such as earthquakes, civil disturbances, billing problems, the California Energy Crisis, and COVID-19 public health crisis. The equations fit historical data quite accurately, producing coefficients of determination (R-Squared) statistics greater than 80%. For the streetlight and the Owens Valley sales classes, time series trend models are used. The results of the five equations plus the TE forecast are summed to forecast Total Sales to Ultimate Customers (TSUC).

The Retail Sales Forecast represents sales that will be realized at the meter. The NEL forecast is a function of the sales forecast and is forecasted by adjusting annual forecasted sales upward by a historic average loss factor and allocating a portion of the annual energy to each calendar month based on historical proportions. Loss factor has the potential to change based on the way that the Power System is run. Electricity generated in distant places will have a higher loss factor than electricity generated locally. The change in loss factor is accounted for in resource planning models.

Energy efficiency savings include utility program savings and expected energy efficiency savings from the Huffman Bill lighting standards. Expected Huffman Bill energy efficiency savings rely on the Energy Efficiency Potential Study prepared in 2014 by Nexant. Planners using the 20231 Forecast should be aware of the potential changes and make appropriate adjustments. Forecasting self-generation, which currently is almost entirely focused on solar rooftops in the LADWP service area follows a process like energy efficiency. Planners working with energy efficiency and self-generation data should be careful to include only the incremental impacts of the programs on retail sales. In the Forecast, energy efficiency and self-generation savings are expected to occur uniformly throughout the year as a simplifying assumption.

A.4 Peak Demand Forecast

The next step is to forecast annual peak demand. The drivers for forecasted peak demand are temperature, load growth, and time of the summer. The temperature variable used in the estimation is the weighted-average of three weather stations and incorporates heat buildup effects and humidity. Temperature is then divided into splines using a unique megawatt-response per degree estimate for different levels of temperature. Ordinary least square regression techniques are used to model maximum weekday summer daily hourly demand against the temperature splines and the time of the summer. The constant that is estimated from the regression model is assumed to be the weather-insensitive demand at the peak hour. To forecast the peak demand, it is assumed that the peak will occur in August and that the peak day temperature is equal to the twenty-year historical mean peak day temperature. Peak demand then is assumed to grow at the same rate as sales.

The forecast process described above produces the trend (or base case) forecast. LADWP also produces alternative peak demand forecasts. LADWP wants to ensure that it can meet native demand with its own resources. System response to weather is uncertain. Temperature and humidity are the primary influences, but other variables such as cloud cover and wind speed can also influence the load. The problem is further complicated by the fact that LADWP serves three distinct climate zones including the Los Angeles Basin, the Santa Monica Bay Coast, and the San Fernando Valley. To prepare for these uncertainties, LADWP formulates its alternative cases by examining expected demands at different temperatures. Based on the Central Limit theorem, it is assumed that the normal distribution produces unbiased and efficient estimators of the true distribution of peak day temperatures. The normal distribution is estimated from the 20-year historical sample of peak day temperatures. From the normal distribution, the probability that the peak day temperature will be below a given temperature can be determined. For the One-in-Ten case, it is the given temperature where 90% of the time the actual peak day temperature is expected to be below it and 10% of the time the actual temperature will be above it. Similar calculations are performed for the One-in-Five and One-in-Forty cases. These temperatures are input into the peak demand regression model to provide alternative peak demand forecasts.

A.5 Hourly Allocation

The final step of the process is to forecast a monthly peak demand and load for each hour in the year. Monthly peak demands, outside of the August annual peak, are forecasted using the load factor formula. The historical average monthly load factor and the forecasted NEL for each month are the known inputs. To forecast load for each hour of the year, the Loadfarm algorithm developed by Global Energy is used. The inputs into Loadfarm are a historical system load shape, monthly forecasted energy, and monthly forecasted peak demand. The system load shape is developed using a ranked-average procedure permuting historical loads so that all peaks occur on the fourth Thursday in August. Table A-1 contains a summary of the 2023 Forecast.

Table A-1 2023 Load Forecast

Fiscal Year	SECTOR SALES Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	Electric Transportation (GWh)	Total Sales to Ultimate Customers (GWh)	Net Energy for Load (GWh)	Peak Demand (MW)
2010-11	8,068	12,428	2,189	378		23,062	26,258	6,142
2011-12	8,162	12,600	1,924	350		23,037	26,561	5,907
2012-13	8,441	12,844	1,947	315		23,548	27,152	5,782
2013-14	7,964	12,700	1,827	269		22,760	26,759	5,862
2014-15	8,145	12,913	1,720	240		23,018	26,688	6,343
2015-16	8,313	13,073	1,630	263		23,279	26,731	6,234
2016-17	8,099	12,550	1,591	251		22,490	26,460	5,762
2017-18	8,076	12,563	1,501	243		22,383	25,857	6,432
2018-19	8,160	12,350	1,225	227		21,961	25,046	6,201
2019-20	8,020	11,645	1,240	223		21,127	24,095	5,637
2020-21	8,523	11,074	1,031	210		20,838	23,781	6,110
2021-22	8,185	11,724	1,185	215		21,309	23,994	4,911
2022-23	8,443	11,763	1,122	219	65	21,611	24,683	6,216
2023-24	8,309	11,639	1,153	219	414	21,734	24,599	5,654
2024-25	8,239	11,397	1,149	221	569	21,574	24,608	5,727
2025-26	8,255	11,252	1,145	222	761	21,635	24,533	5,694
2026-27	8,138	10,887	1,143	223	990	21,380	24,233	5,700
2027-28	7,833	10,228	1,135	224	1,212	20,632	23,650	5,556
2028-29	7,727	9,880	1,127	225	1,448	20,406	23,233	5,415
2029-30	7,738	9,780	1,123	226	1,669	20,537	23,338	5,402
2030-31	7,766	9,686	1,119	227	1,927	20,726	23,569	5,443
2031-32	7,804	9,604	1,116	228	2,247	20,999	23,925	5,491
2032-33	7,863	9,546	1,112	229	2,521	21,272	24,173	5,563
2033-34	7,930	9,494	1,109	231	2,826	21,590	24,488	5,606
2034-35	7,969	9,425	1,105	232	3,096	21,826	24,849	5,657
2035-36	8,147	9,475	1,102	233	3,395	22,352	25,406	5,738
2036-37	8,219	9,446	1,098	234	3,671	22,667	25,806	5,861
2037-38	8,341	9,470	1,094	235	3,974	23,114	26,232	5,912
2038-39	8,448	9,490	1,090	236	4,268	23,532	26,778	5,996
2039-40	8,652	9,600	1,087	238	4,578	24,154	27,492	6,114
2040-41	8,820	9,690	1,083	239	4,889	24,722	28,095	6,254
2041-42	9,019	9,813	1,080	240	5,215	25,367	28,784	6,364
2042-43	9,205	9,915	1,076	241	5,547	25,984	29,555	6,492
2043-44	9,498	10,101	1,073	242	5,890	26,804	30,503	6,655
2044-45	9,774	10,270	1,069	244	6,244	27,600	31,358	6,846

Table updated through December 2022
Electric Transportation Sales before January 2023 included in Residential and Commercial Sales
Intradepartmental sales, historically included in Miscellaneous, are now included in Commercial sector

Annual Percent Change

1996-2010	1.38%	0.68%	-1.43%	0.74%		0.69%	0.75%	1.15%
2012-22	0.03%	-0.72%	-4.73%	-4.77%		-0.78%	-1.01%	-1.83%
2022-27	-0.12%	-1.47%	-0.72%	0.73%		0.07%	0.20%	3.03%
2022-32	-0.48%	-1.97%	-0.60%	0.61%		-0.15%	-0.03%	1.12%
2022-45	0.77%	-0.57%	-0.45%	0.55%		1.13%	1.17%	1.46%

Appendix B - Environmental Issues

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B.1 Overview

LADWP's mission includes a role as an environmentally responsible public agency. LADWP continues to develop and implement programs to improve the environment, including:

- Procuring additional renewable energy to meet the needs of LADWP customers and achieve California's Renewable Portfolio Standard targets (20% by December 31, 2010, 33% by December 2020, and 60% by December 2030) through the development of wind, solar, and geothermal energy sources and acquiring the associated transmission rights to deliver the renewable energy to Los Angeles.

- Prioritizing the use of Energy Efficiency (EE), Demand Side Management (DSM), renewable Distributed Generation (DG), energy storage, and other local resources.

- Continuing the modernization of LADWP's in-basin generating stations, including the replacement of four older, less-efficient utility steam boiler units with advanced hybrid energy generating units capable of running on clean, renewable fuel.

This appendix provides information on a number of environmental issues and policies including oxides of nitrogen (NOX), greenhouse gases (GHGs), climate change, power plant once-through cooling (OTC), and mercury emissions.

B.2 Emissions of Oxides of Nitrogen (NOx)

Oxides of nitrogen (NO_X), is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. NO_X forms when fuel is burned at high temperatures, as in a combustion process. NOx emissions are a precursor to the formation of ground level ozone. The South Coast Air Basin (SCAB), in which Los Angeles is situated, is in non-attainment with the federal ozone standard so is implementing various measures to reduce NOx emissions.

The U.S. Environmental Protection Agency (EPA) first set federal standards for nitrogen dioxide (NO_2) in 1971, setting both a primary standard (to protect health) and a secondary standard (to protect the public welfare) at 0.053 parts per million (53 ppb), averaged annually. In 2007, the California Air Resources Board (CARB) lowered the state's one-hour standard for NO_2 to 0.18 parts per million and retained the state's annual average standard of 0.030 parts per million. In 2010, the U.S. EPA established a new 1-hour federal standard at a level of 0.100 parts per million (100 ppb) to supplement the existing annual standard.

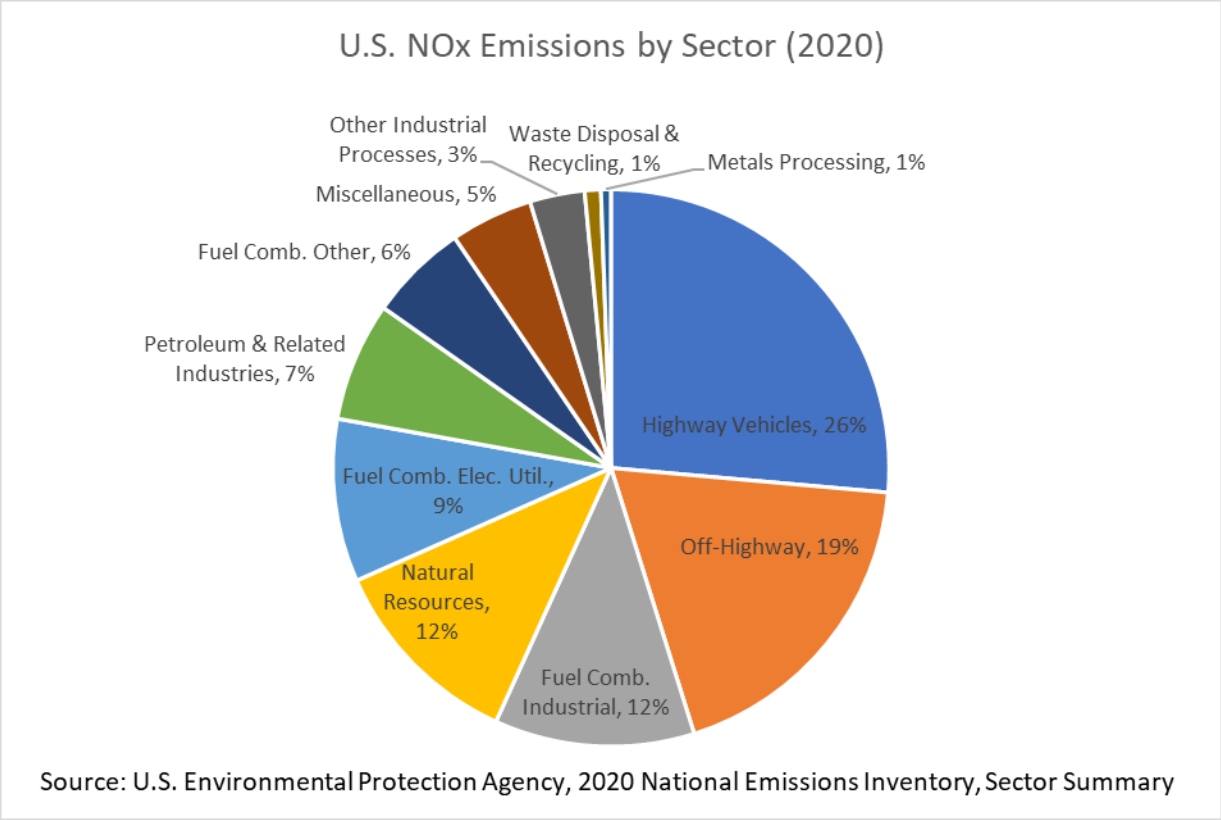


Figure B-1 Sources of NOX emissions in the United States in 2020.

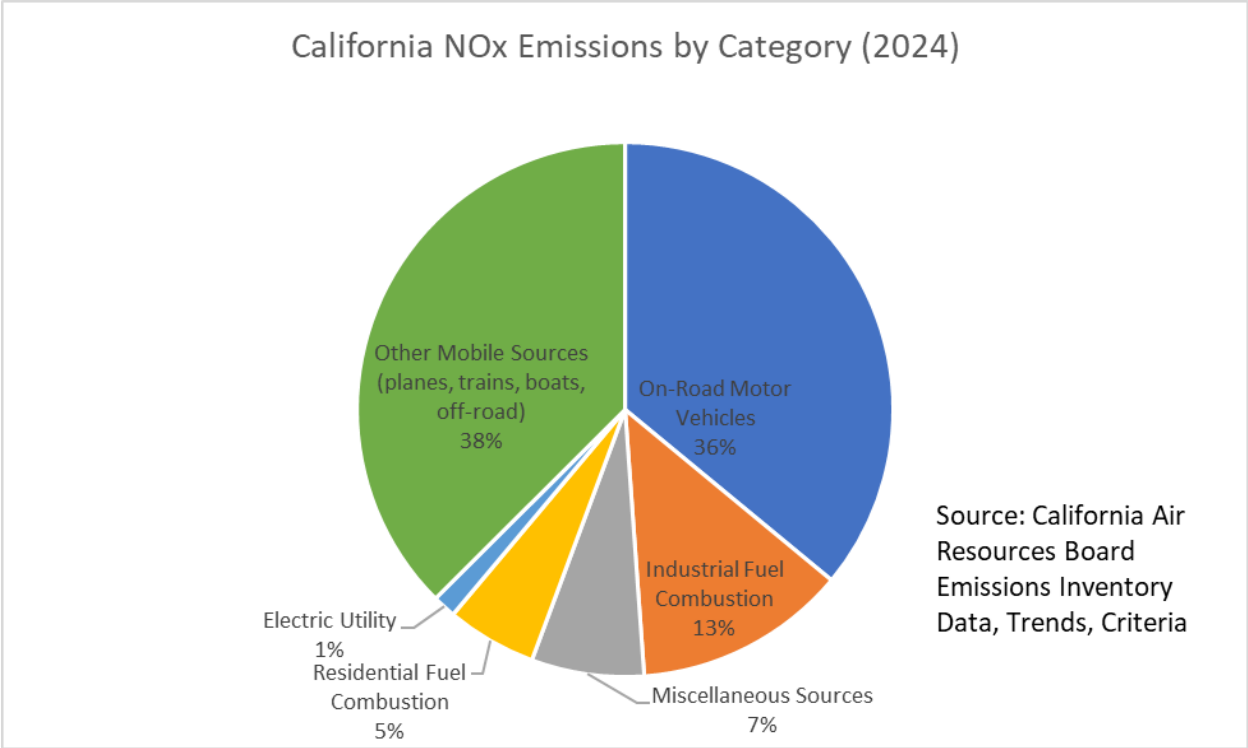


Figure B-2 Statewide NOx Emissions by Sector in 2024.

The South Coast Air Basin (which includes Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties) has some of the worst air quality in the United States due in part to the level of NO_X emissions. The majority of NO_X emissions result from mobile sources such as on-road and off-road vehicles, and not stationary sources such as power plants. A breakdown of NOx emissions by sources and sectors can be seen in Figure B-1 through Figure B-3.

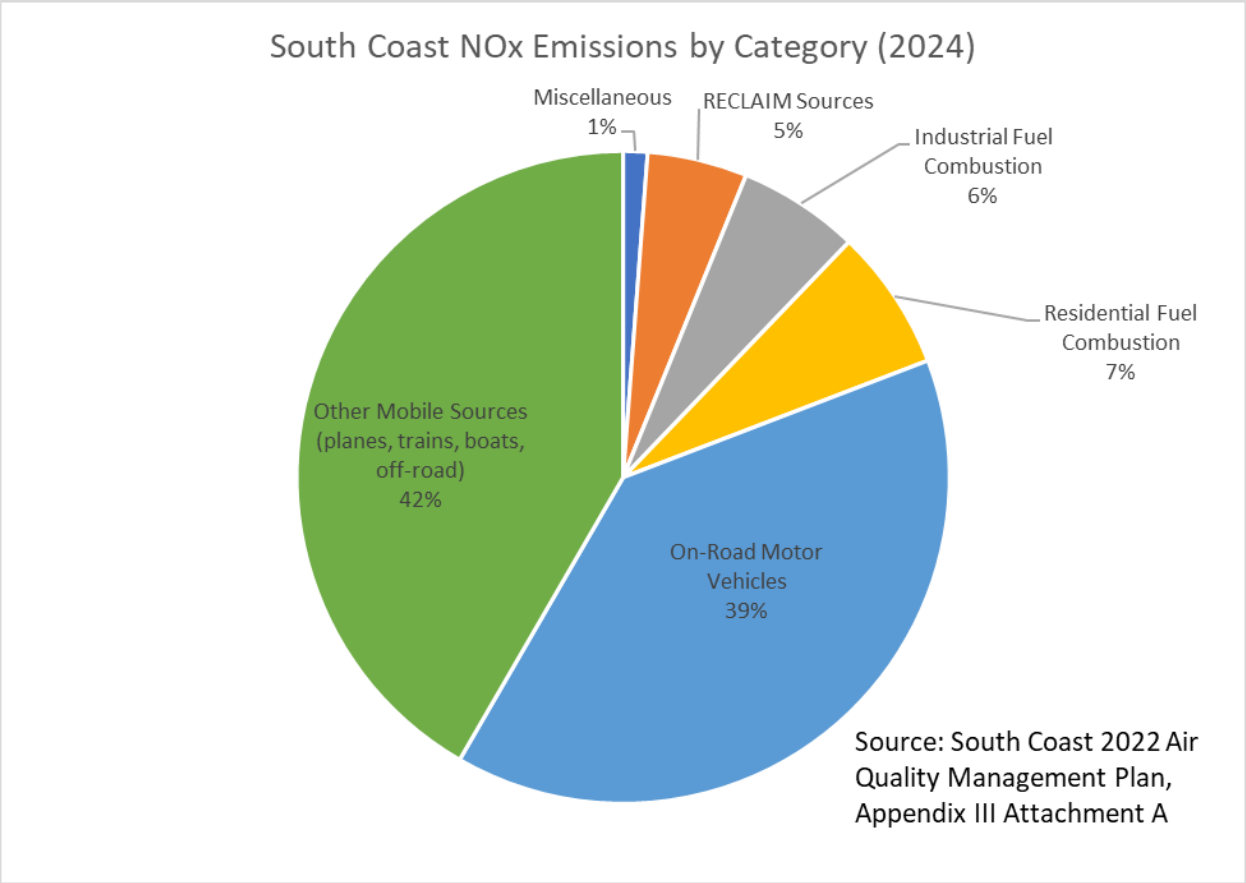


Figure B-3 Sources of NOX Emissions in the South Coast Air Basin in 2024.

In its 2022 draft Air Quality Management Plan (AQMP), the South Coast Air Quality Management District (SCAQMD) emissions inventory shows the average annual NOx emissions were 347 tons per day in 2018. SCAQMD projects that average annual NO_X emissions in the South Coast Air Basin will decrease to 220 tons per day in 2037. SCAQMD states that without any additional control measures, NOx emissions are expected to decrease as a result of existing SCAQMD and CARB regulations, such as controls for on- and off-road equipment and new vehicle standards. The biggest contributor to total NOx emissions is mobile sources. On-road contributions will decrease from 46% in 2018 to 28% in 2037. However, off-road source contributions will increase from 40% to 55%.

For comparison, the combined daily NO_X emissions from LADWP's in-basin generating stations (Harbor, Haynes, Scattergood, and Valley) were 0.58 tons of NO_X per day in 2018, which represents 0.18% of the 2018 average daily NO_X emissions in the South Coast Air Basin. The low NO_X emissions from LADWP's in-basin generating stations are

due to the use of natural gas, which characteristically has low nitrogen content, and advanced NO_x emission control systems on all of LADWP's generating units.

A key regulation employed by the SCAQMD to reduce NO_X emissions from stationary sources is the Regional Clean Air Incentives Market (RECLAIM) trading program. RECLAIM is a market-driven regulatory program started in 1994 that replaced the SCAQMD's "command and control" rules for facilities with NO_X emissions exceeding 4 tons per year. The "command and control" rules which limited the emission rates of stationary combustion equipment were replaced by a facility wide- emissions cap, which gradually declines each year. Facilities received emission allocations, called RECLAIM Trading Credits (RTCs), in which one credit grants the right to emit one pound of NO_X. Facilities must have sufficient RTCs in their RECLAIM facility accounts to cover their actual emissions each year. RECLAIM is a market-driven program because the RTCs can be purchased and sold, which creates an incentive to reduce emissions in the most cost-effective manner.

Despite achieving significant improvements in air quality over the past 20 years, the South Coast Air Basin still exceeds the federal public health standards for both ozone and particulate matter. The SCAQMD's 2016 AQMP laid out several strategies to reduce emissions and bring the area into attainment with federal standards. The AQMP focused on targeting NO_x emissions, as they are a precursor to the formation of ground level ozone, one of the non-attainment pollutants. The AQMP also emphasized reducing emissions from mobile sources, which is the principal contributor to air quality challenges. Additionally, the AQMP outlined key regulations to transition vehicles, buildings, and industrial facilities to use cleaner technologies. To comply with the directives outlined in the 2016 AQMP, SCAQMD engaged in several rulemaking processes to control sources, and amended existing rules to decrease emission limits. SCAQMD's 2022 AQMP laid out the strategy to meet the US EPA National Ambient Air Quality Standards (NAAQS) for ground-level ozone, which was lowered to 70 parts per billion (ppb).

SCAQMD's 2022 AQMP includes emissions reduction goals with strategies to accelerate deployment of available cleaner technologies, best management practices, and co-benefits from existing programs to bring the area into attainment with the federal standards. According to the 2022 AQMP, emissions of NO_x must be reduced by 67% beyond what will be achieved through current programs by 2037 to meet the federal standard. SCAQMD anticipates having to rely on the most stringent methods possible for sources they can regulate, and will also have to rely on "black box" measures. "Black box" measures are projections of future control measures that must be created to meet the

standard, and can include development and deployment of future technologies and reduction of NO_x from sources regulated by the federal and state governments. In fact, only 20% of NO_x reductions are anticipated to come from SCAQMD regulated sources. The remaining 80% will come from federal and state regulated sources.

Areas of concern to LADWP include measures targeting emergency engines, electric utility stationary gas turbines, boilers and diesel internal combustion engines, and solvents and coatings. SCAQMD has initiated rulemaking for several of these categories, including the transition of gas-powered water heaters and boilers to electric by 2029. Additionally, SCAQMD is lowering VOC limits for solvents and coatings. LADWP will continue to provide feedback on these provisions to ensure that facility operations remain feasible and compliant with SCAQMD's requirements.

In December 2015, the SCAQMD amended the RECLAIM regulation to reduce NO_x emissions 12 tons per day by year 2022. In March 2017 as part of the 2016 AQMP, the SCAQMD adopted Control Measure CMB-05 to assess reducing NOx emissions an additional 5 tons per day no later than 2025, in addition to sunsetting the RECLAIM program and transition back to a command-and-control regulatory structure requiring best available retrofit control technology (BARCT) level controls as soon as practicable.

To transition electric generating facilities out of the RECLAIM program, SCAQMD amended Rule 1135 (Emissions of Oxides of Nitrogen from Electricity Generating Facilities) on November 2, 2018. Under this regulation, SCAQMD adopted NO_x concentration limits for combined cycle and simple cycle gas turbines and boiler units, with a compliance date of January 1, 2024. The rule was amended again on January 7, 2022 to remove ammonia limits. Concurrently, Rule 429.2 (Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities) was adopted to incorporate start-up and shut-down procedures and limits for electric generating units after exiting RECLAIM. Rules 218.2 and 218.3 (Continuous Emission Monitoring Performance Specifications and General Provisions) are also in development to address monitoring, recordkeeping, and reporting requirements for facilities after they exit RECLAIM.

All of LADWP's electricity generating units are equipped with advanced pollution control equipment which reduce NO_X emissions by at least 90%. All of LADWP's units have been in compliance with the NOx concentration limits and requirements under Rule 1135 since the effective date of January 1, 2024.

While the sunset date for the RECLAIM Program was initially scheduled for January 1, 2024, which would coincide with the Rule 1135 compliance date, SCAQMD has not made significant progress toward phasing out the RECLAIM program. The end of the RECLAIM Program is contingent on SCAQMD obtaining EPA's approval of SCAQMD's proposed post-RECLAIM command-and-control landing rules and overall approach in aligning with the New Source Review and State Implementation Plan requirements. LADWP will continue monitoring the rulemaking process closely once SCAQMD resumes their working groups.

In December 2024, EPA published a proposed rule setting new source performance standards for stationary combustion turbines and gas turbines. The best system of emission reduction was determined to be combustion controls such as selective catalytic reduction systems. The proposed rule includes a NOx emission limit as low as 3 ppm for large natural gas units operating at higher loads. LADWP units, however, are already subject to and are in compliance with lower emission limits.

B.3 Greenhouse Gas Emissions and Climate Change

This section describes efforts related to greenhouse gas emissions and climate change.

B.3.1 Federal Efforts to Address Climate Change

This section focuses on federal efforts to address climate change.

B.3.1.1 Federal Regulation of Greenhouse Gases Under the Clean Air Act

In the absence of federal legislation to regulate GHG emissions, GHG emissions may still be regulated by the U.S. EPA through its authority under the Clean Air Act. In April 2007, the Supreme Court ruled in *Massachusetts vs. EPA* that the U.S. EPA must make a determination regarding the regulation of motor vehicle emissions. The Supreme Court ruling provided the U.S. EPA with the authority to regulate GHGs under the Clean Air Act for mobile and stationary sources. On December 7, 2009, the U.S. EPA administrator signed two distinct findings regarding GHGs under section 202(a) of the Clean Air Act:

- Endangerment Finding: The administrator found that the current and projected concentrations of the six key well-mixed GHGs--carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)--in the atmosphere threaten the public health and welfare of current and future generations.

- Cause or Contribute Finding**:** The administrator found that the combined emissions of these well-mixed GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG emissions which threaten public health and welfare.

In 2010, the Environmental Protection Agency finalized its "Tailoring Rule," which establishes a phased timetable for implementing Clean Air Act permitting requirements for GHG emissions from major stationary sources. Construction or modification of major sources would become subject to Prevention of Significant Deterioration (PSD) requirements for their GHG emissions if the construction or modification results in a net increase in GHG emissions exceeding a certain threshold of tons per year on a CO_2e basis. In June 2014, the U.S. Supreme Court held that the Clean Air Act does not permit EPA to adopt an interpretation of the act requiring a source to obtain a PSD or Title V operating permit on the sole basis of its potential GHG emissions. The court also held that EPA reasonably interpreted the Clean Air Act to require sources that would need permits based on their emission of conventional pollutants to comply with best available control technology (BACT) for GHG emissions.

In effect, EPA's ability to regulate GHG emissions under BACT is limited to new or modified sources that emit more than a *de minimis* amount of GHG emissions. A new rulemaking is needed in order to establish a *de minimis* threshold for GHG emissions. The new electricity generating units that will be installed to replace older generating units at LADWP's in-basin power plants as part of LADWP's current and future modernization projects will be subject to GHG regulation under BACT since they are "anyway" sources.

On October 23, 2015, the EPA issued the Clean Power Plan under Section 111(d) of the Clean Air Act. The Clean Power Plan is also known as the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units rule. The goal of the Clean Power Plan is to reduce CO_2 emissions from existing power plants 32% from 2005 levels by 2030, with incremental interim goals for years 2022 through 2029. The Clean Power Plan set a CO_2 emission reduction target for each state and required each state to develop a plan to achieve the target. At the same time EPA issued the Carbon Pollution Standards for New, Modified and Reconstructed Power Plants rule under

Section 111(b) of the Clean Air Act, to limit CO_2 emissions from new, modified, or reconstructed electricity generating units by implementing the best system of emissions reduction (BSER) for each type of generating unit.

Shortly after being finalized, the Clean Power Plan was challenged in the United States Circuit Court of Appeals for the District of Columbia by 150 entities (including 27 states, 24 trade associations, 37 rural electric co-ops, and 3 labor unions), citing legal and technical concerns. The United States Supreme Court stayed implementation of the Clean Power Plan on February 9, 2016 for a period of time until the D.C. Circuit renders a decision and the Supreme Court concludes any proceedings brought before it. On October 10, 2017, the U.S. EPA issued a proposed rule to repeal the Clean Power Plan, based on a legal determination that the rule exceeds EPA's authority under Section 111 of the Clean Air Act. At the same time, EPA issued an advance notice of proposed rulemaking to solicit input for a replacement rule. The rationale for the repeal is based on the Clean Power Plan relying on measures that extend beyond the fence line of the power plant facility to reduce emissions, when traditionally, rules issued under Section 111 have been based on measures that can be implemented inside the fence line.

With the Clean Power Plan on hold, states were not required to submit initial plans and the U.S. EPA could not take any action with regards to any state compliance plans. Nevertheless, California chose to develop its proposed Compliance Plan for the Federal Clean Power Plan, which was adopted by the California Air Resources Board on July 27, 2017.

On July 8, 2019, the EPA issued final new regulations entitled the "Affordable Clean Energy (ACE) Rule" to replace the Clean Power Plan. On January 19, 2021, upon a challenge by a number of environmental advocates, state and municipal attorneys, and a coalition of power utilities that included the LADWP, the D.C. Circuit vacated the ACE Rule, declaring that the ACE Rule and the repeal of the Clean Power Plan hinged on a fundamental misconstruction of section 111 (d) of the Clean Air Act. The D.C. Circuit concluded that the ACE Rule rests on the erroneous legal premise that acceptable emission reduction measures are only limited to those that apply at and to the individual source. By June 2021, petitions for certiorari were filed to review the D.C. Circuit's decision to vacate and remand the ACE Rule. On October 29, 2021, the U.S. Supreme Court granted certiorari to petitioners from states such as West Virginia and coal companies challenging EPA's authority to regulate GHG emissions from power plants. During the oral arguments on February 28, 2022, the petitioners challenged EPA's authority to include outside-the-fence line measures such as emissions trading and

generation shifting in emission standards based on BSER, citing that this is of "vast economic and political significance" and without explicit congressional authority.

On June 30, 2022, the Supreme Court ruled in favor of the petitioners in the West Virginia v. EPA case, citing the Major Questions doctrine and indicating that Congress did not grant EPA, under section 111 (d) of the Clean Air Act, explicit authority to devise emissions caps based on the generation shifting approach which ultimately resulted in the push from coal to natural gas and other lower emitting sources such as renewable energy. The court did not comment on the previous administration's inside-the-fence line interpretation of the Clean Air Act under the ACE Rule but confirmed that harmful emissions may be regulated under Section 111 (d). Therefore, the precedent established in Massachusetts v. EPA in which the Supreme Court upheld EPA's authority to regulate GHG emissions remains unchanged. With the reversal of the D.C. Circuit's decision, the Supreme Court remanded the case to the lower court.

On August 16, 2022, President Biden signed the Inflation Reduction Act, which expanded tax credits for carbon capture and hydrogen (as a fuel), changing the cost considerations for these technologies as a potential basis for BSER. On May 11, 2023, EPA proposed GHG emission standards for new gas-fired power plants and existing coal- and gas-fired power plants, and issued its final 111(d) rule implementing regulations for existing sources on November 9, 2023. On May 9, 2024, EPA published the final GHG emission standards for existing coal-fired power plants and new gas-fired power plants. Known as the Power Plant Rule or Clean Power Plan 2.0, the rule includes stringent emission standards that are based on carbon capture and sequestration/storage (CCS) as the BSER. During the summer of 2024, several motions were filed to stay the rule. On October 16, 2024, the Supreme Court denied petitioners' application for a stay of EPA's rule, and the D.C. Circuit heard oral arguments in December 2024. On February 5, 2025, EPA filed a motion to hold the case in abeyance for 60 days "to allow new Agency leadership to review the underlying rule." The motion was granted on February 19, 2025. Because both the D.C. Circuit and the U.S. Supreme Court declined to stay the rule, it remains in effect until EPA repeals it.

On March 12, 2025, EPA Administrator Lee Zeldin announced the agency's plans to undertake 31 historic deregulatory actions to advance the goals of President Trump's Executive Order: "Unleashing American Energy". These deregulatory actions include the reconsideration of Clean Power Plan 2.0 and the reconsideration of the 2009 endangerment finding which essentially codified EPA's finding that GHGs endanger public health, therefore giving EPA authority to regulate GHGs under the Clean Air Act.

These deregulatory actions represent a remarkable shift away from the last administration and even the positions of the last Trump Administration. The announcement was also light on detail, and it is not yet clear whether the Trump Administration intends to revise some of the identified rules or eliminate them entirely. Further clarification is anticipated as Zeldin continues to redirect EPA in line with the current administration's priorities and as EPA begins taking concrete action.

EPA faces scientific and legal barriers to challenging the endangerment finding. Any decision against the findings would be immediately challenged in court. The findings have been upheld against various legal challenges over the years, with the Supreme Court declining to hear challenges to it as recently as December 11, 2023. Nevertheless, recent landmark decisions in the Supreme Court (i.e. *Loper Bright* case) have demonstrated a willingness to deviate from precedent in matters of environmental regulations and otherwise. If challenged, these potential legal proceedings will present opportunities for engagement for environmental and industry groups to file amicus briefs or join likely challenges from Democratic states.

B.3.2 California Efforts to Address Climate Change

This section presents an overview of California's GHG emissions inventory and trends from 2000 through 2022. The 2024 edition of California's GHG emissions inventory was released in September 2024. It includes GHG emissions estimates for years 2000 to 2022.

Figure B-4 shows the trend in California GHG emissions from 2000 to 2022 by economic sector.

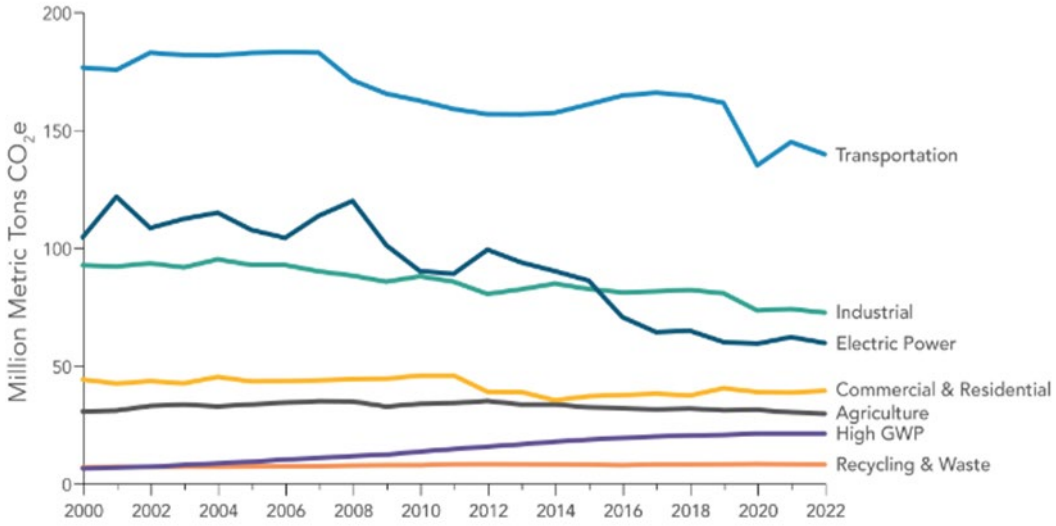


Figure B-4 Trends in California GHG Emissions by Category as Defined in the Scoping Plan. Source: California Air Resources Board GHG Emissions Inventory trends report

As California strives to achieve its GHG emission reduction goals, the California GHG emissions inventory is the tool to track statewide GHG emissions and progress towards the GHG emission reduction target. In 2007, CARB adopted 427 MMT CO_2e as the 1990 statewide GHG emissions baseline and 2020 emission reduction target. The baseline limit was revised in 2014 using the updated global warming potential in the Intergovernmental Panel on Climate Change Fourth Assessment Report. The GHG emission reduction target is now 431 MMT CO_2e. According to the 2024 edition of California's GHG emissions inventory, 2022 California GHG emissions were 371.1 million metric tons of carbon dioxide equivalent (MMT CO_2e), which is 60 MMT CO_2e below the 2020 GHG limit of 431 MMT CO_2e and 112.5 MMT CO2e above the 2030 GHG emission reduction target of 258.6 MMT CO2e based on the Senate Bill 32 (40% below the 1990 statewide GHG emissions baseline by 2030). Since the peak level in 2004, California's GHG emissions have generally followed a decreasing trend. In 2016, statewide GHG emissions dropped below the 2020 GHG limit and have remained below the limit since that time.

Figure B-5 shows California's 2022 statewide GHG emissions inventory by sector.

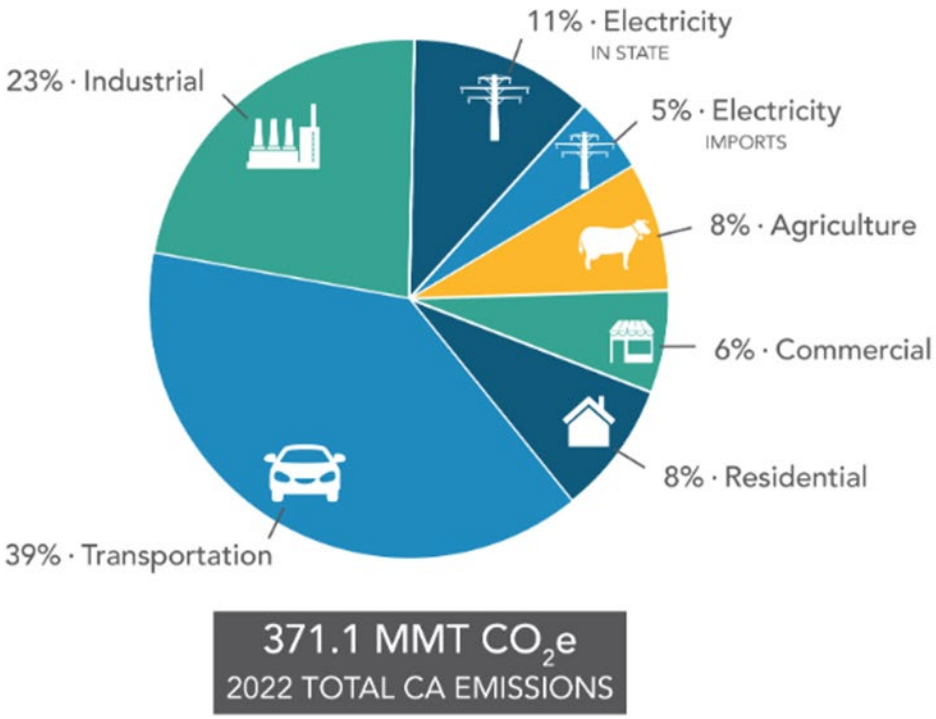


Figure B-5 California GHG Emissions by Sector in 2022. Source: California Air Resources Board GHG Emissions Inventory

In 2022, 16% of California's GHG emissions were from generating electricity to serve load in California. This portion of the statewide GHG emissions inventory consists of electricity production at in-state facilities plus electricity imported from generating resources located outside of California. The overall trend in GHG emissions from electricity is declining due to the requirement that California retail electricity providers procure increasing amounts of renewable electricity to comply with California's Renewable Portfolio Standard target (60% by 2030).

Figure B-6 shows the trends in GHG emissions from in-state and imported electricity from 2000 to 2022.

