2022

Power Strategic Long-Term Resource Plan

Los Angeles Department of Water & Power

Los Angeles Department of Water & Power

2022 SLTRP POWER SYSTEM EXECUTIVE APPROVAL PAGE

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2022 SLTRP Preface

The 2022 Power Strategic Long-Term Resource Plan (SLTRP) serves as a comprehensive roadmap through 2045 that guides the Los Angeles Department of Water and Power's (LADWP) Power System in its efforts to supply reliable electricity in an environmentally responsible and cost-effective manner. Since decisions about which resources to procure and deploy can have significant economic and environmental consequences, it is essential for the planning process to be conducted with transparency, active participation, and collaborative dialogue with affected stakeholders and LADWP's customers. The 2022 SLTRP included a robust and expanded public outreach process and Advisory Committee that, along with a series of public outreach workshops, played an integral role in the development of the resource cases that were evaluated and in the final selection process of the recommended resource case. This year's 2022 SLTRP is largely driven by Mayoral directives and City Council motions that instructed LADWP to prepare an SLTRP to achieve 100% carbon-free energy by 2035 for the City of Los Angeles (City), following the completion of the LA100 (100% Renewables) Study. Previous SLTRPs, including the most recent 2017 SLTRP, only considered incremental updates in clean energy objectives which reflected the general cadence of development within the power utility industry. However, the vision established by the leadership of the City to achieve 100% carbon-free energy by 2035 places LADWP in a pioneering role with the potential to be an industry leader in clean energy resource development. There is also an incredible opportunity to align decarbonization initiatives with other economic sectors, such as transportation and real estate; In order to be successful, LADWP must grow and evolve in a way that prioritizes the foundational principles of reliability/resiliency, cost affordability, and equitable services.

Significant updates were made to this SLTRP to incorporate the latest resource and cost assumptions that built on the LA100 Early and No Biofuels scenario as a blueprint for LADWP to achieve 100% carbon-free energy by 2035. This SLTRP also includes numerous updates including new renewable projects, associated transmission upgrade cost and fuel cost assumptions, staffing requirements, and several other critical updates. The SLTRP uses system modeling tools to analyze and determine the long-term economic, environmental, and operational impact of alternative resource portfolios by simulating the integration of new resource alternatives within LADWP's existing mix of assets and providing the analytic results to inform the selection of a recommended case that considers various factors such as minimal adverse rate impacts on customers, prioritizing environmental stewardship and equity, and maintaining reliability and resiliency.

2022 SLTRP Looking Ahead

The next iteration of the 2024 SLTRP will be an update to the 2022 SLTRP with continued engagement of the Advisory Group and focus on understanding rate drivers and clean energy opportunities to refine and optimize cost over the long-term. LADWP continues to address implementation risk and challenges, including human resources, constructability and outage management, supply chain impacts and commodity volatility, emerging technologies, procurement risk, timely upgrades to transmission and distribution, and electrification of transportation and buildings. Supportive measures such as the Inflation Reduction Act were not considered in this 2022 SLTRP and will be incorporated into the next iteration of the SLTRP that may put downward pressure on overall costs for transforming the electrical grid and customer electricity rates. Realizing this new clean energy roadmap will require an unprecedented buildout of clean energy resources, technologies, and infrastructure.

Lastly, this SLTRP also includes a general assessment of the revenue requirements and rate impacts that support the recommended resource plan through 2035 and 2045. While this assessment is not as detailed and extensive as the financial analysis that will be completed for the upcoming fiscal year rate action, it clearly outlines the general requirements and details. As a long-term planning process, the SLTRP examines the 2045 horizon to secure adequate supplies of electricity. In that respect, the SLTRP will contribute towards future rate actions, by presenting and discussing the programs and projects required to fulfill our City Charter mandate of delivering reliable electric power to the City of Los Angeles.

With great pride, in spirited commitment to excellence for the betterment of our wonderful City, this 2022 SLTRP represents a historic step forward to realizing a clean energy future now for all Angelenos.

Best Regards,

The LADWP Integrated Resource Planning Team

Cover photo courtesy of Pattern Energy

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KEY TAKEAWAYS:

- Achieving 100 percent carbon-free energy is technically achievable.
- Significant investments in renewables, energy storage, and transmission infrastructure are required to achieve 100 percent carbon-free energy.
- Firm, dispatchable generation located near LADWP's load center is essential for maintaining reliability.
- Transportation electrification is the key to affordability and local air quality improvement by increasing total revenue to recover fixed costs and substantially decreasing emissions in other economic sectors, respectively.

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DEFINITIONS

AG	Advisory Group
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
Core Cases	SLTRP Cases 1, 2, and 3
CPUC	California Public Utilities Commission
DER	Distributed Energy Resources
DOE	U.S. Department of Energy
DR	Demand Response
ECCEJR	Energy, Climate Change, Environmental Justice, and River
ELCC	Effective Load Carrying Capability
ES	Executive Summary
EV	Electric Vehicle
GHG	Greenhouse Gas
GWh	Gigawatt-hours
In-basin	Los Angeles Basin
IPP	Intermountain Power Project
IRP	Integrated Resource Planning
kWh	Kilowatt-hour
LA	City of Los Angeles
LA100 Study	Los Angeles 100% Renewable Energy Study
LADOT	Los Angeles Department of Transportation
LADWP	Los Angeles Department of Water and Power
LOLH	Loss of Load Hour
Metro	Los Angeles County Metropolitan Transportation Authority
MMT	Million Metric Tons
MW	Megawatts
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
OTC	Once-Through Cooling

PM	Particulate Matter
POLA	Port of Los Angeles
PPA	Power Purchase Agreement
President	U.S. President
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SB 100	California Senate Bill 100
Sim Reps	Simulation Repetitions
SLTRP	Power Strategic Long-Term Resource Plan
U.S.	United States
WEIM	CAISO's Western Energy Imbalance Market

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 10,664 megawatts ("MW") and net dependable capacity of 8,101 MW as of August 31, 2022. The Power System's highest instantaneous peak demand registered 6,502 MW on August 31, 2017. We are responsible for meeting the electric 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 2020-2021, LADWP supplied 20,936 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 63% of the electricity in Los Angeles. As of Fiscal Year 2021-2022, LADWP had an approved total Power System budget of $4.9 billion, comprised of $1.8 billion for capital projects, $1.6 billion for operations and maintenance, and $1.5 billion for fuel and purchased power.

As shown in Figure 1, LADWP also has vertically-integrated power generation, transmission, and distribution systems that span over five Western U.S. states. 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 "in-basin" generating stations.

Additionally, LADWP owns and operates the Castaic Power Plant, a 1,320 MW pumped-storage hydroelectric generation facility located in Castaic, California. Additionally as of 2021, LADWP has over 550 MW of total installed local solar, leading Los Angeles to be designated the number one solar city in the nation from 2014 to 2016, 2018 to 2020, and once again in 2022 (Figure 2).

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).

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 (Figure 4). Combined with the in-basin renewable energy generation resources, an estimated 35% of LADWP's power resources in the year 2021 were eligible renewable energy resources, as shown in Figure 5. Furthermore, that number increased to 55% 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.

Figure 2. Installation of local rooftop solar.

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

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

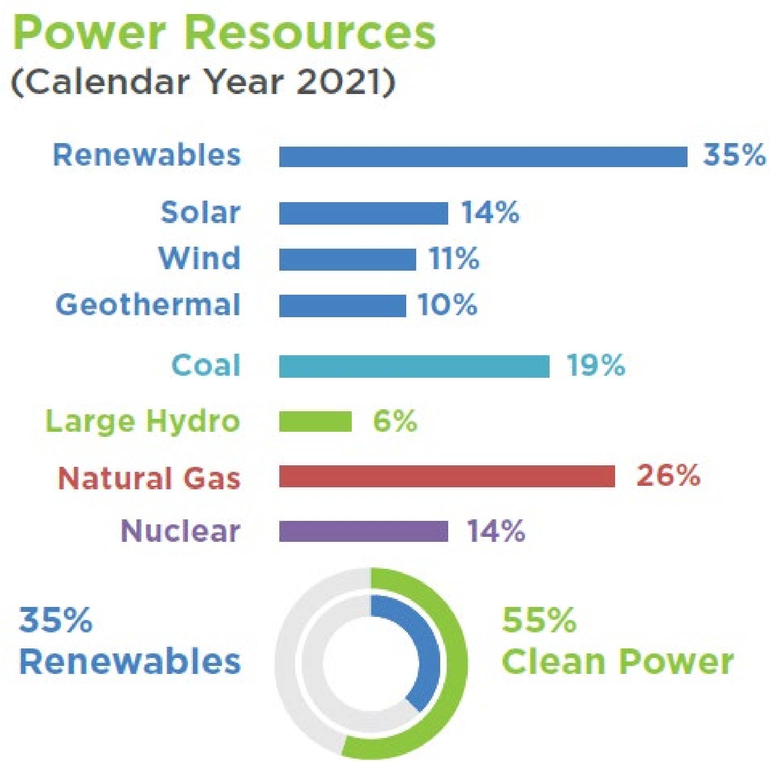


Figure 5. Percentage Breakdown of Power Resources, Calendar Year 2021. Based on energy used to supply retail customer load on an annual basis.

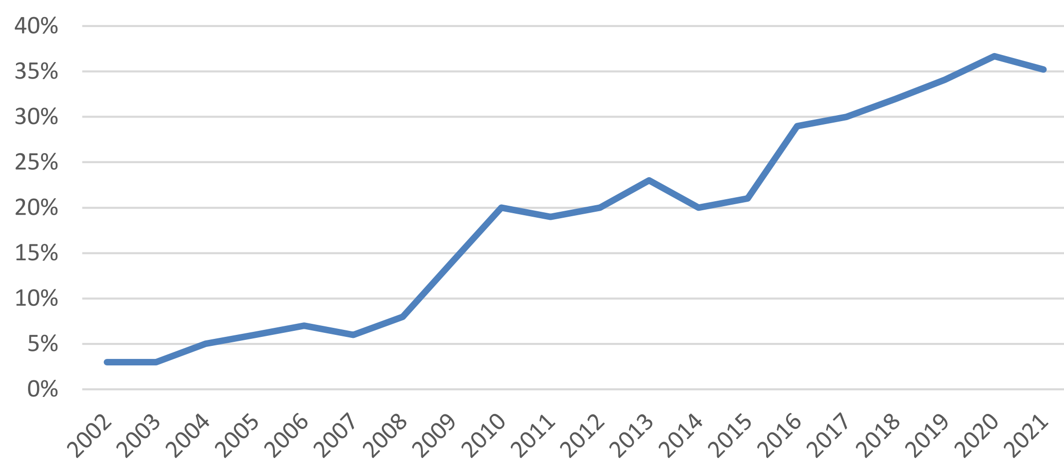


Figure 6. Historical Percentage of Eligible Power System Renewable Energy Resources, 2002-2021. Based on energy used to supply retail customer load on an annual basis.

Figure 6 shows LADWP's historical percentage of eligible renewable energy used to supply retail customer load on an annual basis. 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 2021, LADWP's GHG emissions were approximately 7.0 million metric tons (MMT), nearly 60% below the 1990 emissions baseline of 17.9 MMT.

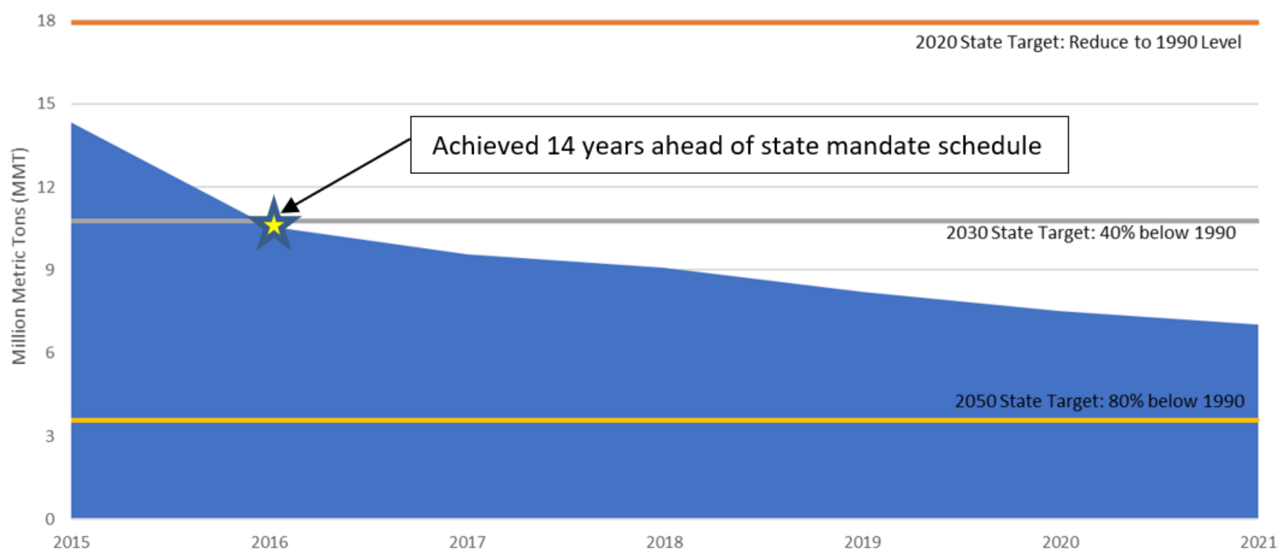


Figure 7. Historical LADWP GHG Emissions, 2015-2021.

As shown in Figure 8, with respect to transmission, LADWP has 4,040 miles of overhead transmission circuits (alternating current and direct current) and 135 miles of underground transmission circuits. On the distribution side, LADWP has 7,265 miles of overhead distribution lines, 3,807 miles of underground distribution cables, and 167 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.

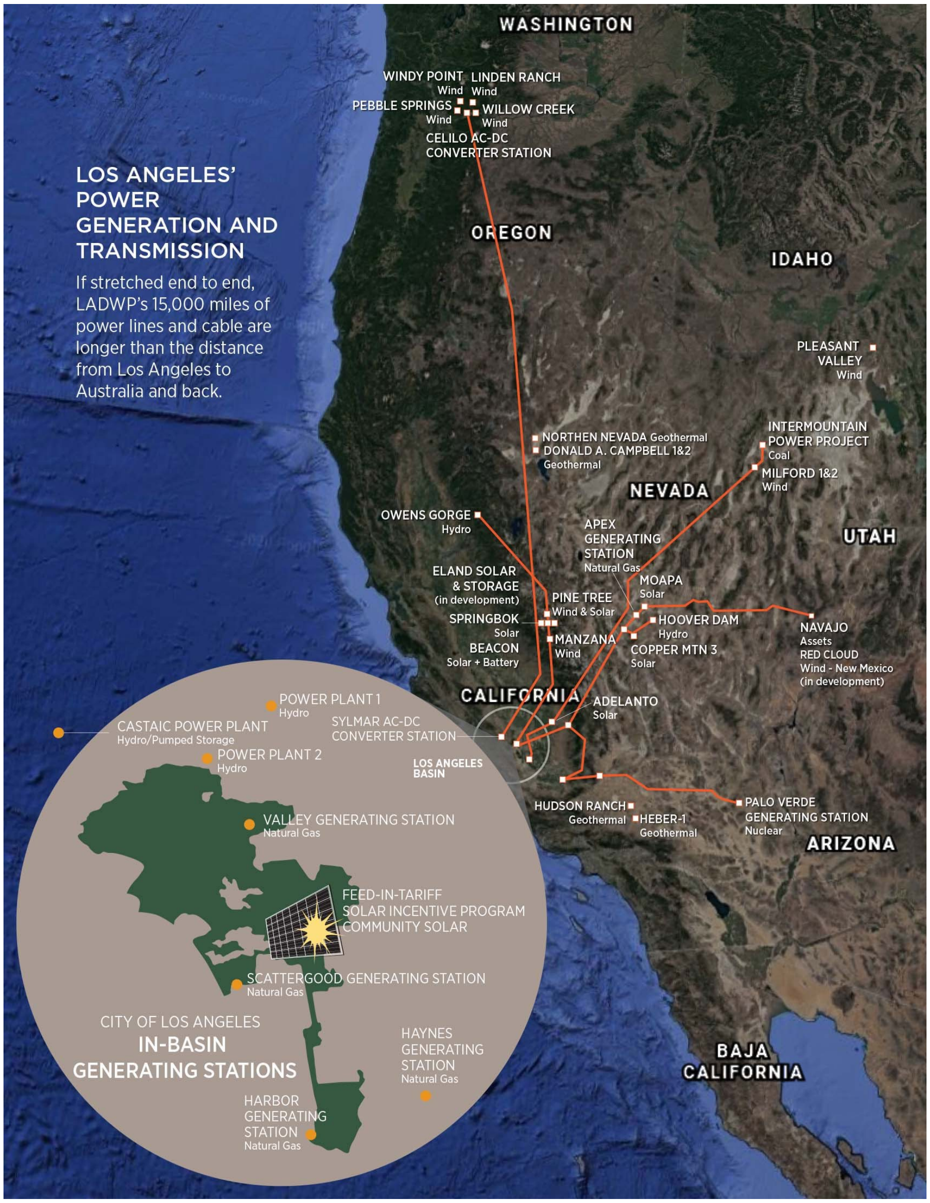


Figure 8. LADWP's generation and transmission resources.

ES-2 Background and Timeline

Several developments occurring over the last several years have culminated in this 2022 Power Strategic Long-Term Resource Plan (SLTRP), 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 created the 2022 Power Strategic Long-Term Resource Plan to establish several cases that achieve 100% carbon-free energy, pursuant to the City Council motion. Additionally, the ongoing LA100 Equity Strategies effort launched in 2021, which aims to ensure that LA's carbon-free energy transition is achieved in an equitable manner, will be incorporated into subsequent SLTRPs as information becomes available.

ES-2.1 California Senate Bill 100 (2018)

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:

- Achieving the goals set forth in SB 100 is 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, the Joint Agencies recommended further analysis which includes:

- Verifying that scenario results satisfy the state's grid reliability requirements
- Evaluating 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 (2019)

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.

ES-2.3 The LA100 Study (2017-2021)

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 9. 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 in order 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:** In order 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 electrification as well as 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 preparing the 2022 Power Strategic Long-Term Resource Plan, LADWP's Resource Planning team incorporated key takeaways from the LA100 Study and utilized LA100's Early & No Biofuels scenario as a blueprint in the development of the 2022 SLTRP case scenarios. The Resource Planning team also integrated significant input from the SLTRP Advisory Group, which includes a broad representation of LADWP's stakeholders reflective of its customer base. This scenario is projected towards the goal of 100% carbon-free energy by 2035. Additionally, this scenario assumes high levels of customer rooftop and distributed solar deployment and prohibits the use of biofuels due to concerns about sustainability. This scenario instead assumes significant clean hydrogen infrastructure is built and deployed to be used as a backup during stressed grid conditions (e.g. wildfires). In order to minimize the usage of future clean hydrogen fuel during normal grid conditions, the LA100 Early & No Biofuels scenario also built high levels of geothermal capacity to provide firm and base loaded renewable energy. As illustrated in Figure 9 and Figure 10, this scenario also assumes large amounts of standalone energy storage and utility-scale solar paired with energy storage.

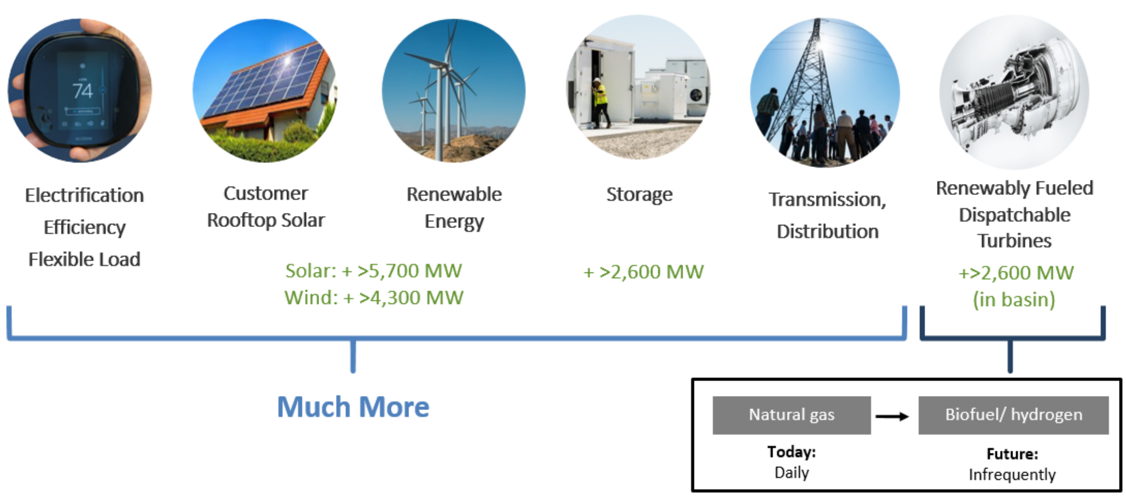


Figure 9. Common investments across all LA100 Study scenarios.

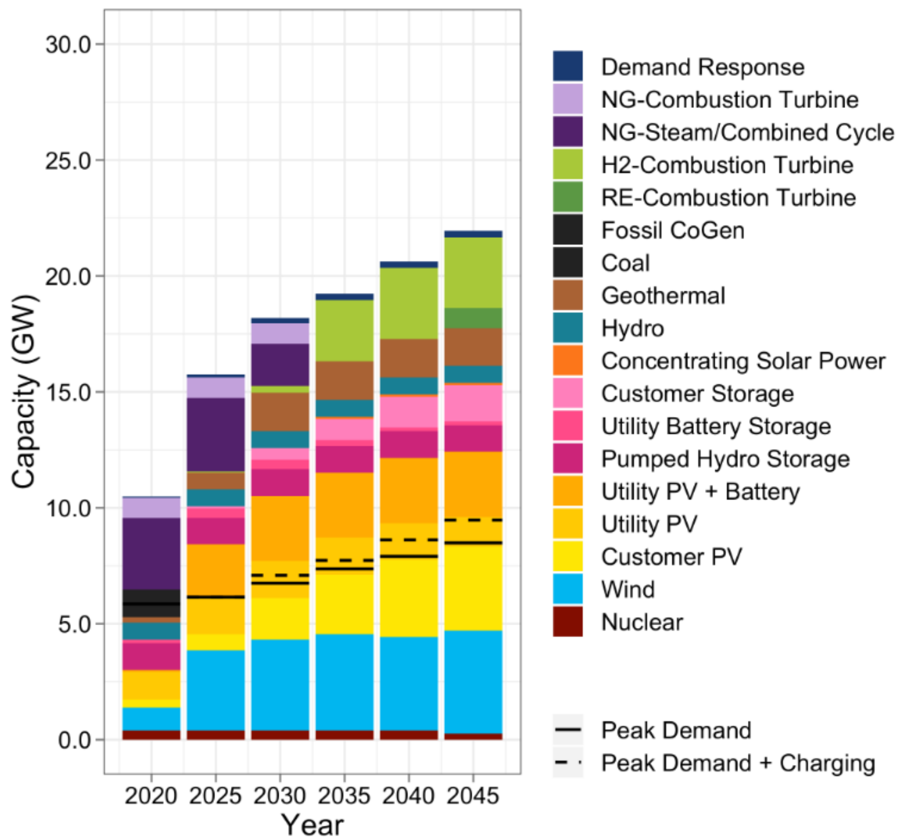


Figure 10. LA100 Study Early & No Biofuels (Moderate Load) Capacity Mix, 2020-2045.

"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."

ES-2.4 LA100 Equity Strategies (2021-2023, estimated)

In June 2021, LA100 Equity Strategies was announced to build upon and advance the concepts of the LA100 Study. LA100 Equity Strategies takes the technical and theoretical results obtained from the LA100 Study and aims to answer how Los Angeles can ensure its clean energy transition is achieved in an equitable manner while all communities share in the benefits and burdens. LA100 Equity Strategies seeks to improve energy equity and justice through community engagement, an Advisory Committee, and a Steering Committee. These groups and their feedback will aid in the development of implementation-ready strategies that can be applied towards intentionally designed policies and programs that help address community priorities relating to energy affordability and burdens, access and use, community health, safety, resilience, and jobs. This effort is ongoing in parallel to the 2022 SLTRP, and as outcomes become available, they will be included in future SLTRPs.

ES-2.5 The Los Angeles City Council Motion (2021)

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 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.

ES-2.6 California Senate Bill 1020 (2022)

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 The 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 began the latest iteration of the SLTRP process in September 2021. The LADWP Integrated Resource Planning (IRP) Group takes the lead in compiling the SLTRP, including gathering stakeholder input and assumptions, interfacing with consultants providing computer modeling and simulation support, participating in public outreach, and writing the SLTRP document.

LADWP's 2022 Power SLTRP 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 its customers. The planning process includes an Advisory Group to ensure LADWP's plans reflect the input of the communities and customers it serves. The 2022 SLTRP is 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 technology risk, minimizing adverse rate impacts, and ensuring an equitably just transition.

ES-2.7.1 Stakeholder Engagement, Outreach, and Feedback

The first step in the SLTRP 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 considered in the SLTRP.

A major component in the process of gathering stakeholder input is the SLTRP Advisory Group. The SLTRP Advisory Group was comprised of over 45 stakeholders representing Neighborhood Councils, Academia, Community Organizations, Existing Customers, and City and Local Government, among others. The Advisory Group is 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 2022 SLTRP Advisory Group, LADWP held several public outreach meetings in August and September of 2022. These meetings were held virtually and were open to the general public. LADWP presented information on the scenarios considered in the SLTRP 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, which was considered when determining the 2022 SLTRP Recommended Case.

Based on feedback provided by the SLTRP Advisory Group and the feedback provided during the public outreach process, the IRP Group was able to categorize the majority of 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, deploying long-duration energy storage assets, incorporating local air quality and health impacts analyses, ensuring affordable electricity rates, addressing the overall feasibility and constructability of each SLTRP case, ensuring reliability, and encouraging local, behind-the-meter assets such as rooftop solar, energy efficiency, and demand response.

ES-2.7.2 Cases

In response to stakeholder input, LADWP staff decided to model four cases for the 2022 SLTRP:

- SB 100 (Reference case, 60% RPS by 2030, 100% carbon-free by 2045)
- Case 1 (80% RPS by 2030, 100% carbon-free by 2035)
- Case 2 (90% RPS by 2030 with focus on large scale renewables, 100% carbon-free by 2035)
- Case 3 (90% RPS by 2030 with focus on distributed energy resources, 100% carbon-free by 2035)

The SB 100 case is the reference case used for comparison purposes and represents the minimum investments needed to comply with California state law, namely, SB 100.

Cases 1, 2, and 3 are referred to as the “Core Cases”. These Core Cases were constructed to highlight the investments needed to achieve the Los Angeles City Council’s motion instructing LADWP to prepare a plan that achieves 100% carbon-free energy by 2035. One of the main differences between the Core Cases is the interim 2030 RPS goals. Case 1 plans for an 80% RPS by 2030, while both Case 2 and Case 3 achieve a 90% RPS by 2030. Case 3 contemplates additional behind-the-meter and distributed energy resources to the greatest extent possible, incorporating the highest amounts of rooftop solar, local energy storage, energy efficiency, and demand response.

One of the key findings of the LA100 Study was the need for firm and dispatchable generation near the primary customer load center to ensure reliability of LADWP’s electricity grid, specifically during stressed load conditions such as wildfires. The SLTRP’s Core Cases also confirmed through modeling that firm and dispatchable generation sites within the Los Angeles Basin would be required and provided by combined-cycle and combustion turbine generating units running on 100% green hydrogen by 2035. The first such generation unit is anticipated to commence commercial operations in 2029 and will be situated at LADWP’s Scattergood Generating Station. This generating unit is assumed to be a fast-ramping combined cycle unit capable of burning 30% green hydrogen by volume at its commencement of commercial operations. This percentage will be increased such that it will run on 100% green hydrogen by 2035. Several other units slated to be running on green hydrogen are assumed to be built during the 2030s and 2040s, situated at LADWP’s Harbor, Haynes, Scattergood, and Valley Generating Stations. These green hydrogen resources will transform LADWP’s in-basin generation to maintain reliability and resiliency metrics with increasing load growth primarily driven by electrification using carbon-free generation.

All the Core Cases (Table 1) seek to meet the Los Angeles City Council’s motion to achieve 100% carbon-free energy by 2035—10 years sooner than what SB 100 mandates. Case 1 has an interim goal of achieving an 80% RPS by 2030. In terms of renewables, Case 1 considers wind, solar, geothermal, and small hydro, but unlike the SB 100 case, does not consider biogas and biofuels, keeping in line with the findings of the LA100 Study.

Similarly, Case 2 seeks to meet the Los Angeles City Council’s motion to achieve 100% carbon-free energy by 2035. Case 2 considers wind, solar, geothermal, and small hydro and does not consider biogas and biofuels. Hydrogen fuel cells were also provided as candidate resources from which the capacity expansion model could choose from. And like Case 1, fuel cells were not selected by the capacity expansion model due to their high capital costs. Recognizing that the last 10% carbon-free energy is the most challenging and expensive to achieve, Case 2 was developed to weigh the trade-offs towards the last 10% carbon-free energy. The main difference between Case 1 and Case 2 is their interim 2030 RPS targets. While Case 1 has an

80% RPS target in 2030, Case 2 has a more aggressive 90% RPS target by 2030, and inherently accelerated transmission upgrades by 2030 to support the additional RPS.

Like Case 1 and Case 2, Case 3 will meet the Los Angeles City Council's motion to achieve 100% carbon-free energy by 2035. As with the other Core Cases, Case 3 considers wind, solar, geothermal, and small hydro and does not consider biogas and biofuels. Case 3 has far higher quantities of behind-the-meter distributed energy resources and local resources compared to the other Core Cases. Case 3 targets 2,900 MW of local solar, 4,770 GWh of energy efficiency savings, 633 MW of demand response, and the highest quantity of distributed local energy storage by 2035 of any of the cases considered.

"One of the key findings of the LA100 Study was the need for firm dispatchable generation near the primary customer load center to ensure reliability of LADWP's electricity grid..."

Table 1. Scenarios included in the 2022 SLTRP. Entries marked with an asterisk (*) indicate that such resources were provided to the capacity expansion model as potential resource candidates. The capacity expansion model then determined the optimal quantities, if any, of each technology to include in each scenario's resource portfolio.

		2022 SLTRP Core Scenarios			
		100% Clean Energy by 2045	100% Carbon Free by 2035		
		SB 100 (Reference Case)	Case #1	Case #2	Case #3
	2030 RPS Target	60% RPS by 2030	80% RPS by 2030	90% RPS by 2030 (80% RPS by generation)	90% RPS by 2030 (80% RPS by generation)
Eligible Technologies	Renewables (Wind, Solar, Geo, Small Hydro) *(primary)*	Yes*	Yes*	Yes*	Yes*
	Energy Storage *(primary)*	Yes*	Yes*	Yes*	Yes*
	Solid Biomass	No	No	No	No
	Biogas/Biofuels	Yes*	No	No	No
	Fuel Cells	Yes*	Yes*, hydrogen only	Yes*, hydrogen only	Yes*, hydrogen only
	Hydro - Existing	Yes*	Yes*	Yes*	Yes*
	Hydro - New	No	No	No	No
	Hydro - Upgrades	Yes*	Yes*	Yes*	Yes*
	Natural Gas	Yes*	Yes*, until 2035	Yes*, until 2035	Yes*, until 2035, Limited (More DERs)
	Zero Carbon H2 Turbines *(secondary)*	Yes*	Yes*	Yes*	Limited (More DERs)
	Nuclear - Existing	Yes*	Yes*	Yes*	Yes*
	Nuclear - New	No	No	No	No
Transform existing gas capacity (non-OTC units)	Haynes, Scattergood, Harbor, Valley	No	Yes	Yes	Yes
Distributed Energy Resources (DERs)	Local Solar	1500 MW by 2035 (Reference)	2240 MW by 2035 (High)	2240 MW by 2035 (High)	2900 MW by 2035 (Highest)
	Local Energy Storage	Reference	High	High	Highest (Max DERs)
	Energy Efficiency	3210 GWh by 2035 (Reference)	4350 GWh by 2035 (High)	4350 GWh by 2035 (High)	4770GWh by 2035 (Highest)
	Demand Response	576 MW by 2035 (Moderate)	576 MW by 2035 (Moderate)	576 MW by 2035 (Moderate)	633 MW by 2035 (High)
	Building Electrification	Reference	High	High	High
Renewable Energy Credits (RECs)	Financial Mechanisms (RECs/Allowances)	Yes	No	No	No
Transmission	New or Upgraded Transmission	Moderate	High	High (possible new corridors)	High

**Note: Optimal portfolio was determined through the capacity expansion model.*

ES-2.7.3 Modeling

A major component of the SLTRP process is the modeling of LADWP's Power System through the use of 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 iteration of the SLTRP, the planning horizon was chosen to span between the years 2022 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 SLTRP utilized the same modeling methodology and approach as the LA100 Study. 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 11, the 2022 SLTRP used *Automated Resource Selection* (ARS), a proprietary software package provided by LADWP's consultant, Ascend Analytics, for capacity expansion modeling.

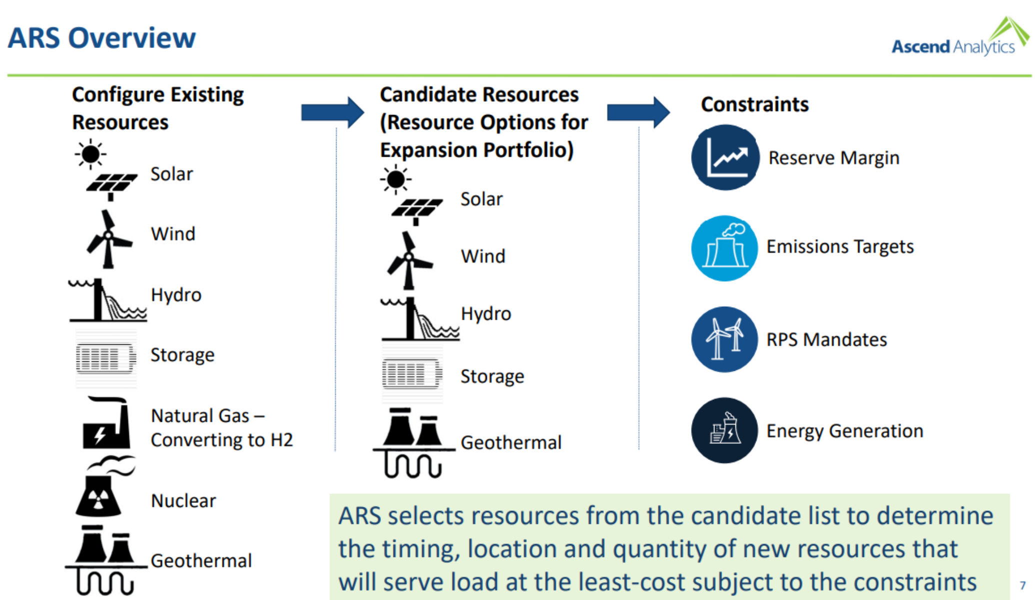


Figure 11. The ARS software package was used for capacity expansion modeling for the 2022 SLTRP.

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 12. For example, in order 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 met at all times.

New to this iteration of the SLTRP is stochastic Monte Carlo simulation. Several years of 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.

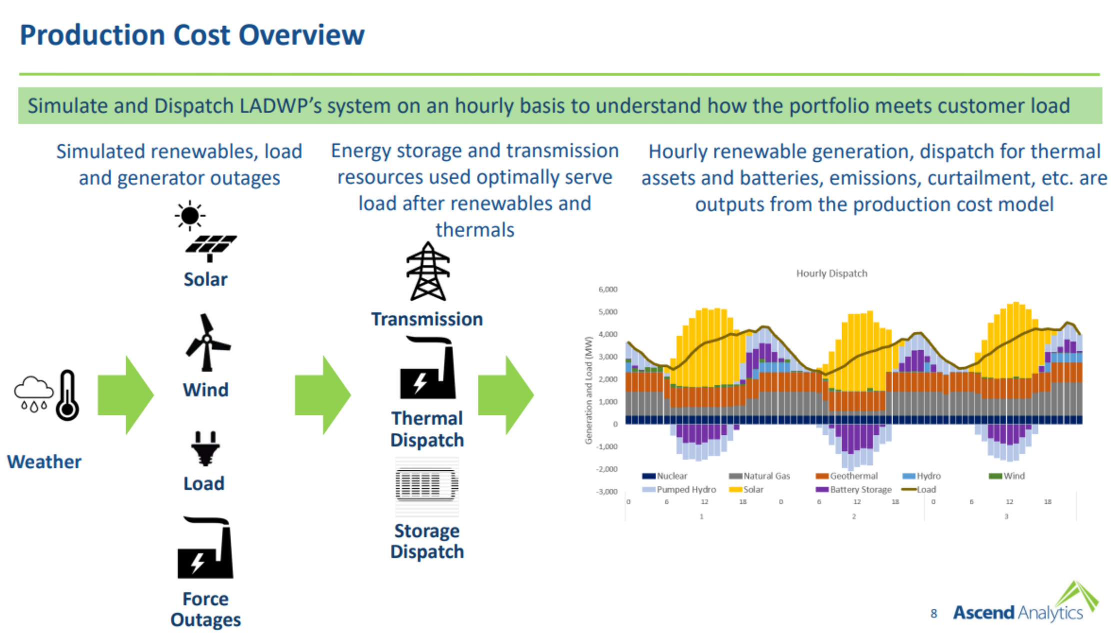


Figure 12. The production cost modeling process used for the 2022 SLTRP.

ES-3 Results

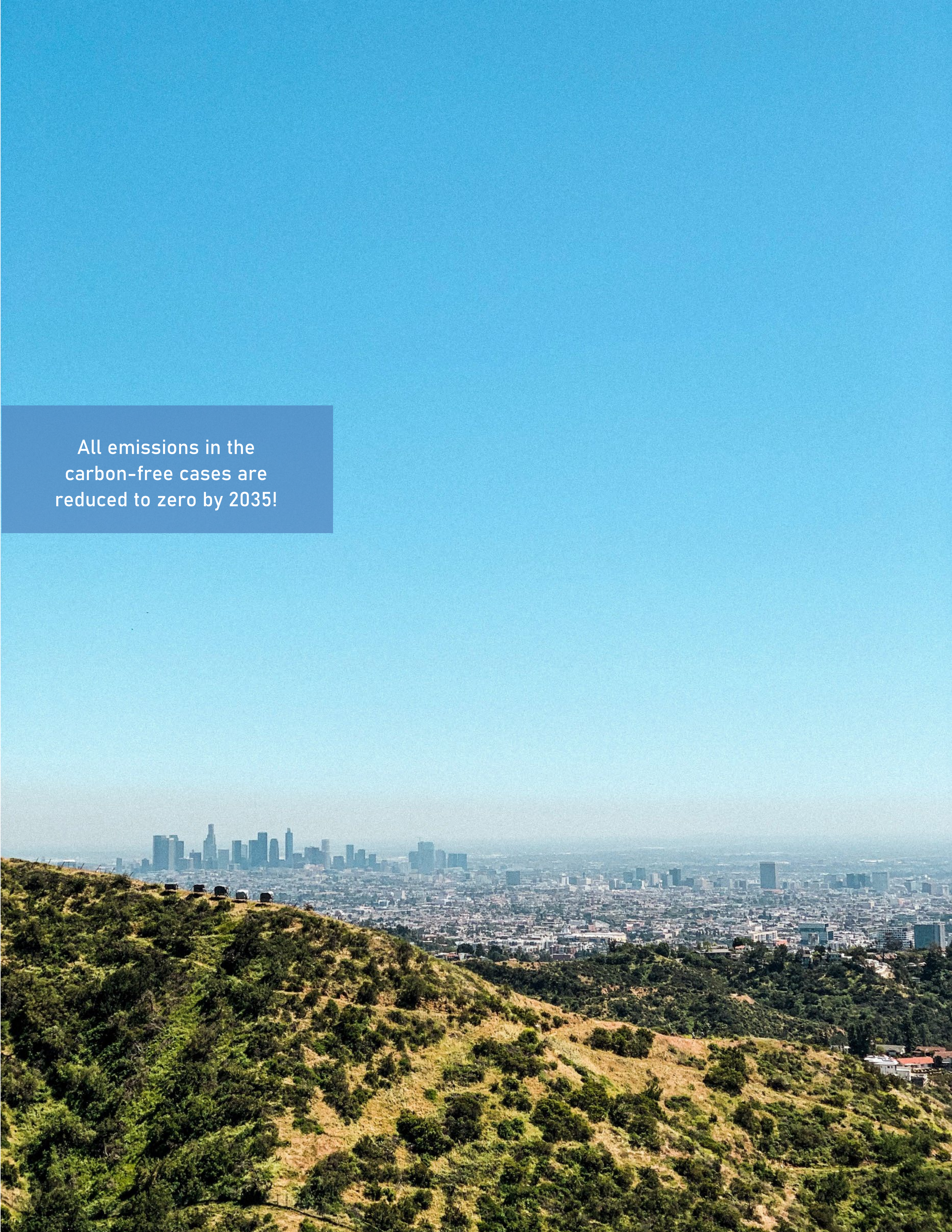
Through the use of computer modeling, metrics such as emissions, costs, reliability, and electricity rates are forecasted for each case and are presented in the following sections.

ES-3.1 Greenhouse Gas Emissions

With respect to GHG, all three carbon-free cases and the reference case (SB 100) start at approximately 8 million metric tons of GHG emissions in 2022 and nearly reduce to half that amount by 2025. The single most significant reduction in carbon emissions throughout the entire study results from LADWP fully divesting away from its last remaining coal asset in 2025. This means that the coal-fired generation at the Intermountain Power Project (IPP) is replaced by cleaner generation from new combined-cycle units capable of operating on a blend of green hydrogen and natural gas. In 2025, the new IPP units operate on a fuel blend of up to 30% green hydrogen and 70% natural gas (by volume), and eventually operate completely on green hydrogen starting in 2035.

Further reductions can be observed starting in 2030. As natural gas-fired once-through cooling (OTC) generating units are retired by the end of 2029 to comply with State of California mandates, they are replaced with carbon-free energy alternatives such as green hydrogen-capable units at Scattergood Generating Station. Also, significant deployment of customer-side resources such as distributed solar, distributed energy storage, energy efficiency, and demand response would reduce GHG emissions. Additionally, substantial amounts of utility-scale renewable energy and energy storage are interconnected into LADWP's system such that by 2030, Case 1 meets an 80% RPS, while Case 2 and Case 3 reach a 90% RPS. The 2030 RPS milestones for the carbon-free cases are not only considerably above the State of California mandate of reaching a 60% RPS in 2030 as required by SB 100, but also more than double LADWP's RPS percentage from 2022 in less than a decade. Furthermore, the phase-out of coal and the increasing integration of renewable energy into LADWP's power generation mix emerge as one of the most important drivers in reducing GHG emissions.

All emissions in the Core Cases are reduced to zero by 2035, as all of LADWP's power generation (including losses) are supplied through carbon-free resources, an entire decade ahead of the California mandate. For the carbon-free cases, all the natural gas-fired generating units are converted to operate on green hydrogen which does not emit carbon. It is important that future SLTRPs evaluate the technical and practical feasibility for transforming LADWP's existing generating units from using natural gas as a fuel to green hydrogen within the short timeframe that is required to meet 100% carbon free by 2035. This transformation may be constrained by the technological maturity of future resources, the need to run a Power System 24/7, outage schedule coordination, and physical space limitations, which will require thorough reviews and input from Power Supply Operations and other LADWP support groups. Although emissions are somewhat higher in the SB 100 reference case, the trade-off is that the overall cost and implementation risk are greatly reduced compared to the Core Cases. The next iteration of the SLTRP will consider implementation feasibility, in terms of the accelerated buildout of green hydrogen production, delivery, and combustion infrastructure within the Core Cases.



All emissions in the carbon-free cases are reduced to zero by 2035!

ES-3.2 Costs

With respect to total bulk power portfolio costs, the net present value of all the fixed costs (including capital, fixed operations and maintenance, power purchase agreements, debt service, and others) and all the variable costs (including fuel, greenhouse gas allowances, nitrogen oxide credits, variable operations and maintenance, and other misc. cost), are considered across the study horizon from 2022 through 2045. This method of discounting the annual cash flows at an assumed 5.5% discount rate to arrive at a net present value, allows for more accurate and fair comparison among the cases.

As seen in Figure 13, SB 100 has the lowest cost in the range of approximately $60 billion, while Case 1, 2, and 3 have estimated costs upwards of $80 billion. Meanwhile, Case 1 is less expensive than Case 2, and Case 2 is less expensive than Case 3. In terms of annual total bulk power costs, all cases start at approximately $3 billion annually and more than triple by the end of the study horizon. The Core Cases incur significant annual costs above those of SB 100, largely a result of a more aggressive deployment of renewable energy resources, energy storage, infrastructure buildout, labor, green hydrogen infrastructure, and other required infrastructure. It should be noted that some of the costs for customer-sided resources, such as distributed solar and energy storage, are assumed to be borne by the customer and are not included here. Furthermore, while comparing the cases from this financial perspective, it must be noted that some nuances and risks fail to be captured by such financial estimates such as the incrementally and significantly more challenging prospects for attaining permitting, securing required outages, procuring enough equipment, hiring sufficient personnel, and other factors, to build the additional transmission and generation projects required under Case 2. In comparison, for Case 1, carbon-free energy resources are procured and installed at a more gradual pace while still achieving the same overall goal by 2035.

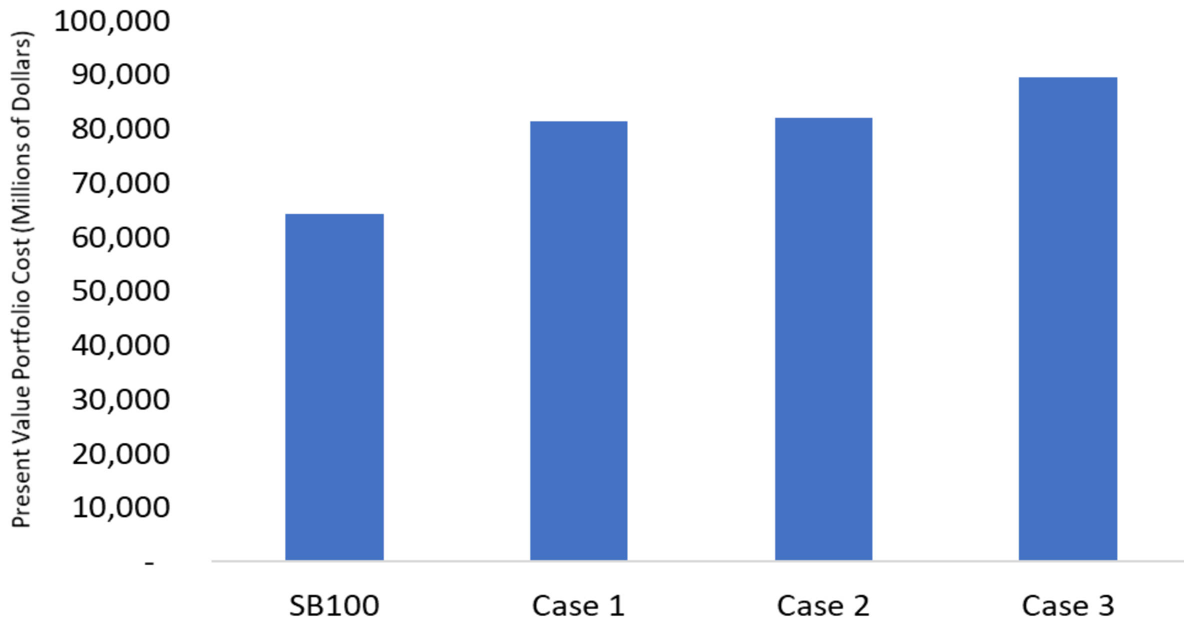


Figure 13. Total net present value bulk power cost for each SLTRP scenario. Total cost for each scenario includes fixed costs, including but not limited to capital expenditures, power purchase agreements, and debt service, and also includes variable costs. Examples of variable costs include fuel, GHG allowance credits, and maintenance.

ES-3.3 Reliability and Resilience

All cases, including the carbon-free cases and the reference case, were modeled to adhere to the North American Electric Reliability Corporation (NERC) industry standard for the loss of load hour (LOLH) metric, which is one day in ten years and translates to being at or below 2.4 LOLH per year.

LOLH, which quantifies the number of expected hours in which generation cannot meet demand, was below 2.4 per year for the SB 100 Case, and below 0.5 per year for Case 1, Case 2, and Case 3, as shown in Figure 14. The high degree of reliability demonstrated by the LOLH for the carbon-free cases, is largely a result of overbuilding renewable and energy storage resources to comply with the accelerated target for 100% carbon-free energy by 2035. In contrast, the more flexible constraints of the SB 100 Case do not require 100% carbon-free energy until 2045 (a decade later than the Case 1, 2, and 3 carbon-free cases), and allows for losses to be made up with low carbon intensity energy resources, and does not overbuild resources like the carbon-free cases.

For the carbon-free cases, the effective load carrying capability (ELCC), or effective system capacity, declines as a result of the oversaturation of non-dispatchable and variable energy resources. These include resources such as solar, wind, and duration-limited energy storage. The need for dependable and dispatchable long-duration electric generation capacity within the Los Angeles Basin led to the selection of long-duration dispatchable green hydrogen turbines (that emit no carbon emissions when fueled entirely with green hydrogen starting in 2035) for all of the carbon-free cases. These green hydrogen turbines are meant to serve as backup resources to maintain reliability during periods of low renewable energy output, and to bolster grid resiliency to ride through and recover from grid outages that can be caused by extreme events such as wildfires, earthquakes, heatwaves, and other types of unplanned events.

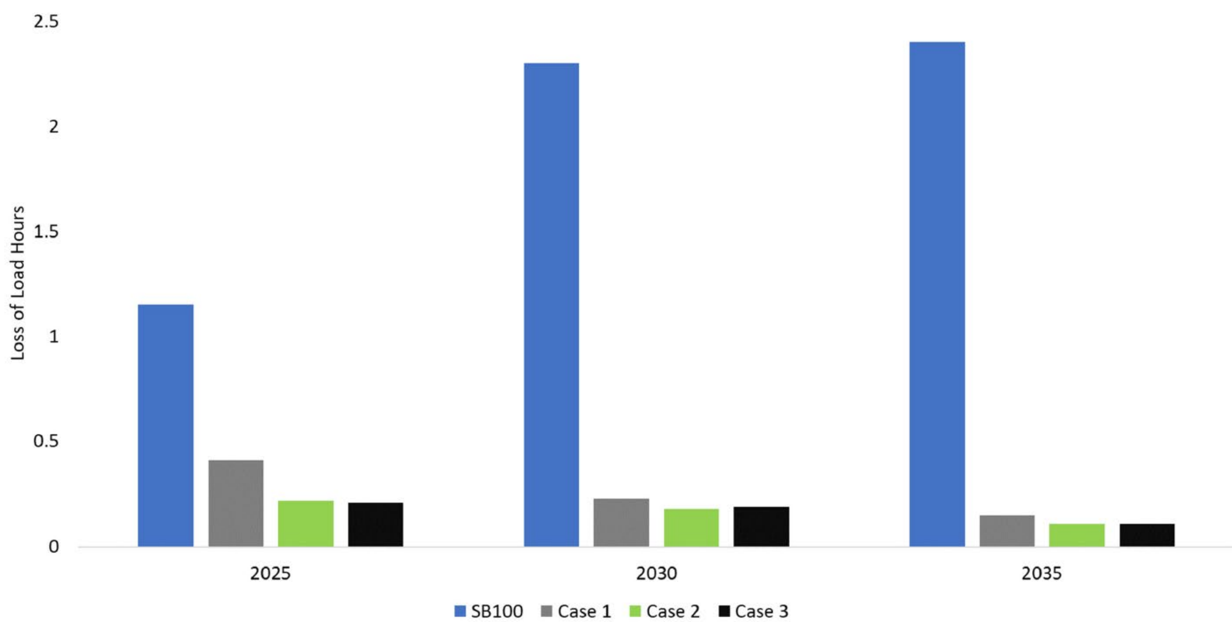


Figure 14. Reliability measured in Loss of Load Hours (LOLH) for the 2022 SLTRP cases.

ES-3.4 Rates

The estimated electric retail rate and bill impacts in the SLTRP are preliminary averages, which are subject to ongoing budget estimate and future rate reviews, and do not yet reflect the potential cost savings from new sources of funding, such as the Inflation Reduction Act, Bipartisan Infrastructure Law, and state and federal grants. The SLTRP team worked closely with LADWP's Financial Services Organization to determine the electric retail rate estimates for key years, such as 2030 and 2035, using the current LADWP rate structure. The overall total portfolio costs shown in Figure 13 and electric customer retail sales in kWh are key factors in determining rates.

In 2030, the projected electric retail rates are $0.30/kWh for SB 100, $0.38/kWh for Case 1 and Case 2, and $0.42/kWh for Case 3. In 2035, the estimated electric retail rates are $0.38/kWh for SB 100, $0.54/kWh for Case 1 and Case 2, and $0.58/kWh for Case 3. From 2022-2035, the estimated average annual rate increase across all scenarios ranges from 4.8% for SB 100, 7.7% for Cases 1 and 2, and 8.4% for Case 3, as shown in Figure 15.

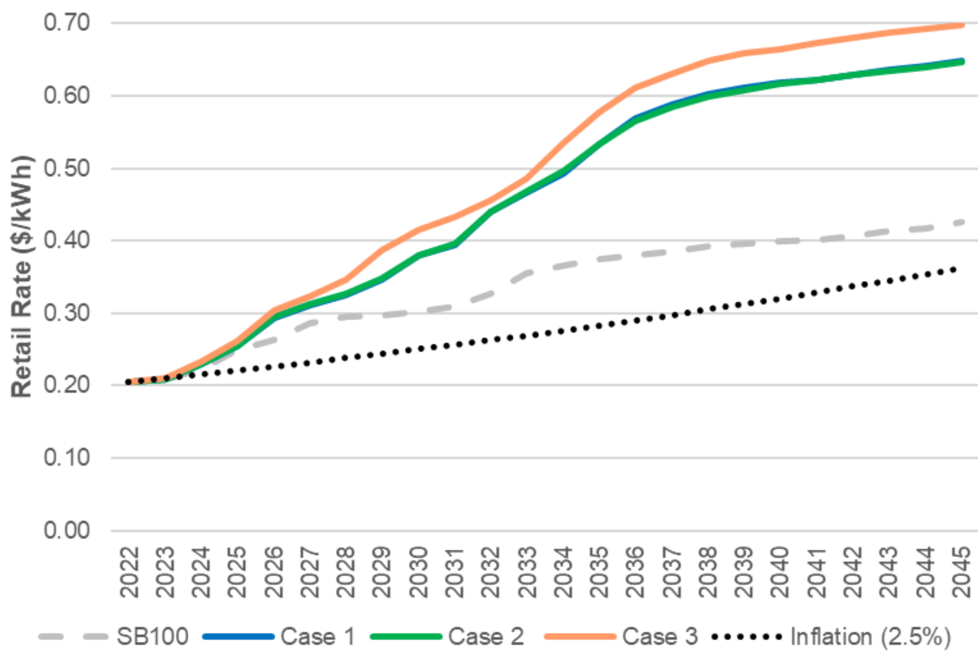


Figure 15. Nominal forecasted electric retail customer rates.

In 2035, the estimated monthly electric retail bill impacts for an apartment shown in Figure 16, assuming an average consumption of 300 kWh/month, are as follows: $112/month for SB 100, $160/month for Case 1 and Case 2, and $174/month for Case 3. Estimated monthly electric retail bill impacts for a single-family residence, assuming an average consumption of 700 kWh/month are as follows: $262/month for SB 100, $373/month for Case 1 and Case 2, and $405/month for Case 3.

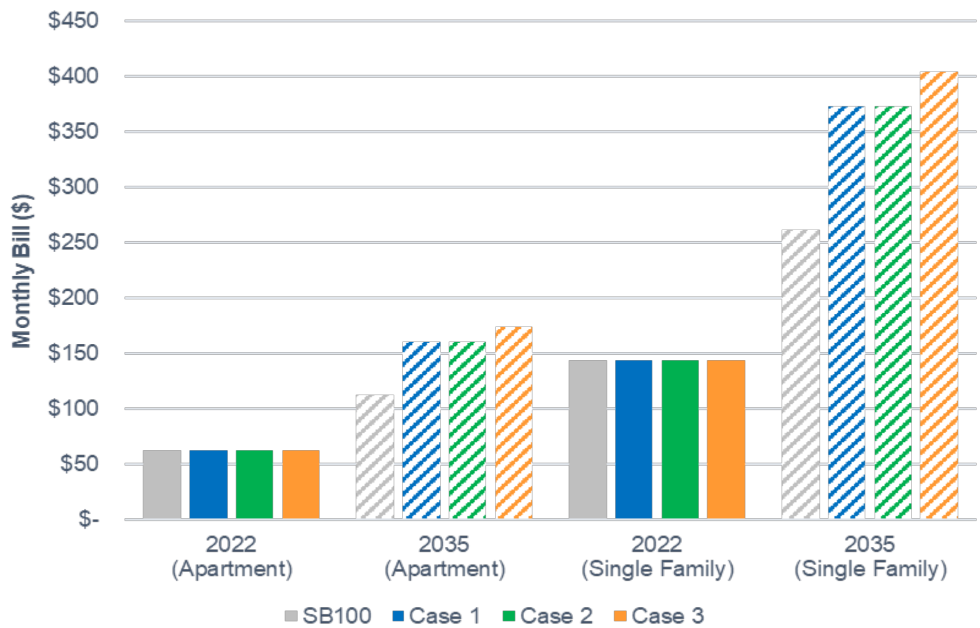


Figure 16. Monthly estimated retail customer electricity bill forecasts for apartments and single-family residences for the year 2022 and year 2035.

It is important to note that although Case 1 and Case 2 appear to have similar rate and bill impacts in these preliminary estimates, Case 2 has a much more aggressive resource buildout. Case 2 includes more transmission and renewable energy resources deployed earlier, which may present significant challenges and risks related to supply chain, permitting, infrastructure, labor, and other factors. It is also important to note that Case 3, which relies the heaviest on the highest deployment of customer-side distributed energy resources, assumes that the costs for resources such as residential rooftop solar and energy storage are borne by the customer, and which may result in higher rates for customers who do not adopt these distributed energy resources.

Breaking down the retail rate cost components of Case 1, as an example shown in Figure 17, it can be observed that distribution (Power System Reliability Program, including revamp to address existing overloads and prepare the distribution system for future load growth due to electrification) and energy efficiency are two of the largest contributors to upward pressure on overall rates. Energy Efficiency results in increased rates due to a combination of the incentives paid and the resulting loss of revenue to LADWP. In contrast, transportation electrification has a downward pressure on rates due to the estimated increase in electric retail sales which allows fixed costs to be spread out over a larger volumetric base of kilowatt-hours. The rate component drivers for Case 1 are broken down by program below in Figure 18, with the total rate forecast represented by the red solid line.

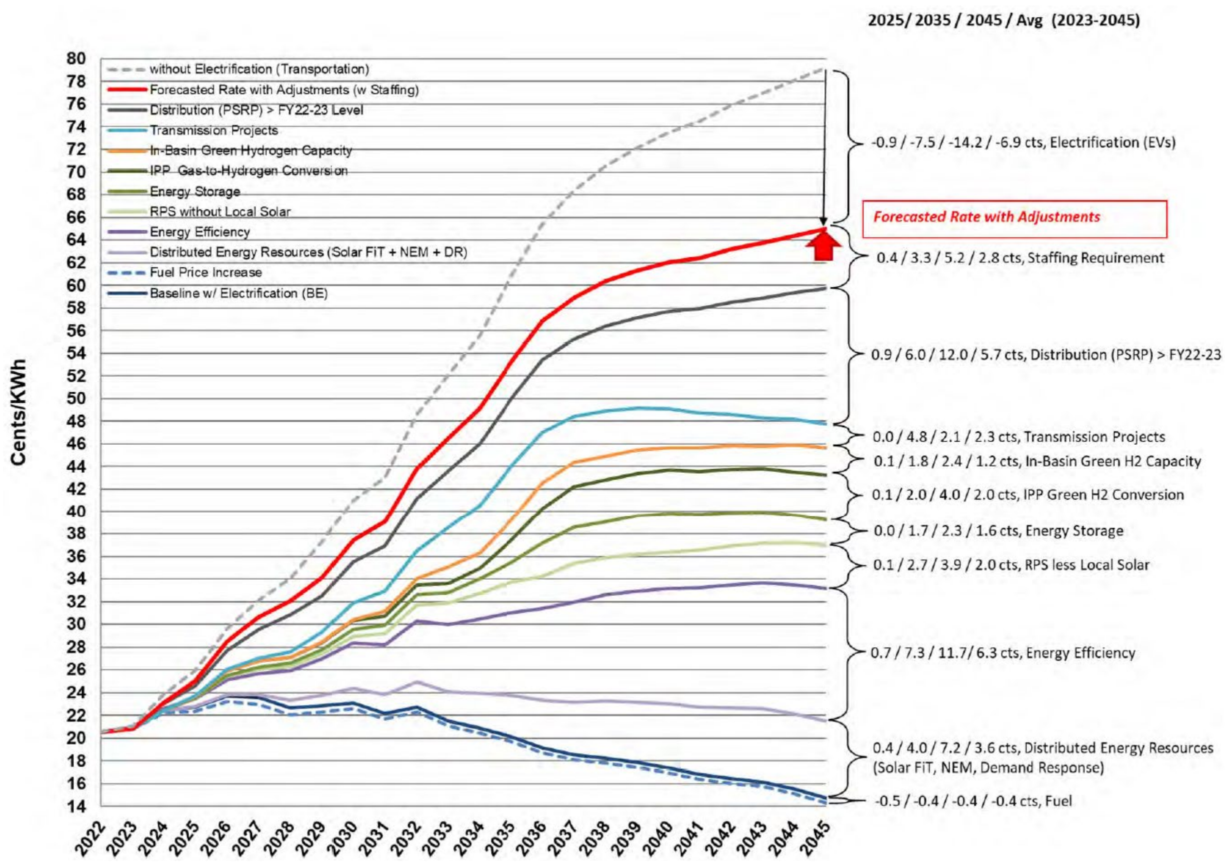


Figure 17. Rate layer diagram for Case 1. This diagram provides a breakdown of components included in the forecasted electricity rate for Case 1.

Each rate driver component is separated into programs as shown in Figure 18 below, which estimates the magnitude of rate increase or rate decrease on an annual basis.

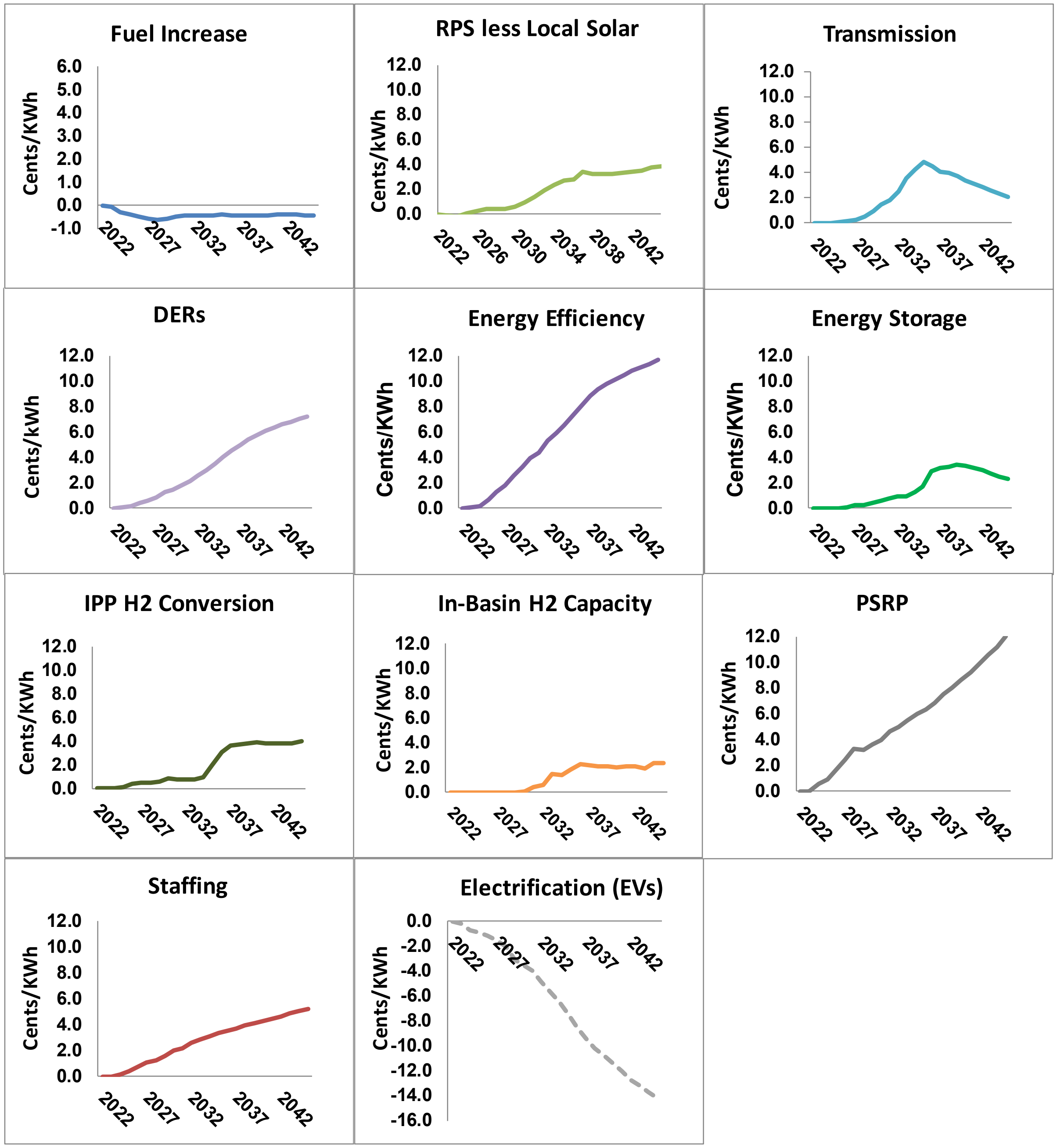


Figure 18. Each component of the forecasted electricity rate for Case 1.

Case 1 monthly electric bill impacts are broken down into annual contributions by programs shown in Figure 19 below. The dotted line represents a residential customer bill after implementing 20% energy efficiency, demonstrating the potential savings that a customer could have after implementing more efficient energy use. Additionally, fuel switching from petroleum vehicles to electric vehicles could also result in a substantial cost savings in transportation-related cost, despite the initial investment cost to purchase the electric vehicle.

Avoided Cost Saving represents bill savings from transportation electrification that resulted through increased electric sales.

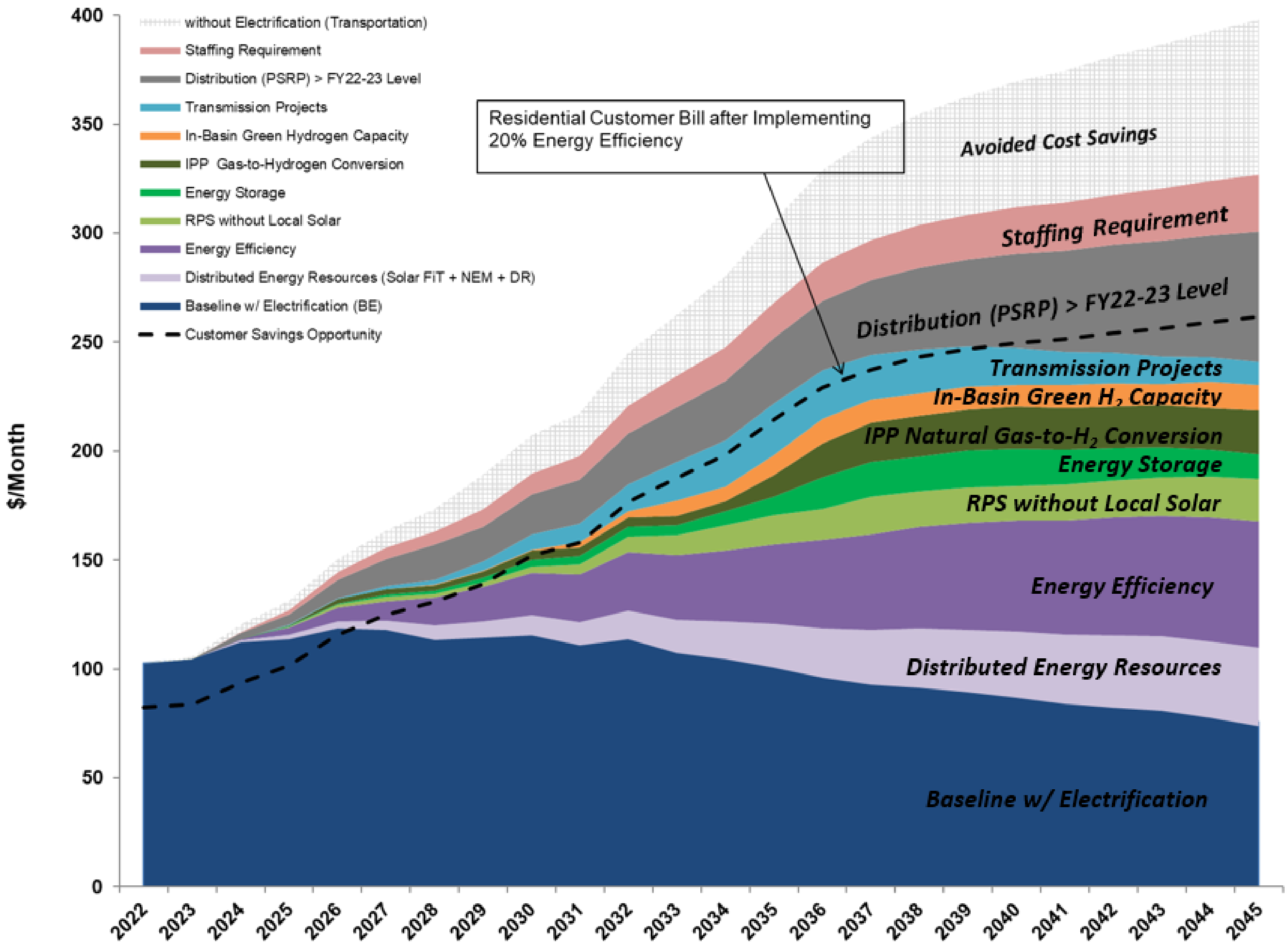


Figure 19. Case 1 customer electricity bill impacts contribution by program.

ES-4 Recommended Case 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 Executive Management recommended Case 1 based on five metrics: cost, emissions, reliability, local air pollutants, and renewable energy curtailments. Case 1 was presented to the Board of Water and Power Commissioners on October 11, 2022 as the recommended case for the Power System.

ES-4.1 Greenhouse Gas Emissions

Case 1 meets the 2035 goal of achieving 100% carbon-free energy. Although the GHG emissions forecast for Case 1 is marginally higher than that of Case 2 and Case 3 (see Figure 20), Case 1 presents the least amount of risk to LADWP, given that over 35 transmission projects are in queue to be completed by 2030 in order for LADWP to achieve 80% RPS by 2030. A 90% RPS target by 2030 would place additional pressure on completing transmission projects, which is somewhat out of LADWP's control. In the event that transmission projects are not completed on time to allow renewable projects to be deployed to serve native load, these renewables could be stranded resulting in additional cost to customers with little to no GHG emissions benefit. Until LADWP has more certainty that all of the slated transmission projects can be completed by 2030 along with the additional transmission capacity needed to achieve 90% RPS by 2030, Case 1 is the preferred case.

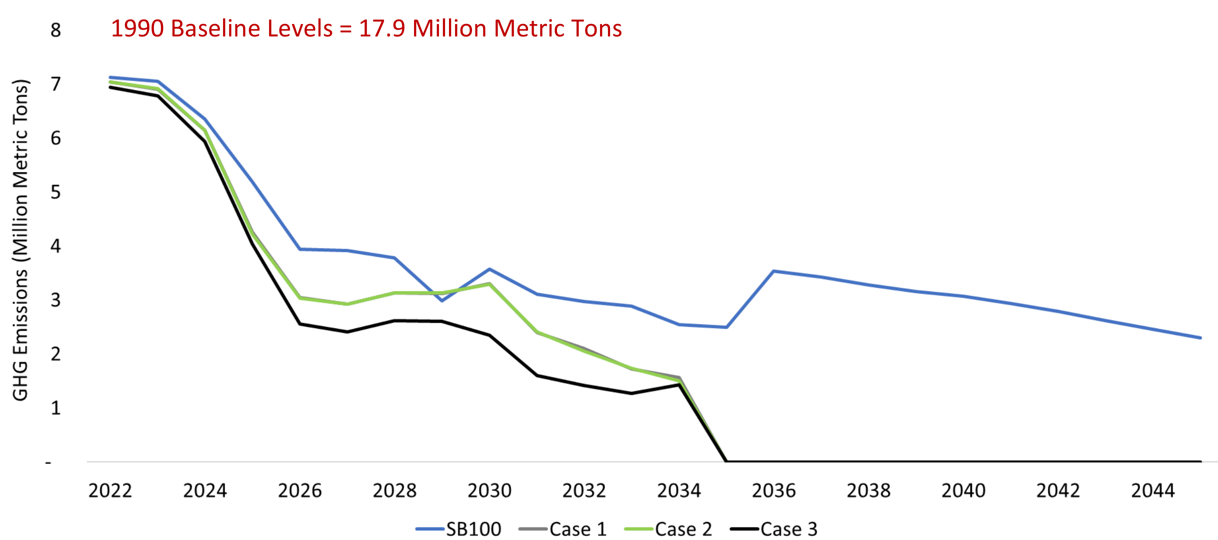


Figure 20. GHG emissions for each 2022 SLTRP case. SB 100 emissions do not go to zero as it allows the use of non-carbon-free resources to compensate for transmission and distribution losses.

ES-4.2 Costs

Based on stochastic production cost modeling, Case 1 is the least expensive case that meets the aggressive carbon-free energy goals established by the City Council. Therefore, Case 1 most closely adheres to the City Council's motion instructing LADWP to prepare a plan that achieves 100% carbon-free energy by 2035 *in a way that is equitable and has minimal adverse impact on ratepayers.* Figure 13 previously shown, demonstrates the total annual portfolio costs of each

2022 SLTRP cases on a net present value basis. A detailed estimated annual cash flows for Case 1 shown in Figure 21 below.

Furthermore, rate impact analysis suggests that Case 1 will result in the lowest rate increases of the Core Cases.

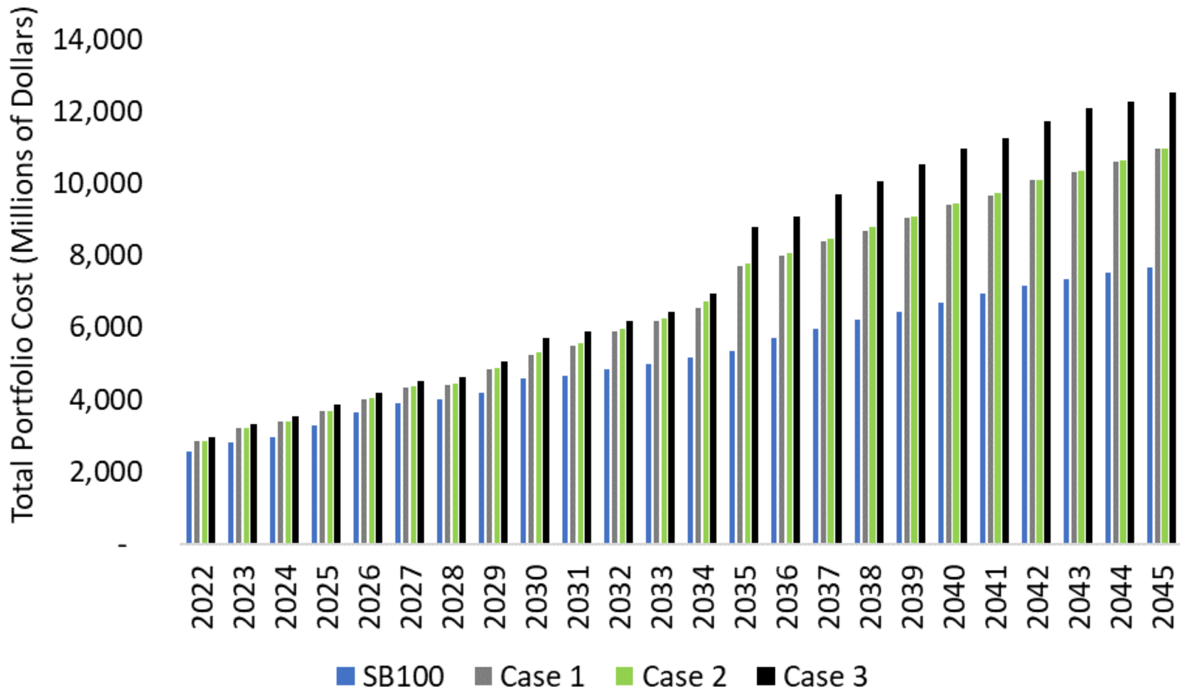


Figure 21. Total annual portfolio costs for Case 1, including the High Load and Low Load sensitivities.

ES-4.3 Reliability and Resilience

Case 1 achieves robust reliability. The industry standard for power system reliability is to achieve at or below 2.4 loss of load hours (LOLH) per year. In fact, all the Core Cases achieve an LOLH of less than 0.5, far exceeding the industry standard of 2.4 LOLH (see Table 2).

Table 2. Reliability measured in Loss of Load Hours (LOLH) for the 2022 SLTRP cases.

	SLTRP Case			
Year	**SB100**	**Case 1**	**Case 2**	**Case 3**
2025	1.26	0.41	0.27	0.26
2030	2.35	0.32	0.23	0.24
2035	2.39	0.23	0.19	0.19

ES-4.4 Local Air Pollutants

Once LADWP has transitioned to 100% carbon-free energy in 2035, Case 1 achieves the lowest nitrogen oxides (NOx) emissions of the Core Cases (see Figure 22). This trend would hold true for other pollutants such as particulate matter (PM). Thus, the health impacts from local air pollutants would be minimized under Case 1. In response to environmental stakeholders' concerns, LADWP is partnering with NREL to conduct an Air Quality and Health Impacts Study for the SLTRP to ensure that emissions do not increase for any period of time at the source level, and translate that to impacts to air quality and health. More details on this study will be included in an appendix.

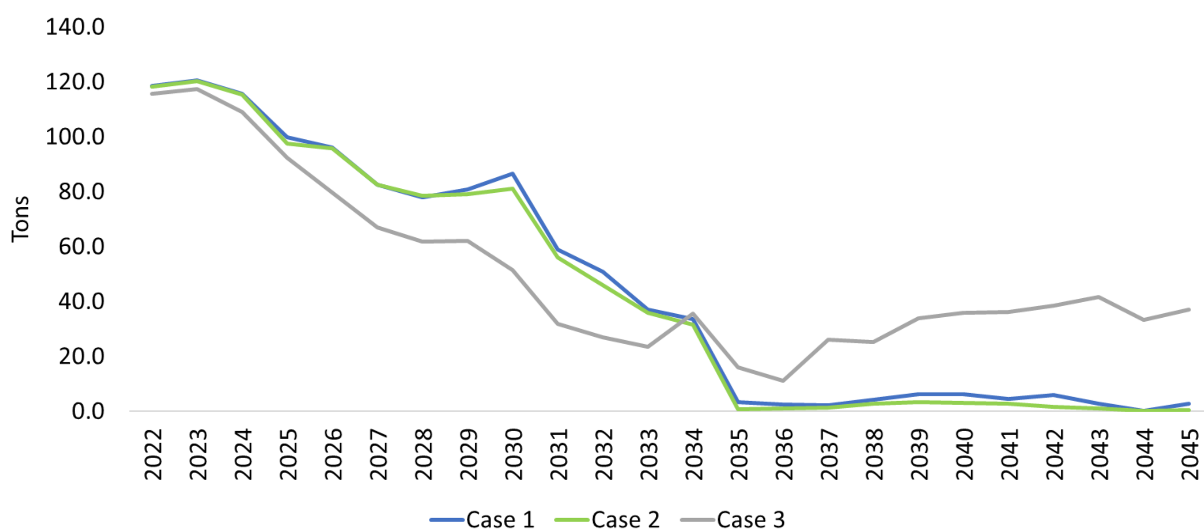


Figure 22. NOx emissions for the 2022 SLTRP Core Cases.

ES-4.5 Technology and Market Availability of Generation Resources

Because Case 1 contemplates an interim 2030 RPS goal of 80% (as opposed to 90% for Case 2 and Case 3), Case 1 is more immune to supply chain disruptions in the renewable energy markets. Developers of renewable energy projects have been suffering from supply chain constraints, especially in the wake of the COVID-19 Pandemic, causing some to rescind offers and other to raise their prices. If the availability of renewable resources is less than is anticipated, this would impact Case 1 (Figure 23) the least.

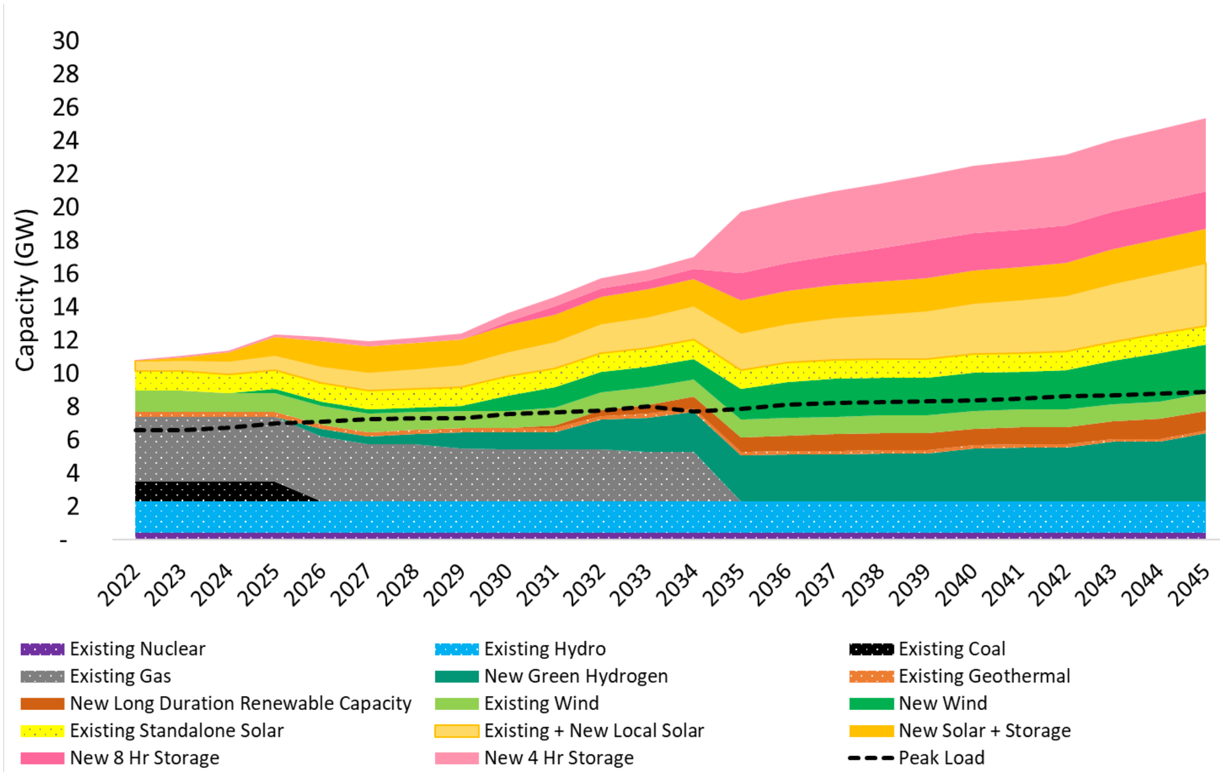


Figure 23. Generation capacity buildout for Case 1. To achieve the 2035 100% carbon-free energy goal set forth by the Los Angeles City Council, significant quantities of new solar + storage, wind, and stand-alone energy storage are built. Long-duration renewable capacity is a generic term that encompasses geothermal as well as other renewables that provide a greater effective load carrying capacity such as concentrating solar-thermal power with storage. The dashed line represents annual peak system demand.

ES-4.6 Renewable Curtailments

Of the Core Cases, Case 1 has the lowest quantity of curtailed renewable energy (see Figure 24). This would allow the renewable resources that do get built in Case 1 to be dispatched most efficiently with the least amount of curtailed energy. As most power purchase agreements (PPAs) are currently structured as take-or-pay agreements, it is advantageous to reduce the quantity of curtailed energy from a renewable energy project, since curtailed energy is energy that has already been paid for but cannot be used. Exploring flexibility in future contract options may also help address curtailment.

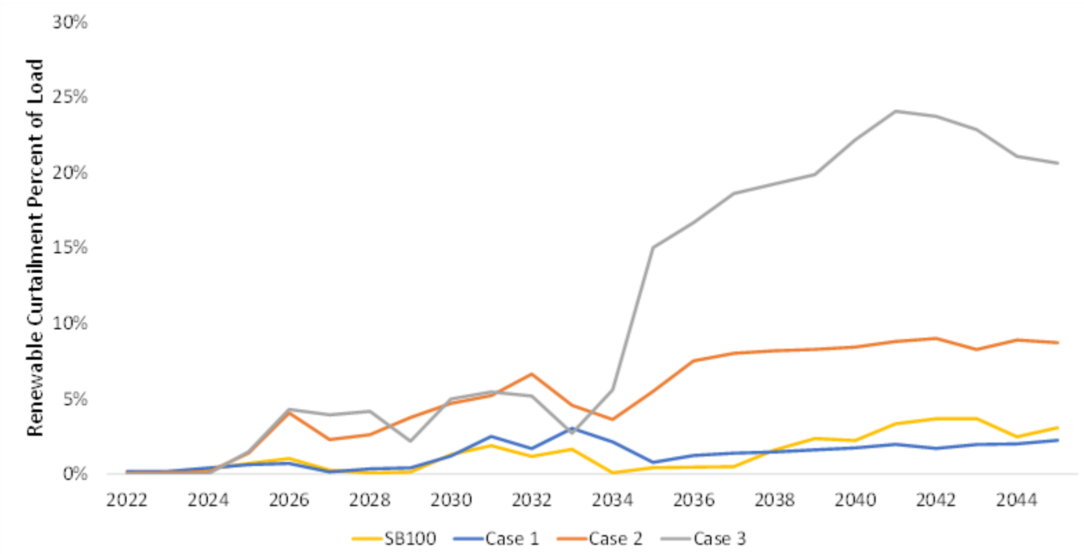


Figure 24. Quantity of renewable curtailments for each 2022 SLTRP case.

ES-4.7 Long-Term Planning Considerations

As the State of California progresses towards decarbonization, LADWP has taken a leadership role to develop an SLTRP that would achieve 100% carbon-free energy by 2035; however, many challenges exist that must be evaluated and overcome in order for LADWP to be successful in its accelerated clean energy transition. These challenges include implementation feasibility, addressing affordability and energy burden, transmission constraints and permitting, and human resource needs, among others. In order for LADWP to be a leader in clean energy transformation, it must do so in a way that is reliable and affordable.

Developing a long-term Power System plan to maintain reliability, competitive rates, and responsible environmental stewardship remains a significant challenge. This 2022 SLTRP outlines an aggressive strategy for LADWP to accomplish goals set forth by Mayor Garcetti and the Los Angeles City Council. In addition to complying with regulatory mandates and providing sufficient resources through 2045 given the information presently available, the following major strategic initiatives and goals will need to be achieved:

1. Eliminate coal from LADWP's Power Supply by replacing IPP by 2025 with green hydrogen-ready units
2. Reach 55% RPS by 2025, 80% RPS by 2030, and 100% carbon-free energy by 2035, including a goal of 1,500 MW of local solar by 2030 and 2,200 MW of local solar by 2035
3. Implement over 35 transmission projects and upgrades by 2030 to accommodate the ramp up in renewable energy
4. Implement over 1,000 MW of Energy Storage by 2030
5. Eliminate the use of Once-through Cooling by 2029 and preserve reliability and resiliency by transforming in-basin generation to carbon-free fuel
6. Invest in the Power System Reliability Program to address existing overloads and prepare the grid for future electrification and load growth
7. Promote charging infrastructure to support high levels of transportation electrification, which is the key to affordability.

The analysis and conclusions contained in this SLTRP are heavily dependent on a number of assumptions, such as the projected fuel and purchase power costs, renewable generation costs, proposed state and federal mandates, and GHG emissions costs. In addition, implementation risk, human resources, permitting, and other factors outside of LADWP's control are key areas of risk. If these assumptions were to change, LADWP's long-term strategies will need to change accordingly. Strategic Long-Term Resource Planning is an on-going and iterative process and LADWP will continue to adapt and refine the SLTRP as the uncertainties are better understood, and policy direction and other requirements are solidified. As LADWP develops and implements new programs, the recommendations made herein and in future SLTRPs may need to be revised based on future economic conditions, technology advancements, and other unknown factors. Next year's SLTRP process will conduct a deeper dive into an assessment of emerging technologies, project implementation risk that considers outage coordination and accelerated implementation schedules to achieve LADWP's clean energy goals. LADWP will continue its collaborative efforts with research organizations, customers, and other major stakeholder groups to continue to develop the SLTRP and to execute successful projects and programs towards achieving the SLTRP goals and initiatives.

ES-4.8 Next Steps

As mentioned previously, the SLTRP is an iterative process that will continue to evolve and receive updates on an ongoing basis.

For this 2022 SLTRP, upon the conclusion of technical modeling and public outreach, the LADWP Board of Commissioners received an update in October of 2022, incorporating modeling results and insights, as well as feedback from the SLTRP Advisory Group and public outreach community meetings. In parallel, the Los Angeles City Council is being briefed periodically in response to Council File No. 21-0352, which set a directive on September 1, 2021, for the LADWP to develop an SLTRP that achieves 100% carbon-free energy by 2035, with minimal adverse impact on rate payers, and without emissions increases in environmental justice communities. Part of these periodic updates includes a six-month report card to the Los Angeles City Council's Energy, Climate Change, Environmental Justice, and River (ECCEJR) Committee, which reports status updates on progress, challenges, and risks in major categories critical toward achieving the LA100 goals. Per approval by LADWP Power System Division Directors and Executive Management, this 2022 SLTRP is being released, and work will begin on the next iteration of the SLTRP.

For the next SLTRP, lessons learned will be synthesized and new development will be evaluated and potentially incorporated on topics such as emerging legislation to provide financial resources to combat climate change and improve climate adaptation, as well as taking a closer look at the overall at the overall energy burden of customers and incorporating the findings of LA100 Equity Strategies, among other factors and considerations.

Furthermore, LADWP's Financial Services Organization will take the SLTRP into consideration and conduct further analysis to determine the need for a potential rate action, for which approval will be required by the LADWP Board of Commissioners and the Los Angeles City Council.

ES-4.9 Caveats of the 2022 SLTRP Recommended Case (Case 1)

While the 2022 Power Strategic Long-Term Resource Plan (SLTRP) has recommended Case 1 in response to the Los Angeles City Council's (City Council) Motion to prepare a plan that achieves 100% carbon-free energy by January 1, 2035, with an interim goal of achieving an 80% renewable portfolio standard (RPS) by 2030, this 2022 SLTRP provides only a conceptual plan and encompasses numerous challenges related to availability of technology, implementation feasibility, system reliability, and affordability. These factors represent risks that ultimately may delay LADWP's transition to 100% carbon free energy. Future iterations of the SLTRP will need to consider various constraints and how they may impact SLTRP assumptions, modeling, and clean energy outcomes as LADWP seeks to optimize the build out of its Power System resource plan in order to balance reliability and resilience, environment, and affordability.

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CHAPTER 1

Introduction and Background

KEY TAKEWAYS:

- The SLTRP Process involves many stakeholders, both internal and external to LADWP.
- The SLTRP is shaped by taking into consideration feedback and input from the public.
- Substantial capital investments in generation, transmission, and behind-the-meter resources are required to achieve 100% carbon-free energy.

CONTENTS

LADWP POWER SYSTEM

LADWP is the nation's largest municipal electric utility. In fiscal year 2020-21, we supplied 20,936 gigawatt-hours (GWh) to more than 1.55 million residential and business customers, as well as more than 5,100 customers in the Owens Valley.

We maintain a diverse and vertically integrated power generation, transmission and distribution system that spans five Western states, and delivers electricity to more than 4 million people in The City of Angels.

DEFINITIONS

AG	Advisory Group
CAISO	California Independent System Operator
CEC	California Energy Commission
City	City of Los Angeles
Core Cases	SLTRP Cases 1, 2, and 3
DCFC	Direct current fast chargers
ECCEJR	Energy, Climate Change, Environmental Justice, and River Committee
EE	Energy efficiency
EIM	Energy Imbalance Market
EJ	Environmental Justice
ELCC	Effective load carrying capability
ERO	Electric Reliability Operator
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FiT	Feed-in Tariff Program
GHG	Greenhouse Gas
GW	Gigawatts
GWh	Gigawatt-hours
HILF	High-impact low-frequency
In-basin	Located within the Los Angeles Basin
IPP	Intermountain Power Project
IRP	Integrated Resource Planning
kW	Kilowatt
kWh	Kilowatt-hour
LA100	LA100 Study
LADWP	Los Angeles Department of Water and Power
LDES	Long-duration energy storage

LOLH	Loss of load hours
LADWP	Los Angeles Department of Water and Power
LDES	Long-duration energy storage
LOLH	Loss of load hours
MW	Megawatt
MWh	Megawatt-hour
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NOx	Nitrous oxides
NREL	National Renewable Energy Laboratory
PPA	Power purchase agreement
RPS	Renewable Portfolio Standard
SB 100	California Senate Bill 100
SLTRP	Strategic Long-Term Resource Plan
VoLL	Value of lost load
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

1 Introduction and Background

The 2022 Power Strategic Long-Term Resource Plan (SLTRP) 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 of 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 SLTRP includes an advisory group (AG) where stakeholders and community members can give us feedback and additional recommendations. Throughout the planning process, LADWP staff considered all technical requirements, regulatory mandates, and community feedback in order to present a comprehensive and robust long-term plan. The 2022 SLTRP 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 SLTRP sets up a framework for LADWP to address key opportunities and risks in order to ensure an effective and equitable clean energy transformation for the City of LA.

1.1 The Power System

LADWP's Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,664 megawatts ("MW") and net dependable capacity of 8,101 MW as of August 31, 2022. 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 Los Angeles, an area covering approximately 473 square miles. 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.

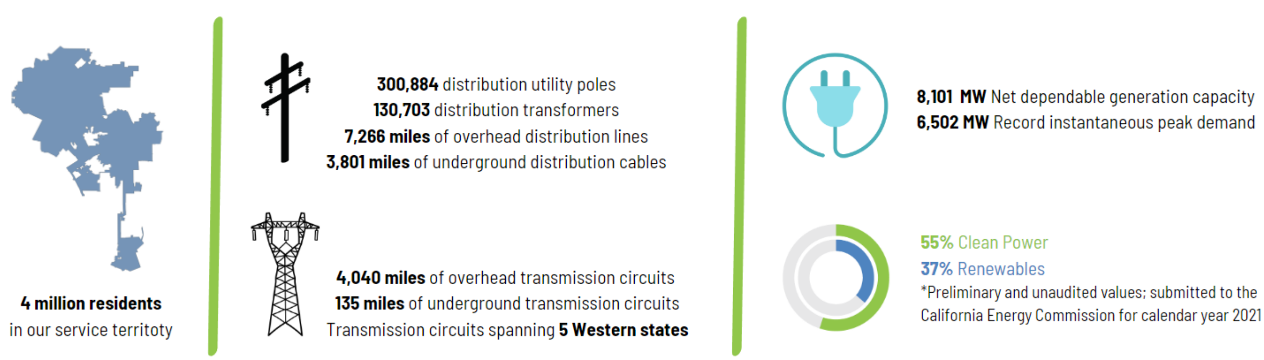


***Figure 1-1**. LADWP Quick Facts and Figures.*

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 1-2**:

- 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 1-2.** 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.

1.2 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.

1.3 LADWP's Partnership with the National Renewable Energy Laboratory

In 2016, the Los Angeles 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 an SLTRP that achieves 100% carbon-free energy by 2035 in an equitable manner, with minimal adverse impact on ratepayers.

1.3.1 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:

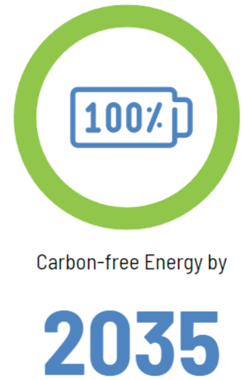
- The LA100 Study determined several investment pathways to achieve the 100% carbon-free energy target while remaining true to the core principles of reliability, environmental stewardship, environmental justice, resiliency, and affordability. With the LA100 Study completed, LADWP now has the tools and 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 Los Angeles. Examples include plans for 1,000 megawatts (MW) of new energy storage and infrastructure to support 580,000 electric vehicles (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 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 Los Angeles 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 Los Angeles.

The framework of the 2022 SLTRP is guided by the LA100 Study results and direction from the City of Los Angeles Mayor Eric Garcetti and City Council. The LA100 Study identified and analyzed nine different pathways to achieve 100% renewable and carbon-free energy by 2045 or earlier. The study included thorough reviews of impacts to job creation, environmental benefits, equity implications, and costs and customer rates. After the LA100 Study was completed in March 2021, Mayor Eric Garcetti committed LADWP to achieving 80% renewables by 2030 and 100% carbon-free energy by 2035, using the LA100 Study's *Early and No Biofuels* scenario as a blueprint to achieve these goals. Subsequently, in September 2022, based on the findings of the LA100 Study, City Council set an accelerated target and requirements for developing the 2022 SLTRP through City Council Motion No. 21-0352. The updated targets and requirements are summarized as follows:



- New target to achieve 100% carbon free by 2035 (with equitable and minimal adverse impact on ratepayers) with interim goals of 80% renewables and 97% carbon free by 2030.
- Prioritize equity in SLTRP for environmental justice (EJ) communities. Ensure no increase in emissions in EJ communities.
- Report on "no-regrets" projects, accelerated pathway, and "shovel-ready" projects.
- Report on community engagement strategies.
- Six-month report card to the Energy, Climate Change, Environmental Justice, and River (ECCEJR) Committee, including challenges and barriers.

