Los Angeles Department of Water & Power

2015 POWER INTEGRATED RESOURCE PLAN

December 2015

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Los Angeles Department of Water & Power

2015 Power Integrated Resource Plan

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December 31, 2015

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Los Angeles Department of Water & Power

2015 Power Integrated Resource Plan

December 31, 2015

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Preface

The 2015 Power Integrated Resource Plan (IRP) document serves as a comprehensive 20 year roadmap 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 resource decisions can have significant economic and environmental consequences, it is essential for the planning process to be conducted with transparency, active participation, and collaborative dialog with affected stakeholders and our customers. The last public outreach process was conducted in 2014 in support of the 2014 IRP and included a newly formed IRP 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 of the recommended resource case. This year's 2015 IRP re-examines and expands its analysis on the 2014 IRP recommended case with updates in line with latest regulatory framework, primarily the recently approved state legislation of a 50 percent renewable portfolio standard by 2030.

This year's 2015 IRP provides detailed analysis and results of several new IRP resource cases which investigated the economic and environmental impact of increased local solar and various levels of transportation electrification. In analyzing the IRP cases and recommending a strategy to best meet the future electric needs of Los Angeles, the IRP 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 our existing mix of assets and providing the analytic results to inform the selection of a recommended case.

Recent updates include an increased renewable portfolio standard of 50 percent by 2030, sale of LADWP's 21 percent share in coal-fired Navajo Generating Station, and completion of a reliability study titled, "Maximum Generation Renewable Energy Penetration Study (MGREPS)." This IRP also includes numerous updates including new renewable projects and fuel cost assumptions.

The major focus this year was on re-evaluating last year's recommended case with an updated 50 percent RPS by 2030 to comply with Senate Bill 350, while examining various scenarios of local solar and transportation electrification to reduce greenhouse gases. Early coal replacement and energy efficiency continue to be key strategies to reduce greenhouse gas emissions. Increasing the renewable portfolio standard to 50 percent by 2030, including increased amounts of local solar within Los Angeles, is another key contributor to reduce greenhouse gas emissions. In order to evaluate the reliability impacts of reaching a 50 percent renewable portfolio standard by 2030, LADWP contracted with URS team in 2015 to perform the MGREPS study; the results of this study is detailed in this IRP. With the considerable investment required for expanding local solar programs, LADWP will continue to advocate for local solar to be counted towards meeting the Renewable Portfolio Standard. This IRP analyzed electrification of the transportation sector as a strategy to further reduce overall greenhouse gas emissions and to significantly reduce local emissions such as VOC, NOx, CO, and PM 2.5 that would result from promoting electrification of local transportation and therefore recommends expanding existing programs to promote increased workplace and residential electric vehicle charging stations to support greater electric vehicle adoption while collaborating with regulatory agencies to reach mutually beneficial policies.

This IRP also includes a general assessment of the revenue requirements and rate impacts that support the recommended resource plan through 2035. While this assessment will not be as detailed and extensive as the financial analysis to be completed for the ongoing rate action for the 2015/16 fiscal year and beyond, it clearly outlines the general requirements. As a long-term planning process, the IRP examines a 20-year horizon in order to secure adequate supplies of electricity. In that respect, it is our desire that the IRP 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.

TABLE OF CONTENTS

1. INTRODUCTION AND PURPOSE 1

1.1 MAJOR CHANGES FROM LAST YEAR'S IRP 3

2. RECENT ACCOMPLISHMENTS 4

3. 2015 IRP DEVELOPMENT PROCESS 7

4. PUBLIC OUTREACH 8

5. CHALLENGES AND CRITICAL ISSUES 10

5.1 ADEQUATE FUNDING TO SUPPORT PROGRAMS 10
5.2 ENSURING RELIABILITY 11
5.3 GREENHOUSE GAS EMISSIONS REDUCTION 12
5.4 INCREASING RENEWABLE RESOURCES 14
5.5 ONCE THROUGH COOLING 15
5.6 STAFFING AND TRAINING THE WORKFORCE – INTEGRATED HUMAN RESOURCES PLAN 16
5.7 OTHER CHALLENGES 18

6. STRATEGIC CASE ALTERNATIVES 19

7. EVALUATION OF STRATEGIC CASE OPTIONS 22

7.1 CO_2 EMISSIONS CONSIDERATIONS 22
7.2 TOTAL POWER SYSTEM COST COMPARISONS 26
7.3 SENSITIVITY ANALYSES 29
7.4 TOTAL POWER SYSTEM RATE IMPACT COMPARISONS 30

8. RECOMMENDATIONS 33

8.1 RECOMMENDED STRATEGIC CASE 33
8.2 RECOMMENDED NEAR TERM ACTIONS 38
8.3 RATE CONTRIBUTIONS BREAKDOWN 40
8.4 STRATEGIC PROGRAMS TO SUPPORT LADWP'S RECOMMENDED STRATEGY 47

Power System

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LADWP's Power System is the nation's largest municipal electric utility, and serves a 465-square-mile area in Los Angeles and much of the Owens Valley. LADWP began delivering electricity in Los Angeles in 1916.

Power Facts and Figures

LADWP's Power System supplies more than 26 million megawatt-hours (MWh) of electricity a year for the City of Los Angeles' 1.4 million residential and business customers as well as over 5,000 customers in the Owens Valley.

Revenues & Expenditures

For Fiscal Year 2015-16, the Power System budget is $4.1 billion. This includes $1 billion for operations and maintenance, $1.6 billion for capital projects, and $1.5 billion for fuel and purchased power.

City Transfer

The Power System transfers 8% of its gross operating revenue (estimated at $265.6 million in FY 2014-15) to the City's General Fund each year to provide critical City services such as public safety.

Electric Capacity

LADWP has over 7,640 megawatts (MW) of generation capacity from a diverse mix of energy sources.

Power Resources (2014)

(As reported to CEC)

Renewable energy	20%
Biomass & Biowaste	5%
Geothermal	1%
Small hydroelectric	1%
Solar	1%
Wind	12%
Natural gas	22%
Nuclear	9%
Large hydro	2%
Coal	40%
Other/Unspecified	7%

Typical residential energy use per customer is about 500 kilowatt-hours (kWh) per month. Business and industry consume about 70% of the electricity in Los Angeles, but residents constitute the largest number of customers. The record instantaneous peak demand is 6,396 MW reached on September 16, 2014.

Power Infrastructure

The Power System is responsible for inspecting, maintaining/replacing, and operating the following:

Generation
4 in-basin thermal plants
14 small hydroelectric plants
1 large hydroelectric plant
1 wind power plant
2 solar photovoltaic plants

Transmission
3,507 miles of overhead transmission circuits (AC and DC) spanning five Western states

124 miles of underground transmission circuits

15,452 transmission towers

Distribution
6,800 miles of overhead distribution lines

3,597 miles of underground distribution cables

162 distributing stations

21 receiving stations

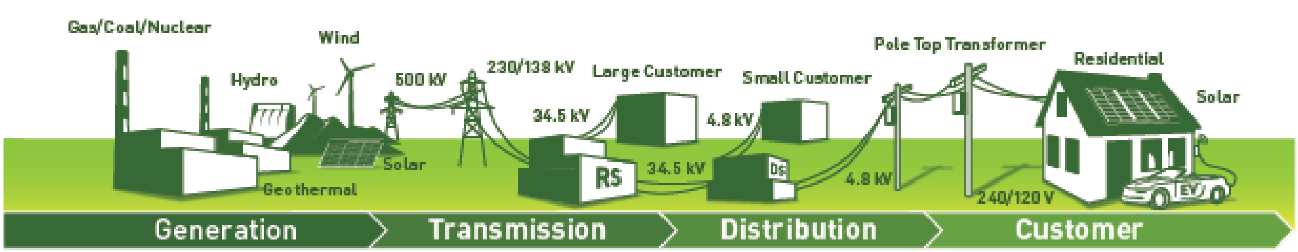
50,636 substructures

321,516 distribution utility poles

3,166 pole mounted capacity banks

1.3 million distribution crossarms

31,728 utilitarian streetlights



1. Introduction and Purpose

This document represents the Los Angeles Department of Water and Power's (LADWP) 2015 Integrated Resource Plan (IRP). The goal of this IRP is to identify a portfolio of generation resources and Power System assets that meets the city's future energy needs at the lowest cost and risk consistent with LADWP's environmental priorities and reliability standards. The IRP is an important planning document for electric utilities, and many states and regulatory agencies require development of an IRP prior to approval of procurement programs or electric rate increases.

This document goes beyond traditional integrated resource planning and incorporates additional Power System planning elements to form a comprehensive Power System plan. It is intended that this Power System plan will drive the priorities, financial planning, and budgeting effort for the Power System.

This IRP considers a 20-year planning horizon to guide LADWP as it executes major new and replacement projects and programs. The overriding purpose is to provide a framework to assure the future energy needs of LADWP customers are met in a manner that balances the following key objectives:

- Superior reliability and supply of electric service
- Competitive electric rates consistent with sound business principles
- Responsible environmental stewardship exceeding all regulatory obligations

In balancing these objectives, LADWP's strategic planning efforts must ensure a high level of system reliability, consider impacts to the local and regional economy, mitigate the volatility in fuel and other cost factors, comply with federal, state, and local regulations, and guarantee fiscal responsibility. As LADWP executes major projects and programs, a strong focus is placed on local programs designed to increase customer participation in programs that transform our power supply and assist in integrating renewables. Programs such as energy efficiency, local solar, demand response, Power System Reliability, and micro-grids create opportunities for community involvement and local job growth in support of LADWP's goals.

LADWP is the largest municipal utility in the nation, and the third largest utility in California. While numerous recent accomplishments have been made – including achieving an average of 20% renewable energy sales in the period 2010 through 2013 – significant challenges lie ahead. Increasing renewable energy to 33% by 2020 and 50% by 2030, the continued rebuilding of coastal generation units, replacement of coal, infrastructure reliability investments, and ramping up energy efficiency, transportation electrification, and other demand side programs are all critical and concurrent strategic actions that LADWP will have to carry out over the coming decade.

The 2015 integrated resource planning process continues to evaluate alternative strategic cases that consider replacement of coal-fired generation, as well as different forecasted levels of renewable portfolio standard (RPS), local solar, and transportation electrification. The cases are modeled to determine their respective operational and fiscal impacts, as well as their effects on greenhouse gas (GHG) emission levels. This document presents the results of this analysis, recommended near-term actions, and a recommended strategy to best meet the future electrical needs of Los Angeles.

LADWP Power System Vision

The transformation that this utility will undergo in the next 20 years will be unprecedented as the use of electricity broadens to new applications and as customer expectations of clean affordable energy continues to take root. Increases in electric vehicle use and our ever-increasing dependence on evolving information technologies will require a stable, resilient power grid that delivers affordable power. As distributed energy resources dramatically increase, there is a growing interest for a transactional grid that includes greater customer participation to help manage variable distributed energy resources, meet reliability needs, alleviate congestion, and avoid costly upgrades. By increasing energy efficiency, implementing demand response, promoting solar rooftop and other clean technologies that mitigate the need to build new fossil-fueled power plants, both LADWP and its customers are embracing the vision of a greener resource portfolio that helps sustain the environment for future generations.

LADWP and its City Leaders have traditionally taken a leadership position, particularly among public power utilities, to ensure a sustainable, diverse supply of generation and transmission resources to provide electricity to our customers. This utility has also been very progressive in adopting aggressive clean energy goals and programs well before many of today's laws and regulations were in place, and participated in the development of many of the laws and regulations that we see today. In 2000, this utility set out to reduce load growth by 50 percent through the use of behind the meter renewables, energy efficiency, and local solar. Today we have the same electricity consumption as we had in 2006 despite population growth, largely due to these earlier efforts. In 2005, we adopted a renewable target of 20 percent renewable by 2010, and we succeeded to be the largest California municipal utility to achieve 20 percent renewable generation in 2010. Since 1990, we have divested of two coal plants with the sale of a third expected in mid-2016, and repowered several natural gas in-basin generating stations using cleaner and more efficient new combustion technology, resulting in 20 percent lower greenhouse gas emissions and over 80 percent lower NOx emissions. Reducing ocean water use and reducing the impact on marine life has also been an on-going effort and we are now utilizing 42% less ocean water from 1990 levels, with total elimination targeted by 2029.

The world today is not the same as it was 20 years ago, and the world 20 years from now will not be the same as it is today. And while LADWP's mission of providing reliable, affordable electricity in an environmentally responsible manner remains the same, the planning and execution of that mission requires continued diligence to account for, adopt, and even influence, the changing public concerns and priorities related to electricity generation and use.

1.1 Major Changes from Last Year's IRP

Major changes from last year's 2014 IRP include expanded discussion on:

- Senate Bill 350 signed into law, requiring a target 50% renewable portfolio standard by 2030 and doubling of energy efficiency savings and demand reduction.

- An agreement under which LADWP will sell its 21 percent share (477 MW) in the coal-fired Navajo Generating Station in Arizona to Salt River Project; the sale will close on July 1, 2016.

- The Maximum Generation Renewable Energy Penetration Study (MGRPES), which analyzed the impact of 40 and 50 percent penetration of variable energy resources (VERs) on LADWP's system balancing requirements, including reserve requirements, ramp rate requirements, system reliability and operation requirements (system inertia and frequency response), and generation dispatch strategies.

- Scattergood Generating Station Unit 3 was repowered with a modern, state-of-the art combined-cycle unit and two simple-cycle gas turbine units for a total generation of 508 MW to reduce the use of once-through cooling.

- Expanded discussion on the Transportation Electrification Program to meet IRP electrification goals.

- Status update on the Integrated Human Resources Plan (IHRP) and Customer Care and Billing (CCB)

- Natural gas prices and renewable energy costs have been revised downwards compared to last year's 2014 IRP.

- In this 2015 IRP, the overall base renewable portfolio levelized cost is $91/MWh, which represents a $1/MWh decrease from last year and a $4/MWh decrease from 2013. This cost reduction was achieved primarily through several recently signed power purchase agreements for cost-effective large central solar and geothermal projects, resulting in a more optimized and diverse portfolio that accounts for changing price trends and market developments. The 2015 IRP excludes Solar Customer Net Metered in the levelized cost calculation because it is not counted toward RPS requirements. By maintaining flexibility in the selection of cost-effective renewable resources, LADWP is able to secure the best pricing as market conditions evolve.

- Updated case scenarios including additional 50 percent Renewable Portfolio Standard (RPS) cases by 2030 with varied amount of local solar and transportation electrification. The 40 percent by 2030 RPS case is no longer considered due to the recent enactment of Senate Bill 350.

This 2015 IRP incorporates updates to reflect the latest load forecast, fuel price and projected renewable price forecasts, and other numerous modeling assumptions. Major renewable projects approved this year by the Board and City Council includes Hudson Ranch Geothermal and Springbok 2 Solar Power Purchase Agreements. Copper Mountain 3 reached full commercial operation and Don Campbell 2, Hudson Ranch, and Heber 1 Geothermal Power Purchase Agreements were also placed in-service this year. These projects were among the approved and executed projects this past year which took advantage of lower renewable prices.

2. Recent Accomplishments

A summary of recent LADWP accomplishments consistent with the objectives of this IRP are presented below in Table ES-1. These accomplishments promote the goals of maintaining high reliability and exercising environmental stewardship, while maintaining competitive rates. See Section 1.5 for more details.

Table ES-1. LADWP RECENTLY ACCOMPLISHED PROJECTS/PROGRAMS

Project/Program	Time Period	Accomplishment
Sale of Navajo to Salt River Project (SRP)	2015-2016	Sold 477 MW share of Navajo Generating Station to SRP
Renewable Portfolio Standard	2003 to 2015	Increased renewable energy percentage from 3% to 20%
Barren Ridge Renewable Transmission Project	2013 to 2016	2,000 MW of added transmission capacity under construction
Hudson Ranch Geothermal	5/4/15-12/31/21	55 MW in-service
Don A. Campbell Geothermal	2013 to 2014	14 MW in-service
Don A. Campbell II Geothermal	2015	16.4 MW in-service
Copper Mountain 3 Solar	2013 to 2015	210 MW in-service
Moapa Southern Paiute Solar, LLC (Moapa) Solar	2013 to 2015	250 MW under construction
Heber-1 Geothermal	2013 to 2015	34 MW
Beacon Bundled Solar	2013 to 2014	Beacon Site Purchased for a 250 MW Solar Project. City Council approved the Beacon Bundled Project, consisting of a 250 MW of large solar facility and 50 MW of Feed-in Tariff solar on June 3, 2014
Springbok Solar	2014-2016	City Council approved the Springbok Project, consisting of 100 MW of Solar on October 7, 2014

Project/Program	Time Period	Accomplishment
Springbok 2 Solar	2016	Board approved the Springbok 2 Project, consisting of 150 MW of Solar on May 19, 2015
Barren Ridge 1 Solar	2014-2016	City Council approved the Barren Ridge 1 Project, consisting of 60 MW of Solar on August 8, 2014.
Energy Efficiency Program	2010 to 2020	Board approved revised energy efficiency targets of 15% by 2020, based on the 2013-2014 Energy Efficiency Potential Study.
Solar Incentive Program	1999 to Present	Provided funding that has enabled the installation of 150 MW of operational net-metered solar at over 18,100 customer locations as of October 2015.
Solar Feed-in-Tariff (Set-Pricing)	2012 to Present	Full scale program launched for 100 MW with 8 MW of projects installed and 52 MW of executed contracts awaiting construction.
Solar Feed-in-Tariff (Competitive Pricing)	2014 to Present	Full scale program launched for 50 MW Beacon Bundled
CO_2 Emissions Reduction	1990 to 2014	CO_2 emission 17% lower than 1990 level.
Once through Cooling (OTC): Haynes 5&6 Repowering	2011 to 2013	Six, 100 MW combustion turbine generators installed and placed in-service on June 19, 2013 (Units 11, 12, 13, 15, and 16) and June 29, 2013 (Unit 14).
OTC: Scattergood Unit 3 Repowering	2013 to 2015	Project under construction for two simple cycle and one combined cycle unit, totaling 508 MW.
Apex Power Project	2014	Purchased Apex Power Project, an existing 531 MW gas fired combined cycle facility located in Southern Nevada. Apex Generating Station was purchased and integrated into LADWP's Power System in 2014.
Castaic Upgrade	2004 to 2014	Project adds up to 80 MW of renewable capacity
Power System Reliability Program	2014 to Present	New Power System Reliability Program initiated to replace the Power Reliability Program and incorporate generation, transmission, and substations, in addition to distribution.

Project/Program	Time Period	Accomplishment
Electric Vehicle (EV) Incentive: Initial EV charger rebate program	2011 to Present	Provide a $2000 rebate for home EV charging systems, which resulted in over 700 residential charger installations in Los Angeles.
Electric Vehicle Program: “Charge Up L.A.” Rebates	2013 to 2015	$2 million rebate program offered to the first 2,000 approved EV customers for large business, small business, multi-family buildings and public use.
Demand Response Implementation Plan	2014	New Demand Response Plan implemented with the goal of achieving 200 to 500 MW of load shifting and interruptible load by 2026, subject to cost studies.
Alternative Marine Power Program	Through 2015	Signed up all container terminals to offset diesel motor emissions from shipping vessels at the Port of LA.
Smart Grid Program	2013 to Present	Refine and implement a Smart Grid strategy that can assist in the procurement and development of advanced technologies to support areas such as weather forecasting, energy scheduling, customer kWh metering, high speed communications and information systems, and energy storage systems.
Energy Storage Procurement Targets	2014	Energy storage targets were adopted by the Board to support increasing renewable energy in the amount of 154 MW by 2021, in addition to the previously adopted amount of 24 MW by 2016.
Pacific DC Intertie (PDCI) Upgrade	2014	LADWP initiated major upgrades of the equipment at the southern terminal of the PDCI which is jointly owned by Southern California Edison and the Cities of Los Angeles, Glendale, Burbank, and Pasadena and brings hydro-electric power from the Pacific Northwest to Southern California.

3. 2015 IRP Development Process

The IRP is prepared by a group of engineers dedicated to LADWP resource planning and preparation of the IRP document. While this group performs the production model and report preparation for the IRP, the bulk of the work is collaborative across the numerous work groups and functional areas of the Power System, including wholesale marketing, grid operations, renewable procurement, environmental and legislative affairs, and financial services.

The following general sequence describes the process to develop this IRP document:

1. Gather stakeholder input
2. Establish clear goals and objectives
3. Identify and approve key assumptions
4. Establish strategic case alternatives
5. Conduct computer modeling of Power System operations
6. Present preliminary findings and gather internal and public comments
7. Recommend and approve a preferred resource case

Stakeholder input was considered in the establishment of the goals and objectives for the IRP analysis. Modeling assumptions and case alternatives were identified and approved by an internal IRP Steering Committee consisting of Power System Division and Section Managers. Preliminary results were analyzed and presented to the public for review and input. This IRP incorporates public feedback and input from Power System Management.

The IRP development process includes coordination among multiple LADWP organizations responsible for different aspects of Power System operations. Recommended positions at the various stages were presented to LADWP's leadership team, including Division and Section Managers. The approval process for recommendations was based on consensus from the managers of each area of responsibility.

4. Public Outreach

LADWP conducts a public review process on its IRP every other year. The previous review process was held in support of the 2014 IRP and this year's 2015 IRP does not include a public review process. The results of the 2014 process are referenced in Section 5 and Appendix O of the IRP.

Comments received during the 2014 IRP outreach process were synthesized into the following major themes. Each theme is considered of equal importance. It is important to note that comments received during the outreach process were primarily from the Environmental Community. The following list is not presented in any order of importance:

1. Eliminate Coal from LADWP's Energy Portfolio
2. Decrease Natural Gas from LADWP's Energy Portfolio
3. Incorporate More Renewables
4. Incorporate More Local Solar
5. Incorporate More Energy Efficiency
6. Promote Electrification of the Transportation Sector
7. Investigate and Incorporate Energy Storage
8. Reduce Greenhouse Gas Emissions
9. Examine New Case Scenarios

The 2014 IRP includes a public review process, including the formation and active participation of a new IRP Advisory Committee (Committee). The purpose of the Committee is to further transparency and build on the collaborative dialog that was conducted in recent IRP processes. The Committee was presented with the major issues facing LADWP and weighed in on how those issues should be addressed.

While the Committee did not have approval authority for the 2014 IRP, it influenced the assumptions that were used in the case scenarios, as well as the final recommendations and near term actions. The Committee contributed to the process in a constructive manner, mutually exchanging information with LADWP for the betterment of the Power System, our customers, and the environment.

The Committee represents a range of stakeholder representatives, including: Neighborhood Councils, Business Customer Representatives, Environmental Representatives, the LA City Council and Mayor's office, and an academic representative from UCLA. The Office of Public Accountability (Ratepayer Advocate) attended most meetings as an observer of the proceedings. The Committee met five times throughout the calendar year and provided input in the development of the preliminary cases that were analyzed and the recommendation of the final 2014 IRP case.

In addition to the IRP Advisory Committee, three Public Outreach Workshops were held in October and November 2014, to provide an overview of the 2014 IRP, collect comments and address concerns from the general public, and provide feedback on the resource cases analyzed to assist in the selection of a final recommended case. The 2014 Draft IRP was made available for public comment through the LADWP IRP website (www.ladwp.com/powerIRP). Considering the public comment and input received, a final set of recommendations was made. A new public review process will be conducted next year in support of the 2016 IRP.

5. Challenges and Critical Issues

LADWP faces a number of concurrent issues and challenges, which require careful assessment. Long-term strategies must focus on these issues so they can be addressed in the most cost effective manner without compromising reliability compliance and environmental stewardship. The strategies of this IRP are centered on the major issues including: adequate funding to support programs; ensuring reliability; greenhouse gas (GHG) emissions reduction; increasing the amounts of renewable generation resources; and addressing once-through cooling.

5.1 Adequate Funding to Support Programs

To support the recommended projects and programs, adequate funding is necessary. The last rate action that concluded on October 5, 2012 was a positive step towards LADWP's fulfillment of its responsibilities and regulatory obligations that are discussed throughout this 2015 IRP. A rate action is currently ongoing and is expected to conclude in 2016. Although many of LADWP's programs have been budgeted with adequate funding, some programs still lack the appropriate funding.

Properly funded programs will enable LADWP to achieve the following objectives:

- Modernize its coastal generation units to replace aging equipment and to satisfy once-through cooling and local emissions regulatory requirements.
- Implement early coal divestiture and replacement to accelerate the reduction of GHG emissions and to enhance integration of renewable energy and energy efficiency measures.
- Secure the state-mandated amounts of renewable energy.
- Increase use of local solar generation and combined heat and power to support State goals. LADWP has expanded its local solar program and adequate funding is necessary to support the expanded program.
- Through the Power System Reliability Program (PSRP), reduce the number and duration of outages and improve system reliability. The PSRP program requires continuous recommended levels of funding to meet critical infrastructure replacement goals. Implement necessary transmission improvements to maintain reliability and support future renewable resources.
- Provide energy efficiency, local solar, and electric vehicle charging incentives to encourage participation by our customers.
- Achieve energy efficiency, local solar, and other demand-side-resource target levels.
- Investigate and incorporate energy storage systems to support increased renewables.
- Implement Smart Grid initiatives.
- Comply with FERC-approved reliability and Cyber-security standards.

- Operation and maintenance support for new facilities resulting from compliance with Federal and State regulations.

Securing adequate multi-year funding is crucial to ensure LADWP's ability to stay on track towards meeting its future long-term goals and obligations. In addition to securing adequate funding for programs such as PSRP, demand response, and local solar, adequate staffing levels are necessary to support these programs.

5.2 Ensuring Reliability

Challenges to ensuring continued reliable electric service include replacement of aging generation facilities, integration of intermittent renewable energy resources, and replacement of equipment related to generation, transmission, distribution, and substations.

LADWP's Repowering Program, which began in 1994, is a long-term program to upgrade LADWP's in-basin generating units. The program is a sequence of projects that extends through 2029 that will eliminate the use of once-through cooling and provide modern units that are more reliable, efficient, flexible, and community-friendly than the units they are replacing.

To maintain grid reliability, LADWP's 2015 Ten-Year Transmission Assessment Plan has identified a number of necessary improvements that are needed to avoid potential overloads on key segments of the transmission system. These overload conditions, if encountered, could require load shedding events (intentional power outages) as a means to protect the overall electric system.

The integration of renewable energy into the grid poses major reliability challenges. Because renewable resources like wind and solar produce electricity variably and intermittently (i.e., only when the wind is blowing or when the sun is shining), integration of these resources requires additional supplemental generating units to compensate for significant and often rapid swings in energy production. These swings present operational challenges and must be balanced by controllable generation capable of equally rapid changes of generation in the opposite direction.

In preparation for the state's anticipated 50 percent renewable portfolio standard bill, LADWP commissioned the Maximum Generation Renewable Energy Penetration Study (MGREPS) in 2015 to analyze the impacts and mitigation strategies associated with high Renewable Portfolio Standard (RPS) scenarios in the LADWP System. A consortium of consultants, headed by URS Corporation Americas (URS) with sub-consultant firms DNV GL and Navigant completed the study. The results of this study are detailed in Section 4.3.1 and Appendix J.

Between 2003 and 2005, LADWP experienced a growing number of distribution outages due to, among other things, aging infrastructure (poles, lines, transformers, etc.), deferred maintenance and asset replacement.[1] In response, LADWP established a comprehensive Power Reliability Program (PRP) in 2006 which provided increased funding to address the growing maintenance and replacement backlog. The PRP experienced initial success as the number of outages decreased from 6,323 in 2006 to 4,523 in 2009. Since then, however, funding constraints have prevented any major improvements.

Recognizing the usefulness of the PRP to centralize reliability program planning through the establishment of reliability metrics and indices, and prioritization of expenditures on the distribution system, LADWP initiated a new multi-year Power System Reliability Program (PSRP) in 2014 to expand the scope of the current PRP, which includes the establishment of metrics and indices to help prioritize infrastructure replacement expenditures from all major functions of the Power System, including generation, transmission, distribution, and substations. The PSRP assesses all power system assets affecting reliability in a truly integral manner, and proposes corrective actions designed to minimize future outages. As funding priorities constantly shift, especially from the demands of mandated regulatory programs, competition for the remaining limited pool of resources necessitates an expanded reliability program and planning process.

5.3 Greenhouse Gas Emissions Reduction

This year's 2015 IRP places a strong emphasis on GHG emissions reduction strategies. On June 2, 2014, the U.S. Environmental Protection Agency, under President Obama's Climate Action Plan, proposed a plan to cut carbon pollution from power plants—the Clean Power Plan, which aims at maintaining an affordable, reliable energy system, while cutting pollution and protecting health and the environment. Specifically, the Clean Power Plan proposes state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. In 2015, the City of Los Angeles released it's first-ever Sustainability Plan with a vision to reduce GHG emissions by 45 percent below 1990 levels by 2025, 60 percent below 1990 levels by 2035, and 80 percent below 1990 levels by 2050. In anticipation of the Clean Power Plan and complying with the Sustainability Plan and current GHG state regulations, the 2015 IRP investigates multiple strategies to reduce GHG in a cost effective manner. It is important to note that GHG targets are subject to changing regulations and local priorities, which will significantly impact LADWP's future strategy in pursuing higher renewables, energy efficiency, and future electrification of existing fossil fuel processes.

While LADWP has multiple and concurrent GHG emissions reduction strategies, the primary focus is on early replacement of coal-fired generation. Because coal-fired energy production emits relatively high levels of CO_2, switching to energy efficiency, renewables and other cleaner fuels will significantly lower the overall emission levels. Early coal replacement facilitates LADWP's compliance with Assembly Bill (AB) 32's Cap and Trade program.

[1] To illustrate the age of the distribution system, over 25 percent of the City's 321,780 distribution poles have already exceeded their 60-year life expectancy.

During calendar year 2015, 40 percent of the energy delivered to LADWP customers was generated from two coal-fired generating stations: the Intermountain Power Project (IPP), located in Utah, and the Navajo Generating Station (NGS), located in Arizona. The NGS's operating agreement and land lease expires in December 2019 and IPP's Power Purchase Agreement (PPA) contract is in effect until June 2027. Although these stations provide dependable, low cost base load generation to Los Angeles, they emit about twice as much CO_2 as energy generated from natural gas. Accordingly, this 2015 IRP continues to focus on early coal replacement options as a means to lower LADWP's CO_2 emission levels. Sections 3 and 4 discuss the coal replacement options in detail.

LADWP's CO_2 emissions reduction strategy must comply with the following state regulations:

- Senate Bill (SB) 1368, the California GHG Emissions Performance Standard Act, enacted in 2006, prohibits LADWP and other California utilities from entering into long-term financial commitments for base load generation, unless it complies with the CO_2 emissions performance standard. The CO_2 emissions level must be equal, or below the emissions performance standard of 1,100 lbs per megawatt-hour (MWh) that can be achieved by gas-fired combined cycle units. This standard also applies to existing power plants for any long-term investments or contractual extensions, effectively prohibiting LADWP from continued acceptance of coal-fired generation beyond the current contractual expiration dates for NGS (2019) and IPP (2027).
- Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006, calls for reducing the state's CO_2 emissions to 1990 levels by 2020. The regulations for implementing a GHG emissions Cap and Trade program under AB 32 were finalized and adopted on October 20, 2011 by the California Air Resources Board (CARB). Enforcement and compliance with the trading program began January 1, 2013. LADWP has been granted an administrative allocation of emission allowances that reflects its resource projections through 2020. The long-term goal of AB 32 is to reduce GHG emissions to 80 percent below 1990 levels by 2050.
- Clean Air Act, Section 111(d), the Clean Power Plan establishes a target emissions rate for each state, or the amount of carbon dioxide that could be emitted per megawatt-hour of power produced. The Clean Power Plan is expected to reduce carbon dioxide emissions from power plants 32 percent below 2005 levels by 2030. It provides flexibility, in which States may decide to pursue rate-based or mass-based plans. A rate-based plan would require the power fleet to adhere to an average amount of carbon per unit of power produced. A mass-based plan would cap the total tons of carbon the power sector could emit each year. States may adopt either an "emissions standards plan," which assigns standards to generators, or a "state measures plan," which can include a combination of enforceable emissions limits and additional programs—such as renewable energy and energy efficiency standards. Both types of plans may involve trading programs—whereby generators can purchase compliance credits from entities inside or outside their state that offset carbon emissions, including zero-carbon renewable energy products.

5.4 Increasing Renewable Resources

LADWP's policy for renewables was initiated in the early 2000's, and has guided the adoption of increasing levels of renewable energy, including the milestone achievement of 20 percent renewable energy sales in 2010. Major legislation affecting LADWP's renewable policy include SB 1, SB 32, SB 2 (1X), and SB 350.

Senate Bill 1 (SB 1)

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, including municipalities, implement a Solar Incentive Program by January 1, 2008. The goal of the CSI is to install 3,000 MW of net-metered solar energy systems over 10 years with expenditures not to exceed $3.35 Billion. Expenditures for local publicly owned electric utilities shall not exceed $784 Million. LADWP's cap amount is $313 Million, based on its serving 39.9% of the municipal load in the state.

SB 32

SB 32, signed into law on October 11, 2009, requires LADWP to make a tariff available to eligible renewable electric generation facilities within its service territory, until LADWP meets its 75 MW share of the statewide target. SB 1332 was signed into law on September 27, 2012, updating the requirements of SB 32. SB32/1332 (SB2) renumbered the relevant code section and added a requirement that publicly owned utilities established a Feed-in Tariff (FiT) by July 1, 2013. Through this program, owners or operators of eligible renewable energy systems may sell their energy directly to LADWP. The purchase of SB 32 qualifying energy includes all environmental attributes, capacity rights, and renewable energy credits. This energy is just one of the many renewable energy sources that will apply towards LADWP's 50 percent renewable energy requirement.

SB 2 (1X) and the California Energy Commission (CEC) RPS Enforcement Procedures

On April 12, 2011, Governor Edmund G. Brown signed into law the California Renewable Energy Resources Act (SB 2 (1X)). SB 2 (1X) set new Renewables Portfolio Standard (RPS) procurement targets, new renewable resource eligibility definitions, and new reporting requirements applicable to local Publicly-Owned Electric Utilities (POUs). SB 2 (1X) required each local POU to obtain a minimum of:

- an average of 20 percent renewables between 2011 and 2013.
- 25 percent RPS by 2016;
- and 33 percent RPS by 2020

In December 2014, LADWP amended its RPS Policy and Enforcement Program to comply with the requirements of SB 2 (1X) and the Regulations. However, LADWP's policy continues to include some requirements that are not a part of SB 2 (1X) or the Regulations but were in place prior to enactment of the State legislation.

This year's IRP evaluates 50 percent renewables as a method of reducing GHG; however, there are operational issues associated with higher levels of renewables, which include over-generation, in which energy generated from renewables exceeds demand, and other transmission and distribution reliability challenges. A more detailed discussion of renewable integration is discussed in Section 1.6.2 of this IRP. As the renewable portfolio continues to grow, especially beyond the current target of 33 percent RPS by 2020 and 50 percent RPS by 2030, the integration of increased intermittent power will cause operational challenges that must be addressed to maintain system reliability. LADWP recently approved plans in 2014 to implement 200 to 500 MW of demand response by 2026 and 154 MW of Energy Storage by 2021 as solutions to address the reliability and operational impacts from implementing 33 and 50 percent RPS by 2020 and 2030, respectively. A study titled, "Maximum Distribution Renewable Energy Penetration Study," which has the objective to analyze the impacts and mitigation strategies associated with high levels of local solar on the LADWP distribution system, is currently ongoing and expected to conclude in 2016.

SB 350

SB 350, signed into law on October 7, 2015, requires utilities to procure eligible renewable energy resources of 50 percent by 2030, including the following interim targets:

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

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.

5.5 Once Through Cooling

Once-through cooling (OTC) is the process of drawing water from a river, lake, or ocean, pumping it through a generating station's cooling system, and discharging it back to the original body of water. OTC is a utility regulatory issue, stemming from the Federal Environmental Protection Agency Clean Water Act Section 316(b) and administered locally by the California State Water Resources Control Board (SWRCB).

OTC regulations affect LADWP's three coastal generating stations – Scattergood, Haynes, and Harbor. To comply with OTC regulations, LADWP has chosen the path to repower all generating units, which utilize OTC, with new units that do not utilize OTC. The amount of generation capacity affected by OTC is significant – approximately 2,839 MW of LADWP's total in-basin plant capacity of 3,415 MW. The total expenditures required are also significant, on the order of $2.2 billion. Because of the size and scope of the effort required, the work to comply with OTC regulation is a long-term program, extending through 2029. Figure ES-1 details the timeline of the program target dates. More information regarding OTC is provided in Section 1.6.7.

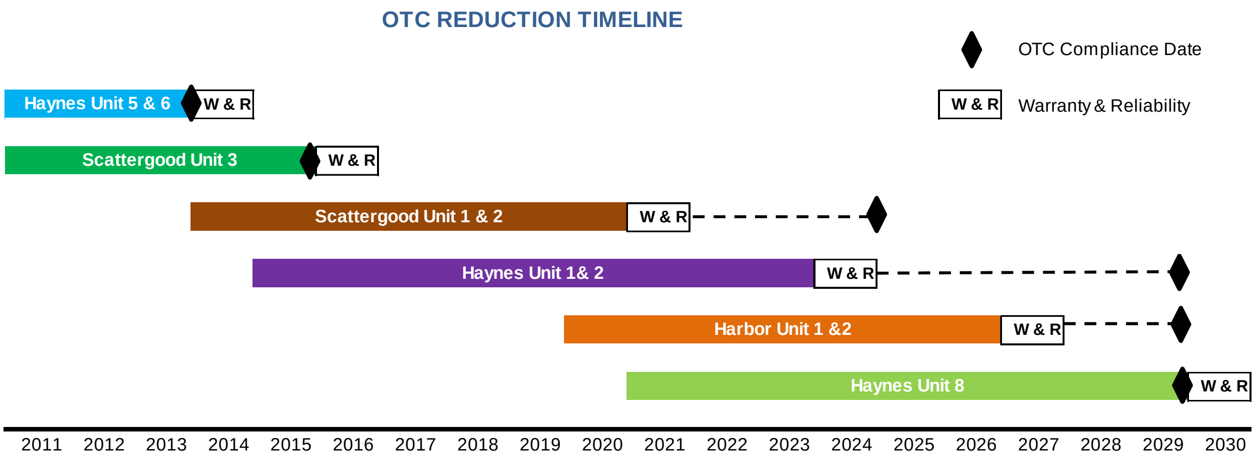


Figure ES-1. Timeline for OTC compliance.

5.6 Staffing and Training the Workforce – Integrated Human Resources Plan

To implement the programs and projects recommended in this IRP, an effective human resources plan is required for the 132 civil service classifications who perform core work related to generation, transmission, and distribution of electricity. The Power System must, therefore, carefully plan and execute human resource solutions to a number of demand side and supply side challenges.

Supply and Demand

The principles of supply and demand that operate in the business world also apply to the long-term development of human resources. The "demand" is the need of the Power System to have a talented workforce available whenever IRP projects and programs require them. The "supply" is the talent pool of human resources that are available to supply this "demand" in a timely manner.

On the demand side, a planning process to identify vacant positions in future operations is needed. These vacant positions are referred to as forecasted workforce "gaps." Currently there is a workforce gap of 353 unfilled positions in the Power System. Current funding is at the level of 4,263 positions with only 3,910 positions actually filled. When the gap is joined by a significant attrition that will occur over the next five years, the Power System will face a large shortfall of workforce availability as shown in Figure ES-2 below.

Adequate Staffing

By 2023 a significant number of the current Power System workforce are expected to retire. The expected level is over 1,200 employees and may exceed 1,700. The loss of 1,200 equals a minimum of 37,400 years of experience and knowledge walking out the door as illustrated in Figure ES-2. The vast exiting of talent, knowledge, and experience places the operations of the Power System at great risk. This exodus of retirees will come at a time when the Power System will be implementing significant changes in operations that utilize new, more efficient and renewable generation methods and advanced smart-grid technologies. These changes demand a larger future workforce with new skills, capabilities, and expertise. Adequate staffing levels must be allocated in order to meet customer expectations for these programs. Since the launch of the IHRP Program, Power System staff has been actively working with the Personnel Department of the City of Los Angeles to ensure critical examinations are administered to meet hiring plans and improve the quality of candidates eligible for hire.

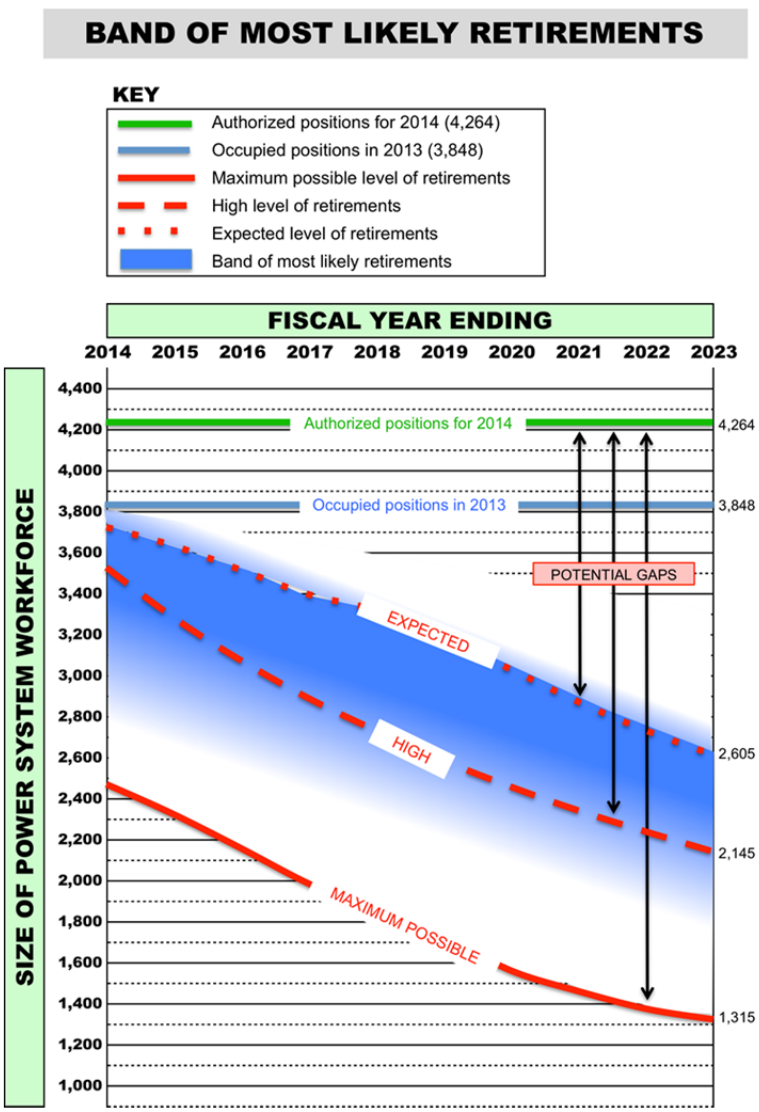


Figure ES-2. The Potential impact of forecasted retirements of Power System work force by 2023.

In 2013, the Power System launched the Integrated Human Resources Plan (IHRP) as a broad staffing solution to address key issues in staffing and training the workforce. Detailed information can be found in Section 1.6.7 and Appendix P.

5.7 Other Challenges

Additional challenges that LADWP must address now and in future years include:

- Managing potential natural gas price volatility
- Incorporating higher levels of Local Solar and Distributed Generation (DG), which will advance renewable resource and local solar objectives, and support the State's promotion for more DG
- A heightened demand for transmission planning to support new and intermittent resources that has introduced greater complexity into the electric system.
- Cyber security regulations
- The relicensing of the Castaic Pumped Storage facility with the Federal Energy Regulatory Commission
- Accounting for the effects of climate change on power generation, operations, and markets
- Acquisition of replacement resources for coal-fired generation
- Promoting electrification of the transportation sector as a strategy to decrease overall GHG emissions and other criteria pollutants in the Los Angeles Basin.

6. Strategic Case Alternatives

The 2015 IRP strategic cases incorporate the latest developments in legislation and regulation, and tactical plans developed by the Power System. This 2015 IRP also includes updated assumptions that have influenced the composition of potential resource portfolios that can fulfill LADWP's goals of environmental stewardship, reliability, and competitive rates. The purpose of the 2015 IRP strategic cases is to balance and optimize all three goals in the best interest of our customers.

One of LADWP's primary goals is to take a leadership position in environmental stewardship and make practical and progressive decisions that will benefit Los Angeles for generations to come. In response to regulations regarding GHG emission, which continue to evolve on the federal and state level, this 2015 IRP analyzes various potential strategies aimed to reduce GHG emissions in the City of Los Angeles to meet long term GHG emission goals. The potential strategies for reducing GHG analyzed in this IRP include:

1. Early Coal Replacement
2. Increase the Renewable Portfolio Standard to 33% by 2020 and to 50% by 2030
3. Advanced Energy Efficiency
4. Increased levels of Local Solar
5. Electrification of the Transportation Sector

Future IRPs may analyze the optimal balance for GHG reduction strategies and provide more in-depth analysis of various combinations of strategies related to integration and cost. Based on input received from the 2014 IRP Advisory Committee meetings, the 2015 IRP considers the following strategic case alternatives:

Early Coal Replacement: The coal cases analyzed in this 2015 IRP considers different replacement dates for the Intermountain Power Project (IPP) – early replacement in 2025 or late replacement in 2027. Both coal cases analyzed reflect the divestiture of Navajo by mid-2016. Although the sale of Navajo was approved in 2015, the sale will close on July 1, 2016 and this is reflected in the IRP cases.

Higher Levels of Renewable Portfolio Standard (RPS): The renewable portfolio standard cases analyzed in this 2015 IRP considers the prior RPS requirement set forth by SB 2 (1X) – a base case 33 percent RPS by 2020 maintained through 2030 as well as several 50 percent by 2030 RPS cases to comply with newly enacted SB 350; the 40 percent RPS by 2030 from the 2014 IRP is now obsolete and has been omitted due to the enactment of SB 350. This IRP provides analysis regarding the amount of over-generation for each case and a separate reliability study was performed to assess the impact of incorporating a 50% RPS into LADWP's Power System. Further discussion is detailed in Section 4.3.1

Advanced Energy Efficiency (EE): The EE cases analyzed in this 2015 IRP considers the Board approved level of 15 percent EE savings by 2020. The base case 10 percent EE savings by 2020 has been superseded and is no longer considered in this IRP.

Higher Levels of Local Solar: The local solar cases in this 2015 IRP considers goals of 800 MW and 1,000 MW of local solar by 2023, dependent on customer participation, technology development, commodity price fluctuations, and policy changes. Higher levels of local solar must be further studied and a study entitled, "Maximum Distribution Renewable Energy Penetration Study (MDREPS)," is underway to determine the maximum amount of solar that can be incorporated reliably into LADWP's Power System. The study will analyze the maximum distribution feeder saturation level to accommodate local solar to avoid issues related to feeder overloads, backward power flows, voltage fluctuations, and islanding. The first phase of this study is expected to be complete in 2016.

Electrification of the Transportation Sector: Recognizing that the electric power generation sector produces considerably less GHG emissions and other criteria pollutants compared to the transportation sector, the 2015 IRP considers electrification of the transportation sector as a strategy to reduce overall GHG while increasing electric sales revenue to support clean energy programs and minimize the associated rate impact; it may also be utilized as a potential solution to absorb higher levels of RPS. Electrification of the transportation sector is the process of converting gasoline and diesel-powered vehicles, light rail, docked shipping vessels and other processes to electric power, and can be promoted through incentives and rebates, similar to Energy Efficiency Programs. The electrification cases in this 2015 IRP considers a base, medium, and high case. The base case is forecasted using the California Energy Commission's 2013 Integrated Energy Policy Report; the medium case is 150% of the base case and high case is 200% of the base case.

The candidate portfolios were modeled and the case results were analyzed and compared against each other to evaluate environmental benefits and cost impacts from different resource alternatives. The analysis includes measurements of power costs, emissions, and fuel usage. High and low scenarios based on fuel prices were also modeled for the coal replacement cases and final recommended case to quantify the risk associated with fuel price volatility. Section 4.3 discusses the modeling results of the updated recommended case.

The assumptions used in the development of all cases have been updated to reflect recent changes in fuel pricing, renewable project cost estimates and renewable resource mix, and energy efficiency goals of 15 percent by 2020.

Section 3 of this IRP provides more information surrounding the development of the cases, including resource adequacy and resource net-shortfall considerations. Table ES-2 provides a detailed description of each strategic case. For comparison purposes, the recommended case from last year's IRP is included in the table.

A more detailed description of the assumptions used in developing these cases can be found in Appendix N.

Table ES-2. CANDIDATE RESOURCE PORTFOLIOS FOR 2015 IRP

COAL REPLACEMENT CASES

		GHG or SB1368 Compliance Date		2030	2010 thru 2020	2010 thru 2035	New Renewables Installed Capacity (MW) 2015 - 2020					New Renewables Installed Capacity (MW) 2015 - 2035				
Case ID	Resource Strategy	Navajo Replacement	IPP Replacement	RPS Target	EE (GWh)	EE (GWh)	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
1 (Base Case)	No Early Coal Divestiture	7/1/2016	6/15/2027	50%	3038	3928	95	0	1088	509	0	293	670	1813	653	799
2	Navajo and IPP Early	7/1/2016	7/1/2025	50%	3038	3928	95	0	1088	509	0	293	670	1813	653	799
2014 Recommended [1]	Navajo and IPP Early Replacement	12/31/2015	6/15/2025	40%	3401	4283	76	70	1059	579	0	216	270	1305	704	723

		2030	2010 thru 2020	2010 thru 2035	New Renewables Installed Capacity (MW) 2015 - 2020					New Renewables Installed Capacity (MW) 2015 - 2035				
Case ID	Resource Strategy	RPS Target	EE (GWh)	EE (GWh)	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
3	Advanced EE, 800 MW Local Solar, Base Electrification	33%	3038	3928	95	0	948	509	0	243	270	1,089	653	152
4	Advanced EE, 800 MW Local Solar, Base Electrification	50%	3038	3928	95	0	1,088	509	0	293	670	1,813	653	533
5	Advanced EE, 800 MW Local Solar, Medium Electrification	50%	3038	3928	95	0	1,088	509	0	293	670	1,813	653	685
6 (Base Case)	Advanced EE, 800 MW Local Solar, High Electrification	50%	3038	3928	95	0	1,088	509	0	293	670	1,813	653	799
7	Advanced EE, 1000 MW Local Solar, Medium Electrification	50%	3038	3928	95	0	1,038	509	0	293	670	1,629	853	799
2015 Recommended [2]	Advanced EE, 800 MW Local Solar, High Electrification	50%	3038	3928	95	0	1088	509	0	293	670	1813	653	799

[1] EE percentages are as follows: By 2020

Advanced EE 14.8% including codes and standards

[2] 2015 recommended case based on the 2015-2020 and 2015-2035 reporting periods for New Renewables Installed Capacity (MW) and 2010 through 2035 for EE (GWh).

7. Evaluation of Strategic Case Options

Key results for each model run were tabulated and compared against each other. Each strategy was compared on average incremental dollars per megawatt hour generation cost and the total million metric tons of CO_2 emissions. The selection of the best case for LADWP customers hinges mainly upon the load forecast, price of fuel, and CO_2 emission levels. All cases, except the 33 percent RPS case that is used for comparison purposes, meet or exceed the mandated RPS percentage targets and resource adequacy standards. The analytics performed for this IRP examined the associated costs of each strategic case.

The key modeling results are summarized below:

7.1 Reliability Considerations

Integrating 50 percent RPS results in significant challenges associated with frequent daily variability, wherein the regulation and load following requirements increases dramatically as solar variable energy penetration increases. The MGREPS study estimates that up to 125 MW/min of additional up-regulation ramping capability could be needed in the 2025-2030 period, compared to a 40 percent RPS scenario. Figure ES-3 below illustrates the “duck curve” that is associated with 50 percent renewables.

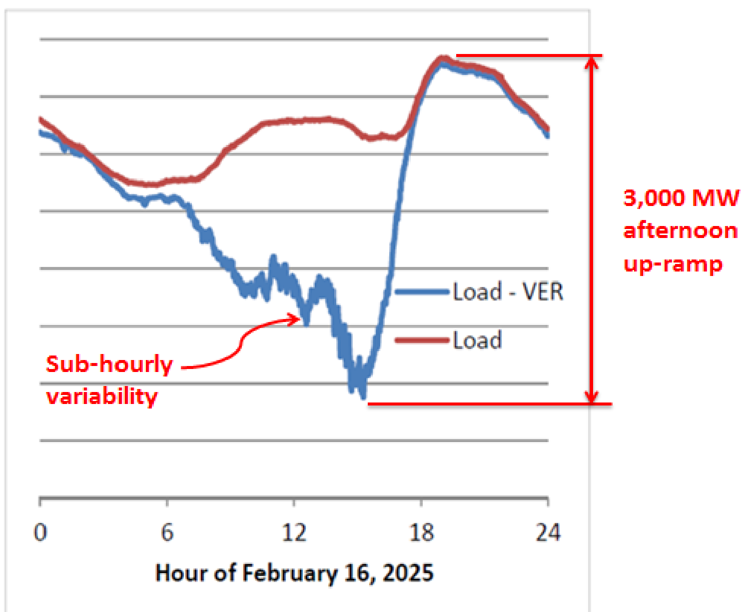


Figure ES-3. Sub-hourly duck curve

The red curve illustrates the load on a simulated day, February 16, 2025, and the blue line illustrates the load that dispatchable resources such as gas-fired and hydro generation must follow after variable energy resources are introduced into the system. The Power System will need to have sufficient flexibility to significantly ramp down its generation as the sun rises and dramatically ramp up its generation as the sun sets to accommodate solar resources. In 2025, it is expected that between 2,500 and 3,500 MW of generation will need to be placed on-line within a

3 to 5 hour period to meet the afternoon peak load as the sun sets. This will result in significant stress on the Power System – thermal units and large hydro will be expected to turn on/off from a minimum loading or cold start, to nearly maximum generation within a few hours on a daily basis. Additional regulation is also required to compensate for the sub-hourly fluctuations of variable energy resources.

A 50 percent RPS high solar scenario indicates upward trends in load-following and regulation requirements over time. The most notable trends are increases in:

- Hourly downward load-following requirements during the morning solar ramp, from almost none in 2014 up to 860 MW in 2030
- Hourly regulation requirements during peak solar hours, from 60 MW up-regulation in 2014 up to 360 MW in 2030
- Hourly upward load-following requirements in the afternoon, from 350 MW in 2014 to 1,400 MW in 2030.

In addition, a 50 percent RPS high solar scenario would result in the following capacity shortfalls in system ramping capability in 2030:

- 47 hours in which 60 minute ramping capability falls short, by a maximum of 480 MW
- 6 hours in which 30 minute ramping capability falls short, by a maximum of 380 MW
- 220 hours in which 10-minute ramping capability falls short, by a maximum of 640 MW.

Although some shortfall can be mitigated through re-dispatch of thermal capacity and large hydro, there is a need for fast-responding resources to compensate for fast fluctuations in solar power output.

In order to meet future load-following and regulation requirement needs, the MGREPS study recommended adopting tools to assess flexibility reserves, adding additional storage for regulation in optimal locations, evaluating the cost effectiveness of fast start gas generation and other flexible resources, evaluating CAISO's Energy Imbalance Market, and upgrades to reduce reliability must run requirements. To remedy the steepness of a future "duck curve," strategies such as improved resource diversification, modifying renewable contracts to alleviate renewable integration issues, and promoting electric vehicle charging during peak hours needs to be evaluated and quantified. The future generator load profile in 2025 is expected to have a steep afternoon up-ramp and there will be cost associated with this ramp—flexible, quick starting gas-fired units will need to be built to compensate for the loss of renewables. Future IRPs will evaluate the true "all-in" cost of renewables including associated integration cost, as well as strategies to reduce the reliability and cost impact of a steep "duck curve."

7.2 CO_2 Emissions Considerations

GHG emissions levels for 2014 were 14.9 million metric tons (MMT), which is 17 percent, below 1990 levels due to the prior elimination of power from the Mojave and Colstrip coal plants, completed repowering of units at Haynes and Valley generating stations with cleaner natural gas-fired replacements, and increased renewable generation from 3% in 2003 to 20% of overall sales on average, over the period 2011-2014. GHG emissions levels for 2014 shows an increase compared to 2013 in which LADWP achieved 22.5 percent GHG emissions reduction below 1990 levels. The reason for the GHG emissions level increase in 2014 is due to scheduled rounding errors, resulting in LADWP receiving excess energy. IPP participants are required to receive the minimum share of energy generated by IPP; however, due to rounding errors, LADWP received excess energy entitlements as the Operating Agent of IPP. The higher than expected generation at IPP resulted in increased coal energy delivered to LADWP, which increased the overall GHG emissions. To prevent this issue from reoccurring in the future, IPP's scheduling system will be transitioning to a true dynamic scheduling system for all participants in 2016, as opposed to static delivery schedules; this will result in more accurate energy delivery.

Using Case 1 (Navajo divestiture in 2016, IPP replacement in 2027) as a baseline, early replacement of IPP in Case 2 results in approximately 5.07 MMT less GHG emission between 2025 and 2027. Over the 2020 to 2035 time period, the Power System is expected to reduce its GHG emissions to approximately 60 percent below 1990 levels. These GHG emission reductions are shown below in and Figure ES-4.

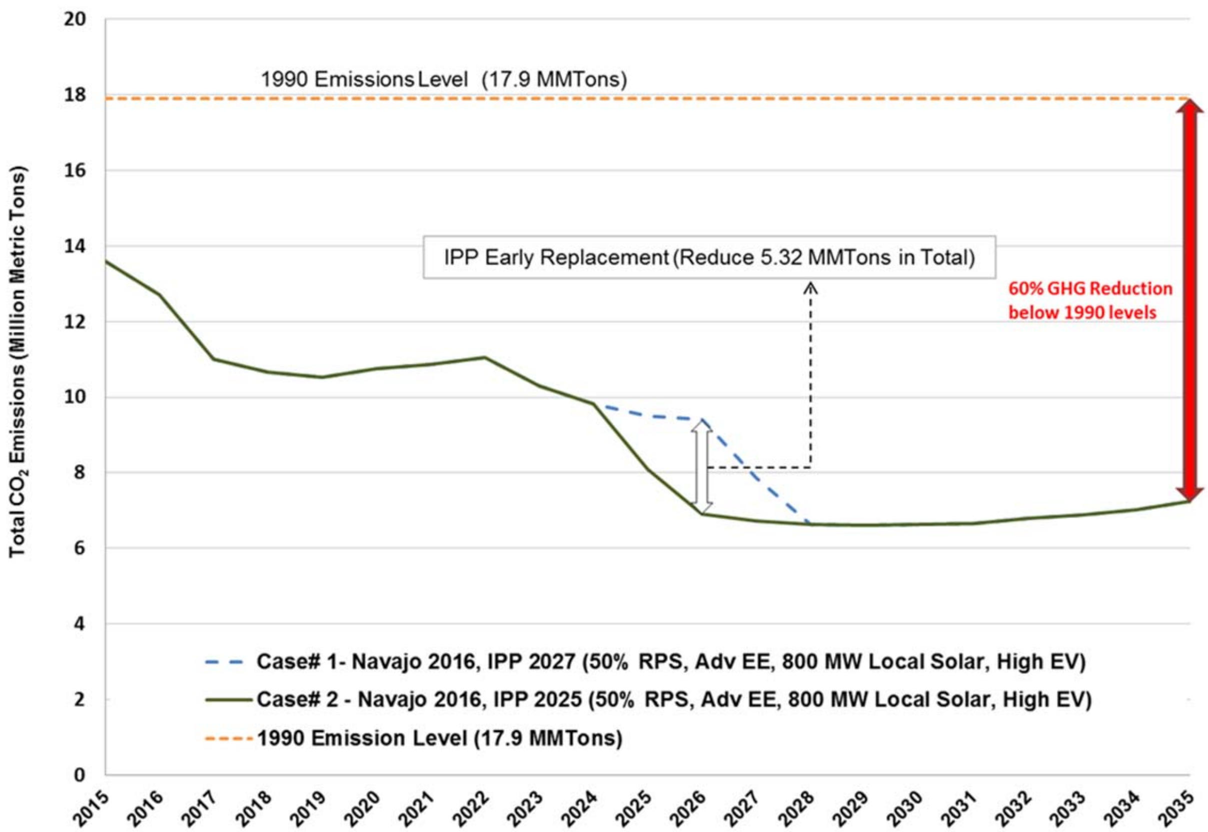


Figure ES-4. GHG emissions comparison by calendar year.

Emissions levels for advanced renewable and energy efficiency cases, Cases 3 through 7, were also evaluated and are shown in Figure ES-5. An increase in local solar from 800 MW to 1,000 MW only slightly reduces the GHG emission level by 0.1 MMT in 2030, as illustrated by Cases 5 and 7 in Figure ES-5. Increasing the renewable portfolio standard level from 33 percent to 50 percent by 2030 would result in an annual GHG emission level reduction of approximately 1.45 MMT in 2030, which is equivalent to removing 278,000 cars from the road. Increase transportation electrification from base to medium and base to high would result in a net annual GHG emission level reduction of approximately 0.64 and 1.28 MMT in 2030, respectively. Although emissions generated by LADWP would increase to supply electricity for transportation, the overall net emissions in the Los Angeles Basin would decrease due to petroleum fuel replacement through transportation electrification. For reference purposes, the CARB emissions allocation for LADWP, as part of the AB 32 Cap and Trade program implemented in 2013, is included in Figure ES-5. The emissions level without contributions from EE and RPS are also shown to provide a baseline to illustrate the significant GHG reductions from investments in clean resources.

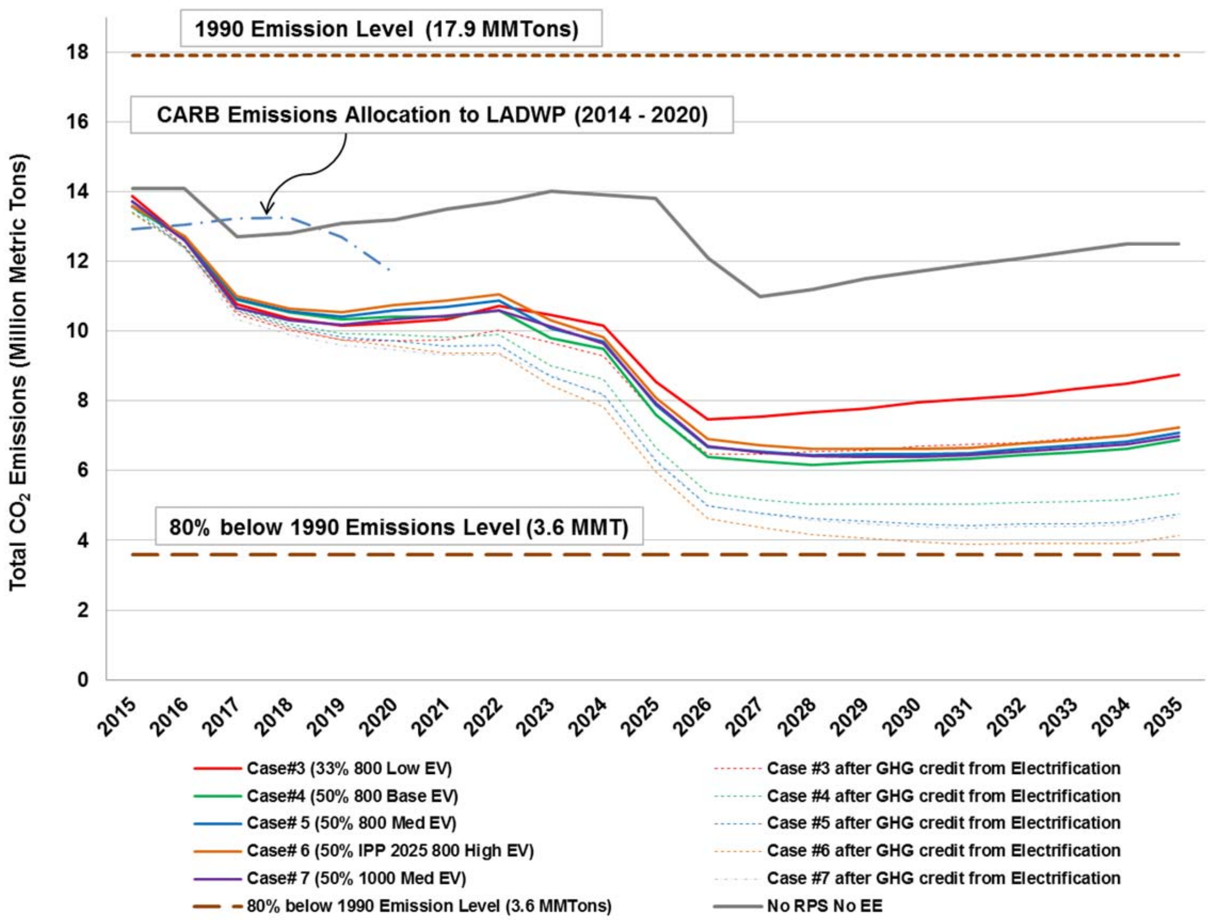


Figure ES-5. GHG emissions comparison for Advanced Renewable and Local Solar cases by calendar year, with and without CO2 savings from Transportation Electrification.

The 2015 IRP continues to investigate the impact of fuel switching/electrification of the transportation sector with higher expected load growth as an opportunity to absorb higher levels of increased renewable energy and reduce GHG emissions. Increased electrification of the transportation sector would provide an opportunity for load shifting and absorbing over-generation from renewable resources by promoting electric vehicle charging during times of over-generation, when increased levels of solar results in the load exceeding demand. In addition, the overall GHG emissions in Los Angeles area would significantly decrease due to higher levels of electrification.

The long term goal of AB 32 is an 80 percent GHG reduction below 1990 levels by 2050. The California Air Resources Board reported in 2012 that the transportation sector accounts for 37 percent of CO2 emissions, whereas In-State Electric Generation accounts for 11 percent. Hypothetically, if LADWP is able to promote electrification of the transportation sector and claim the associated GHG savings credit, LADWP will be one step closer to meeting the AB 32 goal of 80 percent GHG reduction below 1990 levels by 2050, as shown in Figure ES-5. The 50 percent RPS case with high electrification illustrates the greatest reduction in GHG. Consistent with this conjecture, the EPA proposed the Clean Power Plan on June 2, 2014, which allows for flexibility in achieving Statewide GHG emissions intensity levels (lbs/MWh) without prescribing specific measures to achieve those levels, realizing that there are many potential pathways to reducing GHG emissions.

The Integrated Resource Planning process is a continual effort to adjust and refine strategies to achieve an optimal balance between environmental stewardship, reliability, and competitive rates. Future IRPs will include further analysis and evaluate refined strategies for meeting long-term GHG reduction goals. The threshold on the optimal level of RPS and local solar are still to be determined and a combination of strategies will likely be the most reliable and cost-effective approach for achieving long-term GHG reduction goals.

7.3 Total Power System Cost Comparisons

The total Power System cost for each case includes bulk power costs, depreciation costs related to transmission, distribution, and generation, bond debt-service, and city transfer costs[2]. These costs assume full funding of the Power System programs including the Power System Reliability Program and Energy Efficiency programs among others. Total annual Power System costs are shown in Figure ES-6 and reflect the current Rate Action expected to be approved in 2016 to ensure that the longer term IRP recommendations can be implemented. The costs shown in Figure ES-6 does not attempt to represent a thorough analysis of Power System finances, but they do illustrate the general trend of Power System nominal costs relative to the two coal and five advanced renewable and energy efficiency cases analyzed. Nominal value is the economic value expressed in future monetary value and accounts for inflation.

Note:
Unless otherwise stated, forecasted costs in all charts in this IRP are in "nominal" dollars, or the cost reflected in that future year and not in today's "real" dollars.

[2] The city transfer payment is 8% of the previous year's gross operating revenue.

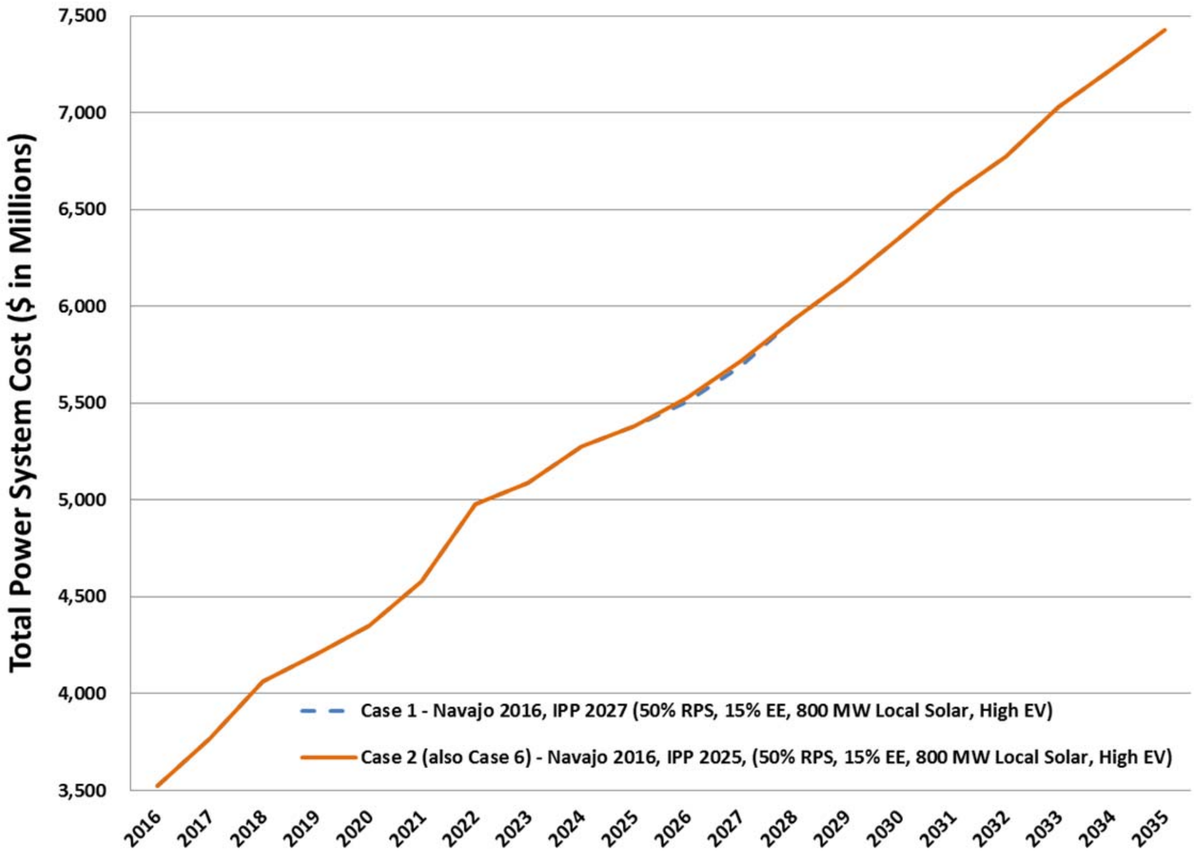


Figure ES-6. Comparison of annual Power System costs over the next 20 fiscal years

The cost differences between the cases are highlighted in Table ES-3, which presents the incremental costs of the two coal cases and the five advanced renewable and energy efficiency cases. In 2015, LADWP sold its share in Navajo to Salt River Project with the sale closing on July 1, 2016. As a result, this IRP and future IRPs incorporates early divestment of Navajo in 2016 for all cases. For the coal cases, the values listed under the Case 2 columns represent the incremental revenue requirement between Cases 1 and 2 for the period between fiscal year ending 2026 and 2027—the cost of early replacement of IPP in 2025. The two coal cases evaluated include the same levels of 50 percent renewable energy by 2030, 15 percent energy efficiency by 2020, 800 MW of local solar by 2023, and a high scenario of transportation electrification. The main drivers of the increased cost between the cases are associated with coal replacement, Renewable Portfolio Standard, energy efficiency, OTC repowering, fuel commodity prices, and the Power System Reliability Program.