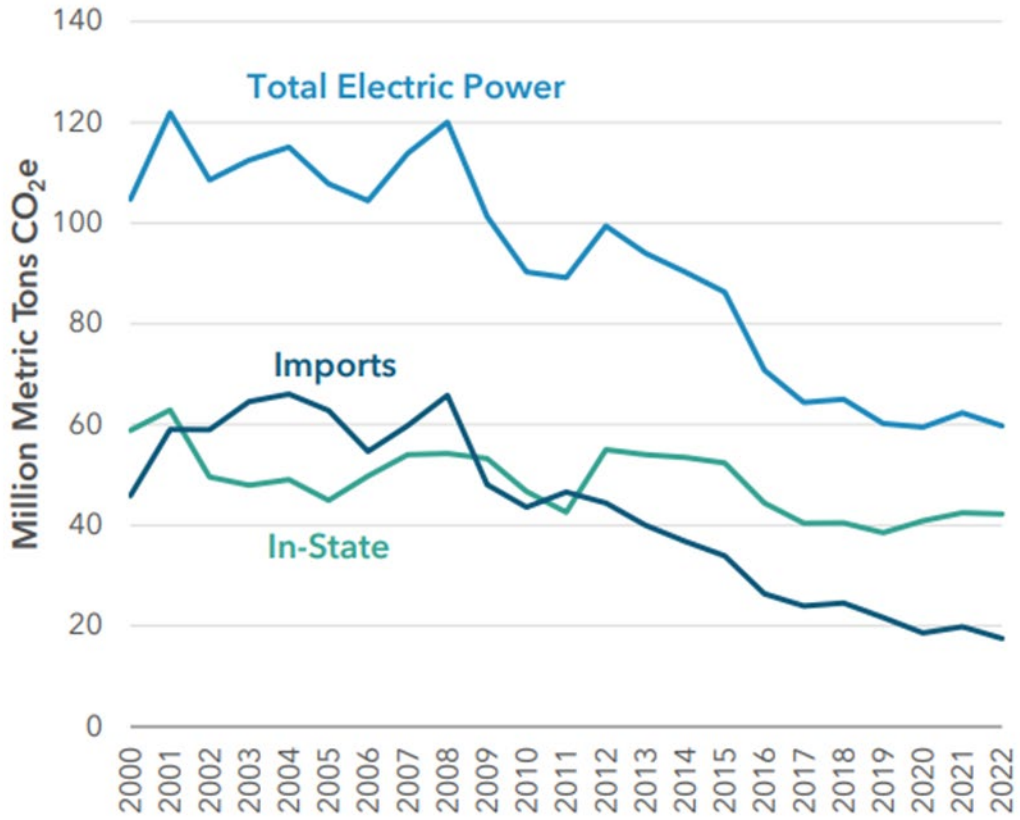


Figure B-6 Trends in Electric Power GHG Emissions. Source: California Air Resources Board GHG Emissions Inventory trends report

B.3.2.1 California SB 1368: Greenhouse Gas Emissions Performance Standard

Senate Bill (SB) 1368 was signed into law on September 29, 2006 and requires the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to establish a GHG emissions performance standard and implement regulations for all long-term financial commitments in baseload generation made by load serving entities (LSEs) including local publicly-owned electric utilities (POUs). The CPUC adopted its regulations for the investor-owned utilities and other LSEs in January 2007. The CEC adopted similar regulations for POUs in August 2007. The CEC's regulations established a GHG emissions performance standard of 1,100 pounds (0.5 metric tons) of CO_2 per megawatt hour (MWh) of electricity generated, based on the

emissions profile of combined-cycle, natural gas fired generating units. This standard was established in consultation with the CPUC and the CARB and is the same as the emissions performance standard adopted by the CPUC for the LSEs.

The broad objectives of these regulations are to internalize the significant and under-recognized cost of emissions and to reduce potential financial risk to California consumers for future emission control costs. Specifically, these regulations are intended to prohibit any LSE from entering into or renewing a long-term financial commitment for baseload generation that exceeds the GHG emissions performance standard.

These regulations would require POUs, within 10 days of making a long-term financial commitment in a baseload facility, to certify to the CEC that such a commitment complies with these regulations and provide back-up material to support such commitment. The regulations then provide for CEC review of these compliance filings and a determination of whether or not the commitment, and the underlying facility as described in the commitment, complies with these regulations. Additionally, the CEC may open an investigatory proceeding and gather additional information if it believes that covered procurements made by a POU do not comply with these regulations.

At its December 14, 2011 business meeting, the CEC granted a petition to "initiate a new rulemaking proceeding to ensure that the current practices of California POUs meet the requirements of SB 1368 and California's Emissions Performance Standards" specifically as it relates to three coal-fired power plants, including the San Juan Generating Station, Navajo Generating Station, and the Intermountain Power Project. The Commission directed Commission Staff to prepare an order instituting rulemaking (OIR) that encompassed the various issues raised by the petitioners and other stakeholders.

At its January 12, 2012 business meeting, the Commission adopted OIR 12-0112-7, which initiated a proceeding to discuss, and if warranted, implement possible changes to the Emissions Performance Standard (EPS) regulations.

The CEC issued a proposed final decision on April 5, 2013 with modifications to the EPS regulations. In June 2014, the CEC adopted amendments to the EPS regulation which modified Section 2908 (Public Notice) to require local publicly owned electric utilities to notify the CEC and all persons on the CEC's master contact list (for notification of POU investments) of the posting of notice for a public meeting to consider a covered procurement or any investment of $2.5 million or more at a non-EPS compliant baseload

facility to meet environmental regulatory requirements. The notification requirement also applies when information is distributed to a POU's governing body related to a covered procurement or investment of $2.5 million or more. In addition, the CEC added a new requirement that a POU file an annual notice within 10 days of the POU's approval of the annual budget for the non-EPS compliant baseload facility, with a list of anticipated investments of $2.5 million or more within the subsequent 12 months at the facility to meet environmental regulatory requirements, as well as any such investments made in the previous 12-month period not included in the previous annual notice. Investments of $2.5 million or more to meet environmental regulatory requirements at a non-EPS compliant facility that are not also covered procurements are not subject to the compliance filing requirement or compliance review.

In 2018, LADWP submitted a compliance filing requesting that the CEC find that the procurement for the Intermountain Power Project Renewal Project be determined to be compliant with the GHG EPS. The CEC approved their staff's recommendation that the project complies with the Standard on November 7, 2018.

B.3.2.2 AB 32: The California Global Warming Solutions Act of 2006

In 2006, the California Legislature passed and Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006, which declared that global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of California. It set into law a goal to reduce statewide GHG[1] emissions back to the 1990 level by 2020.

In 2007, the CARB established a GHG emission limit for year 2020, equivalent to the 1990 statewide GHG emissions baseline of 427 million metric tons of carbon dioxide equivalent (MMT CO_2e). CARB also adopted a regulation for mandatory reporting of GHG emissions from the most significant sources that contribute to statewide emissions, including all electricity consumed in the state as well as imported electricity. In 2014, the 2020 limit was revised to 431 MMT CO_2e using the updated global warming potential in the Intergovernmental Panel on Climate Change Fourth Assessment Report.

[1] GHGs covered by AB 32 include the following: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

B.3.2.3 The AB 32 Scoping Plan

AB 32 requires CARB to develop and approve a Scoping Plan, which serves as California's roadmap for reducing GHG emissions to 1990 levels by 2020. In December 2008, the CARB adopted the Initial AB 32 Scoping Plan. Key elements of the AB 32 Scoping Plan's recommendations for reducing California GHG emissions to 1990 levels by 2020 include:

- Expanding and strengthening existing energy efficiency programs as well as building and appliance standards.
- Achieving a statewide renewable energy mix of 33%.
- Developing a California cap-and-trade program to ensure the target is met, while providing flexibility to California businesses to reduce emissions at the lowest cost.
- Establishing targets for transportation-related GHG emissions for regions throughout California, and pursuing policies and incentives to achieve those targets.
- Adopting and implementing measures pursuant to existing State laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard.

In May 2014, CARB adopted the first update to the AB 32 Scoping Plan. The 2014 Scoping Plan Update describes progress made to meet the near-term objectives of AB 32 and establishes California's climate change priorities and activities over the next several years. It also identifies activities and issues facing California as it develops an integrated framework for achieving climate goals and federal clean air standards in California beyond 2020.

In December 2017, CARB adopted the second update to the Scoping Plan titled *Strategy for Achieving California's 2030 Greenhouse Gas Target*. The 2017 Scoping Plan Update identifies how the State can reach the 2030 climate target to reduce GHG emissions by 40% from 1990 levels, and substantially advance toward the 2050 climate goal to reduce GHG emissions by 80% below 1990 levels.

In June 2021, CARB started holding public workshops to develop the 2022 Scoping Plan Update, which assesses progress toward the statutory 2030 target of reducing GHG emissions at least 40% below 1990 levels by 2030, while laying out a path to achieving

carbon neutrality no later than 2045. This is the first scoping plan that adds carbon neutrality as a goal beyond the statutorily established emission reduction targets and is focused on the state's long-term climate objectives. It identifies a path to achieve carbon neutrality by expanding actions to capture and store carbon including through natural and working lands and mechanical technologies, while drastically reducing anthropogenic sources of carbon pollution including emissions from mobile sources. The initial draft of the 2022 Scoping Plan Update was presented to the Board at its June 2022 meeting. In July 2022, Governor Newsom wrote a letter to CARB "requesting that the final plan incorporate new efforts to advance offshore wind, clean fuels, climate-friendly homes, carbon removal and address methane leaks". In response to the Governor's request and legislation in the Governor's climate legislation package, CARB updated the modeling and revised the draft 2022 Scoping Plan Update. CARB also consulted with the Environmental Justice Advisory Committee (EJAC) regarding the 2022 Scoping Plan Update. The final proposed plan includes changes requested by the Board and the EJAC, and guidance from Governor Newsom. It also reflects direction from Assembly Bill 1279. The final proposed 2022 Scoping Plan was approved at CARB's Board meeting on December 15, 2022. The 2022 Scoping Plan is considered an unprecedented climate action plan to cut greenhouse gas emissions by 85% and achieve carbon neutrality in 2045. It provides a detailed sector-by-sector roadmap to guide California away from its current dependence on fossil fuels to clean and renewable energy resources and zero-emission vehicles. The plan includes an accelerated target of a 48% reduction of greenhouse gas emissions below 1990 levels by 2030. It also aims to reduce fossil fuel demand by 94%, reduce smog-forming pollution by 71%, create 4 million new jobs, and save Californians $200 Billion in health costs due to pollution by 2045. The updated modeling also includes 3 million climate-friendly homes by 2030 (and 7 million by 2035), 6 million heat pumps deployed by 2030, no new fossil gas capacity in the electricity sector, and 20 gigawatts of offshore wind capacity by 2045.

B.3.2.4 Executive Order S-21-09

On September 15, 2009, Governor Schwarzenegger signed Executive Order S-21-09, which, among other things, ordered CARB to work with the state energy commissions to ensure that a regulation adopted under authority of AB 32 to encourage the creation and use of renewable energy sources shall build upon the RPS program, developed to reduce GHG emissions in California and shall regulate all California publicly owned utilities, such as LADWP. In addition, Executive Order S-21-09 provides that CARB may delegate policy development and implementation to the commissions, that CARB is to

consult with the CAISO and other balancing authorities on impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of Executive Order S-21-09, and that CARB is to establish the highest priority for those resources with the least environmental costs and impacts on public health that can be developed most quickly and that support reliable, efficient, and cost-effective electricity system operations including resources and facilities located throughout the Western Interconnection.

B.3.2.5 Executive Order B-30-15

In April 2015, Governor Brown issued Executive Order B-30-15 which established the goal for California to reduce statewide GHG emissions 40% below 1990 levels by 2030. The 40% reduction goal is the mid-term target on the way to achieving the long-term goal of 80% below 1990 levels by 2050. These California emission reduction targets are in line with the scientifically established emission reductions needed in the United States to limit global warming below 2 degrees Celsius, to avoid potential major climate disruptions such as super droughts and rising sea levels.

B.3.2.6 Senate Bill 32

In September 2016, the California Legislature and Governor Brown enacted Senate Bill 32 (SB 32) which codified the 2030 GHG emissions reduction target of 40% below 1990 levels. At the same time, companion bill Assembly Bill 97 (AB 97) was adopted which provided additional direction to CARB for developing the Scoping Plan to achieve the GHG emission reduction target.

B.3.2.7 Executive Order N-79-20

In September 2020, Governor Newsom signed Executive Order N-79-20 to establish targets for the transportation sector to support the state in its goal to achieve carbon neutrality by 2045. These targets are 100% of in-state sales of new passenger cars and trucks will be zero emission by 2035 and 100% of medium- and heavy-duty vehicles will be zero emission by 2045 for all operations where feasible. Drayage trucks are required to be zero emission by 2035. CARB was tasked to develop and propose regulations requiring increasing volumes of zero emission vehicles leading to these targets.

B.3.2.8 California Climate Legislation Package

In September 2022, Governor Newsom signed into law a package of 40 climate and energy related bills that address carbon neutrality, clean electricity supply, transportation electrification, carbon capture and sequestration, and environmental justice. The package includes the following bills pertaining to carbon neutrality and the electricity sector:

- Assembly Bill 1279 (AB 1279): codifies the goal for California to achieve carbon neutrality as soon as possible but no later than 2045, and establishes an 85% statewide GHG emission reduction target for 2045;

- Senate Bill 1020 (SB 1020): accelerates the transition to a 100% clean electricity grid in 2045 by establishing interim targets of 90% clean energy supply by 2035 and 95% by 2040, and requires state agencies to procure 100% clean energy by 2035;

- Assembly Bills 2061 and 2075 (AB 2061 and AB 2075): electric vehicle charging infrastructure and charging standards;

- Assembly Bill 2700 (AB 2700): gather data on medium and heavy-duty vehicle fleets to facilitate electrical distribution grid planning and upgrades to support the anticipated level of electric vehicle charging;

- Senate Bills 529 and 887 (SB 529 and SB 887): electrical transmission facilities and transmission facility planning;

- Senate Bill 1075 (SB 1075): evaluate the deployment, development and use of hydrogen, and include in the Integrated Energy Policy Report a study of the potential growth for hydrogen in the electrical and transportation sectors;

- Senate Bills 905 and 1314 (SB 905 and SB 1314): establish a regulatory framework for the advancement of carbon capture and removal technologies; and

- Assembly Bill 1757 (AB 1757): requires carbon removal targets for natural and working lands.

In September 2024, Governor Newsom signed Senate Bill 1420 which will provide CEQA permit streamlining for hydrogen projects in California funded by the CEC's hydrogen grant program, the state climate bond, or ARCHES (the Alliance for Renewable Clean Hydrogen Energy Systems) which is a public-private partnership to build clean hydrogen infrastructure in California.

In November 2024, California voters approved Proposition 4, a $10 billion state bond for environmental and climate projects including $850 million for clean energy projects.

B.3.2.9 AB 32 Cap-and-Trade Regulation

The Cap-and-Trade Program is a key part of CARB's strategy to reduce California GHG emissions. The Cap-and-Trade Program sets a declining limit on major sources of GHG emissions, including large industrial facilities, electricity generation, natural gas suppliers, oil and gas production, and transportation fuel suppliers. The Cap-and-Trade Program establishes a price signal on carbon emissions needed to drive long-term investments towards cleaner fuels and more efficient use of energy. The program is designed to provide covered entities the flexibility to seek out and implement the lowest-cost options to reduce emissions.

The Cap-and-Trade Program commenced on January 1, 2012. The enforceable compliance obligations started with 2013 GHG emissions, initially applying to electric utilities and large industrial facilities, and then expanded to include distributors of transportation, natural gas, and other fuels in 2015.

CARB held its first auction of California carbon allowances in November 2012 and has been holding auctions on a quarterly basis since then. In 2014, CARB linked its carbon market with Quebec's GHG cap-and-trade program.

In 2017, Assembly Bill 398 (AB 398) was enacted, which authorized extension of California's Cap-and-Trade Program to 2030. In its 2017 Scoping Plan Update, CARB expected non-Cap-and-Trade programs to achieve roughly half of the emission reductions needed to meet the statutory 2030 annual target, with Cap-and-Trade making up the other half. Moreover, the 2017 plan identified Cap-and-Trade as the state policy that would serve as a "backstop" to ensure the state meets its target. That is, the plan explicitly stated that to the degree other policies collectively fell short of meeting the

state's GHG reduction goals, the Cap-and-Trade program would reduce emissions further to make up the difference.

The 2022 Scoping Plan Update explains the role of the Cap-and-Trade program in achieving the accelerated GHG emission reduction target will depend on the actual emission reductions achieved by the sources covered by the program. The Cap-and-Trade program must be scalable to fill the gap as needed to achieve the accelerated 2030 GHG reduction target. CARB is committed to review and Cap-and-Trade program and identify potential legislative or regulatory changes to ensure the program continues to deliver GHG reductions to achieve the statutory climate goals.

In 2023 and 2024, CARB held public workshops to discuss potential changes to the Cap-and-Trade program to align it with the 2022 Scoping Plan and AB 1279. The 2022 Scoping Plan sets an accelerated target for 2030 emissions to be 48% below 1990 levels; AB 1279 mandates an 85 percent reduction (net zero) in GHG emissions by 2045. The formal rulemaking process to amend the Cap-and-Trade program regulation is expected to begin in 2025. In addition, CARB is working with lawmakers to extend authorization of the Cap-and-Trade program beyond 2030.

B.3.3 LADWP's Efforts to Address Climate Change

Since 1998, LADWP has taken steps to move away from dependence on coal-fired generating resources, including the divestiture of its power purchase agreement with Colstrip Generating Station, the shutdown of Mohave Generating Station in December 2005, and the divestiture of its share in the Navajo Generating Station in July 2016. LADWP is also leading the effort to replace Intermountain Power Project's coal-fired generating units with hydrogen-ready gas-fired combined-cycle electricity generating units capable of running on a 30% hydrogen/70% natural gas blend by 2025 and 100% hydrogen by 2035.

Table B-1 shows the downward trajectory in LADWP's power generation portfolio CO_2 emissions and CO_2 emissions intensity between 1990 and 202.

Table B-1 Historical LADWP power generation and CO2 emissions.

Year	CO2 Emissions from Total Owned & Purchased Electricity including wholesale sales	Total Owned & Purchased Electricity	LADWP Electricity CO2 Intensity Metric
	(metric tons)	(Net MWh)	(lbs CO2/MWh)
1990	17,925,410	25,481,532	1,551
2000	18,373,127	28,806,750	1,406
2001	17,951,327	28,032,375	1,412
2002	16,702,541	26,808,569	1,374
2003	17,123,715	27,337,694	1,381
2004	17,618,533	28,138,391	1,380
2005	16,856,511	28,301,700	1,313
2006	16,729,971	29,029,883	1,271
2007	16,338,369	29,141,703	1,236
2008	16,035,649	29,312,779	1,206
2009	14,327,814	27,787,397	1,137
2010	13,165,764	26,521,626	1,094
2011	13,900,590	26,530,254	1,155
2012	13,519,339	27,215,275	1,095
2013	14,174,036	26,963,037	1,159
2014	14,911,781	28,193,617	1,166
2015	14,312,947	27,518,957	1,147
2016	10,578,201	27,810,279	839
2017	9,523,539	27,515,675	763
2018	9,015,366	26,484,002	750
2019	8,230,332	26,442,540	686
2020	7,528,640	26,344,723	630
2021	7,528,364	25,200,297	659
2022	7,236,799	26,099,682	612
2023	6,144,965	24,137,043	562
Difference between 1990 and 2021	-11,780,445	-1,344,489	-989
% Change from 1990	-66%	-5%	-64%

B.3.3.1 Sulfur Hexafluoride (SF6) Emissions

SF_6 is an insulating gas used for quenching electrical arcs in circuit breakers, switchgear, gas-insulated lines, gas-insulated substations, and transformers. SF_6 became the dominant technology for gas-insulated circuit breakers in the 1970s and 1980s, and is in widespread use in the electric grid today. When released into the atmosphere, SF_6 is identified as a greenhouse gas with a high global warming potential due to its stability.

In the early 2000s, as part of LADWP's commitment to good environmental stewardship, LADWP voluntarily implemented internal practices to reduce SF_6 emissions from its gas-insulated electrical transmission and distribution equipment through equipment replacement, repair, and process improvements.

In 2010, both the U.S. EPA and CARB adopted regulations requiring the annual reporting of SF_6 emissions from gas insulated electrical equipment. The EPA regulation is a nationwide program that requires reporting of SF_6 emissions from electric power transmission and distribution systems that are operated as an integrated unit, by the entity that operates the system. The EPA regulation is reporting only and does not include an emissions limit. The CARB regulation requires reporting by the owner of gas-insulated electrical equipment located within California and established a declining limit on each equipment owner's annual average SF_6 emissions rate starting at 10% in 2011 and decreasing to 1% in 2020, as well as additional recordkeeping and reporting requirements. LADWP complied with the emission limits imposed by the CARB SF_6 regulation and often reported an annual SF_6 emission rate that was significantly lower than the limit.

In 2021, CARB revised its regulation and renamed it "Regulation for Reducing Greenhouse Gas Emissions from Gas-Insulated Equipment". Significant changes to the CARB regulation include the following:

- Phasing out the purchase of new SF_6 gas-insulated electrical equipment from 2025 through 2033, depending on the equipment voltage class. The SF_6 phase out is intended to drive the development of alternative equipment that does not use SF_6 as an insulating gas, and to incorporate this alternative equipment into the electric grid.

- A process to obtain an exemption from the SF6 phase out in certain cases, such as like-for-like replacement of failed in-use equipment, or where the use of alternative equipment is not feasible.

- Nameplate Gas Capacity Adjustment Procedure to measure the actual insulating gas capacity of a circuit breaker and adjust the manufacturer nameplate gas capacity value to more accurately reflect the actual gas fill amount.

- Change the annual emission limit from an emission rate that adjusts as equipment is added or removed from inventory to a fixed mass emission limit

based on the total nameplate gas capacity of active (in service) equipment as of December 31, 2024. The annual emission limit is held constant at 1.0% for years 2021 through 2034, then decreases to 0.95% for years 2035 and beyond.

- Effective on January 1, 2025, the U.S. EPA amended its regulation for the Use of Electrical Transmission and Distribution Equipment[2]. The amendments expand the reporting requirements to include emissions of all fluorinated greenhouse gases, including SF_6 and perfluorocarbons. The amendments also include a Nameplate Gas Capacity Adjustment Procedure to measure the actual gas capacity of the equipment and adjust the value provided on the manufacturer nameplate.

B.4 Power Plant Once-Through Cooling Water Systems

Power plants with "once-through cooling" (OTC) systems draw or take in water from coastal and estuarine water, via intake pipes, to cool turbines used to generate electricity. After the water is used for cooling, it is discharged to a nearby water body. OTC systems can impact the marine environment.

LADWP has three coastal generating plants that utilize OTC. The California State Water Resources Control Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy) and the Federal Environmental Protection Agency Clean Water Act Section 316(b) Cooling Water Intake Structures, for Existing Facilities (Rule 316(b)) requires minimizing and/or reducing the impacts on marine life.

In order to reduce these impacts, LADWP has committed to completely eliminate OTC by replacing it with closed cycle cooling to comply with the Policy and the Rule 316(b).

In addition, LADWP has implemented the following:

- In the 1970's LADWP installed a velocity cap (a large disk-shaped structure just upstream of the ocean water intake pipe) at its Scattergood Generating Station to

[2] https://www.epa.gov/ghgreporting/subpart-dd-use-electric-transmission-and-distribution-equipment

control impingement mortality (IM). In 2006, LADWP conducted an effectiveness study on its velocity cap and the results showed that it is 96% effective in reducing IM.

- To date, LADWP has reduced the number of power plant units that utilize OTC from 14 to 6, reducing ocean water use from 1904 MGD to 839.8 MGD, an overall reduction of ocean water usage by 56%.

- LADWP has spent over $1.3 billion dollars to replace the older generating units with more efficient generating units (known as "repowering") at its Scattergood, Haynes, and Harbor Generating Stations. This has resulted in a reduced use of coastal waters.

To further reduce impacts and completely eliminate OTC, LADWP plans to do the following:

- By no later than 2029, Scattergood Units 1&2 Clean Energy Project will be complete, eliminating the use of OTC at the Scattergood Generating Station.
-
- By 2028, the Haynes Unit 8 Clean Energy project will be complete, reducing the number of OTC units to 2 at the Haynes Generating Station, decreasing OTC usage at the Haynes Generating Station from 966 MGD to 276 MGD, an overall OTC reduction of 71% at the Haynes Generating Station.
-
- By 2029, the Haynes Units 1&2 will have been decommissioned, completely eliminating the use of OTC at the Haynes Generating Station.
-

B.4.1 United States Environmental Protection Agency (US EPA) Rule 316(b) Requirements for Cooling Water Intake Structures

EPA's Clean Water Act Section 316(b) Cooling Water Intake Structure, Phase II Rule (Rule 316(b)) released in 2004 was subsequently challenged and ultimately heard in both the Second Circuit Court and in the U.S. Supreme Court. The Second Circuit Court issued its decision on January 25, 2007, and determined that the restoration and cost-benefit elements of the original 2004 Rule 316(b) were unlawful and that other fundamental components of the 2004 Rule 316(b), such as the impact reduction performance standards attainable for certain technologies, were to be remanded for further evaluation

and demonstration by U.S. EPA. The U.S. Supreme Court was subsequently asked to weigh in on the ability to use the "wholly disproportionate" cost-benefit test in the application of the Rule 316(b) regulations. On April 1, 2009, the Supreme Court affirmed that a cost-benefit analysis is permitted to be used by regulatory agencies. While the various challenges proceeded through the court processes, U.S. EPA gave the states permission to continue with implementation and enforcement of the Rule 316(b) requirements using their "Best Professional Judgment (BPJ) when reauthorizing facility National Pollutant Discharge Elimination System (NPDES) permits.

During this period, LADWP completed the required Source Water Baseline Biological Characterization Study to identify baseline biological impacts in order to determine appropriate impingement mortality (IM) and entrainment (E) reduction methods. However, when Rule 316(b) was remanded to U.S. EPA to re-study and then re-propose a rule, it essentially remanded Rule 316(b) and placed the fulfillment of its associated requirements on hold. At that point, LADWP stopped any further work necessary to comply with the suspended Rule 316(b) and awaited the outcome of U.S. EPA's effort to re-propose a new rule. The US EPA publicly noticed the new proposed rule for existing facilities on April 19, 2011 and the comment period ended on August 18, 2011. Following the close of this comment period, US EPA released a Notice of Data Availability (NODA), with relief options to comply with IM. The US EPA was under a settlement agreement to have a Final Rule 316(b) published by July 2012; however, after the release of public comments for the IM NODA, EPA was granted an extension and was under a settlement agreement with the Riverkeeper to finalize Rule 316(b) by no later than June 27, 2013. However, the EPA and Riverkeeper reached an agreement to further extend the deadline to finalize Rule 316(b) by January 14, 2014. Another extension was agreed upon and Rule 316(b) was finalized and signed by EPA on May 16, 2014. Rule 316(b) became effective 60 days after it was noticed in the Federal Register. The new rule allows for the IM compliance schedule to be based on a case-by-case site specific basis approved by the State's permitting authority. LADWP has in place an approved compliance path and schedule by the State permitting authority. The new rule requires baseline characterization and cost studies for determining a compliance alternative, it also allows a waiver from these requirements should the compliance path already be determined, such as in the case of LADWP. The final Rule 316(b) also allows the State permitting authority to impose interim requirements; interim requirements had already been established in California's Statewide OTC Policy as is mentioned below.

B.4.2 State Water Resources Control Board 316(b) Requirements for Cooling Water Intake Structures

On June 30, 2009, the SWRCB released its draft Once-Through Cooling Water Policy for public review and comment, with the accompanying Supplemental Environmental Document released on July 14, 2009. Comments were due September 30, 2009. Subsequent policy drafts were issued on November 23, 2009 and March 22, 2010 with corresponding comment periods. The final Policy version was adopted on May 4, 2010 and became effective on October 1, 2010. The adopted policy has major implications for the coastal power plants making it extremely difficult to continue the use of OTC with retrofitted IM and Entrainment (E) impact control technologies; making the use of cooling towers the only certain compliance path. The policy proposes a two-track compliance pathway. Track I requires OTC flows to be reduced commensurate with wet closed cycle cooling (CCC) equivalent to a 93% flow reduction and essentially requires the installation of cooling towers. If Track I can be demonstrated as "not feasible", Track II compliance option is available. Track II compliance pathway requires the biological impacts to be reduced on a unit-by-unit basis to a level comparable with (i.e., within 10%) what would exist with CCC. New consecutive 36-month IM and E baseline studies will be required if the Track II compliance pathway is pursued. Until compliance is achieved, interim measures are required, which include flow reductions when there is no unit load and mitigation measures (commencing five years from the effective date of the policy and continuing until the facility is in full compliance). Lastly, to prevent disruption in the state's electrical power supply during implementation of the policy, a committee of state energy and resource agencies known as the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) will assist the SWRCB in reviewing the required utility implementation plans along with the annual grid reliability studies in order to monitor any grid reliability impacts and schedules.

LADWP submitted its Implementation Plan to SWRCB for the policy on April 1, 2010, which was the first plan to be reviewed by the SWRCB and SACCWIS. As a result, the SWRCB prepared and adopted an amendment to the policy on July 19, 2011, which was approved by the Office of Administrative Law on March 12, 2012. This Amendment modified LADWP's compliance schedule on a unit-by-unit basis with the following compliance dates: 12/31/2013 for Haynes Units 5 & 6; 12/31/2015 for Scattergood Unit 3; 12/31/2024 for Scattergood Units 1 & 2; 12/31/2029 for Haynes Units 1 & 2 and 8, and Harbor Unit 5. In addition, the amendment requires LADWP to submit any additional information requested, by January 1, 2012, by the SACCWIS and submit the information

responsive to SACCWIS to the SWRCB by December 31, 2012 in order for the SWRCB to evaluate whether further modifications to the 2029 dates are necessary. Furthermore, in the interim LADWP must pay an interim mitigation fee that will be used to offset aquatic impacts until each unit is fully compliant. In addition, LADWP must commit to completely eliminate OTC and must conduct a study or studies, singularly or jointly with other facilities, to evaluate new technologies or improve existing technologies to reduce impingement and entrainment, submit the results of the study and a proposal to minimize entrainment and impingement to the Chief Deputy Director no later than December 31, 2015, and upon approval of the proposal by the Chief Deputy Director, complete implementation of the proposal no later than December 31, 2020. LADWP developed a mitigation plan for each coastal plant and submitted them to the SWRCB's Chief Deputy Director for approval. The Haynes Units 5 and 6 repowering project has been completed and the new units are in operation. The Scattergood Unit 3 project has also been completed and met the 2015 deadline. LADWP is also seeking OTC extensions for Scattergood Units 1 and 2 from 2024 to 2029 in order to facilitate construction of a green hydrogen ready project at Scattergood. This project is expected to come online in 2029.

B.5 Mercury Emissions

Mercury (Hg) emissions present an issue for all coal fired power plants. However, the level of such emissions varies widely based on the type of coal burned and the type of emission controls on the plants.

On February 12, 2012, EPA published its final rule, known as the Mercury and Air Toxics ("MATS") rule to reduce emissions of toxic air pollutants from oil- and coal-fired Electric Generating Units (EGUs). The rules require these EGUs to achieve high removal rates of mercury, acid gases and other metals. MATS requires affected EGUs to comply with the new standards three years after the rule takes effect (April 16, 2012), with specific guidelines for an additional one or two years in limited cases.

The Intermountain Generating Station (IGS) in Utah, of which LADWP is the operating agent, has one of the lowest mercury emission rates in the country. This is due to the fact that the existing emission control devices, which are designed to reduce sulfur dioxide and particulate matter, have the co-benefit of removing about 96% of the mercury from bituminous coal which is burned at IGS. IGS will not be required to install control

technologies to reduce its emissions of toxic air pollutants and EPA has determined that the units at IGS are low emitting electric generating units.

B.6 Coal Combustion Residuals

Coal combustion residuals (CCRs), commonly known as coal ash, are byproducts of the combustion of coal at power plants and are typically disposed of in liquid form at large surface impoundments and in solid form at landfills, most often on the properties of power plants.

In April 2015, the EPA promulgated the final CCR rule, which regulates the disposal and management of CCRs as non-hazardous under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The final CCR rule became effective in October 2015.

Under the CCR rule, existing impoundments for managing CCR must either cease accepting CCR materials as of the rule's effective date, or implement a variety of measures to ensure that such facilities will not result in releases to the environment. One such requirement is that all such facilities be retrofitted with liners that are intended to prevent the migration to groundwater of contaminants found in CCR. In addition, the rule requires monitoring of groundwater to determine whether releases have occurred, and to contain or clean up any such releases that are discovered.

The Intermountain Power Project (IPP) utilizes impoundments (ponds and landfills) for the management of CCR that are subject to the CCR rule. IPP has met all interim compliance requirements for the new CCR rule including: setting up a public website and posting CCR operating records, developing new groundwater monitoring wells and sampling plans, beginning to sample groundwater wells quarterly, and developing and implementing a fugitive dust monitoring plan.

LADWP believes that the IPP's CCR management facilities may not meet the design criteria required for surface impoundments and that releases of certain contaminants have occurred from the current, unlined impoundments. LADWP understands that the Intermountain Power Agency (IPA) has made notification that IPP will cease operations of the coal-fired boilers and switch to another fuel source for generation no later than 2028. LADWP has estimated the IPP's total cost of compliance with the final CCR rule to fall within the range of $55 million to $70 million (in 2019 dollars) over a time period commencing in late 2018 and ending between approximately 2023 and 2028 (except for

long-term monitoring and maintenance, which would last approximately 30 years after closure). Of this total cost, the Power System would be responsible for a percentage equal to its total use of energy produced by IPP.

Appendix C - Renewable Portfolio Standard

Appendix C - Contents

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C.1 Overview

LADWP has historically maintained that its major objectives concerning long-term resource planning are (1) providing reliable service to its customers; (2) remaining committed to environmental leadership; and (3) maintaining a competitive price.

California state law mandated that utilities achieve a 20% renewable portfolio standard (RPS) by 2010, which LADWP achieved.

On April 12, 2011, California's governor signed into law Senate Bill 2 (1X), which increases the RPS target to 25% by December 31, 2016 and 33% by December 31, 2020, which LADWP also achieved.

On December 6, 2011, the LADWP Board approved the Renewables Portfolio Standard Policy and Enforcement Program, which is included in Reference C-1 and C-2.

On October 7, 2015, California's governor signed into law the Senate Bill 350, which extends the RPS target, increasing the requirement to 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030.

In September 2018, then-Governor Brown signed into law SB 100, further increasing statewide RPS targets by requiring retail electric sellers and POUs, such as LADWP, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total energy of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027, and 60% of retail sales by December 31, 2030. In addition, SB 100 establishes that it is the policy of California that eligible renewable energy resources and "zero-carbon resources" supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. SB100 targets are set at the state level and are enforced by the California Energy Commission through its Renewable Portfolio Standard (RPS) program. In addition to state level targets set forth in SB 100, the City of Los Angeles has set its own, more aggressive, renewable energy targets. The targets set forth in this updated sustainability plan require LADWP to supply 55% renewable energy by 2025, and 100% zero-carbon energy by 2035.

In September 2022, California Senate Bill 1020 (SB 1020) was enacted. SB 1020 added interim goals to the mandates already established in SB 100. Under SB 1020, at least 90% of all retail sales of electricity in California must be supplied by eligible renewable and zero-carbon energy resources by December 31, 2035. By December 31, 2040, 95% of all retail electricity sales must be supplied by eligible renewable and zero-carbon energy resources. Additionally, all electricity procured to serve California state agencies must be supplied by renewable or zero-carbon energy resources by the end of 2035.

This LA100 Plan demonstrates how LADWP expects to reach and maintain these accelerated renewable energy goals and describes the process for LADWP's continuing commitment to a cleaner future for the City of Los Angeles and its residents.

Additionally, LADWP will continue to encourage customer participation in its voluntary green pricing program, Green Power for Green LA (GREEN). This program enables LADWP customers to opt in and meet even higher renewable energy goals in excess of what LADWP is already providing its customers. It achieves this by utilizing participating customer contributions to procure additional renewable energy needed to meet such higher targets.

C.2 Renewable Energy Requests for Proposals (RFPs)

To help meet the renewable energy goals for the GREEN Program and the RPS policy, LADWP has issued four major requests for proposals (RFP) for renewable energy projects: January 2001, June 2004, January 2007, and March 2009. LADWP performed detailed technical and economic analysis of the proposals on a least-cost, best-fit basis. This approach considered factors such as cost, technical feasibility, project status, transmission issues, and environmental impact.

Separately, the Southern California Public Power Authority (SCPPA), of which LADWP is a member, has issued multiple RFPs for renewable energy projects.

C.2.1 2001 Renewable RFP

In response to the 2001 RFP, a total of 21 projects were proposed. The 120 megawatts (MW) Pine Tree wind project met LADWP's renewable, economic, technical and least-cost, best fit criteria. Pine Tree Wind Project is an eighty-turbine wind farm facility located in the Tehachapi area, and is owned and operated by LADWP. This project was put in-service in June 2009.

Pine Tree wind farm was expanded with ten new additional wind turbines that added 15 MW, for a total of 135 MW. The expansion was completed in 2011.

C.2.2 2004 LADWP Renewable RFP and the 2005 SCPPA Renewable RFP

In June 2004, LADWP issued another RFP with the intent of securing an increased portion of its power requirements from renewable resources. The goal of LADWP's 2004 RFP was to obtain about 1,300 gigawatts hours (GWhs) per year of renewable energy to meet the then RPS interim goal of 13% by 2010. A total of 57 distinct proposals were received, covering nearly all types of renewables, although wind and geothermal represented the largest share of proposed energy. Most of the proposals were from new California projects, with only a few located in Los Angeles. The proposals offered a mix of power purchase and ownership options.

To ensure fairness and consistency during the evaluation process of the 2004 RFP, the evaluation team included two independent entities. The team evaluated proposals through a structured process consisting of two phases. The Phase 1 evaluation included completeness and requirements screening, a technical and commercial evaluation, and an economic assessment. Proposals short-listed were then evaluated in greater detail in the Phase 2 evaluation, which included a comparison of net levelized cost (NLC). The NLC of each proposal equals the levelized busbar cost of energy, in units of $/MWh, less the avoided energy and capacity costs, and adding the levelized transmission costs to cover wheeling, losses, transmission upgrades, etc.

In 2005, the Southern California Public Power Agency (SCPPA), of which LADWP is a participant, also issued an RFP for renewable resources.

Five contracts for renewable energy resulting from the 2004 and 2005 RFPs have been entered into, which provide 1,179 GWhs/yr of renewable energy from landfills, small hydro and wind.

C.2.3 2006 SCPPA and 2007 LADWP Renewable RFPs

In 2006 SCPPA issued an RFP for renewable resources, in which LADWP participated. In January 2007, LADWP issued another RFP with the intent of obtaining approximately 2,200 GWhs of renewable energy per year to meet the RPS goal of 20% by 2010. A total of 59 distinct proposals were received, covering wind, solar thermal, solar photovoltaic (PV), geothermal, and biomass renewable technologies. The proposals offered a mix of power purchase and ownership options.

Three contracts for renewable energy resulting from the 2006 and 2007 RFPs have been entered into, which provide 424 GWhs/yr of renewable energy from wind and small hydro projects. Several other proposals that were received are currently being negotiated.

C.2.4 2008 SCPPA and 2009 LADWP Renewable RFPs

In 2008 SCPPA issued an RFP for renewable resources, in which LADWP participated.

In March, 2009, LADWP issued a fourth RFP for Renewable Resources. The intent of this RFP was to obtain a sufficient amount of renewable energy per year to achieve the RPS goals, set by the Mayor, of 20% by 2010 and 35% by December, 31, 2020.

The 2008 RFP process resulted in two contracts, which provide 834 GWhs/yr of renewable energy from wind resources.

C.2.5 2011, 2012, 2013, 2014, and 2015 SCPPA RFPs

In January 2011, the Southern California Public Power Agency (SCPPA) also issued an RFP for renewable resources, in which LADWP participated and evaluated RFP proposals. LADWP evaluated proposals through a structured process. The evaluation

included completeness and requirements screening, a technical and commercial evaluation, and an evaluation of deliverability of the product. The evaluation also considered the net levelized cost (NLC) for each proposal. The NLC of each proposal is equal to the levelized busbar cost of energy, in units of $/MWh, less the avoided energy and capacity costs, and adding the delivery cost to LADWP's load, which consist of cost of transmission and cost associated with transmission loss.

In 2011, LADWP performed a renewable valuation study to assess the total cost of integrating various renewable projects, which includes the bus bar cost ("raw" cost of generation), transmission cost, losses from transmission, and integration cost, less the energy value and avoided capacity value. As an integral part of determining the net levelized cost of renewable projects, the integration cost from renewables must be considered. The study analyzed the integration costs, including geothermal from the Salton Sea, wind from the Southern Transmission System, solar photovoltaic from various locations in the Mohave Desert, and biogas from Royal Dutch Shell. The results are summarized in Table C-1 below:

Table C-1 2011 Renewable Energy Project Costs.

Renewable Project		Integration Cost
Geothermal	Salton Sea	$0/MWh
Wind	STS Wind	$7-15/MWh
Solar	PV Mohave Desert	$7-20/MWh
Biogas	Shell	$5-10/MWh

Other factors were also considered, including compliance with pending state renewable portfolio standard legislation, utility scale project experience, capacity, commercial operation date, and labor issues.

In August 2011 and continuing into 2012, SCPPA issued another RFP for renewable resources. The response deadline was November 30, 2012. In January 2013, SCPPA issued an RFP for renewable projects and the response deadline was December 31, 2013. In February 2014, SCPPA issued an RFP for renewable and energy storage projects and the response deadline was December 31, 2014. In January 2015, SCPPA issued an RFP for renewable and energy storage projects and the response deadline

was December 31, 2015. In January 2016, SCPPA issued a new RFP for renewable energy resources. The response deadline was December 31, 2016.

C.2.6 2016, 2017, 2018, 2019, 2020, and 2021 SCPPA RFPs

In January 2016, the Southern California Public Power Agency (SCPPA) also issued an RFP for renewable resources, in which LADWP participated and evaluated RFP proposals. LADWP evaluated proposals through a structured process. The evaluation included completeness and requirements screening, a technical and commercial evaluation, and an evaluation of deliverability of the product. The evaluation also considered the net levelized cost (NLC) for each proposal. The NLC of each proposal is equal to the levelized busbar cost of energy, in units of $/MWh, less the avoided energy and capacity costs, and adding the delivery cost to LADWP's load, which consist of cost of transmission and cost associated with transmission loss.