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, 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.
- 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, 12/31/2024 expected commercial operation date
    - Red Cloud Wind (331 MW) at Navajo, 12/31/2021 commercial operation date
- Launch several new distributed energy resource (DER) programs.
    - Expanded solar feed-in tariff from 150 MW to 450 MW in 2020
    - Advertised a DER Request for Proposal in 2020 for approximately 30 MW (first of many)
    - Expanded commercial demand response program and launched a Power Savers program in 2020 and will expand the Power Savers program for summer 2021
    - Launched a feed-in tariff+ and virtual net metering pilot program in 2021.

1.3.1.1 LA100 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 in order to pursue environmental justice and equity goals and keep LA on the path to 100% renewable energy. These elements are:

1. Accelerating to 80% Renewable Energy & 97% GHG-Free by 2030
2. Transforming Local Generation
3. Accelerating Energy Storage
4. Accelerating Distributed Energy Resources Equitably
5. 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 for 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.

1.3.1.2 Staying on Track to 100% Zero-Carbon Projects and Initiatives

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

1. Accelerate Local Transmission Upgrades

In order to support increased penetration of renewables, LADWP has identified 10 "no regrets" transmission projects that are required by 2030. A total of 36 transmission projects are in the pipeline to accelerate renewable energy imports. 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.

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 3,000 MW of new renewable projects in order 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 minority communities.

3. Transform 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, has clearly demonstrated the need for significant additional in-basin generation capacity—between 2,280 MW to 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 in a just and environmentally sensitive way, LADWP will 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 the Port of LA and 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 Hydrogen-Power Capacity. To implement changes at Scattergood Generation Station, LADWP must work within a limited footprint, transmission constraints, long-duration capacity needs to maintain reliable power supply to the West LA region, and deadlines to retire two existing natural gas units. Accordingly, local energy storage coupled with combined-cycle generation at Scattergood will ensure reliability and resiliency, while also reducing GHG emissions. Local storage will also promote environmental justice by providing the flexibility needed to avoid ramping up generation and increasing related emissions at Valley Generating Station. In order to meet this ambition—with the technology and workforce to support it—we must begin planning our green hydrogen future today.

Hydrogen Request for Information (RFI) for In-Basin Power Plants. In 2022, LADWP issued an in-basin hydrogen RFI to evaluate opportunities for transforming all of LADWP's local generation, including power plants at Valley & Harbor Generating stations, to a decarbonized future.

Haynes Wet Cooling. 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 second most efficient generation unit in LADWP's fleet. If LADWP converts this unit to recycled water cooling, it is expected to result in over $1 billion of total cost savings (NPV) from 2020-2045, as well as significant GHG net savings—approximately 7.8 million metric tons over 25 years. Pursuing Haynes wet cooling has significant environmental justice benefits by ensuring an equitable implementation of the Mayor's February 2019 once-through cooling commitment and reducing in-basin natural gas combustion and associated GHG emissions. This strategy will avoid increasing the use of Valley Generating Station

4. Accelerate Energy Storage

LADWP plans to build over 1,000 MW of energy storage in-basin and out-of-basin by 2030. LADWP is currently negotiating for an energy storage project at Beacon Renewable Power Plant in Mojave and issued an energy storage Rolling Request for Proposal (RFP) in 2020. Haynes Units 3 through 6 have been demolished to make room for future energy storage, and usage of Castaic pumped hydro is expected to increase, allowing for further integration of intermittent renewable energy into LADWP's grid.

5. Accelerate Distributed Resources Equitably

LADWP continues to ramp up distributed resources programs, with goals of deploying 1,000 MW of local solar and 500 MW of demand response, doubling energy efficiency, and supporting 580,000 electric vehicles by 2030. As we design new programs to attract customers, our priority will be to place increased focus on disadvantaged communities and low-income customers. To that end, in 2020, we expanded our solar feed-in tariff program from 150 MW to 450 MW, 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.

1.3.1.3 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 the 2022 SLTRP, 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 the 2022 SLTRP, 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.
- The potential role of the customer has not been fully explored.
- Climate change could impact the ability of LADWP to maintain resource adequacy.
- The 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.

1.4 The SLTRP Process

LADWP's Power Strategic Long-Term Resource 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 2022 SLTRP will sync with LADWP's budget process with updated assumptions and a 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.

1.4.1 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 2022 SLTRP Advisory Group meetings included 11 meetings with over 25 presentations to provide transparency to our community and to guide the development of the final SLTRP scenarios.

1.4.1.1 Advisory Group and Public Outreach Community Feedback

The SLTRP Advisory Group was comprised of over 45 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 11 AG meetings that took place over the course of one year (September 2021 – September 2022), 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, which further helped refine the SLTRP case scenarios. During August and September 2022, LADWP hosted public outreach meetings to share information on the scenarios and trade-offs under consideration. Through these meetings we gained valuable community input which was considered when determining the recommended case for the 2022 SLTRP. 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
- Customer Resources

1.5 Case Selection and Assumptions

The first step of the SLTRP process involves deciding how to construct scenarios for computer modeling. For the 2022 SLTRP, LADWP staff decided to model four cases:

- SB 100 (Reference Case, 60% RPS by 2030, 100% clean energy by 2045)
- Case 1 (80% RPS by 2030, 100% carbon free by 2035)
- Case 2 (90% RPS by 2030 with focus on large scale renewables, 100% carbon free by 2035)
- Case 3 (90% RPS by 2030 with focus on distributed energy resources, 100% carbon free by 2035)

The SB 100 case, also referred to as the "Reference Case," is the base case used for comparison purposes. It represents the minimum investments LADWP must make to comply with SB 100, the California state law that mandates utilities achieve 100% carbon-free energy as a percentage of retail sales by 2045, among other clean energy targets.

Cases 1, 2, and 3 are referred to as the "Core Cases". These three cases were constructed to highlight the investments we will need to achieve 100% carbon-free energy by 2035, per the Los Angeles City

Council's motion. One of the main differences between the Core Cases is the interim 2030 RPS goal. Case 1 plans for an 80% RPS by 2030, while both Cases 2 and 3 achieve a 90% RPS by 2030.

Another major difference between the Core Cases is the quantity of behind-the-meter and distributed energy resources (DERs). These resources include rooftop and distributed solar, home energy storage systems, energy efficiency measures, and demand response programs. Case 1 and Case 2 have the least aggressive rollout of DER resources, achieving approximately 5,000 MW of behind-the-meter and distributed resources by 2045. Case 3 is the most aggressive scenario with respect to DERs, achieving over 7,000 MW of behind-the-meter and distributed resources by 2045.

Once potential scenarios are determined, the next step in the SLTRP 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 External Energy Resources 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 LA100 Study assumed that all existing overloads are addressed by LADWP before any LA100 investments are made, LADWP

has incorporated the additional cost in the 2022 SLTRP 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 1-3***, are: (1) maintaining a high level of electric service reliability, (2) exercising environmental stewardship, and (3) maintaining competitive energy rates.

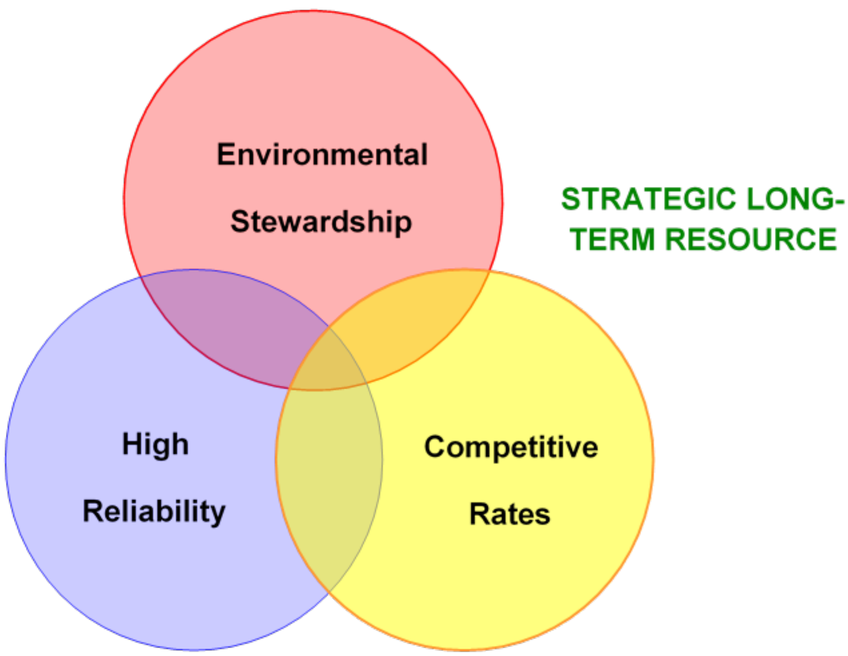


Figure 1-3. *Objectives of this SLTRP.*

Providing reliable electric service to the residents and businesses of Los Angeles 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.

1.5.1 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), 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 of these regulatory agencies enforce reliability standards on owners, operators and users of the bulk power system.

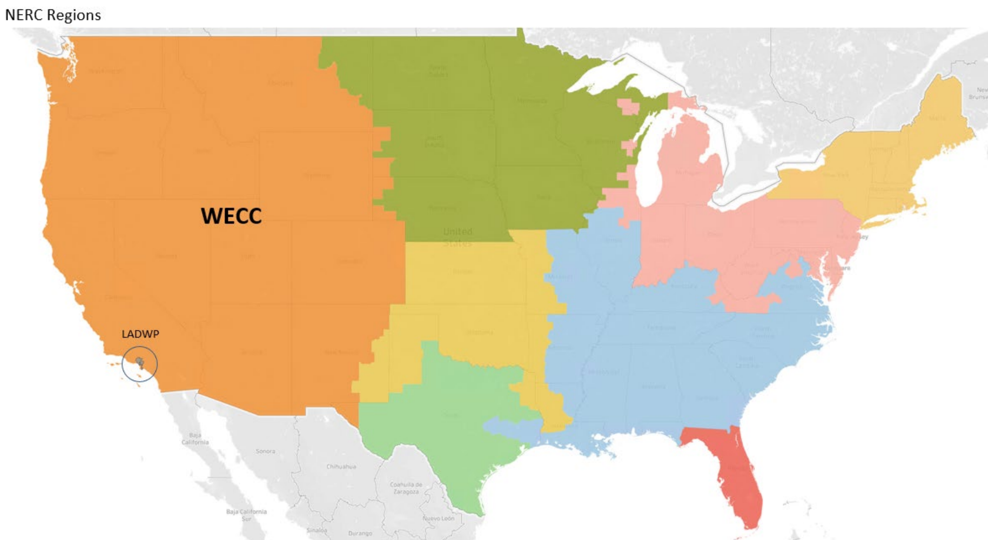


Figure 1-4. *Map of NERC Regions, WECC, and LADWP.*

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 actually 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 enable 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.

1.5.2 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.

1.5.3 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 EIM market, and are presently full participants in the EIM.

1.5.4 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 for Burbank and Glendale.

1.5.5 Self-Sufficiency

At LADWP, we maintain a policy of owning or controlling 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.

1.5.6 Coastal Power Plants

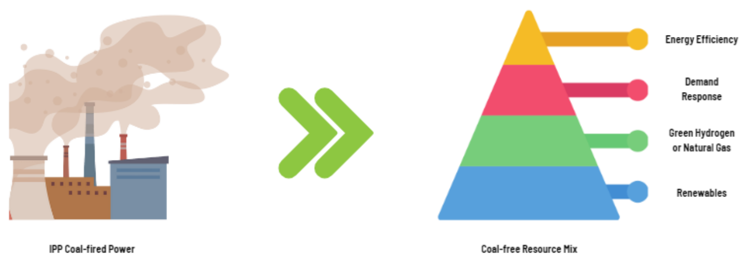
Figure 1-5. *Scattergood Coastal Generating Station.*

LADWP owns and operates three coastal natural gas-fired power plants (Haynes, Harbor, and Scattergood) 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.

Cases 1, 2, and 3 in this SLTRP assume 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 2029. These cases, all of which meet the Los Angeles City Council's motion to prepare a resource plan achieving 100% carbon-free energy by 2035, assume the buildout of several additional green hydrogen-powered generating units. The green hydrogen-powered units, which will be built throughout the 2030s and into the 2040s, 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.

1.5.7 Intermountain Power Project Replacement

LADWP is committed to a strategy of complete divestment from coal-fired resources by 2025. As a result, we will look to a combination of various alternative energy sources as critical for replacing the coal-fired capacity that the Intermountain Power Project provides. Power System staff has 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. To achieve the accelerated goal, IPP will be repowered with two combined-cycle natural gas generating units totaling 1,200 MW. However, the total repowering size that is presently being negotiated is approximately 850 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. The accelerated 2025 replacement date—two years ahead of the existing power purchase contract's June 2027 expiration date—is contingent upon several factors including permitting time, material procurement, and final concurrence from all participants. Although LADWP is planning to complete the repowering project by 2025, the commercial operation date could still be delayed due to circumstances beyond LADWP's sole control.



For this SLTRP, 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. For Cases 1, 2, and 3, 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 The Advisory Group and Public Outreach

The SLTRP Advisory Group is the cornerstone of the 2022 SLTRP. The AG plays a critical role in shaping the case scenarios that we analyze and by informing our key strategic decisions. After the 2017 SLTRP was completed, we expanded the Advisory Group for the 2022 SLTRP. In order to maintain continuity with the LA100 Study, the expanded Advisory Group includes all the members that participated in LA100. The Advisory Group allows LADWP to reinforce full transparency in the planning process and build on the collaborative dialog that has guided past IRP 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 2022 SLTRP, it helped determine the strategic case alternatives that were considered. Input from AG members influenced the assumptions that we used in the case scenarios, as well as the final recommendations and near-term actions in the SLTRP. 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. Due to the COVID-19 pandemic, the Advisory Group meetings for the 2022 SLTRP were held virtually.

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 2022 SLTRP process and provided input in the development and recommendation of the final 2022 SLTRP cases. Summarized below is a breakdown of the 2022 SLTRP Advisory Group and stakeholders (**Table 1-1**), internal subject matter experts (**Table 1-2**), and the meeting map of the 2022 SLTRP process (***Figure 1-6***) pertaining to the Advisory Group's involvement.

Table 1-1. *External stakeholders represented within the SLTRP Advisory Group.*

Stakeholder Category	Organization(s)
Academia	CSUN, UCLA, USC
Business and Workforce	AWEA, CESA, Cal SEIA, CEERT, Center for Sustainable Energy, Central City Assoc, IBEW – Local 18, LABC, LA Chamber, VICA
City Government	CLA, City Attorney, Council Districts, Rate Payer Advocate, Mayor's Office
Neighborhood Council	DWP Advocacy Committee, DWP MOU Oversight Committee, Neighborhood Council Sustainability Alliance
Environmental Community	CBE, Earth Justice, Environment California Research and Policy Center, EDF, Food and Water Watch, NRDC, LAANE, Sierra Club
Premier Accounts and Key Customers	LAUSD, LAWA, Metro, POLA, Valero Wilmington Refinery
Utilities	Southern California Gas, SCPPA

Table 1-2. *Internal stakeholders whose feedback and input is incorporated into each SLTRP.*

Internal Stakeholder Groups	Input Provided for SLTRP
Financial Services Organization	Load Forecast and Sensitivities, Capital Costs, Rate Impacts, System Losses
Power External Energy Division	Fuel Price Forecast and Sensitivities, Hoover and Small Hydro, IPP Cost and Assumptions
Power Engineering and Technical Services	Power System Reliability Program Re-vamp
Power Transmission Planning, Reg. & Innovation	LA100 Equity Strategies, Regulatory Compliance, 10-year Transmission Plan
Power Resource Planning, Dev. & Programs	Candidate Resources, Distributed Solar, Distributed Energy Storage, Demand Response, In-Basin Capacity Needs
Environmental Affairs	Greenhouse Gas Price Forecast
Efficiency Solutions	Energy Efficiency and Building Electrification
Others	National Renewable Energy Laboratory, Community Affairs

Advisory Group Meeting Plan

Phase 1 | Q3 2021 Launch & Laying Foundation	Phase 2 | Q3 2021 Scenario Development	Phase 3 | Q4 2021 Modeling	Phase 4 | Q1-2 2022 Results	Phase 5 | Q2-3 2022 Outreach
#1 September 23 • Advisory Group Launch • LADWP Overview • LA100 (Achieving 100% Renewable Energy) • 2022 SLTRP Orientation • Advisory Group Protocols & Operating Principles	**#4 October 22** • Customer Focused Programs - Energy Efficiency & Building - Electrification - Transportation Electrification - Demand Response • Draft Scenario Matrix	**#7 December 17** • LA100 Equity Strategies Overview • Energy Storage Presentation • 2022 SLTRP What-If Sensitivities Discussion • Final Scenario Matrix	**February** *(Email Update)* • Modeling Progress Check-in, • Upcoming Board Meetings	**#9 June 30** • Preliminary Results on Reliability, resiliency, and Sensitivities
#2 September 30 • *LA100 Study Review (NREL) at 9 am* • LA100 Rates Analysis (OPA) at 10 am • LA100 Next Steps (LADWP) • LA100 Assumptions (PSRP) • Consider Topics for October 22 • Consideration of Scenario Definition	**#5 November 10** • LA100 "No Combustion" Scenario • 2022 SLTRP Assumptions • Metrics & Evaluation Process • Scenario Considerations • Refine Scenario Matrix	**November – May** • Internal Modeling • Analysis of Scenarios	**#8 April 28** • Preliminary Results on Core Scenarios • (Capacity Expansion, LOLP and Production Cost Model)	**#10 August 12** Final Sensitivities SLTRP Key Findings **August** • Community Outreach Meetings • Review Draft 2022 SLTRP
#3 October 08 • SLTRP Deep Dive • SB100 Review (LADWP) • 100% Carbon-Free by 2035 Requirements (NREL) • Green Hydrogen in LA (LADWP) • 2022 SLTRP Key Considerations and Potential Scenarios	**#6 November 19** • Distribution Automation • 2022 SLTRP Advisory Group Feedback and Refined Draft Scenario Matrix • 2022 SLTRP What-If Sensitivities Discussion	Modeling Underway	**TBD** Potential field trip	**#11 September 15** Public Outreach Results NREL Air Quality Modeling **September** Submit 2022 SLTRP for approval

***Figure 1-6**. The 2022 SLTRP Advisory Group meeting schedule. Meetings were held between September 2021 and September 2022.*

Through the 2022 SLTRP Advisory Group process, we updated our assumptions and planning scenarios to incorporate key takeaways from our computer modeling efforts, using the LA100 Study's Early and No Biofuels scenario as a blueprint. Various metrics and tradeoffs shown in our computer modeling results were presented to the Advisory Group for discussion and feedback heading into public outreach meetings. Below is a summary of the Advisory Group meeting topics:

- *Meeting #1 (September 23, 2021)* - Introduced and reviewed roles and responsibilities of the Advisory Group, presented on LADWP overview and progress, LA100 Study components, 2022 SLTRP Orientation, and discussion and polling.
- *Meeting #2 (September 30, 2021)* - LA100 Study Review Session provided by NREL, LA100 Study Review of Rates presented by the Office of Public Accountability, LA100 Next Steps (Clean Grid LA Plan), LA100 Assumption Updates (e.g. Power System Reliability Program), Meeting #1 Review, and SLTRP discussion and polling.
- *Meeting #3 (October 8, 2021)* - Overview on California Senate Bill 100 Joint Agency Report and Recap, LA100 – 100% Carbon Free by 2035 Requirements and Implications presented by NREL, Green Hydrogen in Los Angeles, 2022 SLTRP Key Considerations and Potential Scenarios, and discussion of SLTRP priorities and polling.

- *Meeting #4 (October 22, 2021)* - Energy Efficiency and Building Electrification Programs, Transportation Electrification Programs, Demand Response Programs, 2022 SLTRP Draft Scenario Matrix, and 2022 SLTRP breakout discussion sessions.
- *Meeting #5 (November 10, 2021)* - LA100 “No In-Basin Combustion” Scenario Overview presented by NREL, 2022 SLTRP Assumptions and Evaluation Metrics, and 2022 SLTRP Draft Scenario Matrix discussion.
- *Meeting #6 (November 19, 2021)* - Distribution Automation Overview, 2022 SLTRP Advisory Group Feedback and Refined Draft Scenario Matrix, 2022 SLTRP price sensitivities, and What-if sensitivities discussion.
- *Meeting #7 (December 17, 2021)* - LA100 Equity Strategies Overview, 2022 SLTRP Advisory Group #6 comments review, Energy Storage and New Technologies (Long-Duration Energy Storage), and 2022 SLTRP What-if Sensitivities discussion.
- *Meeting #8 (April 28, 2022)* - 2022 SLTRP Overview and Refinements and 2022 SLTRP preliminary results.
- *Meeting #9 (June 30, 2022)* - 2022 SLTRP Modeling Refinements, 2022 SLTRP Preliminary Results on Reliability, Resiliency, and Sensitivities, and breakout sessions.
- *Meeting #10 (August 12, 2022)* - Recap of SLTRP Advisory Group comments (Meeting #9), SLTRP Risks and Challenges, Part 2 Sensitivities on Load and Transmission, and SLTRP Key Findings (Emissions, Reliability, Rates).
- *Meeting #11 (September 15, 2022)* - Debrief on public meetings and feedback, NREL Air Quality and Health Impacts Modeling presented by NREL, and update on LA100 Equity Strategies.

The SLTRP Advisory Group process is documented on LADWP’s website, where visitors can find detailed agendas, meeting summaries, and meeting presentations.

In addition to the 2022 SLTRP Advisory Group, three virtual public outreach workshops were held on August 31, September 1, and September 6, 2022. These public meetings were an opportunity to provide an overview of the 2022 SLTRP and to collect comments from the general public. The 2022 SLTRP was made available for public comment through the LADWP website, www.ladwp.com/SLTRP.

1.7 Computer Simulation

Creating a robust computer model of LADWP’s Power System is a crucial a component of the SLTRP 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 iteration of the SLTRP, the planning horizon was chosen to span between 2022 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 in order 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, Case 1 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 hours (LOLH) metric. As discussed previously, the 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 2.4 LOLH for each year, which is equivalent to NERC's 1-in-10-year industry standard. A loss of load hour is any hour 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 for that hour (e.g., due to a power plant or transmission line outage), then this would count as one loss of load hour. The industry standard is to plan for an expected LOLH of 2.4 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 in order 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.

1.8 Recommended Case

Based on the results of our in-depth modeling and final analyses, Power System staff recommend a preferred SLTRP case and present its details to LADWP executive management for review and approval.

In making a recommendation, LADWP executive management considered the following metrics associated with each case:

- Cost
- Electricity rates and bill Impacts
- Greenhouse gas emissions and local air pollutants
- Reliability
- Curtailment
- Risks
- Resiliency

1.8.1 Cost

Costs assessed in the SLTRP 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 SLTRP 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 SLTRP into total portfolio costs. The annual cash flows are discounted through a net present value methodology, which more accurately compares costs among the different cases.

1.8.2 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 SLTRP team 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. For these reasons, it is possible that SLTRP cases with higher levels of such programs (e.g. Case 3 with "highest" net-metered solar and energy efficiency) result in higher electric rates.

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 SLTRP are for electric service only, and are averaged out over each month. Using this method, we generate an average monthly electric retail bill estimate. Furthermore, the SLTRP team provides bill estimates for an average residential apartment-sized dwelling and average residential single-family dwelling. The bill estimate for a residential apartment-sized dwelling assumes an average energy consumption of 300 kWh/month, while the estimate for an average residential single-family dwelling assumes an average consumption of 700 kWh/month.

1.8.3 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 SLTRP scenarios 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 SLTRP Case 1, Case 2, and Case 3, 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).

In order 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.

1.8.4 Reliability

Reliability in the SLTRP cases is quantified using a metric called *loss of load hours (LOLH)*. LOLH quantifies the number of expected hours in which aggregate customer demand exceeds LADWP's total generation and energy import capacity. The North American Electric Reliability Corporation's stated industry standard for LOLH is one day in ten years, which translates to no more than 2.4 loss of load hours per year. Due to this reliability constraint, the resource portfolio for each SLTRP case is built to ensure an LOLH at or below 2.4. Because LADWP is a balancing authority that includes Burbank and Glendale, it is imperative that we not only remain below a 2.4 LOLH, but also strive to maintain the same, exceptional level of reliability we have today—approximately 0.22 LOLH per year.

For our SLTRP Cases, 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 becomes lower and lower. 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 deployed in all the core SLTRP cases (Case 1, Case 2, and Case 3). These dispatchable resources have zero carbon emissions when fueled entirely with green hydrogen, which LADWP will begin to do in 2035.

1.8.5 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. In order 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.

1.8.6 Risks

Many potential risks could affect implementation of the SLTRP cases. Some of the main risks that we considered during the 2022 SLTRP development process are:

- Required supply 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 as a result 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 amount 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 in order to assess the aforementioned risks throughout the planning process.

1.8.7 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 caused the derating of three 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 number of customers affected during load shedding or capacity factors of generators during an 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

2022 Power Strategic Long-Term Resource Plan Cases

KEY TAKEWAYS:

- Several pathways to 100% carbon-free energy were modeled in the 2022 SLTRP in order to find a best fit for LADWP's goals.
- Firm and dispatchable generation is required within the Los Angeles Basin in order to ensure reliability.
- Numerous LADWP initiatives related to energy efficiency, building electrification, and transportation electrification are included in the modeling efforts for this SLTRP to showcase the outlook of our electric sales, energy capacity, and load demand.
- Various hypothetical situations were also considered (e.g. "What If" some planned transmission upgrades are not completed by their deadlines?) to prepare for as many path-influencing factors as possible.

CONTENTS

DEFINITIONS

AG	Advisory Group
BE	Building Electrification
CAISO	California Independent System Operator
CAMR	Comprehensive Affordable Multifamily Retrofits
CDI	Commercial Direct Install
CEC	California Energy Commission
CFL	Compact Fluorescent Light
CII	Commercial, Industrial, and Institutional
City	City of Los Angeles
CLIP	Commercial Lighting Incentive Program
CMUA	California Municipal Utilities Association
Core Cases	SLTRP Cases 1, 2, and 3
CPP	Customer Performance Program
CPUC	California Public Utilities Commission
DCFC	Direct current fast chargers
ECC	Energy Control Center
EE	Energy Efficiency
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPM	Efficient Product Marketplace
ERO	Electric Reliability Operator
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission

FiT	Feed-in Tariff Program
FYE	Fiscal year ending
GHG	Greenhouse Gas
GW	Gigawatts
GWh	Gigawatt-hours
In-basin	Located within the Los Angeles Basin
IPP	Intermountain Power Project
IRP	Integrated Resource Planning
kW	Kilowatt
kWh	Kilowatt-hour
LA100	LA100 Study
LADWP	Los Angeles Department of Water and Power
LDES	Long-Duration Energy Storage
LED	Light Emitting Diode
LOLH	Loss of Load Hours
MW	Megawatt
MWh	Megawatt-hour
NEL	Net Energy for Load
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NOx	Nitrous Oxides
NREL	National Renewable Energy Laboratory
PEM	Proton exchange membrane
PPA	Power purchase agreement
REP	Refrigerator Exchange Program

RPS	Renewable Portfolio Standard
SB 100	California Senate Bill 100
SCE	Southern California Edison
SLTRP	Strategic Long-Term Resource Plan
SMUD	Sacramento Municipal Utilities District
TE	Transportation Electrification
TOU	Time of Use
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

2 2022 Power Strategic Long-Term Resource Plan Cases

During the 2022 SLTRP process, LADWP defined four main cases: a reference case based on California Senate Bill 100 ("SB 100"), and three Core Cases outlining various paths that achieve 100% carbon-free energy by 2035— SLTRP Cases 1, 2, and 3. This chapter will describe each case in detail along with the many LADWP programs and initiatives that factor into each case.

2.1 Case Overviews

The 2022 SLTRP examines four cases representing different pathways that achieve 100% carbon-free energy. The cases differ in terms of their aggressiveness in the amount of new generation, energy storage, and transmission assets we will build, as well as the timelines for reaching certain milestones. The reference case, based on the statutory requirements of California Senate Bill 100, achieves 100% carbon-free energy in 2045. All other cases achieve 100% carbon-free energy by 2035 but differ in their interim Renewable Portfolio Standard (RPS) target goals, assumptions regarding the deployment and adoption of energy efficiency, as well as the implementation of behind-the-meter resources like rooftop solar.

SB 100 requires only retail energy sales to be served by clean energy resources. The term "retail sales" excludes any energy expended in the form of transmission and distribution line losses, or otherwise lost during the electricity transmission and distribution process. In contrast, the Los Angeles City Council's motion requires that *all* energy must be produced by carbon-free generation resources that do not emit greenhouse gasses (GHGs)—including line losses. Additionally, while SB 100 mandates that we achieve 100% clean energy by the end of 2045, the City Council motion requires LADWP to develop a plan to achieve 100% carbon-free energy by the beginning of 2035.

In addition to these four cases, our staff conducted several sensitivity analyses. These sensitivities included examining the impacts of high and low fuel. Other sensitivities examined the impacts of high and low customer demand and the effects of higher-than-expected adoption of distributed energy resources (DERs).

In addition to these sensitivities, this SLTRP also examines several "What-If" sensitivities to determine how the loss of key transmission corridors, due to extreme events (e.g. wildfires), could impact the LADWP Power System.

***Table 2-1**. 2022 SLTRP Cases.*

		2022 SLTRP Core Scenarios			
		100% Clean Energy by 2045	100% Carbon Free by 2035		
		SB 100 (Reference Case)	Case #1	Case #2	Case #3
	2030 RPS Target	60% RPS by 2030	80% RPS by 2030	90% RPS by 2030 (80% RPS by generation)	90% RPS by 2030 (80% RPS by generation)
Eligible Technologies	Renewables (Wind, Solar, Geo, Small Hydro) *(primary)*	Yes*	Yes*	Yes*	Yes*
	Energy Storage *(primary)*	Yes*	Yes*	Yes*	Yes*
	Solid Biomass	No	No	No	No
	Biogas/Biofuels	Yes*	No	No	No
	Fuel Cells	Yes*	Yes*, hydrogen only	Yes*, hydrogen only	Yes*, hydrogen only
	Hydro - Existing	Yes*	Yes*	Yes*	Yes*
	Hydro - New	No	No	No	No
	Hydro - Upgrades	Yes*	Yes*	Yes*	Yes*
	Natural Gas	Yes*	Yes*, until 2035	Yes*, until 2035	Yes*, until 2035, Limited (More DERs)
	Zero Carbon H2 Turbines *(secondary)*	Yes*	Yes*	Yes*	Limited (More DERs)
	Nuclear - Existing	Yes*	Yes*	Yes*	Yes*
	Nuclear - New	No	No	No	No
Transform existing gas capacity (non-OTC units)	Haynes, Scattergood, Harbor, Valley	No	Yes	Yes	Yes
Distributed Energy Resources (DERs)	Local Solar	1500 MW by 2035 (Reference)	2240 MW by 2035 (High)	2240 MW by 2035 (High)	2900 MW by 2035 (Highest)
	Local Energy Storage	Reference	High	High	Highest (Max DERs)
	Energy Efficiency	3210 GWh by 2035 (Reference)	4350 GWh by 2035 (High)	4350 GWh by 2035 (High)	4770GWh by 2035 (Highest)
	Demand Response	576 MW by 2035 (Moderate)	576 MW by 2035 (Moderate)	576 MW by 2035 (Moderate)	633 MW by 2035 (High)
	Building Electrification	Reference	High	High	High
Renewable Energy Credits (RECs)	Financial Mechanisms (RECs/Allowances)	Yes	No	No	No
Transmission	New or Upgraded Transmission	Moderate	High	High (possible new corridors)	High

**Note: Optimal portfolio will be determined through the capacity expansion model*
Note: Zero carbon includes RPS + nuclear + large hydro + green hydrogen

2.2 Case Descriptions

What follows is a description of the cases modeled for the 2022 SLTRP. The SB 100 case, built on the requirements of California Senate Bill 100, mandates a 60% RPS by 2030 and 100% carbon-free energy by 2045. This case represents the minimum requirements that California utility companies must achieve, by law, in terms of RPS, mitigating greenhouse gas emissions, and other environmental impacts. The "Core Cases" are Cases 1, 2, and 3, and are designed to fulfill the goal set by the Los Angeles City Council's motion to create a plan to achieve 100% carbon-free energy by 2035.

2.2.1 Senate Bill 100

The SB 100 Case represents the minimum goals that LADWP must achieve in order to comply with California State law—namely California Senate Bill 100. SB 100 mandates utilities achieve a 60% RPS by 2030. Furthermore, utilities must achieve 100% carbon-free energy (as a percentage of sales to ultimate customers) by 2045. The SB 100 Case is included in the 2022 SLTRP for comparison purposes with respect to the Core Cases (Cases 1, 2, and 3) so that stakeholders can clearly ascertain the tradeoffs between the cases in terms of environmental benefits, costs, reliability, and implementation risks.

To build a generation portfolio for the SB 100 Case, we considered renewable technologies such as wind, solar, geothermal, small hydroelectric facilities (excluding hydroelectric facilities greater than 40 MW) and biofuels. Solid biomass was not considered due to its relative paucity and lack of availability. In the context of computer modeling, any resources that were "considered" were made available as candidate resources that our capacity expansion model could use to create an optimal generation portfolio. As mentioned previously, the capacity expansion model chooses which resources to build, when to build them, and in what quantities to build them, subject to constraints such as RPS goals and reliability metrics. All this is done while simultaneously attempting to minimize costs.

In terms of non-renewable resources, the construction of new nuclear plants was not considered due to the operational risks and environmental impacts. Additionally, the construction of new large hydroelectric resources (i.e., hydroelectric resources with a capacity greater than 40 MW) was not considered due to the lack of available building sites as well as environmental impacts.

As part of our analysis, we also evaluated the potential construction of new gas-fired combustion turbines, combined-cycle plants, and carbon-free green hydrogen turbines.

In terms of DERs in the SB 100 case, our assumptions included a buildout of 1,500 MW of local solar, 3,210 GWh of energy efficiency savings, and 576 MW of demand response by 2035.

2.2.2 Case 1

The first of the Core SLTRP Cases is Case 1. The Core Cases all seek to meet the Los Angeles City Council's motion to achieve 100% carbon-free energy by 2035—10 years sooner and with more stringent constraints than SB 100. Additionally, Case 1 has an interim goal of achieving an 80% RPS by 2030.

Case 1 considers wind, solar, geothermal, and small hydro for our renewable generation portfolio. Unlike the SB 100 case, we do not consider biogas and biofuels for Case 1, keeping in line with the findings of the Los Angeles 100% Renewable Energy Study (LA100 Study).

Hydrogen fuel cells were also provided as a candidate resource for the capacity expansion model to use for Case 1. However, fuel cells were not selected by the computer due to their high capital costs.

For the same reasons, new nuclear plants and new large hydroelectric plants were not considered for construction, although existing nuclear and large hydroelectric resources would be retained.

A major distinction between the Core SLTRP Cases and the reference SB 100 case is the use of natural gas. For all three Core Cases, LADWP will end operation of natural gas-fired power plants as of January 1, 2035. Several power plants will begin to use a blend of natural gas and renewably-derived hydrogen, increasing their proportion of hydrogen until 2035, when all combustion turbines and combined cycle plants will either be retired or modified to use 100% green hydrogen.

Case 1 incorporates a higher quantity of DERs compared to the SB 100 case. Case 1 includes 2,240 MW of local solar, 4,350 GWh of energy efficiency savings, high levels of building electrification, and high levels of distributed energy storage by 2035.

2.2.3 Case 2

Case 2 also considers wind, solar, geothermal, and small hydro but not biogas and biofuels. Hydrogen fuel cells were again provided as candidate resources for the capacity expansion model and like Case 1, fuel cells were not selected by the computer model due to their high capital costs.

New nuclear plants and new large hydroelectric plants were not considered for construction, although existing nuclear and large hydroelectric resources would be retained.

The main difference between Case 1 and Case 2 is the interim 2030 RPS target. While Case 1 looks to achieve an 80% RPS target in 2030, Case 2 has a more aggressive 90% RPS target for 2030. For Case 2, all natural gas-fired generation will still be either retired or transformed to 100% green hydrogen by 2035. Case 1 and Case 2 incorporate identical quantities of DERs.

2.2.4 Case 3

Case 3 is the most aggressive scenario in the 2022 SLTRP in terms of our renewable energy buildout and use of behind-the-meter local resources. Like Case 1 and Case 2, Case 3 will meet the Los Angeles City Council’s motion to achieve 100% carbon-free energy by 2035. Case 3 also uses identical considerations as the previous cases in terms of renewables (wind, solar, geothermal, and small hydro only) and green hydrogen fuel cells (which were once again considered but not selected by the computer model due to capital costs).

Like the other Core Cases, new nuclear plants and new large hydroelectric plants were not considered, but existing nuclear and large hydroelectric resources would be retained.

Similar to Case 2, Case 3 achieves a 90% RPS by 2030. Unlike the other Core Cases, Case 3 utilizes far higher quantities of behind-the-meter local and distributed resources and, with input from the SLTRP Advisory Group (AG), was developed with the goal of minimizing the utilization of in-basin green hydrogen. Case 3 targets 2,900 MW of local solar, 4,770 GWh of energy efficiency savings, 633 MW of demand response, and compared to the other Cases, the highest quantity of distributed local energy storage by 2035.

2.3 Sensitivities

In addition to the expected load growth and customer demand assumed for each case, the Integrated Resource Planning (IRP) Group considered resource portfolios and production cost model simulations with low load and high load sensitivity scenarios. Staff also looked at the potential impacts of "What-If" sensitivity scenarios for demand response levels, transmission capacity, and no in-basin combustion.

An additional SLTRP sensitivity explores the overall impacts of high and low market prices for fuels such as natural gas and green hydrogen.

2.3.1 "What-if" Sensitivities

For this SLTRP, we conducted four "What-If" sensitivity analyses in order to explore implementation risks and incorporate feedback from the SLTRP AG. The "What-If" sensitivities allowed us to account for AG feedback related to various components affecting the Power System including emerging technologies, demand side resources, transmission, and load, as shown in the **Table 2-2** below.

***Table 2-2**. "What-if" sensitivities included in the 2022 SLTRP.*

Implementation Risk	Description	"What-if" Sensitivities
Emerging Technologies	No In-Basin Combustion Alternatives	Long duration capacity (e.g. Hydrogen Fuel Cells)
Demand Side Resources	Demand Response	Reaching only half of the 576/633 MW of DR by 2035
Transmission	Transmission Upgrades (over 10 projects by 2030)	More difficult in-basin upgrades not completed by 2030
Load	Transportation/Building Electrification	Low Load and High Load

2.3.2 No In-Basin Combustion

For the "No In-Basin Combustion" modeling sensitivity, LADWP replaced the in-basin green hydrogen turbines with in-basin green hydrogen fuel cells instead. This consideration was in response to feedback from stakeholders in the Advisory Group. Some members asked LADWP to study long-duration resource alternatives—instead of green hydrogen turbines—that would require no in-basin combustion at all. For this sensitivity analysis, we evaluated the impacts of the resource alternatives in mitigating nitrogen oxides (NOx) emissions.

The LA100 Study that preceded this SLTRP found that long-duration, dispatchable clean generation capacity is needed within the L.A. Basin. Such dispatchable generation capacity is vital for maintaining a reliable and resilient Power System in a 100% carbon-free electrical grid. Therefore, the LA100 Study recommended the use of renewably-powered turbines that would be used infrequently under normal grid conditions, but could also be relied upon primarily as a backup resource. These renewably-powered turbines can be called upon during stressed grid conditions resulting from events like heatwaves, or during transmission outages caused by high-impact low-frequency events that impede the import of out-of-basin renewable energy, such as wildfires. Furthermore, the LA100 Study found that by 2045, LADWP power plants would represent a negligible portion of NOx emissions in the City of Los Angeles (as low as 0.03%, falling from an already sub-1% baseline of 0.4% in 2012), and that the majority of the NOx emissions would stem from other sources—the Port of Los Angeles and the Port of Long Beach, residential and commercial buildings, light-duty vehicles, and other industrial sectors. These economic sectors contribute far more heavily to emissions in Los Angeles compared to LADWP power plants. These highly emitting sectors represent the greatest opportunity for significant progress towards reducing local emissions.

For this sensitivity, we assumed that all green hydrogen fuel cells used proton exchange membrane (PEM) technology. These fuel cells were assumed to be slightly more efficient than green hydrogen turbines (thus incurring a small reduction in green hydrogen fuel costs), more operationally flexible, and less emitting (producing zero NOx emissions). However, they were also significantly costlier—roughly four times the capital cost assumed for green hydrogen turbines. Although the sensitivity modeling completely replaced the in-basin green hydrogen turbine capacity with in-basin green hydrogen fuel cell capacity (to investigate the impacts on Power System portfolio costs and NOx emissions), the actual constructability and implementation feasibility of green hydrogen fuel cells requires further evaluation. For fuel cells to be substituted for green hydrogen turbines at the massive scale required (gigawatts) in a land-constrained region such as the City of Los Angeles, several additional factors need to be thoroughly studied.

2.3.3 Demand Response

The demand response "What-If" modeling sensitivity allowed our teams to examine the effects of reduced customer participation in demand response programs and evaluate the impacts on both portfolio cost and reliability. Specifically, our model considered the impact on our system if reduced customer participation resulted in a reduction of 50% of the total subscribed demand response capacity. Our 2035 goals for demand response capacity are 576 MW and 633 MW for the moderate and high levels of demand response, respectively (the goals are defined as existing plus projected cumulative total capacity).

The sensitivity modeling considered two different Power System dispatch scenarios under the Core Cases. The first scenario assumed the demand response target capacities were fully realized through robust customer participation. The second scenario assumed only half of the target capacities were realized through reduced customer participation.

2.3.4 Transmission

For the transmission "What-If" modeling sensitivity we explored the effects of potential delays in critical transmission projects by 2030 (both in-basin and out-of-basin) on the Power System. An analysis of the transmission "What-If" modeling sensitivity revealed the effects on the Power System in 2030 that potential delays in critical transmission projects (both in-basin and out-of-basin) may have.

As a result of the LA100 Study, LADWP was able to identify near-term actions that can and should be taken irrespective of the carbon-free pathway that we elect to follow. At least ten critical in-basin transmission projects were identified as necessary to maintain reliability in light of the once-through cooling (OTC) retirements and to bring renewable power to load centers within the City. Additional out-of-basin transmission projects were also identified as necessary to increase LADWP's power transfer capability on various paths. This would allow for the sufficient import of renewable energy into the LA Basin and in turn, allow LADWP to meet our renewable energy targets. In total, over 30 transmission projects (both in-basin and out-of-basin) were identified as necessary to augment the LADWP Power System in preparation for a 100% carbon-free energy future. Los Angeles is an infrastructure-dense and land-constrained city, and major transmission projects have historically taken over a decade to complete. The unprecedented, rapid deployment of transmission infrastructure that is essential to meet our renewable energy targets exposes various risk factors. These factors include issues such as permit and construction feasibility, project sequencing, supply chain and labor constraints, among others, that could result in delays to the development of the necessary transmission infrastructure.

Our assumptions for this sensitivity included indefinite delays (captured as projects no longer built for purposes of sensitivity) to an out-of-basin transmission project and several at risk in-basin transmission projects that required the increase of in-basin resources to provide replacement energy. We studied Power System impacts from the expected changes in metrics such as RPS percentage, portfolio net present value costs, average annual capacity factor for in-basin green hydrogen power plants, and Power System emissions.

2.3.5 Load

Our model for the electric load "What-If" sensitivity considered "high" load and "low" load conditions for the Power System. This sensitivity analysis allowed us to explore the range of potential resources and portfolio costs correlated with the different potential trends in electric consumption across our service territory.

Policies at the state and local level are projected to escalate the City's electric consumption as they incentivize electrification. These policies are targeting major public spheres such as the electrification of all vehicles on public highways (transportation) and gas-powered home appliances transitioning to electric appliances (building electrification). At the same time, remarkable progress in energy efficiency and the deployment of net-energy metered solar has kept recent load growth flat or even in a slight decline over the past several years. The recent stagnant rate of load growth coupled with potential obstacles to electrification, such as high costs and slow deployment of infrastructure, may result in a continuous decline of retail electric sales.

In this sensitivity, the "high" load conditions, mainly driven by electrification of the transportation and building sectors, were assumed to result in an average annual retail sales growth of approximately 2.4%. The "low" conditions were based on low electrification adoption coupled with considerable penetration of local load-reducing distributed energy resources (such as highest assumed levels of net-metered solar and energy efficiency), and they resulted in average annual retail sales reductions of approximately 1.6%. Based on these conditions, we computed the portfolio capacity requirements for resource adequacy and expected portfolio costs.

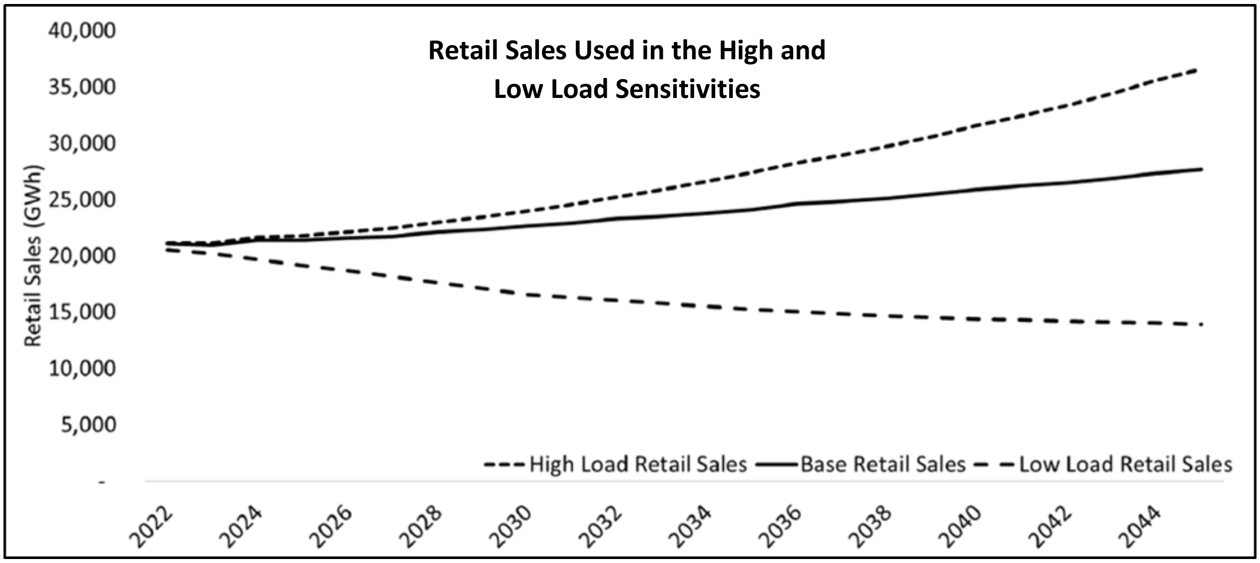


Figure 2-1. *High and low load "What-If" sensitivities included in the 2022 SLTRP.*

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 SLTRP 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 SLTRP 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 SLTRP, 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

Our 2022 SLTRP utilizes LADWP's official 2021 Load Forecast—dated June 15, 2021—of customer demand for electricity over the next 20 years (the complete 2021 Load Forecast will be included in an appendix). The 2021 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, the California Energy Commission 2013 EV (Electric Vehicle) Forecast (with adjustment based on Power System's new Electric Vehicle input) 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.

2.4.2 2021 Retail Electrical Sales and Demand Forecast

The COVID-19 public health crisis began affecting electricity sales during the third quarter of fiscal year-end (FYE) 2020. Sales for FYE 2020 were 21,115 gigawatt-hours (GWh). This was 3.9% below recorded sales of 21,961 GWh in FYE 2019. The compounded growth rate for sales is estimated to be -0.3% over the five-year budget period. Sales growth will be restrained by accelerated incremental savings from our energy efficiency and solar distributed generation programs. Additionally, increasing prices for electricity may alter customer behavior, resulting in less energy usage.

The LADWP billing system may also impact our sales forecasts. The billing system underwent a conversion in September 2013. According to our Load Forecast Team, sales in FYE 2014 and 2015 were potentially underreported. In 2017, the billing data reflects amounts related to legal settlements from the billing system conversion. These billing system anomalies from one-off events create unwanted variability when performing statistical analysis on historical time series data.

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.

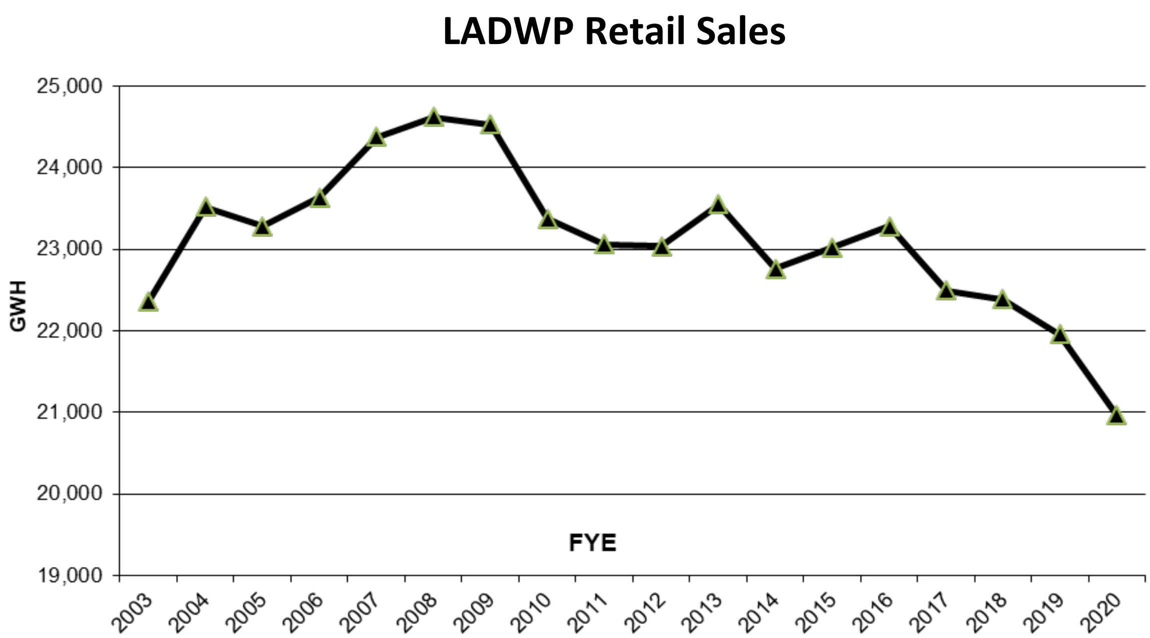


Figure 2-2*. Retail sales net of energy efficiency and distributed generation.*

2.4.3 Losses Incurred in Production

The averaged percentage losses are 12.1% with a standard deviation of 1.1% from Fiscal Year 1980-81 to 2019-20. In Fiscal Years 2013-14 and 2016-17, percentage losses were the highest recorded since 1981. In Fiscal Year 2013-14 and 2016-17 the losses were 14.8% and 15.0% respectively. The formula to compute percentage losses is $\frac{((NEL - Sales) \times 100)}{NEL}$. **Figure 2-3** shows the historical percentage losses.

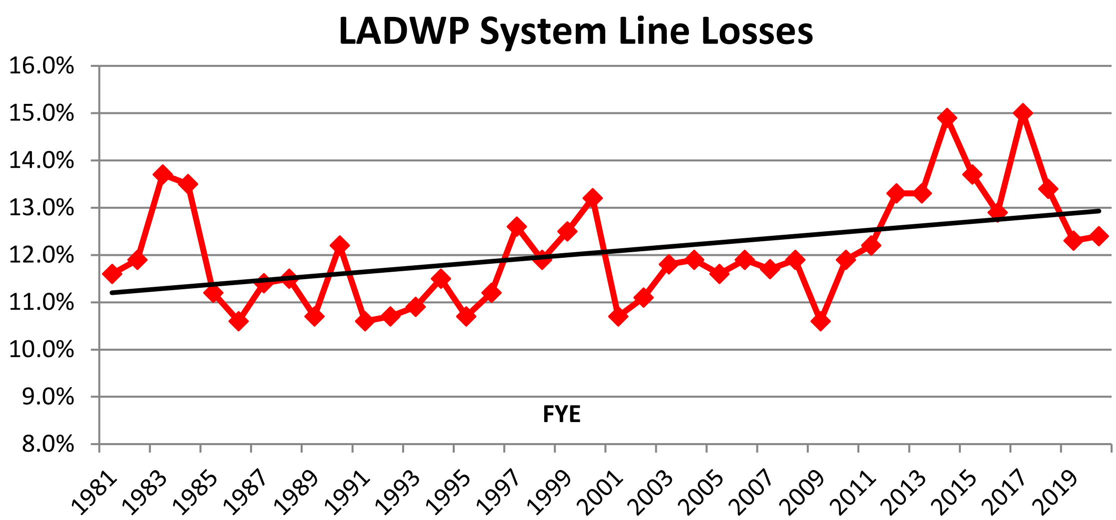


Figure 2-3. *Historical Percentage Losses by Calendar Year.*

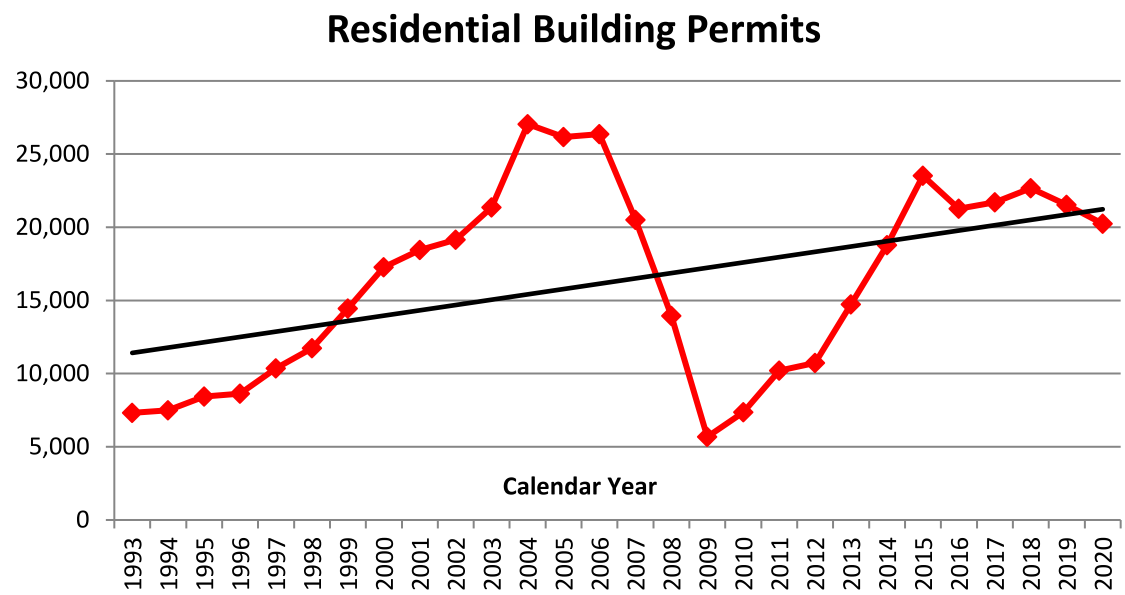
2.4.4 Economics

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 2021 was negative 131,000 people, signaling a loss of residents versus the influx of new residents. 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 decrease 0.3% 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 negative 0.4% –a reduction of approximately 20 MW per year—with negative growth over the next few years due to the steady growth of energy efficiency and solar PV programs. Also, the implementation of the demand response program may further lead to load reduction although the demand response program was not factored into our peak demand forecast. Despite its inclusion from the forecast, it has been considered as a resource to serve peak demand in this SLTRP.

All the data and forecasts in **Figure 2-4** below are taken from the 2022 UCLA Anderson Forecast.


Residential Building Permits
30,000
25,000
20,000
15,000
10,000
5,000
0
Calendar Year
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
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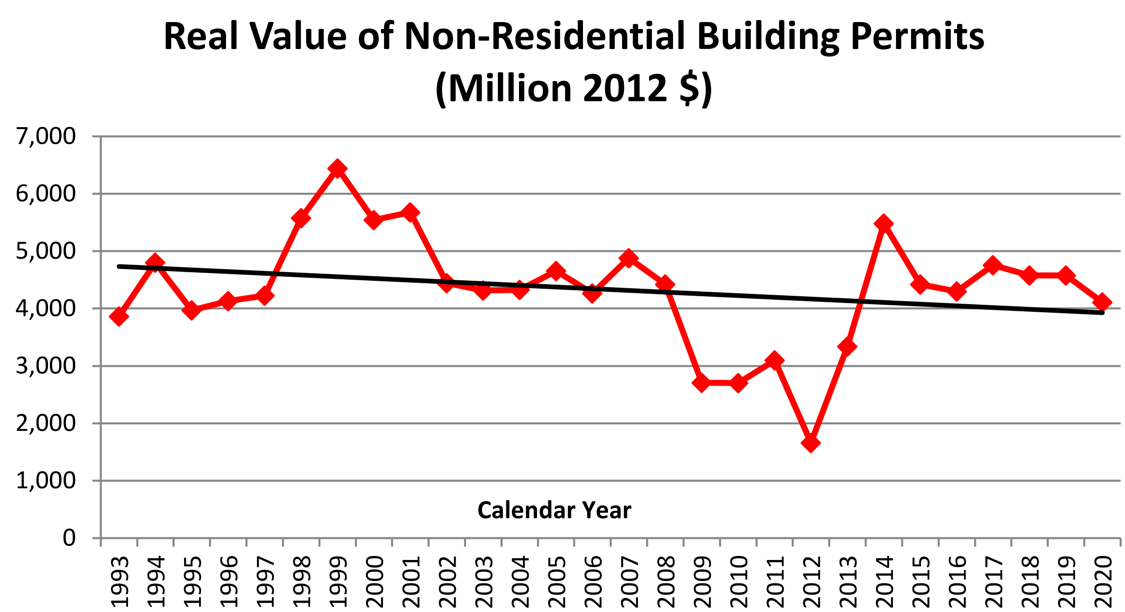
2016
2017
2018
2019
2020


Real Value of Non-Residential Building Permits
(Million 2012 $)
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Calendar Year
1993
1994
1995
1996
1997
1998
1999
2000
2001
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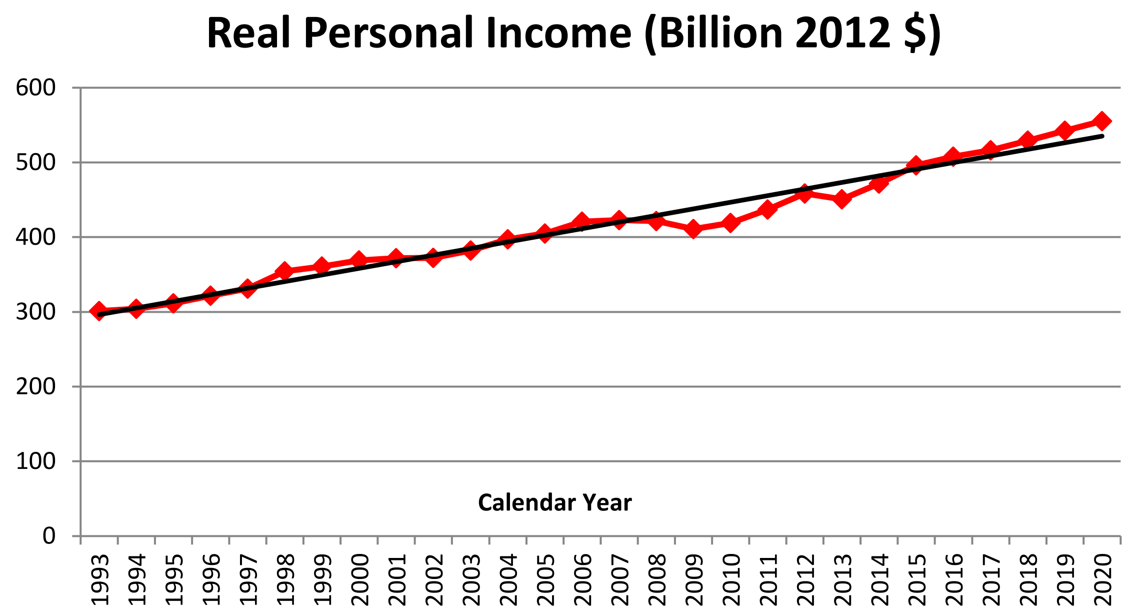


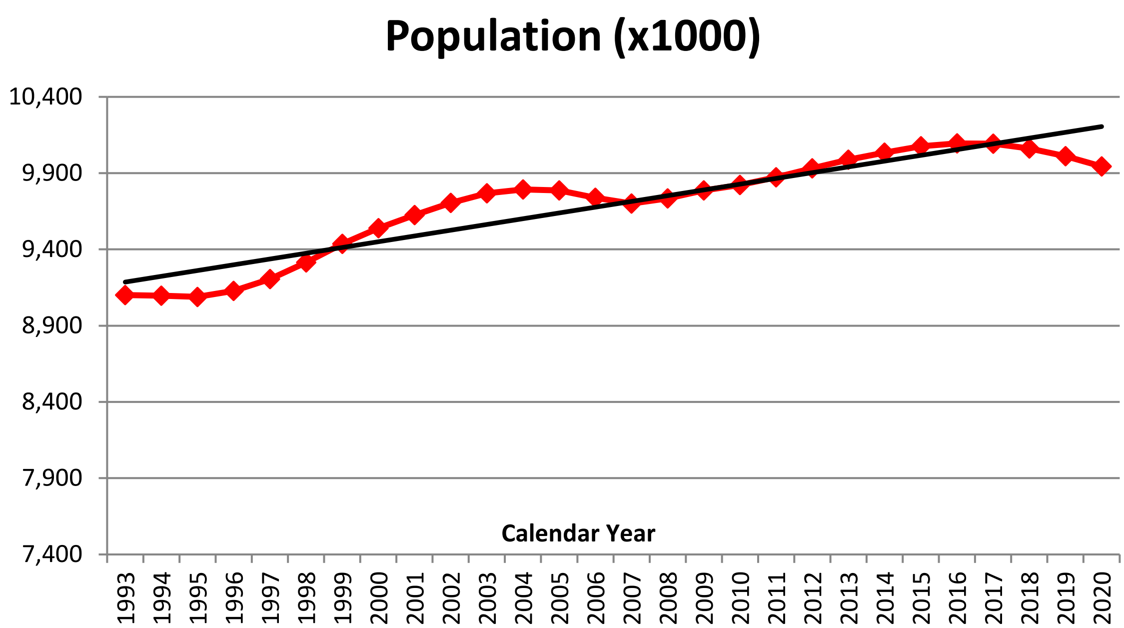


Figure 2-4. *2022 UCLA Anderson historical inputs for residential building permits, real value of non-residential building permits, real personal income, and population by calendar year.*

2.4.5 Forecast Data Sources

The 2021 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 2-3 summarizes the data sources used to develop the forecast and source updates.

***Table 2-3**. Load forecast data sources.*

Data Sources		Updates
1.	Historical Sales through December 2020 were reconciled to the General Accountings Consumption and Earnings Report.	*Historical Sales, Net Energy for Load and weather data is updated through December 2020.*
2.	Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2020 benchmark.	*Employment data is updated through December 2020 using the March 2020 benchmark.*
3.	The Transportation Electrification Forecast is based on the California Energy Commission 2013 Integrated Energy Policy Report forecast with adjustment based on Power System's new Electric Vehicle input.	
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 2017 SLTRP. Historical installation rates are provided by the Energy Efficiency group.	
5.	Projected solar rooftop installations are consistent with the 2017 SLTRP. Historical installations are provided by the Solar Programs Development Group.	
6.	Electric prices are based on approved FY20/21 Final Budget Financial Plan Case-24 developed by Financial Services Organization.	

2.4.6 Five-year Sales Forecast

The 2021 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 2021 Load Forecast assumes that the projected energy efficiency and customer-sided solar savings occur uniformly as a simplification.

Table 2-4 shows projections of short-term retail sales and energy efficiency growth.

***Table 2-4**. Short-term retail sales ad 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)**
2020-21	20,754	-1.7%	3,857
2021-22	20,926	0.8%	4,242
2022-23	20,610	-1.5%	4,664
2023-24	20,671	0.3%	5,092
2024-25	20,834	0.8%	5,535

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

Our estimated sales for FYE 2021 were 360 GWh, or 1.7% below recorded sales in FYE 2020. The compounded growth rate for sales is estimated to be negative 0.3% 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 2021 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 3,652 GWh since FYE 2000 through LADWP-sponsored programs. LADWP is accelerating these savings programs and retail sales are expected to be reduced by another 1,883 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 2022 SLTRP.

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 3,275 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.

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. If LADWP keeps the same pace through 2030, we would double our energy efficiency portfolio per SB 350.

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 contain 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 a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare 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.

2.5.1.4 Customer Performance Program

The Custom Performance Program (the “CPP”) provides 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, retrocomissioning, chiller efficiency, and/or other innovative energy savings strategies.

The CPP’s Custom Express fast tracks smaller, less energy-intensive projects with deemed energy savings projections to help expedite application processing and get customers paid faster, while the CPP’s Custom Calculated conducts an in-depth energy savings analysis to custom calculate customers’ individual efficiency projects’ energy savings. The CPP has achieved over 586 GWhs of energy savings since 2007.

2.5.1.5 Commercial Lighting Incentive Program

The Commercial Lighting Incentive Program (“CLIP”) offers customers incentives to install newly purchased energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilo-watts (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 748 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 Department partners with Southern California Gas Company (“SoCalGas”) to offer a tri-resource efficiency program aimed at reducing the use of electricity, water, and natural gas. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less. This program has achieved 465 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 and retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the most disadvantaged customers.

2.5.1.8 Refrigerator Exchange Program

The Refrigerator Exchange Program (REP) is a free refrigerator replacement program designed to target customers that qualify on either the Department's Low-Income or its Senior Citizen/Disability Lifeline Rates as well as Multi-Residential or Non-Profit customers. The program was expanded to include the following entities: multi-family or mobile home communities, civic, community, faith-based organizations, and educational institutions. The REP leverages a third-party contractor, ARCA (Appliance

Recycling Centers of America), to administer the program's delivery and provide energy-efficient refrigerators to replace older, inefficient, but operational models. Additionally, customers can pair the REP with the Window Air Conditioner Recycling Program, which offers a $25 rebate to residential customers to turn-in their old window air conditioners, achieving an energy savings of 104 GWhs since 2007.

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 program is being expanded as a $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, which are not included in 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.

2.5.2 Building Electrification

Starting in 2018, California set forward a number of 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.

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 main 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 the life cycle cost for the adoption rate and consumption analysis. Measures with lower life cycle costs would see increased adoption rates and vice versa. For the SLTRP, the High Building Electrification scenario would offer incentives covering a percentage of the retail price at the following levels shown in **Table 2-5**.

Table 2-5*. 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

In addition, to account for current increases of measure costs from the COVID-19 pandemic and supply chain issues, an immediate 13% inflationary price increase to the measure cost was added. The increase was based on commodity price data from the bureau of labor statistics. Furthermore, an additional 2% inflationary cost adder is included in the measure costs each of the following year to reflect realistic prices.

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.

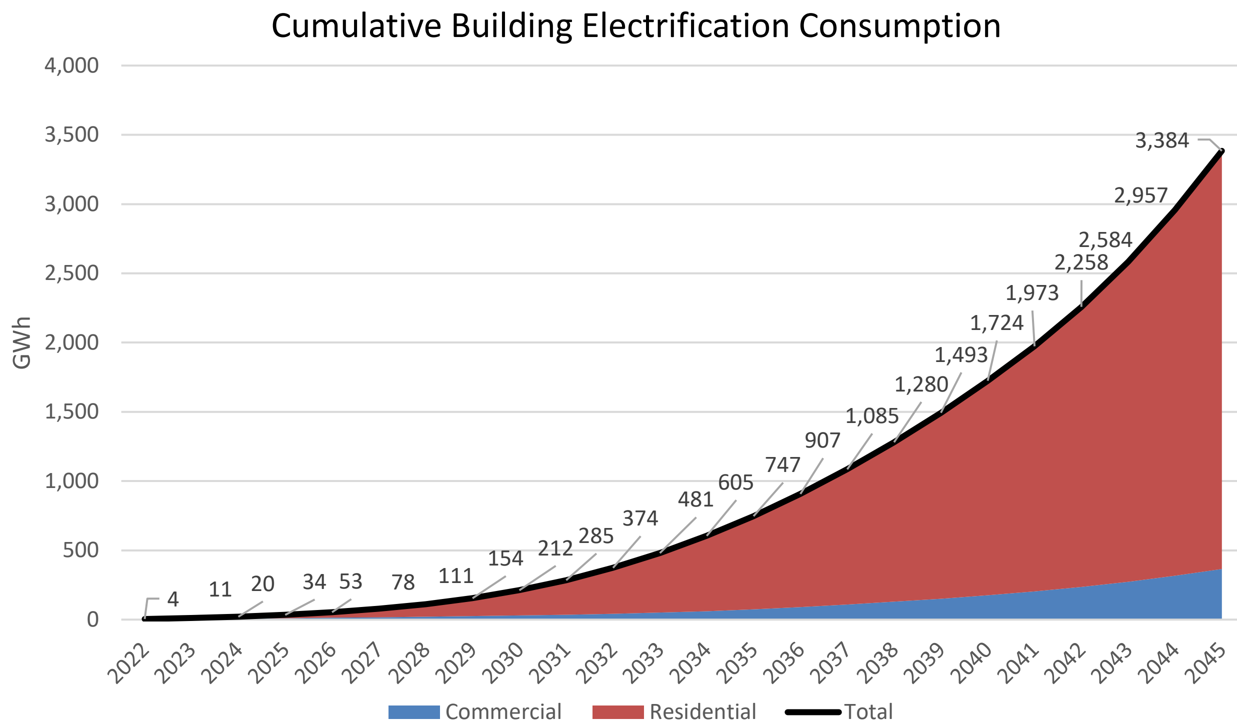


***Figure 2-5**. Forecasted load growth for building electrification in commercial and residential sectors.*

The results of the study indicate that both residential and commercial building electrification adoption begins gradually but exponentially increases after 2030. 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. By 2035, the model forecasts residential sector cumulative energy consumption to increase by 673 GWh while the commercial sector sees a 74 GWh increase. 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 the commercial space conditioning measures is dampened by the space cooling savings incurred by heat pumps. By 2045, the difference between the two sectors becomes much larger, with the residential sector forecasting a cumulative consumption increase of 3,019 GWh compared to the commercial sector increase of 365 GWh of cumulative energy consumption.

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, the 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.

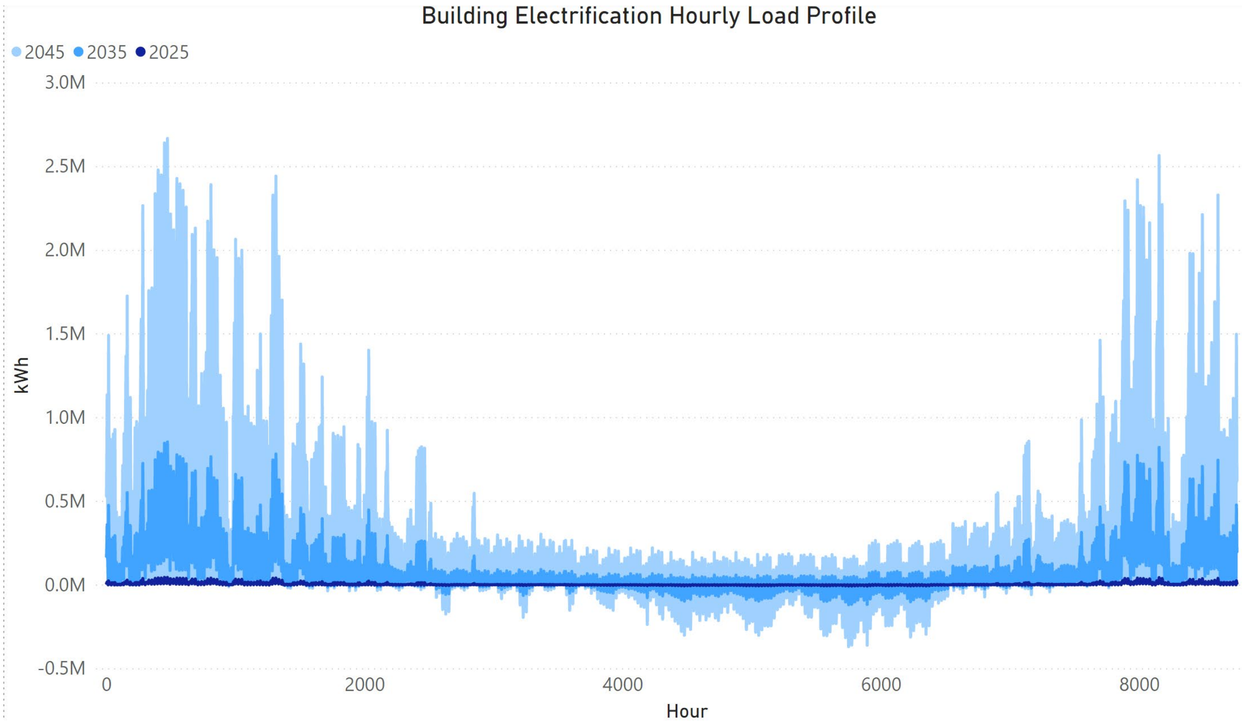


***Figure 2-6**. Hourly Load Profile of building electrification consumption for 2025, 2035, and 2045.*

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 the load growth potential section, 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.

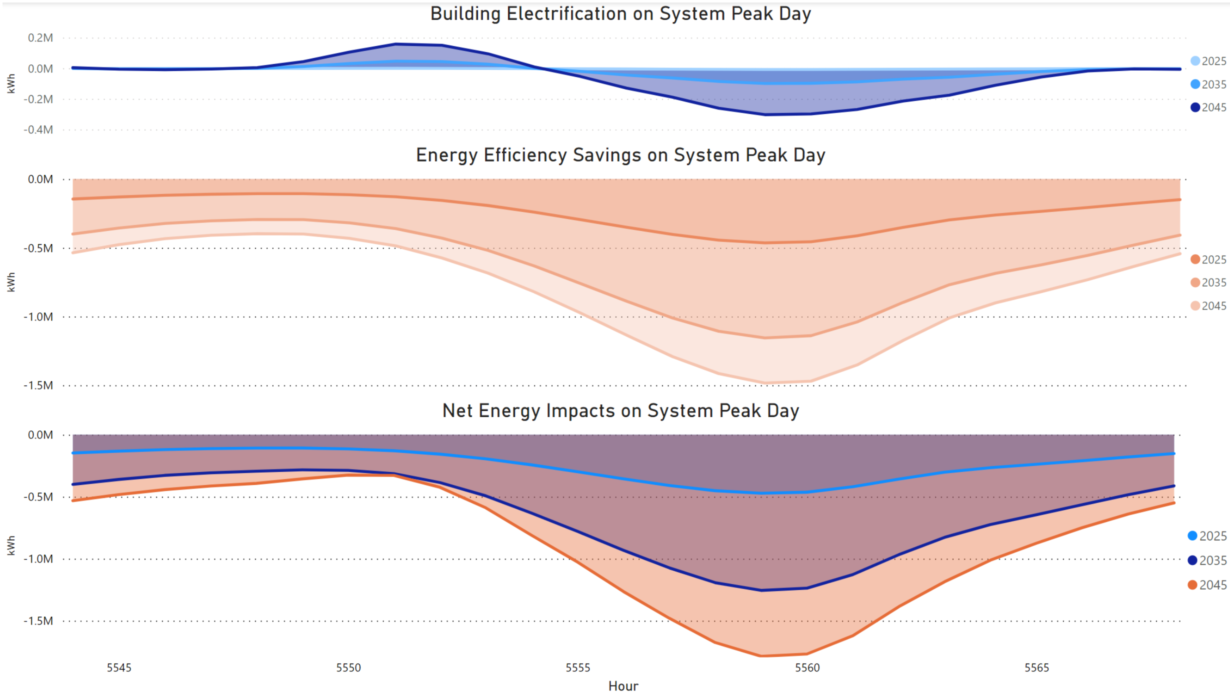


***Figure 2-7**. Building electrification, energy efficiency, and net energy impacts on system peak day.*

On the projected system peak day, the figures display 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.

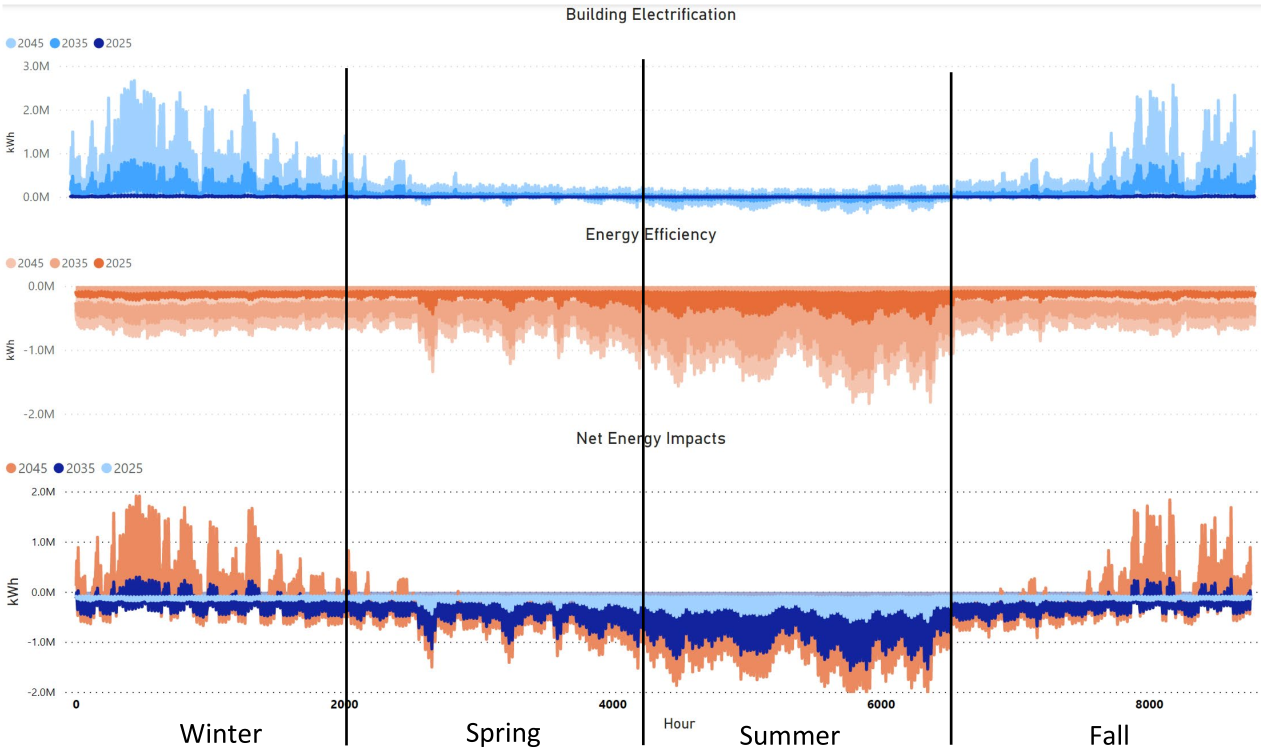


***Figure 2-8**. Hourly profile of combined EE and BE net energy impacts.*

The combined EE and BE net energy impact profiles illustrate the increase in electricity consumption in fall and winter seasons on an annual timeframe. 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 BE Programs Projected Costs and Cost Effectiveness of Investment

The SLTRP High case for BE considers LADWP's economic market intervention with incentives for customers. As discussed previously, the general assumptions included the specified incentives that cover a a percentage of measure installation costs. Considerations were also made for the potential administrative costs that LADWP may incur for the delivery of incentives to customers.

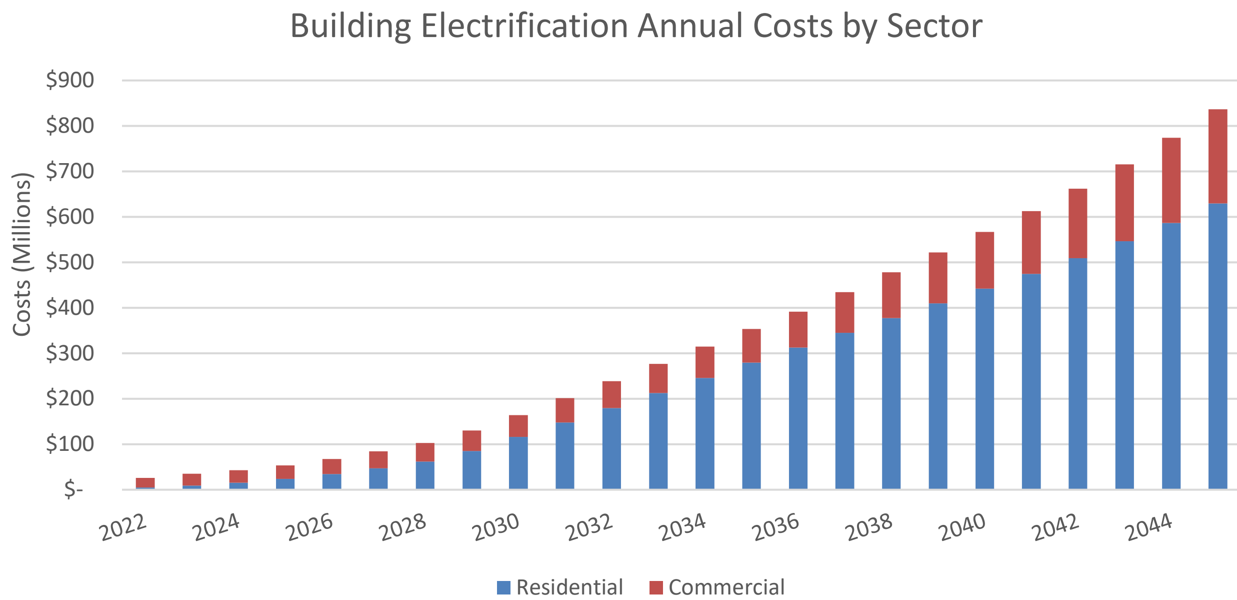


Figure 2-9. *Incremental building electrification budget by sector with assumption that no future building codes has electrification.*

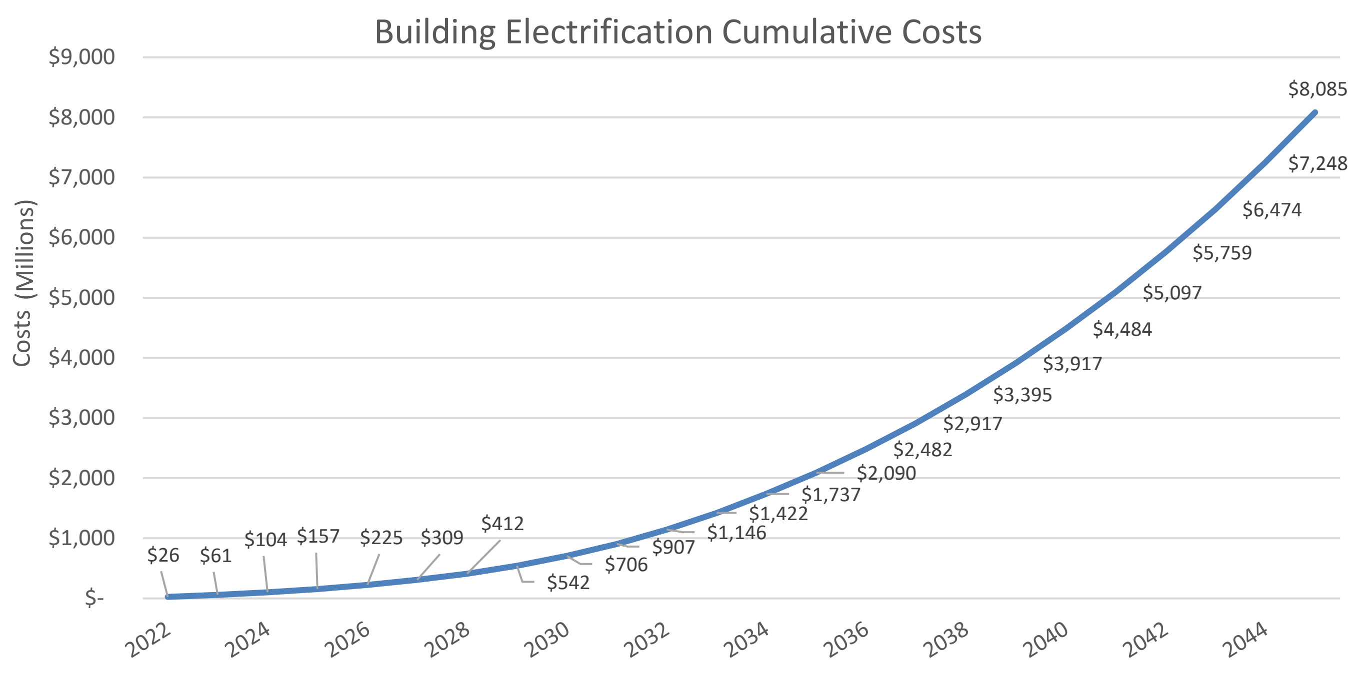


Figure 2-10. *Cumulative building electrification costs.*

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.

In the figure below, positive values represent dollars spent by LADWP as a result of increased load and negative values represent dollars saved by LADWP from load decreases.

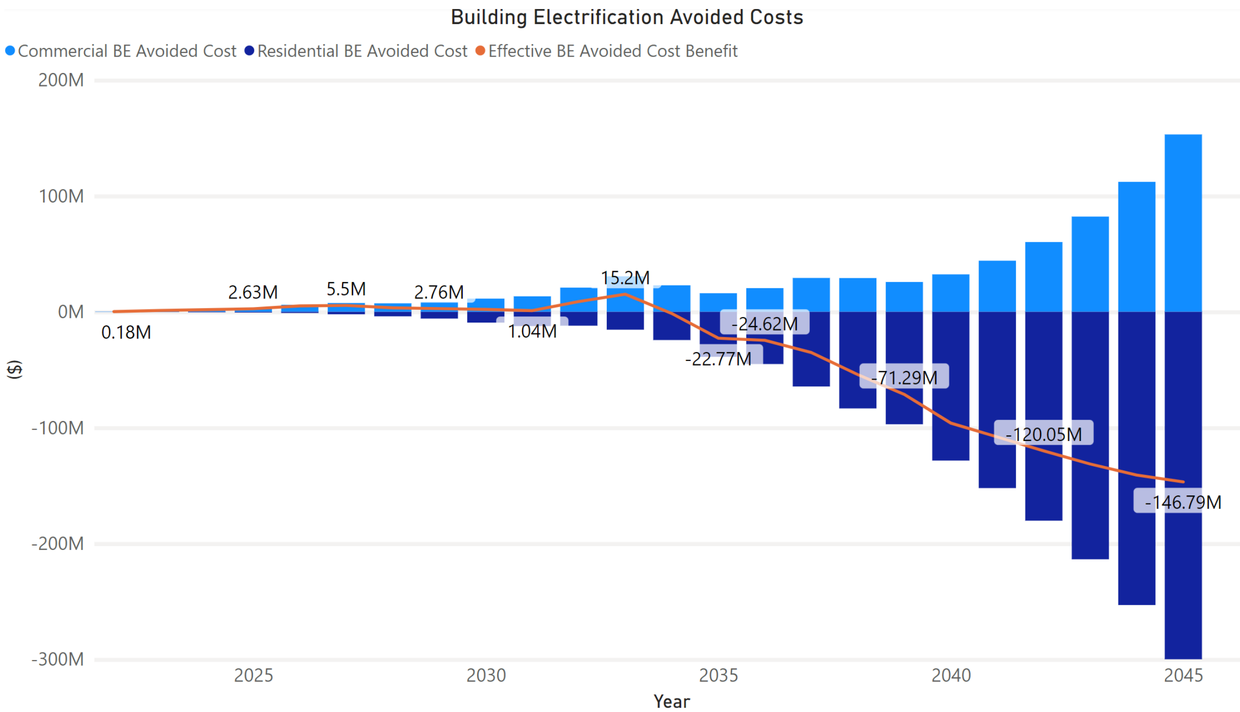


Figure 2-11. *Building electrification avoided cost impacts.*

From the figure, 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.

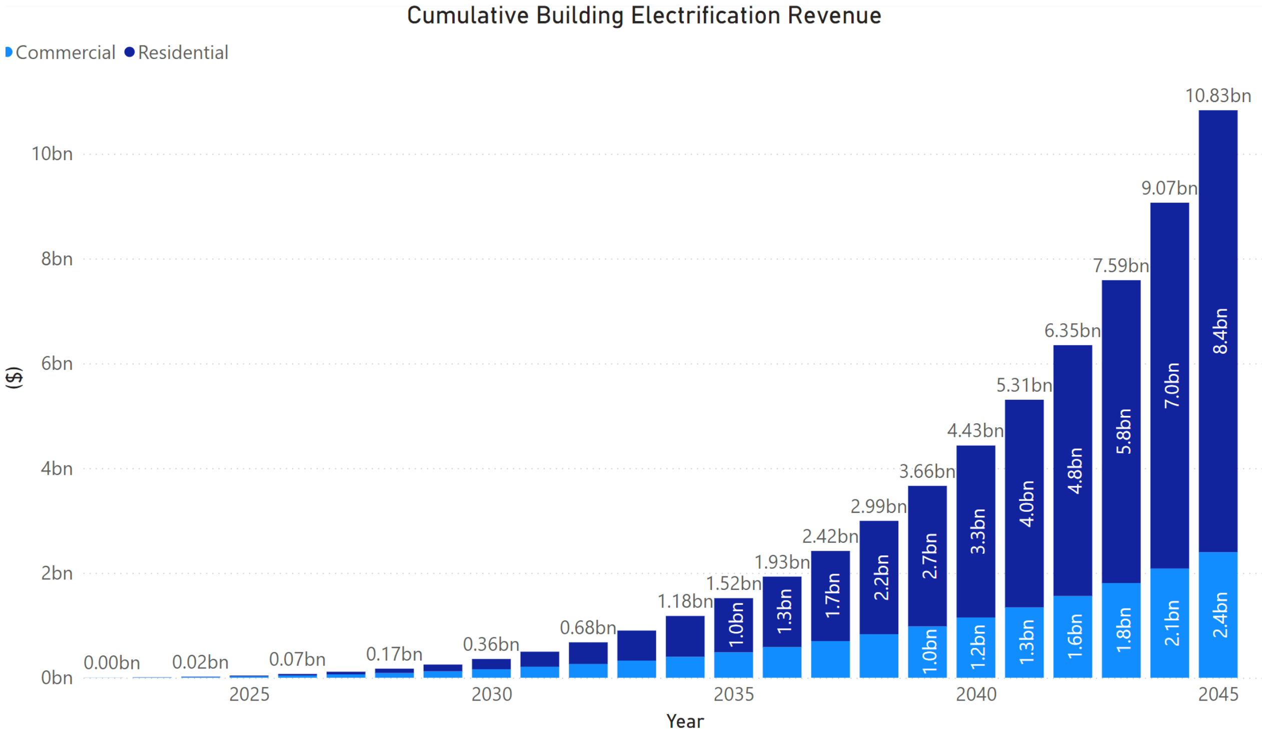


***Figure 2-12**. Cumulative revenue from building electrification.*

Figure 2-12 shows the cumulative revenue earned from commercial and residential building electrification sales. Revenue begins to increase sharply after 2030 by the aforementioned steep increase in gas rates. The revenue earned from electrification greatly outweighs the detrimental avoided costs incurred.

Figure 2-13 demonstrates cumulative revenue growth in comparison to program costs and cumulative avoided costs. The avoided costs are minimal when compared to utility revenue and program costs. The costs are displayed as positive values while benefits are negative. When the net cost trendline falls below the x-axis, it signals that the cumulative electricity sales revenue is greater than program and avoided costs. Overall, the chart demonstrates how the benefits outpace the costs; it's an important variable that can be used to justify investment in BE programs. The analysis indicates that the entire investment in BE hits the breakeven point within 20 years.

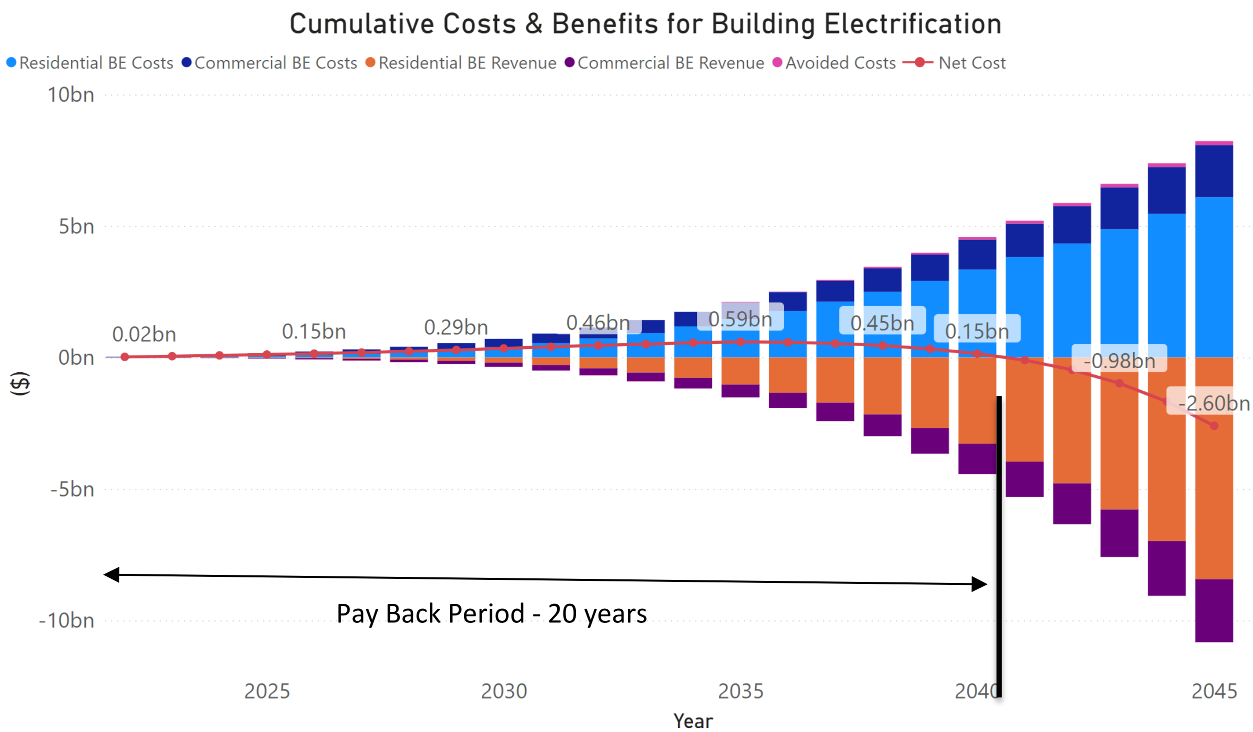


__Figure 2-13__. Cumulative costs and benefits for building electrification.

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 more data visibility and control of DERs, while simultaneously acting as a demand response asset.

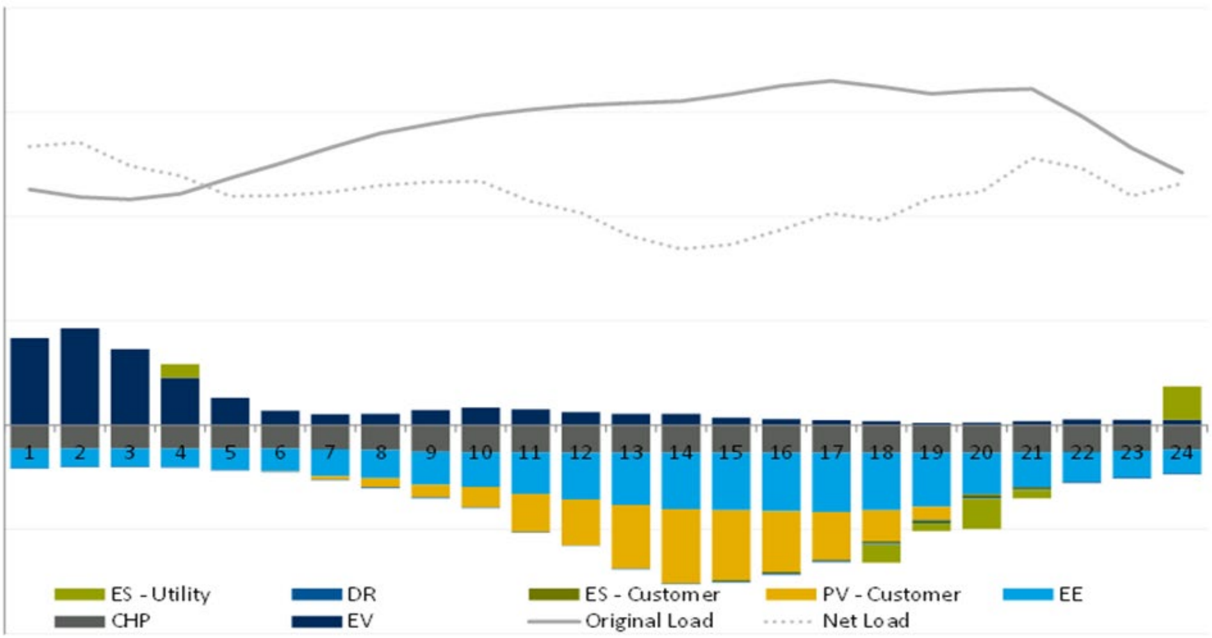


Figure 2-15. Aggregate DER impact on net load.