All advanced renewable and energy efficiency cases assume Navajo divestment in 2016 and IPP replaced in 2025. The values shown for Cases 3 through 7 represent each case's incremental revenue requirement when compared to Case 6 over the time period 2015 through 2035.

TABLE ES-3 INCREMENTAL NOMINAL COST COMPARISONS BETWEEN CASES

Coal Case Summary

		Early IPP Replacement
	Case 1 (Baseline)	Case 2 (2026-2027)
Case Description	Navajo 2016, IPP 2027, Adv EE	Navajo 2016, IPP 2025, Adv EE
Total Incremental Revenue $M	$0	$49
Average Incremental Revenue ($M/yr)	$0	$25

RPS Case Summary

	Case 3 (Baseline) *	Case 4	Case 5	Case 6 (same as Case 2)	Case 7
Case Description	33% RPS, 800 MW, Base EV	50% RPS, 800 MW, Base EV	50% RPS, 800 MW, Med EV	50% RPS, 800 MW, High EV	50% RPS, 1000 MW, Med EV
Total Incremental Revenue $M	$0	$2,612	$3,591	$4,300	$3,963
Average Incremental Revenue ($M/yr)	$0	$137	$189	$226	$209

The incremental cost of GHG reduction through early IPP replacement has an incremental cost of $9.66 to remove one metric ton of GHG removed. This cost is very reasonable considering the environmental benefits achieved from early coal replacement and is lower than the allowance costs from the Cap and Trade Program. Early coal replacement investments are recommended as a strategy to meet long-term GHG emissions reduction goals.

The advanced renewable and energy efficiency cases considers the cost associated with over-generation. The incremental cost to remove one metric ton of GHG through implementing 50 percent RPS ranges from $150 to $180 per metric ton, whereas the cost of GHG reduction through a high scenario of transportation electrification ranges from $30 to $40 per metric ton, considering only utility incentive costs; the GHG removal cost of 50 percent RPS is almost five times more expensive than that of transportation electrification. Transportation electrification is a cost effective strategy that can assist in reducing overall GHG emissions, depending on customer participation and regulatory relief for promoting transportation electrification. Although the cost of 50 percent renewables is significantly higher than coal replacement, it is mandated by state law. The GHG reduction costs are purely economic estimates and do not fully consider all of cost ramifications from increased levels of regulating and load following reserves associated with increased renewables.

An alternative strategy to reduce overall GHG levels in the City of Los Angeles, assuming LADWP can obtain credit for these reductions, is through electrification of the transportation sector. The combination of strategies, including early coal replacement, energy efficiency, increased renewables and local solar, and electrification of the transportation sector provides the optimal solution for meeting long-term environmental objectives, while providing reliable electric service in a cost effective manner.

In 2015, a reliability analysis was conducted on LADWP's Power System to analyze the impacts of 50 percent renewables by 2030 and the study concluded that by 2030, LADWP is likely to experience operational challenges, over-generation issues, and resource shortfalls in system ramping capability. Future IRPs will address these challenges in detail as well as further evaluate mitigation solutions that include fast-start gas generation, two-way demand response, smart electric vehicle charging, energy storage, and weather forecasting tools.

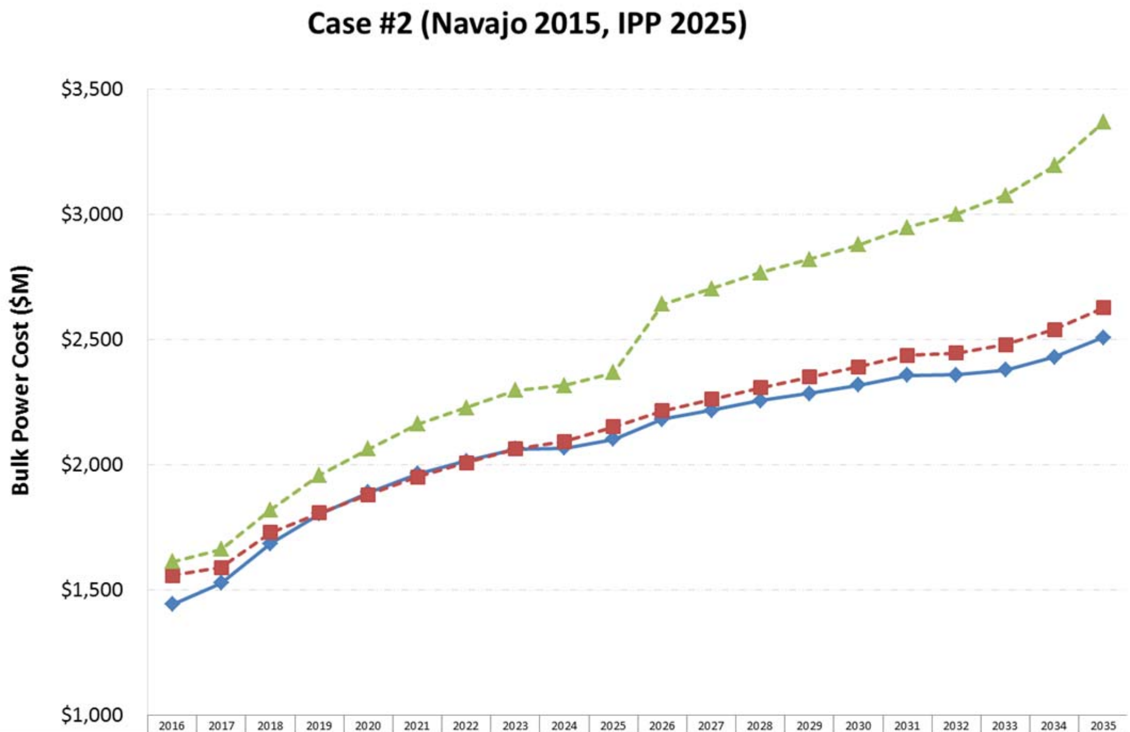
7.4 Sensitivity Analyses

An analysis of the effects of fuel price volatility was performed for the early coal replacement case and is shown in Figure ES-7. With the early divestiture of Navajo by July 1, 2016 and the early replacement of IPP coal by July 1, 2025, increased bulk power costs are expected with the replacement of each of these resources.

Elimination of coal involves the switch to energy efficiency, renewables, and more natural gas generation, which has higher fuel price volatility compared to coal. The resulting decrease in fuel diversity along with the higher volatility of natural gas will increase the risk of fuel cost changes in the future, warranting careful evaluation when comparing the different case scenarios.

Bulk power cost projections shown in Figure ES-7 include fuel, renewable and other purchase power costs in addition to coal replacement costs. After applying high and low fuel prices to these bulk power costs, the replacement of these resources may potentially result in large cost increases if fuel prices remain at higher than expected levels. Conversely, lower than expected fuel prices may have the opposite effect on bulk power costs.

To help manage natural gas fuel price volatility, LADWP employs financial hedges for up to ten years, and physical hedges for up to five years. On March 19, 2014, LADWP finalized a revised hedging strategy with assistance from a third-party consultant. The revised strategy hedges up to 50 percent of the gas supply for the current fiscal year and following fiscal year with declining percentages of 10 percent each year going forward until a maximum hedged amount of at least 50 percent is reached. This approach integrates LADWP's natural gas hedging program into the overall portfolio optimization strategy to satisfy LADWP's risk tolerance.



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Case# 6 (50% 800 HighEV (Low))	$1,442	$1,528	$1,686	$1,804	$1,890	$1,963	$2,016	$2,064	$2,068	$2,102	$2,182	$2,218	$2,257	$2,285	$2,319	$2,358	$2,359	$2,380	$2,431	$2,508
Case# 6 (50% 800 HighEV (Expected))	$1,558	$1,590	$1,729	$1,807	$1,880	$1,951	$2,009	$2,064	$2,094	$2,153	$2,216	$2,262	$2,308	$2,351	$2,391	$2,438	$2,448	$2,481	$2,540	$2,627
Case# 6 (50% 800 HighEV (High))	$1,612	$1,662	$1,820	$1,958	$2,063	$2,162	$2,229	$2,298	$2,317	$2,369	$2,641	$2,704	$2,768	$2,821	$2,879	$2,949	$3,002	$3,076	$3,196	$3,370

Figure ES-7. Bulk power cost comparison - high, low, and expected fuel prices assuming 50 percent RPS by 2030.

To provide reliable power to support intermittent renewables and our customer's energy needs, a significant portion of the coal resources will be replaced with natural gas resources, which results in a range of fuel price uncertainty in total bulk power cost by 2026. Increased risk exposure from high fuel costs may translate into higher customer electric rates. Today, coal costs represent approximately 50 percent of overall fuel expenditures and should average 45 percent annually between 2015 and 2025. Coal expenditures will gradually drop after 2023 before reaching zero percent in 2025 when IPP coal is replaced, and future fuel price increases will be based solely on natural gas and nuclear fuel sources. Higher renewable portfolio cases will reduce the volatility of fuel expenditures, which will reduce the range between the high and low bulk power cost estimates.

7.5 Total Power System Rate Impact Comparisons

Figures ES-8 and ES-9 below illustrates the estimated rate impact for the various IRP cases analyzed. Case 4 through 7 includes a 50 percent RPS, including integration costs, and each have a higher rate impact when compared to Case 3 with 33 percent RPS. Case 6 considers a high scenario of transportation electrification, which results in an overall lower rate impact compared to cases 4 and 5. Case 7 has an overall higher rate impact compared to Case 5 due to an additional 200 MW of local solar, totaling 1,000 MW. The recommended case provides the best case scenario to balance superior reliability, environmental stewardship, and competitive rates.

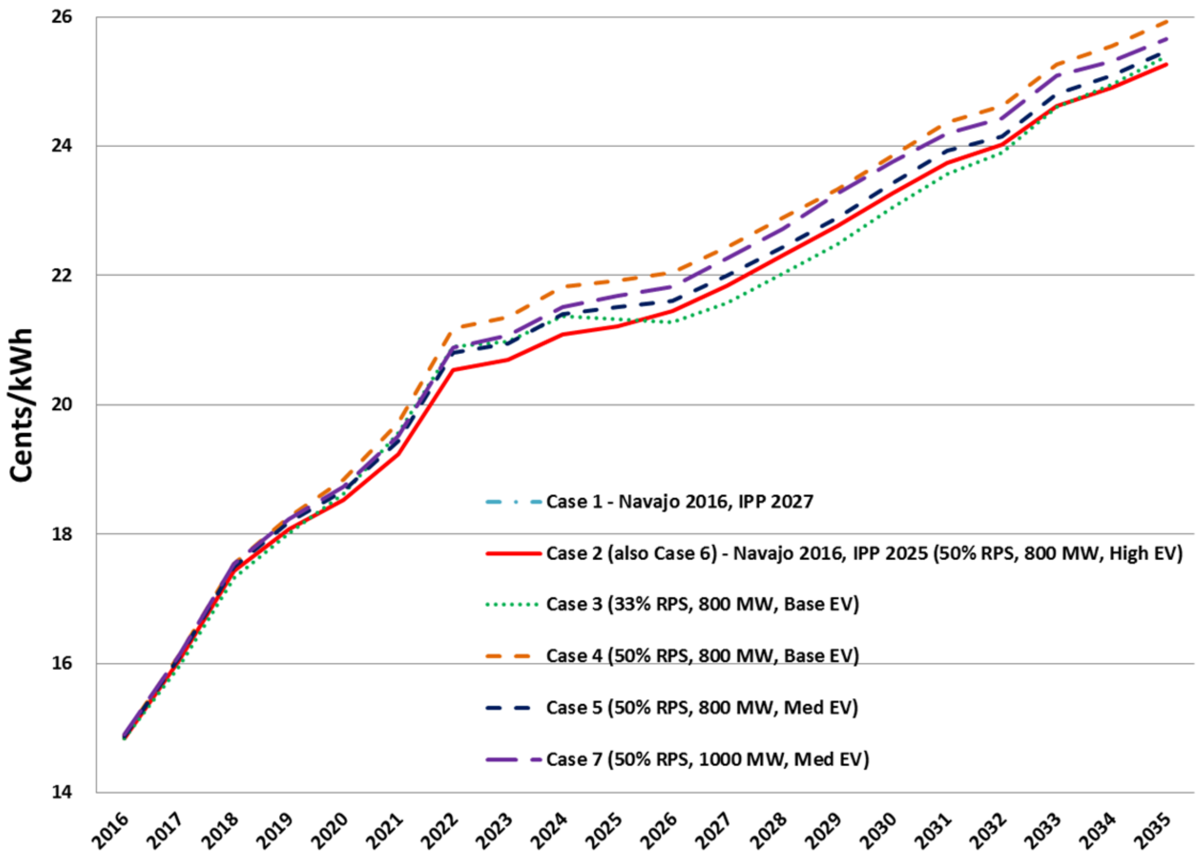


Figure ES-8. Comparison of annual Power System rate impact over the next 20 fiscal years

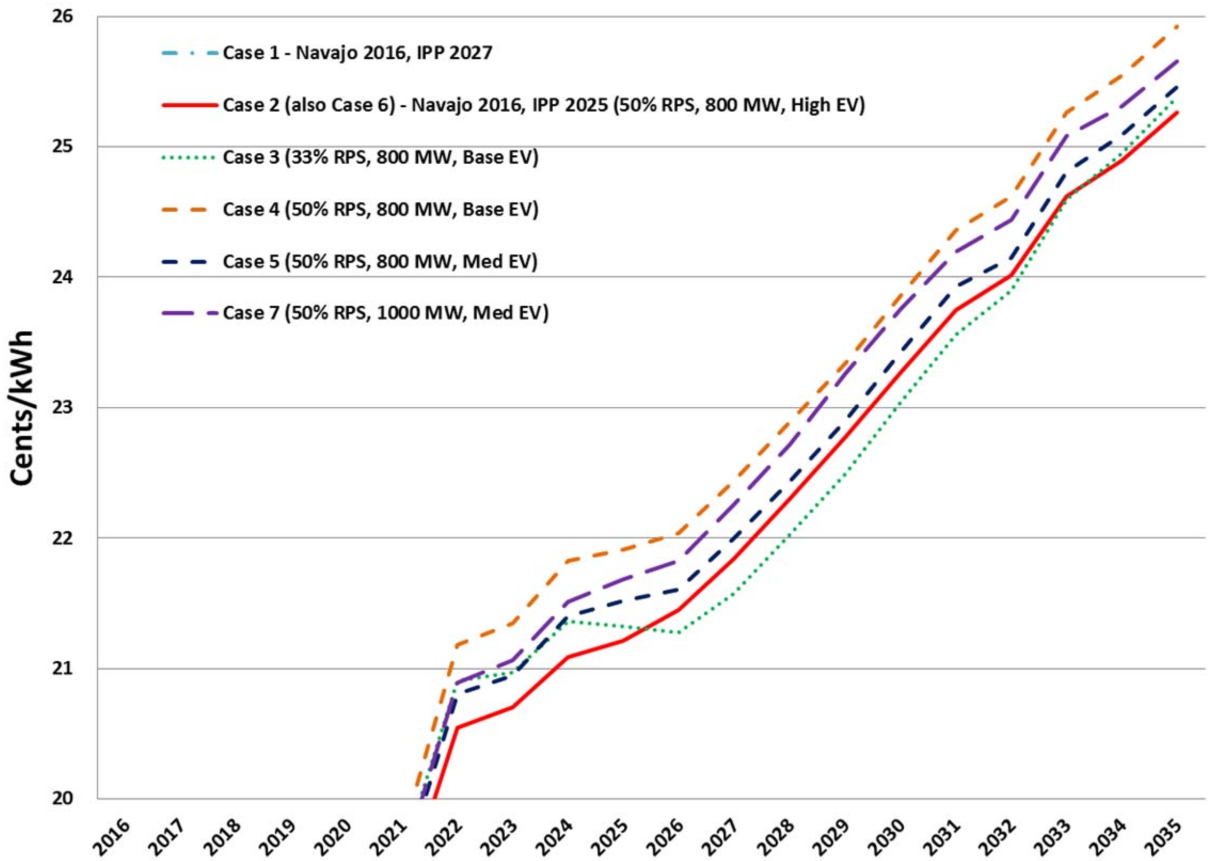


Figure ES-9. Comparison of annual Power System rate impact over the next 20 fiscal years (Zoomed-In)

8. Recommendations

8.1 Recommended Strategic Case

Achieving the goals of reliability and environmental stewardship, while maintaining competitive rates, requires that costs be closely managed. The Recommended Strategic Case is Case 6, which incorporates early Navajo coal divestiture in 2016, early IPP coal replacement in 2025, a 33 percent renewable portfolio standard (RPS) by 2020 and expanded 50 percent RPS by 2030 including a goal of 800 MW local solar by 2023, advanced energy efficiency of 15 percent, and additional program incentives to support high electrification of the transportation sector. Given the available information and assumptions at this time, the Recommended Strategic Case provides the optimal balance between achieving the goals of reliability and environmental stewardship, while maintaining competitive rates.

Early coal replacement strategy has been the primary focus of LADWP's previous IRPs and continues to be a primary strategy in this 2015 IRP as an approach for reducing GHG emissions, while maintaining superior reliability and competitive rates. Early coal replacement remains one of the lowest cost solutions available to reduce GHG emissions over the long-term. The environmental benefits of reducing GHG emissions by 5.07 MMT are clearly present with the early replacement of IPP.

As early coal replacement strategies progress, the IRP further investigates other potential strategies to continue reducing GHG emissions to meet long term GHG emissions goals. The Recommended Strategic Case includes a renewable portfolio standard level of 50 percent by 2030. When compared to 50 percent renewable portfolio standard levels by 2030 with base and medium electrification, the total additional cost of the Recommended Strategic Case with high electrification appears to be more cost effective in light of the benefits in GHG savings. The cost of high electrification is offset by increased electric sales. Therefore, to remain a cost effective strategy, balancing the recommended goal of 50 percent RPS by 2030 and 800 MW of local solar by 2023 with a high level of customer participation in the electrification program, equivalent to 2,344 GWh of added sales by 2030, would be beneficial.

In term of cost effectiveness, electrification of the transportation sector is one of the lowest cost solutions to provide the greatest GHG reduction along with the least amount of investment.

Concerning GHG reduction, Case 3 appears to be unable to meet long term greenhouse emissions goals, whereas Cases 4 through 7 are on track to meet these goals. Next year's IRP will include a public outreach process with the objective of refining the combination of GHG reductions strategies to ensure reliability, environmental stewardship, and competitive rates.

The 2015 IRP recommended case includes a goal of 800 MW local solar, comprising 450 MW of local solar FiT, 310 MW of customer net-metered solar, and 40 MW of Community Solar by 2030. The customer net metered solar projection of 310 MW by 2020 was based on the 2014 peak demand of 6,341 MW. This year, LADWP reevaluated the customer net metered projection and has determined that a long term cap of 5 percent should be based on a non-coincident peak demand, which is 9,300 MW; this would result in a forecasted maximum of approximately

465 MW overall for the customer net metered solar program and will be incorporated into the modeling for next year's 2016 IRP. A 800 MW local solar program by 2023 will provide flexibility for LADWP to learn and grow based on experience gained from the program, and potentially further expand the local solar program up to 1,200 MW by 2029. The current recommendation of 800 MW of local solar by 2023 goal would allow for 50 MW of FiT installations per year, providing optimal, cost effective deployment and administration of the program. The additional cost to customers appears to be reasonable in light of the benefits of job growth and support of the local economy from adopting the higher levels of local solar.

The Recommended Strategic Case incorporates an advanced level of energy efficiency, which reaches 15 percent energy efficiency savings by 2020. An Energy Efficiency Potential Study was performed in fiscal year 2013-2014, which determined that 15 percent energy efficiency by 2020 is attainable in a cost-effective manner below the avoided cost of generation.

The Recommended Strategic Case includes a high scenario of fuel switching/electrification of the transportation sector as a strategy to absorb potential over-generation during peak load, provide increased sales, and decrease GHG by approximately 64 percent below 1990 levels by the year 2030, or 78 percent after including the transportation sector emissions savings benefits from fuel switching/electrification in the Los Angeles basin.

The 2015 IRP recommended case is the same as the 2014 IRP recommended case with the exception of an updated 50 percent renewable portfolio standard as mandated by state legislation. This 2015 IRP Recommended Strategic Case presents a reasonable approach for achieving environmental GHG reduction goals while promoting job growth in the local economy, and limiting potential exposure to possible fuel price volatility to within manageable limits without excessive costs to our customers. Although this 2015 IRP concludes that Case 6 with 800 MW of Local Solar is the optimal solution for balancing environmental stewardship, superior reliability, and competitive rates, future IRPs will continue to adjust and refine the recommended case as LADWP progresses in studying the implication of its strategies and as technology improves.

Table ES-4. 2015 IRP RECOMMENDED CASE

	2030	SB 1368 Compliance Date		New Renewables Installed (MW) 2015-2020				New Renewables Installed (MW) 2015-2035				
Case ID	RPS Target	Navajo	IPP	Geo/ Biomass	Wind	Non-DG Solar	Dist. Solar	Geo/ Biomass	Wind	Non-DG Solar	Dist. Solar[2]	Generic
Case 6 w/ 800 MW Local Solar and high EV	50%[1]	7/1/2016	7/1/2025	95	0	1,088	509	293	670	1,813	653	799

[1]33% RPS by 2020
[2]Incremental to current 100 MW installed

Figure ES-10 illustrates the changing generation resource percentages for 2010, 2020, and 2030, based on the Recommended Case. Because energy efficiency forecasts are forward-looking, the savings of 1,256 GWh or 5.5 percent of sales, which was implemented between 2000 and 2010, are embedded into the load forecast and are not included as part of the generation resource mix shown below.

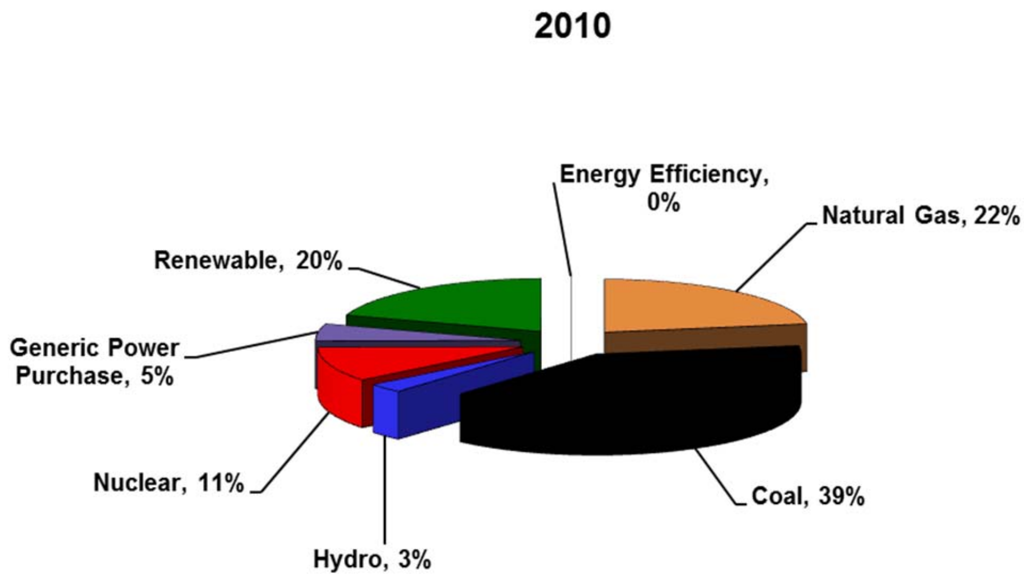
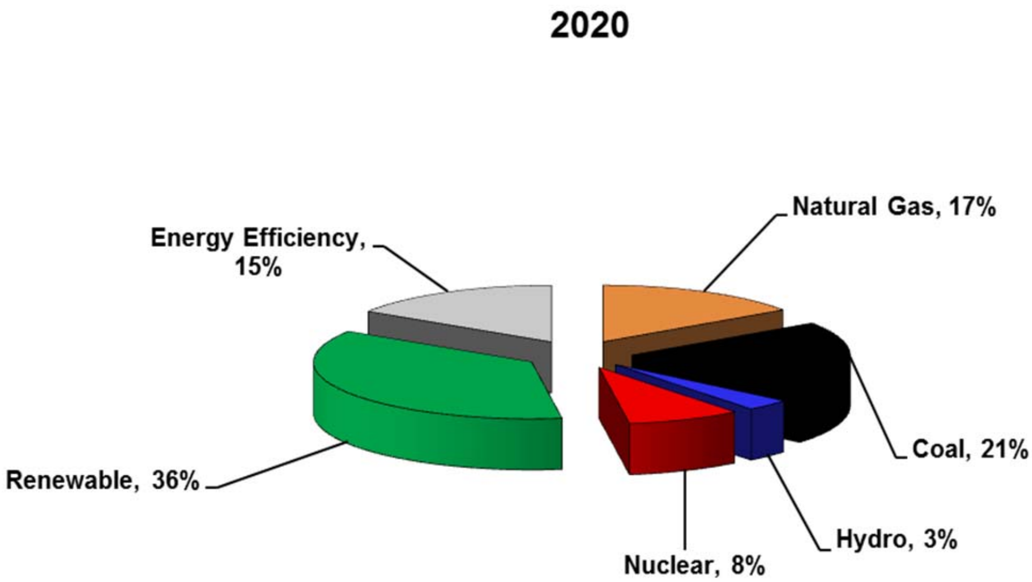


Figure ES-10. Recommended case generation resource percentages for 2010, 2020, and 2030.



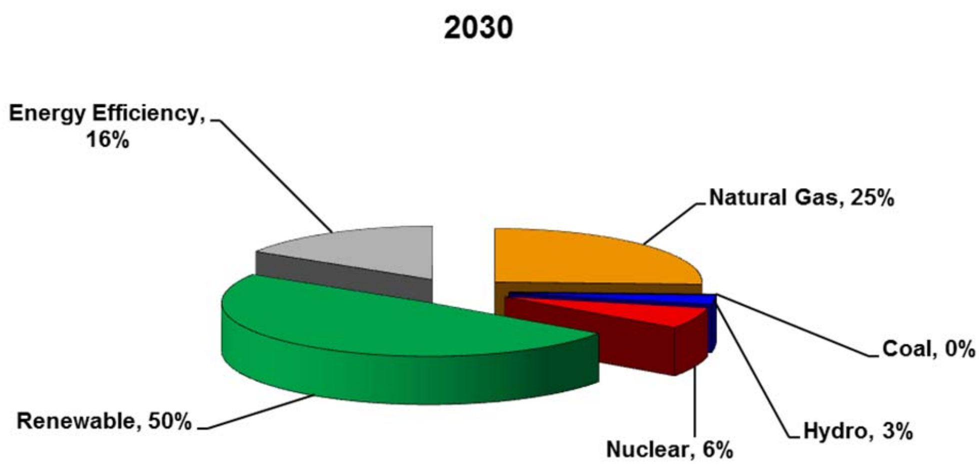


Figure ES-10. Recommended case generation resource percentages for 2010, 2020, and 2030 (continued)

Figure ES-11 shows the breakdown of renewable generation by technology, and Figure ES-12 illustrates the dependable capacity mix for the recommended case.

Note: Chart is subject to change due to technology development, commodity price fluctuations, and policy changes

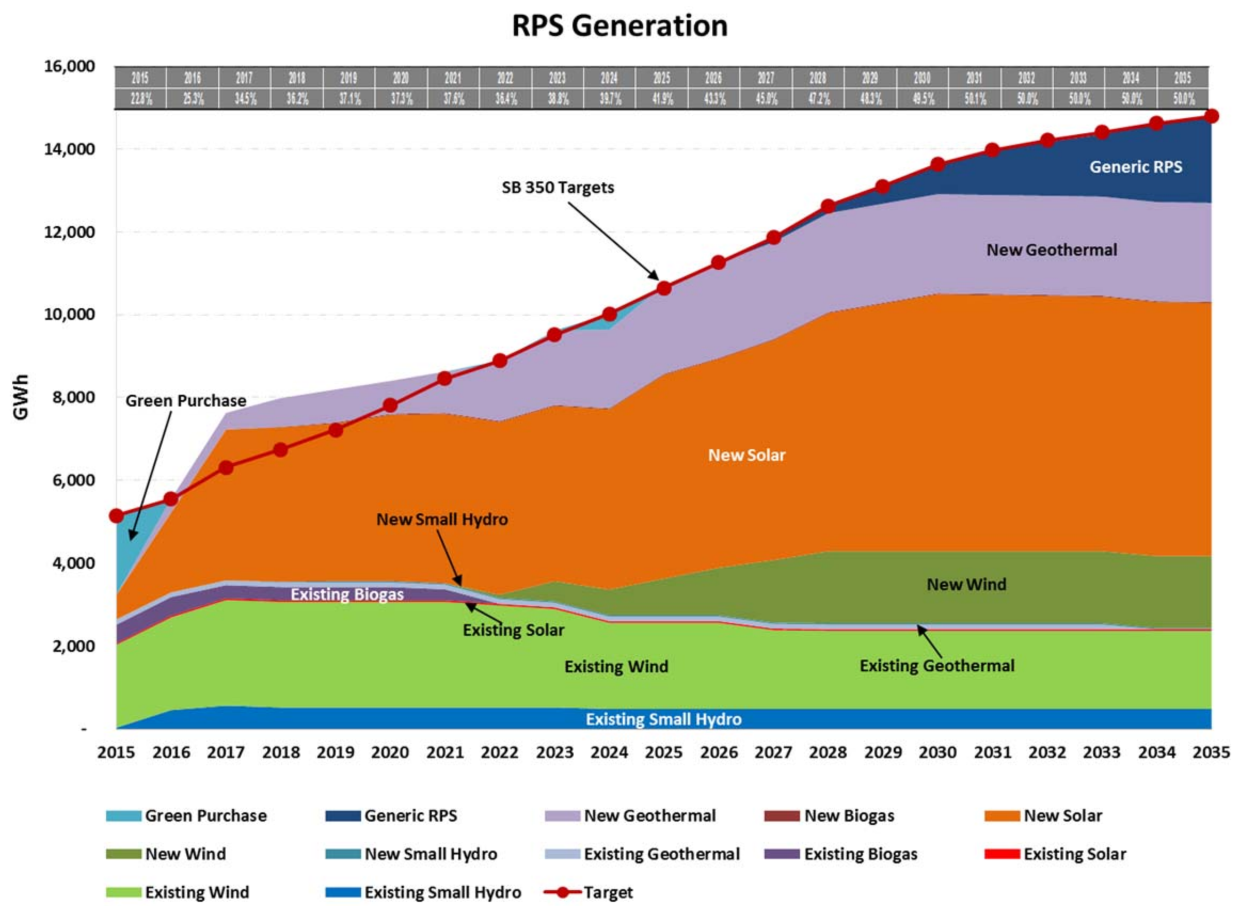


Figure ES-11. Recommended case renewable generation forecast by technology.

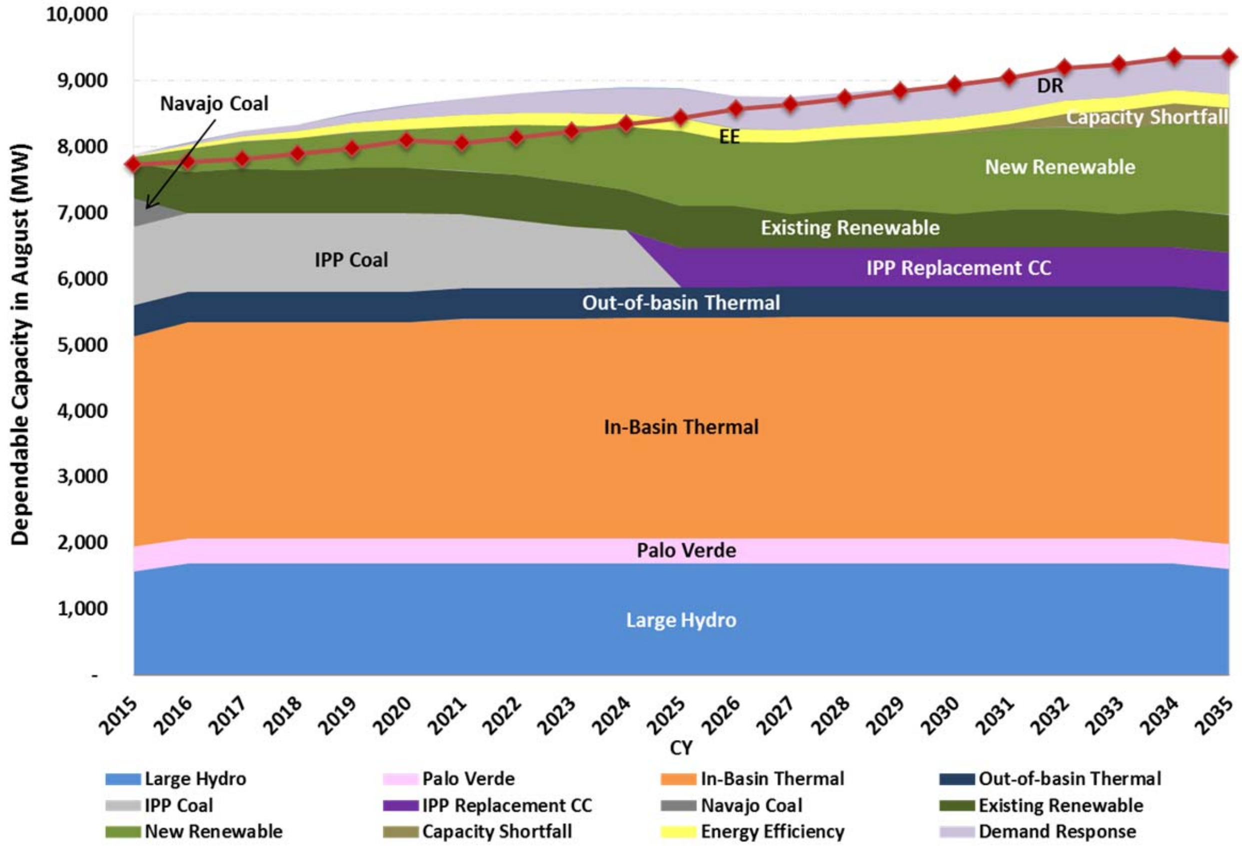


Figure ES-12. Dependable capacity profile, Recommended Case

Compared to the 2014 IRP, which targets 40 percent RPS by 2030, the 2015 IRP recommended case estimates a decreased capacity shortfall over the next 20 years due to new renewable projects that have been planned to meet the 50 percent RPS target by 2030 as mandated by SB 350. Because the analysis and conclusions are dependent on a number of assumptions, LADWP will constantly refresh its analysis as new IRPs are developed in future years.

8.2 Recommended Near Term Actions

Based on the strategic requirements presented earlier and projected resource procurement needs, the following actions are recommended to be taken in the near-term:

1. Place in-service new generation units at the Scattergood Generating Station, and pre-development plans for Haynes and Harbor Generating Stations to meet OTC goals.
2. Continue to investigate the technical and contractual options for coal-fired generation at IPP to retire two years earlier than required by SB 1368.

3. Continue the implementation of existing energy efficiency efforts to reach 15 percent energy efficiency savings by 2020. Perform a new energy efficiency potential study every three years.
4. Continue the implementation of the Power System Reliability Program (PSRP) to replace aging infrastructure components. The PSRP include periodic assessments of the program's effectiveness and identifies modifications to provide continuous improvement and to serve as the backbone for transportation electrification and integration of renewables.
5. Continue the implementation of the Integrated Human Resources Plan by creating a demand forecast of staffing needs, establishing measurable indicators using the five steps of the critical path, and make critical path improvements that will improve job classification, recruitment, selection, training, and placement.
6. Implement recommended electric system upgrades contained in the 2015 Ten-Year Transmission Assessment Plan.
7. Implement a Demand Response Program based on the Demand Response Strategic Implementation Plan, which will reach 200 to 500 MW of new peak load reduction capability by 2026, subject to cost studies.
8. Implement renewable biogas, solar, and wind resources to ensure increasing levels of renewable procurement in accordance with SB 2 (1X) and SB 350 by increasing renewable levels to 33 percent by 2020 and 50 percent by 2030.
9. Conduct further analysis based on the recommendations of the Maximum Generation Renewable Energy Penetration Study by investigating a portfolio of variable energy resources.
10. Develop and incorporate strategies to:
    a. Fully utilize existing transmission assets;
    b. Preserve existing brown field sites to be repurposed for renewable or natural gas generation;
    c. Incorporate the concept of O&M cluster zones[3] to maximize operational efficiencies;
    d. Assess and develop necessary transmission facilities to deliver electricity generated from new facilities.
11. Implement a renewable energy feed-in tariff program to encourage 150 MW of renewable generation resources to be developed by 2016 and to expand the feed-in tariff program to reach 450 MW by 2023.
12. Promote high levels of electrification in the transportation sector as a strategy to decrease overall GHG emissions in the City of Los Angeles. A high level of electrification is expected to provide fuel switching for approximately 580,000 vehicles by 2030, reduce overall GHG emissions in Los Angeles by 2.6 million metric tons by 2030 compared to zero electrification, and increase load growth by 2,344 GWh by 2030.
13. Continue to refine and optimize strategic cases with the goal of balancing environmental stewardship, superior reliability, and competitive rates.

[3] Clustering renewable projects in relative proximity will decrease O&M expenditures due to economies of scales and personnel efficiencies. This would need to be balanced with the need for geographic diversity.

14. Encourage the development of 150 MW incremental, for a total of 310 MW of customer net-metered solar projects to be installed before 2023.
15. Develop up to 40 MW of solar capacity with a cost effective combination of solar installed on existing city owned properties and large scale Power Purchase Agreements before 2020.
16. Implement recommendations from the Fuel Hedging Plan finalized in 2014 to limit LADWP's exposure to volatile natural gas prices.
17. Investigate the feasibility and implement 24 MW and 154 MW of energy storage systems by 2016 and 2021, respectively, per AB 2514.
18. Refine and implement a Smart Grid strategy that can assist in the procurement and development of advanced technologies to support areas such as: weather forecasting/ energy scheduling, customer kWh metering, high speed communications and information systems, and energy storage systems. Deployment of these technologies will increase operational efficiency, help reduce system losses, improve outage response times, increase utilization of predictive/proactive maintenance techniques for improved grid reliability, enable better management, and lower cost of the Power System.

8.3 Rate Contributions Breakdown

Figure ES-13 illustrates the fiscal year breakdown for the Recommended Case comprising rate contributions from power system reliability program, energy efficiency, renewable energy, coal replacement, OTC repowering, electrification, and fuel costs between 2015 and 2035. These individual contributions represent incremental adders to the rates. The Power System Reliability Program (PSRP) includes capital and O&M expenditures to replace over age distribution, transmission, substation, and generation components that have exceeded their life expectancy, and ensure levels of funding to reduce the backlog of “fix-it” tickets which are temporary repairs that need to be corrected.

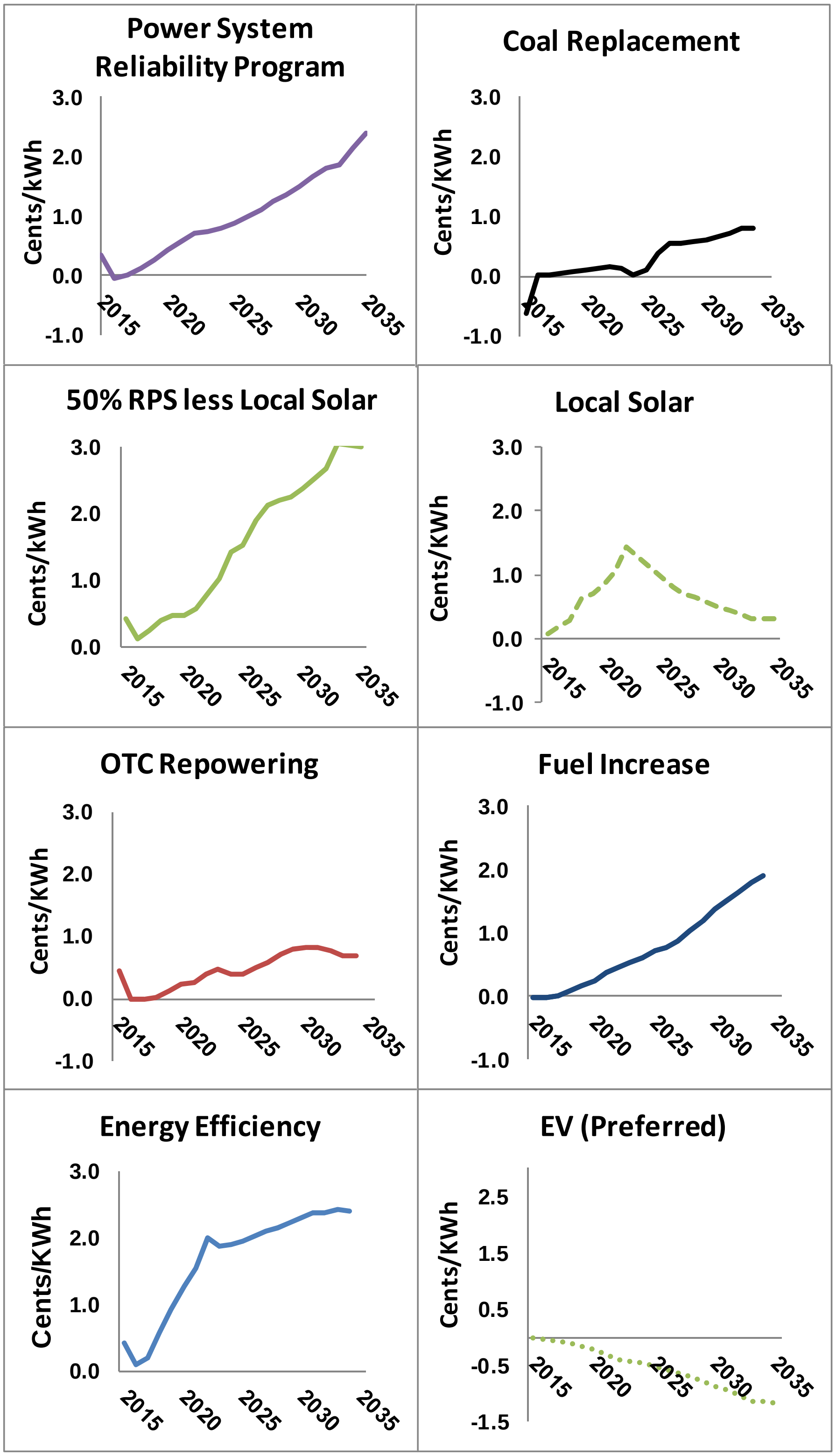


Figure ES-13. Retail electric rate contributions breakdown, based on the 2015-16 budget forecast (Recommended Case).

Figure ES-14 and ES-15 shows the total retail rate impact after combining all of the program rate components. The time period 2015 through 2020 reflects the current Rate Action. One can draw the conclusion that rising fuel costs and complying with various regulatory requirements are the primary drivers of the growth in rates.

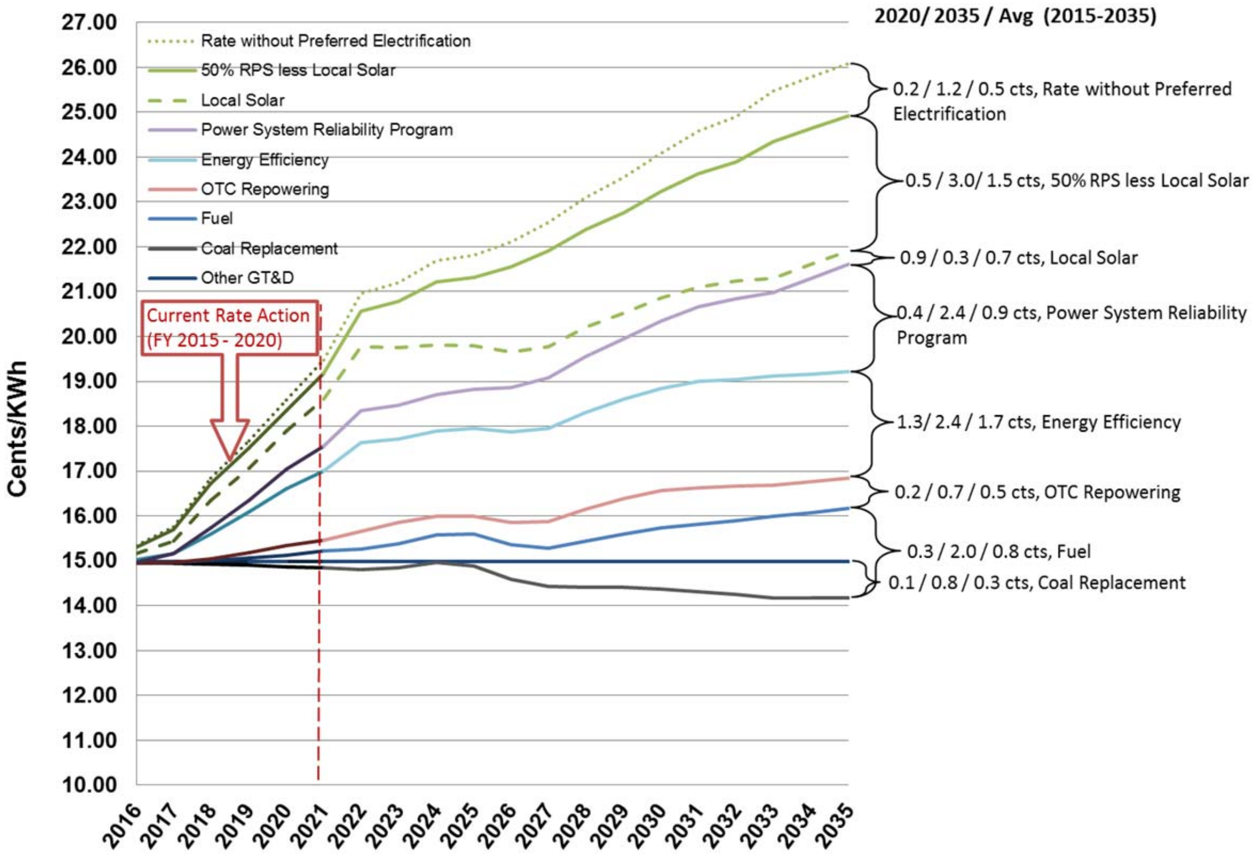


Figure ES-14. Total retail electric rate composite by fiscal year, based on the 2015-16 budget forecast (Recommended Case).

A few observations from Figures ES-15, ES-16, and ES-17[4] can be made regarding the RPS, EE, and OTC Repowering programs, fuel costs, local solar and preferred electrification. The EE program component of rates increases over time as program incentive payments and net revenue loss attributable to the EE program are recovered. The RPS and local solar component of rates steeply increases through 2020 in order to reach 33 percent renewables and the rates continues to increase through 2030 to reach 50 percent renewables by 2030. OTC Repowering results in very low overall rate impacts due to fuel savings resulting from implementation of modern, highly efficient natural gas-fired generation, and starts to decrease rates as fuel prices rise over time. Preferred electrification of the transportation sector has been incorporated into the base rate. Also, general inflation in fuel costs represents a significant growth in rates. The local solar

[4] Figures ES-15, ES-16, and ES-17 represent forecasted rate increases based on system averages, and do not account for rate structure variations across and within customer classes.

component of rates levels off after 2023, after the expanded FiT program has reached the 450 MW build out. A preferred high level of transportation electrification would result in decrease in rates compared to base level of electrification due to increased sales.

The general unevenness in various rate component curves occurs when capital borrowing limits are reached as cash is needed to fund capital expenses. These are short term fluctuations that quickly subside as the capacity to borrow resumes shortly thereafter.

A general upward trend in rates between 4 to 6 percent can be expected from 2015 through 2020, slightly higher than shown in past IRP's since 2010 primarily attributable to mandated programs and this upward trend then gradually reduces over 2021/2022 and remains in the 3 to 5 percent range thereafter. The higher rate increases until the 2021-22 year time period are necessary to support the high capital borrowing requirements to fulfil legislative and regulatory mandates, and to maintain system reliability, while maintaining financial metrics within Board approved limits in order to maintain a favorable AA- bond rating.

Figures ES-16, ES-17, and ES -18[4] further illustrates the impact to average residential (apartment and house) and commercial/industrial customer monthly bills from environmental and reliability programs. To show the potential effect of energy efficiency on customer bills, the dashed lines on these figures illustrate what a total monthly bill would amount to, after implementing energy efficiency measures that result in a 20% usage savings. Although not every customer will implement energy efficiency, customers that elect to implement energy efficiency could experience, on average a 20% savings. LADWP's overall energy efficiency program was recently expanded to a goal of 15% energy efficiency savings by 2020. These figures illustrate what may reasonably be achieved by customers who have not already implemented significant energy efficiency measures to reduce their electricity consumption.

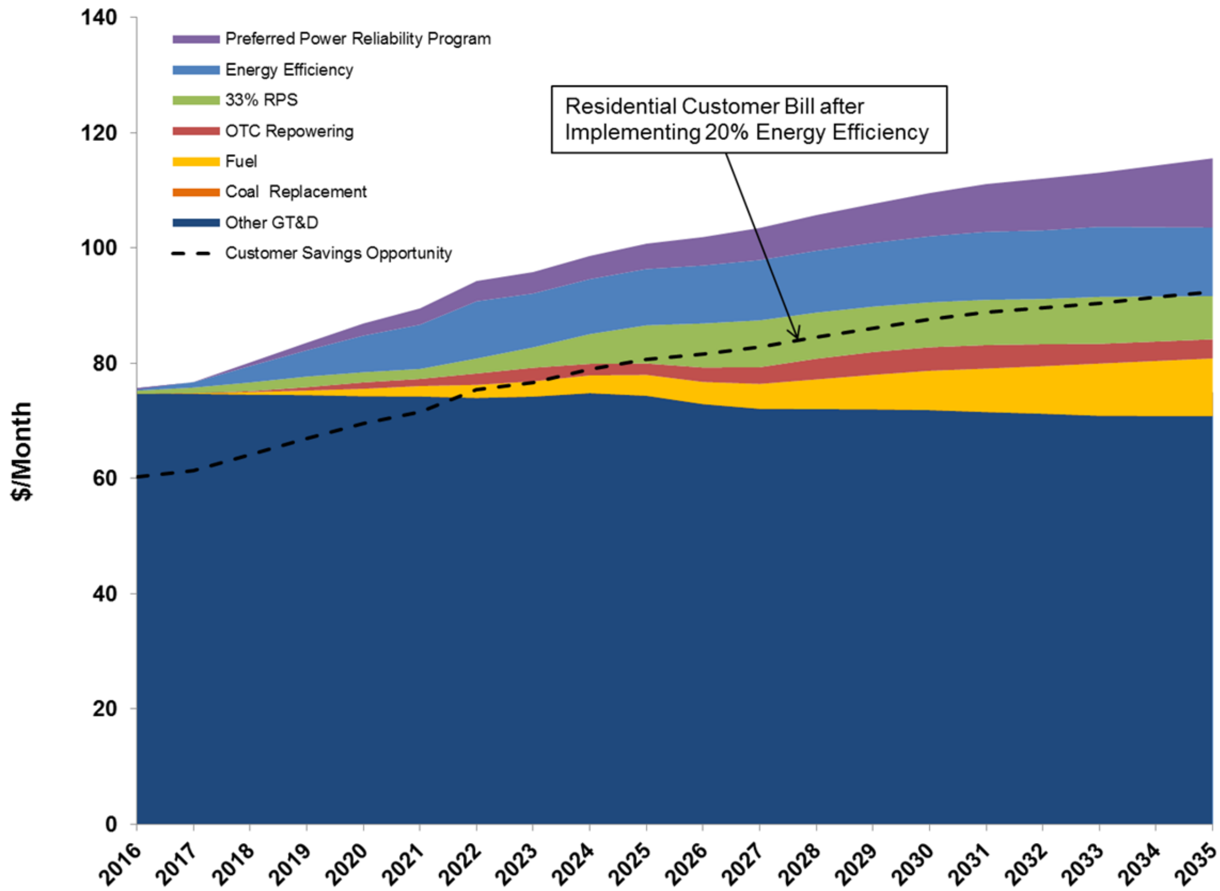


Figure ES-16. Average residential customer bill (500 kWh/month) with environmental and reliability programs by fiscal year based on the 2015-16 budget forecast (Recommended Case).

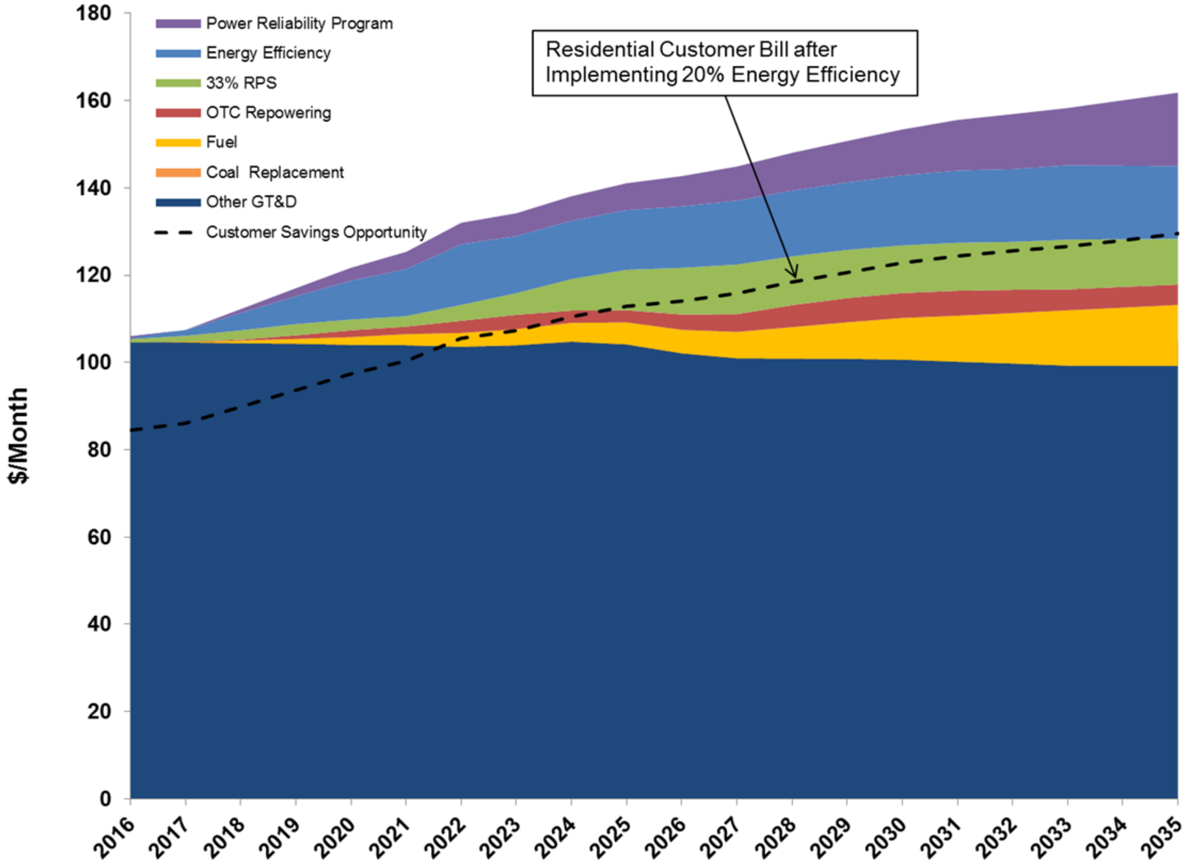


Figure ES-17. Average Valley home with air conditioning, residential customer bill (700 kWh/month) with environmental and reliability programs by fiscal year based on the 2015-16 budget forecast (Recommended Case).

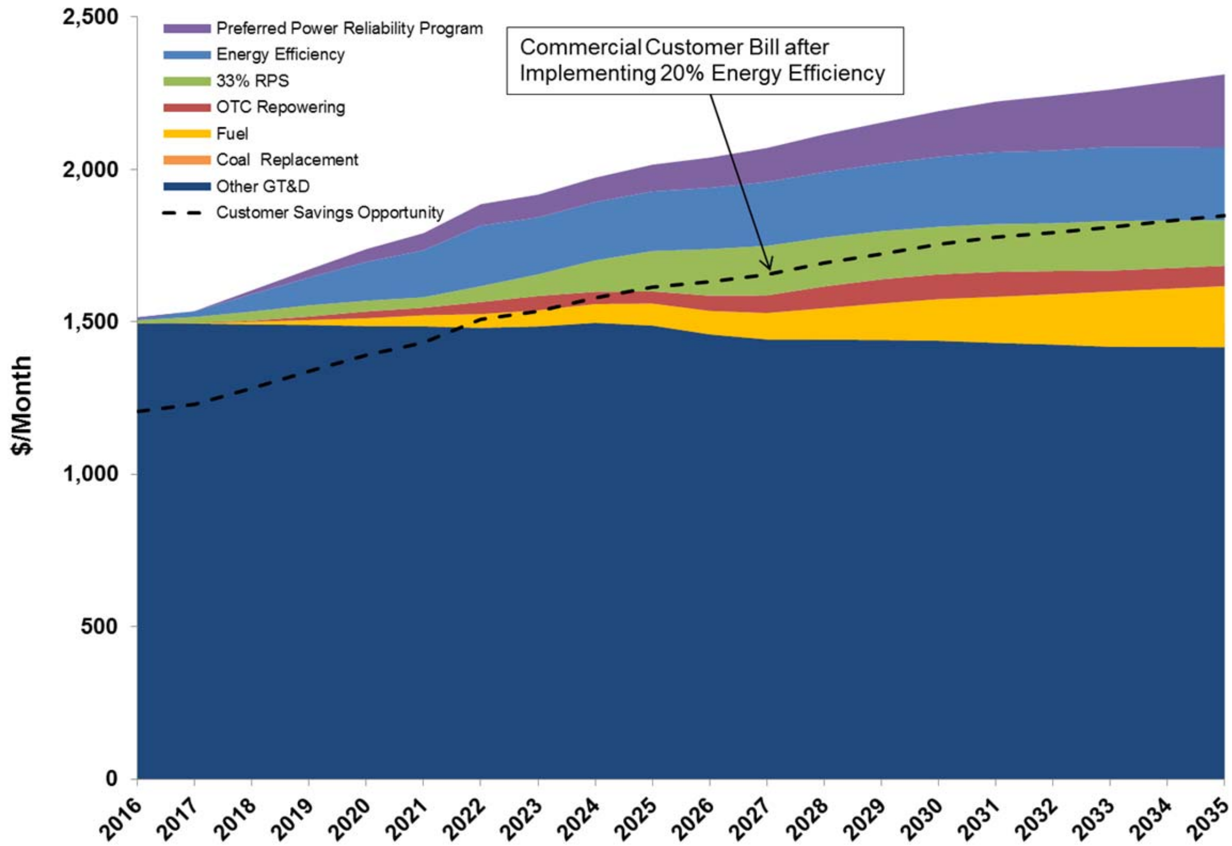


Figure ES-18. Average commercial/industrial customer bill (10,000 kWh/month) with environmental and reliability programs by fiscal year based on the 2015-16 budget forecast (Recommended Case)

8.4 Long-Term Planning Considerations

As the RPS portfolio continues to increase, energy prices will have less value during the mid-day period, when the over-generation is expected to take place. Contrarily, energy will have more value once the sun sets and gas-fired generation and large hydro are expected to quickly ramp up within a few hours to meet the evening peak. Future IRPs will investigate the need for a new rate design, in which time-of-use pricing may be considered as a strategy to encourage customers to reduce the evening peak and consume more during over-generation events when excess energy from renewables is plentiful.

Developing a long term Power System plan to maintain superior reliability, competitive rates and responsible environmental stewardship remains a challenge, but this 2015 IRP outlines an aggressive strategy for LADWP to accomplish its goals and provide sufficient resources over the next 20 years given the information presently available, including the following major strategic initiatives:

1. Eliminate Coal from LADWP's Power Supply – Divest of Navajo by 2016 and Replace IPP by 2025
2. Reach 33 percent RPS by 2020 and 50 percent RPS by 2030, including a goal of 800 MW Local Solar
3. Achieve 15 percent Energy Efficiency by 2020
4. Eliminate the use of Once-through Cooling by Repowering Coastal Units by 2029
5. Invest in the Power System Reliability Program
6. Promote a high scenario of Transportation Electrification

The analysis and conclusions contained in this IRP are heavily dependent on a number of assumptions, such as the projected fuel and purchase power costs, RPS target goals, renewable generation costs, proposed state and federal mandates, and GHG emissions costs. If these assumptions were to change, LADWP's long-term strategies will need to change accordingly. Integrated resource planning is an on-going and iterative process and LADWP will continue to adapt and refine the IRP as the uncertainties are better understood, and policy direction and requirements are solidified. As LADWP implements its programs and continues to learn and develop its programs, the recommendations made by future IRPs may be revised based on future economic conditions, technology, and other known factors. Last year's 2014 IRP process includes a public outreach process and the next IRP public outreach will be undertaken in 2016. The 2016 IRP public outreach process will include an IRP Advisory Committee that will stimulate discussion on future strategies including, but not limited to demand response, advanced metering infrastructure, and future rate design. LADWP will continue its collaborative efforts with customers and other major stakeholder groups to continue to develop the IRP and execute successful programs to realize its vision.

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TABLE OF CONTENTS

1.0 INTRODUCTION 5
1.1 Overview of the 2015 Integrated Resource Plan (IRP) 5
1.1.1 Major Changes from Last Year's IRP 7
1.2 Organization of the IRP 8
1.3 Objectives of the IRP 9
1.3.1 Reliable Electric Service 9
1.3.2 Competitive Rates Consistent With Sound Business Principles 11
1.3.3 Environmental Stewardship 13
1.4 LADWP's Power System 15
1.5 Recent Accomplishments 16
1.6 Key Issues and Challenges 20
1.6.1 Adequate Multi-year Funding to Support Programs 20
1.6.2 Ensuring Reliability 21
1.6.3 Power System Reliability Program (PSRP) 25
1.6.4 Greenhouse gas (GHG) Emissions Reduction 31
1.6.5 Increasing Renewable Resources 33
1.6.6 Once-through Cooling (OTC) 35
1.6.7 Staffing and Training the Workforce – Integrated Human Resources Plan (IHRP)............ 37
1.6.8 Additional Challenges 43
1.7 Public Process 46
1.8 2015 IRP Development Process 49
1.9 Summary 51
2.0 LOAD FORECAST AND RESOURCES 53
2.1 Overview 53
2.2 Forecast of Future Energy Needs 54
2.2.1 2014/2015 Retail Electrical Sales and Demand Forecast 54
2.2.2 Five-year Sales Forecast 60
2.2.3 Electrification 61

2.2.4 Peak Demand Forecast 63
2.3 Demand-Side Resources 65
2.3.1 Energy Efficiency (EE) 66
2.3.1.1 Recommended Target – 15% by 2020 66
2.3.1.2 Total Additional EE Investment Required to Reach Required 15% GWH Savings 69
2.3.1.3 Program Descriptions 71
2.3.1.4 Effect of EE on Electric Rates and Bills 74
2.3.2 Demand Response 75
2.3.3 Distributed Generation (DG) 82
2.4 Generation Resources and Transmission Assets 83
2.4.1 Generation Resources 85
2.4.2 Major Issues Affecting Existing Generation Resources 93
2.4.2.1 Repowering Program to Replace Aging Infrastructure 93
2.4.2.2 Repowering Program to Comply With Regulatory Requirements 94
2.4.2.3 Coal-Fired Generation 95
2.4.3 Future Renewables for LADWP 98
2.4.4 Transmission and Distribution Facilities/Grid Reliability 99
2.4.5 Advanced Technologies and Research and Development 104
2.4.5.1 Smart Grid 105
2.4.5.2 Energy Storage 109
2.4.6 Climate Change Effects on Power Generation 111
2.4.7 Reserve Requirements 113
3.0 STRATEGIC CASE DEVELOPMENT 116
3.1 Overview 116
3.2 2015 IRP Model Assumptions 116
3.2.1 Major Changes From the 2014 IRP Assumptions 117
3.2.2 General Price Inputs 123
3.3 Addressing Legislative and Regulatory Mandates 126
3.4 Candidate Portfolios Development Process 128
3.4.1 Public Input 128
3.4.2 Net Short and Resource Adequacy 129
3.4.3 Renewable Resources Selection Process 129

3.4.4 Local Solar Levels 131
3.4.5 Electrification Levels 132
3.5 2015 IRP Strategic Cases 133
4.0 STRATEGIC CASE ANALYSIS 139
4.1 Overview 139
4.2 Strategic Case Modeling Considerations 140
4.2.1 Modeling Methodology 140
4.2.1.1 Planning & Risk (PROSYM) 140
4.2.1.2 Model Assumptions 141
4.2.1.3 Net Short of Renewables 141
4.2.1.4 Resource Adequacy 141
4.2.1.5 Model Runs and Scorecards 142
4.2.1.6 Post Modeling Analysis 142
4.3 Modeling Results 142
4.3.1 Reliability Considerations 142
4.3.1.1 Resource Adequacy 149
4.3.2 GHG Emissions Considerations 154
4.3.3 Economic Considerations 159
4.3.3.1 Cost Comparison Between Advanced Renewable and Energy Efficiency Cases 3 through 7 159
4.3.3.2 Cost Comparison Between RPS Cases 163
4.3.3.3 Fuel Price Stress Test 165
4.3.3.4 Reliability and Regulatory Revenue Requirements 170
4.3.3.5 Total Power System Cost Comparisons 171
4.4 Strategic Case Conclusions and Recommendations 176
4.4.1 Reliability 176
4.4.2 GHG Emissions Reduction 176
4.4.3 Economic 176
4.4.4 Recommended Case 176
5.0 RECOMMENDATIONS 179
5.1 Strategic Overview 179
5.2 Incorporating Public Input 184
5.3 Recommended Strategic Case 186

5.4 Revenue Requirements 191
5.5 Electric Rates 192
5.5.1 Rates Analysis for Cases 194
5.6 Recommended Near-term Actions 203
5.7 Long-Term Planning Considerations 204

APPENDICES

Appendix A: Load Forecasting

Appendix B: Energy Efficiency

Appendix C: Environmental Issues

Appendix D: Renewable Portfolio Standard

Appendix E: Power System Reliability Program

Appendix F: Generation Resources

Appendix G: Distributed Generation

Appendix H: Fuel Procurement Issues

Appendix I: Transmission System

Appendix J: Integration of Intermittent Energy from Renewable Resources

Appendix K: Energy Storage

Appendix L: Smart Grid

Appendix M: Climate Change Effects on Power Generation

Appendix N: Model Description and Assumptions

Appendix O: Public Outreach

Appendix P: Integrated Human Resources Plan (IHRP)

Appendix Q: Abbreviations and Acronyms

1.0 INTRODUCTION

1.1 Overview of the 2015 Integrated Resource Plan

This document represents the Los Angeles Department of Water and Power (LADWP) Integrated Resource Plan (IRP) for 2015. The goal of this IRP is to identify a portfolio of generation resources and Power System assets that meets the city's future energy needs at the lowest cost and risk consistent with LADWP's environmental priorities and reliability standards. The IRP is an important planning document for electric utilities, and many states and regulatory agencies require development of an IRP prior to approval of procurement programs or electric rate increases.

This document goes beyond traditional integrated resource planning and incorporates additional Power System planning elements to form a comprehensive Power System plan. It is intended that this Power System plan will drive the priorities, financial planning, and budgeting effort for the Power System.

This IRP considers a 20-year planning horizon to guide LADWP as it executes major new and replacement projects and programs. The overriding purpose is to provide a framework to assure the future energy needs of LADWP customers are met in a manner that balances the key objectives of:

- Superior reliability and supply of electric service
- Competitive electric rates consistent with sound business principles
- Responsible environmental stewardship exceeding all regulatory obligations

In balancing these objectives, LADWP's strategic planning efforts must ensure a high level of system reliability, consider impacts to the local and regional economy, mitigate the volatility in fuel and other cost factors, comply with federal, state, and local regulations, and guarantee fiscal responsibility. As LADWP executes major projects and programs, a strong focus is placed on local programs designed to increase customer participation in programs that transform our power supply and assist in integrating renewables. Programs such as energy efficiency, local solar, demand response, Power System Reliability, and micro-grids create opportunities for community involvement and local job growth in support of LADWP's goals.

LADWP is the largest municipal utility in the nation, and the third largest utility in California. While numerous recent accomplishments have been made – including achieving an average of 20% renewable energy sales in the period 2010 through 2013 – significant challenges lie ahead. Increasing renewable energy to 33% by 2020 and 50% by 2030, the continued rebuilding of coastal generation units, replacement of coal, infrastructure reliability investments, and ramping up energy efficiency, transportation electrification, and other demand side programs are all critical and concurrent strategic actions that LADWP will have to carry out over the coming decade.

The 2015 integrated resource planning process continues to evaluate alternative strategic cases that assess different replacement options for coal-fired generation, as well as different projected levels of renewable portfolio standard (RPS), energy efficiency, local solar, and transportation electrification. The cases are modeled to determine their respective operational and fiscal impacts, as well as their effects on greenhouse gas emission levels. This document presents the results of this analysis, recommended near-term actions, and a recommended strategy to best meet the future electrical needs of Los Angeles.

LADWP Power System Vision

The transformation that this utility will undergo in the next 20 years will be unprecedented as the use of electricity broadens to new applications and as customer expectations of clean affordable energy continues to take root. Increases in electric vehicle use and our ever-increasing dependence on evolving information technologies will require a stable, resilient power grid that delivers affordable power. As distributed energy resources dramatically increase, there is a growing interest for a transactional grid that includes greater customer participation to help manage variable distributed energy resources, meet reliability needs, alleviate congestion, and avoid costly upgrades. By increasing energy efficiency, implementing demand response, promoting solar rooftop and other clean technologies that mitigate the need to build new fossil-fueled power plants, both LADWP and its customers are embracing the vision of a greener resource portfolio that helps sustain the environment for future generations.

LADWP and its City Leaders have traditionally taken a leadership position, particularly among public power utilities, to ensure a sustainable, diverse supply of generation and transmission resources to provide electricity to our customers. This utility has also been very progressive in adopting aggressive clean energy goals and programs well before many of today's laws and regulations were in place, and participated in the development of many of the laws and regulations that we see today. In 2000, this utility set out to reduce load growth by 50 percent through the use of behind the meter renewables, energy efficiency, and local solar. Today we have the same electricity consumption as we had in 2006 despite population growth, largely due to these earlier efforts. In 2005, we adopted a renewable target of 20 percent renewable by 2010, and we succeeded to be the largest California municipal utility to achieve 20 percent renewable generation in 2010. Since 1990, we have divested of two coal plants with the sale of a third expected in mid-2016, and repowered several natural gas in-basin generating stations using cleaner and more efficient new combustion technology, resulting in 20 percent lower greenhouse gas emissions and over 80 percent lower NOx emissions. Reducing ocean water use and reducing the impact on marine life has also been an on-going effort and we are now utilizing 42% less ocean water from 1990 levels, with total elimination targeted by 2029.