In 2016, LADWP performed a renewable valuation study to assess the total cost of integrating various renewable projects, which includes the bus bar cost ("raw" cost of generation), transmission cost, losses from transmission, and integration cost, less the energy value and avoided capacity value. As an integral part of determining the net levelized cost of renewable projects, the integration cost from renewables must be considered. The study analyzed the integration costs, including geothermal from the Salton Sea, wind from the Southern Transmission System, solar photovoltaic from various locations in the Mohave Desert, and biogas from Royal Dutch Shell. The results are summarized in Table C-2below:

Table C-2 2016 Renewable Energy Costs

Renewable Project		Integration Cost
Geothermal	Salton Sea	$0/MWh
Wind	STS Wind	$7-15/MWh
Solar	PV Mohave Desert	$7-20/MWh
Biogas	Shell	$5-10/MWh

Other factors were also considered, including compliance with pending State renewable portfolio standard legislation, utility scale project experience, capacity, commercial operation date, and labor issues.

For the next five years from 2016 to 2021, SCPPA issued five RFPs for renewable and energy storage projects with the response deadline of December 31st of each year. The latest RFP for renewable and energy storage projects was released in January 2022 with the response deadline of December 31, 2022.

C.3 Renewable Project Strategy

LADWP (and SCPPA) has increased its renewable energy through successful project development and completed agreement negotiations with multiple developers and project entities resulting from the above described RFPs. Existing renewable projects that supply power to LADWP are geographically diverse; wind energy comes from the ridges of the California Tehachapi Mountains, the north-central hills of Oregon, the southern Washington Columbia River Gorge area, the Milford Valley of Utah, New Mexico, and Southwestern Wyoming, and geothermal energy comes from Southwest Nevada. Planning for future renewable energy will continue to emphasize geographic diversity, as well as technology diversity.

The variety of renewable energy projects and technologies facilitates the Power System's capability to integrate renewable energy reliably. As described in other sections of the LA100 Plan, LADWP will maintain its balancing authority responsibility by addressing system issues such as reserve sharing, reserve commitments, system voltage support, spinning reserves, existing and future quick response combustion turbine units, etc.

C.3.1 Issues

- The "ramp rate", i.e., the annual rate of progress required to achieve at least an 80% RPS by 2030, will be subject to several factors. The time frame is seven years; however, the projected ramp rate is not a straight line, but rather varies from year to year depending on factors both external and internal to the LADWP. These factors include SB 2 (1X) requirements, LADWP fiscal constraints, renewable energy technology improvement over time, renewable

energy pricing, LADWP system integration limits, and transmission constraints, both in the LADWP systems and regionally.

- Steady investment in renewable resources is required to ramp to an 80% RPS by 2030. There are several reasons for this path forward: Between 2010 and 2020, the projects maintaining the 33% RPS have become fully integrated into the system, allowing time for pricing adjustments and efficiencies of certain renewable industries such as solar PV to reach the marketplace.

- Transmission limitations in several regions are constraining development activities. These constraints are being studied at regional, statewide, and Western Electricity Coordinating Council (WECC) levels and potential federal and state legislative actions will affect transmission availability. Further resource decisions are dependent on transmission availability and cost.

- Greenhouse Gas (GHG) and other climate change regulatory and legislative issues are pending. The eventual cap and trade methodology and market mechanisms that are implemented will influence RPS strategic and tactical decisions.

- Within the overall RPS plan, decisions as to specific projects, technologies, operational strategies, and project financial structures, will be made as the marketplace and regulatory environment change.

C.3.2 Principles

Future renewable projects will be strategically obtained with the following principles:

- Geographic diversity is important to maintain and enhance power system reliability.

- The use of existing LADWP assets such as transmission lines, land, and existing generation resources should be maximized.

- Pursue multi-faceted development with adequate back-up strategies to handle project delays, project failures, reduced generation output, and operation or maintenance impacts.

- Projects shall be targeted to specifically meet the Power System/Renewables Policy objectives.

- Flexible RPS goals will be established to address the variable nature of renewable energy while conforming to applicable state and federal requirements.

- Ownership, operation, and maintenance are core objectives to maintain power system reliability and cost stability. The Power System is interested in owning projects that are based on proven technology.

- Operation and maintenance (O&M) management is a key criterion in clustering renewable projects. Keeping projects in close proximity would reduce O&M costs due to economies of scale and personnel efficiencies.

C.3.3 Balancing Renewable Resources

Several of these principles may be overlapping or even conflicting. For example, clustering of renewable projects would decrease O&M expenditures, but too many projects in an area will not meet the needs for geographic diversity. Also, ownership goals may impact project costs and immediate availability. Obtaining tax credits and/or grants may necessitate the need for developers to own a project for a certain number of years (typically 7-10 years) to capture renewable tax credits and depreciation advantages, thereby lowering the ultimate cost to LADWP.

Wind, as shown elsewhere in this LA100 Plan, is a volatile renewable energy resource. It is recommended that LADWP's wind forecasting tools and meteorological analysis capabilities be enhanced to provide efficient integration of wind energy.

Similar studies will be required for solar projects coming online in the next few years, and limitations in percentage of solar will be required. Photovoltaic solar systems can have dramatic voltage changes, resulting from passing cloud cover and/or storms. Large installations of solar PV will likely need to be limited in size within a geographical area, unless it is coupled with solar thermal systems or energy storage systems.

C.3.4 Impacts of CA Senate Bill SB 2 (1X), Senate Bill SB 350, Senate Bill SB 100, and LA Green New Deal

On April 12, 2011, Governor Edmund G. Brown Jr. signed into law the California Renewable Energy Resources Act (herein referred to as "Act" or "SB 2 (1X)"). This Act sets new Renewable Portfolio Standard (RPS) procurement targets, new renewable resource eligibility definitions, and new reporting requirements applicable to publicly owned electric utilities (POUs). SB 2 (1X) became effective on December 10, 2011, 90 days after the end of the special session in which it was enacted.

This bill expresses the intent that the amount of electricity generated from eligible renewable energy resources be increased to an amount that equals at least 20% of the total electricity sold to retail customers in California by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020. In addition, this bill requires POU governing boards to adopt a policy with similar goals imposed on IOUs to enforce the RPS Program on its respective utility.

In September 2015, SB 350 passed state legislation and became effective on October 7, 2015, requiring utilities to further procure eligible renewable energy resources in the long term and achieve 50% by 2030. This bill expresses the intent that the amount of electricity generated from eligible renewable energy resources continues to increase to an amount that equals at least 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. SB 350 also requires a doubling of energy efficiency and conservation savings in electricity and natural gas end uses of retail energy by 2030. The law requires publicly owned utilities to establish annual targets for energy efficiency savings and demand reduction consistent with the statewide goal. The Public Utilities Commission also must approve programs and investments by electrical corporations in transportation electrification, including electric vehicle charging infrastructure.

According to the legislation, POU governing boards were directed to adopt "a program for the enforcement of this article" by January 1, 2012. As such, POU governing boards were given discretion to interpret the following provisions:

- Procurement target goals

- Reasonable progress to achieve such goals
- Procurement requirements
- Rules to apply excess procurement for future compliance periods
- Conditions that allow for delaying timely compliance
- Cost limitations for procurement expenditures.

Resources obtained in compliance with SB 2 (1X) must meet the following criteria:

Category (aka "Buckets")	Percentage of RPS Target
1. Electricity products must be procured bundled to be classified Portfolio Content Category 1, and the POU may not resell the underlying electricity from the electricity product back to the eligible renewable energy resource from which the electricity product was procured. The electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the WECC service territory. The first point of interconnection to the WECC transmission grid is the substation or other facility where generation tie lines from the eligible renewable energy resource interconnect to the network transmission grid. Portfolio Content Category 1 electricity products must also satisfy the criteria identified in Regulation 3203(a).	**Compliance Period 1 (2011-2013):** 50% of RPS minimum from this category. **Compliance Period 2 (2014-2016):** 65% of RPS minimum from this category. **Compliance Period 3 (2017 to 2020)**: 75% of RPS minimum from this category. **Post – 2020** 75% of RPS minimum from this category.
2. Electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the WECC service territory, and the electricity must be matched with incremental electricity that is scheduled into a California balancing authority. Portfolio Content Category 2 electricity products must also satisfy the criteria identified in Regulation 3203(b).	Shall be calculated as the remainder of resources which are not in either Category 1 or Category 3.
3. All unbundled renewable energy credits and other electricity products procured form eligible renewable energy resources located within the WECC transmission grid that do not meet the requirements of either Portfolio Content Category 1 or Portfolio Content Category 2 fall within Portfolio Content Category 3.	**Compliance Period 1 (2011-2013):** 25% of RPS maximum from this category. **Compliance Period 2 (2014-2016):** 15% of RPS maximum from this category. **Compliance Period 3 (2017 to 2020):** 10% of RPS maximum from this category. **Post – 2020** 10% of RPS minimum from this category.

The regulations promulgating this legislation by the California Energy Commission (CEC) over POUs were finalized. The Ninth Edition Renewable Energy Program Overall Program Guidebook and the Ninth Edition Renewable Portfolio Standard Eligibility Guidebook were adopted by the CEC on April 27, 2017.

On August 30, 2013, the California Office of Administrative Law (OAL) approved the California Energy Commission's (CEC) Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (Regulations)[1]. These Regulations became effective as of October 1, 2013. The CEC modified its existing regulations to establish enforcement rules and procedures for the Renewable Portfolio Standard (RPS) for local publicly owned electric utilities (POUs), and these modified regulations have been approved by the OAL, with an effective date of April 12, 2016.

- The adopted Regulations have placed additional criteria to the procurement targets for each compliance period:

- For the compliance period beginning January 1, 2011, and ending December 31, 2013, POUs are required to meet or exceed an average of 20% RPS over the three calendar years in the compliance period.

- For the compliance period beginning January 1, 2014, and ending December 31, 2016, POUs are required to meet or exceed the sum of 20% RPS for 2014, 20% RPS for 2015, and 25% RPS for 2016.

- For the compliance period beginning January 1, 2017, and ending December 31, 2020, POU are required to meet or exceed the sum of 27% RPS for 2017, 29% RPS for 2018, 31% RPS for 2019, and 33% RPS for 2020.

- For the compliance period beginning January 1, 2021, and ending December 31, 2024, POU are required to meet or exceed the sum of 40% RPS by 2024.

- For the compliance period beginning January 1, 2025, and ending December 31, 2027, POU are required to meet or exceed the sum of 45% RPS by 2027.

- For the compliance period beginning January 1, 2028, and ending December 31, 2030, POU are required to meet or exceed the sum of 50% RPS by 2030.

In September 2018, then-Governor Brown signed into law SB 100, further increasing statewide RPS targets by requiring retail electric sellers and POUs, such as LADWP, to

[1] ***Enforcement Procedures For The Renewables Portfolio Standard For Local Publicly Owned Electric Utilities***. California Energy Commission, Efficiency and Renewable Energy Division. Publication Number: CEC-300-2013-002-CMF. Available at: http://www.energy.ca.gov/2013publications/CEC-300-2013-002/CEC-300-2013-002-CMF.pdf

procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027, and 60% of retail sales by December 31, 2030. In addition, SB 100 establishes that it is the policy of the State that eligible renewable energy resources and "zero-carbon resources" supply 100% of retail sales of electricity to State end-use customers by December 31, 2045. Defining resources that constitute a "zero-carbon resources" will be subject to further regulatory proceedings of the CEC and CARB. The author of SB 100, Senator Kevin De León, signed a letter that was filed on August 31, 2018, indicating that the author's intent was to include existing resources that do not produce GHG emissions, such as large hydro and nuclear resources, besides renewables, in the definition of a "zero-carbon resources." The CEC has adopted updates to the RPS Enforcement Procedures for Publicly Owned Utilities which incorporate requirements set forth in SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350 pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of RPS procurement must be from contracts of 10 years or more in duration or in ownership or ownership agreements. The updated regulations were adopted by the CEC on December 22, 2020 and approved by the California Office of Administrative Law with an effective date of July 12, 2021.

On February 10, 2020, Mayor Eric Garcetti released his Executive Directive No. 25 implementing LA's Green New Deal. As part of this directive, the City expects the Department to provide equitable access to clean energy programs, build carbon-free microgrids in City owned infrastructure, deploy smart meters City-wide and institute other similar initiatives. The Department is studying how to implement this directive and other renewable power related directives and the effect they will have on the finances and operations of the Power System through its Clean Grid LA Plan. On April 19, 2021, Mayor Eric Garcetti declared in his 2021 Los Angeles State of the City address that his goal is for the Department to provide an energy mix that is 80% renewable and 97% GHG free resources by 2030, a full six years ahead of the LA Green New Deal, and to use the LA100 Study as a guide to fulfill President Biden's energy vision, with a goal of 100% carbon-free energy by 2035.

The legislation allows for the California Energy Commission to issue a notice of violation and correction, and to refer all violations to the California Air Resources Board. Failure to achieve the targets may result in significant penalties.

The challenges of adopting more renewable resources such as wind, solar and geothermal, are: (i) obtaining local and environmental rights and permits for renewable projects and the associated transmission lines needed to deliver energy to Los Angeles; (ii) establishing reliable and cost-effective integration of large scale wind and/or solar projects into the LADWP balancing area through the addition of regulation-capable generation; and (iii) developing geothermal sites which are potentially scarce, require large capital costs, impose exploration risks, and have limited transmission line access. In addition, energy from renewable resources is generally more expensive than energy from conventional fossil fuel resources and must be fully funded through customer rates.

C.3.5 Renewable Energy Credits

The Public Utilities Code Section 399.12 (h) defines a Renewable Energy Credit (REC) as "a certificate of proof, issued through the accounting system established by the California Energy Commission, that one unit of electricity was generated and delivered by an eligible renewable energy resource." RECs include all renewable and environmental attributes, including avoided greenhouse-gas (GHG) attributes, associated with the production of electricity from the eligible renewable energy resource.

The Western Renewable Energy Generation Information System (WREGIS) is the independent renewable energy tracking system implemented for the region covered by the Western Electricity Coordinating Council (WECC). RECs are created, tracked, and ultimately applied towards programs within this system.

The primary method of renewable energy resource procurement will be through the development and acquisition of physical generation assets and energy purchase contracts, in which LADWP will acquire the "renewable energy credit" (REC) from the renewable resource "bundled" with the associated energy.

In order for RPS compliance targets to be managed effectively, LADWP may purchase, sell, or trade RECs without the associated energy (unbundled). This procurement approach will be limited by the percentage requirements established by the Public Utilities Commission (PUC) Section 399.16(b)(3), and as described in the City of Los Angeles Department of Water and Power Renewable Portfolio Standard Policy and Enforcement Program, as amended on December 2013.

C.4 Transmission of Renewable Energy

California and many of the western states contain a variety of resources (wind, solar, geothermal, and other "eligible" resources previously defined in the RPS Policy) that can be developed to ultimately generate electricity. LADWP has utilized and will continue to utilize the maximum capacity of its existing transmission system to deliver electricity from renewable resources; however, the current transmission system was not primarily designed with these natural resources in mind.

Even with the substantial existing transmission system owned by LADWP, and the other transmissions systems in California, there is only a limited amount of transmission lines to access many of the potential renewable resource locations. In order to gain access to these sources of renewable energy, LADWP is planning on building additional transmission lines and expanding the capabilities of several existing lines, and utilizing transmission lines as part of renewable purchase power agreements. These projects include:

1. Barren Ridge Renewable Transmission Project (BRRTP) - Transmission access and transmission line upgrades are needed to accommodate proposed wind projects in the Tehachapi area and solar thermal projects in the Mojave Desert, totaling nearly 1,000 MW. The initial project was the construction of the Barren Ridge substation which supports the 135 MW Pine Tree Wind project. This substation interconnects with LADWP's existing 230 kV Inyo-Rinaldi transmission line (which was built to gain access to the renewable hydro-generated energy from LADWP's aqueduct system in the Owens Valley). The Inyo-Rinaldi transmission capacity needs to be increased in order to accommodate additional renewable energy projects. A full Environmental Impact Report (EIR) process is complete and construction was finished in September 2016. The line is now in-service, allowing renewable energy from RE Cinco Solar, Beacon, and Springbok 1 and 2 to be delivered to LADWP customers.

2. Related to the BRRTP project, the potential Owens Valley Solar projects may require further upgrades to the Inyo-Barren Ridge segment of this transmission line and a generation tie-line into the project area. Depending on ultimate solar buildout in the Owens Valley, additional new transmission may be required.

C.5 Funding the RPS

For LADWP to develop a responsible and prudent renewable energy policy, it must balance environmental objectives such as fuel diversity, energy efficiency and clean air against its core responsibility to provide and distribute safe, reliable, and low-cost energy to its customers. That means developing a RPS that ensures LADWP's continued financial integrity and striving to mitigate the financial impact on retail customers.

The financial impact of meeting increasingly aggressive RPS goals will vary depending on the mix of resource types and the avoided cost of generation, including fuel, operations and maintenance, emissions savings, capacity savings, and other related infrastructure savings. A diversified energy portfolio, including a larger mix of renewables, may also reduce fuel cost and exposure to price spikes due to fuel supply shortages.

During the early years of the RPS program, low cost, small hydro resources and biogas comprised the bulk of the portfolio with relatively higher cost wind energy being recently introduced over the last several years. Going forward, higher cost resources such as solar, geothermal, and wind must be utilized to comply with RPS standards as other lower cost alternatives have been largely exhausted.

Figure C-1 illustrates the number of renewable energy proposals submitted to the Southern California Public Power Authority (SCPPA) from 2014 through 2025. Proposal activity peaked in 2016 and 2017, with over 130 submittals each year. However, beginning in 2019, there was a sharp and sustained decline, with submittals reaching a low of just 21 in 2021 during the height of the COVID-19 pandemic. This downturn significantly hindered the ability of SCPPA member agencies, including LADWP, to procure new renewable energy projects during this period. While there has been a modest recovery in recent years, volumes remain well below pre-pandemic levels.

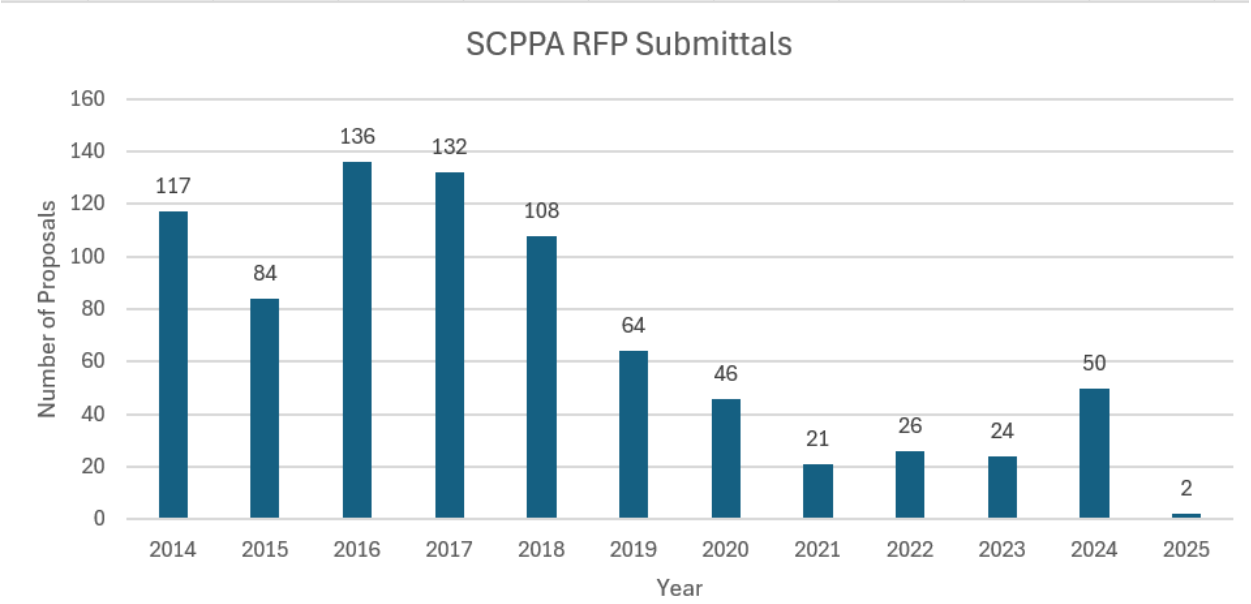


Figure C-1 Annual renewable energy proposal submittals to SCPPA. A pronounced decline during the COVID-19 pandemic limited project procurement opportunities for member agencies.

C.6 Other Renewable Projects

LADWP has several additional projects that are in various stages of development. LADWP also has short-listed additional renewable energy projects that have been offered in response to past LADWP's Request for Proposal (RFPs) or SCPPA RFPs. These short-listed projects and other proposals from upcoming RFP's will be used to select future projects, subject to the criteria enumerated within this section.

The eligibility of wind, solar, and geothermal projects to count toward renewable energy targets is well understood. LADWP has also procured biogas and is considering the use of certain types of biomass. Energy generated from this category is RPS-eligible.

C.6.1 Municipal Solid Waste

The current CEC criteria sets forth several conditions for RPS-eligibility of municipal solid waste (MSW) conversion facilities: The facility uses a two-step process to create energy whereby in the first step (gasification conversion) a non-combustion thermal process that consumes no excess oxygen is used to convert MSW into a clean burning fuel, and

then in the second step this clean-burning fuel is used to generate electricity. The facility and conversion technology must meet certain criteria which include the following:

- The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.

- The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code.

- The technology produces no discharges to surface or groundwaters of the state.

- The technology produces no hazardous wastes.

- To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process, and the owner or operator of the facility certifies that those materials will be recycled or composted.

The facility certifies that any local agency sending solid waste to the facility diverted at least 30% of all solid waste it collects through solid waste reduction, recycling, and composting.

The LADWP currently does not procure energy from any Municipal Solid Waste combustion or conversion facilities, but may consider projects that meet all CEC criteria.

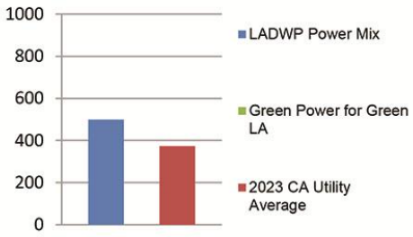
C.7 Power Content Label

In 1997, Senate Bill 1305 was approved, which required Energy Service Providers (ESP) to report to their customers information about the resources that are used to generate the energy that they sell. A form, called the Power Content Label, would be used for this purpose, which would also provide a common reporting method to be used by all ESPs.

In addition, the 2002 Senate Bill 1078 established California's Renewable Portfolio Standard (RPS) which included both a requirement for electric utilities to report annually to their customers the resource mix used to serve its customers by fuel

type, and to report annually to its customers the expenditures of public goods funds used for public purpose programs. The report should contain the contribution of each type of renewable energy resource with separate categories for those fuels considered eligible renewable energy resources, and the total percentage of eligible renewable resources that are used to serve the customers' energy needs.
LADWP's 2023 Power Content Label is shown in Table C-3. As LADWP has two separate renewable programs, the RPS policy and Green Power for Green LA, both of these programs are reported on the Power Content Label.

Table C-3 LADWP's 2023 Power Content Label.

2023 POWER CONTENT LABEL						
LADWP						
https://www.ladwp.com/powercontent →						
Greenhouse Gas Emissions Intensity (lbs CO_2e/MWh)			ENERGY RESOURCES	LADWP Power Mix	Green Power for Green LA	2023 CA Power Mix
LADWP Power Mix	Green Power for Green LA	2023 CA Utility Average	**Eligible Renewable[1]**	**39.5%**	**100.0%**	**36.9%**
499	**0**	**373**	Biomass & Biowaste	0.1%	0.0%	2.1%
			Geothermal	9.5%	0.0%	4.8%
			Eligible Hydroelectric	2.4%	0.0%	1.8%
			Solar	14.0%	100.0%	17.0%
			Wind	13.5%	0.0%	11.2%
			Coal	**10.3%**	**0.0%**	**1.8%**
			Large Hydroelectric	**3.9%**	**0.0%**	**11.7%**
			Natural Gas	**32.4%**	**0.0%**	**36.6%**
			Nuclear	**13.9%**	**0.0%**	**9.3%**
			Other	**0.0%**	**0.0%**	**0.1%**
			Unspecified Power[2]	**0.0%**	**0.0%**	**3.7%**
			TOTAL	100%	100%	100%
Percentage of Retail Sales Covered by Retired Unbundled RECs[3]				**3%**	**0%**	

[1]The eligible renewable percentage above does not reflect RPS compliance, which is determined using a different methodology.

[2]Unspecified power is electricity that has been purchased through open market transactions and is not traceable to a specific generation source.

[3]Renewable energy credits (RECs) are tracking instruments issued for renewable generation. Unbundled renewable energy credits (RECs) represent renewable generation that was not delivered to serve retail sales. Unbundled RECs are not reflected in the power mix or GHG emissions intensities above.

The unbundled RECs retired in association with LADWP's 2023 electricity portfolios were sourced from eligible renewable energy generators such as biomass, biowaste, geothermal, eligible hydroelectric, solar, and wind energy resources.

For specific information about this electricity portfolio, contact:	**Los Angeles Department of Water and Power** **1-800-DIAL-DWP**
For general information about the Power Content Label, visit:	https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure-program

Appendix D - Power System Reliability Program

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D.1 Introduction

The Power System Reliability Program (PSRP) was launched in July 2014 as a long-term program to proactively replace key assets and ensure reliability in the four power system sectors: Generation, Transmission, Substation, and Distribution.

Reliability is one of the most important factors to consider in the planning, design, and operation of a distribution system. The PSRP positions the power system to ensure continued reliability for LADWP customers. The program focuses on aging and critical infrastructure and establishes consistent inspection/replacement life cycles. Table D-1 summarizes the target inspections/replacements for Fiscal Year (FY) 23-24.

Table D-1. Inspection/Replacement Summary, Equipment Life Expectancy & Unit Cost

ASSET	TOTAL UNITS	FY 23-24 TARGET	Avg. Unit Cost (Labor + Equipment)	Average Life Expectancy (Years)
GENERATION				
Generation Transformer (GSU & AUX)	169	2	$5,000,000	45
Major Inspection (Hydro)	22	1	$3,000,000	55
Major Inspection (Pump)	7	0	$4,000,000	55
Major Inspection (Thermal)	26	2	$4,000,000	30
TRANSMISSION				
Transmission Tower Painting	1,800*	133**	$26,000	20
SUBSTATION				
Transmission Circuit Breakers (>100-kV)	542	15	$1,500,000	36
Sub-Transmission Circuit Breakers (34.5-kV)	2,386	59	$450,000	36
Distribution Circuit Breakers (4.8-kV)	2,698	75	$190,000	36
Extra High Voltage Transformers (high side >230-kV)	68	2	$6,000,000	30
High Voltage Transformers (high side 100-kV to 230-kV)	90	3	$5,000,000	30
Medium Voltage Transformers (high side <100-kV)	876	26	$550,000	30
DISTRIBUTION				
Cable (miles)	3,883	60	$1,300,000	75(lead) 40(Synthetic)
Crossarms	768,446	12,600	$2,400	30(wood) 30(fiberglass)
Poles	295,556	3,700	$35,000	60
Substructures	57,000	24	$350,000	50
Transformers	130,236	1,255	$20,000	40

** In Basin*

*** FY 24-25 Target*

D.2 System Description

LADWP maintains and operates a power system that spans five Western states and supplies electricity to approximately 1.5 million residential and business customers in Los Angeles along with more than 5,100 customers in the Owens Valley. Its major wholly owned assets are listed below.

D.2.1 Generation

- 14 small hydroelectric plants
- 5 thermal plants
- 2 solar photovoltaic plants
- 1 large hydroelectric pumped storage plant
- 1 wind plant

D.2.2 Transmission

- 4,081 miles of overhead transmission circuits (AC & DC)
- 136 miles of underground transmission circuits

D.2.3 Substation

- 178 Distributing Stations
- 23 Receiving Stations

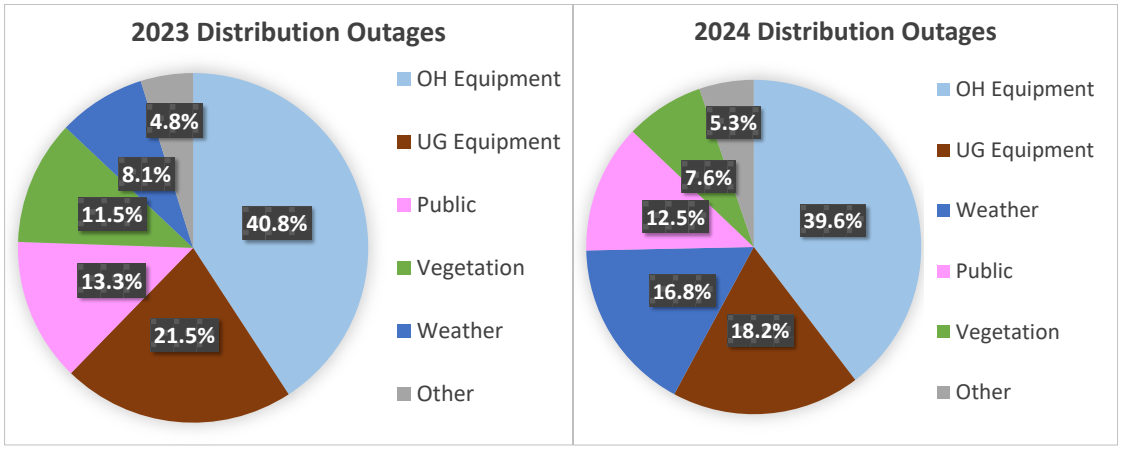
D.2.4 Distribution

- 295,556 distribution utility poles
- 7,380 miles of overhead distribution lines
- 3,883 miles of underground distribution cables
- 130,236 distribution transformers

D.3 Reliability Assessment

D.3.1 Outage History

Per regulatory requirements, LADWP tracks the frequency and duration of interruptions on its system. The total number of sustained distribution outages was 2,813 in 2023 versus 2,566 in 2024. There was a Major Event Day (MED) on February 24, 2023, where the Los Angeles Basin experienced record rainfall. This MED accounted for 5% of the outages in 2023. In comparison, 2024 had no MED recorded despite a heat storm in September and saw a decrease in outages. Figure D-1 shows the percentage contribution of each outage code group to the total number of outages per year.



**Other includes Station Equipment, Wildlife, Lightning, Unknown, and Power Supply*

Figure D-1. Breakdown of Sustained Distribution Outage Causes

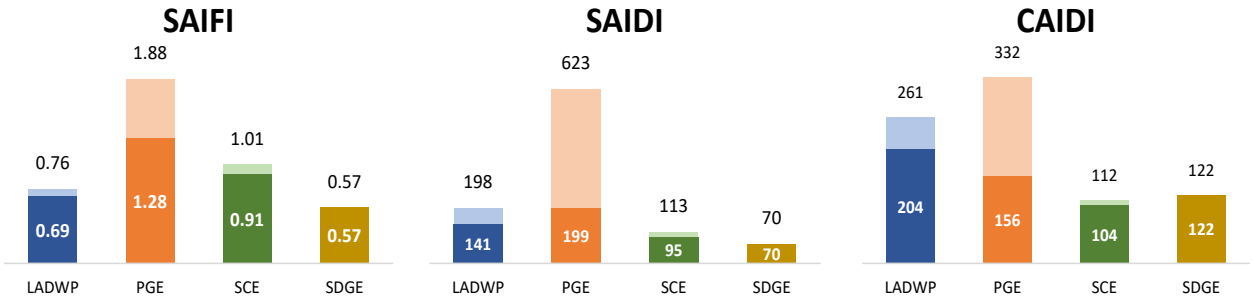
D.3.2 Reliability Indices

The metrics calculated and tracked on a monthly and annual basis are:

- System Average Interruption Frequency Index (SAIFI) – the average number of sustained interruptions (> 5 minutes) per customer during a defined period
- System Average Interruption Duration Index (SAIDI) – the average outage duration in minutes per customer during a defined period
- Customer Average Interruption Duration Index (CAIDI) – the average outage restoration time in minutes per customer during a defined period
- Momentary Average Interruption Frequency Index (MAIFI) – the average number of momentary interruptions (≤ 5 minutes) per customer during a defined period

The California Public Utilities Commission (CPUC) requires the investor-owned utilities (IOUs) to report their rolling 10-year reliability assessment and metrics on an annual basis. The IOUs are allowed to exclude customer interruptions that occurred during MEDs (e.g. windstorms, rainstorms, heat waves, etc.) as determined by the Institute of Electrical and Electronic Engineers (IEEE) 1366 standard.

LADWP's SAIFI and SAIDI remain comparable to neighboring IOUs, as shown in . However, CAIDI is an area where improvement is needed. LADWP's elevated CAIDI in 2023 was primarily due to distribution equipment, extreme weather, and vegetation. To help achieve improved reliability levels, LADWP has set the following FY24-25 targets excluding MEDs: 0.72 for SAIFI, 115 for SAIDI, 160 for CAIDI.



**Top numbers include, and bottom numbers exclude MED*

Figure D-2. 2023 LADWP and IOU Reliability Indices

D.3.2.1 Fix-It Tickets

LADWP has ramped up Capital investments and O&M efforts since implementing the PSRP in 2014. The CPUC General Order (GO) 165 sets inspection requirements for electric distribution and transmission facilities. LADWP uses GO 165 as a guideline (see Table D-2) to maintain and inspect its distribution and transmission assets. Once issues are identified, an Inspection and Maintenance Accelerated Code (IMAC) Work Request is created for corrective action.

Table D-2. GO 165 Correction Timeframes and LADWP IMAC Work Requests

Priority Code	Nature of Issue	Correction Timeframe	Poles*	Work Requests*
1	Non-Conformance/Immediate Safety and/or Reliability Risk	24 hours	11	11
2A	Non-Conformance/Potential for Fire Risk in Tier 3 High Fire Threat District	Within 6 months	10	10
2B	Non-Conformance/Potential for Fire Risk in Tier 2 High Fire Threat District and Brush Clearance Area	Within 12 months	7,668	11,627
2C	Non-Conformance that Compromises Worker Safety	Within 12 months	6,662	7,174
2D	All Other Level 2 Non-Conformance	Within 36 months	44,175	71,272
3	Non-Conformance Low Potential Impact to Safety and Reliability	Within 60 months	68,700	153,339

** Data as of April 17, 2025*

D.3.3 Abnormal Distribution Circuits

Distribution circuits that had/have failed components and/or were included in a load transfer to another adjacent circuit are referred to as abnormal circuits. Restoration work for such circuits is prioritized based on the circuits' abnormal classifications:

- Type A (high priority) – circuits with failed components and load transferred to one or multiple adjacent circuits
- Type B (medium priority) – circuits with failed components and no-load transfer(s)

- Type C (low priority) – circuits with no failed components and load transferred to one or multiple adjacent circuits due to field work or switching operation

There was a total of 197 A- & B-type abnormal circuits at the beginning of FY 23-24. By June 30, 2024, that total stood at 214. Work is done each month to address abnormal circuits.

D.3.3.1 Worst-Performing Circuits

LADWP assesses and ranks every distribution circuit on an annual basis. Circuits that heavily contribute to LADWP's SAIFI and SAIDI reliability indices are prioritized, and remedial work is recommended to improve their performance. In FY 23-24, 96 reliability improvement Work Requests were completed as part of the Worst Performing Circuits (WPC) program.

D.4 Programs and Projects

D.4.1 Generation Transformer

In FY 23-24, LADWP cancelled the contract for the procurement of the Haynes Generating Station, Units 11-16 Spare Main Bank Transformer due to manufacturer issues with delivery. LADWP will re-bid the contract for installation in FY 26-27. LADWP is also working on the replacement of the San Fernando Power Plant Main Bank Transformer with a target completion in FY 24-25.

Plans for FY 24-25 include completing the installation of the San Fernando Power Plant Main Bank Transformer replacement and awarding the contract for the Haynes Generating Station, Units 11-16 Spare Main Bank Transformer. Additionally, LADWP will be progressing with replacements of Harbor Generating Station, Units 1-5 Main Bank Transformers and Upper and Middle Gorge Power Plant Main Bank Transformer replacements.

D.4.2 Generation Major Inspection

Generation reliability depends on regular inspections, preventative maintenance, and timely repairs of Generation assets. LADWP owns, either wholly or jointly, a diverse portfolio of such assets which are supplemented by long-term power purchase agreements and spot market purchases. The reliability of jointly owned and maintained assets, which are located outside of the Los Angeles Basin, is based on contractual agreements. LADWP's wholly owned in-basin thermal assets (Harbor, Haynes, Scattergood, and Valley Generating Stations) are designated as reliability must-run (RMR) by the Energy Control Center's (ECC) Grid Reliability Assessment Group. As such, each in-basin plant is necessary to maintain power system security. Castaic Power Plant is also a critical asset, as it can immediately respond to energy imbalances whether to store surplus energy or to replace displaced energy. Castaic's role has increased because it can true-up imported intermittent renewable energy deliveries by pumping or generating electricity. Details of major inspection in FY 23-24 are provided below.

For FY 23-24, a major inspection was completed on Haynes Generating Station, Unit 14.

- The unit was removed from service due to a rotor ground detected during an annual inspection. The rotor was replaced with Unit 11's, which is on an indefinite outage. The generator was cleaned and inspected, the bearings and seals were refurbished. The unit required rebalancing due to the new rotor installed.

For FY 23-24, a major inspection was completed on Haiwee Power Plant, Unit 1.

- The unit has been on a scheduled outage since 2018. The unit was in poor condition and required a generator and turbine overhaul. The outage took longer than anticipated due to the extensive repairs needed, the impact of the COVID-19 pandemic, and shifting of crews to higher priority projects. The unit was put back in service with no restrictions on June 13, 2024.

For FY 23-24, a major inspection was started on Scattergood Generating Station, Units 4 and 5.

- This is a scheduled time-based major overhaul on the units. The units will be cleaned, inspected, and repaired as needed.

For FY 23-24, a major inspection was started on Haynes Generating Station, Unit 11.

- The unit was on an indefinite outage due to a turbine failure. The generator rotor was removed and placed in Unit 14. The Unit 14 rotor has been sent to a specialist shop for inspection and repairs. The unit will be cleaned, inspected, and repaired as needed. The repaired Unit 14 will be installed and balanced, if needed.

For FY 23-24, a major inspection continues at Castaic Power Plant, Unit 5.

- The generator stator and windings had significant damage, and a partial repair was needed on the unit. Majority of the repairs are complete, the unit was cleaned and inspected as well. The unit is being reassembled and will be commissioned in FY 24-25.

Plans for FY 24-25 include completing the major inspection of Scattergood Generating Station, Units 4 and 5, Haynes Generating Station, Unit 11, and Castaic Power Plant, Unit 5; starting the major inspection of Haynes Generating Station, Unit 1; and performing a major inspection of Valley Generating Station, Unit 7.

D.4.3 Transmission LA Basin Tower Painting Program

This program began in 1993 to contract services to mitigate corrosion issues and extend the useful service life for the existing 1,800 towers in the Los Angeles Basin. Phase 7 of the program is scheduled to start in FY 24/25 with a scope of work to paint nearly 400 towers in 3 years. After phase 7 is completed, this program for the LA Basin may be replaced by a larger program encompassing all towers in LADWP's transmission system.

D.4.4 Substation Transformers

The Transformer, Replacement, & Availability Program (XARAP) provides a prioritized list for recommended transformer replacement. The scoring methodology ranks each transformer based on its condition and system impact derived from specialized tests, including critical location, power factor, dissolved gas analysis, and age. As of 2021, XARAP has been revised to implement the analytics and database of Power Transformer Expert (PTX). PTX is a database and software application that uses test

data and other factors to score the health and provides a list of transformers to be replaced in a ranking order. Please refer to Table D-3 for the recent substation transformer replacements and upgrades through FY 23-24.

Table D-3. Substation Transformer Replacements

Asset Type	Replacements	
	FY 22-23	FY 23-24
Extra High Voltage Transformers (high side >230-kV)	1	0
High Voltage Transformers (high side 100-kV to 230-kV)	2	0
Medium Voltage Transformers (high side <100-kV)	10	13

D.4.5 Substation Circuit Breakers

Replacement of these circuit breakers has historically been reactive (i.e. failures, obsolete technology), or for capacity increases. Proactive replacements are prioritized based on age, maintenance records, and existing work. Table D-4 provides figures on recent circuit breaker replacements through FY 23-24.

Table D-4. Substation Circuit Breaker Replacements

Asset Type	Replacements	
	FY 22-23	FY 23-24
Transmission Circuit Breakers (>100-kV)	5	3
Sub-Transmission Circuit Breakers (34.5-kV)	7	23
Distribution Circuit Breakers (4.8-kV)	27	23

D.5 Distribution Pole Replacements

Proactive pole replacements are prioritized by age, existing work, and inspection results. For reliability purposes, other attached overhead assets such as crossarms and conductors are also replaced or upgraded when the pole is replaced. Please refer to Figure D-3 for pole replacements through FY 23-24.