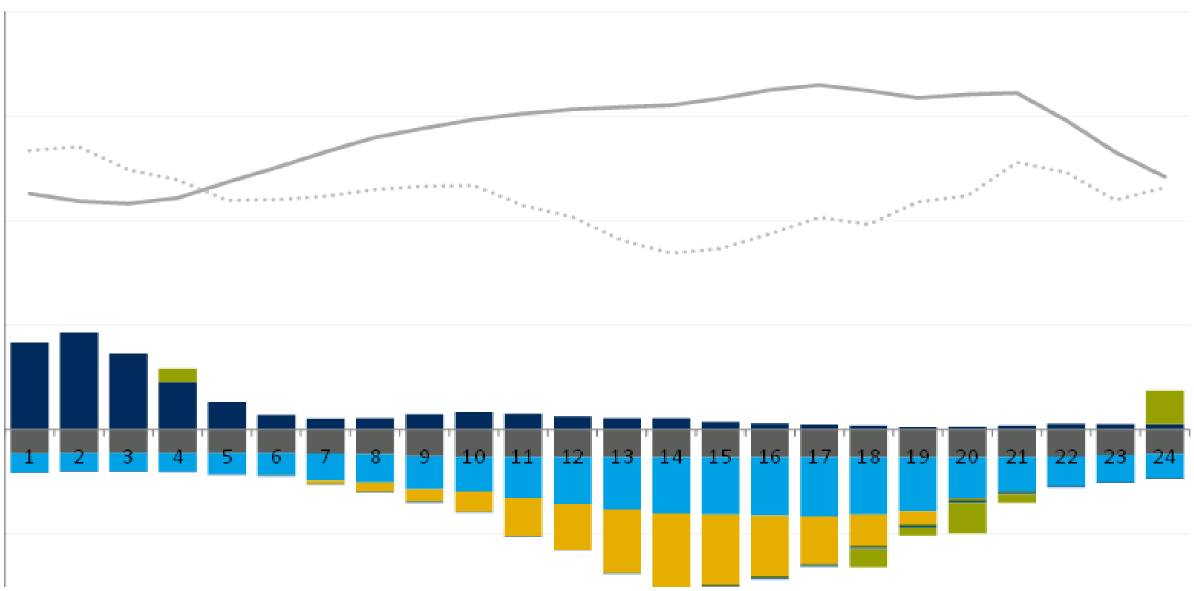


Figure 2-14. Aggregate DER impact on net load

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.

Most of the technologies required for a DER-ready distribution infrastructure are emerging in small-scale demonstrations and pilots around the world, but they are not ready for large-scale deployment. These require substantial modernization of distribution infrastructure, including the development of sophisticated distribution operations, communications, and data processing. Although a significant amount of DERs—especially solar PV generation— are currently in service, many installed communication architectures and protocols do not meet utility requirements for monitoring, control, and cybersecurity. We are presently evaluating the requirements to responsibly manage DERs for distribution system optimization and reliability, including interoperability of legacy devices using a DER Management System (DERMS).

A main focus of the LADWP DER program is to understand all potential system impacts. We are attempting to discover how and where these technologies can provide benefits to the grid and our customers. By synchronizing DER incentive programs with power system planning, engineering, and operations stakeholders, we can potentially defer capital infrastructure upgrades and replacements, decrease generation and transmission operating costs, and increase renewable DG integration.

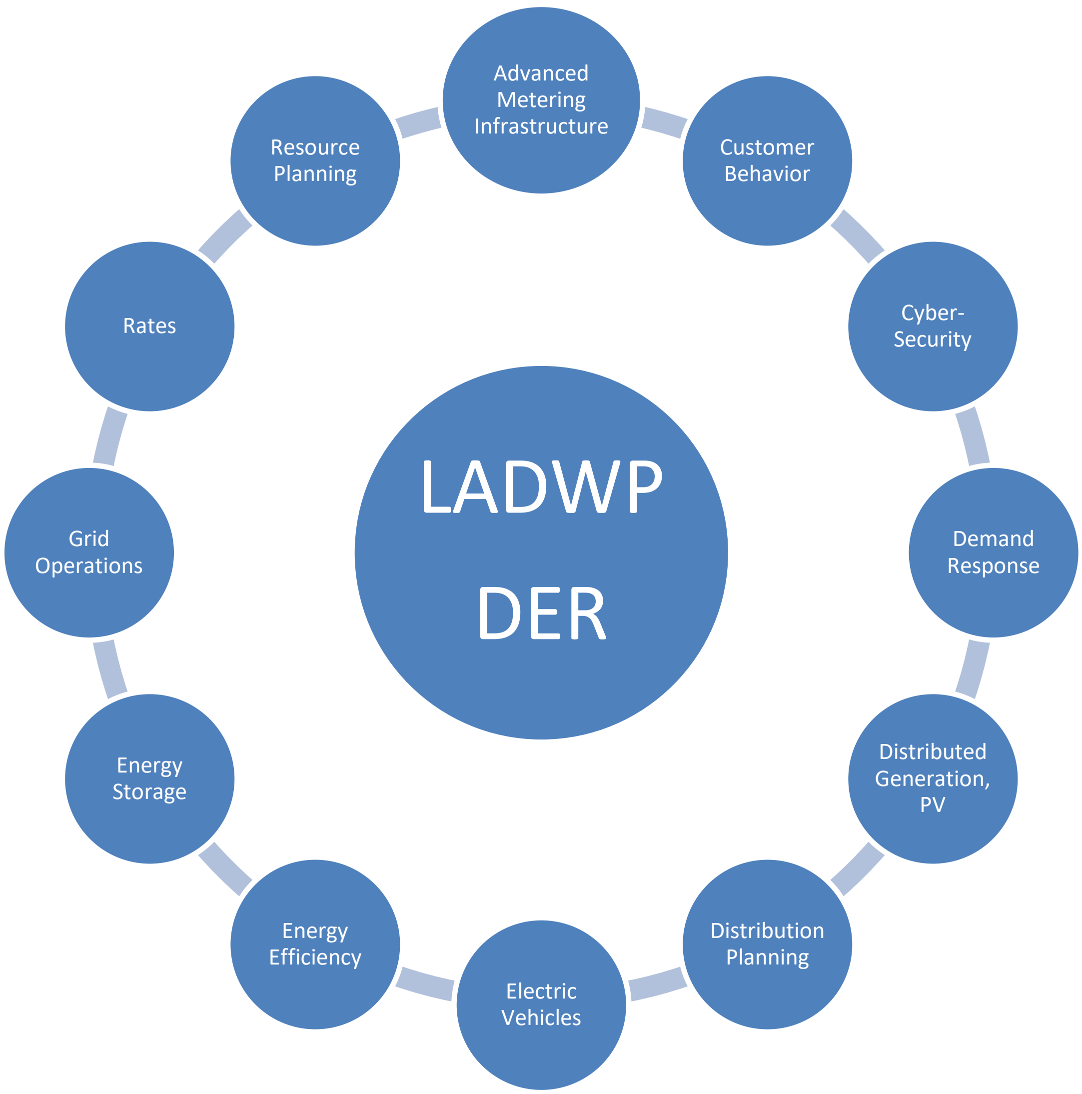


Figure 2-16. *Components of distributed energy resources.*

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 summer time system peak by avoiding 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 2-17**.

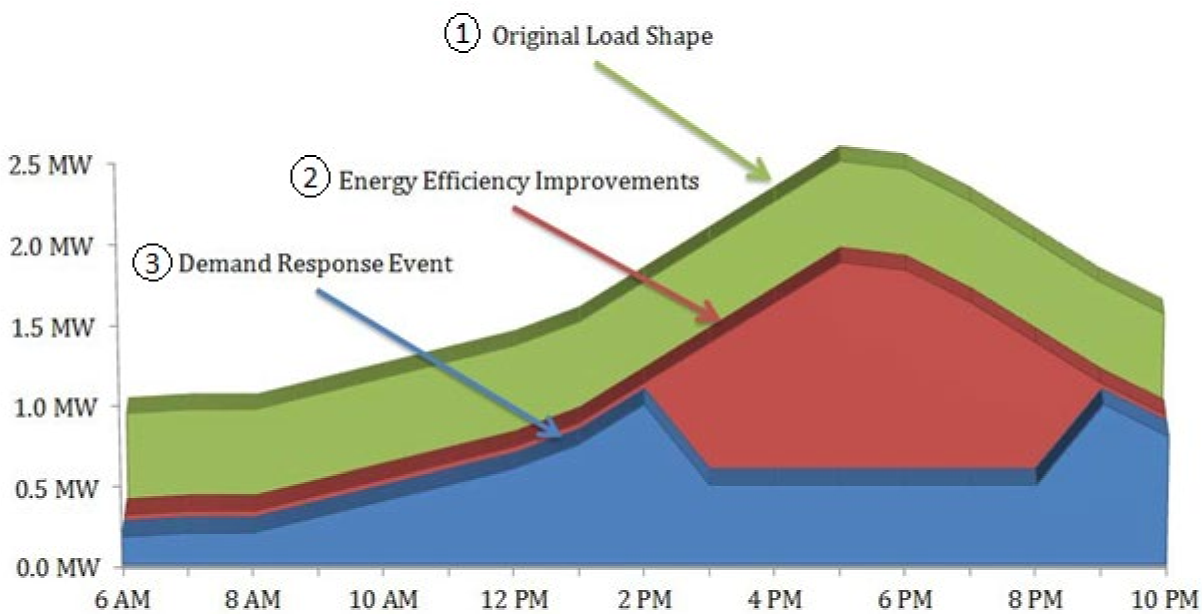


Figure 2-17. *Impacts of energy efficiency and demand response on load.*

Figure 2-17 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 2-17**. 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 off-line.
- *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 where 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:

1. 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.

2. DR will be customer-friendly through ease of enrollment, flexible participation, incentives and rates transparency, and inclusivity.

3. Load curtailment will be available primarily during summer peak periods, within one to two hours of dispatch, with a significant share of the capacity available within 10 minutes.

4. 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 SLTRP 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 SLTRP. 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:

> **1) 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.
>
> **2) 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.
>
> **3) 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.
>
> **4) 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.
>
> **5) 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.

Currently, LADWP requires customers to have building energy management systems (BEMS), and these customers must also commit to a minimum load reduction of 100 kW for each called-for demand response event during the five-month curtailment period (June 15th through October 15th).

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 over-generation.

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 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. In 2019, the rebate program was re-established with a maximum expenditure of $40 million per fiscal year for 10 years. 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. The rebate program has provided 7,273 residential and 14,712 commercial charging station rebates and 4,518 used electric vehicle rebates, totaling over $84 million to customers since the program's inception. To support the City's electric vehicle fleet, LADWP installed 1,037 chargers on LADWP properties and supported the installation of 2,460 chargers on other City properties.

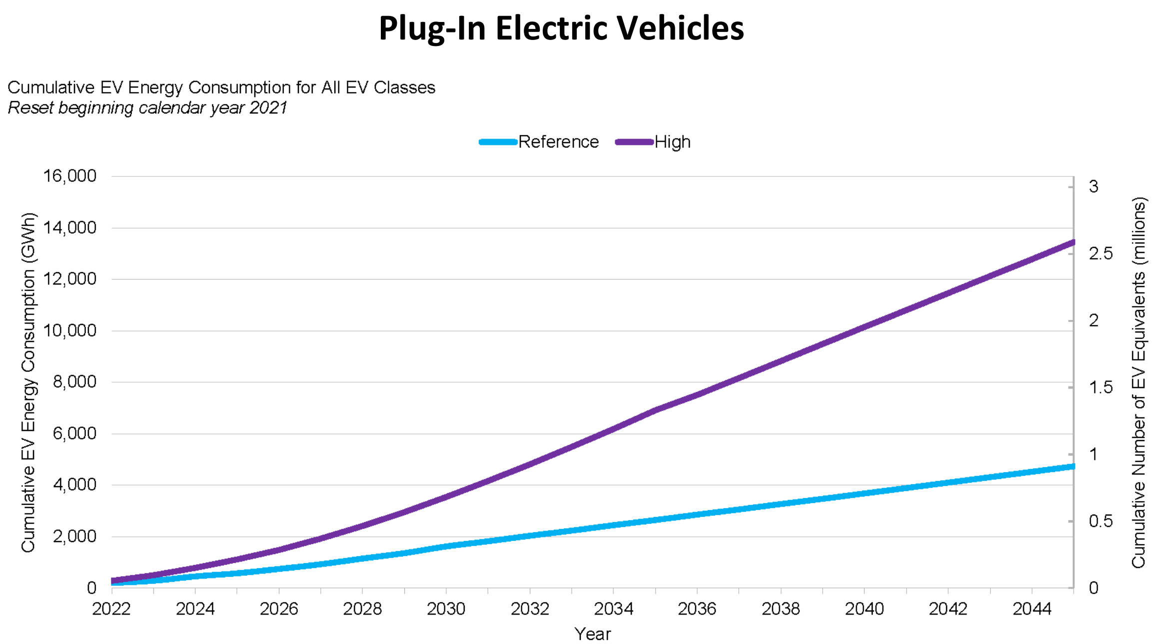


Figure 2-18. *Forecasted energy growth in GWh attributed to plug-in electric vehicles.*

CARB is currently developing Advanced Clean Fleets, a medium and heavy-duty zero-emission fleet regulation with the goal of achieving zero-emission truck and bus fleets by 2045 wherever feasible. Their current application priorities lie within certain market segments such as last mile delivery and drayage applications. 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, 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.

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.

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.
- *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 and launch Phase II: Smart Charge Rewards Program.
- *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, Distribution, and Substation (see **Figure 2-19**). 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. We must also evaluate and increase our distribution system expansion targets in order to meet Electrification and LA100 Study goals.

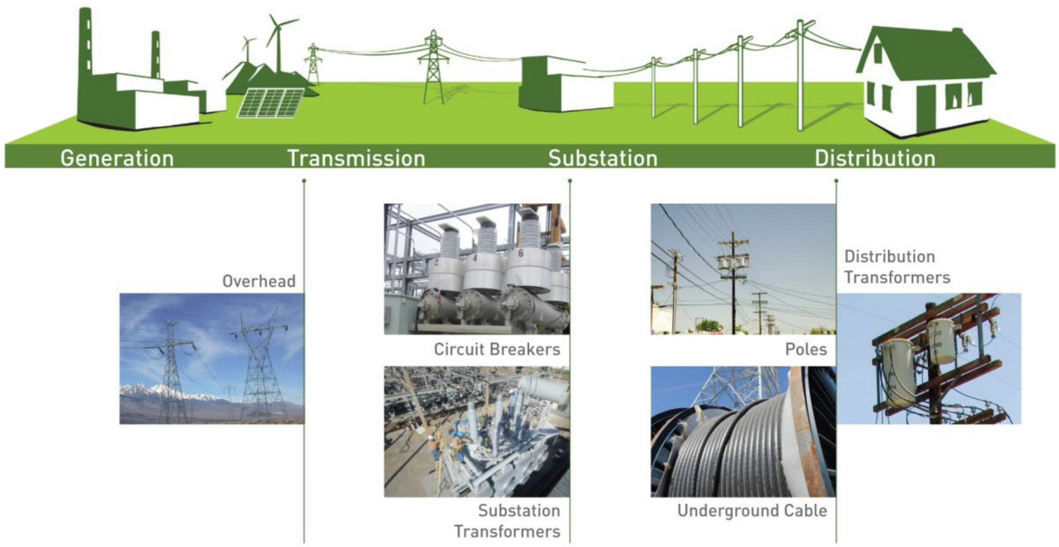


***Figure 2-19**. Power System infrastructure assets that provide electricity to customers.*

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

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

(b) Expedite restoring temporary repairs of equipment failures and target circuits that contribute heavily to LADWP's reliability indices

(c) Commit to proactive maintenance and effective capital improvements needed to expand system capacity and ensure continuance of service

(d) Achieve replacement cycles that align with the assets' respective life cycles, including the replacement of overloaded distribution transformers, worn underground cables, deteriorated overhead poles, and fatigued substation equipment.

The 2022 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 2022 PSRP Report Asset Recommended Replacement List.

2022 PSRP Asset Replacement Categories	
GENERATION	Generation Transformers (GSU & AUX) Major Inspections (Hydro, Pumps and Thermal)
TRANSMISSION	Maintenance Hole Lid Restraints
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

Overall, there has been a reduction in the number of outages since the inception of the PRP and PSRP. However, extreme weather conditions in recent years, coupled with aging infrastructure, have contributed to an increased number of outages during certain years. For example, rain, windstorms, and a station fire all led to an increased number of outages in 2017. A prolonged heat storm led to an increased number of outages in 2020.

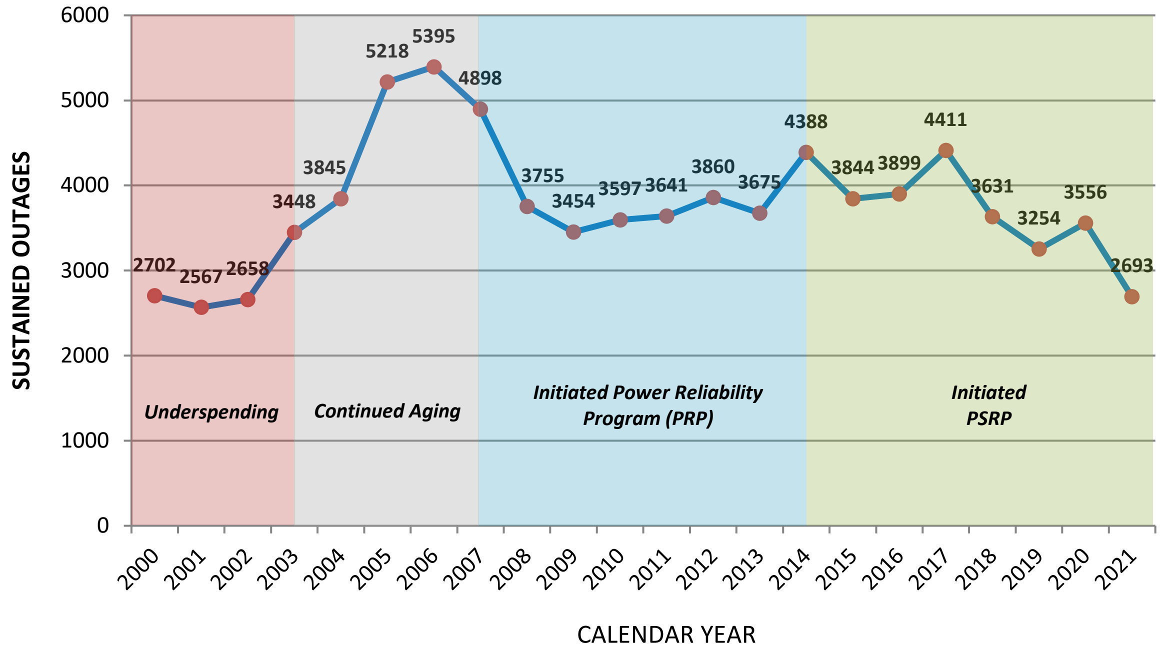


Figure 2-20. *Total sustained outages between January 2000 and December 2021.*

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 Ten-Year Transmission Assessment Plan in compliance with the North American Electricity Reliability Corporation (NERC) Compliance Enforcement Program. LADWP's 2022 Ten-Year Transmission Assessment Plan 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 Project

The Barren Ridge Renewable Transmission Project, completed in 2016, increases the capacity of the existing 230-kV Barren Ridge-Rinaldi transmission segment from 450 MW to approximately 1,700 MW. Barren Ridge provides customers access to approximately 1,000 MW of wind and solar power. The resources include, but are not limited to:

- 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.

This project also increases the transmission capacity to the Castaic Pumped Storage Power Plant and provides enhanced operational flexibility and integration of variable renewable energy.

Important components of the Barren Ridge Renewable Transmission Project are as follows:

- New Haskell Canyon Switching Station
- A new double-circuit 230-kV transmission line from the Barren Ridge Switching Station to the new Haskell Canyon Switching Station
- Expand the existing Barren Ridge Switching Station.

2.5.7.3 Pacific Direct Current Intertie (PDCI) Upgrade

LADWP, along with the other utilities participating in the Pacific Direct Current Intertie, have signed a letter of agreement with the Bonneville Power Administration (BPA) to implement an initial 120 MW capacity increase of the PDCI contingent on cost. In any case, BPA has committed to an extensive overhaul of Celilo HVDC Converter Station which requires coordination at the southern end of the high-voltage direct-current (HVDC) line at Sylmar HVDC Converter Station. BPA's Celilo upgrade project was placed in-service in January 2016. As a result of the Celilo upgrade, plans for an upgrade of the Filter Banks at Sylmar Converter Station were required. The objective of the Sylmar Filters Replacement Project was to replace the old AC and DC filters and upgrade the control system at Sylmar Converter Station East and West. LADWP issued a Notice to Proceed to ABB in January 2017 to commence the design process. Construction of the new AC Filters 3 and 4 began in January 2018 and was commissioned by December 2018. An LADWP Construction Crew, which built all the new switchyard equipment, mobilized to the site on November 1, 2017 to prepare it for construction activities and begin grading the AC filters 3 and 4 areas. ABB is responsible for upgrading the control system to the best available that ABB offers that is equivalent to or better than the control system at Celilo.

2.5.7.4 The Haskell Canyon-Olive Transmission Line Project

LADWP plans to reconnect the existing Power Plant 115-kV Transmission Lines 1 and 2 to the new Haskell Canyon Switching Station. Afterwards, we will replace existing double-circuit 115-kV towers with new 230-kV towers from the new Haskell Canyon Switching Station to the north side of the Los Angeles Basin transmission system. One 230-kV circuit will go 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 1,700 MW of renewables coming from Owens Valley. In the short-term horizon, we plan to change the circuit rating of Olive-Northridge, Haskell-Sylmar, and Haskell-Olive 230 kV lines in order to support 1,050 MW of renewables from Owens Valley.

2.5.7.5 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:

- 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
- Replacing Transformer Bank K and upgrading antiquated equipment 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 and Valley-Rinaldi 230 kV circuits.

2.5.7.6 Los Angeles Basin Projects

The annual Ten-Year Transmission Assessments consistently identified the Scattergood-Olympic 230 kV Cable A installation as an essential upgrade. Every year that passed exposed the increasing urgency for the installation as temporary improvements had decreasing benefits. LADWP decided to move forward with the project and began construction in 2012. The 15-mile long Scattergood-Olympic 230kV Cable A in the Westside was finalized and placed into service in 2018.

Other Los Angeles Basin projects include:

- Upgrading and disconnecting circuit breakers at Receiving Station-U and Receiving Station J.
- Replacing Transformer Banks E and F at Receiving Station K
- Installing 90 MVAR Reactors at RS-D and RS-E
- Reconductoring of the Rinaldi-Tarzana Line 1 and Line 2 230 kV Circuits.

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

2.5.7.7 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.

Figure 2-21 shows our major out-of-basin generation resources. Noteworthy is the fact that while LADWP customers represent roughly 10% of California's electrical load, approximately 25% of the state's total transmission capacity is owned by LADWP. LADWP also differentiates ourselves from our counterparts by continuing to operate as a vertically integrated electric utility. As a result, we own and operate our generation, transmission, and distribution resources rather than as a parent company with subsidiaries carrying out the various functions of the power supply chain.

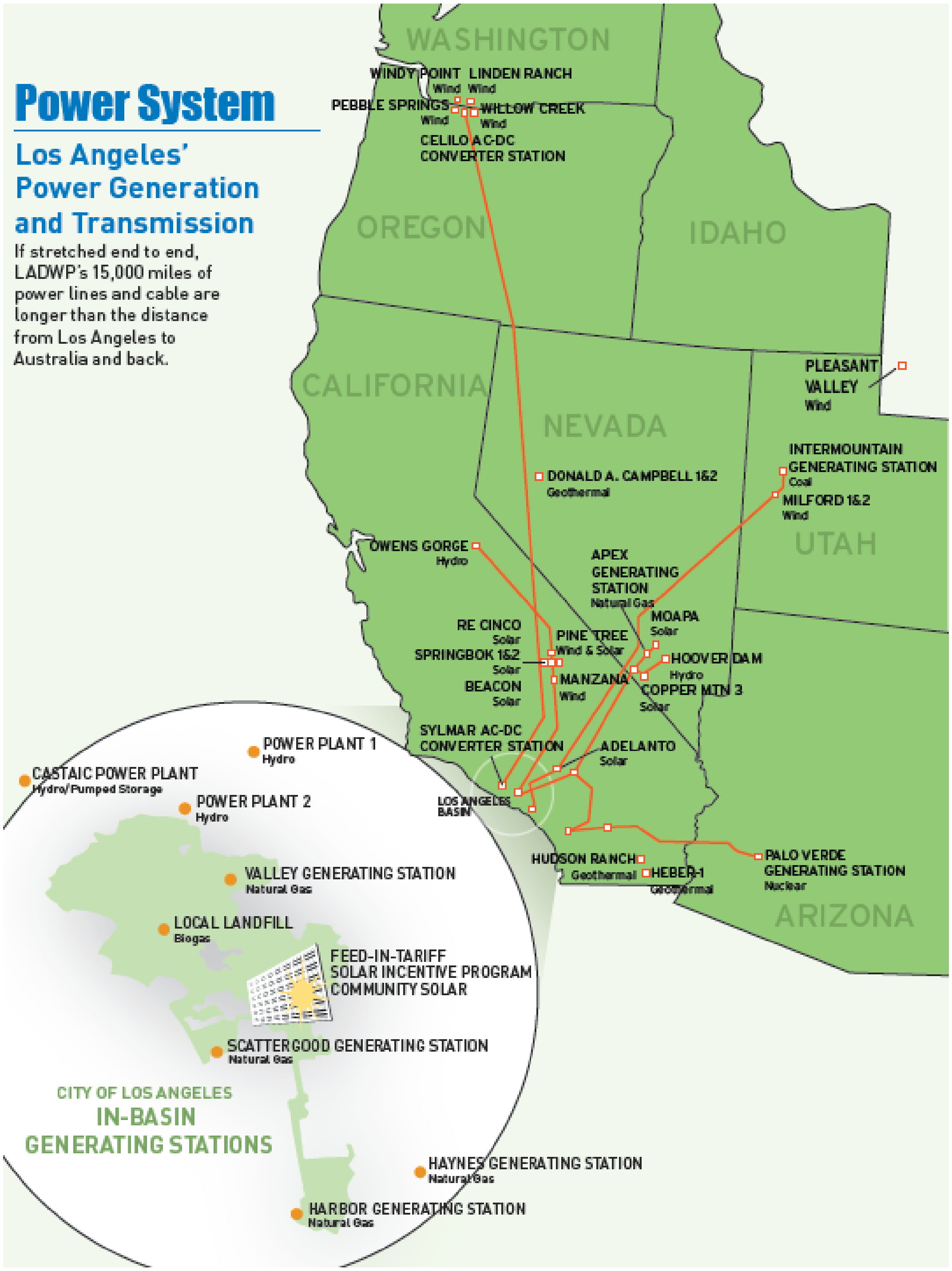


***Figure 2-21**. Major in-basin and out-of-basin generating stations and major transmission lines.*

2.5.8 Procuring Renewable Energy Resources

Initiatives that promote electricity generation from renewable resources support the goal of reducing GHG emissions and decreases LADWP's reliance upon fossil fuels.

California Senate Bill 2 (1X), which was passed in April 2011 and became effective December 10, 2011, required utilities to procure eligible renewable energy resources to meet an RPS goal of 33% by 2020. The following interim targets were as follows:

- Maintain at least an average of 20% renewables between 2011 and 2013
- Achieve 25% renewables by 2016
- Achieve 27% renewables by 2017
- Achieve 29% renewables by 2018
- Achieve 31% renewables by 2019
- Achieve 33% renewables by 2020.

California Senate Bill 350, which was passed in September 2015 and became effective October 7, 2015, requires utilities to achieve 50% eligible renewable energy resources by 2030. The following interim targets are as follows:

- Achieve 40% renewables by 2024
- Achieve 45% renewables by 2027
- Achieve 50% renewables by 2030 and maintain this level in all subsequent years.

SB 350 also requires both the energy efficiency of buildings and conservation savings of retail energy derived from electricity and natural gas end-uses double by 2030. The law also requires publicly owned utilities to establish annual targets for energy efficiency savings and demand reductions consistent with the statewide goal. In addition, electrical corporations must obtain approval from the California Public Utilities Commission for their programs and investments related to transportation electrification which includes electric vehicle charging infrastructure.

California Senate Bill 100, which was passed in August 2018 and became effective September 2018, increased California's RPS targets to 60% by 2030. The interim targets are as follows:

- Achieve 44% renewables by 2024
- Achieve 52% renewables by 2027
- Achieve 60% renewables by 2030 and maintain this level in all subsequent years.

SB 100 also requires that 100% of retail sales to end-use customers and power services to state agencies are derived from zero-carbon resources by December 31, 2045.

California Senate Bill 32 (signed into law on October 11, 2009) and SB 1332 (signed into law on September 27, 2012) requires LADWP to offer a tariff to eligible renewable electric generation facilities until we meet our 75 MW share of the statewide target. Despite the mandated 75 MW requirement, our current target is 135 MW. Through this tariff program, owners or operators of eligible renewable energy systems may sell their energy directly to LADWP. The purchase of this energy will include all environmental attributes, capacity rights, and renewable energy credits which applies towards our 60% renewables requirement.

California Senate Bill 859 (signed into law on September 14, 2016) requires LADWP to procure a proportionate share of 125 megawatts (14.3 MW) of cumulative rated capacity. The share ratio is based on our peak demand to the total statewide peak demand. This share of capacity must be derived from existing bioenergy projects that commenced operations prior to June 1, 2013 and are subject to terms of at least 5 years.

Former Governor Schwarzenegger signed the California Solar Initiative (CSI) outlined in SB 1, on August 21, 2006. The CSI mandated that all California electric utilities implement a solar incentive program by January 1, 2008. The goal of the CSI is 3,000 MW of net-metered solar energy systems over 10 years with an expenditure cap of $3.35 billion. Expenditures for local and publicly owned electric utilities shall not exceed $784 million. Our cap amount is $320 million, based on our servicing of 40% of the municipal load in the state.

The LADWP Board of Commissioners adopted a policy to achieve 20% renewables by 2010, and 33% by 2020. The Board and City Council have approved projects and long-term power purchase agreements that achieved the 20% RPS goal in 2010. The policy has been revised to incorporate SB 2 (1X) requirements. Further revisions to this policy are anticipated to maintain continued compliance with any applicable updates to state law and regulations.

On September 16, 2016, the Los Angeles City Council passed a motion directing LADWP to establish research partnerships with appropriate entities to determine the necessary investments needed to equitably achieve a 100% renewable energy portfolio. The motion also instructed LADWP to examine the impacts of a 100% renewable energy portfolio on the local economy and hiring programs as a result of renewable energy initiatives. Following the release of the groundbreaking LA100 Study results in March 2021, we began aligning our programs and priorities with the City of Los Angeles' accelerated goal of achieving a 100% carbon-free power grid by 2035. We are also striving to achieve the interim milestones of 80% renewable energy and 97% carbon-free energy by 2030. In addition to this Strategic Long-Term Resource Plan, we are working towards improving the equity of programs and services for all customers and residents of Los Angeles through the Equity Metrics Data Initiative.

SB 2 (1X) also set certain conditions regarding renewable energy contracts that began on or after June 1, 2010, as shown in **Table 2-7**.

***Table 2-7**. SB 2 (1X) category requirements for RPS energy contracts.*

Portfolio Content Category[1]	RPS % Target		
	Compliance Period 1 (1/1/2011 – 12/31/2013)	Compliance Period 2 (1/1/2014 – 12/31/2016)	Compliance Period 3 (1/1/2017 – 12/31/2020)
1	Minimum 50%	Minimum 65%	Minimum 75%
2	See footnote 2	See footnote 2	See footnote 2
3	Maximum 25%	Maximum 15%	Maximum 10%

[1]Categories are defined as follows:

Category 1 = Energy and RECs from eligible resources that

- Have the first point of interconnection with a CA balancing authority or with distribution facilities used to serve end users within a CA balancing authority area; or
- Are scheduled into a CA balancing authority without substituting electricity from another source. If another source provides real-time ancillary services to maintain an hourly import schedule into CA, only the fraction of the schedule actually generated by the renewable resource will count; or
- Have an agreement to dynamically transfer electricity to a CA balancing authority.

Category 2 = Firmed and shaped energy or RECs from eligible resources providing incremental electricity and scheduled into a CA balancing authority.

Category 3 = Energy or RECs from eligible resources that do not meet the requirements of category 1 or 2, including unbundled RECs.

[2]Remainder % of resources which are neither in Category 1 nor Category 3.

On August 30, 2013, the California Office of Administrative Law (OAL) approved the California Energy Commission's Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (RPS Regulations)[1]. These Regulations took effect on October 1, 2013.

In December 2013, we amended our Renewable Portfolio Standard Policy and Enforcement Program to comply with the requirements of SB 2 (1X) and the Regulations. However, our Policy continues to include various requirements that do not overlap with SB 2 (1X) or the Regulations. These additional requirements include provisions that give priority to renewable projects located within the City and set a minimum (at least 50%) ownership percentage of LADWP renewable energy resources.

On December 22, 2020, the CEC adopted revised RPS Regulations which modified the California Renewables Portfolio Standard Program as amended by SB 350, SB 1393, SB 100, and SB 1110. The revised regulations became effective on July 12, 2021 after approval by the Office of Administrative Law. Modifications included updating the minimum RPS procurement targets and implementing a major

[1] ***Enforcement Procedures for The Renewables Portfolio Standard for Local Publicly Owned Electric Utilities***. California Energy Commission, Efficiency and Renewable Energy Division. Available at: https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/rps-enforcement-regulations-publicly

provision from SB 350. The major provision pertains to long-term procurement of renewable resources requiring, beginning January 1, 2021, that at least 65% of RPS procurement must be acquired through contracts of 10 years or more, in ownership or ownership agreements.

The CEC verifies that POUs meet minimum RPS procurement requirements through the Procurement Quantity Requirement, the Portfolio Content Category and Balance Requirement, and the new Long-term Procurement Requirement. California law allows for the California Energy Commission to issue a notice of violation and correction, and the ability to refer all violations to the California Air Resources Board. Failure to meet the targets or comply with provisions of the RPS Regulations may result in significant penalties.

There are various challenges associated with adopting an increasing amount of renewable resources such as wind, solar, and geothermal. For example, we will need to obtain local and environmental permits for transmission and generation infrastructure. We must also ensure the reliable and cost-effective integration of large-scale wind, solar, or other renewable projects. Also, adequate sites for geothermal generation are scarce, and geothermal projects require large capital expenditure, impose exploration risks, and have limited transmission line access.

2.5.9 Early Coal Divestment and Transformation of the Intermountain Power Project from Coal to Green Hydrogen

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.

Contractual arrangements for power from IPP will expire on June 15, 2027. 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 by July 1, 2025 (two years before the legal deadline). Although we are planning to complete the conversion by 2025, the commercial operation date may be delayed due to circumstances beyond our control. We are one of thirty-six purchasers of IPP energy.

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"). The 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.

2.5.10 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).

2.5.11 Hydropower

LADWP's large hydroelectric facilities include the Castaic Pumped-storage Hydroelectric Plant and a portion of the capacity of the 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.

2.5.12 Current Renewable Energy Projects

Our renewable resources total over 3,463 MW of existing and planned capacity, and they consist of wind, small hydro, solar, biogas, and geothermal resources.

Here is an outline of our existing renewable energy projects by resource type:

2.5.12.1 Wind

- Linden
- Pebble Springs
- Pine Tree
- PPM Wyoming
- Willow Creek
- Windy Flats
- Milford I
- Milford II
- Manzana
- Red Cloud

2.5.12.2 Small Hydro

- Aqueduct, Owens Valley, and Owens Gorge projects
- Water System Hydro
- North Hollywood
- Sepulveda

2.5.12.3 Solar

- Community Solar/Utility-Built Solar In-Basin/Net Energy-Metered Solar
- Feed-in-Tariff
- Adelanto

- Pine Tree
- Copper Mountain 3
- Moapa Southern Paiute
- Beacon Solar Project
- Springbok 1, 2, and 3
- RE Cinco

2.5.12.4 Geothermal

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

Additional renewable energy comes from market purchases.

2.6 Local Generation in the Los Angeles Basin

LADWP owns and operates four generating stations within the Los Angeles Basin. Additionally, there is an extensive buildout of rooftop solar within LADWP's service territory.

2.6.1 Power System Background

Our Power System was designed and has continued to rely upon our 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 L.A. 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.

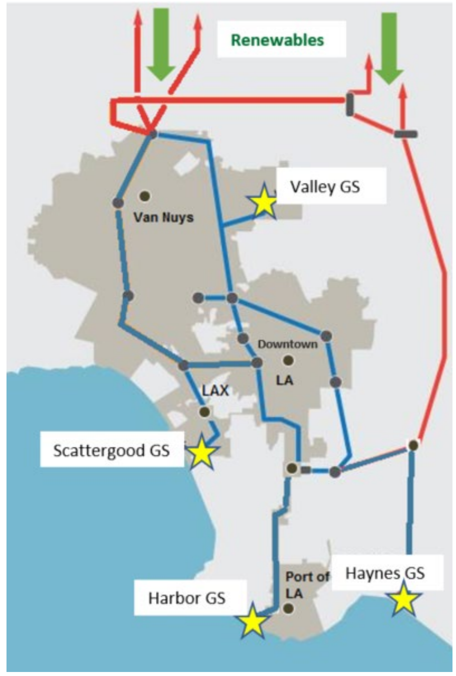


***Figure 2-22**. Simplified LADWP Power System with in-basin generating stations.*

The need to retain firm, dispatchable, in-basin capacity at the coastal generating stations is paramount in order to meet reliability criteria, demand and reserve power, resource adequacy, contingency reserves, replacement reserves, and system stability.

This requirement was rigorously 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 our local system would satisfy the in-basin generation capacity requirements. However, as a result of the dense urbanization in Los Angeles, the local transmission lines are "locked in." That is to say that there is minimal real estate for adding or moving transmission lines. Alternatively, LADWP is planning various local transmission system upgrades to reduce the needed in-basin generation capacity while still 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 our local generating units to maintain reliability without any major concerns. Upon completion, these planned upgrades will relieve some of the transmission stresses on our system. However, continuing to develop local capacity will remain a priority in order to preserve system reliability and resilience.

2.6.2 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 renewables and energy storage as well as the planned transmission upgrades. Long-term, dispatchable power generation is critically relied upon during stressed grid conditions which 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 and upgrades which can be exacerbated if they coincide with periods of high electricity demand.

Saddleridge Fire

The Saddleridge Fire was a wildfire that occurred near the northern San Fernando Valley beginning on October 10, 2019. Tragically, the wildfire resulted in one fatality and eight injuries and burned 8,799 acres. During this event, LADWP's import capabilities were significantly impacted. LADWP lost all capacity through the Pacific DC Intertie and Barren Ridge Corridor. Additionally, two out of five lines were lost on the Victorville-Los Angeles transmission path. As such, LADWP dispatched 1,889 MW from the in-basin generating stations to compensate for the lost capacity in the major transmission paths. Thankfully, the wildfire occurred on a relatively low-load day. Customer blackouts would have likely occurred if the load was materially higher. 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, the National Renewable Energy Laboratory (NREL) confirmed that LADWP's in-basin generation fleet needs a significant amount of firm capacity—otherwise known as dispatchable capacity—in order to maintain a reliable power supply. 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 in the range of hours to weeks.

To meet the local firm-capacity requirements, NREL's models deployed significant amounts of renewably-fueled gas turbines[2] 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 even when they are not running.

2 NREL defined "renewably fueled gas turbines" as turbine-generators that are assumed to use a market-purchased fuel, including but not limited to, hydrogen, biodiesel, biogas, ethanol, and synthetic natural gas.

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 2019, LADWP put new 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 the recent 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 within the path of the fires.

The green hydrogen-fueled capacity requirements for each in-basin generating station are provided in the **Table 2-8** below. Effectively, these are the carbon-free capacity requirements for each facility to ensure system reliability and resilience. With the exception of the planned phase-in of green hydrogen fuel at Intermountain Power Project, new hydrogen-fueled combustion turbines were not allowed prior to 2030. The findings from this scenario are particularly relevant because this achieves 100% carbon-free energy by 2035. This means that, by 2035, all natural gas-fueled generation would be either replaced or modified to run completely on a renewable fuel.

Table 2-8. *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**

2.6.3 Green Hydrogen as a Renewable Fuel

Green hydrogen is gathering strong momentum as a key enabler towards a clean energy transition. It has the potential to displace significant amounts of fossil fuels today—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 policy landscape especially at the federal level. In November 2021, the United States Congress passed the *Infrastructure Investment and Jobs Act*. This law allocates $8 billion for at least four regional clean hydrogen hubs, overseen by the Department of Energy (DOE) as part of its clean energy demonstration program. 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.

2.6.3.1 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 $(\frac{\text{X CO2}}{1\ kg\ H_2})$.[2] Quantifying the carbon intensity of clean hydrogen is important since the production tax credits are calculated on a sliding scale based on the lifecycle GHG emissions. For example, only clean hydrogen produced with lifecycle GHG emissions of 0.45 kilograms of CO2-equivalent or less will be eligible for the full production tax credit under the IRA. We are only interested in green, carbon-free, and electrolytically-produced hydrogen that meets these criteria.

2.6.3.2 Long Duration Energy Storage

Green hydrogen can be used as a form of chemical long-duration energy storage. Excess renewable generation can be used to power electrolyzers for the production of hydrogen, reducing curtailment. This conversion is commonly referred to in the industry as power-to-gas (P2G). The electrolyzers produce green hydrogen by splitting molecules of water (H_2O) into hydrogen (H_2) and oxygen (O_2). The separated hydrogen 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 system effectively constitutes a form of long-duration energy storage which is especially beneficial in systems with high amounts of variable renewable energy sources.

2.6.3.3 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 transportation applications where direct electrification is not suitable, as well as stationary fuel cells for power generation. These alternative applications do not utilize combustion. However, hydrogen-fueled gas turbines are heavily preferred over fuel cells in stationary power applications due to cost and technology development considerations. We do not consider fuel cells to be viable for bulk power generation at the existing in-basin facilities. With that said, distributed fuel cells may provide benefits across the service territory by relieving transmission constraints and provide an emissions-free, distributed generation solution for disadvantaged communities.

2.6.3.4 Green Hydrogen Request for Information

The state of the green hydrogen market and its lack of enabling technologies led us to author and publish a Request for Information (RFI) on this subject. Our goal was to gather information from the hydrogen industry to better understand the opportunities and technologies that may support our green hydrogen requirements. The RFI was advertised in August 2021 and closed in November 2021. A total of 36 submissions were received from companies spanning the complete green hydrogen value chain. LADWP continues to communicate with companies to retrieve the latest updates on technology development, capabilities, and challenges.

2.6.3.5 Alternative Renewable Fuels

While green hydrogen is the most promising renewable fuel to date, LADWP is also monitoring the development of potential alternative renewable fuels including renewable natural gas and biofuels. The viability of these renewable fuels—both technically and politically—is more uncertain than green hydrogen, but LADWP will continue to diligently monitor the development of alternative renewable fuels as we develop our long-term strategy for decarbonizing the local generation stations.

2.6.3.6 Implementation Feasibility Study

SLTRP modeling assumptions considered green hydrogen-fueled capacity to be in service at each generating station in a manner consistent with the LA100 Study requirements. The implementation feasibility of this significant buildout of hydrogen capacity was not within the scope of the LA100 Study. The green hydrogen-fueled units were assumed to use market-purchased green hydrogen, operationally similar to today's natural gas units in which the fuel is delivered directly to the generating stations.

In mid-2022, we began a study on the implementation feasibility of transforming the in-basin generating stations to green hydrogen, including a more detailed analysis of the pertinent risks and challenges that are involved with this transformational endeavor. We are planning to update its buildout assumptions for the next SLTRP to ensure system reliability throughout the transition to green hydrogen-fueled generation within the Los Angeles Basin. Among the many considerations of this study are the technological maturity of green hydrogen-fueled units, environmental and permitting challenges, project sequencing, and demolitions of retired units.

2.6.3.7 Challenges and Risks with Green Hydrogen

This section details the challenges and risks associated with the in-basin transition that are being considered in the implementation feasibility study.

2.6.3.8 Implementation Challenges and Risks

Table 2-9 lists some of the implementation challenges and risks associated with transforming LADWP's in-basin generation capacity to be derived from green hydrogen fuel.

***Table 2-9**. 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	Our OTC units must be retired no later than December 31, 2024 or 2029, depending on the facility. This regulatory deadline is firm and will result in up to 911 MW of lost capacity (Haynes Unit 8 will be retrofitted to eliminate once-through cooling). We are considering this significant loss of generation capacity as we plan this transition.
Technology Maturity	The technology needed to operate a turbine on 100% hydrogen is not commercially available yet, specifically the type of generating unit and combustion system LADWP requires. Turbine manufacturers are developing the enabling technologies and expect that such units will become commercially available by 2035 or sooner.
Infrastructure	As of right now, there is no local green hydrogen infrastructure in Los Angeles. A significant amount of infrastructure to support green hydrogen production, storage, and transportation will be required. These projects will be capital intensive and new pipelines will be difficult to permit, particularly in urban areas where local communities are unlikely to support bulk storage of hydrogen or its carriers. Hydrogen's low 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 the fuel can be reliably supplied to the generating stations.
Environmental and Permitting Requirements	The applicable environmental and permitting requirements are numerous and complex. Additionally, there are significant unknowns involved in the permitting process given that hydrogen-fueled gas turbines for electricity generation are a new endeavor. For example, it will be challenging to secure the emissions credits necessary that would allow for the deployment and operation of hydrogen-fueled gas turbines for air permitting. Air permitting will be especially difficult after the South Coast's Regional Clean Air Incentives Market (RECLAIM) program ends in 2025.
Personnel Needs	Transitioning the in-basin fleet to renewably-derived fuels will require more personnel—both internal to LADWP and outside

	contractors—for successful execution of the projects. Given current economy-wide labor shortages, there is a potential risk of insufficient personnel to support these transformative projects.
Space Constraints	Due to the dense urbanization in Los Angeles, all four in-basin generating stations are surrounded by residential communities and commercial properties with minimal room for future projects. Proper vetting of the possible site configurations for new hydrogen-fueled capacity—with consideration of project sequencing—is required. Space constraints preclude onsite production and storage of hydrogen at the generating stations.

Outage Coordination	As we upgrade the local transmission system with the integration of renewables to bolster system reliability, Grid Operations will rely more on the local generating units to support the system as transmission lines become temporarily unavailable. Additionally, the generating units must be taken out of service periodically for routine maintenance. If existing units are modified to operate on hydrogen, this will require the units to be made unavailable during the modification period. A significant effort to coordinate the necessary transmission and generation outages is required in order to ensure the system reliability during the transitional period.
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. Our buildout includes simultaneous generation projects, retrofits, and demolitions while maintaining the electricity system's reliability. Additionally, project schedules will need to be accelerated in order to meet the rapidly approaching clean-energy targets.
Public Perception	The general public has concerns about the potential negative impacts of hydrogen. There are concerns around the generation of NOx during hydrogen combustion and the indirect greenhouse gas effects hydrogen may have if it were to leak. Safety risks are also of concern to the public. We believe these concerns can be addressed with proper engineering solutions. Multiple industries have used hydrogen for over one hundred years and as a result the safety designs, technologies, and procedures are well established. Additionally, a groundbreaking demonstration was completed in 2022 that showed hydrogen can be combusted safely in a gas turbine with no adverse effects to emissions or reliability. The demonstration achieved as high as a 45% hydrogen fuel blend with a balance of natural gas.

2.6.3.9 Operational Challenges and Risks

Table 2-10 lists the operational risks and challenges associated with transforming our in-basin capacity for the usage of green hydrogen fuel.

***Table 2-10**. List of operational challenges and risks associated with green hydrogen.*

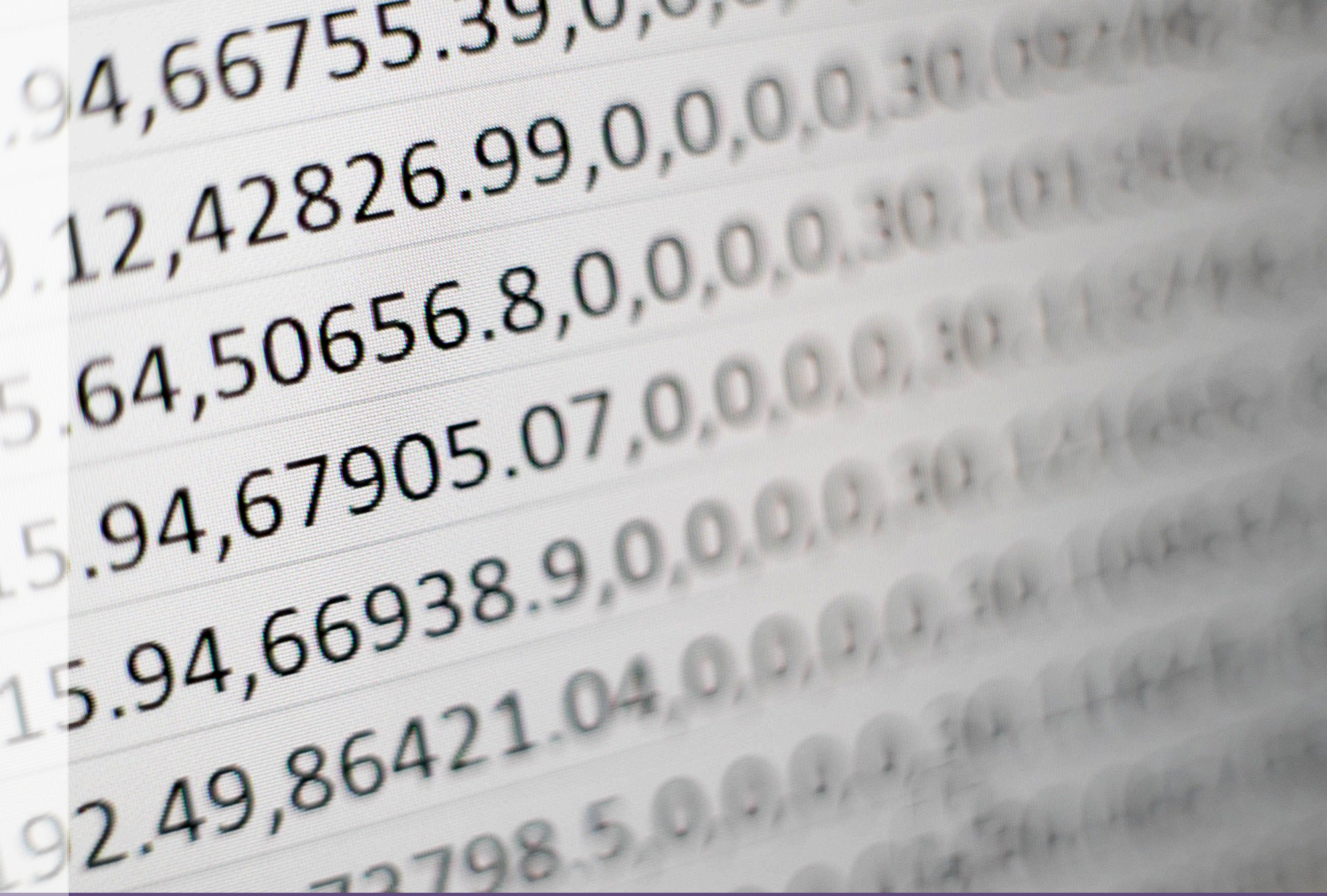
Area of Consideration	Description
Fuel Supply and Storage	A continuous supply of green hydrogen is necessary for the reliable operation of the generating units. On-site storage is impractical due to the low volumetric energy density of gaseous hydrogen and space constraints at our facilities.
Fuel Cost	Green hydrogen is currently expensive to produce, transport, and store. Renewable and low-carbon hydrogen are currently more expensive to produce than fossil-based hydrogen and are much more expensive to use than fossil fuels. While the exact cost will depend on market conditions and infrastructure pricing, the evolving policies in support of green hydrogen are expected to place significant downward pressure on fuel prices.
Backup Fuel	LADWP currently uses diesel as an emergency backup fuel that is stored onsite at three of our in-basin generating stations. It is unclear at this time whether diesel fuel may be used on hydrogen-optimized combustors. Natural gas may not be a suitable backup fuel to hydrogen since natural gas supplies and infrastructure would likely be vulnerable to the same risks as hydrogen resources and facilities.
Safety	Hydrogen has a larger flammability range and a lower ignition point compared to natural gas. Additionally, hydrogen is odorless, it has the propensity to leak, and its flame is colorless. These properties of hydrogen make it difficult to handle while increasing safety risks. LADWP personnel must be trained to handle the significant quantities that would be involved. Various industries have used hydrogen for over one hundred years and they have established effective safety designs, technologies, and procedures. It should also be noted that LADWP has safely worked with hydrogen at all of our in-basin generating stations for decades because hydrogen is used to cool the electrical generators. There is a significant supply maintained at each plant.

Water Constraints	Due to the worsening drought conditions and the increasing importance of water conservation, we are looking to minimize the need for water at the generating stations wherever possible. We recognize that the production of electrolytic hydrogen requires significant amounts of water. This is a challenge that must be addressed to ensure that the transition to green hydrogen is a viable strategy for decarbonization.

2.6.3.10 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* - Rather than build 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 our units to only enable anywhere from 15–35% hydrogen by volume, with the remaining balance of the fuel being natural gas. The scope of the modifications would include 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 our newer generating units instead of our older units that are reaching the end of their 30 year design life (the typical operating life for a gas-turbine power block) . We will continue to evaluate the viability of these modifications on the newer units to best utilize existing assets. At this time, the development of existing units into 100% hydrogen gas powered units poses significant challenges. Since we intend to utilize in-basin hydrogen-fueled generating capacity as a back-up resource to our renewable energy and energy storage, the economics of retrofitting units versus building new units will need to be considered when selecting the least-expensive but adequate resource portfolio.
- *New Electric Transmission Corridors* - While the development of new transmission lines over land is extremely limited due to L.A.'s dense urbanization, subsea transmission lines are in service around the world and could expand our available solution set. Adopting such a technology would allow us to add new transmission corridors along the coastal side of the grid which may alleviate the capacity requirements at each of the in-basin generating stations.
- *New Generation Technologies* - LADWP currently holds the idea that hydrogen-fueled gas turbines will be the key technology that will enable decarbonization at the in-basin generating stations. However, LADWP understands that other technologies are in development which might reduce the need for hydrogen-fueled gas turbines at our local generating stations. Generation technologies that could potentially augment gas turbines in the foreseeable future include advanced hydrogen fuel cells and offshore wind turbines. We will continue to monitor the development of these alternatives as part of our strategy for decarbonizing the in-basin generation fleet.



CHAPTER 3

MODELING INPUTS, ASSUMPTIONS, AND METHODOLOGY

KEY TAKEWAYS:

- Modeling for integrated resource planning is largely driven by input forecasts and assumptions for parameters such as customer demand, fuel costs, and generating resource characteristics.
- The comprehensive modeling process is comprised of various phases such as capacity expansion, reliability, and production cost modeling.
- Modeling stochastically allows planners to more accurately account for renewable energy resources with variable weather-driven output, and helps simulate future conditions that may fall outside of historical observations.

CONTENTS

DEFINITIONS

ATB	Annual Technology Baseline
BE	Building Electrification
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
Case(s)	Reference Case, Case 1, Case 2, and Case 3
CEC	California Energy Commission
CNM solar	Customer Net-Metered solar
Core Case(s)	Cases modeled under their default defined assumptions
DERs	Distributed Energy Resources
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
FSO	Financial Services Organization
GHG	Greenhouse Gas
GWh	Gigawatt-hours
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
LA100 Study	The Los Angeles 100 Percent Renewable Energy Study
LADWP	Los Angeles Department of Water and Power
LOLH	Loss of Load Hours
Monte Carlo analysis	A model that uses repeated random sampling to obtain numerical results
NEL	Net Energy for Load
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PSRP	Power System Reliability Program
Reference Case	SB 100
RPS	Renewable Portfolio Standard
SLTRP	Strategic Long-Term Resource Plan

STS	Southern Transmission System
TE	Transportation Electrification
WECC	Western Energy Coordinating Council

3 Modeling Inputs, Assumptions, and Methodology

One of the critical components of the Power Strategic Long-Term Resource Plan (SLTRP) is computer modeling. The 2022 Power SLTRP Assumptions Package establishes the 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 2022 Power SLTRP, the planning horizon stretches from 2022 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, in order 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 a Monte Carlo analysis, 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 enough generation resources are built or procured to guarantee there are no more than 2.4 hours per year, on average, when customer demand exceeds generation resources. The 2.4 loss of load hours (LOLH) 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 burn, and emissions. This chapter goes into more detail about how modeling assumptions were established and the reason behind their usage. These results are in Chapter 4 of this document.

3.1 Model Input Assumptions

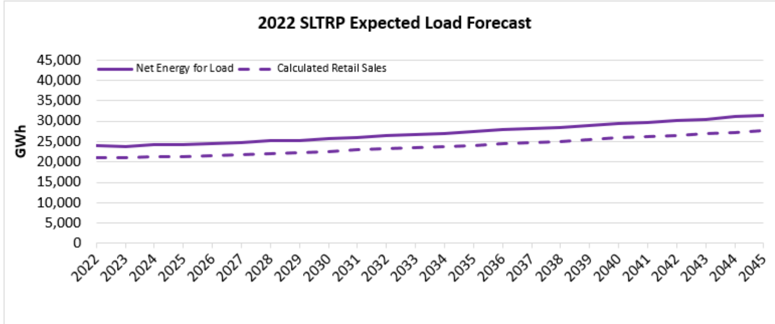
This section describes the input assumptions used in the computer modeling process.

3.1.1 Load Forecast

The SLTRP Expected Load Forecast (**Figure 3-1**) is derived from the LADWP 2021 Retail Electric Sales and Demand Forecast assembled by LADWP's Financial Services Organization (FSO). The IRP Group convened with different program groups to derive projections for varying levels of load modifiers and distributed energy resources (DERs) such as transportation electrification, building electrification, customer net-metered solar, and energy efficiency, to then apply them to the SLTRP cases as defined. The SLTRP Expected Load Forecast is shown for the Reference Case (SB 100), which assumes "Reference" levels of transportation electrification (TE), building electrification (BE), customer net-metered solar (CNM solar), and energy efficiency (EE). The SLTRP expected loads for Cases 1, 2, and 3, are similar to this, but vary slightly based off the respective levels of load modifiers and DERs per each Case's definition. The SLTRP Expected Load Forecast (adjusted per each Case's DER levels) is used for all Core Cases, which is a term used to refer to the Cases when modeled under their default defined assumptions, as opposed to sensitivity conditions; however, "High" and "Low" bookends of the load forecast are also explored in load sensitivity studies.

2022 SLTRP Expected Load Forecast
Reference Case (SB 100)
Assumes "Reference" Levels of Electrification and Distributed Energy Resources

Calendar Year	Net Energy for Load	Calculated Retail Sales
2022	23,911	21,041
2023	23,786	20,932
2024	24,306	21,390
2025	24,290	21,376
2026	24,512	21,570
2027	24,696	21,732
2028	25,122	22,108
2029	25,349	22,307
2030	25,725	22,638
2031	26,022	22,900
2032	26,443	23,270
2033	26,716	23,510
2034	27,012	23,771
2035	27,407	24,118
2036	27,966	24,610
2037	28,167	24,787
2038	28,487	25,068
2039	28,920	25,450
2040	29,427	25,896
2041	29,765	26,193
2042	30,086	26,476
2043	30,510	26,849
2044	31,039	27,314
2045	31,391	27,624



Notes:
1. SLTRP Net Energy for Load is derived from the SLTRP Gross Load (inclusive of transportation & building electrification), by reducing from it the expected contributions of Customer Net-Metered Solar (CNM Solar) and Energy Efficiency (EE). An extra 12% energy savings bonus is applied to both CNM Solar and EE, since they do not incur transmission losses due to being located at the load center.
2. SLTRP Calculated Sales are derived by reducing the SLTRP Net Energy for Load by 12%, the estimated amount of total average transmission & distribution (T&D) system losses.
3. The SLTRP carbon-free cases (Case 1, 2, 3) use the same SLTRP Gross Load, but vary in SLTRP Net Energy for Load and SLTRP Calculated Sales due to different levels of distributed energy resources. These distributed energy resoures include building electrification, customer net-metered solar, and energy efficiency.

***Figure 3-1**. 2022 SLTRP Expected Load Forecast. Net Energy for Load (NEL) and Calculated Retail Sales projections.*

3.1.2 Load Modifiers

***Table 3-1**. 2022 SLTRP Load Modifier Projections. Forecasts for transportation electrification, building electrification, customer net-metered solar, and energy efficiency.*

CY	Transportation Electrification		Building Electrification		Customer Net-Metered Solar			Energy Efficiency		
	Reference	High	Reference	High	Reference	High	Highest	Reference	High	Highest
2022	198	287	0	2	85	104	126	304	304	304
2023	288	505	0	6	179	220	271	463	466	667
2024	456	791	0	13	264	342	428	782	789	1,099
2025	579	1,117	0	24	346	467	599	1,084	1,117	1,516
2026	747	1,483	0	40	428	579	768	1,366	1,454	1,919
2027	930	1,922	0	62	511	695	933	1,628	1,795	2,292
2028	1,151	2,414	0	90	594	815	1,108	1,874	2,137	2,639
2029	1,362	2,956	0	129	678	939	1,294	2,106	2,476	2,972
2030	1,622	3,541	0	182	762	1,066	1,486	2,319	2,808	3,291
2031	1,823	4,166	1	250	845	1,195	1,683	2,511	3,119	3,596
2032	2,037	4,810	7	333	928	1,324	1,885	2,678	3,410	3,875
2033	2,235	5,486	12	430	1,009	1,455	2,086	2,832	3,689	4,142
2034	2,448	6,188	18	544	1,090	1,585	2,285	2,989	3,963	4,405
2035	2,648	6,911	24	673	1,170	1,714	2,471	3,139	4,222	4,652
2036	2,858	7,505	30	817	1,248	1,840	2,648	3,283	4,473	4,893
2037	3,060	8,165	36	977	1,324	1,961	2,815	3,420	4,707	5,115
2038	3,269	8,825	42	1,152	1,398	2,076	2,972	3,546	4,920	5,312
2039	3,472	9,485	47	1,342	1,470	2,185	3,119	3,661	5,118	5,494
2040	3,681	10,145	53	1,548	1,539	2,289	3,253	3,769	5,303	5,666
2041	3,892	10,805	59	1,769	1,605	2,389	3,376	3,872	5,468	5,824
2042	4,102	11,465	65	2,022	1,668	2,484	3,489	4,010	5,631	5,983
2043	4,312	12,125	71	2,311	1,728	2,573	3,591	4,146	5,798	6,146
2044	4,523	12,785	76	2,641	1,785	2,657	3,686	4,241	5,956	6,300
2045	4,733	13,445	82	3,019	1,841	2,737	3,771	4,335	6,115	6,455

Notes:
1. All values are in GWh.
2. All values are cumulative and baselined to 2021 values.

The Reference Case, and Case 1, 2, and 3, were defined with different levels load modifiers, as shown above (**Table 3-1**). These four categories (TE, BE, CNM, and EE) are considered “load modifiers”, as they affect electric consumption, measured in units such as gigawatt-hours (GWh). Both TE and BE modify the load by increasing it whereas TE and BE decrease the load.

For the Core Cases, which used an “Expected” load forecast, the TE levels were fixed at “Reference” across all Cases, while other load modifiers changed per scenario definition (i.e. Case 3 had more CNM Solar and EE than Case 1 and Case 2).

3.1.3 High and Low Load Sensitivities

The “High” load and “Low” load sensitivities shown in **Figure 3-2** and depicted as retail sales in **Figure 3-3** are for Case 1 and Case 2. They are derived from each Core Case’s respective levels of distributed energy resources per their case definitions (both Core Cases are defined to have the same level of DERs). For the “High” load sensitivity, high levels of transportation electrification were assumed to be substantially realized in the late 2020s, such as to drive the annual average increase in retail sales above two percent from 2022 through 2045. For the “Low” load sensitivity, the base demand consumption was modeled as slightly declining, such that with the effect of energy efficiency and customer net-metered solar, the average annual decrease in retail sales was above two percent from 2022 through 2030 before beginning to flatten out. The SLTRP Net Energy for Load (**Figure 3-2**) represents the projected load that remains after subtracting the contributions of customer net-metered solar and energy efficiency, for which LADWP will have to ensure a sufficient resource supply exists after taking into consideration transmission and distribution losses from the generation source to the end customer. The SLTRP Calculated Retail Sales (**Figure 3-3**) results from reducing the SLTRP net energy for load by 12% to strip out the inclusion of transmission and distribution losses. Currently, the California Energy Commission’s (CEC) and SB 100’s RPS percentage is defined with respect to retail sales; hence it is critical to discern the difference between net energy for load and retail sales.

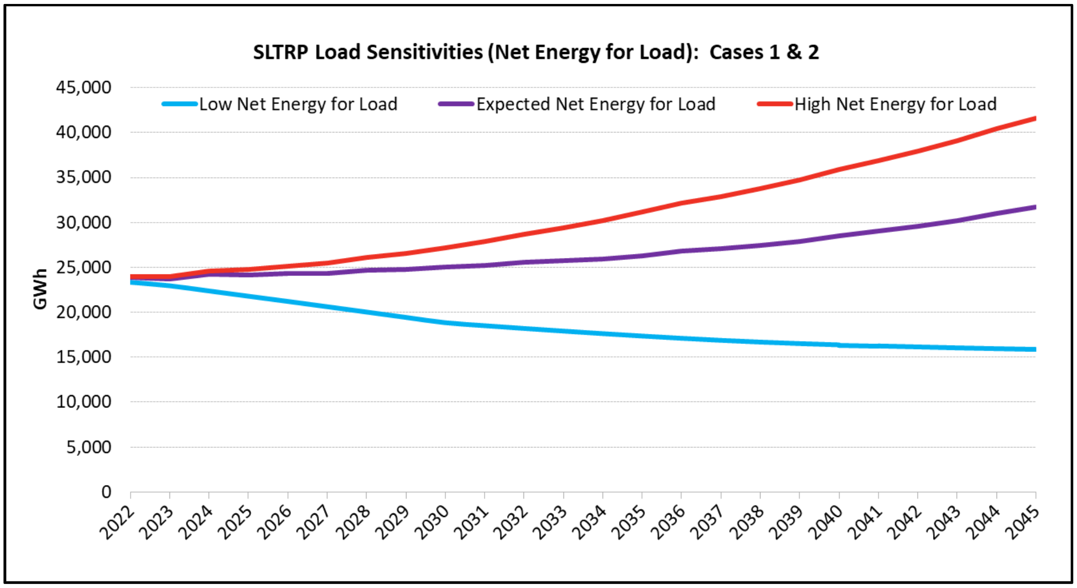


***Figure 3-2**. 2022 SLTRP High and Low Load Sensitivities: Net Energy for Load. Case 1 and Case 2.*

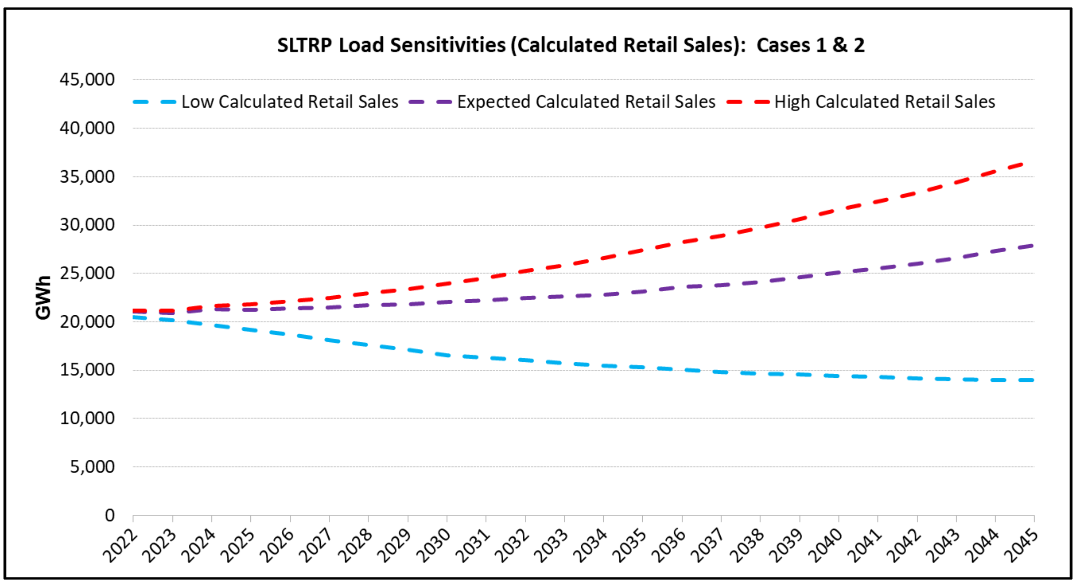
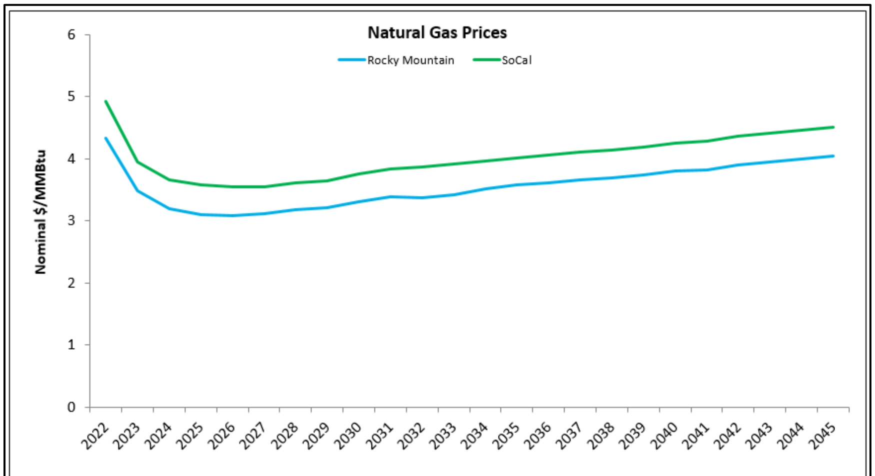


***Figure 3-3**. 2022 SLTRP High and Low Load Sensitivities. Depicted are the calculated retail sales for Case 1 and Case 2.*

3.1.4 Natural Gas Pricing

The two main natural gas regional price indices used for the SLTRP modeling are Rocky Mountain and So Cal (**Figure 3-4**). These “expected” price estimates used for modeling the Core Cases were developed using Platts market data.



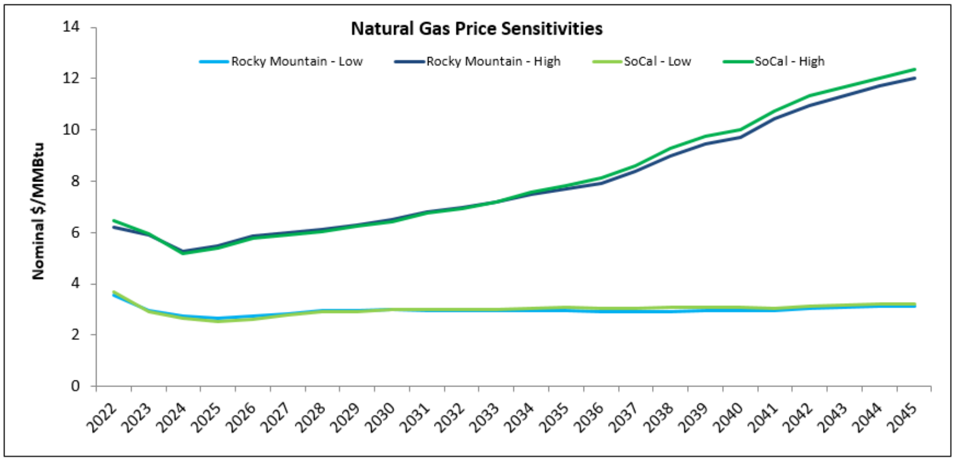
Notes:

1. Updated from TRMT (Platts) using data pulled on 10/21/2021
2. Data from 2042-onwards was linearly extrapolated based on trailing fifteen years.

Figure 3-4*. 2022 SLTRP Expected Natural Gas Price Projections. Rocky Mountain and So Cal.*

"For the "High" load sensitivity, high levels of transportation electrification were assumed to be substantially realized beginning in the late 2020s, such as to drive the annual average increase in retail sales above two percent from 2022 through 2045."

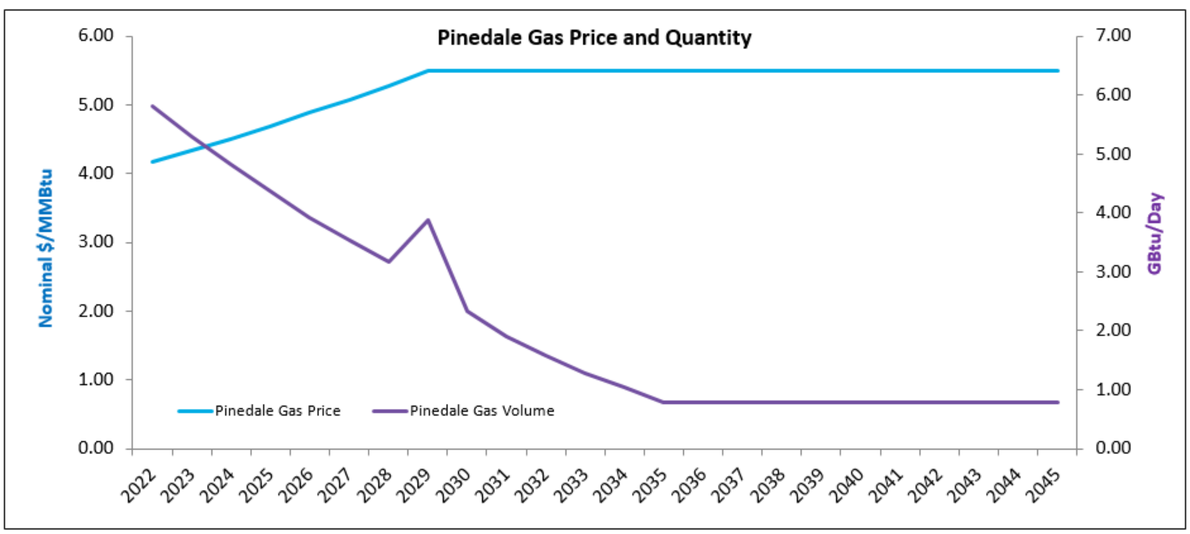
3.1.5 Natural Gas Price Sensitivities



Notes:
1. Updated from Hitachi Energy (f/k/a Ventyx) WECC Fall 2021 reference cases.
2. SoCal prices pulled from "Topock" Liquid Market Center.

Figure 3-5*. 2022 SLTRP Natural Gas High and Low (Sensitivity) Price Projections. Rocky Mountain and So Cal.*

Estimates for the low and high natural gas price sensitivities (**Figure 3-5**) were developed using the Hitachi Energy Fall 2021 Reference Cases for the Western Energy Coordinating Council (WECC) region. These trends were used in the SLTRP price sensitivities that studied portfolio cost impacts as a result of different bookends for commodity prices.



Notes:
1. Last updated on 12/06/2021.
2. Uptick in 2029 gas production was confirmed to be correct by the Natural Gas Group.

Figure 3-6*. 2022 SLTRP Natural Gas Price Assumptions. Pinedale.*

Pinedale natural gas allocations (**Figure 3-6**) are among the first used, as they are relatively inexpensive. After utilizing Pinedale natural gas allocations, the generators switch to natural gas fuel from Rocky Mountain and SoCal allocations.

3.1.6 LADWP Generation Ratings Sheet

***Table 3-2**. 2022 LADWP Generation Ratings and Capacities of Power Resources Document. Ratings for LADWP-owned generating facilities. Information as of January 28, 2022.*

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	6/15/1953	37,500	37,500	36,500	[A] 110,500	46,400
Middle Gorge Power Plant	1	5/11/1952	37,500	37,500	37,500		
Control Gorge Power Plant	1	4/01/1952	37,500	37,500	37,500		
Pleasant Valley Power Plant	1	2/05/1958	4,000	3,200	2,700	2,700	[E][F] 5,400
Big Pine Power Plant	1	7/29/1925	4,000	3,200	3,050	[B] 3,050	
Division Creek Power Plant	1	3/22/1909	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	7/18/1927	3,500	2,800	2,500	[D] 3,600	
	2	7/18/1927	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] 41800
	3	4/16/1917	11,720	9,962	11,000		
	4	5/21/1923	12,500	10,625	12,000		
	5A	4/09/1987	25,000	22,500	27,000		
San Francisquito Power Plant 2	1	7/06/1919	17,500	14,000	0		
	2	8/07/1919	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	6/03/1921	2,500	2,000	2,000	2,000	
Sawtelle Power Plant	1	6/05/1986	711	640	650	650	
North Hollywood Pumping Station	1PT2	1/01/1993	2,025	1,800	1,800	4,300	[L] 4,300
	1PT3	1/01/1993	2,025	1,800	1,800		
	3T1	1/01/1993	584	500	500		
	3T2	1/01/1993	231	200	200		
TOTAL HYDROELECTRIC						204,880	97,900

IN-BASIN THERMAL							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
			(kVA)	(kW)			
Harbor Generating Station	1	7/11/1973	100,400	85,340	73,000	[O] 426,000	425,000
	2	7/09/1974	100,400	85,340	73,000		
	5	7/13/1976	93,750	75,000	60,000		
	10	6/16/1977	71,176	60,500	44,000		
	11	12/16/1977	71,176	60,500	44,000		
	12	8/11/1978	71,176	60,500	44,000		
	13	1/27/1972	71,176	60,500	44,000		
	14	10/22/1922	71,176	60,500	44,000		
Haynes Generating Station	1	9/02/1962	270,000	229,500	222,000	[P] 1,614,200	[Q] [R] 1,512,000
	2	4/07/1963	270,000	229,500	222,000		
	8	1/25/2005	311,000	264,350	250,000		
	9	1/25/2005	215,000	182,750	162,500		
	10	1/25/2005	215,000	182,750	162,500		
	11	6/11/2013	127,282	108,190	99,200		
	12	6/12/2013	127,282	108,190	99,200		
	13	6/12/2013	127,282	108,190	99,200		
	14	6/19/2013	127,282	108,190	99,200		
	15	6/12/2013	127,282	108,190	99,200		
	16	6/12/2013	127,282	108,190	99,200		
Scattergood Generating Station	1	12/07/1958	192,000	163,200	105,000	[S] 778,250	[T] 742,000
	2	7/01/1959	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	8/09/2015	125,765	106,900	102,000		
	7	9/23/2015	125,765	106,900	102,000		
Valley Generating Station	5	8/17/2001	71,176	60,500	44,000	555,000	[U] 532,000
	6	9/04/2003	215,000	182,750	155,000		
	7	9/09/2003	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	3,211,000

EXTERNAL ENERGY RESOURCES							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
			(kVA)	(kW)			
Intermountain Generating Station	1	6/09/1986	991,000	950,000	900,000	1,202,000	[V] 1,202,000
	2	4/30/1987	991,000	950,000	900,000		
Palo Verde Nuclear Generating Station	1	1/30/1986	1,559,100	1,413,190	1,333,000	386,690	[W] 380,410
	2	9/19/1986	1,559,100	1,413,190	1,336,000		
	3	1/19/1988	1,559,100	1,413,190	1,334,000		
Apex Generating Station	1A	3/28/2014	239,000	203,150	168075	577,500	[X][Y] 482,600
	1B	3/31/2014	239,000	203,150	168,075		
	STG	3/28/2014	264,000	237,600	229,879		
Hoover Power Plant	(Energy purchased from WAPA through Sep. 2067) [Z]					496,000	267,594
TOTAL EXTERNAL ENERGY RESOURCES						2,662,190	2,332,604

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	6,906,504
California Department of Water Resources (CDWR) Entitlement [AA]	(120,000)	(39,607)
TOTAL NET CAPACITY OF THE SYSTEM	7,385,520	6,866,884

WIND, SOLAR, AND ENERGY STORAGE							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPACITY[(2)] (kW)	NET MAXIMUM PLANT CAPACITY[(3] (kW)	NET DEPENDABLE PLANT CAPACITY[(4)] (kW)
			(kVA)	(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	6/30/2012	800	800	800	10,000	2,800
Pine Tree Solar Power Plant	1-17	3/15/2013	500	500	500	8,500	2,380
Beacon Battery Energy Storage System	1-13	8/01/2018	2,083	1,695	1,667	[AB] 20,000	[AB] 20,000
TOTAL WIND, SOLAR, AND ENERGY STORAGE						223,500	69,580

Notes:

1. *Power sources included are LADWP's wholly-owned and operated in-basin gas-fired thermal, pump storage, small hydro (excluding North Hollywood Power Plant), wind (Pine Tree, Linden), and solar (Pine Tree, Adelanto) generation, and battery storage (Beacon). Also included are the following specific jointly-owned and operated power sources acquired through power purchase agreements or entitlements: coal-fired (Intermountain), nuclear-fueled (Palo Verde), gas-fired (Apex) thermal generation, and large hydro generation (Hoover). Renewable power purchase agreements (PPAs), market power purchases, and distributed generation are not included.*
2. *Maximum Unit Capacity can be attained only when the weather and equipment are simultaneously at optimum conditions. Hydro power plants' Maximum Unit and Plant Capacity are values based on historical data or benchmarking values based on water flow through the turbine. Thermal units Maximum Unit and Plant capacities were provided by Unit Guide sheets.*
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 thermal 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 2016-2020 where ambient temperatures exceeded 80 degrees Fahrenheit. The NDC for Scattergood Generations 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 NCD for SGS, Unit 1 was calculated utilizing available data during peak day conditions from 2016-2020. 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 provided in the 2020 Unit Guide Sheet for summer. The plant NCD for the PPAs reflect their associated agreements with LADWP.*

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 they could not 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 1.3 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. Extensive damage was found to the impeller sections of the turbine in Haiwee, Units 1 and 2. ETR for Haiwee is June 30, 2021.*

F. *Maximum unit and plant capacities are provided 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 9375 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 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-delate configuration. One of the three transformers was removed because dissolved gases were detected. Unit 2 is out of service for a generator overhaul, with an expected ETR of April 1, 2022. Plant has no black start capability.*

J. *Foothill Power Plant Rated Output is 8800 kW but is limited to 8600 kW due to maximum flow through the penstock of 275 cfs. Plant has no black start capability.*

K. *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 1265 MW at normal 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 capability.

- *L.* *North Hollywood Pump Station, Turbine 3T1 is rated for two different speeds (500 kW and 200 kW0*
- *M.* *Castaic Power Plant's Net Maximum 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 1265 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 3 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 the Angeles Tunnel. Unit 7 is unavailable as a generator and synchronous condenser with an ETR of 12/31/2022. Unit 5 is unavailable from January 4 – December 4, 2021 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 Net Maximum Unit Capacity of 595.2 MW is attained when all six units are running as this is when the lowest average auxiliary power is being drawn per unit.*
- *Q.* *The NDC for HnGS, Units 1 and 2 is limited due to high stator temperatures in the boiler feed pump motors.*
- *R.* *HnGS Net Dependable Plant Capacity includes operating Units 9 and 10 with duct burners running.*
- *S.* *SGS, Unit 2 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 a 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 and 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 may be less than 1,202 MW due to muni's and co-op's recallable entitlement. 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.* *SCCPA 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 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 of FY19-20 was approximately 39.61 MW.*

The LADWP Generation Ratings and Capacities of Power Sources (**Table 3-2**) 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.

3.1.7 In-Basin Generation & Energy Storage Projects (by 2030)

***Table 3-3**. 2022 SLTRP In-Basin Generation & Energy Storage Projects by 2030. Bulk-level generation and standalone energy storage.*

Generation

Project	New Capacity (MW)	Target Comercial Operation Date
Haynes Unit 8 Cooling System Retrofit	565	5/14/2027
Scattergood Hydrogen-Ready Capacity	346	4/1/2029
Valley Units 1–4 Demolition	—	8/31/2025

Energy Storage

Project	New Capacity (MW)	Energy (MWh)	Duration (hr)	Target Comercial Operation Date
Beacon II LDES	50	500	10	12/31/2026
RS-X Li-Ion	60	240	4	12/31/2027
Valley Flow	55	290	5.3	12/31/2029
Scattergood Flow	50	300	6	6/15/2030

The projects shown above reflect planned projects at in-basin generating stations by 2030 (**Table 3-3**), and they are included in all three Core Cases (Case 1, 2, 3), as well as the Reference Case (SB 100).

Beacon 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, while one remains in reserve. When the reserve unit is in operation, the net maximum plant capacity does not increase.

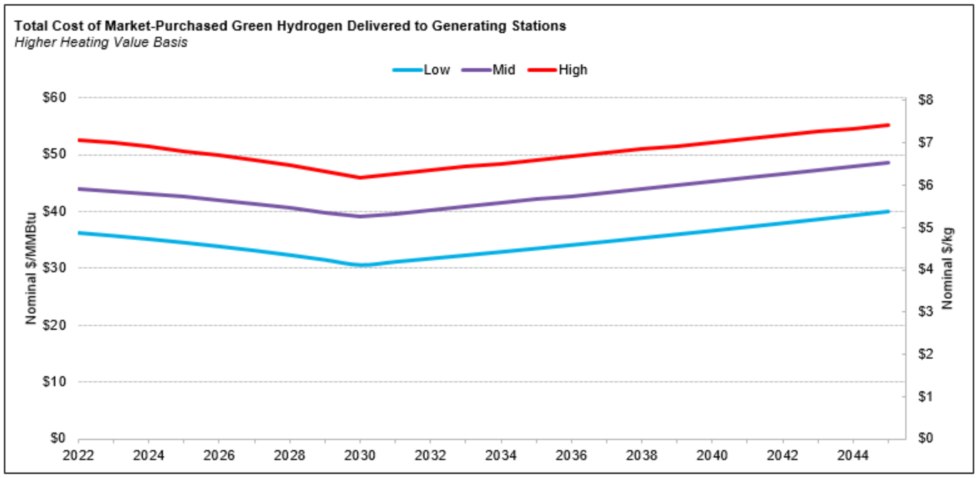
3.1.8 In-Basin Green Hydrogen Transformation for Carbon-Free Cases (2030-2045)

***Table 3-4**. 2022 SLTRP In-Basin Green Hydrogen Electric Generation Projects, 2030-2045.*

Capacity Buildout (MW)	Calendar Year															
	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Harbor 2032			257													
Haynes 2032			762													
Scattergood 2034					342											
Valley 2035						398										
Scattergood 2038									58							
Harbor 2040											291					
Haynes 2041												69				
Harbor 2043														354		
Valley 2045																494
Total Cumulative Capacity	0	0	1,019	1,019	1,361	1,759	1,759	1,759	1,817	1,817	2,107	2,176	2,176	2,530	2,530	3,024

The schedule above shows an estimated timeline for the buildout of in-basin green hydrogen capacity at LADWP's four in-basin generating stations (**Table 3-4**). These capacity buildouts were derived from the LA100 Study's findings that in-basin firm and dispatchable generating capacity is needed for LADWP to maintain a reliable and resilient power system while increasing energy generation to meet the increasing load demand from electrification. In-basin firm and dispatchable generation is crucial for transmission reliability in the face of extreme events like wildfires, where we would lose the ability to import large amounts of renewable energy through its major transmission corridors. All three of the SLTRP Core Cases (Case 1, 2, 3) assume the green hydrogen generating capacity buildouts as shown above.

3.1.9 Green Hydrogen Fuel Price



Notes:
1. Fuel cost estimates are for the fuel "delivered," which includes transportation/tolling charges to bring the fuel to the generating stations.
2. These price assumptions apply for the portions of market-purchased green H2 assumed at the in-basin generating stations and Intermountain Power Project (separate from and in addition to any self-produced H2).
3. These prices were adapted from BloombergNEF references.

***Figure 3-7**. 2022 SLTRP Market-Purchased Green Hydrogen Fuel Price Projections.*

The price projections shown above (**Figure 3-7**) reflect estimates for green hydrogen fuel purchases from the market in the future. For this planning cycle and modeling iteration, the required in-basin green hydrogen fuel was assumed to be purchased from the market, as the technical details for storage and production within the basin are still under investigation. Also, for this planning cycle and modeling iteration, only 50 percent of the Intermountain Power Project's green hydrogen fuel requirements are assumed to be met through market-purchased hydrogen starting 2035. The remaining 50 percent would come from our plans to self-produce green hydrogen with excess renewable energy. The price assumes the green hydrogen is "delivered" to the generating stations, thus this includes the production of supply, storage, and transportation of green hydrogen. All modeling of the SLTRP Core Cases assume the "Mid" green hydrogen price. The sensitivities on price commodities use the "High" and "Low" prices, respectively.

3.1.10 Hoover and Small Hydro

The projections shown below are for the estimated annual generation produced by Hoover Power Plant, a large hydroelectric generating facility, and small hydroelectric generating facilities located in the Owens Gorge, in the Owens Valley, and along the Los Angeles Aqueduct (**Table 3-5**). These projections reflect the latest information regarding the ongoing drought conditions in the Western United States.

***Table 3-5**. 2022 SLTRP Large and Small Hydroelectric Generation Projections. Hoover Power Plant, Owens Gorge, Owens Valley, L.A. Aqueduct.*

Hoover		
	Estimated GWh	
	Calendar Year **2021 GWh**	Calendar Year **2022 GWh**
Jan	35.96	28.27
Feb	32.39	33.24
Mar	58.01	55.36
Apr	63.60	56.03
May	58.79	54.64
Jun	53.94	51.54
Jul	49.27	45.43
Aug	45.81	42.48
Sep	40.80	37.61
Oct	34.40	27.87
Nov	38.32	34.03
Dec	30.90	29.80
	542.19	496.30

Small Hydro – Owens Gorge, Owens Valley, Aqueduct			
Estimated GWh			
CY	Total	FY	Total
2022	418	2022	436
2023	457	2023	477
2024	492	2024	507
2025	464	2025	421
2026	411	2026	402
2027	398	2027	393
2028	395	2028	396
2029	398	2029	400
2030	399	2030	398
2031	392	2031	387
2032	384	2032	381
2033	384	2033	387
2034	392	2034	397
2035	403	2035	409
2036	415	2036	420
2037	420	2037	420
2038	417	2038	413
2039	413	2039	413
2040	414	2040	414
2041	414	2041	414
2042	414	2042	413
2043	412	2043	410
2044	407	2044	405
2045	404	2045	404

3.1.11 Candidate Resource Prices

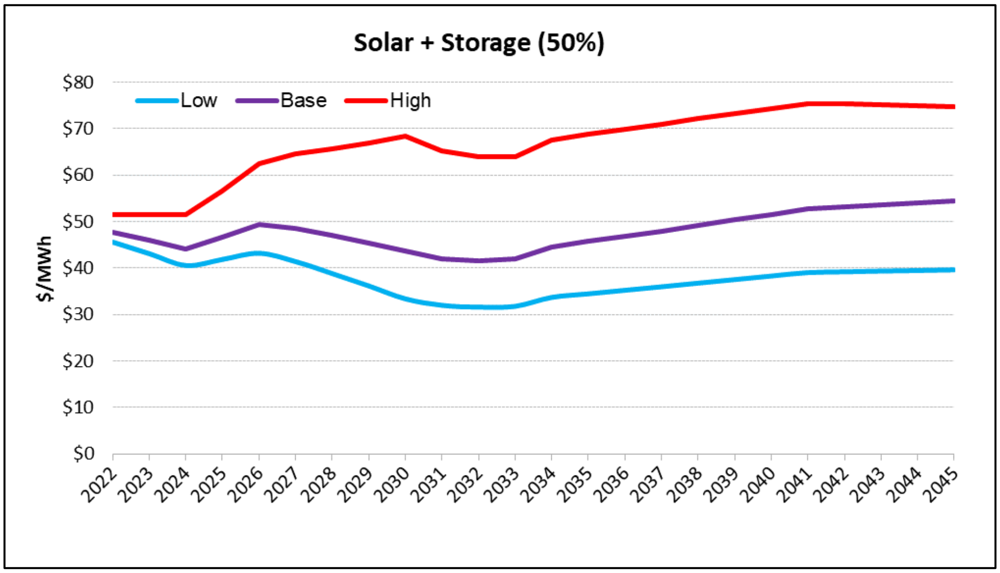


***Figure 3-8**. 2022 SLTRP Solar + Energy Storage Price Projections. Used for capacity expansion modeling; derived from the 2021 NREL ATB.*

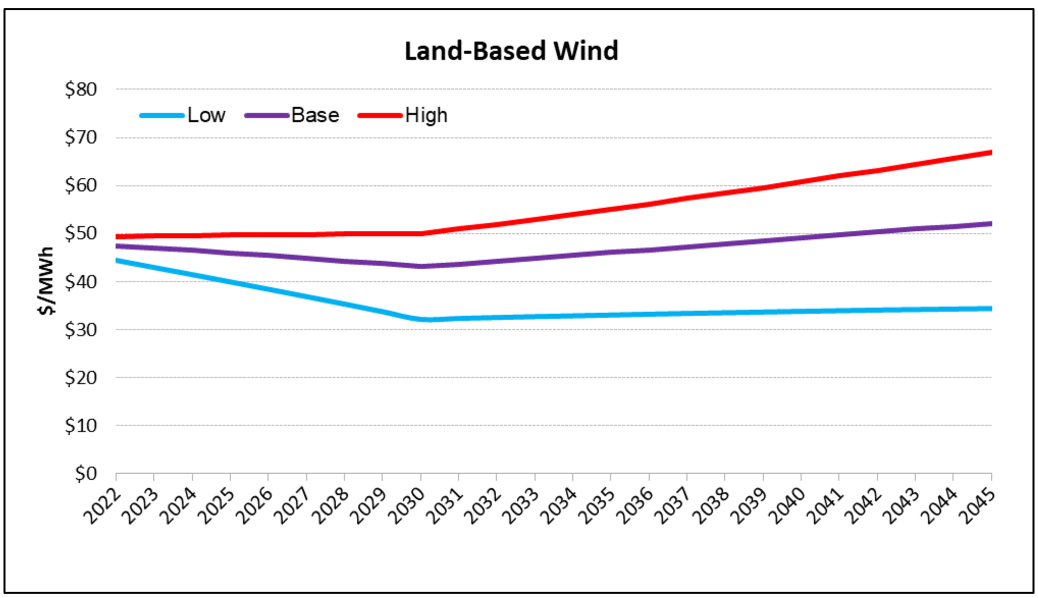


***Figure 3-9**. 2022 SLTRP Land-Based Wind Price Projections. Used for capacity expansion modeling; derived from the 2021 NREL ATB.*

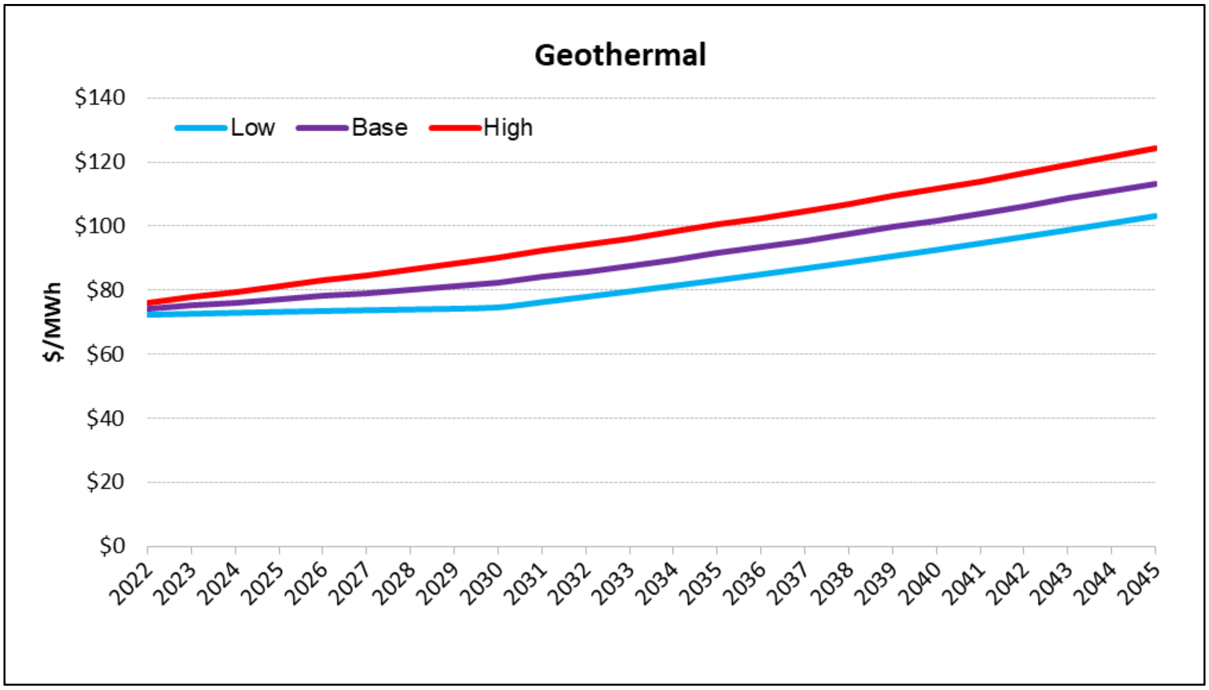


***Figure 3-10**. 2022 SLTRP Geothermal Price Projections. Used for capacity expansion modeling; derived from the 2021 NREL ATB.*

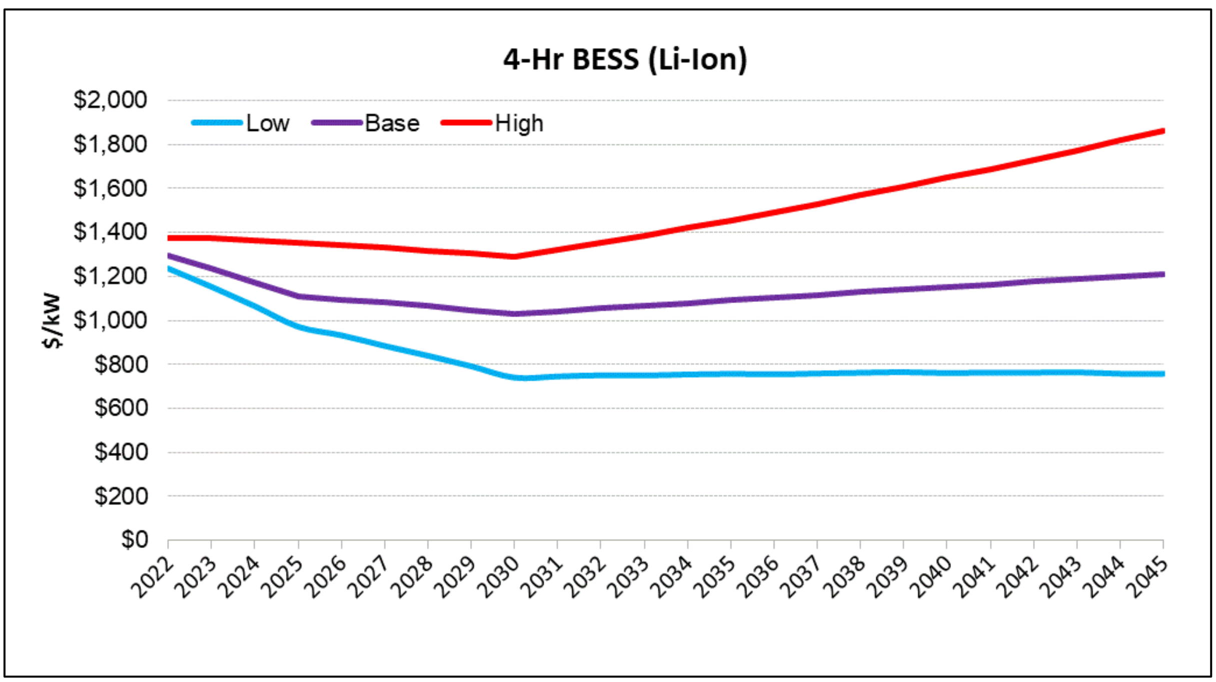


***Figure 3-11**. 2022 SLTRP 4-Hour Battery Energy Storage System (BESS) Price Projections. Used for capacity expansion modeling; derived from the 2021 NREL ATB.*

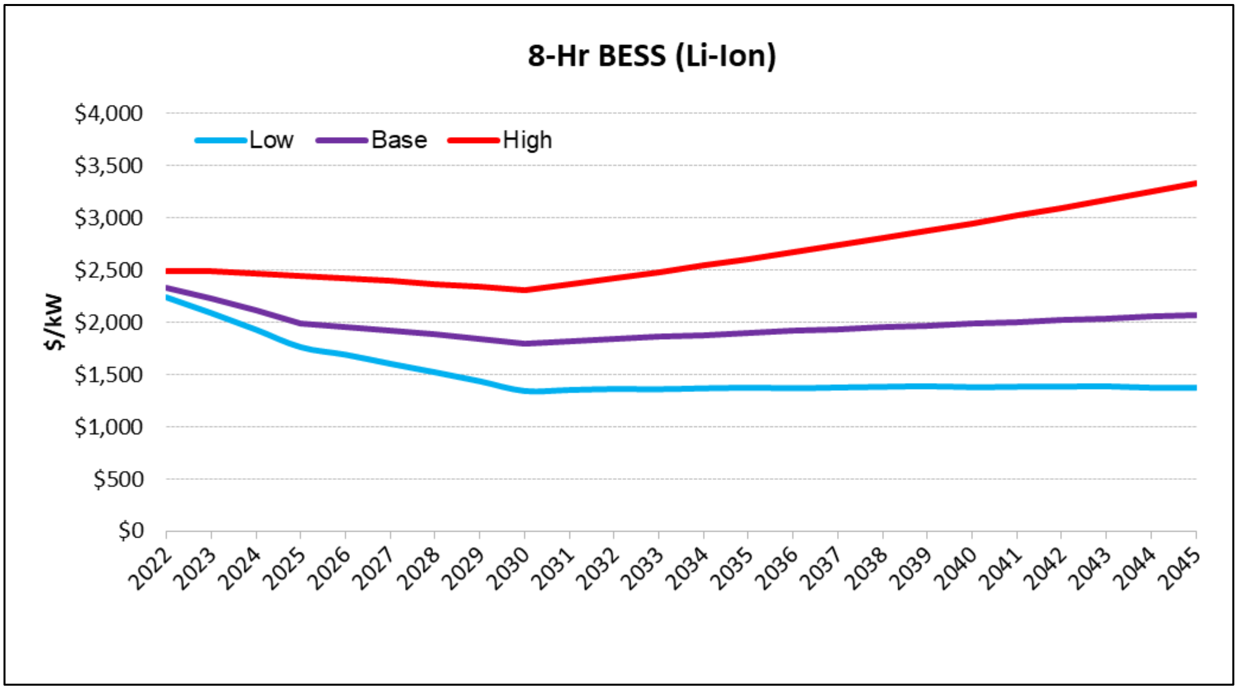


Figure 3-12*. 2022 SLTRP 8-Hour Battery Energy Storage System Price Projections. Used for capacity expansion modeling; derived from the 2021 NREL ATB*

The candidate resource prices shown above (**Figure 3-8** through **Figure 3-12**) represent the estimated average levelized cost of energy (LCOE) for solar + energy storage (assuming coupled energy storage at 50% size of the solar capacity), land-based wind, geothermal, as well as the average capital expenditure (CAPEX) per unit of 4-hour and 8-hour utility-scale energy storage capacity. These price projections were derived from the National Renewable Energy Laboratory's (NREL) 2021 Annual Technology Baseline (ATB), and they are also assumed for future generic resources that LADWP has not yet built or contracted for, as recommended by capacity expansion modeling. All the SLTRP Core Cases used the "Base" price projections, with the "High" and Low" price projections used for the price sensitivities, respectively.