The world today is not the same as it was 20 years ago, and the world 20 years from now will not be the same as it is today. And while LADWP's mission of providing reliable, affordable electricity in an environmentally responsible manner remains the same, the planning and execution of that mission requires continued diligence to account for, adopt, and even influence, the changing public concerns and priorities related to electricity generation and use.

1.1.1 Major Changes from Last Year's IRP

Major changes from last year's 2014 IRP include expanded discussion on:

- Senate Bill 350 was signed into law, requiring a target 50% renewable portfolio standard by 2030 and doubling the energy efficiency of buildings and conservation savings in electricity and natural gas end uses of retail energy by 2030.

- An agreement under which LADWP will sell its 21 percent share (477 MW) in the coal-fired Navajo Generating Station in Arizona to Salt River Project; the sale will close on July 1, 2016.

- A study was commissioned, entitled the Maximum Generation Renewable Energy Penetration Study (MGRPES), to analyze the impact of 40 and 50 percent penetration of variable energy resources (VERs) on LADWP's system balancing requirements, including reserve requirements, ramp rate requirements, system reliability and operation requirements (system inertia and frequency response), and generation dispatch strategies.

- Scattergood Generating Station Unit 3 was repowered with a modern, state-of-the art combined-cycle unit and simple-cycle gas turbine unit for a total generation of 508 MW to reduce the use of once-through cooling.

- A status update on the Integrated Human Resources Plan (IHRP): New Engineering Associate Training (NEAT) Program and Customer Care and Billing (CCB)

- Expanded discussion on the Transportation Electrification Program to meet IRP electrification goals.

- Natural gas prices and renewable energy costs have been revised downwards compared to last year's 2014 IRP and are in-line with prior low price sensitivity forecasts.

- Updated case scenarios including elimination of 40% by 2030 Renewable Portfolio Standard (RPS) case and additional 50% RPS by 2030 cases with varied amount of local solar and transportation electrification.

This 2015 IRP incorporates updates to reflect the latest load forecast, fuel price and projected renewable price forecasts, and other numerous modeling assumptions. Major renewable projects approved this year by the Board and City Council includes Hudson Ranch Geothermal and Springbok 2 Solar Power Purchase Agreements. Copper Mountain 3 reached full commercial operation and Don Campbell 2, Hudson Ranch, and Heber 1 Geothermal Power Purchase Agreements were also placed in-service this year. These projects were among the approved and executed projects this past year which took advantage of lower renewable prices. The levelized costs for the entire renewable portfolio was $95 per megawatt-hour (MWh) in 2013, $92 per MWh in 2014, and $91 per MWh in 2015.

1.2 Organization of the IRP

This document is organized as follows:

- Section 1, "Introduction," presents an overview of the LADWP Power System, and the issues and challenges facing LADWP as it strives to secure a reliable supply of electricity for the next 20 years, at competitive rates, and in an environmentally responsible manner.
- Section 2, "Load Forecast and Resources," provides forecasts of electricity demand, discusses the resources available or needed to meet that demand, and addresses the issues associated with each resource and the Power System in general.
- Section 3, "Strategic Case Development," establishes potential alternatives (Cases) available to LADWP to meet its projected electricity demand, and considers varying levels of renewable portfolio standard, local solar generation, and transportation electrification as well as different options for early replacement of coal-fired generation.
- Section 4, "Strategic Case Analysis," addresses the operational modeling and the results used to assess the impact of each alternative on cost, energy rates, and levels of greenhouse gas emissions.
- Section 5, "Recommendations," provides the strategic overview, the recommended case including the revenue requirements to support it, and the near term actions required to keep LADWP on track towards meeting its obligations and responsibilities.

Detailed information is provided in the following Appendices:

Appendix A: Load Forecasting
Appendix B: Energy Efficiency
Appendix C: Environmental Issues
Appendix D: Renewable Portfolio Standard
Appendix E: Power System Reliability Program
Appendix F: Generation Resources
Appendix G: Distributed Generation
Appendix H: Fuel Procurement Issues
Appendix I: Transmission System
Appendix J: Integration of Intermittent Renewable Resources
Appendix K: Energy Storage
Appendix L: Smart Grid
Appendix M: Climate Change Effects on Power Generation
Appendix N: Model Description and Assumptions
Appendix O: Public Outreach
Appendix P: Integrated Human Resources Plan
Appendix Q: Abbreviations and Acronyms

1.3 Objectives of the IRP

This 2015 IRP documents the long-term planning efforts for LADWP's Power System. It includes a review of the various issues and considerations that LADWP must address moving forward, and summarizes the planning process used to identify future energy resource requirements. The recommended long-term plan is presented, as are the actions and initiatives LADWP must undertake over the next several years. The key objectives of LADWP's long-term planning efforts are: (1) maintaining a high level of electric service reliability, (2) exercising environmental stewardship, and (3) keeping its energy rates competitive.

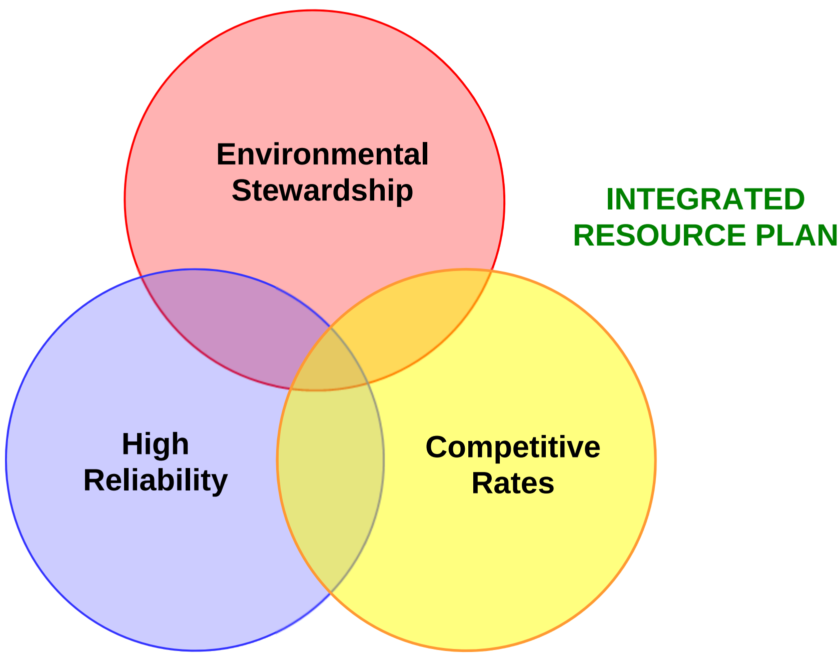


Figure 1-1. Objectives of this IRP

1.3.1 Reliable Electric Service

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 here:

- Reliability Standards

  LADWP continues to be in compliance with all applicable Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) standards regarding bulk power system reliability. With the enactment of the Energy Policy Act of 2005, FERC granted NERC the legal authority to enforce reliability standards with all users, owners and operators of the bulk power system in the United States. WECC, under the delegated authority of NERC, is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. Both of these electric utility organizations enforce reliability standards on owners, operators and users of the bulk power system.

- 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 in 2012 to be a scheduling coordinator which authorizes LADWP to buy and sell energy and ancillary services directly with CAISO.

- 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 system. LADWP will continue to maintain its presence as a Balancing Authority.

- Self-Sufficiency

  LADWP maintains a policy of owning or controlling its transmission and generation resources to serve its native load customers. However, in consideration of economic and environmental factors involved with the coal replacement options (discussed in Section 3 and 4), a limited amount of firm energy is proposed to come from third quarter purchases acquired from the electricity market.

- Coastal Power Plants

  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 from the 1940s up to the 1970s. One of these plants, Harbor Generating Station, was modernized in the 1990s, resulting in increased efficiency and reliability while reducing emissions and maintenance costs. The modernization of the remaining generation units is a long-term program targeted for completion in 2029. LADWP must modernize these plants to comply with environmental regulations, improve efficiency, better integrate renewable resources, and provide for transmission import capability. See Section 1.6.6 and Appendix C for more details.

- Intermountain Power Project Replacement

  To support LADWP's strategy to completely divest from coal-fired resources by 2025, a combination of energy efficiency, demand response, renewable resources (consisting of wind, solar and geothermal), as well as energy from a combined cycle natural gas generating facility are identified as key resources to replace the capacity that the IPP plant provides. In 2015, all 36 participants approved an amendment to replace IPP early by 2025 by repowering IPP with at least one combined cycle natural gas generating unit. The repowered IPP unit will provide flexible capacity that will be used to firm and back up renewable resources, and provide a mechanism to integrate them reliably into LADWP's grid.

- Power System Reliability Program

  In response to an increase in power outages from 2003 through 2005, LADWP established the Power Reliability Program. The goals of the program include: (1) mitigating problem circuits and stations based on the types of outages specific to a given facility, (2) implementing proactive maintenance and capital improvements to prevent problems before they occur, and (3) establishing replacement cycles for facilities that are in alignment with the equipment's life cycle. In 2014, LADWP expanded the scope of the Power Reliability Program, establishing the Power System Reliability Program, which incorporates other major functions of the electric power system including generation, transmission, and substations in addition to distribution. See Section 1.6.4 and Appendix E for more details.

- Smart Grid

  Smart Grid refers to the application of advanced information-based technologies that will improve system operations in a variety of areas. Smart Grid technologies provide information that allows the implementation of real-time, self-monitoring communication networks that are predictive rather than reactive to system disruptions. These technologies will enable LADWP and its customers to make decisions to optimize the use of energy, improve reliability, and reduce the consumption of fossil fuels. More information on Smart Grid can be found in Section 2.4.5.1 and Appendix L.

- Distributed Generation

  Distributed Generation (DG) refers to the installation and operation of small-scale electric generators that are located at or near the electrical load. Cogeneration, solar photovoltaic, and fuel cells are examples of DG applications. As more DG is added within the city of Los Angeles, it is important that these generation sources be managed in a manner that does not reduce grid reliability. More information on DG is provided in Section 2.3.3 and Appendix G.

- Energy Storage

  Energy Storage (ES) refers to the installation and operation of a commercially viable technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy. Energy storage is a viable technology to allow greater penetration of renewable energy. More information on ES is provided in Section 2.4.5.2 and Appendix K.

1.3.2 Competitive Rates Consistent With Sound Business Principles

Historically, LADWP's electric rates have been consistently among the lowest in California. As utilities throughout the industry address renewable energy, greenhouse gas emissions, once-through cooling and other issues, it can be expected that rates for most, if not all utilities, will rise. By continuing its strategic planning and implementation activities, LADWP hopes to maintain its rates as among the lowest in the region.

Energy rates

Based on a typical monthly residential bill for a customer consuming 500 kWh of electricity, the LADWP has the lowest monthly electric bill compared to five of its neighboring utilities in Southern California. See Figure 1-2 below.

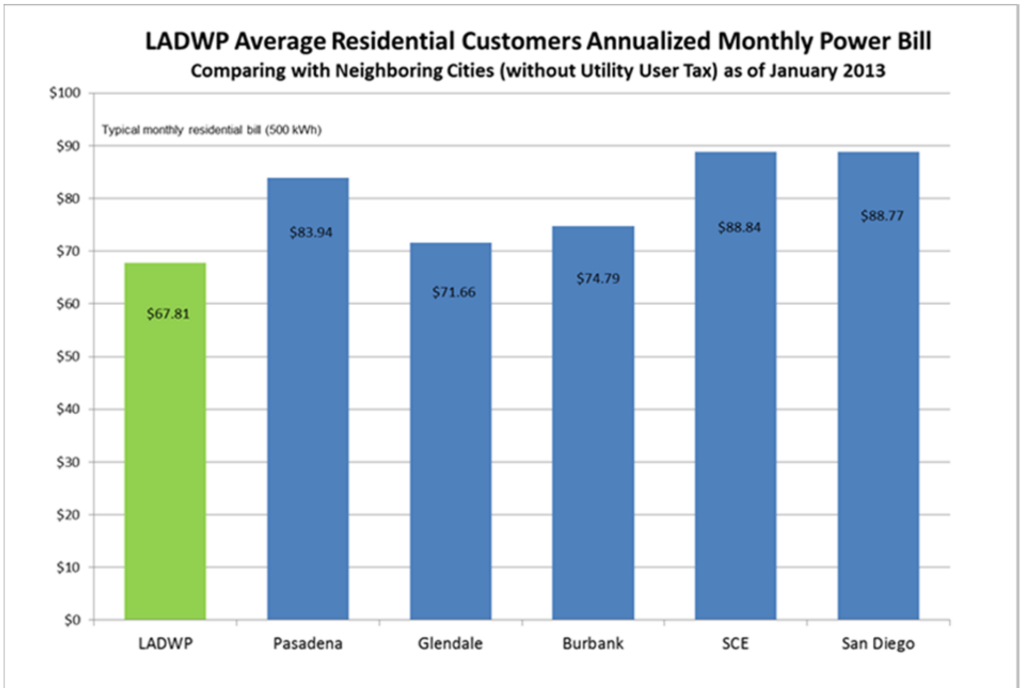


Figure 1-2. LADWP power bill comparison among other electric utilities.

While LADWP provides electricity at competitively low rates, several factors challenge the current rate structure. These factors include the costs to replace aging infrastructure, the potential volatility of natural gas and coal prices, and new regulatory requirements for renewable energy and the reduction of greenhouse gas emissions and use of ocean water for power plant cooling. Transmission capacity upgrades, energy efficiency and demand response programs, and projects to implement coal replacement will also exert upward pressure on energy rates. Because of these and other initiatives, it is expected that future structural rate adjustments and amendments to the rate ordinances will be necessary to maintain appropriate debt ratios and bond ratings.

Since LADWP sells substantial amounts of bonds to finance its capital expenditures, maintaining its high credit rating is essential to minimizing financial costs. To maintain its high credit rating, LADWP adheres to the following policies:

- Debt service coverage

  Maintain a full obligation ratio of at least 1.70

- Cash on hand

  Maintain a cash balance of 170 days

- Capitalization ratio

  Maintain a debt-to-capitalization ratio of less than 68%

These financial parameters are used in the electric rates analysis, discussed in Section 5.5.

1.3.3 Environmental Stewardship

LADWP's mission includes a role as an environmentally responsible public agency. Programs and subject areas related to improving the environment include:

- Renewable energy

  LADWP will continue its efforts to increase the use of renewable energy resources in a cost effective manner. LADWP will, at a minimum, comply with local, state and federal mandates for levels of renewable energy as a percentage of electricity sales. Senate Bill (SB) 2 (1X) sets renewable energy targets of 20% for years 2011-2013, 25% by 2016 and 33% by 2020 . In addition to SB 2 (1X), SB 350 was passed in 2015, which further increases renewable energy targets to 40% by 2024, 45% by 2027, and 50% by 2030 and thereafter. For more information, see Sections 1.6.5, 2.4, 3.4.3, and Appendix D.

- Carbon dioxide (CO_2) emissions

  LADWP will continue its efforts to reduce CO_2 emissions. The potential early replacement of coal-fired generation, a key strategic focal point of this 2015 IRP, is one means of achieving reductions of CO_2 emissions. Additional recommended means of reducing CO_2 emissions include the continuation and expansion of energy efficiency programs, the transition towards increasing amounts of energy generated from renewable resources, and investigating electrification/fuel switching of the transportation industry as a strategy for reducing CO_2. For further information, see Section 1.6.4 and Appendix C.

- Once-Through Cooling (OTC)

  LADWP has embarked on a series of repowering projects that are eliminating the use of ocean water for cooling at its coastal generating stations. A series of repowering projects is planned through 2029. As each project is completed, the use of ocean water decreases. Within the 20-year planning horizon of this IRP, these projects will totally eliminate the use of ocean water. More information on OTC can be found in Sections 1.6.6.

- Energy Efficiency

  Energy efficiency programs have been ongoing for more than a decade, and will be serving a more prominent and strategic resource planning role as LADWP looks to the next 20 years and beyond. LADWP is committed to developing comprehensive programs with measurable, verifiable goals as well as implementing robust, cost-effective energy efficiency programs. Currently, LADWP has set a goal to achieve nearly 15% energy savings by 2020. Further information regarding LADWP's EE Program can be found in Section 2.3.1 and Appendix B.

- Solar Incentive Program and Feed-in Tariff

  LADWP's Solar Incentive Program (SIP) encourages the installation of solar photovoltaic (PV) capacity in Los Angeles. This program is a multi-year investment designed to expand solar power in the city to meet the goals of SB 1. This program provides a one-time incentive to customers who install a solar PV system on their property for their consumption. When a customer's SIP solar system produces more energy than they use for the billing cycle, the excess energy is calculated as a credit to be used on the customer's future bill – this billing arrangement is known as "customer-net metering" (CNM).

  Additionally, LADWP has implemented a Feed-in Tariff (FiT) program in accordance with SB 1332, whereby LADWP contracts to purchase all the power generated from an eligible renewable system under a standard power purchase contract. Although this program is open to all eligible renewable generators, it will most likely be solar.

  The FiT and SIP programs are exclusive from each other; one renewable system cannot be enrolled in both. However, one property may have two separate renewable systems; one system feeding energy directly to LADWP's grid via a FiT meter and the other system feeding the customer's load via a CNM arrangement.

  Solar energy will assist LADWP in achieving its environmental goals of increased energy generated from renewable resources and reduced levels of greenhouse gas emissions.

- Demand Response Program

  Demand Response is a key strategy in this IRP, and will lessen environmental impacts by deferring the need to build additional generation facilities and infrastructure; as well as reducing energy usage and the associated greenhouse gas emissions. In 2014, LADWP finalized its Demand Response Strategic Implementation Plan, which serves as LADWP's near term and long term plan for developing a measurable, cost-effective, and customer-friendly Demand Response portfolio of 200 to 500 MW by 2026.

  "Demand Response" is a mechanism utilities use to manage energy demand, especially during critical peak demand periods. When demand is at its highest (e.g., on a hot August afternoon), almost all of the generation supply is engaged, leaving little reserve available in case a generating unit falters or a transmission line trips. To reduce the risk of system failure that this condition imposes, demand response provides a means to lower the demand. Customers who sign up to participate are provided financial incentives and agree to lower their demand if and when called upon by the utility.

- Electrification of the Transportation Sector

  As a strategy to integrate 50% RPS, the IRP utilized higher levels of fuel switching/electrification of the transportation sector with higher expected load growth as a strategy to absorb solar peak load during the day. Electrification of the transportation sector not only provides the possibility of absorbing peak load, but it also provides the benefit of reducing greenhouse gases in the transportation sector as well as increasing electric sales. Additional details on electrification pertaining to the 2015 IRP case analysis are discussed in Section 5 of this IRP.

1.4 LADWP's Power System

LADWP's Power System serves approximately 3.8 million people and is the nation's largest municipal electric utility. LADWP experienced an all-time net energy-for-load peak demand of 6,341 megawatts (MW) with an instantaneous peak demand of 6,396 MW, which occurred on September 16, 2014, and has an installed net dependable generation capacity of 7,628 MW. Its service territory covers a 465-square-mile area in Los Angeles and much of the Eastern Sierra's in Owens Valley, with annual sales exceeding 23 million megawatt-hours (MWh). LADWP is the third largest California electric utility in terms of consumption, behind Pacific Gas & Electric and Southern California Edison (see Figure 1-3 below). Projected future demand growth for LADWP is less than one percent per year[1].

"Capacity" is a measure of the capability to produce power or the rate at which energy is transferred. The term is applied to the amount of electric power delivered or required to meet the power demand, and is expressed in Megawatts (MW) or Gigawatts (GW). "Energy" is a measure of the quantity of electricity used in a given time period and is expressed in Megawatt-hours (MWh) or Gigawatt-hours (GWh).

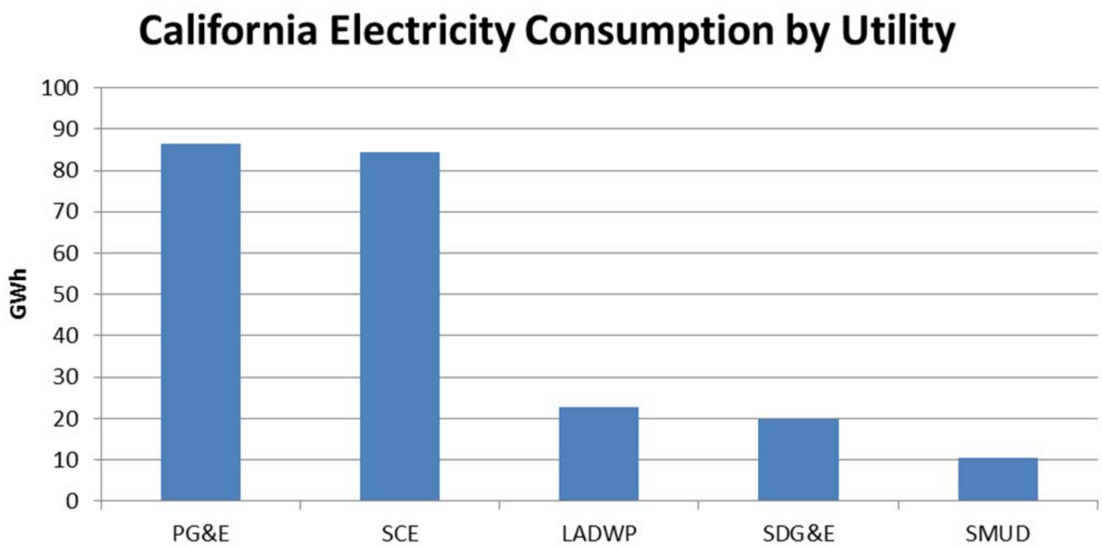


Figure 1-3. Comparison of California utilities by consumption (Source: 2013 Data, CEC Almanac)

LADWP is a "vertically integrated" utility – both owning and operating the majority of its generation, transmission, and distribution systems. LADWP is currently fully resourced to meet peak demand but maintains transmission and wholesale marketing operations to keep production costs low and increase system reliability.

Additional information on the Power System's generation and transmission assets can be found in Section 2.4 and Appendices F and I.

[1] Prior to energy efficiency and distributed generation. When considering these programs, actual yearly load growth is forecasted to average 0.8% between 2015 and 2035.

1.5 Recent Accomplishments

A summary of recent LADWP accomplishments consistent with the objectives of this IRP are presented below. These accomplishments promote the goals of maintaining high reliability and exercising environmental stewardship, while keeping rates competitive.

- Sale of Navajo and Hudson Ranch 1 Geothermal Agreement

  On May 19, 2015, the Board of Water and Power Commissioners at the Los Angeles Department of Water and Power approved an agreement under which LADWP will sell its 21 percent share in the coal-fired Navajo Generating Station in Arizona to Salt River Project (SRP). Under the agreement with SRP, LADWP will stop receiving its 477 megawatt share of coal power from Navajo when the sale closes on July 1, 2016. The sale will reduce LADWP's greenhouse gas emissions by 5.4 million metric tons over the next three and a half years. As part of the Navajo sale, LADWP also entered into a Term Energy Transaction Confirmation Agreement to purchase approximately 55 Megawatts (MWs) of renewable geothermal energy from SRP's rights in the Hudson Ranch Geothermal Project located in the Imperial Valley of Southern California through 2021.

- Renewable portfolio standard

  Through the active procurement of renewable resources, LADWP has increased the renewable energy component of its resource mix from 3% in 2003 to 20% in 2010 and has maintained this same percentage throughout the first SB2-1X compliance period of 2011 through 2013. LADWP is currently on track for meeting the second SB2-1X compliance period of 2014 through 2016, which requires meeting or exceeding the sum of 20% RPS for 2014, 20% RPS for 2015, 25% RPS for 2016, and 33% RPS for 2020. SB 350 was passed in 2015 and requires meeting or exceeding 50% RPS by 2030 with interim targets of 40% RPS by 2024 and 45% by 2027; LADWP plans to meet or exceed these targets in this IRP.

- Barren Ridge Switching Station

  The Barren Ridge Switching Station, located 15 miles north of Mojave, was completed in 2009. This substation is a key component of the Barren Ridge Renewable Transmission Project (BRRTP), which will enable LADWP to interconnect approximately 1,400 MW of wind, solar, and other renewable resources that will be available in the next several years from the Mojave Desert and Tehachapi Mountain areas. The Environmental Impact Report for the BRRTP was approved by the Board of Water and Power Commissioners in September 2012. BRRTP is targeted to be in service in 2016. For more information see Section 2.4.4.

- Don A. Campbell I and II and Heber 1 Southern California Public Power Authority (SCPPA) Agreements

  On March 5, 2013, LADWP approved the power purchase agreement for geothermal energy produced from Ormat's Don A. Campbell Geothermal generating facility. On January 6, 2014, Don A. Campbell geothermal power plant in Mineral County, Nevada, was placed in-service and is producing its full capacity of 16 MW. This adds base loaded renewable energy to our resource mix and produces 114 GWh energy annually. Don A. Campbell II, an expansion of the plant, was placed in-service and is currently producing 19 MW on a yearly average basis above the nominal target of 16.2 MW listed in the 20-year Power Purchase Agreement (PPA). On June 19, 2013, LADWP approved power purchase agreement for geothermal energy produced from Heber-1 Geothermal generating facility. The Heber 1 Project is expected to produce a base loaded renewable energy of 187 GWh annually when it is placed in service by end of 2015. The two geothermal projects will add an additional 1.9 percent to the RPS by 2017.

- <u>Copper Mountain 3 Solar and Moapa Solar Agreements</u>

  Power purchase agreements for two large solar photovoltaic facilities reached commercial operation this year. These solar generating facilities provide 460 MW of replacement power and utilize existing transmission. These projects will add an additional 4.4 percent to the RPS by 2016.

- <u>Springbok 1 and 2 Solar</u>

  Power purchase agreements for Springbok 1 and 2 were approved by the Board in 2014 and 2015, respectively. Springbok 1 and 2 consists of 100 MW and 150 MW, respectively.

- <u>Energy Efficiency</u>

  LADWP continues its commitment to energy efficiency through numerous programs and services to customers, encouraging the adoption of energy-saving practices and installation of energy-efficient equipment. Since 2000, LADWP energy efficiency programs have resulted in 2,214 GWh of energy savings, or about 10% of energy sales.

  In 2013, LADWP continued its implementation of its new $130 million per year portfolio of energy efficiency programs, including the launch and ramp-up of three major direct install programs for residential and small business customers as well as the Los Angeles Unified School District, and its nation-leading partnership with SoCal Gas, under which LADWP has launched ten joint efficiency programs to date.

  On August 5, 2014, the Board of Water and Power Commissioners adopted a goal of nearly 15% energy efficiency by 2020, based on the 2013/2014 Energy Efficiency Potential Study results.

- <u>Solar Incentive Program and Feed-in-Tariff (FiT)</u>

  As of October 2015, LADWP has encouraged the installation of over 150 MW of solar capacity at over 18,100 customer locations through its ratepayer-funded Solar Incentive Program. Separately, a FiT program was launched, which will enable a full-scale program launch for 150 MW of FiT projects by 2016 through the 100 MW Set Pricing FiT (FiT100) and a 50 MW Beacon Bundled FiT (FiT50). FiT100 currently has 8 MW of projects installed and in operation and an additional 52 MW of executed contracts awaiting construction. The Competitive Pricing Program is a full scale program launched for 150 MW including and 50 MW of Beacon Bundled Local Solar.

  In the fall of 2014, LADWP began developing an Expanded FiT program. Paced at 50 MW per year, the Expanded FiT program will be priced in a manner that is responsive to program participation. The ultimate Expanded FiT program size will be determined by the RPS needs detailed in the IRP.

- Community Solar Program (CSP)/Utility Built Solar (UBS)

  LADWP is currently developing the CSP/UBS to provide an opportunity to participate in a solar program for all LADWP customers. CSP/UBS provides solar access to customers who are unable to install solar on their own. Reasons may stem from lack of finance, being a renter and not owning a roof, or having shaded roofs. LADWP will aggregate solar projects, preferably in low-income communities and large desert PPAs and sell the clean solar energy to program participants so that customers are able to lower costs through economies-of-scale and optimized-project-siting. LADWP will do all the work (developing, designing, constructing, operating, maintaining, financing, contracting, etc.) and pass the savings to participants. Customers who participate in the program will reduce their ecological footprint for the environment while hedging against rising energy costs.

- Emissions reduction

  As of 2014, CO_2 emissions from power generation are 17% lower than 1990 levels. The lower emissions are attributed to discontinued generation from the Colstrip and Mohave generation stations, increased generation from renewable resources, and the ongoing repowering of the in-basin natural gas units.

  Due to the installation of advanced pollution control equipment at all of its in-basin generating stations, NO_X emissions from LADWP's local generating plants in 2013 are 92 percent lower than 1990 levels.

- Once-through cooling

  As a result of completed repowering projects, LADWP has reduced the use of once-through ocean water cooling by 42% from 1990 levels. The current plan calls for a complete phase-out of ocean water cooling by 2029.

- Haynes 5 & 6

  The September 2011 groundbreaking ceremony signified the start of construction for the replacement of Haynes Units 5 and 6. The original units, which date back to the mid 1960's, were replaced with efficient modern units that will facilitate the integration of intermittent renewable energy. This project was placed into service on June 19, 2013 for Units 11, 12, 13, 15, and 16, and June 29, 2013 for Unit 14. The replacement of Haynes Units 5 and 6 is one of many projects that will eliminate the use of ocean water for cooling by 2029.

- Scattergood 3

  On September 29, 2013 LADWP broke ground on the Scattergood Unit 3 Repowering Project which will be the first of two major repowering phases at Scattergood to completely eliminate once–through cooling and provide flexible, efficient combined cycle and simple cycle gas turbine units to help facilitate the integration of renewable energy. This project will include one 308 MW combined cycle and two simple cycle gas turbines with a combined replacement of 508 MW of older gas fired generation and is expected to be place in-service by December 2015.

- Castaic

  The seven units of the Castaic Hydroelectric Plant are currently being rotated out of service for modernization, including control system upgrades. This multi-phase process began in

2004 and is expected to continue through April 2017. To date, six units have been completed. The associated increase in efficiency is projected to add up to 80 MW of renewable qualifying capacity to Castaic. The increased capacity also results in more reserves available to reliably meet peak system demands.

- Power System Reliability Program (PSRP)

  The Power Reliability (PRP) is a comprehensive, long-term power reliability program developed by LADWP to replace aging infrastructure and make permanent repairs to generation, transmission, and distribution infrastructure. Through the program, LADWP successfully reduced the number of distribution outages by 28% between 2006 and 2009 by accelerating the replacement of transformers, poles, underground cables, and other equipment. In FY 2013-14, 1,617 poles, 1,944 transformers, and 41 miles of underground cable were replaced. In 2014, LADWP expanded its PRP program into the PSRP, which incorporates generation, transmission, and substations, in addition to distribution. See Section 1.6.3 and Appendix E for more information.

- Energy Storage Procurement Targets

  The LADWP board adopted new energy storage targets to support increasing renewable energy in the amount of 154 MW by 2021, in addition to the previously adopted amount of 24 MW by 2016. See Section 2.4.5.2 and Appendix K for more information.

- Green Power Program

  LADWP offers its customers an opportunity to participate in the Green Power Program. "Green Power" is produced from renewable resources such as wind energy, geothermal, or other renewable resources, rather than conventional generating plants. In 2014, 15,630 LADWP customers participated in the program, receiving approximately 64,400 MWh of renewable energy. Since program inception in 1999 to the end of 2014, 1,067,562 MWh of renewable energy was procured, making it one of the largest voluntary green pricing programs in the nation.

- Pacific DC Intertie (PDCI) Upgrade

  LADWP initiated major upgrades of the equipment at the southern terminal of the PDCI which is jointly owned by Southern California Edison and the Cities of Los Angeles, Glendale, Burbank, and Pasadena and brings hydro-electric power from the Pacific Northwest to Southern California.

- Electric Vehicles Incentive for Home Chargers

  To encourage the transition towards electric vehicles, LADWP launched a demonstration program in April 2011 providing a $2,000 rebate for home charging systems. LADWP also worked with other City agencies to streamline the process time for permitting and installation of these systems. Building upon the success of its initial EV charger rebate program, which offered rebates to residential customers, LADWP introduced its "Charge Up L.A.! – Home, Work and On the Go." The new program is designed to encourage more widespread installation of EV charging stations at large businesses for their own employees, as well as smaller businesses and multi-family buildings for public use and employees of businesses.

- IPP Coal Replacement

  An amendment to the IPP power purchase contract has been drafted to construct a natural gas replacement facility located at the IPP site. The amendment establishes an in-service date of July 1, 2025, for the new facility. The IPP Coordinating Committee and the IPA Board could move the date up if a super majority of the participants support the decision. As of October 29, 2015, all 36 participants have approved the amendment.

- Demand Response and Smart Grid

  LADWP is developing and enhancing its Demand Response and Smart Grid programs, which are important components of its future resource plan. To date, 60 MW of load shifting and interruptible load has been secured. In 2014, LADWP finalized its Demand Response Implementation Plan, which sets a goal of 200 to 500 MW of load shifting and interruptible load by 2026.

- Alternative Maritime Power (AMP)

  On June 21, 2004, the Port of Los Angeles and China Shipping Container Line announced the grand opening of the West Basin Container Terminal at Berth 100, the first container terminal in the world to use AMP, which provides shore-side electrical power to a ship at berth, while its main and auxiliary engines are turned off. Since then, the Port of Los Angeles has equipped every container terminal with AMP.

1.6 Key Issues and Challenges

LADWP faces a number of concurrent and interdependent challenges that require careful assessment. Long-term strategies must focus on these issues so they can be addressed in the most cost effective manner without compromising reliability compliance and environmental stewardship. The major issues around which the strategies of this IRP are centered include: ensuring reliability, greenhouse gas emission reduction, increasing the amounts of renewable generation resources, and addressing once-through cooling.

1.6.1 Adequate Multi-year Funding to Support Programs

To support the recommended projects and programs, adequate funding is necessary. LADWP balances numerous multi-year programs that require adequate funding in order to achieve its goal of providing cost competitive electric rates while maintaining superior reliability and responsible environmental stewardship. Therefore, maintaining adequate multi-year funding is an essential element in supporting LADWP's programs.

Properly funded programs will enable LADWP to achieve the following objectives:

- Modernize its coastal generation units to replace aging equipment and to satisfy once-through cooling and local emissions regulatory requirements.
- Implement early coal divestiture and replacement to accelerate the reduction of

greenhouse gas emissions and to enhance integration of renewable energy and energy efficiency measures.

- Secure the state-mandated amounts of renewable energy.
- Increase the use of local solar generation and combined heat and power to support State goals.
- Through the Power System Reliability Program, reduce the number and duration of outages and improve system reliability.
- Implement necessary transmission improvements to maintain reliability and support new resources, including renewables.
- Provide energy efficiency, demand response, customer solar programs, and electric vehicle programs for participation by our customers through the Customer Opportunities Program.
- Achieve energy efficiency and other demand-side resource target levels.
- Investigate and incorporate energy storage systems in conformance to AB2514 to support increased renewables.
- Implement Smart Grid initiatives.
- Comply with FERC-approved reliability and Cyber-security standards.
- Operation and maintenance support for new facilities resulting from compliance with Federal and State regulations.

Securing adequate multi-year funding is crucial to ensure LADWP's ability to stay on track towards meeting its future long-term goals and obligations.

1.6.2 Ensuring Reliability

Challenges to ensuring continued reliable electric service include the replacement of aging generation facilities, maintaining grid reliability, the integration of intermittent renewable energy resources, and the replacement of equipment related to generation, transmission, distribution, and substations (reliability is further discussed in Section 1.6.3 below).

Aging Facilities and Infrastructure

LADWP's generating plants sited within the Los Angeles Basin were primarily built in the late 1950s and early 1960s. While many generating units at these plants have undergone extensive upgrades, others are approaching the end of their service lives. Replacement of these older units (also known as "repowering") began in 1994, and will continue through 2029. As older generating units continue to age, unplanned outage rates have been increasing, requiring additional planning reserve margins until these units are repowered with more reliable units as described in Section 4.3.1.1. The new repowered units will be substantially cleaner, and more reliable, efficient, and community-friendly than the units they are replacing. Repowering LADWP's gas-fired units will also assist in integrating intermittent renewable resources into LADWP's energy mix by providing quick–response, back-up generation capacity.

Grid Reliability

LADWP's local transmission system cannot be reliably operated without generation from local thermal generating plants. The amount of generation required to provide transmission reliability is termed Reliability Must Run (RMR) generation. Repowering these local units will maintain transmission reliability by maintaining the reliability of RMR generation.

Historically, LADWP's local generation has provided voltage control for the basin transmission system. Over the years, as imports into the basin transmission system have increased, fewer local generators are needed on-line at any given time to supply power, reducing voltage control options for Power System operators. LADWP is countering this with plans to install static capacitors and reactors at strategic locations throughout the city. These installations are increasingly important as more renewables are imported.

LADWP's latest 2015 Ten-Year Transmission Assessment Plan has identified a number of infrastructure improvements that are needed to avoid potential overloads on key segments of the Basin transmission system. These overload conditions, caused by either loss of a particular substation or loss of more than two transmission components simultaneously, could lead to load shedding events (intentional power outages) to minimize the overall impact on the Power System.

Integration of Intermittent Renewable Energy

"Regulation" is necessary because the amount of electricity generated must always match system load, or electricity demand. If load and generation do not match, the power frequency would vary from the target frequency, resulting in problems that can damage motors, appliances and other equipment, and may lead to system collapse and power outages.

The integration of renewable energy into the grid poses major challenges. Because renewable resources like wind and solar produce electricity variably and intermittently (i.e., only when the wind is blowing or when the sun is shining), integration of these resources requires that controllable generators are online to smooth significant and often rapid changes to energy production. This stabilizing activity is known as "regulation" (see discussion box). A potential solution would use energy storage systems to regulate delivery of energy and reduce the severity of issues associated with integrating intermittent renewable energy. For regulation, LADWP currently uses natural gas-fired combustion turbines and hydro-electric resources, including pumped water storage. Ramping of fossil fuel-fired generation to compensate for the solar diurnal ramp up and down in the morning and evening will also require generation to be quick starting and fast ramping as illustrated by the gas energy sub-hourly profile effects of the duck curve shown in Figure 1-4. Issues with meeting the sub-hourly duck curve includes required regulation to address renewable sub-hourly variability and sufficient resources to meet an estimated 3,000 MW afternoon ramp when the sun sets.

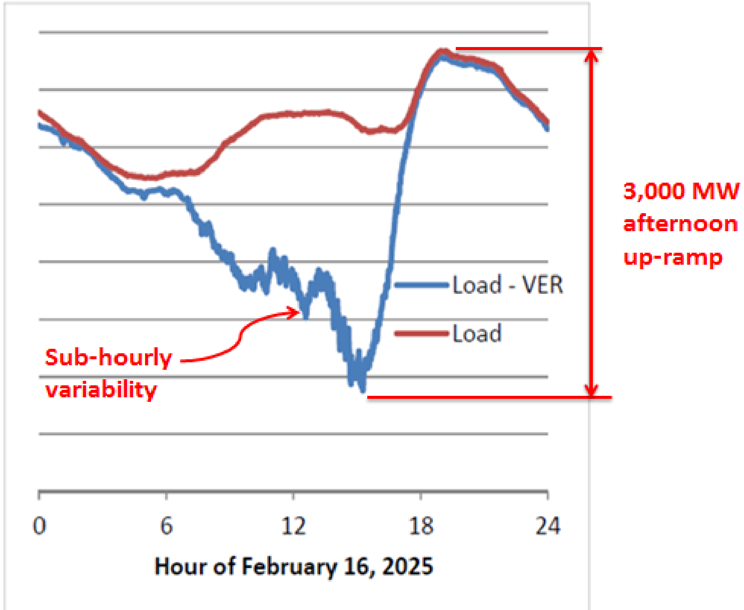


Figure 1-4. Generation profile for year 2025 illustrating over-generation and ramping issues.

Over-generation as shown in Figure 1-5, or generation that exceeds customer load demand, particularly on sunny days where load demand is correspondingly low, is of great concern with increasing amounts of solar generation. The operational issues associated with over-generation will require costly solutions to integrate these resources while maintaining a reliable system. Multiple solutions will need to be employed including: increased use of pumped hydro-electric energy storage, customer demand response incentives, and sales of excess energy. These solutions will drive up the incremental cost of these renewable resources especially as more renewable resources are added beyond the generation system's basic load requirements. Advanced energy storage technologies, such as batteries and compressed air energy storage, offer alternative energy storage solutions to help shift these resources to peak demand hours where these resources can provide greater benefit in meeting peak load that occurs in the late afternoon, early evening. However, these advanced energy storage technologies are still in development and have not yet been proven commercially viable or cost effective for utility scale applications. Until then, improved operations at the Castaic pumped hydro-electric facility will serve as the primary energy storage solution to help alleviate over-generation problems. Another promising solution which is currently being investigated is to offer our customers demand response incentives to shift customer electricity use to hours where over-generation occurs. (Refer to Section 2.4.5.2 and Appendix K for a discussion of LADWP's energy storage development activities.)

In 2015, LADWP contracted with a consulting team consisting of URS, DNV GL (Kema) and Navigant to examine the impacts of large amounts of variable energy resources (VER) on a range of system metrics and provide recommendations for actions and further study on cost-effective, reliable methods of VER integration. The study examines a large number of alternative scenarios over the 2014-2030 period, including VER penetrations of up to 50 percent, and covered a detailed sub-hourly analysis of operating reserves and system stability. A resource adequacy analysis was first performed on long-term production cost simulation results from the

IRP process. Results showed that the planned LADWP system is sufficiently flexible to integrate a high level of renewables, even at a 50% RPS requirement, although stresses increase towards the end of the 20-year forecast period. In parallel with the resource adequacy analysis, an analysis of the sub-hourly effects of increased VER penetration, including the effect on load-following and regulation requirements, was conducted. Based on the analyses and findings in this study, the consulting team offered the following recommendations – adopt a multi-dimensional metric for flexibility reserves and implement ECC tools that will allow ongoing assessment of hourly needs and availability of reserves, consider the cost-effectiveness of adopting 30-50 MW of battery storage for regulation, consider the cost effectiveness of alternative flexible resources such as flexible, fast ramping, fast starting generations, evaluate participation in CAISO's Energy Imbalance Market (EIM) as an additional means of managing VER variability, and gain further insight into the stability of the system under challenging conditions. For more information on the analysis, refer to Section 4.3.1 and Appendix J.

LADWP is currently conducting studies to determine the maximum levels of intermittent energy resources that can be integrated reliably on both the transmission and distribution systems in order to identify the investments necessary to maintain power grid reliability and minimize occurrences of over-generation. In particular, studies are ongoing to determine the impact of incorporating high levels of local distributed solar on the distribution grid and to determine what future measures would be required. The results of these reliability studies along with its ensuing economic impacts will be further analyzed and described in next year's 2016 IRP.

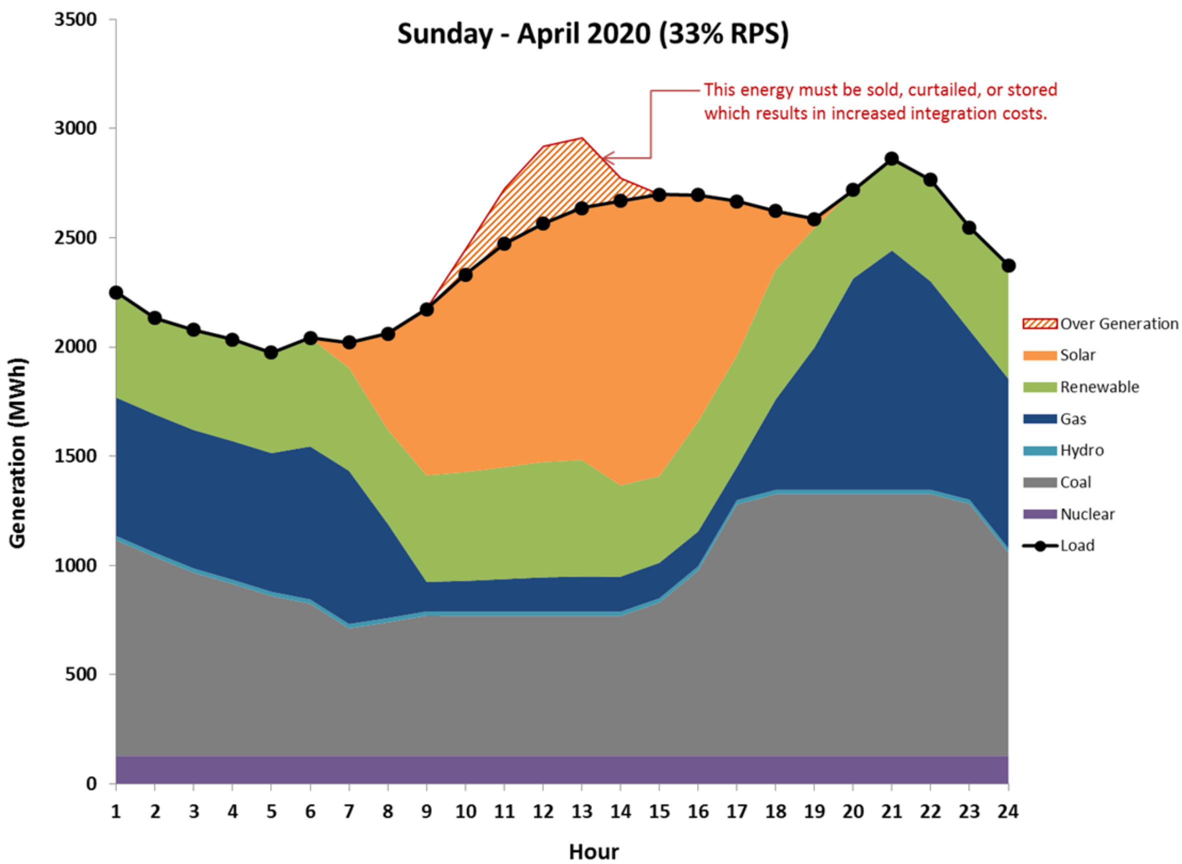


Figure 1-5. Generation profile for year 2020 illustrating over-generation and ramping issues.

1.6.3 Power System Reliability Program (PSRP)

In July 2014, the Power System Reliability Program (PSRP) was initiated to replace the existing Power Reliability Program (PRP). The PSRP includes the establishment of metrics and indices to help prioritize infrastructure replacement and expenditures from all major functions of the Power System, including generation, transmission, substation, and distribution (see Figure 1-6). It also includes all Power System assets affecting reliability in an integrated and comprehensive manner and proposes corrective actions as well as capital expenditures designed to minimize outages and maintain reliability in the short and long term.

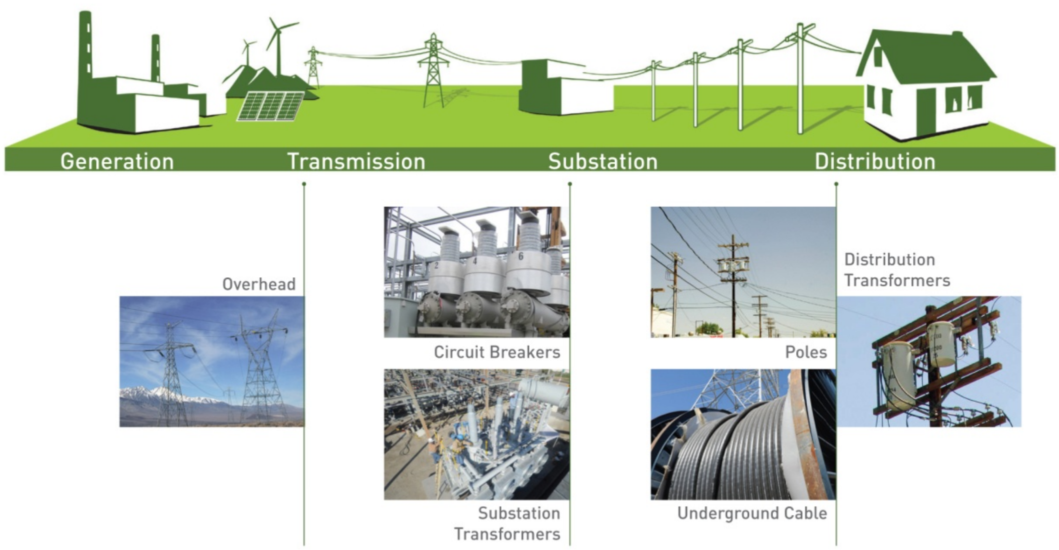


Figure 1- 6. Power System infrastructure assets for electricity delivery

It is a comprehensive, long-term power reliability program with the following major components: (a) mitigation of problem circuits and stations based on the types of outages specific to the facility, including permanent repairs of failed components after a failure and fixing poorly performing circuits, (b) proactive maintenance and capital improvements that take into account system load growth and (c) replacement cycles for facilities that are in alignment with the equipment's life cycle, including replacement of overloaded distribution transformers, as well as replacing aging underground cables, overhead poles and circuits and substation equipment.

The PSRP's initial focus will be based on the 2013 Power System Reliability Plan's asset replacement list (see Table 1-1). PSRP targets are anticipated to be updated on an annual basis to adjust to varying Power System conditions and resource allocations.

2013 PSRP Report Asset Recommended Replacement List			
Generation	**Transmission**	**Substation**	**Distribution**
Generator Step Up Transformers	138kV UG Transmission Circuit	High Side Transformers (RS)	Poles
Generation Station Transformers	138kV Stop Joints	Load Side Transformers (RS)	Crossarms
Major Inspection (Thermal)	Maintenance Hole Restraints	Local Substation Transformers (DS)	Lead Cable Miles
Major Inspection (Hydro)		Substation Transmission Breakers	Synthetic Cable Miles
Major Inspection (Pump)		34.5kV Substation Circuit Breakers	Transformers
San Fernando Power Plant		4.8kV Substation Circuit Breakers	Substructures
Contingency Fund		Substation Battery Banks	
		Substation Automation	

Table 1- 1. The 2013 PSRP Report Asset Recommended Replacement List

Ongoing Reliability Challenges:

- Adequate funding to support reliability programs
- Increasing reliability regulatory mandates
- Addressing aging infrastructure
- Integration of intermittent renewable energy resources
- Maintaining grid reliability

The number of overall outages has decreased since the PRP was initiated back in 2007. The PSRP will strive to continue the decreasing trend (see Figure 1-7).

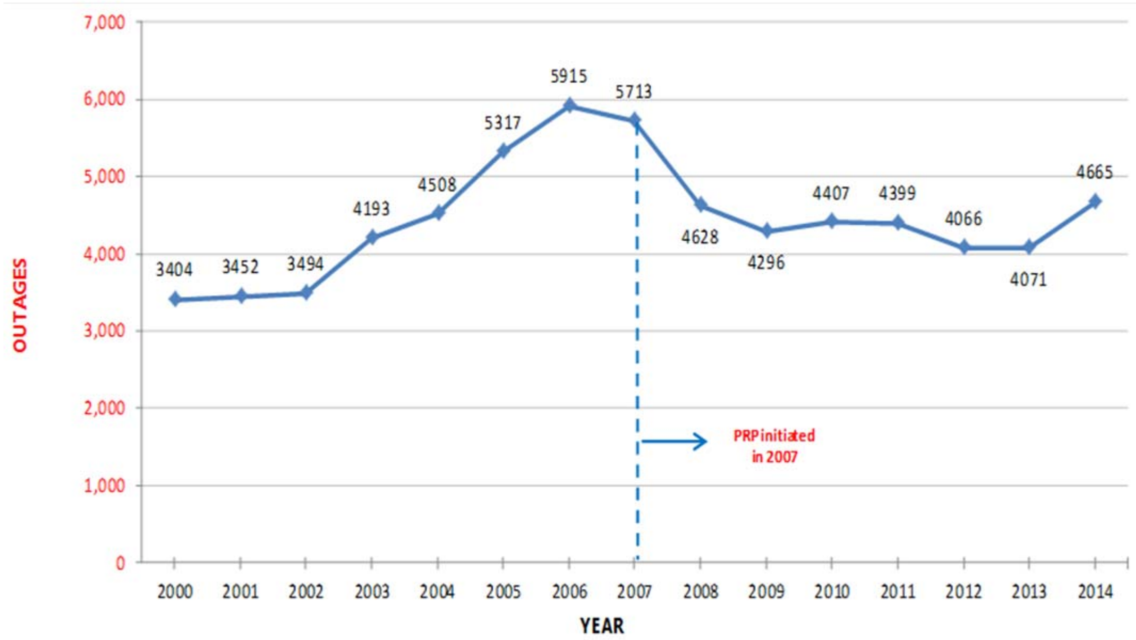


Figure 1- 7. Total outages between January 2000 and December 2014

1.6.3.1 Generation Reliability Program (GRP)

Single or multiple generation element failures can directly or indirectly impact generation resource operation and performance. For that reason, a robust generation system maintenance program aimed at sustaining a continuous and reliable power supply is desired.

The objectives of the Generation Reliability Program are:

- Determine and evaluate performance at generation facilities.
- Evaluate the existing generation system maintenance programs.
- Strengthen the existing generation system maintenance programs by proposing meaningful improvement solutions.
- Provide an evaluation of the overall generation system reliability through benchmarking.

Program Overview:

- Major Inspections of Thermal Generation (Thermal)
- Major Inspections of Large Hydroelectric Generation (Pump)
- Major Inspections of Small Hydroelectric Generation (Hydroelectric)
- Generation Step Up (GSU) and Station Service (SST) transformers

1.6.3.2 Transmission Reliability Program

The objectives of the Transmission Reliability Program are:

- Meet FERC, NERC, WECC and DWP reliability standards
- Establish asset replacement targets to address aging infrastructure
- Develop expansion programs to accommodate future growth

1.6.3.3 Substation Reliability Program:

The reliability discussed in this section refers to the substation infrastructure, and its performance in delivering uninterrupted power supply to customers.

The objectives of the Substation Reliability Program are:

- Transformers
  - High Voltage Transformers (>= 230kV)
  - Load Side Transformers (138kV, 230kV)
  - Local Bank Transformers (34.5kV to 4.8kV)
- Breakers
  - Receiving and Distribution Station Breakers (4.8kV, 34.5kV)
  - Transmission Breakers (>100kV)
- Substation Battery Banks
- Substation Automation Program

1.6.3.4 Distribution Reliability Program:

The reliability discussed in this section refers to the electricity delivery infrastructure, and its performance in delivering uninterrupted power supply to customers.

Certain assets of the electrical distribution infrastructure (e.g., poles, cables, transformers, etc.) will eventually reach the end of their service lives. Unless they are replaced, they will begin to fail, causing power outages and various problems. While the overall number of outages has decreased, the LADWP must address the growing backlog of aging assets to maintain, and conceivably continue to improve, the current level of reliability.

The objectives of the Distribution Reliability Program are:

- Meet IEEE standards, CPUC guidelines, and DWP reliability standards
- Establish asset replacement targets to address aging infrastructure
- Develop expansion programs to accommodate future growth

Reliability Performance Indicators

LADWP uses a number of industry-standard reliability metrics to quantify the performance of its Distribution system in terms of average outage frequency and outage duration. The two primary metrics are called SAIFI (frequency) and SAIDI (duration). These metrics allow LADWP to appropriately benchmark and compare the reliability performance of its Distribution system to other utilities.

System Average Interruption Frequency Index (SAIFI): It measures how many times the average customer has been out of service in a year.

2014 IEEE Survey:

Southern California Edison (2013): 0.88

San Diego Gas & Electric (2013): 0.47

Pacific Gas & Electric (2013): 0.92

LADWP (2014): 0.65

System Average Interruption Duration Index (SAIDI): It measures how long the average customer was without power in a year.

2014 IEEE Survey:

Southern California Edison (2013): 101.61

San Diego Gas & Electric (2013): 75.03

Pacific Gas & Electric (2013): 102.40

LADWP (2014): 77.69

Customer Average Interruption Duration Index (CAIDI): It tells us the average restoration time for any given outage in a year.

Southern California Edison (2013): 115.47

San Diego Gas & Electric (2013): 159.63

Pacific Gas & Electric (2013): 111.30

LADWP (2013): 149.68

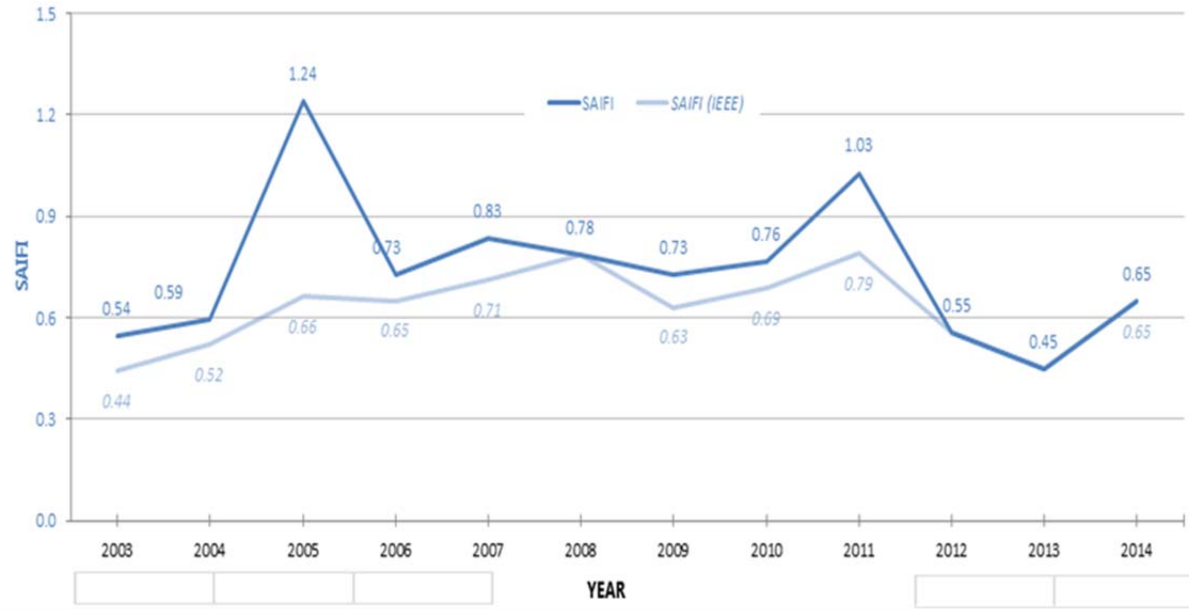


Figure 1-8. SAIFI indices (2003-2014) with and without Major Events excluded per IEEE 1366-2003

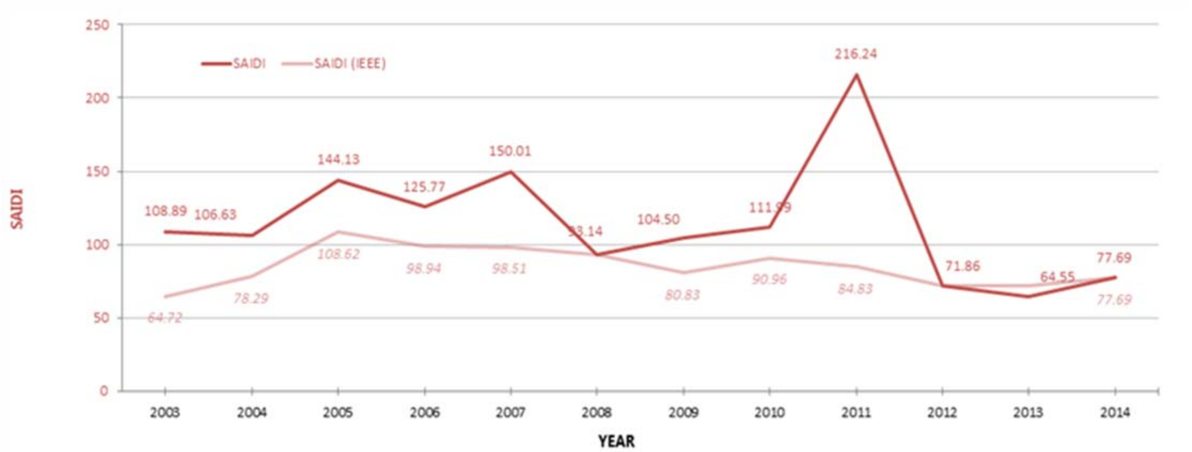


Figure 1-9. SAIDI indices (2003-2014) with and without Major Events excluded per IEEE 1366-2003

1.6.3.5 PSRP Budget

Reliability improvement in light of aging infrastructure and limited resources has become an issue for LADWP. Both customers and policy makers are demanding increased service levels at the same time that funding for additional initiatives is limited due to financial constraints and competing priorities. LADWP's investment decisions will balance the following factors:

- Strict Asset Management Principles,
- A Rigorous Reliability Analysis; and
- Staffing and Other Resource Optimization.

LADWP's approach to addressing these challenges will be based on a systematic analytical approach to manage the available resources and expenditures to meet basic service needs in a manner to maintain good overall reliability (See Figure 1-10).

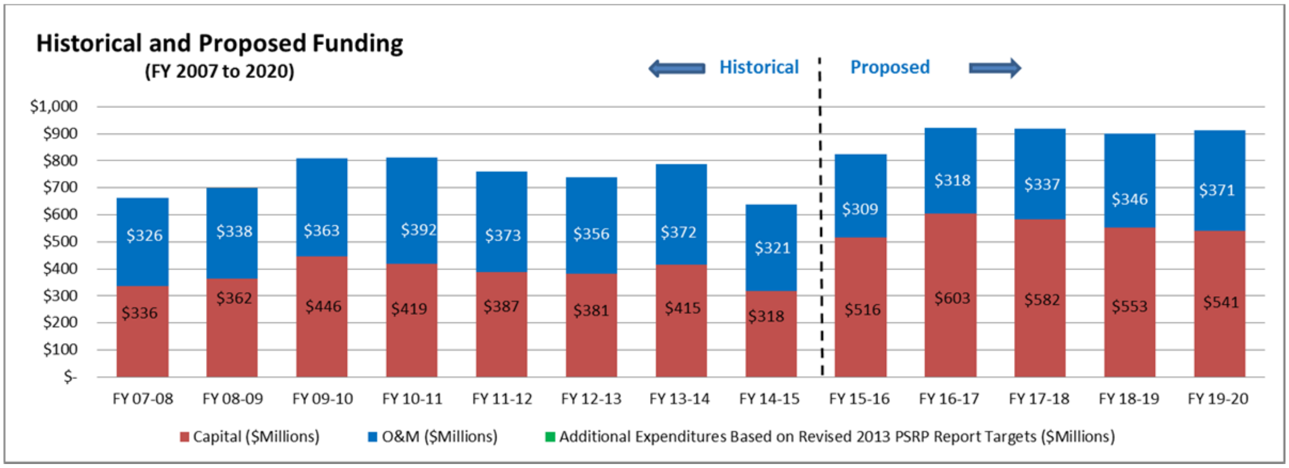


Figure 1-10. Historical and proposed O&M and Capital funding (FY 2014 - 2020)

1.6.4 GHG Emissions Reduction

The focus of LADWP's GHG or CO_2 equivalent (CO_2e) emissions reduction strategy is early replacement of coal-fired generation. Because coal emits relatively high levels of CO_2, switching to energy efficiency, renewables and other fuels will significantly lower overall emission levels. Early coal replacement facilitates LADWP's compliance with Assembly Bill (AB) 32's cap and trade program.

LADWP's GHG emissions reduction strategy must comply with state and federal regulations:

- SB 1368, the California Greenhouse Gas Emissions Performance Standard Act, enacted in 2006, prohibits LADWP and other California utilities from entering into long-term financial commitments for base load generation unless it complies with the GHG emissions performance standard. The GHG emissions level must be equal, or below, that of a gas-fired combined cycle units (i.e., 1,100 lbs per MWh). This standard also applies to existing power plants for any long-term investments or contractual extensions, thus effectively prohibiting LADWP from continued coal-fired generation beyond the current contractual expiration dates for NGS (2019) and IPP (2027).
- AB 32, the California Global Warming Solutions Act of 2006, calls for reducing the state's CO2 emissions to 1990 levels by 2020. The regulations for implementing a

greenhouse gas emissions Cap and Trade program under AB 32 were finalized and adopted on October 20, 2011 by the California Air Resources Board (ARB). Enforcement and compliance with the trading program began January 1, 2013. LADWP has been granted an administrative allocation of emission allowances that reflects its resource projections through 2020. On April 29, 2015, Governor Brown issued Executive Order B-30-15 to establish a California greenhouse gas reduction target of 40 percent below 1990 levels by 2030. California's new emission reduction target of 40 percent below 1990 levels by 2030 will make it possible to reach the ultimate goal of reducing emissions 80 percent below 1990 levels by 2050, as targeted by AB32.

- Clean Air Act, Section 111(d), the Clean Power Plan establishes a target emissions rate for each state, or the amount of carbon dioxide that could be emitted per megawatt-hour of power produced. The Clean Power Plan is expected to reduce carbon dioxide emissions from power plants 32 percent below 2005 levels by 2030. It provides flexibility, in which States may decide to pursue rate-based or mass-based plans. A rate-based plan would require the power fleet to adhere to an average amount of carbon per unit of power produced. A mass-based plan would cap the total tons of carbon the power sector could emit each year. States may adopt either an "emissions standards plan," which assigns standards to generators, or a "state measures plan," which can include a combination of enforceable emissions limits and additional programs—such as renewable energy and energy efficiency standards. Both types of plans may involve trading programs—whereby generators can purchase compliance credits from entities inside or outside their state that offset carbon emissions, including zero-carbon renewable power produced.

LADWP has historically relied upon coal for base load generation. In calendar year 2011, 41 percent of the energy delivered to LADWP customers was generated from NGS and IPP. At the end of 2011, a major cable failure resulted in damage to equipment at IPP, which took one unit off-line for six months. Since half of the energy from IPP was unavailable due to the outage, LADWP imported other resources and coal energy delivery decreased in 2012 to 33 percent. Once the unit at IPP was restored, coal energy delivery to LADWP customers returned to historical levels and in 2013, 42 percent of the energy delivered to LADWP customers was from coal. In 2015, LADWP approved an agreement to sell its share in Navajo to Salt River Project with the sale closing mid-2016. IPP's Power Purchase Agreement (PPA) contract is in effect until 2027; however, all 36 participants have agreed to repower the facility in 2025 with lower emitting gas-fired units and renewables. These stations have provided dependable, low cost base load generation to Los Angeles. However, as coal-fired electricity emits about twice as much CO_2 as energy generated with natural gas, this 2015 IRP focuses on early coal replacement as a means to lower LADWP's GHG emission levels. Section 2.4.2.3 presents more detail on LADWP's early replacement plans, and Sections 3 and 4 discuss the alternative coal replacement options that were modeled and analyzed.

1.6.5 Increasing Renewable Resources

Initiatives to utilize renewable resources to generate electricity support the goal of reducing GHG emissions and decrease our reliance upon fossil fuels.

- State legislation – SB 2 (1X) – which was passed in April 2011 and became effective December 10, 2011, requires utilities to procure eligible renewable energy resources of 33 percent by 2020, including the following interim targets:
  - Maintain at least an average of 20 percent renewables between 2011 and 2013.
  - Achieve 25 percent renewables by 2016.
  - Achieve 27 percent renewables by 2017.
  - Achieve 29 percent renewables by 2018.
  - Achieve 31 percent renewables by 2019.
  - Achieve 33 percent renewables by 2020.

- State legislation – SB 350 – which was passed in September 2015 and became effective October 7, 2015, requires utilities to procure eligible renewable energy resources of 50 percent by 2030, including the following interim targets:
  - Achieve 40 percent renewables by 2024.
  - Achieve 45 percent renewables by 2027.
  - Achieve 50 percent renewables by 2030 and maintain this level in all subsequent years.

  SB 350 also requires a doubling of energy efficiency of buildings 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 reductions 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.

- SB 32, signed into law on October 11, 2009, and SB 1332 signed into law on September 27, 2012, requires LADWP to make a tariff available to eligible renewable electric generation facilities until LADWP meets its 75 MW share of the statewide target. Through this program, owners or operators of eligible renewable energy systems may sell their energy directly to LADWP. The purchase of energy will include all environmental attributes, capacity rights, and renewable energy credits which will apply towards LADWP's 50 percent renewable requirement.

- 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, including municipals, 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 expenditures not to exceed $3.35 Billion. Expenditures for local publicly owned electric utilities shall not exceed $784 Million. The LADWP cap amount is $313 Million, based on its serving 39.9% of the municipal load in the state.

- The LADWP Board of Commissioners has adopted a policy to achieve 20 percent renewables by 2010, and 33 percent by 2020. The Board and City Council have approved projects and long-term power purchase agreements that achieved the 20 percent RPS goal in 2010. The policy has been revised to incorporate SB 2 (1X) requirements, and is included as Reference D-2 of Appendix D.

In addition, SB 2 (1X) sets certain conditions regarding renewable energy contracts entered into on or after June 1, 2010, as shown in Table 1-2.

Table 1-2. 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.

SB 2 (1X) became effective on December 10, 2011, and required the governing board of a local Public Owned Utility (POU), such as LADWP, to adopt a program for enforcement in accordance with Public Utilities Code (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 (OAL) approved the California Energy Commission's (CEC) Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (Regulations)[2]. These Regulations became

[2] ***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-

effective as of October 1, 2013.

The adopted Regulations have placed additional criteria to the procurement targets for each compliance period:

1. For the compliance period beginning January 1, 2011, and ending December 31, 2013, POUs are required to meet or exceed an average of 20 percent RPS over the three calendar years in the compliance period.
2. 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.
3. 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.

In December 2013, LADWP amended its Renewable Portfolio Standard (RPS) Policy and Enforcement Program to comply with the requirements of SB 2 (1X) and the Regulations. However, LADWP's policy continues to include some requirements that are not a part of SB 2 (1X) or the Regulations but were in place prior to enactment of the State legislation. These additional requirements include the provision for LADWP to own at least 50 percent of its renewable energy resources, and to give preference to projects located within the City.

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.

1.6.6 Once-through Cooling

Once-through cooling (OTC) is the process of drawing water from a river, lake, or ocean, pumping it through a generating station's cooling system, and discharging it back to the original body of water. OTC is a utility regulatory issue, stemming from the Federal Environmental Protection Agency (EPA) Clean Water Act Section 316(b) and administered locally by the State

002-CMF. Available at: http://www.energy.ca.gov/2013publications/CEC-300-2013-002/CEC-300-2013-002-CMF.pdf

Water Resources Control Board (SWRCB). The interpretation of rules and development of guidelines for OTC have been several years in the making. See Appendix C for details.

OTC regulations affect LADWP's three coastal generating stations – Scattergood, Haynes, and Harbor. To comply with OTC regulations, generation units at those stations that utilize ocean water for cooling will be repowered with new units that do not utilize ocean water. The amount of generation capacity affected by OTC is significant – approximately 2,839 MW of LADWP's total in-basin plant capacity of 3,415 MW. The amount of expenditures required is also significant, on the order of $2.2 billion. Because of the size and scope of the effort required, the work to comply with OTC regulation is a long-term program, extending to 2029.
It should be noted here that many of the units being replaced are older units that would have eventually been replaced even without the OTC requirement. However, the OTC mandate requires a significant reduction in the use of ocean water and therefore, OTC is being eliminated and replaced with closed cycle cooling. Satisfying the OTC mandate accelerates the replacement schedule of the affected generation units.