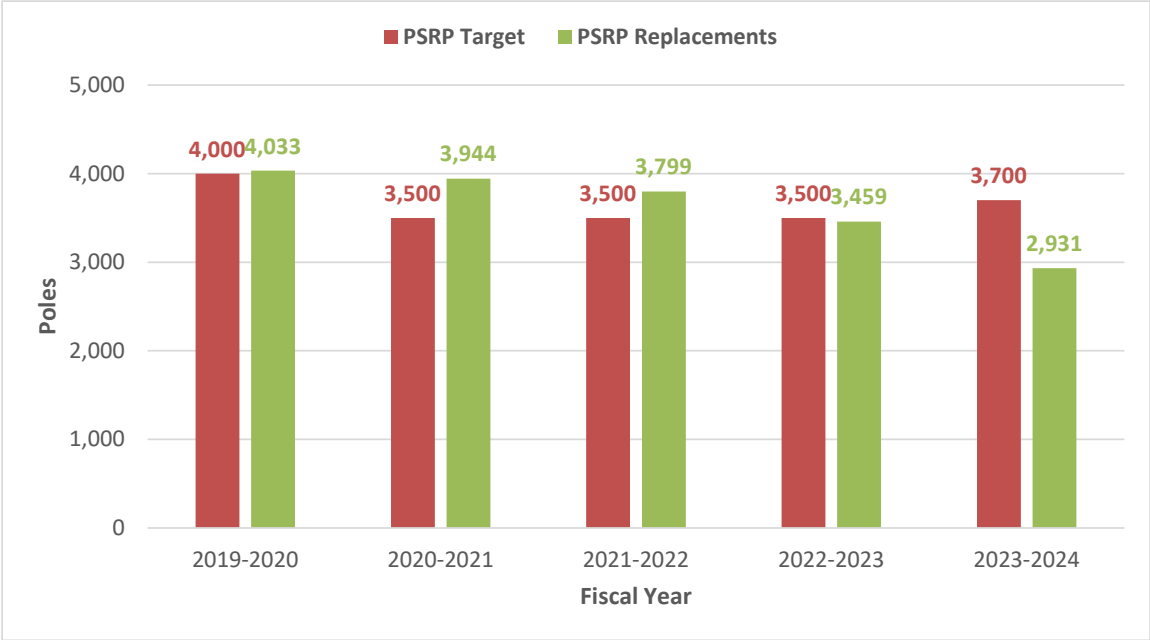


Figure D-3. Distribution Pole Replacements

D.5.1 Crossarms Replacements

Crossarm failures are frequent contributors to overhead-related incidents. Proactive work to replace crossarms is prioritized based on existing work and inspection results. However, most crossarms are reactively replaced due to failure from deterioration or from other incidents causing them to fail. Since 2007, wooden crossarms have been replaced with fiberglass due to their superior strength capabilities. Please refer to Figure D-4 for crossarm replacements through FY 23-24.

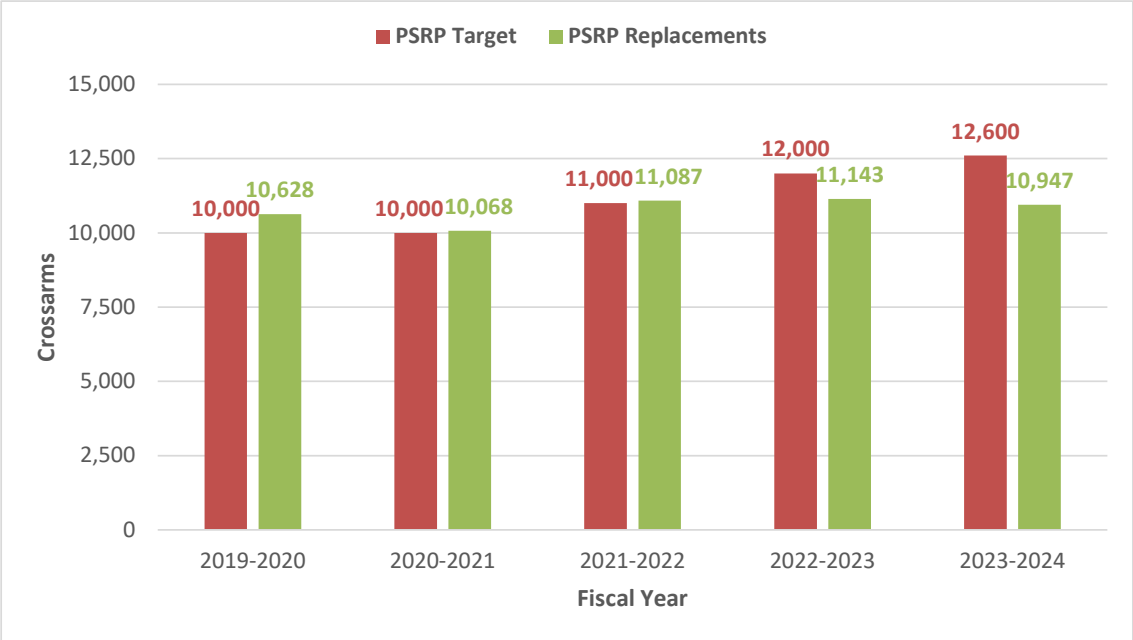


Figure D-4. Crossarm Replacements

D.5.2 Distribution Cable Replacements

Most type-A abnormal circuit configurations stem from underground cable and splice failures due to the difficulty of quickly identifying and permanently repairing such failures on the spot. Please refer to Figure D-5 for cable replacement progress through FY 23-24.

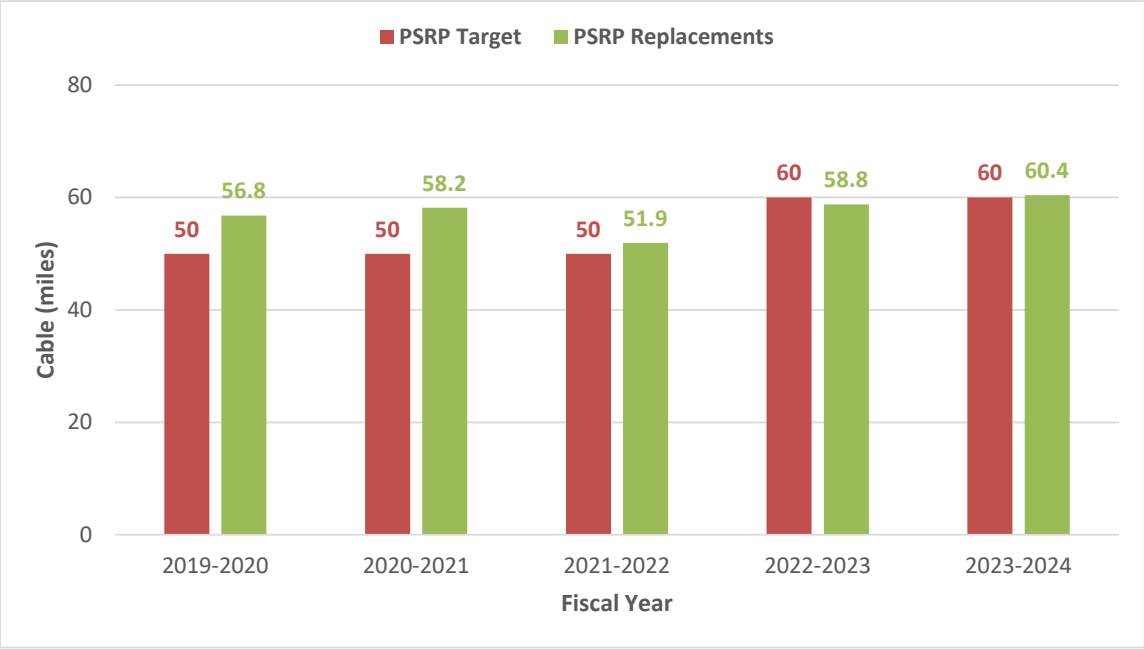


Figure D-5. Distribution Cable Replacements

D.5.3 Distribution Transformer Replacements

Distribution transformers are replaced based on age, size, overload and power quality issues, existing work, and inspection results. LADWP maintains a Transformer Load Assessment list that tracks known overloaded and near-capacity transformers and prioritizes their upgrade to be completed before the summer season. Figure D-6 illustrates the installation and replacement of distribution transformers through FY 23-24.

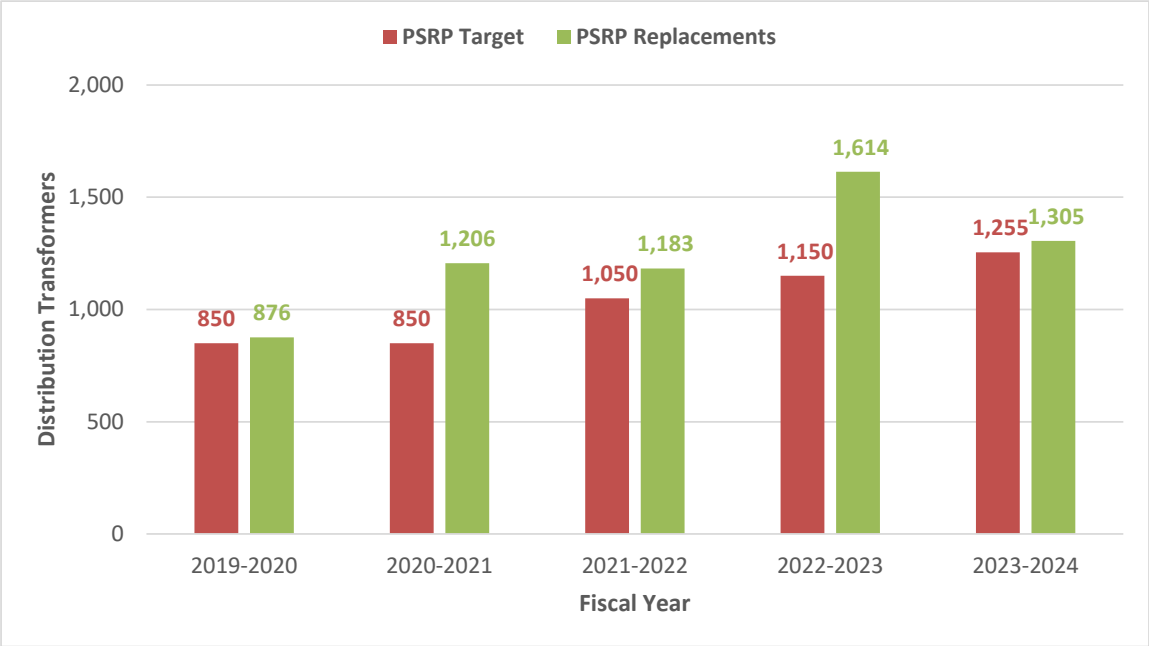


Figure D-6. Distribution Transformer Replacements

D.5.4 Substructure Restorations and Replacements

This project oversees over 57,000 substructures (i.e. underground vaults) across the entire power system. Work to restore or replace substructures is prioritized based on the substructure's level of deterioration (e.g. leaks, structural damage) and existing work. Please refer to Figure D-7 for the progress on substructure restorations and replacements through FY 23-24.

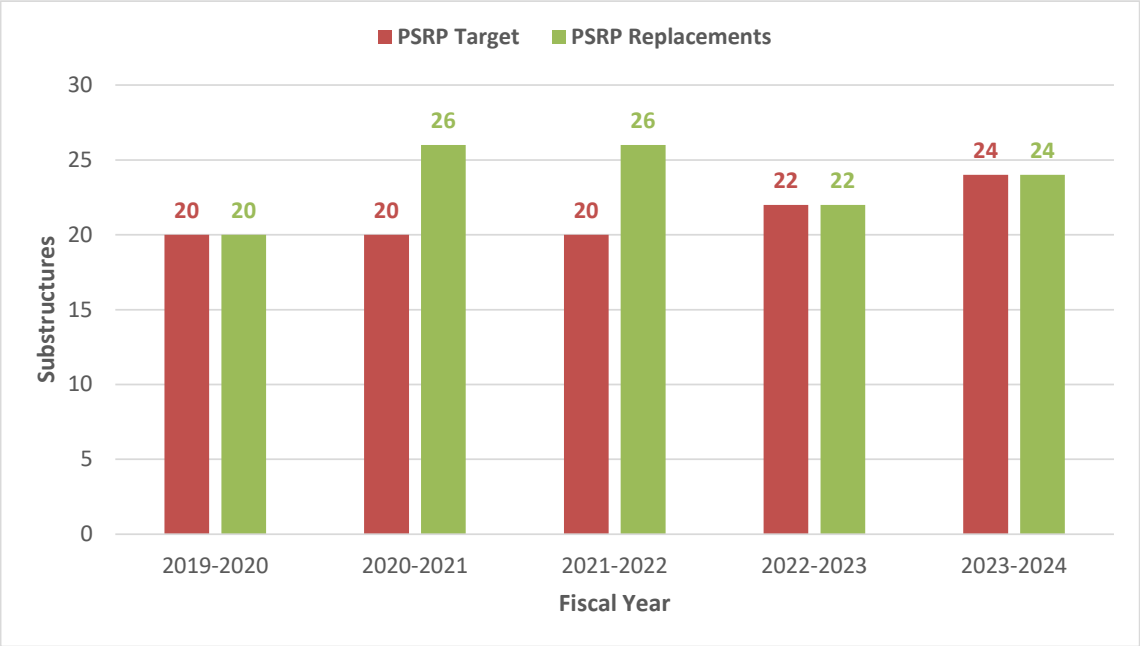


Figure D-7. Substructure Restoration/Replacements

D.6 Budget

Please refer to Figure D-8 for a breakdown of FY 23-24 PSRP actual expenditures.

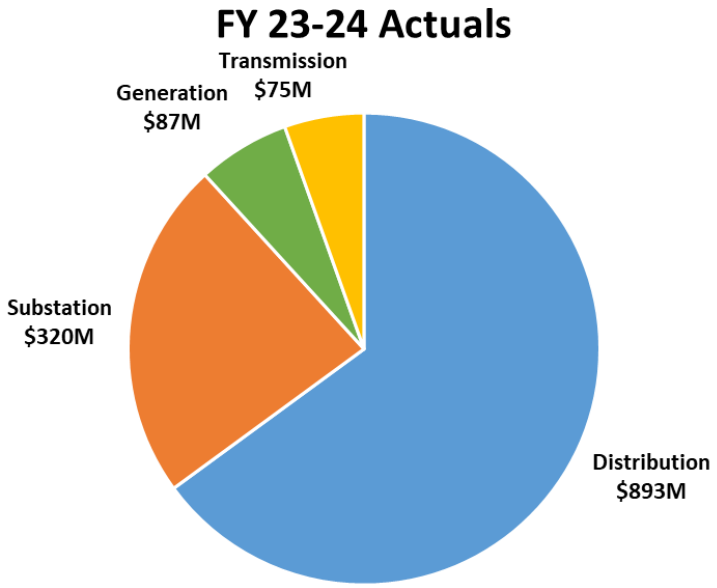


Figure D-8. FY 23-24 PSRP Actuals

D.6.1 Budget Ramp Up

PSRP expenditures are expected to ramp up to the approved FY 26-27 budget of $2,085 million (Figure D-9). This is to allow LADWP to achieve the preferred replacement cycle for all its major assets within Generation, Transmission, Substation, and Distribution.

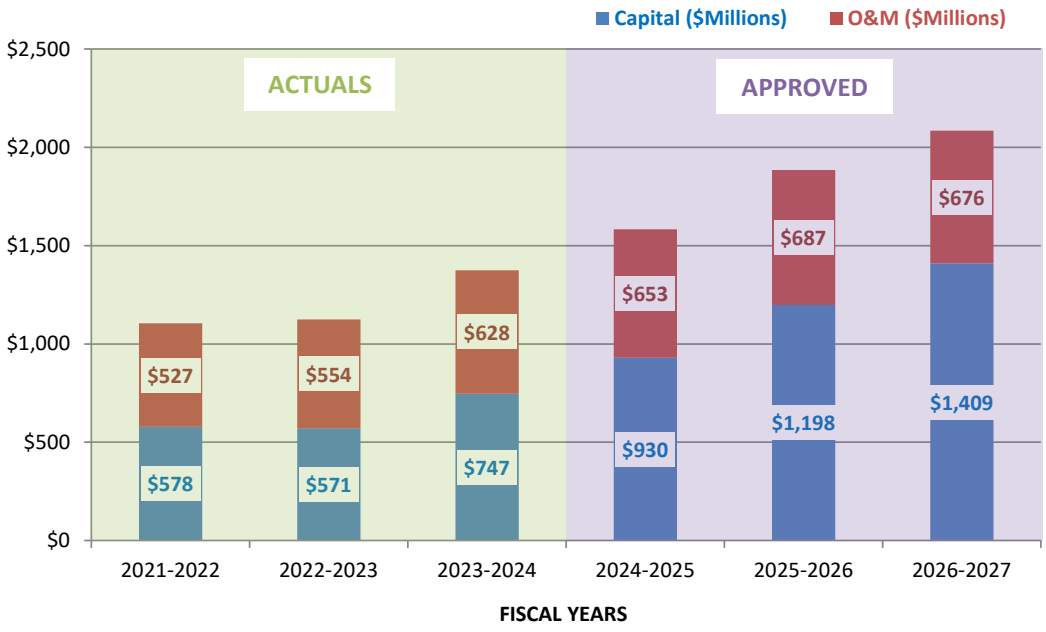


Figure D-9. Chart of Actuals and Approved PSRP funding

D.7 Expanding Distribution System Capacity

To keep up with the convergence of aging infrastructure, increasing demand on the distribution system and electrification, LADWP must address existing overloads (Table D-5) and revamp the distribution system expansion and upgrade targets to meet the goals of the LA100 Plan and the mandates of California Senate Bills 100 and 350 (SB 100 & SB 350). Electric Transportation is the single largest driver of the load growth, expected to increase the distribution system demand by 927 MVA by 2035 based on the moderate load growth scenario. Distribution Load Forecast estimates that the peak load will increase from 6,308 MW to 7,410 MW by 2035.

Capacity expansion for many large distribution assets is needed to meet the forecasted load growth. Without system expansion, tens of substations and

hundreds of feeders and circuits will exceed their planning capacity by 2035. This will require significant labor and capital resources.

Table D-5. Overload Asset Counts and Mega-Watt Shortfall

Assets	Asset Counts (2024) due to Overloads	Asset Counts (2035) due to Overloads	Capacity Shortfall (Mega-Watt)
Receiving Station Sections	1	7	340
Distributing Stations	19	33	97
34.5-kV Sub-transmission Circuits	13	49	112
4.8-kV Distribution Feeders	270	395	230

The PSRP targets will need to start accounting not only for asset replacement but also for the distribution system expansion required to meet growing peak demand from decarbonization and electrification. Distribution system upgrade targets will need to be increased four to six-fold. Table D-6 shows revamped PSRP distribution system targets required to achieve the goals of getting to 100% carbon-free energy by 2035 while enabling more distributed energy resources (DERs) and electrification. Additionally, the Distribution Capital budget will need to approximately increase by $41 million each FY through 2035 to meet the moderate load growth scenario targets.

Table D-6. PSRP Distribution System LA100 Revised Targets – Moderate Scenario

PSRP Distribution System LA100 Revised Targets – Moderate Scenario												
Asset	FY 24/25	FY 25/26	FY 26/27	FY 27/28	FY 28/29	FY 29/30	FY 30/31	FY 31/32	FY 32/33	FY 33/34	FY 34/35	2035 Totals
4.8kV New Feeder (miles)	12	12	12	12	12	12	12	12	12	12	12	132
4.8kV New Feeder (positions)	20	20	20	20	20	20	20	20	20	20	20	220
4.8kV Feeder Upgrade (miles)	5	5	5	5	5	5	5	5	5	5	5	55
DS Transformer Banks (cans)	26	26	26	26	26	26	26	26	26	26	26	286
34.5kV Line (miles)	10	10	10	10	10	10	10	10	10	10	10	110
34.5kV Line (positions)	8	8	8	8	8	8	8	8	8	8	8	88
New RS Racks	1	1	1	1	1	1	1	1	1	0	0	9

To ensure system reliability, LADWP initiated a new multi-year PSRP in 2014 to expand the scope of the previous Power Reliability Program (PRP). This includes the establishment of metrics and indices to prioritize infrastructure replacement

expenditures from all major sectors of the Power System – Generation, Transmission, Substation, and Distribution. The PSRP assesses all power system assets affecting reliability and proposes corrective actions designed to minimize future outages. As resource priorities constantly shift, especially from the demands of regulatory mandated programs and customer driven projects, competition for the remaining limited pool of resources necessitates an expanded power system reliability program and planning process. LADWP must also evaluate and increase its distribution system expansion targets to meet electrification and LA100 Plan goals.

Appendix E - Generation Resources

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E.1 Overview

LADWP's generation resources are presented in this Appendix. Resources that are not wholly owned by LADWP are available either as long-term power purchase agreements or as entitlement rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. Most of these additional resources are available through LADWP's participation in the Southern California Public Power Authority (SCPPA). Each project participant with respect to jointly-owned units is responsible for providing its share of construction, capital, operating, and maintenance costs.

E.2 Resources

Generation resources for LADWP are comprised of the following five categories:

- In-Basin Thermal Generation
- Out-of-Basin Gas-fired Thermal Generation
- Coal-Fired Thermal Generation
- Nuclear-Fueled Thermal Generation
- Large Hydroelectric Generation
- Renewable Resources and Distributed Generation.

E.2.1 In Basin Thermal Generation

LADWP is the sole owner and operator of four electric generating stations in the Los Angeles Basin (the "Los Angeles Basin Stations"), with a combined net maximum generating capacity of 3,377 megawatts (MW) and a combined net dependable generating capacity of 3,182 MW. Natural gas is used as fuel for the Los Angeles Basin Stations. Low-sulfur, low-

ash residual distillate is used in the event of natural gas curtailment and for diesel readiness testing. To date, distillate has not been used for natural gas curtailment by SoCalGas. LADWP's natural gas-fueled generating plant capabilities are shown in Table E-1.

Table E-1. Natural gas generating resources as of February 25, 2025.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Capacity (kW)	Net Dependable Capacity (kW)
Harbor	1	1995	85,340	72,000	423,000[2]
	2	1995	85,340	72,000	
	5	1995	75,000	68,000	
	10	2002	60,500	44,000	
	11	2002	60,500	44,000	
	12	2002	60,500	44,000	
	13	2002	60,500	44,000	
	14	2002	60,500	44,000	
Haynes	1	1962	229,500	222,000	1,503,000[3]
	2	1963	229,500	222,000	
	8	2005	264,350	250,000	
	9	2005	182,750	162,500	
	10	2005	182,750	162,500	
	11	2013	108,190	99,200	
	12	2013	108,190	99,200	
	13	2013	108,190	99,200	
	14	2013	108,190	99,200	
	15	2013	108,190	99,200	
	16	2013	108,190	99,200	
Scattergood	1	1958	163,200	105,000	731,000[5]
	2	1959	163,200	156,250	
	4	2015	216,920	206,000	
	5	2015	118,900	105,000	
	6	2015	106,900	102,000	
	7	2015	106,900	102,000	
Valley	5	2001	60,500	44,000	525,000[4]
	6	2003	182,750	155,000	
	7	2003	182,750	155,000	
	8	2003	264,350	201,000	
Total				3,377,450	3,182,000

Notes:

1. COD refers to Commercial Operation Date.
2. Harbor Generating Station Net Dependable Plant Capacity is 423 MW, reflecting the reduced performance of Units 1, 2, and 5 during hot weather conditions. The Net Maximum Capacity of Units 1, 2, and 5 have been updated as a result of the Dry Low NOx Combustor Upgrade project completed in 2024.
3. Haynes Generating Station Net Dependable Plant Capacity is 1,503 MW, reflecting the reduced performance of Units 8, 9, and 10 during hot weather conditions.
4. Valley Generation Station Net Dependable Plant Capacity is 525 MW, reflecting the reduced performance of Units 6, 7, and 8 during hot weather conditions.
5. Scattergood Unit 1 was derated to 105 MW as part of Unit 3 repowering. Scattergood Generation Station Net Dependable Plant Capacity is 731 MW, reflecting the reduced performance of Units 4 and 5 during hot weather conditions. Unit 3 was decommissioned on December 18, 2015.

E.2.1.1 Haynes Generating Station

The largest of the Los Angeles In-Basin Generating Stations is Haynes Generating Station, located in Long Beach, California. Haynes Generating Station currently consists of eleven generating units with a combined Net Maximum Capacity of 1,614 MW and a Net Dependable Capacity of 1,503 MW. This generating station includes a 575 MW combined cycle installed in February 2005. The combined cycle includes two gas turbines with heat recovery steam generators, which supplies one steam turbine. The combined cycle combustion turbines can each operate with the steam turbine independently in a one-plus-one configuration, or together in a two-plus-one configuration. Six additional peaking combustion units were installed in 2013.

E.2.1.2 Harbor Generating Station

Harbor Generating Station is in Wilmington, Los Angeles, California. Harbor Generating Station currently consists of eight generating units with a combined Net Maximum Capacity of 432 MW and a Net Dependable Capacity of 423 MW. This generating station was repowered in 1995 with the addition of a combined-cycle, and five additional peaking combustion turbines were installed in 2002.

E.2.1.3 Valley Generating Station

Valley Generating Station is in Sun Valley, Los Angeles, California. Valley Generating Station currently consists of four generating units with a combined Net Maximum Capacity of 555

MW and a Net Dependable Capacity of 525 MW. This generating station includes a 511 MW combined cycle installed in 2003. The combined cycle combustion turbines can each operate with the steam turbine independently in a one-plus-one configuration, or together in a two-plus-one configuration. A single peaking combustion turbine was installed in 2001.

E.2.1.4 Scattergood Generating Station

Scattergood Generating Station is in Playa del Rey, Los Angeles, California. Scattergood Generating Station currently consists of six generating units with a combined Net Maximum Capacity of 776 MW and a Net Dependable Capacity of 731 MW. Scattergood Generating Station comprises two independent steam generating units with a Net Maximum Capacity of 261 MW, one one-plus-one combined cycle with a Net Maximum Capacity of 311 MW, and two simple cycle units with a Net Maximum Capacity of 102 MW each. LADWP completed the process of repowering 460 MW of Scattergood Unit 3 with the combined cycle generating unit and two simple cycle gas turbines in 2015. Scattergood Unit 3 was decommissioned in December 2015 and has been demolished to create the construction area for a future energy project.

E.2.2 Out of Basin Gas-Fired Thermal Generation

In order to plan for and implement an early divestiture strategy for Navajo Generating Station (NGS), LADWP worked with SCPPA and executed an Agreement to purchase the output of Apex Generating Station (AGS) from SCPPA. AGS was purchased by SCPPA on March 26, 2014. LADWP is the sole participant and purchaser of power from AGS through SCPPA.

AGS is located in Clark County, north of Las Vegas, Nevada. AGS includes combined-cycle generating units consisting of two 7FA.03 gas turbines with heat recovery steam generators, which supplies one D-11 steam turbine with a combined net maximum capacity of 578 MW. The total net dependable capacity for the Apex Generating Station is 483 MW. Apex Generating Station also houses the Balance of Plant equipment, which includes heat recovery equipment, air inlet filtering, air cooled condenser, continuous emission control system, exhaust stack, zero liquid discharge, and distributed control systems.

Apex Generating Station capabilities are shown in Table E-2.

Table E-2. Natural gas generating resources as of February 25, 2025.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Plant Capacity (kW)	Net Dependable Capacity (kW)
Apex	1A 1B STG	2003[2] 2003[2] 2003[2]	203,150 203,150 237,600	577,500	482,600[3]

Notes:
1. COD refers to Commercial Operation Date.
2. Units 1A and STG were originally placed in-service by the original owner on January 13, 2003, and Unit 1B on January 20, 2003. SCPPA took ownership of Apex Generating Station on March 26, 2014 and maintains a sales agreement for the station's generated power. LADWP's entitlement is 100% of Apex Generating Station's power produced.
3. Apex Generating Station's Net Dependable Plant Capacity includes operating Units 1A and 1B with duct burners running. None of the Apex Generating Station's units have black start capability.

E.2.3 Coal Fired Thermal Generation

LADWP's coal generating capacity comes from the Intermountain Generating Station (IGS). IGS is also referred to as the Intermountain Power Project (IPP). Coal generating resources are summarized in Table E-3.

Table E-3. Coal generating resources as of February 25, 2025.

Plant Name	Unit	COD[1]	Net Max Capacity (Total kW)	Net Max Capacity (LADWP kW)	Net Dependable Capacity (LADWP kW)	LADWP Expiration	LADWP Share
Intermountain	1 2	1986 1987	900,000 900,000	437,553 437,553	437,553 437,553	15Jun2027	48.617%
Intermountain	1 2	1986 1987	900,000 900,000	163,512 163,512	163,512 163,512	15Jun2027	18.168% (Recallable)
Total[3]				1,202,130[2]	1,202,130[2]		

Notes:
1. COD refers to Commercial Operation Date.
2. LADWP's IPP entitlement is 44.617% direct ownership plus a 4% purchase from Utah Power & Light Company (UP&L), plus 86.281% of up to 21.057% of muni's and co-op's recallable entitlement, which can vary. Net Maximum Unit Capacity of Units 1 and 2 is 900 MW each. Intermountain Generating Station's Net Dependable Plant Capacity may be less than 1,202 MW due to Excess Power recall. None of the Intermountain Generating Station's units have black start capability.
3. Effective July 01, 2016, the Department divested its 21.2% generation share (equivalent to 477 MW) from the coal-fired Navajo Generation Station, pursuant to the Asset Purchase and Sale Agreement (the "Navajo Sale Agreement"), entered into with Salt River Project (SRP), Arizona.

E.2.3.1 Intermountain Power Project (IPP)

E.2.3.1.1 General

The IPP consists of: (a) a two-unit coal-fired, steam-electric generating plant located near Delta, Utah, with net rating of 1,800 MW and a switchyard located near Delta, Utah; (b) a rail car service center located in Springville, Utah; (c) certain water rights and coal supplies; and (d) certain transmission facilities consisting primarily of the Southern Transmission System. Pursuant to a Construction Management and Operating Agreement between the Intermountain Power Agency (IPA) and LADWP, IPA appointed LADWP as project manager and operating agent responsible for, among other things, administering, operating, and maintaining IPP.

E.2.3.1.2 Power Contracts

Power is provided to LADWP under two separate agreements:

- Pursuant to a Power Sales Contract with IPA (the "IPP Contract") LADWP is entitled to 44.617% of the capacity of the IPP (equal to 803 MW). However, pursuant to a Power Purchase Termination Agreement between LADWP and PacifiCorp which was executed in August 2015, LADWP acquired PacifiCorp's 4% IPP generation entitlement share, increasing LADWP's total IPP generation entitlement share to 48.617% (currently equal to 875 MW). The IPP Contract terminates in 2027, at which point the Renewal Power Sales Contract with IPA will immediately take operational effect and continue for a term ending in 2077.

- LADWP also has available additional capacity in the IPP through an excess power sales agreement with certain other IPP participants (the "IPP Excess Power Sales Agreement"). Under the IPP Excess Power Sales Agreement, LADWP is entitled to a maximum 18.168% of the capacity of IPP (equal to approximately 327 MW). However, this amount varies as portions of it may be recalled by other participants. Of the maximum possible 327 MW allowed under this agreement, approximately 186 MW was the summer 2024 entitlement amount.

E.2.3.1.3 Fuel Supply

LADWP, in its role as operating agent, manages all fuel supply contracts on behalf of IPA, including several long-term coal supply agreements that can provide approximately 50% of the coal requirements for the IPP. Spot market and opportunity purchases provide the balance of the fuel requirements for the facility.

E.2.3.2 Navajo Generation Station (NGS)

Effective July 01, 2016, LADWP divested its 21.2% generation share (equivalent to 477 MW) from the coal-fired Navajo Generation Station, pursuant to the Asset Purchase and Sale Agreement (the "Navajo Sale Agreement"), entered into with Salt River Project (SRP), Arizona. Power instead comes from renewable energy resources and energy efficiency programs, backed by natural gas. The backup natural gas power resource is located outside the LA-basin and is not affected by problems associated with the Aliso Canyon Natural Gas Storage Facility. With the completion of the Navajo transaction, LADWP reduced coal-generated power from 40% to 30% of the City's energy portfolio. This divestment reduces greenhouse gas emissions by 5.39 million metric tons over the next three and a half years – equivalent to taking over one million cars off the road. This transaction also assured compliance with Senate Bill 1368, the Global Warming Solutions Act of 2006 (Assembly Bill 32) and LADWP's Integrated Resource Plan. Finally, with this divestiture, LADWP avoids potential negative impact of rising costs of 0peration and maintenance (O&M), capital projects, and fuel costs at Navajo Generating Station. LADWP is still responsible for 19.70% of the decommission costs.

E.2.3.3 Mohave Generation Station (MGS)

With this transaction, LADWP acquired all of SRP's ownership interest in the decommissioned Mohave Generating Station. LADWP anticipates selling the land for potential development but keeping right-of-ways for existing transmission lines and the switching station. LADWP also acquired all of SRP's ownership interest in the Eldorado Transmission System which includes 158 MW on the Eldorado Transmission Line, Eldorado Switchyard, the Mohave Switchyard, and other ancillary equipment.

E.2.4 Nuclear-Fueled Thermal Generation

LADWP's nuclear-fueled generating plant capabilities are shown in Table E-4.

Table E-4. Nuclear generating resources as of February 25, 2025.

Plant Name	Unit	COD[1]	License Expiration	Net Max Capacity (Total kW)	Net Max Capacity (LADWP kW)	Net Dependable Capacity (LADWP kW)	LADWP Share[2]
LADWP Direct Ownership Interest:							
Palo Verde	1 2 3	1986 1986 1988	2045 2046 2047	1,333,000 1,336,000 1,334,000	75,981 76,152 76,038	74,727 74,898 74,784	5.7%
LADWP Entitlement Interest Through SCPPA:							
Palo Verde	1 2 3	1986 1986 1988	2045 2046 2047	1,333,000 1,336,000 1,334,000	52,787 52,906 52,826	51,916 52,034 51,955	3.96% (SCPPA)
Total					386,690	380,314	

Notes:

1. COD refers to Commercial Operation Date.
2. LADWP's contract entitlement is 9.66% of generation comprised of 5.7% direct ownership in Palo Verde and another 67% power purchase of SCPPA's 5.91% ownership of Palo Verde.

E.2.4.1 Palo Verde Nuclear Generation Station (PVNGS)

PVNGS is located approximately 50 miles west of Phoenix, Arizona. PVNGS consists of three nuclear electric generating units (numbered 1, 2 and 3), with a net design electrical rating of 1,333 MW (Unit 1), 1,336 MW (Unit 2) and 1,334 MW (Unit 3) and a net dependable capacity of 1,311 MW (Unit 1), 1,314 MW (Unit 2) and 1,312 MW (Unit 3). PVNGS's combined net design capacity is 4,003 MW, and its combined net dependable capacity is 3,937 MW. All three units have been operating under 40-year Full-Power Operating Licenses from the Nuclear Regulatory Commission (NRC) expiring in 2025, 2026, and 2027, respectively. In April 2011, the NRC approved Palo Verde's application to extend the units' operating licenses to 20 years beyond the original term, allowing Unit 1 to operate through 2045, Unit 2 through 2046, and Unit 3 through 2047. Arizona Public Service (APS) is the operating agent for PVNGS. For the fiscal year ending June 30, 2022, PVNGS provided over 3.1 million megawatt-hours ("MWhs") of energy to the Power System. LADWP has a 5.7% direct

ownership interest in the PVNGS (approximately 224 MW of dependable capacity). LADWP also has a 67.0% generation entitlement interest in the 5.91% ownership share of PVNGS that belongs to SCPPA through its "take-or-pay" power contract with SCPPA (totaling approximately 156 MW of net dependable capacity), a joint powers authority in which LADWP participates, so that LADWP has a total interest of approximately 380 MW of net dependable capacity from PVNGS. Co-owners of PVNGS include APS; the SRP Agricultural Improvement and Power District, a political subdivision of the state of Arizona, and the Salt River Valley Water Users' Association, a corporation (together, the "Salt River Project"); Edison; El Paso Electric Company; Public Service Company of New Mexico; SCPPA, and LADWP.

The aftermath of the 2011 Fukushima earthquake and tsunami prompted the U.S. nuclear industry to form a task force under the direction of Palo Verde's Chief Nuclear Officer to take immediate actions in ensuring the reliability of all U.S. nuclear plants. Palo Verde itself has established a task force to evaluate the plant's safety and emergency preparedness. An initial assessment of the plant systems, safety policies, and emergency procedures revealed significant differences between Palo Verde and Fukushima. Palo Verde's low-seismic location, robust pressurized water reactor design, redundant safety features, ample effluent water supply, and multiple back-up power sources make a similar catastrophe in Arizona highly improbable. Despite the seemingly substantial advantages, Palo Verde, in conjunction with other nuclear agencies, is continuously working to make sure that the plant is adequately prepared to meet beyond design basis events, respond to extended loss of power supply situations, and mitigate potential fire and flood events.

E.2.5 Large Hydroelectric Generation

LADWP's large hydroelectric facilities include the Castaic Pumped Storage Power Plant and an entitlement portion of the Hoover Power Plant. LADWP's hydroelectric plant capacities are shown in Table E-5.

Table E-5. Large hydroelectric generating resources as of February 25, 2025.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Capacity (LADWP kW)	Net Dependable Capacity (LADWP kW)	LADWP Expiration	LADWP Share
Castaic[2]	1 2 3 4 5 6 7	1973 1974 1976 1977 1977 1978 1972	271,000 271,000 271,000 271,000 271,000 271,000 56,000	271,000 271,000 271,000 271,000 271,000 271,000 56,000	1,265,000	Owned Asset	100%
Hoover[3]		1936	2,074,000	496,000	269,797	30Sep2067	25.16%
Total				2,178,000	1,532,594		

Notes:

1. Commercial Operation Date.
2. The Castaic Power Plant (CPP) units have completed modernization improvements as follows: Unit 2 in September 2004, Unit 6 in December 2005, Unit 4 in June 2006, Unit 5 in July 2008, Unit 3 in July 2009, Unit 1 in October 2013, and Unit 7 in August 2016.
3. LADWP has a power purchase agreement with the United States Department of Energy Western Area Power Administration (WAPA), the Balancing Authority, for Hoover Power Plant. LADWP's entitlement through September 2067 is 23.9% of the total contingent capacity (2,074 MW) and 14.7% of Firm Energy (approximately 663,283 kWh). Hoover Power Plant output constantly varies due to lower water levels at Lake Mead resulting from the drought conditions. LADWP's estimated average Net Dependable Capacity, based on data from the U.S. Bureau of Reclamation for CY 2025, is 269.80MW.

E.2.5.1 Castaic Pumped Storage Power Plant

Castaic Pumped Storage Power Plant (the "Castaic Plant") is located near Castaic, California. Castaic Plant is LADWP's largest source of hydroelectric capacity and consists of seven units with a net dependable capacity of 1,265 MW. The Castaic Plant provides peaking and reserve capacity for LADWP's load requirements.

E.2.5.2 Hoover Power Plant

E.2.5.2.1 General

Hoover Power Plant (the "Hoover Plant") is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada and is part of the Hoover Dam facility,

which was completed in 1936 and controls the flow of the Colorado River. The Hoover Plant consists of 17 generating units and two service generating units with a total installed capacity of 2,074 MW. LADWP has a power purchase agreement with the United States Department of Energy Western Area Power Administration ("Western") for 496 MW of capacity (calculated based on 25.16% of 2,074 MW of total contingent capacity). In 2016, the agreement was extended another 50 years starting October 1, 2017, through September 30, 2067. On December 20, 2011, the U.S. President signed H.R. 470, the "Hoover Power Allocation Act of 2011," into law. The legislation reallocates, for 50 more years, power from the Hoover Dam Power Plant to existing contractors while creating an additional pool of 5% power for new entrants. The facility is owned and operated by the United States Bureau of Reclamation.

E.2.5.2.2 Drought Conditions

Hoover Power Plant output constantly varies due to lower water levels at Lake Mead resulting from the drought conditions. LADWP's estimated average Net Dependable Plant Capacity based on the U.S. Department of the Interior for CY 2022 is 267.59 MW.

E.2.6 Renewable Resources

LADWP's Renewable Resources consists of:

- Eligible renewable small hydro resources as shown in Table E-6, Table E-7, and Table E-8
- Renewable resources as shown in Table E-9

Table E-6. Owens Valley small hydroelectric generating resources of February 25, 2025.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capacity (LADWP kW)	Net Max Plant Capacity (LADWP kW)	Net Dependable Capacity (LADWP kW)
Haiwee[2]	1 2	1927 1927	2,800 2,800	2,500 2,500	3,600	1,340
Cottonwood[3]	1 2	1908 1909	750 750	1,200 1,200	1,800	260
Division Creek	1	1909	600	680	680	0
Big Pine[4]	1	1925	3,200	3,050	3,050	1,522
Pleasant Valley	1	1958	3,200	2,700	2,700	878
Total					11,830	4,000[2]

Notes:

1. Commercial Operation Date.
2. Owens Valley combined Net Dependable Capacity reflects year-round output capability and are calculated from the last five years of net actual generation over the units' available hours. Haiwee's Net Maximum Unit Capacity is 2.5 MW each, but only 3.6 MW when both units are in-service and feed is taken from the North Haiwee Reservoir. Haiwee's Net Dependable Capacity is limited by Division of Safety of Dams (DSOD) reservoir level.
3. Cottonwood Power Plant Units 1 and 2 were re-wound to higher Net Maximum Unit Capacity of 1.2 MW each, but only a combined 1.8 MW when both units are in-service due to limited maximum flow through the penstock.
4. Big Pine's Net Maximum Unit Capacity is limited by a maximum flow through the penstock.

Table E-7. Owens Gorge small hydroelectric generating resources of February 25, 2025.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capacity (kW)	Net Max Plant Capacity (kW)	Net Dependable Capacity (kW)
Upper Gorge	1	1953	37,500	37,500	36,500	10,649
Middle Gorge	1	1952	37,500	37,500	37,500	9,935
Control Gorge	1	1952	37,500	37,500	37,500	9,270
Total[2]					111,500	29,855

Notes:

1. Commercial Operation Date.
2. Upper Gorge Power Plant is limited to 36.5 MW due to penstock losses. When all three Owens Gorge Power Plants are running, the Net Maximum Plant Capacity is lowered to 110.5 MW to reflect a maximum generation output at Upper Gorge of 35.5 MW, and 37.5 MW at Middle and Control Gorge. This is due to a lower effective head from a longer tunnel and venturi losses at Upper Gorge to which the other two plants are not subjected.