3.1.12 Distributed Solar

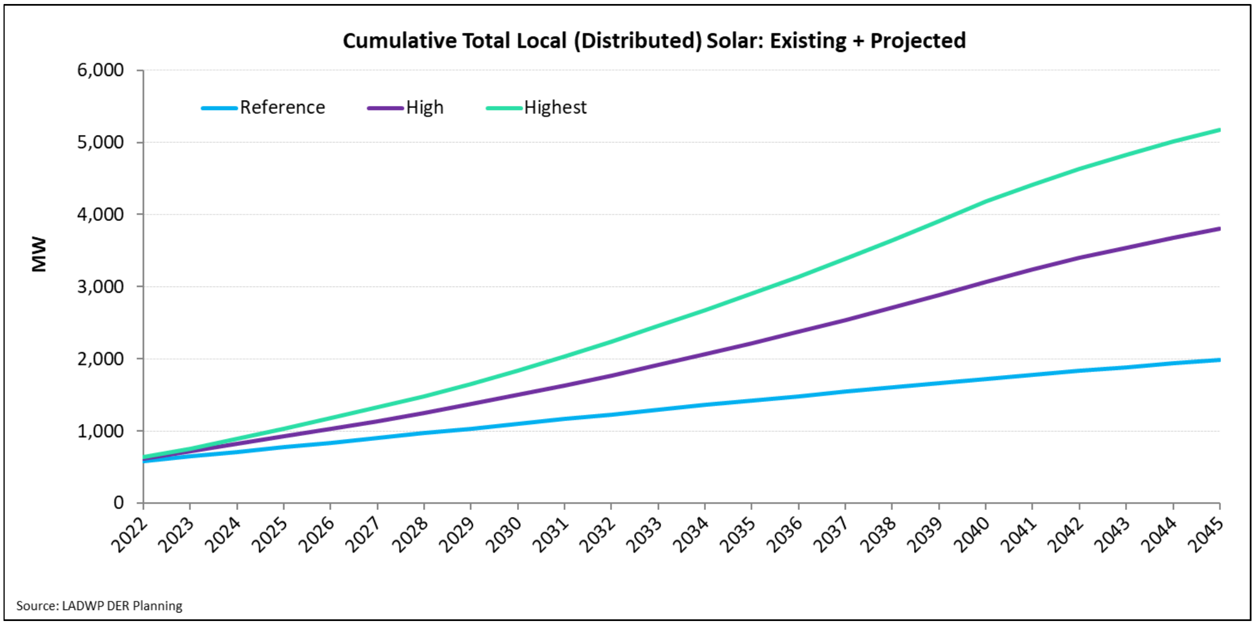
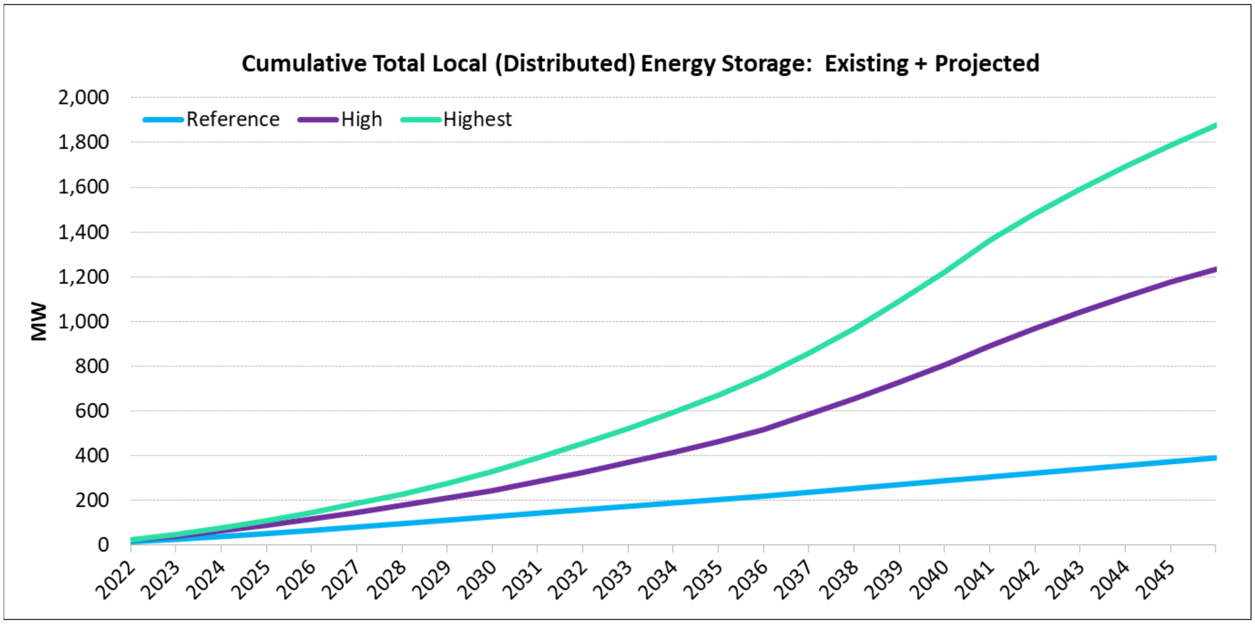


***Figure 3-13**. 2022 SLTRP Distributed Solar Capacity (MW) Projections. Cumulative, including existing installations.*

The SLTRP Core Cases assume different levels of local (distributed) solar, per their scenario definitions: "Reference" levels for the Reference Case (SB 100), "High" levels for Case 1 and Case 2, and "Highest" levels for Case 3 (**Figure 3-13**). The values shown above reflect cumulative total distributed solar capacity assumed for the SLTRP Cases, as provided by the LADWP Distributed Energy Resource Planning groups. However, we must upgrade our distribution system to alleviate circuit and feeder overloads and increase distribution system capacity to accommodate higher levels of DERs including distributed solar. It must also be noted that distributed solar adoption also depends on customer participation.

3.1.13 Distributed Energy Storage



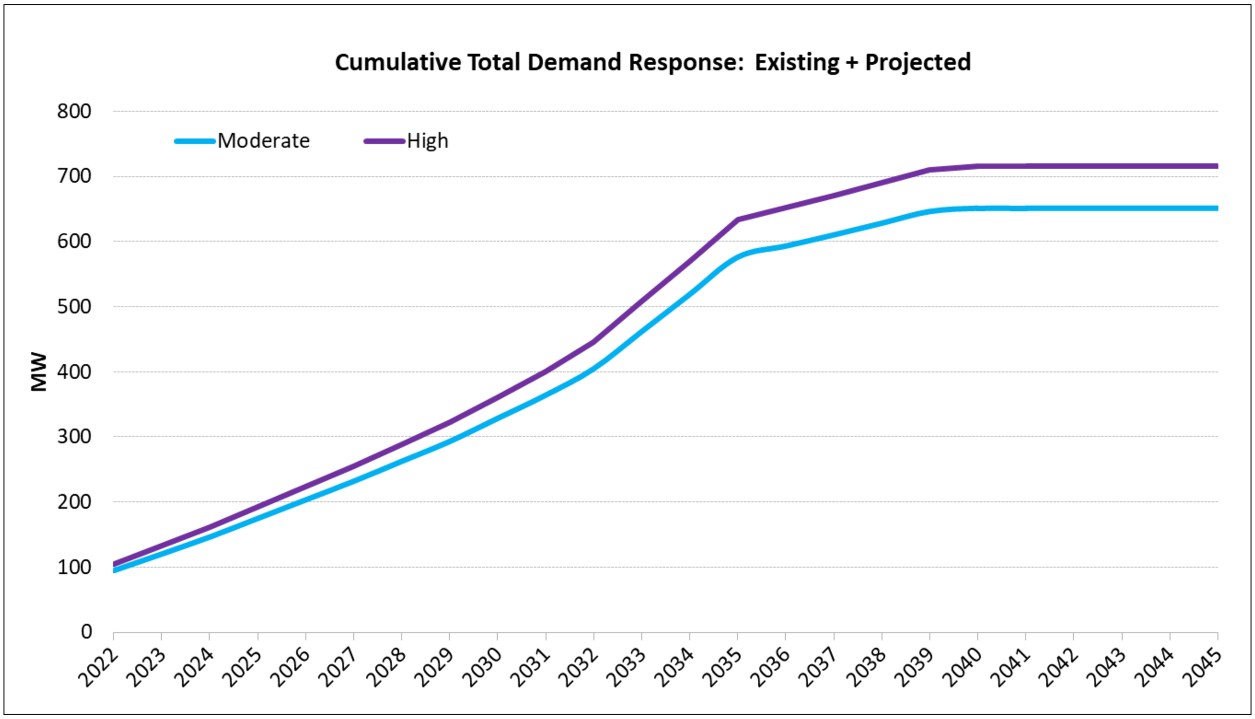
Notes:

1. These numbers reflect total distributed energy storage capacity, including both existing and projected installations.
2. Total Local Energy Storage is a sum of "FiT (Feed-in Tariff) + UBS (Utility-Built Solar) energy storage" and "Behind-the-Meter energy storage."
3. Last updated on 1/31/2022

***Figure 3-14**. 2022 SLTRP Distributed Energy Storage Capacity (MW) Projections. Cumulative, including existing installations.*

The SLTRP Core Cases assume different levels of local (distributed) energy storage, per their scenario definitions: "Reference" levels for the Reference Case (SB 100), "High" levels for Case 1 and Case 2, and "Highest" levels for Case 3 (**Figure 3-14**). It is expected that much of the distributed energy storage will be paired with distributed solar. The values shown above reflect cumulative total distributed energy storage capacity that was assumed for the SLTRP Cases, as provided by the LADWP Distributed Energy Resource Planning groups. However, upgrades to the distribution system to alleviate circuit and feeder overloads, as well as increasing distribution system capacity, will be necessary to accommodate higher levels of DERs, including distributed energy storage. It must also be noted that distributed energy storage adoption also depends on customer participation.

3.1.14 Demand Response



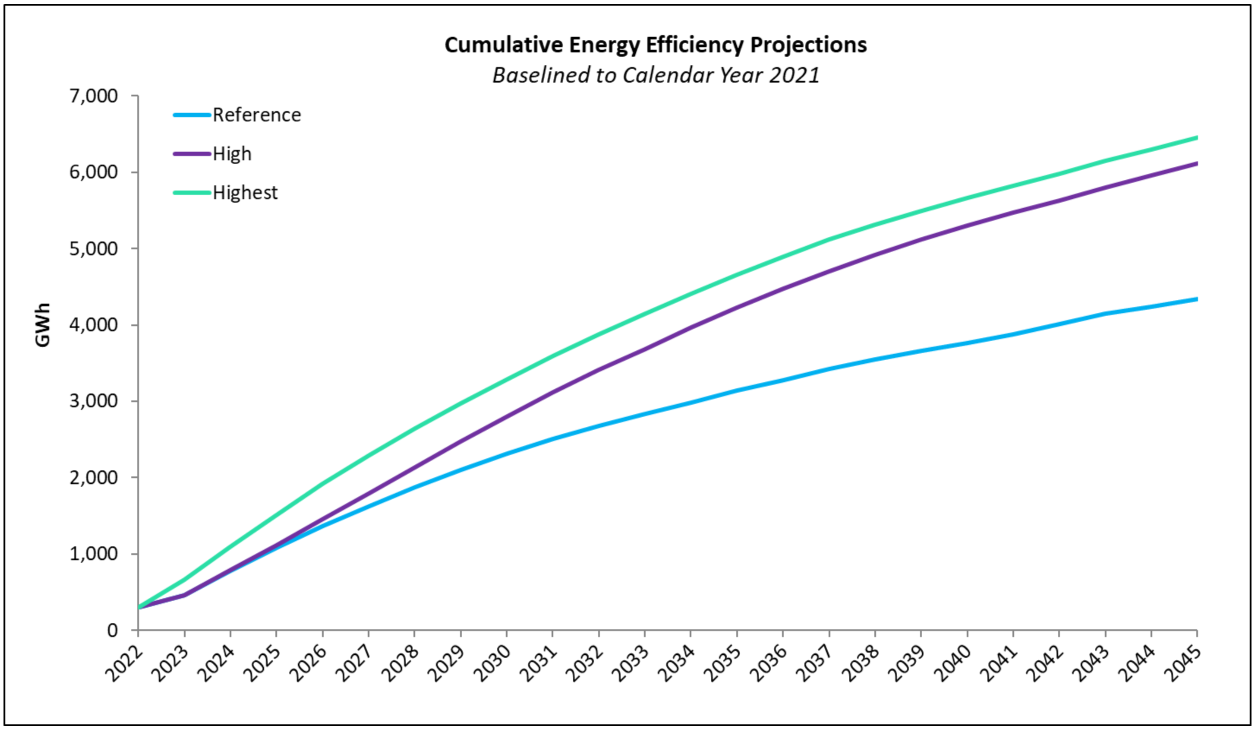
Note:

1. Demand response projections are cumulative and include both existing and projected DR capacity.
2. Numbers received from LADWP Demand Response Group.
3. Last updated 3/18/2022

***Figure 3-15**. 2022 SLTRP Demand Response Capacity (MW) Projections. Cumulative, including existing installations.*

The levels of demand response (DR) shown above (**Figure 3-15)** cumulatively reflect both the existing and planned capacities. For the SLTRP Reference Case (SB 100), Case 1, and Case 2, the "moderate" DR levels were assumed for demand response. For Case 3, "High" DR levels were assumed. It must be noted that DR operates under specific criteria; therefore, it may not be available all hours of the year as a resource. Similar to other DERs, DR also depends on customer participation.

3.1.15 Energy Efficiency



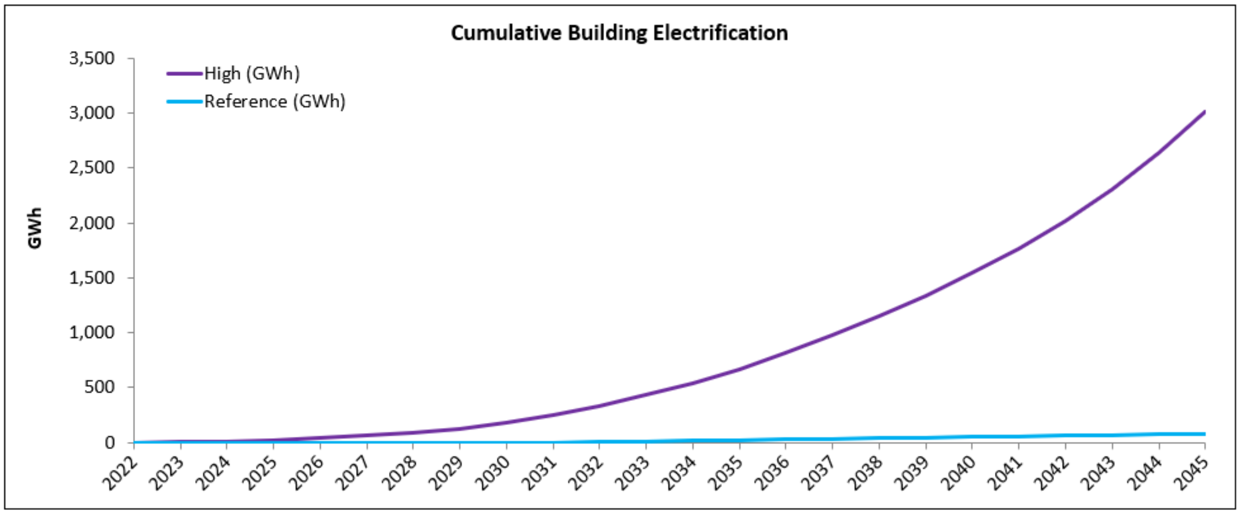
Notes:

1. Energy efficiency (EE) cumulative savings are baselined to CY 2021.
2. EE cumulative savings include Codes & Standards (C&S).
3. Source: 2020 Energy Efficiency Potential Study (GDS Associates and internal LADWP subject-matter expert modeling)
4. Last Updated 06/24/22

***Figure 3-16**. 2022 SLTRP Energy Efficiency Savings (GWh) Projections. Cumulative, reset starting from the year 2021, as historical savings are incorporated into the load forecast.*

The levels of energy efficiency (EE) shown above (**Figure 3-16**) are cumulative projections starting from the year 2022. Per the SLTRP Case definitions, the Reference Case (SB 100) uses "Reference" levels of EE, Case 1 and Case 2 use "High" levels of EE, and Case 3 uses "Highest" levels of EE. EE is also considered a "load reducer" because it lowers the net energy for load and electric retail sales that LADWP ultimately has to meet. Like other DERs, EE depends on customer participation.

3.1.16 Building Electrification

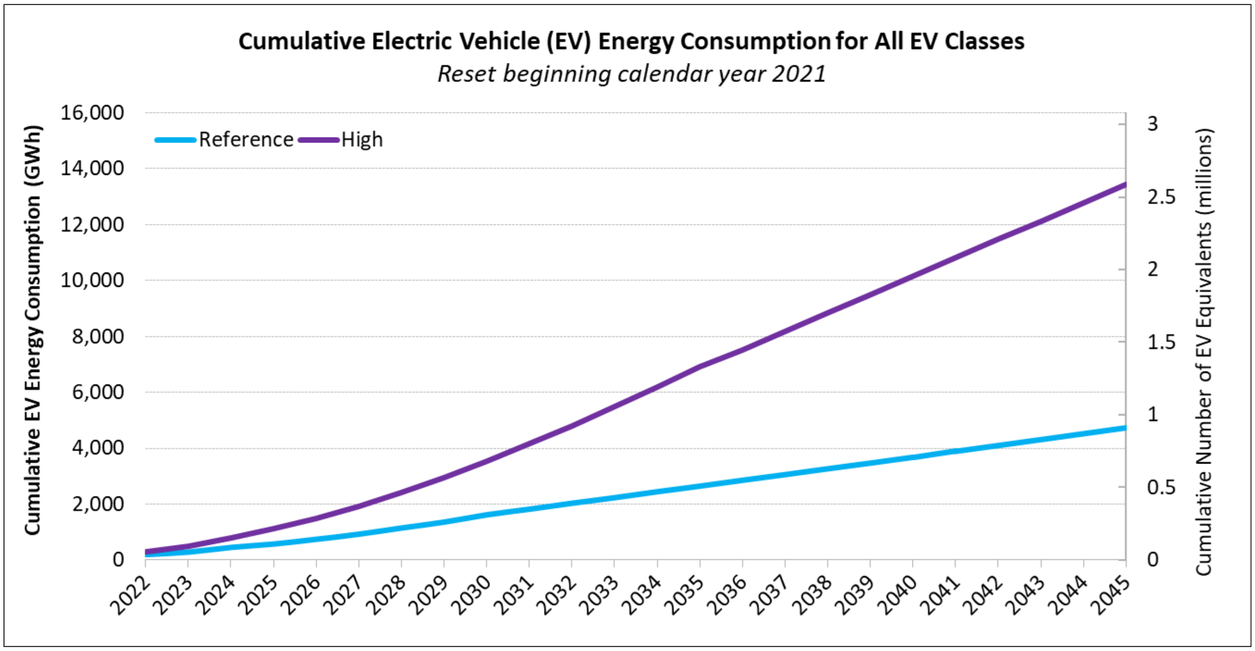


Notes:
1. "Reference" based off CEC 2021 SB 100 modeling (no incremental BE through 2030) assuming LADWP load is ~9% of State load
2. "High" currently reflective of the residential sector only, which will be updated when commercial projections are available.
3. Sources: E3, SMUD, SCE, LADWP
4. Last updated 2/2/2022

Figure 3-17*. 2022 SLTRP Building Electrification Load (GWh) Projections. Cumulative, starting from the year 2022. New SLTRP load category.*

Per the SLTRP Core Case definitions, the Reference Case (SB 100) uses "Reference" levels of building electrification, while Case 1, Case 2, and Case 3 use "High" levels of BE (**Figure 3-17**). Distribution system upgrades will be necessary to accommodate future levels of BE in LADWP's service territory.

3.1.17 Transportation Electrification



Notes:
1. Cumulative EV Energy Consumption (GWh) is reset beginning calendar year 2021, in accordance with the 2021 FSO Load Forecast, which acts as the load basis for modeling in the 2022 SLTRP.
2. The "Reference" projections are obtained from the 2021 FSO Load Forecast, and are based on the approved 2017 SLTRP levels of "High" transportation electrification, with adjustments based on near-term electrification projects.
3. The "High" projections are obtained from the Electric Transportation Programs group and reset beginning calendar year 2021, as cumulative consumption through the end of calendar year 2020 is already incorporated into the 2021 FSO Load Forecast.
4. Energy consumption includes contributions from all EV classes (light duty, medium duty, and heavy duty).
5. Cumulative number of EV equivalents is for illustrative purposes only and calculated based on estimates for "Annual Energy Consumption per EV Equivalent" derived from data provided by the Electric Transportation Programs group.

***Figure 3-18**. 2022 SLTRP Transportation Electrification Load (GWh) Projections. Cumulative, reset starting from the year 2021, as historical load is incorporated into the load forecast.*

The SLTRP Core Cases all use the "Reference" levels of transportation electrification shown above (**Figure 3-18**). In the "High" load sensitivity, the "High" TE levels are applied to all the SLTRP Cases to study the incremental amount of resources that would be needed in order to reliably meet the increased load. The "High" TE levels include light-duty, medium-duty, and heavy-duty electric vehicles, and align with a trajectory of 762,000 electric vehicles in the City of Los Angeles by 2030 - mandated by state and local policies.

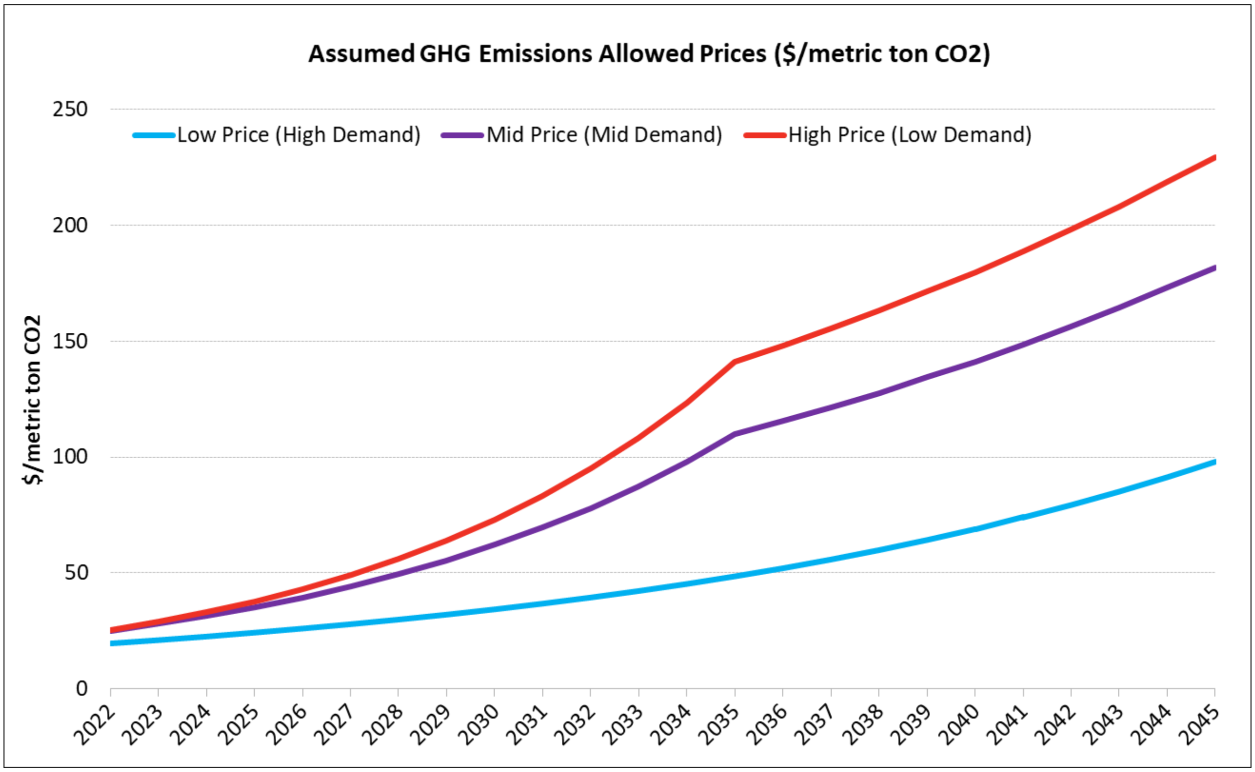
3.1.18 Power System Reliability Program (PSRP) Re-Vamp

***Table 3-6**. SLTRP Power System Reliability Program (PSRP) Re-vamp Cost Projections. SB 100, Cases 1, 2, and 3. Estimated costs to address distribution system overloads and expand distribution system capacity to accommodate distributed energy resource deployment theorized in the LA100 Study.*

Case	Reference (SB 100)	100% Carbon-Free by 2035
PSRP - Capital & O&M	PSRP - Total Annual Fixed Cost ($M)	PSRP - Total Annual Fixed Cost ($M)
FY 21/22	$899	$1,101
FY 22/23	$1,124	$1,358
FY 23/24	$1,271	$1,539
FY 24/25	$1,285	$1,597
FY 25/26	$1,421	$1,768
FY 26/27	$1,511	$1,883
FY 27/28	$1,537	$1,845
FY 28/29	$1,646	$2,012
FY 29/30	$1,744	$2,130
FY 30/31	$1,741	$2,074
FY 31/32	$1,826	$2,178
FY 32/33	$1,931	$2,286
FY 33/34	$2,029	$2,401
FY 34/35	$2,131	$2,512
FY 35/36	$2,236	$2,639
FY 36/37	$2,350	$2,774
FY 37/38	$2,471	$2,915
FY 38/39	$2,600	$3,067
FY 39/40	$2,729	$3,219
FY 40/41	$2,871	$3,386
FY 41/42	$3,019	$3,561
FY 42/43	$3,170	$3,738
FY 43/44	$3,314	$3,910
FY 44/45	$3,472	$4,100
SLTRP Est Totals ($M)	$50,330	$59,992

The table above (**Table 3-6**) reflects cost estimates regarding the revamp of LADWP's Power System Reliability Program (PSRP). A revamp includes alleviating existing distribution system overloads and expanding distribution system capacity. These upgrades will accommodate LA100 Study projections for distributed energy resources and electrification of the transportation and building sectors. The costs for the SLTRP Reference Case are slightly lower, as denoted in the column "Reference (SB 100)", whereas the costs for Case 1, Case 2, and Case 3 are higher as denoted by the column "100% Carbon-Free by 2035".

3.1.19 Greenhouse Gas (GHG) Emissions Allowance Prices



Notes:

1. Source: Final 2021 IEPR GHG Allowance Price Projections on 12/17/2021.
2. Link to IEPR Report: https://efiling.energy.ca.gov/GetDocument.aspx?tn=240982&DocumentContentId=74834

Figure 3-19*. 2022 SLTRP Greenhouse Gas Emission Allowance Price Projections. "Mid" is used for Core Cases.*

The prices above (**Figure 3-19**) show projections for greenhouse gas emission allowances, derived from the 2021 California Energy Commission's Integrated Energy Policy Report (IEPR). The "Mid" price was assumed for the SLTRP Core Cases, while the "High" and "Low" prices were assumed for the price sensitivities.

3.2 Modeling Methodology and Simulation In-Depth

LADWP contracted with a consultant, Ascend Analytics, to augment its existing computer modeling and simulation capabilities for this SLTRP. 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 3-20**).

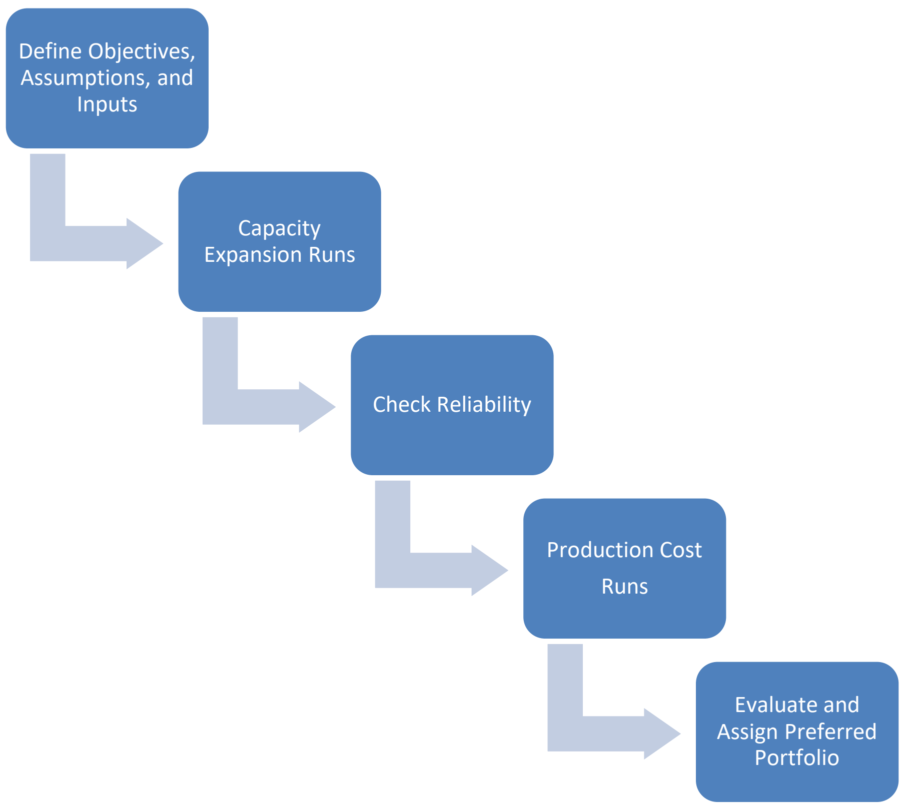


***Figure 3-20**. 2022 SLTRP Modeling Process.*

3.2.1 Capacity Expansion

For the SLTRP, 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 each of the Core Cases 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 2021 NREL 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 SB100, our system needed to meet 100% clean energy by 2045, and in the Core Cases, 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 SLTRP and to reliably serve customer load with 100% carbon-free energy by 2035. To achieve these goals, the SLTRP 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 portfolios for the Core Cases, the portfolios are assessed for resource adequacy.

"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".

3.2.2 Reliability

Resource adequacy models are used to understand a power system's ability to meet demand. To meet the SLTRP 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 current portfolio was modeled for 2023 to establish the baseline loss of load hours, which translates to the number of hours across the year that total generation capacity cannot meet customer demand. The resource adequacies of the Core Case portfolios were modeled for every fifth year starting with 2025. Through resource adequacy modeling, LADWP showed that the Core Case portfolios were able to maintain reliability while transitioning to 100% carbon-free energy. Understanding that the Core Case 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 SLTRP was used to quantify how the LADWP Power System was dispatched hourly to serve customer load and 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 Core Cases, sensitivities were considered such as the resiliency to transmission outages or the effects of delaying key transmission projects. The resiliency sensitivities investigated the dispatch of potential LADWP generation changes to be made in order to meet the demands of our system in the case of an extreme event such the Saddle Ridge wildfire or an outage on the Southern Transmission System (STS).

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 TAKEAWAYS:

- The highest driver of greenhouse gas emissions reduction is divesting from coal in 2025, followed by an abundant integration of carbon-free energy resources by 2030.
- Substantial overbuild of variable energy resources such as solar and wind, is required to achieve the carbon-free energy generation targets while retaining a reliable system, due to declining capacity value contributions to the Power System.
- Carbon-free, long-duration, and dispatchable electric generating resources such as green hydrogen are required in the Los Angeles Basin for reliability and resilience.
- On a preliminary basis, total portfolio costs (net present value) are expected to range between $60 billion to $90 billion. Additional risks including but not limited to supply chain, permitting, infrastructure, labor, and affordability, must also be considered.

CONTENTS

Model outputs include, but are not limited to, portfolio capacity buildouts, total cost, fuel consumption, emissions, curtailed energy, and reliability metrics such as loss of load hours.

DEFINITIONS

ATB	Annual Technology Baseline
BE	Building Electrification
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
Case(s)	SB 100 Case (i.e., Reference Case), Case 1, Case 2, and Case 3
CEC	California Energy Commission
CNM solar	Customer Net-Metered Solar
Core Case(s)	Cases Modeled Under Their Default Defined Assumptions
DERs	Distributed Energy Resources
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
FSO	Financial Services Organization
GHG	Greenhouse Gas
GWh	Gigawatt-Hours
HVDC	High Voltage Direct Current
IEPR	Integrated Energy Policy Report
In-basin	Located Within the Los Angeles Basin
IRP	Integrated Resource Planning
LA100 Study	The Los Angeles 100% Renewable Energy Study
LADWP	Los Angeles Department of Water and Power
LOLH	Loss of Load Hours
Monte Carlo analysis	A Model That Uses Repeated Random Sampling to Obtain Numerical Results
NEL	Net Energy for Load
NPV	Net Present Value
NREL	National Renewable Energy Laboratory

PPA	Power Purchase Agreement
PSRP	Power System Reliability Program
Reference Case	SB 100 Case
RPS	Renewable Portfolio Standard
SLTRP	Strategic Long-Term Resource Plan
STS	Southern Transmission System
TE	Transportation Electrification
WECC	Western Energy Coordinating Council

4 Modeling Results

This chapter presents the results of computer modeling for the Reference Case (SB 100 Case), Case 1, Case 2, and Case 3. The new generation and energy storage resources for each case were built using the capacity expansion model described in Chapter 3. This model determines the least-cost and best-fit portfolio of generation and energy storage resources. Once the optimal buildout was determined by the capacity expansion model, detailed hourly production cost models were run on each portfolio using a Monte Carlo stochastic method with varying weather conditions.

Model outputs include, but are not limited to, portfolio capacity buildouts, total cost, fuel consumption, emissions, curtailed energy, and reliability metrics such as loss of load hours.

Additionally, several commodity price sensitivities and “what-if” sensitivities were modeled. Such sensitivities include high and low customer demand, high and low fuel prices, high and low greenhouse gas (GHG) allowance costs, high and low renewable energy project costs, and high and low adoption of distributed energy resources. “What-if” sensitivities examined the impacts of losing key transmission corridors due to events such as wildfires.

4.1 SB 100

Figure 4-1 below shows the results of the capacity expansion model applied to the SB 100 Case. SB 100 mandates that all retail sales of electricity to California end-use customers must be supplied through carbon-free energy resources by 2045. To achieve this, the capacity expansion model builds significant capacities of new solar + storage, wind, and stand-alone energy storage projects.

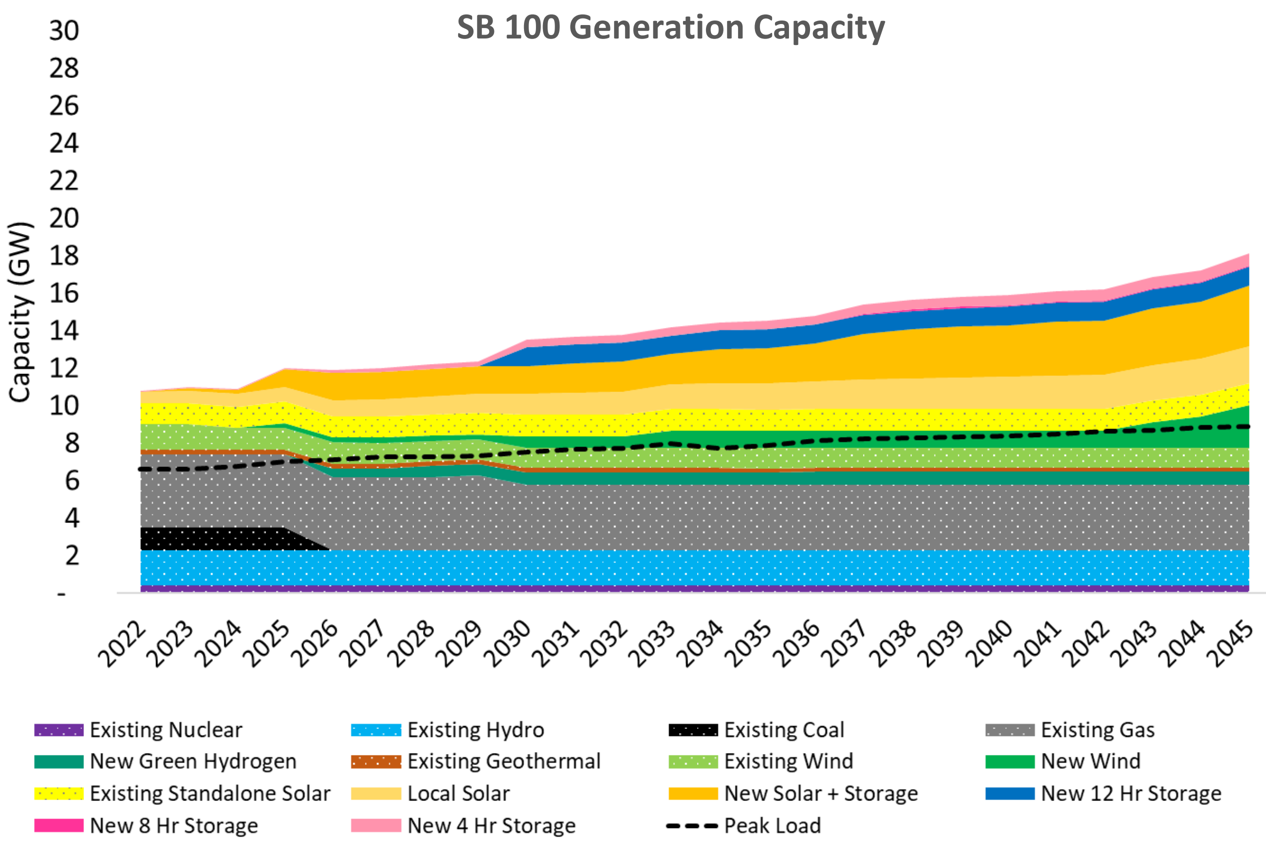


***Figure 4-1**. Generation capacity buildout for the SB 100 Case. To achieve the 2045 100% carbon-free energy mandate, significant quantities of new solar + storage, wind, and stand-alone energy storage are built. The dashed line represents annual peak system demand.*

The capacity expansion model also builds smaller quantities of local solar and green hydrogen-fueled resources. Many existing gas units are retained or modernized to eliminate once-through ocean water cooling. It is important to note that under SB 100, electrical energy losses, which arise primary through resistive heating in transmission and distribution lines, can be served with fossil-fired generation. LADWP's Power System averages approximately 12% electrical energy losses. In order to minimize total cost, the SB 100 case retains some gas-fired generation, unlike the Core Cases, which transition to an in-basin fleet powered entirely by green hydrogen

Figure 4-2 shows the expected energy generation by fuel type for the SB 100 case. The SB 100 case relies heavily on energy from solar photovoltaic (PV) resources, which include local rooftop and other types of distributed solar, as well as utility-scale solar + storage projects, in order to achieve the 2045 100% carbon-free energy mandate.

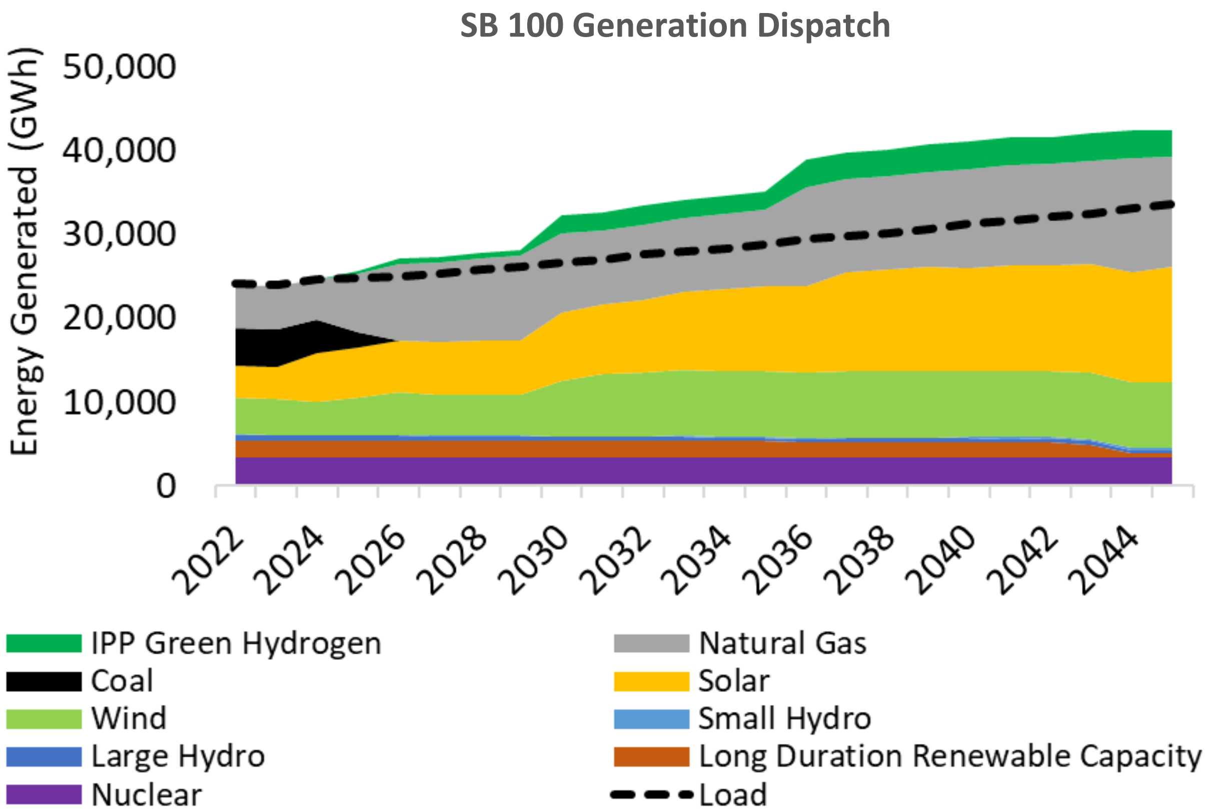


Figure 4-2*. SB 100 case generation by fuel type. This case relies heavily on energy from solar PV, which includes local rooftop solar, as well as utility-scale solar + storage projects, to achieve the 2045 carbon-free energy mandate. The dashed line represents total customer demand before energy efficiency and demand response measures are applied, in addition to transmission and distribution losses.*

The SB 100 case also relies on a significant quantity of wind, and smaller amounts of geothermal to meet the 2045 100% carbon-free energy mandate. **Figure 4-2** also shows that more energy is generated each year than is consumed by customers and line losses. This is due to curtailment of intermittent renewable energy resources such as solar and wind. Since these resources are not dispatchable, LADWP must attempt to integrate them into our system as their electricity is generated. However, due to their intermittent nature, the capacity expansion model must overbuild these resources to ensure the 2045 100% carbon-free energy mandate, as shown in **Figure 4-3**, can be met under a variety of weather and customer demand situations. Furthermore, the capacity expansion model overbuilds these resources to provide additional reliability to the system and minimize total loss of load hours. Due to this need to overbuild these intermittent resources, there are times when they produce more energy than what LADWP's system can absorb—either through customer demand or stored for later use, thus resulting in curtailment.

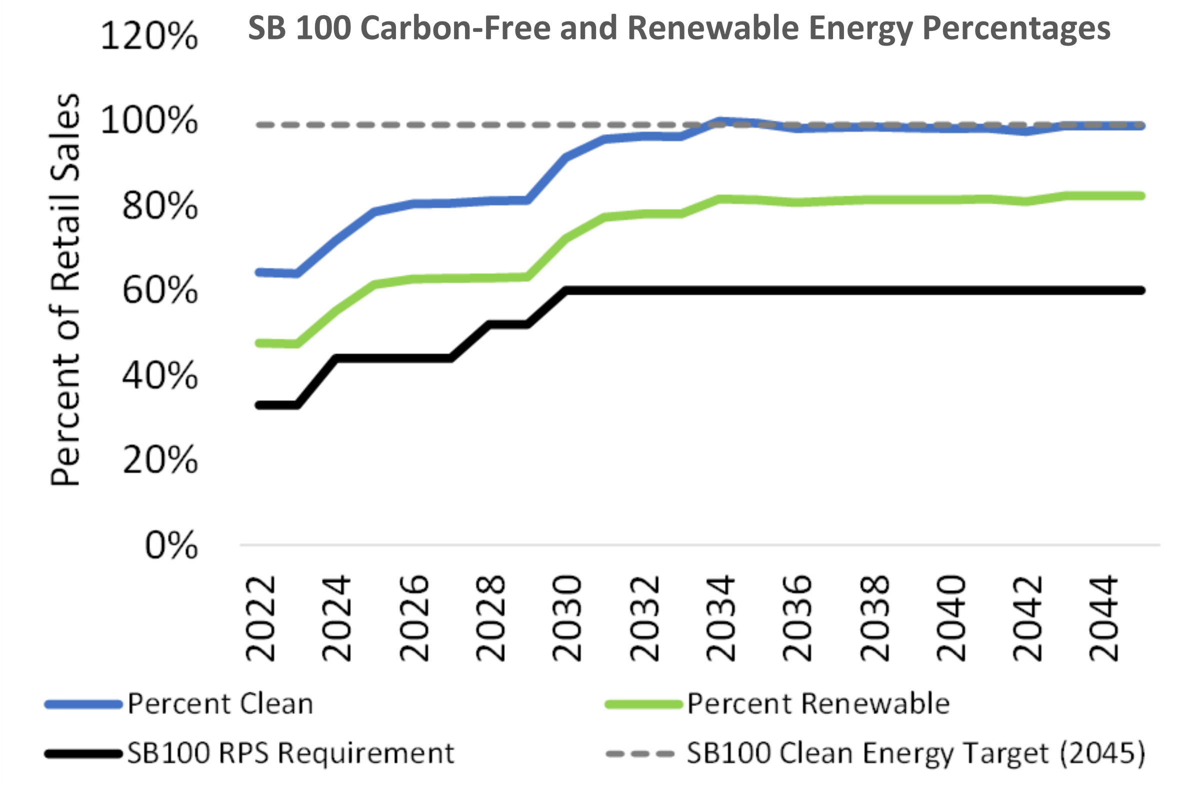
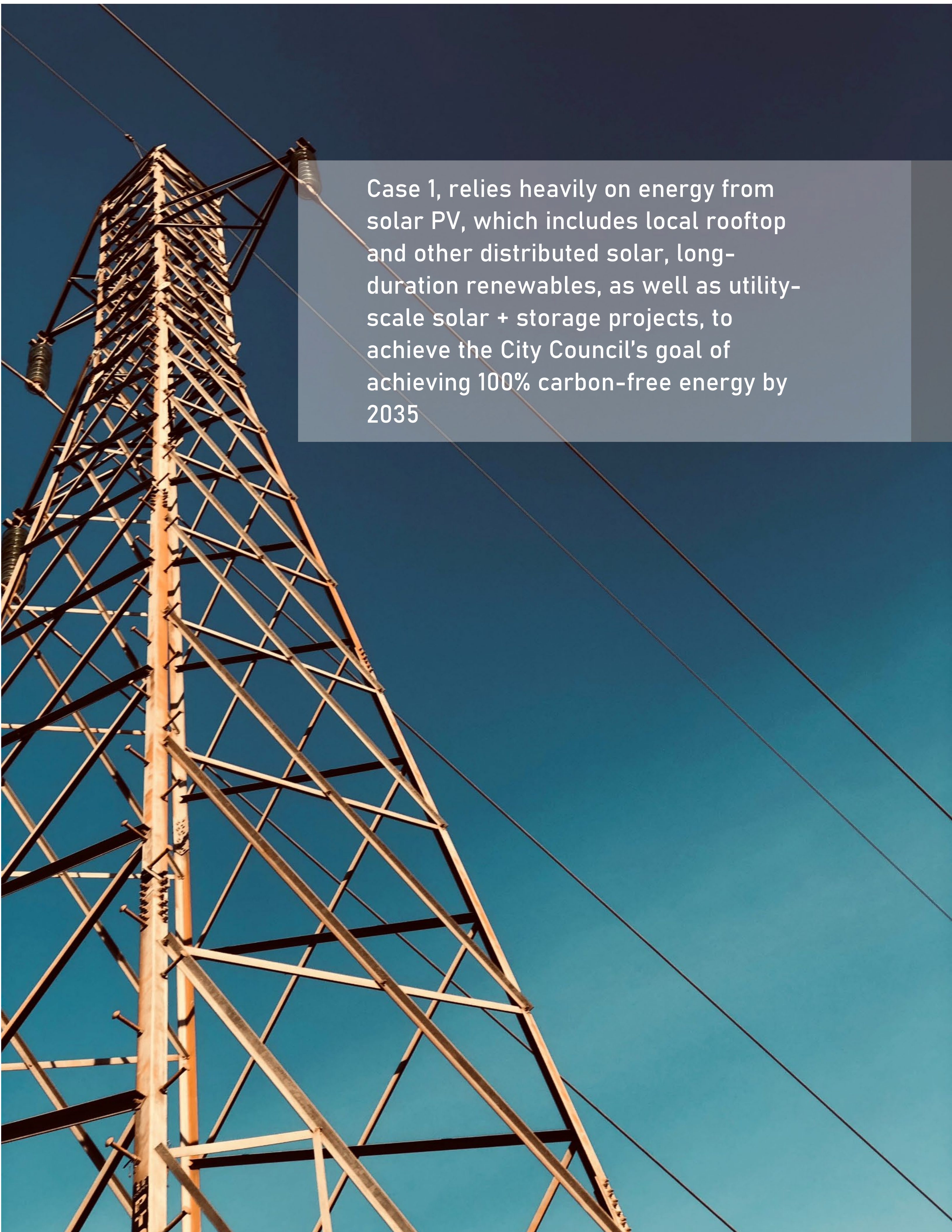


***Figure 4-3**. Percent clean (carbon-free) energy, percent renewable energy, and SB 100 RPS requirement. Renewable energy resources (whose percentage is depicted by the green line) can include wind, solar, geothermal, small hydroelectric, and biomass. Clean energy (depicted by the blue line) includes all renewable resources in addition to large hydroelectric and nuclear. SB 100 mandates that utilities achieve and maintain at least a 60% renewable portfolio standard (RPS) by 2030 (depicted by the black line). Additionally, SB 100 mandates that utilities achieve 100% clean (carbon-free) energy by 2045 (depicted by the dashed line).*



Case 1, relies heavily on energy from solar PV, which includes local rooftop and other distributed solar, long-duration renewables, as well as utility-scale solar + storage projects, to achieve the City Council's goal of achieving 100% carbon-free energy by 2035

4.2 Case 1

Case 1 is the first of the Core Cases which satisfy the Los Angeles City Council motion to create a plan that achieves 100% carbon-free energy by 2035. In contrast to SB 100, the City Council motion requires that all energy must be produced by generation resources that do not emit greenhouse gasses. Unlike under SB 100, which requires only retail sales to be served by carbon-free energy resources while excluding line losses, the City Council motion requires even line losses to be served with carbon-free resources. Additionally, while SB 100 requires to achieve 100% carbon-free energy by the end of 2045, the City Council motion requires LADWP's plan to achieve 100% carbon-free energy by the beginning of 2035.

In addition to the 2035 100% carbon-free goal, Case 1 sets forth an interim goal of achieving an 80% RPS by 2030. Case 1 also sets a goal of achieving 2,240 MW of local distributed solar, 4,350 GWh of energy efficiency savings, 520 MW of distributed energy storage, and 576 MW of demand response by 2035.

4.2.1 Case 1 Capacity Expansion and Production Cost Modeling Results

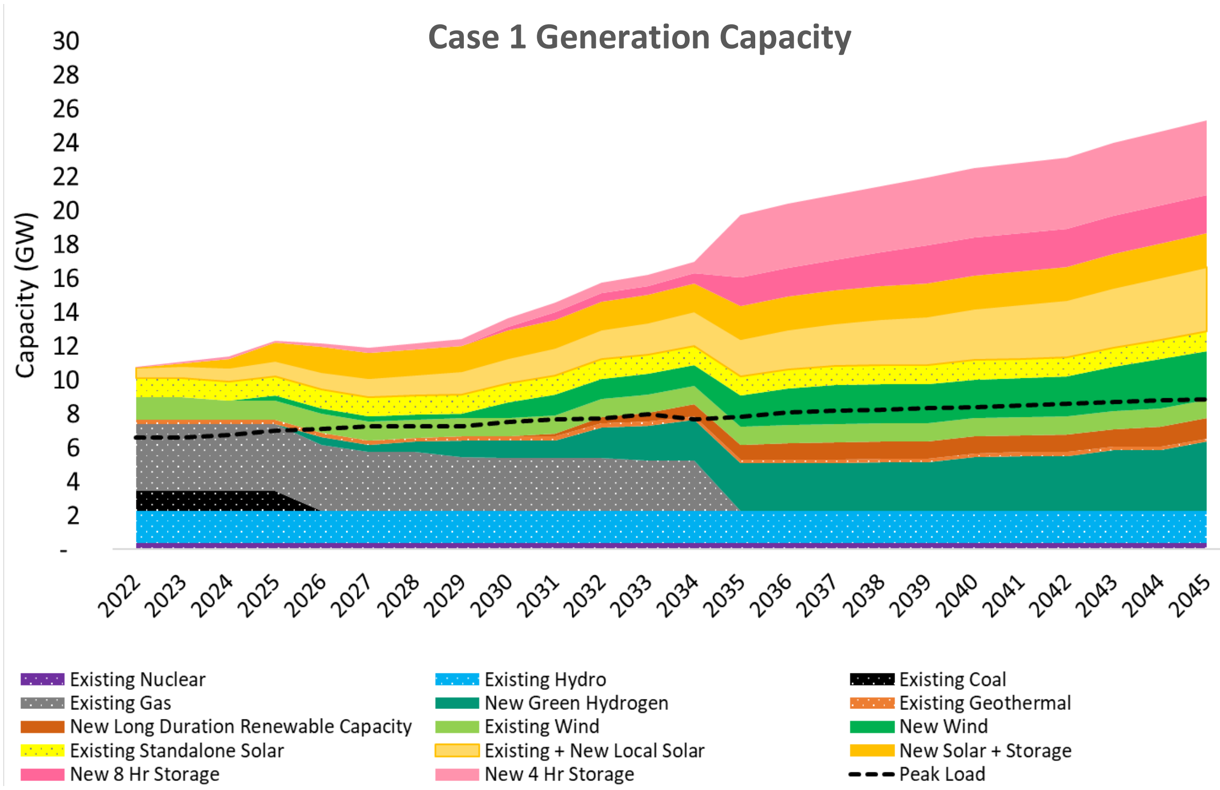


***Figure 4-4**. Generation capacity buildout for Case 1. To achieve the 2035 100% carbon-free energy goal set forth by the Los Angeles City Council, significant quantities of new solar + storage, wind, and stand-alone energy storage are built. Long-duration renewable capacity is a generic term that encompasses geothermal as well as other renewables that provide a greater effective load carrying capacity (ELCC) such as concentrating solar-thermal power. The dashed line represents annual peak system demand.*

Figure 4-4 shows that to achieve 100% carbon-free energy by 2035, Case 1 will need significant quantities of new solar + storage, wind, and stand-alone storage. The last of LADWP's coal-fired generation is retired by 2025, and by 2035 all natural gas-fired generation has been retired or converted to run completely on green hydrogen, a carbon-free fuel. **Figure 4-4** also shows a modest buildout of long-duration renewable capacity. Such renewables include geothermal and other renewable technologies such as concentrating solar power that have a greater effective load carrying capacity than wind and solar photovoltaics. Case 1 also assumes all in-basin capacity will be converted to operate off of green hydrogen by 2035. It is important to note that according to the Los Angeles 100% Renewable Energy Study (LA100 Study) conducted by the National Renewable Energy Laboratory (NREL), LADWP requires firm, dispatchable generation near load centers in the Los Angeles area to ensure reliability and resiliency. To ensure a transition to 100% carbon-free energy by 2035, such firm, dispatchable generation is anticipated to come from green hydrogen-fueled resources. Although capacity from green hydrogen is anticipated to be built in Case 1, it is important to note that such capacity will be used sparingly during times when there is insufficient wind and solar generation, or during extreme system stress and outage conditions

As with the SB 100 case, there is a significant overbuilding of renewables in order to ensure the 2035 goal of achieving 100% carbon-free energy is met. Due to the intermittent nature of solar photovoltaics and wind, overbuilding of these resources is required to ensure LADWP can take delivery of sufficient wind and solar energy to meet customer demand. Additionally, greater amounts of these resources must be procured to account for their lower ELCC. Finally, LADWP seeks to limit the use of in-basin green hydrogen combustion, which requires even more quantities of wind and solar to be procured.

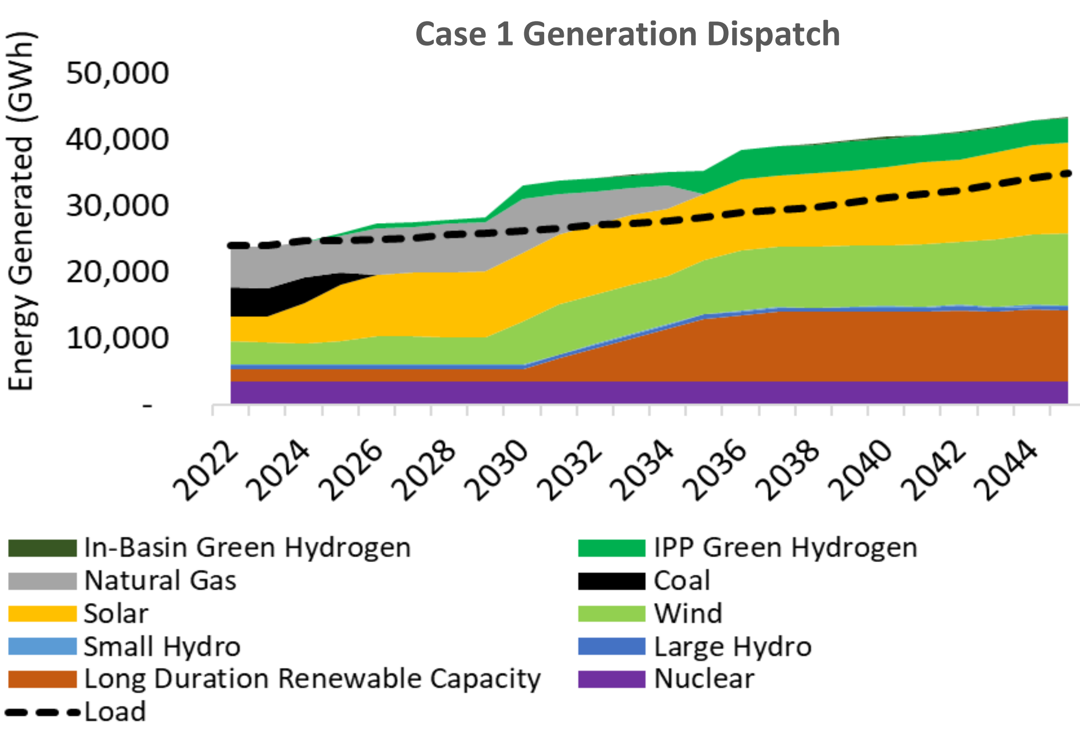


Figure 4-5*. Case 1 generation by fuel type. The dashed line represents total customer demand before energy efficiency and demand response measures are applied, in addition to transmission and distribution losses.*

Figure 4-5 shows the generation by fuel type for Case 1. This case relies heavily on energy from solar PV, which includes local rooftop and other distributed solar, long-duration renewables, as well as utility-scale solar + storage projects, to achieve the City Council's goal of achieving 100% carbon-free energy by 2035. Energy from all fossil-fired generation, including coal and natural gas, is completely eliminated by the beginning of 2035. All energy is provided by wind, solar PV, small hydroelectric, large hydroelectric, nuclear, green hydrogen, and long-duration renewables potentially consisting of geothermal, concentrating solar power, and other renewables with higher ELCC values. **Figure 4-5** also shows curtailment increasing with increasing penetration of renewables, with potential total energy produced by all generating resources exceeding total customer demand and losses depicted by the dashed black line. In practice, such energy can be curtailed (not generated) or sold to other utility companies. In general, LADWP seeks to minimize curtailed energy since most power purchase agreements (PPAs) stipulate an annual minimum quantity of energy that must be purchased regardless of whether or not LADWP is able to take delivery of that energy.

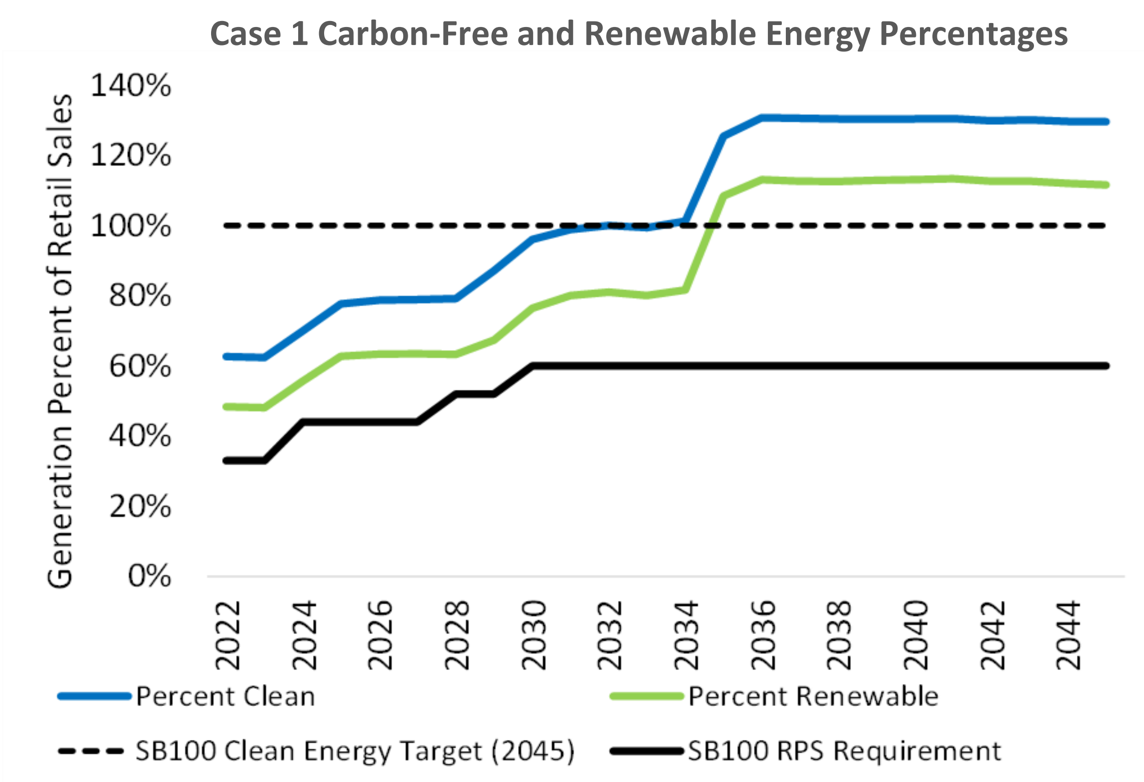


Figure 4-6*. Case 1 percent clean (carbon-free) energy, percent renewable energy, and SB 100 RPS requirement. As can be seen, Case 1 exceeds both the SB 100 RPS requirement and the SB 100 2045 clean (carbon-free) energy target.*

Figure 4-6 shows the annual percent of carbon-free energy achieved, annual percent of renewable energy achieved, and the SB 100 RPS requirement for Case 1. SB 100 mandates that utilities achieve and maintain at least a 60% renewable portfolio standard by 2030 (depicted by the black line). Additionally, SB 100 mandates that utilities achieve 100% clean (carbon-free) energy by 2045 (depicted by the dashed line). Case 1 reaches an 80% RPS by 2030, and this percentage continues to increase with each subsequent year. Percent clean (carbon-free) and percent renewable energy exceed 100% of retail sales by the mid-2030s, due to significant quantities of overbuild and resulting curtailment from renewables under Case 1.

Figure 4-7 shows the weekly dispatch of generating resources for Case 1 for the year 2025. The solid red line represents the average customer load for each week and is averaged across all hours of the week, including peak load hours in the afternoon and early evening as well as low load hours in the early morning. The dashed red line represents weekly average customer load plus average weekly energy storage charging load. In-basin thermal assets are dispatched frequently during the summer months to provide additional energy during peak load and to maintain reliability.

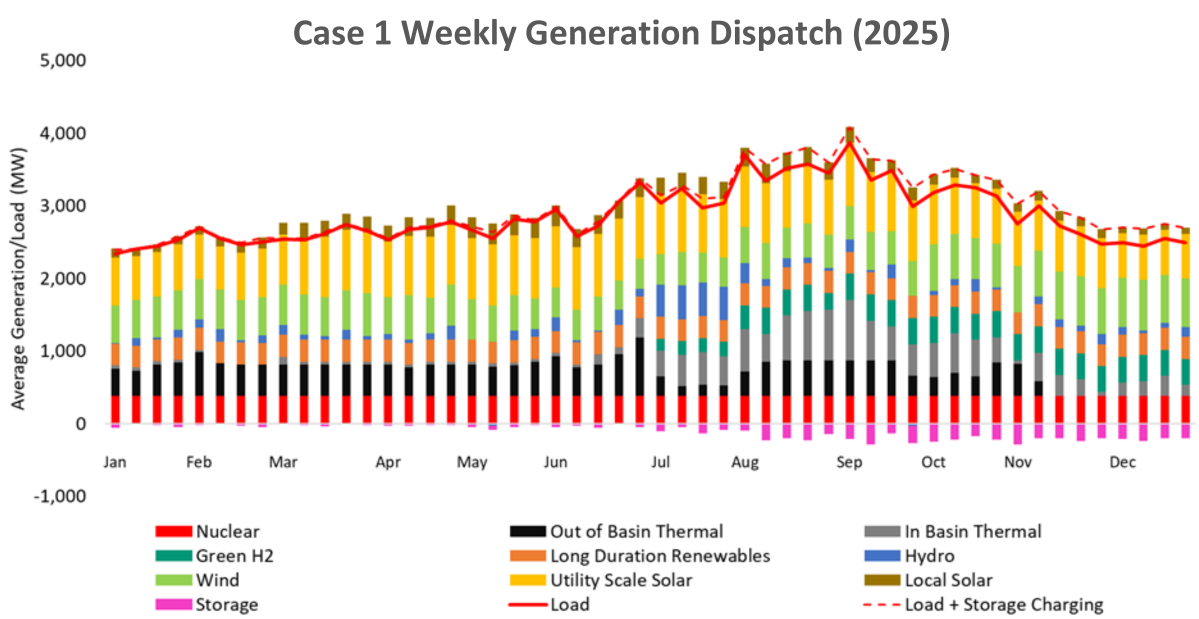


***Figure 4-7**. Case 1 weekly generation dispatch for the year 2025. The solid red line indicates the average 24-hour customer load for each week. The dashed red line indicates average customer load plus average energy storage charging load.*

Figure 4-8 shows the weekly generation dispatch for Case 1 for the year 2035. The year 2035 is the first year in which all energy is provided by carbon-free resources. The solid red line indicates the average 24-hour customer load for each week. Green hydrogen resources are dispatched sparingly and are used mainly for backup and to provide reliability during times of insufficient renewable energy generation. Energy storage assets are used extensively throughout the year to absorb excess energy from renewables and to store that energy for later use (depicted in magenta).

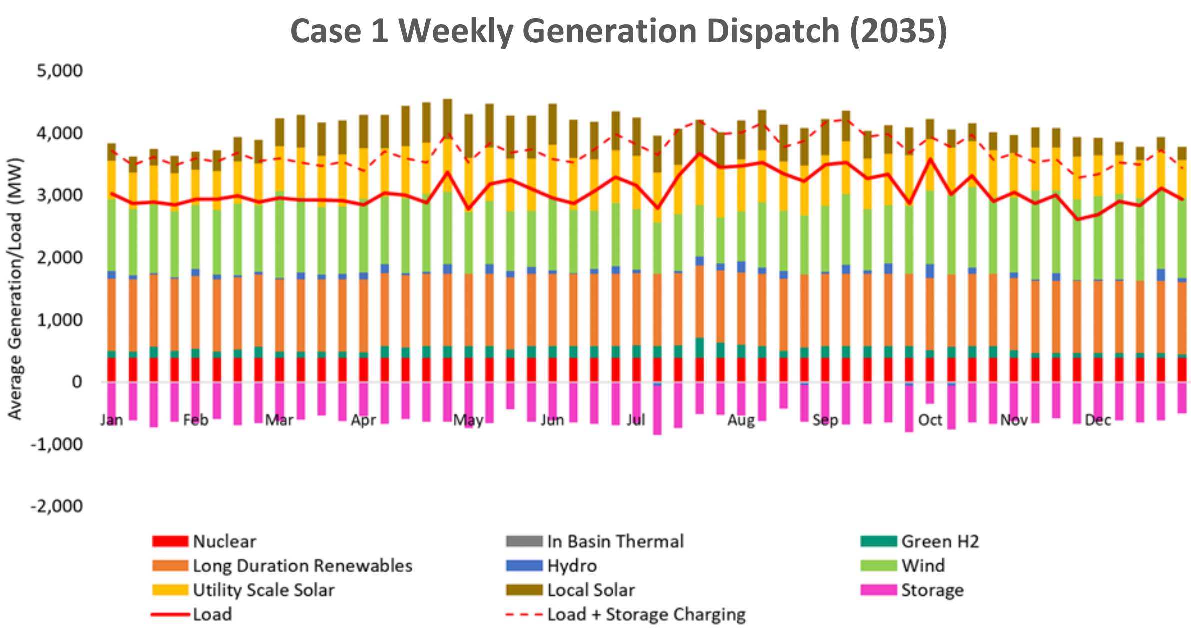


__Figure 4-8__. Case 1 weekly generation dispatch for the year 2035. The dashed red line indicates average customer load plus average energy storage charging load.

Figure 4-9 shows the hourly dispatch during the forecasted peak customer demand period for Case 1 for in the year 2035. Peak customer demand is forecasted to occur in late August and is driven by warm summer temperatures. Extensive use of energy storage is required, with energy storage assets charging in the morning hours and discharging during the evening hours when solar production diminishes.

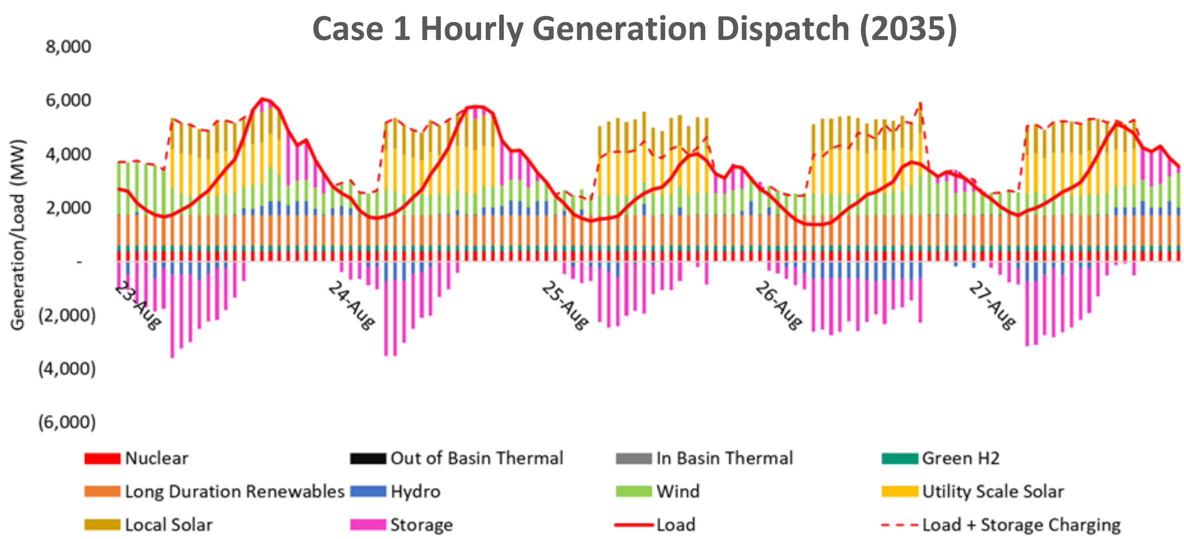


***Figure 4-9**. Case 1 hourly generation dispatch during the forecasted peak customer demand period in the year 2035. Even during peak customer load, green hydrogen is used sparingly, with the majority of energy coming from wind and solar + storage.*

Large quantities of energy generated by wind, utility-scale solar, and long-duration renewable resources serve the bulk of customer demand, with local solar, hydroelectric, nuclear, and green hydrogen resources serving the remaining customer demand. Even during periods of peak customer demand, model results show that green hydrogen would be rarely dispatched.

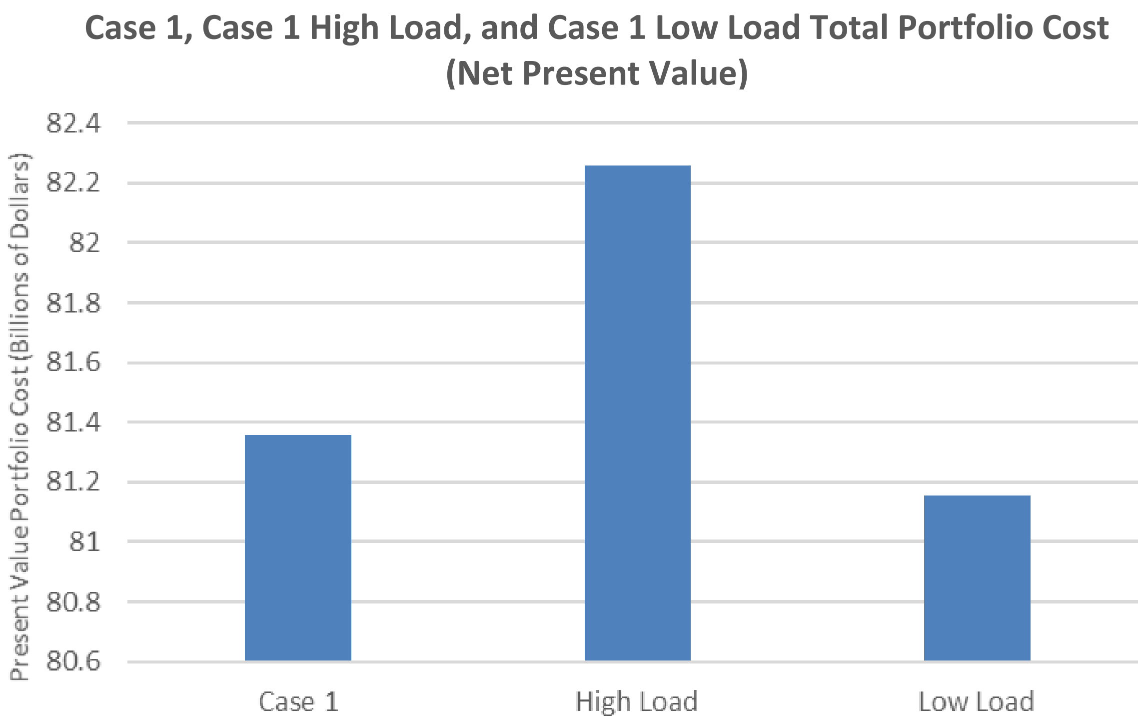


***Figure 4-10**. Case 1, Case 1 with High Load Sensitivity, and Case 1 with Low Load Sensitivity present value total portfolio costs.*

Figure 4-10 compares the total present value costs for Case 1 with both the High Load Sensitivity and Low Load Sensitivity. Present value costs include all fixed and variable costs incurred over the entire planning horizon, which spans from year 2022 to the year 2045. As expected, the High Load Sensitivity has the highest total costs due to the need to build or procure additional generation and storage assets as well as increased variable costs such as fuel and GHG allowances. Conversely, the Low Load Sensitivity has the lowest costs due to the need to build or procure fewer generation and storage assets as well as reduced variable costs. Present value costs for Case 1, the Case 1 with High Load Sensitivity, and Case 1 with Low Load Sensitivity are approximately $81.4 billion, $82.3 billion, and $81.2 billion, respectively.

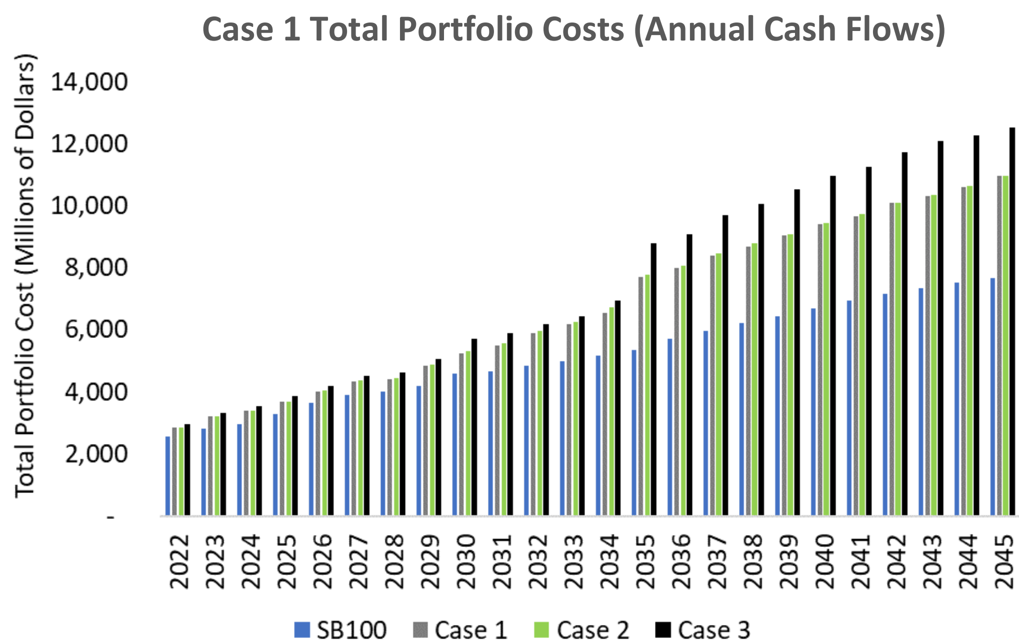


__Figure 4-11__. Case 1 annual total portfolio costs. Costs include all fixed costs and variable costs.

Figure 4-11 shows the total annual portfolio costs for Case 1. Total portfolio costs include all costs, including both fixed and variable costs. Examples of fixed costs include capital costs spent on power plant, transmission, and distribution system development and construction (including equipment, permitting, and construction labor), fixed operations and maintenance (including routine maintenance, inspection, and monitoring), and fixed power purchase agreements like those for renewable energy. Examples of 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).

4.2.2 Case 1 High Load Sensitivity

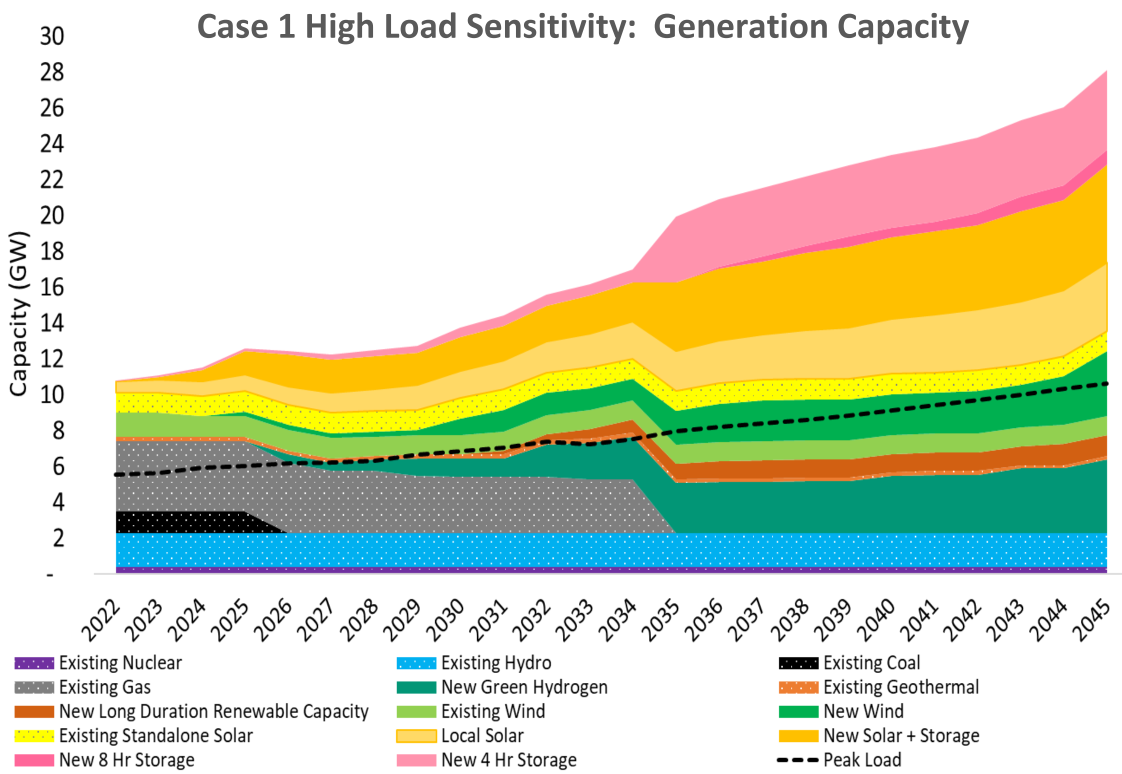


Figure 4-12*. Generation capacity buildout for Case 1 with High Load Sensitivity. Additional quantities of wind, solar, storage, and long-duration renewables are required if customer load grows at rates faster than anticipated (represented by the dashed black line). These additional resources will increase overall capital costs, as well as associated variable costs.*

Figure 4-12 shows the capacity buildout for Case 1 with High Load Sensitivity. With increased customer demand comes increased need for additional energy generation and storage assets. In particular, larger quantities of renewables are required in order to meet the interim 2035 target of achieving an 80% RPS, as renewable portfolio standard goals are calculated as a percentage of retail electricity sales. Furthermore, at least this percentage of renewables must be maintained indefinitely even as customer demand increases each year. Additionally, enough carbon-free resources must be built or procured to achieve the Los Angeles City Council goal of achieving 100% carbon-free energy by 2035. With the increased penetration of intermittent renewables comes the increased need for additional energy storage, which is also depicted in **Figure 4-12**.

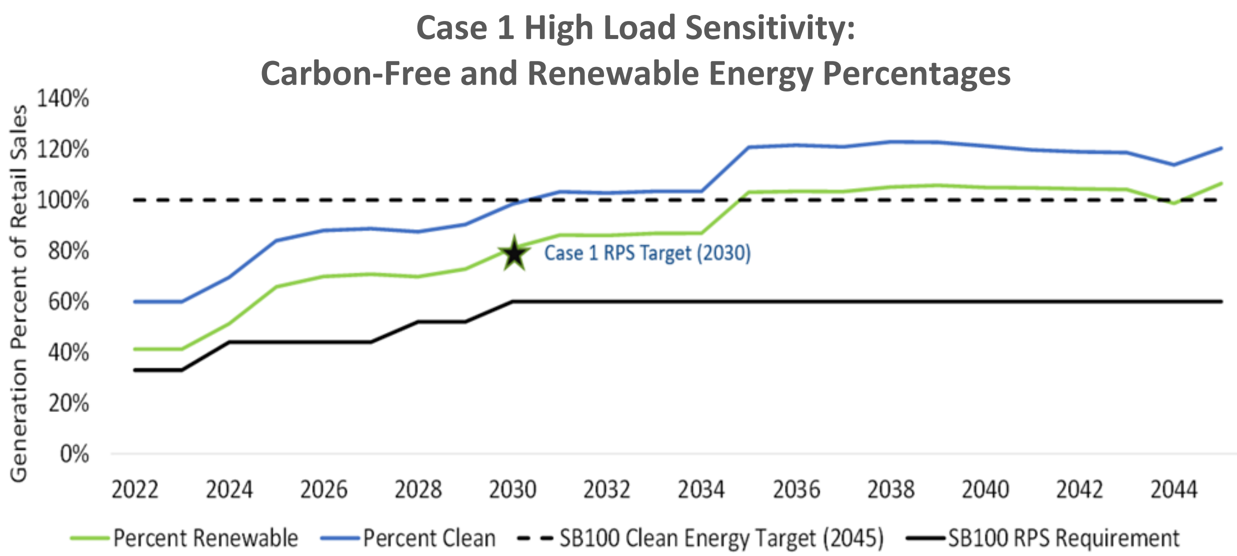


***Figure 4-13**. The Case 1 High Load Sensitivity meets the 80% RPS target by 2030 and the 100% carbon-free mandate by 2035.*

Figure 4-13 shows the annual percent of clean (carbon-free) energy achieved, annual percent of renewable energy achieved, and the SB 100 RPS requirement for Case 1 with High Load Sensitivity. Case 1 with High Load Sensitivity achieves an 80% RPS by 2030, and this percentage continues to increase each year. Although the capacity expansion model only constrained the buildout to achieve a minimum RPS of 80% from 2030-onward, additional renewables were built in order to achieve the 2035 goal of 100% carbon-free energy as well as increase system reliability. Percent clean (carbon-free) and percent renewable energy exceed 100% of retail sales by the mid-2030s, due to significant quantities of overbuilding and resulting curtailment from renewables under Case 1 under the High Load Sensitivity. Additionally, **Figure 4-14** shows the hourly generation dispatch under the High Load Sensitivity and Low Load Sensitivity during the peak load days in August 2035.

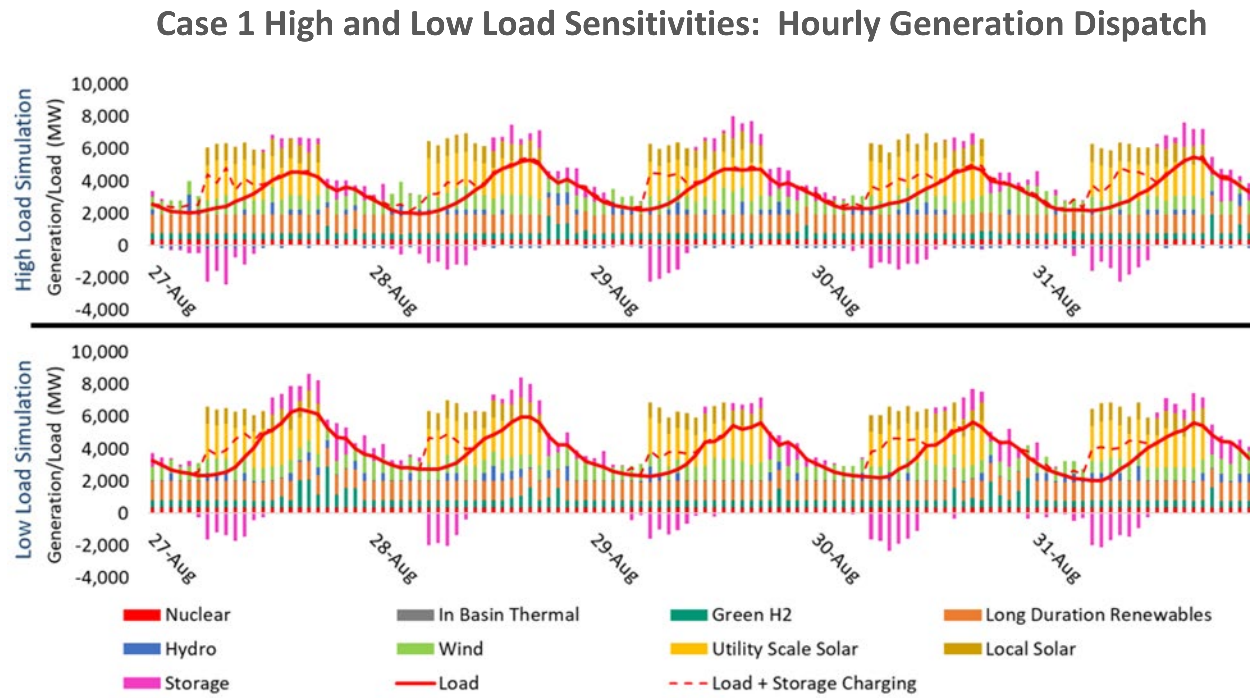


Figure 4-14*. Case 1 generation dispatch for the high-and low-load sensitivities. The chart shows the dispatch over the expected annual peak load in 2035, occurring in late August.*

4.2.3 Case 1 Low Load Sensitivity

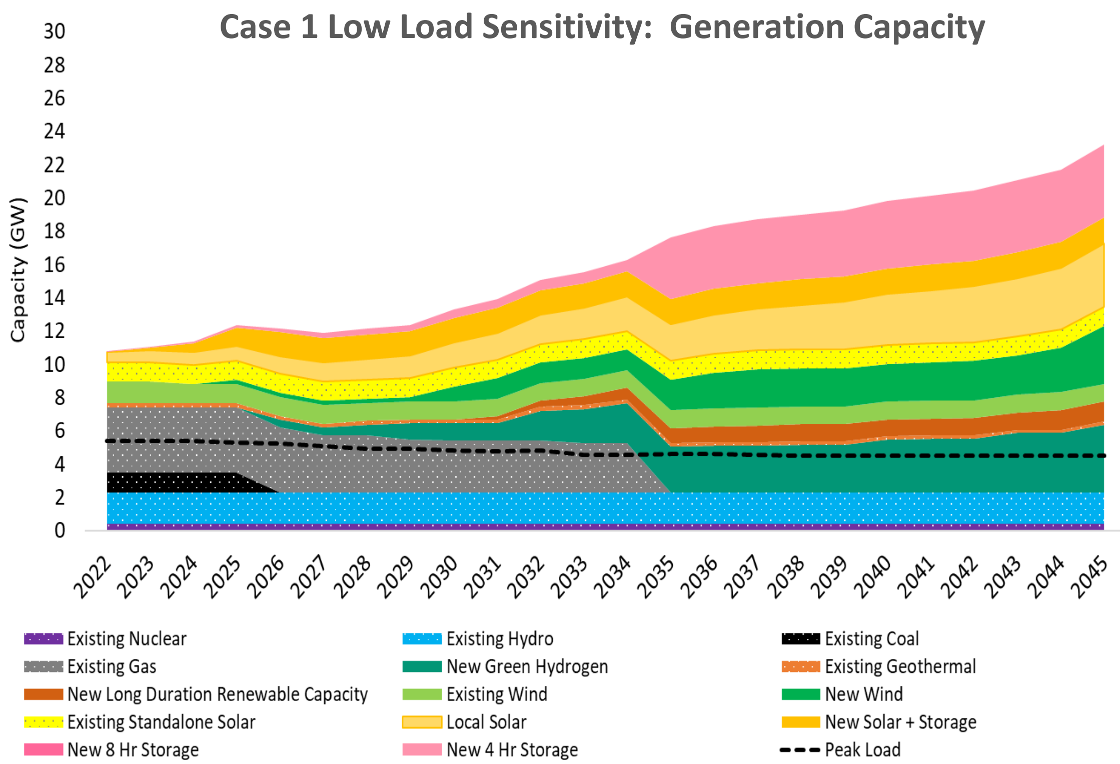


Figure 4-15*. Generation capacity buildout for Case 1 with Low Load Sensitivity. Smaller quantities of wind, solar, storage, and long-duration renewables are required if customer load grows at rates slower than anticipated (represented by the dashed black line). Even with lower customer loads, a significant amount of resource overbuild is required for reliability and to achieve the 2030 80% RPS target.*

Figure 4-15 shows the capacity buildout for Case 1 with Low Load Sensitivity. Reduced customer demand resulted in reduced quantities of generation and energy storage assets being built. Under the Low Load Sensitivity, customer demand is expected to decrease each year. Although the quantity of generation and energy storage resources built out under this sensitivity is significantly less than the High Load Sensitivity, the total quantity of resources remains several multiples higher than customer demand, beginning in the early 2030s. This is due to the intermittent nature of wind and solar resources.