Discussions between LADWP and the SWRCB have resulted in the following timeline for OTC compliance (Figure 1-11).

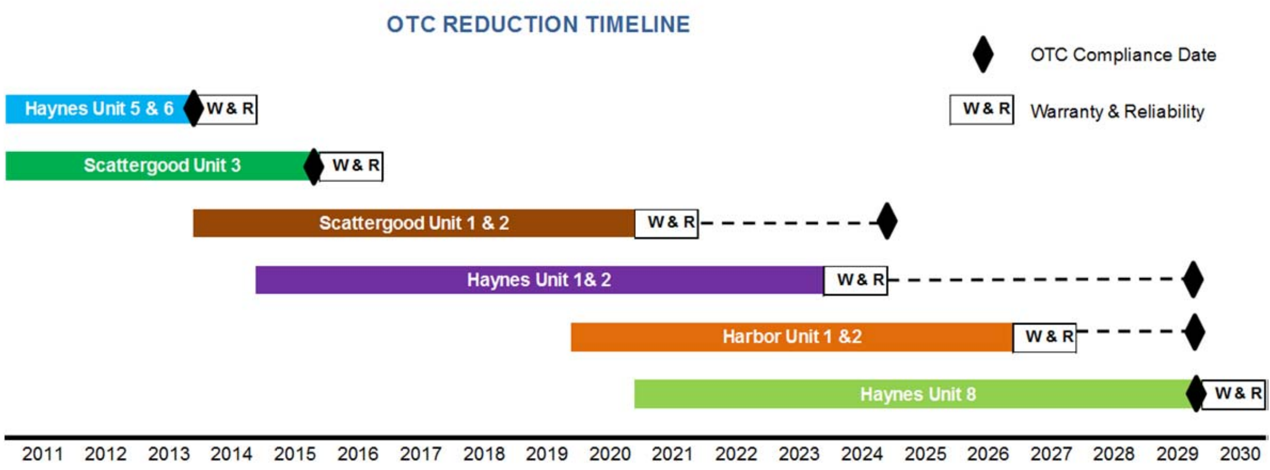


Figure 1-11. Timeline for OTC compliance.

There are many constraints and considerations that were factored into the development of the OTC compliance timeline. Because the LADWP Power System relies on the in-basin units to provide voltage support and stability to the entire system, in addition to transmission system reliability, as well as local sources of power generation, it is important to keep all of the units available to meet local capacity requirements. An existing unit that is being replaced cannot be decommissioned (shut down) until the new replacement unit is built, tested, and ready to go on-line. This requires a strict sequencing of the separate repowering projects, as shown on Figure 1-11.

There are many challenges to meeting the target dates. The limited space available within all of the generating station property boundaries presents planning and construction difficulties. Other issues include the long lead times required for environmental permitting, engineering design, and equipment procurement. Any unforeseen delay – for example, a delay in acquiring an environmental permit or a delay in delivery of new plant components – will adversely affect the schedule. The timeline shown in Figure 1-12 represents LADWP's best effort to comply with the mandated compliance deadlines while also meeting its reliability responsibilities.

The effects of the repowering program on OTC use are shown in Figure 1-12. As individual units are replaced with new units that do not utilize OTC, OTC levels decrease. The overall goal of the program is the total elimination of OTC by 2029. Additional discussion regarding LADWP's compliance with OTC regulations can be found in Appendix C.

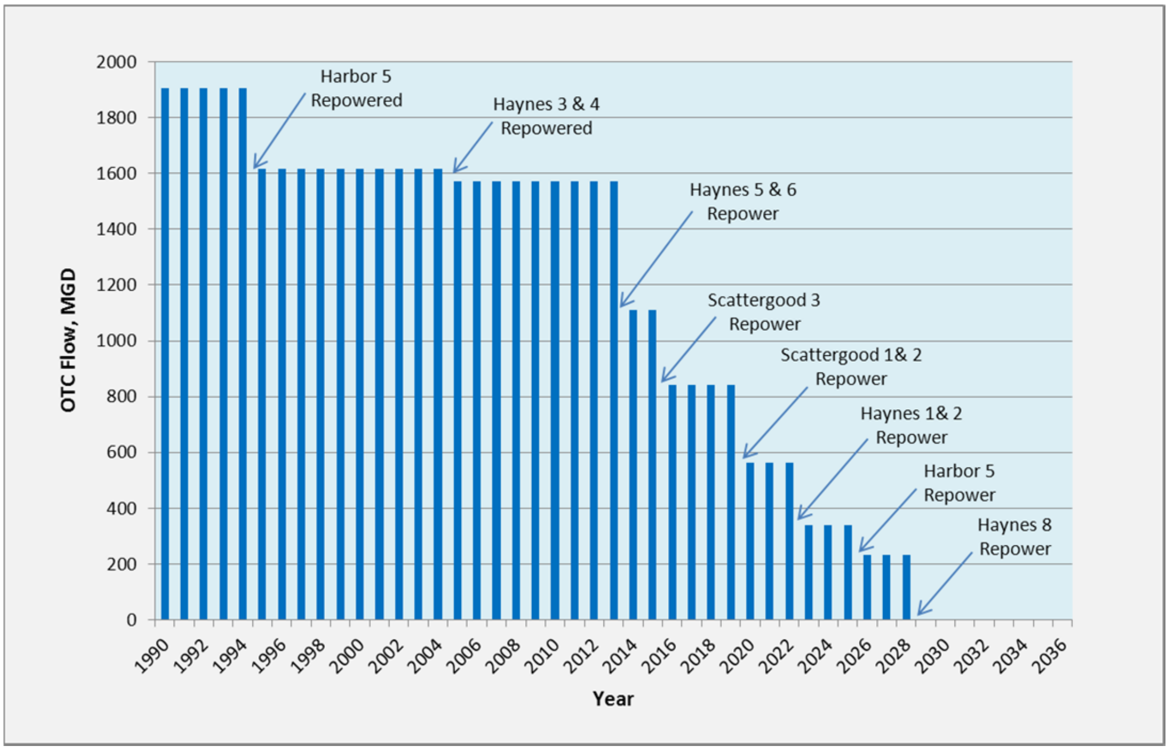


Figure 1-12. LADWP's reduction in once-through cooling from 1990 to 2029.

1.6.7 Staffing and Training the Workforce - Integrated Human Resources Plan (IHRP)

To effectively implement the programs and projects recommended in this IRP, an effective human resources plan is required for the 132 civil service classifications who perform core work related to generation, transmission, and distribution of electricity. The Power System must therefore carefully plan and execute human resource solutions to a number of demand side and supply side challenges.

Supply and Demand

The principles of supply and demand that operate in the business world also apply to the long-term development of human resources. The "demand" is the need of the Power System to have a talented workforce available whenever IRP projects and programs require them. The "supply" is the talent pool of human resources that are available to supply this "demand" in a timely manner. Figure 1-13 below represents some of these dynamics of demand and supply:

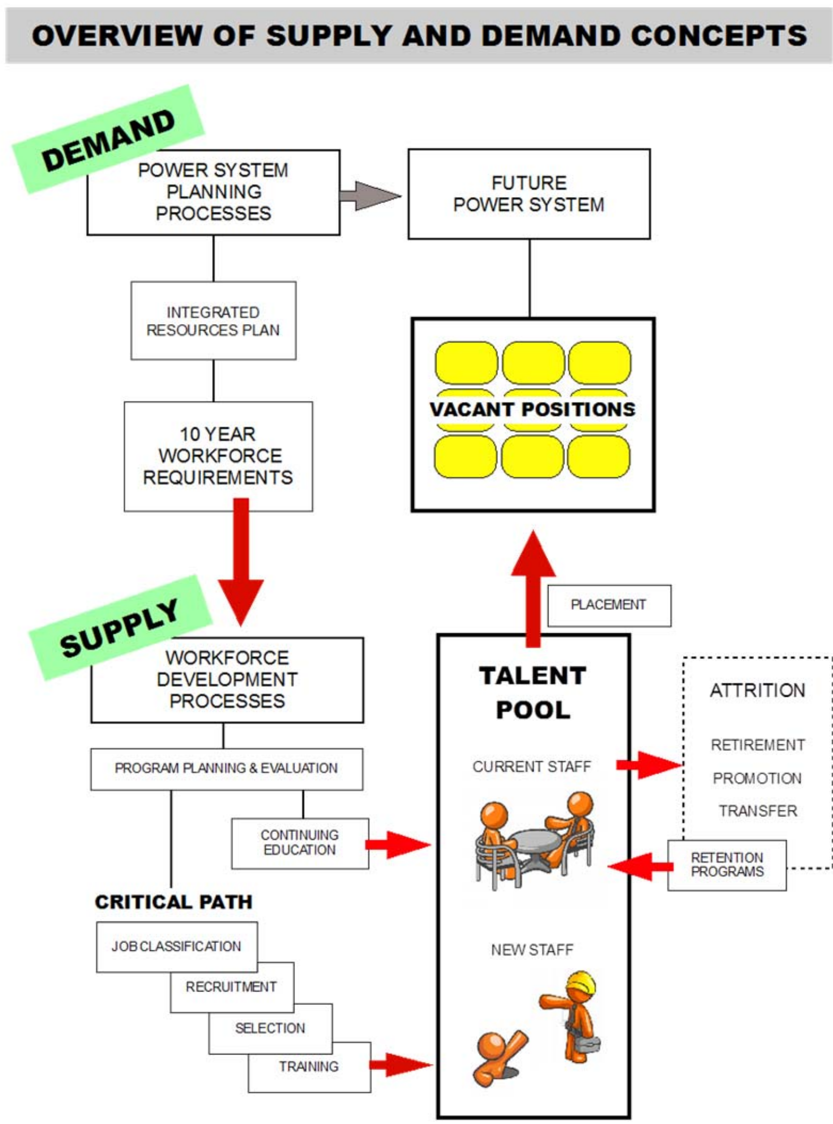


Figure 1-13. Overview of the supply and demand concepts for the Power System

On the demand side, Figure 1-13 illustrates the planning process that will identify vacant positions in future operations. These open positions are referred to as forecasted workforce "gaps." Currently there is a workforce gap of 394 unfilled positions in the Power System. Current funding is at the level of 4,263 positions with only 3,869 positions actually filled. When this gap is joined by the significant attrition that will occur over the next ten years, the Power System will face a large shortfall of workforce availability. There are two causes of workforce gaps. A gap may be the result of the increase in approved positions through business expansion and growth. Some of the current drivers for expansion of the Power System are greater service demands, the acquisition of new technologies to improve reliability, and mandated O&M repairs, upgrades, and use of renewables. A workforce gap can also result from employee attrition through retirements, promotions, and transfers. Of these, potential retirements will be the strongest driver over the next ten years.

Adequate Staffing

By 2023 a significant number of the current Power System workforce are expected to retire. The expected level is over 1,200 employees and may exceed 1,700. The loss of 1,200 equals a minimum of 37,400 years of experience and knowledge walking out the door as illustrated in Figure 1-14. The vast exiting of talent, knowledge, and experience places the operations of the Power System at great risk. This exodus of retirees will come at a time when the Power System will be implementing significant changes in operations that utilize new, more efficient and renewable generation methods and advanced smart-grid technologies. These changes demand a larger future workforce with new skills, capabilities, and expertise.

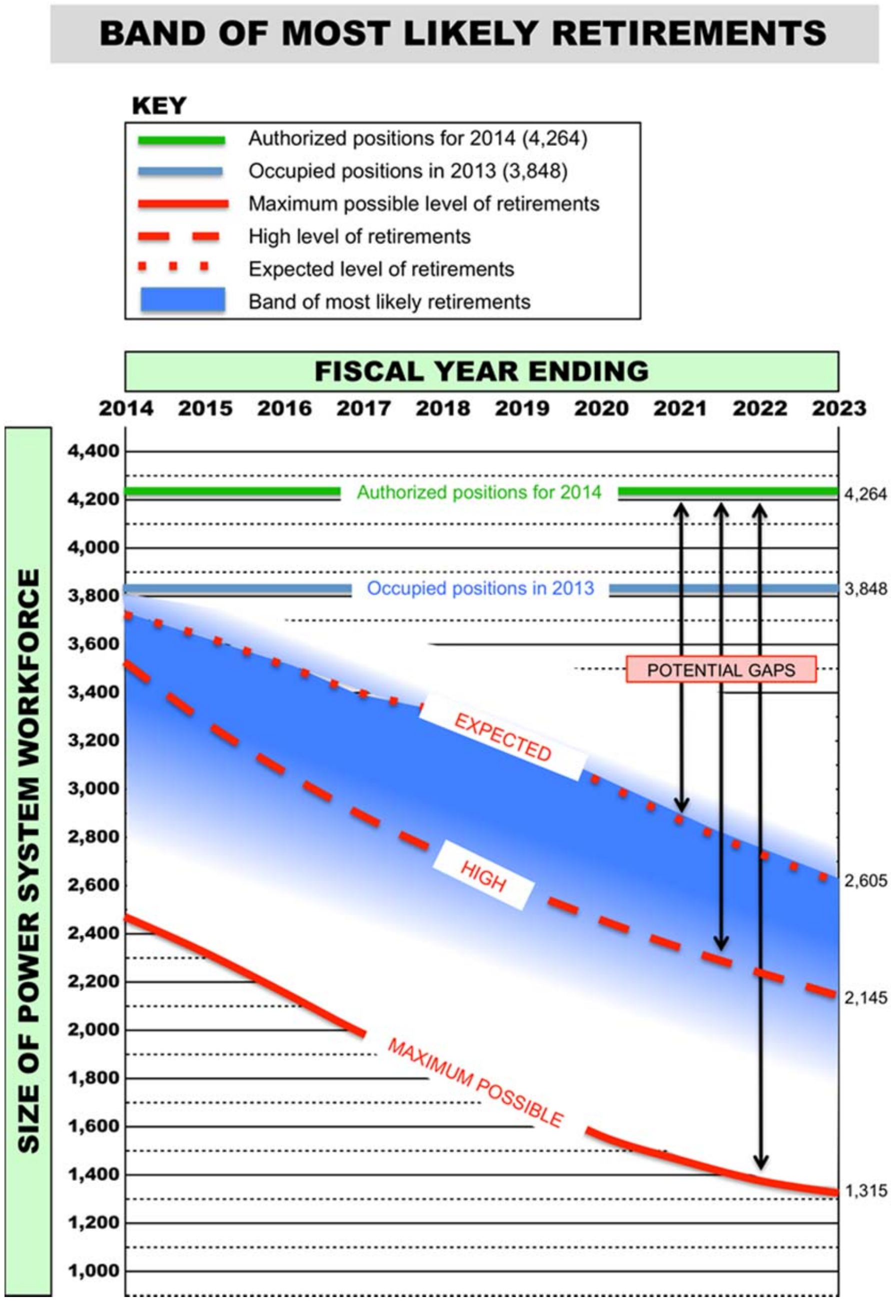


Figure 1-14. The Potential impact of eligible retirements of Power System work force by 2023

Forecasted Gaps

An examination of specific job classifications reveals some important trends. Figure 1-15 below shows the potential cumulative impact of retirement that will cause attrition in 34 selected positions. These positions are integral to the core business of the Power System and can have replacement lead times of up to 6 years or longer.

FORECASTED GAPS IN 34 KEY POSITIONS FROM 2014 TO 2023

CUMULATIVE PERCENTAGE OF 2013 APR

- >75 to 100%
- ≥50 to <75%
- ≥25 to <50%
- <25%

CLASS TITLES	CODE	2013 ACTUALS APR	2013 ACTUALS OCC	2013 ACTUALS GAP	2014 RET	2014 GAP	2014 CUM %	2015 RET	2015 GAP	2015 CUM %	2016 RET	2016 GAP	2016 CUM %	2017 RET	2017 GAP	2017 CUM %
ELECTRIC DISTRIBUTION MECHANIC (a)	3879	548	428	120	5	125	23%	5	130	24%	5	135	25%	7	142	26%
ELECTRICAL CRAFT HELPER	3799	362	270	92	1	93	26%	3	96	27%	4	100	28%	4	104	29%
ELECTRICAL ENGR ASSOCIATE	7525	313	279	34	5	39	12%	4	43	14%	8	51	16%	9	60	19%
ELECTRICAL MECHANIC (a)	3841	263	258	5	3	8	3%	1	9	3%	2	11	4%	4	15	6%
ELECTRIC STATION OPERATOR (a)	5224	224	206	18	1	19	8%	5	24	11%	8	32	14%	12	44	20%
STEAM PLANT ASSISTANT	5622	134	119	15	0	15	11%	0	15	11%	0	15	11%	1	16	12%
ELEC DISTR MECH SUPV	3873	104	95	9	3	12	12%	3	15	14%	3	18	17%	7	25	24%
ELECTRICAL TESTER	7512	102	96	6	1	7	7%	1	8	8%	1	9	9%	0	9	9%
STEAM PLANT OPERATOR	5624	91	90	1	3	4	4%	1	5	5%	2	7	8%	2	9	10%
SENIOR ELECTRICAL MECHANIC	3834	66	59	7	3	10	15%	2	12	18%	1	13	20%	1	14	21%
ELECTRICAL REPAIRER	3853	62	46	16	0	16	26%	1	17	27%	1	18	29%	2	20	32%
ELECTRICAL ENGINEER	7539	58	52	6	3	9	16%	1	10	17%	5	15	26%	4	19	33%
STM PLT MTNC MCHC	5630	57	51	6	1	7	12%	1	8	14%	2	10	18%	0	10	18%
SENIOR ELECTRICAL TESTER	7515	49	38	11	2	13	27%	2	15	31%	2	17	35%	2	19	39%
MACHINIST	3763	44	38	6	1	7	16%	0	7	16%	1	8	18%	1	9	20%
ELTC SRVC REPTV	7520	42	44	-2	1	-1	-2%	3	2	5%	2	4	10%	3	7	17%
ELECTRICAL SERVICE MANAGER	5265	41	35	6	5	11	27%	2	13	32%	4	17	41%	4	21	51%
LOAD DISPATCHER	5233	40	34	6	1	7	18%	0	7	18%	1	8	20%	1	9	23%
TRANS & DISTR DIST SUPV	3875	39	32	7	1	8	21%	2	10	26%	2	12	31%	3	15	38%
INSTRUMENT MECHANIC	3843	37	38	-1	1	0	0%	1	1	3%	2	3	8%	1	4	11%
STM PLT OPRG SUPV	5625	31	24	7	5	12	39%	4	16	52%	4	20	65%	2	22	71%
POWER ENGINEERING MANAGER	9453	25	23	2	1	3	12%	0	3	12%	3	6	24%	4	10	40%
TREE SURGEON SUPERVISOR	3117	24	22	2	2	4	17%	1	5	21%	1	6	25%	1	7	29%
CHIEF ELECTRIC PLANT OPERATOR	5237	22	17	5	2	7	32%	3	10	45%	2	12	55%	2	14	64%
SENIOR LOAD DISPATCHER	5235	22	19	3	0	3	14%	0	3	14%	0	3	14%	2	5	23%
SR ELTL MCHC SUPV	3836	22	23	-1	1	0	0%	1	1	5%	1	2	9%	1	3	14%
STM PLT MTNC SUPV	3786	15	12	3	1	4	27%	0	4	27%	1	5	33%	2	7	47%
ELECTRICAL REPAIR SUPERVISOR	3855	8	9	-1	0	-1	-13%	0	-1	-13%	0	-1	-13%	1	0	0%
MACHINIST SUPERVISOR	3768	8	8	0	1	1	13%	0	1	13%	0	1	13%	1	2	25%
SR ELTC TRBL DSPR	3829	8	5	3	0	3	38%	0	3	38%	1	4	50%	0	4	50%
INSTRUMENT MECHANIC SUPV	3844	6	6	0	0	0	0%	0	0	0%	0	0	0%	1	1	17%
SR ELTC SRVC REPTV	7521	4	5	-1	0	-1	-25%	1	0	0%	0	0	0%	1	1	25%
SR ELTL RPR SUPV	3858	3	3	0	0	0	0%	0	0	0%	0	0	0%	0	0	0%
SENIOR MACHINIST SUPERVISOR	3788	1	1	0	0	0	0%	0	0	0%	0	0	0%	1	1	100%

CLASS TITLES	2018 RET	2018 GAP	2018 CUM %	2019 RET	2019 GAP	2019 CUM %	2020 RET	2020 GAP	2020 CUM %	2021 RET	2021 GAP	2021 CUM %	2022 RET	2022 GAP	2022 CUM %	2023 RET	2023 GAP	2023 CUM %
ELECTRIC DISTRIBUTION MECHANIC (a)	8	150	27%	8	158	29%	11	169	31%	10	179	33%	15	194	35%	14	208	38%
ELECTRICAL CRAFT HELPER	5	109	30%	5	114	31%	5	119	33%	5	124	34%	7	131	36%	7	138	38%
ELECTRICAL ENGR ASSOCIATE	4	64	20%	6	70	22%	7	77	25%	6	83	27%	5	88	28%	10	98	31%
ELECTRICAL MECHANIC (a)	2	17	6%	6	23	9%	7	30	11%	6	36	14%	5	41	16%	9	50	19%
ELECTRIC STATION OPERATOR (a)	6	50	22%	5	55	25%	3	58	26%	3	61	27%	4	65	29%	4	69	31%
STEAM PLANT ASSISTANT	0	16	12%	0	16	12%	1	17	13%	1	18	13%	1	19	14%	1	20	15%
ELEC DISTR MECH SUPV	5	30	29%	5	35	34%	9	44	42%	10	54	52%	7	61	59%	7	68	65%
ELECTRICAL TESTER	0	9	9%	1	10	10%	1	11	11%	0	11	11%	1	12	12%	5	17	17%
STEAM PLANT OPERATOR	2	11	12%	1	12	13%	1	13	14%	1	14	15%	3	17	19%	1	18	20%
SENIOR ELECTRICAL MECHANIC	2	16	24%	2	18	27%	3	21	32%	1	22	33%	2	24	36%	3	27	41%
ELECTRICAL REPAIRER	1	21	34%	3	24	39%	2	26	42%	2	28	45%	2	30	48%	3	33	53%
ELECTRICAL ENGINEER	3	22	38%	3	25	43%	5	30	52%	4	34	59%	4	38	66%	3	41	71%
STM PLT MTNC MCHC	2	12	21%	1	13	23%	1	14	25%	1	15	26%	3	18	32%	1	19	33%
SENIOR ELECTRICAL TESTER	2	21	43%	1	22	45%	2	24	49%	2	26	53%	3	29	59%	2	31	63%
MACHINIST	1	10	23%	0	10	23%	0	10	23%	2	12	27%	1	13	30%	0	13	30%
ELTC SRVC REPTV	3	10	24%	2	12	29%	2	14	33%	2	16	38%	2	18	43%	2	20	48%
ELECTRICAL SERVICE MANAGER	2	23	56%	2	25	61%	3	28	68%	4	32	78%	2	34	83%	2	36	88%
LOAD DISPATCHER	1	10	25%	0	10	25%	1	11	28%	1	12	30%	1	13	33%	0	13	33%
TRANS & DISTR DIST SUPV	2	17	44%	2	19	49%	4	23	59%	4	27	69%	3	30	77%	3	33	85%
INSTRUMENT MECHANIC	1	5	14%	0	5	14%	1	6	16%	1	7	19%	2	9	24%	0	9	24%
STM PLT OPRG SUPV	1	23	74%	1	24	77%	0	24	77%	1	25	81%	0	25	81%	0	25	81%
POWER ENGINEERING MANAGER	3	13	52%	2	15	60%	2	17	68%	2	19	76%	2	21	84%	1	22	88%
TREE SURGEON SUPERVISOR	2	9	38%	1	10	42%	2	12	50%	1	13	54%	1	14	58%	1	15	63%
CHIEF ELECTRIC PLANT OPERATOR	1	15	68%	2	17	77%	1	18	82%	0	18	82%	0	18	82%	1	19	86%
SENIOR LOAD DISPATCHER	2	7	32%	0	7	32%	2	9	41%	1	10	45%	2	12	55%	0	12	55%
SR ELTL MCHC SUPV	1	4	18%	2	6	27%	2	8	36%	1	9	41%	0	9	41%	3	12	55%
STM PLT MTNC SUPV	1	8	53%	1	9	60%	1	10	67%	0	10	67%	2	12	80%	1	13	87%
ELECTRICAL REPAIR SUPERVISOR	1	1	13%	0	1	13%	2	3	38%	1	4	50%	1	5	63%	1	6	75%
MACHINIST SUPERVISOR	0	2	25%	0	2	25%	0	2	25%	2	4	50%	1	5	63%	0	5	63%
SR ELTC TRBL DSPR	0	4	50%	1	5	63%	0	5	63%	2	7	88%	1	8	100%	0	8	100%
INSTRUMENT MECHANIC SUPV	0	1	17%	0	1	17%	1	2	33%	2	4	67%	1	5	83%	0	5	83%
SR ELTC SRVC REPTV	0	1	25%	1	2	50%	0	2	50%	0	2	50%	0	2	50%	0	2	50%
SR ELTL RPR SUPV	0	0	0%	1	1	33%	1	2	67%	0	2	67%	0	2	67%	0	2	67%
SENIOR MACHINIST SUPERVISOR	0	1	100%	0	1	100%	0	1	100%	0	1	100%	0	1	100%	0	1	100%

OCC = Positions currently occupied as of 10/28/13
(a) = The "occupied" number has been reduced by the historical graduation rate for trainees in this job classification from 2008 to today
EDMT graduation rate = 40%
ESOT graduation rate = 47%
EMT graduation rate = 75%

Figure 1-15. Forecasted gaps in 34 key positions from 2014 to 2023

Feeder Class Vacancies

Feeder class vacancies are increasing and will impede normal promotional ladders from filling positions that have routinely become vacant. Therefore, alternative hiring practices will be required to fill these vacancies, including exempt and contract labor. To illustrate this issue, the Electrical Craft Helper (ECH) position is a talent pool that over time can feed vacancies for 27 other positions in three Power System Divisions; however, at present the ECH position has 92 unfilled positions. Figure 1-16 illustrates the ECH career ladder that is located in Integrated Support Services, Power Supply Operations, and Transmission & Distribution Divisions and shows the potential retirement rate for 28 positions (including ECH) at or above the ECH. This chart shows the cumulative impact of forecasted retirement by 2018 in nearly all positions. These impending vacancies put great pressure on the ECH position to be the main source of promotable talent, particularly for the 10 positions that are directly above the ECH. This problem is exacerbated because the ECH position is also vulnerable to a high amount of attrition.

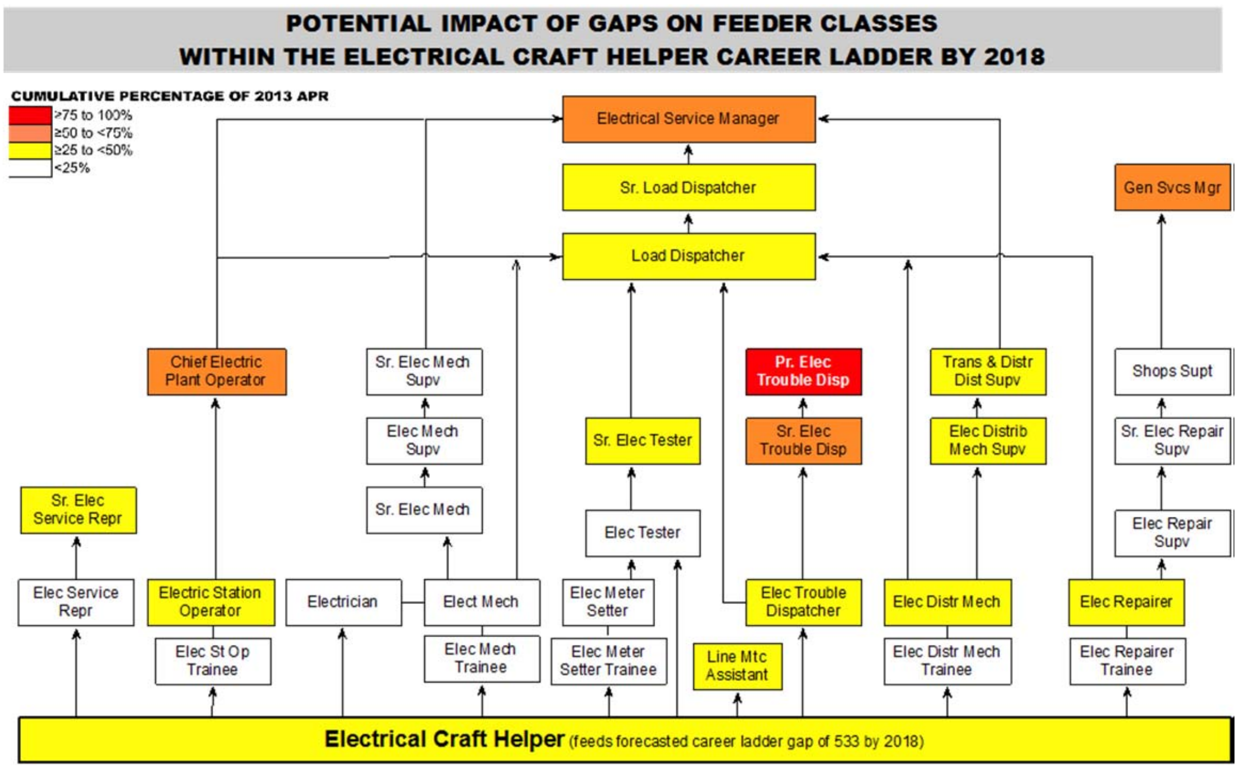


Figure 1-16. The potential impact gaps on feeder classes within the Electrical Craft Helper career ladder by 2018.

The Critical Path

The time currently required to fill a position can take up to six years or longer. This duration puts the Power System at a significant competitive disadvantage. Others cities and private employers can make job offers to prospective DWP employees within days, not over an extended period of time. Figure 1-17 below displays the durations of the five steps in the Critical Path. It is evident that the three steps prior to training (job classification, recruitment, and selection) can create serious delays in hiring. These durations must be reduced to allow LADWP to compete effectively for talent in the marketplace.

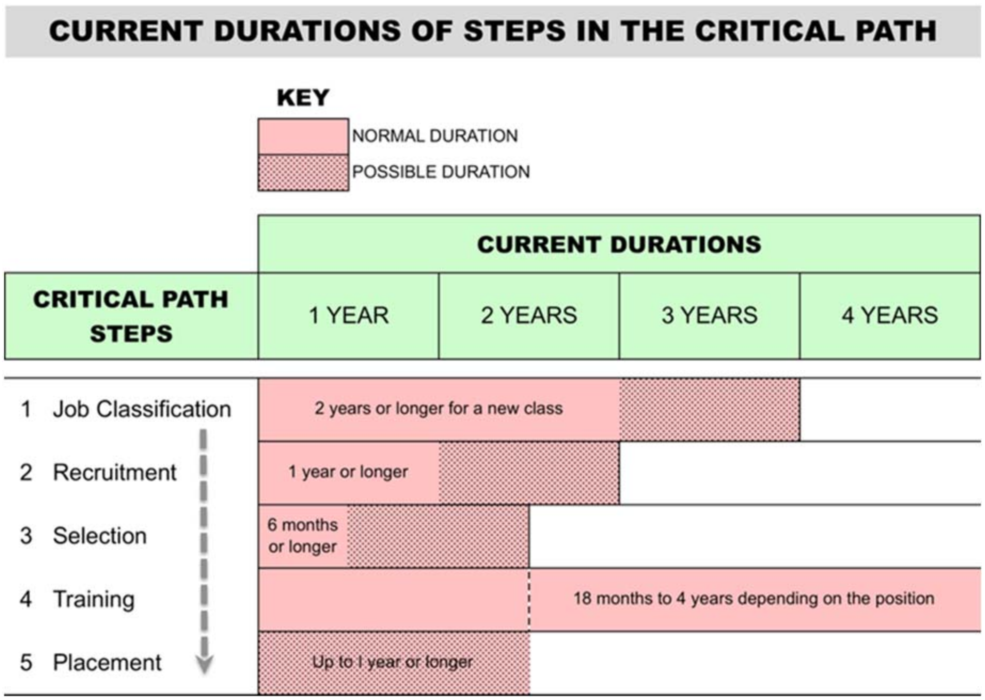


Figure 1-17. Current durations of steps in the Critical Path.

In 2013, the Power System launched the Integrated Human Resources Plan (IHRP) as a broad and systemic solution that can be found in Appendix P. It is a significant and far-reaching strategy that will manage the availability of the Power System's workforce for the next ten years and beyond. The IHRP is an integral part of resource planning that can make reasonable forecasts of the Power System's long-term employment needs while taking into consideration statistical retirement projections. The IHRP will ensure that trained and talented employees will always be available when needed to perform the important work that is described in this IRP document. The IHRP is a cooperative effort between the Los Angeles Department of Water and Power and the International Brotherhood of Electrical Workers (IBEW) Local 18. Since the launch of the IHRP Program, Power System staff has been actively working with the Personnel Department of the City of Los Angeles to ensure critical examinations are administered to meet hiring plans and improve the quality of candidates eligible for hire.

New Engineering Associate Training Program

One of the key outcomes of the IHRP is the New Engineering Associate Training (NEAT) Program launched in 2013, which aims to train Power System engineers in engineering processes and standards, to closely integrate design, operations and maintenance, and construction, and to understand how their work fits in the context of the overall Power System. The program is directed by the Joint Labor Management Committee with the objective of providing "on the job training" through central classroom teaching and rotation experience. NEAT engineers undergo three 4-month rotations in different Sections within the Power System their first year and are placed in a permanent group their second year.

Customer Care Billing System

In 2014, LADWP experienced a problematic rollout of the new Customer Care Billing (CCB) System, which disrupted the ability to collect unpaid bills. LADWP hired an outside consultant, who conducted a root cause analysis and determined that inadequate project management, vendor inexperience with the level of system complexity, and an unprepared workforce were the key issues related to CCB. In an effort to address key CCB issues, LADWP transitioned its leadership to focus on CCB, increased transparency in communication through dashboard reporting and increased community outreach, refocused its resources on critical issues, and hired additional customer service representatives and meter readers. Additionally, LADWP developed formal training curriculums for new and existing employees, engaged supplemental technical assistance for root cause analysis, system stabilization, reporting functionality, customer enhancements, data clean-up activities, and address collections through lenient payment arrangements. As a result, billing issues and customer wait times have significantly decreased. LADWP continues to focus its attention on customer service and increased transparency.

1.6.8 Additional Challenges

Additional challenges that LADWP must address include an increased risk from natural gas price volatility, a push towards higher levels of distributed generation, a need for more robust and precise transmission planning, addressing cyber security legislation, hydro-plant re-licensing, the future effects of climate change on power generation and operations, and improving system load factor.

- Natural Gas Price Volatility

  To the extent that LADWP seeks to reduce its GHG footprint, but cannot meet all its future needs through renewable resources and EE programs, a greater percentage of generation utilizing natural gas will be forthcoming. To reduce the price risk inherit when relying so much on a single fuel type, LADWP will need to continue to develop and implement strategies to hedge against natural gas price volatility.

- Local Solar

  The Governor has called for a statewide goal of 12,000 MW of renewable power generation within the local distribution grid. LADWP's portion of that would amount to approximately 1,200 MW. While this IRP analyzes a 50 percent renewable portfolio standard and high local solar (see Section 3 and 4), a number of complicating factors could make this a difficult goal to attain. Addressing operational impacts such as back flow prevention and voltage regulation on the distribution level, and loss revenues from net metering that would have to be made up elsewhere, are some of the factors that need to be considered and analyzed. This issue will require on-going attention and assessment beyond this current IRP and should be an item for discussion in subsequent IRPs.

- Transmission Planning

  As resource planning has become more dynamic and complex in response to the growing number of external drivers and influencing factors, so too are the demands on transmission planning to support it. It is important that transmission considerations be connected to resource planning so that alternative options are evaluated in a realistic and effective manner. Importing new renewable energy from distant locations, dealing with intermittent energy, switching away from coal which may free up transmission capacity, the transmission needs for potential new power plants; these and other resource planning considerations all require adequate transmission. As LADWP controls a large amount of transmission in the state, it should leverage those assets to best meet the needs of the City and its customers.

- Cyber Security Legislation & Regulation

  LADWP has taken a lead in implementing and vetting its Cyber Security Programs. A Cyber Security Group has been formed and dedicates itself to develop, implement, and manage the LADWP Critical Infrastructure Protection (CIP) Compliance Program in accordance with the North American Electric Reliability Corporation (NERC) Standards CIP-002 through CIP-009, protecting critical infrastructure against cyber-attacks. Standards and policies are in place for identifying and protecting LADWP assets from Cyber Security threats. Congress is currently contemplating several Cyber Security Bills, all of which have their unique approach to protect the nation's critical infrastructure against cyber-attacks. The two prominent approaches to cyber security legislation range from Information Sharing to Federal Oversight and the development of new cyber security standards. Public power is working with House and Senate representatives to develop a bill that focuses more on information sharing and would allow a utility to take voluntary actions as they see best for their organization.

  Along with Cyber security legislation, electric utilities are also concentrating on the development and implementation of NERC cyber security reliability programs as mandated by the current Version 3 NERC CIP Standards. Further, the Federal Energy Regulatory Commission (FERC) approved on November 22, 2013, the new Version 5 NERC CIP-002-5 through CIP-011-1 Standards. The new standards include additional mandated cyber security controls and extend the scope of the systems that will be protected by the CIP standards. The Version 5 standards will result in a paradigm shift by necessitating the categorization of every Bulk Electric System (BES) cyber system into a low, medium, or high impact on the reliability of the BES. LADWP will be required to comply with the associated requirements of the Version 5 CIP Standards that apply to each evaluated impact category. This will result in an exponential expansion of the current LADWP CIP Cyber Security Program from approximately 172 critical cyber assets to over two thousand BES cyber assets.

- Castaic FERC Re-licensing Program

  On January 31, 2022, the Federal Energy Regulatory Commission's (FERC) license to operate Castaic Pumped-storage Hydroelectric Plant will expire. The license is a co-license between LADWP and the Department of Water Resources (DWR) and includes a number of hydro power plants along the California Aqueduct. Both parties have initiated the re-licensing process that, on average, requires ten years to complete. Through 2015, LADWP expects to complete preliminary studies, contract negotiations, and prepare a filing strategy.

In 2016, LADWP expects to file a notice-of-intent (NOI) and initiate the formal studies and applications.

- Effects of Climate Change/Global Warming

  While LADWP is actively working to reduce its GHG emissions and thus lower its contribution to the problem of global warming, it must also look at the consequences of climate change and how it affects power generation and operations. Warmer temperatures, more volatile weather patterns, an increase in the number and duration of heat waves, stricter water availability and rising sea levels are some of the impacts that must be considered to ensure adaptation of the Power System to those future conditions. See Section 2.4.6 and Appendix M.

- Load Factor Improvement

  Load factor represents how constant energy usage is over a given day. A 100 percent load factor means that the same amount of power is used throughout the day, so the system is getting full use of its generation, transmission, and distribution resources. A low load factor results in generators being started more often to serve load for a few hours a day, which is not optimum. As an analogy, a car traveling at constant speed will get the best gas mileage and reduced wear and tear than a car in stop-and-go traffic.

  From the 1990s through 2005, annual system load factors were trending slowly upward, which is a positive movement. Since 2006, however, system load factors are trending down. Some of this decline is due to the fact that much of the historic energy efficiency effort is directed at lighting, which has higher impact on energy sales when compared to peak demand. Also, most customers are making greater efforts to conserve energy but during extreme weather events safety and comfort predominate over conservation causing the peak to spike. LADWP will consider programs to shift load from peak hours to off peak hours to reverse this trend and improve system performance. The 2013 California Energy Commission's forecasted load factors shows that forecasted load factor will continue to decline for earlier years of the forecast, due to energy conservation; however, forecasted load factors increase in later years due to increasing electric vehicle usage.

1.7 Public Process

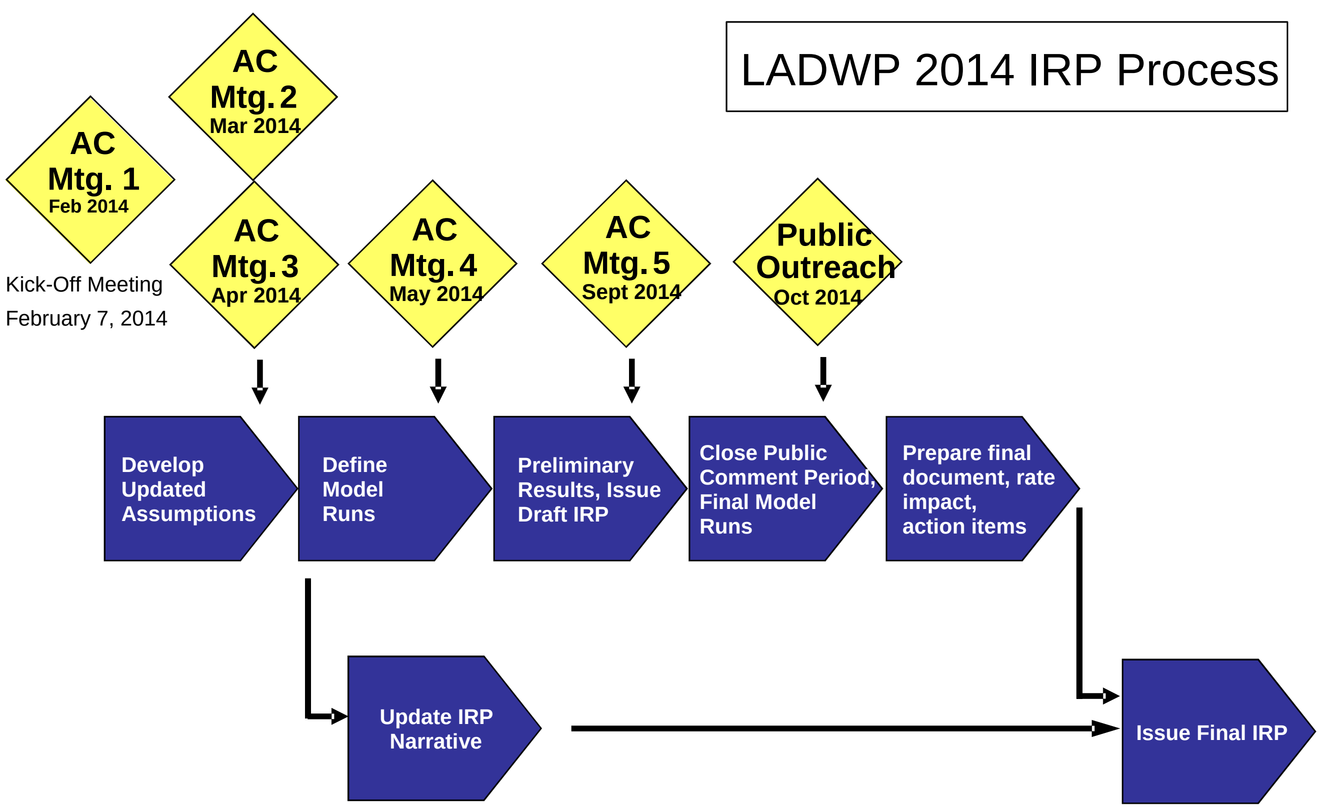
LADWP conducts a public review process on its IRP every other year. The previous review process was held in support of the 2014 IRP and this year's 2015 IRP does not include a public review process. The results of the 2014 public review process are referenced in Section 5 and Appendix O of the IRP.

Last year's 2014 IRP includes a public review process, including the formation and active participation of a new IRP Advisory Committee (Committee). The purpose of the Committee is to further transparency and build on the collaborative dialog that was conducted in recent IRP processes. The Committee was presented with the major issues facing LADWP and weighed in on how those issues should be addressed.

While the Committee did not have approval authority for the 2014 IRP, it influenced the assumptions that were used in the case scenarios, as well as the final recommendations and near term actions. The Committee contributed to the process in a constructive manner, mutually exchanging information with LADWP for the betterment of the Power System, the ratepayers, and the environment.

Through the Committee, LADWP obtained stakeholder feedback on several specific power-related issues, such as Energy Efficiency, Renewable Portfolio Standard, Local Solar, Demand Response Programs, Electrification, etc. The Committee also provided an opportunity for stakeholders to understand and appreciate the diverse viewpoints among the different stakeholder groups.

The Committee represents a range of stakeholder representatives, including: Neighborhood Councils, Business Customer Representatives, Environmental Representatives, the LA City Council and Mayor's office, and an academic representative from UCLA. The Committee met five times throughout the calendar year and provided input in the development and recommendation of the final 2014 IRP cases. Comments received during these stakeholder meetings were considered in the development of the preliminary cases that were analyzed. Below is the timeline of the 2014 IRP process pertaining to the Advisory Committee's involvement:



In addition to the IRP Advisory Committee, three Public Outreach Workshops were held on October 28, October 30, and November 4, 2014, to provide an overview of the 2014 IRP and accept comments from the general public. The 2014 Draft IRP was made available for public comment through the LADWP website:

www.ladwp.com/powerIRP

Comments were accepted through the end of November 2014. Considering the public comment and input received, a final set of recommendations was made.

A summary of the public comments received is included in Section 5 and Appendix O.

1.8 2015 IRP Development Process

The IRP is prepared by a group of engineers dedicated to LADWP resource planning and preparation of the IRP. While this group performs the production model and report preparation for the IRP, the bulk of the work is collaborative across the numerous work groups and functional areas of the Power System, including wholesale marketing, grid operations, renewable procurement, environmental and legislative affairs, and financial services.

The IRP is developed in multiple stages, including:

1. Gather stakeholder input

   Meetings are held with stakeholder groups to discuss the key strategic planning issues and to gather input. This is done early in the process to ensure those concerns expressed are given due consideration in the establishment of goals and objectives, and in the development of the alternative cases for study and analysis.

2. Establish clear goals and objectives

   The overarching goal of LADWP's IRP planning effort is to produce a long-term plan that ensures a future supply of electricity that is reliable, competitively priced, and is secured and operated in a manner consistent with environmental stewardship. Through the planning and development process, specific initiatives, programs and projects (many which are in progress) are identified and assessed. The planning effort is collaborative among cross functional organizations within LADWP. Each initiative, program and project will have its own appropriate set of goals and objectives, which in turn supports the collective goal of reliable, affordable electricity that is sensitive to the environment.

3. Identify and approve key assumptions

   The assumptions form the basis for subsequent analysis, and include such factors as load and fuel price forecasts, renewable resource percentage targets, CO_2 allowances and pricing, projected energy efficiency implementations, repowering schedules, projected transportation electrification growth, etc. Assumptions are prepared and approved by the internal LADWP organizations responsible for the respective subject areas. The assumptions are then presented to LADWP management for comments and acceptance.

4. Establish strategic case alternatives

   Each of the strategic cases is developed by IRP staff with input from each of the internal LADWP organizations. The strategic cases are designed to consider alternative future resource portfolios, and reflect real decision points and plans that LADWP will have to implement. The current major decision areas for LADWP is coal replacement, RPS technology and locations, energy efficiency, local solar, and transportation electrification; therefore, this IRP considers cases which offer alternative options for these three subject areas. Each case is vetted through LADWP management and working meetings are held to agree on final cases to be assessed.

5. Conduct computer modeling of Power System operations

   Simulations of the case alternatives are made using the Planning and Risk (PAR) software. PAR is a widely used hourly production cost model that commits and dispatches resources to minimize the cost of serving electric load. PAR is used by many utilities across the US and the world. The modeling results are vetted for quality. Post model analysis is then conducted to account for non-generation system costs, including transmission and distribution. The final results compare each case in terms of reliability, costs, and CO_2 emissions reduction. The results are reviewed by management for comments and approval. If needed, modifications are made to the model input assumptions for new computer runs.

6. Present preliminary findings and gather public comments

   Public meetings are held where the findings of the case analysis are presented. These results are considered preliminary at this point. Following public input, a final analysis of the cases is then conducted. It is possible that one or more of the cases may be modified as a result of public input.

7. Recommend and approve a preferred case

   Based on the results of the final analysis, a preferred case is recommended. The preferred case is then presented to management for review and acceptance.

The IRP development process includes coordination among multiple LADWP organizations responsible for different aspects of Power System operations. Recommended positions at the various stages are presented to LADWP's leadership team, including Division and Section Managers. The approval process for recommendations is based on consensus from the managers of each area of responsibility.

1.9 Summary

LADWP is in the process of transforming its Power System. Approximately 70% of its Power System generation will be replaced within the next 15 years. Numerous challenges are being addressed concurrently, including meeting renewable resource requirements, once-through cooling, natural gas repowering, coal replacement, GHG reduction, energy efficiency, demand response programs, transportation electrification and others. Meeting all of these challenges requires considerable amounts of labor and capital resources, which applies upward pressure on LADWP's electric rates.

LADWP is focusing on both near-term and long-term solutions. To achieve the objectives and goals documented in this 2015 IRP, LADWP will continue to implement its existing programs and projects, but will also introduce and expand new initiatives and program areas. The following list shows the major activities that require action over the next 3-5 years (for more information, see the referenced IRP sections).

Major Power System Activities 2015-2019

Program Areas in Progress

- **Scattergood Repowering** (Sections 1.6.6, 2.4.2.2, 3.3; Appendix F)
- **Coal Replacement Planning and Implementation** (Sections 1.6.4, 2.4.2.3, 3.3, 3.5, 4, and 5)
- **Replacing aging distribution infrastructure** (Sections 1.6.2, 1.6.3 and 2.4.2.1; Appendix E)
- **RPS procurement** (Sections 1.6.5, 2.4.3, 3.3, and 5; Appendices D and N)
- **Solar Program Development** (Sections 2.4.3, 3.2, 4 and 5; Appendices D, G, and N)
- **Existing EE program elements** (Section 2.3; Appendix B)

New and Expanded Program Areas

- **Demand Response Program** (Sections 2.3.2 and 5.6; Figure 2-9, Table 4-3)
- **New EE program elements** (Section 2.3.1; Appendix B)
- **Grid Reliability Improvements** (Sections 2.4.4 and 5.1)
- **Distributed Generation and Local Solar** (Sections 2.3.3, 3.4.4,: Appendix G)
- **Electrification of the Transportation Sector** (Section 2.2.3 and 3.4.5)
- **Maximum Generation Renewable Energy Penetration Study** (Section 4.3.1 and Appendix J)

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2.0 LOAD FORECAST AND RESOURCES

2.1 Overview

Utilities are required to forecast the demand for energy and determine how that demand will be met. Meeting forecasted demand is accomplished by the planning and delivery of electric power generating ("supply-side") resources through transmission and distribution systems. Another key element of IRP planning is to determine how to reduce or tailor energy demand and increase the efficiency of the utility customer's use of electricity, known as "demand-side resources."

This section of the IRP addresses the following:

- Forecasting of future energy demand
- Demand-side Resources (DSR), including Energy Efficiency and Demand Response
- Distributed Generation
- Supply-side Resources
- Transmission/Distribution, 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 affect LADWP's planning 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. Also highlighted in this IRP are 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 system.

2.2 Forecast of Future Energy Needs

This 2015 IRP utilizes LADWP's 2014 Load Forecast, dated September 26, 2014, of customer demand for electricity over the next 20 years (the complete 2014 Load Forecast is included in Appendix A). The 2014 Load Forecast divides customer sales into seven classes. Econometric models are used to forecast sales in the Residential, Commercial, and Industrial classes. Trend models are used to forecast sales in the Intradepartmental, Streetlight and Owens Valley classes. For the Electric Vehicle (EV) sales class, the California Energy Commission 2013 EV forecast is adopted. The drivers in the retail sales models include normalized weather, population, employment, construction activity, and personal consumption and income. The retail sales forecasted from the class models are adjusted for LADWP programs that affect consumption behind the meter such as energy efficiency and rooftop 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 percent. NEL is defined as the energy production necessary to serve retail sales. Losses can vary between 10 and 13 percent 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 year as drivers. Peak demand grows over time as a function of the NEL forecast adjusted for energy efficiency 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.

2.2.1 2014/2015 Retail Electrical Sales and Demand Forecast

Los Angeles Department of Water and Power (LADWP) adopted the 2014 Retail Electric Sales and Demand Forecast (Appendix A) as the 2015 Retail Electric Sales and Demand Forecast. Incorporating the sales data reported by the Customer Care & Billing System (CCB) System, implemented in September 2013, through December 2014 resulted in a forecast significantly below the 2014 Appendix A Forecast. The reported CCB sales numbers are low due to billing issues identified in other studies and reports. Since 2014 was an exceptionally hot year, incorporating the lower reported 2014 sales in the model caused the weather coefficients to be underestimated, which led to a lower forecast. Since none of the other data supports a lower forecast, the 2014 Appendix A Forecast seems more appropriate on which to base planning decisions. Figure 2-1 below compares the 2014 load forecast to the 2015 preliminary forecasts:

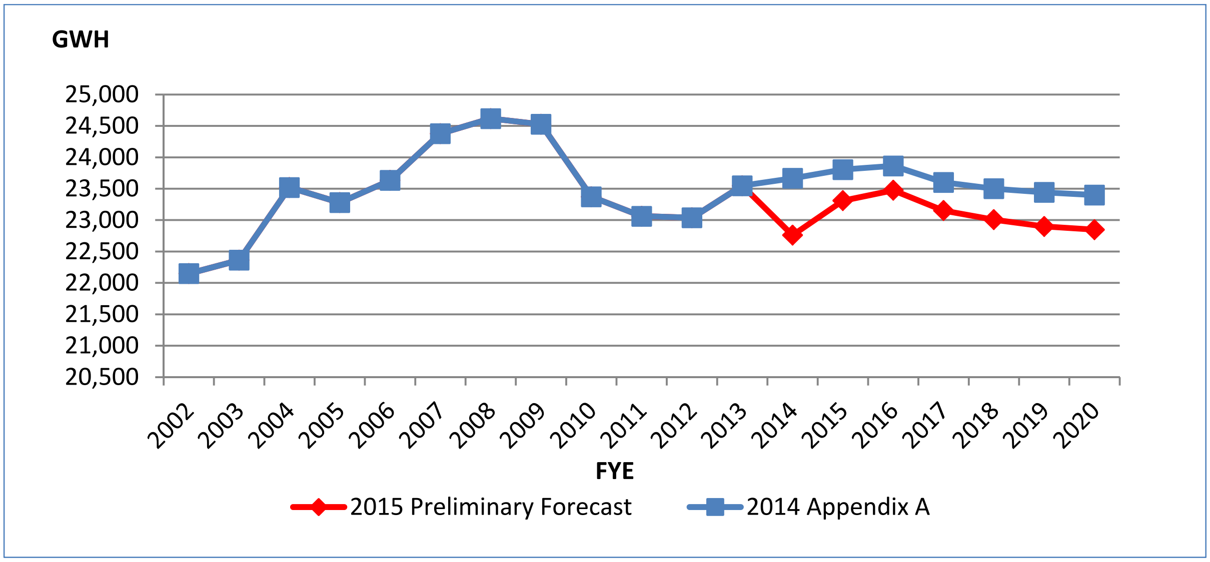


Figure 2-1. Total Sales to Ultimate Customers by calendar year.

Statistical Significance of the Billing Change

Statistical modeling implies that LADWP either under billed or under reported its sales to ultimate customers 619 GWH in Calendar Year 2014 as shown in Table 2-1 below:

Table 2-1: 2014 LOAD FORECAST BREAKDOWN BY SECTOR

Sector	GWh	Confidence Level
Residential	239	95%
Commercial	287	89%
Industrial	96	84%
Total	**619**	

The confidence levels are not as high as a researcher may support in this type of analysis. The lower than expected confidence level can be partially explained by the use of the calendar year as the proxy for the billing change. Adding 619 GWh to reported sales of 23,455 GWh means that expected sales for 2014 were 24,074 GWh, which is two percent higher than Calendar year 2012—the last full year under TRES, when the reported sales were 23,601 GWh. At first glance, this growth appears to be too high; however, after weather is factored in, the sales approaches the expected growth rate. Calendar year 2014 was a very hot year as measured by Cooling Degree Days (CDD). There were 1,769 CDD in 2014 compared to 1,488 CDD in 2012. Normal CDD is 1,311 CDD.

Losses incurred in Production

In Calendar Years (CY) 2013 and 2014, percentage losses were the highest recorded since 1977. The formula for percentage losses is ((NEL – Sales) x100) / NEL. In CY 2013 and 2014 the losses were 14.5% and 14.2% respectively. Percentage losses averaged is 11.5% with a standard deviation of 1.1% from CY 1977 to 2012. A percentage loss of 14.5% is equivalent to a 1 in 365 year event. Similarly a percentage loss of 14.1% has a one in 165 probability. The percentage losses for CY 2013 and 2014 are possible, but highly improbable. Figure 2-2 below shows the loss factor in 2013 & 2014 was significantly above trend.

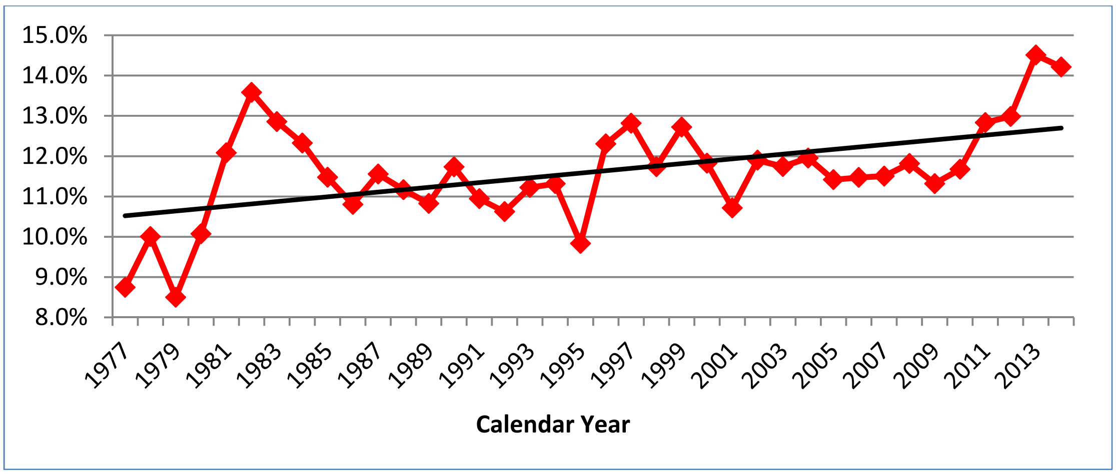
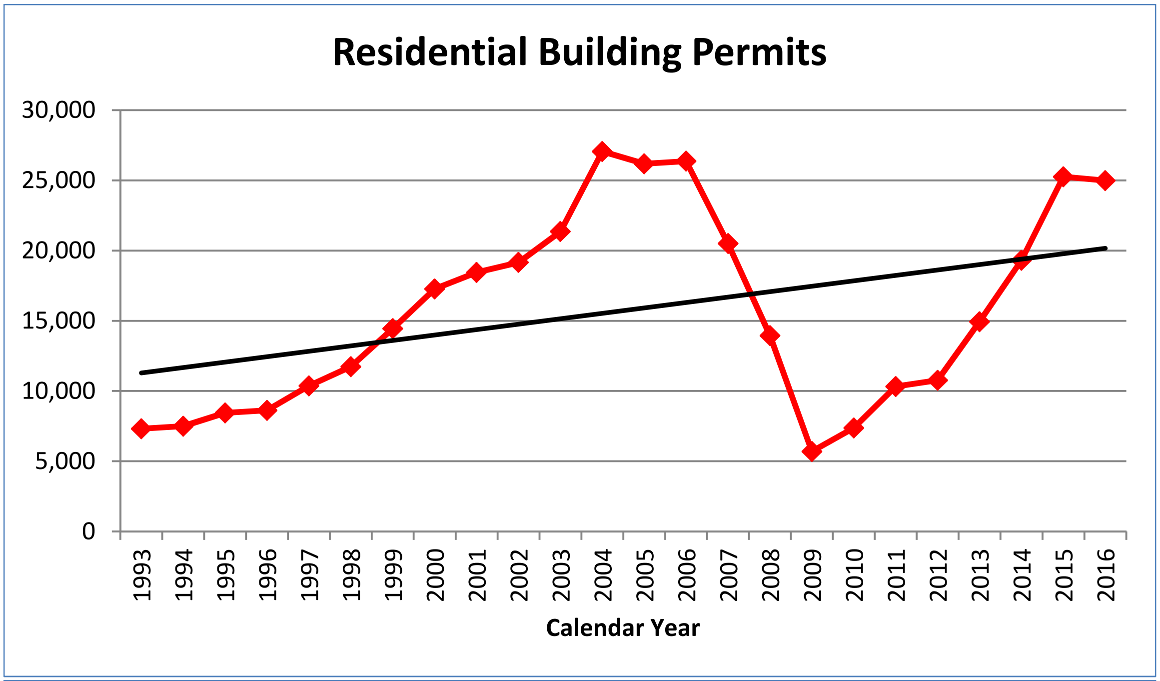


Figure 2-2. Historical percentage losses by calendar year.

Economics

The underlying demographic and economic data indicates that Los Angeles County is in a modest expansion. Nothing in the data suggests a downturn. The LADWP service area is most commonly modeled as a constant share of Los Angeles County. Data at the County level is considered more accurate. All the data and forecasts in Figure 2-3 below are from the 2014 UCLA Anderson Forecast.


Residential Building Permits
30,000
25,000
20,000
15,000
10,000
5,000
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
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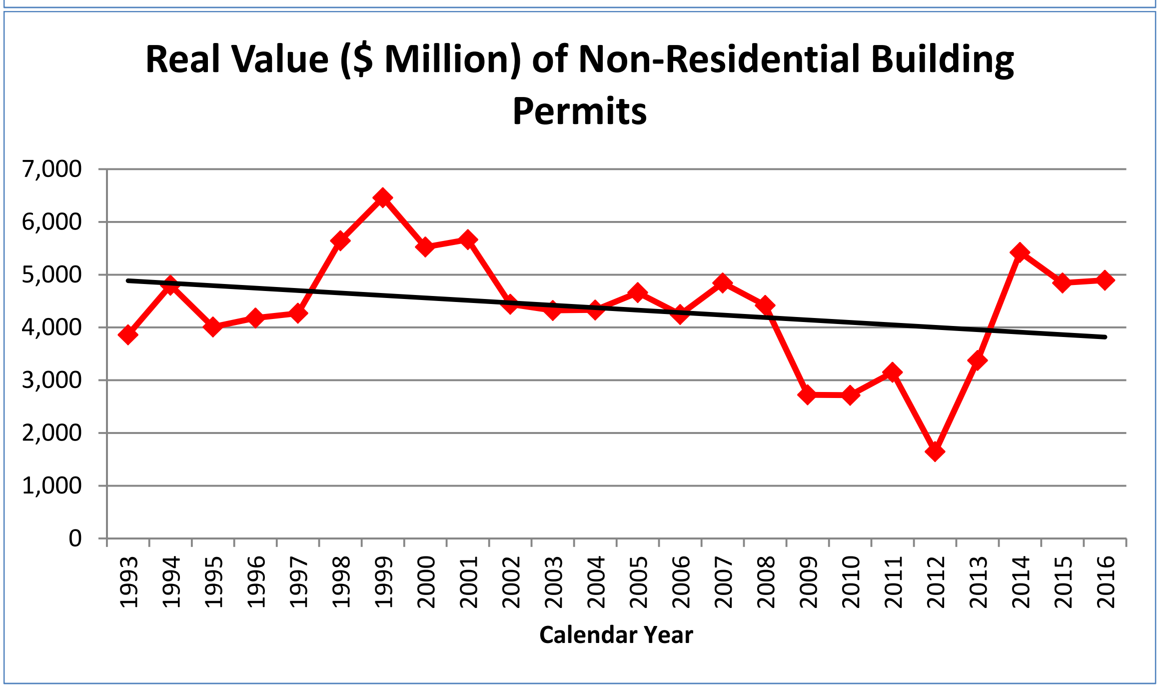
2013
2014
2015
2016
Calendar Year


Real Value ($ Million) of Non-Residential Building Permits
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1993
1994
1995
1996
1997
1998
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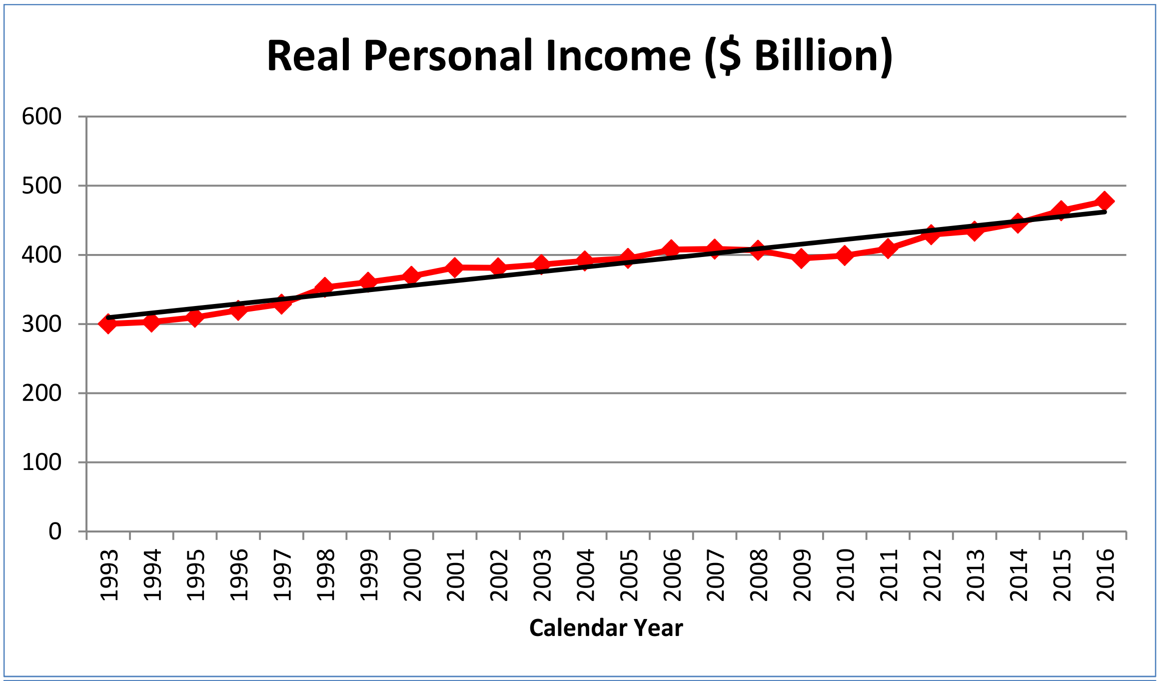
2015
2016
Calendar Year



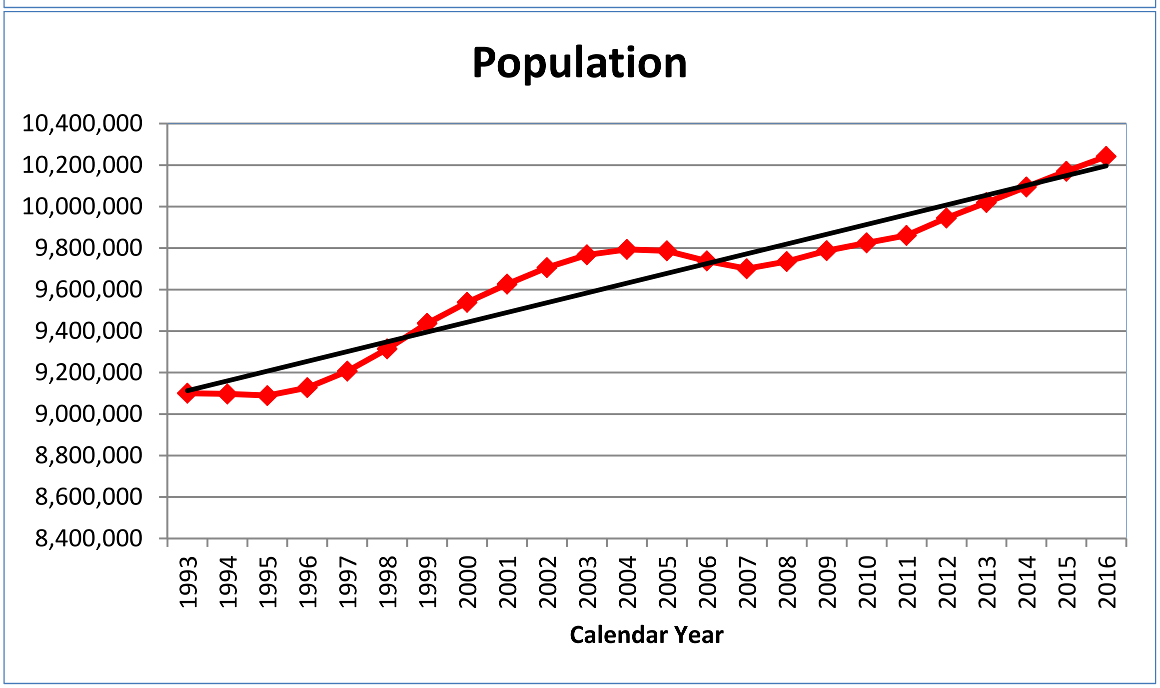


Figure 2-3. 2014 UCLA Anderson Forecasts by calendar year.

The Los Angeles economy remains in recovery mode from the 2008-09 recession. Electric sales peaked in fiscal year 2007-08. In fiscal year (FY) 2013-14, reported billed sales were 22,760 GWh as compared to 23,548 in FY 2012-13. This represents a loss of sales of 787 GWh or 3.33 % year over year. The Load Forecasting group believes that the majority of the loss of sales can be attributed to unbilled sales caused by the new billing system as detailed previously above.

Calendar sales for 2014 have already rebounded to 23,456 indicating that that retail sales are getting close to being back on historical trend as LADWP continues to fix the billing errors in CCB. Summer 2014 was hotter than normal whereas summer 2013 was cooler than normal, so there is no evidence to support that the loss of sales is weather related. Weather can cause up to a two percent plus or minus variation in sales in any given year. Electric sales growth will lag economic growth as electric consumption becomes more efficient and customers consume their own native generation behind the meter. Construction activity is returning to a normal pace but there is still a large amount of commercial floor space vacancy that needs to be absorbed.

The electricity consumption within LADWP's service territory is forecasted to be flat over the next five years as energy efficiency and customer installed solar rooftop expansion offset growth from economic activity. Based upon weather-normalized annual peak demand of 5,683 MW in fiscal year 2013-14, the growth in annual peak demand over the next ten years is predicted to be about 0.8 percent –approximately 45 MW per year - with less growth over the next few years due to energy efficiency, and solar rooftop programs. Some of this growth will not be realized at the meter with the implementation of the demand response program which is not presently included in the peak demand forecast but is considered in this IRP as a resource to serve peak demand.

Forecast Data Sources

The 2014 Appendix A forecast is LADWP's official Power System forecast. This forecast is used as the basis for LADWP Power System planning activities including, but not limited to, integrated resource planning, transmission and distribution planning, and wholesale marketing. The forecast is a public document that uses only publically available information.

Table 2-2 summarizes the data sources used to develop the forecast and where these data sources have been updated from previously published forecasts.