Table E-8. Aqueduct small hydroelectric generating resources of February 25, 2025.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capacity (kW)	Net Max Plant Capacity (kW)	Net Dependable Capacity (kW)
Foothill (PP4)	1	1971	8,800	8,600	78,250	27,377[2]
Franklin (PP5)	1	1921	2,000	2,000		
San Francisquito 1 (PP1)	1A 3 4 5A	1983 1917 1923 1987	22,500 9,962 10,625 22,500	27,000 11,000 12,000 27,000		
San Francisquito 2 (PP2)	1 2 3	1919 1919 2006	14,000 14,000 18,000	0 14,000 18,000		
San Fernando 1 (PP3)	1 2	1922 1922	2,800 2,800	3,250 3,000		
Sawtelle (PP6)	1	1986	640	650		
Total[3]					78,250	27,377

Notes:

1. Commercial Operation Date

2. San Francisquito Power Plant 1, Unit 3 rating is 60 Hz and 11,720 kVA instead of 50 Hz and 9,375 kVA as indicated on original nameplate. Unit 3 was rewound in 1980. San Francisquito Power Plant 2 (PP2), Unit 1 has been out of service since 1996. PP2, Unit 3 has a new generator rated at 18 MW with refurbished turbine as of December 2, 2006. Foothill Power Plant Rated Output is 8,800 kW but is limited to 8,600 kW due to maximum flow through the penstock of 275 cfs. The Net Dependable Capacity reflects year-round output capability. The NDC for small hydro units are calculated from the last five years of net actual generation over the units' available hours.

3. This Table does not include the North Hollywood Pumping Station Power Plant which is operated by the LADWP Water System and has not generated since 2014.

4. LADWP has applied to the CEC for certification of the Gorge Units and PP1 and PP2 and the CEC approved the application for RPS Certification on December 15, 2014.

E.2.6.1 Owens Gorge and Owens Valley Hydroelectric Generation

The Owens Gorge and Owens Valley Hydroelectric generating units (the "Owens Gorge and Owens Valley Hydroelectric Generation") are located along the Owens Valley in the Eastern High Sierra. The Owens Gorge and Owens Valley Hydroelectric Generation are networks of hydroelectric plants which use water resources of the Los Angeles Aqueduct and three creeks along the Eastern Sierras. The water flow fluctuates from year to year; as a result, water flow may be reduced from seasonal norms from time to time.
LADWP worked with Voith Hydro, Inc., to recondition and refurbish selected components of the Upper, Middle, and Control Gorge Power Plants to extend the life of the three units, increase reliability, and improve efficiency. Voith completed major construction and field support in February 2016. The work consisted of:

- Reconditioning the generator stator windings, generator stator core iron, generator rotor field poles, main exciter, vibration monitoring system, wicket gates valves, bushings, facing plates, stationary wear rings, turbine servomotor, thrust bearing, guide bearings, turbine shutoff valve, by-pass shutoff valve, and by-pass relief valve.

- Refurbishing the generator stator frame, auxiliary generator components, turbine runner, existing wicket gates, turbine shaft, head cover, discharge rings, stay vanes, spiral case, and draft tube.

E.2.6.2 San Francisquito Canyon and at the Los Angeles and Franklin Reservoirs

LADWP also owns and operates 12 units located north of the city along the Los Angeles Aqueduct in San Francisquito Canyon and at the Los Angeles and Franklin Reservoirs. Sawtelle Power Plant is in Bel Air near the Sawtelle Tank. The net aggregate dependable plant capacity of these smaller units is 41.8 MW under average water conditions. Table E-9 summarizes these 12 units.

Table E-9. Renewable generating resources[1] (includes only Projects in Service as of November 2022).

Plant Name	PPA/Own	COD	Generator Nameplate[2] (kW)	Net Max Plant Capacity[3] (LADWP kW)	LADWP Share
PPM SW Wyoming	PPA	2006	144,000	82,200	57%
Willow Creek	PPA	2008	72,000	72,000	100%
PPM Pebble Springs	PPA	2009	98,700	68,695	70%
Pine Tree	Own	2009	140,850	135,000	100%
Milford Wind Phase I	PPA/Own	2009	200,000	185,000	93%
Windy Flats	PPA/Own	2010	262,200	262,200	100%
Pine Tree Expansion	Own	2010	15,000	15,000	100%
Linden	Own	2010	52,000	50,000	100%
Milford Wind Phase II	PPA/Own	2011	102,000	102,000	100%
Manzana	PPA	2012	189,000	39,000	21%
Red Cloud	PPA	2021	331,000	331,000	100%
Wind Subtotal				**1,342,095**	
DWP Built Solar	Own	1999-2022	6,800	6,800	100%
Solar CNM (SB1)	Own (REC's only)	1999-2022	522,600	522,600	100%
Solar Feed-In-Tariff	PPA	2012-2022	102,600	102,600	100%
Adelanto Solar	Own	2012	10,400	10,000	100%
Pine Tree Solar	Own	2013	8,500	8,500	100%
Copper Mountain Solar 3	PPA/Own	2015	250,000	210,000	84%

Springbok 1 Solar	PPA/Own	2016	105,000	105,000	100%
RE Cinco	PPA/Own	2016	60,000	60,000	100%
Springbok 2 Solar	PPA/Own	2016	155,000	155,000	100%
Springbok 3	PPA/Own	2019	90,000	90,000	100%
Moapa Paiute	PPA/Own	2016	250,00	250,000	100%
Beacon 5	PPA/Own	2017	36,700	36,700	100%
Beacon 4	PPA/Own	2016	50,000	50,000	100%
Beacon 3	PPA/Own	2016	56,000	56,000	100%
Beacon 2	PPA/Own	2017	44,900	44,900	100%
Beacon 1	PPA/Own	2017	56,000	56,000	100%
Solar Subtotal				**1,764,100**	
Small Hydro	Own	1908-1987	255,227	201,580	100%
MWD Sepulveda	PPA	2008	8,540	8,540	100%
North Hollywood PS Power Plant	Own	2010	4,300	4,300	100%
Small Hydro Subtotal				**214,420**	
Plant Name	**PPA/Own**	**COD**	**Generator Nameplate[2] (kW)**	**Net Max Plant Capacity[3] (LADWP kW)**	**LADWP Share**
Don A. Campbell I[4]	PPA	2014	25,000	21,555	85%
Don A. Campbell 2	PPA	2015	25,000	25,000	100%
Heber 1[5]	PPA	2016	62,500	48,750	78%
Ormesa	PPA	2018	35,000	30,000	86%
Tungsten Mountain	PPA	2017	38,000	38,000	100%
Steamboat Hills	PPA	2018	28,400	28,400	100%
McGinness Hills 3	PPA	2018	69,250	69,250	100%
Galena 2	PPA	2019	5,000	5,000	100%

Brady	PPA	2022	12,000	12,000	100%
Geothermal Subtotal				**277,955**	
Total In-Service Renewables				**3,598,570**	

Notes:

1. Table include LADWP's renewable generating sources from LADWP-owned and contracted projects. This table is based on data from the LADWP RPS Master Project List as of November 2022, and contracted sources, and may include rounding and approximations.
2. The full-load continuous rating of a generator unit under specified conditions as designated by the manufacturer.
3. Maximum Plant Capacity reflects water flow limits at hydro plants; or aggregation of units at renewable plants.
4. LADWP's share of Don A. Campbell I is 13,710 kW or 84.62%; Burbank's share is 2,490 kW or 15.38%
5. LADWP's share of Heber 1 is 66.67% for the first contract period (years 1-3) and 78% for the second contract period (years 4-10); IID's share of Heber 1 is 33.33% for the first contract period and 22% for the second contract period.

Appendix F - Distributed Generation

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F.1 Introduction

Distributed Generation (DG) is a concept of installing and operating small-scale electric generators, at or near a service territory and interconnected to the electric utility distribution system. Technologies used today for DG include turbines, internal combustion engines (ICEs), fuel cells, energy storage, and solar photovoltaic (PV). In addition to providing environmental, cost, and reliability benefits, DG provides the potential to improve power quality and defer transmission or distribution system upgrades as the electric grid integrates larger amounts of renewable energy assets. DG can be installed by a utility or customer.

This appendix describes DG on LADWP's Power System.

F.2 Distributed Generation on the Grid

Most of the combined heat and power DG is made up of 20 MW or larger natural gas combustion engines. The amount of customer DG installed in the future will depend on several factors including reliability, cost of the technologies, and natural gas and electricity prices. With the current trends of increasing electricity prices, distributed generation is becoming more in demand. As of December 31, 2024, over 678 MW have been installed from over 89,700 systems with the help of LADWP's Net Energy Metering (NEM) program. Additionally, LADWP has installed 27 MW of solar PV energy systems on LADWP and City of Los Angeles (City) facilities to generate carbon-free, renewable energy for the LADWP grid.

F.3 Photovoltaics

PV systems convert sunlight directly into electricity. PV systems are modular, portable, and highly reliable, making them ideal for power applications of all sizes. Several large PV systems capable of powering thousands of homes are now connected to utility grids throughout the United States. LADWP has seen the popularity of local customer-owned solar generation increase due to the combination of utility-paid incentives and federal tax law changes, as well as declining solar equipment costs.

F.3.1 Solar Incentive Program (SIP)

In 2006, CA State Legislation SB 1 required all utilities to offer incentives to customers to install solar energy systems through 2016. LADWP's Solar Incentive Program (SIP) was developed with a goal of encouraging the installation of 280 MW of customer-installed solar PV systems by 2019 with a budget of $313 million over 10 years. SIP, which was available to both commercial and residential customers, saw tremendous growth since 2014 due to drastic drops in solar panel costs, availability of an Investment Tax Credit (ITC) from the Federal government, and solar-equipment-leasing opportunities. As of 2019, SIP funds were depleted and no longer available for new applications. Even though the SIP program has closed, LADWP continues to offer the Net Energy Metering program, without LADWP's incentive.

F.3.2 Community Solar Program (CSP)

The economic, environmental, and social benefits of distributed PV solar systems are not equally available to all of the LADWP's customers. In an effort to make PV solar available to more residential customers, especially those in areas of low-installed solar penetration, LADWP has created the Community Solar Program (CSP). The CSP will hold multiple renewable energy programs that are focused on providing equitable solar benefits for residential ratepayers. The CSP is responsible for the development and deployment of the Solar Rooftops (SRP – 2017) and Shared Solar Programs (SSP – 2018). The CSP aims to primarily focus on two customer segments: 1) homeowners with inadequate solar procurement capabilities and 2) customers without suitable rooftops for solar installations (e.g. renters, condominium owners, etc.). These new programs will enable customers to help LADWP meet its renewable energy goals, help reduce overall greenhouse gas emissions, and support local job creation.

F.3.3 Solar Rooftops Program (SRP)

The Solar Rooftops Program (SRP) is performing inspections, installing PV systems, and will enable LADWP to install up to 1 megawatt (MW) of new solar power. SRP PV solar systems are installed on customers' rooftops in exchange for a fixed monthly lease payment of up to $50 per month per rooftop, or $600 per year, which pays for

the use of a customer's property. A unique benefit to SRP participants is that the lease payment is given regardless of PV energy production. There are no up-front costs/fees and no credit checks required to enroll; this helps the program reach disadvantaged communities and helps with environmental justice.

F.3.4 Shared Solar Program (SSP)

The Shared Solar Program (SSP) enables LADWP to install large-scale PV solar plant(s) in/near the LA Basin and allow customers, especially renters, condominium owners, and those who do not have suitable rooftops for traditional residential PV systems, to subscribe and purchase a portion of the energy produced. LADWP intends to procure up to 10 megawatts (MW) of PV solar for this program. The SSP launched in May 2019.

F.3.5 Feed-in Tarrif (FiT) Program

Through the Feed-in Tariff (FiT) Program, the LADWP purchases energy from eligible renewable projects ranging from 30 kW up to ten megawatts (MW) in capacity within its service territory. The FiT program allows developers to sell the output of local renewable energy projects directly to LADWP (as opposed to consuming the energy to satisfy the customer's load). Additionally, local generation can be rapidly developed, deferring the need for costly new transmission lines which can take over a decade to plan and construct. FiT Program participants are eligible for the Investment Tax Credit, bringing an important amount of federal funding into Los Angeles. By supporting and allowing the development of new rooftop solar systems, the FiT Program helps create local jobs, support local sustainable businesses, and also indirectly provide monthly dividends to commercial building owners who rent out their rooftop space.

In 2009, LADWP was mandated by the State to offer a 75 MW FiT Program. Subsequently, LADWP expanded its FiT programs to a capacity of 150 MW. In 2019, the Los Angeles City Council (City Council) authorized the LADWP Board of Commissioners to expand LADWP's FiT programs to a total of 450 MW. Of the 450 MW of FiT program capacity authorized by the City Council, 275 MW have been allocated by LADWP. Of the 275 MW allocated, 215 MW have been allocated to FiT,

10 MW to the Feed-in Tariff Plus Pilot Program (FiT+, which promotes the development of paired solar plus energy storage projects), and 5 MW to the Virtual Net Energy Metering Pilot Prog PV systems convert sunlight directly into electricity. PV systems are modular, portable, and highly reliable, making them ideal for power applications of all sizes. Several large PV systems capable of powering thousands of homes are now connected to utility grids throughout the United States. LADWP has seen the popularity of local customer-owned solar generation increase due to the combination of utility-paid incentives and federal tax law changes, as well as declining solar equipment costs.

F.3.6 Virtual Net Energy Metering (VNEM) Program

The VNEM program allows property owners and developers to install solar photovoltaic systems at multifamily sites and sell the solar energy generated to LADWP. A minimum of 40% of the proceeds will be distributed among on-site tenants, allowing multifamily tenants to experience first-hand the savings solar power provides. Five (5) MW of capacity or up to five projects, whichever is less, is available on a first come, first-served basis. Each project can have a capacity no greater than 3 MW. Any unused capacity from this program will revert to the current FiT allocation, pursuant to the VNEM Program Guidelines.

Appendix G - Fuel Procurement Issues

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G.1 Overview

This appendix presents issues and strategies related to LADWP procurement of both natural gas and coal.

G.2 Natural Gas

LADWP generates about 32% of its energy from natural gas-fired generation, which exposes LADWP to the risk of gas price volatility. This percentage of gas-fired generation has increased over the years as coal is removed from LADWP's resource portfolio, and with the integration of additional variable energy resources. Figure G-1 below graphically illustrates the daily natural gas spot market price (excluding delivery charges to LADWP's gas plants) and the large price fluctuations from the year 2015 through March - 2025.

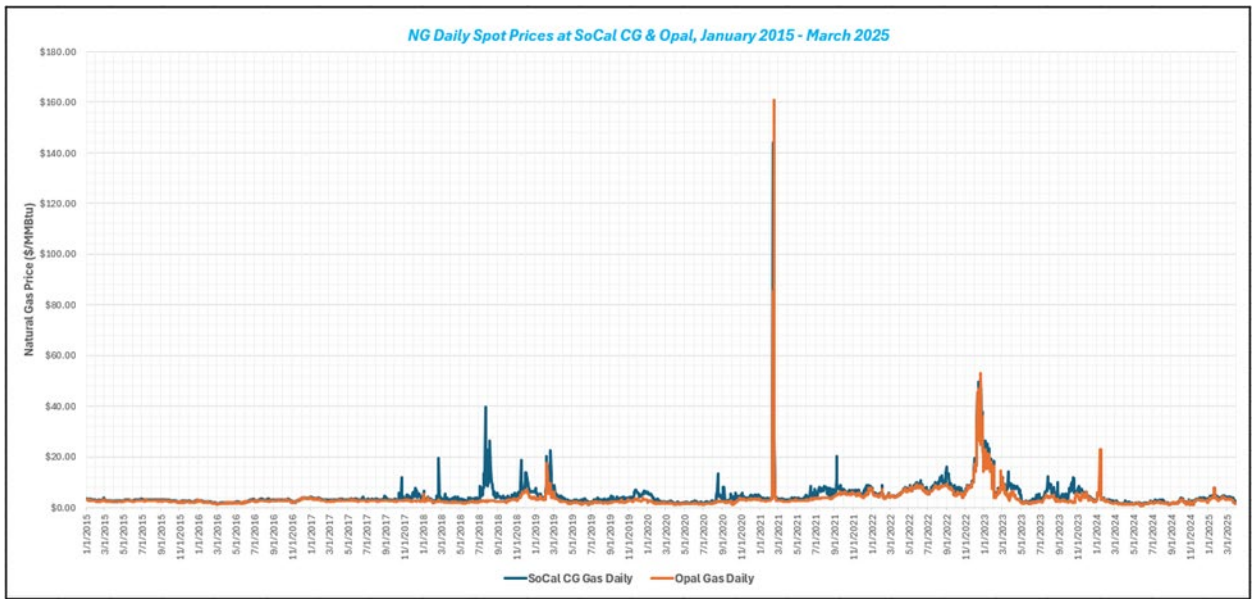


Figure G-1 Natural gas daily spot prices at So Cal Gas City Gate

As is shown on Figure G-1, the natural gas market has been very volatile with extreme variations of prices from month to month. Since gas currently plays such an important role in LADWP's generation portfolio, it is paramount that the impact of gas price volatility to the resource plan be mitigated.

To minimize LADWP's exposure to natural gas price volatility, LADWP has implemented a variety of actions since the 2000 Integrated Resource Plan (IRP), which include:

Created a financial risk management program to mitigate natural gas price spikes and a comprehensive gas procurement strategy to support renewable generation and long-term financial goals.

Established executive controls over energy risk management and natural gas hedging activities by creating an Executive Risk Policy Committee to provide clearance for all major hedging decisions.

Established a Fuels and Risk Advisory Working Group to examine forecasting methodologies, term hedging strategies and other items of importance to fuel procurement.

LADWP obtained approval from the Los Angeles City Council to delegate its award authority to LADWP's General Manager for approving limited term and price gas procurement contracts. LADWP also approved pro forma NAESB (North American Energy Standards Board) contracts for use in procuring natural gas. Additional authority was obtained for procurement of up to 10-year strips of biogas.
LADWP has participated with SCPPA in purchasing an active natural gas reserve in the Pinedale Anticline area of Wyoming. This reserve is currently producing for SCPPA over 4,000 million British thermal units (MMBtu)/day, for the LADWP.
LADWP has approximately 1,100 megawatts (MW) of electrical generation with combined-cycle technology. This technology is much more efficient in generating electricity than the generating units it replaced, resulting in a 30% to 40% decreased usage of natural gas to generate the same amount of electricity. LADWP also has 600 megawatts (MW) of quick-start simple cycle natural gas units that assist in firming and shaping renewable energy projects.
Overall use of fossil fuel is expected to decrease due to the adoption of additional renewables. LADWP's usage of natural gas is expected to increase due to the retirement of the Intermountain Power Plant coal units and their replacement with units that use a blend of Hydrogen and Natural Gas. A general discussion on natural gas issues is provided in the following subsections.

G.2.1 Natural Gas Issues

G.2.1.1 Gas Price Volatility

In general, Gas Price Volatility occurs mostly during winter months when demand is highest for natural gas, production issues (e.g. well freeze offs) are likely, and weather can vary from day to day. High natural gas prices volatility days were also observed during the summer months when electric demand surges due to higher cooling loads. Over the long term, rising LNG export capacity, which will put pressure on domestic supplies, increasing seasonal consumer demands, and the potential for significant demand from data centers are likely factors contributing to future volatility in natural gas spot markets. With the replacement of the IPP Coal units, the opportunity to resource switch between these two fuels is no longer available, limiting LADWP's ability to avoid high natural gas prices during volatile months.

G.2.1.2 Gas Storage

The storage at Aliso Canyon is an important piece of the Southern California natural gas transmission and distribution system, which serves the heating and cooking needs of 11 million residential customers. Following the plugging of the Aliso Canyon leak in 2016, Southern California Gas Company (SoCalGas) has continued to operate the storage facility in accordance with the California Public Utility Commission's (CPUC) Aliso Canyon Withdrawal Protocol. The withdrawal protocol ensures that SoCal Gas must meet specific system conditions before withdrawing gas from the storage facility and the protocol provides guidelines for emergency use. But on August 2023, CPUC ended the Aliso Canyon Withdrawal Protocol, and increased the natural gas storage capacity to 68.6 Bcf. The increased flexibility to use Aliso Canyon storage was necessary for reliability and to help moderate volatility in gas and electricity prices.

G.2.2 Natural Gas Procurement Strategy

G.2.2.1 Implementation Actions

LADWP has adopted strategies to reduce exposure to daily gas price swings: by the use of monthly spot purchases, implementation of index based financial swaps, physical term purchases, and ownership of gas reserves. Monthly spot purchases lock in first of the month indexes and reducing the volumes subject to floating daily prices. The reserve acquisition will reduce overall costs through amortization of the purchase price for the reserve. For example, the Pinedale gas reserves owned by LADWP continues to provide a low-cost source of gas and has proven to be an effective hedge against gas volatility. Additional administrative procedures were put in place to further strengthen deal tracking and audit trails.

LADWP continues to utilize the Natural Gas Hedging Program to reduce the impact of gas price volatility on the cost of the natural gas required by LADWP to meet its fuel requirements. The decision-making process for the Natural Gas Hedging Program involves three steps: establishing risk tolerance, understanding position, and developing and evaluating hedge alternatives.

In summary, LADWP has attempted to mitigate the impacts of volatile natural gas supplies and prices by acquiring a natural gas field, utilizing financial hedging contracts, and utilizing our more efficient combined-cycle generating units.

G.3 Coal Procurement Strategy for the Intermountain Generating Station

G.3.1 Intermountain Generating Station

The Intermountain Power Agency (IPA) owns the Intermountain Generating Station (IGS). LADWP receives part of the power from IGS under a power purchase agreement with IPA that currently runs through 2027. Efforts are underway to extend the termination of the power purchase agreement contingent upon converting the IGS site to natural gas-fired combined-cycle generating units capable of utilizing hydrogen for 840 MW net

generation output, with the current projected year of such transition being 2025. The new natural gas generating units will be designed to utilize 30 percent hydrogen fuel at start-up, transitioning to 100 percent hydrogen fuel by 2045 as technology improves. LADWP is additionally under contract with IPA to oversee the operations of IGS and is known in that role as the Operating Agent. One of LADWP's duties as the Operating agent is to arrange for the procurement of coal or coal assets, including any transportation services needed to get the procured coal to IGS. All contracts for coal procurement or coal asset ownership are done under the name of IPA. Management approval for coal procurement or coal asset ownership is given by the Intermountain Power Project Coordinating Committee (IPPCC), which can be made up of IGS power purchasers (including LADWP), and the IPA Board of Directors (which does not include LADWP). Future coal procurement and coal asset ownership and related strategic development are therefore, done at the discretion and approval of the IPPCC and IPA Board of Directors on behalf of the power purchasers and owners of IGS.

G.3.2 Coal Supply – A Role for the Operating Agent

In its role as Operating Agent, LADWP administers, on behalf of IPA, a diversified portfolio of coal supply contracts that should by design hedge IGS power purchasers against escalating coal prices. The portfolio is comprised of multiple fixed-price coal supply contracts.

G.3.3 Coal Portfolio

The Operating Agent procured between one and three million tons of coal per year for IGS based on recent annual capacity factors.
Historically, the vast majority of coal procured for IGS has come from Utah sources. Due to the transition from coal to natural gas, the procurement of coal in the near-term will be done by adding short-term fixed priced agreements to create a mixed portfolio. While Utah coal is expected to remain a key part of the IGS coal supply through 2025, Utah sources of coal are diminishing, thus the Operating Agent (with IPPCC and IPA Board of Directors guidance and approval) will seek out sources from other known mining areas. Several times, over the years, the operating agent has procured short-term contract coal from more than a half dozen sources in Colorado and Wyoming and will likely seek out additional contracts from those regions.

G.4 Alternative Fuels for Basin Generation

Although there will be ample supplies and delivery capacity for natural gas to power all in-basin generation for the foreseeable future, there is some concern that LADWP will become too dependent on a single fuel. As a consequence, a great deal of thought has been put into identifying potential backup supplies in the event of an emergency. Among those considered are liquefied natural gas and ultra-low sulfur (CARB) diesel. Both fuels present unique storage, handling, operational, and/or environmental problems. Both are deemed too expensive to implement.

The most probable natural disaster that may affect LADWP's ability to generate electrical energy for native load would be a massive earthquake such as the Northridge Earthquake that afflicted Los Angeles in 1994. During that event, due to transmission line problems, the entire power system in Los Angeles was islanded and all available basin generation was brought online. No power was brought in from the Pacific DC Intertie and minimal power from Palo Verde, Navajo, Mohave, or Intermountain was available. Natural gas demand for power increased by 200,000 MMBtu/day and was provided by a minority-owned supplier in a timely fashion. This situation persisted for over two weeks until field crews could repair damage to transmission lines. No power plants were damaged as a result of the earthquake, but some were temporarily taken offline until the situation stabilized. All generation was eventually brought online within a few hours of the earthquake. If the earthquake were much more severe, damage to the power plants' turbines would have necessitated them to be taken offline. The gas delivery system, both SoCal Gas' distribution system as well as the interstate transmission systems, were not harmed by the Northridge quake. Characteristically, gas pipelines are imbedded in sand-filled trenches that allow the pipes to move about when the earth shifts, thereby reducing the possibility of breaking. Major transmission lines bring gas from the east and cross the San Andreas Fault, which moves frequently, but rarely cause delivery outages. We can conclude from this that although it is probably desirable to maintain some type of backup supply of fuel for in-basin power plants, the existing natural gas supply system is likely both adequate and reliable enough to withstand a major disruption event. However, as a matter of prudent management of electric operations, the issue of backup fuel supplies or some other accommodation is actively studied by the Fuels and Risk Advisory Working Group.

Appendix H - Transmission System

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H.1 Transmission Resources

LADWP is one of only a handful of electric utilities that own and operate a system with both alternating current (AC) and direct current (DC) transmission lines. The typical utility is exclusively an AC system with a shorter geographical reach than the LADWP network. LADWP employs its DC lines to import bulk power across state lines from markets and power plants including but not limited to Utah, Wyoming, New Mexico, Washington, Oregon, Arizona, and Nevada. To lower transmission losses, AC/DC conversion equipment is utilized to interconnect its long-distance DC lines with the AC system. Table H-1 lists LADWP's transmission resources.

Table H-1 Transmission line lengths.

Voltage	AC/DC	Circuit-Miles
Out-of-Basin		
±500kV	DC	1,068
500kV	AC	1,449
345kV	AC	101
287kV	AC	341
230kV	AC	198
Sub-Total		3,157 (75%)
In-Basin		
230kV	AC	865
138kV	AC	167
115kV	AC	28
Sub-Total		1,060 (25%)
TOTAL		**4,217 (100%)**

As Table H-1 shows, the majority of LADWP's transmission assets are located outside of the Los Angeles Basin. Originally constructed to supply lower cost electricity to its customers and thereby maintain lower electricity rates, these assets are vitally important to LADWP's attainment of its renewable and carbon-free energy goals. Excess transmission capacity is sold on a non-discriminatory basis in a wholesale market under an Open-Access Transmission Tariff (OATT) largely conforming to FERC Order 890.

H.2 LADWP Basin Transmission System

LADWP's basin transmission network is comprised of overhead and underground lines ranging from 115 kV to 230 kV; 4 switching stations that tie together multiple transmission system circuits; and 22 receiving stations that serve as gateways to the distribution system and as tie points for basin power plants.

Because LADWP serves a metropolis, system reinforcements, additions, and improvements are often challenging; construction in crowded thoroughfares causes inconveniences to very many people. Compounding this challenge is the very real need to invest in an aging transmission infrastructure, parts of which date back to 1916. LADWP continues to explore and exercise feasible options to increase the utility of its resources, including dynamically rating critical belt-line segments. Even so, it is clear that long-term investments must be made in the near-term. According to the Annual Transmission Assessment released in December 2021, LADWP's transmission system is capable of handling expected system peak loads for the next four years when supported by approved remedial actions to address vulnerable, critical contingencies during stressed conditions.

Further, the annual Ten-Year Transmission Assessments have consistently identified the need for basin transmission upgrades for many years now. With each passing year, the urgency becomes more apparent such that now even remedial actions have limited benefit. For this reason, LADWP is moving forward with an unprecedented amount of transmission work within the next 8 years. The transmission upgrades are necessary to maintain reliability of the power system for expected load growth, increased renewable imports, and once-through cooling (OTC) retirements. Table H-2 lists the planned Infrastructure Improvements assumed in the 2022 Annual Transmission Assessment.

Table H-2 Transmission infrastructure improvements.

Infrastructure Improvements	
1	New Barren Ridge STATCOM
2	New RS-E Reactor
3	New Hollywood (RS-H) 138kV Shunt Capacitors (52 MVAR)
4	New RS-B Rack A and Bank A
5	Upgrade Victorville Bank K (Phase IV)
6	New IPP Synchronous Condensers (2 x 375 MVA and 1 spare 375 MVA)
7	Upgrade Wavetraps and CVTs at Mead 287kV to 300kV
8	New Station Surge Arrestor installation

9	Clearance Mitigation Upgrade for Victorville - Rinaldi Line 1
10	New Wilmington (RS-C) 138kV Shunt Capacitors Construction 66 MVAR (2x33 MVAR)
11	Adelanto AC Switchyard extension
12	New Rosamond Switching Station
13	New Barren Ridge STATCOM
14	New RS-E Reactor
15	New Hollywood (RS-H) 138kV Shunt Capacitors (52 MVAR)
16	New RS-B Rack A and Bank A
17	Upgrade Victorville Bank K (Phase IV)
18	New IPP Synchronous Condensers (2 x 375 MVA and 1 spare 375 MVA)
19	Upgrade Wavetraps and CVTs at Mead 287kV to 300kV
20	New Station Surge Arrestor installation
21	Clearance Mitigation Upgrade for Victorville - Rinaldi Line 1
22	New Wilmington (RS-C) 138kV Shunt Capacitors Construction 66 MVAR (2x33 MVAR)
23	Adelanto AC Switchyard extension
24	New Rosamond Switching Station
25	Upgrade McCullough – Victorville Series Compensation
26	New RS-E Bank G Replacement
27	Upgrade Lugo-Victorville Line 1
28	Upgrade Lugo-Victorville Terminal Equipment
29	Clearance Mitigation & Station Equipment Upgrade for Sylmar - Pardee Lines 1 and 2
30	Upgrade Wavetraps and CVTs at Victorville 287kV to 300kV
31	Upgrade Wavetraps and CVTs at Century (RS-B) 287kV to 300kV
32	Upgrade Tarzana - Olympic 1A and 1B - Conversion to 2-230kV lines
33	Clearance Mitigation Upgrade for Adelanto - Toluca Line 1
34	Upgrade Fairfax - Olympic 138kV Series Reactor
35	New RS-N Rack E Expansion
36	Upgrade McCullough – Victorville Circuit Switcher
37	Upgrade Hollywood - Fairfax 138kV Series Reactor
38	New RS-Rinaldi Bank G1 and G2 Replacement
39	RS-A Substation Replacement
40	Upgrade Rinaldi - Airway Lines 1 and 2
41	New Valley - Toluca Line 3 and upgrade Valley -Toluca Lines 1 and 2
42	New Valley - Rinaldi Line 3 and upgrade Valley -Rinaldi Lines 1 and 2
43	New Toluca - Atwater Line 2 and upgrade Toluca -Atwater Line 1

H.3 Victorville-to-LA Basin Transmission System

The Victorville-to-LA Basin System (Table H-3) transmits power into the Los Angeles Basin from distant resources in Utah and the Desert Southwest. The Adelanto Converter Station receives power from the Intermountain DC corridor. The Victorville Switching Station is similarly joined to the task of receiving power from the West-of-River System.

Table H-3 Victorville-to-LA Basin Transmission System.

Transmission Lines
Victorville-Century 287kV Lines 1 & 2
Victorville-Rinaldi 500kV Line 1
Adelanto-Toluca 500kV Line 1
Adelanto-Rinaldi 500kV Line 1

H.4 WECC's West-of-the-Colorado River (WOR) and East-of-the-Colorado River (EOR) Systems

The Western Electricity Coordinating Council (WECC)'s West-of-the-Colorado River (WOR) system transmits power from the Mead/McCullough/Marketplace area to the Adelanto/Victorville area along WECC's WOR (Path 46) system. WECC's East-of-the-Colorado River (EOR) system transmits power from the north-central and central areas of Arizona to the McCullough/Marketplace/Mead area along the WECC EOR (Path 49) system. Path 46 and Path 49 facilitate transportation of electricity coming through the Navajo Generating Station (Page, Arizona) and the Palo Verde Generating Station (Wintersburg, Arizona) to Southern Nevada and to Southern California, respectively. Until the 1,580 MW Mohave Generating Station was shut down in 2005, the Mohave-Lugo 500kV and the Mohave-Eldorado 500kV Lines primarily interconnected that station to the WECC power grid. Since 1996, LADWP has been selling available capacity in the wholesale markets via the open access same-time information system (OASIS). The Palo Verde-Devers 500kV Line 1, of which LADWP has 368 MW of bi-directional transmission service rights, and 368 MW of bi-directional transmission service rights between Devers and Sylmar, is common to both the WOR and the EOR systems. Both systems are also related in that the capacity ratings are seasonally adjusted according to the Southern California Import Transmission (SCIT) Operating nomogram.

H.5 Owens Valley Transmission System

Essentially a segmented single line, the Owens Valley System is becoming increasingly important as a corridor to import renewable resources that support LADWP's Renewable Portfolio Standard (RPS) goals. Developers have proposed interconnecting renewable resource projects totaling more than 3,270 MW. These projects have been placed in the interconnection queue but require continued construction and upgrade of LADWP's Barren Ridge Renewable Transmission Project.

H.6 Intermountain System

The Intermountain System is comprised of three WECC paths operated by LADWP on behalf of the Intermountain Power Agency (IPA):

- WECC Path 27, the 488-mile Intermountain Power Project HVDC (high-voltage direct-current) line has been accommodating transmission of wind and coal based energy from Utah to the Los Angeles area.

- WECC Path 28, the 50-mile Intermountain-Mona 345kV line 1& 2 ties PacifiCorp to LADWP's Balancing Authority Area.

- WECC Path 29, the 144-mile Intermountain-Gonder 230kV line ties NV Energy to LADWP's Balancing Authority Area.

H.7 Pacific DC Intertie System

Also known as WECC Path 65, the Pacific DC Intertie is a ±500kV DC line stretching from the Pacific Northwest to the Los Angeles Basin. This corridor provides the means for LADWP to import wind energy and hydroelectricity created from spring runoffs. For the Pacific Northwest, it provides access to low-cost generation resources during cold winter months.

H.8 Scheduling Point with Other Utilities

A number of utilities interconnect with LADWP's transmission system. The tie points are listed in Table H-4.

Table H-4 Transmission tie point with other utilities.

Utility	Regional Transmission Organization	Location	Voltage (kV)
Arizona Public Service	--	Navajo Generating Station	500
Bonneville Power Administration	--	Pacific DC Intertie @ Nevada Oregon Border	500
City of Anaheim	California ISO	Marketplace Switching Station	500
City of Azusa	California ISO	Marketplace Switching Station	500
City of Banning	California ISO	Marketplace Switching Station	500
City of Burbank	--	Marketplace Switching Station Toluca Receiving Station	500 69
City of Colton	California ISO	Marketplace Switching Station	500
City of Glendale	--	Marketplace Switching Station Airway Receiving Station	500 230
City of Pasadena	California ISO	Marketplace Switching Station St. John Receiving Station (emergency)	500 34.5
Cities of Modesto Redding Santa Clara	California ISO	Marketplace Switching Station	500
City of Riverside	California ISO	Marketplace Switching Station	500
City of Vernon	California ISO	Marketplace Switching Station	500
Intermountain Power Agency	--	Adelanto Switching Station	500

NV Energy	--	McCullough Switching Station Gonder, Crystal Switching Station	500 and 230 230 500 500
Pacificorp	--	Mona	345
Salt River Project	--	Marketplace Switching Station	500
Southern California Edison	California ISO	Eldorado Substation Victorville-Lugo midpoint Velasco Receiving Station-Laguna Bell (emergency) Sylmar Switching Station Inyo Substation Haiwee (emergency)	500 500 230 220 115 115
Western Area Power Administration	--	Marketplace Switching Station McCullough Switching Station Mead Substation	500 500 and 230 287

Appendix I - Integration of Intermittent Energy from Renewable Resources

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I.1 General Integration Principles

One of the main responsibilities of power system operators is to maintain the balance between the total aggregate electrical demand of the system's customers and the amount of energy generated to meet that demand on an instantaneous basis. Conventional electrical generation technologies, such as nuclear, coal, natural gas, and large hydro are controlled and dispatched by power system operators throughout the day to maintain the instantaneous balance between demand and generation.

However, some renewable resources generate energy following the vagaries of nature in a variable and intermittent manner. The energy from these renewable resources is generally not controlled by power system operators, but received dynamically as it is produced. For example, solar resources only produce energy during daylight hours, and wind resources only produce energy when the wind is blowing. Such variable and intermittent renewable resources are often referred to as variable energy resource (VER) technologies.

The amounts of energy generated from VER's will be substantial and increasing over time. The percentage of VER's compared to the total capability of a utility's power system may also be defined as "percent penetration." Percent penetration can be measured by either using capacity or energy method. Either measurement method is important; since a utility may use this information to determine the maximum amount of VERs that a power system can accommodate without impairing the utility's ability to reliably maintain the required instantaneous balance between demand and generation.

Because power system operators cannot control or dispatch the production of energy from many renewable resources, the remainder of the power system must be controlled and dispatched to accommodate both the changes in renewable energy production and the changes in customer demand. In general, with the addition of increasing amounts of VERs, over-generation and "ramping" capability will be among the major operational challenges.

I.2 Findings of System Integration Studies

Over the last two decades, LADWP has been increasing its efforts to acquire renewable resources. In 2003, 3% of energy sold to its customers was generated from renewable energy resources, which increased substantially to 20% by 2010. Senate Bill X1-2 mandated a 33% renewable portfolio standard (RPS) by 2020, and Senate Bill 350 further increased the RPS mandate to 50% by 2030. Subsequently, Senate Bill 100 was passed and currently mandates that California electric utilities must achieve a 60% RPS by 2030, and 100% zero-carbon energy by 2045. In 2021, the Los Angeles City Council established a goal for LADWP of achieving 100% carbon-free energy by 2035—10 years ahead of the SB 100 mandate. With the much higher percentage of renewables coming on-line, a variety of modifications will need to be made to the Power System, in order to successfully and reliably integrate these higher penetrations of renewable resources. In preparation, LADWP has conducted several studies on integrating renewable resources, and this effort will be improved as more operating experience is obtained over time. For example, in 2015, LADWP contracted with URS team and conducted a reliability study entitled, the "Maximum Generation Renewable Energy Penetration Study (MGREPS)," to examine the impacts of 40-50% penetrations of VER on LADWP's Power System and provide recommendations for actions and further study of cost-effective, reliable methods of variable energy resources integration. LADWP has also reviewed many renewable integration studies published over the last several years. These studies have yielded some common observations and recommendations regarding the integration of VERs into power system generation portfolios.

I.2.1 Operational Challenges

Some operational challenges imposed by renewable resources are as follows:

1. Over-generation: Solar energy is the major VER among the new renewable energy resources being planned for LADWP's resource portfolio. Solar energy production patterns are more closely aligned with daily load patterns, which can assist in meeting the load demand, at least until the system exceeds the load requirement and experiences an over-generation condition. Over-generation is when generation – including non-dispatchable renewables, nuclear generation, gas and coal minimum generation levels, run-of-river hydro and reliability -must-run (RMR)

generation – exceeds the system load. Daily generation forecasts preliminarily indicate that generation will exceed system load during certain hours of days, especially in the spring season.

Over-generation is also a challenge to the local distribution system where high penetration levels of distributed solar photovoltaic (PV) will be installed on particular feeder circuits. When there is a low penetration of distributed solar PV, there may be savings from avoided transmission and potential distribution capacity upgrade costs. Conversely, when there is high penetration of distributed solar PV, there may be increased costs associated with the interconnection.

2. "Ramping" capability: "Ramping" capability is the ability of controllable generation resources to increase or decrease output in order to accommodate changes in system load or non-dispatchable VER generation over time. A lack of ramping capability as the solar portfolio increases will cause reliability problems. Historically, the ramping requirement came from variation in load demand; now the ramping requirement has become even greater with increasing amount of VERs. As there are generally more wind and solar VERs in service, special attention is focused on their energy generation characteristics, as is further described.

    - Energy generated from solar PV technology is highly sensitive to cloud cover. Depending on the physical size and location of a PV system, these PV systems can experience significant variations in output. For example, the output from a 50 MW PV plant can vary by 70% in both 60-second and 10-minute time intervals. Therefore, when a single large sized PV facility experiences these rapid changes in power output, the LADWP's power system must also be able to react just as quickly with other generation resources to accommodate such rapid changes. The startup and ramping capabilities of a power system's dispatchable resources will limit the amount of solar that can be implemented without effecting system reliability. A volatility study considering current LADWP planned solar plants is being conducted, and the results will provide estimated solar output volatility for different seasons, and the maximum amount of solar PV that can be accommodated by LADPWP's Power System.

    - Individual wind power plants tend to have a high variability in the amount of energy produced.

- Wind energy production patterns are not usually aligned with daily load patterns.

- Average daily and monthly wind and solar energy production profiles are not representative of actual hourly production, due to the high variability in hourly and sub-hourly energy production.

I.2.2 Potential Solutions and Cost Impact

Discussions to identify potential solutions and cost impacts associated with the operational challenges resulting from high penetrations of intermittent renewables have determined the following:

1. Over-generation is expected to occur during certain hours of the day and energy curtailment will be necessary. A reverse demand response program, more diverse renewable resources, energy storage (including pumped storage hydro), and sales of excess generation may help to mitigate over-generation problems.