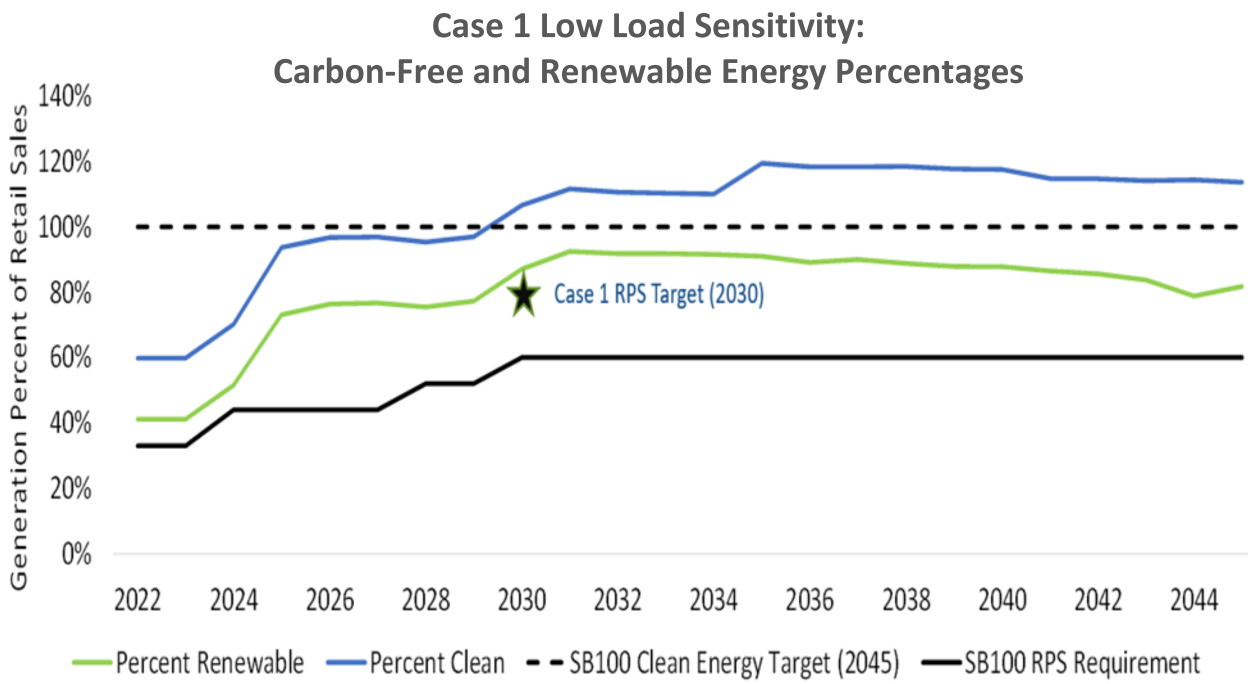


***Figure 4-16**. The Case 1 Low Load Sensitivity meets the 80% RPS target by 2030 and the 100% carbon-free target by 2035.*

Figure 4-16 shows the annual percent of clean (carbon-free) energy achieved, annual percent of renewable energy achieved, and the SB 100 RPS requirement for Case 1 with Low Load Sensitivity. Unlike Case 1 and Case 1 with High Load Sensitivity, Case 1 with Low Load Sensitivity does not achieve an RPS that exceeds 100% of retail sales. Total clean (carbon-free) energy, on the other hand, does exceed 100% of retail sales, beginning in the early 2030s.

Figure 4-17 gives a comparison on retail electric rate impacts for the SB 100 Case and Case 1 with each load sensitivity. Case 1 with High Resource Build and Low Load has the highest rates. This is a scenario in which a relatively large quantity of new renewables and energy storage assets are deployed in anticipation of higher aggregate customer demand but where customer demand falls short of current forecasts. In such a situation, costs must be recouped over a smaller quantity of customer sales, necessitating higher electricity rates. Conversely, the High Load sensitivity results in lower customer electricity rates due to the high revenues generated by increased demand.

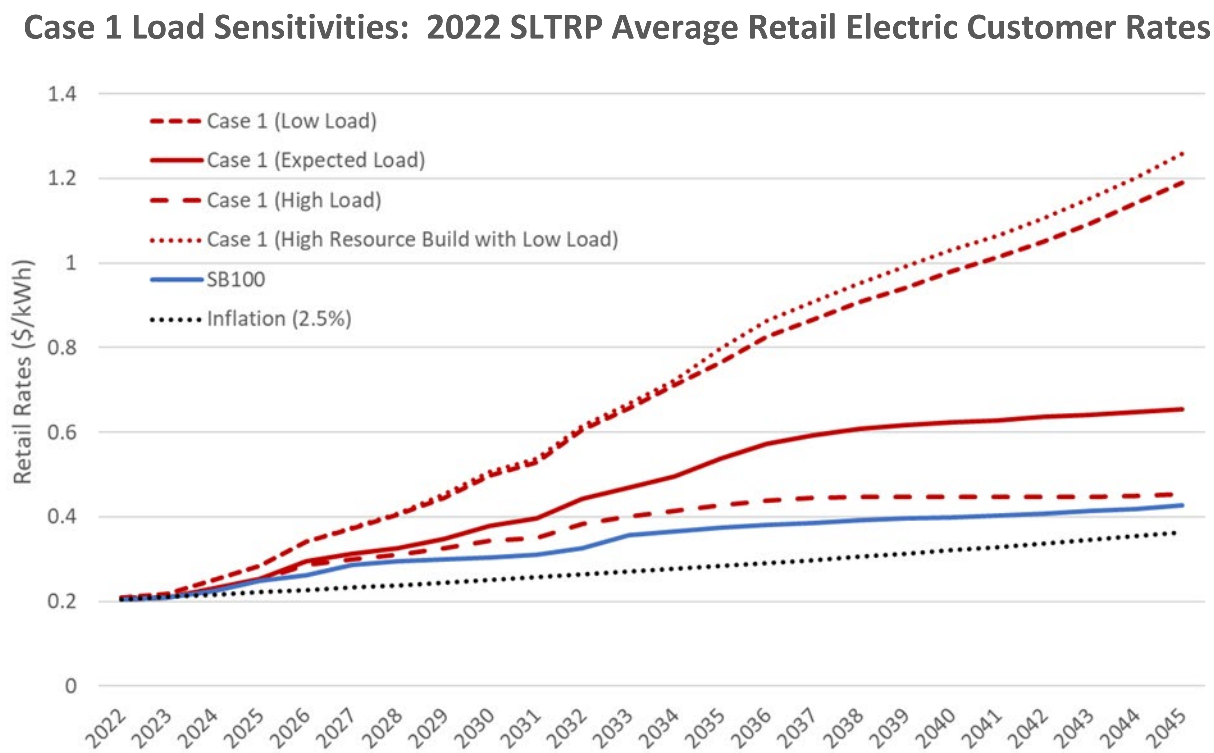


Figure 4-17*. Comparison of Case 1 average retail electric customer rates for expected load, high load, low load, high resource build with low load, and SB 100.*

4.2.4 Case 1 Demand Response Sensitivity

For this "What-If" modeling sensitivity, LADWP explored the effects on resource supply dispatch and adequacy to meet electric demand, in the event that customer participation resulted in only half of the aspired demand response capacity being subscribed for.

Under Core Case modeling, Case 1 targeted "moderate" levels of demand response with a goal of achieving 576 MW of demand response (existing plus projected cumulative total capacity) by 2035. The Core Case modeling assumed that this target demand response capacity was fully subscribed for by customers, and was then followed by a sensitivity where only half of the target capacities were subscribed for. Specifically, dispatch was observed for LADWP's four in-basin generating stations (Harbor, Haynes, Scattergood, Valley) via comparison of the estimated annual average plant capacity factors for the years 2025 and 2030 in the "Reduced DR" sensitivity vs the "Base" Core Case modeling. Overall, it was observed that additional demand response has a minimal impact on the need for dispatchable in-basin generation in the years 2025 and 2030, with almost no impact in 2035 (**Figure 4-18**). Generally, across the in-basin generating stations, it was observed that a 50% reduction in demand response, relative to the Core Case modeling, resulted in a slight increase in annual average plant capacity factors.

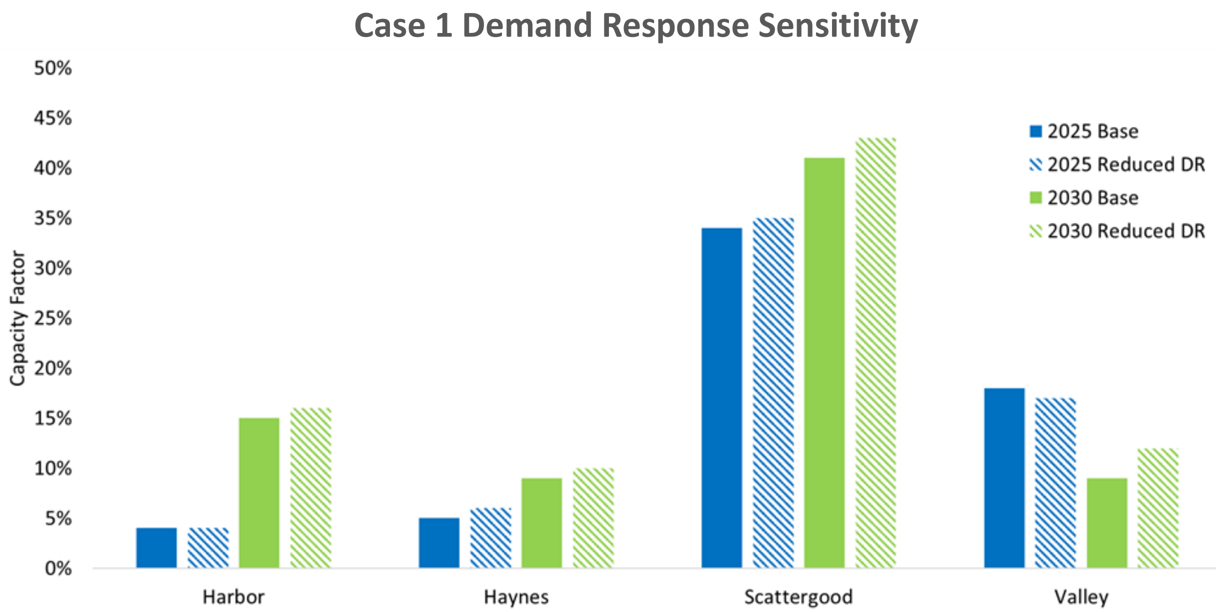


Figure 4-18. Capacity factors for LADWP's in-basin generating stations for 2025 and 2030 for the base and reduced demand response sensitivities.

4.2.5 Case 1 Transmission Sensitivity

During the 2022 Power Strategic Long-Term Resource Plan (SLTRP) Advisory Group (AG) process, several participants expressed concern regarding reliability, referencing recent wildfires that temporarily affected several of LADWP's transmission lines, reducing LADWP's transmission line capacity and energy import capability. Because LADWP has ample local generation capacity situated within the Los Angeles Basin, and because of unseasonably cool weather, LADWP was able to successfully serve customer load uninterrupted during these wildfires. However, with the anticipated increased penetration of intermittent renewables and volatile weather conditions associated with climate change, the concept of resiliency becomes paramount. In response to the SLTRP Advisory Group's request to examine resiliency, the Integrated Resource Planning (IRP) team modeled the effects of losing a major transmission line, as what could occur during another wildfire. The Barren Ridge line, with a capacity of approximately 1,700 MW, was chosen for this study. This line runs the length of the Owens Valley in California, and provides extensive wind, solar, and small hydroelectric power to the

Los Angeles Basin. Case 1 was modeled for one year with this line inoperative to ascertain the effects on system reliability, as shown in **Figure 4-19**.

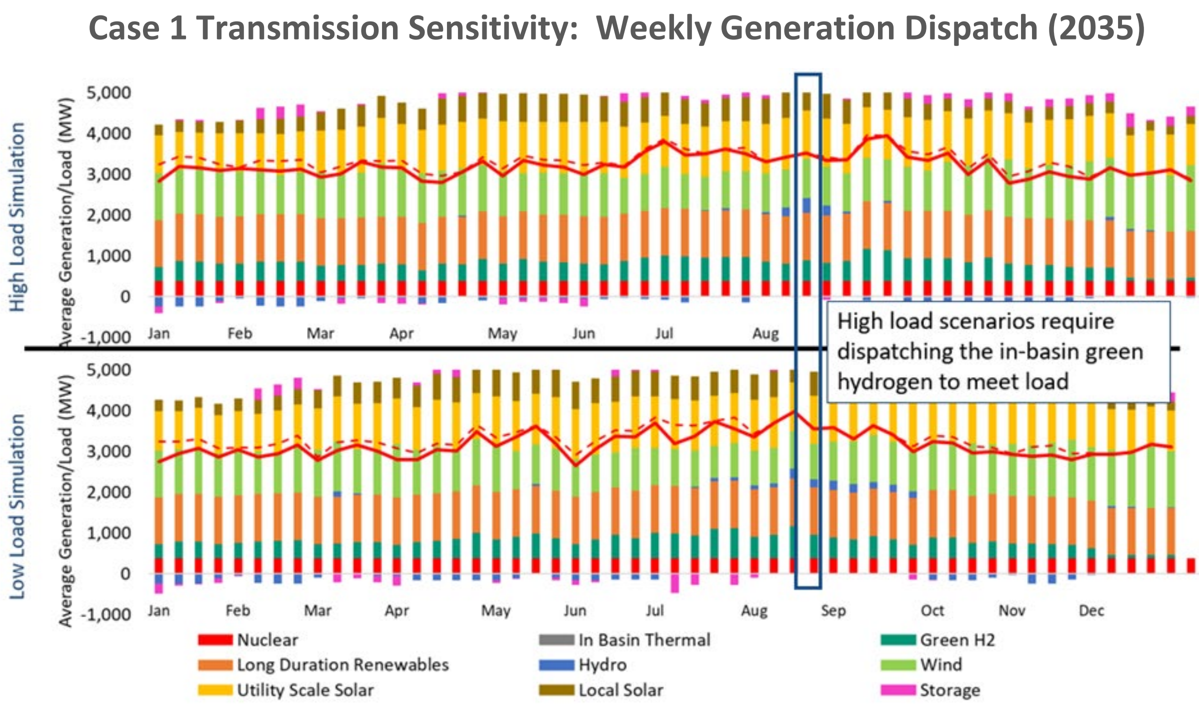


Figure 4-19. *Case 1 weekly generation dispatch for the year 2035 with the Barren Ridge transmission line removed. Both high load and low load sensitivities were examined.*

In addition to studying the Barren Ridge transmission line, the impact of not completing certain other out-of-basin transmission line upgrades by 2028, expected to provide approximately 475 MW of import capability from out-of-state resources located northeast of Los Angeles, was investigated. A gradual build out of new renewables between 2031 and 2035 reaches 475 MW on this transmission corridor, consisting of 375 MW of long-duration renewables and 100 MW of wind. The Transmission Sensitivity omits this gradual build of renewables through 2035, and omits the full 475 MW thereafter while downrating this transmission corridor by a corresponding 475 MW.

Results of this sensitivity indicate that RPS percentage drops by approximately 15% in 2035, but still remains above 100%, as shown in **Figure 4-20**.

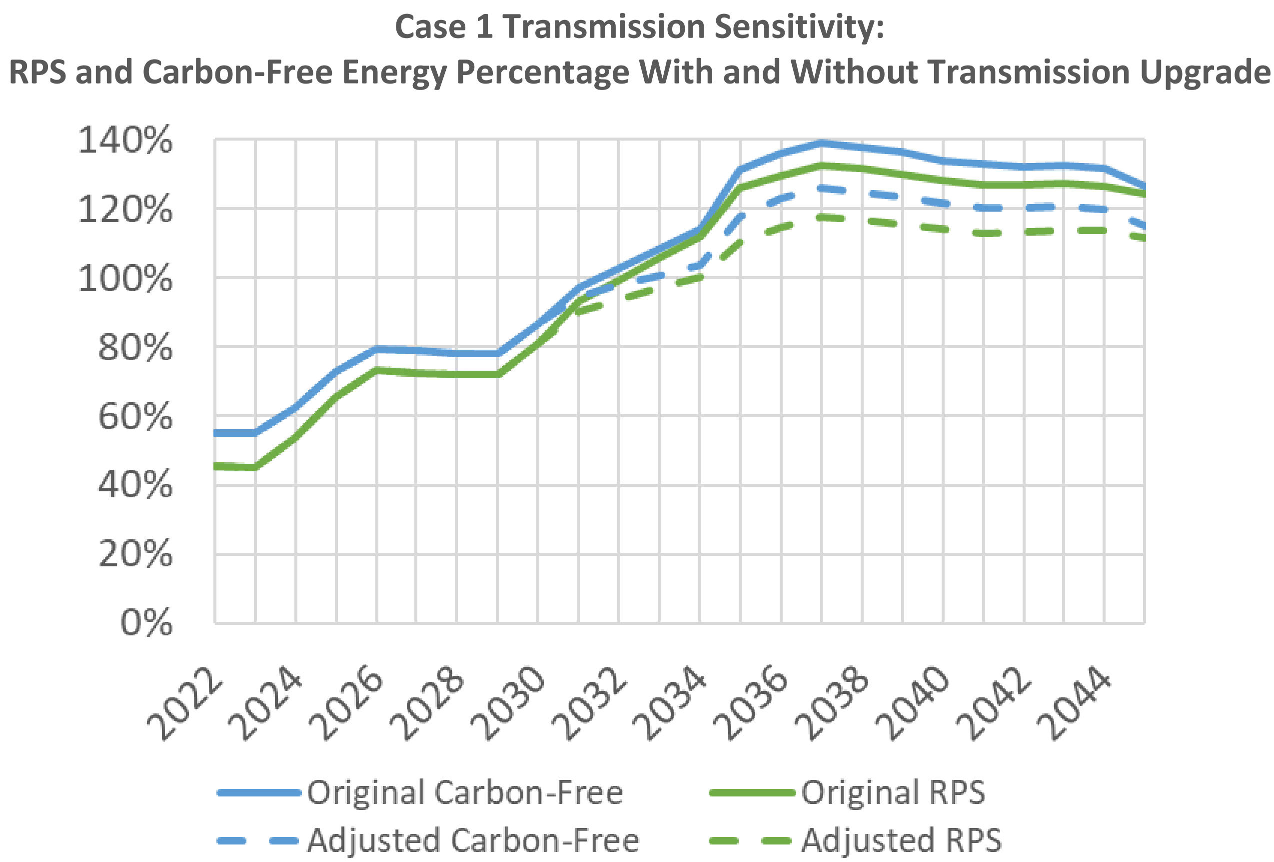


Figure 4-20*. Percentage RPS and carbon-free energy with and without the transmission line upgrade. Due to reduced import capacity, less renewable and carbon-free energy can be delivered to LADWP (dashed lines); however, both RPS and carbon-free energy make up more than 100% of total retail sales from the mid-2030s and beyond.*

Failure to complete this transmission line upgrade would result in additional costs to LADWP. If the anticipated transmission line upgrade is not completed, the energy that would have been imported via this transmission corridor must be replaced with other sources. Such energy is likely to come from LADWP's generation resources situated within the Los Angeles Basin, and will mainly consist of energy produced from green hydrogen generation resources. Although green hydrogen is a zero-carbon resource, such resources tend to be costlier to operate than renewable resources, owing to the elevated cost of the green hydrogen fuel. Although, LADWP would forego the costs of purchasing the renewable resources that would have been imported via this transmission corridor as well as the cost of the transmission upgrade itself, the net effect would be in increase in overall costs of approximately $7 billion between 2028 and 2045 on a net present value basis. This increase is due mainly to the increased use of green hydrogen resources and the increased need to purchase additional green hydrogen fuel (**Figure 4-21**).

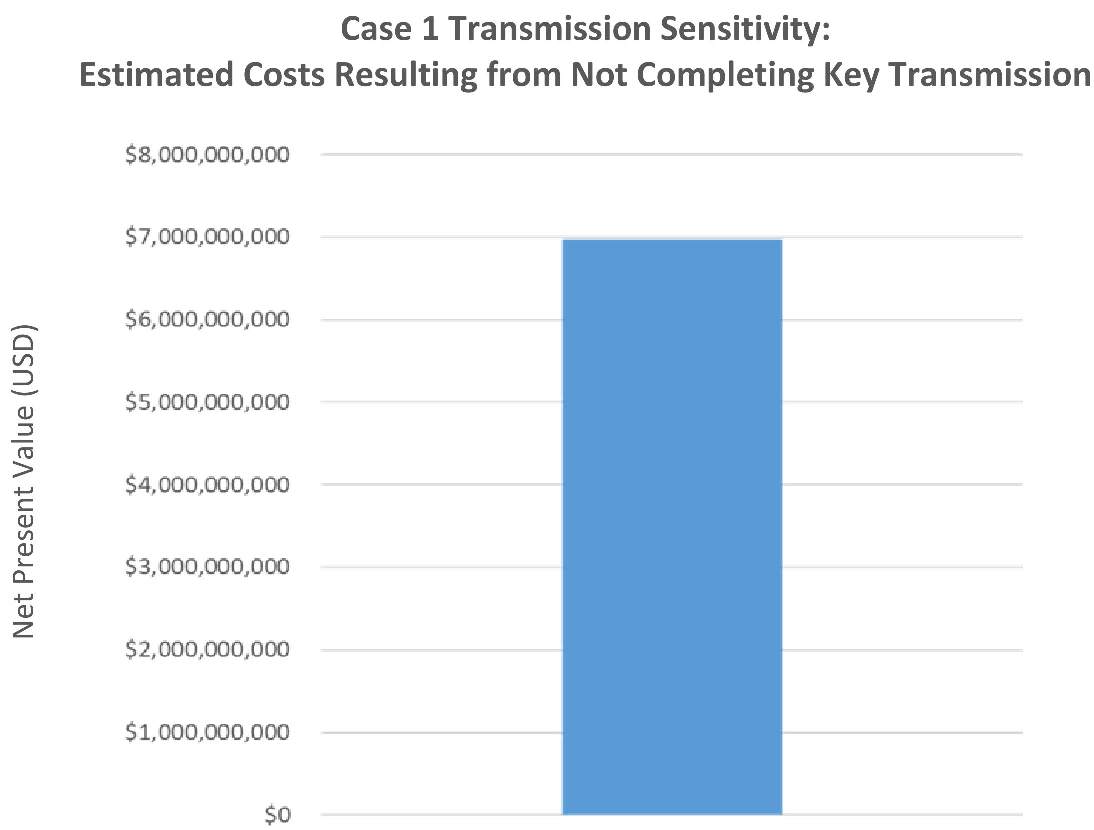


***Figure 4-21**. Increased cost associated with not completing key transmission line upgrades located to the northeast of LADWP's service territory. Overall costs would increase by approximately $7 billion between 2028 and 2035 on a net present value basis. Increased costs are due mainly to the increased reliance on green hydrogen resources to replace the energy that would have been imported via this transmission corridor.*

The average capacity factor of in-basin green hydrogen generation resources between 2028 and 2045 is expected to increase in the absence of this transmission upgrade. With the transmission upgrade in place, in-basin green hydrogen achieves a low capacity factor, averaging less than 2%. Conversely, if the transmission upgrade is not completed, LADWP must rely on in-basin hydrogen resources to replace this lost energy, with a capacity factor averaging approximately 18% between 2028 and 2045 (**Figure 4-22**).

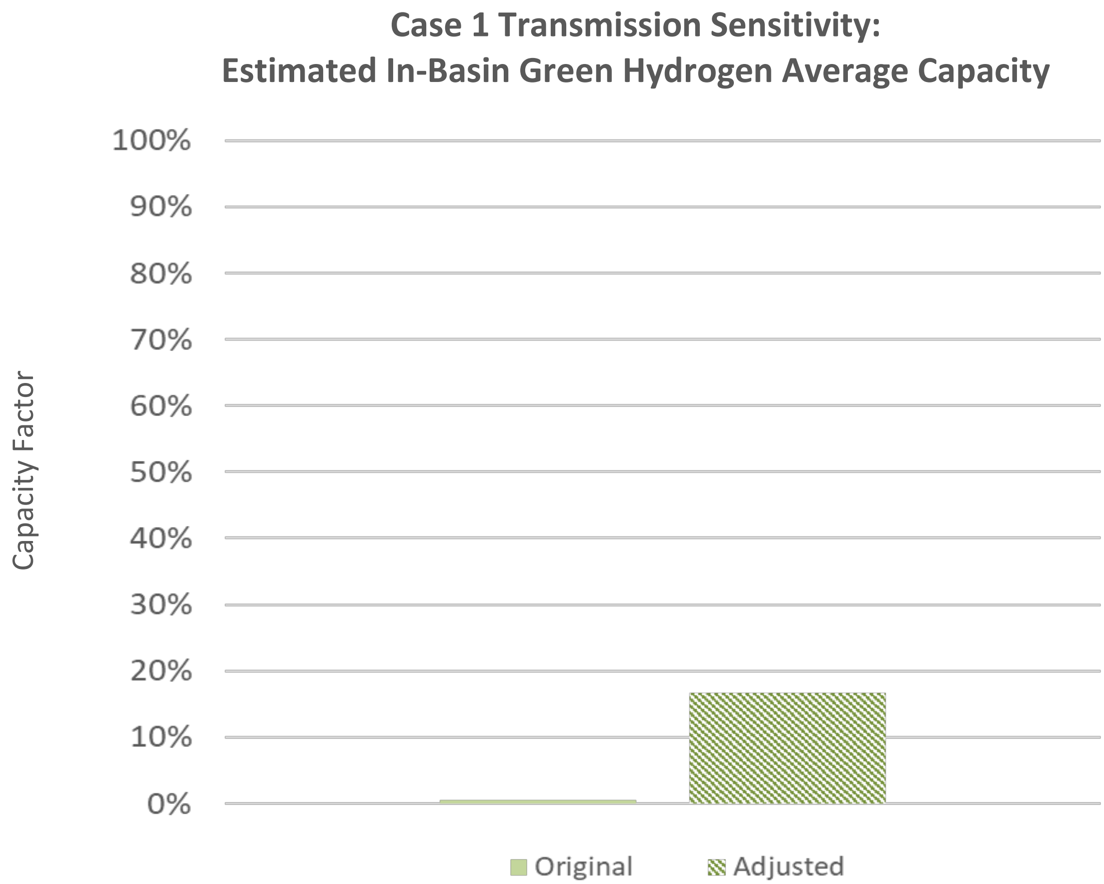


***Figure 4-22**. Average capacity factor of in-basin green hydrogen generation resources between 2028 and 2045. With the transmission upgrade in place, in-basin green hydrogen achieves a low capacity factor, averaging less than 2%. Conversely, if the transmission upgrade is not completed, LADWP must rely on in-basin hydrogen resources to replace the lost energy, with a capacity factor averaging approximately 18% between 2028 and 2045.*

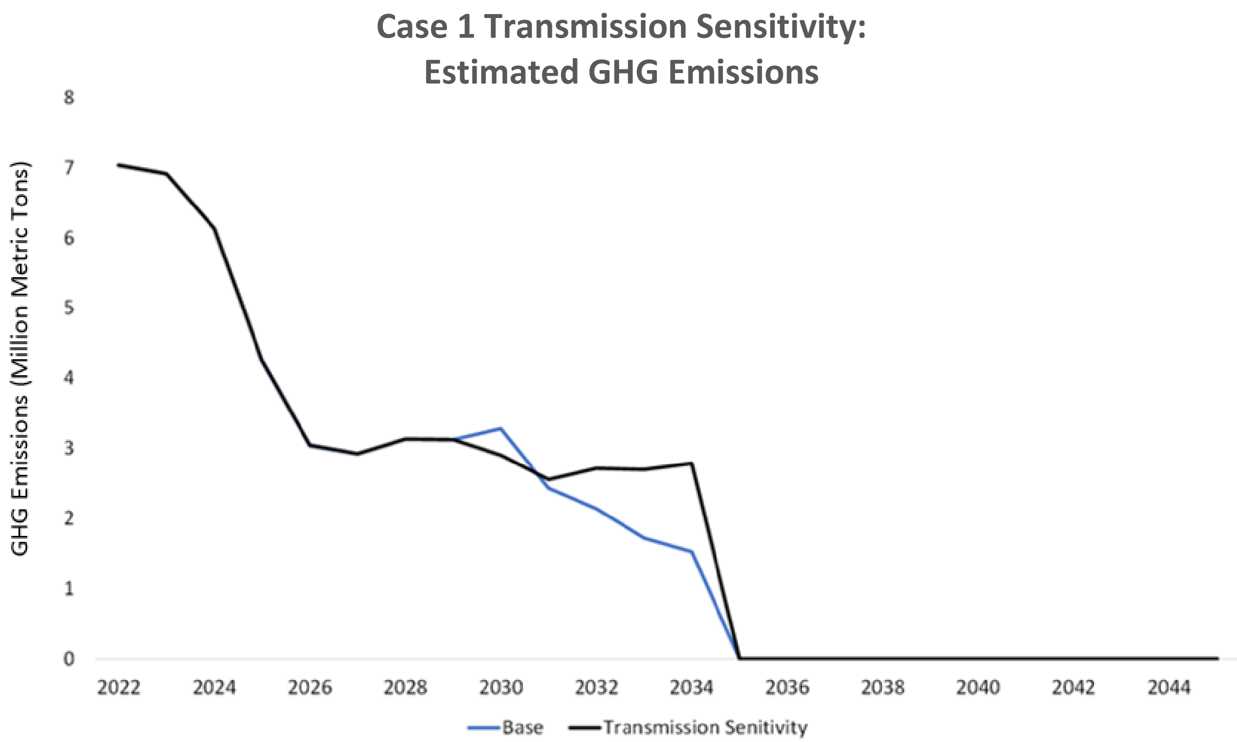


Figure 4-23. *GHG emissions with and without the transmission upgrade. Energy that would have been delivered via this transmission corridor is replaced primarily by LADWP's in-basin generating stations, which are not completely re-powered or replaced by green hydrogen facilities until 2035.*

GHG and NOx emissions also increase without the transmission upgrade. Energy that would have been delivered via this transmission corridor is replaced primarily by LADWP's in-basin generating stations, which are not completely re-powered or replaced by green hydrogen facilities until 2035. Thus, GHG emissions and NOx emissions are expected to increase slightly between 2028 and 2035 (**Figure 4-23** and **Figure 4-24**).

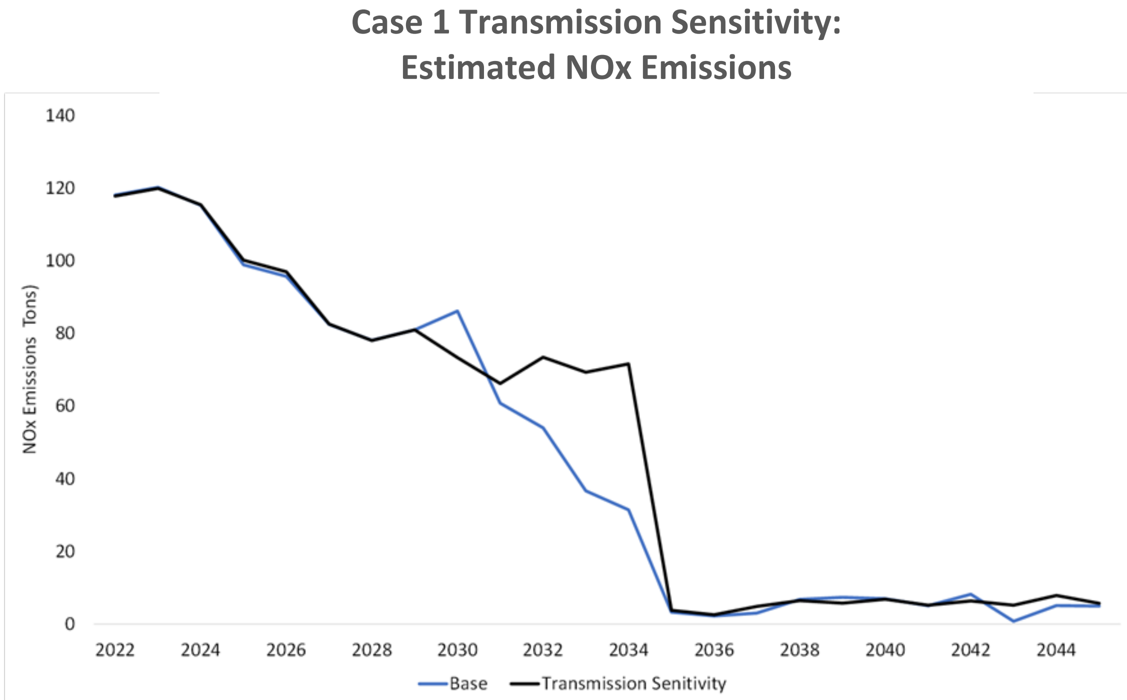


***Figure 4-24**. NOx emissions with and without the transmission upgrade. As with carbon emissions, energy that would have been delivered via this transmission corridor is replaced primarily by LADWP's in-basin generating stations.*

4.2.6 Case 1 No In-Basin Combustion Sensitivity

During the 2022 SLTRP Planning Process, the Los Angeles Department of Water and Power (LADWP) held a series of Advisory Group meetings that were fundamental in developing the case scenarios to evaluate for the 2022 SLTRP. Stakeholders, including Sierra Club and California Energy Storage Alliance, among others, were also involved in the LA100 Study, which was a groundbreaking, science-based study to determine the investments required for LADWP to achieve 100% renewable energy by 2045 or earlier. As stakeholders have expressed interest in evaluating a "no in-basin combustion" scenario for the 2022 SLTRP, LADWP seeks to be responsive to this request while planning within the framework of LADWP's core planning pillars—reliability and resiliency, environmental stewardship, and cost affordability.

The 2022 SLTRP is building off of the LA100 Study to chart an equitable carbon-free future that maintains reliability, resiliency, an affordability. The LA100 Study found that firm, dispatchable in-basin generation capacity powered by renewable-derived resources was a common investment in all carbon-free scenarios (**Figure 4-25**). As NREL modeled a future 100%

renewable Power System, NREL scientists utilized multiple models—capacity expansion to determine the best fit, least cost resources to meet future peak load, resource adequacy models to determine granular loss of load probability metrics while considering intermittency of variable energy resources, and a production cost model to simulate the operations of the Power System. Each of these models were iterative and there were check points to refine additional resources to ensure that LADWP's future Power System is reliable and resilient. The following is a description from the Chapter 6 of the LA100 Study (www.LA100study.com) describing the need for firm capacity in-basin:

"However, there are days to weeks when the availability of wind and solar resources is so low that insufficient energy exists to meet load during all times of the day, even given the extensive ability to diurnally shift energy. Certainly, more wind and solar capacity could be built to create additional available energy, however, the incremental capacity credit of these resources, even with additional diurnal storage, is very low as the LADWP system approaches 100% renewables. Furthermore, these additions would result in increases in energy availability not just on days with a 24-hour renewable energy deficit, but also increases in surplus energy during high-resource quality periods when wind and solar availability already exceeds 24-hour load. On balance, this means that the value of additional wind or solar capacity is declining as they would be producing a decreasing amount of usable energy and contributing less to meeting peak load conditions. As a result, other options for maintaining energy balance during these periods can be procured at lower net-system cost. So, in order to cost-effectively balance supply and demand on every day of the year, renewable firm capacity resources—resources that can generate on demand and provide uninterrupted supply over the course of days to weeks—are deployed across the LA100 scenarios. Historically, these services have been provided by in-basin natural gas generation units at the Harbor, Haynes, Scattergood, and Valley generation sites. However, a number of these units are once-through cooled and expected to retire by 2030. In the SB 100, Transmission Focus, and Limited New Transmission scenarios, as OTC power plants are retired and load grows, new in-basin renewably fueled combustion turbines are deployed to meet the firm capacity deficit by 2035. Outside of the basin, in the same timeframe, the replacement of IPP coal units with units burning natural gas and hydrogen makes up for a portion of the retired coal capacity, while a small amount of geothermal capacity provides additional firm capacity. Wind, solar, and diurnal storage assets continue to make up a substantial portion of the firm capacity needs. but as noted above, their declining capacity credit make it cost-prohibitive to meet all capacity needs with those assets alone. Firm capacity technologies thus make up the difference."

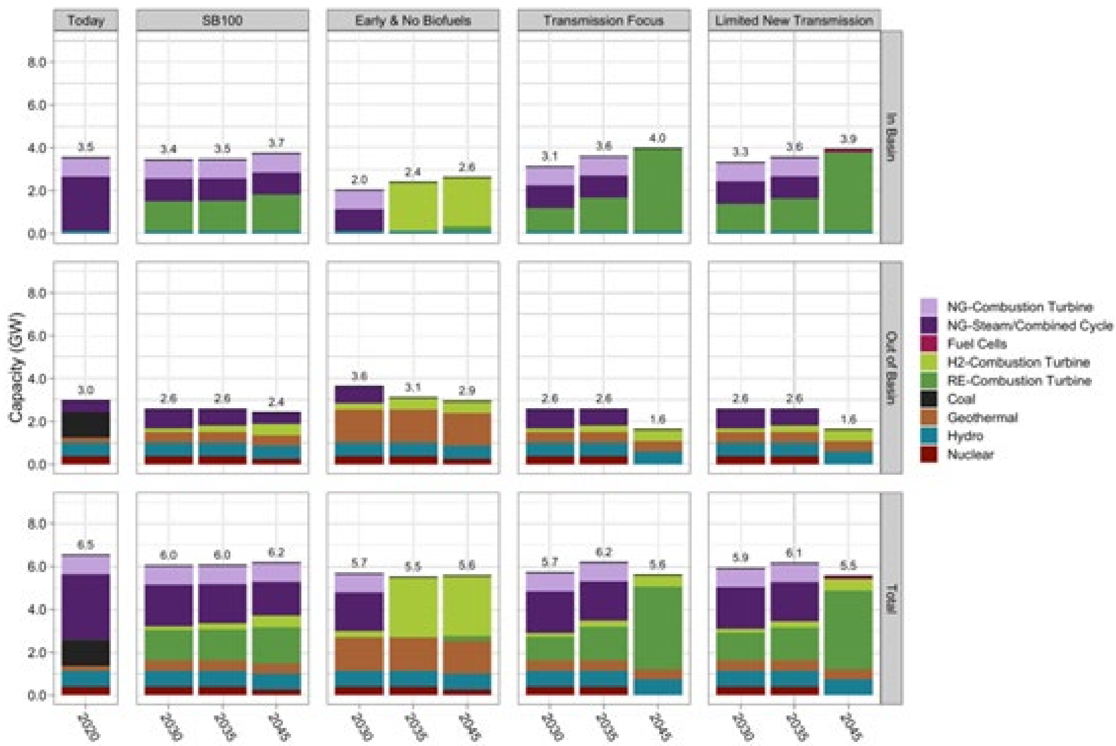


***Figure 4-25**. Nominal capacity from firm capacity resources, High scenarios, 2030-2045.*

The National Renewable Energy Laboratory attempted to build a "no combustion" scenario that included an initial scenario early on in the study that did not pass reliability metrics and, later, a sensitivity to the "Early, No-Biofuels" scenario. This sensitivity resulted in the following outcomes:

- Increased out-of-basin hydrogen combustion of approximately 1,600 MW; and
- Significant quantities of in-basin utility-scale solar requiring a total of approximately 9,000 acres or 14 square miles; and
- Significantly increased in-basin transmission, including 5 new in basin transmission lines.

Even with the above increases in required resources, the scenario resulted in the inability to serve load during high impact, low frequency events (e.g. wildfires, earthquakes, heat storms). These findings from the LA100 Study were presented in depth by NREL scientists during the SLTRP Advisory Group Meeting #5 on November 10, 2021. Key takeaways from NREL's presentation include:

- In-basin long-duration, dispatchable resources are used infrequently under normal grid conditions, but may be heavily relied upon during stressed grid conditions
- Lack of in-basin long-duration dispatchable resources leads to increased reliance on the transmission system, which creates vulnerability to transmission outages
- Unexpected or low probability events (e.g. wildfires) can be very disruptive in systems with heavy reliance on transmission.

The LA100 Study evaluated “no combustion” scenarios at two points of the study—early on and as a final sensitivity. The initial scenario definition of Early and No Biofuels scenario did not include hydrogen of any sort. Reliability challenges were seen, so the Advisory Group allowed the inclusion of hydrogen at all locations. The final scenario sensitivity around Early and No Biofuels scenario included no combustion resources within the Los Angeles Basin (**Figure 4-26**). This sensitivity was not fully analyzed through all the tools for the main scenarios; however, the firm capacity in-basin dropped from 2,000 MW to 0 MW, which likely would result in challenges if the sensitivity were evaluated through subsequent tools—resource adequacy, production cost, and power flow models.

In the final scenario sensitivity on Early and No Biofuels, which disallowed combustion in-basin, the model shifted combustion capacity outside the basin and increased reliance on transmission.

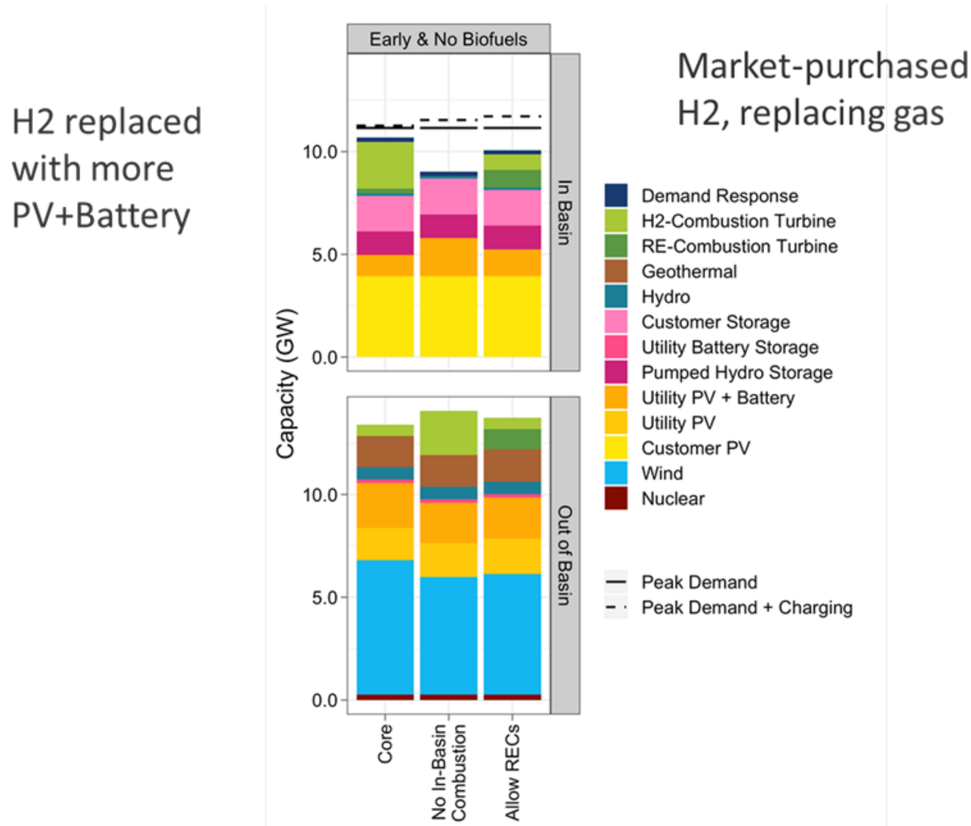


Figure 4-26*. Market-purchased hydrogen replacing natural gas. The column on the left shows the core scenario for Early and No Biofuel, High load. Sufficient capacity exists to meet nearly all of the expected peak demand in-basin, including 2.3 GW of in-basin H2 combustion turbines.*

In the "No In-basin Combustion" scenario, all of this combustion turbine capacity shifts out of the basin with an increase in "Utility PV [solar photovoltaic] + Battery" as well as an increased reliance on transmission to meet load. The "Allow RECs [Renewable Energy Credits]" scenario utilizes natural gas in earlier years, which is then phased into market-purchased hydrogen generation by 2045. Greater reliance on out-of-basin resources also requires more out-of-basin and in-basin transmission (**Figure 4-27**).

Location	Core	No In Basin Combustion	Allow RECs
In Basin	468 MW 3 lines 24.8 km	1,457 MW 8 lines 90 km	143 MW 3 lines 38 km
Out of Basin	2,354 MW 3 lines 379 km	2,032 MW 2 lines 107 km	

Figure 4-27*. The "Core" and "No In-basin Combustion" scenarios built similar amounts of out-of-basin transmission, but the sensitivity built significantly more in-basin transmission, both upgrading more lines and more overall capacity. This is in addition to the 30+ transmission projects LADWP is upgrading or building by 2030 to accommodate 80% renewables by 2030.*

Allowing RECs significantly reduced the amount of transmission built. Although in-basin hydrogen capacity is built for reliability and resiliency, the actual usage of in-basin hydrogen is generally minimal and primarily for backup (**Figure 4-28**).

Capacity Factor of All Combustion, Hydrogen

Year	RPM, Core	RPM, No In-Basin Comb.	RPM, Allow RECs
2025	10%, 0%	14%, 0%	14%, 0%
2030	2%, 0%	2%, 0%	2%, 0%
2035	0.5%, 0.5%	0%, 0%	8%, 0%
2040	0.4%, 0.4%	0%, 0%	4%, 1%
2045	1%, 1%	0%, 0%	2%, 2%

Figure 4-28*. Capacity factors for green hydrogen-fueled electric generation, under different load conditions. Estimates derived from NREL's Resource Planning Model (RPM).*

Under stressed load conditions, however, hydrogen is utilized much more during certain outage conditions on the grid.

Key takeaways from the LA100 Study regarding in-basin combustion include:

- In-basin long-term dispatchable resources are used infrequently under normal grid conditions, but may be heavily relied upon during stressed grid conditions
- Lack of in-basin long-term dispatchable resources leads to increased reliance on the transmission system, which creates vulnerability to transmission outages
- Unexpected or low probability events (e.g. wildfires) can be very disruptive in systems with heavy reliance on transmission

Recognizing that LADWP needs to maintain firm, dispatchable capacity in-basin in order to reliably decarbonize, the 2022 SLTRP includes a “No In-basin Combustion” green hydrogen fuel cell sensitivity. Hydrogen fuel cells also provide long-duration capacity needs without the use of combustion, resulting in zero NOx emissions, and serve as a valuable proxy for understanding the air quality benefits of a no in-basin combustion scenario. Additionally, LADWP is partnering with NREL to expand emissions analysis to locational and temporal air quality and health outcomes for the SLTRP. One of the key takeaways from the LA100 Study was that under a carbon-free scenario, electrification is the main driver for improved air quality and health benefits as illustrated in **Figure 4-29** below. Chapter 9 of the LA100 Study provides detailed information on these findings.

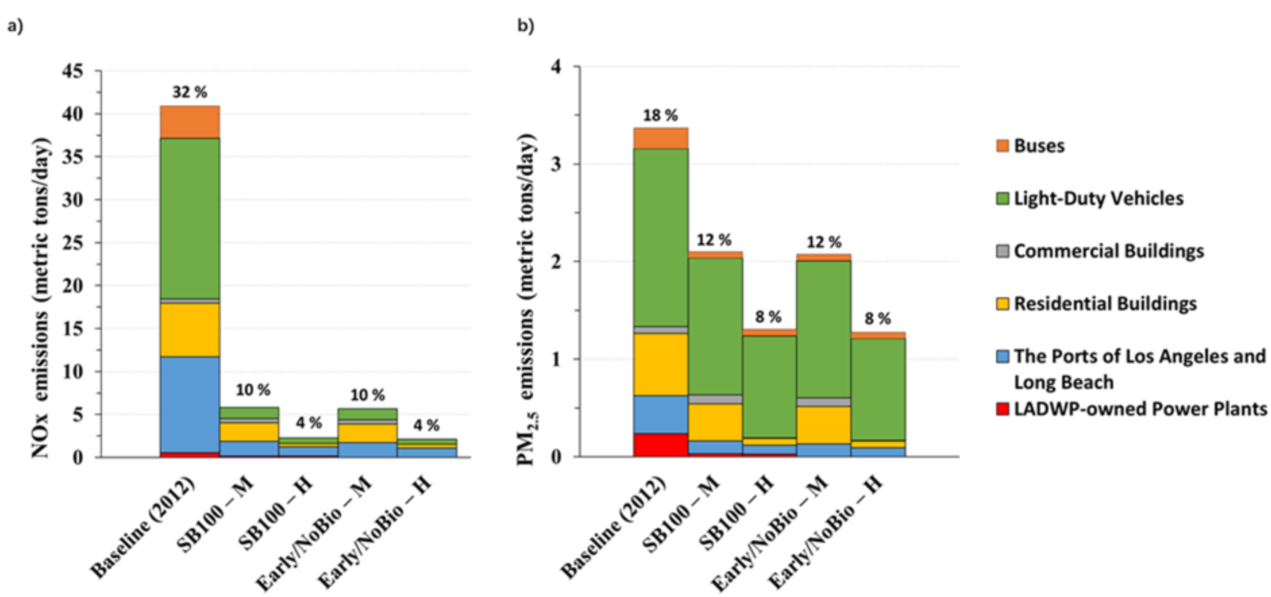


***Figure 4-29**. NOx emissions from various LA100 scenarios in 2045 compared to 2012 baseline.*

Building off of the LA100 Study, the 2022 SLTRP modeled three case scenarios that achieved 100% carbon free by 2035. These three cases included sufficient amounts of green hydrogen in-basin generating capacity by 2035 to achieve the zero-carbon goal, while ensuring that LADWP has a reliable and resilient system even during stressed load conditions, like wildfires. Overall, the results from the 2022 SLTRP were consistent with the LA100 Study's Early and No Biofuels scenarios, with in-basin green hydrogen generating capacity operating at minimal levels during normal operations, in the single digit capacity factors. However, during stress load conditions, the SLTRP modeling indicates that in-basin generation is heavily relied on in 2035 with all green hydrogen units dispatched to meet load when there is loss of transmission. Simulations studied various wildfire scenarios – including loss of the Southern Transmission System only, loss of Barren Ridge only, and a Saddle Ridge Fire scenario which simulates loss of Barren Ridge, Pacific DC Intertie, and a 40% de-rate of the Victorville to Los Angeles transmission segment (VIC-LA).

Typically, wildfires occur for a duration of 12 hours or more. In the event of the Saddle Ridge Fire on October 10, 2019, wildfires impacted the Pacific DC Intertie for 22 hours, Barren Ridge for 10 hours, and VIC-LA for five hours. Crews were dispatched to put out the fires and restore the transmission lines. Typically, energy storage with four-hour duration would not be sufficient to provide enough power capacity for the duration of the event, even if located in-basin. Additionally, the state of charge of and resource availability (transmission and renewable energy) for the energy storage is a constraint on how much capacity and energy the device can provide during extreme events.

Although transmission outages caused by fire are infrequent, LADWP has experienced several wildfires over the last five years. When wildfires take place, they are extreme events that place stress on the Power System, and in-basin firm capacity is heavily relied on during these times to serve load to customers. Over the last five years, fires have impacted transmission for approximately 7% of the time or less, depending on the transmission line.

As LADWP decarbonizes our grid to be carbon-free by 2035, it must also lead by example and plan our resources in a way that is not only reliable during normal load conditions, but also reliable during stressed load conditions (extreme events). Firm, in-basin generating capacity fulfills this requirement. LADWP is planning our future Power System so that a 2035 Power System will be as reliable and resilient as it is today. This has served LADWP well, as it had a robust Power System with sufficient in-basin generating capacity to endure the October 2019 Saddle Ridge Fire, and also provide support to the California Independent System Operator (CAISO) during the August 2020 rotating outages.

Additionally, the NOx mitigation potential and the total quantity of NOx emission reductions were investigated for the 2022 SLTRP Cases 1, 2, and 3, under a sensitivity where in-basin combustion resources were replaced with green hydrogen fuel cells. **Figure 4-30** shows the estimated impact on the cost of NOx mitigation and total NOx emissions, resulting from replacing in-basin combustion resources with green hydrogen fuel cells.

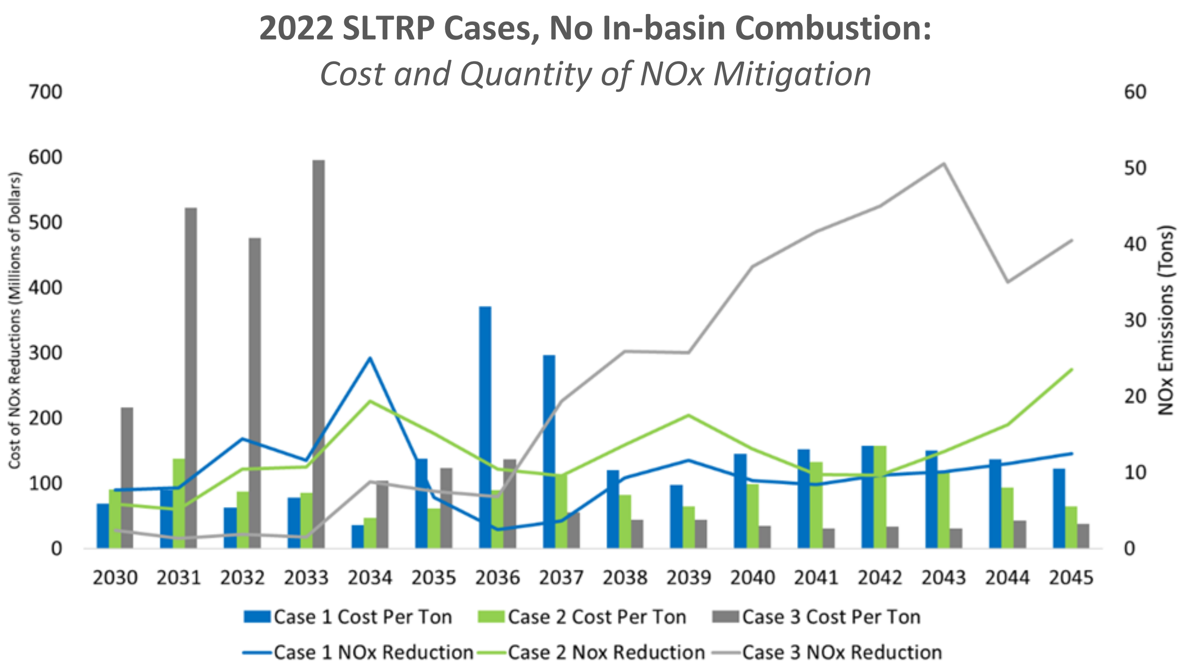


***Figure 4-30**. Cost of NOx reduction and quantity of NOx reduction for No In-basin Combustion sensitivities.*

Case 2 has a more aggressive interim RPS target than Case 1, setting a goal of achieving 90% renewables by 2030 (compared to 80% in Case 1)

4.3 Case 2

Case 2 is the second of the Core Cases which satisfy the Los Angeles City Council motion to create a plan that achieves 100% carbon-free energy by 2035. Case 2, however, is more aggressive than Case 1 in terms of the interim 2030 RPS target. Whereas Case 1 sets forth a 2030 RPS target of 80%, Case 2 sets forth a 2030 RPS target of 90%. Like Case 1, Case 2 sets a goal of achieving 2,240 MW of local distributed solar, 4,350 GWh of energy efficiency savings, 520 MW of distributed energy storage, and 576 MW of demand response by 2035.

4.3.1 Case 2 Capacity Expansion and Production Cost Modeling Results

As with Case 1, **Figure 4-31** shows that Case 2 will require significant quantities of new solar + storage, wind, and stand-alone storage to achieve 100% carbon-free energy by 2035. The last of LADWP's coal-fired generation is retired by 2025, and by 2035 all natural gas-fired generation has been retired or transformed to run on green hydrogen. Case 2 has a more aggressive interim RPS target than Case 1, setting a goal of achieving 90% renewables by 2030 (compared to 80% in Case 1). This will require a more aggressive buildout of renewables and energy storage throughout the 2020s compared to Case 1.

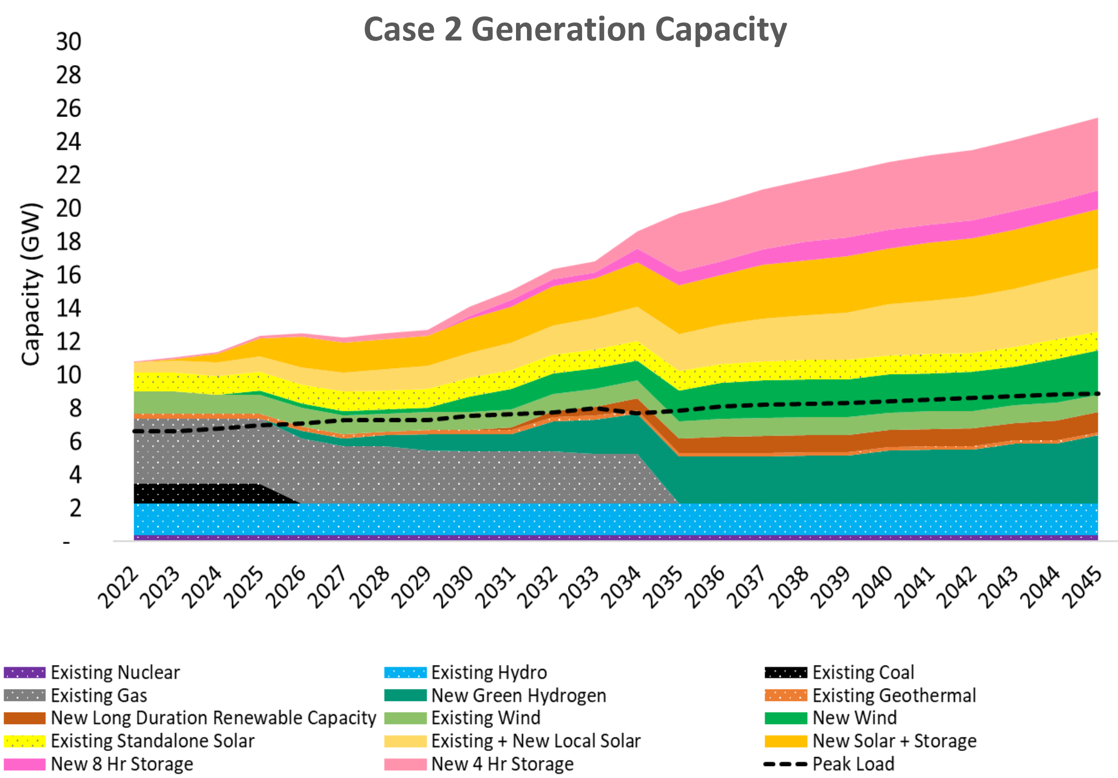


***Figure 4-31**. Generation capacity buildout for Case 2. To achieve the interim goal of 90% RPS by 2030, even more renewable and energy storage resources are required when compared to Case 1 in the short term. By 2035, both Case 2 and Case 1 have similar buildouts of renewables and energy storage in order to meet the 100% carbon-free energy goal established by the Los Angeles City Council. The dashed line represents annual peak system demand.*

Case 2 also assumes all in-basin capacity will be converted to operate on green hydrogen by 2035, as shown in **Figure 4-31**. Like Case 1, in-basin green hydrogen resources are expected to be dispatched sparingly during times of low wind and solar energy production. By 2035, both Case 1 and Case 2 have similar buildouts of renewables and energy storage in order to meet the 100% carbon-free energy goal established by the Los Angeles City Council.

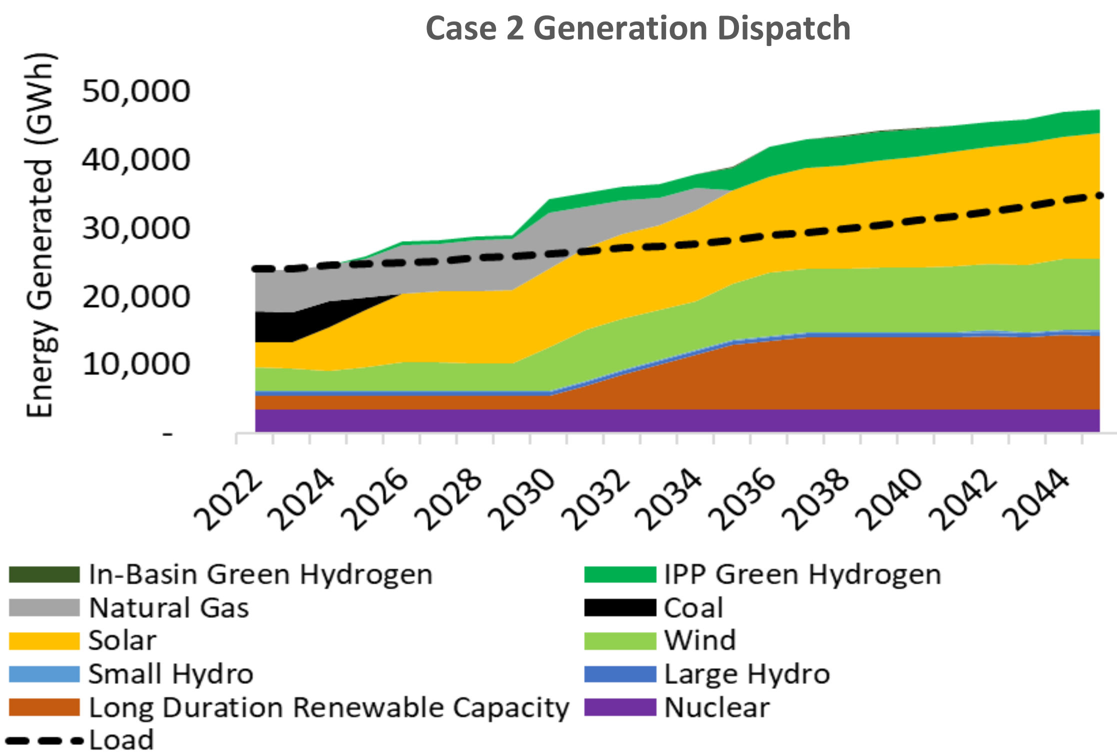


Figure 4-32*. Case 2 generation by fuel type. Case 2 has a more aggressive buildout of renewables and energy storage in the 2020s, leading up to the 90% RPS in 2030.*

Figure 4-32 shows the generation by fuel type for Case 2. Case 2 has a more aggressive buildout of renewables and energy storage in the 2020s leading up to the 90% RPS in 2030. Thus, Case 2 has an overall higher quantity of renewables and slightly lower emissions in the 2020s. As with Case 1, Case 2 relies heavily on energy from solar PV, which includes local rooftop solar and utility-scale solar + storage, long-duration renewables, and wind, to achieve the City Council's goal of achieving 100% carbon-free energy by 2035. The dashed line represents total customer demand before demand response measures are applied, in addition to transmission and distribution losses.

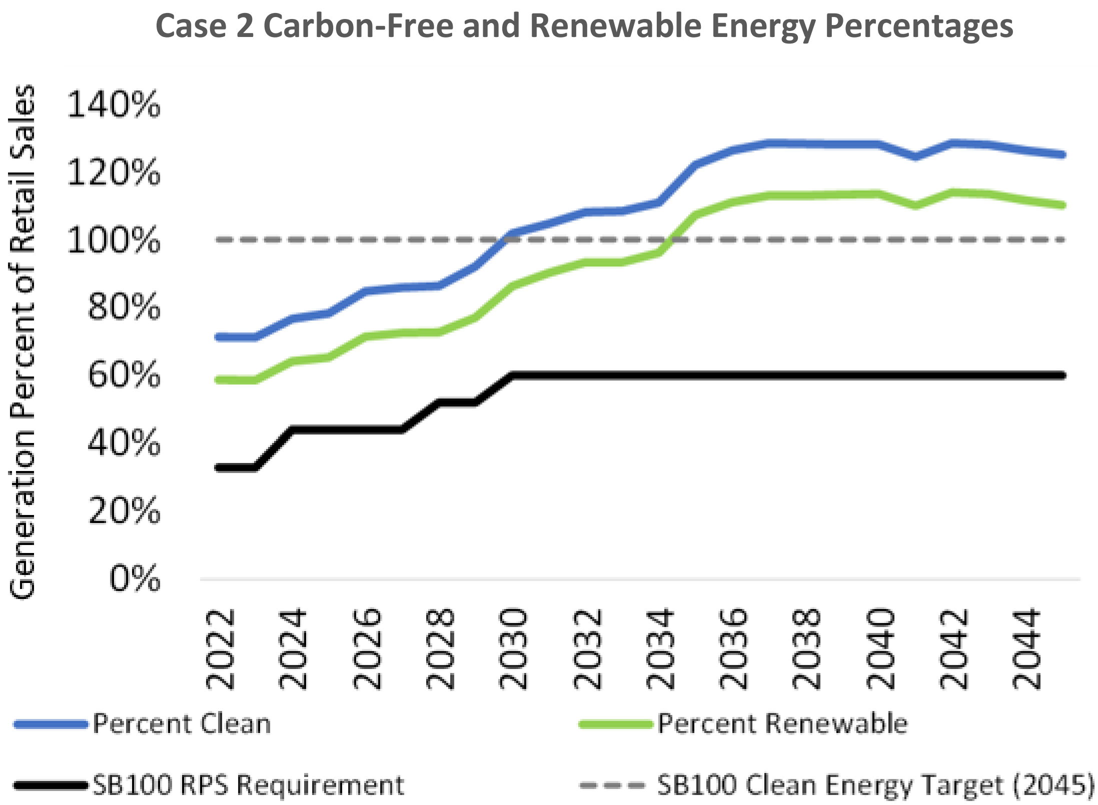


***Figure 4-33**. Case 2 percent clean (carbon-free) energy, percent renewable energy, and SB 100 RPS requirement as a percentage of gross load. SB 100 mandates that utilities achieve and maintain at least a 60% renewable portfolio standard by 2030 (depicted by the black line). Additionally, SB 100 mandates that utilities achieve 100% clean (carbon-free) energy by 2045 (depicted by the dashed line).*

Figure 4-33 shows the percent clean (carbon-free) energy and percent renewable energy for Case 2 along with the SB 100 RPS requirement for reference. Like Case 1, Case 2 exceeds both the SB 100 RPS requirement and SB 100 2045 clean (carbon-free) energy target. Case 2 also achieves a 90% RPS by 2030 (measured as a percentage of retail sales).

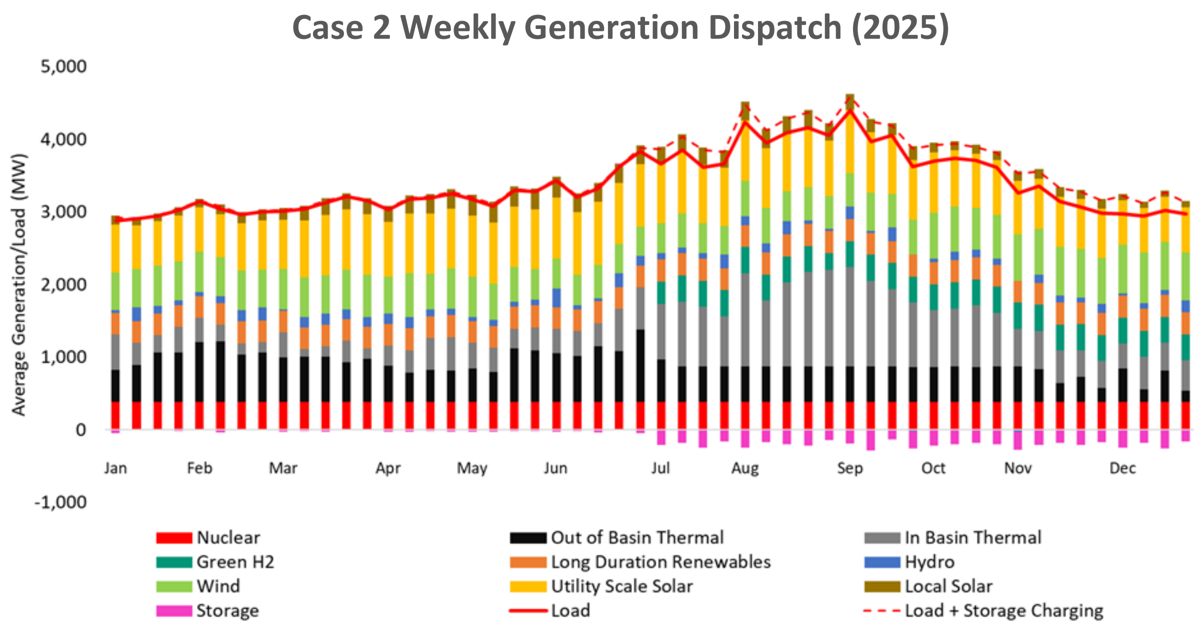


Figure 4-34*. Case 2 weekly generation dispatch for the year 2025. The solid red line indicates the average 24-hour customer load for each week. The dashed red line indicates average customer load plus average energy storage charging load.*

Figure 4-34 shows the weekly dispatch of generating resources for Case 2 for the year 2025. The solid red line represents the average customer load for each week and is averaged across all hours of the week, including peak load hours in the afternoon and early evening as well as low load hours in the early morning. The dashed red line represents weekly average customer load plus average weekly energy storage charging load. In-basin thermal assets are used extensively during the summer months to provide additional energy during peak load and to maintain reliability.

Figure 4-35 shows the weekly generation dispatch for Case 2 for the year 2035. As with Case 1, the year 2035 is the first year for Case 2 in which all energy is provided by carbon-free resources. In contrast to the year 2025 depicted in **Figure 4-34**, in-basin green hydrogen resources attain low capacity factors, being dispatched infrequently. Energy storage assets are used extensively throughout the year to absorb excess energy from renewables and to store that energy for later use (depicted in magenta).

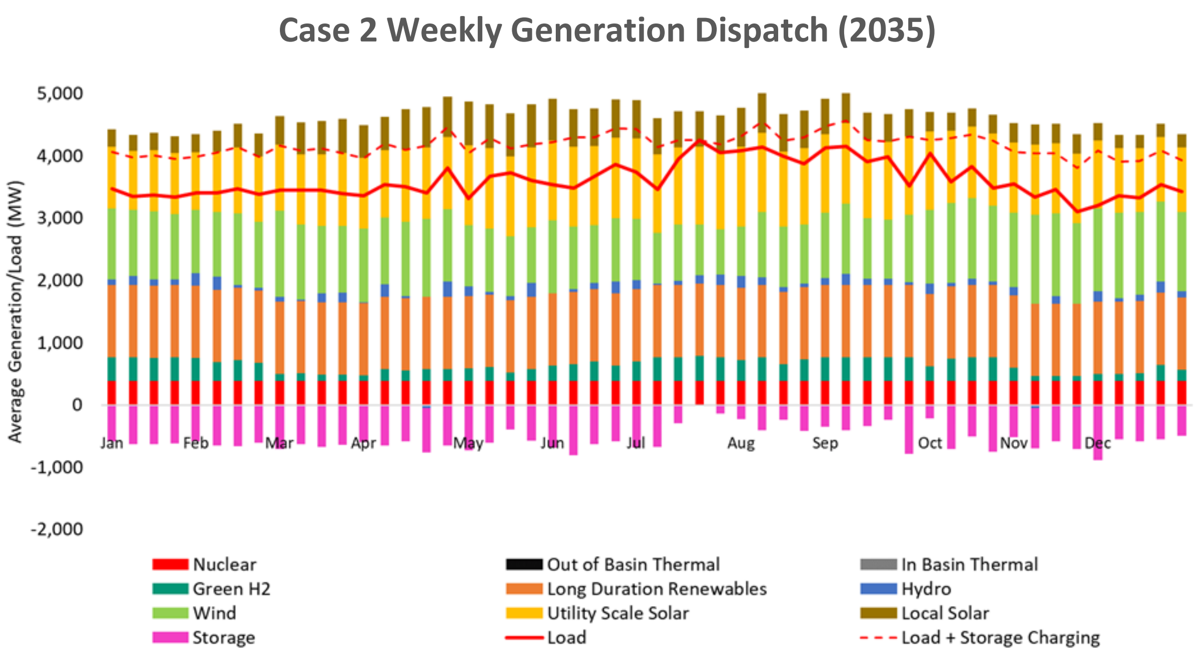


Figure 4-35*. Weekly generation dispatch for Case 2 for the year 2035. The solid red line represents total load, inclusive of line losses, average over all hours of each week, including high load hours in the afternoon and evenings and low load hours in the early morning.*

4.3.2 Case 2 Fuel Cost Sensitivity

Among the 2022 SLTRP sensitivities conducted was a commodity price sensitivity for Case 2, which explored high and low fuel price bookends for natural gas and green hydrogen, relative to the base fuel price used for Core Case modeling.

As can be seen in **Figure 4-36** below, the annual fuel costs ranged the greatest among the bookends in the early 2030s, from less than $400 million for the low fuel price sensitivity in 2030, to around $1 billion for the high fuel price sensitivity in 2034. It can be noted that the year 2034 is the year with the single highest expected fuel costs as it is the last year in the modeling horizon before full compliance with the 2035 100% carbon-free energy target, which drastically reduces the use of combustion fuels and shifts their use case to serve as more of a contingency backup resource, while the priority resources to serve load become renewable energy resources such as wind, solar plus energy storage, and long-duration renewables such as geothermal.

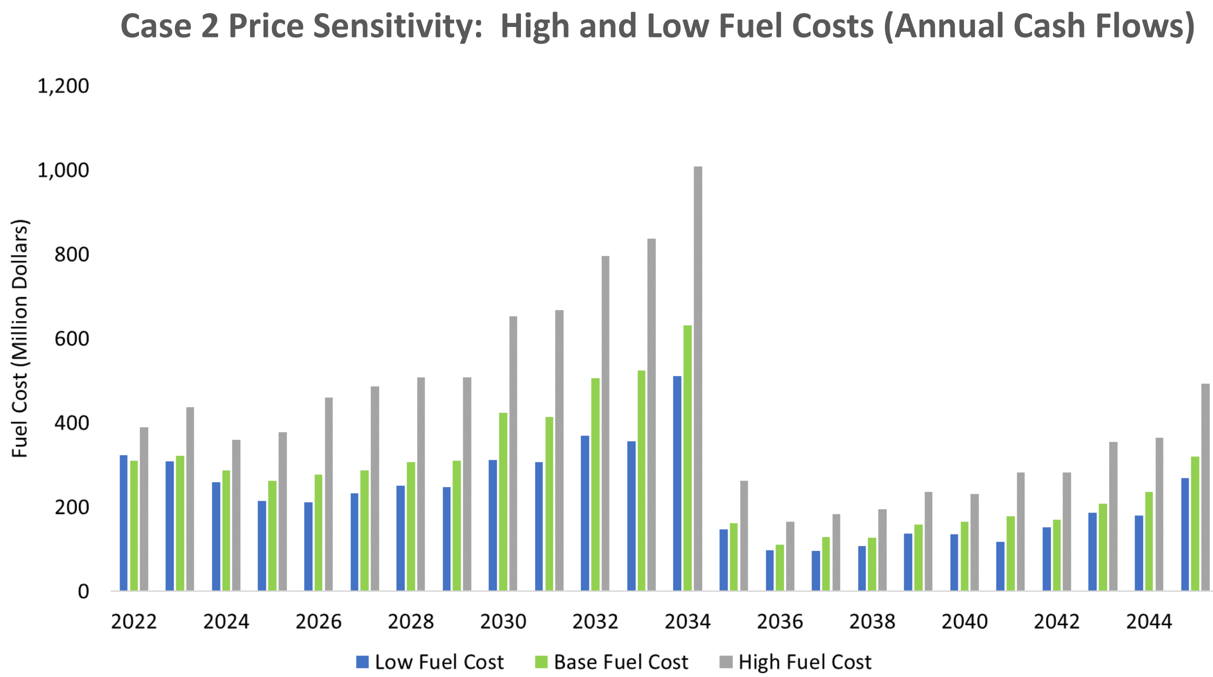


***Figure 4-36**. 2022 SLTRP Case 2 Price Sensitivity. Annual fuel costs for the base, low, and high fuel sensitivities are shown.*

From a net present value perspective, it can be observed in **Figure 4-37** that the low and high fuel price bookends cause a significant change in total fuel costs for Case 2, more between the base fuel price versus the high fuel price, in comparison to the difference between the base fuel price and the low fuel price. The approximate percentage differences in portfolio fuel costs, in net present value, are that the base fuel costs are approximately 18% greater than the low fuel costs, and the high fuel costs are approximately 52% greater than the base fuel costs. In total, across the bookends, the net present value fuel costs range from below $4 billion to almost $7 billion.

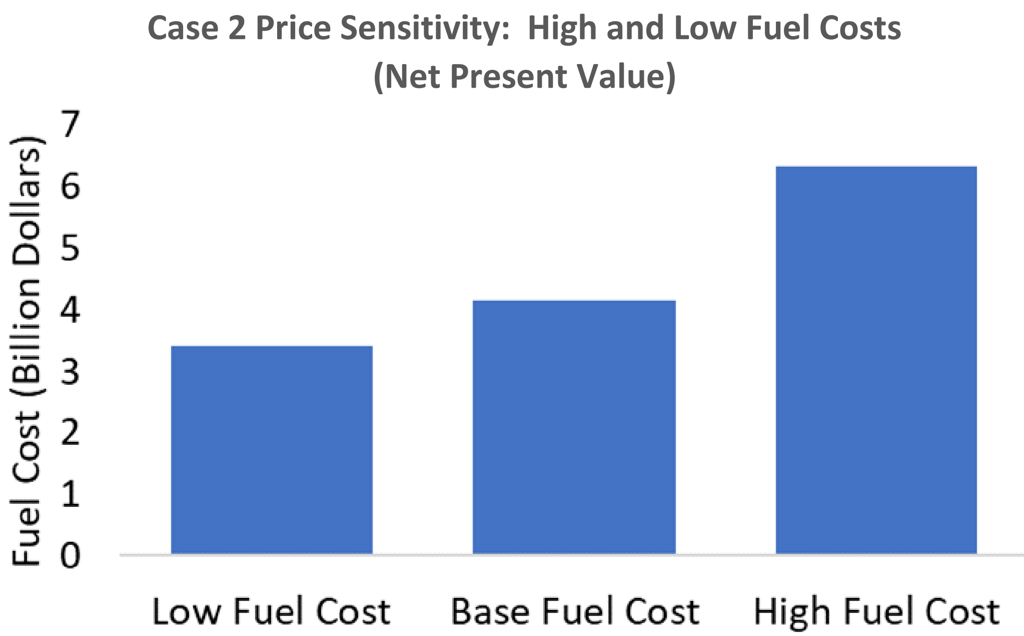


Figure 4-37*. Total fuel costs on a net present value basis for the Case 2 Price Sensitivity.*

Case 3 is the most aggressive case in terms of behind-the-meter resources such as rooftop and other distributed solar, local distributed energy storage, energy efficiency, and demand response.

4.4 Case 3

Case 3 is the third of the Core Cases which satisfy the Los Angeles City Council motion to create a plan that achieves 100% carbon-free energy by 2035. Similar to Case 2, Case 3 sets forth a 2030 RPS target of 90%. However, in contrast to Case 1 and Case 2, Case 3 sets a more aggressive goal for highest customer adoption of distributed energy resources, including 2,906 MW of local distributed solar, 4,652 GWh of energy efficiency savings, 755 MW of distributed energy storage, and 633 MW of demand response by 2035. Case 3 is the most aggressive case in terms of behind-the-meter resources such as rooftop and other distributed solar, local distributed energy storage, energy efficiency, and demand response.

4.4.1 Case 3 Capacity Expansion and Production Cost Modeling Results

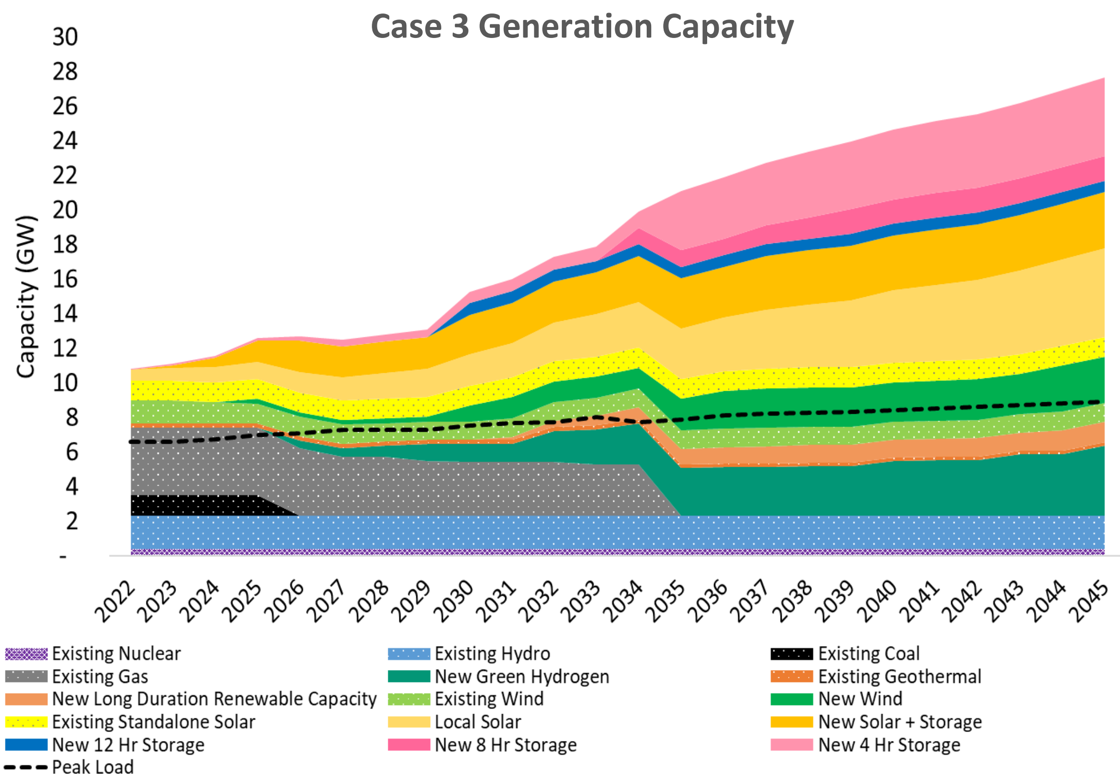


***Figure 4-38**. Generation capacity buildout for Case 3. Similar to Case 2, to achieve the interim goal of 90% RPS by 2030, even more renewable and energy storage resources are required when compared to Case 1 in the short term. By 2035, Case 3 has similar buildouts of renewables and energy storage in order to meet the 100% carbon-free energy goal established by the Los Angeles City Council. The dashed line represents annual peak system demand.*

Figure 4-38 shows the capacity expansion modeling results, which resulted in significantly building more solar, wind, long-duration renewables, and in particular, standalone energy storage for Case 3 than for SB 100, Case 1, and Case 2. These additions are on top of assuming the highest level of distributed energy resource deployment as outlined in the Case 3 definition. Like the rest of the carbon-free cases, Case 3 capacity resource buildouts phase out the use of natural gas resources and retain only carbon-free resources beginning in the year 2035.

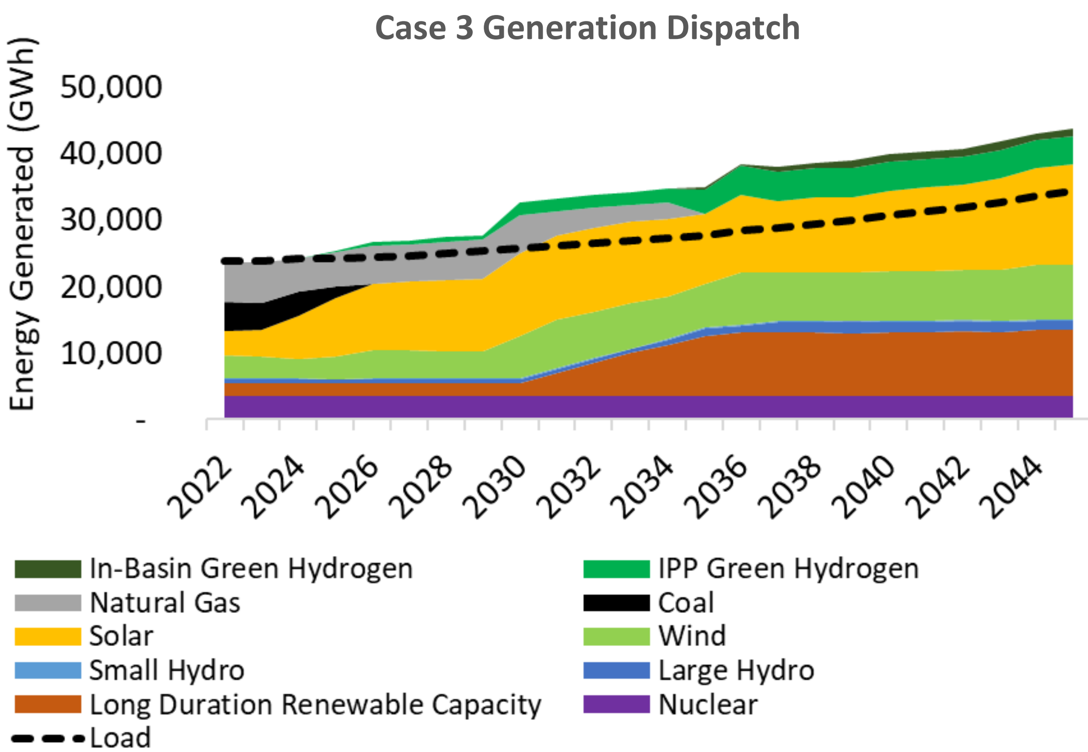


***Figure 4-39**. Case 3 generation by fuel type. Similar to Case 2, Case 3 has a more aggressive buildout of renewables and energy storage in the 2020s leading up to the 90% RPS in 2030. Thus, Case 3 has an overall higher quantity of renewables and lower emissions in the 2020s. Among the carbon-free cases, Case 3 relies the most on distributed energy resources such as solar PV, which includes local rooftop and distributed solar, to augment utility-scale solar + storage projects, to achieve the City Council's goal of achieving 100% carbon-free energy by 2035. The dashed line represents total customer demand before energy efficiency and demand response measures are applied, in addition to transmission and distribution losses.*

In contrast to the capacity buildout, **Figure 4-39** shows that the majority of the actual generation to meet customer demand for electric consumption is coming from long-duration renewables, wind, and solar, and only a minimal portion is being obtained from green hydrogen from 2035-onwards. Similar to the other cases, more energy is generated each year that compared to what is consumed by customers or incurred as transmission and distribution line losses, thus resulting in overgeneration and curtailment of renewable energy resources.

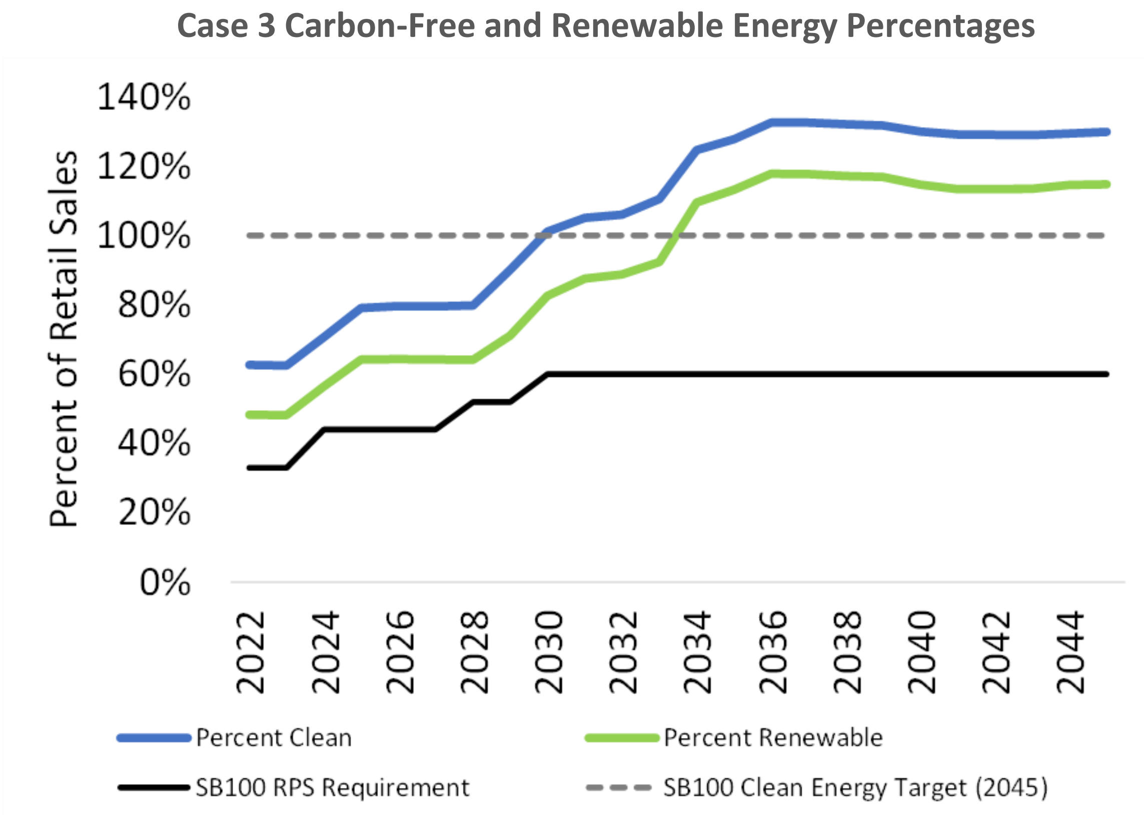


Figure 4-40*. Case 3 percent clean (carbon-free) energy, percent renewable energy, and SB 100 RPS requirement. SB 100 mandates that utilities achieve and maintain at least a 60% renewable portfolio standard by 2030 (depicted by the black line). Additionally, SB 100 mandates that utilities achieve 100% clean (carbon-free) energy by 2045 (depicted by the dashed line). As can be seen, Case 3 exceeds both the SB 100 RPS requirement and the SB 100 2045 clean (carbon-free) energy target.*

Figure 4-40 shows that similar to the other carbon-free cases, the Case 3 RPS percentage (green line) and carbon-free percentage (blue line) is well above the State of California SB 100 mandates shown in solid black and dashed gray lines respectively. As mentioned before, given the definition of the carbon-free cases is to supply sufficient resources to ensure all generation is carbon-free by 2035 (inclusive of transmission and distribution losses), eligible resources need to be overbuilt with respect to 100% of retail sales, to ensure that system losses are also covered by carbon-free resources and to maintain reliability.

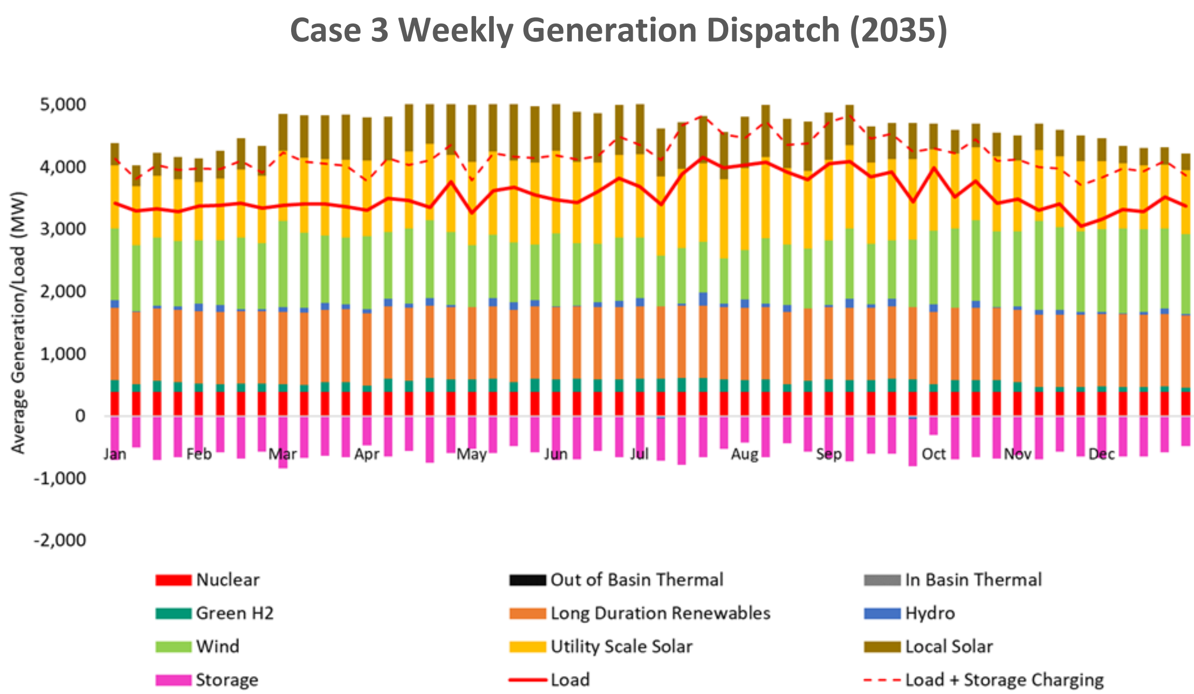


***Figure 4-41**. Case 3 weekly generation dispatch for the year 2035. The year 2035 is the first year in which all energy is provided by carbon-free resources. The solid red line indicates the average 24-hour customer load for each week. The dashed red line indicates average customer load plus average energy storage charging load. Green hydrogen resources are dispatched sparingly and are using mainly for backup and to provide reliability during times of insufficient renewable energy generation. As can be noted, there is more local solar generation than in Case 1 and Case 2. During the spring and late fall seasons however, much of the local solar generation is curtailed due to system integration challenges as a result of supply and demand mismatches, as well as not enough energy storage.*

Figure 4-41 shows the weekly generation dispatch for the year 2035, the first year in which all the energy is provided by carbon-free resources. The colored bars going above the load (solid red line) and load + energy storage charging (dashed red line) indicators show that Case 3 has a significant amount of overgeneration in the Spring and late Fall seasons as a result of highest levels of local solar generation and system integration challenges as a result of supply and demand mismatches.

4.4.2 Green Hydrogen Generation

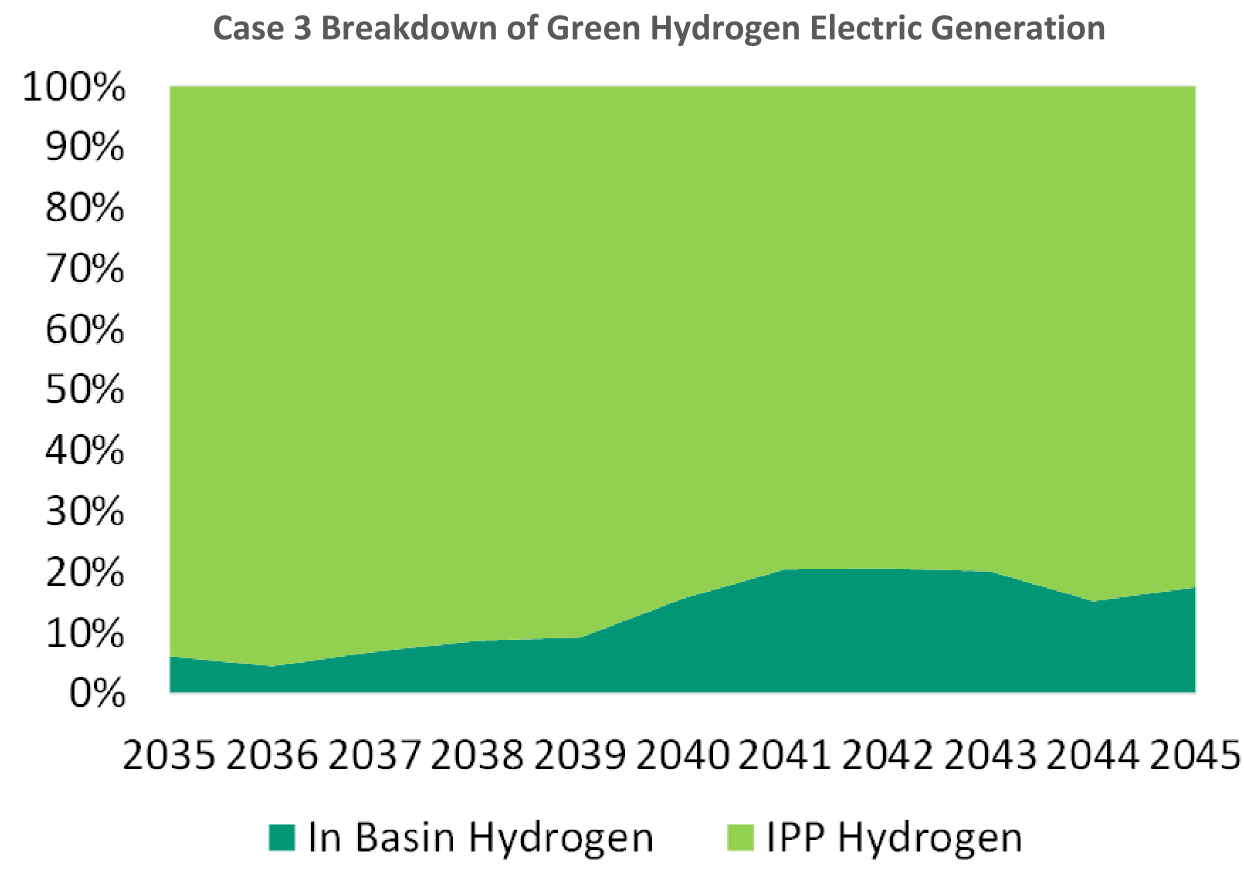


Figure 4-42*. Case 3 breakdown of green hydrogen electric generation. From 2035 through 2045, all generating stations are running solely on green hydrogen, both within the Los Angeles Basin and outside of the Basin. This figure breaks down the estimated total power generation fueled by green hydrogen into out-of-basin generation (light green) at the Intermountain Power Project (IPP), versus in-basin generation (dark green). Overall, it must be noted that usage of green hydrogen power plants within the Los Angeles Basin is expected to be very small, serving as backup resources for times of system stress such as high loads with low renewable outputs, or extreme weather events like earthquakes and wildfires.*

Figure 4-42 shows that of the amount of green hydrogen generation forecasted for Case 3, the majority of it occurs outside the Los Angeles Basin at the Intermountain Power Project, and only a very minor portion is estimated to take place inside the Los Angeles Basin. In-basin green hydrogen resources are meant to serve as backup to renewable and energy storage resources, in case of grid stress conditions such as heat waves during days of low-renewable output or extreme events such as earthquakes and wildfires. IPP green hydrogen operates more due to “must-run” reliability criteria on the coupled Southern Transmission System (STS) high-voltage direct current (HVDC) transmission line, that requires a minimum amount of IPP generation to be online at all times in order to operate reliably. The STS is one of the most instrumental transmission lines in LADWP’s Power System and is critical in transmitting large amounts of renewable energy from Delta, Utah to Adelanto, California.