Table 2-2: LOAD FORECAST DATA SOURCES

Data Sources		Updates
1.	Historical Sales through August 2013 were reconciled to the General Accountings Consumption and Earnings Report.	*Historical Sales, Net Energy for Load and weather data is updated through August 2013.*
2.	Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2013 benchmark.	*Employment data is updated through December 2013 using the March 2013 benchmark.*
3.	The plug-in electric vehicle (PEV) forecast is based on the California Energy Commission (CEC) 2013 Integrated Energy Policy Report forecast.	
4.	The LADWP program energy efficiency forecast is based on the Draft LADWP 2014 Energy Efficiency Potential Study dated June 24, 2014. Historical installation rates are provided by the Energy Efficiency group.	
5.	Projected solar rooftop installations are consistent with the 2014 Integrated Resources Plan. Historical installations are provided by the Solar Energy Development Group.	
6.	Electric Price Forecast is developed by Financial Services organization. Real electric prices beyond FYE 2019 are assumed to be constant.	

2.2.2 Five-year Sales Forecast

The Retail Sales Forecast represents sales that will be realized at the meter through the budget period which ends in Fiscal Year End 2019. After the FYE 2019, energy efficiency and distributed generation programs are not included in the forecast and will be treated as a resource in the Integrated Resource Plan.

The historical accumulated Energy Efficiency and Solar Savings are from 1999 forward. True accumulated energy efficiency would more likely be dated back to 1974 when the Warren-Alquist Act passed in California but good records are not available. In the Forecast, energy efficiency and solar savings are expected to occur uniformly throughout the year as a simplifying assumption.

Ignoring the losses caused by unbilled sales, the flat growth rate in sales over the budget period can be attributed to 1) the Huffman Bill, which significantly raises the energy efficiency standard of light bulbs, 2) accelerated incremental savings rate in LADWP's energy efficiency of 15% by 2020 and solar rooftop programs, and 3) expected increases in real electric rates. Growth rates begin rising again near the end of the budget period due to the completion of the light bulb replacement cycle and the increasing market share of electric vehicles. FYE 2017 is unusual as it faces the full effect of energy efficiency savings and electric price increases.

Retail sales would be significantly higher absent LADWP energy efficiency and local solar programs. Based on installed savings, sales have been reduced by 1909 GWh since FYE 2000 through LADWP-sponsored programs. LADWP is accelerating these savings programs and retail sales are expected to be reduced another 2,437 GWh over the next six years.

Table 2-3 shows projections of short-term retail sales growth:

Table 2-3. SHORT-TERM GROWTH

Fiscal Year	Retail Sales		Additional Load if not for EE & Solar Savings
Ending June 30	(GWH)	Growth Rate (Year-Over-Year)	(GWH)
2014-15	23,633	3.8%*	2790
2015-16	23,708	0.3%	3282
2016-17	23,554	-0.7%	3777
2017-18	23,613	0.3%	4220
2018-19	23,727	0.5%	4613

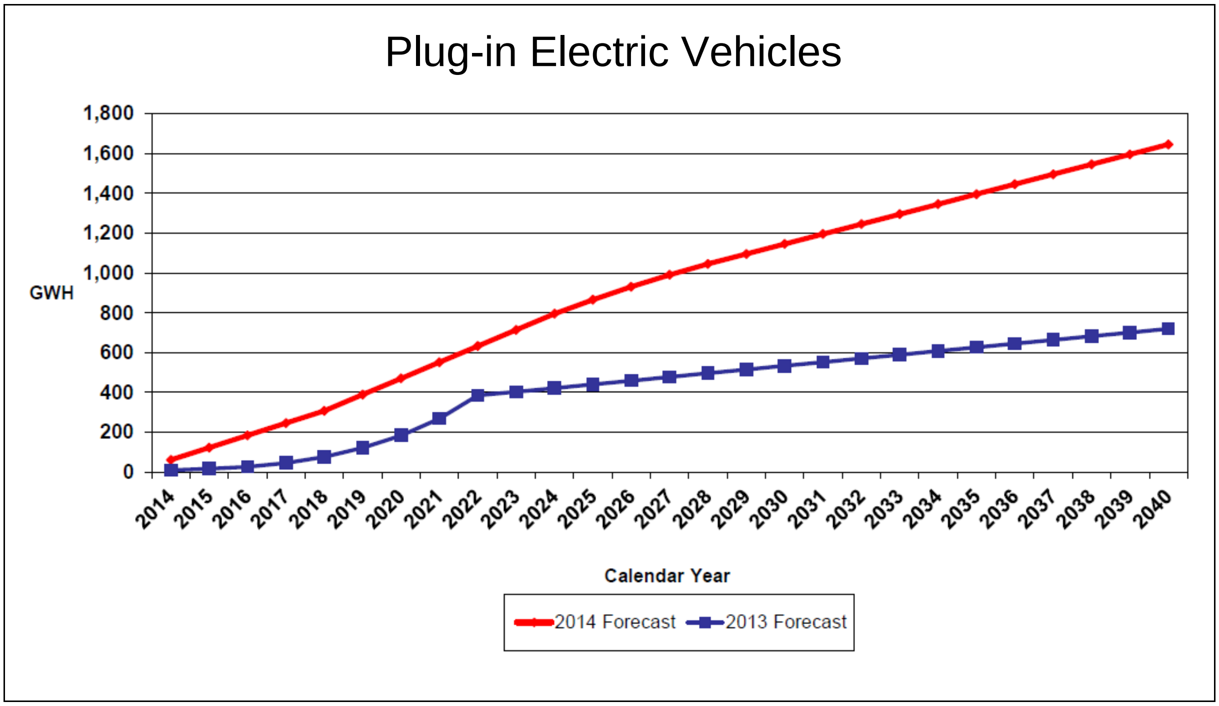
* Estimated growth due to correction of unbilled accounts

For IRP modeling and analysis, adjustments are made to the approved load forecast to account for the alternative energy efficiency targets and customer net-metered solar projections. These adjustments are shown in Appendix N.

2.2.3 Electrification

State legislation such as AB 32, SB 350, and CARB's Mobile Source Strategy development, would facilitate increased electrification as a means 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 both additional resulting load and the speed of implementation of electrification programs.

In the transportation sector, fuel switching from diesel and gasoline to electric power can result in air quality improvements if the sources of electric power are clean. Figure 2-4 shows the forecasted number of plug-in electric vehicles (PEVs) within the LADWP service area over the next 20 years. To support the adoption of electric vehicles, LADWP launched a pilot program in May 2011 that provides 1000 customer rebates 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, which is a $2 million rebate program offered to the first 2,000 approved electric vehicle customers for large businesses, small businesses, multi-family buildings and public use. Supporting the City's electric vehicle infrastructure, LADWP is also in the process of retrofitting 117 vintage chargers on City property.



Based on 2013 CEC Forecast

Figure 2-4. Forecasted energy growth in GWh attributed to plug-in electric vehicles.

Other agencies in the LA air basin have initiatives underway for “electrification” to replace existing diesel fueled trucks and gasoline powered cars with electric power. In addition, planned expansions to light railway and the metro system 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 many mobile sources as well as some fixed sources. This includes trucks, locomotives, ships, harbor craft, cranes, and various types of yard equipment. One of the programs, Alternative Marine Power (AMP), 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 Electrical Vehicles (PEVs)

Large scale deployment of electric vehicles will significantly affect the way electricity is consumed. It is estimated that by 2015, the United States will have one million EVs in deployment, 10% of which is expected to be in California. The introduction of electric vehicles in Southern California brings a challenging set of planning, regulatory and cost issues. Because EVs require a unique infrastructure, including specialized charging equipment and adequate electric service, it is essential to anticipate and predict the grid impact in Southern California from the EV deployment.

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

PEVs also present an opportunity to influence charging patterns by incentivizing charging during off-peak time periods, resulting in better system load factors or as a targeted load participation program to maximize the use renewables that might otherwise be curtailed due to over generation. Currently 80% of PEV charging in Los Angeles occurs during off peak hours (per US DOE)

LADWP will use a part of the $120 million Smart Grid demonstration grant award from DOE to demonstrate the integration of electric vehicles into the LADWP-managed electric system. The demonstration will use internal fleet equipment, privately owned EV chargers, and will include electric vehicle fleets from both UCLA and USC. These complementary fleets provide the opportunity to test EVs in both the controlled environment of a corporate fleet and the "real world" usage of individuals. These opportunities will test the integration of EVs into the grid, along with acquisition of EV communications to the grid management.

LADWP Electric Transportation Program (Fiscal Year 2015-2020)

Realizing the benefits of overall greenhouse gas reduction in the LA Basin and increased electric sales, LADWP launched its electric transportation program in support of electrification goals detailed in the City of Los Angeles' Sustainability Program and LADWP's 2014 IRP recommended case. The five year goal seeks to achieve an equivalent of 137,000 electric vehicles (EV) in LA by increasing EV adoption to 15% of vehicle purchases, counting public and workplace chargers as EV equivalents, and considering non-light duty vehicles as EV equivalents (i.e. medium and heavy duty trucks). The Electric Transportation Program is summarized by the following elements:

1. Education and Outreach: Achieve 15% plug-in electric vehicles sales of all new vehicle purchases in LA by 2020, through promoting driving events, social media, etc.
2. Electrify LADWP and LA City Fleet: 100% of new LADWP light duty vehicles and 50% of new LA City light duty vehicles are to be electric vehicles.
3. Residential Charging Rebates: Continue LADWP's "Charge-Up LA!" residential rebates and launch Phase II: Smart Charger Rebate Program.
4. Commercial Charging Rebates: Provide rebates for workplace and public charging. Phase II of the program includes direct install and Green Building Ordinance, which would require newly constructed buildings to supply electric vehicle chargers.
5. City Electric Vehicle Infrastructure: Install curbside and parking lot public chargers, City Fleet Chargers, City DC Fast Chargers, and City workplace chargers throughout L.A.

6. Medium and Heavy Duty Fleet Charging: Electrify Port of LA, Los Angeles World Airports, forklifts, rail, and busses.

LADWP's Electric Transportation Program would clearly illustrate LA's visible support for EV technology through 10,000 City and private commercial chargers for public, workplace, and City vehicles, support residential charging, and assist in meeting LADWP's goals of greenhouse gas reductions, integration of renewables, better utilization of assets, and customer savings.

2.2.4 Peak Demand Forecast

Growth in annual peak demand over the next ten years is 0.8 percent as shown in Table 2-4.

Table 2-4: FORECASTED GROWTH IN ANNUAL PEAK DEMAND

Fiscal Year End June 30	Base Case Peak Demand (MW)	Growth rate Base Year 2010-11	One-in-Ten Peak Demand (MW)
2014-15	5742[1]		6206
Forecast			
2018-19	5786	0.4%	6311
2023-24	6166	0.8%	6728
2033-34	7065	1.1%	7715
2039-40	7629	1.1%	8332

[1] Weather-normalized. Actual peak was 6343 MW due to a hot 2014 summer.

In 2014, the System set its all-time annual net energy for load peak at 6,341 MW on September 16, 2014 on a day that was a one-in-seventeen year weather event. Figure 2-5 presents the one-in-ten peak demand forecast, which is used for integrated resource and transmission planning. In the 1990s through 2008, annual system load factors were trending slowly upward. Since 2009, system load factors are trending down. Two factors are generally thought to be contributing to this effect. Most customers are making greater efforts to conserve energy but during extreme weather events safety and comfort predominate over conservation causing the peak to spike. Much of the historical and forecasted energy efficiency effort is lighting which has a greater impact on consumption rather than peak which lowers the load factor.

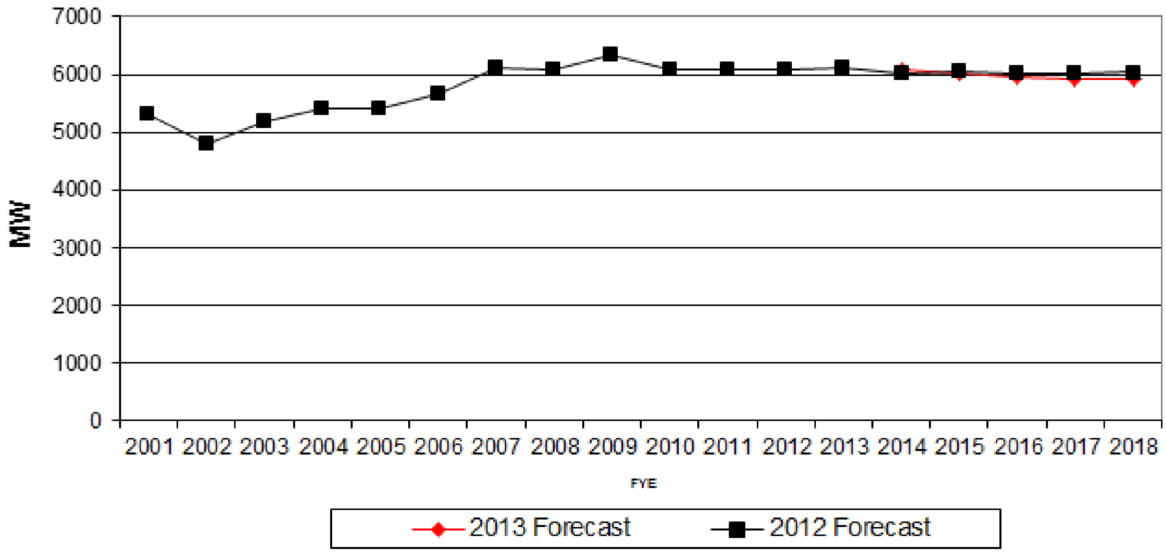


Figure 2-5. One-in-ten peak demand forecast comparison.

2.3 Demand-Side Resources

Demand Side Resource (DSR) programs, including energy efficiency, have become important elements of IRP planning. Also known as Demand Side Management, DSR programs help to counter or minimize energy demand growth and thereby lessen the need to build more physical generation assets and improve load factor. This section discusses the following DSR initiatives:

- Energy Efficiency (EE)
- Demand Response (DR)
- Distributed Generation (DG)

Key DSR data assembled for this IRP included:

- The energy efficiency forecast, which was based on the Board-approved 2014 LADWP Energy Efficiency Goals for Submission to the California Energy Commission (CEC) as required by Assembly Bill 2021, the City of Los Angeles Green Plan, and Demand Forecast Energy Efficiency Quantification Project working papers. Historical installation rates were referenced as part of the forecast.
- An estimate of the amount of solar rooftop and other distributed generation.
- Board-approved 2014 LADWP Energy Storage System Procurement Targets

2.3.1 Energy Efficiency

Energy Efficiency (EE) is a key strategic element in LADWP's resource planning efforts. EE is an overall cost effective resource in LADWP's supply portfolio, and serves an important and multi-faceted role in meeting customer demand. A common example of a successful EE measure is the replacement of incandescent lights with compact fluorescent lamp (CFL) bulbs. CFLs consume up to 75% less energy than incandescent bulbs while producing an equivalent amount of illumination and last up to 10 times longer.

Since 2000, LADWP has spent approximately $502.4 million in capital and O&M on its energy efficiency (EE) programs and these programs have reduced consumption by approximately 2,052 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, was recommended and adopted by the Board of Water and Power Commissioners on August 5, 2014. The next EE Potential study will be conducted in 2017.

2.3.1.1 Recommended Target – 15% by 2020

The base plan for energy efficiency programs established in December 2011 put LADWP on a path to achieve energy savings equivalent to 8.6% of 2010's energy consumption by 2020. This level of savings reflects the findings of the energy efficiency potential study that was approved by the LADWP's Board of Water and Power Commissioners in December 2011. The 2010 reference point is specified by AB 2021, which encourages the state's electric utilities to achieve cumulative savings of 10% of total energy consumption levels by 2020. The Board's adoption of an 8.6% energy savings goal by 2020 was an interim goal. In that adoption, the Board requested LADWP to evaluate options to increase the rate of energy efficiency savings to achieve the target goal of 10% by 2020. LADWP determined that a 10% goal by 2020 was indeed achievable, and the Board formally adopted this target on May 24, 2012. The Board also acknowledged plans to conduct a new updated energy efficiency potential study to be completed by March 2014. The new potential study was used to develop a long-term plan for the scope and estimated costs to achieve 10%, 12.5%, and 15% by 2020.

The LADWP hired Nexant Inc. (Nexant) to conduct the 2013 Energy Efficiency Potential Study (Study) for LADWP's service territory to determine the potential energy savings over a 10-year period.

The Study presented a number of energy savings scenarios compliant with AB 2021 requirements and estimates the annual program expenditure levels necessary for achieving the cumulative targets for energy savings and peak demand reduction potential for each investigated scenario. LADWP sought a scenario yielding a high level of total savings across the ten-year planning period while keeping estimated annual expenditures reasonably in line with previous projections.

The AB 2021 targets adopted represent a total goal of 3,596 GWh in energy use reduction compared to the baseline forecast over the ten-year period from FY 2013-14 through FY 2022-23, which will result in total cumulative annual energy savings of across the ten-year target period of 13.7%. This exceeds the minimum AB 2021-required cumulative energy savings goal of 10% by 37%.

In addition to exceeding state requirements by setting annual targets that would achieve 13.7% across the AB 2021 timeframe of FY 2013-14 through FY 2022-23, LADWP also seeks to accelerate program efforts such that the majority of the total savings will be achieved by 2020. Using FY 2010-11 as the starting year, LADWP seeks to build on the actual energy efficiency results of FYs 2010-11, 2011-12, and 2012-13 to achieve cumulative energy savings of 15% versus baseline sales projections across the ten-year period from FY 2010-11 through FY 2019-20. The acceleration of the program will result in more customers participating in energy efficiency programs sooner, and thus realizing more energy and bill savings.

2.3.1.2 Updated Energy Efficiency Potential Study (2013)

In 2013, LADWP commissioned a new updated energy efficiency potential study to support its business plan and energy efficiency goals for 2020. Nexant, in collaboration with its subcontractors Cadmus and RetroCom Energy (the Nexant team) performed this study, which encompassed the residential, commercial, institutional (City of Los Angeles buildings and facilities), and industrial sectors. The Study was finalized and published on June 24, 2014 and indicated that a 15% EE target by 2020 was achievable. The proposed target of up to 14.5% energy efficiency savings by 2020, based on the recommended "Scenario 10" in the Study findings, was adopted by the Board of Water and Power Commissioners on August 5, 2014.

The new updated energy efficiency study assessed the annual program expenditure levels necessary for achieving cumulative targets for energy savings and peak demand reduction potential, excluding demand response potential. The study reviewed the technical, economic, maximum achievable, and program potential of achieving various energy efficiency targets through a 20 year timeframe with a focus on achievable targets by 2020 and 2023. As energy efficiency savings targets increases in various scenarios, the required budget increases as well. The goal of the energy efficiency potential study was to achieve the aspirational target of 15% energy efficiency in a manner that is cost-effective, reliable, and feasible. In determining the energy efficiency potential, the technical potential for energy efficiency measures was first assessed, which includes all measures that are technically feasible regardless of cost. Next, the economic potential was assessed, which is a subset of technical potential and filters out measures that are not cost-effective based on a Total Resource Cost (TRC) perspective. The maximum achievable potential further removes energy efficiency measures with low TRC benefit-cost ratios. Finally, the Program Potential presents the energy efficiency measures that can possibly be achieved through utility programs or codes and standards. Individual measures may not be necessarily cost-effective; however measures with a low benefit-cost ratios are excluded.

In assessing cost effective energy efficiency scenarios, the energy efficiency potential study initially analyzed the cost effectiveness of various amounts of energy efficiency savings, which include a low scenario (10.2% EE by 2020), moderate scenario (12.2% EE by 2020), high scenario (13.2% by 2020), advanced scenario (14.0% by 2020 or 14.3% by 2020 accelerated), and extreme scenario (14.3% by 2020 or 17.5% by 2020 accelerated), using a broad-brush approach to estimate potential based on assumed incentive and administration/marketing costs.

These scenarios highlighted the increasingly high budget requirements to achieve 15% energy efficiency savings. As a solution, the Nexant team then analyzed in more detail, ten program planning scenarios to demonstrate how changing assumptions on program delivery, including incentives, administration/marketing, benefit-cost thresholds, and market participation rates can create a range of projected expenditures required to reach the annual savings targets, and roughly 15% savings by 2020.

Planning Scenario 10 in the energy efficiency potential study was adopted by the Board of Water and Power Commissioners on August 5, 2014. This proposed scenario 10 targets a total goal of 3,596 GWh in energy use reduction compared to the baseline forecast over the ten year period from FY 2013-14 through FY 2022-23, resulting in a total cumulative energy savings of 13.7 percent. This exceeds the minimum AB 2021 required cumulative energy savings goal of 10 percent over the ten-year period by 3.7 percent and satisfies LADWP’s intent to accelerate savings results by 2020. In comparison to the low, moderate, high, advanced, and extreme scenarios, Scenario 10 was an optimized case that aspires to achieve close to 15% energy efficiency savings while maintaining a reasonable budget. Figure 2-6 compares and illustrates the cost effectiveness of the various scenarios.

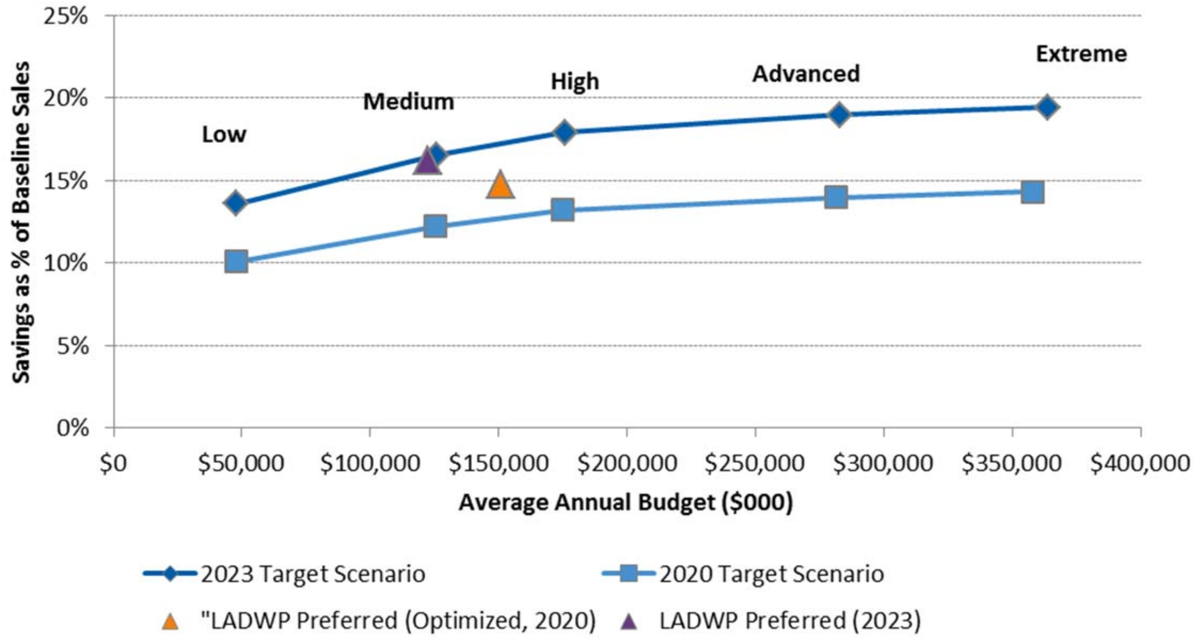


Figure 2-6: Cost Effectiveness of Various EE Potential Planning Scenarios

For further information on the Study, please refer to Appendix B: Energy Efficiency.

2.3.1.3 Total Additional EE Investment Required to Reach Required 15% GWH Savings

The energy efficiency programs required to meet the proposed savings targets totaling 3,596 GWh for the ten-year period between FY 2013-14 and FY 2022-23 will require a substantial investment currently estimated at $1.225 billion over the ten-year period. This level of additional spending is well above LADWP's historic and current levels and produces the GWh savings required in the next two fiscal years to put LADWP on a path to achieve the targets adopted. Notably, this level of funding puts LADWP on par with California's Investor Owned Utilities (IOUs) in terms of EE investment on a per-ratepayer basis, giving LADWP the third largest portfolio of EE programs in California.

The chart below shows the estimated annual expenditures for FY 2013-14 through FY 2022-23 for the adopted targets from the Study. For reference, actual expenditures are included for FY 2010-11 through FY 2012-13. The dotted red line represents level to which energy efficiency is currently funded annually as a result of the Power rate increase (Adopted Board Resolution 013 053, September 12, 2012). This level corresponds to an annual funding level of $138 million, and demonstrates that substantive additional funding for energy efficiency is not expected to be needed until FY 2016-17.

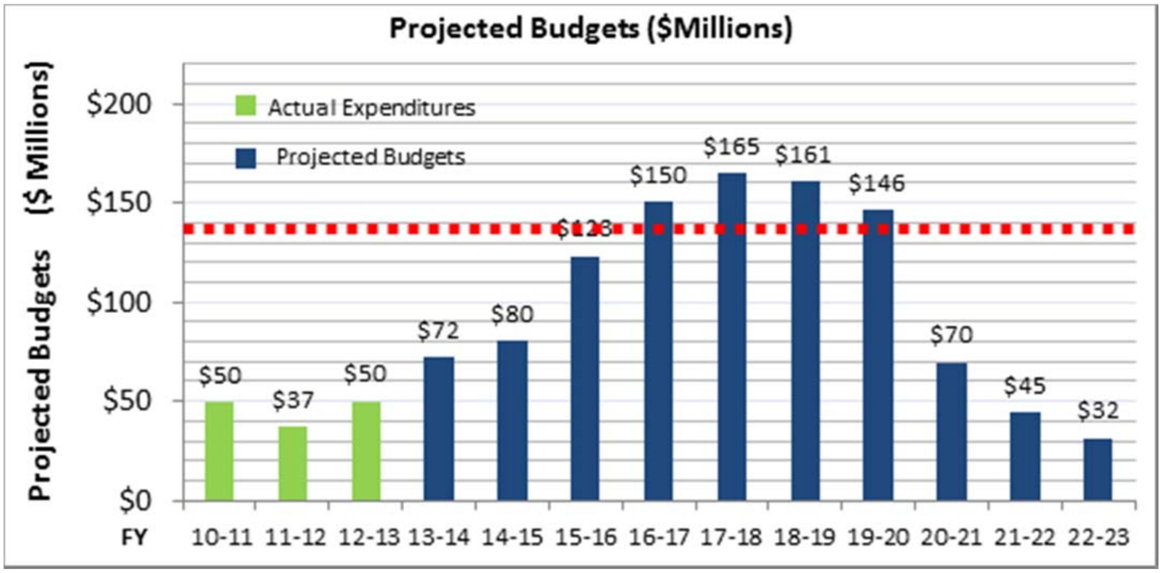


Figure 2-7: Adopted Targets - Projected Budget Per Fiscal Year

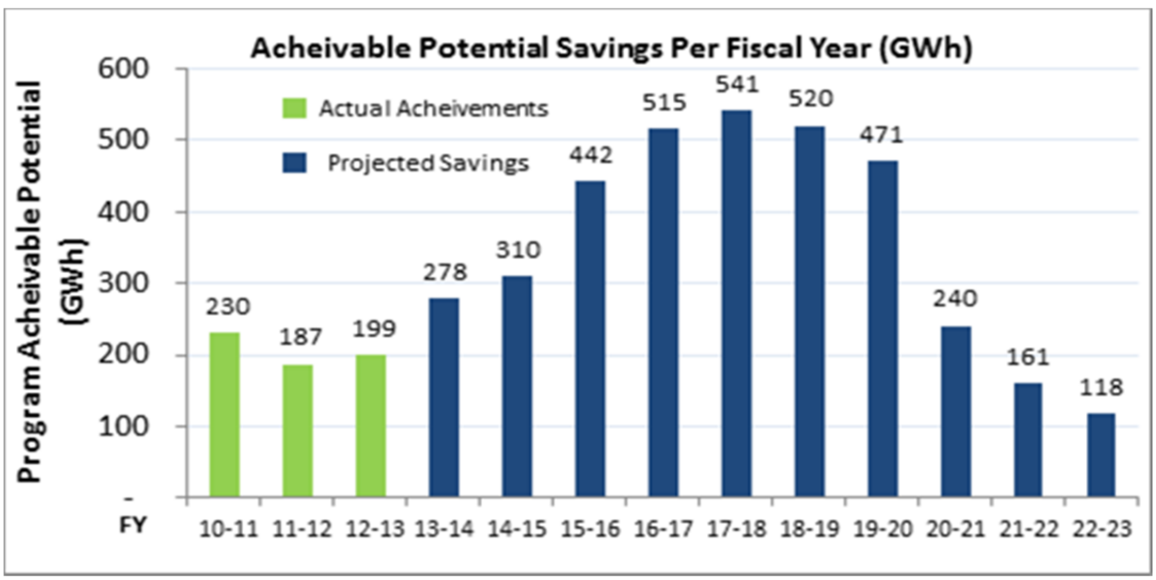


Figure 2-8: Adopted Targets - Energy Savings Per Fiscal Year

Note: LADWP reserves the right to adjust programs, budgets, and individual program savings target at any time in order to respond to changing business conditions and market need.

2.3.1.4 Program Descriptions

The different EE program elements are briefly described as follows:

Mass Market Programs

- Small Business Direct Install Program (SBDI): This program retrofits the existing lighting of qualifying business customers to new, high efficiency lighting systems. The SBDI will initially target the smallest business customers in the A1 rate class, but may be expanded to other customer segments. This program is expected to operate for three years.
- LAUSD Direct Install: The Los Angeles Unified School District Direct Install (LAUSD DI) Program is designed to improve energy and water efficiency throughout LAUSD's facilities through upgrades in electricity, water and natural gas consuming systems, in partnership with the Southern California Gas Company (SoCal Gas). This Program provides energy efficiency design assistance, project management experience and retrofitting installation, utilizing LADWP engineering and Integrated Support Staff (ISS), to assist LAUSD facilities in need of aid in reducing energy usage and corresponding utility expenses.
- Refrigerator Exchange Program: Provides new energy-efficient refrigerators to low-income customers in exchange for existing inefficient, older models. Program planning includes improved outreach and continued expansion to apartment owners.
- Refrigerator Recycling Program: The program provides free pick-up and recycling of old, inefficient refrigerators, along with a cash incentive for each recycled refrigerator.
- Home Energy Improvement Program: This program, offers residential customers the opportunity to reduce their energy bills by allowing qualified Department staff to make energy efficiency and water conservation upgrades to their home. For residential customers residing in multi-family dwelling, common area efficiency upgrades will also be addressed. All residential customers may apply; however, first consideration will be given to registered low-income and lifeline customers, and Tier 2 residential customers who demonstrate the greatest economic need.
- California Advanced Home Program: The California Advanced Home Program (CAHP) is an incentive program that utilizes the statewide CAHP through its partner utility, Southern California Gas Company, for cost-effective energy efficiency upgrades in residential new construction. CAHP intends to target high density, residential new construction, including single and multi-family high rise buildings, as this is the area with the greatest new construction energy savings potential in LADWP's service territory.
- Energy Upgrade California: This is a collaborative program administered by the California Energy Commission in partnership with public and private utilities, the California Public Utilities Commission, and participating counties. The program is

funded by grants and contracts from the U.S. Department of Energy, the Energy Commission, and California utility customers. This is a new program not included in the base efficiency program.

- Consumer Rebate Program (CRP): The CRP is designed to both educate and encourage the LADWP's residential customers to purchase high efficiency refrigerators, air-conditioners, appliances, and other energy-saving products that meet or exceed Energy Star efficiency rating.
- Gas Co Weatherized Homes: LADWP is partnering with Southern California Gas Company through a Memorandum of Understanding to share data on our respective weatherization programs to avoid duplication. As this effectively creates a joint program, LADWP will report the electric savings from Southern California Gas service homes, and offer them the savings from LADWP serviced homes.

Commercial, Industrial & Institutional Programs

- Custom Performance Program: This program continues offering savings-based incentives for the installation of energy savings measures, equipment or systems that exceed Title 24 or minimum industry standards, with differing incentive rates established for three categories or efficiency measures (lighting, Heating, Ventilation, and Air Conditioning (HVAC), other).
- Commercial Lighting Efficiency Offer: Provides menu-based rebates for energy efficient lighting technologies, including T8 and T5 lamps with electronic ballasts, high bay linear fluorescent fixtures, induction lamps, LED exit signs, LED channel signs, occupancy sensors, and others.
- Savings by Design: The Savings by Design (SBD) Program is a California statewide non-residential new construction program, in which LADWP will partner with Southern California Gas Company (SoCal Gas) to offer a uniform, multi-faceted program designed to consistently serve the needs of the commercial building community. SBD encourages energy-efficient building design and construction practices, promoting the efficiency use of energy by offering up-front design assistance, owner incentives, design team incentives, and energy design resources.
- Retrocommissioning (RCx) Express: (RCx Express) program is a continuation of the American Recovery and Reinvestment Act (ARRA) grant-funded pilot program for non-residential customers, replacing the ARRA grant funding with Department funding from rate revenue. The pilot program design is based on lessons learned from SCE's Retrocommissioning program. The LADWP program offers a cash incentive (rebate) to those who undertake a "tune-up" of their existing building system equipment and bring it back up to its original performance level. The program does not require a Retrocommissioning study, but offers a menu of 13 items that qualify for incentives. Program offerings include incentives for replacement or repair of certain lighting sensors, air conditioning economizers, restoration of fan and pump variable frequency drives, operations set point strategies for supply air, temperature or duct pressure, chilled water and condenser water, operating schedules and boiler lockout.

- Refrigeration Program: The Refrigeration Efficiency Program encourages best practices and retrofit measures and technologies to reduce energy in food store refrigerator cases and cold storage facilities.
- Chiller Efficiency Program: Rebates are available for all types of chillers (air-cooled and water-cooled). In addition, water-cooled centrifugal chillers now can be tested at either standard. Air-conditioning and Refrigeration Institute (ARI) or non-standard ARI conditions provided the cooling tower meets specific performance criteria. Higher rebate levels are based on the percentage that the chiller's Integrated Part-Load Value performance exceeds California's Current Title 24 requirements for chillers.
- Low Income Economic Development Program: LADWP Economic Development provides grants to low income housing developers, and projects must achieve 15% greater savings than codes. This is the first time LADWP is quantifying and reporting these savings.

Crosscutting Programs

- Codes & Standards (C&S) Program: The Codes & Standards /Compliance (C&S) is a resource program that conducts advocacy activities to improve building and appliance efficiency regulations. The principal audience is the LA City Department of Building Safety and the LA City Council, which together develop and adopt codes & standards specific to LA that go beyond state and federal regulation. A secondary audience is the CEC, which conducts periodic rulemakings, usually on a three-year cycle (for building regulations), to update building and appliance energy efficiency regulations.
- City Plants: City Plants is an initiative and partnership aiming to plant one million trees in the city. The trees will provide shade and save on energy costs, clean the air, and help reduce the greenhouse gases that cause global warming, capture polluted urban runoff, improve water quality, and add beauty to Los Angeles neighborhoods.
- Upstream HVAC: Upstream HVAC is a program targeted to launch in the upcoming fiscal year 2014-15 that will allow LADWP to participate in the California statewide IOU's upstream HVAC program, which will bring synergies and cost savings. This program expects approximately 5-10 GWh per year and is the same program offered by Southern California Edison.
- LADWP Facilities Program: The LADWP Facilities Program strives to improve energy efficiency throughout LADWP's facilities with energy efficiency upgrades in HVAC and lighting. It identifies and assists those LADWP facilities in reducing energy usage, which will result in a reduction in energy consumption and procurement expense for LADWP that would otherwise be borne by LADWP customers.
- Embedded Energy from Water Measures: LADWP maintains a comprehensive suite of water efficiency programs to help our residential and non-residential water customers reduce their water usage through the adoption of various hardware measures. These actions to promote water use reduction have corresponding energy

use reduction benefits, due to the amount of energy embedded in LADWP water throughout the cycle of treatment, distribution, and wastewater collection and treatment. All of this embedded energy is sourced from the LADWP grid (out-of-territory conveyance is omitted for now), so reductions in water usage due to these programs also save LADWP electricity.

- Plumbing Ordinance, Article V Codes & Standards: LADWP wrote the plumbing ordinance and shepherded it through City Council. Using the same factor used by Environmental Affairs to translate LADWP's water savings into embedded energy savings, an estimate of water use reduction due to the ordinance is used to estimate kWh savings; however, not enough data exists to estimate kW at this time and the numbers are subject to further refinement.
- Low Impact Development (LID) Ordinance: LADWP wrote this ordinance and supported its passage through City Council. Environmental Efficiency engineers are working to estimate the energy savings due to this ordinance.

2.3.1.5 Effect of EE on Electric Rates and Bills

The key factor that determines EE's effect on electric rates and customer bills is the comparison of its costs to the cost of the generation it is replacing. The following Table 2-5 conceptually illustrates the three possibilities – EE costs are lower, the same, or higher than the costs of the generation resources being replaced.

Table 2-5: Effect of EE on Rates and Bills

Are EE costs lower, the same, or higher than the generation it is displacing?	Effect on Total Cost $ (Which Must Equal Revenue Collected)	Effect on Total Energy Sales kWh	Effect on Rates $/kWh	Effect on "System-wide" Average Bill
Lower	Lower	Lower	see discussion below	Lower
Same	Same	Lower	Higher	Same
Higher	Higher	Lower	Higher	Higher

When EE costs are lower than the generation it is replacing (see Row 1 in Table 2-5), there are overall reductions in both total costs and energy sales. This could result in upward rate pressure since there are less kWhs to spread fixed costs over. However, the reduction in total costs may be large enough to keep rates flat, and more so in the long-term as avoided cost benefits accrue over time. Lower total costs also means less revenue collected from customers; hence the "System-wide" average customer bill is lower, which benefits all customers. Those who implement energy efficiency measures will see further reductions.

Table 2-5 also illustrates the case where EE costs are higher than the generation it is replacing. If EE is replacing less expensive resources (such as or coal, notwithstanding CO_2

allowance costs), the effect is a higher rate *and* higher "average" bill due to the higher total system costs.

As a practical consideration, there is little choice regarding which generation will be replaced by energy efficiency. While the effect of EE on Power System operations is to lower energy consumption and thus lower the amount of generation to be dispatched on a given day, the methodology for dispatching generation continues to be based on the economics of the generation available. Thus, the key measure of EE's impact on overall rates and bills is the comparison of its cost to the Power System's avoided cost of generation. As long as the cost of EE is lower than the avoided cost of generation, there is the beneficial effect of lower total costs and lower total revenue required.

The variations in EE costs, based on the different measures available, are identified in the energy efficiency potential study, and are factored into the development of EE program elements.

Further information regarding LADWP's EE program is included in Sections 4 and 5, and Appendix B. A detailed discussion of avoided costs of generation can be found in Section 4.3.3 and Appendix N, Section N.4.

2.3.2 Demand Response

Background & Purpose

Demand Response (DR) is an important energy management tool that facilitates the reduction in energy use over a given time period 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 investment in expensive natural gas power plants. 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 will be 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 2-9:

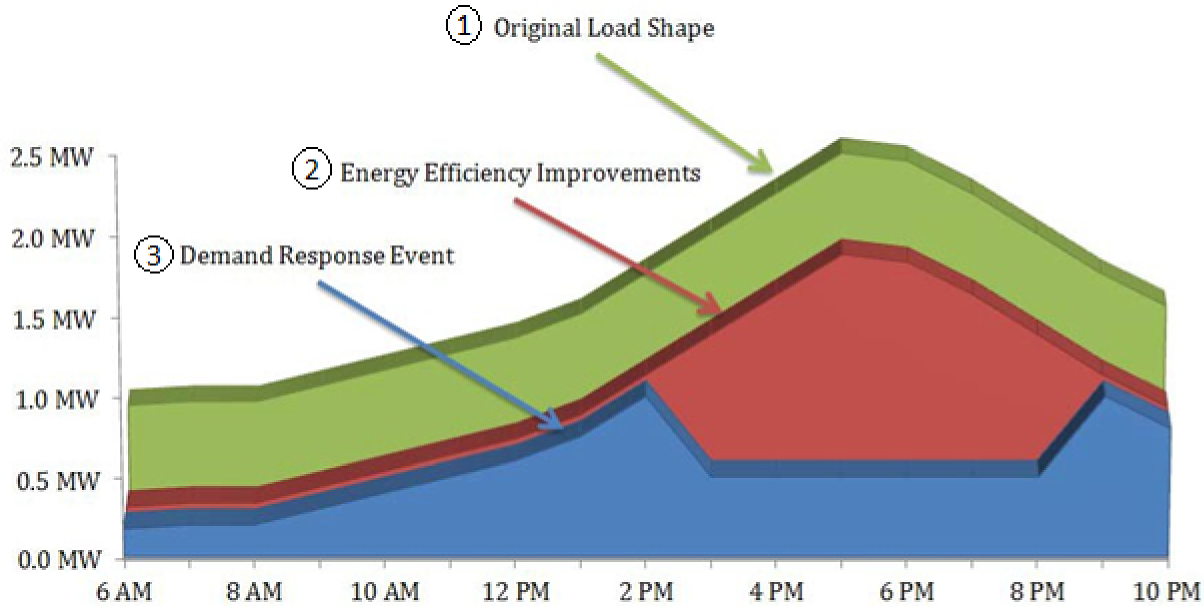


Figure 2-9 – Comparison of Load Impact between EE and DR

Figure 2-9 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 targeted 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 2-9, which targets the hours between 2 p.m. and 9 p.m. thereby flattening the load shape between those hours. The combination of demand response and energy efficiency complements one another and can be an important asset in reducing overall peak load.

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 and the associated transmission and distribution infrastructure. Additionally, DR may reduce purchased energy costs by reducing the amount of energy that would otherwise be purchased to meet load, especially during the expensive peak demand periods. The overall effect is to save money which helps keep rates low.

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 benefits customers who do not participate as DR reduces the need for long term investment in new power plants, transmission, and distribution equipment.

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 at those few critical peak times each year when demand is at its highest, as well as those times when generation units are off-line, whether due to a forced outage or scheduled maintenance.

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 less operational impacts, including less fuel consumption, less carbon emissions, and less transmission use.

Integrating Renewables. Advanced Automated DR can enable customer loads to respond to fluctuations in generation 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.

Major Legislation and Policy Drivers

The updated Title 24 standard that took effect on July 1st, 2014 includes an updated requirement for Automated Demand Response (Auto DR) readiness. Any new building larger than 10,000 sq-ft and any existing building replacing 10% or more of existing luminaries must enable lighting fixtures to be controllable by a building management system capable of receiving Auto DR signals via the internet. 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.

Program Development

LADWP's vision for DR is to enroll a realistically achievable quantity of a dispatchable, demand-side resource within LADWP's service territory that is both reliable and cost effective. The DR resource will help to defer generation capacity investments and to provide local transmission and distribution support, operating reserves, and integration of intermittent renewable energy.

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, which means an easy process for enrollment into programs, flexibility to change participation decisions, transparent incentives and rates, and inclusive of all rate classes.

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, where the DR goals will be revisited each year during the IRP update process and realigned with projections of supply and demand and with changing strategic priorities at LADWP.

LADWP's focus is on DR resources that are cost-effective and proven. Cost-effectiveness tests determine whether the DR resource is a better investment overall than alternatives for meeting future load growth, given the best available current information. Upon review of these considerations, the current plan calls for LADWP to build 200 to 500 MW of capacity by 2026 – 481 MW dispatchable – accelerating its implementation and evaluation of DR programs from an initial 5-10 MW of new peak demand capacity beginning in 2014, and to gradually build to 100 to 200 MW by 2020 and adding additional, cost-effective resources over the subsequent decade. Ramping the program in this manner—gradually and through internal programs rather than outsourced contracts for capacity—will promote the development of in-house expertise, and will also allow time to deploy the supporting information systems necessary to implement these systems successfully.

In 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 details the estimated DR resources, measurement and verification methods for load and billing impacts, cost-effectiveness methodology and results, enabling hardware and software requirements, customer outreach plans, and program staffing requirements. The DR implementation plan is updated annually and is incorporated into LADWP's IRP. All customer classes and sizes will be eligible to participate in some form of demand response, with the principal sources of load curtailment provided by the following customers and programs:

1) Commercial, Industrial, and Institutional (CII) Curtailable (215 MW) – Participants receive monthly capacity payments in return for providing guaranteed load reduction of at least 100kW when requested by LADWP. Additional incentives are provided based on energy reduced during DR events.

2) Residential & Small Commercial Direct Load Control (DLC) (145 MW) – Participants with less than 30kW peak load receive an annual payment that varies based on their ability and willingness to reduce power consumption from equipment which may include central air-conditioning units, wall-mounted air-conditioning units, pool pumps, and other equipment.

3) Critical Peak Pricing (93 MW) – Residential, small commercial, large commercial, and industrial participants of all sizes will be given a dynamic Time-of-Use 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 (EV) Rider (12 MW) – 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) (41 MW) – The California Air Resources Board 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.

LADWP's projected DR Portfolio in 2026 is as follows:

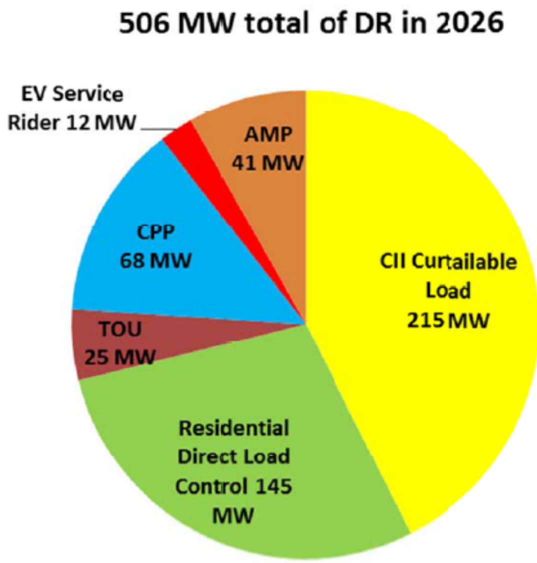


Figure 2-10: Demand Response Portfolio in 2026

Implementation Schedule

The initial vision for DR extends through 2026, with the steady growth of CII and mass market load curtailment capability beginning in 2014. Early pilot programs will provide real DR capacity and build operator confidence in the resource, while also refining LADWP's choice of technologies, program designs, and outreach strategies. The first new offerings will extend new DR opportunities to large CII customers and to residential customers with central air conditioning. By 2020 new avenues for participation will be available such as critical peak pricing for CII customers and inclusion of pool pumps and window air conditioning for residential direct load control. 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 existing Building Energy Management Systems (BEMS) and commit to a minimum load reduction of 100 kW for each called-for Demand Response Event during the five-month curtailment season of June 15th through October 15th. As of November 2015, LADWP has enrolled 26 Commercial, Industrial, and

Institutional participants to commit a total of 4 MW load curtailment. Five Demand Response events took place (July 29, August 13, August 14, September 10, and October 8, 2015), in which LADWP managed to record 5 MW average of actual curtailed load. In one event, participants were able to curtail up to 8 MW of load, exceeding their committed curtailment.

Achieving the planned trajectory of DR growth from 0 MW today to 100 to 200 MW by 2020 and 200 to 500 MW by 2026 will require laying a strong foundation of internal resource deployment, stakeholder participation, program development, and technology acquisition. Figure 2-11 illustrates the growth of demand response by program:

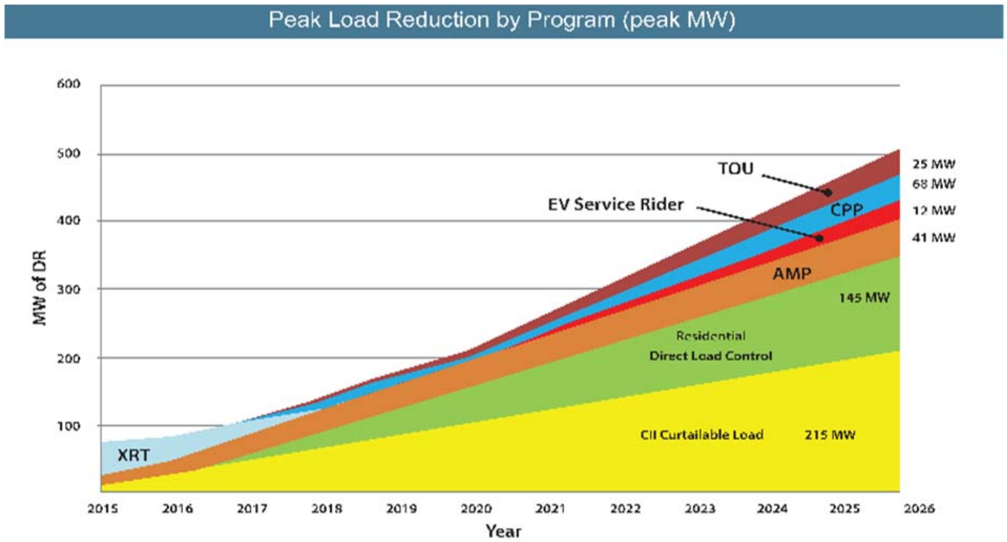


Figure 2-11: Demand Response Growth (2015-2026)

A tentative near-term schedule through 2016 is comprised of the following components:

- **Plan development –** This DR Strategic Plan was finalized in mid-2014, including a detailed schedule for pilot programs and alignment with the efforts and findings of the smart grid team. The plan will be updated each year to ensure consistency with current system needs and LADWP's objectives.
- **Stakeholder feedback –** Internal stakeholders have already contributed to the Plan during its development via interviews with the DR team and responses to data requests. Early 2014 allowed for a review of the Plan and feedback from stakeholders including groups conducting grid operations, wholesale power purchasing, and resource planning, as well as from other stakeholders such the smart grid team, the rates group, and the energy efficiency group.
- **Pilot development and launch –** Detailed design of the pilot programs will begin in 2014, with launch of a pilot for LADWP facilities in late 2014 and for external CII customers by 2014/2015. The residential direct load control pilot will launch by summer 2015, and an Auto-DR component of the CII pilot by 2016.
- **External outreach –** Engagement with customers to gain program design feedback and to promote enrollment in programs will begin in 2014 for CII customers and late 2014 or early 2015 for residential customers. Outreach will broadly educate

customers on DR and how it contributes to a cleaner, more reliable system, and may leverage energy efficiency outreach efforts for greater cross-departmental efficiencies and more streamlined customer messaging. Outreach will also take the form of targeted recruitment for pilot program participation in specific geographic areas and among specific demographics best suited to realize benefits for the customer and the system.

- **Program development** – Development of the initial DR programs will begin in mid-2014 with hiring or assignment of program staff; training of non-program staff who are part of key business processes such as Premier Account representatives, call center staff, and ECC staff; creation of program manuals, contract templates, and informational materials; and solicitation of technology providers and DR technologies to enable load curtailment, program tracking, and DR resource management.

The schedule in Table 2-6 represents an approximate flow of activities over the next three years. As the Plan is updated each year and incorporated into LADWP's annual IRP, the precise schedule may change to accommodate new information and changing needs.

	2013	2014				2015				2016			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Plan Development		2014											
Finalize 2014 DR Implementation Plan		Final											
Develop Pilot Schedules													
Technology Alignment with SG				2014				2015				2016	
Update				Update				Update				Update	
Plan Circulation & Feedback from Stakeholders													
Grid Operations													
Wholesale													
IRP													
Other key stakeholders (SG, Rates, EE, etc)													
Pilot													
Preliminary Development (IDing facilities)													
CII Program Pilot Launch (LADWP facility)													
CII Program Pilot Launch (External)													
Residential AC Load Control													
CII Auto DR													
External Outreach													
Large CII Customers													
Premier Account													
Non-Premier Account													
Mass Market Customers													
Program Development													
Staffing													
Staff training													
Develop Manuals, Contracts, Materials													
RFPs for technology vendors													
IT integration													
2014 IRP Incorporation													

Table 2-6 Demand Response Implementation Schedule (2014-2016)

<u>Demand Response's Role in Renewable Over-generation, Co-generation, and Energy Storage</u>

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. Curtailing renewable generation is both costly and a waste of 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 IOUs to 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 towards those goals to the California Energy Commission (CEC). As details of LADWP's Energy Storage goals develop, staff will identify any coordination opportunities and potential synergies between DR and Energy Storage programs.

2.3.3 Distributed Generation

Distributed Generation (DG) is the concept of installing and operating small-scale electric generators located at or near the electrical load. These numerous small generators are "distributed" across the service area, as opposed to the traditional configuration of a few large centralized generating stations. DG sources can be utility-owned or customer-owned. A large subset of DG is combined heat and power systems, also known as cogeneration, which are primarily owned and operated by industrial and commercial customers. Known subsets of DG include SIP, FiT, Community Solar, fuel cells, cogeneration, wind turbine, and vehicle-to-grid.

Many categories of electrical generation fall under the DG definition, with the key characteristic being that they are located at or near the service load. The most common technologies used today for DG are turbines and internal combustion engines. Solar PV is a newer technology that is forecasted to account for an increasing percentage of DG. Other, less common DG technologies are microturbines and fuel cells. Under a pilot project, LADWP installed a total of four 200-250 kW fuel cell power plants in various locations in Los Angeles. Although the pilot project is now complete and inactive, it has provided considerable operational data and experience. LADWP continues to closely monitor fuel cell development. More details regarding DG can be found in Appendix G.

2.4 Generation Resources and Transmission Assets

The Supply-Side Resources discussed in this section include:

- Existing Generation Resources
    - Natural Gas
    - Coal
    - Nuclear
    - Large Hydro
    - Existing Renewable energy resources (small hydro, wind, solar, biogas, and geothermal)
- Spot Purchases

The major issues affecting generation are presented, including the need to repower the in-basin natural gas units and the future disposition of coal-fired generation.

This section concludes with:

- Future Renewable Resources
- Transmission and Distribution Facilities/Grid Reliability
- Advanced Technologies and Research and Development
- Climate Change Effects on Power Generation
- Reserve Requirements

The LADWP Power System has a diverse mix of generating resources. Figure 2-12 shows LADWP's energy percentages based on past Power Content Label (PCL) submittals to the California Energy Commission.[3] The largest change between these two periods is the decrease in coal-fired energy from 52 percent in 2004 to 33 percent in 2012, and the corresponding increase in energy from renewable resources, from 3 percent in 2003 to 20 percent in 2014. These changes in resources are attributed to environmental mandates, such as SB 1368, AB 32, SB 2 (1X), and SB 350.

[3]Throughout this document, the term energy and capacity are used interchangeably when describing various resources so an explanation is warranted. "Capacity" is a measure of the capability to produce power or the rate at which energy is transferred. The term is applied to the amount of electric power delivered or required to meet the power demand, and is expressed in Megawatts (MW) or Gigawatts (GW). "Energy" is a measure of the quantity of electricity used in a given time period and is expressed in Megawatt-hours (MWh) or Gigawatt-hours (GWh).

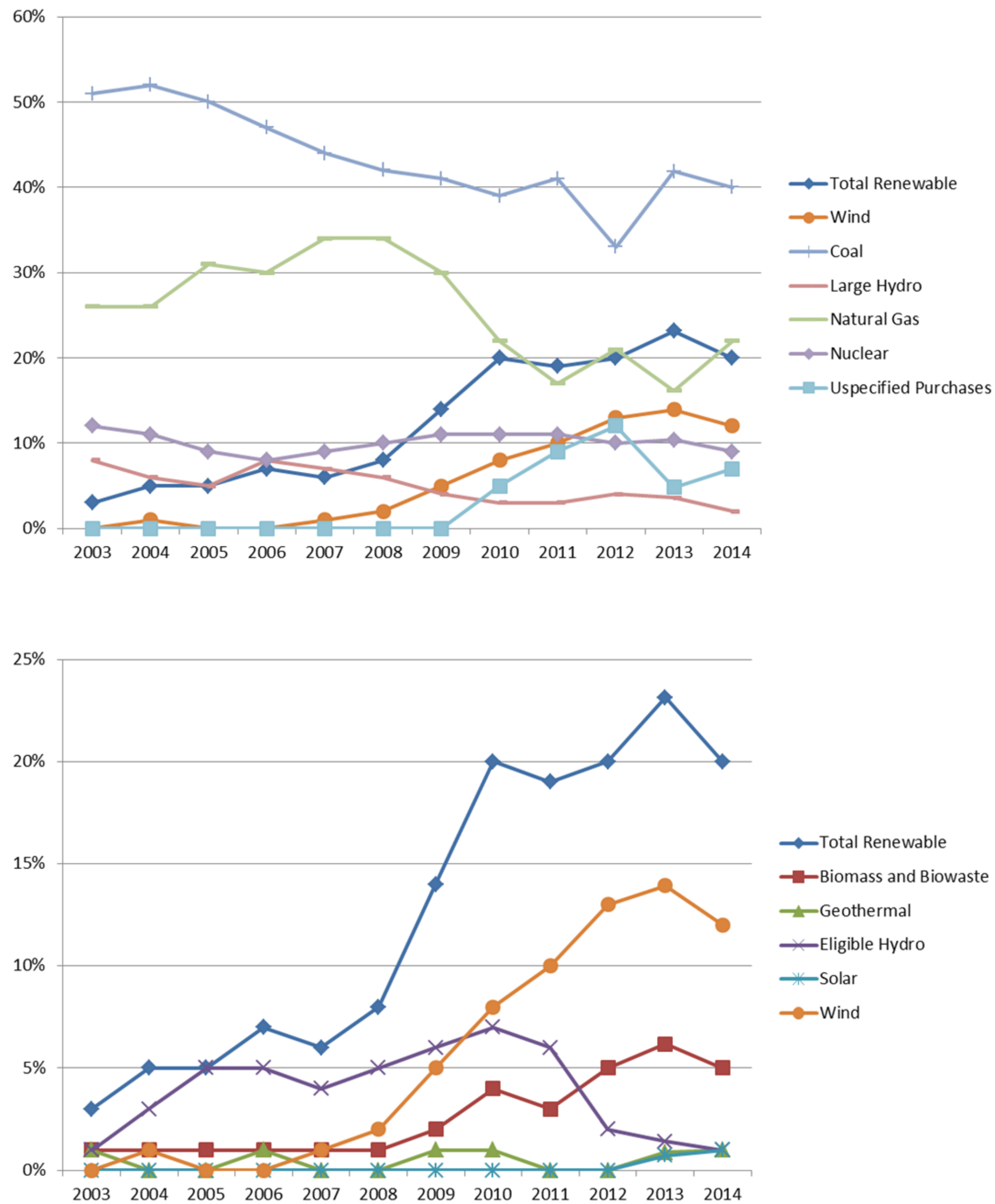


Figure 2-12: LADWP power content label historical energy percentages between 2003 and 2014.

2.4.1 Generation Resources

LADWP is vertically integrated, both owning and operating the majority of its generation, transmission and distribution systems. Generation resources that are not wholly owned by LADWP are available as entitlement rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. Table 2-7 lists existing LADWP generation resources.

Table 2-7. CAPABILITY OF EXISTING LADWP GENERATING RESOURCES[1] (AS OF JUL, 2015)

CITY OF LOS ANGELES - DEPARTMENT OF WATER AND POWER
GENERATION RATINGS AND CAPABILITIES OF POWER SOURCES [1]
Based on Information Available as of July 1, 2015

NAME OF PLANT	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPABILITY [2] (kW)	NET MAXIMUM PLANT CAPABILITY [3] (kW)	NET DEPENDABLE PLANT CAPABILITY [4] (kW)
San Francisquito Power Plant 1	1A	12/10/1983	25,000	22,500	27,000	83,050	[A] [B] 24,230
	3	4/16/1917	9,375	7,500	10,000		
	4	5/21/1923	12,500	10,000	12,000		
	5A	4/9/1987	25,000	22,500	27,000		
San Francisquito Power Plant 2	1	7/6/1919	17,500	14,000	0		
	2	8/7/1919	17,500	14,000	14,000		
	3	12/2/2006	20,000	18,000	18,000		
San Fernando Power Plant	1	10/22/1922	3,500	2,800	3,200		
	2	10/22/1922	3,500	2,800	2,900		
Foothill Power Plant	1	10/6/1971	11,000	11,000	9,800		
Franklin Power Plant	1	6/3/1921	2,500	2,000	2,000		
Sawtelle Power Plant	1	6/5/1986	711	640	650		
Haiwee Power Plant	1	7/18/1927	3,500	2,800	2,500	[D] 11,830	[C] [E] [F] 1,200
	2	7/18/1927	3,500	2,800	2,500		
Cottonwood Power Plant	1	11/13/1908	937	750	1,200		
	2	10/13/1909	937	750	1,200		
Division Creek Power Plant	1	3/22/1909	750	600	680		
Big Pine Power Plant	1	7/29/1925	4,000	3,200	3,050		
Pleasant Valley Power Plant	1	2/5/1958	4,000	3,200	2,700		
Upper Gorge Power Plant	1	6/15/1953	37,500	37,500	37,500	112,500	[G] 109,500
Middle Gorge Power Plant	1	5/11/1952	37,500	37,500	37,500		
Control Gorge Power Plant	1	4/1/1952	37,500	37,500	37,500		
Hoover Power Plant (Energy Purchase from WAPA through Sept. 2017) [H]						491,000	390,000
TOTAL HYDRO						**698,300**	**524,930**
Castaic Power Plant	1	7/11/1973	287,600	271,000	271,000	1,247,000	[I] [J] 1,175,000
	2	7/9/1974	287,600	271,000	271,000		
	3	7/13/1976	287,600	271,000	271,000		
	4	6/16/1977	287,600	271,000	271,000		
	5	12/16/1977	287,600	271,000	271,000		
	6	8/11/1978	287,600	271,000	271,000		
	7	1/27/1972	70,000	56,000	56,000		
TOTAL PUMP STORAGE						**1,247,000**	**1,175,000**
Harbor Generating Station	1	1/31/1995	100,400	85,340	78,000	458,000	[K] 452,000
	2	1/31/1995	100,400	85,340	78,000		
	5	1/31/1995	93,750	75,000	66,000		
	10	1/4/2002	71,176	60,500	47,400		
	11	1/4/2002	71,176	60,500	47,400		
	12	1/4/2002	71,176	60,500	47,400		
	13	1/4/2002	71,176	60,500	47,400		
	14	1/4/2002	71,176	60,500	47,400		
Valley Generating Station	5	8/17/2001	71,176	60,500	43,000	576,000	[L] 556,000
	6	9/4/2003	215,000	182,750	162,000		
	7	9/9/2003	215,000	182,750	162,000		
	8	11/13/2003	311,000	264,350	209,000		
Scattergood Generating Station	1	12/7/1958	192,000	163,200	183,000	817,000	796,000
	2	7/1/1959	192,000	163,200	184,000		
	3	10/6/1974	552,000	496,800	450,000		
Haynes Generating Station	1	9/2/1962	270,000	230,000	222,000	[V] 1,615,202	[M] 1,585,200
	2	4/7/1963	270,000	230,000	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	99,367		
	12	6/12/2013	127,282	108,190	99,367		
	13	6/12/2013	127,282	108,190	99,367		
	14	6/19/2013	127,282	108,190	99,367		
	15	6/12/2013	127,282	108,190	99,367		
	16	6/12/2013	127,282	108,190	99,367		
TOTAL BASIN THERMAL (Based on gas fuel ratings)						**3,466,202**	**3,389,200**
Navajo Generating Station	1	2/1/1974	892,400	803,000	750,000	477,000	[N] 477,000
	2	12/2/1974	892,400	803,000	750,000		
	3	11/29/1975	892,400	803,000	750,000		
Intermountain Generating Station	1	6/9/1986	991,000	820,000	900,000	1,202,000	[O] 1,202,000
	2	4/30/1987	991,000	820,000	900,000		
Palo Verde Nuclear Generating Station	1	1/30/1986	1,550,000	1,413,000	1,333,000	386,690	[P] 380,314
	2	9/19/1986	1,550,000	1,413,000	1,336,000		
	3	1/19/1988	1,550,000	1,413,000	1,334,000		
Apex Generating Station [S] [T]	1A	3/28/2014	239,000	203,150	162,000	531,860	[U] 479,900
	1B	3/31/2014	239,000	203,150	162,000		
	STG	3/28/2014	264,000	237,600	207,860		
TOTAL THERMAL						**2,597,550**	**2,539,214**
SUBTOTAL NET DEPENDABLE SYSTEM CAPABILITY						**8,009,132**	**7,628,344**
Transfer	State's Capacity Entitlement [Q]					(120,000)	(43,720)
NET DEPENDABLE SYSTEM CAPABILITY						**7,889,132**	**7,584,624**

CITY OF LOS ANGELES - DEPARTMENT OF WATER AND POWER
GENERATION RATINGS AND CAPABILITIES OF POWER SOURCES (1)
Based on Information Available as of July 1, 2015

NAME OF PLANT	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPABILITY (2) (kW)	NET MAXIMUM PLANT CAPABILITY (3) (kW)	NET DEPENDABLE PLANT CAPABILITY (4) (kW)
			(kVA)	(kW)			
Pine Tree Wind Power Plant	1 - 90	6/14/2009	1,667	1,500	1,500	**135,000**	[R]
Pine Tree Solar Power Plant	1 - 17	3/15/2013	500	500	500	**8,500**	[W]
Adelanto Solar Power Plant	1 - 13	6/30/2012	770	770	770	**10,000**	[X]

(1) Power from Power Purchase Agreements and fuel cells is not included in this table.
(2) All units can attain maximum capability only when the weather and equipment are simultaneously at optimum conditions.
(3) Reflects water flow limits at hydro plants; or sum of each unit at in-basin thermal or wind power plants; or entitlements from external thermal plants.
(4) Reflects year-round outputs adjusted for low-generation season. For hydro plants, winter is the low generation season.
[A] Aqueduct combined Net Dependable Plant Capability reflects low water availability during winter.
[B] San Francisquito Power Plant 2, Unit 1 has been out of service since 1996. San Francisquito Power Plant 2, Unit 2 stator heating limits capacity to 8 MW during hot weather conditions. San Francisquito Power Plant 2, Unit 3 has a new generator with refurbished turbine as of December 2, 2006. Contract specification is 18 MW output, but unit was tested to only 16 MW due to low water flows and restricted downstream capacity. Assumed maximum actual output is 18 MW.
[C] Owens Valley combined Net Dependable Plant Capability is 1.2 MW based on 20 years of historical data. 1.2 MW consists of 0 MW from Haiwee and Pleasant Valley and 0.4 MW each from Cottonwood, Division Creek, and Big Pine.
[D] Haiwee maximum unit capability is 2.5 MW each when only one unit is in service; when both units are in service, the Net Maximum Plant Capability is 3.6 MW when feed is taken from North Haiwee Reservoir. Cottonwood Power Plant, Units 1 and 2 Net Maximum Unit Capability is 1.2 MW each. Cottonwood Net Maximum Plant Capability is 1.8 MW.
[E] Big Pine and Cottonwood Net Maximum Unit Capability is limited to a maximum flow through penstock.
[F] Pleasant Valley Power Plant output is limited by Division of Safety of Dams (DOSD) reservoir level restriction.
[G] Owens Gorge Net Dependable Plant Capability reflects re-watering flow.
[H] LADWP's entitlement is 25.16% of the plant capability of 1,951 MW. The reduced entitlement is due to lower lake levels resulting from the drought which causes plant capability to constantly vary. The most recent available average Net Plant Capability is 390 MW for FY 2014-2015.
[I] Castaic Power Plant is re-rated at 1,175 MW, but is capable of generating 1,247 MW for short periods or for extended periods if sufficient flow-through water schedules are received.
[J] Castaic Power Plant, Units 1-6 have completed modernization improvements: 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, and Unit 1 in October 2013.
[K] Harbor Generating Station Net Dependable Plant Capability is 452 MW due to Units 1, 2, and 5 reduced performance during hot weather conditions. Units 1 and 2 were de-rated to 78 MW due to gas turbine wear.
[L] Valley Generating Station Net Dependable Capability is limited to 556 MW reflecting reduced performance during hot weather conditions. This includes operating Units 6 and 7 with duct burners in service. Units 6, 7, and 8 can only produce power in a combine cycle combination (1+1, 2+1).
[M] Haynes Generating Station Net Dependable Capability is 1,585 MW reflecting reduced performance during hot weather conditions. This includes operating Units 9 and 10 with duct burners in cycle. Unit 4 was decommissioned in November 2003 and Unit 3 was decommissioned in September 2004. Units 5 and 6 were decommissioned in June 2013. Units 8, 9, and 10 can only produce power in a combine cycle combination (1+1, 2+1).
[N] LADWP's entitlement is 21.2% of total Navajo net generation.
[O] IPP Net Dependable Plant Capability may be less than 1,202 MW due to Excess Power Recall. For FY 2014-2015, the Dependable Capability is approximately 1,202 MW. The LADWP 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. The nominal Net Maximum Unit Capability and Net Dependable Capability of both Units 1 and 2 is 900 MW.
[P] LADWP's 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.
[Q] The maximum State (CDWR) Capacity Entitlement from Castaic Power Plant is 120 MW. The average for FY 2014-2015 was approximately 43.72 MW.
[R] Pine Tree Wind Power Plant was commissioned in June 2009. Wind generation is not considered to be dispatchable and dependable.
[S] Apex Generating Station Net Dependable Capability is limited to 479.9 MW reflecting reduced performance during hot weather conditions. This includes operating Units 1A and 1B with duct burners in service. Units can only produce power in a combine cycle combination (1+1, 2+1).
[T] SCCPA owns Apex Generating Station. Units 1A and STG were originally placed in-service by the original owner on January 13, 2003, and Unit 1B was originally placed in-service on January 20, 2003. SCCPA took ownership of Apex Generating Station on March 26, 2014, and maintains a sales agreement for the Station's generated power.
[U] Currently LADWP purchases one-hundred percent of Apex Generating Station's production of power.
[V] For Haynes Generating Station, Units 11-16, the net maximum unit capability occurs when all 6 units are in-service as this is when the lowest average auxiliary power is being drawn per unit.
[W] Pine Tree Solar Power Plant was commissioned in March 2013. Solar generation is not considered to be dispatchable and dependable.
[X] Adelanto Solar Power Plant was commissioned in June 2012. Solar generation is not considered to be dispatchable and dependable.

ALV LBB/ALV DKY

Reviewed by: Anton L. Vu, Lars B. Black, and Daryl K. Yonamine

Approved by:

Kenneth A. Silver
Director of Power Supply Operations Division

Natural Gas

LADWP is the sole owner and operator of the following four electric generating stations in the Los Angeles Basin (the "In-basin stations"):

- Haynes Generating Station, located in Long Beach
- Harbor Generating Station, located in Wilmington
- Scattergood Generating Station, located in Playa del Rey
- Valley Generating Station, located in the San Fernando Valley

A map of the in-basin generating stations is shown in Figure 2-13.