2. Detailed studies on the local distribution system will be necessary to avoid significant cost increases from interconnections, due to potential saturation of distributed solar PV beyond individual feeder load requirements. Local distributed solar PV penetration limits should be applied to individual feeder circuits as a means to alleviate the potential for backflow conditions.

3. To provide the necessary ramping capability, newer generation should be able to operate in a more flexible manner, meaning it must be able to start and stop quickly as well as cycle on and off multiple times throughout the day. It should also be able to ramp quickly and operate at low minimum generation levels. LADWP's new modernized units will be far more flexible than the older generating units that they will be replacing, which will help to better integrate VERs.

4. Greater amounts of reserves will be needed to help integrate higher levels of VERs. There is a financial cost associated with increasing on-line reserves and this cost escalates with increasing amounts of VERs. Further studies will be required in order to accurately determine the future costs of integration.

5. Variable generators need to have NERC reliability standard compliant features,

including low-voltage ride-through, voltage control, and reactive power control.

6. Improvements in forecasting accuracy in the day-ahead timeframe, particularly for load, solar, and wind resources, needs to be made available to power system operators.

7. Larger power systems with robust transmission systems tend to have a greater ability to integrate VERs, although voltage stability issues will become more of a concern as more VERs are introduced. Therefore, investments in transmission and more flexible generation resources, and cooperative operational agreements between power system operators and energy providers, will greatly assist in the integration of VERs.

Appendix J - Energy Storage

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J.1 Overview

Historically, LADWP energy storage system (ESS) procurement goals centered around legislation at the state level.

Pursuant to California Assembly Bill (AB) 2514, which became effective on January 1, 2011, LADWP was required to procure viable and cost-effective ESS by December 31, 2016 and December 31, 2021. This was superseded by California AB 2227, which accelerated the energy storage (ES) target date from December 31, 2021, to December 31, 2020. On September 2, 2014, the Board adopted a resolution authorizing procurement of 24 MW of ES by 2016 and an additional 155MW by 2021 consistent with the LADWP's recommendation. In August 2017, a resolution was passed by the Board revising the 2021 ES procurement target to be achieved in 2020. A summary of the LADWP ES procurement targets and achievements is found in Table J-1.

Table J-1: Energy Storage Procurement Targets and Achievements

Connection level	2016 Achieved	2020 Targets	2020 Achieved
Generation and Transmission	21 MW	128.4 MW	320 MW
Distribution	-	25 MW	-
Customer	1.6 MW	2 MW	7.8 MW
Total	**22.6 MW**	**155.4 MW**	**327.8 MW**

In March 2021, the National Renewable Energy Laboratory (NREL) completed and released the Los Angeles 100% Renewable Energy Study (LA100 Study), which evaluated four potential scenarios targeting 100% renewable energy. Of the four scenarios NREL modeled, one is capable of meeting said target by 2035. This is ten years earlier than the 2045 target set by California Senate Bill (SB) 100, which was signed on September 10th, 2021. The study further stated that this target can be achieved through rapid deployment of wind, solar, and ES. For these pathways to be viable, LADWP would have to deploy a minimum of 1,000 MW of ES by 2030 to ensure reliability and address expected load increases. On August 30th, 2021, the Los Angeles City Council unanimously voted to switch to targeting 100% carbon-free energy by 2035.

Procuring over 1,000 MW of ES, both within and outside the basin, by 2030 is a fundamental component of Los Angeles' clean energy future. To achieve this, we begin by identifying the specific needs for ES, and various technologies are evaluated to meet system requirements.

LADWP continues to advance new ES projects, including the Beacon Energy Storage Center situated near our renewable energy facilities in the Mojave Desert.

Going forward, large-scale solar power purchase agreements will incorporate ES, whenever feasible. LADWP is also promoting the development of customer "behind-the-meter" ESS connected to the local distribution network. In 2024, LADWP participated in the Demand Side Grid Support (DSGS) program, administered by the California Energy Commission, which provides incentives to electric customers for reducing load and supplying backup power during extreme events, helping to mitigate blackout risks. These incentives encourage the adoption of behind-the-meter ES by creating additional value for deployment. By the end of the 2024 DSGS season, LADWP had approximately 1.4 MW of battery capacity enrolled in the program.

As of Q4 2024, the Power System deployed 1,505 MW of ES, including 1,450 MW of utility-scale storage, 53.5 MW of customer-owned behind-the-meter storage, and 1.6 MW of utility-owned behind-the-meter storage.

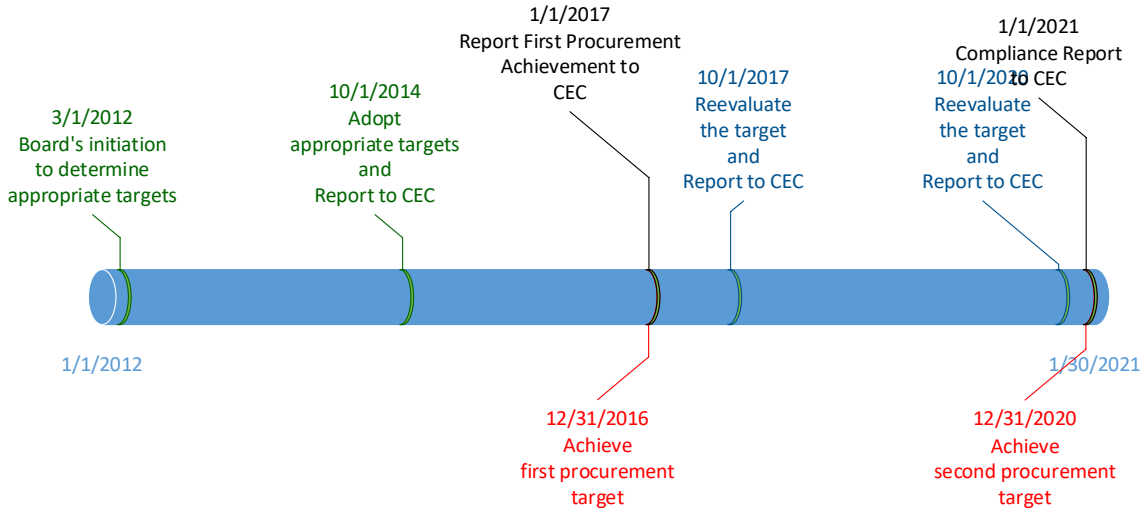


Figure J-1 POU Energy Storage Timeline

J.2 Applications of Energy Storage

ESS can be placed in one of two general categories: systems that are optimized for power output and systems that are optimized for ES. The applications that are best suited for an ESS are determined by how it is categorized.

J.2.1 Applications of Power Optimized Storage Systems

Power optimized storage systems are well suited for applications which use high output power capacity for a short length of time. These applications include Voltage/VAR control, frequency response, ramp rate control, and capacity firming. Volt/VAR control refers to the capability of inverter-based ESS to either source or sink reactive power, resulting in raised or lowered local voltage respectively. As the penetration of distributed generation and renewable generation increases due to LADWP's transition to a renewable energy resource mix, Volt/VAR control will play an increasingly important role in maintaining power quality. ES can provide Volt/ VAR control at transmission and distribution levels.

ES can also provide frequency response to support inverter-based generation from variable renewable sources such as solar PV and wind. Unlike traditional methods of generation, inverter-based generation does not have a rotating mass to synchronize frequency and overcome sudden imbalances between power supply and demand. Synthetic inertia supplied by an ESS can be used to compensate for the lack of physical inertia and maintain the stability of system frequency.

ES can further supplement variable renewable generation by compensating for high rates of change in energy production. This application, referred to as ramp rate control, lessens the negative impact of renewable generation by reducing the rate of demand change seen by the rest of the grid.

With appropriately designed controls, an ESS can be used to compensate for moment-to-moment intermittency in renewable generation. This application, referred to as capacity firming, mitigates some of the power quality challenges that are inherent to generation from variable renewable sources.

J.2.2 Applications of Energy Optimized Storage System

Energy optimized storage systems are well suited for applications that involve storing energy for later use, such as energy-time shifting and maintaining energy reserves.

Energy time-shifting: Energy time-shifting refers to charging the ESS with a significant amount of energy and discharging it later. When integrating with renewable sources, such as wind and solar, energy time-shifting allows the generated energy to be available on-demand and allows for the use of excess energy that would otherwise be curtailed. When used to reduce peak demand, energy time-shifting is also referred to as peak shifting. Peak shifting alleviates stress on transmission and distribution lines, allowing for

the deferral of infrastructure upgrades that would otherwise be necessary. These systems are designed to maximize the amount of energy stored and efficiently deliver it over time.

Maintaining Energy Reserves: LADWP is required to maintain a reserve of generation capacity, which can be categorized as either non-spinning or spinning. Non-spinning reserve refers to generation capacity that can be connected to the power system after a delay, whereas spinning reserve refers to generation capacity that is readily available. Gas-fired generation has been traditionally used for both types of reserve. ES, however, can be used to satisfy some of LADWP's reserve requirements while reducing fuel consumption and Green House Gas (GHG) emissions.

J.3 Energy Storage Technologies under Consideration

The following are some of the ES technologies that are being considered:

J.3.1 Emerging Technologies: Long Duration Energy Storage

Due to regulatory requirements and anticipated load growth from the clean energy transition, the ESS industry has been focusing on developing and screening for a reliable long-duration energy storage (LDES) technology. More specifically, California's SB 100 mandates 100% of retail electricity sales to customers by 2045 to be from carbon-free resources. Integration of more renewable energy resources comes with its own set of challenges, such as generation intermittency and power quality issues that ESSs are well-positioned to address.

The Los Angeles's 2019 Sustainability plan under Mayor Eric Garcetti's LA's Green New Deal further set intermediate goals for LA's renewable energy supply leading up to 100% by 2045.

California Governor Gavin Newsom issued Executive Order N-79-20 in 2020, requiring all new sales of passenger vehicles in California to be zero-emission vehicles by 2035. This order, in conjunction with the transportation electrification goals in the LA Green New Deal, means grid stress from electric vehicles (EV) is expected to increase greatly in the future.

While LDES definitions vary across entities, most generally agree that an ESS must have a duration of 10 hours or more to qualify as a LDES technology. The longer duration has several benefits over the traditionally deployed shorter duration lithium-ion BESS technology:

- Support integration of higher amounts of renewable energy resources by mitigating intermittent generation and overgeneration.

- Increases grid resiliency by providing ESS applications for longer periods of time.

At the time of updating this LA100 Plan, emerging LDES technologies include Compressed Air Energy Storage (CAES), Flow Battery ESS (BESS), and Pumped Heat Thermal Energy Storage (PHTES). LADWP continues to investigate and evaluate LDES technologies for potential grid-scale deployment in collaboration with EPRI under various programs and studies.

J.3.2 Battery Energy Storage

BESS are used extensively in LADWP's plans for future ES projects. Many of these planned projects utilize lithium-ion batteries, which have become the most widely used battery type in the utility space. In addition to lithium-ion, LADWP is exploring other battery technology options such as flow batteries

J.3.2.1 Lithium-ion Battery

Lithium-ion batteries are a type of battery in which lithium ions move from the negative electrode to the positive electrode during discharge. Rechargeable lithium-ion batteries use an intercalated lithium compound as the electrode material, in contrast to the metallic lithium used in non-rechargeable lithium batteries. Electrolyte and two electrodes are the primary components of a lithium battery cell. Lithium-ion Battery strengths and weaknesses can be seen in Table J-2.

Table J-2 Lithium Battery Technology Summary

Strengths	Weaknesses
• High energy density • Lower cost • Commercial availability • Maturity of logistics and supply chain	• Lower state of charge (SOC) tolerance range • Shorter life span • Flammable

J.3.2.1.1 Industry Efforts to Enhance Lithium-Ion Battery Safety

The lithium-ion battery industry has faced several thermal runaway incidents involving fires and explosions, highlighting the need for enhanced safety measures. In response, key stakeholders—including battery original equipment manufacturers (OEMs), system integrators, the U.S. Department of Energy (DOE), the National Fire Protection Association (NFPA), the Electric Power Research Institute (EPRI), utilities, regulators, and research institutions—have collaborated proactively to improve safety through prevention, mitigation, and education.

J.3.2.1.1.1 Regulatory and Code Enhancements

A major aspect of this effort has been the continuous refinement of fire codes and safety standards. The NFPA has introduced and updated several key regulations, including NFPA 855, which governs the installation of stationary ESS, as well as NFPA 70 and NFPA 69, which address electrical safety and explosion prevention. Meanwhile, organizations such as Underwriters Laboratories (UL) and the Institute of Electrical and Electronics Engineers (IEEE) have been instrumental in developing stringent certification and testing protocols to ensure that lithium-ion battery systems meet rigorous safety criteria. These evolving codes and standards provide a critical framework for guiding manufacturers, integrators, and ES facility operators in designing and implementing safer systems.

J.3.2.1.1.2 Technology and Design Improvements

At the same time, battery manufacturers and integrators have been working to improve the technology itself. Advances in battery management systems (BMS) are allowing for

real-time monitoring and automated shutdown capabilities, reducing the likelihood of thermal runaway events. Improved thermal management strategies, including liquid cooling and phase-change materials, are being integrated into battery systems to prevent overheating. Engineers are also exploring the use of fire-resistant materials and coatings, as well as designing better separators to minimize the risk of internal short circuits. Additionally, site designs for BESS are evolving to incorporate explosion and deflagration control mechanisms, such as pressure relief systems, gas detection sensors, and optimized ventilation configurations.

J.3.2.1.1.3 Risk Prevention and Incident Mitigation

Beyond technological advancements, the industry has also placed a strong emphasis on risk prevention and incident mitigation. General site and system specifications are being developed to ensure that battery storage facilities are properly spaced and equipped with robust containment measures. Lessons learned from past battery incidents are being systematically documented and analyzed to inform best practices and improve future deployments. Research into fire suppression technologies, including water-based and aerosol-based extinguishing agents specifically tailored for lithium-ion battery fires, continues to refine emergency response strategies.

To complement these mitigation efforts, the industry made significant progress in improving emergency response programs. Collaborations between utilities, fire departments, and regulatory agencies have led to the development of detailed emergency response plans designed to address lithium-ion battery fires and explosion hazards. Fire protection organizations are conducting specialized firefighter training programs, equipping first responders with the knowledge and tools needed to handle battery-related incidents safely. Additionally, real-world emergency response drills and simulations are being conducted to test and refine best practices, ensuring that fire departments and facility operators are well-prepared to act swiftly in the event of an emergency.

J.3.2.1.1.4 Training, Education, and Industry Collaboration

Education and training have also become critical components of the industry's safety initiatives. Utilities, OEMs, and fire protection organizations have launched firefighter training programs to equip first responders with the knowledge and tools needed to manage battery-related emergencies safely. The industry is also collaborating with

insurance companies and risk assessment firms to develop safety-driven criteria for underwriting policies and financial protections. Meanwhile, research institutions and pilot projects are exploring the potential of next-generation battery technologies, such as solid-state batteries and non-flammable electrolytes, which could offer inherently safer alternatives to conventional lithium-ion chemistries.

J.3.2.1.1.5 A Safer Future for Lithium-Ion Batteries

Through these concerted efforts, the lithium-ion battery industry is making significant progress in improving safety and reliability. By combining technological innovation, regulatory enhancements, risk mitigation strategies, and workforce education, stakeholders are working to ensure that lithium-ion batteries remain a viable and secure ES solution for the future.

J.3.2.2 Flow Battery

Flow batteries are a type of battery which use two liquid solutions separated by a membrane. Flow batteries are composed of two key components: cell stacks and tanks of electrolyte. The most popular flow battery on the market uses vanadium redox technology, which uses charged vanadium in a diluted sulfuric acid solution to store energy. Other emerging types include iron flow batteries that utilize an iron-based electrolyte. The appeal of flow batteries in grid applications is that they combine the strengths of both conventional batteries and fuel cells. Strengths and weaknesses of flow batteries can be seen in Table J-3.

Table J-3. Flow Battery Technology Summary.

Strengths	**Weaknesses**
• Scalability • Long cycle life • Wide SOC tolerance range • Lesser environmental impact • Lower cost at utility-scale • Non-flammable	• Low energy density • Low efficiency compared to other battery types • Lower commercial availability • Maturity of logistics and supply chain

J.3.3 Thermal Energy Storage

Thermal Energy Storage (TES) have traditionally been systems that use conventional air conditioning equipment and a storage tank to time shift electricity used for space cooling in customer facilities from peak periods to off-peak periods. This time shifting is performed by producing ice or chilled water during off-peak periods and circulating this ice or chilled water during peak periods to produce the desired cooling. TES system installations can be an effective alternative to adding generation capacity and/or demand response programs.

J.3.4 Pumped Heat Thermal Energy Storage

PHTES is an emerging technology that falls under the broader category of TES. It utilizes a heat pump cycle to store energy as a temperature difference. The process begins with electrical energy powering a heat pump, which converts electricity into thermal energy. This thermal energy creates a temperature differential that is stored in separate mediums—cold energy in a chilled liquid, such as a coolant, and heat in another storage medium. When energy is required, the stored temperature difference is converted back into electricity using a heat engine.

J.4 Description of LADWP Developed Energy Storage Systems

J.4.1 Castaic Hydroelectric Power Plant

Castaic Power Plant is a seven unit pumped storage hydroelectric plant owned and operated by LADWP located near Castaic Lake, approximately 22 miles north of the Los Angeles upper-city limits. Pumped storage is a mature ES technology used throughout the utility sector. Castaic Power Plant provides ES in the form of water pumped and stored in Pyramid Lake reservoir on the west branch of the California State Aqueduct. The power plant is a cooperative venture between LADWP and the Department of Water Resources of the State of California. An agreement between the two organizations was signed on September 2, 1966 for construction of the

project. Castaic Power Plant, Units 1 through 6, reversible units that function as pumps as well as generators, were rated at over 250MW each, Unit 7, a conventional generator unit , was rated at 56 MW. with a combined total plant rated capability of 1,265 MW. Units 1 through 6 function as pumps as well as generators, whereas Unit 7 is a conventional unit. The plant's capability to pump and generate without emissions or fuel consumption increases the operating flexibility and cost effectiveness of the facility. The plant has been in operation since the early 1970s, and major overhauls have increased reliability and unit performance. Castaic Power Plant now has a combined total rated capacity of 1,265 MW. Table J-4 below provides additional information on upgrades to Castaic Power Plant.

Table J-4. Castaic Power Plant Recent Upgrades.

	Unit No.	Date First Carried System Load	Rating (MW)	Recent Upgrades	New Rating (MW)	Net Increase (MW)
Castaic Power Plant	1	7/11/1973	250	11/21/2013	271	21
	2	7/9/1974	250	9/8/2004	271	21
	3	7/13/1976	250	7/10/2009	271	21
	4	6/16/1977	250	6/10/2006	271	21
	5	12/16/1977	250	7/12/2007	271	21
	6	8/11/1978	250	12/25/2005	271	21
					Total =	126

Castaic Power Plant will continue to be an important asset to LADWP. LADWP utilizes Castaic Power Plant to store thousands of megawatt-hours of energy to maintain reliability of the Power System through essential grid services including (i) balancing load and generation, (ii) integrating intermittent energy resources, and (iii) providing crucial ancillary services to the grid such as reactive power support, regulation and frequency response, and operating reserves (both spinning and supplemental).

Castaic Power Plant plays a crucial role in meeting LADWP resource adequacy, improving system-wide reliability, and integrating renewable energy resources now and in the future. Its presence in LADWP's resource mix significantly impacts LADWP ESS procurement decisions.

J.4.2 Thermal Energy Storage (TES) Systems

The LADWP has promoted TES technology to its customers since the early 1990s, offering incentives and rebates for successful TES installations.

Notable installations at the University of Southern California (USC) and the University of California at Los Angeles (UCLA) were implemented to reduce peak demand by up to 9 MW. Peak demand reduction enhances LADWP's load factor by shifting customer load from peak to off-peak periods.

LADWP also provided a rebate to Los Angeles International Airport (LAX), a major customer within its service territory to implement TES for peak load shifting (PLS). The incentive was based on the maximum capacity shifted using the rebated TES system. Testing confirmed the LAX TES system contributed 1,250 kW toward LADWP's procurement targets. Table J-5 below provides a list of completed thermal storage systems in LADWP's service territory.

Table J-5. Completed TES Projects.

Facility Name	Project In-Service Date	Peak Reduction Capacity
LACCD—LA Valley College	5/2021	593 kW
Century Theaters, Inc.	8/2016	23 kW
Los Angeles World Airports (LAX)	1/2015	1,250 kW
Sylmar Converter Station	3/2011	97 kW
McDonalds	7/2008	30 kW
Taix Restaurant	12/2005	4 kW
LADWP Boyle Heights Facility	10/2005	6 kW
University of Southern California (USC)	1/2006	4,375 kW
University of California, Los Angeles (UCLA)	6/2004	4,668 kW
	Total	11,046 kW

J.4.3 Beacon BESS, Phase I

Commissioned in 2018, LADWP's first grid-scale BESS is a 20 MW/10 MWh lithium-ion system built in response to Aliso Canyon gas reserve shortages. The system interconnects at LADWP's largest renewable energy corridor which is planned to

supply LADWP with significant amounts of solar photovoltaic and wind generation. The BESS provides LADWP's grid with frequency regulation, frequency control, and load following capacity while alleviating stress and emissions from gas-fired generating units. LADWP is reviewing plans to procure additional energy storage in this area.

J.4.4 Eland BESS, Phase I & II

In response to SB 801, LADWP conducted a cost-effectiveness study for BESS procurement. The study determined that pairing a 100 MW BESS project with a 200 MW Solar project after 2022 would be cost-effective due to declining battery prices. Pairing solar generation with ES allows for dispatchable renewable energy – shifting excess energy to high demand periods – which helps in reducing reliance of gas generation while providing ancillary services for a stable grid. Subsequently, LADWP issued an RFI and evaluated development opportunities for solar plus BESS project proposals from 130 vendors.

On November 6, 2019, Los Angeles Mayor Eric Garcetti and LA City Council approved a power purchase agreement (PPA) for the Eland solar and storage project. Paired with Eland solar generation in the Mojave Desert, Eland BESS is a 300 MW/1,200 MWh lithium-ion BESS procured through SCPPA. LADWP claimed 281 MW/1,124 MWh toward procurement targets with its share of the BESS. Eland BESS complements the Eland solar facility via energy-time shifting of renewable energy overgeneration to help supply LADWP's evening peak loads, among other ancillary services applications described previously. Eland Phase I was commissioned in 2024, and Phase II is expected to be commissioned in 2025.

J.4.5 Pilot Energy Storage Projects

J.4.5.1 La Kretz BESS

Location: 525 S. Hewitt St, Los Angeles, CA 90013

A 60 kW/222 kWh (approx. 3.7h) lithium-ion BESS was integrated into the existing solar panel system at La Kretz Innovation Center in 2016 to create a micro-grid demonstration. This system is used for demonstration purposes to the public and provides some peak-

shaving and back-up power benefits to the facility. The La Kretz Innovation Center is an incubator for several clean technology start-ups and LADWP demonstration facilities, including the Energy Efficiency and Emerging Technology Center, Customer Engagement Center, and Energy Efficiency/Water Conservation Laboratory.

J.4.5.2 Truesdale Training Center BESS

Location: 11781 Truesdale St, Sun Valley, CA 91352
This early lithium-ion BESS project consists of 56.6 kW/113.2 kWh (approx. 2h), located at LADWP's Truesdale Training Center. Commissioned in 2017, it was designed to help LADWP staff develop hands-on experience with lithium-ion BESS installation, interconnection, and operations.

J.4.5.3 LAFD Fire Station 28 BESS

Location: Los Angeles Fire Department Fire Station 28, 11641 Corbin Ave, Porter Ranch, CA 91326
In February 2018, LADWP completed the installation of a solar and battery system at Los Angeles Fire Department (LAFD)'s Station 28 near Porter Ranch to increase the resiliency of the station. The site consists of a 12 kW/40 kWh lithium-ion battery and 11 kW rooftop solar array. The system was designed to provide backup power for critical loads at the station, shift the peak demand, and provide demand-response capabilities. Incidentally, on March 22, 2018, there was a power outage due to heavy rain that lasted over seven hours. The BESS was sufficient to provide backup power to Fire Station 28 during this outage. LADWP later transferred the solar and battery system to the Los Angeles General Service Department facility.

J.4.5.4 JFB BESS

Location: 111 N Hope St, Los Angeles, CA 90012
In 2019, in a joint project with EPRI, LADWP commissioned an ES system at its headquarters, John Ferraro Building (JFB) in downtown Los Angeles. The John Ferraro Building Battery Energy Storage System (JFB BESS) is a research project consisting of two 100 kW/400 kWh (4h) BESS utilizing flow battery and lithium-ion technologies. The project aims to evaluate the performance of flow battery technology by benchmarking it

against lithium-ion battery performance. This project will inform technology selection decisions in LADWP ES planning and deployment efforts to meet 100% carbon-free energy goals. If the flow battery performance is deemed acceptable, LADWP will have another option for ES deployment with economical long duration (more than 4h), minimal degradation, and minimal fire risk benefits. This effort will pave the way for deploying multiple large-scale ES projects at transmission and distribution level.

J.5 Energy Storage Projects in Development

J.5.1.1 Beacon Phase II Long Duration Energy Storage

LADWP continues to advance new ES projects, including the 50 MW Beacon LDES project, strategically located near multiple renewable energy facilities in Mojave, California. Following its successful commissioning in 2029, LADWP plans to expand the technology to various locations within its balancing authority area.

J.6 Energy Storage Target Setting Methodology

LADWP begins by identifying the specific needs for ES, which plays a vital role in supporting grid stability through functions life frequency regulation, spinning and non-spinning reserves, frequency response, black start, and voltage regulation. Project locations are determined and prioritized based on transmission needs, potential solutions, and feasibility analysis.

Various technologies, including lithium-ion and flow batteries, TES, and CAES, are evaluated to meet system requirements. Each option is assessed for its technology readiness level, charging source, supply chain constraints, cycle life, efficiency, complexity, geographic considerations, and footprint. Safety and end-of-life recycling are also critical factors in technology selection. Collaboration with the Electric Power Research Institute (EPRI) enables LADWP to conduct studies, analyze data, and engage with vendors, fostering new insights and staying current with the ever-evolving ES industry.

The process described above and detailed in the LADWP Energy Storage Development Plan is illustrated in Figure J-2.

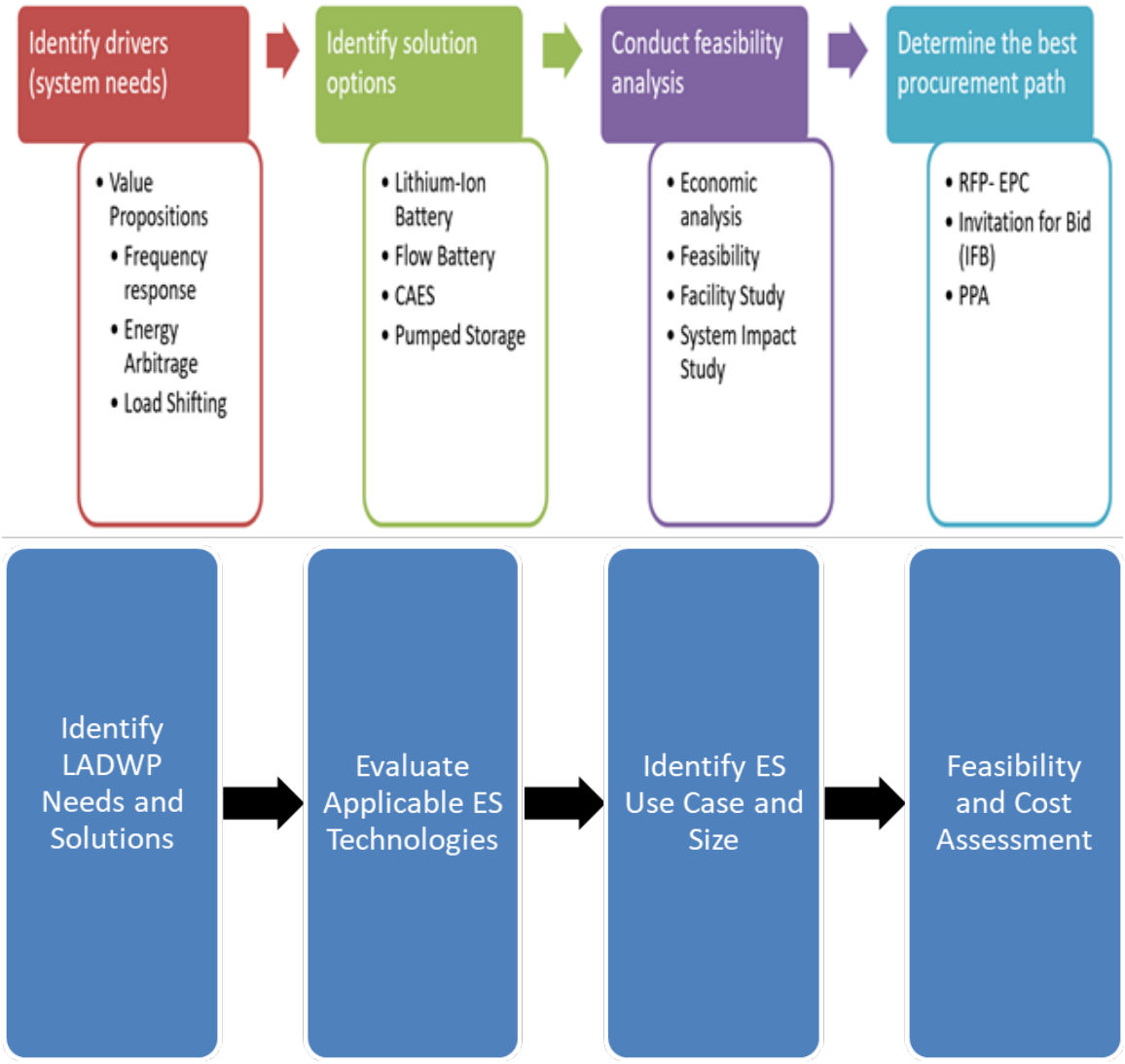


Figure J-2. ESS Target Development Process.

J.7 Energy Storage Procurement Targets Summary

LADWP set updated goals to meet 1,000 MW of ES by 2030. A summary of the projects in planning can be seen in Table J-6.

Table J-6. Summary of Planned Energy Storage Projects.

Project Name	Planned Capacity (MW)	Energy MWh	Duration (Hr)	Target COD
Beacon Long-Duration Energy Storage	50	250	5	2029
Adelanto BESS	500	2,000	4	2030
In-Basin Project	55	275	5	2031
In-Basin Project	50	200	4	2033

J.8 Procurement Approaches

LADWP may increase ES deployment through five main approaches:

- LADWP Ownership
- Power Purchase Agreements
- Build-Own-Operate-Transfer (BOOT) Agreements
- Customer Incentive Programs
- Collaborative Ownership

J.8.1 LADWP Ownership

LADWP may procure generation, transmission, and distribution connected ESS through its competitive solicitation process by issuing a Request for Proposal (RFP) to potential suppliers. The RFP outlines the bidding process, outlines the contract terms, and provides guidance on how the bid should be presented. An RFP is typically open to a wide range of bidders, creating open competition between companies. To issue an RFP, LADWP follows guidelines that include but are not limited to (i) informing vendors about LADWP procurement needs and encouraging them to participate in the bidding process, (ii) informing vendors about the

competitive nature of the selection process, (iii) allowing a wide range of solutions and responses, (iv) ensuring that the vendors are responsive to the bid and ensuring that vendors' responses are consistent with the identified requirements, and (v) following LADWP's evaluation and selection procedure to ensure impartiality in the awarding process. Under this structure, LADWP will own the facility starting from year one.

J.8.2 Power Purchase Agreements

Grid-scale ES can be procured through power purchase agreements (PPA) or Energy Service Agreements (ESA) between LADWP and a third-party developer. Under this approach, the third-party developer retains ownership of the energy storage asset and is responsible for its operation and maintenance. LADWP purchases the right to use the ES capacity for its needs according to a predetermined payment structure.

J.8.3 Build-Own-Operate-Transfer Agreements

In addition to the LADWP ownership approach previously described, LADWP may also use build-own-operate-transfer (BOOT) agreements. By deferring to a power purchasing agreement structure until the terms of transfer are met, LADWP is able to mitigate the inherent risk in emerging LDES technologies. The operating period allows time to evaluate the performance of the project while the developer operates the ESS according to our instructions.

J.8.4 Collaborative Ownership

LADWP has successfully procured many projects through SCPPA, which encourages joint ownership among its members. LADWP will continue to actively look for collaborative opportunities with SCPPA members for ESS procurement projects. Responders to SCPPA's RFPs may propose the following options:

- Project ownership by SCPPA

- Power purchase agreement or an equivalent commercial agreement with an ownership option

- Power purchase agreement or an equivalent commercial agreement without an ownership option

J.9 Rate Recovery

The procurement of ESSs described herein will have a significant impact on LADWP's power system both operationally and financially. Operationally, incorporating ESSs into the grid may improve the overall system reliability, especially with the integration of renewable energy resources, but may add complexity to the day-to-day operation of the LADWP bulk power system. Financially, ESS procurement requires capital investment. While the rates and charges of investor-owned utilities (e.g. PG&E, SCE, and SDG&E) are approved at the state level, rates and charges for LADWP are approved at the local government level by the Los Angeles City Council. To obtain approval for ES procurement targets from LADWP's Board of Commissioners, LADWP must first demonstrate that meeting these procurement targets will (i) be cost-effective, (ii) improve the reliability of the grid, thereby providing significant savings to the Los Angeles City ratepayers, and (iii) not risk impacting ratepayers with unnecessary costs for ESSs that do not have direct utility or customer benefits. These guidelines form the basis for the LADWP ES procurement targets.

Appendix K - Advanced Technologies Infrastructure

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K.1 Background

The electric and water utility industry has been undergoing a major transformation driven by several environmental, economic, regulatory, and strategic challenges. To effectively tackle the challenges associated with addressing climate change and energy independence, and continually improve customer service while maintaining low costs, utilities are looking at advanced technologies to transform their business.

The Los Angeles Department of Water and Power (LADWP) must continue to ensure reliable service, maintain competitive rates, reduce emissions, and transition to a cleaner energy generation base. LADWP has adopted inspiring visions to become a utility supplying 100% carbon-free energy by 2035, and at the same time, is facing growing demand due to increasing population and special occasions such as hosting Olympics and FIFA World Cup in the City of Los Angeles in the next few years.

Meeting these challenges requires maximizing reliability of the power grid, automation, and remote data communications. LADWP's Advanced Technologies Infrastructure Division has established several programs to implement these goals. The Distribution Automation (DA) Program was created in 2018, and parts of this program were later spun out into the Advanced Metering Infrastructure (AMI) Program and the Line Monitoring (LM) Program. These programs utilize lessons learned and achievements from previous similar efforts within LADWP, such as Smart Grid Regional Demonstration Program (SGRDP), and Smart Grid Implementation Plan (SGIP).

In 2018, considering industry's progress in distribution line monitoring and use of reliable two-way communication networks to communicate with DA and metering devices, LADWP decided to plan and execute the DA and AMI programs to address ongoing challenges with the distribution system, and test some of the automation solutions, as well as two-way communication network.

Improving reliability of distribution network (measured by indices such as SAIDI and SAIFI) was introduced as one of the main objectives.

K.2 Vision for Advanced Technologies Infrastructure

The following paragraphs provides an essence of the Advanced Technologies Infrastructure vision.

- "LADWP envisions to have all the foundational elements in place to build a smarter, more reliable distribution system that effectively utilizes new technology and innovation to improve system reliability and customer experience."

- … "this program's vision… is for a resilient distribution system that has the intelligence required to automatically self-heal, greatly reduce outage duration and frequency, and shift our employees' focus toward proactive decision-making rather than reacting to issues after they occur."

K.3 Advanced Technologies Infrastructure Objectives

The current objectives of Advanced Technologies Infrastructure programs are listed below.

- DA Program
    - Enable applications such as Volt Var Optimization (VVO), automated switching, Fault Location, Isolation, and Service Restoration (FLISR), and other automation technologies
- AMI Program
    - Implement a city-wide communication network across LADWP's service territory
    - Deploy new smart meters across LADWP's service territory
    - Build integrations with critical systems

- Fully operationalize AMI, including effective system operation
- Improve the billing process through automation
- Evaluate and implement new or modified business processes

- LM Program
  - Identify and prioritize monitoring for circuits with the greatest need for additional visibility
  - Evaluate several vendors and sensor products
  - Deploy line monitoring sensors across the entire distribution system

K.4 Individual Projects and Value Proposition

To accomplish the objectives of the DA and AMI Program in various disciplines, of the program was divided into individual projects, as listed below.

K.4.1 Communication Network Project

The mission of the Communication Network (COM) project is to study, site survey, design, and create a city-wide communication network to establish reliable and secure two-way wireless communication with DA devices and smart meters.

The COM Project includes the following scope:

- Conduct **site surveys** throughout LADWP's service territory to identify the best locations for communication network devices.
- Prepare **communication design packages** to identify quantity and location of devices for providing optimal communication coverage through LADWP's service territory.

- **Install Access Points and Relays** throughout LADWP service territory.to cover all future smart meters, DA devices, and line monitoring sites.

- Following the completion of device installations**, test performance of communication system**, and install additional devices to optimize the network.

Access Points collect the data from all the endpoints and back-hauls to the back office. Relays function as 'repeaters' for the RF mesh extending the RF mesh communication so the data can "hop" towards a nearby Access Point (Figure K-1).

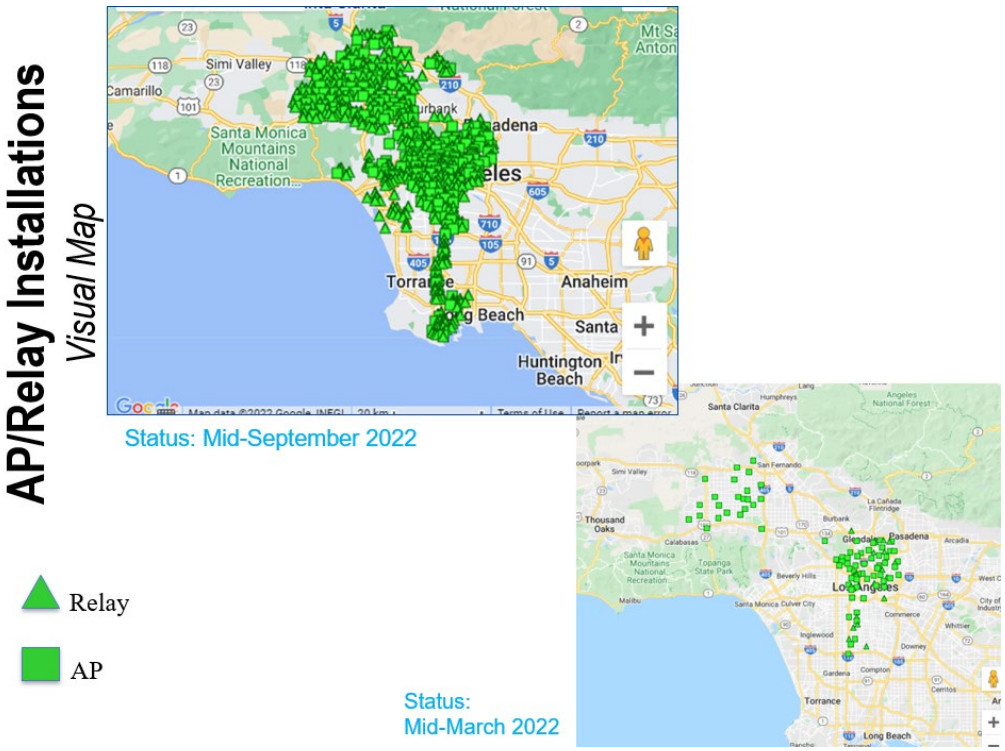


Figure K-1 Installation of Access Points and Relays as of September 2022.

K.4.2 Distribution Automation Project

The mission of the Distribution Automation (DA) project is to study and design automation of the distribution system, including FLISR, VVO, and other operational practices of distribution circuits. Equipment controllers and sensors for capacitors, switches, reclosers, and other devices may be installed as part of this effort.

The DA scope includes:

- Creating a lab for the testing and implementation of DA devices and communication equipment

- Installing **reclosers and capacitor bank controllers** to enable automated operations such as Fault Location, Isolation, and System Restoration (FLISR) and Volt Var Optimization (VVO).

- Install **Voltage Regulator controllers** to support automated control of voltage level through the distribution circuits.

- Install **Distribution Automation Controller (DAC)** to receive data from DA field devices, process based on pre-configured models, and send commands as needed to conduct automated actions.

- Install **DA communication devices.** Master Bridges will be deployed at stations and communicate with the Energy Control Center (ECC) via the Fiber Optic network. Remote Bridges will be installed in Distribution Automation equipment controllers on distribution circuits and will utilize the RF communication network to transmit data to the Master Bridges.

K.4.3 Back Office Project

The mission of the Back Office (BO) project is to support data collection and enable remotely operable functions for all field devices and endpoints that are part of the communication network, distribution automation system, and AMI meters.

The BO scope includes:

- **Installation of software and servers** to remotely collect and store data from metering and DA devices, to monitor communication, and to use data for various functions.

    - Security measures have been added to the back-office applications such as data encryption and decryption, preventing bad-actors from causing harm like disconnecting a large number of smart meters.

K.4.4 Systems Integrations

The mission of the Systems Integrations project is to study, design, and deploy necessary integrations between systems and applications to meet the objectives of the AMI and DA Program and make the systems work together as a whole.

The Systems Integrations Project includes the following scope:

- Implement a "service bus" to facilitate data exchange between various applications.
- Integrate various Power Systems applications with the service bus to facilitate data communication between the systems.
- Develop a set of business processes for various functions related to DA use cases.