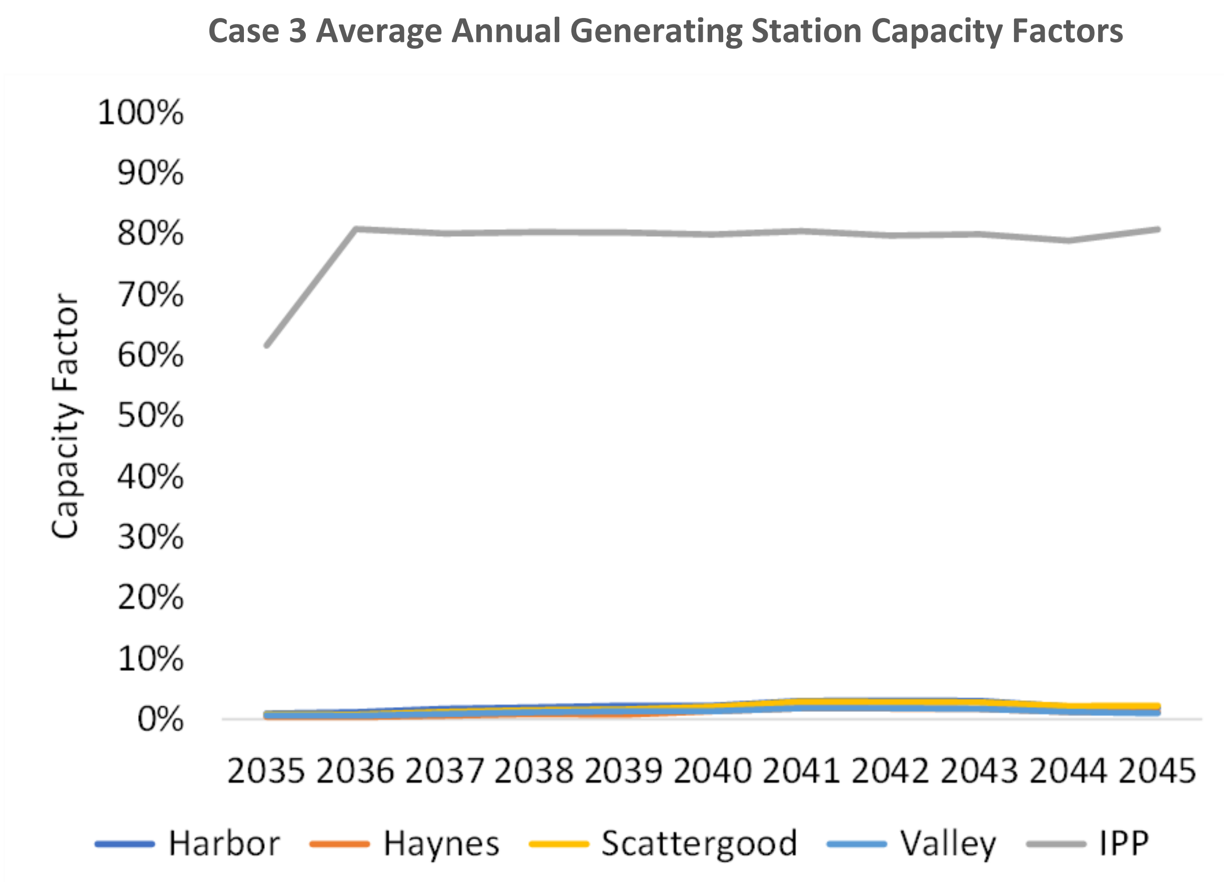


Figure 4-43. *Case 3 generating station expected average annual capacity factors. From 2035-onwards, it is expected that the average annual capacity factors of the in-basin generating stations (Harbor, Haynes, Scattergood, Valley) will drop to approximately 1% under normal system conditions. The in-basin generating stations will act as a backup resource to renewable energy and energy storage resources, during times of grid stress and outage conditions. The IPP capacity factor appears more elevated largely due to reliability and operational constraints that require a minimum amount of IPP generation to be on at all times, to maintain the STS HVDC transmission line energized and reliably operating.*

Figure 4-43 shows that on average, the annual capacity factors of LADWP's in-basin generating stations (Harbor, Haynes, Scattergood, and Valley) are near zero percent from 2035-onwards. In comparison, the average annual capacity factor of IPP is at about 80%. As stated before, the utilization of in-basin green hydrogen generation as a backup resource for reliability and resiliency, and the "must-run" constraints on IPP to maintain the STS energized, are the main factors for the capacity factor estimates shown.

In the 2030 milestones for the carbon-free cases, LADWP more than doubles our renewable portfolio standard percentage from 2022, in less than a decade.

4.5 Case Comparisons

This section compares the results of the various cases included in the 2022 SLTRP. Metrics and attributes to be compared include reliability, emissions, costs, implementation considerations, and retail electricity rate impacts.

4.5.1 Reliability Comparison

As described in detail in Chapter 3, the primary metric measuring reliability is loss of load hours (LOLH). **Figure 4-44** shows the expected LOLH for the SB 100 Case, Case 1, Case 2, and Case 3 for the years 2025, 2030, and 2035. The lower the LOLH metric, the more reliable the system. The industry standard is to plan for an expected LOLH at or below 2.4 hours annually. The SB 100 case has the highest LOLH, but still falls below the industry standard 2.4 hours for each year depicted. Cases 1, 2, and 3 have even lower LOLH values, indicating a highly reliable system is achieved. Cases 1, 3, and 3 all achieve an LOLH value well below 1.0.

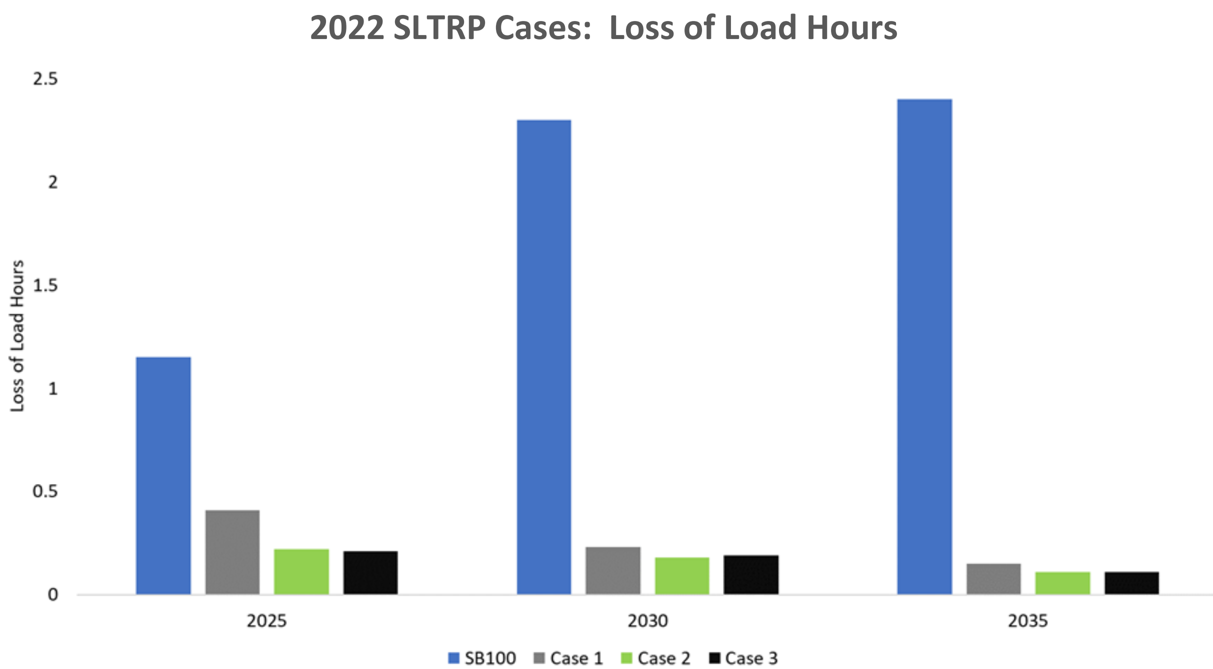


***Figure 4-44**. Expected loss of load hours for the SB 100 Case, Case 1, Case 2, and Case 3. Although the SB 100 Case has the highest loss of load hours, it still falls below the industry standard of incurring no more than 2.4 loss of load hours annually. Cases 1, 2, and 3 fall well below the industry standard, indicating a very reliable system is achieved.*

New to the 2022 SLTRP is the concept of stochastic modeling. Stochastic modeling involves running hundreds of simulations with varying weather, outages, and levels of aggregate customer demand. When planning a system to have an LOLH at or below 2.4 hours annually, only a small fraction of simulations will have a shortfall of generation resources during any hour. The fraction of simulations that do have a shortfall of generation resources typically involve extreme weather situations that would be expected to occur only once in several decades. **Figure 4-45** and **Figure 4-46** compare the hours where a shortfall occurs average only over those simulations that have a shortfall. These shortfalls tend to occur in late August and early September during hot weather and during the late afternoon and evening hours.

2022 SLTRP Cases: MWh Short (2025)

		HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Case 1	Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51	363	587	622	438	397	267	18	0
	Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 2	Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	686	601	729	411	0	0	0	0	0
	Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	520	640	662	496	166	0	0	0	0
	Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 3	Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	218	369	383	180	343	171	3	0	0
	Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

***Figure 4-45**. Comparison of MWhs short in 2025 averaged over stochastic simulations that have any shortage for any given hour. Stochastic modeling involves running hundreds of simulations with varying weather, outages, and levels of aggregate customer demand, and only a small fraction of simulations forecast a shortfall of generation resources during any hour.*

2022 SLTRP Cases: MWh Short (2035)

Case	Month	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Case 1	Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	131	0	0	0	0	0	0
	Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	144	951	722	856	816	598	859	358	0	0
	Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 2	Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	54	101	0	0	0	0	0	0
	Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	483	453	983	1458	1027	859	358	0	0
	Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 3	Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	54	101	0	0	0	0	0	0
	Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	483	453	984	1458	1027	859	358	0	0
	Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 4-46*. Comparison of MWhs short in 2035 averaged over stochastic simulations that have any shortage for any given hour*

4.5.2 Emissions Comparison

With respect to GHG emissions, all three carbon-free cases and the Reference Case (SB 100 Case) start below 8 million tons in 2022 and reduce this by almost half by 2025, as can be seen in **Figure 4-47**. This single most significant reduction in carbon emissions throughout the entire study horizon results from LADWP fully divesting away from our last remaining coal asset in 2025, as coal-fired generation at the Intermountain Power Project is replaced by cleaner generation from green hydrogen-capable units, which in 2025 operate off a fuel blend capable of 30% green hydrogen and 70% natural gas by volume, and eventually run completely off of green hydrogen starting in 2035.

Further reductions can be observed starting 2030, as substantial amounts of renewable energy are interconnected into LADWP's system, along with large amounts of energy storage of various technology types and durations to integrate the renewable energy onto the electric grid, such that Case 1 meets an 80% renewable portfolio standard by 2030, while Case 2 and Case 3 reach a 90% renewable portfolio standard by 2030, all considerably above the state mandate of reaching a 60% renewable portfolio standard by 2030 as represented in SB 100. In the 2030 milestones for the carbon-free cases, LADWP more than doubles our renewable portfolio standard percentage from 2022, in less than a decade. Additionally, contributing to emission reductions entering into the 2030s are the retirement of once-through cooling generating units by the end of 2029, in order to comply with state mandates. These retired units are replaced with carbon-free energy alternatives such as green hydrogen-ready units at Scattergood Generating Station, in addition to significant deployment of customer-sided resources such as distributed solar, distributed energy storage, energy efficiency, and demand response, which all play a contributing role in reducing emissions within the Los Angeles Basin.

By 2035, all the emissions in the carbon-free cases are reduced to zero, as all of LADWP's power generation (including losses) is supplied through carbon-free resources, an entire decade ahead of the state mandate. For the carbon-free cases, reaching the 2035 goal is significantly made possible through the conversion of in-basin generating stations from running off of natural-gas to instead running off of green hydrogen, which does not emit carbon. The SB 100 emissions can be seen plateauing beyond 2035 as its definition calls for supplying 100% of retail sales with carbon-free energy by 2045 (a decade later than the SLTRP carbon-free cases), and SB 100 allows for transmission and distribution losses to be met with non-carbon-free resources such as natural gas. Given significant load growth beginning in the mid-2030s from electrification in LADWP's service territory, SB 100's emissions remain mostly constant through the end of the study horizon.

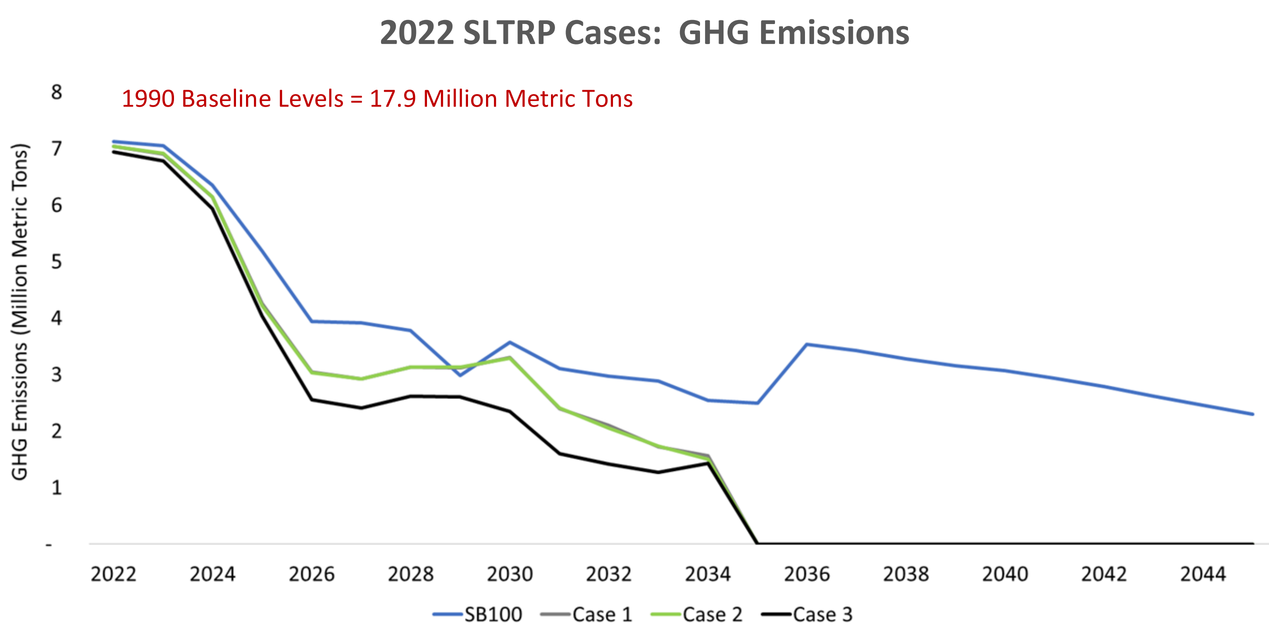


***Figure 4-47**. GHG emissions for the SLTRP cases.*

4.5.3 Renewable Energy Curtailment Comparison

With respect to renewable energy curtailment, it is important to note that in order to meet the 100% carbon-free target by 2035 and ensure all power generation comes from carbon-free resources, there will have to be an overbuild of renewable energy resources such as solar, wind, and others, as many of these variable energy resources can have an intermittent generation output due to their weather-dependent characteristics (e.g. solar generation mainly occurs when the sun is shining and wind generation mainly occurs when the wind is blowing). It is also important to note that the effective load carrying capability of these resources, or their effective system value, often declines when the system becomes oversaturated with a resource of the same characteristics, thus it incrementally requires more nameplate capacity to get the same effective capacity as before. Due to these circumstances, the SLTRP cases show varying levels of renewable energy overgeneration, or curtailment, during times that there is a mismatch between renewable energy supply and electric demand. As a result of such supply and demand mismatches, or system limitations such as transmission constraints, some of the renewable energy output is not able to be absorbed by the system at certain times.

As shown in **Figure 4-48**, prior to 2030, curtailment in all cases is below 10% of load. After 2030, it becomes apparent that Case 2 and Case 3, which have a higher renewable portfolio standard target in 2030 (90% vs 80% for Case 1 and 60% for SB 100), also have more curtailment. In particular, Case 3 which has the highest amount of distributed energy resources coming online, including the highest levels of local solar and energy efficiency, has the highest levels of curtailment. Despite tremendous amounts of energy storage to integrate renewable energy into the system, the very high levels of distributed solar that make up the resource portfolio of Case 3, likely lead it to have less geographical diversity in solar resources compared to the other cases, and the high correlation among distributed solar resources can cause them to have a coincident maximum output that during times of high solar irradiance and moderate electric demand such as during the spring, can exacerbate curtailment.

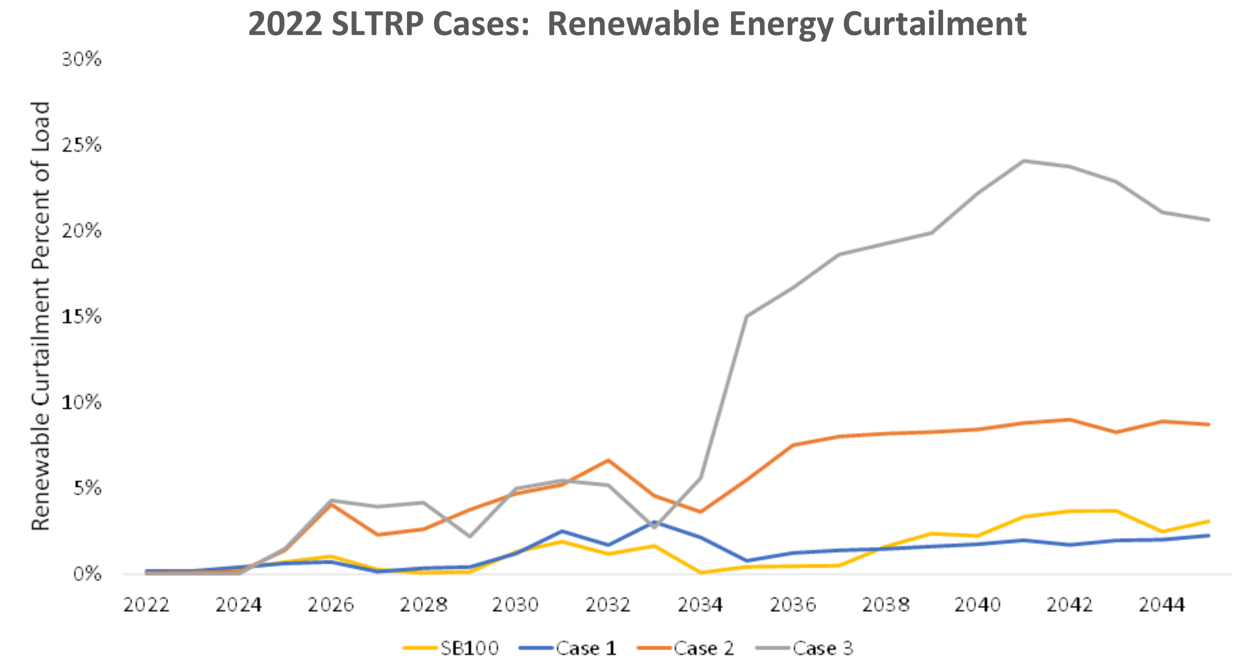


***Figure 4-48**. Renewable energy curtailment for the SLTRP cases.*

4.5.4 Total Portfolio Cost Comparison

With respect to total portfolio costs, the net present value is taken of all the fixed costs (including capital, fixed operations and maintenance, power purchase agreements, debt service, and others) and all the variable costs (including fuel, greenhouse gas allowances, nitrogen oxide credits, variable operations and maintenance, and others), across the study horizon from 2022 through 2045, to arrive at the costs seen in **Figure 4-49**. This method of discounting the annual cash flows to arrive at a net present value, allows for more accurate and fair comparison among the cases.

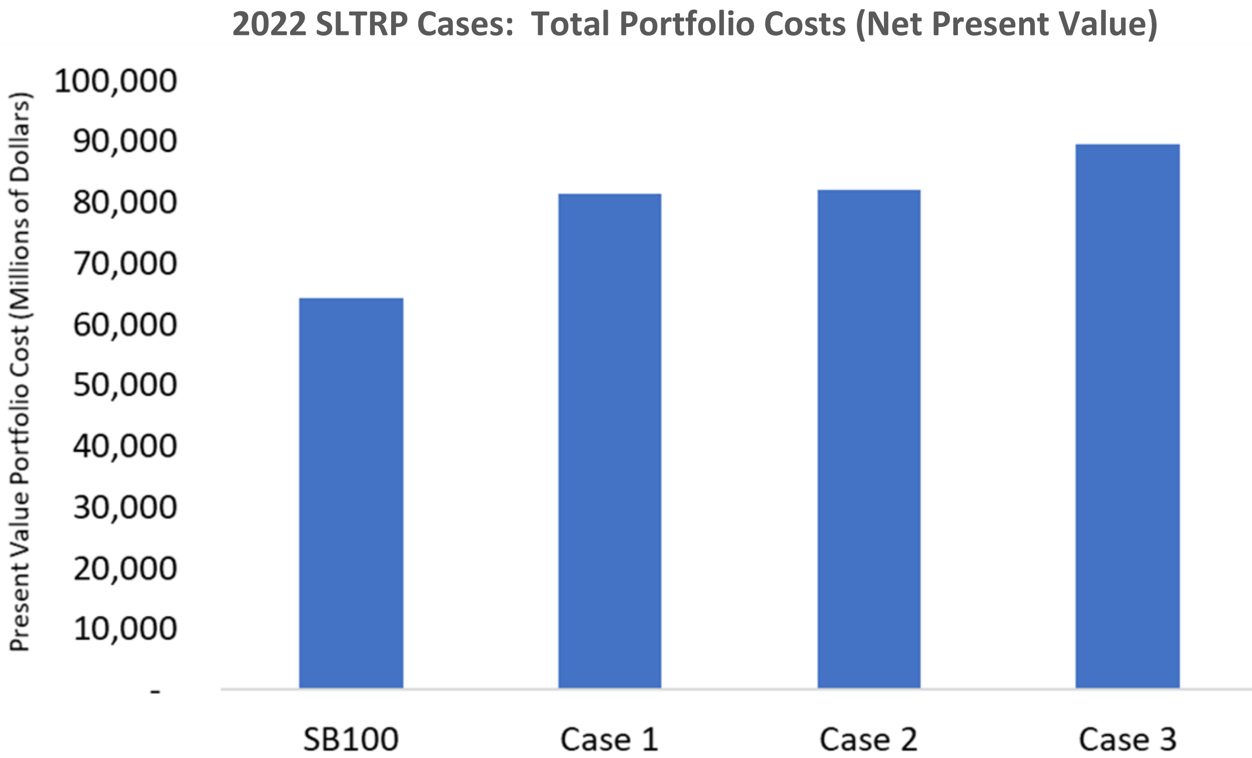


Figure 4-49*. Total portfolio costs (net present value) for the SLTRP cases.*

As can be seen in **Figure 4-49**, SB 100 has the lowest cost in the range of $60 billion, while Case 1, 2, and 3 have estimated costs exceeding $80 billion, with Case 1 being less expensive than Case 2, and Case 2 being less expensive than Case 3. While comparing the cases from this financial perspective provides many insights, it must also be noted that there exist nuances and risks that fail to be captured by such financial estimates, such as the incrementally and significantly more challenging prospects for attaining permitting, securing required outages, procuring enough equipment, and hiring sufficient personnel to build the additional transmission and generation projects required under Case 2, in comparison to those for Case 1.

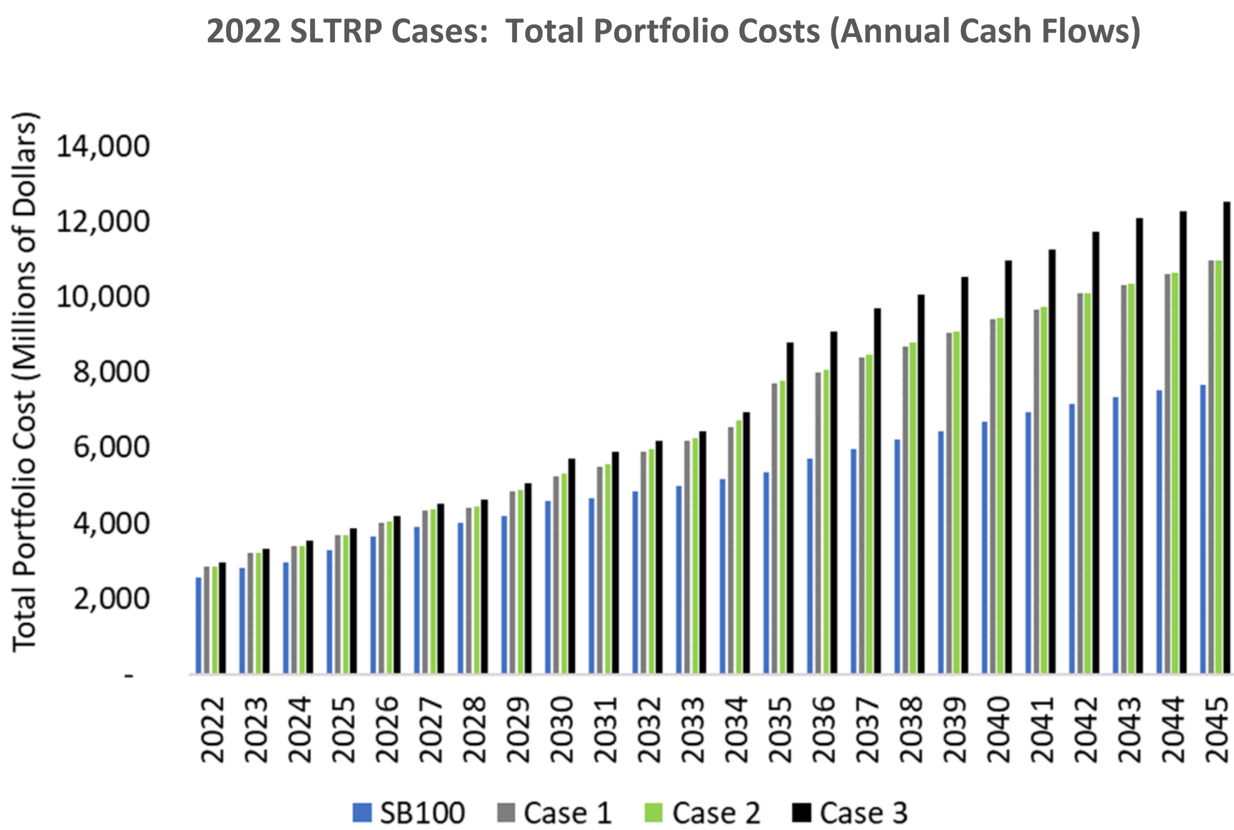


***Figure 4-50**. Total portfolio costs (annual cash flows) for the SLTRP cases.*

When looking at the total portfolio costs from an annual cash flow perspective, it can be seen in **Figure 4-50** that all cases start at around $3 billion annually and more than triple by the end of the study horizon. The carbon-free cases incur significant annual costs above those of SB 100, largely a result of more aggressive deployment of renewable energy resources, energy storage, infrastructure buildout, labor, and green-hydrogen infrastructure, among others. As shown previously, Case 1 is less expensive than Case 2, and Case 2 is less expensive than Case 3. It should also be noted that some of the costs for customer-sided resources such as distributed energy storage, are assumed to be borne by the customer and are not included here.

4.5.5 Implementation Feasibility Comparison

Achieving carbon-free energy by 2035 will require a monumental investment in renewable energy, energy storage, transmission, and green hydrogen resources. LADWP remains constrained by various factors including, but not limited to, cost and staffing that may limit the maximum quantity of resources that may be procured, built, or otherwise deployed during any given year.

Figure 4-51 compares the annual build rates required for each SLTRP case. The SB 100 Case, being the least aggressive in terms of its decarbonization goals, has the lowest build rate. The most aggressive scenario, Case 3, has the highest build rate. Build rates for Cases 1, 2, and 3 are much higher in the years leading up to 2035 and taper off thereafter. **Figure 4-52** shows the cumulative capacity of new renewables, energy storage, and green hydrogen resources that must be built before 2035.

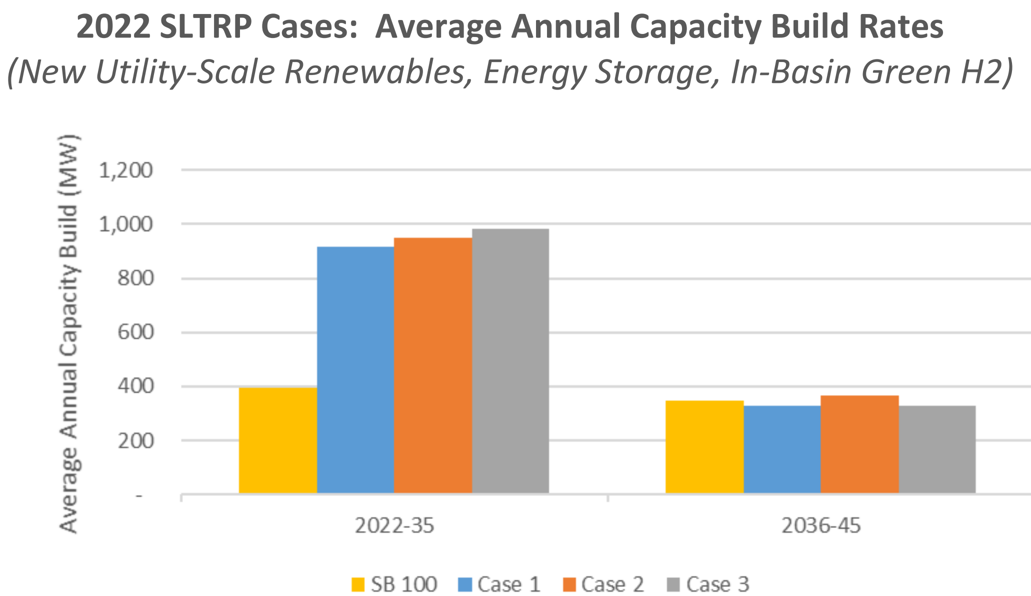


***Figure 4-51**. Average annual build rates for new utility-scale resources, 2022-2035 and 2036-2045. Build rates are much higher in the 2022-2035 time period in order to achieve the goal of attaining 100% carbon-free energy by 2035.*

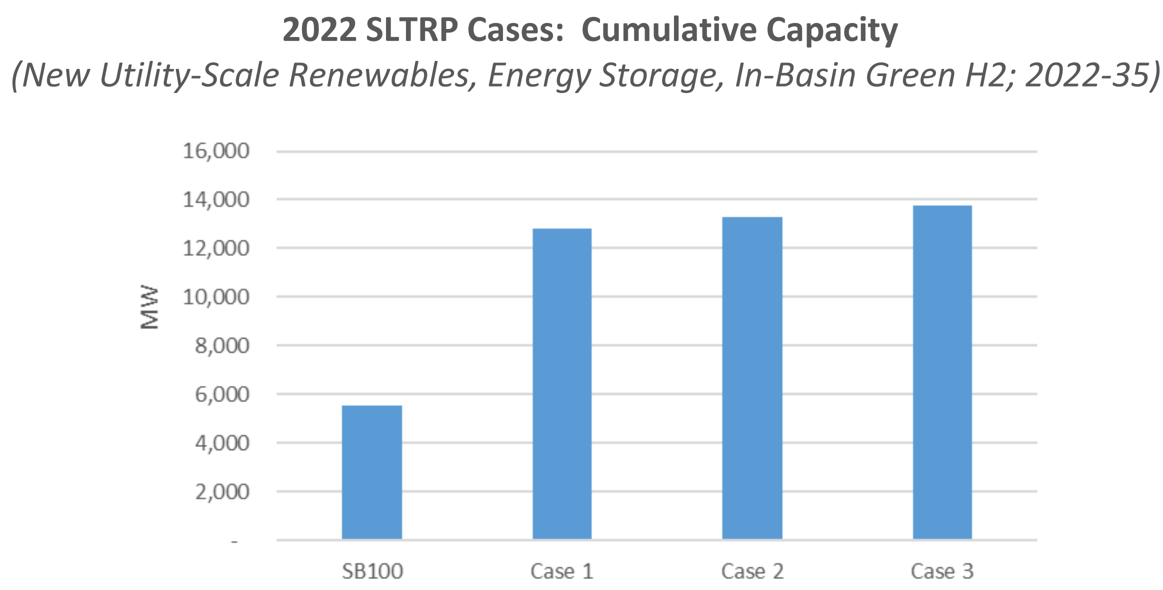


Figure 4-52*. Total cumulative new capacity of renewables, energy storage, and in-basin green hydrogen to be built between 2022 and 2035. Cases 1, 2, and 3 add substantial renewable, energy storage, and green hydrogen capacity to attain 100% carbon-free energy by 2035.*

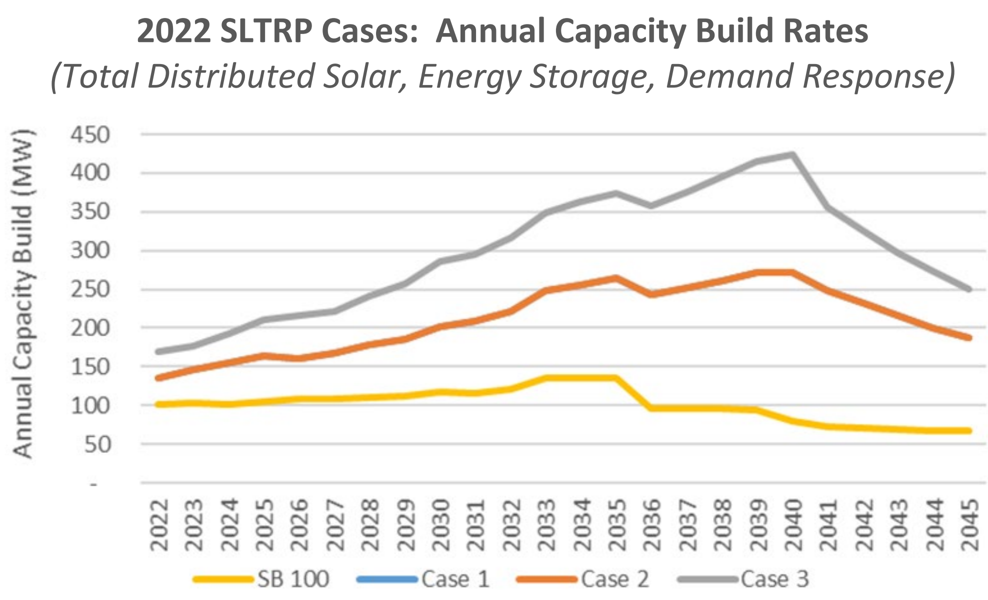


Figure 4-53*. Annual capacity build of distributed solar, distributed energy storage, and demand response resources for the 2022 SLTRP cases.*

In addition to utility-scale projects, each SLTRP case anticipates significant quantities of behind-the-meter resources will be deployed. **Figure 4-53** shows the annual capacity build for distributed solar, distributed energy storage, and demand response resources. **Figure 4-54** shows the cumulative new distributed solar, distributed energy storage, and demand response capacity builds between 2022 and 2045.

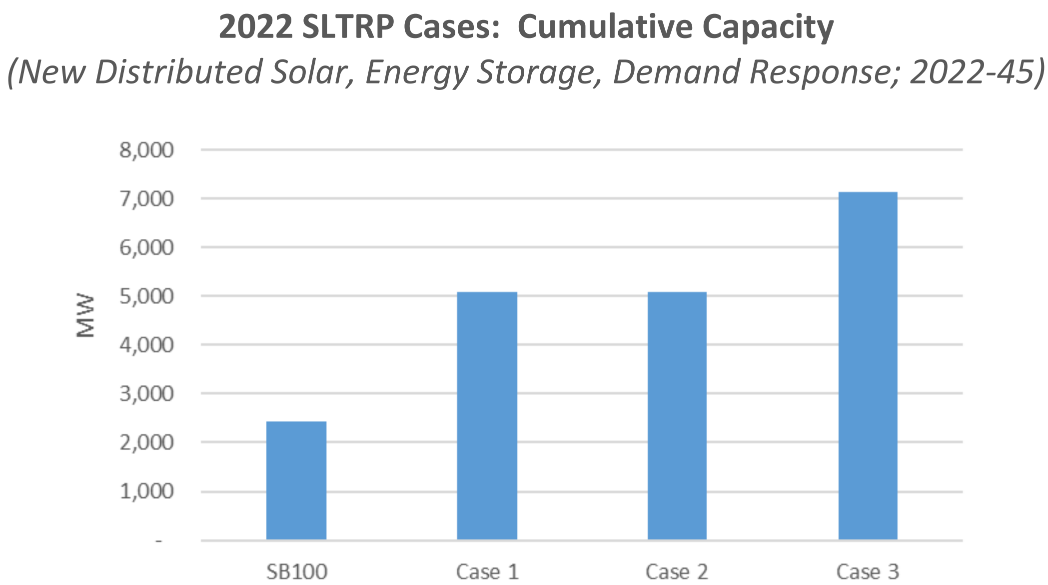


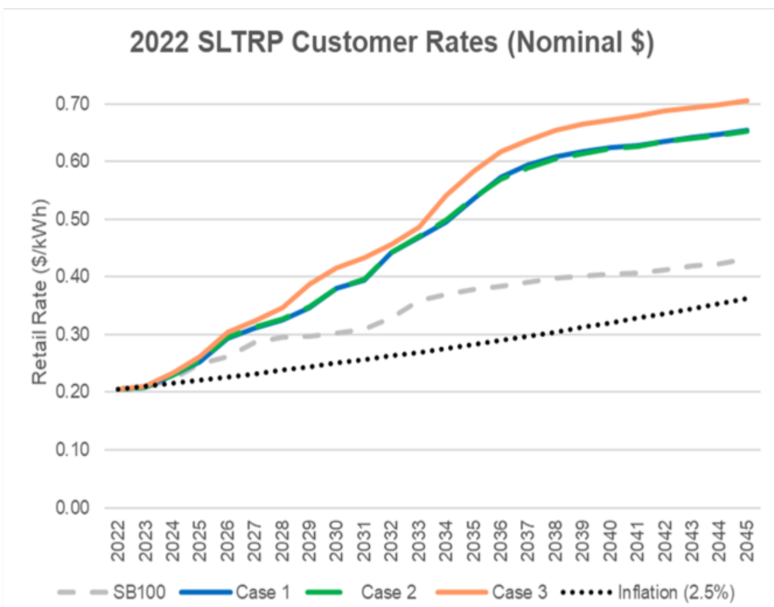
Figure 4-54*. Cumulative new distributed solar, distributed energy storage, and demand response capacity built between 2022 and 2045 for the 2022 SLTRP cases.*

4.5.6 Retail Electric Rate and Bill Impact Comparison

Forecasts of retail electricity rates were conducted for each SLTRP case.

Figure 4-55 shows the average retail electricity rate forecasts for the SB 100 Case, Case 1, Case 2, and Case 3. The retail electricity rate for the SB 100 Case is forecasted to be $0.30/kWh in 2030 and $0.38/kWh in 2035. By 2035, this represents an average rate increase of 4.8% annually over today's rates. Both Case 1 and Case 2 forecast rates of $0.38/kWh and $0.54/kWh for the years 2030 and 2035, respectively. By 2035, this would represent an average rate increase of 7.7% annually. Case 3's retail rate forecast for 2030 is $0.42/kWh, while its rate forecast for 2035 is $0.58/kWh. Between now and 2035, Case 3's average rate increase would be 8.4% annually.

2022 SLTRP Cases:
Estimated Average Retail Electric Rate Impacts



2022 SLTRP Scenario	Rate in 2030 and 2035 ($/kWh)	Est. Avg. Rate Increase (2022-35)	Est. Avg. Rate Increase (2022-45)
SB100	***$0.30*** *(in 2030)* ***$0.38*** *(in 2035)*	*4.8%*	*3.3%*
Case 1	**$0.38** (in 2030) **$0.54** (in 2035)	7.7%	5.2%
Case 2	**$0.38** (in 2030) **$0.54** (in 2035)	7.7%	5.2%
Case 3	**$0.42** (in 2030) **$0.58** (in 2035)	8.4%	5.6%

Note: Preliminary, subject to ongoing budget estimate and future rate review.

Figure 4-55*. Forecasted average retail electricity rates for the SB 100 Case, Case 1, Case 2, and Case 3.*

Figure 4-56 shows the estimated average monthly customer bill (electric) impacts for the SB 100 Case, Case 1, Case 2, and Case 3 for the year 2035. Both estimates for single-family and apartment dwellings are included. For the SB 100 Case, the estimated average increase in monthly electricity bills is expected to increase by 84% by 2035, as compared to 2022. Both Case 1 and Case 2 show an increase of 161% by 2035, while Case 3 shows an increase of 184% by 2035.

2022 SLTRP Cases:
Estimated Average Retail Electric Bill Impacts (2035)

2022 SLTRP Scenario	Average Customer Bill in 2035 (Apartment)	Average Customer Bill in 2035 (Single Family)	% Increase from 2022
SB100	$112	$262	**84%**
Case 1	$160	$373	**161%**
Case 2	$160	$373	**161%**
Case 3	$174	$405	**184%**

Note: Average monthly bill in 2022 is $61.66 per month for apartment and $143.86 per month for single-family home.

Apartment represents 300 kWh per month. Single family represents 700 kWh per month.

Preliminary, subject to ongoing budget estimate and future rate review.

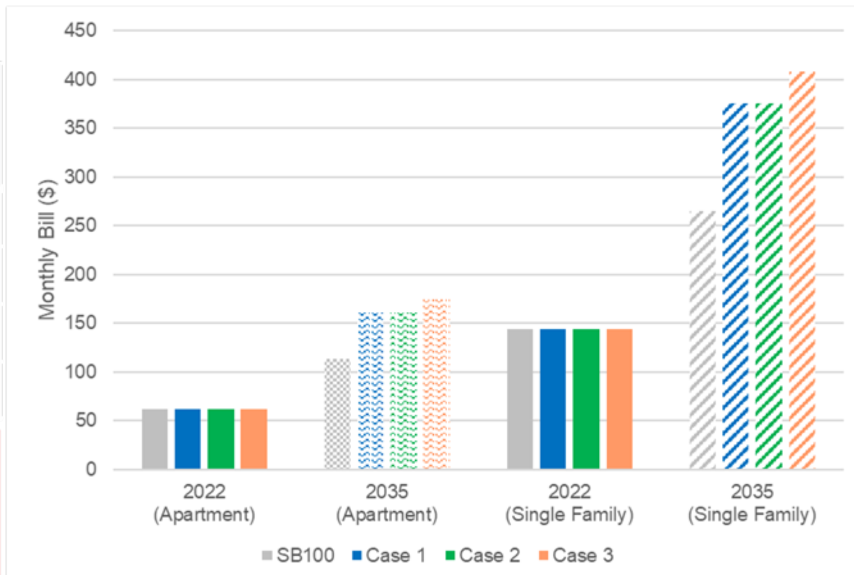


__Figure 4-56__. Estimated average monthly customer bill (electric) impacts for the SB 100 Case, Case 1, Case 2, and Case 3 for the year 2035. Both estimates for single-family and apartment dwellings are included.

CHAPTER 5

RECOMMENDED CASE AND NEXT STEPS

KEY TAKEAWAYS:

- The Reference Case (SB 100) gets to 100% carbon free energy by 2045 based off of retail sales, and the carbon-free cases get to 100% carbon-free energy by 2035, an entire decade ahead of the state mandate, and are based off total generation.
- Case 1 is the recommended case, based on tradeoffs in comparison to other cases on metrics such as cost, emissions, reliability, local air pollutants, technology and market availability of resources, and curtailment.
- Other factors including but not limited to constructability, implementability, and human resources also need to be considered and often requires supplemental assessment to integrated resource planning modeling.

CONTENTS

DEFINITIONS

CEC	California Energy Commission
Core Cases	SLTRP Cases 1,2, and 3
ECCEJR	Energy, Climate Change, Environmental Justice, and River
EGU	Electricity Generation Units
IRP	Integrated Resource Planning
LADWP	Los Angeles Department of Water and Power
LOLH	Loss of Load Hour
NOx	Nitrogen Oxides
PPAs	Power Purchase Agreements
RPS	Renewable Portfolio Standard
SLTRP	Strategic Long-Term Resource Plan

5 Recommended Case and Next Steps

This chapter makes a recommendation regarding which 2022 SLTRP case LADWP should adopt and implement. This chapter also outlines the recommended next steps LADWP should pursue in order to actualize this recommended case.

5.1 Recommended Case

In September of 2021, the Los Angeles City Council passed a motion with 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."

To that end, the Los Angeles Department of Water and Power (LADWP) Integrated Resource Planning (IRP) Group began the process of drafting the 2022 Strategic Long-Term Resource Plan (SLTRP). The 2022 SLTRP consists of four cases:

- SB 100 – Used as a reference case illustrating a resource plan that achieves the mandates set forth in California Senate Bill (SB) 100. The two primary mandates established in SB 100 are a 2030 renewable portfolio standard (RPS) mandate of 60% and a 2045 mandate of 100% carbon-free energy as a percentage of retail sales.
- Case 1 – Achieves an 80% RPS by 2030 and a 100% carbon-free generation portfolio by 2035, pursuant to the City Council's motion.
- Case 2 – Achieves a 90% RPS by 2030 and a 100% carbon-free generation portfolio by 2035.
- Case 3 – Also achieves a 90% RPS by 2030 and a 100% carbon-free generation portfolio by 2035, with additional quantities of energy efficiency, demand response, behind-the-meter resources, and electrification.

The IRP team is recommending Case 1, based on six metrics: cost, emissions, reliability, local air pollutants, technology and market availability of generation technologies and resources, and renewable energy curtailments.

5.2 Cost

Based on stochastic production cost modeling, Case 1 is the least expensive case that meets the aggressive carbon-free energy goals established by the City Council. Therefore, Case 1 most closely adheres the City Council's motion instructing LADWP to prepare a plan achieving 100% carbon-free energy by 2035 in a way that is equitable and has minimal adverse impact on ratepayers. **Figure 5-1** below shows the costs of each of the 2022 SLTRP cases on a net present value basis. Of the Core Cases that meet the 2035 100% carbon-free energy goal (i.e., Cases 1 through 3), Case 1 is the least-cost option.

Furthermore, preliminary rate impact analysis suggests Case 1 will result in the fewest rate increases of the Core Cases. Although Case 3, the most aggressive in terms of behind-the-meter resources, energy efficiency, and demand response appears to be only marginally costlier on a net present value basis, aggressive quantities of load reduction measures will necessitate greater rate increases to pay for increased quantities of renewable energy and green hydrogen infrastructure.

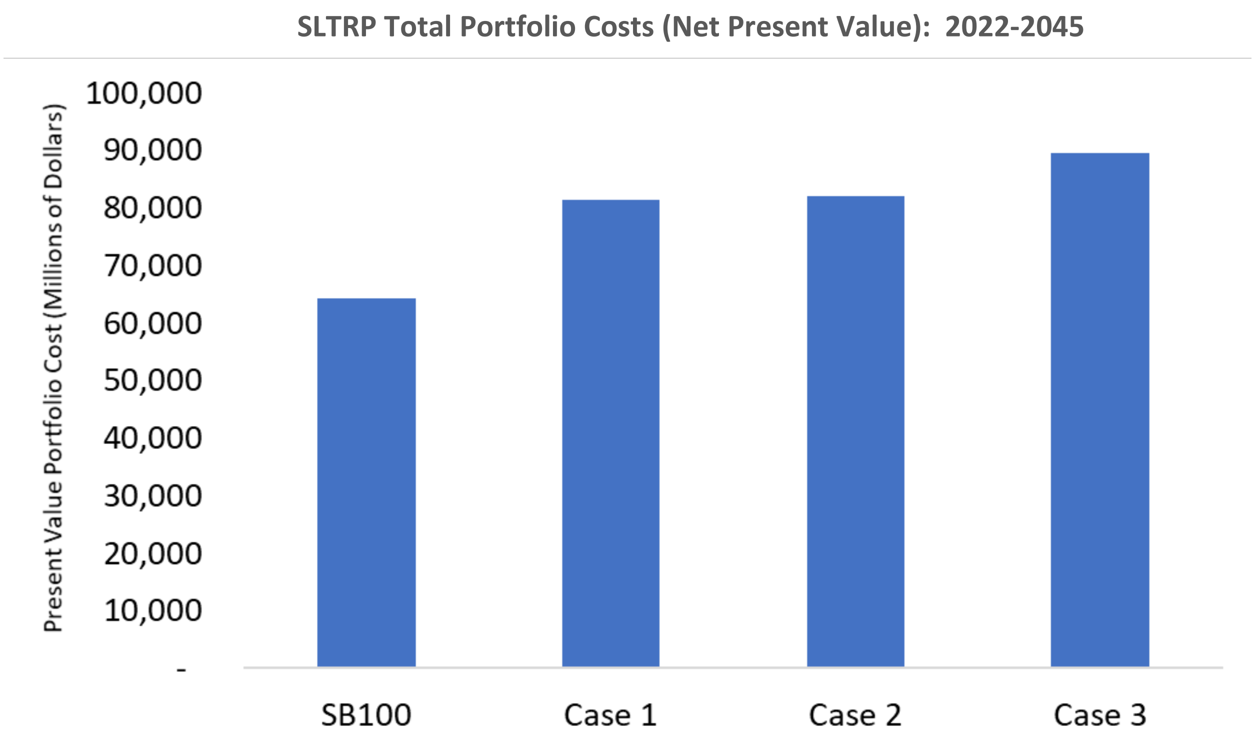


***Figure 5-1**. Costs (Net Present Value) of the 2022 SLTRP Cases.*

5.3 Emissions

Case 1 meets the 2035 goal of achieving 100% carbon-free energy. Although not as low as Case 3, Case 1's emissions are consistently below Case 2's emissions except for one year (2034) as shown in **Figure 5-2**, below. Case 1 also achieves this at a lower cost than Case 2.

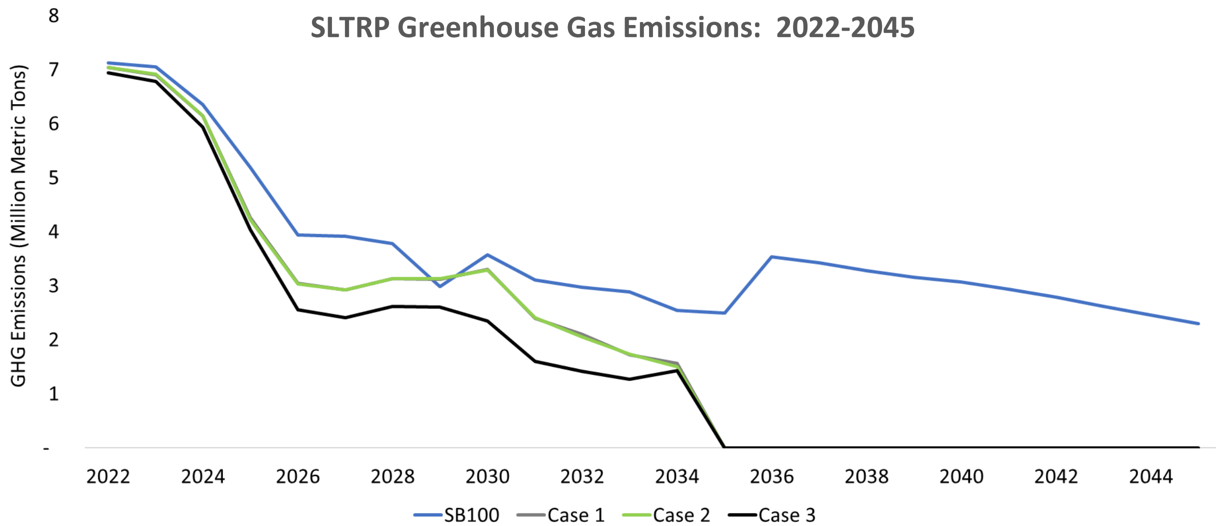


***Figure 5-2**. GHG emissions for the SB100 case, Case 1, Case 2, and Case 3.*

5.4 Reliability

Although Case 1 has slightly higher loss of load hours (LOLH) than Case 2 and Case 3, it still achieves robust reliability. The industry standard for power system reliability is to achieve at or below 2.4 LOLH per year. In fact, all the Core Cases achieve an LOLH of less than 0.5, far exceeding the industry standard of 2.4 LOLH (**Figure 5-3**). From an operational perspective, the slightly higher LOLH of Case 1 would be unnoticeable.

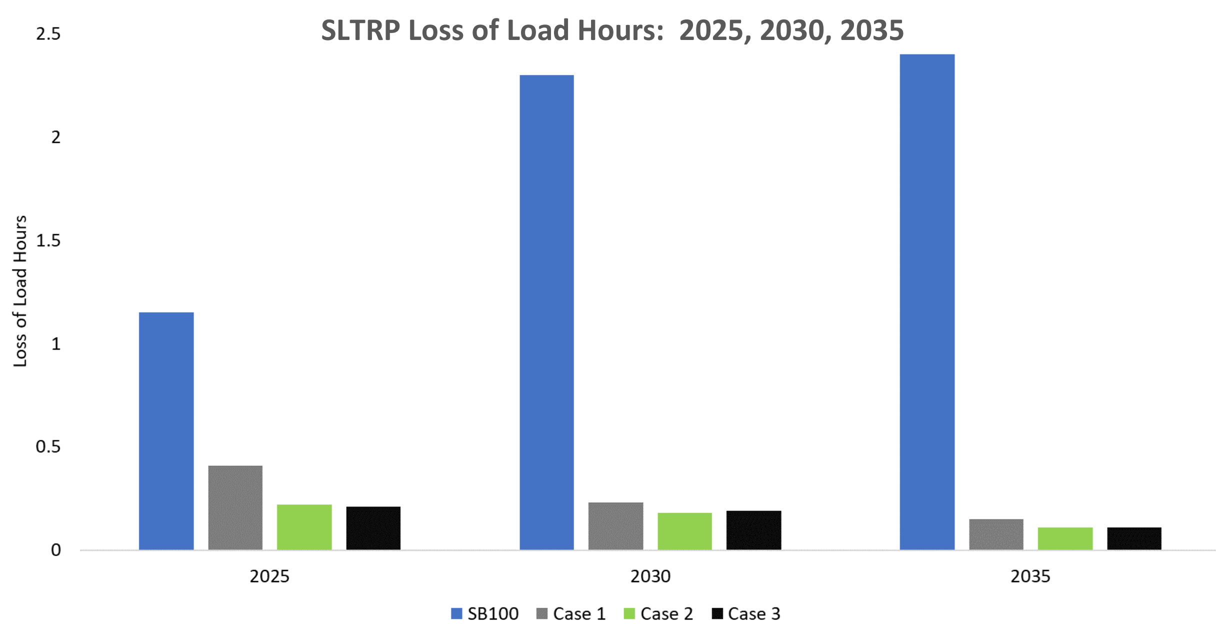


***Figure 5-3**. Reliability measured in Loss of Load Hours (LOLH) for the 2022 SLTRP cases.*

5.5 Local Air Pollutants

SLTRP Advisory Group stakeholders have requested that LADWP analyze the potential changes to air quality and public health caused by changes to operations of in-basin LADWP-owned electricity generation units (EGUs), under the various scenarios developed in the 2022 SLTRP process. In response, LADWP has partnered with NREL to conduct an Air Quality and Health Impacts Study for the SLTRP to ensure that emissions do not increase for any period of time at the source level, and translate that to impacts to air quality and health. Developing emissions inventory for each scenario, running air quality models, and inputting the concentrations to a health benefit model to estimate changes to health were all steps that were followed. Preliminary results on current and future in-basin power plant emissions relative to other economic sectors will be included in an appendix in this SLTRP and more detailed analysis on air quality and health metrics will be included in the next iteration of the SLTRP.

5.5.1 City Council Motion

Motivated by concern that combustion of hydrogen – even green hydrogen produced from renewable electricity sources – will still emit air pollutants, the Los Angeles (LA) City Council passed Motion 16-0243-S2 on March 31, 2021 which states:

> *"The plan [SLTRP] should ensure that emissions are not increased for any period of time at facilities in environmental justice communities, particularly Valley Generating Station."*

Because hydrogen gas contains no carbon or other elements, most air pollutants emitted from combustion of fossil fuels such as carbon monoxide and sulfur dioxide, as well as greenhouse gases (carbon dioxide and methane), are not formed. However, high temperatures in combustion environments cause nitrogen present in the air to form oxides of nitrogen (NOx), a phenomenon also applicable when combusting hydrogen. Thus, NOx is the focus of analysis of air pollutant emissions from the SLTRP cases in comparison to historical emissions from the four in-basin electricity generation facilities owned by LADWP. Results of this analysis are summarized in this section; additional detail will be provided in an appendix.

5.5.2 SLTRP NOx Emissions in the Context of Other Sources

It should be emphasized that in the context of all NOx emission sources within the City of LA, LADWP facilities are small contributors. That's because there are so many other economic sectors that are larger and emit more. This result was found in the LA100 study (Heath et al. 2021), as well as for the SLTRP cases analyzed here (**Figure 5-4**); in fact, the emissions in 2045 in

Cases 1 and 2 are estimated to be even lower under SLTRP cases than those estimated under LA100 scenarios. (Case 3 emissions in 2045 are higher than estimated under LA100, yet still approximately 1,000 times lower than the sum of all other sources in the City.)

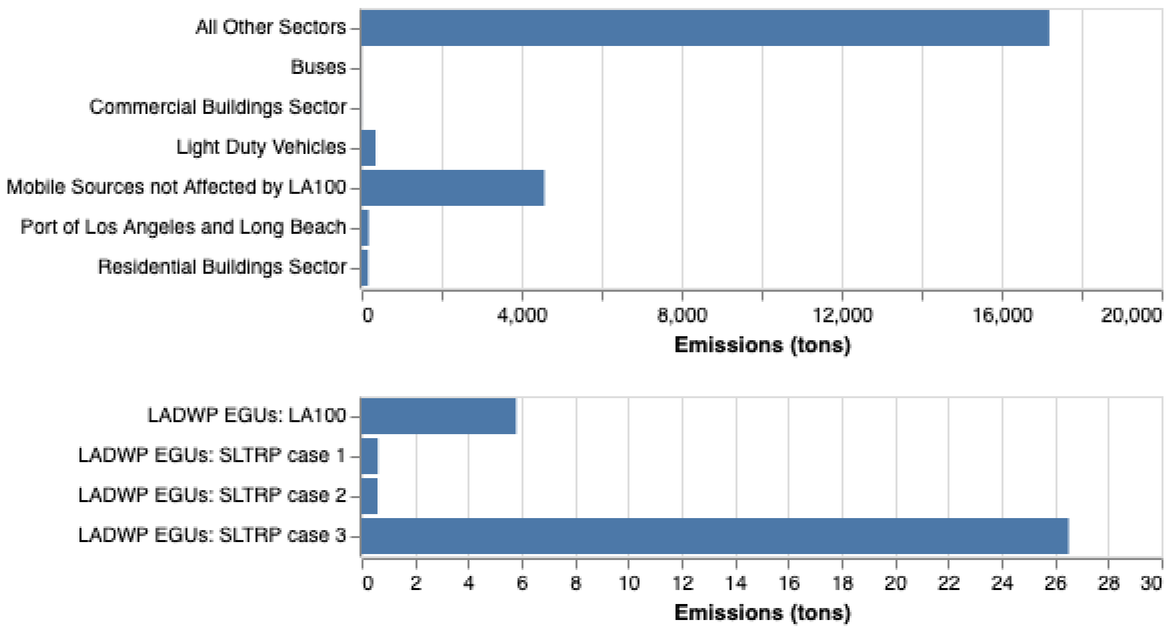


***Figure 5-4**. Annual 2045 citywide NOx emissions (upper figure), as reported in the LA100 study for the Early & No Biofuels – High scenario (Heath et al. 2021), compared to 2045 annual NOx emissions estimated for SLTRP Cases 1-3 (lower figure). (Results for LADWP's in-basin electricity generation units (EGUs) in 2045, as reported in LA100, shown for reference.) NOx emissions from SLTRP cases are on the order of 1,000 (Case 3) to 23,000 times (Cases 1 and 2) smaller than total emissions from the sum of other sectors in the City of LA. (Note that the x-axis scale in the bottom panel is 1,000 times smaller than the top panel.)*

In the analysis supporting creation of **Figure 5-4**, NOx emission rates from hydrogen combustion have been assumed to equal those from natural gas. This assumption is based on analysis of the latest scientific literature and consultation with experts in combustion science, gas-fired turbine design and local regulators. Some prior literature identified the potential for higher NOx emissions from hydrogen than from natural gas because left uncontrolled, hydrogen combustion can achieve higher flame temperatures than natural gas. However, when flame temperature is controlled to the same level as for combusting natural gas, NOx emissions are then equalized; also, NOx emission control devices work the same for hydrogen combustion as for natural gas. The future hydrogen combustion units will be designed to meet the strict emissions regulatory requirements within the South Coast Air Quality Management District.

5.6 Technology and Market Availability of Generation Resources

Because Case 1 contemplates an interim 2030 RPS goal of 80% (as opposed to 90% for Case 2 and Case 3), Case 1 is more immune to supply chain disruptions in the renewable energy markets. Developers of renewable energy projects have been suffering from supply chain constraints, especially in the wake of the COVID-19 Pandemic, causing some to rescind offers and other to raise their prices. If the availability of renewable resources is less than is anticipated, this would impact Case 1 the least.

5.7 Renewable Curtailments

Of the Core Cases, Case 1 has the lowest quantity of curtailed renewable energy and a snapshot is found in **Figure 5-5**. This would allow the renewable resources that do get built in Case 1 to be used most efficiently with the least amount of wasted energy. Power purchase agreements (PPAs) for renewable resources typically establish a minimum guaranteed quantity of energy that must be purchased, regardless of whether or not the utility company is able to take delivery of that energy. It is therefore advantageous to reduce the quantity of curtailed energy from a renewable energy project, since curtailed energy is energy that has already been paid for but cannot be used.

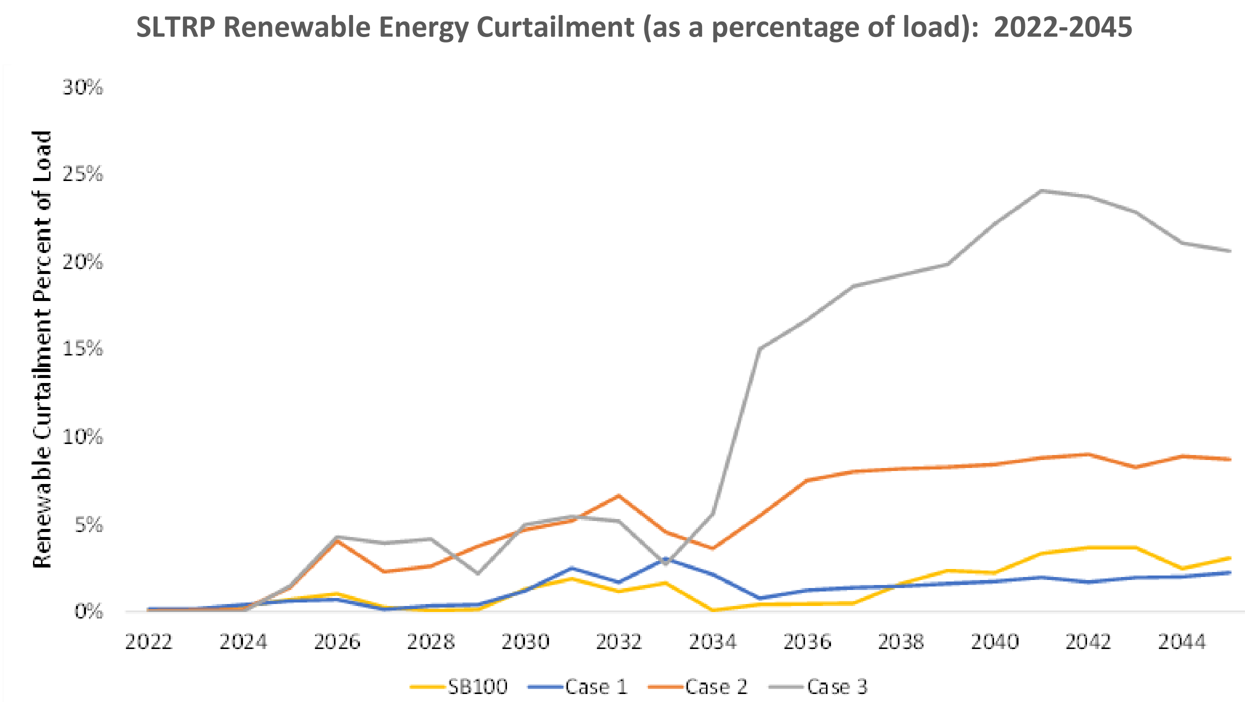


***Figure 5-5**. Quantity of renewable curtailments for each 2022 SLTRP case.*

5.8 Retail Electricity Rates

Although retail electricity rate impacts are similar between Case 1 and Case 2, the 90% RPS goal contemplated by Case 2, to be achieved by 2030, would require several additional key transmission upgrades. Case 1 has a goal of achieving an 80% RPS by 2030, which would require fewer transmission upgrades, and thus lower the risk of uncertainty associated with these additional upgrades. Upgrading transmission lines is a lengthy process, requiring several years of conducting transmission and system studies, permitting, and construction. If the necessary transmission line upgrades are not completed by 2030, Case 2 would result in curtailments and increased reliance on LADWP's in-basin generation fleet, potentially increasing emissions.

Additionally, Case 1 reduces the risk associated with market availability of renewables. Case 2's goal of achieving a 90% RPS by 2030 would require much higher annual buildout rates of new generation and energy storage assets, in addition to transmission upgrades, as compared to Case 1. There is a potential risk associated with the ability to source sufficient quantities of renewable and carbon-free generation and energy storage resources in locations near LADWP's existing transmission system with a 90% RPS goal as compared to an 80% RPS goal.

Figure 5-6 shows the cost components of the retail electricity rate for Case 1. Components include costs associated with distributed energy resources such as local solar and demand response. Additional cost components include energy efficiency, renewables, energy storage, green hydrogen, transmission line upgrades, the Power System Reliability Program, and staffing. Additional revenue from electrification has the effect of reducing rates.

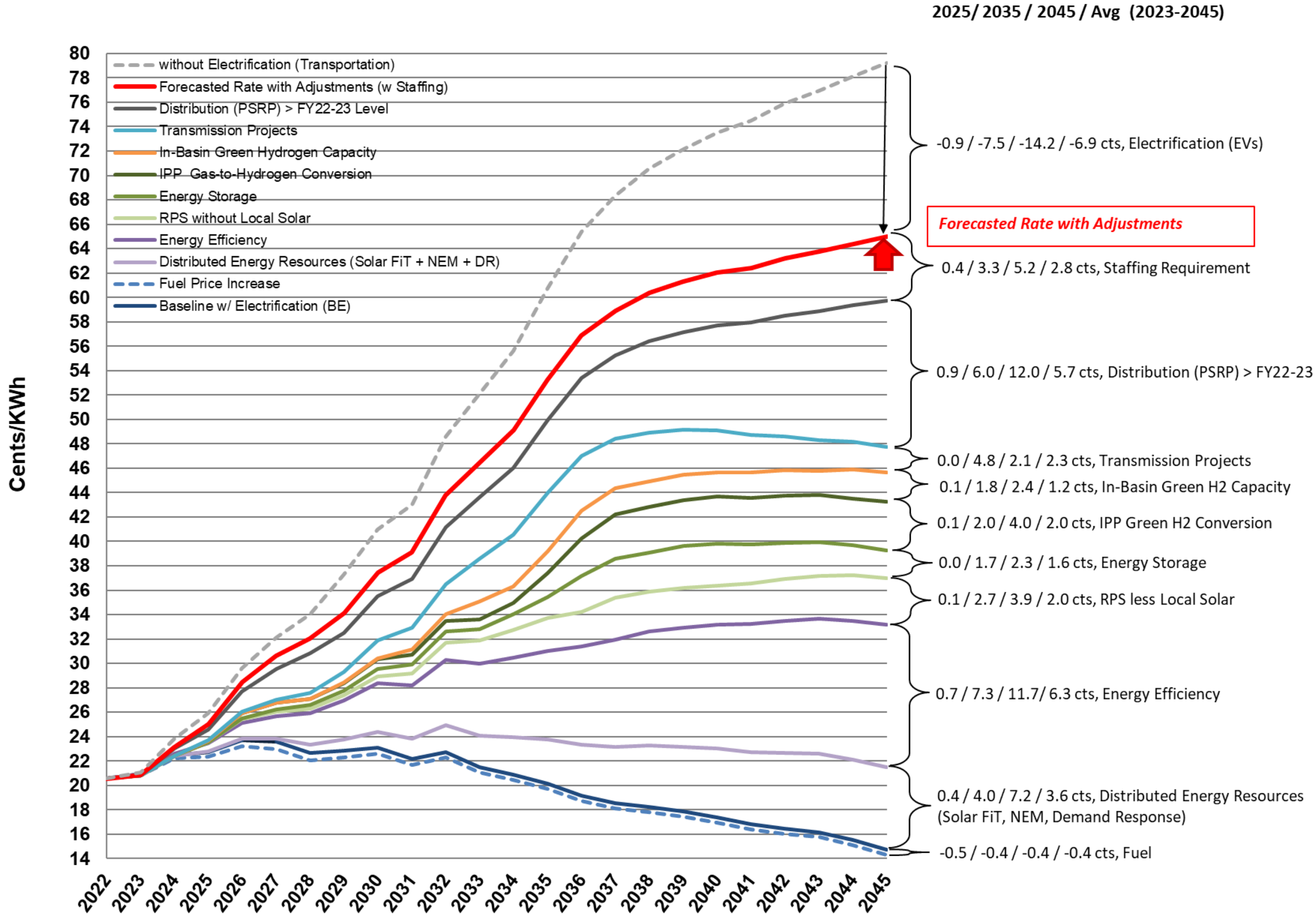


***Figure 5-6**. Case 1 cost components of the retail electricity rate. Components include costs associated with distributed energy resources such as local solar and demand response. Additional cost components include energy efficiency, renewables, energy storage, green hydrogen, transmission line upgrades, the Power System Reliability Program, and staffing. Additional revenue from electrification has the effect of reducing rates.*

Figure 5-7 shows the cost components of Case 1's retail electricity rates broken out individually. Energy efficiency, distribution system upgrades falling under the Power System Reliability Program, and distributed energy resources make up the top three highest components of cost.

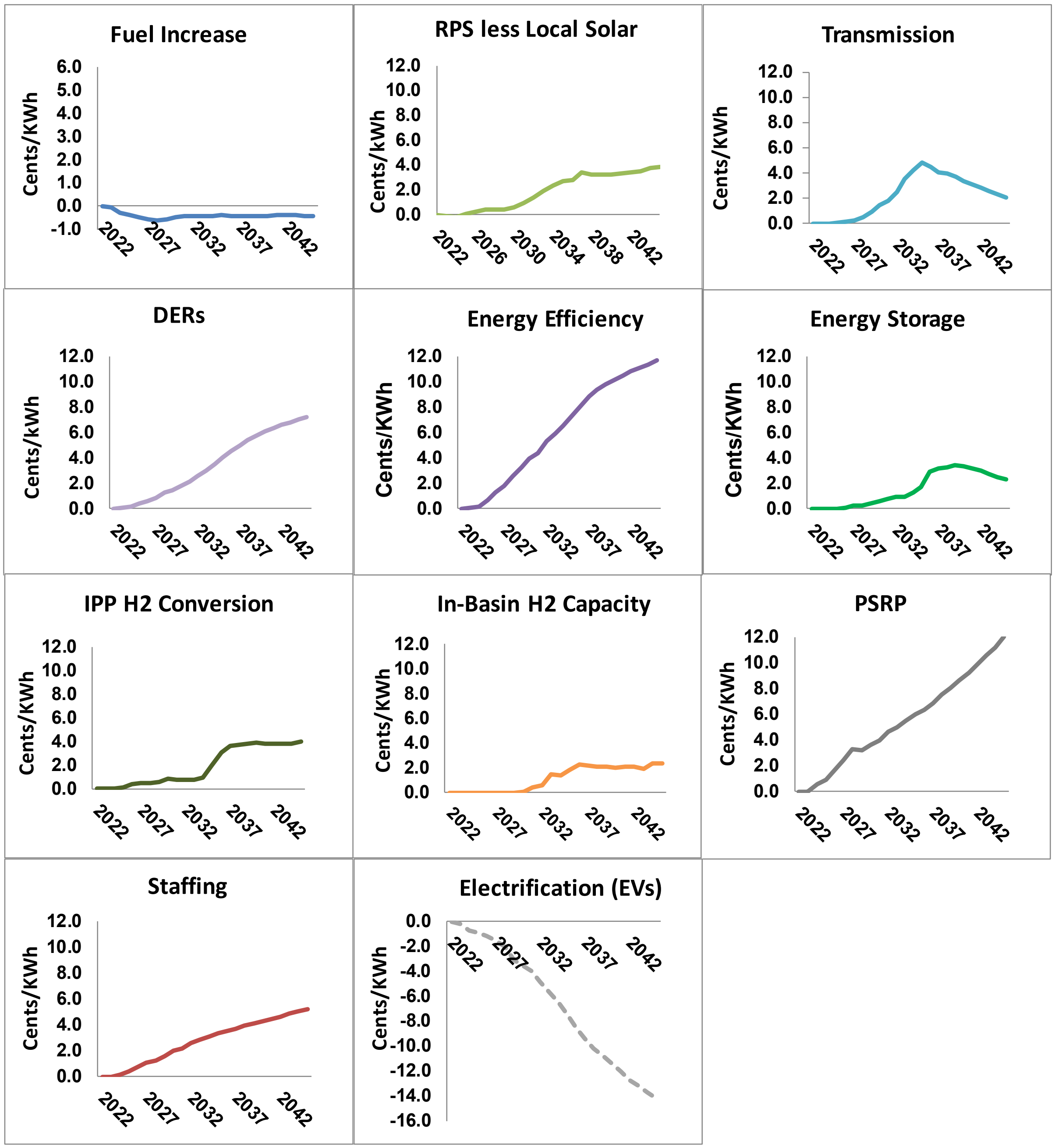


__Figure 5-7__. Case 1 cost components. Energy efficiency, distribution system upgrades falling under the Power System Reliability Program, and distributed energy resources make up the top three highest components of cost.

Figure 5-8 shows the estimated monthly retail customer bill impacts for Case 1. Additional revenue from electrification of buildings and within the transportation sector has the effect of reducing retail electricity rates and associated bill impacts. The dashed line provides an example showing how implementing 20% energy efficiency measures can have a large effect in reducing monthly bill impacts.

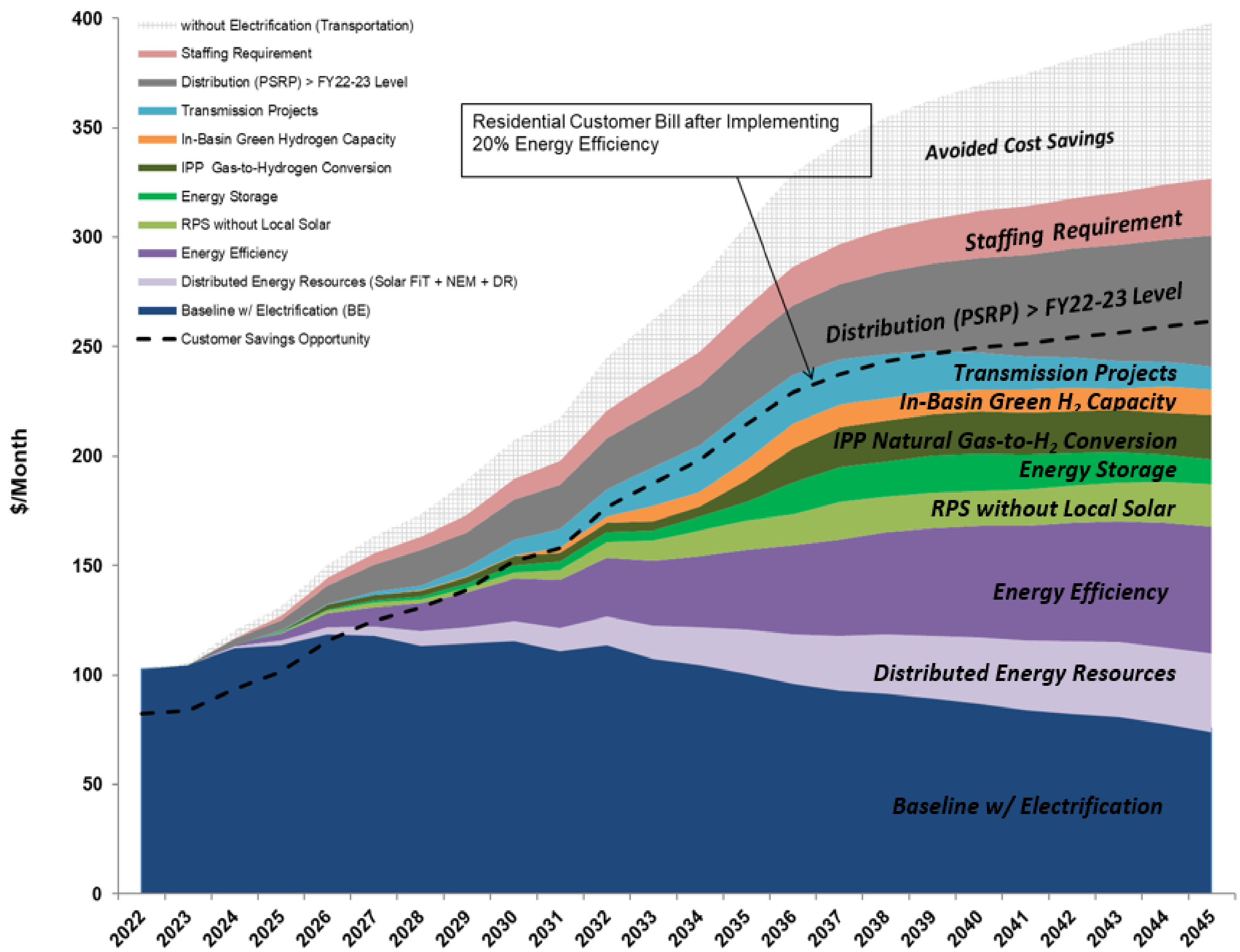


***Figure 5-8**. Retail monthly customer bill impacts. Retail customers can greatly reduce their monthly bill by implementing energy efficiency measures. The dashed line represents a customer's bill impact after 20% energy efficiency measures are implemented.*

SLTRP is an iterative process that will continue to evolve and receive updates on an ongoing basis.

5.9 Next Steps

Regarding next steps, it is of utmost importance to reiterate that the SLTRP is an iterative process that will continue to evolve and receive updates on an ongoing basis.

For this 2022 SLTRP, upon the conclusion of technical modeling and public outreach, the LADWP Board of Commissioners received an update on October 2022, incorporating modeling results and insights, as well as feedback from the SLTRP Advisory Group, public outreach community meetings. Subsequent to the LADWP Board of Commissioners update, a draft SLTRP was released. In parallel, the Los Angeles City Council is being briefed periodically in response to Council File No. 21-0352, which set a directive on September 1, 2021, for the LADWP to develop an SLTRP that achieves 100% carbon-free energy by 2035, with minimal adverse impact on rate payers, and without emissions increases in environmental justice communities. Part of these periodic updates include a six-month report card to the LA City Council's Energy, Climate Change, Environmental Justice, and River (ECCEJR) Committee, which reports status updates on progress, challenges, and risks in major categories critical toward achieving the LA100 goals, including renewable energy, energy storage, generation, transmission, distribution, distributed energy resources, and electric vehicles, among others. Per approval by LADWP Power System Division Directors and Executive Management, this 2022 SLTRP is being released and work will begin on the 2024 SLTRP.

For the 2024 SLTRP, lessons learned will be synthesized and dynamic development will continue to perform due diligence analysis on topics such as impact of emerging legislation to support financing the efforts to combat climate change and improve climate adaptation, as well as taking a closer look at energy burden and incorporating the findings of LA100 Equity Strategies, among other factors and considerations. An integrated resource plan will also need to be developed by the end of 2023, for submission to the California Energy Commission (CEC) as required by CA's SB 350 (Clean Energy and Pollution Reduction Act).

Furthermore, LADWP's Financial Services Organization will take the SLTRP into consideration and conduct further analysis to determine the need for a potential rate action, for which approval will be required by the LADWP Board of Commissioners and LA City Council, and a dedicated outreach process will take place for engagement with stakeholders and the community.

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CHAPTER 6

RISKS AND CHALLENGES

KEY TAKEWAYS:

- Risks and challenges must be overcome in order to achieve LADWP's progressive carbon-free energy goals.
- Risk factors outside of LADWP's control, such as supply chain and commodity volatility, technology readiness, and human resources need to be fully vetted and understood.
- The 2024 SLTRP will incorporate limitations and constraints and continue incorporating new business insights and limitations.

CONTENTS

DEFINITIONS

COVID-19	Coronavirus Disease 2019
IHRP	Integrated Human Resource Plan
kWh	Kilowatt-hours
LA100 ES	LA100 Equity Strategies
LADWP	Los Angeles Department of Water and Power
PSRP	Power System Reliability Plan
SLTRP	Power Strategic Long-Term Resource Plan
STP	Strategic Transmission Plan

6 Risks and Challenges

With the completion of this 2022 Strategic Long-Term Resource Plan (SLTRP), 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 solution to realizing the City of Los Angeles' goal of achieving 100% carbon-free energy by 2035. Although the recommended Case 1 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).

6.1 The Path Forward

A critical update to the traditional SLTRP 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 next iteration of the SLTRP - the 2024 SLTRP - are to identify constraints and risks actively exerting pressure on LADWP, and to incorporate them into complex planning tools and models to determine how Case 1 may be affected by real-world limitations, such as 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, the SLTRP will continue to update and revise the capabilities of future years with advancements in technology, financial products, and the global energy ecosystem. 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.

6.2 Mitigating Implementation Risks

Since the Industrial Revolution 200 years ago, humans have depended on fossil fuels. 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 SLTRP 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 a successful SLTRP implementation process 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 during the 2022 SLTRP process, only a limited number of topics have been able to be studied at this time.

6.3 Supply Chain and Commodity Volatility

As the world weans itself off fossil fuels, it must switch to cleaner energy sources. That translates into huge demand for the 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. More than two years after the COVID-19 pandemic began, supply chains are still volatile and dynamically adjusting to a new normal that is still being understood.


"Related clean energy risks and impacts must be addressed as early as possible."

6.4 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 annual updates to the SLTRP 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.

6.5 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.

6.6 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.

6.7 Generation System Development

As LADWP transforms its Power System to operate off of carbon-free power generation resources, LADWP will have 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.

6.8 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. Currently, the Strategic Transmission Plan is being updated, which will provide long-term transmission options for 2035 and 2045, and should be available in 2023. The budgetary cost for the preliminary transmission system upgrades and new corridors have been captured in this year's 2022 SLTRP 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.

6.9 Distribution System Development

Largely governed by the PSRP, LADWP's distribution system will require significant upgrades to enable the electrification of homes, buildings, vehicles, and other consumer products. As the electric grid decentralizes and diversifies over time, an equal amount of development must occur in upgrading or replacing distribution stations, transformers, poles, regulating equipment, system protection devices, and other critical infrastructure. Increased interconnections from behind-the-meter resources and load from increased building and transportation electrification could result in impacts to grid reliability. The budgetary cost for revamping the PSRP to address existing overloads and to prepare the distribution system for future electrification load growth has been incorporated into this year's 2022 SLTRP, and will continue to be evaluated in future SLTRPs.

6.10 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. Currently, a rate review is being conducted and more updates from the LADWP's Financial Services Organization should be available in 2023. The rate comparisons in this year's 2022 SLTRP 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.

6.11 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. This year's 2022 SLTRP addresses this through a low load and high load sensitivity.

6.12 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). Currently, the existing IHRP is being updated and should be available in 2023. The human resource requirements to implement Case 1 will be a critical factor in the 2024 SLTRP. Preliminary budgetary estimates include approximately 2,500 to 3,000 additional positions to address existing system needs, PSRP revamp, load growth, and both SLTRP and STP goals, which have been included in this SLTRP and will continue to be refined over time.

The Integrated Human Resource Plan (IHRP) update will be located in an appendix.

LADWP will undergo an unprecedented transformation in infrastructure, technical resources, and human labor.

7 Addendum - Challenges in Achieving LADWP's Decarbonization Goals Affordably, Equitably, and Reliably

7.1 Summary - Caveats of the 2022 SLTRP Recommended Case (Case 1)

While the 2022 Power Strategic Long-Term Resource Plan (SLTRP) has recommended Case 1 in response to the Los Angeles City Council's (City Council) Motion to prepare a plan that achieves 100% carbon-free energy by January 1, 2035, with an interim goal of achieving an 80% renewable portfolio standard (RPS) by 2030, this 2022 SLTRP provides only a conceptual plan and encompasses numerous challenges related to availability of technology, implementation feasibility, system reliability, and affordability. These factors represent risks that ultimately may delay LADWP's transition to 100% carbon free energy. Future iterations of the SLTRP will need to consider various constraints and how they may impact SLTRP assumptions, modeling, and clean energy outcomes as LADWP seeks to optimize the build out of its Power System resource plan in order to balance reliability and resilience, environment, and affordability.

7.2 Availability of Technology - City Council instructed LADWP to prepare a Strategic Long-Term Resource Plan (SLTRP) that achieves 100% carbon-free energy by 2035

As contemplated by the 2022 SLTRP, LADWP's plans to decarbonize its portfolio of generation assets hinge on the availability of future technology that would transform LADWP's in-basin gas-fired generation to carbon free by January 1, 2035. Under the LA100 Study, conducted by the National Renewable Energy Lab (NREL), all pathways to a decarbonized grid still require some firm and dispatchable generation resources and NREL identified combustion turbine generators as the only technology to date that could maintain reliability and resiliency, as higher quantities of intermittent renewables are integrated into LADWP's system along with transmission upgrades. This is especially important because dispatchable turbine generators have a compact footprint that would provide large amounts of capacity within a short period of time. To that end, the 2022 SLTRP makes two important assumptions:

- Turbine technology will have improved sufficiently by 2035 where utilizing a renewably derived fuel is possible.
- A market for renewably derived fuel (i.e., hydrogen derived via carbon-free processes) exists along with an associated pipeline infrastructure that provides sufficient quantities of fuel to LADWP's in-basin generating units to ensure system reliability.

If either of these two conditions are delayed, it would likely impact LADWP's goal of a 100% carbon-free generation portfolio by 2035.

7.3 Implementation Feasibility - Human resources, real estate, and supply chain must be vetted and ramped up to support the buildout of clean energy resources

Both the LA100 Study and the 2022 SLTRP demonstrated that thousands of megawatts (MW) of new renewables, energy storage, and dispatchable generation resources must be procured, built, or transformed to carbon-free by 2035. Such an aggressive buildout of resources poses several challenges.

LADWP must hire several thousand additional employees to implement the plan established by the 2022 SLTRP, in addition to backfilling existing positions. These positions are critical to support the build rates for new construction and maintenance of new clean energy projects. LADWP employees must also be trained before they can begin the process of engineering, negotiating new resources, administering contracts, and managing overall construction. There is also a concomitant need for additional administrative support staff (e.g., clerical and timekeepers). All staff must also be provided with office space and information technology equipment.

Building and interconnecting several thousand megawatts of new capacity will also require close coordination with LADWP Grid Operations and Wholesale Energy Resource Management (WERM). Building new capacity in-basin will require temporary outages of existing generation resources, which could affect system reliability. Construction schedules must be carefully staggered and considered in order to minimize concurrent generation and transmission outages, which may impact the reliability of LADWP's day-to-day operations and build rates.

Building new generation and storage capacity will require the purchase of new real estate. This can pose unique challenges, especially when building within the Los Angeles Basin, where there is little undeveloped space available. LADWP must be able to negotiate new real estate purchases, while taking zoning constraints into account. The procurement of real estate by LADWP may also be opposed by local stakeholders, presenting additional challenges.

Issues with the overall fragility of the supply chain system became apparent during the pandemic. For example, most solar photovoltaic panels are manufactured in China. Due to the unavailability of these solar panels, many developers who proposed solar projects to LADWP increased their prices significantly. If such supply chain issues continue to persist or arise again in the future, LADWP may need to delay its decarbonization efforts or be willing to pay a premium in order to achieve the aggressive goals set forth by the City Council.

Significant levels of building electrification (BE) and adoption of electric vehicles (EVs) are anticipated. The additional revenue associated with BE and EVs serves to attenuate the forecasted increase in customer rates. However, the influx of electrification is on the cusp of materializing and such programs will require significant investment in local distribution systems.

7.4 System Reliability - Firm, dispatchable capacity in-basin needs to be retained even in a decarbonized future Power System for reliability and resiliency

Achieving 100% carbon-free energy by 2035 will require the procurement of several thousand megawatts of new intermittent renewables such as wind and solar. In addition to keeping a certain level of firm, dispatchable generation, the 2022 SLTRP demonstrates that overbuilding renewables is a necessary component to achieving reliability due to their intermittent nature. A concomitant quantity of energy storage assets must also be built to store energy when it is not needed. Even with energy storage assets, the 2022 SLTRP forecasts that a significant quantity of energy will either need to be sold in wholesale markets or curtailed due to the overbuild of renewables. Energy output of solar and wind assets is dictated by weather patterns. If weather patterns become more volatile over time due to climate change, the volatility of such intermittent renewables will increase as well, which will require additional and unanticipated storage and generation assets to be built. As part of decarbonizing the Power System by 2035, there is a critical need to maintain firm, dispatchable generating capacity at LADWP's existing power plants due to the design of the grid, where renewable energy is imported from the north, and power plants located on the south side of the system provide power flow regulation for transmission reliability. This is especially critical during times of low frequency, high impact events, like wildfires, that will constrain major transmission lines for long periods of time.

7.5 Affordability - Additional flexibility in planning to optimize resources is needed to improve cost affordability and minimize energy burden

The anticipated changes to LADWP's generation, energy storage, and transmission portfolio required to achieve the goals set forth by the City Council are unprecedented. Thousands of megawatts of additional capacity must be built per year, and this will require significant financial outlays. If these outlays are not offset by corresponding increases in retail customer rates, LADWP's cost of borrowing money, which will be necessary to achieving the goals established by the City Council, will increase substantially. As such, LADWP's retail customer rates are expected to increase well above the rate of inflation until the mid-2030s if the City Council's goals are to be achieved. Additionally, the 2022 SLTRP assumes high levels of building electrification and adoption of electric vehicles. This anticipated increase in associated revenue has had an attenuating effect on the forecasted increase in retail customer rates. If the anticipated levels of electrification fail to materialize—either because LADWP was unable to make the necessary upgrades to its distribution system, or customer adoption is lower than anticipated—forecasted retail rates could substantially increase. The 2022 SLTRP forecasts the average rate requirements for LADWP to achieve its clean energy goals. The inability to secure funding through a multi-year rate action and/or support from outside funds, such as the Inflation Reduction Act and Bipartisan Infrastructure Law, may jeopardize LADWP's progress towards 100% renewable energy.

7.6 Power System Roadmap and Next SLTRP - There is a critical need to review internal and external constraints, optimize future resource plans, which may ultimately impact clean energy goals

Over the last several years through the LA100 Study, LA100 Next Steps, and SLTRP, LADWP has gained significant experience in planning for a 100% clean energy future, and one outcome is clear—there are common pathways across all scenarios. This was evident in the LA100 Next Steps that was presented to the Water and Power Board of Commissioners in 2021 and detailed in this SLTRP. LADWP has initiated its clean energy transformation and will continue to make progress, which will be detailed as part of an upcoming Power System Roadmap based on the 2022 SLTRP, to identify an actionable roadmap over the next 5 to 10 years.

Through the 2022 SLTRP, LADWP has responded to the City Council's call to action to develop an SLTRP that would achieve 100% carbon free by 2035, and the SLTRP has detailed the requirements (clean energy resources mix, cost, reliability needs, etc.) to meet this goal. As part of resource planning, LADWP's goal has traditionally been to balance environmental stewardship, reliability, and cost affordability; however, as City Council prioritized environmental benefits while maintaining reliability as a federal requirement, cost affordability was sacrificed through this 2022 SLTRP process. LADWP will continue to optimize its resource planning efforts as part of the next SLTRP to re-examine opportunities to balance and reduce cost. Additionally, several key initiatives were ongoing while the 2022 SLTRP was in progress that were not factored in to the assumptions. The next iteration of the SLTRP will need to vet through these critical pieces, including the Integrated Human Resource Plan, LA100 Equity Strategies, Inflation Reduction Act, Implementation Feasibility and Constructability, Supply Chain and Procurement Risk, and Emerging Technology Readiness. Flexibility in planning and developing scenarios would also allow LADWP to develop a more optimized SLTRP in the best interest of LADWP's Power System and its customers.

Considering the foregoing challenges, the next SLTRP will be developed over a two year planning cycle, spanning calendar years 2023 through 2024. In 2023, LADWP expects to incorporate and complete a thorough vetting of the abovementioned constraints, submit and file its Integrated Resource Plan to the California Energy Commission, and develop a shorter term, actionable Power System Roadmap based on the 2022 SLTRP. Subsequently, LADWP will reconvene the SLTRP Advisory Group to report back on its findings, and initiate the next iteration of the SLTRP that will include updated data and assumptions, technical modeling, analysis, and updated SLTRP based on the latest planning framework of the Power System.

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2022 Strategic Long-Term Resource Plan

Appendices

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Appendix A

Load Forecast

2022 SLTRP

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A Load Forecast

A.1 Overview

The 2021 Retail Sales and Demand Forecast (2021 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 on 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.

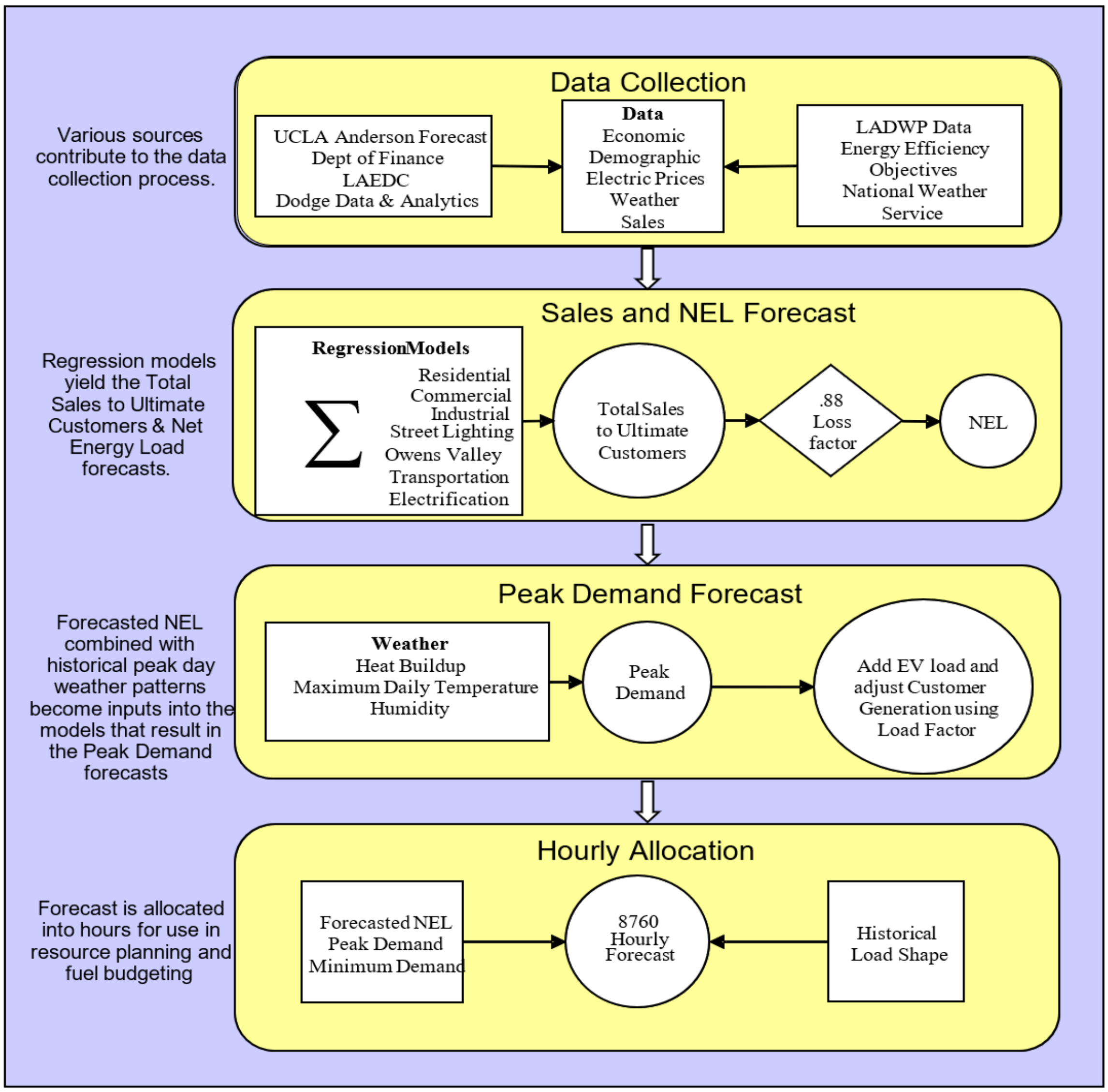

Figure A-1. Overview of the load forecasting process.

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 2021 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 2021 Forecast.

Table A-1. 2021 Load Forecast.

Fiscal Year	SECTOR SALES Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	Transportation Electrification (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	11,632	1,240	223		21,115	24,095	5,637
2020-21	8,429	11,122	962	230	12	20,754	24,119	6,110
2021-22	7,979	11,764	805	247	131	20,926	23,606	5,584
2022-23	7,926	11,482	714	248	239	20,610	23,466	5,598
2023-24	7,919	11,379	752	249	372	20,671	23,564	5,537
2024-25	7,943	11,324	801	249	517	20,834	23,699	5,658
2025-26	7,951	11,186	828	250	659	20,874	23,735	5,646
2026-27	7,970	11,106	857	251	834	21,017	23,885	5,680
2027-28	7,979	11,121	882	251	1,040	21,273	24,309	5,718
2028-29	8,098	11,323	901	252	1,252	21,826	24,786	5,832
2029-30	8,168	11,505	919	253	1,495	22,339	25,368	5,907
2030-31	8,224	11,686	936	253	1,725	22,824	25,932	6,007
2031-32	8,276	11,864	952	254	1,930	23,276	26,518	6,089
2032-33	8,335	12,045	966	254	2,136	23,737	26,960	6,190
2033-34	8,387	12,217	980	255	2,342	24,181	27,437	6,254
2034-35	8,392	12,356	994	256	2,547	24,546	27,930	6,322
2035-36	8,529	12,605	1,006	256	2,753	25,149	28,591	6,412
2036-37	8,544	12,768	1,019	257	2,959	25,547	29,071	6,544
2037-38	8,597	12,963	1,032	258	3,165	26,014	29,527	6,595
2038-39	8,612	13,125	1,045	258	3,370	26,411	30,048	6,670
2039-40	8,713	13,358	1,056	259	3,576	26,962	30,686	6,769
2040-41	8,758	13,548	1,068	260	3,786	27,420	31,162	6,882
2041-42	8,814	13,750	1,080	260	3,997	27,901	31,665	6,952
2042-43	8,823	13,909	1,093	261	4,207	28,292	32,187	7,028
2043-44	8,920	14,140	1,104	261	4,417	28,843	32,823	7,126
2044-45	8,960	14,328	1,116	262	4,628	29,294	33,292	7,237

Table updated through December 2020
Transportation Electrification Sales before December 2020 included in Residential and Commercial Sales
Intradepartmental sales, historically included in Miscellaneous, are now included in Commercial sector

Annual Percent Change	Residential	Commercial	Industrial	Miscellaneous*	Transportation Electrification	Total Sales to Ultimate Customers	Net Energy for Load	Peak Demand
1996-2010	1.38%	0.68%	-1.43%	0.74%		0.69%	0.75%	1.15%
2010-20	-0.34%	-0.78%	-5.01%	-6.11%		-1.01%	-0.96%	-0.13%
2020-25	-0.19%	-0.54%	-8.37%	2.29%		-0.27%	-0.33%	0.07%
2020-30	0.18%	-0.11%	-2.95%	1.26%		0.57%	0.52%	0.47%
2020-45	0.44%	0.84%	-0.42%	0.65%		1.32%	1.30%	1.00%

*Miscellaneous' includes Streetlighting, Owens Valley.