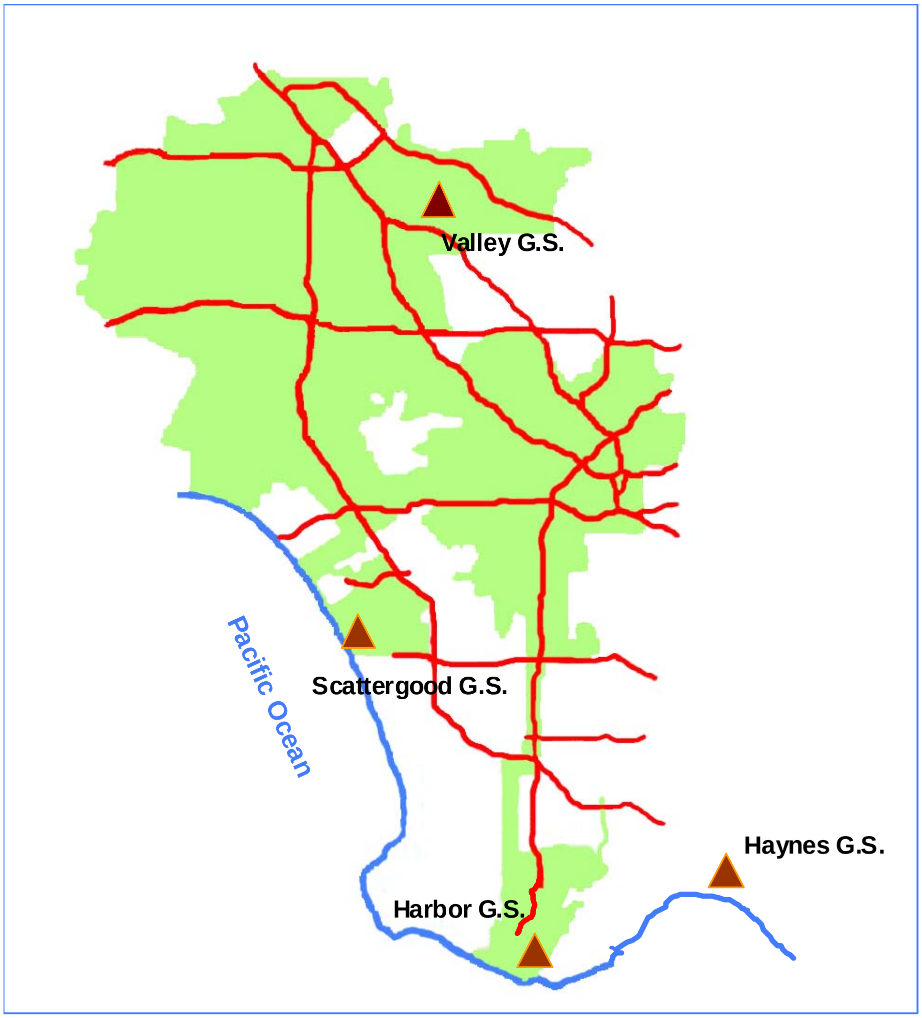


Figure 2-13. LADWP in-basin generating stations.

Each station consists of multiple generating units, with each unit ranging in size between 43 MW and 450 MW. A summary of each station's capabilities is shown in Table 2-7. Detailed information on each generating station is included in Appendix F.

While all of these stations utilize natural gas as a fuel source, a special arrangement has been made that enables the Scattergood Generating Station to also use digester gas from the adjacent Hyperion Sewage Treatment Plant. The digester gas currently accounts for 16 MW of Scattergood's generation output. The existing agreement between LADWP and the Los Angeles Bureau of Sanitation enabling this arrangement will end by 2016. LADWP is currently accommodating operation on digester gas from the Hyperion Sewage Treatment Plant at the Scattergood Generating Station. Due to the extensive modifications being made to the station in order to comply with the mandated South Coast Air Quality Management District and the Once-Through Cooling requirements, continuing operation on digester gas at the Scattergood Generating Station will not be feasible nor possible beyond 2016.

Securing continued local generation capacity is important for grid reliability. LADWP's local transmission system cannot be reliably operated without generation from local thermal generating plants where output can be dispatched by LADWP to meet net changes in load. The amount of generation required to provide transmission reliability is termed Reliability Must Run (RMR) generation. RMR generation is incorporated into all of the strategic cases considered in this IRP.

The major issues facing the in-basin stations include the need to replace some of the older units that are approaching the end of their service life, compliance with regulations related to once-through cooling and NO_X emissions, and fuel price volatility. Natural gas fuel prices and procurement issues are presented in detail in Appendix H.

Natural gas will continue to be the essential fuel for LADWP's generation due to abundant supply levels. Natural gas will be used to supply base load (as is currently used), and will also provide for the integration of intermittent renewable generation. Natural gas is also a major component of LADWP's coal replacement strategy.

Coal

LADWP's coal generating capacity comes from the Navajo Generating Station (NGS) and the Intermountain Generating Station (IGS). IGS is also referred to as the Intermountain Power Project (IPP). The amount of capacity available to LADWP from these stations is 477 MW from NGS and up to 1,200 MW from IPP. A summary of each station is included in Table 2-7. Further details and discussion is provided in Appendix F.

Contractual arrangements for power from IPP will expire on June 15, 2027. LADWP and the other participants at IPP have negotiated an agreement between Intermountain Power Agency and IPP participants to convert the facility to new highly efficient gas-fired generators no later than July 1, 2025 (two years before the legal deadline). LADWP is one of thirty-six purchasers of IPP energy.

NGS operates under a co-tenancy agreement that remains effective throughout the initial term of its land lease until December 31, 2019. On May 19, 2015, the Board of Water and Power Commissioners at the Los Angeles Department of Water and Power approved an agreement under which LADWP will sell its 21 percent share of NGS to Salt River

Project (SRP). Under the agreement with SRP, LADWP will stop receiving its 477 megawatt share of coal power from Navajo when the sale closes on July 1, 2016. See Section 2.4.2.3 for more details.

Nuclear

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 is available through a power sales agreement with the Southern California Public Power Authority (SCPPA). Further details are provided in Appendix F.

Large Hydro

LADWP's large hydroelectric facilities include the Castaic Pumped-storage Hydroelectric Plant and an entitlement portion of the capacity of Hoover Dam. The Castaic Pumped-storage Hydroelectric Plant, located in Castaic, California, is LADWP's largest source of hydroelectric capacity and consists of seven units. Hoover Dam, located on the Arizona-Nevada border, consists of seventeen units. Details of these plants are provided in Appendix F.

A distinction is made between "large hydro" and "small hydro." According to a provision of SB 2 (1X), small hydro includes facilities which consist of generating units with a nameplate capacity not exceeding 40 MW for each unit that is 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.

Current Renewable Energy Projects

LADWP's existing renewable resources total over 1,600 MW of capacity, and consist of wind, small hydro, solar, biogas, and geothermal resources. More detailed information is presented in Section F.2.6 of Appendix F. A listing of existing renewable projects by resource type is as follows:

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

- Small Hydro
    - Aqueduct, Owens Valley and Owens Gorge projects
    - North Hollywood
    - Sepulveda
    - Castaic Efficiency Upgrades

- Solar
    - Utility Built Solar In-Basin
    - Feed-in-Tariff
    - Customer Net Metered
    - Adelanto
    - Pine Tree
    - Copper Mountain 3
    - Moapa Southern Paiute
    - Beacon Bundled
    - Springbok 1 and 2
    - Barren Ridge
    - RE Cinco

- Geothermal
    - Don A. Campbell I and II
    - Heber-1
    - Hudson Ranch

- Biogas/Biomass
    - Bradley
    - Shell Biomethane
    - Toyon
    - Hyperion Digester Gas

Additional renewable energy comes from market purchases.

Figure 2-14 presents the profile for LADWP's renewable resources portfolio as of 2014.

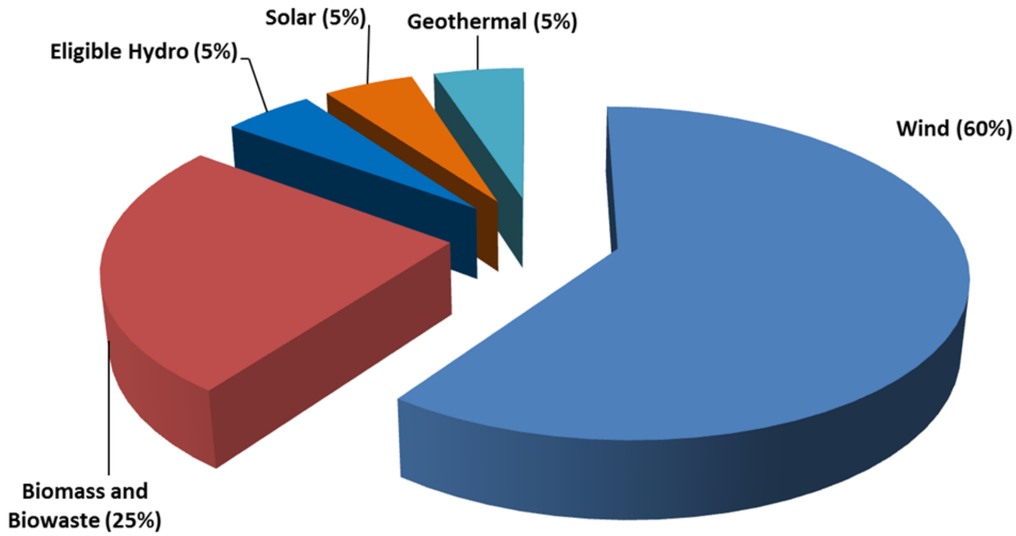


Figure 2-14: 2014 LADWP renewable energy mix.

Spot Purchases

Although LADWP's policy has been to be self-sufficient and capable of generating all of its energy needs from resources it owns or controls, it also participates in energy markets if it is in the City's best economic interest. This happens when energy can be acquired from the wholesale market for less than LADWP's generation cost. Periodically, capacity and energy is purchased from providers within the Western Electricity Coordinating Council (WECC) jurisdiction under short-term "spot" arrangements. These purchases are used by LADWP in conjunction with other resources for economic Power System operation.

The cost and availability of energy on the spot market has fluctuated greatly in recent years. While LADWP currently continues to execute economic spot purchase opportunities, it cannot guarantee the future availability of energy from either the Pacific Northwest or the Southwest at prices below LADWP's costs for producing power from its own resources.

Spot Sales

LADWP often has a surplus of generating capacity and energy. Consistent with prudent utility practice, LADWP offers this surplus into wholesale electricity markets at prices above LADWP's production costs. This way, LADWP's customers benefit both by receiving the lowest cost energy in the Power System and from economic purchases, in addition to economic benefits resulting from wholesale revenue generated from sales. With the implementation of California's GHG Cap and Trade program, sales opportunities will be limited because of the additional cost of carbon emissions that out-of-state suppliers do not have to consider in their pricing of electricity. As a result, California utilities in general are not expected to be competitively priced in out-of-state energy markets.

2.4.2 Major Issues Affecting Existing Generation Resources

Three major issues affecting LADWP's existing generation fleet are: (1) the need to rebuild or "repower" some of its in-basin generating units, (2) compliance with state and local regulations regarding once-through cooling and NO_X emissions, and (3) strategies for replacement of coal-fired energy to accelerate GHG reductions.

2.4.2.1 Repowering Program to Replace Aging Infrastructure

There is a need to modify or replace some of LADWP's older gas-fired generation facilities located at Scattergood generating stations. These units were primarily built in the late 1950s and the early 1960s and are approaching the end of their service lives. LADWP must modernize these plants to maintain system reliability, improve efficiency, and better integrate renewable resources.

- System reliability

  As facilities age, they require more maintenance and become more susceptible to operational limitations and outages. The units to be replaced at Scattergood Generating Station are between 45 and 54 years old, and are among the oldest remaining units in LADWP's generation fleet. LADWP's local basin transmission system was never intended to be reliably operated without generation from these plants. By virtue of their location within the basin transmission system, Scattergood generation ensures that loading on basin transmission lines remain within the circuits' ratings, and system voltage remains within acceptable limits. Minimizing outages at these locations is therefore especially important. Variable-energy resources, such as solar or wind power, can augment existing in-basin gas-fired generation, but the variable resources cannot replace the role local gas-fired generation plays in transmission reliability. The amount of generation required to provide transmission reliability is termed Reliability Must-Run (RMR) generation. Repowering these local units will maintain transmission reliability by increasing the availability of RMR generation.

- Increased efficiencies

  New units will operate more efficiently, generating more energy and fewer emissions with the same amount of fuel. Operational costs per energy output will decrease.

- Integrating renewables

  The new units will incorporate new technologies which will enable faster start-up and faster ramping of generation output. This ability to increase or decrease generation on short notice, measured by what is termed "ramp rate," is an important requirement for integrating renewable resources. Wind resources produce power when the wind is blowing. When the wind suddenly begins blowing or stops blowing, the energy being delivered also changes but the customer load (the amount of energy the power system requires) remains substantially the same. Solar photovoltaic resources are subject to even greater output variability as clouds pass overhead and vary the intensity of available sunlight. To compensate for these fluctuations, natural gas "peaker" units (which are included in the new unit configurations) are able to quickly start, stop, and ramp up and down so that the total energy generated continuously matches customer load. Integrating significant amounts of intermittent renewable resources, such as wind and solar photovoltaic, will not be possible without the fast load-following and renewable energy generation following capability that the repowering program will provide.

2.4.2.2 Repowering Program to Comply With Regulatory Requirements

In addition to the reasons stated in Section 2.4.2.1, the repowering program is necessary to comply with State and Federal regulations related to once through cooling as well as local NO_X emission mandates.

- Once-through cooling

  Once-through cooling (OTC) is the process where water is drawn from the ocean, is pumped through equipment at a power plant to provide cooling, and then is discharged back to the receiving water source. A cooling process is necessary for nearly every type of conventional electrical generating station and an OTC process utilizing ocean water is a major reason why many electrical generating stations were sited along the coastline. Typically, the water used for cooling is not chemically changed in the cooling process; however, the temperature of the water increases before it is returned to the ocean.

  LADWP operates three coastal generating stations – Scattergood, Harbor, and Haynes, which utilize OTC. The combined net capacity of these stations is 2,839 MW. Further information regarding repowering can be found in Section 1.6.6.

  In order to comply with the statewide OTC policy, LADWP has chosen to eliminate OTC and replace it with closed cycle cooling. Interim requirements are necessary until a facility is deemed fully compliant, including the funding by LADWP of mitigation projects to alleviate impacts, such as habitat restoration through the development of wetlands; in addition, feasibility pilot studies are required for the installation of alternative technologies to reduce impingement and/or entrainment in the interim. These issues are discussed in more detail in Appendix C.

- NO_X compliance

  In mid-2000, during the statewide energy crisis, LADWP predicted that NO_X emissions from the in-basin generating units would exceed the available supply of NO_X RECLAIM Trading Credits issued by the South Coast Air Quality Management District (SCAQMD). Although LADWP's NO_X emissions ultimately did not exceed its allocation in 2000, on August 29, 2000 the SCAQMD Hearing Board issued a "Stipulated Order for Abatement" to the LADWP. Under the terms of the Order, LADWP was required to perform a series of repowering projects at its in-basin generating stations. The Stipulated

Order was later superseded by a Settlement Agreement to accommodate scheduling and other issues. This agreement was revised in September 2011 and addresses the current repowering projects at the Haynes and Scattergood Generating Stations.

2.4.2.3 Coal-Fired Generation

SB 1368, the California Greenhouse Gas Emissions Performance Standard Act, enacted in 2006, prohibits California utilities from entering into long-term financial commitments for base load generation, unless it complies with the GHG emissions performance standard. As this standard also applies to existing power plants for any long-term investments or contractual extensions, it affects LADWP's coal-fired generation resources.

SB 1368 Compliant Coal-Fired Generation

As presented in Section 3, the analysis of future potential resource portfolios includes a set of strategic cases that accelerate compliance with SB 1368 for coal-fired generation. The feasibility of adopting and implementing this will depend on a number of factors, including: (1) resolving contractual issues, (2) the cost of alternatives (and LADWP's ability to cover its costs) and (3) other legislative and regulatory factors.

SB 1368 compliant power will reduce the GHG emissions for LADWP, reduce regulatory compliance costs, and spur development of renewable resources in the western United States. SB 1368 established a greenhouse gas emissions performance standard that limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard, which was jointly established by the California Energy Commission and the California Public Utilities Commission. Subsequently, the Energy Commission designed regulations that establish a standard for base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lbs CO_2 per megawatt-hour (MWh).

There are several methods to achieve SB 1368 compliance, for example; replace coal generation with energy efficiency, renewable energy, natural gas-fired generation, carbon sequestration, coal gasification, or the application of other potentially emerging technologies. Since coal generation operates as a base load resource for LADWP, any replacement option would also need to provide some base load generation around the clock while reducing GHG emissions.

Intermountain Power Project

The Intermountain Power Project (IPP) is a coal-fired generating station located near Delta, Utah. IPP consists of two generating units with a combined capacity of 1800 MW. LADWP is the Operating Agent. LADWP is also the largest single purchaser and has a power purchase agreement for 44.617 percent (803 MW) of IPP's total output. LADWP has additional purchase obligations for up to 22.168 percent (399 MW) of additional output. These additional obligations are dependent on the power usage of the Utah and Nevada participants. The power sales contract for IPP expires in 2027.

In addition to the generating units, IPP includes four important transmission lines, a 500-kV DC transmission line from the generating station to Adelanto, California (a distance of 490 miles); two parallel 345-kV AC transmission lines from the generating station to Mona, Utah 50 miles away; and a single 230-kV AC transmission line from the generating station to the Gonder Switchyard near Ely, Nevada about 144 miles away.

At IPP, LADWP has no ownership rights in the generating station or the transmission lines. Rather, LADWP has a long-term power purchase contract which expires in 2027 and which also includes renewal option rights. With firm "take or pay" obligations, LADWP is contractually committed to the project to 2027. LADWP is one of 36 participants that purchase power. The owner of IPP is the Intermountain Power Agency (IPA), a separate entity and a political subdivision of the State of Utah.

IPP Coal Conversion

For some time, the 36 participants and IPA have been considering the future disposition of the IPP facility. In addition to satisfying SB 1368 requirements, pending and potential federal legislative and regulatory actions regarding CO_2, NO_X, fly ash, etc., have introduced uncertainty to the future operating economics for the facility. Considering these uncertainties, as well as other changes across the coal industry and factors unique to the IPP organizational structure, the IPP parties have investigated alternatives to the continued use of coal as a fuel source.

The feasibility of converting the IPP site from coal to natural gas has been studied, and efforts to convert have been initiated. The method and timing of a conversion requires concurrence from all participants and IPA, and establishing a new contractual structure. Some of the considerations that concern LADWP are:

- LADWP and the other IPP participants are contractually obligated to continued debt payments through 2023. An early exit from IPP prior to the end of the debt payment schedule will incur a financial penalty, not only for LADWP but for all of the 36 project participants.
- The existing power purchase contract extends to June 15, 2027. These are "take or pay" contracts which LADWP could not walk away from without incurring monetary/legal penalties.
- Any penalties incurred by LADWP through the preceding bullet points would be incurred by LADWP customers.
- By remaining with the project, LADWP can continue to use the project's transmission assets to deliver renewable energy from the Utah region.
- In addition to the transmission, LADWP can also continue to use the site, the staffing, and the other related infrastructure that has been developed over the years at IPP.

In response to these and other considerations, an amendment to the power purchase contract has been drafted to construct a natural gas replacement facility located at the IPP site. The amendment establishes an in-service date for the new facility of July 1, 2025. The IPP Coordinating Committee and the IPA Board could move the date up if a super majority of the participants support the decision. The current debt payments for the coal plant are scheduled to be completed at the end of 2023 and the end date for the existing power contracts in June 2027. For modeling purposes, July 1, 2025 will be used as an assumed conversion date (see Case 2 in Section 3.5).

As of this writing, the IPP participants are considering the conversion to natural gas with an energy storage system component. The following steps have been identified to establish the new contractual structure and are in progress:

1. Amend the Utah Interlocal Cooperation Act and Electric Power Facilities Act – completed by the Utah legislature in March 2012 (Complete).
2. Amend the IPP Organization Agreement between the 23 Utah municipal members (Complete).
3. Adopt the Second Amendatory Power Sales Contract between all 36 power purchasers (Complete).
4. Adopt Renewal Power Sales Contracts
5. Adopt Renewal Excess Power Sales Agreements

Navajo Generating Station

The Navajo Generating Station (NGS) is a coal-fired generation station located near Page, Arizona. It consists of three units with a combined capacity of 2,250 MW. Salt River Project (SRP) is the Operating Agent. As one of six owners, LADWP has a 21.2 percent ownership share in the station's generation. NGS operates under a co-tenancy agreement which shall remain effective throughout the initial term of the land lease with the Navajo Nation and throughout the lease extension thereafter.

While LADWP is contractually committed to NGS until December 31, 2019, negotiations were made to sell and divest from the project. In 2015, LADWP sold its 477 MW share of coal power from Navajo to SRP; the sale will close on July 1, 2016. Early divestiture of NGS is in LADWP's best interest for a number of reasons:

1. A better sales price than waiting until the 2019 deadline.
2. Avoids the risk that pending federal regulations could potentially encumber the plant with expensive mitigation requirements.
3. Better availability of replacement generation.
4. Reduced CO_2 emissions.
5. Makes room on the transmission network for importing additional solar and geothermal resources.
6. Maximizes the value of the plant to help pay for renewables and energy efficiency.
7. Provides time to handle contingencies, and to ensure that competition is going to benefit our customers.
8. Provides opportunity, for remaining NGS owners outside of California, to close one of the NGS units by 2019, which would result in reduced in emissions.

The coal replacement options considered in this IRP analysis are presented in Section 3 – "Strategic Case Development."

2.4.3 Future Renewables for LADWP

SB 2 (1X)

The increase of renewables, as a percentage of electricity sales, to the regulatory mandated 33% by year 2020 requires the continued diligence of LADWP to pursue renewable projects and power purchase contracts. The development of a solar feed-in tariff and continued encouragement for customer net-metered solar is also necessary to support increased solar capacity. Because the acquisition of additional renewables is mandated by law, all of the strategic cases analyzed in this IRP include portfolios that meet or exceed the required amount of renewable resources. The 2015 recommended case includes the following targets for new renewable acquisitions between 2015 and 2020, subject to change based on technology development, commodity price fluctuations, policy changes, and customer partipation:

New Renewable Installed Capacity (MW) 2015-2020			
Geothermal & Biomass	Wind	Solar PPA	Local Solar
95	0	921	509

Furthermore, maintaining at least 33% of renewables beyond 2020 and achieving 50% of renewables by 2030 requires additional renewables to account for system loading, project turnover, and output degradation as projects age. The 2015 Recommended Case includes the following additional targets for new renewable acquisitions between 2015 and 2035, subject to change based on technology development, commodity price fluctuations, policy changes, and customer participation:

	New Renewable Installed Capacity (MW) 2015-2035			
Geothermal & Biomass	Wind	Solar PPA	Local Solar	Generic
293	670	1646	653	799

SB 1 Solar Requirements

Former Governor Schwarzenegger signed the California Solar Initiative (CSI), outlined in Senate Bill 1 (SB 1), on August 21, 2006. The CSI mandates that all California electric utilities, including municipals, 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 expenditures not to exceed $3.35 Billion. Expenditures for local publicly owned electric utilities shall not exceed $784 Million. The LADWP cap amount is $313 Million, based on its serving 39.9% of the municipal load in the state, representing 280 MW of the 3,000 MW goal.

SB 32 – FiT

SB 32, signed into law on October 11, 2009, and SB 1332, signed into law on September 27, 2012, requires LADWP to make a tariff available to eligible renewable electric generation facilities within its service territory until LADWP meets its 75 MW share of the statewide target. On February 1, 2013 the FiT program was expanded to 100 MW through Set Pricing Program. In July 2013, 50 MW of local solar from Beacon Bundled was added to the FiT program. Through this program, owners or operators of eligible renewable energy systems may sell their energy directly to LADWP. The purchase of SB 32 qualifying energy includes all environmental attributes, capacity rights, and renewable energy credits. This energy is just one of the many renewable energy sources that will apply towards LADWP's 33 percent by 2020 and 50 percent by 2030 renewable requirement.

Power Purchase Agreement (PPA) Option to Own Clause

As policy, PPAs for renewable energy are required to contain purchase options which LADWP may choose to exercise at different times during the term of the agreement. LADWP's goal is to own (either directly or through joint powers authority) at least 50% of its eligible renewable energy resource portfolio. For more detailed information regarding LADWP's Renewable Portfolio Standard Policy and Enforcement Program, see Reference D-2 in Appendix D.

Further information regarding renewables can be found in Appendices D, F, J, and N.

2.4.4 Transmission Facilities/Grid Reliability

Electricity from LADWP's power 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 20,000 miles of alternating current (AC) and direct current (DC) transmission and distribution circuits operating at voltages ranging from 120 volts to 500 kilovolts (kV). Major transmission lines connecting to out-of-basin generating resources are shown in Figure 2-15. Appendix I provides more details regarding LADWP's transmission system.

In addition to using its transmission system to deliver electricity from its power generation resources, LADWP arranges for the transmission of energy for others through its Open Access Same-Time Information System (OASIS) when surplus transmission capacity is available and saleable. LADWP uses its extensive transmission network to sell its excess energy and capacity in the California, Northwest, and Southwest energy markets. Revenues from these excess energy sales are used to reduce costs to 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, after the nearby San Onofre Nuclear Generating Station retired, the California Independent System Operator is attempting to secure the delivery of replacement energy from other potentially available generation sources.

LADWP annually performs a Ten-Year Transmission Assessment Plan, in compliance with the North American Electricity Reliability Corporation (NERC) Compliance Enforcement Program. LADWP's 2015 plan identified a number of transmission improvements that are needed to maintain reliability.

Transmission for Renewable Energy

Since renewable resources are often located long distances from the City of Los Angeles and where transmission facilities do not exist, accessing renewable resources will require extensive infrastructure improvements, including the construction of new transmission lines, upgrades to existing long and short transmission lines, and improvements at transmission facilities and stations to increase their transfer capability. The following sections provide a summary of the major projects:

Barren Ridge Renewable Transmission Project

The Barren Ridge Renewable Transmission Project, scheduled to be completed in 2016, will increase the capacity of the existing 230-kV Barren Ridge-Rinaldi transmission segment from 450 MW to approximately 1,700 MW. As of April 2015, approximately 1,798 MW from a combination of wind, solar, and geothermal projects are being investigated for potential interconnection. This project will also increase the transmission capacity to the Castaic Pump Storage Power Plant, providing 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.
- New double-circuit 230-kV transmission line from the Barren Ridge Switching Station to the new Haskell Canyon Switching Station.
- New 230-kV circuit on existing structures from the new Haskell Canyon Switching Station to the Castaic Power Plant.
- Re-conductor the existing 230-kV transmission line from the Barren Ridge Switching Station to the existing Rinaldi Receiving Station, through the new Haskell Canyon Switching Station.
- Expand the existing Barren Ridge Switching Station.

Up-to-date information on this project is available at:

https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-projects

Pacific Direct Current Intertie (PDCI) Upgrade

LADWP and its southern DC partners have signed a letter of agreement with the Bonneville Power Administration (BPA) to implement an initial 120 MW capacity increase of PDCI, if the cost is reasonable. In any case, BPA has committed to an extensive overhaul of Celilo HVDC Converter Station which requires coordination at the southern end of the HVDC line at Sylmar HVDC Converter Station. The projected completion date for BPA's Celilo upgrade project is January 2016.

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, and then 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, with one 230-kV circuit going 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 as well as assist with supporting 1,700 MW of renewables coming from Owens Valley. In the short term horizon, LADWP plans 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.

The Victorville-Los Angeles (Vic-LA) Project

The Vic-LA Projects, which are targeted to be completed by August 2020, involve making infrastructure and operational improvements between the Victorville area and the Los Angeles Basin which will allow LADWP to add 500-600 MWs 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 transformer to raise the operating voltage from 287 kV to 300 kV,
- Installing new 525/300 kV transformer bank paralleled to existing Bank K, upgrading antiquate equipment at Victorville Switching Station,
- Installing shunt capacitors at different strategic locations to improve Los Angeles Basin load power factor,
- Replace Toluca Bank H,
- Replacing the 230 kV circuit breakers and the disconnect switches at the Rinaldi Receiving Station, and
- Reconductoring Valley-Toluca 230 kV circuits and Valley-Rinaldi 230 kV circuits.

Los Angeles Basin Projects

The annual Ten-Year Transmission Assessments have consistently identified the need to install Scattergood-Olympic 230kV Cable A for many years now. With each passing year, the urgency becomes more apparent so that now even remedial actions have limited benefit.

For this reason, LADWP is moving forward with the installation. With construction that began in 2012, the new 15-mile long Scattergood-Olympic 230kV Cable A in the Westside should be in-service before December 2016. Other Los Angeles Basin projects include:

- Upgrade circuit breakers and disconnects at Receiving Station-U and Receiving Station J.
- Install a variable 90-MVAR shunt reactor bank at Scattergood 230 kV and a variable 90-MVAR shunt reactor bank at Receiving Station-K 230 kV.

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

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 it can be assessed costs under the regional cost allocation methodology. FERC also stated that non-jurisdictional entities must have a right to withdraw and avoiding cost allocations from the region.

However, Order 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 to include a regional planning process in October 2012. FERC has recently issued orders with findings 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 access to third party transmission services limited.

Even though Order 1000 doesn't require non-public TOs to enroll in a region the LADWP decided to enroll in WestConnect as a Coordinated Transmission Owner (CTO) because it may benefit from the regional planning process which can identify transmission regional needs. A board package for the enrollment of WestConnect was compiled and presented in the November 2015 board meeting.

LADWP's extensive network of transmission resources is described in Appendix I; Figure 2-15 shows its major out-of-basin generation resources. Noteworthy is the fact that while LADWP customers represent roughly ten percent of California's electrical load, approximately 25 percent of the state's total transmission capacity is owned by LADWP. LADWP also differentiates itself from its counterparts by continuing to operate as a vertically integrated electric utility, owning and operating its generation, transmission, and distribution resources rather than as a parent company with subsidiaries carrying out the various functions that comprise the supply chain.

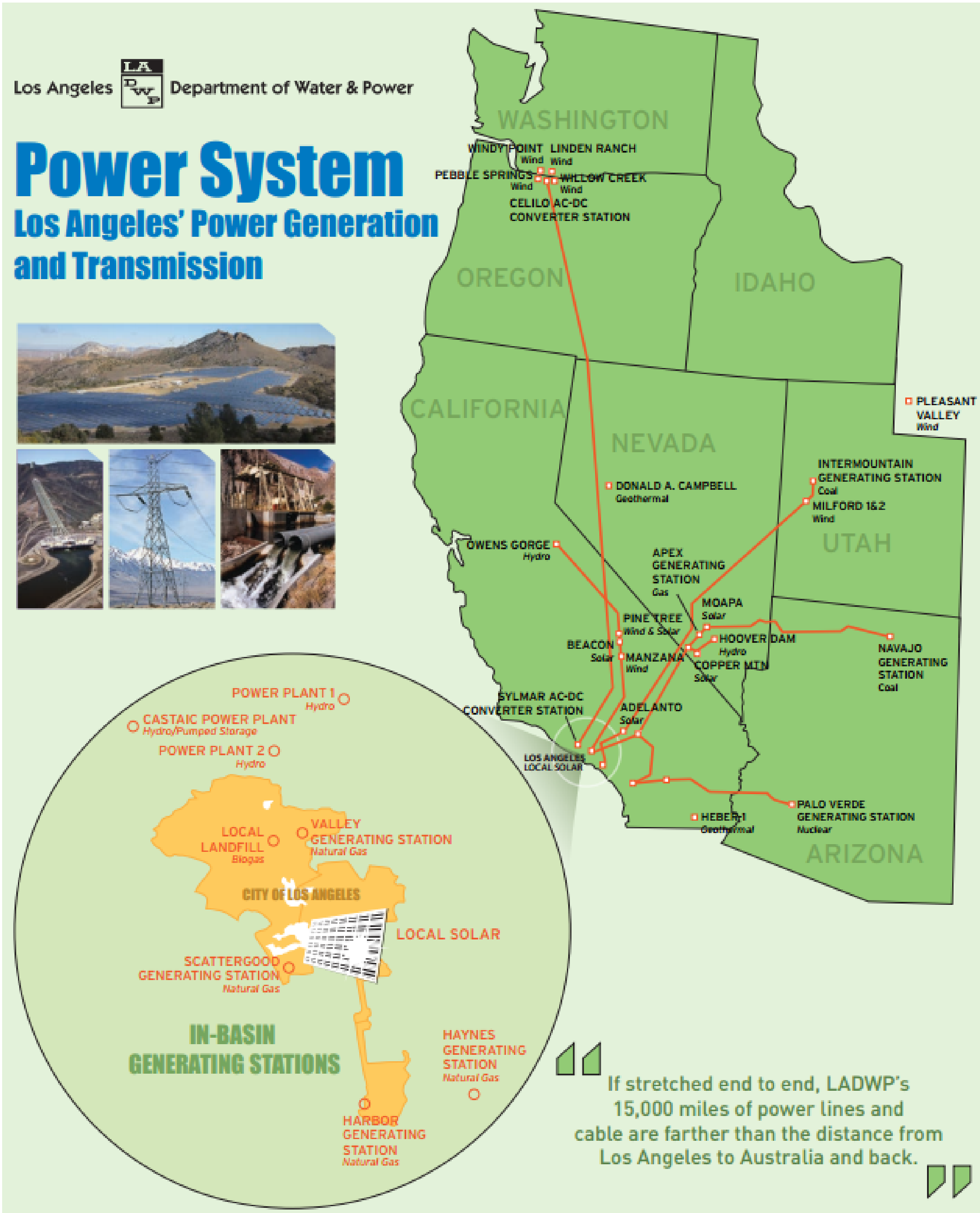


Figure 2-16: Major out-of-basin generating stations and major transmission lines.

2.4.5 Advanced Technologies and Research and Development

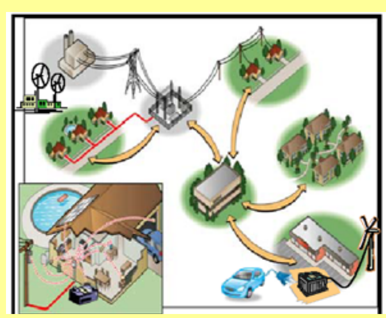
LADWP is looking ahead to technologies, including "smart grid" applications that will benefit operations and enhance reliability, empower customers with better knowledge and tools, and encourage the expansion of renewables, electric transportation, and other distributed resources on our system. Implementation of the Smart Grid technologies requires many strategic decisions which require clear vision, coordination across business units, and upfront planning. As part of this program, LADWP has developed a comprehensive Smart Grid strategy defined in an implementation roadmap, architecture, and a supporting business plan to maximize the expected benefits and to provide direction to the overall program. These plans have been developed using a benefits-driven approach to identify Smart Grid areas for investment.

2.4.5.1 Smart Grid

"Smart Grid" is a term used to describe a variety of advanced information-based utility improvements. Smart Grid refers to intelligent data gathering and advanced two-way digital communication capabilities overlaid on electric distribution networks to provide real-time data that enhances the utility's ability to optimize energy use. Smart Grid is a national policy evolving from the Energy Policy Act of 2005, as well as the Energy Independence and Security Act of 2007, which called for the goal of modernizing the nation's electricity grid, making improved digital information available to customers to empower customer choice, facilitating integration of distributed clean renewable resources, improving grid reliability and resiliency, and supporting the integration of electric vehicles.

A smart grid has the following characteristics:

- *Enables new products, services and markets*
- *Enables active participation by consumers through self-monitoring and more responsible consumption decisions*
- *Auto-selects safest and most efficient forms of storage and generation based on real-time energy needs and concerns*
- *Provides power quality for the digital economy*
- *Optimizes asset utilization and operates efficiently*
- *Anticipates and responds to system disturbances (self-heals)*
- *Operates resiliently against attacks and natural disasters*



Smart Grid technologies can turn every point in the existing network—including every meter, switch and transformer—into a potential information source, able to feed performance data back to the utility instantly. Smart Grid Technologies will provide LADWP with the information required to implement real-time, self-monitoring networks that are predictive rather than reactive to instantaneous system disruptions. It can enable the utility and consumers to make decisions to optimize the use of energy, improve reliability, and reduce the consumption of fossil fuels.

<u>Smart Grid Implementation Program (SGIP)</u>

The SGIP consists of 12 projects that will be implemented over a period of 10 years with a priority on foundational and high-value projects that are assessed based on the technologies required for implementation, strategic or regulatory priorities, and benefits to the customer and LADWP. The Advanced Metering Infrastructure (AMI) is foundational to seven of these projects. The SGIP program also includes five projects where improvements can be realized without investing in AMI.

a) Advanced Metering Infrastructure (AMI)

This project consists of procuring and installing the AMI components necessary to provide a set of Smart Grid metering functions that are comprehensive but are initially deployed on a limited scale. LADWP does not plan to roll out AMI meters to all customers universally in the near term. First deployments will focus on selected areas, such as where the remote connect and disconnect capabilities are most useful. These will be followed by subsequent deployments targeting other value-based attributes such as areas with hard to read meters or where demand response or other special customer based programs are desirable. The scope of this project includes both electric and water customers. Installation of AMI electric and water meters will provide capabilities that include remote meter reading, customer web portal, customer display, remote connect/disconnect, outage management, meter tamper detection, and energy/water theft and leak analysis. Further, the AMI infrastructure will enable LADWP to subsequently implement the following customer programs and operational improvements.

b) Projects Dependent on Advanced Metering Infrastructure (AMI)

Customer Service Programs	***Grid Management Capabilities***
a. Customer pre-payment The AMI metering will enable us to allow customers to pre-pay for electric and water service, enable LADWP to send automated messages to pre-pay customers once the balance approaches a minimum threshold, allow customers to setup auto-payments for replenishing account balance, and provide usage data and account balance information through the LADWP website or in-premises display device. ***b. Demand response(DR) for small customers*** The AMI infrastructure will enable LADWP to provide a DR program for residential and other small customers allowing them to earn benefits by reducing their load during peak load situations. Using smart meter infrastructure, LADWP will be able to offer DR programs for residential customers such as - Peak Time Rebate (PTR) enabled by Programmable Communicating Thermostats (PCT), and voluntary Air Conditioner cycling program. ***c. Electric vehicle (EV) charging management*** High penetration of electric vehicles may cause demand fluctuations and reliability issues. In order to manage such events, the SGIP includes implementation of technologies to communicate with customers and control/optimize EV charging during periods of high demand or reliability problems. Implementation of these technologies will also enable LADWP to potentially use EVs as source of energy storage and ancillary services in the future once the technologies mature.	***d. Distributed generation monitoring and management*** Integration of increased levels of renewable generation to 33% and beyond requires changes to distribution planning as well as weather forecasting to assist with generation scheduling, control and dispatch. AMI meters with interval and voltage measurement can provide LADWP with data at the distribution system level that can assist in measuring distributed generation impacts. Communications with customer devices can permit the development of voluntary customer programs that permit LADWP output control of these distributed energy resources to alleviate localized voltage or VAR fluctuations. ***e. Advanced Voltage, Power Quality and Volt/VAR Control*** The AMI meter data will provide LADWP a detailed view of the voltage profile of distribution lines at a level that is currently not available. This will provide LADWP greater visibility into our distribution system; visibility that is increasingly important at higher penetration levels of solar and other distributed energy resources. This function builds upon the 'System Voltage/VAR Control' project described separately in the next section, as that will provide the automation for capacitor banks and voltage regulators to enable voltage/VAR control based on the AMI voltage data. ***f. Distribution modeling and planning*** The AMI meter data will provide detailed information about LADWP's distribution system, and the SGIP plan involves installing software applications to use AMI data for system modeling and planning purposes. Specifically, LADWP will potentially be able to use this information to improve transformer utilization, better forecast load growth, and manage circuit loading more effectively.

c) AMI-Independent Projects

- Large customer demand response: This project is unique to Commercial & Industrial customers (>100kW demand) and focuses on allowing these resources to be dispatchable and visible to the LADWP system operators.
- Enhanced system operations: Enabling advanced features of the existing energy management systems to enhance visibility into grid operations and empower its

power system operators with more detailed, accurate, and real-time information about power flow.

- System voltage/VAR control (Non-AMI): Implementing distribution automation devices to improve the measurement and control of voltage and VARs thereby improving reliability, power quality, and system efficiency. The distribution/sub-transmission system project is a required precursor to the "Advanced Volt/VAR Control System" which uses the AMI system to provide additional detailed voltage measurements within the distribution system.
- Asset Condition Monitoring: Installation of advanced sensors and communication devices to provide information on the health of assets in our power system to maximize the life and utilization of the assets and optimizing maintenance activities while avoiding unplanned outages and damage to the equipment.
- Enhanced forecasting of renewable generation: Identifying and implement mature weather forecasting tools to provide localized data to assist with *generation scheduling, control and dispatch of solar and wind generation.*

Smart Grid Regional Demonstration Program (SGRDP)

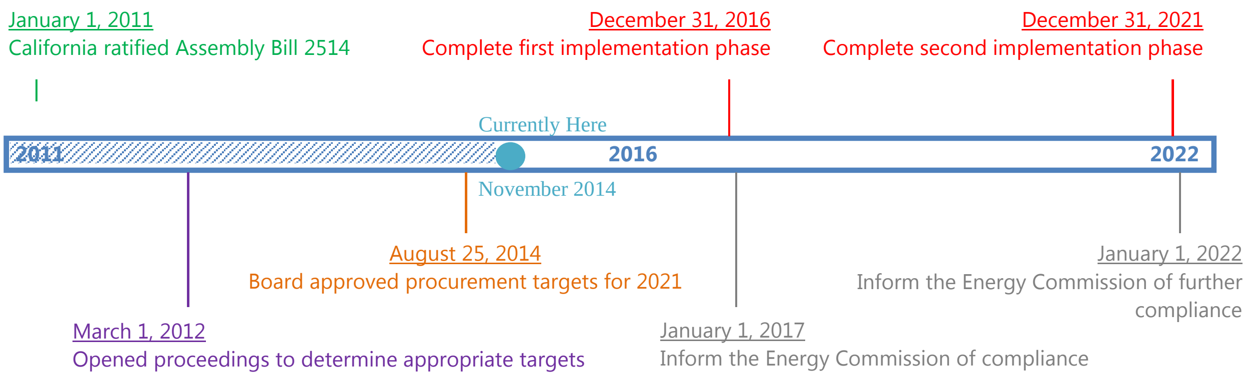
LADWP was awarded a grant by the US Department of Energy in 2010 and is leading a group of local research institutions in a Smart Grid regional demonstration program. The objective of this program is to demonstrate Smart Grid technologies in the Los Angeles area to validate the technologies, their application, and benefits to LADWP as well as to other Utilities across the industry. This is helping LADWP validate the technologies in real time and incorporate the lessons learned into the planning for the Smart Grid Implementation Program (SGIP) implementation.

The program includes pilot projects in five interrelated areas – Advanced Metering Infrastructure, Demand Response, Consumer Behavior, Cyber Security and Electric Vehicle Integration. The goal is to conduct live demonstrations of selected technologies and collect information necessary for customers, distributors, and generators to change their behavior in a way that reduces system demands and costs, increases energy efficiency, optimally allocates and matches demand and resources to meet that demand, and increases the reliability of the grid. To support these goals, the LADWP and its research partners—the University of Southern California (USC), the University of California at Los Angeles (UCLA), and the NASA Jet Propulsion Laboratory (JPL) — are demonstrating innovations in key areas of smart grid technologies. The program is using the USC and UCLA campuses and surrounding neighborhoods, city facilities, and LADWP labs as testing grounds to prove out the technologies and architectures. Behavioral studies are being carried out in parallel to identify the behavioral determinants essential for successful adoption of Smart Grid technologies and improved energy usage patterns.

More information on the demonstration program and all of LADWP’s Smart Grid initiatives can be found in Appendix L.

2.4.5.2 Energy Storage

California Assembly Bill (AB) 2514, which became law on January 1, 2011, requires governing boards of local publicly-owned electric utilities[4], including LADWP, to identify as well as evaluate viable and cost-effective energy storage (ES) systems. Procurement of said ES systems is to be achieved through two implementation phases – the first by December 31, 2016 and the second by December 31, 2021. The procurement targets for each phase were formally approved by the Board of Water and Power Commissioners on August 25, 2014.



Per Section 2835 of AB 2514, ES systems eligible towards the procurement targets must (1) be cost effective; (2) have been installed and first operational after January 1, 2010; and (3) store energy[5] that was generated from a mechanical, chemical, or thermal process at one time for use at another time with the purpose of:

- Reducing emissions of greenhouse gases;
- Reducing demand for peak electrical generation;
- Deferring or substituting for an investment in Generation, Transmission, or Distribution assets; and/or
- Improving the reliable operation of the electrical Transmission or Distribution grid

It is important to note that LADWP has been practicing pumped storage (one form of ES) for more than forty years through its operation of the Castaic Power Plant. Unfortunately, its establishment before January 1, 2010 disqualifies it from being counted for all, if any, ES procurement targets set by LADWP. This way should not discourage the use of pumped storage as it offers similar, if not more viable, benefits compared to all emerging storage technologies.

LADWP is developing a strategic plan to identify all significant barriers for obtaining the benefits of ES systems as well as assess and define various ES technologies that will support its unique electric grid, resource plan, and projects related to renewable integration, distributed generation, demand-side management and reliability concerns.

[4] Serving greater than or equal to 60,000 customers within California
[5] Examples: stored thermal energy for future heating/cooling needs, energy generated from renewable resources, and energy generated from mechanical processes that would otherwise be wasted

To support the development process of the strategic plan, LADWP plans to follow through with the initiatives below:

1. Participation in a working group with the US Department of Energy (DOE) for the development of an ES protocol for use in measuring and quantifying the performance of ES system applications. It is anticipated that the protocol will assist with evaluating the performance of ES systems and to make more informed decisions as potential applications are consider for implementation.

2. Incorporate results from three ES research projects conducted by the Electric Power Research Institute (EPRI):

    a. Strategic Intelligence and Technology Assessments of Energy Storage and Distributed Generation, Project 94.001
        i. This project provides analysis and strategic information on ES and distributed energy resource systems. It includes assessments and evaluations of various technologies.

    b. Distributed Energy Storage Options for Power Delivery and End Use, Project 94.002
        i. This project provides information and guidelines for using distributed ES and distributed generation systems for power delivery and end user applications such as peak management, peak shifting, etc.

    c. Bulk Power Energy Storage Solutions, Project P94.003
        i. This project provides information and guidelines for using bulk ES to shift off-peak energy and integration of variable renewable generation.

3. Collaboration with a working group established by the Southern California Public Power Authority (SCPPA) to work alongside other municipal utilities on researching and identifying the most viable ES systems for any given unique purpose.

4. Continued dialog with various vendors and third-party entities (i.e. contractors) on the current and future development of all energy storage technologies as well as application at the utility scale.

On August 25, 2014, the Board of Water and Power Commissioners adopted Energy Storage Systems Targets, totaling 154 MW by 2021. These targets are subject to cost benefit assessments and feasibility studies, prior to implementation. A summary of the approved ES targets are shown in Table 2-8 below:

Table 2-8: Summary of Energy Storage System Targets

CONNECTION LEVEL	Existing TARGETS			PROPOSED TARGETS					
	PRE 2010			2016 TARGETS			2021 TARGETS		
	Project Name	Energy Storage Type	Capacity	Project Name	Energy Storage Type	Capacity	Project Name	Energy Storage Type	Capacity
GENERATION	Castaic	Pump Storage Hydro	1275 MW	Castaic	Pump Storage Hydro	21 MW	Valley Generating Station	Thermal Energy Storage	60 MW
		Sub-Total	1275 MW		Sub-Total	21 MW		Sub-Total	60 MW
TRANSMISSION	None			None			Beacon Solar Project	Battery Energy Storage	30 MW
							Springbok Area Solar Projects	Battery Energy Storage	20 MW
								Sub-Total	50 MW
DISTRIBUTION	None			None			Distribution Circuit	Battery Energy Storage	4MW
								Sub-Total	4 MW
CUSTOMER	UCLA	Thermal Energy Storage	4.375 MW	LAX	Thermal Energy Storage	3 MW	Distributed Energy Storage System	Thermal Energy Storage	40 MW
	USC	Thermal Energy Storage	4.668 MW						
	TAIX	Thermal Energy Storage	.004 MW	LA Downtown (Pilot)	Battery Energy Storage	.05 MW			
	LADWP Boyle Heights Facilities	Thermal Energy Storage	.006 MW	Garage of the Future (Pilot)	Battery Energy Storage	.025 MW	John Ferraro Building Energy Storage System	Battery Energy Storage	300KW
	McDonald	Thermal Energy Storage	.03 MW						
		Sub-Total	9.08 MW		Sub-Total	3.08 MW		Sub-Total	40.3 MW
		TOTAL	1284.08 MW		TOTAL	24.08 MW		TOTAL	154.3 MW

For more information regarding Energy Storage Systems, please refer to Appendix K in this IRP.

2.4.6 Climate Change Effects on Power Generation

Because the energy sector is an acknowledged contributor to the problem of climate change, much discussion and effort has been directed towards mitigation strategies – mainly in the form of GHG emissions reduction. However, as climate change is increasingly being accepted as a reality, it is important to also consider the energy sector as one that will be subjected to the impacts of global warming. Rising average temperatures, changes in precipitation amounts and patterns, more frequent extreme weather events and a rise in sea level are some of the consequences that may be expected. Understanding how these effects impact power generation and incorporating that knowledge into the planning process facilitates adaptation of the power system to respond in ways that mitigates potential problems and takes advantage of any opportunities.

The influence of climate change on resource planning can be addressed on two levels: (1) how it affects *energy consumption*, and thus how much generation should be planned for and secured, and (2) how it affects *power generation* operations and the siting of new facilities.

<u>Energy Consumption</u>

Mean temperatures in Los Angeles are expected to rise. Additionally, extreme heat conditions, such as heat waves and very high temperatures, may last longer and become more common place.[6] In response to these conditions, electricity consumption will increase, mainly due to increased air conditioning demand. These effects are reflected in LADWP's energy and demand forecast. It is important to ensure that the latest findings and conclusions continue to be incorporated into future load forecasts.

A recent study by the UCLA Department of Atmospheric and Oceanic Sciences[7] focuses on temperature changes in the local region in years 2041-2060. The study concluded that annual average temperatures will increase between 3.7 °F and 4.3 °F across the City of Los Angeles. While the UCLA study looked at temperature changes in the 2041-2060 timeframe (which is beyond the 20-yr planning horizon for the 2015 IRP), the findings corroborate other studies and supports the expectation of higher future temperatures which will increase electricity use. More information on this study can be found in Appendix M.

Power Generation

An increase in frequency and duration of heat waves, and potentially more volatile weather patterns will add stress to the utility infrastructure. Areas may become more prone to flooding, and river flows may increase or decrease depending on location. At the same time, other areas may become more drought stricken, affecting water available for power plant cooling. Thermal efficiencies will decrease as temperatures rise, resulting in more fuel required to generate the same amount of power. New facility siting will have to account for these new environmental and weather-related conditions. Sea level rise, although not a foreseeable problem within the 20-year planning horizon of this IRP, will need to be monitored and mitigation measures implemented, if required.

Actions to Address Climate Change

LADWP should continue its efforts towards reducing GHG emissions. These efforts include adopting more renewable resources, repowering its older natural gas generating stations, investing in energy efficiency and demand response programs, and pursuing coal replacement. To prepare for and adapt to climate change, LADWP should ensure that its load forecast continues to properly incorporate expected higher temperatures (and the corresponding higher electricity demand) due to global warming, and that its Power System Reliability Program is fully funded to optimize the resiliency of its infrastructure to better withstand the more volatile weather patterns that will be expected. This year's IRP considers the effects of decreasing overall GHG emissions in the Los Angeles basin through fuel switching/electrification of the transportation sector. See Sections 2.2.3 and 4.3.2 of this IRP for more information.

As the science of climate change continues to evolve, LADWP should stay abreast of the latest findings and conclusions. Subsequent IRPs will monitor developments in climate change and develop/refine recommendations to mitigate any negative impacts as part of the resource planning process.

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[6] Global Climate Change, California Energy Commission, CEC-600-2005-007, page 2
[7] Hall, et al., 2012: Mid-Century Warming in the Los Angeles Region. Available at: www.c-change.LA

More detailed information regarding climate change and its effect on power generation can be found in Appendix M.

2.4.7 Reserve Requirements

Two important aspects of electric power system reliability are "resource adequacy" and "security." Resource adequacy refers to the availability of sufficient generation and transmission resources to meet customer's projected energy needs plus reserves for contingencies. Security refers to the ability of the system to remain intact after experiencing sudden disturbances, outages or equipment failures.

LADWP, as part of the electric power grid of the western United States and Canada (and a small section of northern Mexico), is required to meet operational, planning reserve and reliability criteria, and the resource adequacy standards of the WECC and the North American Electric Reliability Corporation (NERC). Based on these standards, the system reserve margin requirements and other criteria which LADWP uses to plan and operate are defined as follows:

Generation Capacity Requirement = Net Power Demand + System Reserve Requirement
System Reserve Requirement = Operating Reserve + Replacement Reserve
Operating Reserve = Contingency Reserve + Regulation

The "Net Power Demand" is the total electrical power requirement for all of LADWP's customers at any time. The other reserve requirements are defined below, as well as numerically calculated.

The loss of the largest single contingency of generation or transmission is a key reserve margin determinant for LADWP and defines the amount of Contingency Reserves required. Replacement Reserves are required in addition to contingency reserves in order to replace the contingency reserves within 60 minutes of a contingency event. The Regulation Requirement of 25 MW is related to system load variations due to customer load changes. This regulation requirement is anticipated to increase in the future as additional amounts of intermittent renewable generation are added to the generation mix. To account for unplanned outages, historical forced outage information is used to determine an appropriate reserve margin which is currently 449 MW. With the repowering of Scattergood generating units over the next 7 years, the unplanned outage reserve margin will drop in stages to eventually reach an expected level of 150 MW. Given LADWP's current total generation portfolio, the system reserve requirement is 1,400 MW in 2015 with the repowering of Scattergood 3, and will drop to a level of 1,250 MW with the repowering of Scattergood 1 and 2 in 2021. Therefore, if the system demand is 5,000 MW, LADWP must currently have a total of 6,400 MW of dependable and dispatchable generating capacity (and the transmission for that capacity) to meet the 5,000 MW demand.

Due to the variable and intermittent nature of some renewable resources, particularly resources such as wind and solar photovoltaic, their generation capacity cannot be fully depended upon to meet peak demand conditions. As LADWP acquires a larger proportion of such resources, studies on the characteristics of these variable and intermittent resources will need to be carried out to determine their effect on reserve and regulation requirements. Refer to Appendix J for additional information on issues associated with integrating intermittent energy resources.

The capacity value of a generating resource is based on its ability to provide dependable and reliable energy and capacity during peak periods when the system requires reliable resources for stable operation. Resources that can provide firm capacity will have a higher capacity value than resources that cannot. For purposes of planning LADWP's reserves adequacy calculations, it is assumed that the dependable capacity of wind would be 10 percent of its nameplate capacity (unless a firming and shaping contract is in place), and the dependable capacity of solar photovoltaic would be 27 percent of its nameplate capacity. Because dependable capacity is an on-going area of study, these percentage values are subject to change. Any changes will be incorporated into future IRPs.

Local Resources for Grid Stability and Contingencies

As a subset of the reserve requirements, LADWP has located a significant amount of generating resources within the Los Angeles (LA) area. The specific amount of capacity that needs to be located in the LA Basin is approximately 3,400 MW, but varies, depending on the combination of which units are operating and how much power is flowing on the transmission system at the time. LADWP's local transmission system cannot be reliably operated without generation from local thermal generating plants. The amount of generation required to provide transmission reliability is termed Reliability Must Run (RMR) generation. RMR generation is incorporated into all of the strategic cases considered in this IRP.

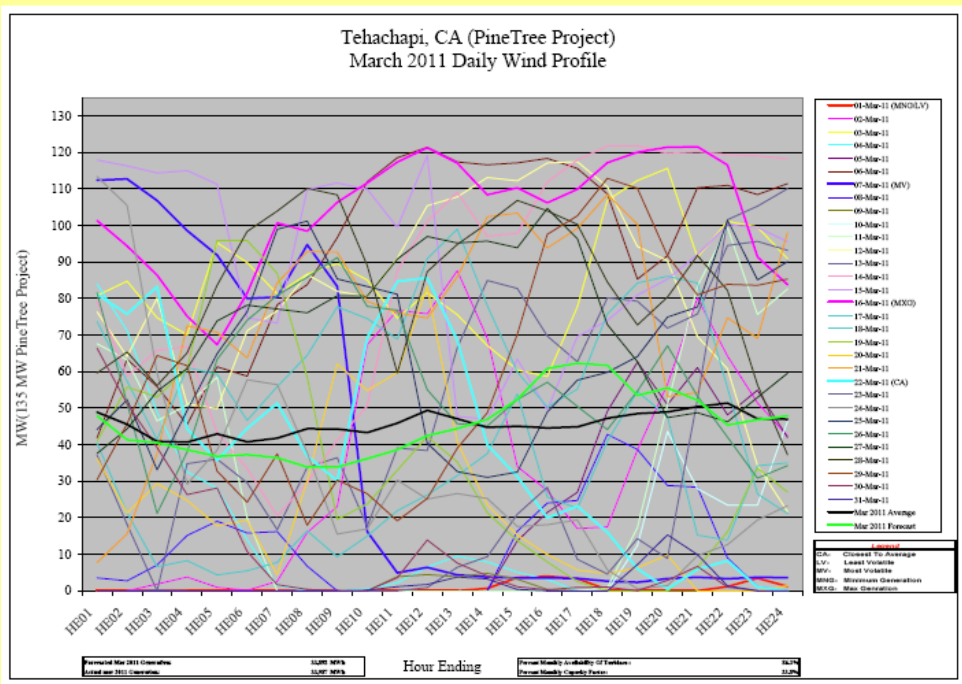
This local requirement is particularly important in the context of deciding how to schedule the repowering of units that utilize once-through cooling. It is for this reason that no unit will be taken out of service before an equivalently-sized, locationally-equivalent replacement unit is constructed, tested and ready to be placed in-service.

Integration of Intermittent Energy

One of the main responsibilities of power system operators is to maintain the balance between the total aggregate electrical demand of the power 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 controllable and dispatchable by the power system operators throughout the day to maintain this instantaneous balance between demand and generation.

With the much higher percentage of renewables coming on line, a variety of modifications will need to be made to the Power System to successfully and reliably integrate these higher penetrations of renewable resources. In preparation, LADWP has conducted preliminary studies on integrating renewable resources, and has also reviewed many renewable resource integration studies published over the last several years.

Individual wind farms tend to have a high variability in the amount of energy produced (see figure below), but multiple wind farms located in diverse geographic areas are thought to reduce the overall variability in the amount of aggregated wind energy production.



Energy generated from Solar PV technology is highly sensitive to cloud cover. For example, a large 50 MW PV facility can experience variations in output of 36 MW within 60 seconds. Smaller sized PV facilities can have their entire output eliminated in seconds. When a single large sized PV facility experiences these rapid changes in output, the Power System must also be able to react just as quickly with other generation resources to accommodate such rapid changes. The capabilities of a power system's dispatchable resources will limit the amount of solar PV and wind that can be reliably integrated.

3.0 STRATEGIC CASE DEVELOPMENT

3.1 Overview

IRP planning is an on-going process and as such, the development of the 2015 IRP strategic cases incorporates the latest changes that have occurred in the regulatory landscape and tactical plans developed by the Power System. Also included are many updated and new assumptions that have been developed over the past year. These assumptions have influenced the composition of potential resource portfolios that can fulfill LADWP's goals of reliability, competitive rates, and environmental stewardship.

The coal cases analyzed in this 2015 IRP consider different replacement dates for LADWP's two coal resources – the Navajo Generating Station (NGS), and the Intermountain Power Project (IPP). The coal replacement dates for Cases 1 and 2 are the same cases analyzed in last year's 2014 IRP. Case 1 analyzes the baseline contract expiration dates of Navajo in 2016 and IPP in 2027. Case 2 analyzes early divestiture of Navajo by 2016 and replacement of IPP by 2025.

In addition to the coal cases, this 2015 IRP also analyzes four additional cases that considers 50 percent renewables by 2030 to comply with state law, 15 percent energy efficiency by 2020, 800 MW and 1,000 MW of local solar, and various levels of transportation electrification.

The 2014-15 fiscal-year financial planning process included many of the assumptions and recommendations that were used in the 2015 IRP. This is a continual process that requires the budget and the IRP model to be guided by the same assumption set. These assumptions change frequently based on market conditions for fuel, energy resource availability and pricing, regulatory environment, load forecasts, and the reliability needs of our system.

Regulatory interpretations of primary regulations and state laws affecting the Power System, including AB 32, SB 1368, SB 1, SB 2 (1X), SB 350, SB 32, US EPA Rule 316(b), and US Clean Power Plan continue to evolve particularly with certification requirements of existing renewable projects and their applicability towards meeting in-state or out-of-state qualifications. This year's IRP attempts to incorporate the latest interpretation of these major regulations and state laws as we understand them today.

Section 3.2 summarizes the major changes from last year's model assumptions. Section 3.3 discusses the legislative and regulatory mandates that have a bearing on the resource portfolios being considered. Section 3.4 describes the development process for the candidate strategic cases, and Section 3.5 presents the final candidate cases that were analyzed. The analyses and comparison of the case results are presented in Section 4.

3.2 2015 IRP Model Assumptions

At the heart of the IRP analysis effort is the computer-based production cost modeling of the LADWP Power System. To perform this modeling, a significant amount of input data is developed. The production model and input assumptions are covered in detail, in Section 3.2.2 and Appendix N. This section summarizes the major changes in the assumptions since last year's IRP, followed by a discussion of the general price inputs that were applied to the 2015 IRP.

3.2.1 Major Changes From the 2014 IRP Assumptions

Major assumption changes from last year's IRP are summarized here. Additional detail regarding the assumptions can be found in Appendix N.

Load Forecast

As shown in Table 3-1, the 2014 load forecast, dated September 26, 2014, was adopted as the 2015 load forecast due to errors reported by the Customer Care and Billing System, which resulted in a forecast significantly below the 2014 Load Forecast. The load forecast estimates the overall need for energy to be 23,983 GWh in 2020 and 27,828 GWh in 2030. The complete load forecast is included in Appendix A. Adjustments made to the approved load forecast to account for the latest projections of energy efficiency savings and customer-net-metered solar are shown in Appendix N.

Table 3-1. TOTAL ADJUSTED ELECTRICITY SALES IN GWH

	2020	2030
New Forecast – 2015 IRP	23,983	27,828
Old Forecast – 2014 IRP	23,983	27,828
Difference	0	0

Energy Efficiency

The Energy Efficiency (EE) forecast used in the 2015 IRP is essentially the same when compared to the 2014 IRP as shown in Figure 3-1.

The base case energy efficiency savings target in the 2014 IRP is no longer analyzed in this 2015 IRP since the Board approved an energy efficiency savings target of 15 percent by 2020 in 2014.

The cumulative advanced EE savings incorporated in the 2015 IRP will reach 3,038 GWh from 2010 through 2020 and 3,928 from 2010 through 2035. Using The Total Sales to Ultimate Customers of 23,983 as the baseline, the 2015 IRP advanced EE case forecasts a 15 percent energy efficiency savings by 2020 and 16.4 percent energy efficiency savings by 2035. Historical efficiency savings of 1620.5 GWh from fiscal year 2000/01 through fiscal year 2011/12, which is equivalent to 6.4 percent of customer sales, are already embedded in the load forecast. Figure 3-1 below shows the projected cumulative gross savings from 2015 through 2035.

State energy efficiency codes and standards savings and a small share of Federal codes and standards savings, retroactively to 2010, are counted towards energy efficiency savings targets, due to LADWP's and Los Angeles' multi-pronged efforts to support code development and enforcement. The revenue impacts are accounted for in the sales load forecast and contributes to reducing overall sales and load growth.

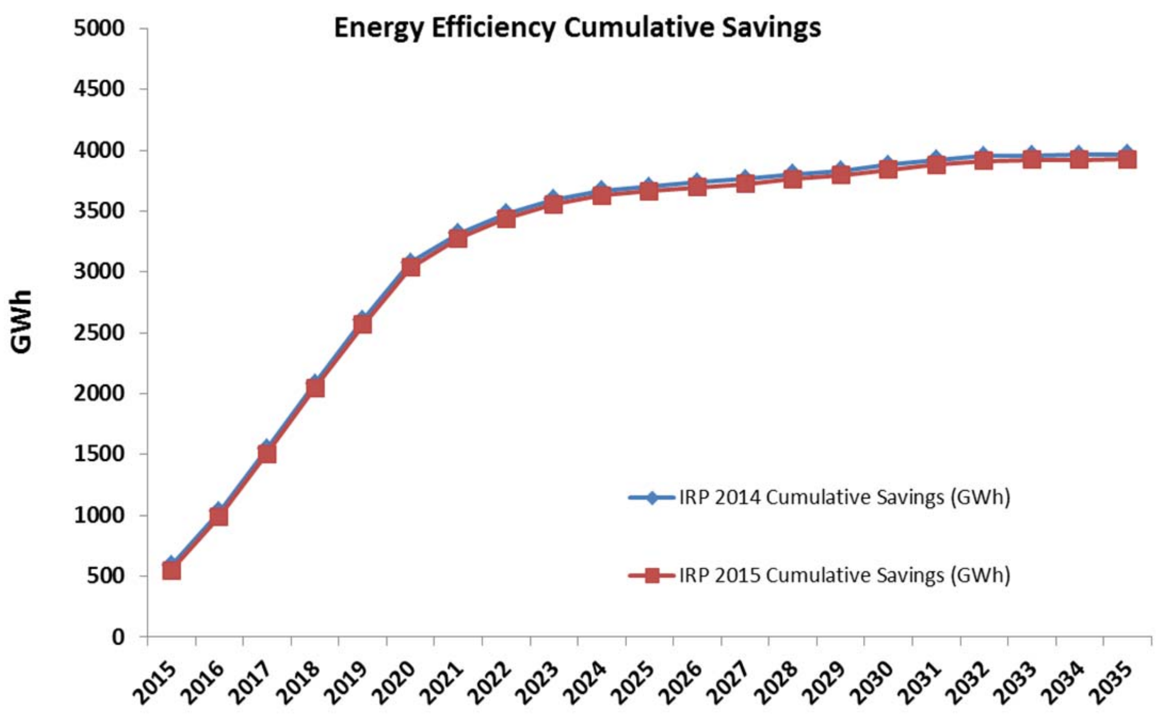


Figure 3-1. Comparison of 2014 and 2015 Cumulative Energy Forecasts by Fiscal Year

Energy Efficiency Hourly Savings Shape in 2020

The base energy efficiency hourly savings shape used in the 2014 IRP, as shown in Figure 3-2 below, is no longer considered in the 2015 IRP. The hourly savings shape illustrated a linear trend of increased energy efficiency savings from approximately 1 p.m. through 8 p.m. due to various factors. Some of these factors include emphasis on residential appliance and HVAC programs as well as LED street lighting conversion. The current hourly savings shape for the advanced energy efficiency cases incorporates redeveloped energy efficiency programs, based on the 2014 energy efficiency potential study. As a result, existing programs across all sectors – residential, commercial, institutional, and industrial, were modified to attract greater market participation throughout the energy efficiency portfolio, which adjusted the hourly savings shape. The hourly savings shape for the advanced energy efficiency case targets the peak daytime load, from approximately 10 a.m. through 5 p.m. This is primarily attributed to factors such as higher incentives contributing to greater market penetration and emphasis on "harder to reach" efficiency improvements in the commercial, industrial, and institutional sectors, specifically in the HVAC, refrigeration, interior lighting as well as plug/process end uses.

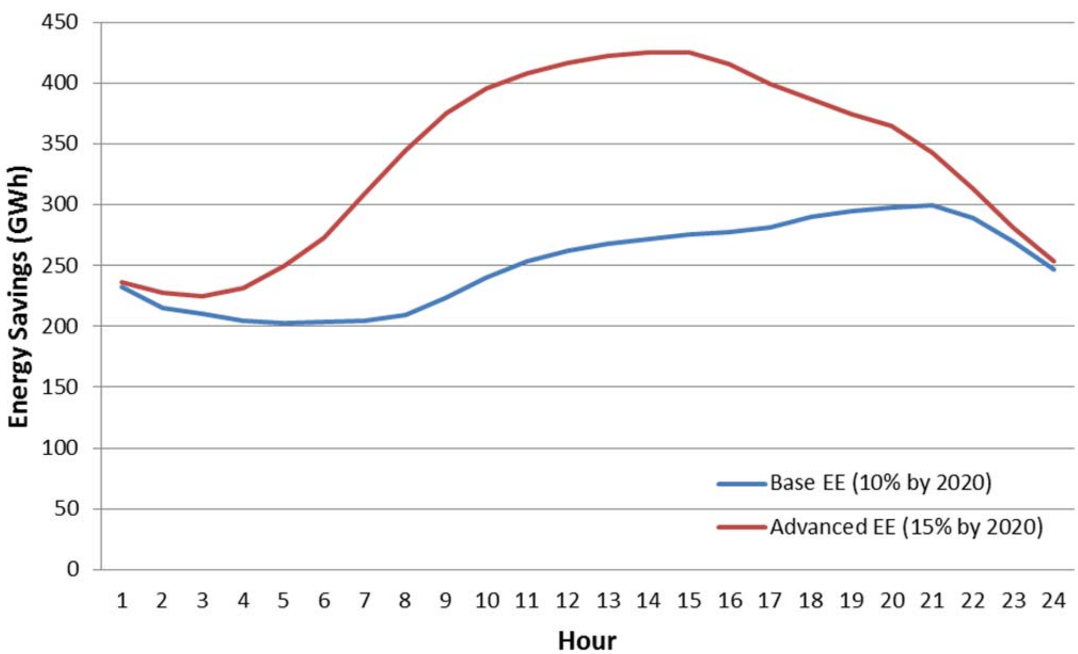


Figure 3-2. Comparison of 2013 and 2015 Hourly Energy Efficiency Savings in 2020

Local Solar – CNM, FiT, and Community Solar/Utility Built Solar

The projected growth of the solar Customer-Net-Metered (CNM) program (a.k.a. Solar Incentive Program), Feed-In-Tariff (FiT) program, and Community Solar used in the 2015 IRP are shown in Figure 3-3. CNM incentive levels were lowered to encourage greater customer participation to install 280 MW or 462 GWh within the allocated funding cap of $313 million approved, through the end of 2016 but completion of these systems under SIP will likely extend to 2019 because of the requirement to complete these systems within a 3 year period after approval. It is assumed that further CNM installations without SIP incentives will be interconnected. The FiT program was increased to 150 MW in the 2014 and 2015 IRP, reflecting the plan to take advantage of tax benefits available through 2017. Minor adjustments to the expected solar energy output are incorporated to reflect solar degradation as photovoltaic panels age. The local solar cases in this 2015 IRP considers goals of 800 MW and 1,000 MW local solar; local solar cases comprised of various levels of FiT (450 MW or 650 MW), 310 MW of customer net-metered and 40 MW of Community Solar.

The local solar energy forecasts are used in all four advanced renewable and energy efficiency strategic cases evaluated in the 2015 IRP. The 50 percent renewables cases analyzed targets of 800 MW and 1,000 MW of local solar. The detailed analysis was conducted using the PROSYM production cost modeling software.