K.4.5 Smart Meter Project

The mission of the Smart Meter Program is to modernize the utility's metering infrastructure by deploying advanced metering technology that supports improved data collection, operational efficiency, and customer engagement. By leveraging smart meter technology, the utility aims to enhance system visibility, improve service reliability, and lay the foundation for future grid modernization efforts.

This project includes the following key components:

- Installation of approximately 1.6M smart meters across the service territory.
- Deployment of supporting communications infrastructure to enable secure, two-way data transmission between field devices and utility systems.
- Integration of smart meter data into the utility's back-office applications, including billing, load analysis, and outage management systems.

- Assessment of customer engagement tools that provide near real-time usage insights to help customers better manage energy consumption.

Smart meters enable the utility to remotely collect granular usage data, including 15-minute interval load profiles, and transmit this information over a wireless network to centralized systems for storage and analysis. This real-time visibility into energy usage supports improved demand forecasting, outage detection, and system planning, while also offering customers access to more detailed and timely usage information.

K.4.6 Line Monitor Deployment Project

The mission of the project is to increase visibility of the distribution system by installing monitoring equipment on circuits throughout LADWP's service territory. Line monitors can include various sensors for measuring current, voltage, and temperature. This data can be used for fault detection and load flow analysis.

This project includes the following scope:

- Evaluate sensors and technologies from multiple vendors. Supplier diversity may enable more use cases and will reduce supply chain risks.

- Utilize multiple communication networks if feasible, including one or more cellular providers and potentially the DA/AMI communication network. Putting various monitors on separate networks will reduce the risk of losing all grid visibility if any single system fails.

- Deploy line monitoring sensors across the entire distribution system, prioritizing circuits with the greatest need for additional visibility. Factors that may influence priority include the level of automation on a circuit or at the station feeding it, reliability indices (SAIDI, SAIFI), power quality (power factor, voltage), and rate of failures.

- Support the integration of line monitors with other systems that support operations, such as SCADA, to enable real-time alerts.

K.5 Benefits of Grid Edge Technologies

The Los Angeles Department of Water and Power believes that strategic investments on Advanced Metering Infrastructure and Distribution Automation is a foundational requirement to evolve the system to achieve the goals set forth in LA100 and will also produce long term benefits for the customers, environment, and our society as a whole, such as the benefits listed below.

K.5.1 Improving Distribution System Reliability

By using line monitors and automation of operations throughout the distribution circuits, frequency and duration of outages will be significantly reduced, improving reliability throughout system. It will also provide information and data to improve maintenance and replacement programs needed to meet growing energy demands.

K.5.2 Improving Power Quality

Monitoring power quality elements of distribution grid such as power factor and voltage stability, identifying issues and mitigating them through DA devices such as cap bank controllers and/or implementation of volt-var optimization will result in improvement of power quality for customers. Improving power factor on the distribution grid can maximize real power flow and reduce overloading leading to longer asset life for distribution lines. Smart meters will also have the ability to report any voltage sag, swell, fluctuations, and power outages.

K.5.3 Efficient Power Outage Detection and Restoration

Smart meters provide alarms and alerts to the operators in case of a power outage in a timely manner. Customer convenience and utility's revenue will be improved due to pro-active outage response and repair. The alarms and alerts will be reported to Outage Management System (OMS) so the process for restoration can be initiated in a proactive manner.

K.5.4 Resource and Vehicles Reduction in Field Operations

Remote monitoring, data reading, and automated distribution grid operations, such as isolation of faulty circuit, opening and closing circuits for system restoration, enabling or disabling controllers, etc. will result in reduction of field operations, and therefore, saving on operational costs.

K.5.5 Improving Safety

By reducing the manual tasks in the field, and relying on automated operations, the work environment will be safer for the utility personnel, as well as the customers.

K.5.6 Enabling Many Future Possibilities with the City-Wide Communication Network

The RF mesh network can be leveraged for various projects and objectives in the future. Potential communication with all electric and water meters, streetlight controllers, transformer monitors, etc. can all be enabled on the same 900 MHz RF mesh network that has been deployed.

K.5.7 Enabling Full Deployment of Advanced Metering Infrastructure (AMI)

With the deployed RF mesh network as well as back-office applications, and a population of smart meters that indicate successful operation of this system as a whole, LADWP can be confident that the full deployment of smart meters throughout the system territory can be achievable.

K.5.8 Societal Benefit: Reduction in Green House Gas (GHG) Due to Reduction in Use of Vehicles

Less use of vehicles in field operations due to automated operations, as described in previous section, will cause a reduction in generation of greenhouse gas emissions.

Appendix L - Power System Integrated Human Resource Plan (IHRP) Report

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L.1 Introduction

LADWP's Power System is undergoing a major transition that will require an unprecedented build-out of its generation, transmission, and distribution infrastructure and a monumental transformation of its workforce to ensure the necessary and qualified level of staffing is in-place to sustain and realize its various initiatives and goals.

In essence, Power System needs to attract, develop, and maintain a high-performing, diverse, engaged, and flexible workforce with the skills needed to adapt to workload changes and to effectively carry out its mission now and in the future. To achieve this objective in a dynamic workload environment where work forecasts change, skills required of the workforce evolve, and onboard skills inventories shift, this Integrated Human Resources Plan (IHRP) is developed to help integrate Power System's workload projections, skills identification, human capital management, individual development, and workforce management activities.

The IHRP is prepared to lay the foundation for Power System to more effectively identify and align its workload, skillset needs, and organizational structure iteratively to significantly reduce its vacancy rates and meet its short- and long-term human resources and operational objectives.

Through consultation with all Power System Divisions, the IHRP aims to address all Power System human resource needs required to keep the lights on, expand the electric system infrastructure to support future load growth, develop future transmission infrastructure, and develop/operate new energy resources prescribed by the LA100 Plan. The IHRP includes a road map and a set of recommendations to help the Power System determine the appropriate level of staffing each year as well as identify the gap between present and future capabilities and capacities.

This IHRP report is organized into the following sections:

- Purpose and Background summarizes the project history, overall objectives, strategic priorities, hiring constraints, methodology used, proposed schedule, assumptions, data sources, and proposed scenarios.

- Current State presents the Power System organization, functions, demographics, vacancies, retirement data, succession planning, and employee survey results.

- Future State presents Power System's work backlog, future work scenarios, and the skillsets needed to fulfill the scenarios.

- Next Steps summarizes the results and presents policy recommendations and next steps.

L.2 Purpose and Background

LADWP is leading the transformation of its electricity grid and resource systems to meet the decarbonization goals established by the City of Los Angeles (City).

Achieving 100% carbon-free energy by 2035 is a venture that requires LADWP to prepare itself and its workforce to effectively and efficiently deliver the LA100 program. Empowered by the LA City Council directive to provide affordable, equitable, and reliable renewable and zero-carbon energy to all LADWP customers, LADWP developed the IHRP to realize this transition.

L.2.1 IHRP Objectives

Power System must adapt to new ways of doing business in the midst of an accelerated transformation of the electric utilities industry. The emphasis is more than ever for Power System to explore ways of doing business that promote agility, speed, and innovation, all of which become compromised in the absence of dynamic and robust human resource practices. The objectives of the Integrated and Division Human Resource Plans are discussed below.

L.2.1.1 Power System Integrated Human Resource Plan

The IHRP 3.0 – hereafter referred to as simply IHRP – is a process used by Power System's Executive Office for the management of human resources working in the entire Power System. A core objective of the IHRP (Figure L-1) is to address the challenge of maintaining the appropriate number of employees in every Power System Division. The IHRP aims to proactively manage the rapid transformation of Power System due to changes in regulations and public policies, new and emerging technology products, and

high customer expectations. These changes call for continuous allocation or reallocation of skills. In the absence of such planning, there might be an underutilization of human resources, or worse, a lack of staffing to carry out various Power System initiatives. Each Power System Division will have its own Division Human Resource Plan. The integration of all Power System Division Human Resource Plans forms the IHRP. As such, each Power System Division Human Resource Plan is a subset of the IHRP.

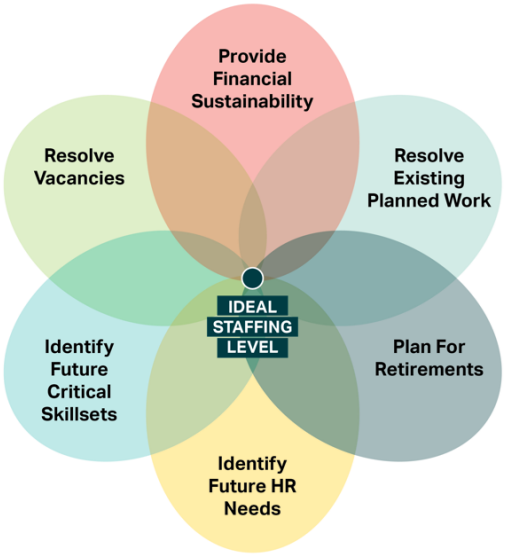


Figure L-1 Ideal Staffing Level Process.

L.2.2 Power System's Strategic Priorities

Power System is undergoing an accelerated transformation due to changing regulations, legislation and policies, technology advancements and innovation, and increasing customer choice and expectation. To keep pace, Power System needs to adapt to new ways of doing business, invest in the operation and the modernization of its electric infrastructure, and invest in the human resources needed to sustain this transformation. This transformation will come with unprecedented challenges. By anticipating these challenges, the IHRP identifies opportunities to affirm Power System's strategic priorities. These include energy transition, grid resiliency, building and transportation electrification, innovation, and equitable energy.



Energy Transition



Grid Resiliency



Building & Transport Electrification



Innovation



Equitable Energy

L.2.2.1 Energy Transition

As the energy transition accelerates, Power System will need to invest in every aspect of its operations from generation to transmission and distribution assets, to human resource needs to meet its goal of achieving 100% carbon free renewable energy by 2035. Power System is already tackling this challenge by developing the LA100 Plan, which forges a path for a cleaner and reliable grid by identifying investment levels, types of resources, and technology deployments needed to decarbonize LADWP's grid. In addition to the LA100 Plan, a Strategic Transmission Plan (STP) is being developed to identify new transmission projects to bring diverse resources to LADWP from throughout the western region.

L.2.2.2 Grid Resiliency

The unprecedented frequency, intensity, and unpredictability of climate-induced extreme weather events point toward a need for an increased focus on Power System's resiliency strategies. Power System is already addressing the impact of climate change-related incidents on the reliability of electricity delivery to LADWP customers. Extended heat waves have affected the operation of distribution transformers due to overload, causing service disruptions. In addition, the increasing occurrence and intensity of wildfires have the potential to disrupt power flow on major transmission corridors.

Grid resiliency planning is key because extreme events such as wildfires are expected to continue to impact both electricity supply and demand. Currently, Power System has a Power System Reliability Program (PSRP) to address aging infrastructure and extend the life span of major Power System assets to maintain a high level of system reliability throughout LADWP's service territory. The challenge in maintaining these assets is two-fold: First, many assets are aging rapidly and are unable to meet the needs of a changing

industry. Second, the pool of skilled talent that can maintain these aging assets is dwindling year over year.

Power System is presently planning significant investment in its in-basin and out of basin generating stations to meet decarbonization goals. Those generating assets are critical to meet demand and ensure reliability and resiliency during extreme events such as wildfires and extended heat waves.

Furthermore, Power System is expected to invest significantly in transmission infrastructure both in-basin and out of basin to provide a high level of grid reliability and to support grid decarbonization.

L.2.2.3 Building and Transportation Electrification

Power System expects a significant amount of load growth as a result of greater electrification of transportation, buildings and industry, along with other technological advancements, as more businesses set net-zero goals. Meeting this anticipated demand will require significant investment in the distribution system to reliably deliver electric energy to existing LADWP customers and non-native mobile load (electric vehicle [EV] charging to support non-LADWP customers that are in transit in Los Angeles). Additionally, investment will be needed to accommodate distributed battery storage and relevant technologies that are all critical enablers in stabilizing the grid as renewables grow more prominent.

L.2.2.4 Innovation

Innovation is essential for the future power system to ensure that generated electric energy is delivered to customers in a manner that is safe and reliable, clean and sustainable, and affordable and equitable. To achieve this, Power System will need to invest in the deployment of increasingly clean power plants and new and emerging technologies. Power System's objectives for investing in grid technologies are to reduce or eliminate pollution, ensure system reliability, safeguard physical and virtual assets from malicious or accidental harm, and improve and upgrade the grid infrastructure. These investments will support all functions of Power System, namely generation, transmission, and distribution which include, but are not limited to, the following:

- Hydrogen-Fueled Turbines – Gas turbines supporting power generation in and out of basin are capable of operating on a wide range of hydrogen concentrations from 20% up to ~100% (by volume) for storable, dispatchable energy.

- Advanced High Voltage Direct Current (HVDC) System – This system is a cost-effective means for transporting renewable energy long distances to load centers.

- Battery Energy Storage System (BESS) – This system can improve resilience and reliability while offering Power System a lower cost alternative to traditional transmission and distribution solutions.

- Distribution Automation – As Power System continues to modernize its distribution system, the Distribution Automation program will provide greater visibility in the distribution system using advanced communication technologies to harness the power of connected distributed devices throughout Power System.

- Fleet Electrification – Investment in fleet electrification will reduce LADWP's carbon footprint.

L.2.2.5 Equitable Energy

In this energy transition, Power System will need to balance affordability and resiliency, and deliver equitable outcomes for all communities it serves, including those that have been traditionally impacted disproportionately. Among other tasks, this includes examining Power System's past investments deployed in the areas of enhancing energy efficiency, building out EV infrastructure, and expanding access to renewable and distributed energy throughout LADWP's service territory.

Currently, Power System is performing a ground breaking study with the National Renewable Energy Laboratory (NREL) and University of California, Los Angeles (UCLA) to develop equity strategies and metrics focusing on diversity, equality, and social justice that will guide Power System in the deployment of investments related to this energy transition; from the construction of assets in traditionally minority neighborhoods, to diversifying its workforce and management teams to better reflect the communities it serves.

Tackling those challenges collectively will require investment above long-term historical averages and years of focused efforts to execute the planning of various Power System initiatives. These investments include human resource needs to support Power System's objectives throughout all 11 Power System Divisions.

L.2.3 Hiring Constraints

While Power System continues to strive to meet its hiring goals, it also needs to stay abreast of the latest trends in recruitment and recognize certain constraints that may impede accessing and hiring the right candidate at the right time.

L.2.3.1 Budgetary Support

The most affecting human resource recruiting constraint is cost or approved budgetary position. Adding new staff has a financial impact on Power System's Revenue Requirement (RR), which is the total revenue that must be collected through electric rates to cover the costs associated with planning and developing projects, and maintaining and operating Power System. Adding staff will increase Power System's RR in some magnitude. One way to reduce such impact on RR is to capitalize labor costs so that such costs become part of the rate base (value of the added asset). Therefore, there may or may not be a need for rate actions to support Power System hiring needs, and determination of such rate actions is subject to Financial Services Organization (FSO) financial analyses.

L.2.3.2 City Personnel Policies

Certain City personnel policies also act as a constraint on Power System's recruitment effort. The following policies collectively contribute to the observed slow hiring process throughout Power System: Section 1009 of Article X of City Charter, which regulates promotional examination, slows the Construction and Field Services side of Power System, and Civil Service Rule 4.2, which governs the administration of exams, slows the Engineering and Technical Services side. Such policies potentially render Power System less competitive in attracting talent and restrict its recruitment efforts.

L.2.3.3 Hiring and Training Capacities

Hiring Capacity refers to the maximum number of hires that Power System's recruitment team can realistically handle in a given time by performing specific tasks that support hiring efforts. Those tasks include, but are not limited to, preparing job descriptions, processing inbound resumes, interviewing, extending offers, and onboarding new hires. Historical data for Fiscal Year 2018/2019 indicates that the increase in total occupancy for LADWP was 320 employees of which 131, or 41%, was attributed to Power System. Given the magnitude of the anticipated staffing increase to support Power System's various initiatives, it is therefore imperative that a separate exercise be performed to assess whether the current hiring capacity is sufficient to support Power System's hiring needs.

Training Capacity refers to the number of trainees that can be accommodated in a given training facility or program to develop, improve, and retain the skills and knowledge in order to perform their jobs competently without compromising safety, supervisor to trainee ratio, and the quality of training. Therefore, it is imperative that a separate exercise be performed to increase trainee graduation rates for specific civil service classifications as well as exploring potential increase in training capacity.

L.2.3.4 Space Availability

For every employee that is recruited, current policy states there must be an associated cubicle to host the new employee. In addition, there is also the need to have new facilities to support training working areas for staff, and this is more prominent in the Construction and Field Services side of Power System. While new methods and work styles have accelerated because of the pandemic, Power System has not yet undertaken a workplace strategy. At this time, it is important to coordinate the timing of facilities' availability and staff addition to reduce spatial constraints.

L.2.4 Methodology and Schedule

Undertaken over 12 months from November 2021 through October 2022, the IHRP process was organized into four stages as shown in Figure L-2 below, supported by five

data requests and multiple work sessions with each Division, joint services organizations FSO and Human Resources, and meetings with Senior Leadership.

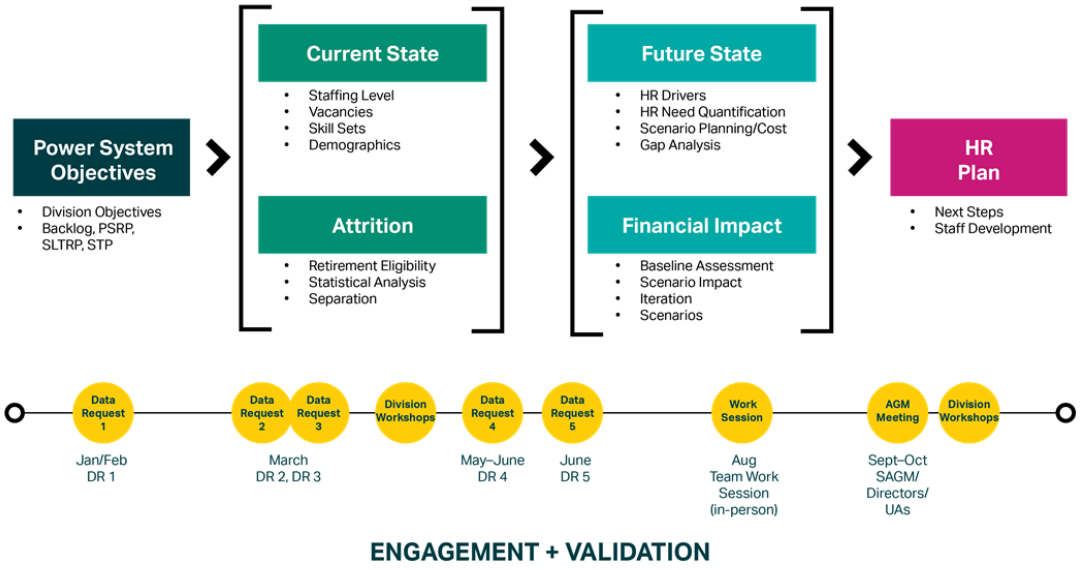


Figure L-2 IHRP Methodology

During the first stage, Power System Objectives, research was collected on each Division's objectives, functions, and backlog, as well as Power System initiatives PSRP, LA100 Plan, and the Strategic Transmission Plan (STP).

The second stage of the IHRP included two components: Current State and Attrition. Leveraging the data collected from the first stage, a current state assessment of each Division provided insight as to the active population versus total vacancies by civil service classification, and demographics (gender, diversity, age and tenure) relative to the Power System population as a whole, and where relevant, to the City. Attrition analytics were developed for retirement eligibility and separation, providing insight as to the most critical and vulnerable positions for each Division.

The third stage of the IHRP represents a pivot from data reconnaissance, analytics, and workshop discussion to the organization of the IHRP data into a future focused framework

Future State articulated the Human Resource drivers for each Division and Scenario, undertook Scenario specific methodologies to map Division function, work, and Human Resources needs in terms of Full Time Equivalents (FTEs).

The fourth and final stage, Human Resources Plan, assembled all aforementioned analyses into a cohesive set of findings and recommendations. Engagement with Senior Leadership and the Divisions proved essential to identify foundational policy changes necessary for success and confirm the Human Resources requirements by Division by Scenario. The Human Resources Plan was presented to the Board of Commissioners on October 25, 2022.

L.2.5 Four Scenarios

The IHRP utilized four (4) scenarios depicted in Figure L-3 below to assess the staffing needs of the Power System and its 11 Divisions (FAS, PCM, PEER, PETS, PNBE, PSISS, PSO-PECGR, PSST, PTD, PTPRI and RPDP). These scenarios build on each other and are intended to show the need for the Power System workforce to support these activities. The staff assessment starts with the performance of each Division's core business and then layers on other critical initiatives such as the PSRP, transportation and building electrification buildout, distribution substation buildout, and development of the electric system enhancements necessary to support the LA100 Plan and achieve a 100% carbon-free energy supply by 2035.

The four scenarios are Scenario 1 – System Intact, Scenario 2 – Marginal Increase in PSRP, Scenario 3 – Load Growth, and Scenario 4 – STP and LA100 Plan Buildout.

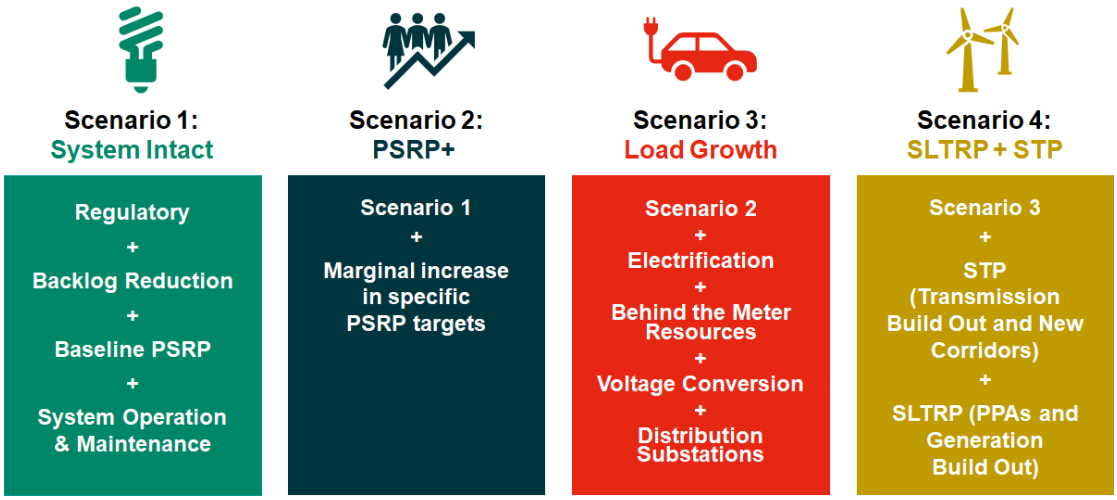


Figure L-3 Hiring Planning Scenarios.

L.2.5.1 Scenario 1 – System Intact

Scenario 1 identifies the FTEs to do the work necessary to keep the electric system functional to maintain quality of service for the existing system and LADWP's electric customers. It includes the following components:

- System Operations and Maintenance (O&M) – The work necessary to provide electricity to the City; repair or replace equipment that fails due to age, overloading, or events such as storms; and perform critical preventative maintenance to prevent failures when possible.

- Baseline PSRP – Sustaining the minimum work necessary to maintain the system already identified due to aging electric infrastructure and/or overloading on the LADWP electric system.

- Regulatory Requirements – The work necessary to satisfy certain regulatory requirements related to public and worker safety such as Federal Energy Regulatory Commission orders like the North American Electric Reliability Corporation's Reliability Standards, WECC requirements, and California state mandates.

- Backlog Reduction – The work necessary to start the process of catching up on planned and required work related to safety, quality of service, system operations, maintenance and/or achieving the baseline PSRP work. For the purpose of this study, backlog reduction assumes a 10-year horizon profile.

L.2.5.2 Scenario 2 – Marginal Increase in PSRP (PSRP +)

Scenario 2 includes the items in Scenario 1 and identifies the additional FTEs needed to accelerate components of the PSRP that require the wholesale replacements of large numbers of items in major asset categories, including, but are not limited to poles, wire, and transformers to keep up with aging infrastructure.

L.2.5.3 Scenario 3 – Load Growth

Scenario 3 includes all of Scenario 2 and identifies the additional FTEs needed to expand the electric system infrastructure necessary to support the following:

- Transport Electrification – Providing the system reinforcements necessary to support the required charging infrastructure for the continuously increasing numbers of EVs or other electric devices in Los Angeles.

- Voltage Conversion – Systematically converting portions of the distribution system to a higher voltage to more cost effectively alleviate overloads and support expected load growth due to transportation and building electrification.

- Distributed Energy Resources – Developing and supporting the programs and updating the distribution infrastructure needed to achieve the Distributed Energy Resources (DER) targets necessary to satisfy the 2035 100% carbon-free objectives.

- New Distribution Substations – Designing, developing, and constructing 10 new distribution substations (DSs) identified in the PSRP to address aging infrastructure and support transportation and building electrification, and expansion of DER throughout the LADWP electric system. LADWP's current practice and standards for designing, engineering, and constructing DSs in-house was used in developing the FTE estimates.

L.2.5.4 Scenario 4 – STP and LA100 Plan Implementation

Scenario 4 includes all of Scenario 3 and identifies the additional FTEs necessary to develop the transmission projects identified in the STP and to implement the PPAs and perform the hydrogen conversion identified in the LA100 Plan.

L.3 Current State

This section presents data and information as they relate to Power System's current disposition. Contents of the section include organization charts, and an overview of the

Power System's functions, demographics, active population and vacancies, retirement, and separation and accession data. This section also specifies significant findings pertaining to succession planning and findings from a survey administered to the Power System's employee base.

L.3.1 Organization Chart

Power System has 11 Divisions. As shown in Figure L-4 below, these Divisions are organized into two main functional bodies. One of these Division subsections: Construction, Operation, and Maintenance Services, includes all construction, operations, and maintenance support services. The other Division subsection: Technical and Engineering Services, provides specialty services that create, plan, and field energy technologies that Power Systems utilize in day-to-day operations. Inside the organization exists two smaller teams that manage budgeting and administrative services for Power System Divisions.

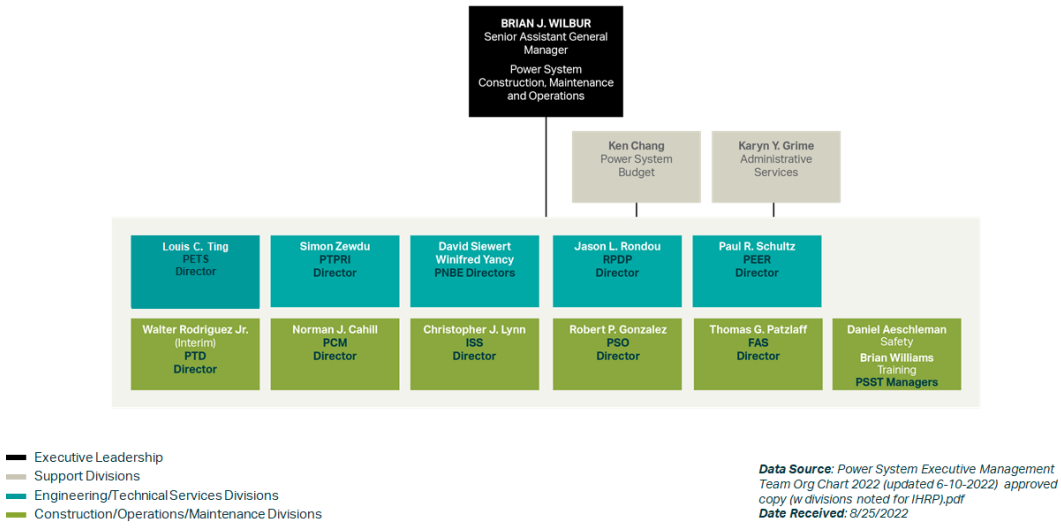


Figure L-4 Power System Organization Chart.

L.3.2 Demographics

Power System's demographic composition, as shown in Figure L-5 below, was analyzed to gather ethnic backgrounds and gender data about the organization. This data was then compared against Los Angeles' demographic composition to benchmark the

organization's diversity against the surrounding geographical area. In circumstances where the population chose not to disclose their ethnicity, an ethnicity of not applicable (N/A) was assigned to the participant.

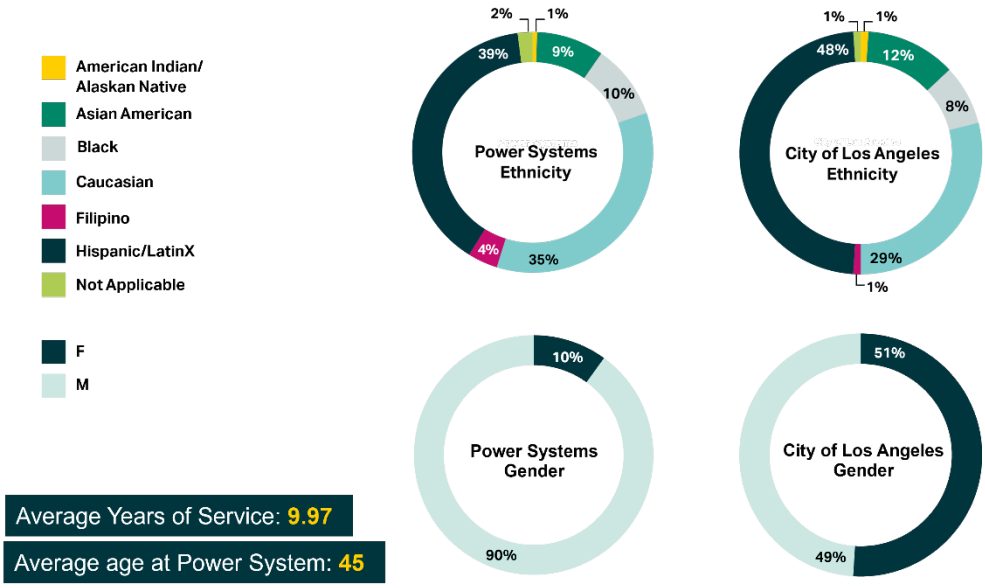


Figure L-5 Power System Demographic Analysis.

Key analyses are as follows:

- Employees within Power System have an average tenure of 9.97 years, with a median of 11 years. Employees within the Power System department have an average age of 45, and a median age of 45.
- Power System has 41% more males than females when compared to the population of the City.
- Power System's employee ethnic background consists notably of Hispanic (39%), Caucasian (35%), Asian Americans (9%), Filipino (4%) and African American (10%) peoples.

L.3.3 Active Population and Vacancies

The organization's active population and vacancies were analyzed for Power System, as shown in Table L-1, to showcase position staffing needs within the organization. This data shows the population of the entire department and displays the most prominent job roles within the organization. Additionally, the data displays the total number of

vacancies within the department, the respective jobs that hold those vacancies, and the percentage of vacancies that each job title is responsible for.

Table L-1 Power System Active Population and Vacancies.

Engineering/Technical Services: 128 Vacancies

Civil Service Classification	Total Vacant Positions	% of Total Vacancies
7525 – Electrical Engrg Associate	136	11.29%
7512 – Electrical Test Technician	34	2.82%
1368 – Sr. Administrative Clerk	24	1.99%
5265 – Electrical Svcs Manager	9	0.75%
7554 – Mechanical Engrg Asso.	8	0.66%
7246 – Civil Engrg Associate	8	0.66%
7539 – Electrical Engineer	7	0.58%
7232 – Cvl Engrg Drafting Tech	7	0.58%
7209 – Sr Eltl Engrg Drafting Tech	5	0.41%
7207 – Sr Civil Engrg Drafting Tech	5	0.41%
7515 – Senior Electrical Test Tech	5	0.41%
7532 – Eltl Engrg Drafting Tech	5	0.41%
1358 – Administrative Clerk	5	0.41%

Total Power Systems Vacancies: **1,213**

Construction/Operations/Maintenance: 1085 Vacancies

Civil Service Classification	Total Vacant Positions	% of Total Vacancies
3879 – Electric Distribution Mechanic	198	16.43%
3799 – Electrical Craft Helper	65	5.39%
5224 – Electric Station Operator	40	3.32%
3841 – Electrical Mechanic	37	3.07%
3873 – Electric Dist Mchc Supvsr	34	2.82%
3812 – UG Distbn Constr Mchc	32	2.66%
5622 – Steam Plant Assistant	32	2.66%
3834 – Sr. Electrical Mechanic	31	2.57%
5624 – Steam Plant Operator	27	2.24%
3835 – Electrical Mchc Supvsr	25	2.07%
3822 – Electric Meter Setter	23	1.91%
3344 – Carpenter	23	1.91%
3853 – Electrical Repairer	18	1.49%
3115 – Mtnc Construction Helper	17	1.41%

Power System has a job population of 4,849 with 1,213 vacancies, showing that the organization has 20% of all positions currently vacant.

Significant findings are as shown in Table L-2 and Table L-3 below.

Table L-2 Major Skillset Distribution Under Engineering/Technical Services.

Engineering /Technical Services (Population = 958)

Civil Service Classification Overlaps

PCM ISS PETS FAS
PTPRI RPDP PEER PSST
PTD PSO PNBE

Total Active Power Systems Population: **4,849**

Civil Service Classification	% of Power Systems Population	PCM	ISS	PETS	PTD	PSO	PNBE	PTPRI	RPDP	PEER	FAS	PSST
7525 – Electrical Engrg Associate	9.61%	●		●	●	●	●	●	●	●		
1368 – Sr. Administrative Clerk	3.57%	●	●	●	●	●	●	●	●	●	●	●
7512 – Electrical Test Technician	2.45%	●										
7554 – Mechanical Engrg Asso.	1.67%	●		●		●	●	●	●	●	●	
7539 – Electrical Engineer	1.63%	●		●	●		●	●	●	●		●
7246 – Civil Engrg Associate	1.42%	●		●			●	●	●	●		
7232 – Cvl Engrg Drafting Tech	1.07%			●								
9453 – Power Engrg Manager	0.99%	●		●			●	●	●	●		
9184 – Management Analyst	0.87%	●		●	●	●	●	●	●	●	●	●
7515 – Senior Electrical Test Tech	0.85%	●										
1202 – Principal Clerk Utility	0.78%	●	●	●	●	●	●		●	●	●	●
7207 – Sr. Civil Engrg Drftg. Tech	0.62%			●								
9105 – Utility Administrator	0.54%	●		●	●	●	●	●		●	●	●
7532 – Elctrl. Engrg. Drftng. Tech.	0.39%			●								
7558 – Mechanical Engineer	0.37%			●		●		●	●	●	●	
Others	**8.17%**			●			●	●	●	●		

Table L-3 Major Skillset Distribution Under Construction/Operations/Maintenance.

Construction/Operations/Maintenance (Population = 3,891)

Civil Service Classification Overlaps

PCM ISS PETS FAS
PTPRI RPDP PEER PSST
PTD PSO PNBE

Total Active Power Systems Population: 4,849

Civil Service Classification	% of Power Systems Population	PCM	ISS	PETS	PTD	PSO	PNBE	PTPRI	RPDP	PEER	FAS	PSST
3879 – Electric Dist. Mechanic	8.93%				●							●
3841 – Electrical Mechanic	8.43%	●	●		●	●						
3799 – Electrical Craft Helper	6.78%	●	●		●	●						●
5224 – Electric Station Operator	4.52%					●						●
5622 – Steam Plant Assistant	2.39%					●						
3743 – Heavy Duty Equip. Mchc.	1.96%										●	
3873 – Elec. Distr. Mech. Supv.	1.88%				●							●
3812 – UG Dist. Constr. Mechanic	1.61%				●							
5624 – Steam Plant Operator	1.59%					●						
3834 – Sr. Electrical Mechanic	1.40%	●	●			●						●
3835 – Electrical Mchc. Supv.	1.24%	●	●			●	●					●
5265 – Elctrl. Services Manager	1.20%	●			●	●		●		●		●
5630 – Stm. Plant Mtnc. Mechanic	1.07%					●						
3584 – Heavy Duty Truck Operator	1.05%	●									●	
3711 – Equipment Mechanic	1.05%										●	
Others	**36.9%**	●	●		●	●					●	●

L.3.4 Retirement

A vulnerability analysis was conducted to determine the vulnerable positions within Power System based on the counts of retirement eligibility over the next 4 years (Table L-4). The table indicates the breakdown of those positions eligible to retire now, eligible to retire in the next 3 years and then eligible to retire in the next 6 years. In this analysis, retirement eligibility included those who were at least 55 years of age and had at least 30 years of service at LADWP. Through this analysis, it was determined that 415 positions are eligible to retire now, accounting for 8.62% of the current population, and 550 positions are eligible over the next 3 years, accounting for 11.43% of the population. In addition, 13% of the population will be eligible to retire over the next 6 years, representing 625 positions.

Within the vulnerability analysis, top positions with the most counts of eligible retirees were considered "critical" positions as these would need the most attention for back filling and succession planning. The bar chart shown in Figure L-6 Major Retirement Eligibility by Civil Service Classification. below indicates the implications these critical positions have in terms of the percentage of the whole popular
tion. From the criticality analysis, the *Electrical Services Manager (5265)* position was identified as a critical position to be aware of, as 46% are eligible to retire now.

Additionally, the position of Trans & Distr Dist Supv (3875) demonstrated criticality with 37% eligible to retire now and Elec Distr Mech Supv (3873) with 38% currently eligible.

Table L-4 Retirement Eligibility Summary.

Vulnerability (Retirement Eligibility Today)

Engineering/Technical Services
Construction/Operations/Maintenance

Eligible To Retire Now	
Civil Service Classification	**Qty**
Electric Distribution Mechanic - 3879	34
Electrical Engrg Associate – 7525	27
Electrical Services Manager – 5265	26
Electric Station Operator – 5224	20
Elec Distr Mech Supv – 3873	15
Trans & Distr Dist Supv – 3875	15
Electrical Mechanic – 3841	13
Electrical Craft Helper – 3799	13
Power Engineering Manager – 9453	13
Electrical Mechanic Supervisor – 3835	11
Others	228
Total	**415**

Eligible To Retire 0-3 Years	
Civil Service Classification	**Qty**
Electric Distribution Mechanic - 3879	42
Electrical Engrg Associate – 7525	29
Electrical Services Manager – 5265	33
Electric Station Operator – 5224	27
Elec Distr Mech Supv – 3873	24
Trans & Distr Dist Supv – 3875	20
Electrical Mechanic – 3841	19
Electrical Craft Helper – 3799	19
Power Engineering Manager – 9453	18
Electrical Mechanic Supervisor – 3835	18
Others	301
Total	**550**

Eligible To Retire 0-6 Years	
Civil Service Classification	**Qty**
Electric Distribution Mechanic - 3879	51
Electrical Engrg Associate – 7525	30
Electrical Services Manager – 5265	35
Electric Station Operator – 5224	29
Elec Distr Mech Supv – 3873	31
Trans & Distr Dist Supv – 3875	31
Electrical Mechanic – 3841	20
Electrical Craft Helper – 3799	22
Power Engineering Manager – 9453	18
Electrical Mechanic Supervisor – 3835	20
Others	338
Total	**625**

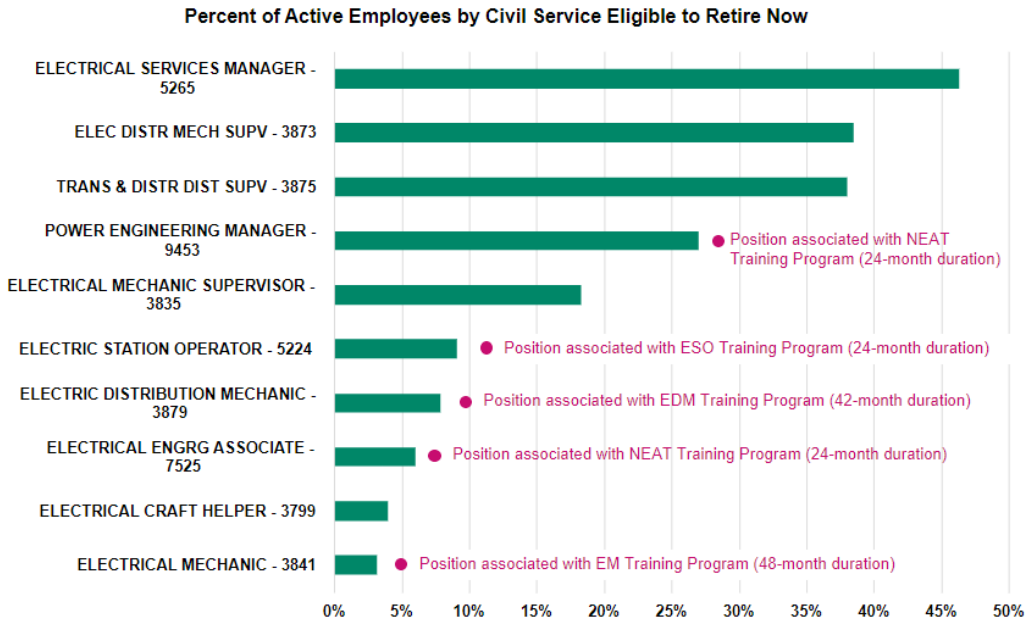


Figure L-6 Major Retirement Eligibility by Civil Service Classification.

To make a reasonable projection of Power System's long-term employment needs, statistical retirement projection is also considered. As such, a systematic, conditional approach to estimate Power System's labor force retirement projection is employed. To that end, a hazard-based duration model framework is used to study the transitions from

employment into retirement. The main advantage of using duration analysis is that it allows modeling the length of time spent in a given state (i.e. employment) before moving into another state (i.e. retirement). Relative to other approaches such as those that focus on the unconditional probability of an event taking place (e.g. probit or logit models), the focus of the retirement analysis is on the conditional probability, or, the probability that the duration of one particular status (e.g., employment) will end in the next short interval of time, given that it has lasted until recently. Figure L-7 shows both the historical retirement levels and retirement projections based on statistical analyses of Power System retirements.