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Appendix B

Environmental Issues

2022 SLTRP

CONTENTS

B Environmental Issues

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 (NO_X), 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 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 annual average standard of 0.030 parts per million. In 2010, the U.S. EPA established a new 1-hour standard at a level of 0.100 parts per million (100 ppb) to supplement the existing annual standard.

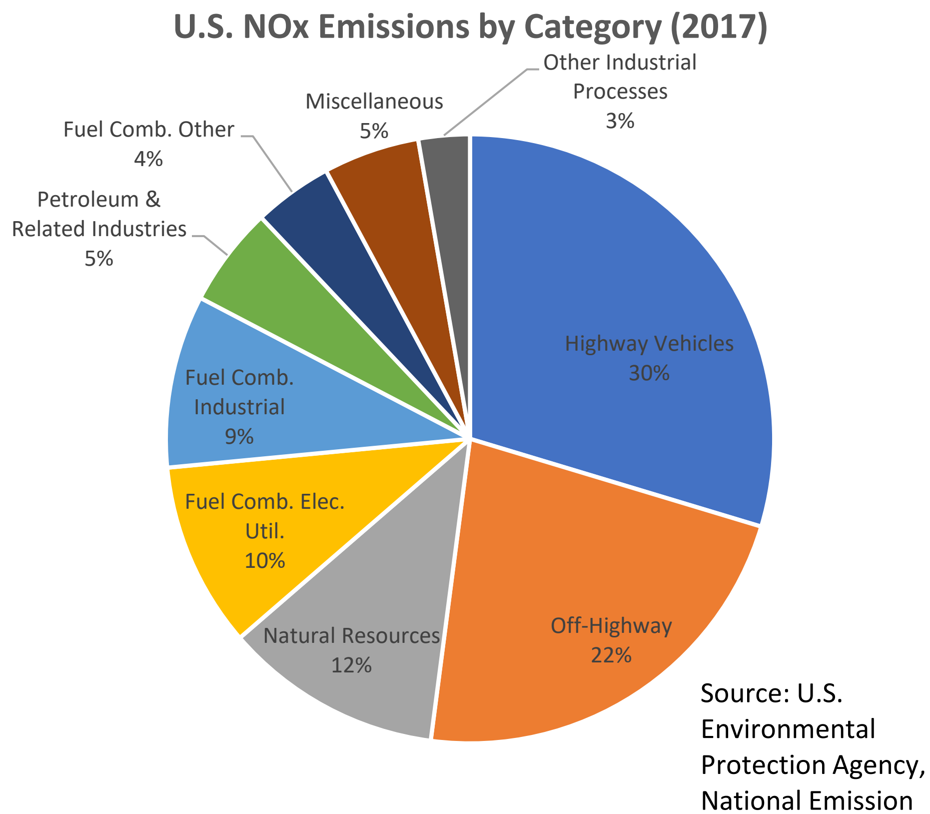


Figure B-1. Sources of NO_X emissions in the United States in 2017.

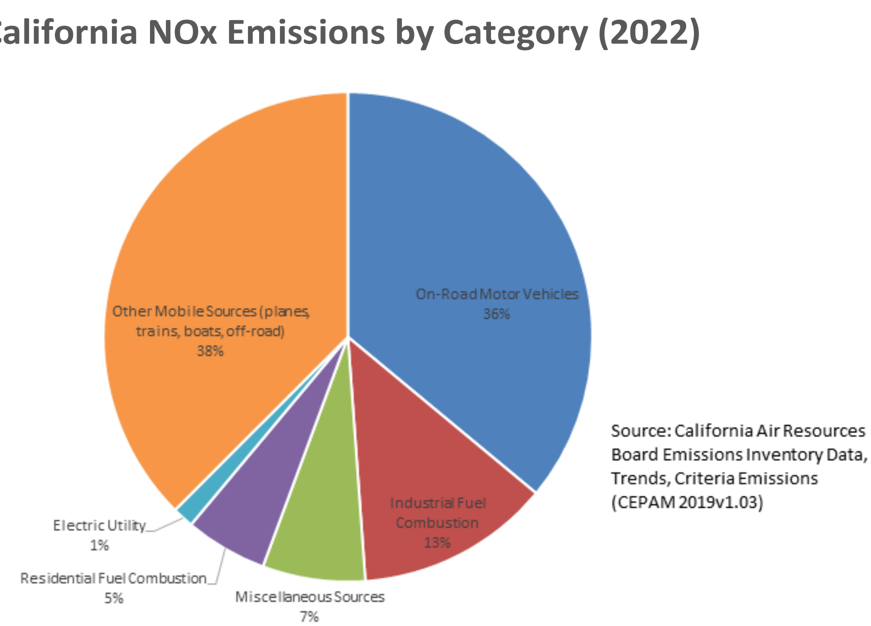


Figure B-2. Statewide NOx Emissions by Sector in 2022.

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.

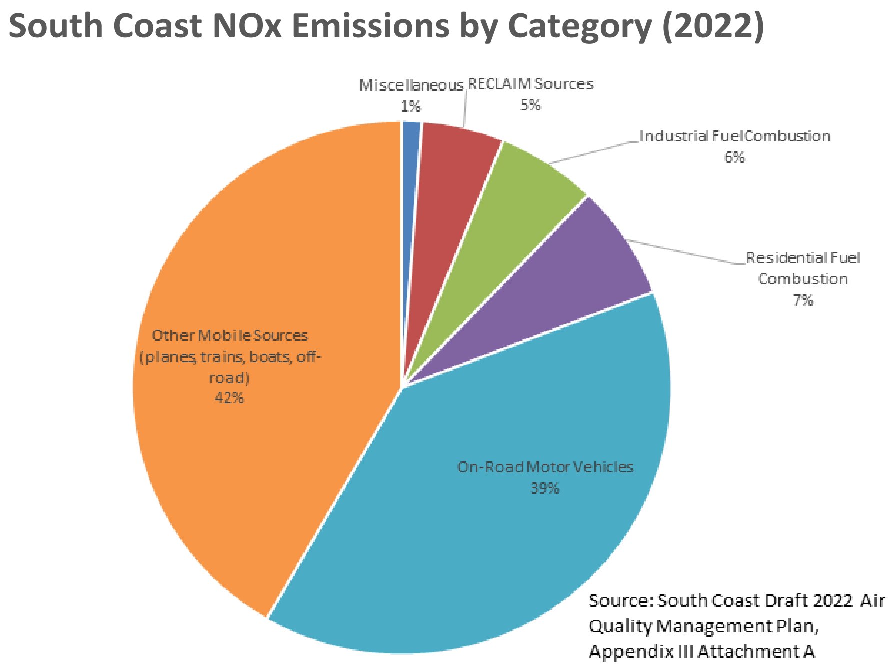


Figure B-3. Sources of NO_X Emissions in the South Coast Air Basin in 2022.

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 will lay 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 is actively soliciting stakeholder input for development of the 2022 AQMP through a series of workgroup meetings. SCAQMD's 2022 draft 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 draft 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.

LADWP has been attending AQMP working group meetings and has been monitoring the development of control measures to meet the goals of the 2022 AQMP. Thus far, 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.

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%. Most of LADWP's electricity generating units currently meet the Rule 1135 NO_x concentration limits. The few units that do not meet the newly adopted limits are being upgraded to optimize their NO_x emission control systems to reach compliance by 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 announced that the program will likely not end until December 31, 2025. 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 is monitoring the rulemaking process closely to ensure compliance by the established deadlines. LADWP is expected to meet Rule 1135 requirements by the compliance deadline of January 1, 2024.

B.3 Greenhouse Gas Emissions and Climate Change

B.3.1 Federal Efforts to Address Climate Change

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

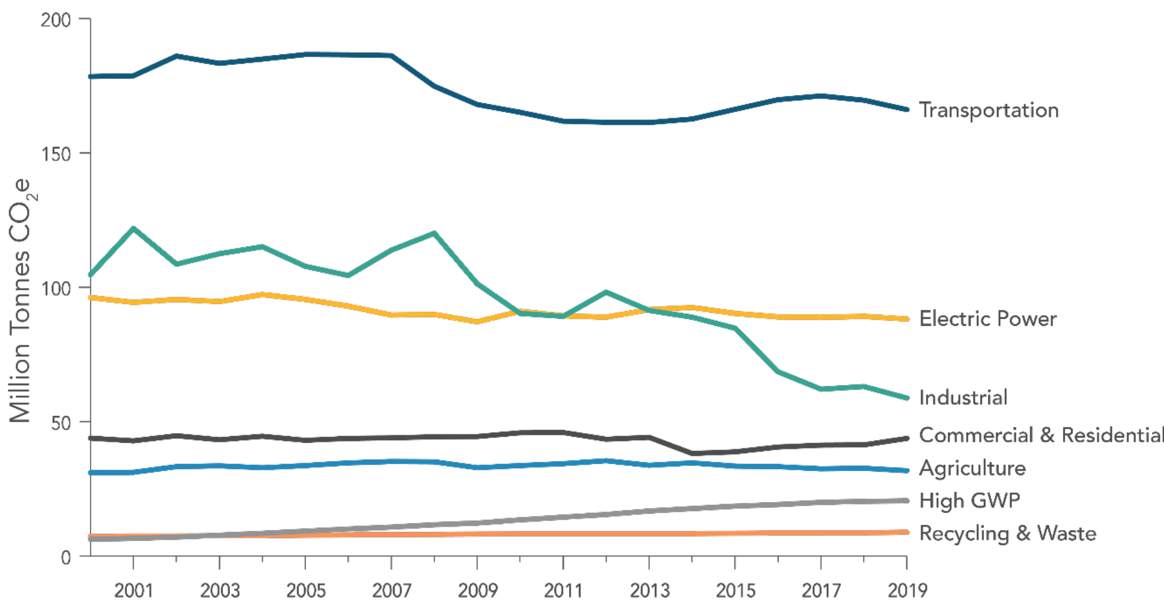
ACE Rule rests on the erroneous legal premise that acceptable emission reduction measures are only limited to those that apply at and to the individual source. By June 2021, petitions for certiorari were filed to review the D.C. Circuit's decision to vacate and remand the ACE Rule. On October 29, 2021, 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. EPA is currently working on a new 111 (d) rulemaking for electric generating utilities, to be proposed in March 2023.

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 2019. The 2021 edition of California's GHG emissions inventory was released in July 2021. It includes GHG emissions estimates for years 2000 to 2019.

Figure B-4 shows the trend in California GHG emissions from 2000 to 2019 by economic sector.

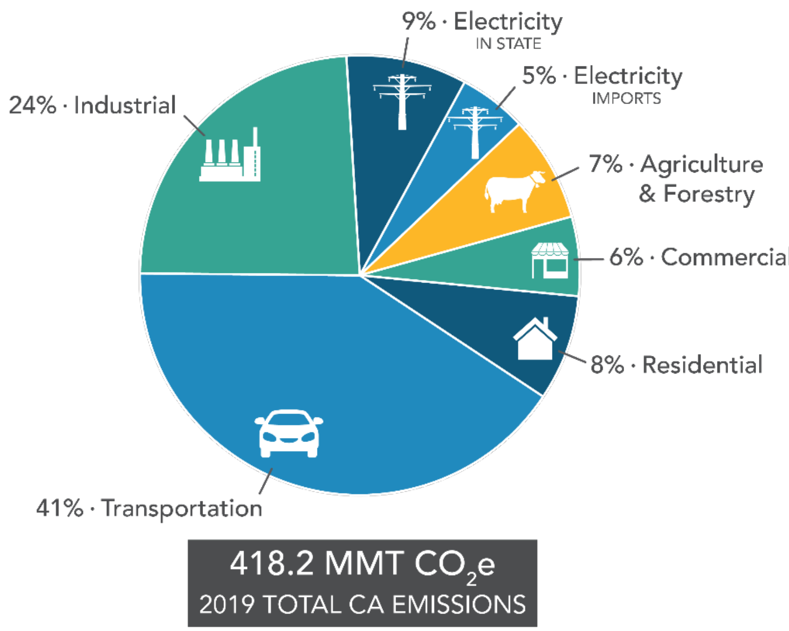


Source: California Air Resources Board GHG Emissions Inventory trends report

Figure B-4. Trends in California GHG Emissions by Category as Defined in the Scoping Plan.

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 level 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 2021 edition of California's GHG emissions inventory, 2019 GHG emissions were 418.2 million metric tons of carbon dioxide equivalent (MMT CO_2e), which is 7.1 MMT CO_2e lower than 2018 levels and almost 13 MMT CO_2e below the 2020 GHG limit of 431 MMT CO_2e. 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 2019 statewide GHG emissions inventory by sector.

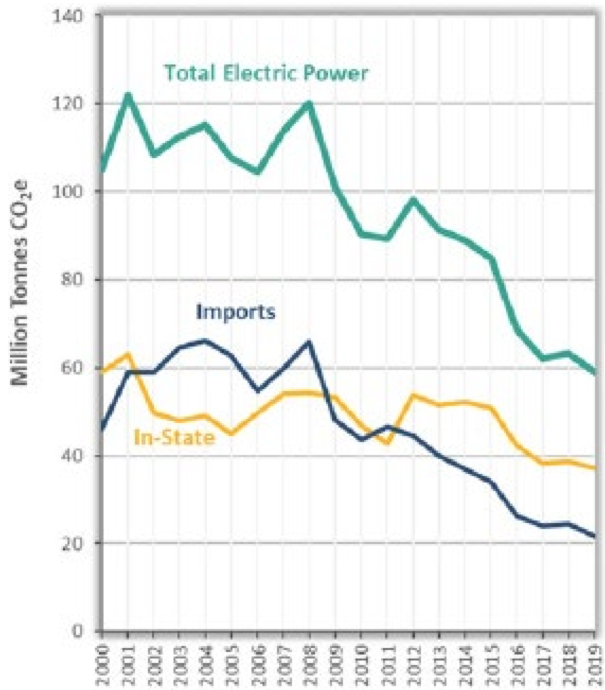


Source: California Air Resources Board GHG Emissions Inventory

Figure B-5. California GHG Emissions by Sector in 2019.

14% of California's GHG emissions are the result of 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 2019.



Source: California Air Resources Board GHG Emissions Inventory trends report

Figure B-6. Trends in Electric Power GHG Emissions.

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 at the November 7, 2018 meeting.

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.

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.

[1] GHGs covered by AB 32 include the following: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

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.

CARB is currently working on the 2022 Scoping Plan Update, which assesses progress toward the 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 technologically feasible, cost-effective, and equity-focused 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. 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"[2]. In response to the Governor's request and legislation in the Governor's climate legislation package, CARB is updating the modeling and revising the draft 2022 Scoping Plan Update. Adoption of the final draft 2022 Scoping Plan Update is expected in December 2022, but could be delayed.

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

[2] Office of Governor Gavin Newsom press release https://www.gov.ca.gov/2022/09/16/governor-newsom-signs-sweeping-climate-measures-ushering-in-new-era-of-world-leading-climate-action/

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.

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.

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.

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.

California Climate Legislation Package

In September 2022, Governor Newsom signed into law a package of forty 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.

AB 32 Cap-and-Trade Regulation

The Cap-and-Trade Program is a key element in the AB 32 scoping plan. The Cap-and-Trade Program sets a statewide limit on sources responsible for 85% of California's GHG emissions, and establishes a price signal 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 extended to 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. The 2022 Scoping Plan Update will evaluate the role of the cap-and-trade program as the state examines its strategies for tackling climate change over the next decade and long-term carbon neutrality goal.

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 30% hydrogen 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 2021.

Table B-1. HISTORICAL LADWP POWER GENERATION CO_2 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	10,566,904	27,810,279	838
2017	9,554,640	27,515,675	766
2018	9,077,848	26,484,002	756
2019	8,230,332	26,442,540	686
2020	7,528,640	26,344,723	630
2021	7,527,570	25,200,297	659
Difference between 1990 and 2021	-10,397,840	-281,235	-892
% Change from 1990	-58%	-1%	-58%

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 1970’s and 1980’s, and is in widespread use in the electric grid today. When released into the atmosphere, SF_6 is also a greenhouse gas with a high global warming potential due to its stability.

In the early 2000’s, 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 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 not only complied with the emission limits imposed by the CARB SF_6 regulation, but often reported an annual SF_6 emission rate that was significantly lower than the limit.

In 2021, CARB finalized amendments to its Regulation for Reducing Greenhouse Gas Emissions from Gas-Insulated Equipment. Significant changes to the CARB regulation include phasing out the use of SF_6 in newly purchased gas-insulated electrical equipment from 2025 through 2033, depending on the equipment voltage class. The SF_6 phase out is intended to drive development of alternative equipment that does not use SF_6 as an insulating gas, and incorporation of this alternative equipment into the electric grid. The amended regulation includes a process to obtain an exemption from the 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. Other changes include adjusting the insulating gas capacity on the equipment nameplate to more accurately reflect the actual gas fill amount. 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. In addition, the amended regulation changes 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.

In 2022, the U.S. EPA is in the process of amending its regulation for the Use of Electrical Transmission and Distribution Equipment[3] to expand the reporting requirements to include emissions of all fluorinated greenhouse gases, including SF_6 and perfluorocarbons. The proposed amendments also include a procedure to measure and adjust the insulating gas capacity on the equipment 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 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.

[3] 40 CFR Part 98, Subpart DD

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.

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Appendix C

Renewable Portfolio Standard

2022 SLTRP

CONTENTS

C Renewable Portfolio Standard

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 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 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 2022 SLTRP 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 actually 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-2 below:

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, 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 SLTRP, 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:

1. Geographic diversity is important to maintain and enhance power system reliability.
2. The use of existing LADWP assets such as transmission lines, land, and existing generation resources should be maximized.
3. Pursue multi-faceted development with adequate back-up strategies to handle project delays, project failures, reduced generation output, and operation or maintenance impacts.
4. Projects shall be targeted to specifically meet the Power System/Renewables Policy objectives.
5. Flexible RPS goals will be established to address the variable nature of renewable energy while conforming to applicable state and federal requirements.
6. 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.
7. 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 SLTRP, 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.

The renewable energy mix of 2021 is shown on Figure C-1.

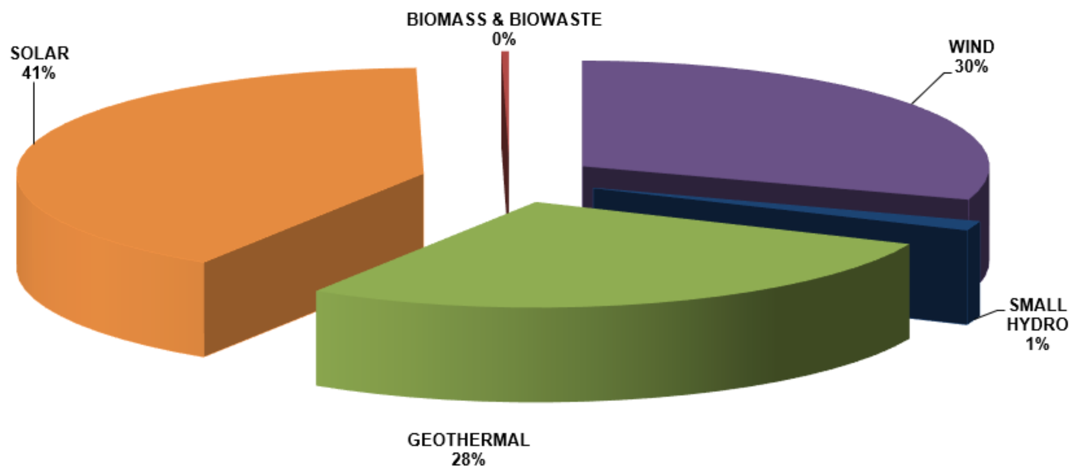


Figure C-1. 2021 LADWP Renewable Energy Mix.

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 procure a minimum quantity of electricity products from eligible renewable energy

[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

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.

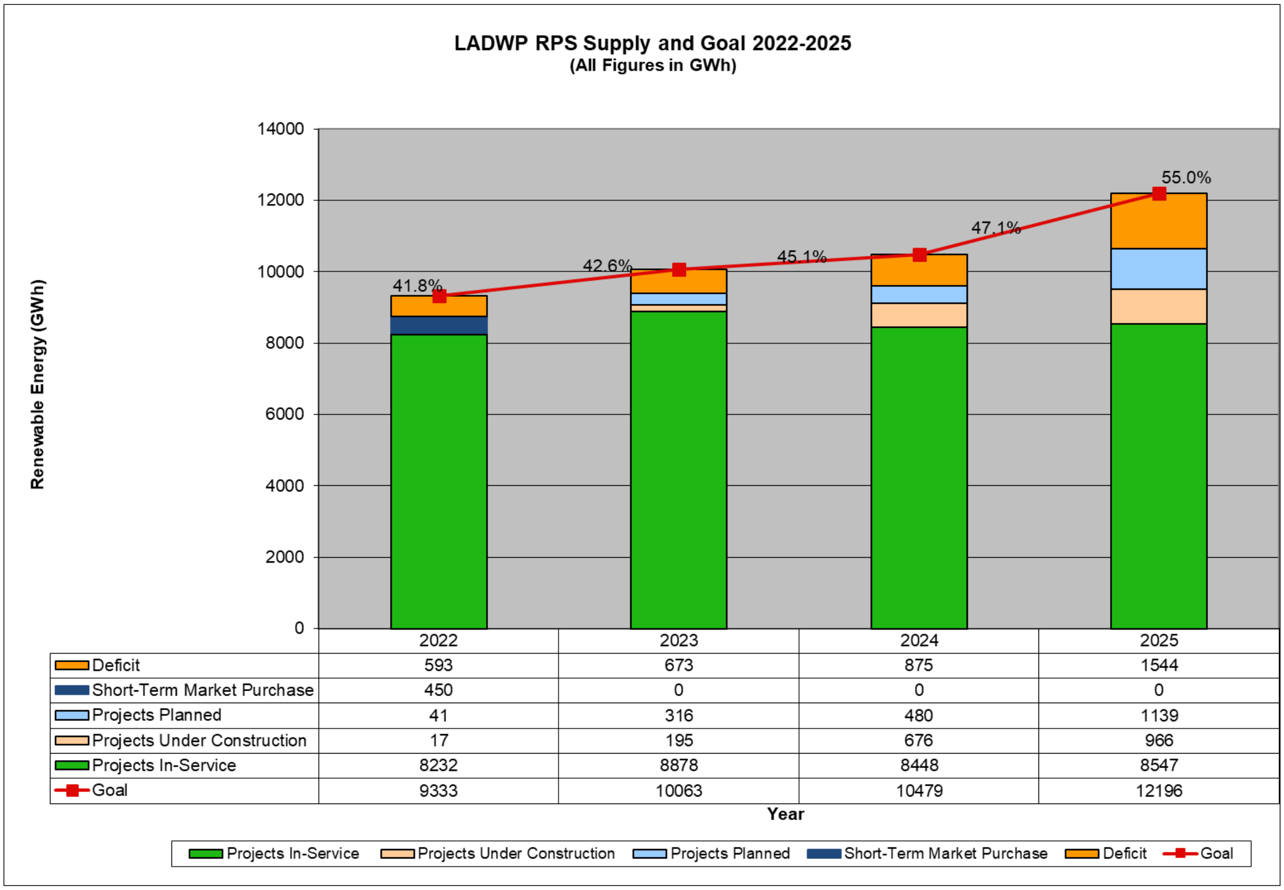
C.5 Funding the RPS

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.

Figure C-2 shows LADWP's RPS goals out to the year 2025. Revenues requirements are expected to increase substantially over the next several years.

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.



	2022	2023	2024	2025
Deficit	593	673	875	1544
Short-Term Market Purchase	450	0	0	0
Projects Planned	41	316	480	1139
Projects Under Construction	17	195	676	966
Projects In-Service	8232	8878	8448	8547
Goal	9333	10063	10479	12196

Figure C-2. LADWP RPS supply and goals for 2021-2025.

C.6 Other LADWP 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 Biofuels

Biogas continues to be one of the few renewable energy resources available that provides dispatch and base load characteristics, which effectively makes it a reliable and predictable renewable energy resource. Biogas is also needed to support other renewable resources that have low capacity factor characteristics, such as wind and solar. By capturing biogas for the use of electricity generation rather than flaring it and creating a secondary source of greenhouse gas emissions, utilities are clearly reducing the total amount of greenhouse gases emitted. Furthermore, by injecting biogas into the existing natural gas pipeline system, utilities are effectively offsetting the cost of building additional unnecessary infrastructure to supply biomethane to California.

The California Energy Commission (CEC) Overall Program Guidebook of April, 2013 defined biogas as “includes digester gas, landfill gas, and any gas derived from an eligible biomass feedstock”, and biomethane or pipeline biomethane as “biogas that has been upgraded or otherwise conditioned such that it meets the gas quality standards applicable to the natural gas transportation pipeline system into which the biogas is first accepted for transportation. The pipeline owner/operator must have written gas quality standards that are publicly available.”

Digester gas is typically derived from the anaerobic digestion of agricultural, human or animal waste and biomass is typically defined as any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, biosolids, sludge derived from organic matter, and wood and wood waste from timbering operations. The CEC also considers landfill gas (LFG) - gas produced by the breakdown of organic matter in a landfill - a renewable fuel.

In keeping with capturing the intent of the California legislature to increase use of renewable fuels, the LADWP amended its RPS policy when the CEC issued its third edition of the Guidebook in January 2008. Language from the then CEC Guidebook stated, “RPS-eligible biogas (gas derived from RPS-eligible fuel such as biomass or digester gas) injected into a natural gas transportation pipeline system and delivered into California for use in an RPS-certified multi-fuel facility may result in the generation of RPS-eligible electricity.”

The LADWP’s gas-fired generating units capable of burning a mixture of biogas/biomethane and conventional natural gas, fall under the CEC multi-fuel designation. The CEC Guidebook stated, “…only the renewable portion of generation will count as RPS eligible, and only when the Energy Commission approves a method to measure the renewable portion.”

Pursuant to the CEC Guidebook, the LADWP calculates the amount of RPS-eligible electricity produced at its gas-fired generating units by multiplying the total generation of the facility by the ratio of the quantity of biogas used to the quantity of total gas used by the facility. Both the energy generated and the quantity of gas used must be measured on a monthly basis.

The LADWP currently produces RPS-eligible energy derived from biogas/biomass. Digester gas produced at the Hyperion Wastewater Treatment facility is piped to the adjacent Scattergood Generating Station, where it is used to produce RPS-eligible energy. Additionally, the LADWP procures biogas/biomass-derived renewable energy via gas-fired microturbines located at several landfills throughout Los Angeles.

The LADWP currently holds contracts with developers to purchase pipeline biomethane. Under these contracts, the LADWP obtains LFG from several landfill sites located outside California. LFG produced by the landfills is scrubbed and filtered to pipeline grade and injected into the interstate natural gas pipeline system for delivery to the LADWP's most efficient gas-fired generating units.

The passage of the California Assembly Bill 2196 in 2012 modified the RPS eligibility requirements for electrical generation facilities using biomethane to generate electricity. With adoption of the Seventh Edition of the RPS Eligibility Guidebook, the CEC implemented AB 2196 and concurrently lifted its suspension of eligibility for biomethane which was previously imposed on March 28, 2012. New requirements in the Seventh Edition Guidebook have been added for tracking and verifying the use of biomethane, including tracking and verifying the quantities and sources of biomethane and the related environmental and renewable attributes, and the deliveries of biomethane. In addition, the passage of the California Assembly Bill 1900 in 2012 required the CPUC to develop testing protocols for landfill gas and to adopt standards for biomethane that would be injected into a common carrier pipeline.

The passage of the California Senate Bill SB 859 in 2016 required a local publicly owned electric utility serving more than 100,000 customers shall procure its proportionate share, based on the ratio of the utility's peak demand to the total statewide peak demand, of 125 megawatts of cumulative rated capacity from existing bioenergy projects that commenced operations prior to June 1, 2013. At least 80% of the feedstock of an eligible facility, on an annual basis, shall be a byproduct of sustainable forestry management, which includes removal of dead and dying trees from Tier 1 and Tier 2 high hazard zones and is not that from lands that have been clear cut. At least 60% of this feedstock shall be from Tier 1 and Tier 2 high hazard zones.

In March 2018, the City Council approved a power purchase agreement with SCPPA for a share of the output of the ARP-Loyalton Biomass Project in Sierra County, California, which began commercial operation in April 2018. SCPPA partnered with other State POUs to purchase a total of 18 MWs of capacity for a term of five years towards satisfaction of procurement obligations under SB 859. The Department's share of the ARP-Loyalton Biomass Project is 8.9 MWs. In addition, the Department has contracted with SCPPA to purchase 5.4 MWs of rated capacity from the Roseburg SB 859 biomass project. These two projects allow the Department to meet its requirement to purchase 14.3 MWs of rated capacity from biomass sourced energy facilities in order to comply with SB 859.

C.6.2 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 2021 Power Content Label is shown in Table C-3. As LADWP has two separate renewable programs, the RPS policy and GREEN, both of these programs are reported on the Power Content Label.

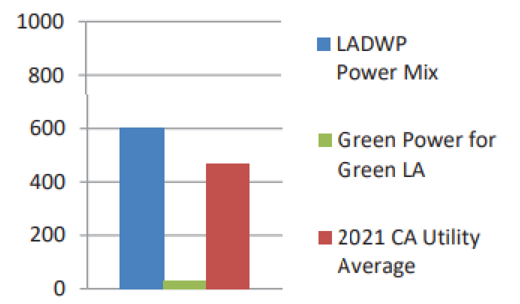
Table C-3. LADWP's 2021 Power Content Label.

2021 POWER CONTENT LABEL

LADWP

https://www.ladwp.com/powercontent

Greenhouse Gas Emissions Intensity (lbs CO_2e/MWh)		
LADWP Power Mix	Green Power for Green LA	2021 CA Utility Average
609	**0**	**456**



Energy Resources	LADWP Power Mix	Green Power for Green LA	2021 CA Power Mix
Eligible Renewable[1]	**35.2%**	**100.0%**	**33.6%**
Biomass & Biowaste	0.1%	0.0%	2.3%
Geothermal	9.7%	0.0%	4.8%
Eligible Hydroelectric	0.5%	0.0%	1.0%
Solar	14.3%	100.0%	14.2%
Wind	10.6%	0.0%	11.4%
Coal	**18.6%**	**0.0%**	**3.0%**
Large Hydroelectric	**6.6%**	**0.0%**	**9.2%**
Natural Gas	**25.9%**	**0.0%**	**37.9%**
Nuclear	**13.7%**	**0.0%**	**9.3%**
Other	**0.0%**	**0.0%**	**0.2%**
Unspecified Power[2]	**0.0%**	**0.0%**	**6.8%**
TOTAL	**100.0%**	**100.0%**	**100.0%**
Percentage of Retail Sales Covered by Retired Unbundled RECs[3]:	**0%**	**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 2021 electricity portfolios were sourced from eligible renewable energy generators such as biogas, biomass, eligible hydroelectric, solar, wind and geothermal 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:	http://www.energy.ca.gov/pcl/
For additional questions, please contact the California Energy Commission at:	Toll-free in California: 844-454-2906 Outside California: 916-653-0237

Reference C-1 – LADWP Renewables Portfolio Standard Policy and Enforcement Program Amended December 2013 - Board Resolution:

WHEREAS in August 2000, the Board of Water and Power Commissioners (Board) approved a resolution that authorized the Los Angeles Department of Water and Power (LADWP) to adopt an Integrated Resource Plan that established a goal of meeting 50 percent of projected load growth through a combination of Demand-Side-Management, Distributed Generation, and Renewable Resources; and

WHEREAS in 2002, the California Legislature passed Senate Bill 1078 that established the California Renewables Portfolio Standard (RPS), and a goal for all investor-owned utilities (IOUs) to increase their use of renewable resources by at least 1 percent per year, until 20 percent of their retail sales were procured from renewables by 2017; and

WHEREAS local publicly-owned utilities (POUs), like LADWP, were exempt from California Senate Bill 1078, however they were encouraged to establish renewable resource goals consistent with the intent of the California Legislature; and

WHEREAS on June 29, 2004, the Los Angeles City Council adopted an RPS Framework and requested that the Board establish a RPS Policy, including achieving “20 percent renewable energy by 2017” and incorporating this “RPS into all future energy system planning”; and

WHEREAS on October 15, 2004, the Los Angeles City Council adopted a resolution approving the inclusion of existing LADWP hydroelectric generation units greater than 30 megawatts in size, excluding the Hoover hydroelectric plant, as part of the City’s RPS list of eligible resources; and

WHEREAS on June 29, 2005, the Los Angeles City Council approved LADWP’s Renewables Portfolio Standard Policy (RPS Policy), which was designed to increase the amount of energy LADWP generated from renewable power sources to 20 percent of its energy sales to retail customers by 2017, with an interim goal of 13 percent by 2010; and
WHEREAS in December of 2005, the Board recommended that LADWP accelerate its RPS goal to obtain 20 percent renewables by 2010, which recommendation included updating LADWP’s Integrated Resource Plan to incorporate this goal, proceeding with the negotiation and contract development for renewable resources proposed and selected in LADWP’s 2004 RPS and Southern California Public Power Authority’s 2005 RPS, supporting the cost of accelerating the RPS, and maintaining the financial integrity of LADWP’s Power System during times of natural gas price volatility; and

WHEREAS on April 11, 2007, the Board amended LADWP's RPS Policy by advancing the 20 percent goal to December 31, 2010, and by establishing renewable energy procurement ownership targets; and

WHEREAS, on May 20, 2008, the Board approved an amended RPS Policy, which included an additional RPS goal that required 35 percent of energy sales to retail customers be generated from renewable resources by December 31, 2020, expanded the list of eligible renewable resources, and provided new energy delivery criteria; and

WHEREAS, the California Renewable Energy Resources Act (Act) became effective on December 10, 2011, which establishes procurement targets within specified compliance periods and required the governing board of a POU, such as LADWP, to adopt a program for enforcement, in accordance with Public Utilities Code Section 399.30(e); and

WHEREAS, on December 6, 2011, the Board adopted Resolution 012-109 comprehensively updating LADWP's RPS Policy to comply with the Act; and

WHEREAS, in August 2013 the California Office of Administrative Law approved regulations by the California Energy Commission entitled "Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities for the California Renewable Energy Resources Act", which became effective on October 1, 2013.

NOW, THEREFORE BE IT RESOLVED that the Board of Water and Power Commissioners of the City of Los Angeles hereby adopts the Renewables Portfolio Standard Policy and Enforcement Program, Amended December 2013, approved as to form and legality by the City Attorney, and on file with the Secretary of the Board.

I HEREBY CERTIFY that the foregoing is a full, true, and correct copy of a resolution adopted by the Board of Water and Power Commissioners of the City of Los Angeles at its meeting held

____

Secretary

Reference C-2 – LADWP Renewables Portfolio Standard Policy and Enforcement Program Amended December 2013:

City of Los Angeles Department of Water and Power

Renewables Portfolio Standard Policy

and

Enforcement Program

Amended December 2013

1. Purpose

This Renewables Portfolio Standard (RPS) Policy and Enforcement Program (RPS Policy) as amended, represents the continued commitment by the Los Angeles Department of Water and Power (LADWP) to renewable energy resources. The RPS Policy was amended and adopted in December 2011 as a result of the adoption of the California Renewable Energy Resources Act (Act or SB 2 [1X]) and its requirement for the governing boards of local publicly owned electric utilities (POUs) to adopt "a program for the enforcement of this article" on or before January 1, 2012[2].

The RPS Policy is being amended in accordance with recently adopted Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (Regulations) adopted by the California Energy Commission (CEC) pursuant to Section 399.30(l) of the Act. This amendment incorporates the "Optional Compliance Measures" found in the Regulations, including "excess procurement," "delay of timely compliance," "cost limitations," and "portfolio balance requirement reduction."

The Regulations state that the CEC may issue an administrative complaint to a POU for "failure to comply with any of the requirements" in the Regulations in accordance with applicable law.[3] These Regulations were promulgated under SB 2 (1X), which required the CEC to establish procedures for enforcement of the California Renewables Portfolio Standard Program[4] and

[2] Public Utilities Code (PUC) Section 399.30 (e)
[3] Regulations, section 3208(b).
[4] PUC Section 399.30 (m)(1) states "failure to comply with this article," which is interpreted to mean Article 16 of Chapter 2.3 of Part 1, Division 1 of the Public Utilities Code.

provided for the CEC to determine if a POU "has failed to comply" with the California Renewables Portfolio Standard Program. The CEC is further required to refer failures to comply with the California Renewables Portfolio Standard Program[5] to the California Air Resources Board, "which may impose penalties to enforce" the California Renewables Portfolio Standard Program consistent with Part 6 of the California Global Warming Solutions Act of 2006.[6] In addition, "[a]ny penalties imposed shall be comparable to those adopted by the [California Public Utilities Commission] for noncompliance by retail sellers."[7]

In accordance with Public Utilities Code (PUC) Section 399.30 (e) the Board of Water and Power Commissioners of the City of Los Angeles (Board) will retain its jurisdiction to enforce the RPS Policy.

2. Background

In 2002, California Senate Bill 1078 (SB 1078) added Sections 387, 390.1 and 399.25, and Article 16 (commencing with Section 399.11) to Chapter 2.3 of Part I of Division 1 of the PUC, establishing a 20 percent RPS for California IOU's. SB 1078 provided that each governing board of a local POU be responsible for implementing and enforcing an RPS that recognizes the intent of the Legislature to encourage renewable resources and the goal of environmental improvement, while taking into consideration the effect of the standard on rates, reliability, and financial resources.

On June 29, 2004, the Los Angeles City Council (City Council) passed Resolution 03-2064-S1 requesting that the Board adopt an RPS Policy of 20 percent renewable energy by 2017 setting applicable milestones to achieve this goal, and incorporate this RPS into a future Integrated Resource Plan (IRP).

On May 23, 2005, the Board adopted an RPS Policy that established the goal of increasing the amount of energy LADWP generates from renewable power sources to 20 percent of its energy sales to retail customers by 2017, with an interim goal of 13 percent by 2010. On June 29, 2005, the City Council approved the LADWP RPS Policy.

On April 11, 2007, the Board amended the LADWP RPS Policy by accelerating the goal of requiring that 20 percent of energy sales to retail customers be generated from renewable

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[5] Id.
[6] Id.
[7] Id. "Retail sellers" is interpreted to mean Investor Owned Electric Utilities ("IOUs"). See PUC §399.12 (j)(4)(C)

resources by December 31, 2010. In addition, the amended policy established a Renewable Resource Surcharge and also established renewable energy procurement ownership targets.

The Board subsequently approved an RPS Policy, as amended in April 2008, which included an additional RPS goal of requiring that 35 percent of energy sales to retail customers be generated from renewable resources by December 31, 2020, expanded the list of eligible renewable resources, and provided new energy delivery criteria.

In 2010, LADWP achieved its RPS goal of 20 percent.

On April 12, 2011, Governor Edmund G. Brown signed into law SB 2 (1X). This Act set Renewables Portfolio Standard (RPS) procurement targets, renewable resource eligibility definitions, and new reporting requirements applicable to POUs. SB 2 (1X) required each POU to attain a minimum of 25 percent RPS by 2016 and 33 percent RPS by 2020 and report on reasonable progress for each intervening year. SB 2 (1X) became effective on December 10, 2011, and required the governing board of a POU, such as LADWP, to adopt a program for enforcement in accordance with PUC Section 399.30(e), by January 1, 2012. On December 6, 2011, the Board adopted Resolution 012-109 comprehensively updating the existing RPS Policy to comply with SB 2 (1X).

On August 30, 2013, the California Office of Administrative Law approved the Regulations, which became effective as of October 1, 2013.

The Board adopts an annual fiscal year budget, including a Fuel and Purchased Power Budget (FPP), which defines the specific expenditures for renewable energy resources. The annual fiscal year budget, including the FPP, comprises LADWP's Renewable Energy Resources Procurement Plan (RPS Procurement Plan), as required under Section 3205(a) of the Regulations. This RPS Policy is not making any revisions or updates to LADWP's RPS Procurement Plan.

3. <u>RPS Procurement Targets</u>

1. In 2011, the Board adopted the RPS procurement targets in the Act to promote stable electricity prices, protect public health, improve environmental quality, provide sustainable economic development, create new employment opportunities, reduce reliance on imported fuels, and ensure compliance with applicable state law. Regulation Section 3204(a) has specified calculations and requirements for achieving the RPS procurement targets; consequently, this Board adopts the RPS procurement targets, calculation methods, and limitations, as specified in Section 3204(a), as provided herein: For the compliance period beginning January 1, 2011, and ending December 31, 2013, LADWP shall demonstrate it has procured electricity products sufficient to meet or exceed an average of 20 percent of its retail sales over the three calendar years in the compliance period.

2. For the compliance period beginning January 1, 2014, and ending December 31, 2016, LADWP shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 20 percent of its 2014 retail sales, 20 percent of its 2015 retail sales, and 25 percent of its 2016 retail sales.
3. For the compliance period beginning January 1, 2017, and ending December 31, 2020, LADWP shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 27 percent of its 2017 retail sales, 29 percent of its 2018 retail sales, 31 percent of its 2019 retail sales, and 33 percent of its 2020 retail sales.
4. For the calendar year ending December 31, 2021, and each calendar year thereafter, LADWP shall procure renewable electricity products sufficient to meet or exceed 33 percent of its retail sales by the end of that year.

4. <u>Voluntary Program – Green L.A.</u>

LADWP will continue to encourage voluntary contributions from customers to fund renewable energy resources in addition to the stated RPS procurement targets, in accordance with its Green Power for a Green L.A. Program or any successor program. The Green Power for a Green L.A. Program currently does not count towards the RPS, but encourages ratepayers to partake in this renewable energy transformation for powering the City.

5. <u>Eligible Renewable Energy Resources to be Counted in Full Towards RPS</u>

Prior to the enactment of SB 2 (1X), the LADWP RPS Policy defined the following technologies as "eligible renewable resources": "biodiesel; biomass; conduit hydroelectric (hydroelectric facilities such as an existing pipe, ditch, flume, siphon, tunnel, canal, or other manmade conduit that is operated to distribute water for a beneficial use); digester gas; fuel cells using renewable fuels; geothermal; hydroelectric incremental generation from efficiency improvements; landfill gas; municipal solid waste; ocean thermal, ocean wave, and tidal current technologies; renewable derived biogas (meeting the heat content and quality requirements to qualify as pipeline-grade gas) injected into a natural gas pipeline for use in renewable facility; multi-fuel facilities using renewable fuels (only the generation resulting from renewable fuels will be eligible); small hydro 30 Mega Watts (MW) or less, the Los Angeles Aqueduct hydro power plants, other qualifying hydroelectric generation; solar photovoltaic; solar thermal electric; wind; and other renewables that may be defined later."

All renewable energy resources approved by the Board as part of its renewables portfolio in accordance with applicable law and previous versions of this RPS Policy, including without limitation those in Appendix A, will continue to be eligible renewable energy resources. These renewable energy resources will count in full towards LADWP's procurement requirements.

6. Eligible Renewable Energy Resources Procured After the Effective Date of the Act

For RPS resources procured after the effective date of SB 2 (1X), December 10, 2011, “eligible renewable energy resource” means an electrical generating facility that meets eligibility criteria under applicable law, including a renewable electrical generation facility, as defined in Section 399.12 (e) of the PUC and a facility satisfying the criteria of Section 399.12.5 of the PUC.

7. Long-Term Resources

LADWP will integrate the RPS Policy into its long-term resource planning process, and the RPS Policy will be consistent with LADWP's IRP objectives of service reliability, competitive electric rates, and environmental leadership. Future IRPs may incorporate and expand upon RPS procurement requirements, and further define plans for procuring eligible renewable energy resources by technology type and geographic diversity.

8. Portfolio Content Categories and Portfolio Balance Requirements

As required by SB 2 (1X), eligible renewable energy resources, procured on or after June 1, 2010, will be in accordance with PUC Sections 399.16 (b) and (c). Section 399.16 (b) defines eligible renewable energy resources in three distinct portfolio content categories. LADWP will ensure that the procurement of its eligible renewable energy resources on or after June 1, 2010, will meet the specific percentage requirements set out in Section 399.16 (c) and the Regulations for each portfolio content category in each compliance period.

These portfolio content categories and percentage requirements for the portfolio balance requirements are summarized in Table 1 below:

Table 1: Portfolio Content Categories and Portfolio Balance Requirements

Portfolio Content Category	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 form 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).	**<u>Compliance Period 1 (2011 – 2013):</u>** 50% of RPS minimum from this category. **<u>Compliance Period 2 (2014 – 2016):</u>** 65% of RPS minimum from this category. **<u>Compliance Period 3 (2017 – 2020):</u>** 75% of RPS minimum from this category. **<u>Post 2020:</u>** 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.	**<u>Compliance Period 1 (2011 – 2013):</u>** 25% of RPS maximum from this category. **<u>Compliance Period 2 (2014 – 2016):</u>** 15% of RPS maximum from this category. **<u>Compliance Period 3 (2017 – 2020):</u>** 10% of RPS maximum from this category. **<u>Post 2020:</u>** 10% of RPS maximum from this category.

Subject to the provisions of Regulations Section 3202 (a)(2), renewable electricity products procured before June 1, 2010, are exempt from these portfolio content categories and will continue to count in full toward LADWP's RPS compliance targets. This exemption is subject to the limitations in Regulation Section 3202(a)(2) and (3).

LADWP will develop specific scheduling methods, including firming services, as needed, to maintain transmission system reliability and compliance with the procurement content categories and portfolio balance requirements.

9. Optional Compliance Measures

9.1 Excess Procurement

As permitted under Regulation Section 3206(a)(1), LADWP opts to allow the application of excess procurement and adopts the following rules:

1. LADWP may, in the discretion of its General Manager, or his or her designee:
    a. designate electricity products qualifying as excess procurement;
    b. apply excess procurement in one compliance period to a subsequent compliance period, as specified in Regulation Section 3206(a)(1) and subject to the limitations specified therein;
    c. For the calendar year ending December 31, 2021, and each calendar year thereafter, apply excess procurement from one calendar year to a subsequent calendar year or to more than one subsequent calendar year.
2. LADWP may begin accruing excess procurement as early as January 1, 2011.
3. There is no requirement to use all or any excess procurement prior to seeking a "delay in timely compliance" or prior to seeking a "portfolio balance requirement reduction."

9.2 Delay in Timely Compliance

Within the discretion of LADWP's Board, as permitted by law, LADWP may delay the timely compliance with the RPS procurement requirements upon a finding by the Board that "conditions beyond the control" of LADWP exist to delay the timely compliance with RPS procurement requirements specified in Regulation Section 3204. Such a finding shall be limited to one or more of the causes for delay identified in Regulation Section 3206(a)(2)(A) and shall demonstrate that LADWP would have met its RPS procurement requirements but for the cause of delay. For example, the causes identified in the PUC and Regulations include "inadequate transmission capacity to allow for sufficient electricity to be delivered" and "permitting, interconnection, or other circumstances that delay procured eligible renewable energy resource projects."[8]

As permitted under Regulation Section 3206(a)(2)(A), LADWP adopts the following rules:

1. The Board shall make the findings and adopt the delay of timely compliance by a Board resolution;
2. The Board resolution shall state the compliance period(s) that correspond to the delay of timely compliance;
3. The delay of timely compliance may apply to more than one compliance period;
4. For the calendar year ending December 31, 2021, and each calendar year thereafter, the delay of timely compliance may apply to more than one calendar year, as long as the Board resolution specifies the calendar year(s) that correspond to the delay of timely compliance;
5. Evidentiary hearings shall not be required to make the required findings;
6. The standard of showing for any of the required findings, including the "but for cause of delay" showing, is by a "preponderance of the evidence standard," which is also known as "a more likely than not" standard;
7. These rules regarding the required findings, as well as the facts surrounding the conditions causing the delay, shall be interpreted and applied broadly, on a case-by-case basis;

9.3 Portfolio Balance Requirement Reduction

Within the discretion of LADWP's Board, as permitted by law, LADWP may reduce the portfolio balance requirement for Portfolio Content Category 1 consistent with PUC Section 399.16(e) and subject to the limitations specified in Regulation 3206(a)(4).

As permitted under Regulation Section 3206(a)(4)(A), LADWP adopts the following rules :

1. The Board shall make the findings and adopt the reduction of the portfolio balance requirement for Portfolio Content Category 1 by a Board resolution;
2. The Board resolution shall specify the compliance period that corresponds to the reduction of the portfolio balance requirement for Portfolio Content Category 1;
3. The reduction of the portfolio balance requirement for Portfolio Content Category 1 must be for a specific compliance period and must identify the level to which LADWP will reduce the requirement;
4. For the calendar year ending December 31, 2021, and each calendar year thereafter, the reduction of the portfolio balance requirement for Portfolio Content Category 1 may

[8] Public Utilities Code §399.15(b)(5); Regulation §3206(a)(2)(A)

apply to more than one calendar year, as long as the Board resolution specifies the calendar year(s) that corresponds to the reduction of the portfolio balance requirement for Portfolio Content Category 1;

5. A reduction of the portfolio balance requirement for Portfolio Content Category 1 below 65 percent is allowed for any compliance period before January 1, 2017; however, after December 31, 2016 a reduction of the portfolio balance requirement for Portfolio Content Category 1 below 65 percent will not be considered consistent with PUC Section 399.16.(e).
6. Evidentiary hearings shall not be required to make the required findings;
7. The standard of showing for any of the required findings is by a “preponderance of the evidence standard,” which is also known as “a more likely than not” standard;
8. These rules regarding the required findings, as well as the facts surrounding the conditions causing the reduction of the portfolio balance requirement for Portfolio Content Category 1, shall be interpreted and applied broadly, on a case-by-case basis.

9.4 Change in Law or Regulations

1. If the CEC adopts guidelines or suggested rules that impact any of the rules adopted by the Board for any of the Optional Compliance Measures that are inconsistent with these rules, these Board-adopted rules will control.
2. If the Office of Administrative Law approves CEC regulations that amend or change the Regulations (Changed Regulations) that are inconsistent with these Board adopted rules, then the Changed Regulations shall control if not contested by LADWP. If the Changed Regulations are contested by LADWP, then these Board-adopted rules shall control until a final decision by the CEC or final decision on a petition for writ of mandate, whichever is later.
3. If SB2 (1X), is amended or changed (Changed SB2 (1X)), and the Changed SB2(1X) sections are inconsistent with these Board-adopted rules, then the Changed SB2(1X) sections shall control if not contested by LADWP. If the Changed SB2(1X) sections are contested by LADWP, then these Board adopted rules shall control until a final decision by a court of competent jurisdiction.

9.5 Cost Limitations

As permitted under Regulation Section 3206(a)(3), LADWP hereby adopts the following rules on cost limitations for the expenditures made to comply with its RPS procurement requirements:

System Rate Impact

1. LADWP may not make any major financial commitment to procure eligible renewable energy resources prior to evaluating the rate impact and any potential adverse financial impact on the City transfer.
2. The costs of all procurement credited toward achieving the RPS will count toward this System Rate Impact limitation.
3. Procurement expenditures will not include any indirect expenses including, without limitation, imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades, or the costs associated with relicensing any owned hydroelectric facilities.

In adopting these cost limitation rules, LADWP shall rely on all of the following:

1. The most recent RPS Procurement Plan.
2. Procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable energy resources.
3. The potential that some planned resource additions may be delayed or canceled.

When assessing procurement expenditures under an adopted cost limitation rule, LADWP shall apply only those types of procurement expenditures that are permitted under the adopted cost limitation rules. In the event the projected cost of meeting the RPS procurement requirements exceeds the cost limitation, then LADWP shall seek to implement the other Optional Compliance Measures, including a delay of timely compliance, and/or portfolio balance requirement reduction.

If the cost limitation for LADWP, as determined by the Board, is insufficient to support the projected costs of meeting the renewables portfolio standard procurement requirements, LADWP may refrain from entering into new contracts or constructing facilities beyond the quantity that can be procured within the limitation, unless eligible renewable energy resources can be procured without exceeding a de minimis increase in rates, consistent with the LADWP's IRP.

10. Procurement of Eligible Renewable Energy Resources

LADWP will procure eligible renewable energy resources based on a competitive method evaluation consistent with the goals of procuring the least-cost and best-fit electricity products from eligible renewable energy resources. Furthermore, preference will be given to projects that are located within the City of Los Angeles or on City-owned property and are to be owned and operated by LADWP to further support LADWP's economic development and system reliability objectives.

Notwithstanding the foregoing, LADWP will also procure eligible renewable energy resources through programs such as Feed-In-Tariff, Senate Bill 1 (SB1) Customer Net Metered Solar PV, or other local renewable energy programs, or similar procurement processes. These transactions will be made in as cost-effective a manner as is feasible in each respective instance, with pricing that reflects applicable legal requirements and market conditions, prevailing policy, and competitive methods. Short-term renewable energy transactions will be needed as well, on a limited basis, to manage LADWP's RPS eligible renewable energy resources portfolio effectively based on prevailing wholesale practices.

Before December 31, 2010, LADWP pursued its 20 percent RPS goal in a manner which resulted in a minimum of 40 percent renewable energy generation ownership that LADWP developed or that LADWP procured through contracts with providers of renewable energy. Further, with respect to the foregoing contracts with providers, such contracts provided for LADWP ownership or an option to own, either directly or indirectly (including through joint powers authorities).

On or after January 1, 2011, a minimum of 75 percent of all new eligible renewable energy resources procured by LADWP will either be owned or procured by LADWP through an option-to-own, either directly or indirectly (including through joint powers authorities) until at least half of the total amount of eligible renewable energy resources, by Megawatt-hour (MWh), is supplied by eligible renewable energy resources owned or with an option to own either directly or indirectly (including through joint powers authorities) by LADWP.

The first priority for LADWP will be to pursue outright ownership opportunities, and the second priority will be consideration of procuring option-to-own, cost-based renewable energy resources. In comparing outright ownership to option-to-own, option-to-own projects must show clear economic benefits, such as pass-through of Federal or State tax credits or incentives, which could not otherwise be obtained, or the need to evaluate new technology. The option-to-own will be exercisable with the minimum terms necessary to obtain and pass those tax credits and/or incentives to LADWP and/or upon a reasonable amount of time to evaluate the operation of the new technology.

11. Use of Renewable Energy Credits

The primary method of renewable energy resource procurement will be through the development and acquisition of physical generation assets and energy purchase contracts where the Renewable Energy Credit (REC) is bundled with the associated energy. PUC Section 399.12 (h) sets forth the REC definition.

In order for RPS procurement requirements to be managed effectively, LADWP may buy, sell, or trade RECs without the associated energy (unbundled). This approach will be limited by the percentage requirements established by PUC Section 399.16 (b) (3), the Regulations and the REC Policy discussed below.

12. REC Policy and Cost Limitations Pending City Council Approval.

On or about February 12, 2013, the LADWP Board adopted an "Environmental Credit and REC Policy" and submitted an ordinance for approval by the Los Angeles City Council that included a cost limitation on purchases of renewable energy credits (RECs), which is pending before the Los Angeles City Council. If and when it is finally approved, the applicable policy limits, including the cost limitation on REC purchases shall be incorporated into this RPS Policy by this reference.

13. Enforcement, Reporting and Notice Requirements

13.1 Enforcement

If the Board determines, by a Board resolution, that LADWP will not meet its RPS procurement requirements under Regulation Section 3204, then the Board may require the following:

1. A report from the General Manager, or his or her designee, identifying actions taken by LADWP demonstrating reasonable progress toward meeting its RPS procurement requirements. The information reported shall include a discussion of:
    - (A) Solicitations released to solicit bid for contracts to procure electricity products from eligible renewable energy resources to satisfy the RPS procurement requirements.
    - (B) Solicitations released to solicit bid for ownership agreements for eligible renewable energy resources to satisfy the RPS procurement requirements.
    - (C) Actions taken to develop eligible renewable energy resources to satisfy the RPS procurement requirements, including initiating environmental studies, completing environmental studies, acquiring interests in land for facility siting or transmission, filing applications for facility or transmission siting permits, and receiving approval for facility or transmission siting permits.
    - (D) Interconnection requests filed for eligible renewable energy resources to satisfy the RPS procurement requirements.
    - (E) Interconnection agreements negotiated and executed for eligible renewable energy resources to satisfy the RPS procurement requirements.

   (F) Transmission - related agreements negotiated and executed to transmit electricity products procured from eligible renewable energy resources to satisfy the RPS procurement requirements.
   (G) Other planning activities to procure electricity products from eligible renewable energy resources.
2. A report from the General Manager, or his or her designee, identifying actions planned by LADWP to demonstrate reasonable progress toward achieving the RPS procurement requirements. The description of actions planned shall include, but not be limited to: a discussion of activities specified in subparagraphs (A) - (G), above.
3. An updated enforcement program and/or procurement plan that includes a schedule identifying potential sources of electricity products currently available or anticipated to be available in the future for meeting LADWP's shortfall.

13.2 Reporting

LADWP will submit reports to the CEC as required by Section 3207 of the Regulations. Additionally, LADWP will provide a regular RPS progress report to the Board.

13.3 Notice

Pursuant to Section 3205(a) of the Regulations, LADWP will post notice whenever the Board will deliberate in public on its Renewable Energy Resources Procurement Plan. LADWP will notify the CEC of the date, time, and location of the meeting in order to enable the CEC to post the information on its Internet Web site by providing the CEC with the Uniform Resource Locator (URL) that links to this information or sending an email to the CEC with the information in Portable Document Format (PDF). In addition, upon distribution to the Board of information related to LADWP's renewable energy resources procurement status and future plans, for the Board's consideration at a noticed public meeting, LADWP shall make that information available to the public and shall provide the CEC with an electronic copy of the documents for posting on the CEC's Internet Web site, by providing the CEC with the URL that links to the documents or information regarding other manners of access to the documents or sending an email to the CEC with the information in PDF.

LADWP will continue to provide a Power Content Label Report to its customers as required by SB 1305 (1997) and AB 162 (2009), and an annual report of the total expenditure for eligible renewable energy resources funded by voluntary customer contributions.

If LADWP seeks to reduce its portfolio balance requirements for Portfolio Content Category 1, then it will provide advance notice to the CEC as required in Regulation Section 3206 (a)(4)(D). The notice will contain the information required by Regulation Section 3206 (a)(4)(D), including the reasons proposed for adopting the reduction. Also, as required in the Regulation, LADWP will update its RPS Procurement Plan.

List of LADWP RPS Resources prior to SB 2 (1X)

Project	Technology
PPM SW Wyoming – Pleasant Valley Wind	Wind
Linden Wind	Wind
PPM Pebble Springs Wind	Wind
Willow Creek Wind	Wind
Pine Tree Wind Power Project	Wind
Milford Wind Phase I	Wind
Milford Wind Phase II	Wind
Windy Point Phase II	Wind
Powerex - BC Hydro	Hydro
MWD Sepulveda	Hydro
Lopez Canyon Landfill	Biofuel
WM Bradley Landfill	Biofuel
Penrose Landfill	Biofuel
Toyon Landfill	Biofuel
Valley Generating Station (GS) – Multi-fuel	Biofuel
Scattergood GS – Multi-fuel	Biofuel
Haynes GS – Multi-fuel	Biofuel
Harbor GS – Multi-fuel	Biofuel
Shell Energy Landfill Gas	Biofuel
Atmos Energy Landfill Gas	Biofuel
Hyperion Digester Gas – Scattergood GS	Biofuel
LADWP Small Hydro Power Plants (PP)	Hydro
San Francisquito PP 1	Hydro
San Francisquito PP 2	Hydro
San Fernando PP 2	Hydro

Foothill PP	Hydro
Franklin PP	Hydro
Sawtelle PP	Hydro
Haiwee PP	Hydro
Cottonwood PP	Hydro
Division Creek PP	Hydro
Big Pine PP	Hydro
Pleasant Valley PP	Hydro
Project	**Technology**
Upper Gorge PP	Hydro
Middle Gorge PP	Hydro
Control Gorge PP	Hydro
North Hollywood Pump Station PP	Hydro
Castaic Hydro Plant – Efficiency Upgrades	Hydro
LADWP Built Solar	Solar
Silverlake Library	Solar
LA Convention Center Canopy	Solar
Sun Valley Library	Solar
Lake View Terrace Library	Solar
Canoga Park Library	Solar
North Central Animal Shelter	Solar
Ascot Library	Solar
Hyde Park Library	Solar
Ducommon Fitness Center	Solar
Truesdale Warehouse	Solar
Van Nuys Truck Shed	Solar
Distribution Station 3 (Vincent Thomas Bridge)	Solar

Main Street Yard	Solar
Exposition Park Library	Solar
Granada Hills Yard	Solar
LADWP JFB Parking Lot	Solar
LA Convention Center Cherry St Parking Lot	Solar
Council District 6 Field Office	Solar

Appendix D

Power System Reliability Program

2022 SLTRP

CONTENTS

D Power System Reliability Program

D.1 Introduction

The Power System Reliability Program (PSRP) was launched in July 2014 as a comprehensive asset management and rehabilitation program, covering the four major asset classes: Generation, Transmission, Substation, and Distribution.

Reliability is one of the most important factors to consider in the planning, design, and operation of a distribution network. 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) 21-22.

Table D-1. Target Inspection/Replacement Summary.

ASSET	TOTAL UNITS	FY 21-22 TARGET
GENERATION		
Generation Transformer (GSU & AUX)	169	2
Major Inspection (Hydro)	22	2
Major Inspection (Pump)	7	1
Major Inspection (Thermal)	26	1
TRANSMISSION		
Maintenance Hole Restraints	238	18
SUBSTATION		
Transmission Circuit Breakers (>100-kV)	542	2
Sub-Transmission Circuit Breakers (34.5-kV)	2,386	18
Distribution Circuit Breakers (4.8-kV)	2,698	16
Extra High Voltage Transformers (high side >230-kV)	78	2
High Voltage Transformers (high side 100-kV to 230-kV)	73	2
Medium Voltage Transformers (high side <100-kV)	876	21
DISTRIBUTION		
Cable (miles)	3,807	50
Crossarms	684,411	11,000
Poles	310,750	3,500
Substructures	56,938	20
Transformers	130,919	1050

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.

Generation

- 14 small hydroelectric plants
- 1 large hydroelectric plant
- 5 thermal plants
- 1 wind plant
- 2 solar photovoltaic plants

Transmission

- 4,040 miles of overhead transmission circuits (including solely and jointly owned, entitlement rights, and transmission service agreement and purchases)
- 135 miles of underground transmission circuits

Substation

- 167 Distributing Stations (127 DS, 40 Pole Top DS)
- 21 Receiving Stations
- 12 Switching Stations, 7 Switchyards, 3 Converter Stations

Distribution

- 310,750 distribution utility poles
- 684,411 distribution crossarms
- 7,265 miles of overhead distribution lines
- 3,807 miles of underground distribution cables
- 130,919 distribution transformers
- 56,938 substructures

D.3 Reliability Assessment

Outage History

Per regulatory requirements, LADWP tracks the frequency and duration of interruptions on its system. The total number of sustained distribution outages was 3,556 in 2020 versus 2,693 in 2021. There were two Major Event Days (MED) in 2020 on September 5 and 6 where temperatures reached up to 114°F in the San Fernando Valley and 99°F in Downtown Los Angeles. These two MEDs accounted for 15% of all the outages in 2020. In comparison, 2021 had no MEDs recorded and saw a decrease in outages. Figure D-1 shows the percent-contribution of each outage code group to the total number of outages per year.

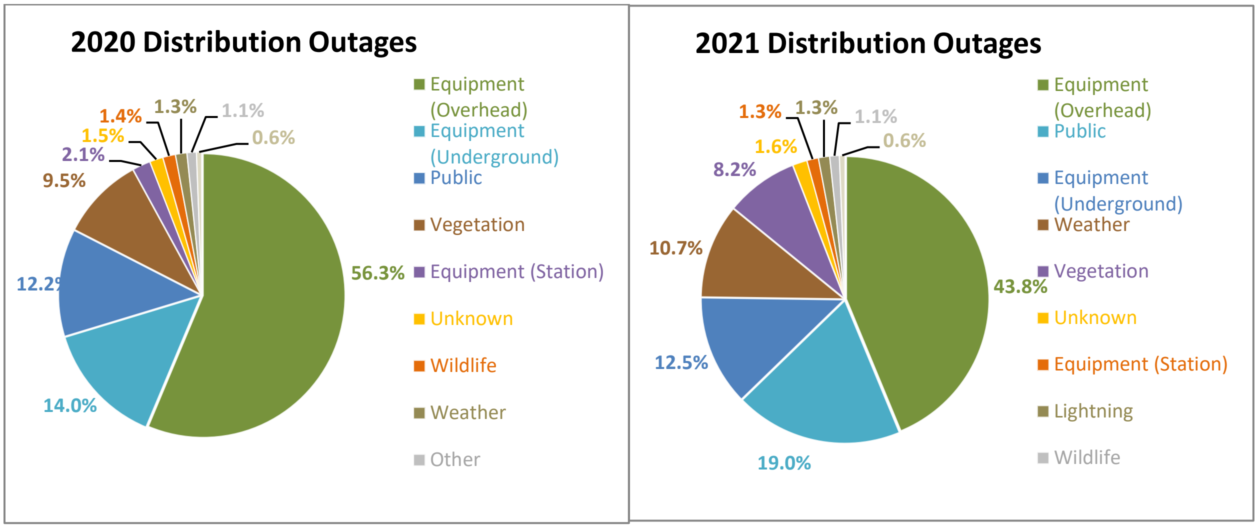

Figure D-1. Breakdown of Sustained Distribution Outage Causes.

<u>Reliability Indices</u>

The metrics calculated and tracked on a monthly and annual basis are:

- ✓ System Average Interruption Frequency Index (SAIFI), which is the average number of sustained interruptions (> 5 minutes) per customer during a defined period
- ✓ System Average Interruption Duration Index (SAIDI), which is the average outage duration in minutes per customer during a defined period
- ✓ Customer Average Interruption Duration Index (CAIDI), which is the average outage restoration time in minutes per customer during a defined period
- ✓ Momentary Average Interruption Frequency Index (MAIFI), which is 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 Major Event Days (e.g. windstorms, rainstorms, heat waves, etc.) as determined by the 1366-2012 standard which is established by the Institute of Electrical and Electronic Engineers (IEEE).

LADWP has seen a downtrend in SAIFI since 2017. The increased SAIFI in 2017 was due to severe wind and rain storms in January and February and a station fire in July. These events fall under the Major Event Days category determined by the IEEE 1366-2012 standard. LADWP also experienced heat waves in August and September, with an all-time peak load of 6,502 MW on August 31, 2017. In comparison to the three IOUs listed in Figure D-2, only San Diego Gas & Electric (SDG&E) has consistently maintained a lower SAIFI than LADWP.

LADWP has continued to perform in line with similarly sized or larger utilities such as SCE and SDG&E for SAIDI. Since 2017, LADWP has maintained a more consistent SAIDI despite experiencing weather-related events each year, as shown in Figure D-3.

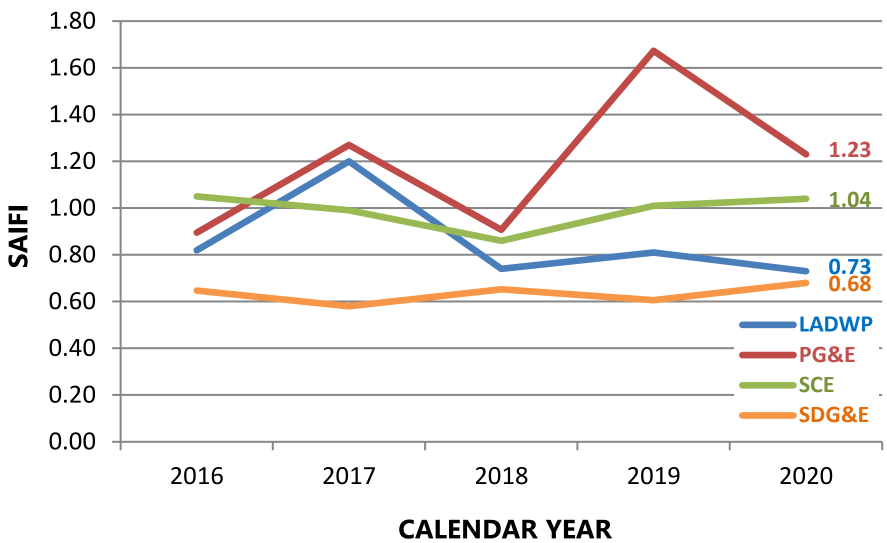

Figure D-2. SAIFI (including Major Events).

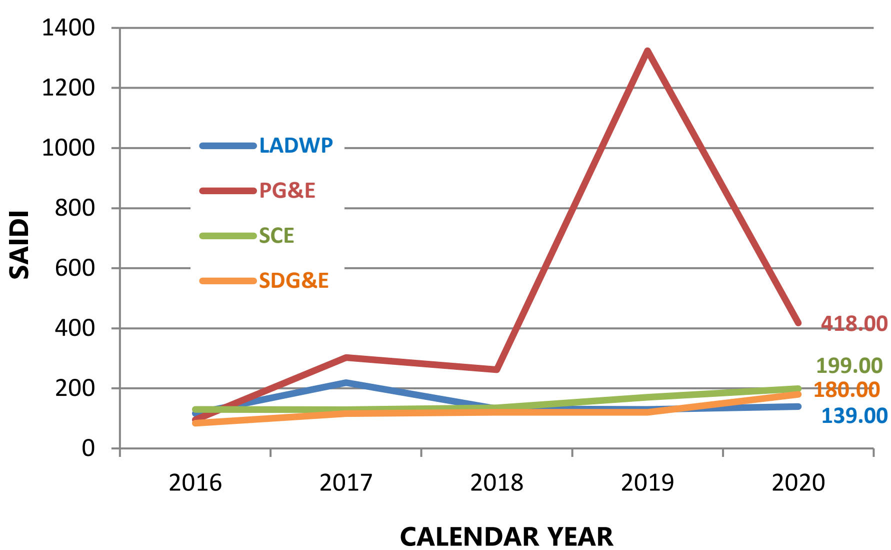

Figure D-3. SAIDI (including Major Events).

Fix-It Tickets

The CPUC established General Order (GO) 165 to set inspection requirements for electric distribution and transmission facilities. LADWP uses GO 165 as a guideline to maintain and inspect its distribution and transmission assets. Figure D-4 illustrates the backlog of Fix-It Tickets as well as the number of Fix-It Tickets initiated and completed per fiscal year.

LADWP has ramped up capital investments and O&M efforts since implementing the PSRP in 2014. This has led to a growing backlog of Fix-It Tickets in recent years as more tickets are created than completed. Approximately half of the backlogged Fix-It Tickets are from inspection maintenance, and the remaining are approximately equally divided between trouble maintenance, preventative maintenance, and system modifications.

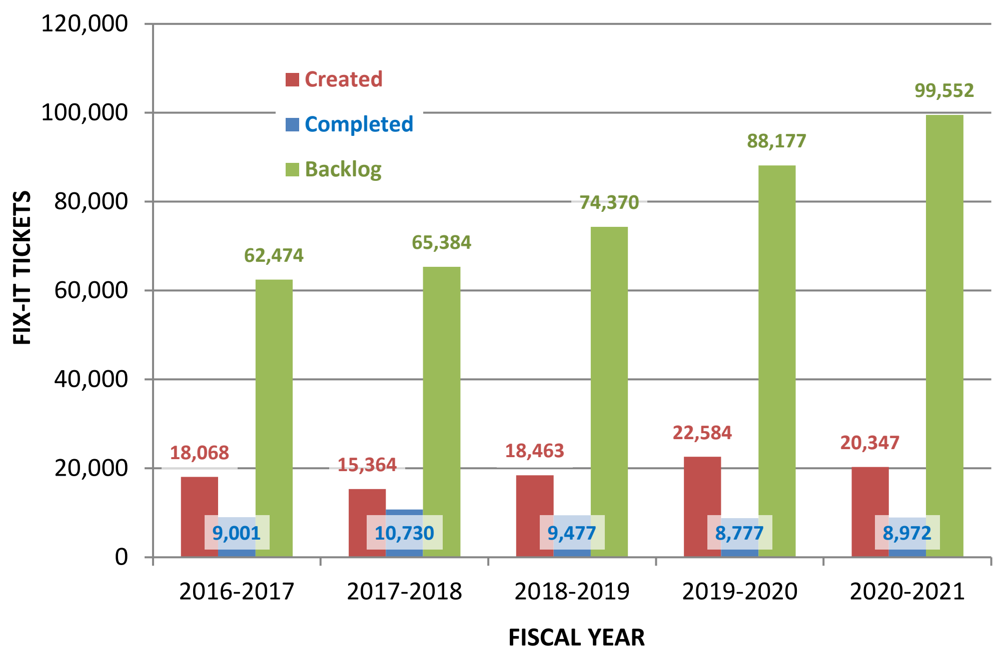

Figure D-4. Fix-It Tickets Progress.

Abnormal Distribution Circuits

Distribution circuits that had/have failed components and/or were included in a load transferred 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 the load was 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 had load transferred to one or multiple adjacent circuits due to field work or switching operation

There were a total of 98 A- & B-type abnormal circuits at the beginning of FY 20-21. By June 30, 2021, that total stood at 92.

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 20-21, five worst-performing circuits plans were issued and three plans were completed.

D.4 Programs and Projects

Generation Transformer

In FY 21-22, installation was completed for one station service transformer at Castaic Power Plant in May 2022. The transformer is scheduled to be placed in service in June 2022. Engineering also continued with the design of the generator step-up (GSU) transformer replacement and relocation for San Fernando Power Plant. LADWP also specified and issued a purchase order for a new Spare GSU for Haynes Generating Station (GS) Units 11-16. The target to complete two transformers in the fiscal year was not met due to COVID-19 resource issues during the fall and winter seasons.

Plans for FY 22-23 include completion of the San Fernando Power Plant GSU Transformer installation. In addition, the fabrication, factory acceptance testing, and delivery of the Haynes GS Spare GSU is scheduled for the Spring of 2023, and installed by June 2023.

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 21-22 are provided below.

For FY 21-22, a major inspection was completed on San Fernando Power Plant, Unit 1.

- Multiple thrust bearing failures triggered an investigation into the Unit 1 generator. The generator field was removed and sent to LADWP Main St. Repair Shop for cleaning and repair. Since Unit 2 is on a forced outage indefinitely, due to major damage found on the turbine runner, the thrust bearing from Unit 2 was installed in Unit 1. This enabled Unit 1 to be returned to service.

For FY 21-22, a major inspection was completed on Upper Gorge Power Plant.

- The unit was experiencing high vibrations leading to multiple trips while operating. The major inspection found that the rotor was rubbing and required a realignment. The turbine and generator bearings were repaired/replaced. The unit was realigned and balanced to reduce vibration.

For FY 21-22, a major inspection was performed on Valley Generating Station, Unit 6.

- This was an unplanned major inspection triggered by findings from a General Electric fleetwide issue. Early signs of possible generator core loosening were found, which has led to catastrophic failure of five other General Electric units. The generator core was tightened, cleaned, and repaired. No other major issues were found.

For FY 21-22, a major inspection was performed on Haynes Generating Station, Unit 9.

- No major issues were found. The generator field was replaced with a refurbished field to extend the life of the generator. The turbine rotor was removed and all buckets were replaced to extend the life of the turbine. The generator and turbine bearings were inspected and repaired/replaced. The generator was realigned.

For FY 21-22, a major inspection was performed on Harbor Generating Station, Unit 5.

- No major issues were found. The generator and turbines were inspected and cleaned. A boresonic inspection of the turbine rotor and generator field was performed. All bearings and seals were repaired/replaced. Partial discharge damage on the generator stator was repaired.

For FY 21-22, a major inspection was performed on Harbor Generating Station, Unit 2.

- No major issues were found. A major inspection was performed on the turbine only. The turbine rotor was removed and repaired.

For FY 21-22, a major inspection was started on Castaic Power Plant, Unit 5.

- The unit went on a forced outage one month before the scheduled major inspection due to a ground fault trip. Significant damage was found on the generator stator and windings.

Plans for FY 22-23 include completing the major inspection of Haiwee Power Plant, Unit 2 and Castaic Power Plant, Unit 5, which began in FY 21-22, starting the major inspection of Castaic Power Plant, Unit 3, and performing a major inspection of Pleasant Valley Power Plant.

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 1,400 towers. Phase 6 of the program has been completed. Potential transmission line segments for phase 7 have been identified and a list of specific towers to be painted is being developed. Approval for a new three-year contract is expected to be occur by 7/1/2023, with work estimated to start in FY 23/24.

Maintenance Hole Restraints

Maintenance hole restraints are used as a security measure to prevent public access to vaults or manholes and are also used as a safety measure to reduce the impact of potential explosions from electrical equipment failures. Due to recent vault explosions that caused major road and property damage, there has been a larger concern to retrofit the existing restraints. For FY 20-21, twenty-five (25) restraints were retrofitted. The target for FY 21-22 is eighteen (18) restraints.

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 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-2 for the recent substation transformer replacements and upgrades through FY 20-21.

Table D-2. Substation Transformer Replacement Plan.

Asset Type	Actuals	
	FY 19-20	FY 20-21
Extra High Voltage Transformers (high side >230-kV)	1	3
High Voltage Transformers (high side 100-kV to 230-kV)	0	3
Medium Voltage Transformers (high side <100-kV)	15	13

Substation Circuit Breakers

The useful design life of a substation circuit breaker is expected to be 36 years. The Distribution (4.8-kV) and Transmission (>100kV) circuit breakers that are currently in-service have average ages of 46 and 26 years, respectively. 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-3 provides figures on recent circuit breaker replacements through FY 20-21.

Table D-3. Substation Circuit Breaker Replacement Plan.

Asset Type	Replaced	
	FY 19-20	FY 20-21
Transmission Circuit Breakers (>100-kV)	2	1
Sub-Transmission Circuit Breakers (34.5-kV)	5	14
Distribution Circuit Breakers (4.8-kV)	8	17

Distribution Pole Replacements

Proactive pole replacements are prioritized by, in no particular order: 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-5 for the latest pole replacement figures through FY 20-21.

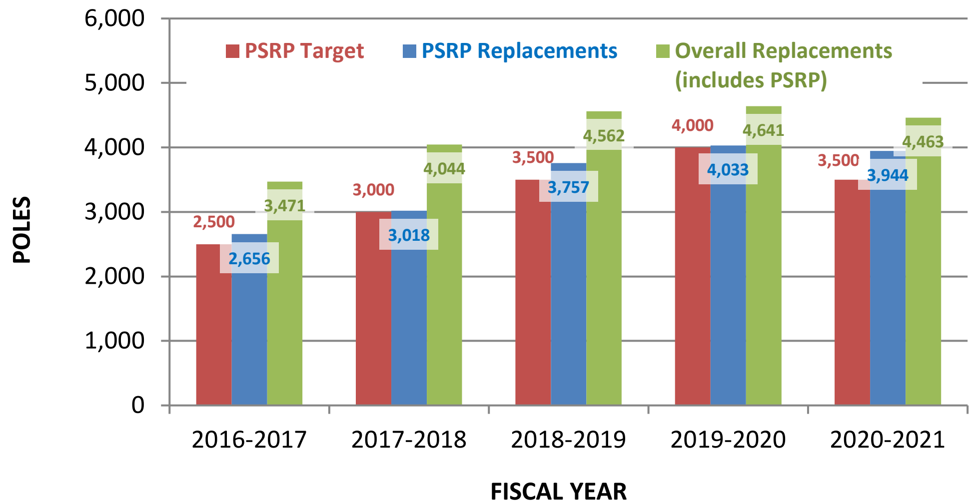

Figure D-5. Distribution Pole Replacement.

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, fiberglass crossarms have been replacing wooden ones due to their superior strength capabilities. Please refer to Figure D-6 for the latest crossarm replacement numbers through FY 20-21.

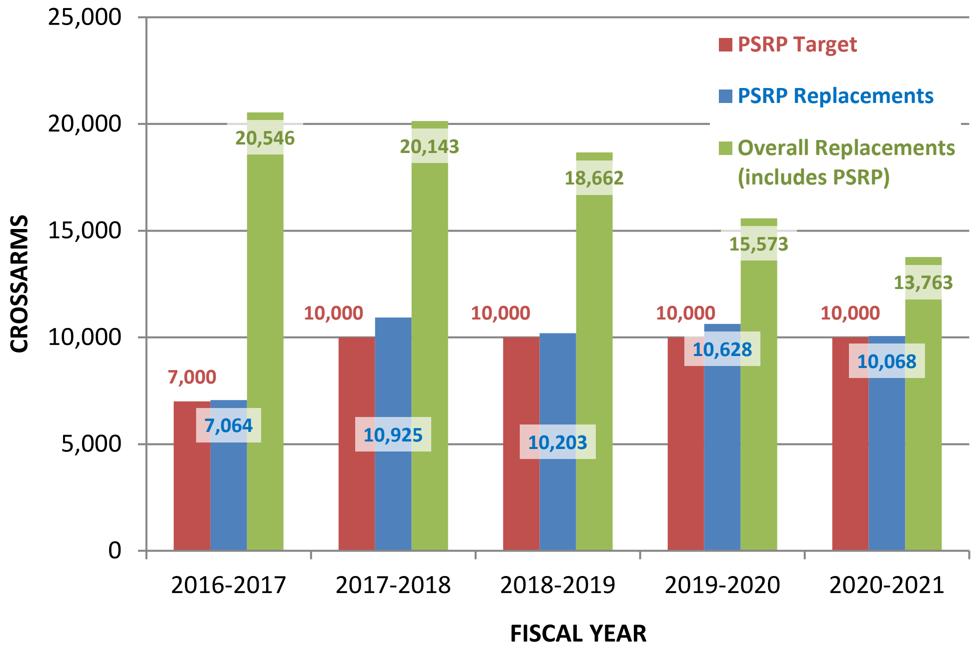

Figure D-6. Crossarm Replacement.

Distribution Cable Replacements

Most A-type 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. Proactively replacing cable allows LADWP to avoid such situations and to effectively plan the work involved to replace/upgrade underground equipment. This naturally lowers capital costs, reduces stress on resources, and avoids compromising the distribution system's flexibility to transfer load between adjacent circuits. Please refer to Figure D-7 for the cable replacement progress through FY 20-21.

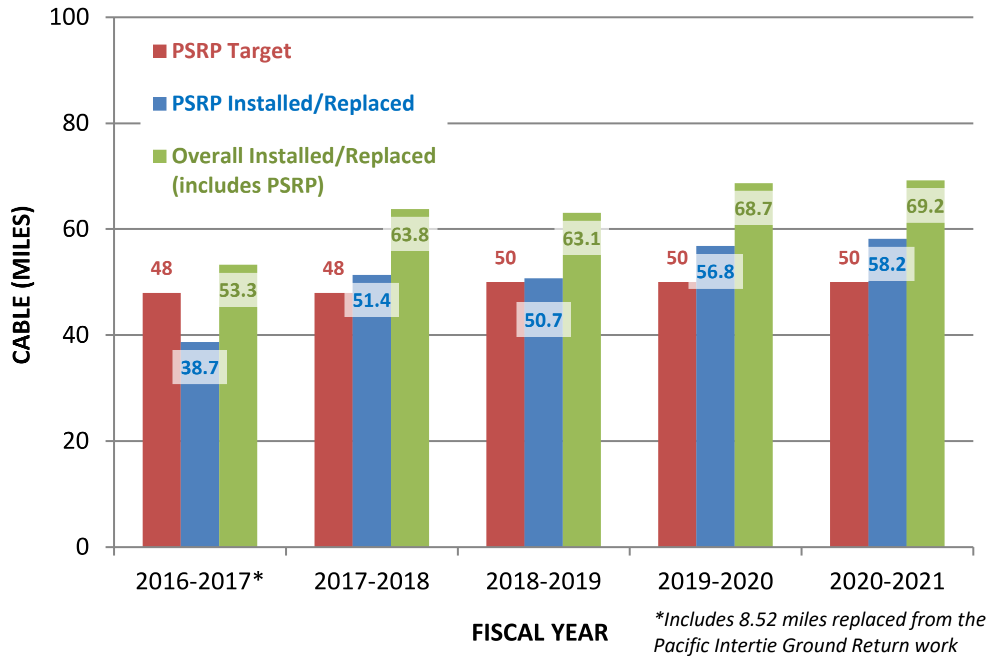

Figure D-7. Distribution Cable Installation/Replacement.

Distribution Transformer Replacements

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-8 illustrates the installation and replacement of distribution transformers through FY 20-21.

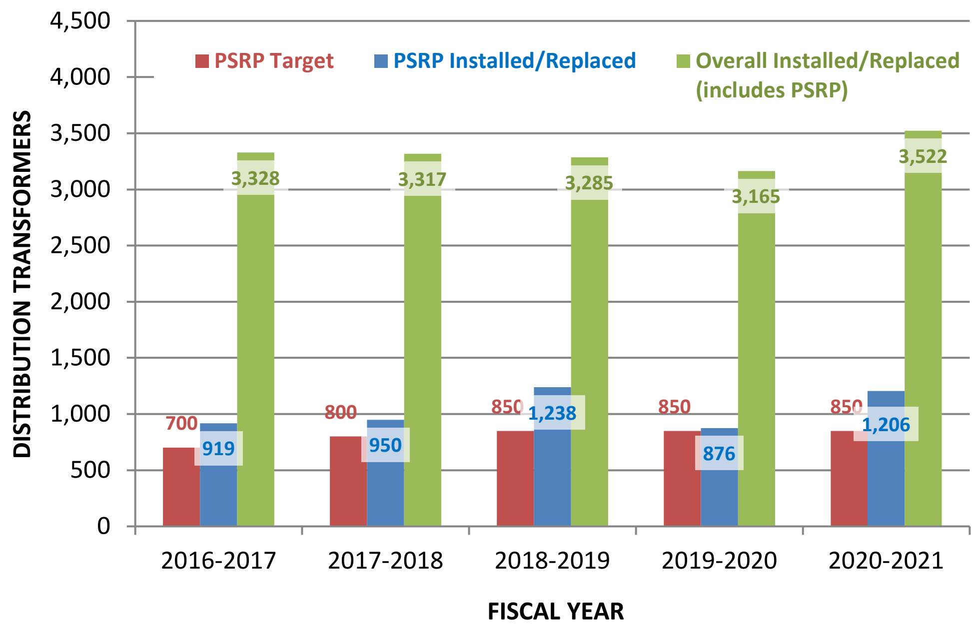

Figure D-8. Distribution Transformer Installation/Replacement.

<u>Substructure Restorations and Replacements</u>

This project oversees the 56,938 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-9 for the progress on substructure restorations and replacements through FY 20-21.

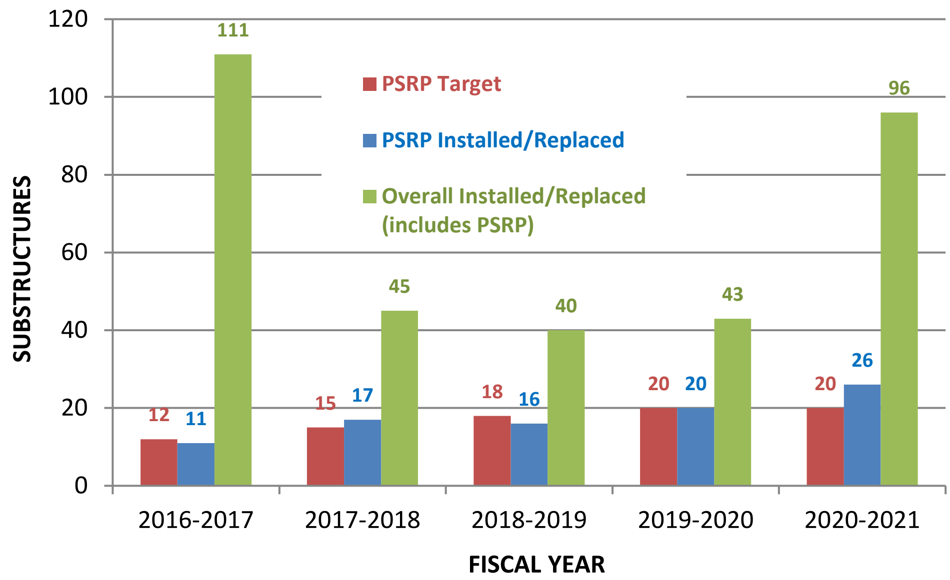

Figure D-9. Substructure Restoration/Replacement.

D.5 Budget

Please refer to Figure D-10 for a breakdown of Actuals PSRP funding for FY 20-21.

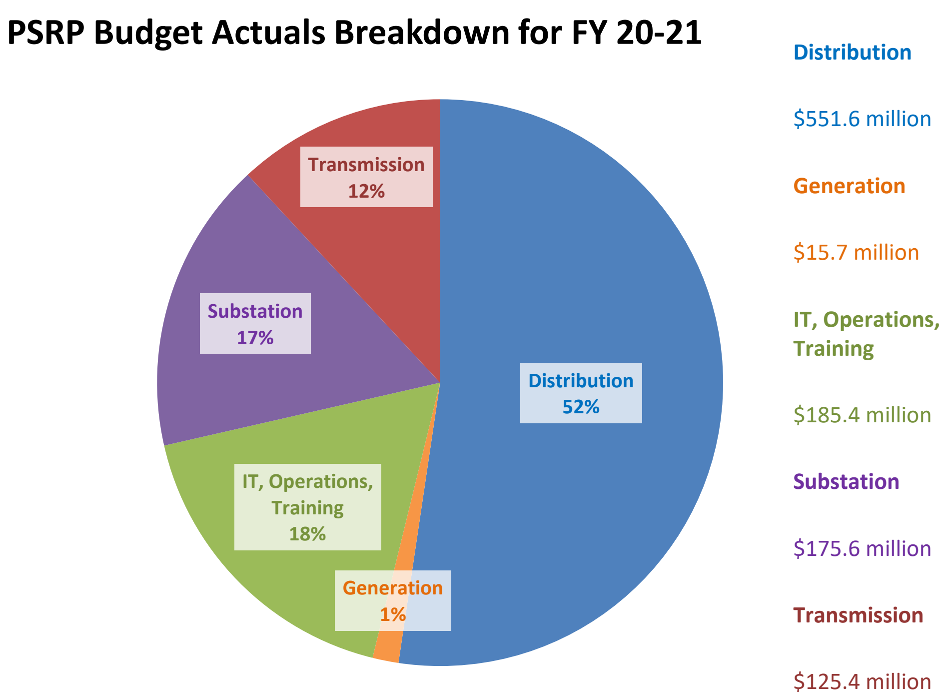

Figure D-10. Percentage Breakdown for FY 20-21 Budget Actuals.

Budget Ramp Up

Starting with the Actuals since FY 18-19 (i.e. $987.5 million), the PSRP expenditures are expected to ramp up to the approved FY 23-24 budget of $1,145.8 million (Figure D-11). This is to allow LADWP to achieve the preferred replacement cycle for all its major assets within Generation, Transmission, Substation, and Distribution.

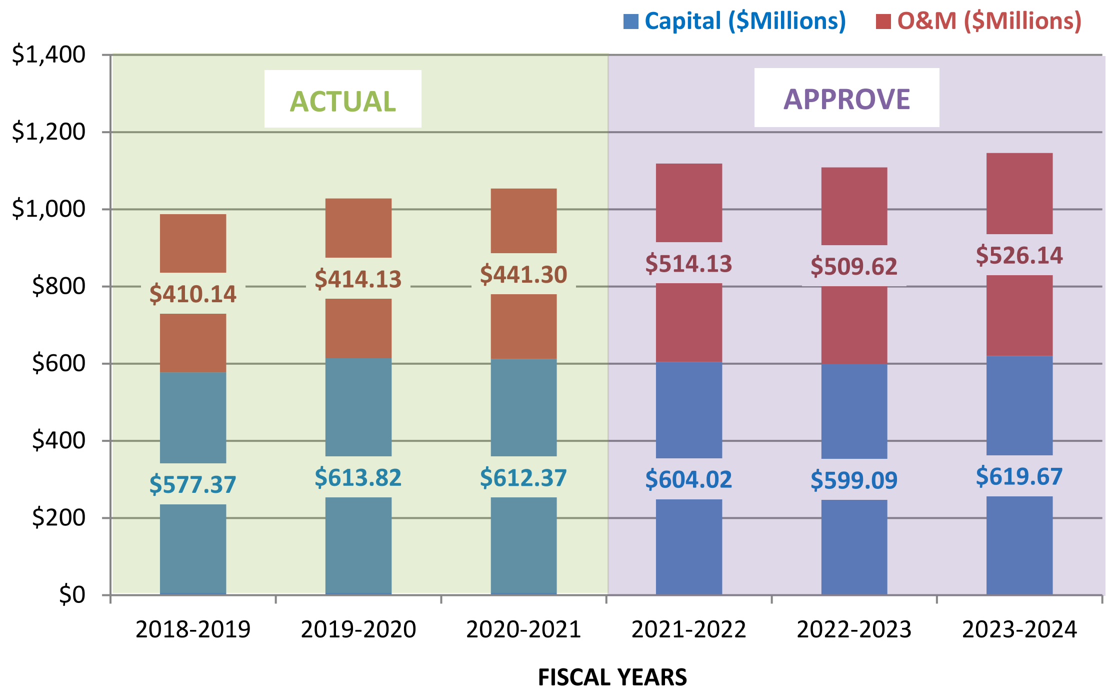

Figure D-11. Chart of Actuals and Approved PSRP funding.

D.6 Overloads and Expanding Distribution System Capacity

In order to keep up with the convergence of aging infrastructure, increasing demand on the distribution system and electrification, LADWP must address existing overloads and revamp the distribution system expansion and upgrade targets in order to meet the goals of the LA100 Study and the mandates of California Senate Bills 100 and 350 (SB 100 & SB 350).

Our current 4.8 kV distribution system is highly stressed with over 300 feeders (20%) loaded above their rating. Over the next 13 years alone we will need to grow our distribution station capacity by 800 MW and our receiving station capacity by 650 MW. This will require significant additional labor and capital resources.

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. In particular, distribution system upgrade targets will need to be increased four to six-fold. Table D-4 shows revamped PSRP distribution system targets required to achieve the goals of getting to 100% carbon-free energy by 2035 while enabling more DERs and electrification.

Table D-4. PSRP Distribution System LA100 Revised Targets.

PSRP Distribution System LA100 Revised Targets								
Asset	FY 21/22	FY 22/23	FY 23/24	FY 24/25	FY 25/26	FY 26/27	FY 27/28	2035 Totals
4.8kV Feeder (miles)	10	20	20	30	30	40	40	470
4.8kV Feeder Positions	20	20	20	30	30	35	35	500
34.5kV Trunk (miles)	5	10	15	20	25	25	25	300
34.5kV Line Positions	4	4	4	6	6	6	8	102
Reconductor (miles)	3.5	3.5	5	5	7.5	7.5	10	112
Voltage Conversion (DS)	0	0	0	1	0	0	1	4
DS Banks (Transformers)	15	15	15	15	15	20	20	265
New 4.8 kV DS	0	0	0	0	1	1	1	10
RS Racks	1	0	1	0	1	0	1	8
New RS	0	0	0	0	0	0	0	1

Additionally, the distribution system capital budget will need to increase from its current $69 million to $406 million by 2030 (Figure D-12).

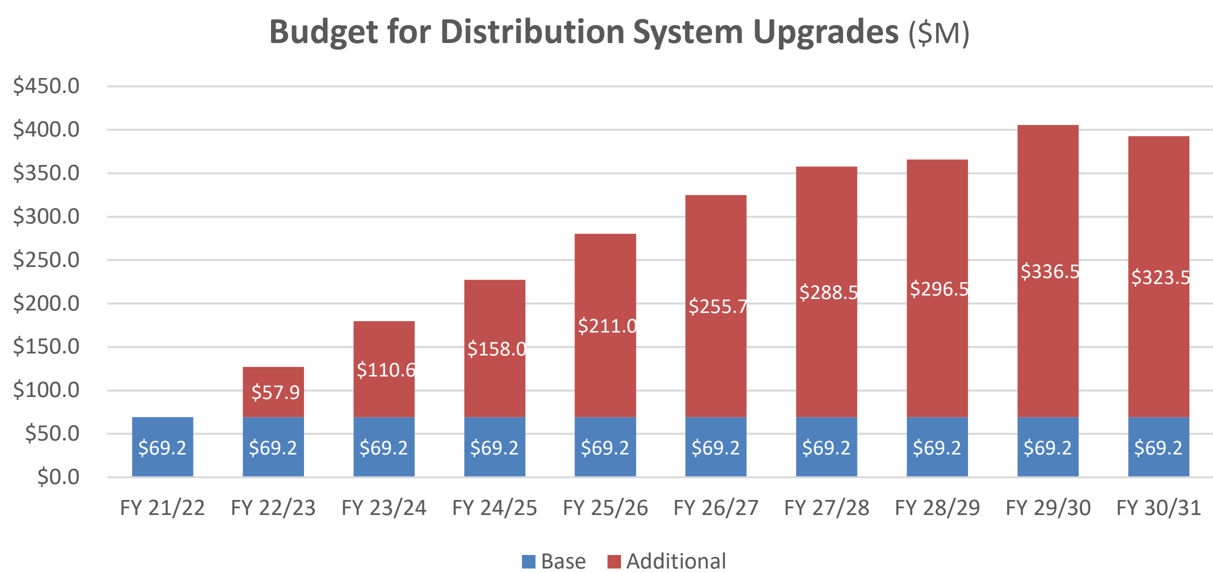

Figure D-12. Budget Distribution System Upgrades in Millions.