Renewables

Table 3-2 is a comparison of the overall renewable additions planned for the 2015 IRP vs. the 2014 IRP:

Table 3-2. RENEWABLE ADDITIONS, 2014 VS. 2015

		2030	New Renewable Installed Capacity (MW) 2015 – 2020					New Renewable Installed Capacity (MW) 2015 – 2035				
Case ID	Resource Strategy	RPS Target	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biogas	Wind	Non-DG Solar	Dist. Solar	Generic
Base Case in 2014 IRP	33% RPS SB 2 (1X) Compliant	33%	33%	70	0	1059	0	216	270	0	1019	447
Base Case in 2015 IRP	50% RPS SB 350 Compliant	50%	95	0	1088	509	0	293	670	1813	653	799

Consistent with last year's IRP, solar holds a prominent position in the overall portfolio mainly replacing future planned geothermal projects as prices for solar PPAs have dropped significantly over the last few years, while the availability of competitively priced geothermal projects remains low. Solar is also well suited to utilize the existing Vic-LA transmission lines and Barren Ridge transmission line capacity which is expected to be placed in service in 2016. It was assumed that the expiration of Investment Tax Credits (ITC) would be extended from 2016 to 2017, making further adoption of solar more attractive. Increased use of solar will further diversify the renewable resource mix, which currently contains a strong wind focus.

In addition to the base case 50 percent RPS case with 800 MW of local solar and base transportation electrification, three other scenarios of local solar and transportation electrification levels were considered for the 2015 IRP, including the base case analyzed with both medium and high transportation electrification, and a 50 percent RPS case by 2030 with 1,000 MW local solar and medium electrification. A 33 percent RPS case by 2030 with 800 MW of local solar and base electrification was also analyzed as a baseline for comparison purposes as shown in Figure 3-4 below:

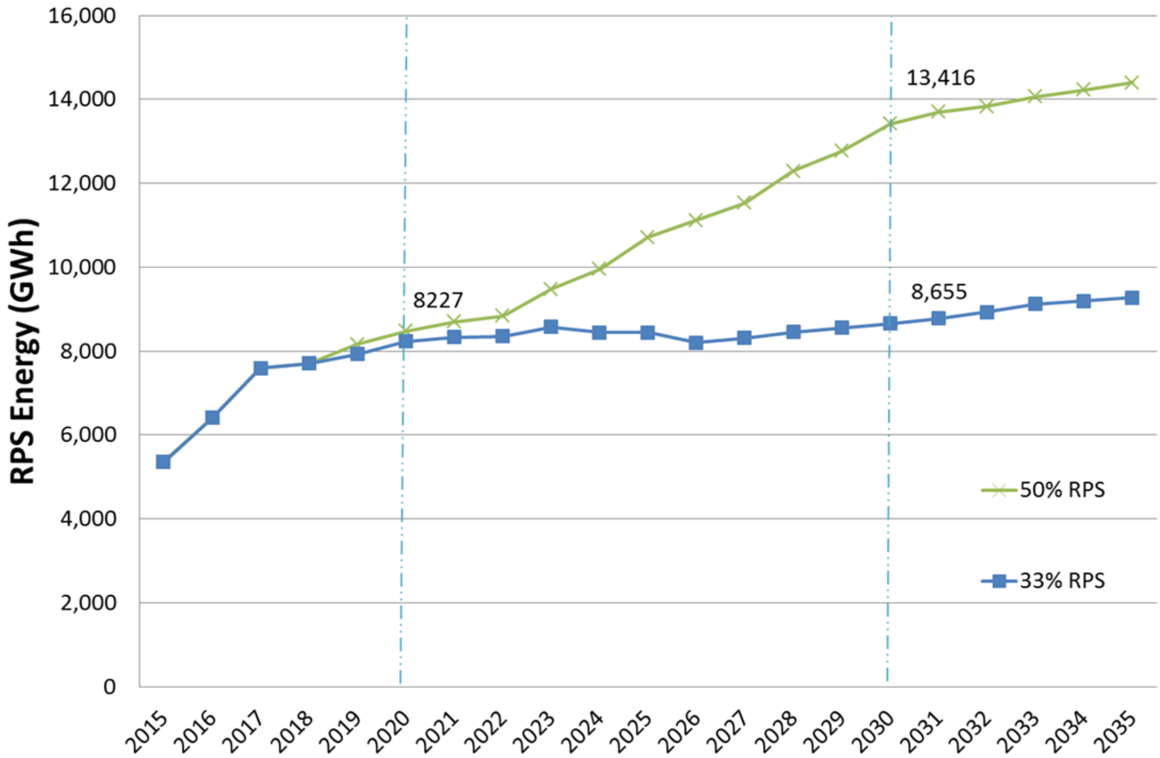


Figure 3-4. Renewable Portfolio Standard Cases, Cumulative Energy in GWh

In 2014, LADWP, in partnership with Pacific Gas and Electric Company, Sacramento Municipal Utilities District, San Diego Gas & Electric Company, and Southern California Edison Company, co-funded a study to examine the operational challenges and potential consequences of meeting a higher RPS, specifically 40 and 50 percent RPS. The study concluded that renewable integration challenges, particularly over-generation during daylight hours, are likely to be significant at 50 percent RPS. Subsequently, LADWP performed its own Maximum Generation Renewable Energy Penetration Study (MGREPS) in 2015 to examine the impacts 50 percent RPS by 2030 on LADWP's Power System. See Section 4.3.1 and Appendix J for further information.

Electrification

This 2015 IRP continues to consider electrification of the transportation sector as a strategy to reduce overall greenhouse gas and increase electric sales; it may also be utilized as a potential solution to absorb higher levels of RPS. Electrification of the transportation sector is the process of converting gasoline and diesel-powered vehicles and light rail to electric power. Electrification can be promoted through incentives and rebates, similar to incentives for Energy Efficiency. The electrification cases in this 2015 IRP include a base, medium, and high case. The base case is forecasted from the California Energy Commission's 2013 Integrated Energy Policy Report; medium case is 150% of the base case and high case is 200% of the base case.

Coal Replacement

After retirement of Mohave Generating Station, LADWP focused on replacement of its share in Navajo Generating Station (NGS) and Intermountain Power Plant (IPP).

Regarding NGS, LADWP worked with SCPPA and acquired Apex Generating Station (AGS), a Combined Cycle Natural Gas Generating Station, on March 26, 2014. AGS has been integrated into LADWP's portfolio which allowed LADWP to divest of NGS ahead of the contractual schedule. LADWP's share in NGS was sold to Salt River Project in 2015 and the sale will close on July 1, 2016, completing LADWP's transition out of coal-fired generation at NGS.

Regarding the replacement of coal generation at IPP, an amendment to the power purchase contract has been drafted to construct a natural gas replacement facility located at the IPP site. The amendment establishes an in-service date of July 1, 2025, for the new facility. The IPP Coordinating Committee and the IPA Board could move the date up if a super majority of the participants support the decision. The current debt payments for the coal plant are scheduled to be completed at the end of 2023 and the expiration date for the existing power contracts is June 15, 2027. For modeling purposes, July 1, 2025 will be used as an assumed conversion date (see Case 2 in Section 3.5).

Gas Prices

Long-term natural gas price forecasts have been revised downwards from last year with recent prices reaching very low levels over the last year. However, it is expected that these unusually low prices will eventually reach an equilibrium supply/demand level over the next year as new gas drilling continues to decline and new sources of demand come on-line. Opal and SoCal expected gas prices used in the 2015 IRP were 27 percent and 26 percent lower on average, over the short-term (2015-2020), and were 22 and 20 percent lower on average and over the long-term (2021-2034), respectively, as compared to the 2014 IRP. The Pinedale gas reserves owned by LADWP continue to provide a low cost source of gas and hedge against future gas volatility. Estimates of gas volumes to be produced from Pinedale have been revised as of July 2015 and show a moderate decline typical for producing reservoirs.

Coal Prices

Based on forecasted prices received from LADWP's Power and Fuel Division, IPP forecasted coal prices are on average 3.3 percent lower for the period 2015 through 2023, as compared to the 2014 IRP. Navajo coal prices are 3.1 percent lower for the period 2015 through 2019, as compared to the 2014 IRP.

IPP Recall

IPP capacity is a function of the capacity recalled by Utah participants, under the IPP Excess Power Sales Agreement. Estimates for these excess shares transferred to LADWP by Utah participants remains the same in the amount of 327 MW in both the 2014 IRP and 2015 IRP with no net impact to LADWP's share of the IPP capacity entitlement.

3.2.2 General Price Inputs

General price assumptions are presented here for supply side resources, fuel, GHG allowances, and FiT pricing. More details are provided in Appendix N.

Supply-side Resources

Table 3-3 presents a summary of the major price assumptions for supply-side resources. Lower prices for solar and geothermal have been incorporated into the 2015 IRP modeling, as price competition has resulted in lower prices for both resources. Dependable capacity is an on-going area of study and could change in future IRP's as more data becomes available.

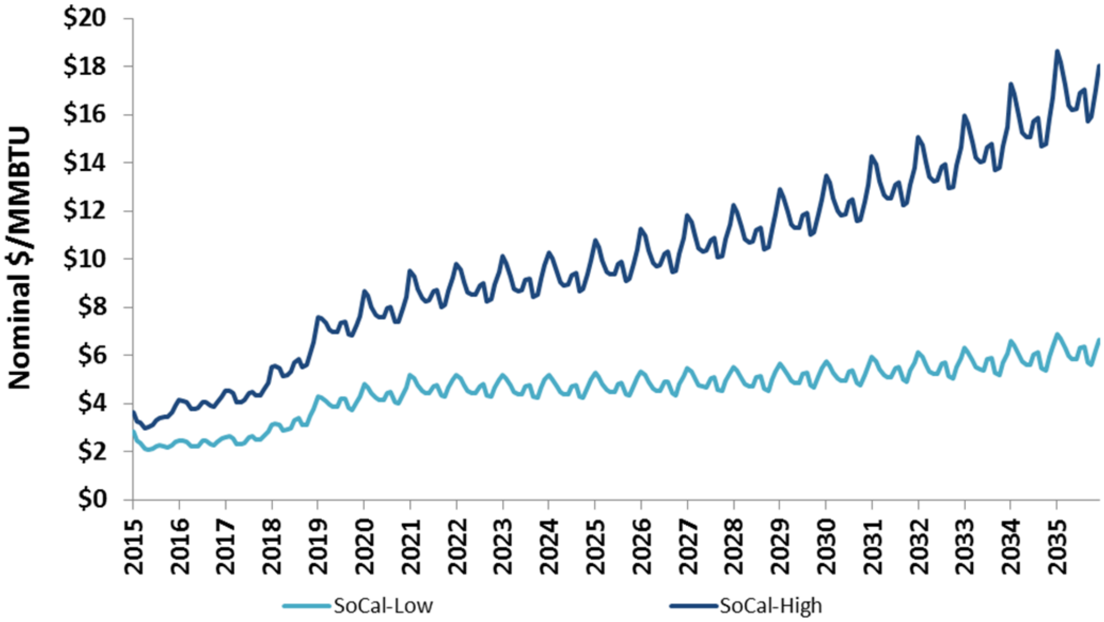
Table 3-3. SUMMARY OF SUPPLY-SIDE RESOURCE ASSUMPTIONS

	Levelized Cost ($/MWh) [1]	Capacity Factor	Dependable Capacity
Solar Photovoltaic - PPA	$ 69	28% - 35%	27%- 38%
Solar Photovoltaic - LA Solar	$ 153	19% - 23%	27%
Solar Photovoltaic - Owens	$ 100	25%	27%
Solar Feed-In-Tariff	$ 182	20%	27%
Wind	$ 94	24% - 33%	10%
Geothermal	$ 96	91% - 95%	90%
New Combined Cycle Gas	$ 106	31%	100%
New Simple Cycle Gas	$ 122	15.8%	100%

[1]Net Present Value (annual costs, 2015-2035) / NPV of Energy Produced

Natural Gas Prices

High, low, and medium natural gas price forecasts were developed to test each portfolio against a range of potential natural gas prices. The medium or expected gas forecast originates from Platts and is the standard used by LADWP for financial and fuel procurement planning. The high and low forecast, shown on Figure 3-5, are forecasts obtained from Ventyx, which considers a range of future assumptions, including economic growth, supply and demand, and environmental regulations.



Source: Ventyx, Spring 2015

Figure 3-5. Natural gas price forecast (SoCal).

Note: Unless otherwise stated, forecasted costs in all charts in this IRP are "nominal."

Coal Prices

A +10 percent and -5 percent high and low factor was applied to the expected coal fuel price, provided by LADWP's External Generation Division, to determine a high and low range for coal prices. Actual coal fuel prices have intentionally been left out of this IRP to comply with non-disclosure agreements with coal suppliers.

GHG Emissions Allowance Prices

Cost scenarios were tested using GHG allowance prices obtained from staff estimates and price forecasts available from recent brokerage transactions.

Feed-in Tariff Prices

The 2015 Power System Integrated Resource Plan's (IRP) strategic case scenarios includes Local Solar Cases consisting of varied targets of Solar Feed-in Tariff (FiT) – 450 MW and 650 MW. Since the IRP considers a 20-year planning horizon, foresight assumptions for FiT prices are required for resource planning. The FiT program prices are structured according to a tiered price system that caps the amount of power that can be reserved at each price, with the assumption that a greater percentage of larger systems will subscribe in earlier years followed by smaller systems. The 2015 IRP assumes a price schedule according to tiers as show in Figure 3-6:

FiT Tiers	Years	System (assumption)*
1	2015 – 2017	100% large/0% small
2	2017 – 2020	80% large/20% small
3	2020 – 2023	60% large/40% small
4	2023 – 2026	40% large/60% small
5	2026 – 2029	20% large/ 80% small

*Small system (30 kW – 150 kW); large system (151 kW – 3 MW)
Note: ITC is expected to be reduced from 30% to 10% beyond 2017.
Price includes administrative cost and operation and maintenance cost.

Figure 3-6. Assumed FiT tiers.

The solar FiT build out assumes a delivery of 50 MW per year from 2017 through 2029. This pacing will allow LADWP to provide appropriate staffing levels while providing developers with a predictable level of development opportunities to avoid boom and bust cycles. Each FiT system tier assumes a certain percentage of large systems (150 kW to 3 MW) compared to small systems (30 kW to 150 kW), as detailed in the table above.

The IRP considers system size, solar market trends, inflation, and available incentive tax credits (ITC) in forecasting its FiT price assumptions for the next 15 years. In determining the initial FiT price allocations, the IRP examines residential and commercial rates, fixed costs, avoidable costs, renewable energy credits, and administrative costs in order to determine appropriate prices for tier levels based on system size. Due to the fact that smaller systems are more costly than larger systems, the projected FiT prices are expected to increase over time as larger system subscriptions deplete and smaller system subscription increases.

The IRP incorporates the declining capital costs of solar systems over time to account for technology improvement. The United States Solar Market Insight Quarter 1, 2014 Full Report (solar market report) provides historical data on the capital cost of photovoltaic solar over time for both residential and commercial installations. In determining the capital cost, the solar market report considers all factors, including the cost of photovoltaic modules, photovoltaic inverters, electrical balance of systems, structural balance of systems, direct labor, engineering, design, permitting, interconnection, inspection, supply chain, logistics, customer acquisition, and overhead and mark up. The solar market report indicates that the cost of solar technology decreases logarithmically over time as technology improves. Using the historical quarterly data of solar technology capital costs detailed in the solar market report, the IRP extrapolates the declining cost trend to extend to 2029. Inflation is also considered, using historical and forecasted data from the United States Consumer Price Index, which drives the cost of solar up over time. On average, from 2015 through 2029, the annual national solar pricing decreases at a rate of 2.06%, whereas projected inflation rate increases at a rate of 1.85%. As a result, the overall projected FiT pricing in each tier level remains relatively steady in nominal terms. The main contributing factor for the jump in forecasted FiT prices from 2018 through 2029 is the expected reduction in the ITC from 30% to 10%, accelerated depreciation, and property taxes. These assumptions are used for IRP modeling purposes only and are subject to change based on further analysis.

3.3 Addressing Legislative and Regulatory Mandates

The 2015 IRP strategic cases must satisfy the requirements of the most-recently implemented environmental and RPS regulations. In many cases, the regulations have predetermined a limited set of resources that can be considered to meet future generation needs. The net effect is to constrain and limit the set of alternatives that can be analyzed.

Coal Replacement/GHG Reduction

SB 1368 requires that imported base load energy from outside California meet a GHG emissions performance standard of 1,100 lbs CO2 per MWh. To comply with this requirement, all future base load generation outside the LA Basin will need to come from either highly efficient combined cycle gas turbines (if fossil fueled), or from renewable energy resources. This eliminates the use of coal-fired generation, at least until future coal combustion and sequestration technology improves sufficiently to make this a viable option. As a result, two coal replacement cases (see Table 3-7, IRP Case Analysis Flowchart) have been considered in this 2015 IRP to define the costs and operational impacts, in which replacement of these facilities will have in meeting future energy and capacity load requirements.

OTC

Once-through cooling regulations effectively prohibits the use of ocean water cooling in all of the coastal power stations, which comprises 3 of the 4 in-basin gas-fired generation facilities, and sets specific deadlines to repower this generation by 2029. The limited resources available to repower these in-basin generation units under the accelerated time frame further limits the flexibility of altering repowering schedules based on system operation and capital requirements. Therefore, all strategic cases considered include the same repowering schedule as shown in Table 3-4 below:

Table 3-4. BASIN PLANTS REPOWERING SCHEDULE

Unit	Current Unit Nameplate Capability* (MW)	Action and Resulting Nameplate Capacity	Compliance Date (No Later Than)	LADWP Target Date**
Haynes 1	230	Replace with 460 MW CC	12/31/2029	12/31/2023
Haynes 2	230			
Haynes 5	343	Replace with 600 MW CT	12/31/2013	6/30/2013
Haynes 6	343			
Scattergood 1	163	Replace with 297 or 346 MW CC	12/31/2024	12/31/2020
Scattergood 2	163			
Scattergood 3	497	Replace with 346 MW CC, 200 MW CT	12/31/2015	12/31/2015
Harbor 1, 2, & 5	246	Replace with same MW	12/31/2029	12/31/2026
Haynes 8, 9, & 10	630	Replace with same MW	12/31/2029	12/31/2029

*Maximum or dependable capacity of the unit will be different based on permitting requirements as well as other constraints.
**Subject to further evaluation and reliability studies.

Out-of-State Renewables, Energy Efficiency and Distributed Generation

As discussed at the end of Section 1.6.5, SB 2 (1X) defines categories with predefined percentage limitations, based on the amount of out-of-state renewable generation and renewable energy credits that can be used towards meeting renewable portfolio standards. Wind, small hydro, and biogas provide the largest contributions to LADWP's current portfolio as shown in Figure 2-14. Future renewable generation will rely heavily on solar PV located within the State to fulfill the in-state percentage requirements of SB 2 (1X). This limits the potential use of renewable resources located outside of California. The strategic cases evaluated in the 2014 IRP established a diversified resource mix for the next 20 years including goals for estimated MW's installed for each renewable technology. The 2015 IRP retains the same diversified renewable mix goals set forth in the 2014 IRP recommended case while including an expanded solar PPA portfolio to reach the new state mandate of 50 percent renewables by 2030.

As shown in Table 3-6, Coal Replacement cases being considered in the 2015 IRP use the 50 percent renewable resource plan with 800 MW local solar and high transportation electrification goals. However, the local solar cases described in Figure 3-7 include different Local Solar and Transportation Electrification options to account for the effects of increased customer sales from electrification. Future IRP's will likely revisit different renewable resource mixes as the CEC further develops specific qualifying criteria for meeting in-state and out-of-state category requirements.

The 2015 IRP Strategic Cases were developed to assist policymakers and customers to make informed decisions regarding the accelerated replacement of Coal resources to promote GHG reduction prior to SB 1368 compliance, advanced levels of energy efficiency to comply with and exceed the 10 percent by 2020 goals set forth by AB 2021, and higher levels of solar distributed generation to help achieve the Governor's statewide goal of 12,000 MW of solar distributed generation by 2020. The 2015 IRP Strategic Cases are a refinement of the 2014 cases based on evolving regulatory landscape.

3.4 Candidate Portfolios Development Process

A candidate portfolio is a set of renewable and non-renewable generation resources, demand side resources, regulatory constraints, policy goals, and assumptions that are used to model strategic scenarios. Candidate portfolios are selected to cover a spectrum of possible scenarios, providing decision makers information on which portfolios are likely to be the most desirable. Additionally, each candidate portfolio must ensure resource adequacy—the ability to meet total peak demand.

3.4.1 Public Input

For the first time in the IRP public outreach process, an IRP Advisory Committee consisting of representatives from the Mayor's office, council districts, key major customers, business associations, environmental organizations, neighborhood councils, and academia was included as part of the 2014 IRP Public Outreach Process. The Committee met five times between February 2014 and September 2014, and provided collaborative dialog and stakeholder feedback on major power-related issues and cases developed for the IRP. Comments received from the IRP Advisory Committee were factored into the overall objectives, goals, and policy guidelines used in the initial construction of the draft candidate portfolios. Subsequent public review of the preliminary findings provided further input which was considered prior to finalizing a recommendation. The cases analyzed for the 2015 IRP carries over the same elements from the cases developed through the 2014 IRP Advisory Committee with the latest regulatory updates as summarized in Figure 3-7 below:

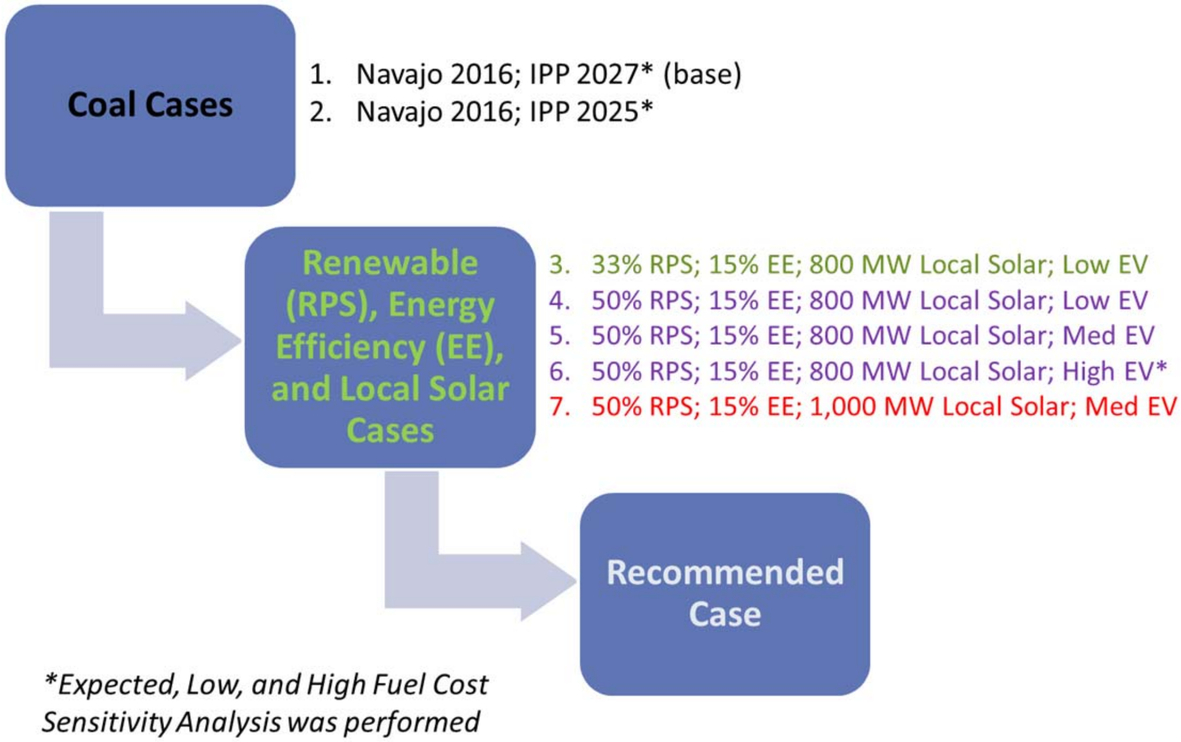


Figure 3-7. 2015 IRP Case Analysis Flow Chart

3.4.2 Net Short and Resource Adequacy

The first step in developing the 2015 IRP candidate portfolios was to determine how LADWP can meet and maintain its renewable energy policy goals: 20 percent renewables in 2010, 33 percent renewables by 2020, and 50 percent renewables by 2030. The net short—the gap between renewable energy policy goals and current renewable generation—was calculated for each strategic case and the contribution of its renewable energy component towards resource adequacy was determined. Energy efficiency, demand response, combined-cycle gas generation, and term purchases were then considered to supply the remaining deficiency in resource adequacy. Details regarding net short calculations and resource adequacy are included in Section 4.3.1.1 and Appendix N.

3.4.3 Renewable Resources Selection Process

Over the last eleven years, LADWP has issued several requests for proposals for renewable energy and gained a thorough understanding of the nature and availability of the different renewable resource technologies. This knowledge was used in developing the candidate portfolios. Additionally, LADWP largely considered renewable resources within the Western Governors' Association's Western Renewable Energy Zones (WREZ). In the WREZ initiative, Qualified Resource Areas were defined as areas of dense, high-quality renewable energy resources, meeting various resource size, quality, environmental, and technical criteria. LADWP screened all resources to ensure they are located near available LADWP transmission infrastructure, or can be delivered to areas under LADWP's balancing authority.

A valuation process designed to provide a single ranking value to a resource was then applied. This step is intended to identify resources with the combination of lowest cost and highest value. The valuation approach is similar to the bid evaluation process many utilities use when procuring renewable resources. Some of the considerations in selecting these resources are as follows:

- Cost differences for different renewable technologies and projects
- Cost trends that reflect decreasing prices
- Variable integration costs and operational impacts
- Value of peak dependable capacity and energy delivered
- Technologies that deliver more energy during peak hours
- Preference for local projects
- Proximity of projects to transmission
- For PPA resources, tax credits that can be passed along as cost savings
- PPA proposals that provide future ownership opportunities
- Overall diversity of resource mix and geography
- Satisfying category, or "bucket," requirements according to CEC RPS regulation and guidelines (see Section 1.6.6)
- Available Transmission to Load

After applying the appropriate constraints, resources were selected and added progressively to its renewable resource mix based on lowest rank cost and transmission availability until the net short was mitigated.

Based on a similar portfolio of renewable resources, the overall renewable portfolio levelized cost is $91/MWh, which represents a $1/MWh decrease from last year and a $4/MWh decrease from 2013. This cost reduction was achieved primarily through several recently signed power purchase agreements for cost-effective large central solar, geothermal, and wind projects, resulting in a more optimized and diverse portfolio. Solar projects have experienced significant reductions in cost, particularly over the last three years. These same reductions have been seen in several recently approved geothermal power purchase agreements, although these resources tend to be geographically confined to specific resource rich areas that typically lie a greater distance from existing transmission, or require transmission that must be purchased from other utilities. The possible end of solar tax credits or ITC's in 2017 appears to be one of the main reasons for the significant short-term reduction in solar prices. Biogas continues to provide a very cost effective and fully dependable resource that uses the existing gas delivery infrastructure and existing combined cycle generating units. By maintaining flexibility in the selection of cost-effective renewable resources, LADWP is able to secure the best pricing for its customers, as market conditions evolve.

3.4.4 Local Solar Levels

This year's IRP continues to expand on cases with higher levels of Local Solar, partly in response to the Governor's State-wide initiative for 12,000 MW of local solar. Due to reliability and operational concerns, the maximum amount of local solar considered is limited to 15% of the maximum annual peak load per circuit[8]. Because this is a relatively new area of study, LADWP is proceeding cautiously until it has a better understanding of the operational impacts that intermittent resources will have on its distribution grid. Potential impacts include cost increases for infrastructure enhancements, such as the need for advanced distribution automation including bi-directional feeder/substation protective relaying, forecasting technologies and further development of smart inverters to maintain reliability. As more experience is gained, along with more industry-wide research in this area, it is possible that future IRPs will consider higher local solar levels.

Based on the success of the solar feed-in tariff program, the 2014 IRP considers higher levels of local solar to provide greater margins for meeting RPS requirements. Incorporating input from the 2014 IRP Advisory Committee, the 2015 IRP considers expanding its local solar portfolio target to 800 MW and 1,000 MW in the 2015 IRP. Each local solar case considers the same 40 MW of Community Solar and 310 MW of customer net metered solar. The customer net metered solar projection of 310 MW by 2020 was based on the 2014 peak demand of 6,341 MW. This year, LADWP reevaluated the customer net metered projection and has determined that a long term cap of 5 percent should be based on a non-coincident peak demand, which is 9,300 MW; this would result in a forecasted maximum of 465 MW overall for the customer net metered solar program and will be incorporated into the modeling for next year's 2016 IRP. As a component of the total local solar, the feed-in tariff solar programs cases were expanded to a goal of 450 MW and 650 MW to provide greater margins for meeting RPS requirements. A summary of the local solar cases considered for the 2015 IRP is shown in Figure 3-8 below:

	Feed-in Tariff	Customer Net Metered	Community Solar	Total
Case 3 33% RPS; Moderate EE; **800 MW Local Solar**	**450 MW**	310 MW	40 MW	**800 MW**
Cases 4-6 50% RPS; Advanced EE; **800 MW Local Solar;**	**450 MW**	310 MW	40 MW	**800 MW**
Case 7 50% RPS; Advanced EE; **1000 MW Local Solar;**	**650 MW**	310 MW	40 MW	**1000 MW**

Figure 3-8. Breakdown of Local Solar Cases

[8] Refer to "Updated Recommendations for Federal Energy Regulatory Commission - Small Generator Interconnection Procedures Screens" Prepared by Sheehan and Cleveland, July 2010; and "Model Interconnection Procedures" by the Interstate Renewable Energy Council, 2009 Edition

3.4.5 Electrification Levels

As a strategy to absorb higher levels of renewables in the IRP cases considered, various levels of electrification were analyzed for the 50 percent RPS cases. Electrification can come from a variety of sources including electric vehicle charging, hydrogen fuel production, Port of LA shore power for cargo ships, and mass transit and cargo transport among others. As one example, increased electrification of the transportation sector would provide an opportunity for load shifting and absorbing potential over-generation from renewable resources by promoting electric vehicle charging during times of over-generation. An additional benefit would be reduced local GHG and other constituent emissions from switching higher emitting fuels such as gasoline and diesel to much cleaner electricity, and increased electric sales and revenue.

The base 33 percent RPS case considered a base case electrification, which is based on a forecast published by the 2013 California Energy Commission's Integrated Energy Policy Report (IEPR). The IEPR provides a forecast of plug-in electric vehicle growth for the State of California. Based on the IEPR forecast, LADWP deduces that by 2020, 127,000 plug-in electric vehicles will be on the road in the Los Angeles basin; by 2030, an estimated 290,000 plug-in electric vehicles are expected to be on the road. This is equivalent to an annual energy demand of 1,172 GWh in 2030 that is required to charge these vehicles.

Recognizing the benefit of electrification on a utility level, the 2014 IRP Advisory Committee suggested a medium and high electrification case for the 2014 and 2015 IRP. The medium electrification case assumes a 50 percent increase in electric vehicles and the high electrification case assumes a 100 percent increase in electric vehicles, as shown in Figure 3-9 below:

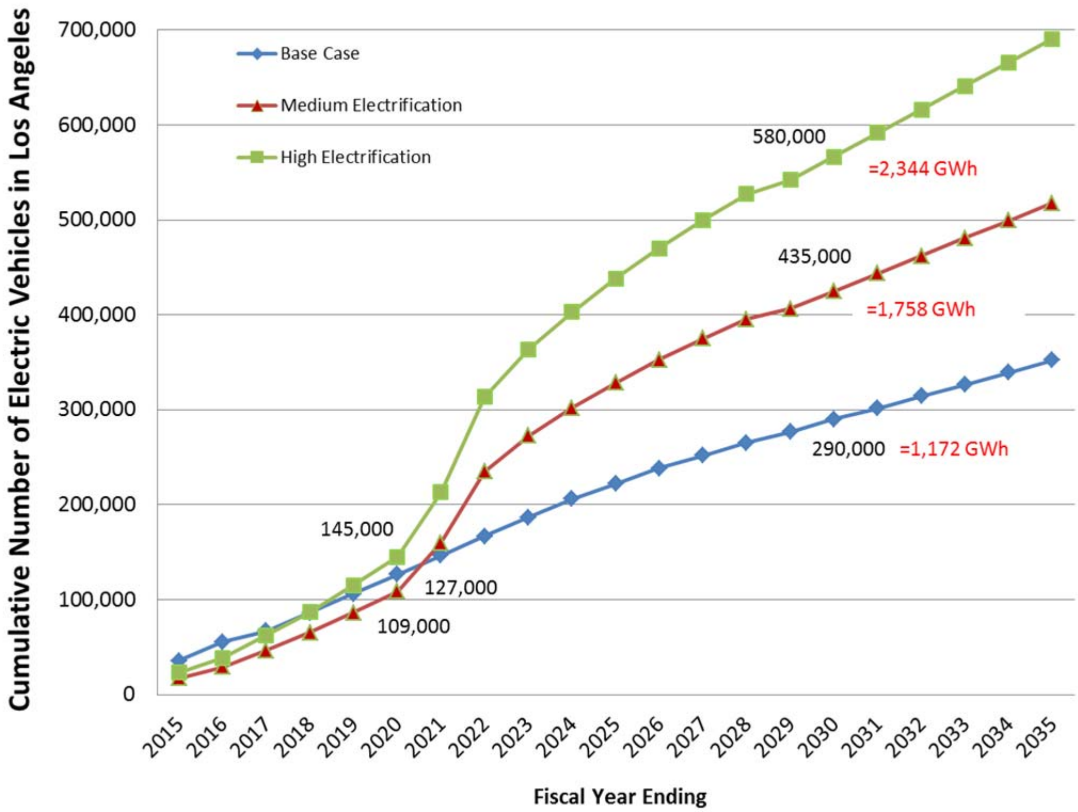


Figure 3-9. Electrification levels in the Los Angeles basin

A medium and high level of electrification assumes 435,000 and 580,000 electric vehicles, respectively, in the Los Angeles basin by 2030. This is equivalent to 1,758 GWh and 2,344 GWh of energy usage in 2030 attributed to medium and high electrification, respectively.

3.5 2015 IRP Strategic Cases

The 2015 IRP provides analyses on a focused set of strategic cases that incorporates the recent mandate of 50 percent renewables by 2030. A streamlined set of two coal replacement cases and five advanced renewable, energy efficiency, local solar, and electrification cases were evaluated for the 2015 IRP. Unlike other resources that are constrained by mandated regulatory requirements (such as repowering for OTC compliance), the decision to divest from coal earlier than legally required, accelerate RPS levels, energy efficiency programs, local solar programs, or transportation electrification is discretionary and thus appropriate for analysis. The 2015 IRP strategic cases are designed to assist policymakers and customers in making informed decisions regarding these major initiatives, particularly with regards to the environmental benefits and resulting resource and financial impacts.

Tables 3-5 and 3-6 provide a detailed description of each strategic case.

It should be noted that the same renewable resource plan applies to Cases 1 through 2. Cases 3 through 7 include the mandated 50 percent renewables by 2030 and 33 percent renewables as a comparison, increasing amounts of local solar, and varied levels of transportation electrification. Table 3-5 summarizes each renewable portfolio. For comparison purposes, the recommended case from the 2014 IRP is also included.

The different cases require distinct resource strategies to replace coal generation capacity and to meet future load growth. These strategies include the construction of new natural gas units, renewable generation, and limited electricity purchases in the 3rd Quarter, as needed to fill short-term resource adequacy deficiencies, and the implementation of demand response and energy efficiency programs. A detailed breakdown of these strategies is discussed in Sections 4 and 5.

The candidate portfolios were modeled and the case results were compared against each other. The analysis includes measurements of power costs, emissions, and fuel usage. High and low scenarios based on fuel prices were also modeled for both the coal replacement cases and for the base case advanced renewable and energy efficiency cases to quantify the risk associated with fuel price volatility. Section 4 discusses the modeling results of the strategic cases.

Section 5 discusses the final Recommended Case in greater detail which includes early divestiture of Navajo in 2016, replacement of IPP in 2025, 50 percent renewables by 2030, 15 percent energy efficiency by 2020, 800 MW of local solar by 2023, and a strategy to promote high electrification of the transportation sector. The discussion in Section 5 primarily describes the impact on Power System revenue requirements, rates, and customer bills.

Table 3-5. DESCRIPTION OF STRATEGIC CASES

Case ID	Description
Case 1 (Coal Base Case)	No Early Coal Replacement of IPP – This case assumes divestment of Navajo on 7/1/2016 but no early compliance with SB 1368 in regards to IPP. IPP is assumed to be replaced with combined cycle natural gas and renewable resources upon the expiration the coal contract in 2027. Maintains the 33 percent standard renewables mix recommended to comply with SB 2 (1X) and increases to 50 percent renewables by 2030 to comply with SB 350, 15 percent energy efficiency savings by 2020, 800 MW of local solar, and a high scenario of transportation electrification.
Case 2	IPP Early Divestiture Strategy – This case considers divestment of Navajo on 7/1/2016, or 3.5 years prior to contract expiration, with IPP replacement on 7/1/2025, or 2 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix to comply with SB 2 (1X) and increases to 50 percent renewables by 2030 to comply with SB 350, 15 percent energy efficiency savings by 2020, 800 MW of local solar, and a high scenario of transportation electrification.
Case 3 (Advanced Renewable and Energy Efficiency Base Case)	33 percent Renewable Portfolio Standard, Advanced Energy Efficiency, and 800 MW Local Solar – Used as a baseline comparison to Cases 3 through 7. This case considers early divestment of Navajo on 7/1/2016, 3.5 years prior to contract expiration, and early replacement of IPP on 7/1/2025 or 2 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix to comply with SB 2 (1X) with 800 MW of local solar. Considers 15 percent energy efficiency savings by 2020 to exceed the requirements of AB 2021. Includes a base forecast of electrification based on the CEC IEPR.
Case 4	50 percent Renewable Portfolio Standard, Advanced Energy Efficiency, 800 MW Local Solar, and Base Electrification - This case considers early divestment of Navajo on 7/1/2016, 3.5 years prior to contract expiration, and early replacement of IPP on 7/1/2025 or 2 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix by 2020 to comply with SB 2 (1X) but extends the renewables mix to 50 percent by 2030 with 800 MW of local solar. Considers 15 percent energy efficiency savings by 2020 to exceed the requirements of AB 2021. Includes a base forecast of electrification based on the CEC IEPR.
Case 5	50 percent Renewable Portfolio Standard, Advanced Energy Efficiency, 800 MW Local Solar, and Medium Electrification – This case considers early divestment of Navajo on 7/1/2016, 3.5 years prior to contract expiration, and early replacement of IPP on 7/1/2025 or 2 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix by 2020 to comply with SB 2 (1X) but extends the renewables mix to 50 percent by 2030 including 800 MW of local solar, 15 percent energy efficiency savings by 2020 to exceed the requirements of AB 2021, and a medium (50% over base) electrification strategy of the transportation sector with higher expected load growth.

Case ID	Description
Case 6 (Base Advanced RPS, EE, and Local Solar Case)	50 percent Renewable Portfolio Standard, Advanced Energy Efficiency, 800 MW Local Solar, and High Electrification – This case considers early divestment of Navajo on 7/1/2016, 3.5 years prior to contract expiration, and early replacement of IPP on 7/1/2025 or 2 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix by 2020 to comply with SB 2 (1X) and extends the renewables mix to 50 percent by 2030 including 800 MW of local solar, 15 percent energy efficiency savings by 2020 to exceed the requirements of AB 2021, and a high (100% over base) electrification strategy of the transportation sector with higher expected load growth.
Case 7	50 percent Renewable Portfolio Standard, Advanced Energy Efficiency, 1,000 MW Local Solar, and Medium Electrification – This case considers early divestment of Navajo on 7/1/2016, 3.5 years prior to contract expiration, and early replacement of IPP on 7/1/2025 or 2 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix by 2020 to comply with SB 2 (1X) but extends the renewables mix to 50 percent by 2030 including 1,000 MW of local solar, 15 percent energy efficiency savings by 2020 to exceed the requirements of AB 2021, and a medium (50% over base) electrification strategy of the transportation sector with higher expected load growth.

Table 3-6. CANDIDATE RESOURCE PORTFOLIOS FOR 2015 IRP

COAL REPLACEMENT CASES

		GHG or SB1368 Compliance Date		2030	2010 thru 2020	2010 thru 2035	New Renewables Installed Capacity (MW) 2015 - 2020					New Renewables Installed Capacity (MW) 2015 - 2035				
Case ID	Resource Strategy	Navajo Replacement	IPP Replacement	RPS Target	EE (GWh)	EE (GWh)	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
1 (Base Case)	No Early Coal Divestiture	7/1/2016	6/15/2027	50%	3038	3928	95	0	1088	509	0	293	670	1813	653	799
2	Navajo and IPP Early	7/1/2016	7/1/2025	50%	3038	3928	95	0	1088	509	0	293	670	1813	653	799
2014 Recommended [1]	Navajo and IPP Early Replacement	12/31/2015	6/15/2025	40%	3401	4283	76	70	1059	579	0	216	270	1305	704	723

		2030	2010 thru 2020	2010 thru 2035	New Renewables Installed Capacity (MW) 2015 - 2020					New Renewables Installed Capacity (MW) 2015 - 2035				
Case ID	Resource Strategy	RPS Target	EE (GWh)	EE (GWh)	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
3	Advanced EE, 800 MW Local Solar, Base Electrification	33%	3038	3928	95	0	948	509	0	243	270	1,089	653	152
4	Advanced EE, 800 MW Local Solar, Base Electrification	50%	3038	3928	95	0	1,088	509	0	293	670	1,813	653	533
5	Advanced EE, 800 MW Local Solar, Medium Electrification	50%	3038	3928	95	0	1,088	509	0	293	670	1,813	653	685
6 (Base Case)	Advanced EE, 800 MW Local Solar, High Electrification	50%	3038	3928	95	0	1,088	509	0	293	670	1,813	653	799
7	Advanced EE, 1000 MW Local Solar, Medium Electrification	50%	3038	3928	95	0	1,038	509	0	293	670	1,629	853	799

[1] 2014 Recommended based on 2014 - 2020 and 2014 - 2034 reporting period for New Renewables Installed Capacity and 2010 thru 2034 for EE (GWh)

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4.0 STRATEGIC CASE ANALYSIS

4.1 Overview

Section 3 discussed the development process for alternative case options, and presented the resulting six cases being considered for study. This Section 4 presents the analysis of the six cases, including the modeling methodology and the analysis results.

The analysis was performed on the generating resources using an hourly chronological production cost model. The model simulated the operation and electric loading of the LADWP Power System over a 20-year planning horizon with different portfolios of generating resources. The objective function of the production cost model is to minimize system cost, which is achieved by finding the least cost method to meeting the electric system demand using the specified generating resource portfolios.

The resources defined in the model consist of existing LADWP generating resources, generation currently under differing stages of development, and generic types of future generating resources with locations or projects that are not yet identified. The resource mix of renewable generating resources and thermal generating resources must satisfy: (1) resource adequacy requirements for reliability, (2) specific increasing targets of renewable resources as a percentage of total energy sales, and (3) other goals and objectives such as 15 percent energy efficiency, reliable integration of renewables, etc.

The 2015 IRP continues to evaluate the coal replacement strategies considered in the 2014 IRP with updated cost and assumptions information.

The five advanced renewable and energy efficiency scenarios (Cases 3 – 7) are updated cases developed based on input from the 2014 IRP Advisory Committee as part of the public outreach process. These cases focus on a 50 percent renewable portfolio standard, 15 percent energy efficiency, local solar, and electrification strategies over the next 20 years. These five new advanced renewable and energy efficiency scenarios include the same coal replacement timeline, with Navajo divested in 2016 and IPP replaced in 2025. The detailed discussion on the scenarios and the analyzed results can be found in Sections 3.4, 3.5, and 4.3.

All five cases were modeled, and the results were tabulated and compared against each other. Each strategy was ranked on average dollars per megawatt hour generation cost and the total million metric tons of CO_2 emissions.

Load forecast, prices of natural gas and coal, GHG emissions levels, capital, and O&M costs are the major cost drivers for bulk power in the cases analyzed. All cases meet or exceed, beyond 2020 and 2030, the mandated RPS percentage targets and renewable resources are adjusted for each case analyzed depending on energy sales adjustments needed, based on varying amounts of local solar and electrification. A 33 percent RPS case by 2030 was analyzed as a baseline for cost and GHG comparison purposes.

Section 4.2 reviews the modeling considerations for the cases that were presented in Section 3, along with the model assumptions and analysis methodology. Section 4.3 presents the modeling results, including cost comparisons and the rate impact results of the different cases. Section 4.4 presents the strategic case conclusions and the recommended case.

Section 5 includes long and short-term actions that are recommended towards implementation of the recommended case, including an estimate of the revenue requirements and electricity rate schedule needed to support it.

4.2 Strategic Case Modeling Considerations

The cases analyzed in this 2015 IRP were introduced in Section 3.5 and are briefly discussed here. The timing of coal replacement and the variations in renewable energy including local solar, energy efficiency, and level of electrification quantities and the resultant changes in resource mix are the key parameters that differentiate the seven cases evaluated. Table 3-5 summarizes the portfolios for each case.

The following inter-related resource parameters were assumed to occur in the seven coal and advanced renewable and energy efficiency potential resource strategies:

- OTC Repowering Schedule per Figure 1-11
- Net Energy efficiency penetration of approximately 3,928 GWh by FY 2035 for advanced EE
- RPS Resource Mix, schedule per Table 3-6
- Gas and Coal Fuel prices, as discussed in Section 3.2.2.
- IPP capacity and recall schedule shown in Appendix N
- Local Solar Levels as discussed in Section 3.4.4
- Transportation Electrification Levels as discussed in Section 3.4.5

Coal strategic cases and the recommended renewable portfolio standard case were also subjected to high and low scenario runs, which were based on high and low values for natural gas and coal prices. The high and low scenarios simulated production over the same 20-year horizon, and provided a measure of the level of risk due to potential future fuel price volatility.

4.2.1 Modeling Methodology

4.2.1.1 Planning & Risk (PROSYM)

Simulations were performed using Planning & Risk (PAR), a third-party software program sold and distributed by Ventyx Corporation. PAR is an hourly chronological production cost model that commits and dispatches resources with certain operational constraints applied to the system to minimize the cost of serving electric load. It utilizes the PROSYM unit commitment and dispatch algorithm. PAR is a widely used production cost model used by many utilities across the US and the world to help plan and optimize power systems. Additional information on the model can be found in Appendix N.

4.2.1.2 Model Assumptions

To perform model simulations, a large set of input data is required. The key parameters that influence the analysis results are fuel prices, load forecast (including adjustments for energy efficiency, electrification growth, and other demand side management programs such as customer net-metered solar), coal replacement strategies, and operational inputs regarding future gas-fired units. Details regarding the model assumptions are provided in Section 3 and Appendix N.

4.2.1.3 Net Short of Renewables

In developing the future renewable portfolio mix, the primary requirement was to meet the SB 2 (1X) goals and SB 350 for RPS percentage (see Section 1.6.5 for details) which includes meeting the RPS portfolio content categories as shown in Table 1-2. Other considerations included costs, resource and geographical diversity, renewable integration cost, capacity and energy value of resource, and proximity to existing transmission. The process by which the renewable resource portfolio was constructed is described in Section 3.4.

4.2.1.4 Resource Adequacy

As a prerequisite for any potential future portfolio, all cases considered must satisfy Resource Adequacy (RA) requirements. RA is the ability to supply the aggregate demand and energy requirements of customers at all times, taking into consideration future load growth and planning reserve margins. In calculating RA for a given portfolio, generation resources are assigned a percentage of their nameplate capacity, known as “Net Dependable Capacity” that can be counted towards the RA requirement. The net dependable capacity values vary depending on the type of generation resource. Throughout the energy industry there is an on-going debate on how much variable energy resources can be relied upon during the summer system peak. Table 4-1 lists the net dependable capacities of the different resource technologies assumed for this IRP analysis.

Table 4-1: NET DEPENDABLE CAPACITY ASSUMPTIONS FOR NEW RESOURCES

Plant Technology	Net Dependable Capacity
Natural Gas Combined-Cycle	100%
Natural Gas - Gas Turbine	100%
Wind	10%
Solar PV – Fixed Tilt	27%
Solar PV – Single Axis Tracking	38%
Solar Thermal	68%
Geothermal	90%

The specific RA analyses for each of the two coal strategic cases are presented later in Section 4.3.1.1.

4.2.1.5 Model Runs and Scorecards

The evaluation of each strategic case yielded a tremendous amount of information about the LADWP Power System. In order to organize and interpret the modeling results, a scorecard system was developed to rank and check the output results. The scorecard is a very detailed and complex Microsoft Excel based spreadsheet that summarizes all the important inputs and outputs and includes metrics such as total system power costs, plant generation, CO_2 emissions, and fuel costs.

4.2.1.6 Post Modeling Analysis

While the production cost modeling provides detailed information on estimated bulk power costs, reliability and mandated regulatory program revenue requirements are evaluated through analysis external to the production cost model. The results of this analysis are provided in Section 4.3 to provide a more complete view of the total cost components that make up total Power System costs. This Section also illustrates the revenue requirements to fund these specific programs to maintain a reliable electric system, while also complying with regulatory requirements for renewable portfolio standards, local solar, once-through-cooling, and energy efficiency.

4.3 Modeling Results

The modeling results are presented in terms of LADWP's overall goals of: (1) reliability, (2) environmental stewardship and (3) economic, or cost considerations.

4.3.1 Reliability Considerations

Resource strategies are not designed to completely avoid the probability of a power outage due to inadequate supply side resources. Such a strategy would be very expensive and would mean that some resources would be built with a small probability of ever operating, or would have an unacceptably low capacity factor. Most power outages are distribution based (e.g., a winter storm that knocks down local distribution lines) and not a result of insufficient generation resources. The reliability criterion of “1 day in 10 years” attempts to quantify what is an acceptable amount of loss of load (i.e. a power outage). The generally accepted industry interpretation of the criteria is that a system is considered reliable if there are no more than a total of 24 hours of loss of load in a 10 year period (87,600 hours). This criterion translates to a 0.03 percent probability that load will not be served. While this criteria served its purposes with traditional generation resources, todays variable energy resources (VER’s) may require the development of new reliability standards.

Based on recent studies of higher levels of RPS, it is believed that, increasing levels of renewables will result in exponentially greater operational challenges including over generation, generation flexibility, and VER forecasting. Integrating renewables is the subject of intense study nationwide and reliability impacts are not fully understood at this point but we are making good progress towards more fully analyzing and quantifying these impacts. The challenges vary considerably depending on the size and type of renewable facility, penetration level of specific types of VER’s, renewable resource blends, and geographic diversity of these resources. Utility specific transmission/generation topologies are another potential limitation. For instance, a smaller balancing authority with large resources far from the load center may require higher levels of on-line and replacement generation reserves to protect the system from the sudden loss of VER’s. In contrast, a large balancing authority such as the California Independent System Operator (CAISO) covering a large geographic region with a greater number of smaller resources relative to the overall load served, may experience different operational challenges, such as contractual limitations on curtailment capability and energy imbalance market mechanisms.

In 2015, LADWP contracted with URS and their team of experts to conduct a reliability study to examine the impacts of 40 and 50 percent renewables on LADWP’s Power System by 2030. As part of the study, a resource adequacy analysis was first performed on long-term production cost simulation results from the 2014 IRP production cost models. Study results showed that the planned LADWP system is sufficiently flexible to integrate a high level of renewables, even at a 50% RPS requirement, with stresses appearing primarily towards the end of the study period. Figure 4-1 below illustrates an hourly and a sub-hourly duck curve simulated for February 16, 2025. While system planning analyses typically takes place at hourly time scales (left panel), increased VER penetration introduces sub-hourly variability (right panel) that has a substantial impact on system flexibility needs, dispatch costs, and reliability risks. For example, the hourly curve on the left implies a maximum load-less-VER ramp of 19 MW/min, in the late afternoon. A sub-hourly ramping analysis, however, shows that 28 MW/min is necessary to match the first 30 minutes of the afternoon ramp, showing that LADWP must account for sub-hourly effects to ensure adequate ramping capability, and system performance, under high VER penetrations. Figure 4-1 also highlights the 2,000 to 4,000 MW ramp that takes place over a 3 to 5 hour period in the afternoon, an event that would not be unusual in LADWP’s system give the proposed additional solar capacity. This will result in significant stress on the Power System – thermal units and large hydro will be expected to turn on/off from a minimum or cold start to nearly maximum generation within a few hours on a daily basis. Additional regulation is also required to compensate for the sub-hourly fluctuations of variable energy resources.

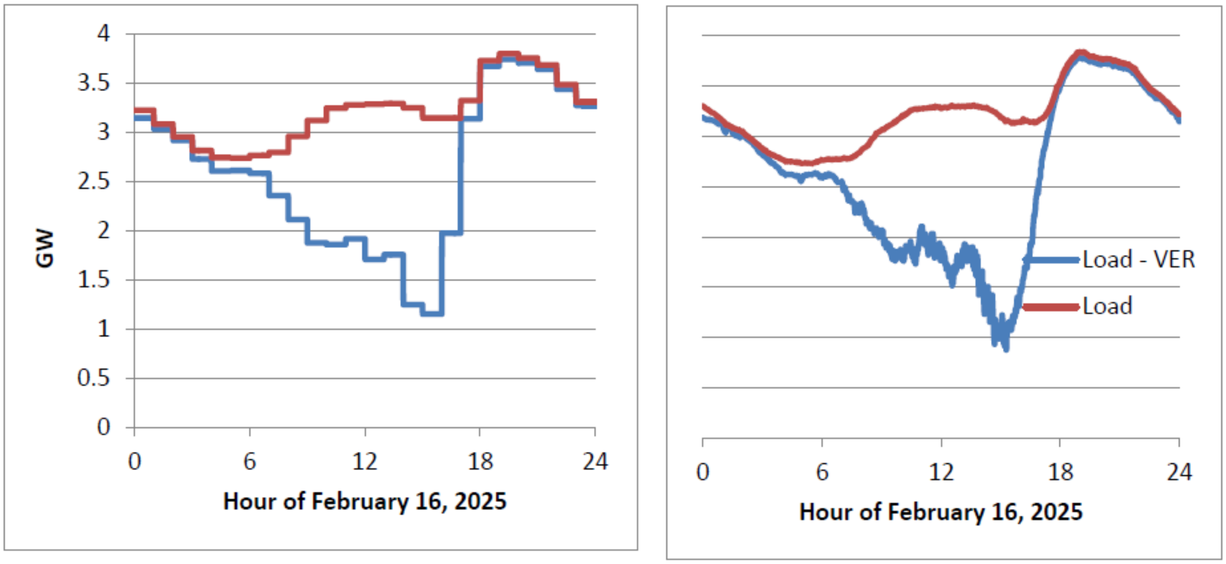

Figure 4-1. Hourly (left) and sub-hourly (right) duck curves

In parallel with the resource adequacy analysis, an analysis of the sub-hourly effects of increased VER penetration, including the effect on load-following and regulation requirements, was conducted. Load following capacity will need to increase under all scenarios from today's levels of about 150 MW during average winter conditions to 1,000 MW under a 50% RPS high solar scenario. Taking uncertainty into account, the load following requirements could occasionally reach as high as 1,400 MW by 2030, from 375 MW in 2014, at the 99th percentile. The hourly load-following requirements are summarized in Figure 4-2 below:

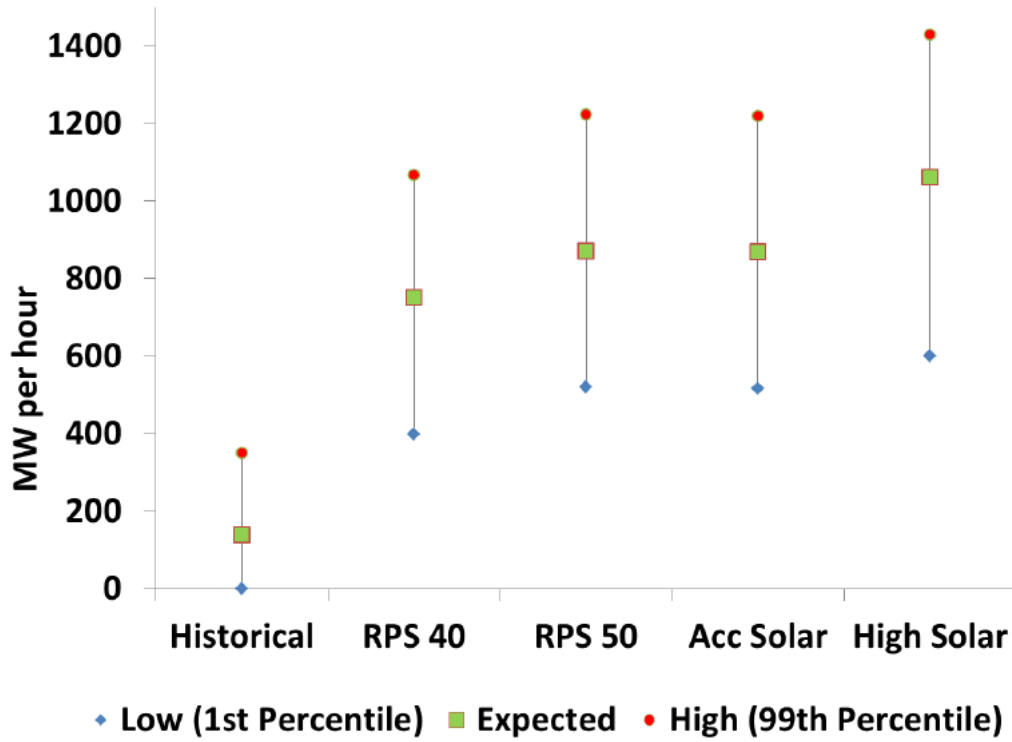

Figure 4-2. Hourly load-following requirements: afternoon ramp, winter 2030

As indicated in Figure 4-2, several scenarios were considered, including a 40 percent RPS, a 50 percent RPS, as well as two alternative 50 percent scenarios – Accelerated Local Solar and High Solar. Regulation requirements are poised to increase significantly, even under the most conservative 40 percent RPS scenario. The study results estimates that up to 125 MW/min of additional up-regulation ramping capability could be needed in the 2025-2030 period, compared to a 40 percent RPS scenario.

A 50 percent RPS high solar scenario indicates upward trends in load-following and regulation requirements over time (reported at the 99^{th} percentile). The most notable trends are increases in:

- Hourly downward load-following requirements during the morning solar ramp, from almost none in 2014 up to 860 MW in 2030
- Hourly regulation requirements during peak solar hours, from 60 MW up-regulation in 2014 up to 360 MW in 2030
- Hourly upward load-following requirements in the afternoon, from 350 MW in 2014 to 1,400 MW in 2030.

In addition, a 50 percent RPS high solar scenario would result in the following capacity shortfalls in system ramping capability in 2030 (reported at the 99^{th} percentile):

- 47 hours in which 60 minute ramping capability falls short, by a maximum of 480 MW
- 6 hours in which 30 minute ramping capability falls short, by a maximum of 380 MW
- 220 hours in which 10-minute ramping capability falls short, by a maximum of 640 MW.

Although some shortfall can be mitigated through re-dispatch of thermal capacity and large hydro, there is a need for fast-responding resources to compensate for fast fluctuations in solar power output. The following Table 4-2 summarizes the current and future maximum load following capacity requirements in summer and winter.

Table 4-2: MAXIMUM LOAD FOLLOWING CAPACITY REQUIREMENTS – 50% RPS

Load Following Capacity Requirements (MW/hour)	Winter 2014	Winter 2030 High Solar	Summer 2014	Summer 2030 High Solar
Downward Load Following Capacity (morning hours 0700-0800)	23.6	963	9	998
Upward Load Following Capacity (afternoon hours 1600-1700)	360	1500	95	1500
Regulation Ramping Requirements (MW/min)	Winter 2014	Winter 2030 High Solar	Summer 2014	Summer 2030 High Solar
Downward Regulation Ramping (peak solar 1300-1400)	100	400	150	510
Upward Regulation Ramping (peak solar 1300-1400)	110	490	260	720

The study also simulated key system performance metrics under normal operating conditions (non-contingency) as well as under a contingency event. The analysis showed that the system meets minimum performance requirements under normal operating conditions and during a contingency event; however, the study concluded that three percent of the selected scenario days did not have adequate generation resources to fully recover from the contingency event unless large hydro continues to operate for more than one hour following the event. While this normally would not be an issue, there will be times when large hydro will have limitations due to reservoir storage limits or outage constraints. Figure 4-3 below depicts how a range of Battery Energy Storage Systems (BESS) can assist in alleviating RBC excursions for contingency events. 30 MW of BESS improves RBC significantly, and the effect of additional storage plateaus at less than 50 MW BESS. Simulations show that 30 MW of BESS with 1.5 hours duration would be sufficient to reduce RBC to the 10-minute target for the simulated scenario-day.

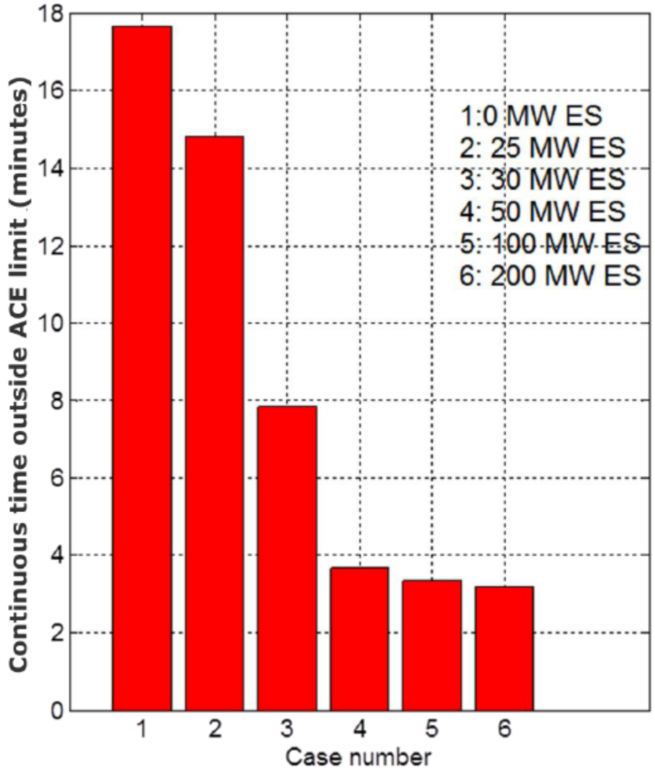

Figure 4-3. Worst RBC excursion for a range of BESS sizes for the uncommon winter day, 2025 (High Solar RPS scenario)

A 50 percent RPS high solar scenario indicates upward trends in load-following and regulation requirements over time. The most notable trends are increases in:

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- 220 hours in which 10-minute ramping capability falls short, by a maximum of 640 MW.

Although some shortfall can be mitigated through re-dispatch of thermal capacity and large hydro, there is a need for fast-responding resources to compensate for fast fluctuations in solar power output.

The study scenarios also do not represent a worst case scenario or an analysis of composite days, wherein challenging system conditions compound or persist over longer periods of time. In addition, the study results emphasize that large hydro is a critical resource for restoring

LADWP's resource balance and reserves and the absence of large hydro would likely cause the area control error (ACE) to stretch more than 15 minutes, introducing a risk of NERC Disturbance Control Standard (DCS) violations. Based on the analyses and findings in the study, the consulting team made the following recommendations:

- Adopt a multi-dimensional metric for flexibility reserves and implement tools that will allow ongoing assessment of hourly needs and availability of such reserves. By having access to such tools, LADWP is likely to better anticipate real-time changes in the need for flexible resources, load following and ramping needs, and thereby be able to reduce the amount of committed resources relative to a situation without such real-time tools. The metric would incorporate real-time system parameters such as VER forecast (both energy and variability), system headroom and legroom, ramping capability, transmission constraints, unit availability, and demand-response capability, on an hour ahead or better time-resolution.
- Consider the cost-effectiveness of adopting 30-50 MW of additional battery storage for regulation. This level of storage can significantly reduce large Reliability Based Control (RBC) excursions and fulfill the majority of regulation requirements introduced by increased VER. This level of storage cannot, however, fulfill load-following requirements or contribute in a meaningful way to respond to contingency events.
- Consider the cost effectiveness of alternative flexible resources such as:
    - Fast-start gas generation to compensate for extreme afternoon ramps and provide regulation services
    - Two-way demand response (provide the ability to both decrease load through demand response and increase load through electric vehicle charging)
    - Smart EV charging and strong time-of-use incentives to discourage charging during the early evening ramp
    - Behind-the-meter energy conservation programs with a storage component.
    - New software tools to analyze sub-hourly operational requirements.

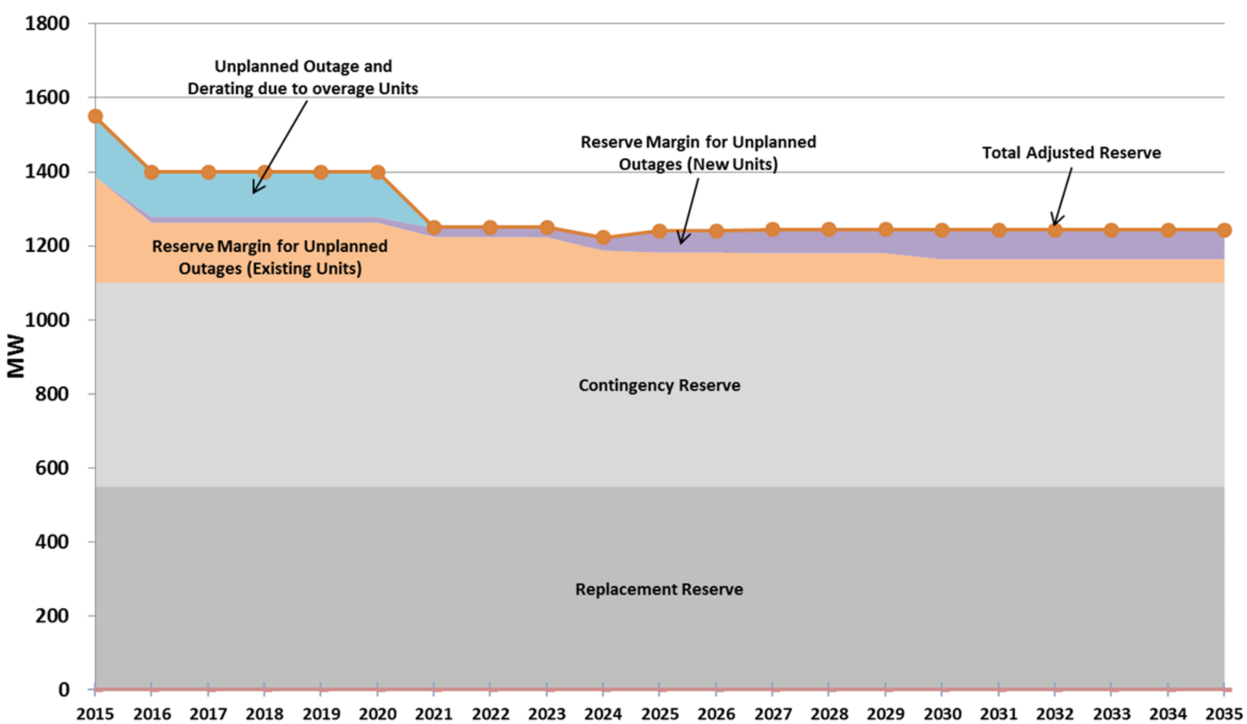
    The best mitigation portfolio from the perspectives of both cost and reliability will consist of a balance of these options. While some of them fulfill the same role—with fast-start generators and demand response both mitigating drops in VER output, for example—others are complementary. Energy conservation programs and storage, for example, would help shift and decrease peak load on a day-to-day basis rather than mitigating the fast fluctuations introduced by VER.
- Evaluate participation in CAISO's Energy Imbalance Market (EIM) as an additional means of managing VER variability.
- Evaluate the optimal location of mitigation devices such as storage in LADWP's system. For example, locating storage near renewables can alleviate transmission congestion but sacrifices the smoothing effect of aggregating VER system-wide.
- Investigate the system frequency and ACE under a long lasting and possibly compound set of system challenges (composite days) in order to gain further insight into the stability of the system under challenging conditions.
- Quantify the benefit of reduced reliability-must-run in the future high-VER system when planning transmission investments.

To remedy the steepness of a future "duck curve," strategies such as resource diversification, modifying renewable contracts to alleviate renewable integration issues, and electric vehicle charging during peak hours needs to be evaluated and quantified. The future load profile in 2025 is expected to have a steep afternoon up-ramp and there will be cost associated with this ramp—flexible, quick starting gas-fired units will need to be built to compensate for the loss of renewables. Future IRPs will evaluate the true "all-in" cost of renewables including associated integration cost, as well as strategies to reduce the reliability and cost impact of a steep "duck curve." For more detailed information on the analysis of the reliability study, refer to Appendix J.

In 2015, LADWP contracted with Black and Veatch to study the impact of high solar penetration on LADWP's distribution system and recommend mitigation solutions that would allow for increased solar penetration in a study titled, "Maximum Distribution Renewable Energy Study (MDREPS)." Because LADWP does not have a Power Flow model of the 2000+ circuits, the study analysis relies on testing 20 select circuits and then generalizing the results to a greater population of LADWP circuits. The methodology of the study includes statistical clustering analysis on the available circuit data by grouping subsets of circuits into clusters with similar attributes. In order to determine the maximum solar PV hosting capacity of each circuit studied, Black and Veatch will review both steady-state and long-term dynamic (quasi-steady-state) conditions to capture the various conditions that could be seen on these circuits as well as various PV deployment arrangements along each circuit. The testing of each circuit involves incrementally increasing the solar PV penetration until a system performance is encountered. The results of this study will inform the maximum solar PV hosting capacity for the 20 studied circuits and the results will be extrapolated to the greater population of circuits in LADWP's territory. The MDREP study is expected to be complete in 2016.

4.3.1.1 Resource Adequacy

One of the primary objectives of resource planning is to ensure that adequate resources are secured to meet system peak load, while also supplying adequate reserves or back up generation to supply contingency and replacement reserves, as required under NERC operating standards. Unplanned outages are an additional planning concern for utilities, especially as generation units age and generally become less reliable. To account for unplanned outages, historical forced outage rate percentages are applied to each generating unit's nameplate capacity, to provide an estimate of the amount of generation that is typically unavailable during peak load periods, which is approximately 150 MW. Planned maintenance schedules are also considered in determining the available generation capacity to meet peak demand. Based on the FERC 714 reports submitted to FERC each year, 423 MW of capacity on average, from 2013 through 2014, was not available during summer months to serve peak load and reserve margin requirements. This is primarily due to the excessive age of in-basin gas-fired generator units that are scheduled for OTC repowering over the next 15 years, as shown in Figure 1-10. To account for this higher level of unplanned outages due to overage units, supplemental reserves to match the 423 MW of unplanned outages have been added to the total planning reserve margin as shown in the top layer of Figure 4-4. As the repowering of Scattergood Unit 3, and then Scattergood Units 1&2 are completed, these additional reserve requirements ratchet downward in 150 MW steps, until the expected reserve margin for unplanned outages reaches 150 MW in 2020, upon final completion of the Scattergood Units 1&2 repowering project.