In addition, the retirement rate in the Power System will drop drastically after 2022 after many years of trending upward. The Power Systems retirement rate will also be exiting a big wave of retiring employees in 2022.

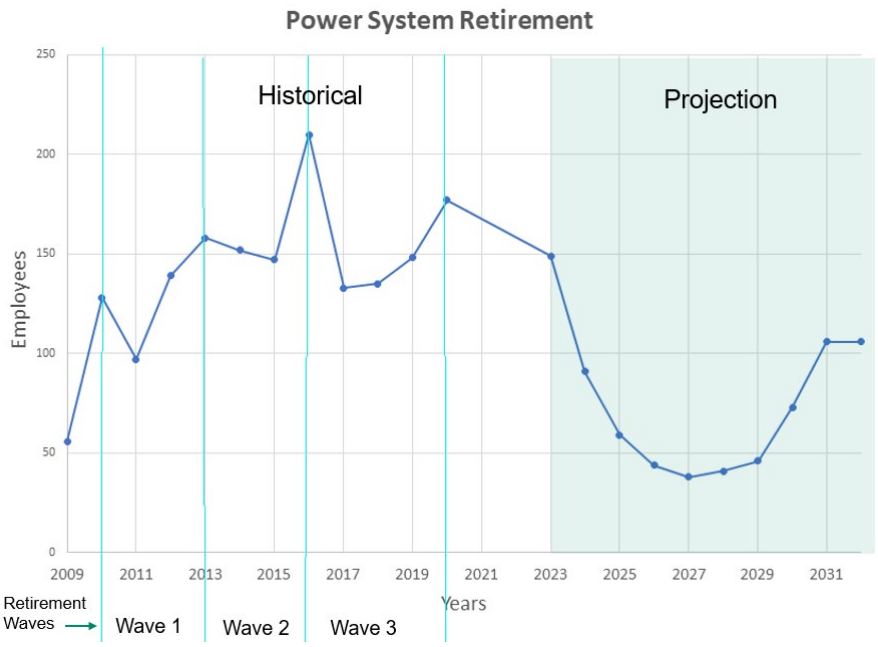


Figure L-7 Power System Retirement Profile.

L.3.5 Separation and Accession

Separations and accessions within Power System were analyzed to determine how and why employees within the organization left their respective roles. Separation refers to the number of employees departing from Power System due to retirement and voluntary departure for a given period. Accession is the number of employees that joined Power

System for the same period. This information will help LADWP to identify how situational factors impact certain roles within the organization, and the impact those factors have on attrition. The data that examined the attrition rate of the organization was analyzed as it relates to Power System's population over a five-year period. Attrition in this context was limited to data from separations and retirements within Power System. Overall, Power System does keep up with retirements and does take steps to fill vacancies associated with retirements. In addition, Power System has very little separation of staff. This in turn reflects the great benefit package offered by LADWP. Nevertheless, there are a few civil service classifications that tend to have a higher separation rate, those include, but are not limited to, Electric Mechanic, Electric Distribution Mechanic, Electric Station Operator, Load Dispatcher, and Steam Plant Assistant. Figure L-8 below shows a gap between accession and separation levels for those civil service classifications, and the bar charts compare some of those civil service classifications at risk of high separation with a sample of overall civil service classifications that are not subject to the same risks.

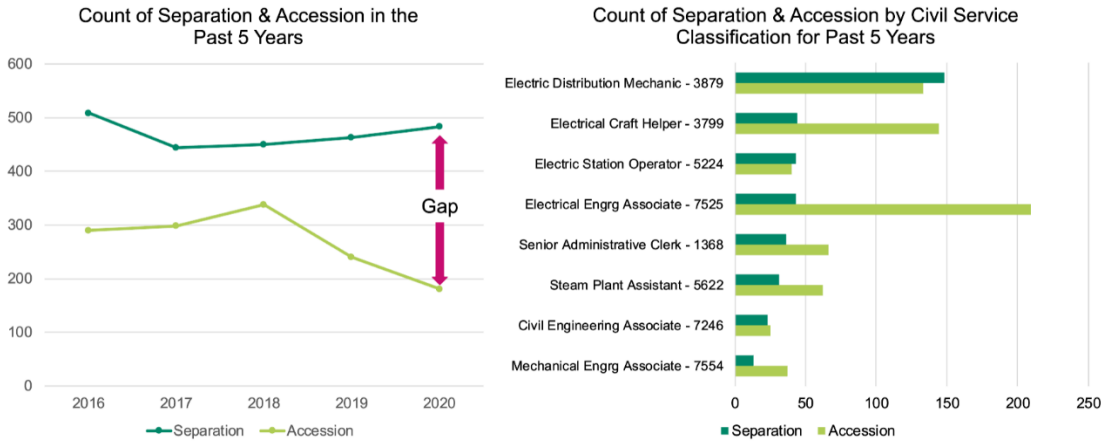


Figure L-8 Power System Accession and Separation for Classifications at Risks.

L.3.6 Succession Planning

LADWP is unique in that many of the employees within the Power System are eligible to retire at a rate that can threaten key operations within the organization. Recruitment is a substantial effort that helps to offset the number of retirements the organization faces. Both retirements and recruitment trends were analyzed to measure their impact upon the overall population of each Division.

Almost all positions within LADWP are impacted by their respective career ladder. Feeder classifications were analyzed to see how long a position would take to fill based off the

respective career progression of that position. Some positions as they are managed impact several other positions that are worth consideration when making hiring and promotional decisions.

There were significant key findings made through these analyses:
In the last 5 years, significant promotion efforts have been dedicated toward *Electric Distribution Mechanics (3879)* with approximately 133 employees moving into their respective position, and *Electrical Craft Helpers (3799)* with approximately 145 employees moving into their position.

In the last 5 years, these same departments have had a significant number of employees retire, the *Electric Distribution Mechanic (3879)* position had 147 employees retire, while the *Electrical Craft Helper (3799)* position had 48 employees retire.

This data shows the organization overall is losing more employees than they are promoting internally. Although not all positions have more retirements than accessions.

Reviewing the pipeline and training requirements of the feeder classifications, specifically of those defined to be critical previously, will be useful in ensuring the proper succession planning and preparation for the near future.

L.4 Future State

This section presents data and information as they relate to Power System's Human Resource needs for each Scenario. Contents of this section include backlog quantification, marginal increase targets for the PSRP and assumptions used for Large Projects for Scenarios 3 and 4. This section also specifies the positions required within the overall staffing needs. Future State also accounts for interdependency among Power System Divisions to capture how the workload on one Division impacts the others and the associated staffing needs when implementing a new project or Power System program.

L.4.1 Backlog

The number of hours that Power System needs to account for to meet the current workload was analyzed based off the current number of FTEs available, the current number of backlog hours, and the forecasted backlog change to be recovered by hiring more employees over a ten-year period.

The IHRP took each Division's estimated new FTE (e.g., hours) needs for backlog and other System Intact scenario elements and turned them into a levelized hiring profile over a 10-year period. This approach spreads the hiring and financial impact over a 10-year period, which is more achievable than a high initial change.

L.4.2 Scenario 1

The FTEs required under Scenario 1 were estimated for each Division based on work registered in the works management systems (WMS and Maximo) for field and related engineering work, or based on changes in legal and regulatory requirements and an estimate of the associated workload.

1,800 hours per FTE per year was assumed for non-field personnel, reflecting an assumed level of overtime on average above the more standard 1,600 hours per FTE per year assumption used for resource planning. Field personnel FTE requirements assumed 1,300 hours per year per FTE as standard, and the same relative level of overtime per year, or 1,563 hours per year per FTE. Note that higher utilization of skilled staff using overtime provides resourcing flexibility, capacity, and capability that is more efficient on average than a workforce with zero overtime but lower rates of utilization.

L.4.3 Scenario 2

Scenario 2 involves the acceleration of the existing PSRP program to completely recover backlog hours over the next 10 years.

The estimated number and types of FTEs required by Division for Scenario 2 were estimated in the same way as the field and related engineering work detailed in Scenario 1. In addition, some level of interdependency is considered to account for

interdependency among certain Divisions that are impacted by the increase on Power System infrastructure replacement targets.
The incremental impact of Scenario 2 on Power System was estimated to be significant.

L.4.4 Assumptions for Scenarios 3 and 4

For Large Projects, a projected electric system buildout was provided that builds out the LADWP electric system by or near 2035 to satisfy compliance with the 2035 City Council target. This buildout model was used as the basis for estimated LADWP staff necessary to support this work.

L.4.5 Scenario 3

FTE needs to support transportation and building electrification programs, as well as distributed energy resource programs including PV, storage, and energy efficiency were estimated by each Division based on historical productivity levels, and sustainable utilization levels (i.e. hours per year per FTE).

Hour estimates were developed for voltage conversion related work based on a bottom-up estimate of the type of work involved in the substation and related field work. These were then converted to FTEs by type using the standard hours per FTE per year methodology described in Scenario 1.

Scenario 3 also includes the development of 10 DSs as called out in the PSRP plan. GS Section under PCM Division would provide the construction resources for the buildout of the 10 DSs.

L.4.6 Scenario 4

For Large Projects, a projected electric system buildout was provided that builds out the LADWP electric system by or near 2035 to satisfy compliance with the 2035 City Council target. This buildout model was used as the basis for estimated LADWP staff necessary to support this work.

All new Receiving Stations (RSs) are assumed to be designed and developed using LADWP engineering and field staff consistent with current practice.
For new energy storage facilities, the FTE estimates assumed a PPA would be used to select a third party to develop utility scale energy storage facilities. These facilities would be connected to existing RSs using LADWP engineering and PCM field staff consistent with current practice.

For transmission, receiving stations, BESS and Hydrogen projects in Scenario 4, PCM is expected to provide Field Services support. See Section 5.1 for total FTE needs by year and incremental FTE needs by year broken out by Division and scenario.

L.5 Next Steps

This section presents the human resources summary, Power System's and Division-specific policy recommendations, and the bigger picture.

L.5.1 Human Resources Summary

This section presents the Human Resources Summary for Power System (Table L-5), identifies the foundational changes and policy recommendations required for Power System to achieve success, and identifies policy recommendations specific to each Division.

Table L-5 ***Human Resource Need Summary by Scenario and Cumulative.***

New FTEs per Year (By Individual Scenario)

Scenario	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Scenario 1: System Intact	119	119	115	115	115	115	115	115	115	108	**1154**
Scenario 2: PSRP+	62	54	60	53	54	61	53	53	45	41	**536**
Scenario 3: Load Growth	131	102	128	90	130	131	91	89	88	91	**1071**
Scenario 4: SLTRP + STP	50	31	30	30	20	16	9	43	18	3	**248**

New FTEs per Year (By Cumulative Scenario)

Scenario	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Scenario 1: System Intact	119	119	115	115	115	115	115	115	115	108	**1154**
Scenario 2: PSRP+	181	173	175	169	169	176	168	168	160	149	**1690**
Scenario 3: Load Growth	312	276	303	259	299	308	259	257	248	240	**2761**
Scenario 4: SLTRP + STP	362	307	333	288	319	323	268	300	266	243	**3009**

L.5.2 Power System's Policy Recommendations

The following policy recommendations represent foundational changes required for Power System to be successful in implementing any of the four scenarios. Stated differently, the findings of the IHRP study conclude that the risk of not undertaking the following policy recommendations will compromise the LADWP's ability to achieve its objectives.

Policy recommendations related to the Construction, Operations and Maintenance Divisions are as follows:

- To improve the hiring process, recruit qualified candidates, and maintain a trainee in every field crew, the IHRP recommends Power System work with the City to:

- Amend City Charter 1009 from open and promotional city exams to "Open Exam Only."

- Retain Section 5.30 for Senior Civil Servants.

- Increase flexibility in Service Rule 4.2 to obligate the City to provide larger and continuous pools of qualified candidates.

To accelerate project delivery and enhance Power System collaboration with the Bureau of Engineering and Department of Transportation, the IHRP recommends Power System work with the City to:

- Create a new ordinance for Field Crews to access public Right of Ways for nine continuous hours of work bearing in mind current noise and congestion ordinances.

- Identify City properties that could be used to expand training facilities and sites critical to accommodate additional trainees.

- Policy Recommendations related to the Engineering and Technical Services Divisions are as follows:

- To fill vacancies and develop subject matter engineering and technical experts, the IHRP recommends developing Division-specific staff onboarding program and develop and implement training plans for new engineers and technical staff.

In addition to these recommendations, the IHRP sets forth Power System policy recommendations in six areas described in the charts in Figure L-9 below.

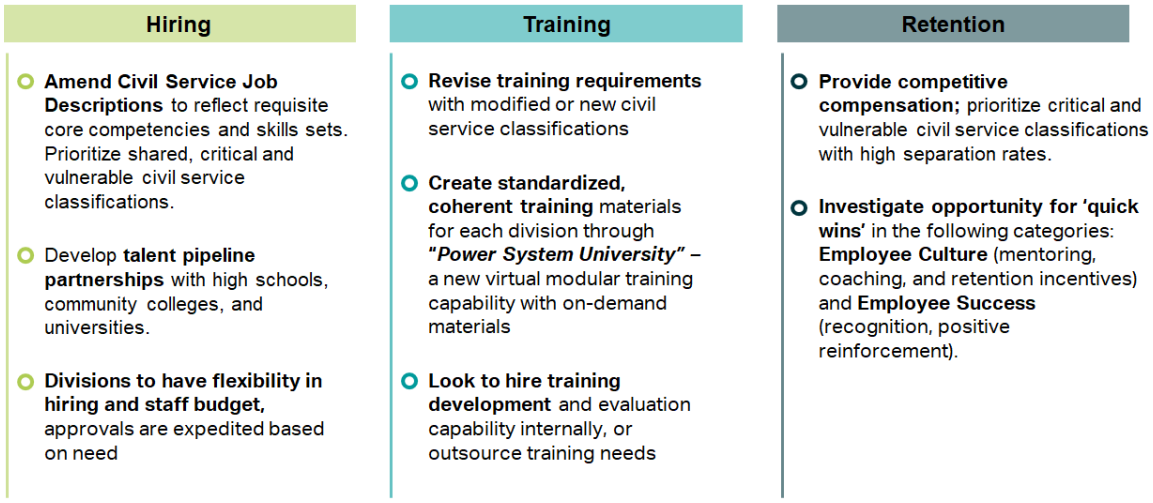


Figure L-9. First Set of Power System Specific Policy Recommendations.

The Hiring recommendations focus on ensuring that civil service classifications and their respective DDRs reflect the skillsets and competencies required to perform the work enshrined in Scenarios 1 through 4. This recommendation is of critical importance as the revised job descriptions will set the groundwork for a revamped hiring process. The IHRP recommends that the civil service classification DDRs be prioritized based on the criticality and vulnerability of the position. Additionally, the IHRP recommends that Power System cultivate strategic partnerships with educational institutions, especially community colleges.

The Training recommendations focus on developing capacity in three areas: modernizing training programs based on revised DDRs and as described at the Division level; standardizing training materials and making them available on demand; and Division level's training capacity through partnerships or outsourcing methods.

The Retention recommendations focus on providing competitive compensation and enhancing employee culture and success. The IHRP recommends that Power System undertake a benchmarking study to confirm competitive compensation by civil service classification in the Southern California market and collate insight from other utility providers' strategies around culture, success and employee engagement.

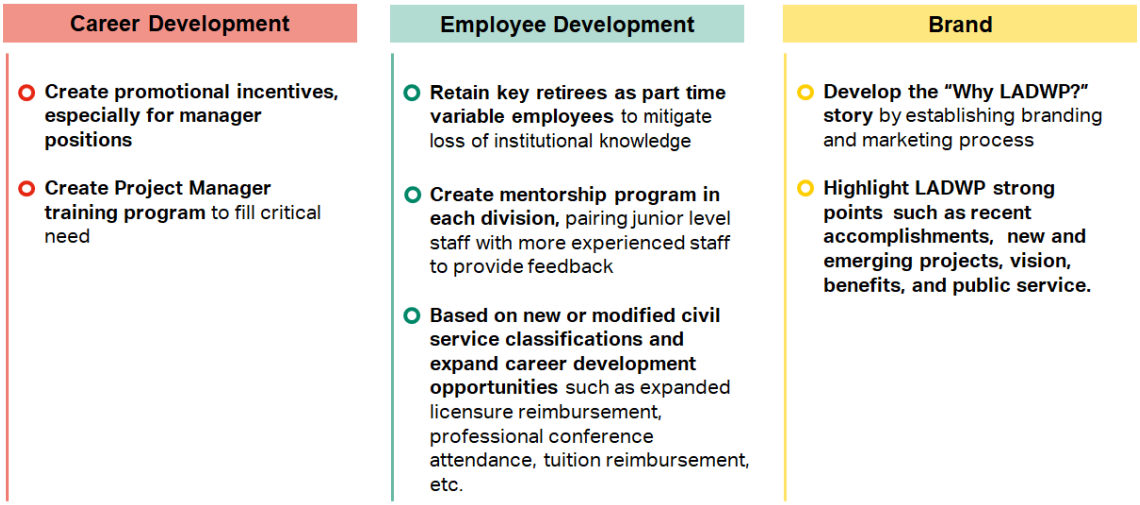


Figure L-10. Second Set of Power System Specific Policy Recommendations.

The Career Development recommendations focus on career progression (Figure L-10). Due to the evidence gained through the succession planning analysis and workshops with the Divisions, the IHRP recommends that Power System create promotional incentives, especially for Manager and Supervisor positions so that as senior employees retire, qualified candidates are motivated to progress in their careers and the positions are filled as quickly as possible. Project Managers are required throughout all the Divisions, and in increasing high demand through Scenarios 3 and 4. Because Project Managers are practitioners developed from many engineering disciplines (civil, electrical, mechanical, others), the IHRP recommends that Power System create a Project Manager certification program to standardize training and create a recognizable credential across all Divisions. Evidence shows that employees have and will continue throughout their Power System tenure to move Divisions, and the IHRP contends that the Project Manager credential will provide both efficiency and productivity gains for all Divisions.

The Employee Development recommendations center on knowledge creation and knowledge transfer, and the professional development of LADWP employees at all levels of their career. The Power System retirement forecast shows that hundreds of employees are eligible to retire now, and hundreds more will be eligible over the next six years. To prevent institutional knowledge loss and promote knowledge transfer from retirees to their successors, the IHRP recommends that key retirees retain a part time variable employment status. Strengthening bonds between managers and supervisors and junior staff is an important aspect for retention and employee development. The IHRP recommends that a Power System mentorship program be established in all Power System Divisions. Additionally, the IHRP recommends that Divisions create deliberate programs and/or structured advice and guidance on how to strengthen the bond

between manager and direct report. Lastly, the IHRP recommends that Power System evaluate career development offerings to amplify talent and promote the development of their subject matter expertise, especially in the modified DDRs that reflect the future of clean energy positions.

The brand recommendations focus on leveraging this unique moment in history to become 100% renewable by 2035 as a major local, regional and nationwide differentiator for talent acquisition. The extent of the transformation should be leveraged through the lens of socioeconomic mobility and pathways to the green jobs of the future. The IHRP recommends that Power System develop unified and targeted messages to recruit the next generation of clean energy practitioners.

In summary, the IHRP policy recommendations lay the blueprint for how the Department must transform itself to be equipped to hire, retain, and develop the staff critical for work implementation. While there is much work to be done to operationalize the policies described above, the transformation requires active and visible executive sponsorship from the LADWP Board of Commissioners and Power System Executive Leadership. The chart in Figure L-11 below describes the roles and responsibilities the IHRP asks these leadership teams to assume, including FSO, an integral partner in the budget process.

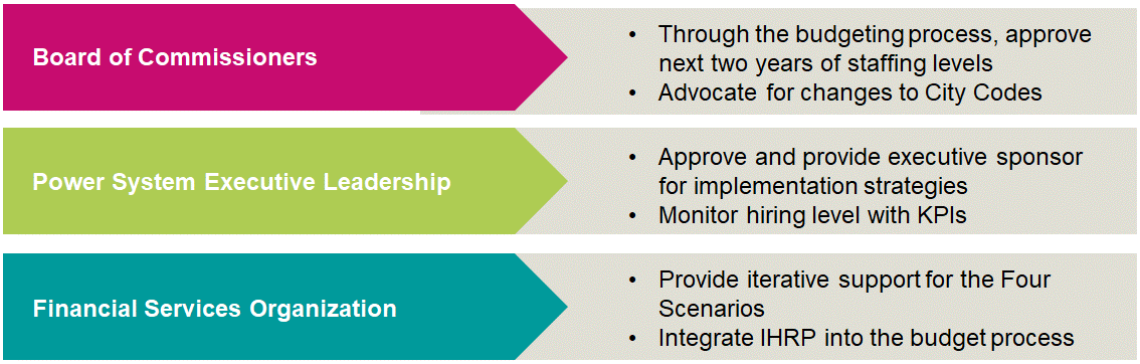


Figure L-11. IHRP Roles and Responsibilities.

Taking into consideration the Power System policy recommendations and the roles and responsibilities requested of the Board of Commissioners and LADWP Executive Leadership, the recommendations can be prioritized and undertaken in parallel to build change momentum. The next three years will be definitive years for how Power System can set its course to achieve 100% renewable and carbon-free energy by 2035. Effective leadership is required at all levels to address these recommendations with urgency, streamline efforts for effective implementation, and for Power System to hold itself accountable for its performance.

L.5.3 The Bigger Picture

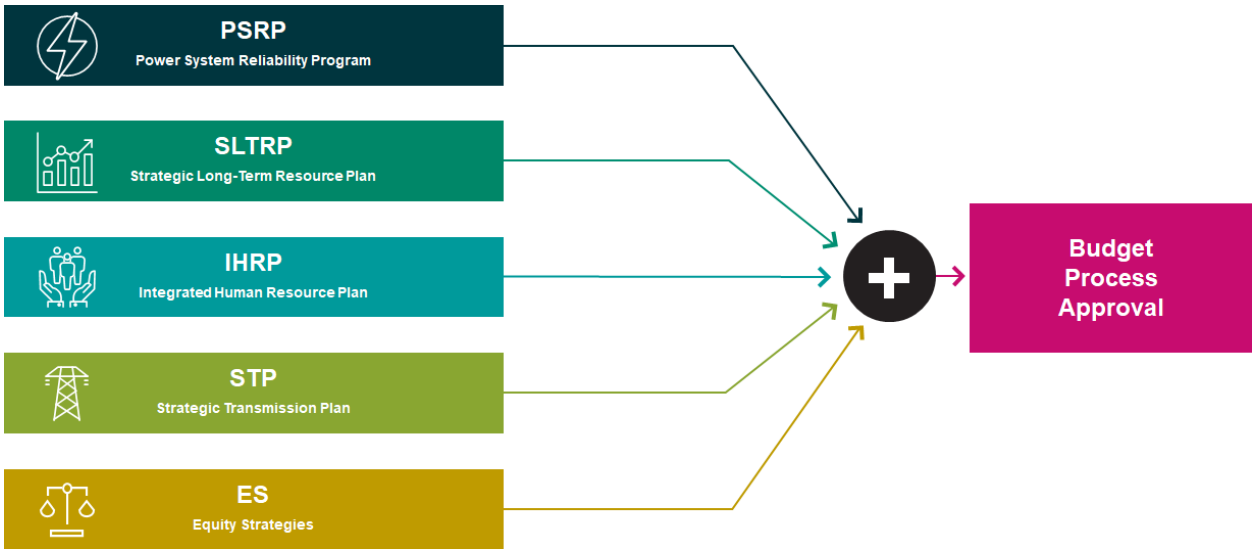


Figure L-12. Power System Independent Studies.

As referred to throughout this report, Power System is undertaking simultaneous and detailed studies to validate the technical requirements necessary to achieve its Strategic Priorities as described in Power System's Strategic Priorities, section L.2.2. Successful implementation of any work stream requires that the recommendations set forth in these independent studies shown in Figure L-12 above be integrated holistically with deep understanding of how the various components reinforce one another and can be executed in parallel. The mechanism to integrate and validate the extent of work Power System can undertake and maintain long term financial stability is through the budget process. The IHRP recommends an iterative and innovative scenario planning approach to the budget process that considers findings from PSRP, IHRP, STP, and ES. In general, the balance of work Power System takes on internally versus potentially outsourcing to contractors will be partly defined by the total number of new FTEs the Department can support for generations to come.

Appendix M - Stakeholder Engagement and Outreach

Appendix M - Contents

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M.1.1 Advisory Group Meetings M-3
M.1.2 Community Meetings M-5
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M.1 Introduction

The LA100 Plan is grounded in rigorous modeling and shaped by extensive community engagement. Every two years, LADWP develops the Plan through a comprehensive process that integrates stakeholder input, technical analysis, and outreach to help identify the optimal combination of resources to meet the Department's mission: delivering low-cost, reliable, resilient, equitable, and carbon-free electricity to more than 4 million residents and businesses across Los Angeles.

Stakeholder engagement is led by the Los Angeles-based *Advisory Group (AG)*, which convenes regularly throughout the planning cycle. This group is designed to reflect the city's diversity in lived experience, community needs, and technical expertise—ensuring that a wide range of perspectives informs planning decisions. The AG provides valuable feedback on resource strategies, modeling assumptions, and community priorities.

In addition to the AG meetings, LADWP hosted four public outreach meetings open to all members of the public. These events offered opportunities for broader engagement, transparency, and dialogue with Angelenos about the City's transition to a carbon-free power system.

Presentation materials from Advisory Group meetings, community meetings, and the 2022 SLTRP process are available at: www.ladwp.com/la100plan.

M.1.1 Advisory Group Meetings

The composition of the Advisory Group is designed to reflect the diverse perspectives and expertise necessary to understand the challenges and possibilities for meeting Los Angeles' electricity supply needs, with particular consideration of the transition to renewable energy resources, reliability, resiliency, affordability, and equity. The AG roster for the LA100 Plan included over 90 members (Figure M-1), inclusive of stakeholders from LA100 Equity Strategies, and reflects the following stakeholder interests, as well as technical and policy expertise:

- Academia
- Business and Workforce

- City of Los Angeles Government
- Environment
- Large Accounts
- Neighborhood Councils
- Utilities
- Community Based Organizations

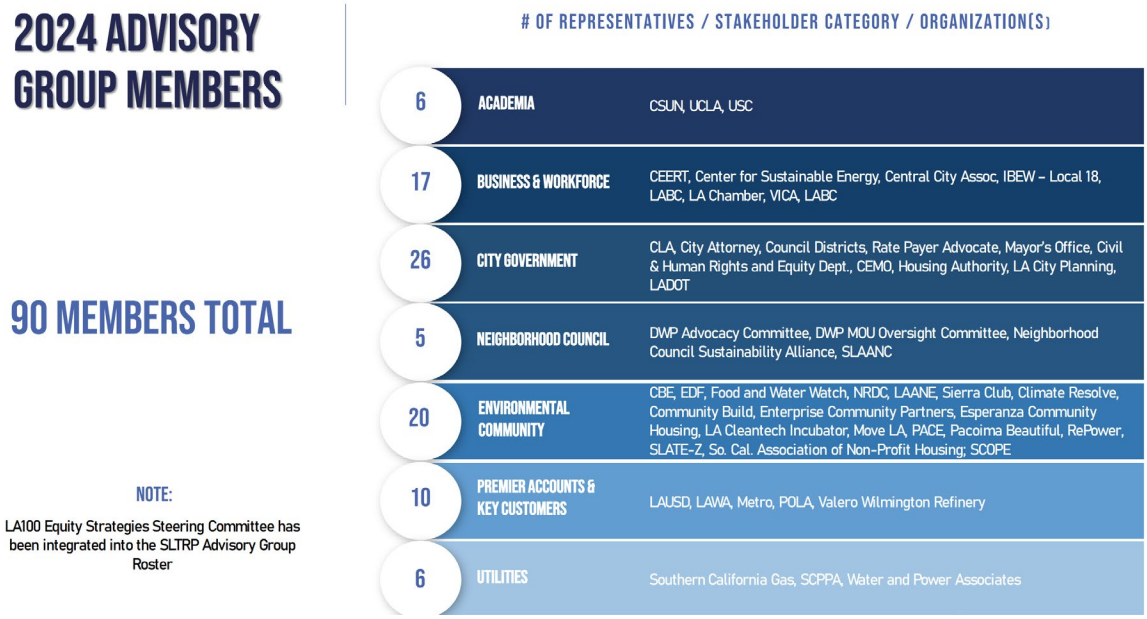


Figure M-1 LA100 Plan Advisory Group.

The Advisory Group's role is to provide input and feedback based on the expertise, knowledge, and resources of the organizations, institutions, and constituent groups represented by the AG members. Among these include:

- **Provide Perspectives.** Discuss major issues that LADWP will face in the next 10-20 years. Provide input and review of strategic scenarios and sensitivities that are used in the resource analysis and final recommendations for near-term actions.
- **Continue the Collaborative Dialogue.** Build upon the momentum from LA100 Equity Strategies and the 2022 SLTRP process.

- **Conduct Outreach to Respective Constituent Groups.** Bring diverse input into the process and keep constituents informed of the LA100 Plan process.

- **Consider Broader Community Input.** During Advisory Group discussions, think of the various communities and considerations throughout the City of Los Angeles.

- **Provide Technical Information & Perspectives.** Add value through areas of expertise.

- **Read Pre-Meeting Materials.** Come prepared to each meeting by reading meeting materials and agendas that are distributed before the meeting. This includes reading and reviewing the 2022 SLTRP and LA100 Equity Strategies Report.

- **Participate in All Meetings.** A total of eight (8) meetings between March 2024 and May 2025. Meetings are expected to alternate between in-person and virtual. Each meeting will be conduced in 2-to-3 hour segments.

- **Alternate Representatives.** If an AG member cannot attend a meeting, send an alternate on the primary AG member's behalf.

- **Balancing Perspectives.** To maintain stakeholder balance – only allow one representative per member organization in meeting discussions.

M.1.2 Community Meetings

Following the culmination of the LA100 Plan modeling process and the series of eight Advisory Group meetings, LADWP hosted four virtual community meetings at the end of June 2025, open to the general public. These meetings were open-house format and consisted of presentations by subject matter experts, with opportunity for general public questions and comments. Presentation slides included language in both English and Spanish, and opportunities for additional language translation was available upon request, via the Zoom meeting platform.

The purpose of the community meetings is to provide an overview of the LA100 Plan and collect public feedback on how LADWP can achieve the LA100 Plan in a reliable, affordable, sustainable, and equitable manner. Among the outreach methods used to promote awareness of the community meetings were:

- The LADWP public website
- LA100 Plan fact sheets
- Traditional media including print advertisements in the L.A. Times, Daily News, CityWatch, and La Opinion (Spanish)
- Emails to Neighborhood Councils and other stakeholder lists
- Social Media
- Community Newsletter articles

M.2 Meetings

As detailed below and shown in Figure M-2, the stakeholder engagement and outreach process for the LA100 Plan spanned well over a year in duration, from March 2024 to June 2025, consisting of eight AG meetings and four Community Meetings. The AG meetings spanned numerous diverse and detailed topics, while the Community Meetings focused on providing a high-level overview on the LA100 Plan and providing an opportunity for open comments and questions from the general public.

Advisory Group Meetings:

- **AG Meeting #1: March 21, 2024**
    - Kickoff, 2022 SLTRP Review, LA100 Equity Strategies, Power System Vision, 2024 LA100 Plan Overview
- **AG Meeting #2: April 18, 2024**
    - Schedule, Questionnaire (Mentimeter) results, Overview of LA100 Plan Assumptions, AG Breakout Sessions, Scattergood Modernization

- **AG Meeting #3: May 16, 2024**
    - LA100 Equity Strategies Implementation, Review of AG Feedback, Modeling Overview and Sample Model Run, Draft Scenario & Sensitivity Matrix, AG Breakout Sessions, Questionnaire (Mentimeter)

- **AG Meeting #4: June 27, 2024**
    - LA100 Equity Strategies Implementation, Distribution System Planning, Review of AG Feedback, Updated Scenario & Sensitivity Matrix, AG Breakout Sessions, Questionnaire (Mentimeter)

- **AG Meeting #5: September 19, 2024**
    - Scenarios & Sensitivities Update, Distribution System Planning

- **AG Meeting #6: December 5, 2024**
    - LA100 Plan, LADWP Recent Accomplishments, Distribution System Planning Assessment Results, LA100 Plan Preliminary Results, Public Meetings

- **AG Meeting #7: March 20, 2024**
    - LA100 Plan Results – Risks and Modeled Sensitivities, NREL Presentation on Scattergood Modernization Project Alternatives, Transmission System Planning Assessment

- **AG Meeting #8: May 15, 2025**
    - LA100 Plan Model Recap, LA100 Plan Rates Analysis and Overview, Customer Bill Impacts and Energy Burden, Risks and Challenges, Public Outreach Workshops, Questionnaire (Mentimeter)

Community Meetings:

- **Community Meeting #1: June 23, 2025**

- **Community Meeting #2: June 25, 2025**

- **Community Meeting #3: June 26, 2025**

- **Community Meeting #4: June 28, 2025**

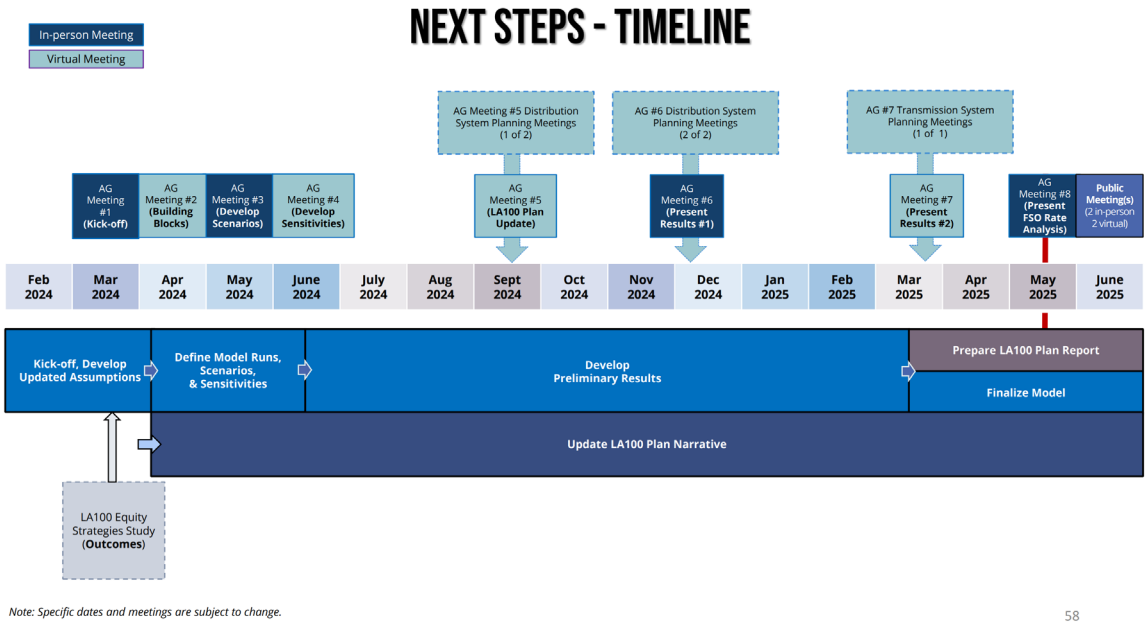


Figure M-2. LA100 Plan Process Timeline.

M.3 Feedback

Stakeholders in the LA100 Plan process provided feedback via multiple avenues, including the AG meetings, the Community Meetings, as well as via email to the LA100Plan@ladwp.com email address. Below is a list of the most common themes and topics pertaining to stakeholder questions and comments:

Themes & Topics from Advisory Group Comments

1. **Equity, Affordability, and Energy Burden**

    - Ensuring a just transition to a carbon-free energy future.
    - Concerns about rate impacts on low-income and disadvantaged communities.
    - Need for programs that directly benefit vulnerable customers.
    - Interest in energy burden metrics (e.g., % of household income spent on energy).

2. **Rates, Costs, and Financial Transparency**

    - Strong interest in rate modeling assumptions (inflation, incremental vs. budgeted costs, financing).
    - Concern that achieving 100% carbon-free energy by 2035 could lead to rate increases.
    - Calls for safeguards to protect limited-income households.

3. **Reliability and Resiliency**

    - Repeated concerns about maintaining grid reliability during the transition.
    - Climate-driven risks: extreme heat, fires, and aging infrastructure.
    - Calls for redundancy, contingency planning, and climate adaptation measures.
    - Support for distributed energy resources (DERs) and battery storage as resilience solutions.

4. **Distribution System and Infrastructure Upgrades**

    - Electrification (specifically transportation) identified as the largest driver of load growth.
    - Concerns about adequacy of substations, feeders, circuits, and electric vehicle (EV) charging infrastructure maintenance
    - Workforce shortages flagged as a bottleneck for required grid upgrades.

5. **Clean Energy Resource Mix & Technology Choices**

    - Debate around the role of green hydrogen vs. non-combustion alternatives.
    - Interest in more solar + storage, geothermal, and distributed generation.
    - Questions about new high-load industries (e.g., data centers, artificial intelligence (AI)).

6. **Climate Change and Environmental Justice (EJ)**
    - Need to incorporate climate resiliency into planning (fire, heat, air quality).
    - Calls to prioritize environmental justice communities in investments and project siting.
    - Concerns about health impacts from combustion-based solutions.
7. **Community Engagement and Transparency**
    - Requests for clearer communication of assumptions and results.
    - Suggestions for more tools (apps, dashboards, bill estimators) to engage with data.
    - Desire for deeper engagement with EJ communities
8. **Jobs, Workforce, and Economic Transition**
    - Concerns about labor shortages and the pace of workforce training.
    - Calls for union-built, local workforce-centered projects.
    - Balancing job creation opportunities with fossil fuel-related job losses.

Themes and Topics from Community Meetings

1. Green Hydrogen

- **Topics/Questions Raised**
    - Safety concerns: flammability, NOx emissions, leakage, health impacts.
    - Cost concerns: hydrogen seen as expensive, water-intensive, and requiring new infrastructure.
    - Availability: skepticism about commercial readiness by 2035.
    - Reliability: some argued hydrogen is needed for dispatchable backup power; others saw it as risky and unnecessary.

- Questions about dependence on SoCalGas' Angeles Link pipeline.

- Requests for alternatives (battery storage, virtual power plants, microgrids).

- **Responses:**

  - LADWP confirmed hydrogen is part of LA100 Plan modeling but acknowledged market uncertainties.

  - LADWP noted that timelines assume limited in-basin hydrogen until ~2034–2035, with full replacement of gas plants later.

  - Resources like battery storage and demand response were also evaluated but do not provide the same long-duration reliability as firm, in-basin, dispatchable power generation capacity.

2. Rates, Costs, and Energy Burden

- **Topics/Questions Raised**

  - Widespread concern about electric rate increases, with projections of bills doubling or tripling.

  - Requests to compare LA100 Plan costs against SB100 or other alternatives.

  - Questions on whether LADWP is following the City Council directive of achieving transition with *"minimal adverse impact to ratepayers."*

  - Concerns about disproportionate impacts on low-income and energy-burdened communities.

  - Suggestions to expand energy efficiency and electrification programs to reduce bills.

- **Responses:**

  - LADWP explained that cost estimates are in present-day dollars and include capital investments for reliability.

- Similarly, rate projections factor in LA100 costs but are also affected by broader infrastructure needs, such as distribution and transmission upgrades.

- LADWP acknowledged City Council's directive and stated that multiple modeling sensitivites were conducted to analyze the balance and tradeoffs between affordability and carbon reduction goals.

3. Reliability and Timeline Feasibility

- **Topics/Questions Raised**

  - Doubts about whether the 2035 goal is realistic, especially with reliance on unproven technologies.

  - Concerns about outages during extreme weather (fires, heatwaves).

  - Comparisons made to Spain/Portugal blackout as a cautionary tale.

  - Questions about what backup plans exist if technologies (hydrogen, long-duration storage, transmission) do not reach the required scale in time.

  - Suggestions to align with the State's 2045 target to reduce risk and costs, and questions about clarifying the State vs City carbon-free energy mandates.

- **Responses:**

  - LADWP emphasized that reliability is a core priority and hydrogen/energy storage are included in planning for this reason.

  - LADWP acknowledged the challenge of the timeline but reiterated its mandate from City Council to pursue 100% carbon-free by 2035.

4. Energy Efficiency, Solar, and Electrification Programs

- Topics/Questions Raised
    - Requests for more information on rooftop solar, Feed-in-Tariff (FiT), and shared/community solar.
    - Calls for programs to help residential neighborhoods, homeowner associations (HOAs), and nonprofits (e.g., churches) participate.
    - Questions about virtual net metering, virtual power plants, and community choice aggregation.
    - Suggestions to expand electrification to lower household bills and reduce reliance on combustion.
- **Responses**:
    - LADWP referred participants to existing programs (FiT, Shared Solar, appliance rebates) and discussed ongoing efforts to expand existing programs and develop new programs to have greater customer access.

5. Transparency and Engagement Process

- Topics/Questions Raised
    - Participants asked why meeting recordings stopped before question and answer (Q&A) segments,
    - Requests for more Q&A time, more transparency on assumptions, and follow-up sessions.
    - Suggestions for public-facing tracking systems to monitor LA100 Plan project progress, as well as advertising meetings more prominently home directly page of LADWP's website.

- **Responses:**

    - LADWP acknowledged feedback on meeting format, referred participants to the publicly-available LA100 Plan website (www.ladwp.com/la100plan) for copies of the presentation slides and other information, and reiterated the intentionality to not record the Q&A segment, to allow for more respect towards participant confidentiality and privacy