Please refer to Table D-5 for PSRP equipment unit cost and average life expectancy.

Table D-5. Equipment Life Expectancy and Unit Cost.

ASSET	Units	Unit Cost (labor + equip)	Average Life Expectancy (years)
GENERATION			
Generation Transformer (GSU & SST)	169	$5,000,000	45
Major Inspection (Hydro)	22	$3,000,000	55
Major Inspection (Pump)	7	$4,000,000	55
Major Inspection (Thermal)	26	$4,000,000	30
TRANSMISSION			
Maintenance Hole Restraints	238	$27,000	-
SUBSTATION			
Transmission Circuit Breakers (>100-kV)	542	$1,500,000	36
Sub-Transmission Circuit Breakers (34.5-kV)	2386	$250,000	36
Distribution Circuit Breakers (4.8-kV)	2698	$160,000	36
Extra High Voltage Transformers (high side >230-kV)	78	$4,000,000	30
High Voltage Transformers (high side 100-kV to 230-kV)	73	$4,000,000	30
Medium Voltage Transformers (high side <100-kV)	876	$550,000	30
DISTRIBUTION			
Cable (miles)	3,807	$1,300,000	75 (lead) 40 (synthetic)
Crossarms	807,950	$2,400	30 (wood) 30 (fiberglass)
Poles	310,750	$35,000	60
Substructures	56,938	$127,900	50
Transformers	130,919	$20,000	40

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, Distribution, and Substation. 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. We must also evaluate and increase our distribution system expansion targets in order to meet electrification and LA100 Study goals.

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Appendix E

Generation Resources

2022 SLTRP

CONTENTS

E Generation Resources

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 3,373 megawatts (MW) and a combined net dependable generating capacity of 3,211 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 January 28, 2022.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Capacity (kW)	Net Dependable Capacity (kW)
Harbor	1	1995	85,340	73,000	425,000[2]
	2	1995	85,340	73,000	
	5	1995	75,000	60,000	
	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	1,512,000[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	742,000[5]
	2	1959	163,200	156,250	
	4	2015	216,920	206,000	
	5	2015	118,900	107,000	
	6	2015	106,900	102,000	
	7	2015	106,900	102,000	
Valley	5	2001	60,500	44,000	532,000[4]
	6	2003	182,750	155,000	
	7	2003	182,750	155,000	
	8	2003	264,350	201,000	
Total				3,373,450	3,211,000

Notes:

1. COD refers to Commercial Operation Date.
2. Harbor Generating Station Net Dependable Plant Capacity is 425 MW, reflecting Units 1 and 2 reduced performance during hot-weather conditions.
3. Haynes Generating Station Net Dependable Capacity is 1,512 MW reflecting 8, 9, and 10 reduced performances during hot weather conditions
4. Valley Generation Station Net Dependable Capacity limited to 532 MW reflecting reduced performance during hot weather conditions.
5. Scattergood Unit 1 was derated to 105 MW as part of Unit 3 repowering. Scattergood Generating Station Net Dependable Capacity limits is reflecting reduced performance during hot weather conditions. Unit 3 was decommissioned on December 18, 2015.

Haynes Generating Station

The largest of the Los Angeles Basin 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 1,512 MW. This station includes a 575 MW combined-cycle generating unit installed in February 2005. The combined-cycle generating unit includes two gas turbines with heat recovery steam generators, which supplies one steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-on-one configuration (and are counted by LADWP as three generating units). Six additional peaking combustion units were installed in 2013.

Harbor Generating Station

Harbor Generating Station is located in Wilmington, California. The Harbor Station was repowered in 1995 with a combined-cycle generating unit (counted as three units). Five additional peaking combustion turbines were installed in 2002 for a total of eight generating units. These activities resulted in the Harbor Station’s net maximum capacity of 426 MW and a net dependable capacity of 425 MW.

Valley Generating Station

Valley Generating Station currently consists of four generating units with a combined net maximum capacity of 555 MW and a dependable capacity of 532 MW. The combustion turbines can each operate with the steam turbine independently or together in a two-on-one configuration (and are counted by LADWP as three generating units). The combined-cycle unit has a net maximum plant capacity of 511 MW. A single peaking combustion turbine was installed in 2001.

Scattergood Generating Station

Scattergood Generating Station is located in Playa del Rey, California and is comprised of two steam generating units with a net maximum capacity of 261 MW, one one-plus-one combined cycle with net maximum capacity of 311 MW and two simple cycle LMS100 units with net maximum capacity of 102 MW each. The station's net dependable capacity is 742 MW. 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 January 28, 2022.

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Plant Capacity (kW)	Net Dependable Capacity (kW)
Apex	1A	2014[2]	203,150	577,500	482,600[3]
	1B	2014[2]	203,150		
	STG	2014[2]	237,600		

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 January 28, 2022.

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	1986	900,000	437,533	437,533	15Jun2027	48.617%
	2	1987	900,000	437,533	437,533		
Intermountain	1	1986	900,000	163,512	163,512	15Jun2027	18.168% (Recallable)
	2	1987	900,000	163,512	163,512		
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)

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.

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 and is subject to renewal under certain circumstances, as well as legal and regulatory mandates.

- 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 327 MW is the summer 2016 entitlement amount.

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 Generating 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. The 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 January 28, 2022.

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	1986	2045	1,333,000	75,981	74,727	5.7%
	2	1986	2046	1,336,000	76,152	74,898	
	3	1988	2047	1,334,000	76,038	74,784	
LADWP Entitlement Interest Through SCPPA:							
Palo Verde	1	1986	2045	1,333,000	52,787	51,916	3.96% (SCPPA)
	2	1986	2046	1,336,000	52,906	52,034	
	3	1988	2047	1,334,000	52,826	51,955	
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 Generating 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 January 28, 2022.

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	1973	271,000	271,000	1,265,000	Owned Asset	100%
	2	1974	271,000	271,000			
	3	1976	271,000	271,000			
	4	1977	271,000	271,000			
	5	1977	271,000	271,000			
	6	1978	271,000	271,000			
	7	1972	56,000	56,000			
Hoover[3]		1936	2,074,000	496,000	267,594	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 Plant Capacity based on the U.S. Department of the Interior for CY 2022 is 267.59 MW.

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

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.

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 January 28, 2022.

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	1927	2,800	2,500	3,600	2,142
	2	1927	2,800	2,500		
Cottonwood[3]	1	1908	750	1,200	1,800	376
	2	1909	750	1,200		
Division Creek	1	1909	600	680	680	0
Big Pine[4]	1	1925	3,200	3,050	3,050	1,530
Pleasant Valley[5]	1	1958	3,200	2,700	2,700	1,264
Total					11,830	5,312[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 Maximum Unit Capacity is 2.5 MW each, but only 3.6 MW when both units are in-service, when feed is taken from North Haiwee Reservoir.
3. Cottonwood Power Plant Units 1 and 2 were re-wound to higher Net Maximum Unit Capacity of 1.2 MW each, but only 1.8 MW when both units are in-service, due to limited maximum flow through the penstock.
4. Big Pine Net Maximum Unit Capacity is limited to maximum flow through penstock.
5. Pleasant Valley Power Plant output is limited to Division of Safety of Dams (DOSD) reservoir level restriction.

Table E-7. Owens Gorge small hydroelectric generating resources of January 28, 2022.

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	15,542
Middle Gorge	1	1952	37,500	37,500	37,500	16,121
Control Gorge	1	1952	37,500	37,500	37,500	14,655
Total[2]					111,500	46,400

Notes:

1. Commercial Operation Date.
2. Owens Gorge Power Plants' Net Maximum Plant Capacity of 110.5 MW reflects a maximum generation output at Upper Gorge of 35.5 MW, and 37.5 MW at Middle and Control Gorge when all three units are running. 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 January 28, 2022.

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	41,800[2]
Franklin (PP5)	1	1921	2,000	2,000		
San Francisquito 1 (PP1)	1A	1983	22,500	27,000		
	3	1917	9,962	11,000		
	4	1923	10,625	12,000		
	5A	1987	22,500	27,000		
San Francisquito 2 (PP2)	1	1919	14,000	0		
	2	1919	14,000	14,000		
	3	2006	18,000	18,000		
San Fernando 1 (PP3)	1	1922	2,800	3,250		
	2	1922	2,800	3,000		
Sawtelle (PP6)	1	1986	640	650		
Total[3]					78,250	41,800

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.Net Maximum Unit/Plant Capacity for San Fernando Power Plant is 3.5 MW due to the main transformer bank being placed in open-delta configuration since one of the three transformers was removed because of detected dissolved gases. 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 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 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.
3. This Table does not include the North Hollywood Pumping Station Power Plant which is operated by the LADWP Water System. The plant has 8 turbine units and currently provides a net output capacity of approximately 1,000 kW.
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 located 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	Own	2010	4,300	4,300	100%

PS Power Plant					
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.

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Appendix F

Distributed Generation

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CONTENTS

F Distributed Generation

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, 2021, over 455 MW have been installed from over 60,300 systems with the help of LADWP's Net Energy Metering (NEM) program. Additionally, LADWP has installed 25.7 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.

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. As of December, 2021, we have over 450 MW of NEM (which includes SIP) capacity installed.

LADWP's Utility Built Solar (UBS) or Local Solar development has resulted in 25.7 MW of PV installed at LADWP facilities and other City facilities, utilizing LADWP construction forces.

The economic, environmental, and social benefits of distributed PV solar systems are not 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.

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 or bill credit 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 or bill credit 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.

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.

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, 200 MW have been allocated by LADWP. Of the 200 MW allocated, 185 MW has been allocated to FiT, 10 MW for the Feed-in Tariff Plus Pilot Program (FiT+, which promotes the development of paired solar plus energy storage projects), and 5 MW for the Virtual Net Energy Metering Pilot Program (VNEM). Under the FiT program, approximately 97.5 MW have been constructed and are delivering energy, with another 73.3 MW accounted for in various phases of development, resulting in 14.2 MW of unclaimed capacity available to new participants. Of the 10 MW of capacity allocated for FiT+, approximately 2 MW have been accounted for. However, the existing FiT+ program is limited to the facilities interconnecting at the 4.8 kV distribution system. Although this program is open to all forms of eligible renewable energy, most systems are solar PV. Additional information can be found at www.ladwp.com/fit.

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.

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Appendix G

Fuel Procurement Issues

2022 SLTRP

CONTENTS

G Fuel Procurement Issues

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 a quarter 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 2012 into 2022.

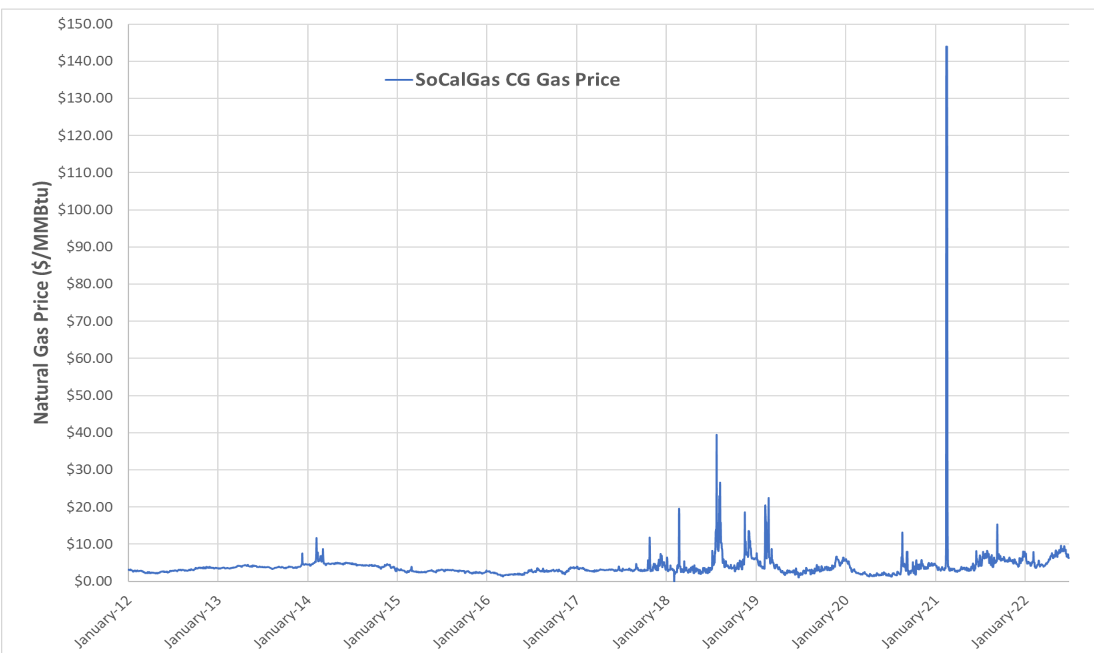

Figure G-1. Natural gas daily spot prices at So Cal Gas City Gate

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:

1. 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.
2. 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.
3. Established a Fuels and Risk Advisory Working Group to examine forecasting methodologies, term hedging strategies and other items of importance to fuel procurement.
4. 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.
5. 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 15,000 million British thermal units (MMBtu)/day, for the LADWP.
6. 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.
7. As a result of implementing the greater use of renewable energy, LADWP's usage of natural gas and coal will be reduced considerably. A general discussion on natural gas issues is provided in the following subsections.

G.2.1 Natural Gas Issues

Gas Price Volatility

Since 2017, gas prices have been extremely volatile. For the most part, extreme price volatility in 2022 has been linked to natural gas inventories being below the five-year average, a steady demand for U.S. liquified natural gas (LNG) exports, and a higher demand for natural gas from the electric power sector brought on by fewer opportunities for natural gas-to-coal switching. It is expected that natural gas consumption will stay about the same as 2022. However, warmer than expected temperature could push energy demands up which could result in lower inventories and increased prices through Q3 and Q4.

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. Maintaining reliable fuel supply for in-basin generation continues to be challenging due to SoCal Gas' system constraints stemming from their restricted use of the storage facility.

G.2.2 Natural Gas Procurement Strategy

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 units, with the current projected year of such transition being 2025. 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 long-term coal supply contracts, which are fixed price-based.

G.3.3 Coal Portfolio

The current coal procurement portfolio mix is as follows:

Long-term fixed pricing (with contracts beyond 2016): **50%**

The operating agent procures between three and four 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. The procurement of coal in the near- and far-term will likely be done by adding short-term spot 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 Rocky Mountain states. 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 Transmission System

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	199
Sub-Total		3,158 (76%)
In-Basin		
230kV	AC	821
138kV	AC	152
115kV	AC	28
Sub-Total		1,001 (24%)
TOTAL		**4,159 (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	Upgrade RS-K 138kV-230kV Bus Bank E
2	Upgrade Victorville Bank K
3	New RS-B Shunt Capacitor 99MVAR (3x33 MVAR)
4	New Castaic - Haskell Line 230kV Line 3
5	Barren Ridge Re-Expansion
6	New Eland Line 1 Line Termination at Barren Ridge
7	Clearance Mitigation & Station Equipment Upgrade for Sylmar - Pardee Lines 1 and 2
8	New RS-E Reactor
9	New Hollywood (RS-H) 138kV Shunt Capacitors (52 MVAR)
10	New Wilmington (RS-C) 138kV Shunt Capacitors Construction 66 MVAR (2x33 MVAR)
11	Upgrade Rinaldi Circuit Breakers (2 sets) and disconnect switches (3 sets) rating to 5000A
12	New Haskell Bank G (PP1-Haskell L1)
13	Upgrade Wavetraps and CVTs at Victorville 287kV to 300kV
14	Upgrade Wavetraps and CVTs at Century (RS-B) 287kV to 300kV
15	Upgrade Wavetraps and CVTs at Mead 287kV to 300kV
16	Clearance Mitigation Upgrade for Victorville -Rinaldi Line 1
17	Upgrade RS-E (Toluca) 500kV Bank H
18	New Haskell-Sylmar Line 2 & Station Equipment at Sylmar
19	Upgrade RS-K 138kV-230kV Bus Bank F
20	New RS-B Rack A and Bank A
21	New Barren Ridge STATCOM
22	New Smart Wires
23	IPP AC Switchyard extension
24	Upgrade Rinaldi Tarzana Line 1 & 2

25	New Scattergood-Pershing 230kV Cable A
26	New Olympic-Pershing 230kV Cable A
27	New Scattergood-Pershing 230kV Cable B
28	New Olympic-Pershing 230kV Cable B
29	New Receiving Station RS-X (LAX)
30	Upgrade RS-K Bus 1 and 2
31	Upgrade Barren Ridge – Haskell Line 1
32	New Spare Mead Bank M
33	Upgrade Scattergood Auto and Phase Shifting Transformer
34	New RS-N Rack E Expansion
35	Upgrade Lugo-Victorville Line 1 & terminal equipment
36	Upgrade McCullough – Victorville Series Compensation
37	Upgrade Circuit Breakers at Victorville 500kV
38	Adelanto AC Switchyard extension
39	Upgrade Tarzana - Olympic 1A and 1B - Conversion to 2-230kV lines
40	New Rosamond Switching Station
41	New IPP Synchronous Condensers(3 x 250 MVA and 1 spare 250 MVA)
42	Upgrade Toluca-Hollywood Line 1 Underground Cable
43	New Valley - Toluca Line 3 and upgrade Valley -Toluca Lines 1 and 2
44	New Converter Station at IPP and Adelanto
45	New Station Surge Arrestor installation
46	Upgrade McCullough – Victorville Transmission Line
47	Clearance Mitigation Upgrade Adelanto - Rinaldi Line 1
48	Clearance Mitigation Upgrade for Adelanto - Toluca Line 1
49	Clearance Mitigation & Station Equipment Upgrade for Sylmar - Pardee Lines 1 and 2
50	New Valley - Rinaldi Line 3 and upgrade Valley-Rinaldi Lines 1 and 2

51	New Toluca - Atwater Line 2 and upgrade Toluca -Atwater Line 1
52	Upgrade Rinaldi - Airway Lines 1 and 2

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 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:

- 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 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. Research into the various technological options to increase the capacity of the Pacific DC Intertie is being conducted.

H.8 Scheduling Points 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 POINTS 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

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Appendix I

Integration of Intermittent Energy from Renewable Resources

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I Integration of Intermittent Energy from Renewable Resources

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

In the last several years, 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. This increased substantially to 20% by 2010, and 33% is mandated by 2020. Senate Bill 350 further increases this mandate to 50% by 2030. Subsequently, Senate Bill 100 was passed and mandated that California electric utilities must achieve 100% carbon-free 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. 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. Forecasted daily generation in all seasons of 2020 were spot checked, and preliminary results 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. The 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 is 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 repowered 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, an investment 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.

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.

Appendix J

Energy Storage

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J Energy Storage

J.1 Introduction

Appendix J provides an overview of grid scale energy storage systems.

J.2 Background

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 energy storage (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.

Prior to the LA100 Study, LADWP energy storage system (ESS) procurement goals centered around legislation at the state level.

On February 7, 2012, the Board initiated a process by directing LADWP to determine appropriate targets, if any, for LADWP to procure viable and cost-effective energy storage systems by December 31, 2016 and December 31, 2021 pursuant to California Assembly Bill (AB) 2514, which became effective on January 1, 2011. Through a resolution passed in September 2014, the Board formally adopted procurement targets for 2016 and 2021. In August 2017, a resolution was passed by the Board revising the 2021 energy storage procurement target. Energy storage targets shall be reevaluated at least every three years. California AB 2227 supersedes AB 2514 and accelerates the energy storage target date from December 31, 2021 to December 31, 2020. A timeline of LADWP's milestones can be seen in Figure J-1 below.

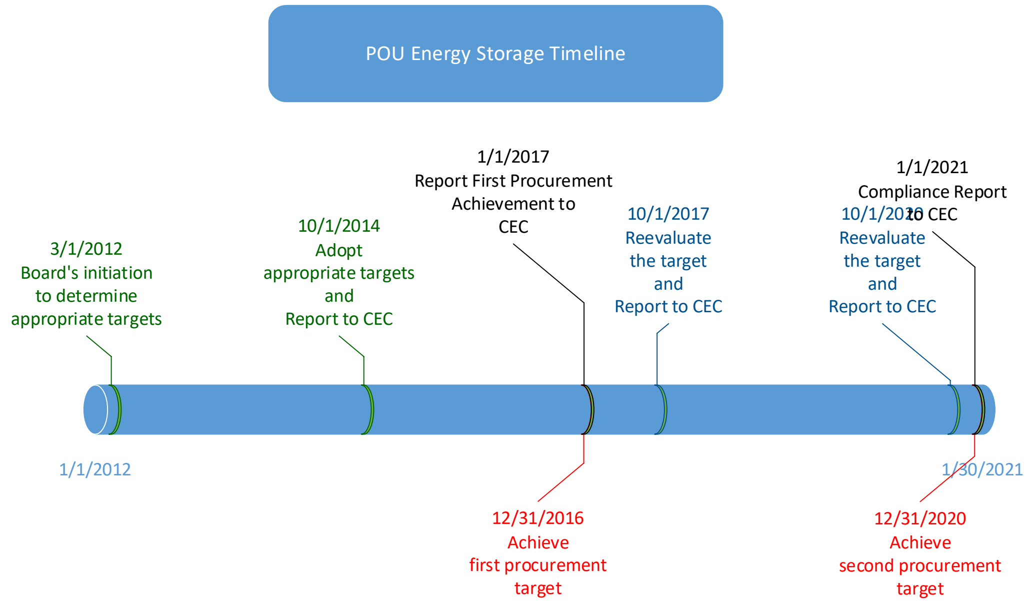

Figure J-1. POU Energy Storage Timeline.

California SB 801, which became effective on October 14, 2017, mandates that by June 1, 2018, LADWP must determine the feasibility of procuring a minimum of 100 MW in aggregate of additional energy storage.

Driven by the requirements of AB 2514 and SB 801, LADWP developed strategies to effectively incorporate energy storage into the Power System. The individual tasks that compose these strategies can be seen in Table J-1 below.

Table J-1. Energy Storage System Development Strategy.

STRATEGY	TASK
LADWP Efforts	➢ Discussion with subject matter experts ➢ Research relevant topics ➢ Participate with industry working groups, including other utilities ➢ Working with consultants and the Electric Power Research Institute (EPRI) ○ Selected Location Energy Storage Evaluation • Generation & Transmission Level • Distribution Level • Behind-the-Meter Level ○ Cost Benefit Assessments and Feasibility Studies
Collaborative Efforts with SCPPA* ESS Working Group	➢ Develop cost benefit evaluation models ➢ Evaluate joint efforts in ESS procurement ➢ Issue RFI** or RFP*** for ESS

*Southern California Public Power Authority
**RFI: Request for Information
***RFP: Request for Proposal

At the conclusion of the study, LADWP procured Eland Battery Energy Storage System (BESS) (300 MW/1,200 MWh) for the Eland Solar facility in the Mojave Desert area.

J.3 Applications of Energy Storage

Energy storage systems can be placed in one of two general categories: systems that are optimized for power output and systems that are optimized for energy storage. The applications that are best suited for an ESS are determined by how it is categorized.

J.3.1 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 ESSs 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.

Energy storage 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.

Energy storage 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.3.2 Applications of Energy Optimized Storage System

Energy optimized storage systems are well suited for applications which use relatively low output power for an extended duration. Examples of such applications include energy-time shifting and maintaining energy reserves.

Energy time-shifting refers to charging the ESS with a significant amount of energy and discharging it at a later time. When used in conjunction with renewable generation from variable 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.

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. Energy storage, however, can be used to satisfy some of LADWP's reserve requirements while reducing fuel consumption and GHG emissions.

J.4 Energy Storage Technologies under Consideration

The following are some of the energy storage technologies that are being considered:

J.4.1 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 8 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 Power Strategic Long-Term Resource Plan (SLTRP), emerging LDES technologies include Compressed Air Energy Storage, Liquid Air Energy Storage, Flow

BESS, and Pumped Thermal Energy Storage. A notable emerging trend is that most current LDES technologies are mechanical or thermal due to the correlation between ESS size & duration. LADWP continues to investigate and evaluate LDES technologies for potential grid-scale deployment in collaboration with EPRI under various programs and studies.

J.4.2 Battery Energy Storage

Battery energy storage systems are used extensively in LADWP's plans for future energy storage projects. The majority 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.

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. Strengths and weaknesses of lithium batteries 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

Flow batteries are a type 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
• 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.4.3 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.4.4 Pumped Thermal Energy Storage

In recent times, new technology vendors utilizing "Pumped Thermal Energy Storage (PTES)" technology have emerged. While the difference between TES and PTES is under discussion, PTES appears to store heat in novel mediums, e.g. rock or salt. PTES works by using electrical energy to drive a heat pump that converts the electrical energy to thermal energy. The thermal energy created produces a temperature difference that can be stored in a medium. The cold is stored in a chill liquid medium such as a coolant, heat is stored in another medium. When energy is needed, the difference in temperature is converted back to electrical energy by the use of a heat engine. The benefits of pumped thermal energy storage are in scalability, as increasing the medium volume can allow for increased duration.

J.5 Description of Existing LADWP Energy Storage Systems

J.5.1 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 energy storage technology used throughout the utility sector. Castaic Power Plant provides energy storage 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 has six reversible units (Units 1 through 6) rated at over 250MW each and one conventional unit (Unit 7) 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. 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 has been and 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 is a large plant with enormous dependable generating capacity (1,265 MW) allowing it to play 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.5.2 Thermal Energy Storage (TES) Systems

The LADWP has promoted TES technology to its customers since the early 1990s and has paid incentives for the successful installations of TES systems. Two specific examples include installations at the University of Southern California (USC) and the University of California at Los Angeles (UCLA), together accounting for up to 9 MW of peak demand reduction. This peak demand reduction improves LADWP's load factor, shifting customer load from the peak to the base period. Table J-5 below provides a list of existing 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.5.3 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.6 AB 2514 Compliant Energy Storage Systems

J.6.1 Eligibility Criteria

AB 2514 establishes the statutory definition of an "energy storage system" to be a "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy". In addition, the system must use a "mechanical, chemical or thermal processes to store energy". The system may be centralized or distributed, and may be owned by a load-serving entity, a customer, or a third party. To be considered an eligible ESS, the system has to be installed and be first operational after January 1, 2010. In addition, ESSs that count towards LADWP's procurement targets shall do one or more of the following:

(A) Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.

(B) Store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time.

(C) Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.

(D) Use mechanical, chemical, or thermal processes to store energy generated from mechanical processes that would otherwise be wasted for delivery at a later time.

Based on these eligibility criteria, LADWP has identified the following ESSs to be used toward the 2020 procurement target.

J.6.2 Castaic Hydroelectric Power Plant Unit 1

Castaic Power Plant has undergone major mechanical upgrades which have resulted in incremental capacity that can be used to integrate renewable energy resources, provide additional generation flexibility, and improve system reliability. For those reasons, LADWP has claimed incremental Castaic Power Plant upgrades which became operational after January 1, 2010, toward the 2020 procurement target. Per the AB 2514 2016 Compliance Report filed with the California Energy Commission (CEC), Unit 1's upgrade contributes 21 MW towards LADWP's procurement targets. Table J-6 below provides a summary of Castaic Power Plant Unit 1 capacity gain and performance improvements.

Table J-6. Castaic Hydroelectric Power Plant Unit 1 Upgrade.

Owner/Operator	LADWP
Utility	LADWP
System/Vendor/Installer	New Generating and Control System/VOITH
Location	CASTAIC
Capacity Before Upgrade	250 MW
Capacity After Upgrade	271 MW
Net Capacity Gain	21 MW

Operational Status	In operation since 11/21/2013
Primary Benefit	Improved Efficiency in Generation Mode by 1%
Secondary Benefit	Improved Efficiency in Pump Mode by 2.5%
Total Project Cost (271MW)	$41,000,000

J.6.3 Thermal Energy Storage Systems

LADWP's commitment to achieving aggressive energy efficiency goals emphasizes a compelling need to promote innovative programs that save both energy and reduce demand. A rebate was provided to Los Angeles International Airport (LAX), a large customer in LADWP's service territory, to use TES to achieve peak load shifting (PLS). This incentive was based on the maximum capacity shifted using the rebated TES system. Through testing, the LAX TES system was found to contribute 1,250 kW towards LADWP's procurement targets. Table J-7 below provides a summary of LAX's approved TES system.

Table J-7. Approved LAX TES Project Summary.

Owner/Operator	LAX
Utility	LADWP
System	TES
Location	LAX
Shifted Capacity	1,250 kW
Operational Status	In operation since 1/2015
Primary Benefit	Annual energy saving of 2,477,681 kWh
Secondary Benefit	Minimize LADWP Peak demand
Incentive Level Cost	$1,134,375

J.6.4 Beacon BESS

Commissioned in 2018, LADWP's first grid-scale BESS contributes 20 MW/10 MWh of lithium-ion BESS towards procurement targets. The system interconnects at one of 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 storage in this area.

J.6.5 Various Behind-the-Meter BESS

Multiple customers have installed behind-the-meter (BTM) energy storage within LADWP territory, compliant with LADWP interconnection requirements. BTM energy storage contributed over 7.8 MW towards procurement targets.

J.6.6 Pilot Energy Storage Projects

J.6.6.1 La Kretz BESS

Location: 525 S. Hewitt St, Los Angeles, CA 90013

A 30 kW/111 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.6.6.2 Truesdale Training Center BESS

Location: 11781 Truesdale St, Sun Valley, CA 91352

This early lithium-ion BESS project consists of 55 kW/111 kWh (approx. 2h), located at LADWP's Truesdale Training Center. Commissioned in 2017, LADWP staff used the BESS to gain familiarity with lithium-ion BESS installation, interconnection, and operations. Currently, Truesdale BESS performs peak-shaving to reduce peak load and provide back-up power at the training center.

J.6.6.3 LAFD Fire Station 28 BESS

In February 2018, LADWP completed the installation of a solar and battery system at the Los Angeles Fire Department (LAFD)'s Station 28 in the neighborhood of Porter Ranch. 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.

J.6.6.4 JFB BESS

Location: 111 N Hope St, Los Angeles, CA 90012

The John Ferraro Building Battery Energy Storage System (JFB BESS) is a hybrid research project commissioned in 2019, consisting of two 100 kW/400 kWh (4h) BESSs utilizing flow battery and lithium-ion technologies. The project researches flow battery technology performance by bench-marking flow battery and lithium-ion battery performance. This project will inform technology selection decisions in LADWP energy storage 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 energy storage deployment with economical long duration (more than 4h), minimal degradation, and minimal fire risk benefits. As is the case with any emerging technology, flow batteries come its own set of challenges:

- component quality control due to its relatively less mature supply chain
- quality of field service (i.e., maintenance, repair) due to less developed logistics chain
- performance quirks unique to the technology's characteristics, such as a higher rate of wear and tear due to more moving parts.

J.6.7 Energy Storage Projects in Development

J.6.7.1 Eland BESS Phase I & II

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.

J.7 Energy Storage Target Setting Methodology

LADWP first evaluated the existing and eligible ESSs that could be counted toward LADWP ESS procurement targets. Procurement of additional cost-effective and technologically-viable energy storage was then evaluated using two approaches:

1. <u>Selected Location Energy Storage Evaluation</u> – This approach evaluates the benefits of energy storage on the local level and emphasizes locational value of energy storage. The DER integration study has identified locations where DER deployment, including distributed energy storage, may provide benefits to both customers and the grid by deferring capital improvement

projects required for load growth, increasing renewable energy generation, modernizing infrastructure, and improving reliability.

2. Whole Power System Energy Storage Evaluation – This approach investigates whether ESSs can be integrated at all levels within the Power System (i.e. generation, transmission, distribution, and behind-the-meter) and places emphasis on system-wide benefits of energy storage such as (i) integrating renewable energy, (ii) reducing peak load demand, (iii) deferring power system upgrades, and (iv) improving the overall system reliability. To accomplish this approach, LADWP has completed maximum penetration studies for renewable energy in the generation and distribution portions of the Power System. The Whole Power System Energy Storage Evaluation was used to refine the ESS procurement target for 2020.

The process described above and detailed in the LADWP Energy Storage Development Plan is illustrated in Figure J-2 below. This plan formed the analytical framework from which LADWP determined its ESS procurement targets for 2016 and 2020. Reevaluation of these targets occurs at least once every three years.

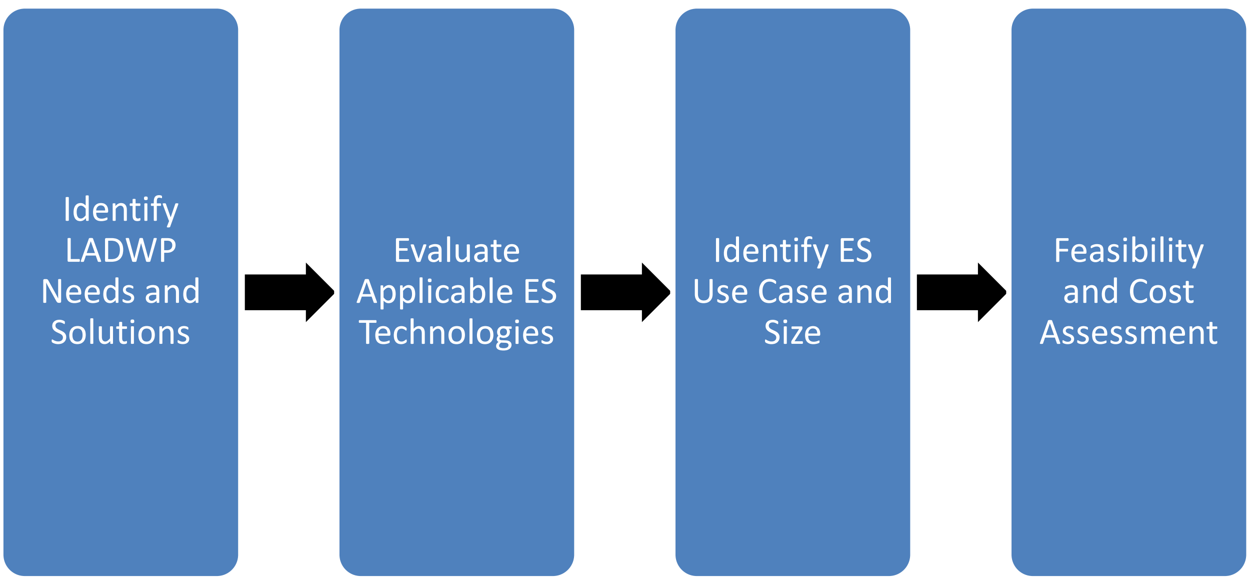

Figure J-2. ESS Target Development Process.

J.8 Energy Storage Procurement Targets Summary

Using the methodology described above, LADWP has met the procurement targets set by AB 2514 and AB 2227. A summary of LADWP's procurement achievements can be seen in Table J-8.

LADWP set goals for procuring a total of 179.5 MW of energy storage, split into 24.1 MW by 2016 and an additional 155.4 MW by 2020. LADWP procured well over the net total target of 179.5 MW by the end of 2020.

Table J-8. Summary of AB 2514, AB 2227 ESS Procurement Targets & Achievements.

Connection Level	Pre-2010 Existing ES (MW)	Total Procurement Target (MW)	ES Procured by end of 2020 (MW)
Generation & Transmission	-	149.4	322.3
Distribution	-	25	-
BTM	-	5.1	9.37
Total	1,284	179.5	331.67

J.9 Procurement Approaches

LADWP may increase energy storage deployment through five main approaches:

- LADWP Ownership
- Power Purchase Agreements
- Build-Own-Operate-Transfer (BOOT) Agreements
- Customer Incentive Programs
- Collaborative Ownership

J.9.1 LADWP Ownership

LADWP may procure generation, transmission, and distribution-connected ESSs 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 distribution 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.9.2 Power Purchase Agreements

Grid-scale energy storage can be procured through power purchase agreements (PPAs) 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 energy storage capacity for its needs according to a predetermined payment structure. Due to the availability of solar investment tax credits, energy storage PPAs offered by developers are often tied to solar generation PPAs.

J.9.3 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.9.4 Customer Incentive Programs

LADWP offers a rebate incentive for non-residential behind-the-meter TES through its Custom Performance Program. In order to be eligible, the TES system must perform PLS, or shifting energy use from one period of time to another. The rebate amount is determined by the quantity of peak load that is time shifted by the TES system. This TES incentive is consistent with LADWP's Board-approved efficiency programs that promote the efficient use of electrical energy.

An additional rebate incentive for qualified behind-the-meter DER is provided by the California Public Utilities Commission (CPUC) under the Self-Generation Incentive Program (SGIP). Through the end of 2024, the authorized incentive collections according to the 2022 SGIP Handbook, which can be found through the Southern California Gas Company (SoCal Gas) website, is approximately $813.4 million, with 88% of incentives reserved for energy storage projects. As described in Table J-9, the rebate amount is determined by the size of the storage. Additional SGIP incentives may apply.

Table J-9. SGIP Energy Storage Incentive Rate.

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Step 6**	**Step 7**
Storage Size	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**
Large Storage (>10 kW)	$0.50	$0.40	$0.35	$0.30	$0.25	N/A	N/A
Large Storage Claiming Investment Tax Credit (ITC)	$0.36	$0.29	$0.25	$0.22	$0.18	N/A	N/A
Residential Storage (<= 10kW)	$0.50	$0.40	$0.35	$0.30	$0.25	$0.20	$0.15

J.9.5 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.10 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 energy storage 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 energy storage procurement targets.

Appendix K

Distribution Automation

2022 SLTRP

CONTENTS

K Background

The electric and water utility industry has been undergoing a major transformation. This is driven by a number of economic, regulatory, and strategic challenges that utilities have been facing in modern times. In order 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) has been facing a series of environmental, regulatory, and economic challenges. LADWP must continue to ensure reliable service, maintain competitive rates, reduce emission, 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, which was the reason and vision for the Distribution Automation (DA) Program to be introduced and executed. This program utilizes 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 program 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.1 Vision for Distribution Automation

The Distribution Automation *Program Charter*, signed by stakeholders during September and October 2018, defines high level visions of the DA Program. The following paragraphs provides an essence of this 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.2 Distribution Automation Objectives

Objectives of the DA Program, at a high level, have been divided into two phases, as listed below:

- **Phase 1**
    - Identify 'worst performing distribution circuits'
    - Build city-wide communication network across LADWP's service territory
    - Deploy Line Monitor Sensors
    - Enable applications such as Volt Var Optimization (VVO), automated switching

- **Phase 2** (to be deployed based on lessons learned from phase-1)
    - Deploy additional line monitor sensors
    - Further deploy VVO, Fault Location, Isolation, and Service Restoration (FLISR), and other automation technologies

K.3 Individual Projects and Value Proposition

In order to accomplish the objectives of the DA Program in various disciplines, Phase 1 of the program was divided into individual projects, as listed below.

K.3.1 Distribution Automation Project

This project supports LADWP in creating a testbed for automation of the distribution grid, allowing various aspects of such automation to be tested in a safe and secure environment. The implementation of line monitors and remote communication with distribution devices will add monitoring, tracking, resulting in higher reliability and efficiency of the system.

The mission of the Distribution Automation (DA) project, has been defined as follows:

“To study and design automation of the distribution system, including FLISR, VVO, and other operational practices of distribution circuits. Smart meters and distribution automation devices, such as line monitors, controllers, sensors, capacitors, switches, reclosers and other devices may be installed as part of this effort, as needed, to meet the project's objectives.”

To meet its mission and objectives, the DA Project is perusing completion of the following scope:

- Prepare criteria, and list of **Worst Performing Circuits**
    - The DA team worked with stakeholders and defined the criteria to include reliability indices (SAIDI, SAIFI) power quality of distribution circuits (power factor, voltage), and rate of failures.

- Install **line monitor sensors** on identified circuits
    - The DA team selected line monitors that can report fault information (time and duration of fault), load information (Amps), as well as temperature of the conductor over the cellular network or the radio frequency (RF) mesh network. This product is also supported by a back-office application to communicate with devices to store and analyze the data.

- Installation of around 5000 **smart meters** as a proof of concept
    - Smart meters enable the utility to remotely collect data from meters over a wireless network, and provide to a back-office application for storage and analysis. They can also store the data as detail as 15-minute load profile or even more granular.

- Install **DA devices** (reclosers, controllers) on two identified circuits
    - DA project conducted a study on the identified “worst performing circuits”, and selected two 4.8KV circuits for proof-of-concept deployment of new reclosers and controllers.
    - Reclosers and Controllers make it possible for utilities to design and implement automated operations such as Fault Location, Isolation, and System Restoration (FLISR) and Volt Var Optimization (VVO).

- Install **Voltage Regulator controllers**
    - The DA project has identified voltage regulator controllers to be replaced with advanced Controllers, which will support automated control of voltage level through the distribution circuits.

- Install **Distribution Automation Controller (DAC)**
    - The DAC can be the central command system for a DA operation, receiving data from DA field devices, processing based on pre-configured models and sending commands as needed to conduct automated actions.

- Install **DA communication devices** (Master and Remote Bridges) on distributing circuits and stations
    - As part of Phase-1, Remote Bridges will be installed in Distribution Automation equipment controllers that will be installed on two designated circuits. Master Bridges will be deployed at identified stations. This configuration will allow the DA devices to communicate with the DAC and the ECC through the RF communication between Remote Bridge and Master Bridge. The Master Bridge communicates with the control center via the Fiber Optic network.

K.3.2 Communication Network Project

The mission of the Communication Network (COM) project, has been defined as follows:

"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."

To meet its mission and objectives, the COM Project is perusing completion of the following scope:

- Conduct **site surveys** throughout LADWP's service territory to identify best locations for communication network devices.

- Prepare '**communication design package**' 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.
    - According to the design package, Access Points, and Relays need to be installed throughout the LADWP service territory to cover all future smart meters and line monitor installation.
    - 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).

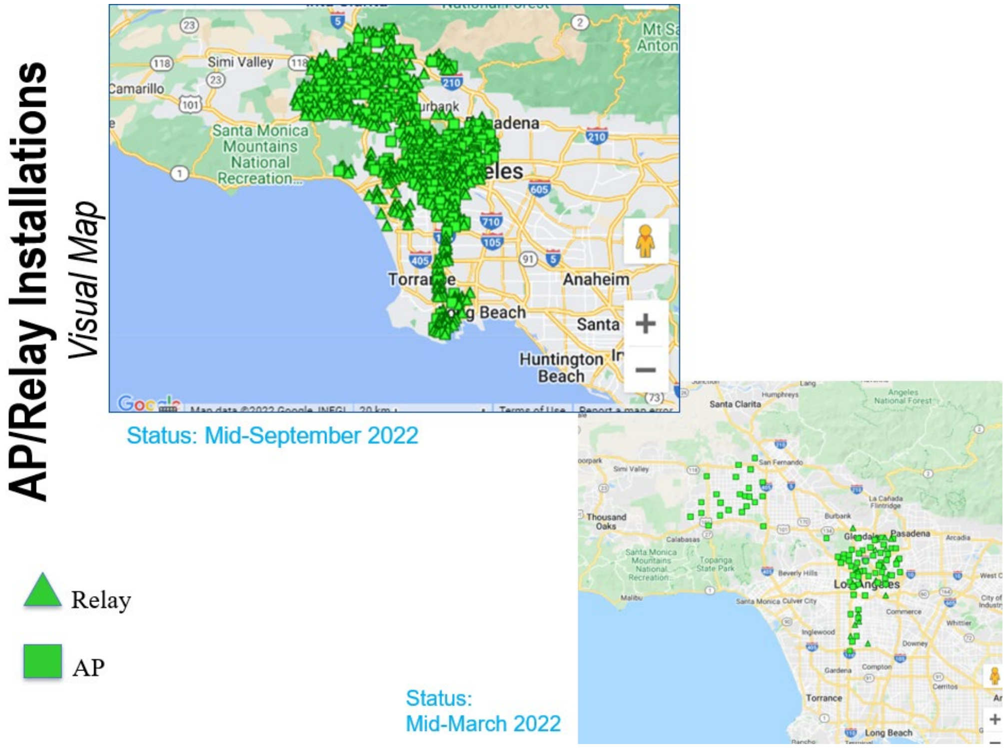

Figure K-1. Installation of Access Points and Relays as of September 2022.

- **Test performance of communication system**
  - Following the completion of device installations, a performance test will be conducted which can result in the installation of additional devices to optimize the network.

K.3.3 Back Office Project

The mission of the Back Office (BO) project has been defined as follows:

"To support data collection and enable remotely operable functions for all field devices and endpoints that are part of the proposed communication network, distribution automation system, and AMI [Advanced Metering Infrastructure] meters."

To meet its mission and objectives, the BO Project is perusing completion of the following scope:

- **Install software and servers** to remotely collect, store data from metering and DA devices, to monitor communication and to use data for various functions
  - User Acceptance Tests and Functional Tests for these applications have also been conducted as part of this project.

- Security measures have been added to the back-office applications such as data encryption/ decryption, preventing bad-actors from causing harm like disconnecting a large number of smart meters.

K.3.4 Complete System Project

The mission of the Complete System (CS) project, has been defined as follows:

“To study, design, and deploy necessary integrations between systems and applications to meet the objectives of the DA Program. To create business processes as they relate to distribution systems. To make the DA systems work together as a whole.”

To meet its mission and objectives, the CS Project is perusing completion of the following scope:

- Study, select, procure, and install a “service bus” to facilitate data exchange between various applications.

- Integrate various Power Systems applications with the service bus
  - This integration will facilitate data communication between the systems and changing the data format as needed.

- Develop a set of business processes for various functions related to DA use cases

K.4 Distribution Automation Benefits

The Los Angeles Department of Water and Power believes that strategic investments on Distribution Automation will produce long term benefits for the customers, environment, and our society as a whole, such as the be benefits listed below:

K.4.1 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.

K.4.2 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. Smart meters will also have the ability to report any voltage sag, swell, fluctuations, and power outages.

K.4.3 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.4.4 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.4.5 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.4.6 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.4.7 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.4.8 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

2022 SLTRP

CONTENTS

Acronym/Abbreviation List

The terms summarized in Table L-1 below are used throughout the project. As such, some terms may not apply to this report. All terms used in this report are defined at their first occurrence in the text.

Table L-1. Acronym and Abbreviation List.

Term	Definition
AGM	Assistant General Manager
APR	Annual Percentage Rate
BESS	Battery Energy Storage System
CC	Constant Current or Combined Cycle
CCP	Castaic Power Plant
CEA	Civil Engineering Associate
CEMS	Continuous Emission Monitoring System
CEQA	California Environmental Quality Act
CIP	Capital Improvement Plan
CREL	California Renewable Energy Lab
CR&FS	Central Repair & Fabrication Services
CUPA	Certified Unified Program Agency
DA	Distribution Automation
DCM	Distribution and Maintenance
DDR	Description of Duties and Responsibilities
DER	Distribution Energy Resource
DO	Distribution Operations Section
DS	Distribution Substations
DWP	Department of Water and Power
EC	Electrical Construction
ECGR	Recently merged with PSO, stands for Energy Control and Grid Reliability
EDM	Electrical Discharge Machining
EEA	Electrical Engineering Associate

Term	Definition
EIM	Energy Imbalance Market Group
EPPM	Engineering, Procurement, and Project Management
ESM	Electrical Station Maintenance
ET	Electric Trouble
ETD	Electric Trouble Dispatch
EV	Electric Vehicle
FAS	Fleet and Aviation Services
FERC	Federal Energy Regulatory Commission
FSO	Financial Services Organization
FTE	Full-Time Equivalent
GC	General Construction
GHG	Greenhouse Gas
GIS	Geographic Information System
HS	Handheld Solar or Health and Safety
IHRP	Integrated Human Resources Plan
I&M	Distribution Inspection and Maintenance
ISS	Integrated Support Services
JFB	John Ferraro Building
LA100	Los Angeles 100% Renewable Energy Study
LADWP	Los Angeles Department of Water and Power
MEA	Mechanical Engineering Associate
MCC	McCullough
NEAT	New Engineering Associate Training
NERC	North American Electric Reliability Corporation
NEM	Net Energy Metering
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PCM	Power Construction and Maintenance

Term	Definition
PECGR	Power Energy Control and Grid Reliability
PEER	Power External Energy Resources
PETS	Power Engineering and Technical Services
PEX	Power Executive Office
PKPI	PSRP Key Performance Indicator
PM certification	Project Manager
PM	Preventative Maintenance
PNB	New Business/Meter Services and Field Operations
PNBE	Power New Business and Electrification
PPA	Purchase Power Agreement
PSISS	Power System Integrated Support Services
PSO	Power Supply Operations
PSRP	Power System Reliability Program
PSST	Power Systems Safety and Training
PST	Power Safety and Training
PTD	Power Transmission and Distribution
PTPRI	Power Transmission Planning, Regulatory and Innovation
PVG	Pressure Vessels Group
RFI	Request for Information
RFP	Request for Proposal
ROW	Right of Way
RPDP	Power Resource Planning, Development, and Programs
RR	Revenue Requirement
RS	Receiving Station
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SF6	Sulfur Hexafluoride/Greenhouse Gas
SIR	Scheduled Inspection and Repair

Term	Definition
SLS	Streetlight Maintenance
SLTRP	Strategic Long Term Resource Plan
SME	Subject Matter Expert
SS	Switching Station
STP	Strategic Transmission Plan
UCLA	University of California, Los Angeles
VIC	Victorville
VM	Vegetation Management
WECC	Western Electricity Coordinating Council
WERM	Wholesale Energy Resource Management
WMIS	Work Management Information System

L Power System Integrated Human Resource Plan (IHRP) Report

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 2022 Strategic Long-Term Resource Plan (SLTRP).

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.

  For the purpose of this IHRP, the following 11 Divisions within LADWP collectively represent the "Power System":

    - Power Transmission and Distribution (PTD)
    - Power Construction and Maintenance (PCM)
    - Power Integrated Support Services (ISS)
    - Power Engineering and Technical Services (PETS)
    - Power Supplies and Operations (PSO)
    - Fleet and Aviation Services (FAS)
    - Power New Business and Electrification (PNBE)
    - Power Resource Planning and Program Development (RPDP)
    - Power Transmission Planning, Regulatory, and Innovation (PTPRI)
    - Power External Energy Resources (PEER)
    - Power System Support Training (PSST).

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.

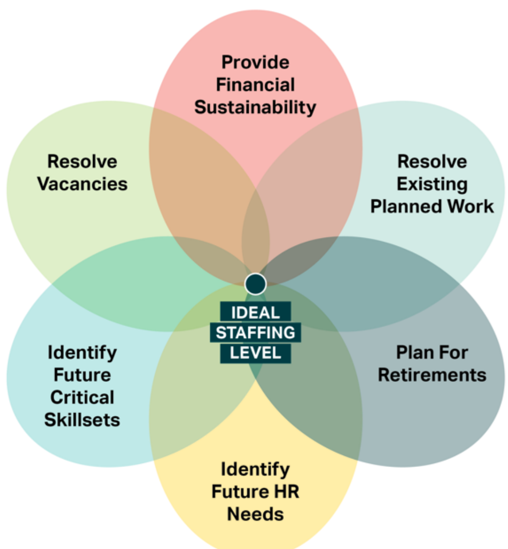

Figure L-1. Ideal Staffing Level Process.

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 SLTRP, 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 SLTRP, 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.

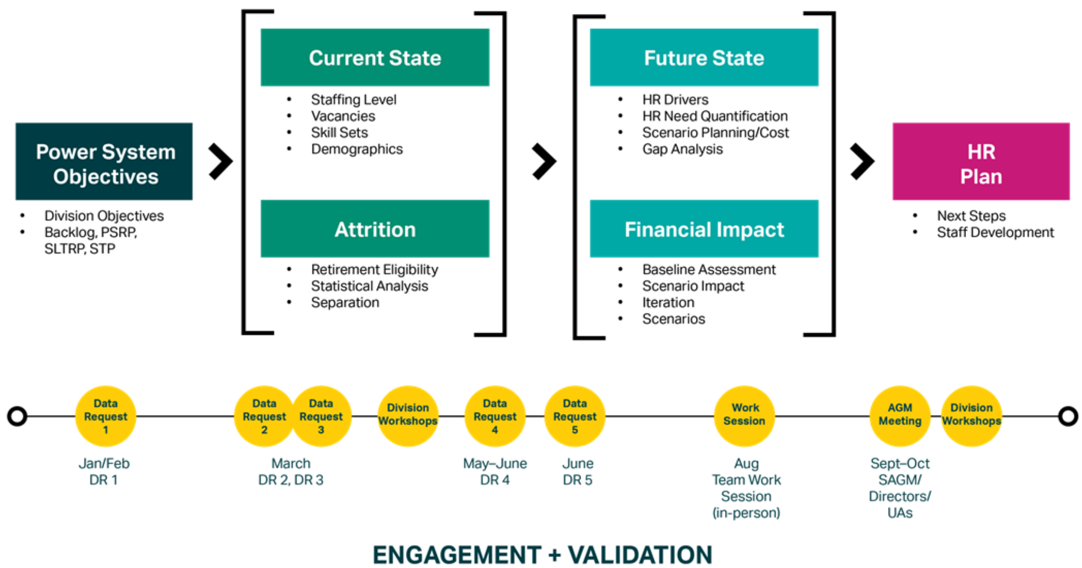

Figure L-2. IHRP Methodology.

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, SLTRP, 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 SLTRP 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 SLTRP Buildout.

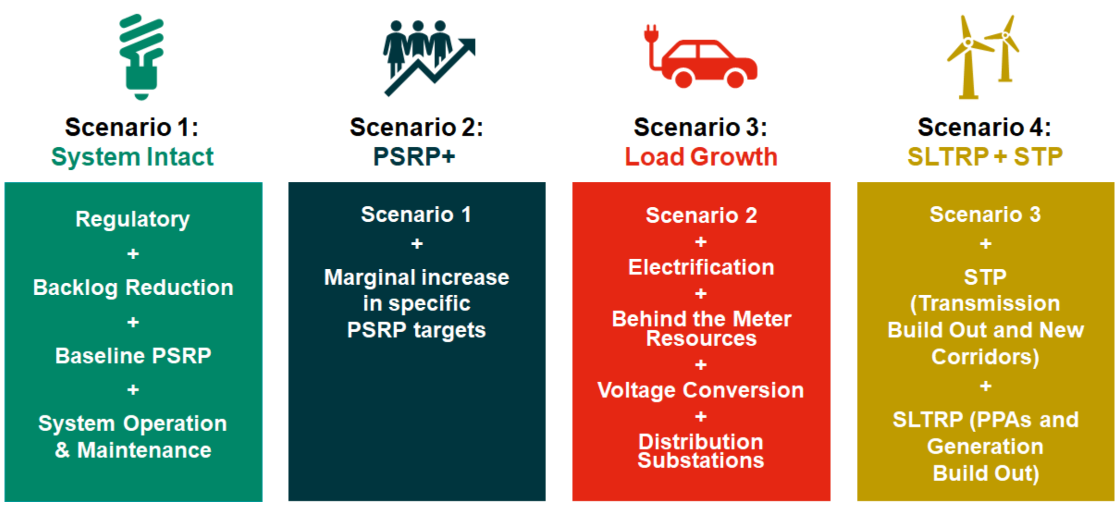

Figure L-3. Hiring Planning Scenarios.

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 SLTRP 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 SLTRP.

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.

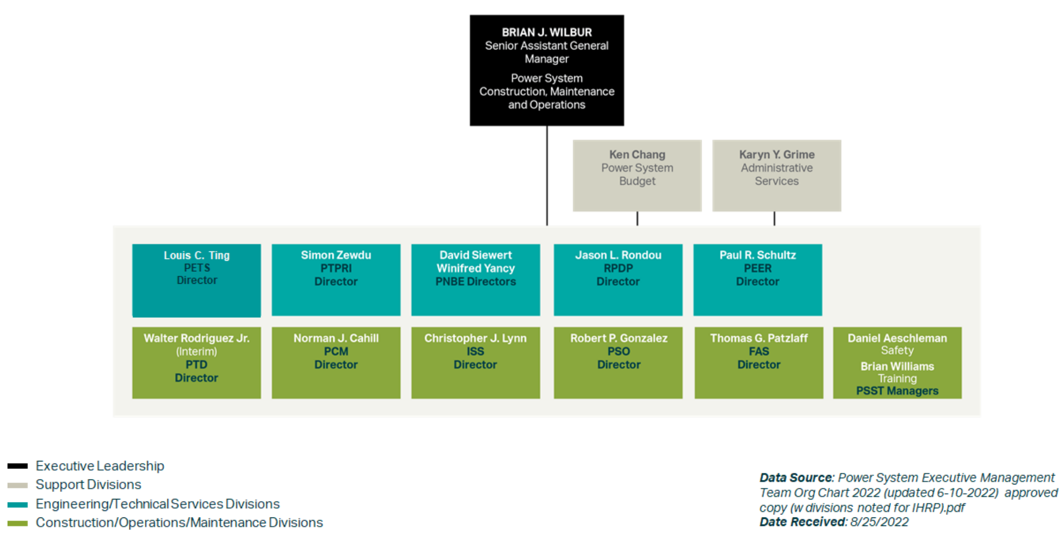

Figure L-4. Power System Organization Chart.

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.

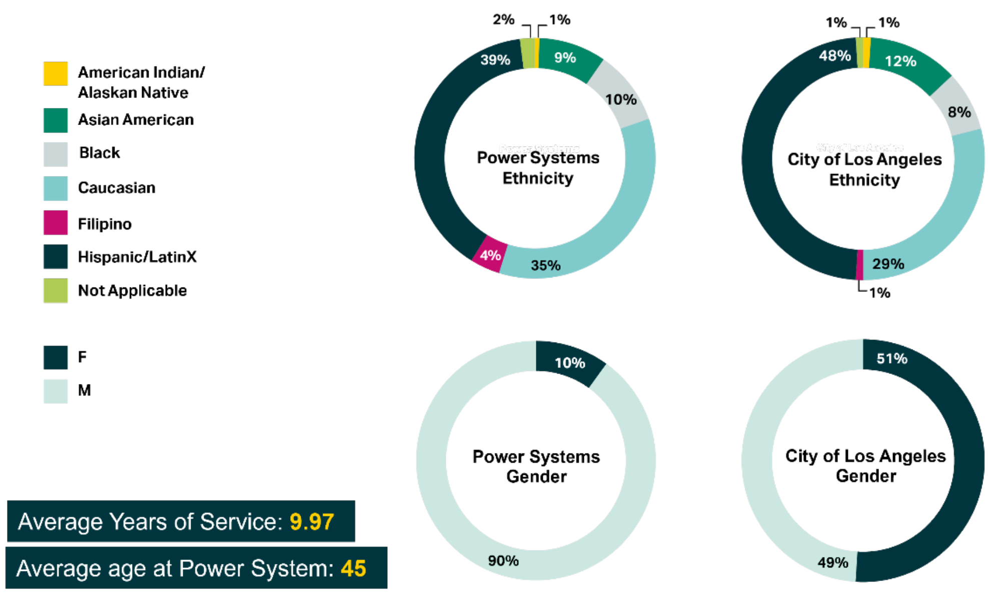

Figure L-5. Power System Demographic Analysis.

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 6 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 below indicates the implications these critical positions have in terms of the percentage of the whole population. 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**

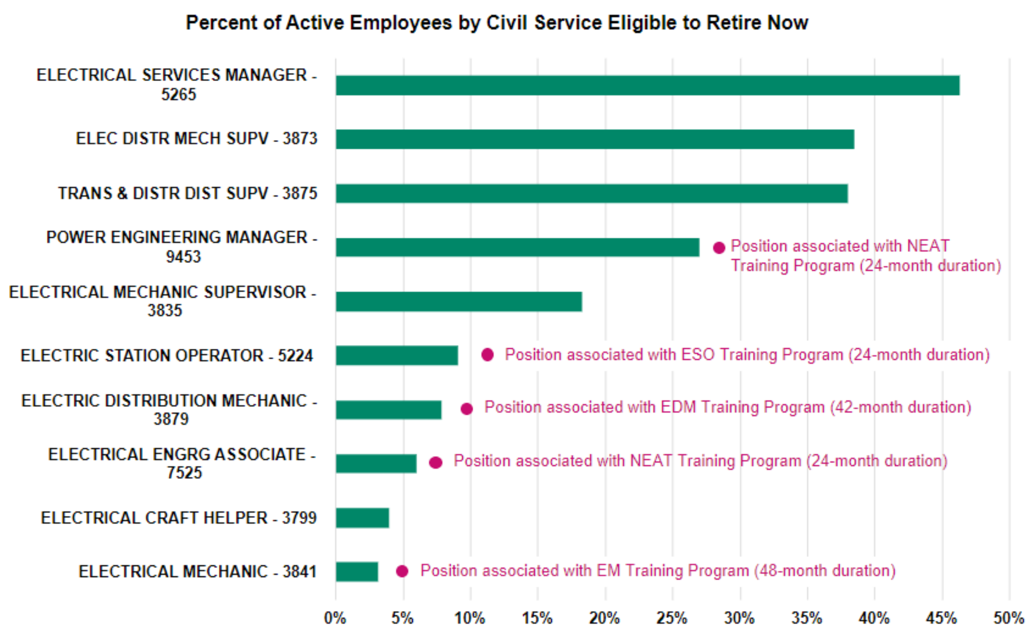

Figure L-6. Major Retirement Eligibility by Civil Service Classification.

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.

Figure L-7 below depicts Power System's retirement profile which includes both the historical retirement levels over the past 12 years and retirement projection (shaded in green) for the following 9 years using statistical analyses. It can be seen that Power System retirement follows a wave pattern reflecting Power System mass hiring over the years.

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.

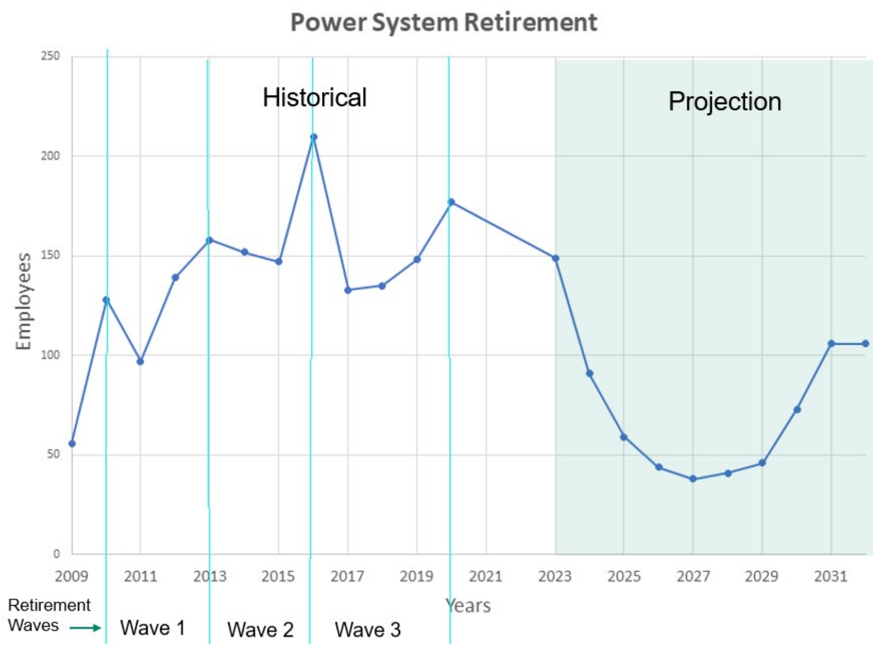

Figure L-7. Power System Retirement Profile.

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.

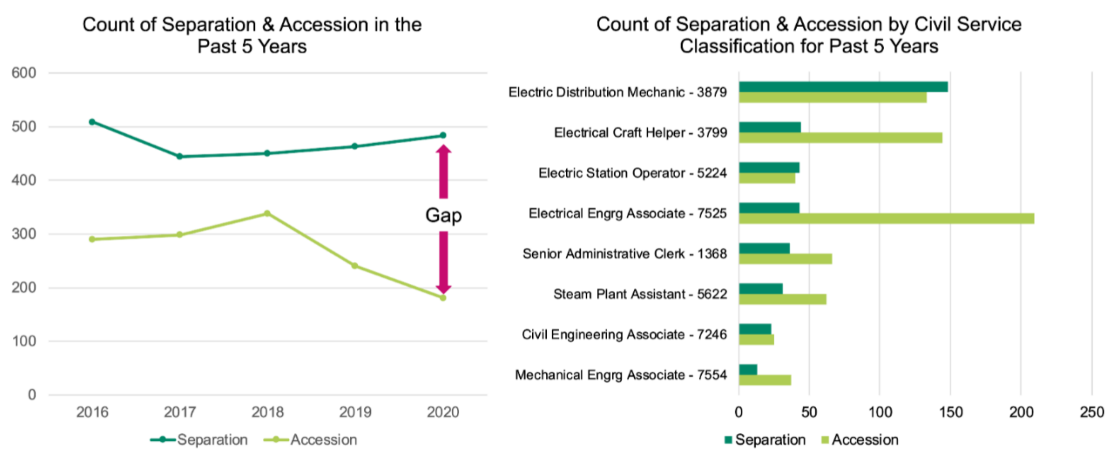

Figure L-8. Power System Accession and Separation for Classifications at Risks.

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.

Hiring	Training	Retention
Amend Civil Service Job Descriptions to reflect requisite core competencies and skills sets. Prioritize shared, critical and vulnerable civil service classifications.	**Revise training requirements** with modified or new civil service classifications	**Provide competitive compensation;** prioritize critical and vulnerable civil service classifications with high separation rates.
Develop **talent pipeline partnerships** with high schools, community colleges, and universities.	**Create standardized, coherent training** materials for each division through ***"Power System University"*** **–** a new virtual modular training capability with on-demand materials	**Investigate opportunity for 'quick wins'** in the following categories: **Employee Culture** (mentoring, coaching, and retention incentives) and **Employee Success** (recognition, positive reinforcement).
Divisions to have flexibility in hiring and staff budget, approvals are expedited based on need	**Look to hire training development** and evaluation capability internally, or outsource training needs	

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.

Career Development	Employee Development	Brand
Create promotional incentives, especially for manager positions **Create Project Manager training program** to fill critical need	**Retain key retirees as part time variable employees** to mitigate loss of institutional knowledge **Create mentorship program in each division,** pairing junior level staff with more experienced staff to provide feedback **Based on new or modified civil service classifications and expand career development opportunities** such as expanded licensure reimbursement, professional conference attendance, tuition reimbursement, etc.	**Develop the "Why LADWP?" story** by establishing branding and marketing process **Highlight LADWP strong points such as recent accomplishments, new and emerging projects, vision, benefits, and public service.**

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.

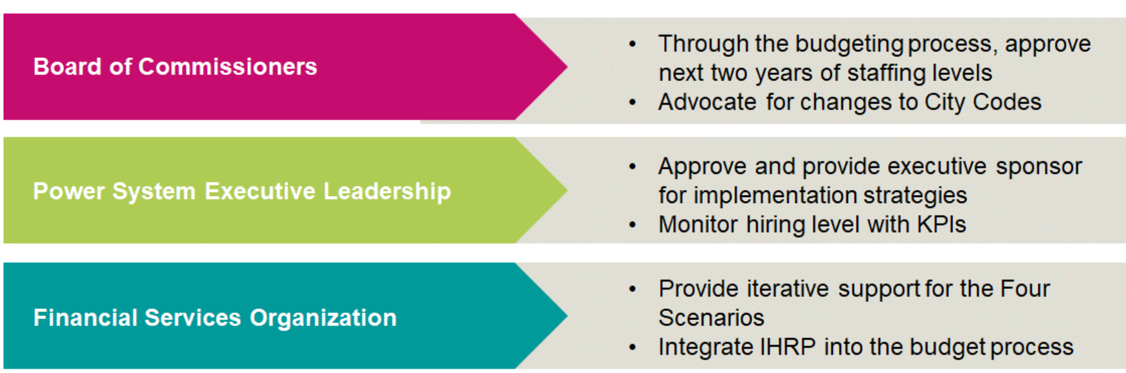

Figure L-11. IHRP Roles and Responsibilities.

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

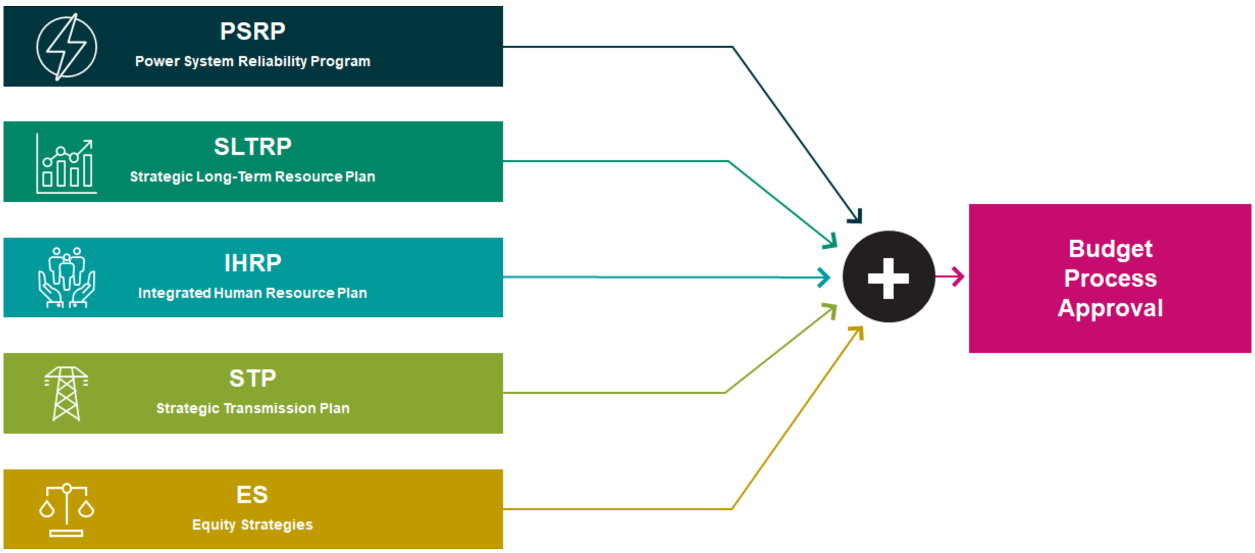

Figure L-12. Power System Independent Studies.

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 Section 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.

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Appendix M

Air Quality and Emissions Analysis

2022 SLTRP

CONTENTS

DEFINITIONS

NREL	National Renewable Energy Laboratories
IHRP	Integrated Human Resource Plan
LADWP	Los Angeles Department of Water and Power
LA100	Los Angeles 100% Renewable Energy Study
NO_x	Nitric oxide and Nitrogen dioxide
SLTRP	Power Strategic Long-Term Resource Plan

M Air Quality and Emissions Analysis

Stakeholders of the Strategic Long-Term Resource Plan (SLTRP) process have requested that the Los Angeles Department of Water and Power (LADWP) analyze the potential changes to air quality and public health caused by changes to operations of in-basin LADWP-owned electricity generation units (EGUs) under scenarios developed in the SLTRP process. LADWP has requested that the National Renewable Energy Laboratory (NREL) support them in this analysis and, in addition, to train LADWP staff on the air quality model used. Thus, tasks will be described below, the first regarding the modeling of air quality and public health of selected SLTRP scenarios, the second regarding the equity analysis of the SLTRP results.

TASK 1: AIR QUALITY AND PUBLIC HEALTH CHANGES FROM SLTRP SCENARIOS

Air quality and public health modeling proceed in a series of steps:

1. Development of an emissions inventory for each scenario-year combination to be analyzed;
2. Running the air quality model whose outputs are concentrations for selected air pollutants;
3. Input of the concentrations to a health benefits model to estimate changes to health when two scenarios are compared.

An emissions inventory defines the where, when, how much and which of all air pollutants whose emissions impact the formation of the pollutants of concern in ambient concentration. It is the step that is the most labor intensive in terms of data collection and analysis, and typically involves many assumptions.

TASK 2: EQUITY ANALYSIS OF SLTRP RESULTS FROM TASK 1

NREL will support LADWP to analyze and develop an equity analysis included within the SLTRP scope. NREL will compare pollutant concentrations and health effects (each individually) for populations living within CalEnviroScreen-designated disadvantaged communities (DAC) as compared to non-DACs. NREL will do so across selected scenarios and milestone years, providing comparisons between the Recommended SLTRP case to the Reference (SB100) case, as well as final scenario-years (2035 or 2045) to start year (2030) to provide both scenario and longitudinal results.

M.1 City Council Motions

Air pollution factors are a critical part of the Los Angeles Department of Water and Power (LADWP) Strategic Long-Term Resource Plan (SLTRP) development process, the National Renewable Energy Laboratory (NREL) is contracted to conduct an analysis of air pollutant emissions from LADWP's four in-basin electricity generation facilities. The aim of the emissions analysis is to evaluate whether our SLTRP cases meet the request of the Los Angeles (LA) City Council per their Motion 16-0243-S2,[1] as well as to ensure alignment with the goals and inputs of external SLTRP stakeholders from the LA community. City Council Motion 16-0243-S2 states:

> "The plan [SLTRP] should ensure that emissions are not increased for any period of time at facilities in environmental justice communities, particularly Valley Generating Station."

To effectively evaluate this Motion, it is necessary to compare projected future air pollutant emissions under the SLTRP to historical emissions levels. NREL has analyzed sub-hourly continuous emissions monitoring system (CEMS) data for each stack at every unit within the four LADWP in-basin facilities to establish a historical emissions baseline. The baseline will be compared to future emissions, estimated through engineering calculations that leverage both historical data as well as the latest scientific research. Furthermore, NREL and LADWP are working in conjunction to establish robust, practical future emissions projections by incorporating operational constraints and protocols for utilization of each of the four facilities, based on the SLTRP. Particular attention is paid to estimating emissions from the combustion of hydrogen—both in blends with natural gas and in pure form—which is planned for all four facilities. The robust air quality and emissions analysis will enable LADWP to effectively communicate the forecasted changes to air pollutant concentrations and related health effects resulting from the SLTRP Cases.

Additionally, NREL is contracted to extend the emissions analysis to model the effect of air pollutant emissions on air pollutant concentrations in the areas surrounding the four in-basin facilities, potential community health effects, and to determine whether the distribution of both concentrations and health effects is equitable among LA neighborhoods and citizens of different demographic groups. The NREL equity analysis will compare pollutant concentrations and health effects (each individually) for populations living within CalEnviroScreen-designated disadvantaged communities (DAC) as compared to non-DACs within Los Angeles.

[1] https://lacity.primegov.com/Portal/viewer?id=387001&type=2.

Both of the aforementioned analyses will be completed and reviewed after the publication of the 2022 SLTRP report. The final results will be included as part of the next iteration of LADWP's SLTRP.

M.2 The Power Sector and Air Quality

Air pollution is one of the top five risk factors that lead to premature death worldwide, resulting in millions of deaths, and exposure to outdoor air pollution dominates the health burden associated with air pollution as compared to indoor air pollution[2,3]. As the air pollutant that causes the most negative health impacts, fine particulate matter (particles with an aerodynamic diameter less than 2.5 micrometers, $PM_{2.5}$) adversely affects human respiratory and cardiovascular systems[4]. In addition to $PM_{2.5}$, ozone and nitrogen oxides (including nitric oxide (NO) and nitrogen dioxide (NO_2), collectively known as NO_x) also have negative impacts on public health. Several studies have also found that air pollution exposure varies across racial, ethnic and income groups, and have concluded that people of color and persons from low-income groups have been exposed to higher air pollution levels.

The U.S. power sector, which uses fossil fuels such as coal and natural gas for electricity generation, is a major source of both outdoor air pollution in urban areas and greenhouse gases. Compared with other sectors, the power sector is not a major emission source in LA. (See the next section, for more such insights into the results from The Los Angeles 100% Renewable Energy Study (LA100)). However, electricity generation powered by fossil fuels can still negatively affect public health, especially in neighborhoods close to power plants, and this has exaggerated the air pollution exposure disparities in disadvantaged communities[5,6]. Therefore, in addition to reducing greenhouse gas emissions, the transition from natural gas to clean

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[2] Burnett, et. al. (2018). Global estimates of mortality associated with long-term exposure to outdoor fine particulate matter. Proceedings of the National Academy of Sciences of the United States of America, 115(38), 9592–9597. https://doi.org/10.1073/pnas.1803222115
[3] State of Global Air 2020: A Special Report on Global Exposure to Air Pollution and Its Health Impacts. Health Effects Institute, Institute for Health Metrics and Evaluation 2020. https://www.stateofglobalair.org.
[4] Bu, et. al. 2021. "Global PM2.5-Attributable Health Burden from 1990 to 2017: Estimates from the Global Burden of Disease Study 2017." Environmental Research 197 (June): 111123. https://doi.org/10.1016/j.envres.2021.111123.
[5] Thind, et. al. 2019. "Fine Particulate Air Pollution from Electricity Generation in the US: Health Impacts by Race, Income, and Geography." Environmental Science & Technology 53 (23): 14010–19. https://doi.org/10.1021/acs.est.9b02527.
[6] Luo, et. al. 2022. "Diverse Pathways for Power Sector Decarbonization in Texas Yield Health Cobenefits but Fail to Alleviate Air Pollution Exposure Inequities." Environmental Science & Technology 56 (18): 13274–83. https://doi.org/10.1021/acs.est.2c00881.

energy sources such as green hydrogen[7] at the power generation facilities operated by LADWP is expected to significantly influence air pollutant emissions and concentrations and to improve public health, especially for those nearby neighborhoods.

M.3 The LA100 Study: Prologue to the SLTRP

The LA100 study developed several different scenarios, each of which shared the same end goal: 100% renewable energy for the power system owned by the City of LA (Cochran 2021). However, the scenarios differed in the way the end goal of 100% renewable energy for the power sector is achieved. These scenarios can be distinguished by modeling results for the demand side and the supply side of the power system.

For demand projections, the LA100 study used two different assumptions:

- **Moderate Demand:** A moderate level of electrification by electricity consumers, including end uses of electricity such as that for light-duty vehicles, home appliances, commercial building heating, and other purposes. Also, moderate demand for the Ports of Los Angeles and Long Beach (the Ports) is consistent with their 2017 Clean Air Action Plan.[8]
- **High Demand:** A high level of electrification in building end uses (i.e., almost 100% electrification) and more aggressive electric vehicle adoption than the moderate demand scenario for buses and light-duty vehicles. High demand for the Ports also increases electrification of shore power used by ocean-going vessels at berth.

Several scenarios were devised with regard to the supply side of electricity, two of which were the focus of the LA100 study's air quality, health, and environmental justice (EJ) analyses:

- **SB 100:** This scenario assumed compliance with the California Senate Bill 100 (hence the name SB 100) and was considered the reference scenario. The scenario included 60% renewable energy generation by 2030 and a target of 100% zero carbon energy by 2045. SB100 allows for the use of renewable energy credits, thus allowing for the combustion of natural gas to provide up to 10% of generation.
- **Early & No Biofuels:** This scenario assumed 100% zero carbon electricity and earlier compliance (2035) than SB100 (2045). Under the scenario, electricity generation could come from green hydrogen combustion, but no fossil or biofuel use was allowed.

[7] Green hydrogen means there are no upstream air pollutant emissions from hydrogen production to account for since the hydrogen is produced from renewable electricity sources.
[8] San Pedro Bay Ports, 2017 Clean Air Action Plan, https://cleanairactionplan.org/.

Combining the electricity supply and demand assumptions results in four scenarios[9]:

- SB100 – High
- SB100 – Moderate
- Early & No Biofuels – High
- Early & No Biofuels – Moderate.

Based on the emissions inventories developed for these four scenarios in the LA100 study, the emissions from LADWP-owned power plants are smaller than the citywide emissions of various pollutants, and they collectively contribute <1% of total mass emitted from all sources in the city in 2045, as shown in Figure M-1 (for NO_x and $PM_{2.5}$. Note, the fractional contribution of LADWP plants is similar in magnitude for other air pollutants not shown in Figure M-1).

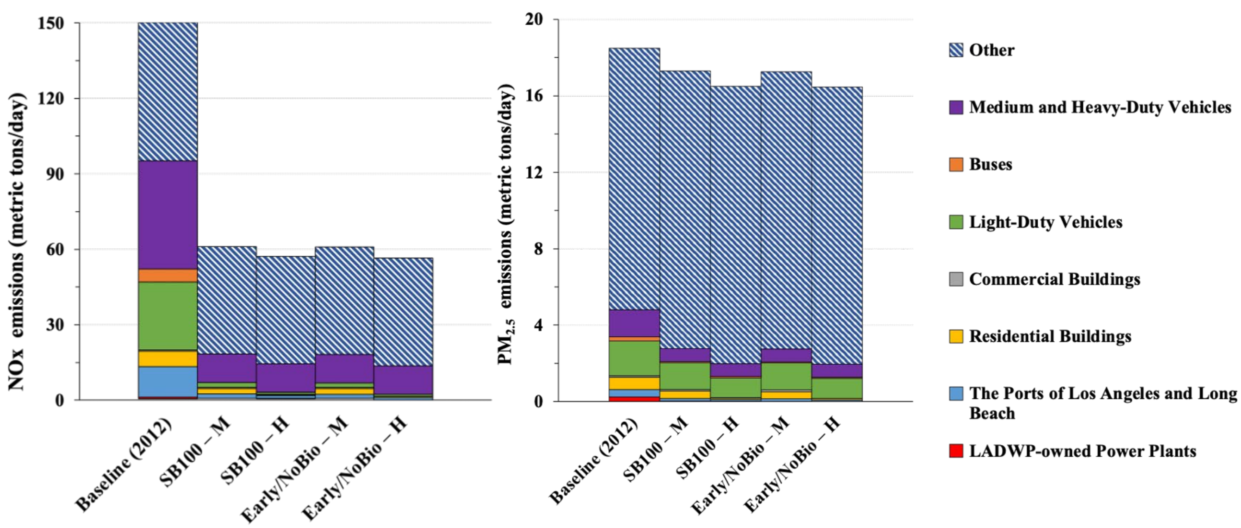

Figure M-1. Annually averaged daily NOx and PM2.5 emissions from all anthropogenic sources in LA for selected LA100 study scenarios. Some of the largest contributing sources to the "Other" category are shown in Figure M-2. M = moderate demand; H = high demand; Early/NoBio = Early & No Biofuels.

[9] The LA100 study used more demand and supply-related scenarios than are listed here, but the study only modeled a subset of those (listed in the text) for air quality, public health, and environmental justice analyses to reduce the computational cost associated with simulated emissions and air quality modeling.

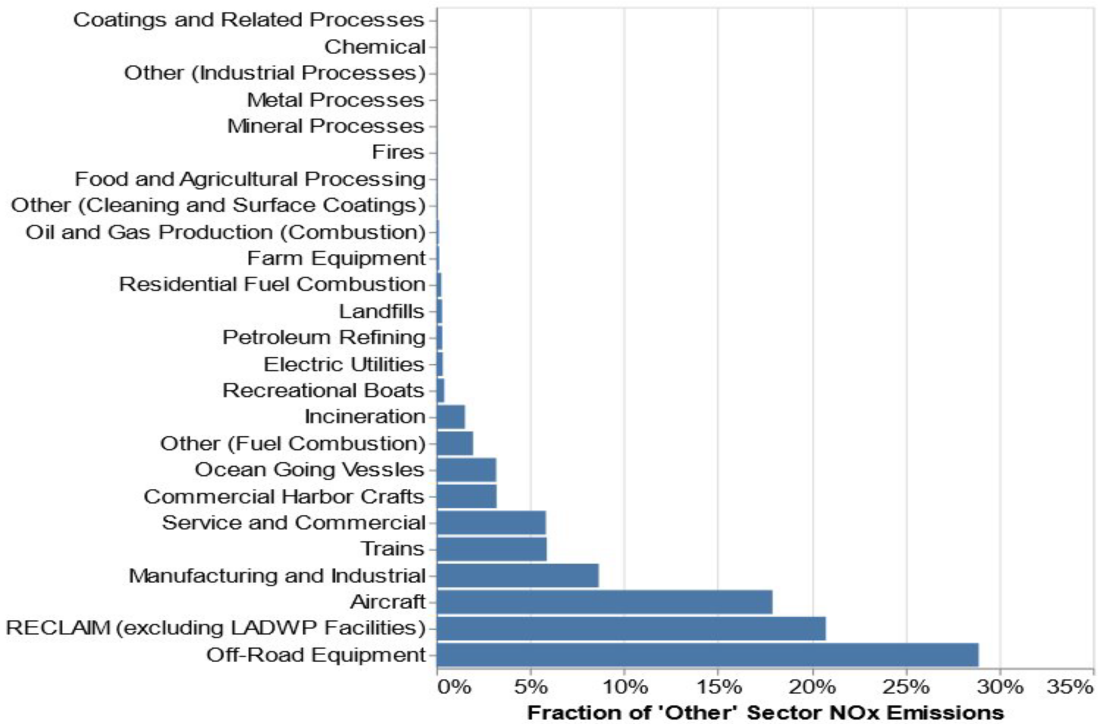

Figure M-2. The percentage distribution of the largest 25 contributing sources to the "Other" category in Figure M-2 (Baseline 2012 scenario) in ascending order

All SLTRP cases for the present analysis were developed by LADWP and originate from the LA100 study's Early & No Biofuels scenario with high end-use electrification. Because of their common origin, the SLTRP cases' emissions are comparable to those estimated in the LA100 study.

M.4 Pollutants of Concern Related to Hydrogen Power Plants

The final analysis results in the next SLTRP will address air pollutant emissions from hydrogen combustion (in comparison with fossil fuel combustion). Presently, renewably generated hydrogen gas is likely to eventually replace natural gas as the fuel source at LADWP's in-basin generating facilities.

Fossil fuels are commonly used for power generation. They are known as hydrocarbons because their molecular form consists of combinations of hydrogen and carbon atoms, sometimes along with other elements. Carbon and other fuel-bound elements such as sulfur and nitrogen (both of which are present in coal, oil, and natural gas), when combusted, create a suite of air pollutants that have been found to cause deleterious health effects in humans and have consequently been regulated. These pollutants include nitrogen dioxide (NO_2), carbon monoxide (CO), and sulfur dioxide (SO_2).[10] The carbon in these fuels, along with other elements, also creates small particles referred to as particulate matter (PM) and a suite of other gaseous carbonaceous pollutants collectively referred to as volatile organic[11] compounds (VOCs).[12] $PM_{2.5}$, as mentioned before, is the most harmful air pollutant for human health and can be either directly emitted, or form in the atmosphere through complex chemical reactions of various particulate and gaseous pollutants.

In contrast with fossil fuels, because hydrogen gas (H_2) consists only of two bonded atoms of the element hydrogen, the only product of combustion attributable to hydrogen is water vapor (H_2O). It is worth emphasizing that because there are no carbon, sulfur, nitrogen, or other elements in hydrogen fuel, the suite of air pollutants commonly associated with combustion of fossil fuels—including PM, CO, SO_2, and air toxics—is not present in the hydrogen combustion exhaust gas. In addition, unlike hydrocarbon-containing fossil fuels, when hydrogen is combusted there is no emission of carbon dioxide (CO_2) or methane (CH_4), two greenhouse gases that have the greatest influence on Earth's climate.[13]

However, through another pathway of formation, hydrogen combustion does still lead to emissions of NO_x.[14] NO_x is a pollutant (in this case, NO_2) that can cause health effects when inhaled. NO_x also important chemically reacts in the atmosphere to contribute to the formation of PM and ozone. The pathway of formation of NO_x from hydrogen combustion is called "thermal NO_x", whereby nitrogen molecules in the air (which is 78% nitrogen) oxidize to NO_x in high-temperature environments like combustion chambers.[15] Of three NO_x formation pathways,[10] thermal NO_x is the dominant pathway in high-temperature environments observed during fuel combustion (Lewis 2021), and is the only pathway of NO_x formation from use of hydrogen due to absence of fuel-bound nitrogen. The adiabatic flame temperature of hydrogen, if left uncontrolled, can exceed 1,800–2,000 K. At such temperatures, NO_x formation

[10] There are three pathways to the emission of NO_x from combustion sources: "thermal NO_x", "fuel NO_x", and "prompt NO_x". The pathway that gains its nitrogen atom from nitrogen in the fuel is called "fuel NO_x".

[11] Anything that is organic has carbon in it.

[12] VOCs are also commonly known as air toxics and regulatorily belong to the group of hazardous air pollutants (HAPs).

[13] This report focuses on the air pollutants that cause human health effects, and thus, it does not address the potential global warming effect of either water vapor or hydrogen gas leaked to the atmosphere (i.e., not combusted). Both of these can be considered second-order effects relative to carbon dioxide and methane emissions from typical fossil fuel combustion systems, but they could be addressed in future work.

[14] Technically, nitrogen can be emitted as either NO or NO_2. To simplify communication, scientists have developed the collective term NO_x where the "x" refers to the number of oxygen atoms (either one or two in this case), to refer to the sum of emissions of both of these pollutants.

[15] Interested readers can refer to U.S. EPA (1999) to learn about the two other NO_x formation mechanisms: "fuel NO_x" and "prompt NO_x".

can be significantly enhanced compared to common flame temperatures of natural gas, which are about 150 K lower (Ilbas et al. 2005; Cooper and Alley 2010; Shih and Liu 2014).

The fact that hydrogen combustion does not eliminate all air pollutant emissions, and in particular does emit NO_x, has led to (1) discussion about how hydrogen's NO_x emission factor compares to the NO_x emission factor of natural gas, and (2) concern about potential residual effects on the health of downwind citizens. Several studies have examined NO_x emissions from hydrogen combustion. Some of those studies assert that NO_x emissions for hydrogen combustion *could* be higher than they are for natural gas combustion, based on the potential for higher flame temperatures. High NO_x emissions can be a regulatory concern for power plants because of emission limits required by air quality control agencies.

In the context of all NO_x emission sources within the City of L.A., LADWP facilities are small contributors. There are many other economic sectors with far greater emissions. This result was found in the LA100 study, as well as for the preliminary analysis of the 2022 SLTRP cases. In fact, the emissions in 2045 in SLTRP Cases 1 and 2 are estimated to be even lower than those estimated under LA100 scenarios. (Case 3 emissions in 2045 are higher than estimated under LA100, yet still approximately 1,000 times lower than the sum of all other sources in the City.[16])

[16] This result could appear counter intuitive: Case 3 has higher RPS and DERs and yet is found to have higher NOx emissions. This is because the DER resources were fixed inputs, mostly local solar and energy storage which have fixed periods of operation. The capacity expansion model optimizes to fulfill remaining load after fixed resources are deployed, which results in less overall diversity in resources and results in more pressure on in-basin generation to back up renewable resources.

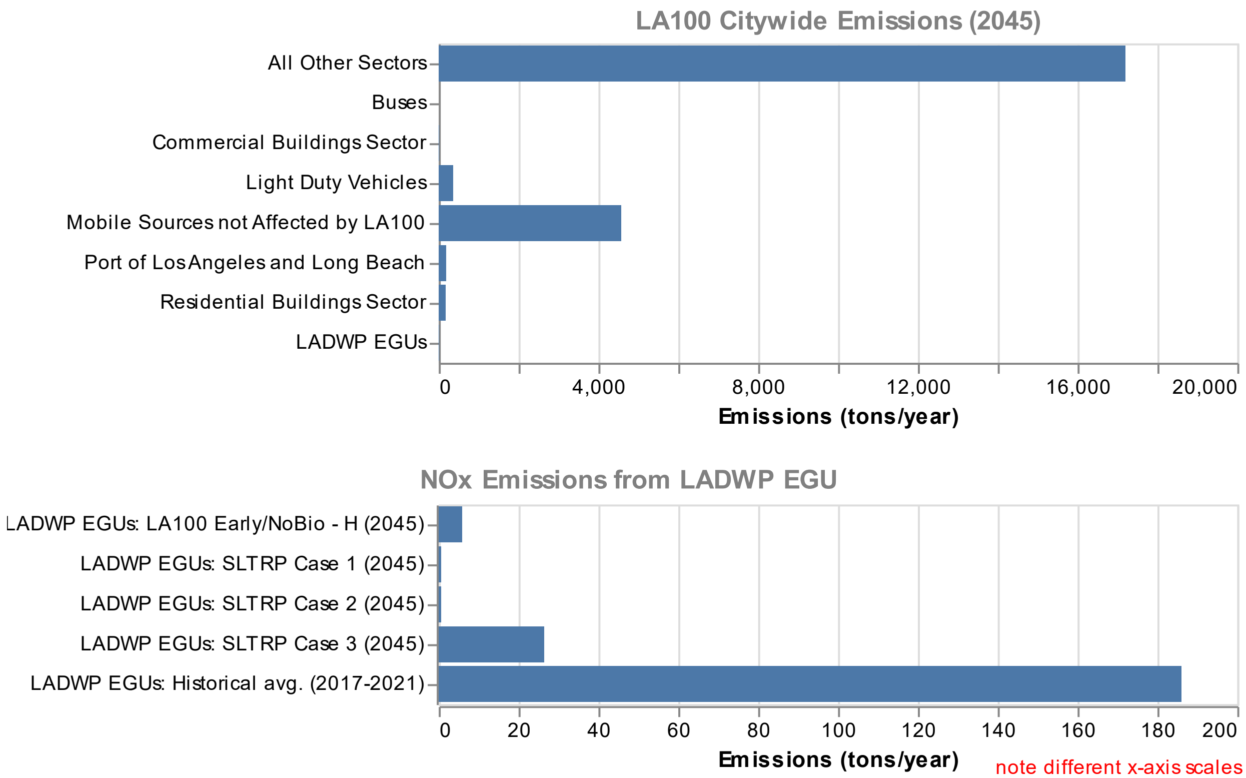

Figure M-3. Annual 2045 citywide estimated NOx emissions

Annual 2045 citywide estimated NO_x emissions (Figure M-3), as reported in the LA100 study for the Early & No Biofuels – High (Early/NoBio – H) scenario (Heath et al. 2021), compared to 2045 annual NO_x emissions estimated for SLTRP Core Cases 1–3 (lower figure). In addition, for reference, the lower figure displays historical average (2017–2021) emissions, and reproduces (in different scale) the LA100 results for LADWP's in-basin electricity generation units (EGUs) in 2045. Estimates of NO_x emissions from SLTRP cases in 2045 are on the order of 1,000 (Case 3) to 23,000 times (Cases 1 and 2) smaller than LA100's 2045 estimate of emissions from the sum of sources in the City of LA. (Note that the x-axis scale in the bottom panel is 1,000 times smaller than the top panel.)

In the analysis supporting creation of Figure M-3, it is assumed NO_x emissions from hydrogen combustion can be controlled to the same level as NO_x emissions from natural gas combustion[17]. This assumption is based on analysis of the latest scientific literature and consultation with experts in combustion science, gas-fired turbine design and local regulators. Some prior literature identified the potential for higher NO_x emissions from hydrogen than

[17] Hammerstrom et al. 2022; NETL 2022; Douglas, Shaw, et al. 2022; Douglas, Emerson, et al. 2022

from natural gas because hydrogen combustion, if left uncontrolled, can achieve higher flame temperatures than natural gas[18]. However, when flame temperature is controlled to the same level as for combusting natural gas, NOx emissions are then equalized. Also, NO_x emission control devices work the same for hydrogen combustion as for natural gas.

For the next SLTRP emissions analysis results, it will be assumed that NO_x emissions from hydrogen combustion can be controlled to the same level as NO_x emissions from natural gas combustion, and LADWP hydrogen power plants can thus meet current natural gas-based emissions limits within the jurisdiction of South Coast Air Quality Management District (the regulatory air quality agency responsible for the LA region). This assumption is based on recent research and expert consultation, including:

1. Recent studies indicate emissions of NO_x from hydrogen combustion turbines can be controlled by using appropriate emissions control technologies and/or controlling flame temperatures. These approaches include combustion at lower fuel-to-air ratio, water injection to reduce flame temperature, and use of selective catalytic reduction to reduce post-combustion NO_x.
2. Earlier studies on higher NO_x emissions from hydrogen turbines almost always reported emissions as a concentration in terms of parts per million by volume (ppmv), which is a count of NO_x molecules per million molecules of all constituents in the sampled volume of exhaust gas. However, use of this concentration-based metric can inflate one's perception of NO_x emissions by as much as 40% compared to a mass-based metric (like pounds per million British Thermal Units, or lbs/MMBtu). The mass of a pollutant emitted (and subsequently inhaled) is what relates to community health, and thus a mass-based emission factor is a better measure of hydrogen's NO_x emissions. Using the mass-based measure, recent research has found that NO_x emitted from hydrogen combustion is only up to ~5% greater than NO_x emitted from natural gas.
3. In public forum, turbine manufacturers reported they tested hydrogen-natural gas blends and found that NO_x emissions were within regulatory emission limits prescribed by air quality agencies. According to the unpublished panel discussion at a recent conference,[19] these tests were conducted on blends containing up to 30% hydrogen.
4. The South Coast Air Quality Management District has publicly indicated hydrogen turbines using fuel blends or pure hydrogen will be subject to the same emissions standards as natural gas.[20]

[18] Therkelsen et al. 2009; Lam, Geipel, and Larfeldt 2014; Shih and Liu 2014; Cellek and Pınarbaşı 2018

[19] The panel discussion occurred at the Air & Waste Management Association's 115th Annual Conference and Exhibition, during the session titled "Hydrogen Fuel for Power Generation, Decarbonization, and Emissions Control," and was held in San Francisco, California, June 27–30, 2022. See the conference program at https://www.awma.org/files/ACE2022/ACE%202022FinalProgramUpdated.pdf.

[20] This is also according to the unpublished panel discussion at the June 2022 Air & Waste Management Association conference. See previous footnote.

M.5 Pollutants of Concern from SLTRP Cases and Scope of Analysis

Although NO_x is the only pollutant of concern for pure hydrogen combustion, combustion of natural gas emits other air pollutants, including $PM_{2.5}$ and SO_2 (from sulfur contamination in the fuel). Therefore, because of blending of hydrogen with natural gas in the 2030 SLTRP cases—and because under the City Council motion future emissions must be compared to historical emissions—a full inventory of emissions of all pollutants is developed for air quality modeling and health impact analysis. Yet, the NREL analysis focuses on only NO_x for two reasons. First, as shown in Figure M-1, LADWP's power plants are very small sources of primary $PM_{2.5}$ emissions in the context of all emissions sources in LA, and the same is true of SO_2, VOCs, and other air pollutants. Second, because the City Council motion focuses on comparison of future and historical emissions, and because 100% hydrogen combustion will emit neither SO_2 nor $PM_{2.5}$, the answer to the comparison question is obvious: emissions will always be lower in the future than the past for these pollutants.

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