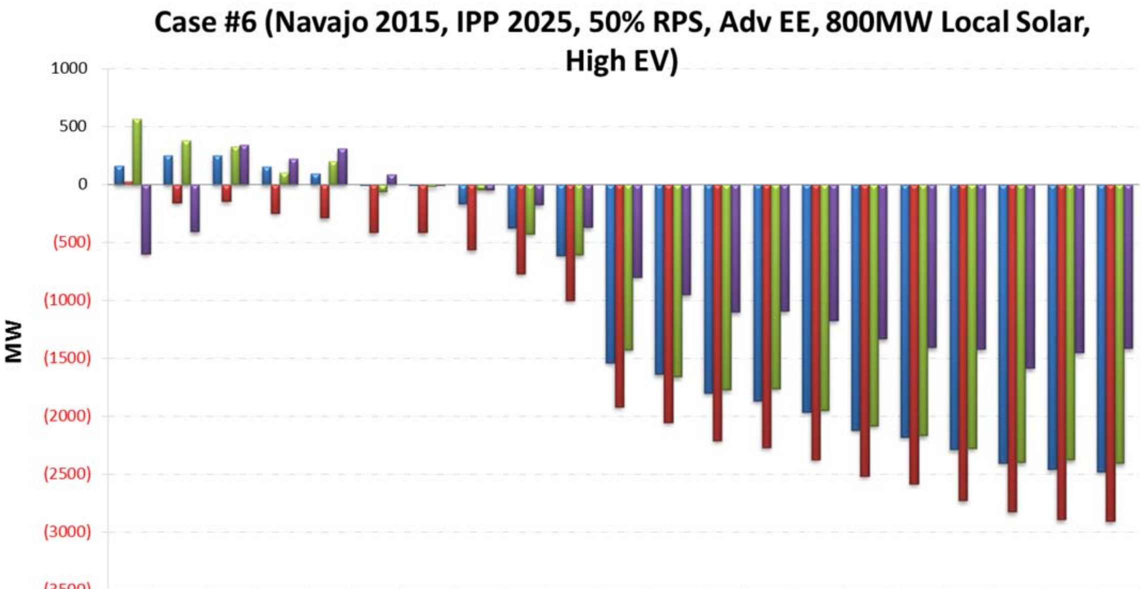
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
% of Planning Reserve Margin to 1-in-10 Peak Load	24%	21%	21%	21%	21%	20%	18%	18%	17%	17%	17%	17%	16%	16%	16%	16%	16%	15%	15%	15%	15%

Figure 4-4. Planning reserve margin as a percentage of 1 in 10 peak load by calendar year

The process of ensuring resource adequacy for each strategic case is iterative. Initially, a resource adequacy analysis is made for each case without any resource additions. The results indicate the amount of resource surplus or shortfall into the future. Without any resource additions, a deficit is eventually reached as a result of coal replacement, generation unit retirements, and the expiration of power purchase contracts on the supply side, as well as load growth adjusted for resources such as EE, Local Solar, and electrification of transportation on the demand side.

Figure 4-5 presents the resource shortfalls for the Case 2 (also Case 6) prior to any resource additions. For planning purposes, the figures focus on the most critical months of each year – July through October.

Resource Shortfall



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
July	164	250	250	155	97	(5)	(5)	(167)	(373)	(613)	(1537)	(1640)	(1798)	(1867)	(1964)	(2118)	(2181)	(2286)	(2402)	(2459)	(2478)
August	31	(155)	(145)	(248)	(286)	(415)	(414)	(563)	(767)	(999)	(1918)	(2052)	(2208)	(2268)	(2374)	(2516)	(2584)	(2727)	(2825)	(2893)	(2906)
September	562	382	328	103	202	(62)	(19)	(44)	(425)	(607)	(1426)	(1660)	(1770)	(1759)	(1949)	(2081)	(2168)	(2277)	(2400)	(2375)	(2406)
October	(596)	(408)	343	223	309	88	(4)	(49)	(175)	(370)	(799)	(952)	(1099)	(1092)	(1175)	(1332)	(1406)	(1422)	(1584)	(1451)	(1415)

Year/Month

Figure 4-5. Summer months resource adequacy shortage for Cases 2 and 6, by calendar year

("1 in 10" reliability criteria)

Once the deficits have been quantified, the means of satisfying the shortfall is assessed. Some of the considerations that LADWP accounted for in identifying potential solutions include:

- Any additional renewables will increase LADWP's overall renewable resource portfolio and help achieve compliance with SB 2 (1X) and SB 350.
- Energy efficiency, demand response, peak season Q3 term purchases, and replacement gas-fired generation were considered to provide the most economical and well diversified blend of resources.
- The additions had to be separate and distinct from the in-basin OTC repowering projects, which are already included in the shortfall calculation.
- Large scale generation additions were located out-of-basin to take full advantage of the existing transmission infrastructure and to comply with local environmental regulations.
- Where feasible, the new generation sites should make use of existing transmission and fuel supply infrastructure.

- As with all planning activities, the solution must address reliability, costs, and environmental stewardship.

After careful consideration, LADWP's IRP team consisting of the IRP staff, Power System Management, Environmental Affairs, and the Energy Efficiency Group, developed a resource replacement strategy for each case. The resource solution employs a mix of new renewable generation, energy efficiency, demand response, new gas-fired combined cycle units, and Q3 Term Purchases to replace Navajo and IPP Coal and to supplement load growth adjusted for demand side resources and electrification. Table 4-3 shows the breakdown of the replacement resources recommended for Case 2 (also 6). Replacement resources for the five advanced renewable and energy efficiency cases were also developed and are shown in Appendix N.

Table 4-3. RESOURCES RECOMMENDED FOR RESOURCE ADEQUACY BY CALENDAR YEAR

Case #2 and 6 (Navajo 2015, IPP 2025, 50% RPS, Adv EE, 800MW Local Solar, High EV)

Capacity (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy Efficiency	29	52	79	108	135	160	172	181	187	191	193	194	196	198	199	202	204	206	206	206	206
Demand Response	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500	500	500
New Renewable	79	348	411	485	535	584	667	753	849	961	1132	968	1049	1075	1123	1182	1225	1246	1267	1311	1332
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600
Capacity Shortfall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	70	192	268	292	284
Total Replacement	128	440	566	692	820	943	1089	1233	1386	1552	2374	2262	2345	2373	2422	2532	2600	2743	2841	2909	2922

Figure 4-6 shows the net dependable capacity profiles for Case 2 and 6 after including the recommended resources to satisfy resource adequacy requirements. In each case, Navajo is replaced with new renewable generation, with the remaining capacity from a 500 MW replacement combined cycle gas-fired unit located out-of-basin. Energy efficiency and demand response supply capacity that primarily contributes to peak load growth. The 50 percent RPS requirement results in an increased dependable capacity of 250 MW by 2030 provided by new renewables, which reduces the need for dependable capacity from Demand Response to a range of 200 to 500 MW by 2026.
When IPP energy ceases in 2027 for Case 1, and 2025 for Case 2 the IPP generation will be replaced with at least one 600 MW combined cycle natural gas unit. A capacity shortfall is expected in 2024 with continued load growth beyond 2020 and additional capacity will be required. By 2020, the renewable portfolio will have been built to replace Navajo and will continue to grow to meet the 50% RPS mandate. Energy efficiency, demand response, Q3 term purchases, and additional combined cycle gas-fired units will assist in supporting new renewables.

Q3 term purchases are used to satisfy planning reserve margins in the summer months, where capacity is needed only over a short period of time, typically over a few weeks of the summer months. The planned addition of Q3 term purchases helps to limit the amount of capital intensive resources that would be necessary to supply these short-term capacity shortfalls. Continual evaluation of future market conditions will be needed to ensure that the market possesses adequate depth and reasonable pricing so that these term purchases can be relied upon to fill system capacity needs.

In Case 2, with the Navajo Generating Station (NGS) divested in 2016, the 500 MW combined cycle gas-fired unit and demand response resources are fulfilling two purposes, (1) replacing additional capacity and energy that would have been provided by NGS and (2) providing dispatchable resources to enable the integration of increasing amounts of intermittent renewable energy as these resources are ramped up from the current 20% RPS to 33% RPS in 2020 and 50% in 2030.

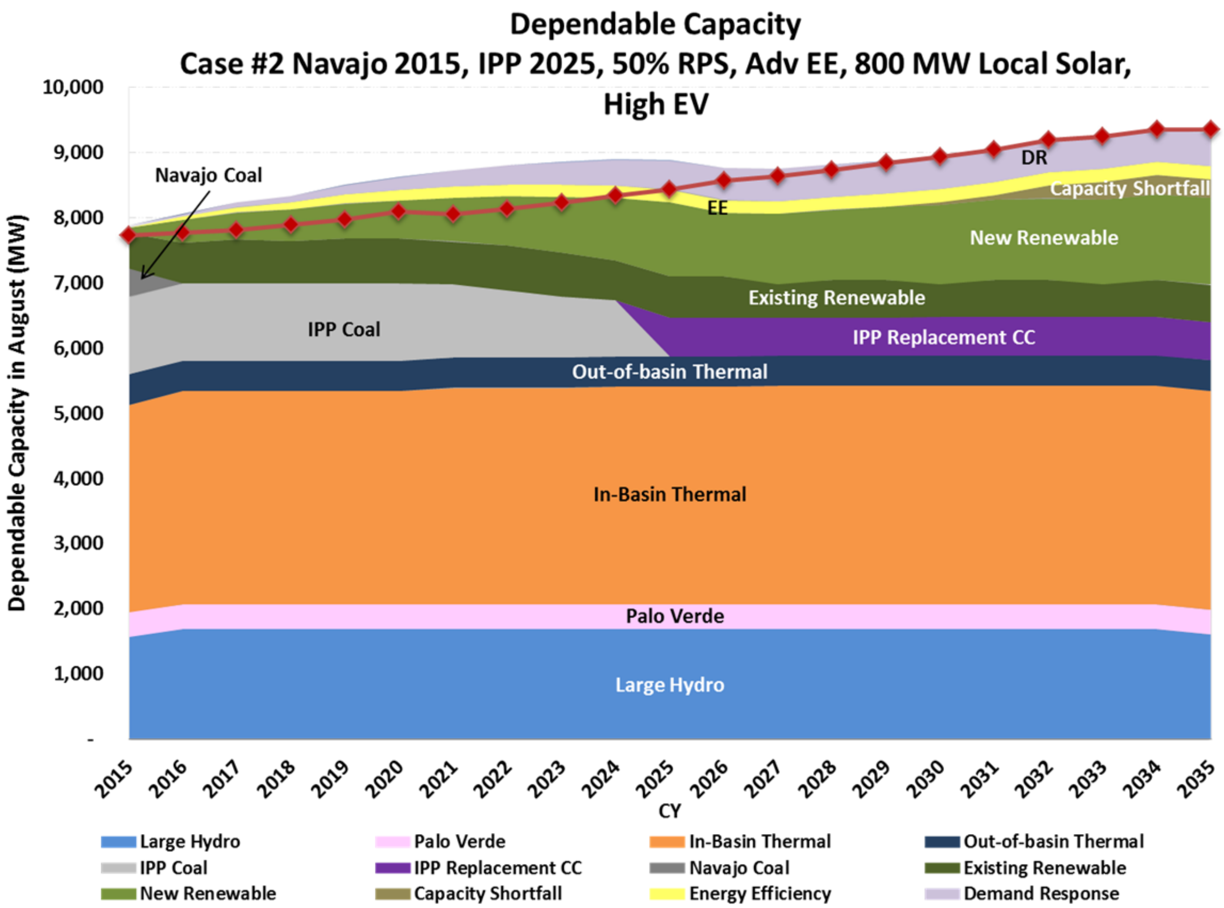


Figure 4-6. Dependable capacity profiles, Case 2 (also 6)

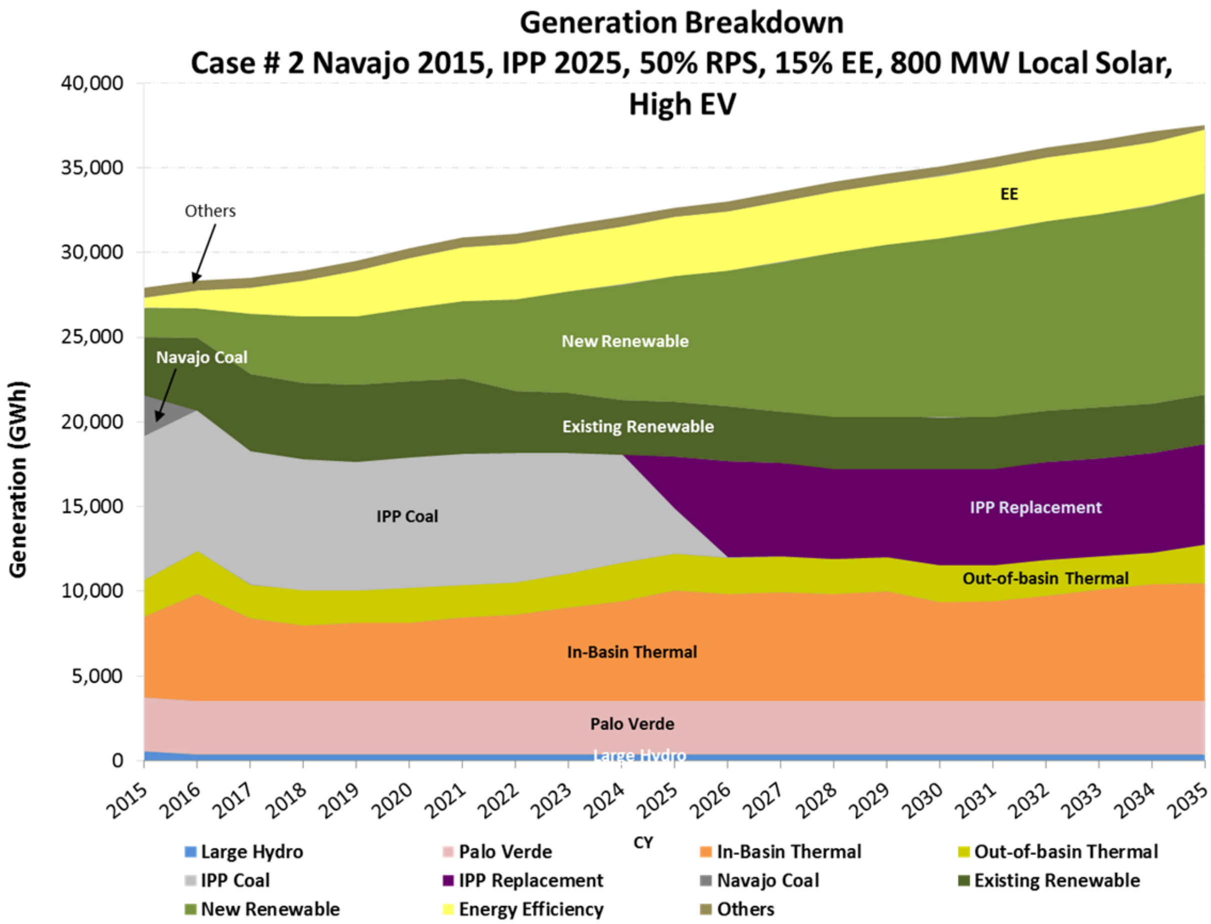


Figure 4-7. Generation mix profiles, Case 2 (also 6)

When considering resource recommendations to meet future resource adequacy requirements, the IRP follows a loading order that is consistent with the California Energy Commission's Loading Order for Electricity Resources by increasing energy efficiency and demand response first, followed by renewable and distributed generation resources, then by clean fossil-fueled generation. However, reliability is the first priority followed by cost effectiveness of these resources and attainment of environmental goals, which may result in adjustments to the loading order. Cost effectiveness and environmentally sound principles are considered in resource adequacy planning.

4.3.2 GHG Emissions Considerations

The primary objective of coal replacement is to reduce overall GHG emissions. Energy produced from coal emits approximately twice the amount of GHG emissions, as compared to energy produced from natural gas. The reductions of GHG emissions are reflected in the production cost model simulations. Figure 4-8 illustrates a comparison of the resulting GHG emission levels of the two cases. Early replacement of IPP results in an average of 5.07 MMT over two years. GHG reductions are accelerated in Case 2, with the replacement of IPP, prior to the expiration of existing power contracts with these facilities. Case 1 represents the normal course of emissions reductions with no early replacement. Reduction levels are eventually reached in both cases in 2027 for IPP, when SB 1368 essentially prohibits the import of energy produced from coal, after existing power contracts expire.

GHG emissions levels for 2014 are 14.9 MMT, which is 17 percent below 1990 levels due to the elimination of Mojave and Colstrip coal plants, completed repowering of units at Haynes and Valley generating stations, with cleaner natural gas-fired replacements, and increased renewable generation from 3% in 2003 to 20% in 2014. Using Case 1 (Navajo divestiture in 2016, IPP replacement in 2027) as a baseline, early replacement of IPP in Case 2 results in approximately 5.07 MMT less GHG emissions between 2025 and 2027. Over the next 20 years, the Power System is expected to reduce its GHG emissions to approximately 60 percent below 1990 levels These GHG emission reductions are shown below in Figure 4-8.

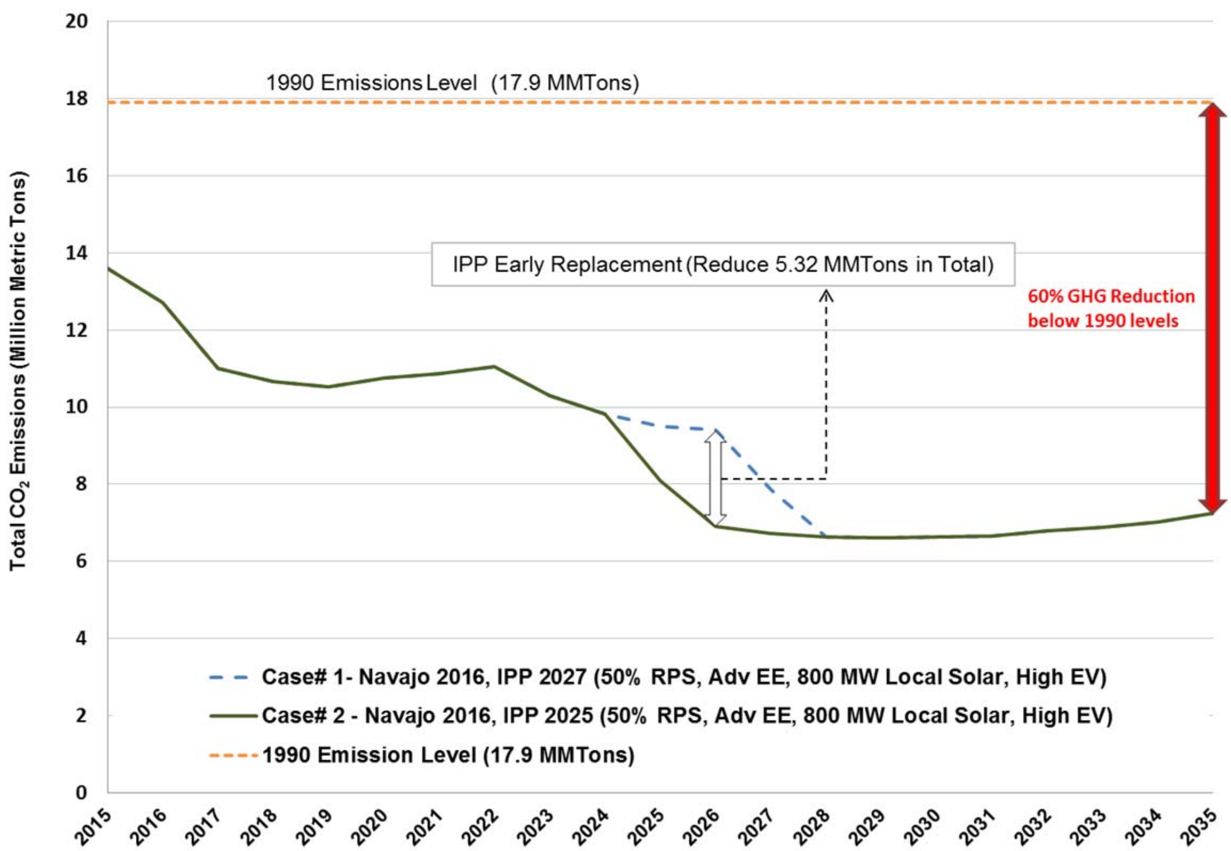


Figure 4-8. GHG emissions comparison by calendar year.

Emissions levels for advanced renewable and energy efficiency cases, Cases 3 through 7, were also evaluated and are shown in Figure 4-9. An increase in local solar from 800 MW to 1,000 MW only slightly reduces the GHG emission level by 0.1 MMT in 2030, as illustrated by Cases 5 and 7 in the figure. Increasing the renewable portfolio standard level from 33 percent to 50 percent by 2030 would result in an annual GHG emission level reduction of approximately 1.45 MMT in 2030, which is equivalent to removing 278,000 cars from the road. Increase transportation electrification from base to medium and base to high would result in a net annual GHG emission level reduction of approximately 0.64 and 1.28 MMT in 2030, respectively. Although emissions generated by LADWP would increase to supply electricity for transportation, the overall net emissions in the Los Angeles Basin would decrease due to petroleum fuel replacement through transportation electrification. For reference purposes, the CARB emissions allocation for LADWP, as part of the AB 32 Cap and Trade program implemented in 2013, is included in Figure 4-9. The emissions level without contributions from EE and RPS are also shown to provide a baseline to illustrate the significant GHG reductions from investments in clean resources.

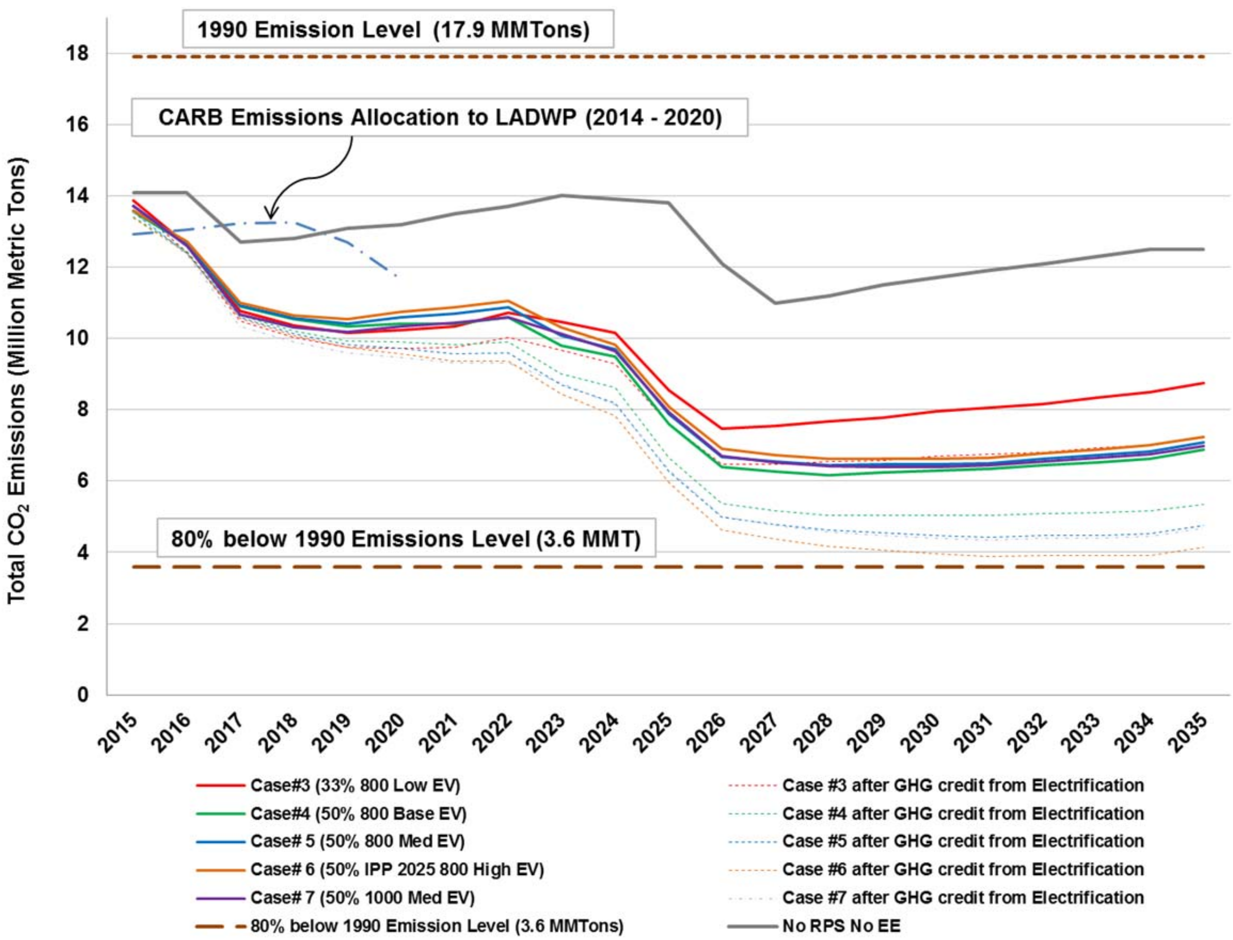


Figure 4-9. GHG emissions comparison for Advanced Renewable and Local Solar cases by calendar year, with and without CO2 savings from Transportation Electrification.

The 2015 IRP continues to investigate the impact of fuel switching/electrification of the transportation sector with higher expected load growth as an opportunity to absorb higher levels of increased renewable energy and local solar and reduce GHG emissions. Cases 4, 5, and 6 (50 percent RPS with 800 MW local solar) were analyzed with low, medium, and high levels of electrification, respectively. Case 7 (50 percent RPS with 1,000 MW local solar) was matched with a medium level of electrification. Increased electrification of the transportation sector would provide an opportunity for load shifting and absorbing over-generation from renewable resources by promoting electric vehicle charging during times of over-generation, when increased levels of solar results in load exceeding demand. In addition, the overall GHG emissions in the Los Angeles area would significantly decrease due to higher levels of electrification.

The SCAQMD emissions sources show that the pollution from gasoline and diesel passenger vehicles is greater than that of coal fired generation, as shown in Figure 4-10. LADWP's current resource mix has the carbon intensity of less than half that of passenger vehicles using an equivalent energy basis. LADWP's future resource mix in 2026 will have the carbon intensity of less than a quarter of passenger vehicles. Based on SCAQMD emission sources, transportation and off-road vehicles currently accounts for approximately 60 percent of the SCAQMD criteria pollutants in the Los Angeles Basin and this percentage will increase over time as LADWP continues to transform its resource mix to eliminate coal, and increase renewables and energy efficiency. SCAQMD criteria pollutants include VOC, NOx, CO, SOx, and PM 2.5, among others. In addition, the California Air Resources Board reported in 2012 that the transportation sector accounts for 37 percent of CO2 emissions, whereas In-State Electric Generation accounts for 11 percent. Fuel switching/electrification of the transportation sector could potentially have a significant impact in reducing the overall GHG levels and other criteria pollutants in the Los Angeles basin.

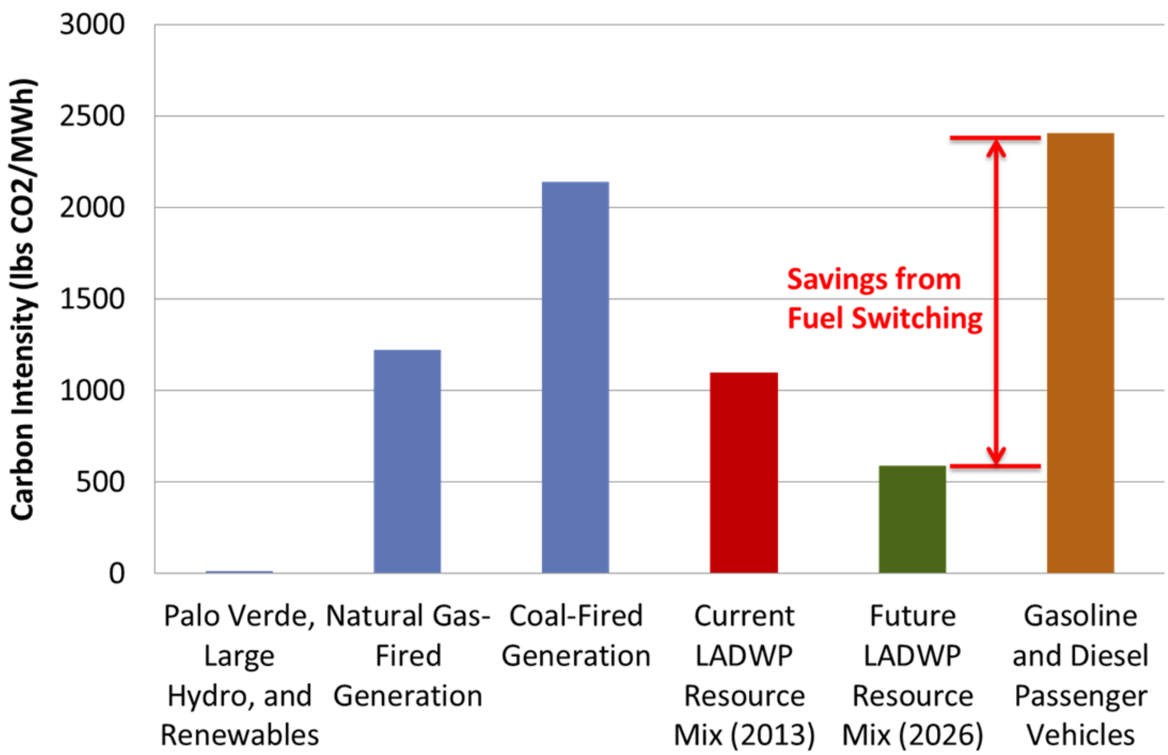


Figure 4-10. Carbon Intensity of Various Sources

AB 32 includes a goal of 80 percent GHG reduction below 1990 levels by 2050. Hypothetically, if LADWP is able to promote electrification of the transportation sector and claim the associated GHG savings credit, LADWP will be within less than 1 MMT of meeting the AB 32 goal of 80 percent GHG reduction below 1990 levels by 2035, as shown in Figure 4-9. Cases 3 and 4, which includes 33 and 50 percent renewable portfolio standard, respectively, both incorporate a base electrification assumption adopted by the California Energy Commission Integrated Energy Policy Report's electric vehicle growth projection. The GHG savings from base case electrification (Case 4) is equivalent to an annual savings of approximately 1.5 MMT in 2035. Case 5 and 7, assumes medium electrification of the transportation sector, an increase of 50 percent above the base electrification assumption and results in an annual GHG savings of approximately 2.25 MMT in 2035. Case 6, assumes high electrification of the transportation sector or double the base case electrification, and results in an annual GHG savings of approximately 3.0 MMT in 2035. The GHG savings achieved from an assumed base case electrification of the transportation sector is comparable to the GHG savings that results from increasing RPS levels from 33 percent to 50 percent – 1.5 MMT versus 1.7 MMT, respectively. Medium and high levels of electrification would achieve even greater GHG savings.

In addition to GHG, Oxides of Nitrogen (NO_X) were also quantified within the production model. Figure 4-11 summarizes NO_X emissions for each of the two coal cases considering all generation resources including resources both within, and outside of the State. With the installation of SCR equipment since 1989, NO_X emissions from in-basin generation has been reduced by 90 percent and now represents less than 0.1 percent of all NOx emissions within the SCAQMD.

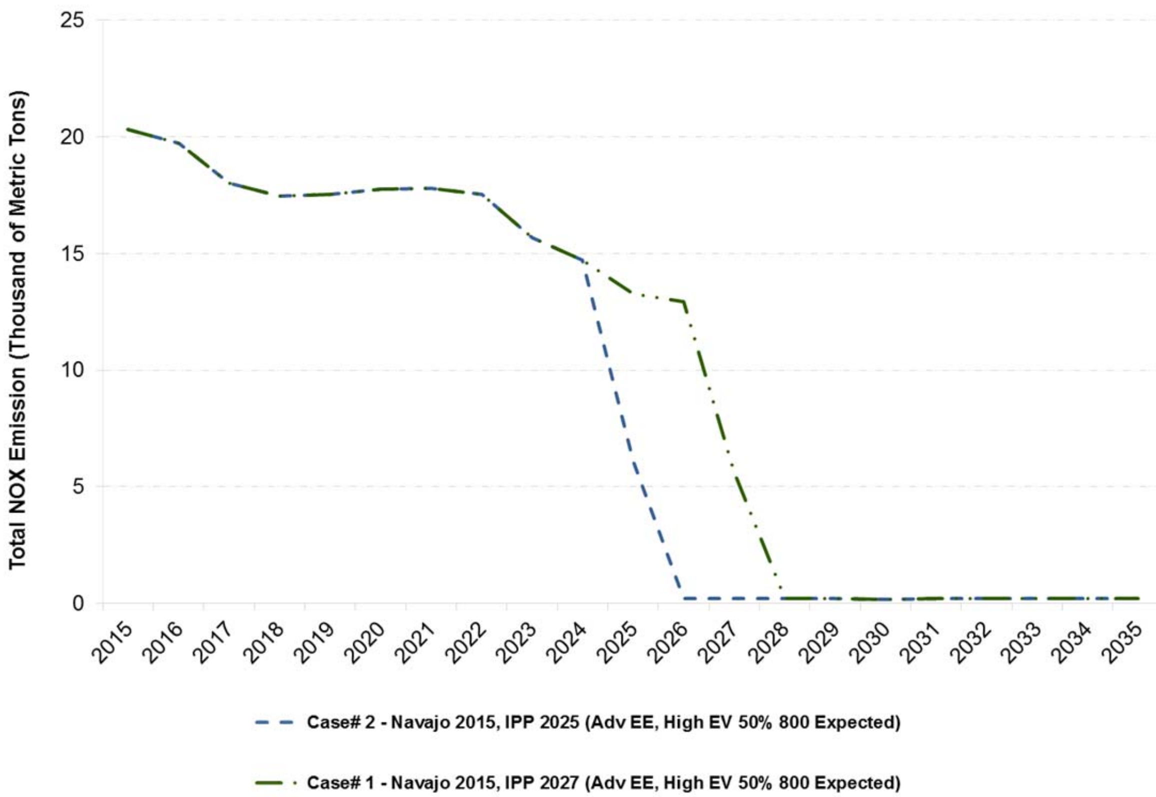


Figure 4-11. Total NO_X emissions comparison by calendar year

4.3.3 Economic Considerations

The economic considerations for the coal and advanced renewable and energy efficiency cases included a comparison of fuel and variable costs. The coal cases were further subjected to fuel price stress tests to account for potential future price volatility which affects possible ranges of bulk power costs related to coal replacement. Reliability and regulatory revenue requirements are also addressed to quantify the impact of these programs on future total Power System costs.

4.3.3.1 Cost Comparison Between Advanced Renewable and Energy Efficiency Cases 3 through 7

Two levels of Renewable Portfolio Standard (RPS) were considered and comprised a 33 percent and 50 percent RPS. The 33 percent RPS case, which is comprised of advanced energy efficiency, 800 MW local solar, and base electrification, was used for cost and GHG comparison purposes with the 50 percent RPS cases. The 50 percent RPS cases that were analyzed all included advanced energy efficiency, 800 MW or 1,000 MW local solar, and varied levels of transportation electrification. Transportation electrification resulted in higher electricity sales from electric vehicles with a commensurate increase in RPS sales of 734 GWh by 2035 which increases the overall cost. The increased cost from higher RPS levels is primarily attributed to higher energy costs from renewables and increased costs associated with upgrading the transmission system to integrate more renewables with the assumed capital investments required in Cases 4 through 7, estimated at $1.3 to $1.4 billion by 2035. The RPS costs of the various RPS cases are show in Figure 4-12 below:

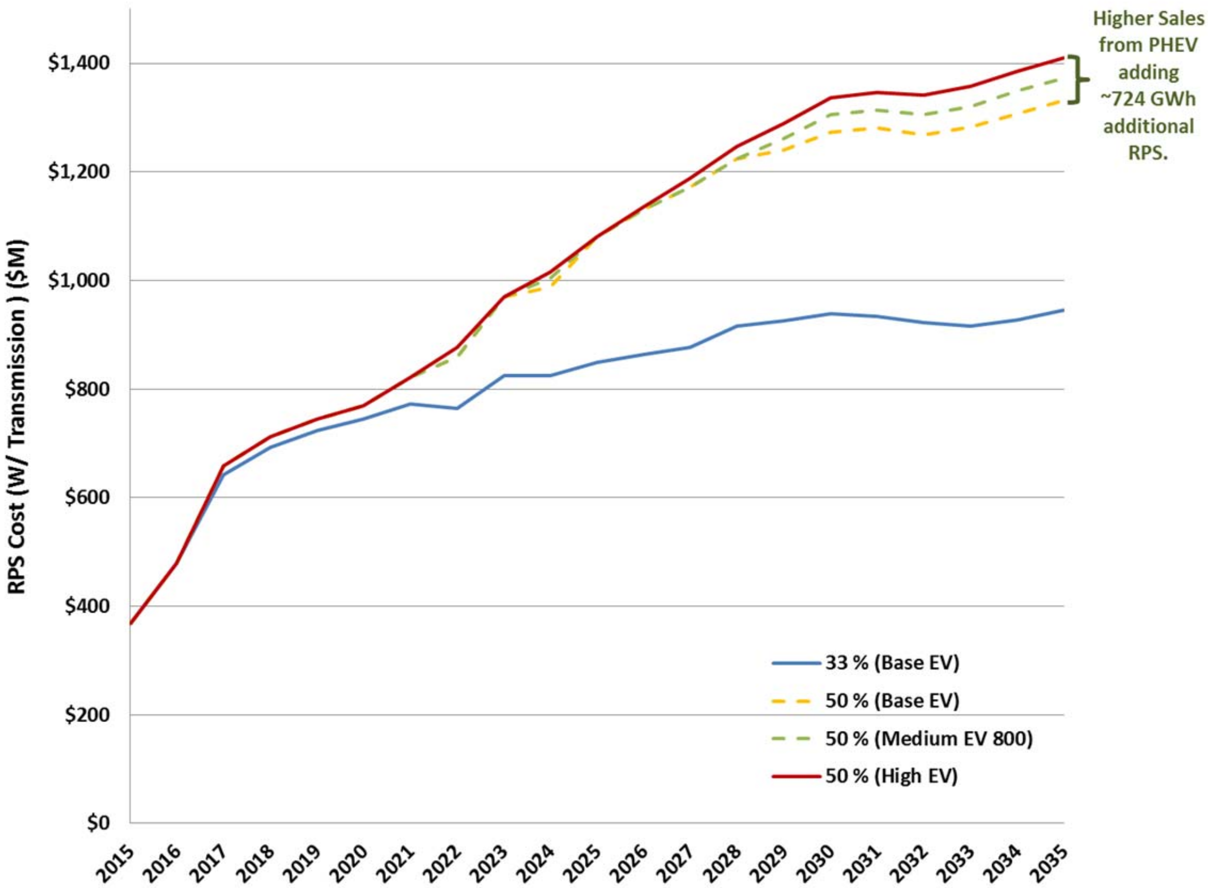


Figure 4-12. RPS Cost Comparison (with transmission upgrade costs) in $ (millions)

As a strategy to absorb increased levels of renewable energy in the advanced renewable and energy efficiency cases, the 50 percent RPS case with 800 MW local solar includes a base, medium, and high level of electrification of the transportation sector which results in increased sales. A medium level of electrification would result in $470 million in estimated energy sales in 2030. Similarly, a high level of electrification would result in $627 million in estimated energy sales in 2030, as shown in Figure 4-13. As a result, the overall cost of RPS energy increases due to energy sales from electric vehicles.

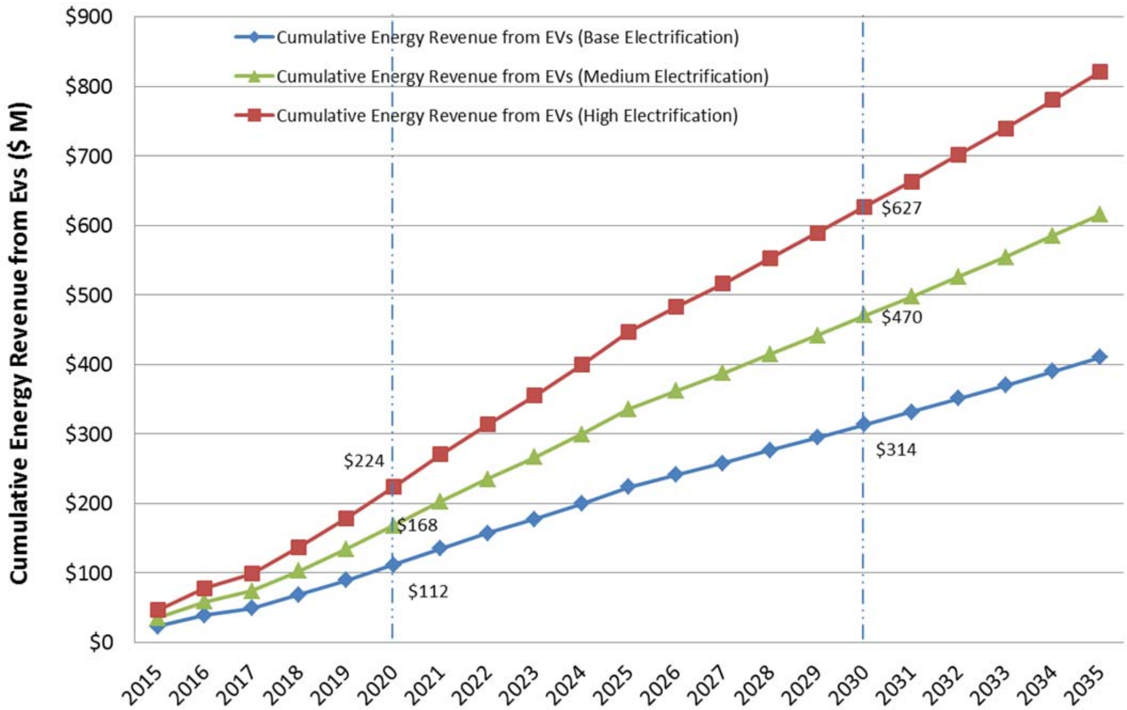


Figure 4-13. Cumulative Energy Revenue due to Electric Vehicle Growth ($ in millions)

In comparing the cost between various advanced renewable and energy efficiency cases, the amount of over-generation is a major economic consideration. As the level of RPS increases, over-generation will occur, which is the amount of generation that exceeds customer load demand, particularly on sunny days where load demand is correspondingly low. This energy must be either be stored or sold in order to maintain reliability on the Power System. Based on LADWP's current planned resources, the amount of over-generation expected from the 50 percent RPS case is 69 GWh in 2029and is expected to be manageable with LADWP's current resource mix. This is illustrated in Figure 4-14 below:

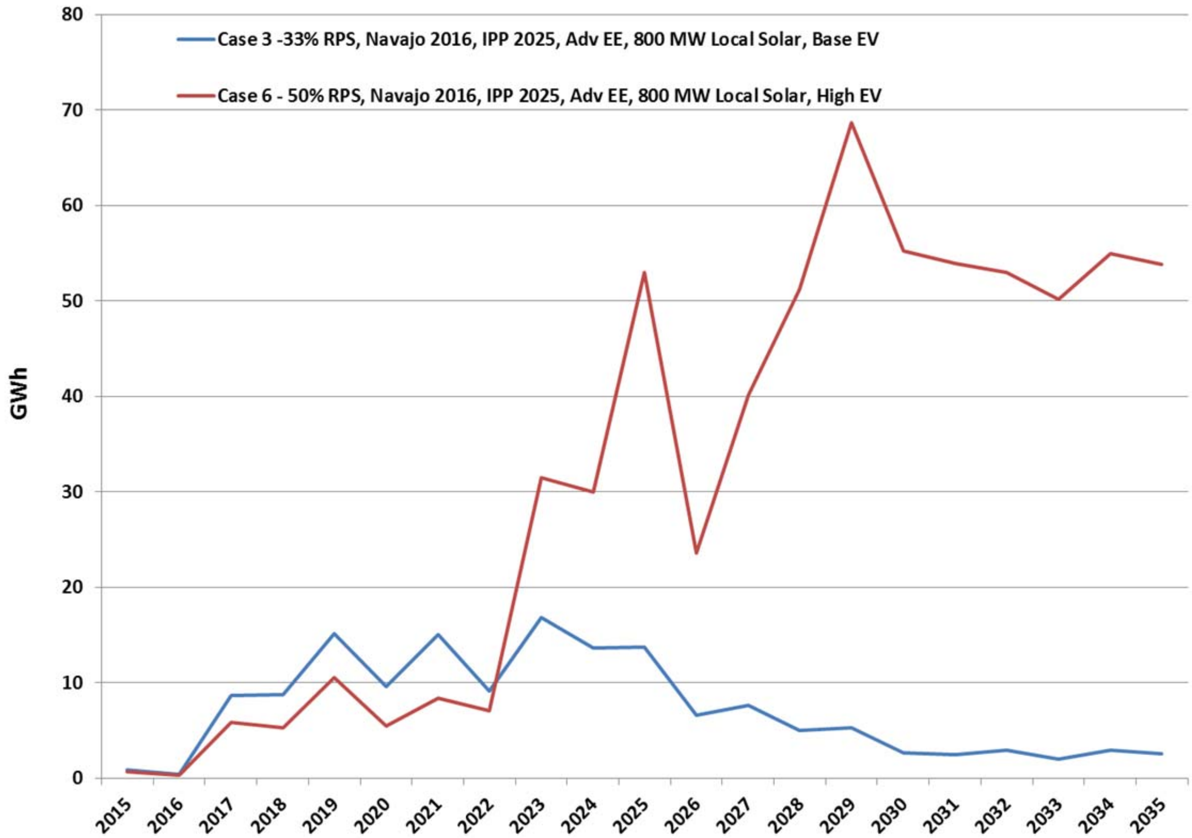


Figure 4-14. Advanced Renewable Portfolio Standard Cases, Over-generation Energy in GWh

Based on the findings of a recent study prepared in January 2014 by the consulting firm E3 entitled, "Investigating a Higher Renewables Portfolio Standard in California", over-generation levels experienced by the 5 largest electric utilities was found to be 0.2%, 1.8%, and 8.9% of all in the 33%, 40%, and 50% RPS levels, respectively, considering a high solar scenario. The amount of over-generation on LADWP's system is expected to be lower than that experienced by other California utilities. The reason for the lower expected over generation most likely lies in the development of a RPS portfolio that includes a diverse mix of renewable resources. LADWP owns and operates a large pumped hydro-electric facility, which has the capability of pumping water to store energy during over-generation events. As a result, LADWP will have capability to absorb over generation with increased RPS levels. Whereas LADWP is expected to experience 0.5 percent over-generation in the 50 percent RPS case, the E3 study revealed 8.9 percent over-generation for the State of California with 50 percent RPS as shown in Figure 4-15 below.

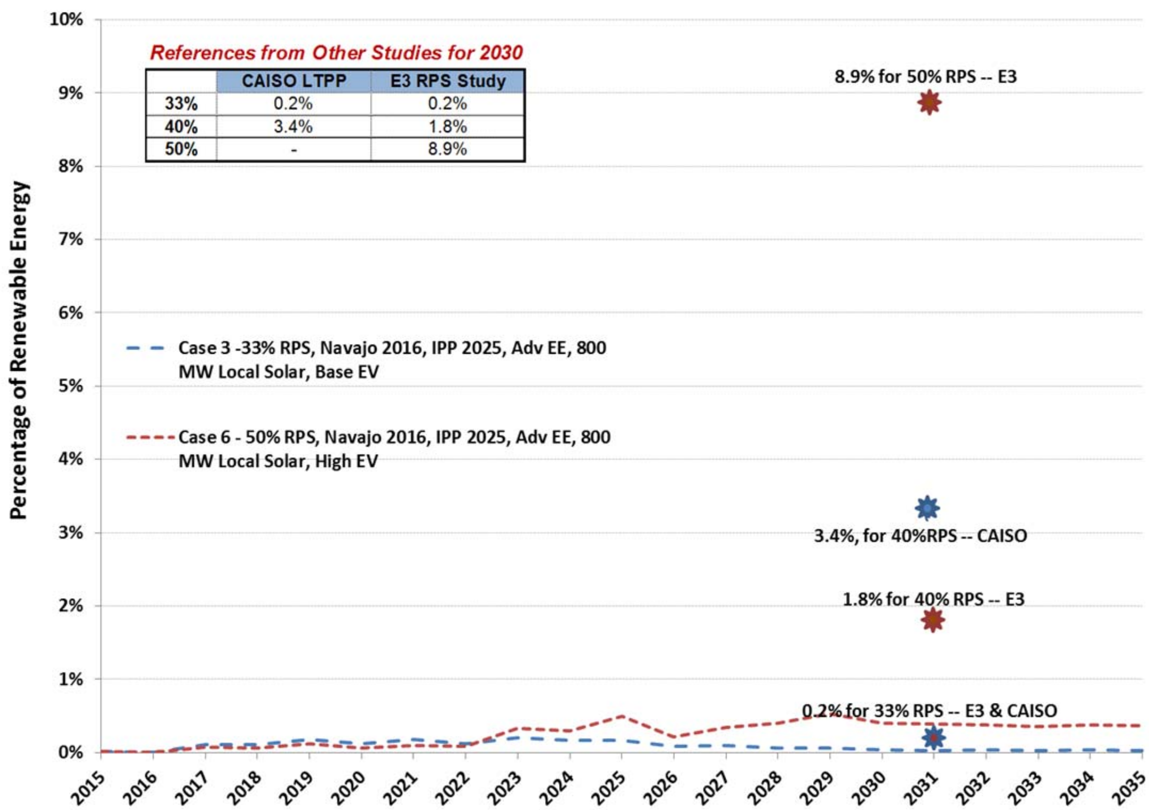


Figure 4-15. Advanced Renewable Portfolio Standard Cases, Over-generation Energy Comparison in GWh

Based on the amount of potential over-generation from the various advanced renewable cases, a cost range attributed to the over-generation can be estimated. Over generation from the 50 percent RPS case will potentially cost $30 million in the year 2029. These cost estimates are highly speculative at this time because they depend on market conditions, transmission constraints, predominance of solar resources within the renewable portfolio, overall RPS levels reached in California and neighboring states, and the availability of energy storage to help reduce over generation.

4.3.3.2 Cost Comparison Between RPS Cases

The total fuel and variable costs for the 33 percent RPS, 50 percent RPS with 800 MW local solar, and 50 percent RPS with 1,000 MW local solar cases are shown in Figure 4-16 below. The 50 percent RPS cases result in a higher fuel and variable cost compared to the 33 percent RPS case, primarily due to greater renewable energy program cost from an increased renewable portfolio standard. The natural gas price used in the production model was obtained from Platt's 20-yr long-term natural gas price forecast and is also considered as the expected natural gas price in the stress test study in Section 4.3.3.3.

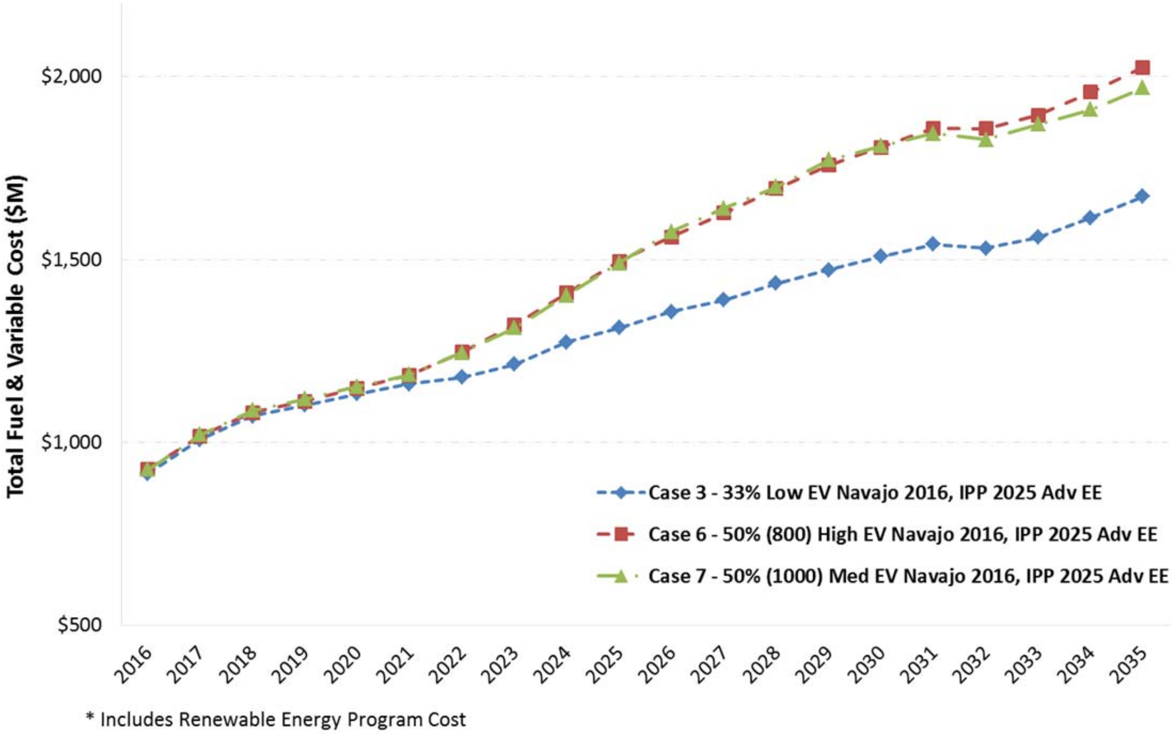


Figure 4-16. Total fuel and variable cost comparison by fiscal year (Includes renewable project costs).

Replacement of IPP results in higher fuel and variable O&M costs, as less expensive coal is replaced with relatively higher cost gas-fired energy. In reality, resources replacing IPP consist of a blend of new energy efficiency, new renewable energy, and new gas-fired combined cycle units. The costs associated with gas-fired replacement resources for IPP can be better seen in Table 4-4. Because the two coal cases analyzed have the same renewable portfolio, the cost differences between the cases can only be attributed to increased gas-fired generation costs; therefore, the costs shown in Table 4-4 do not include any incremental costs associated with new renewable resources.

Table 4-4. Increased incremental capital, fuel, and variable O&M costs related to replacement of IPP by fiscal year

Delta - IPP Early Conversion Study (Case 2 - Case 1) ($M) [FYE]	2026	2027	Total
Capital and Fixed O&M Cost			
IPP Replacement Cost	$43	$44	$87
Natural Gas Pipline Cost	$4	$4	$8
Subtotal			
Fuel and Emission Cost	$198	$203	$401
Variable O&M Cost	$3	$3	$7
Total Cost Delta	**$249**	**$255**	**$ 503**

4.3.3.3 Fuel Price Stress Test

Coal purchased by LADWP over the last 30 years has traditionally been provided primarily through long-term coal contracts, where future costs are reasonably predictable. Additionally, a small portion of LADWP's coal supply is provided through short-term coal purchases subject to market fluctuations. Natural gas prices have become the primary concern when assessing future cost impacts. Replacing Navajo and IPP Generating Stations with gas fired generation would expose our customers to fuel markets which may result in higher or lower fuel costs, which are much less predictable.

Fuel price is a key contributing factor to the overall Power System cost and directly varies to the quantity of natural gas—increased natural gas usage would result in an increased exposure to fuel price volatility. In comparing the various IRP case scenarios, natural gas usage for the various IRP cases must be considered in order to limit fuel price volatility. Whereas Case 1 considers the contractual coal expiration dates for energy delivery from IPP coal, Case 2 considers early coal replacement of IPP, which increases the amount natural gas required to replace energy from coal with energy from natural gas. The natural gas usages for Cases 4 through 7 are less than Case 3 due to an increase from 33 percent to 50 percent RPS by 2030, which increases the overall energy served by renewable resources thereby requiring less energy from natural gas. Figure 4-17 below illustrates the natural gas usage for the various IRP cases considered, all of which impacts economic risk:

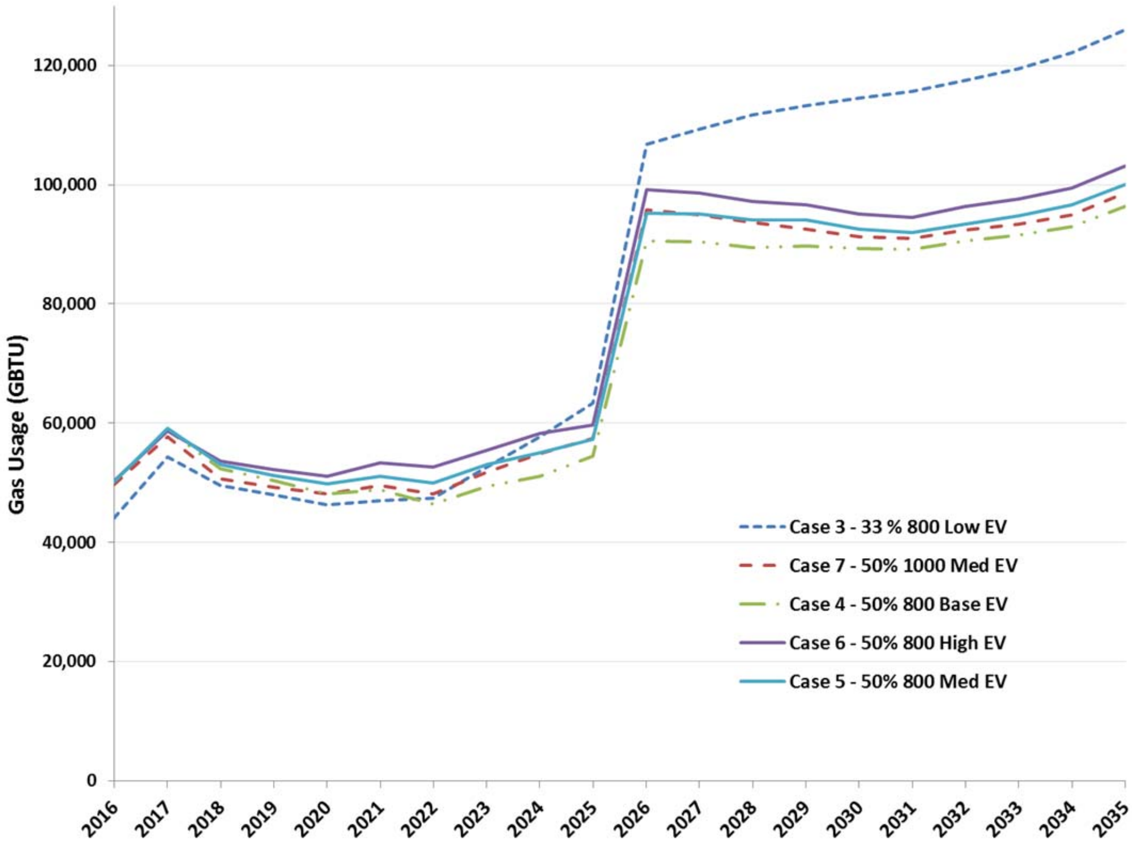


Figure 4-17. Natural Gas usage for Cases 1 through 5 and Recommended Case.

Fuel price volatility from natural gas usage is less apparent in the 50 percent RPS cases compared to the 33 percent RPS cases due to reduced natural gas consumption. The importance of stress testing the model results of the two coal cases is to determine the range of exposure to economic risk due to fuel price volatility. Historically, natural gas prices tended to be volatile and unpredictable and LADWP employs hedging techniques to constrain volatility within acceptable ranges. However, diversification of fuel resources is also an effective means to mitigate economic exposure to a single fuel source. For example, renewable energy supplies a necessary hedge against increased fuel price exposure and decreases the cost of fuel for about 23 percent of our current fuel supply.

Realizing the need for accurate fuel price forecasts, LADWP utilized Ventyx to provide natural gas price, high and low forecasts to stress test future power production costs as shown in Figure 4-18. Also included in the high and low range fuel forecasts were high and low coal prices received from LADWP's External Generation Group based on the expertise and experience of the Coal Supply Group.

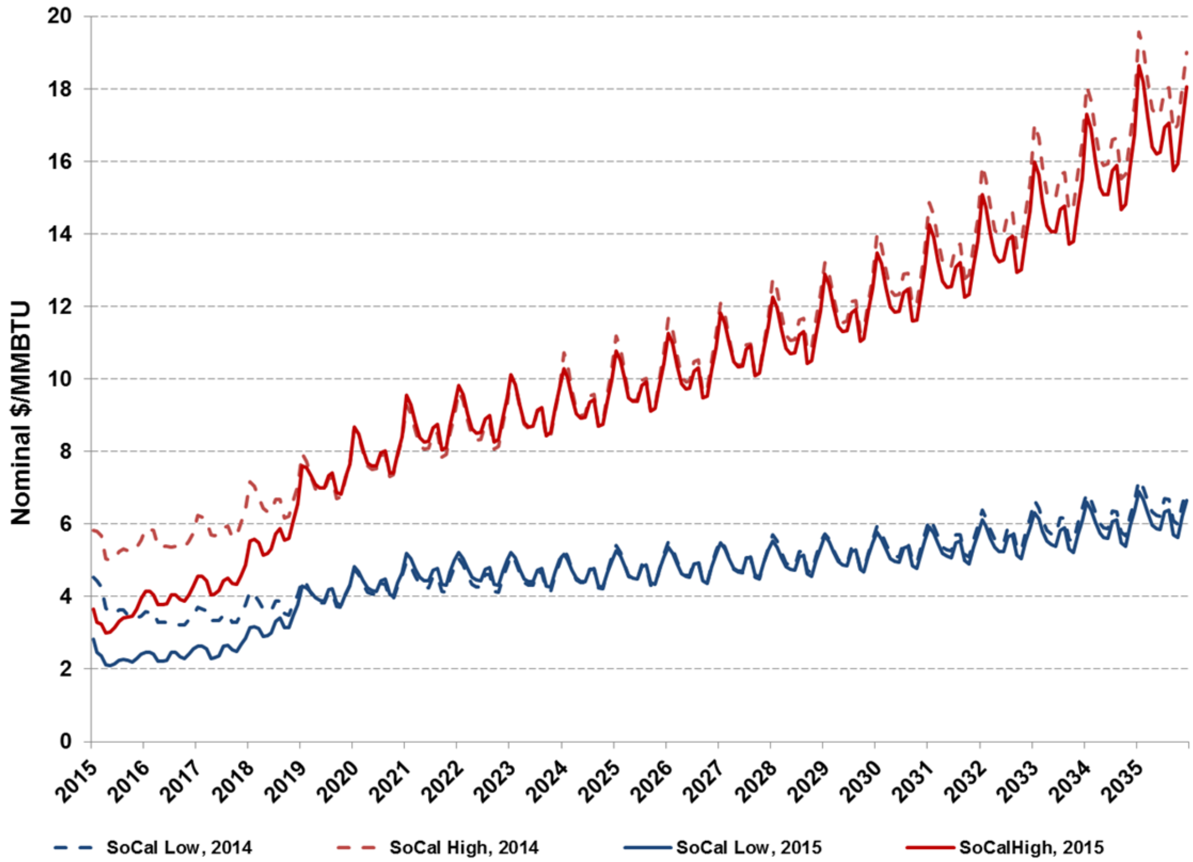


Figure 4-18. High and low natural gas price forecasts (So Cal Gas) for 2014 and 2015.

The natural gas price curves furnished by Ventyx show a greater potential range between high and expected gas fuel prices, and less risk of experiencing lower than expected prices. This is wholly consistent with past historical gas prices which are shown in Figure 4-19: the relative shape of the curve is asymmetrical with the forward tail (higher prices) extending further away from the mean of the curve. Figure 4-19 also shows that over the last five years, the probability distribution has a much greater concentration around the mean price value, indicating lower volatility in gas prices as compared to the ten year comparison period. This lowered gas price volatility can also be seen in Appendix H, Figure H-1.

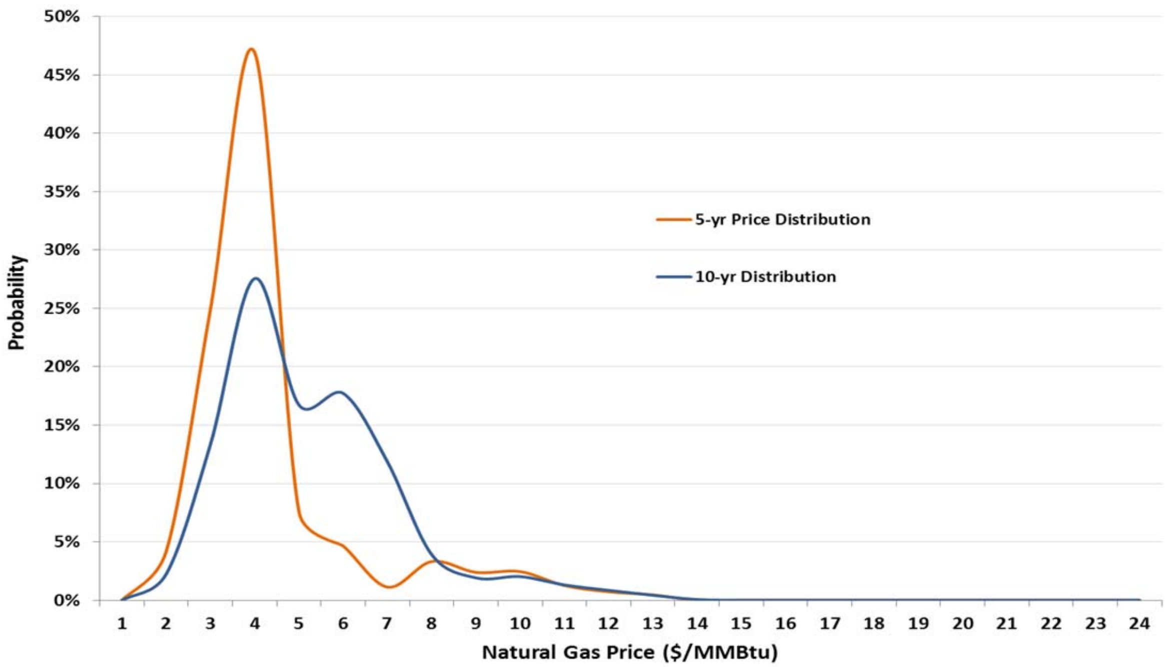
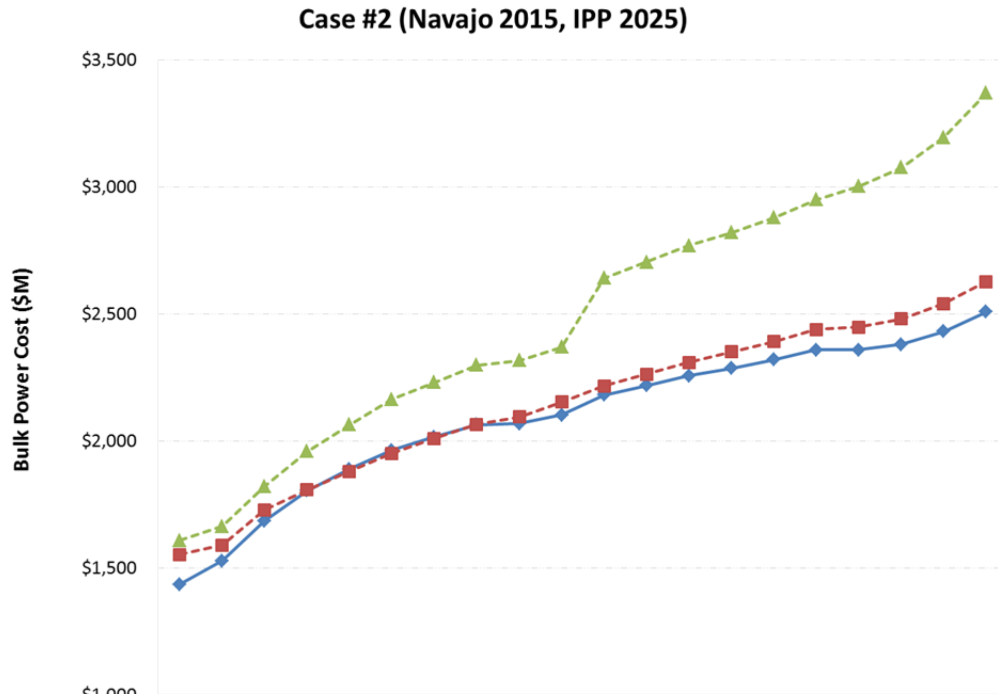


Figure 4-19. Historical distribution of natural gas prices (SoCal, 2003 through 2013).

The high and low fuel price ranges were then incorporated into the three strategic case model runs. The chart shown in Figure 4-20 displays the results of bulk power costs for the early coal case 2. The wider range from the high fuel case to the medium fuel case indicates increased exposure to risk from the higher fuel costs.



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Case# 6 (50% 800 HighEV (Low))	$1,436	$1,529	$1,686	$1,804	$1,890	$1,963	$2,016	$2,064	$2,068	$2,102	$2,182	$2,218	$2,257	$2,285	$2,319	$2,358	$2,359	$2,380	$2,431	$2,508
Case# 6 (50% 800 HighEV (Expected))	$1,553	$1,590	$1,729	$1,808	$1,881	$1,952	$2,009	$2,064	$2,094	$2,153	$2,216	$2,262	$2,309	$2,351	$2,391	$2,439	$2,448	$2,481	$2,541	$2,627
Case# 6 (50% 800 HighEV (High))	$1,609	$1,664	$1,822	$1,959	$2,064	$2,163	$2,230	$2,298	$2,317	$2,369	$2,642	$2,704	$2,769	$2,821	$2,879	$2,949	$3,002	$3,076	$3,195	$3,370

Figure 4-20. Bulk power cost comparison - high, low, and expected fuel prices.

An analysis of the effects of fuel price volatility was performed for the two coal cases. With the early divestiture of Navajo in 2016 and the IPP coal replacement expected by June 15, 2025, increased bulk power costs are expected with the replacement of each of these resources.

Elimination of coal involves the switch to more natural gas generation, which has higher fuel price volatility compared to coal. This higher volatility will increase the risk of fuel cost changes in the future and careful evaluation is needed, when comparing the different case scenarios.

To help manage natural gas fuel price volatility, LADWP employs financial hedges for up to ten years, and physical hedges for up to five years. LADWP finalized a revised hedging strategy in 2014.

By 2025, Case 2 shows NGS will have been retired and IPP would be replaced with one 600 MW natural gas combined cycle units and another 600 MW alternative resource. With all coal generation being eliminated, the exposure risk of much higher spending on fuel and variable costs will be present.

Increased risk exposure from high fuel costs may translate into higher customer electric rates. Today, coal costs represent approximately 50 percent of overall fuel expenditures and will average 40 percent annually between 2015 and 2025. Coal expenditures will gradually drop after 2023 before reaching zero percent in 2025, when IPP coal is replaced, and future fuel price increases will be based solely on natural gas and nuclear fuel sources.

4.3.3.4 Reliability and Regulatory Revenue Requirements

Bulk Power costs discussed previously make up less than half of the cost to support the electric power system. Continued investments in transmission, distribution, and generation resources are required to maintain a reliable electric system. While specific regulatory and reliability programs such as RPS, OTC, and PSRP attract the most attention, investments in these programs are a subset of the generation, transmission, substation, and distribution system that comprises the Power System. Besides fuel and inflation costs, these reliability and regulatory programs are the largest factors driving increases in Power System costs.

The revenue requirements of these programs are further illustrated in Figure 4-21 and Table 4-5. Today, these reliability and regulatory programs comprise 32% of all Power System costs and in 2024 these same programs will grow to approximately 52%.

Table 4-5 shows the breakdown of these reliability and regulatory costs with RPS and PSRP programs clearly being the major drivers behind overall increases in Power System costs. The importance of adequately funding of these programs through consistent revenue increases over time is essential to achieving the goals of reliability, environmental stewardship, and maintaining competitive rates.

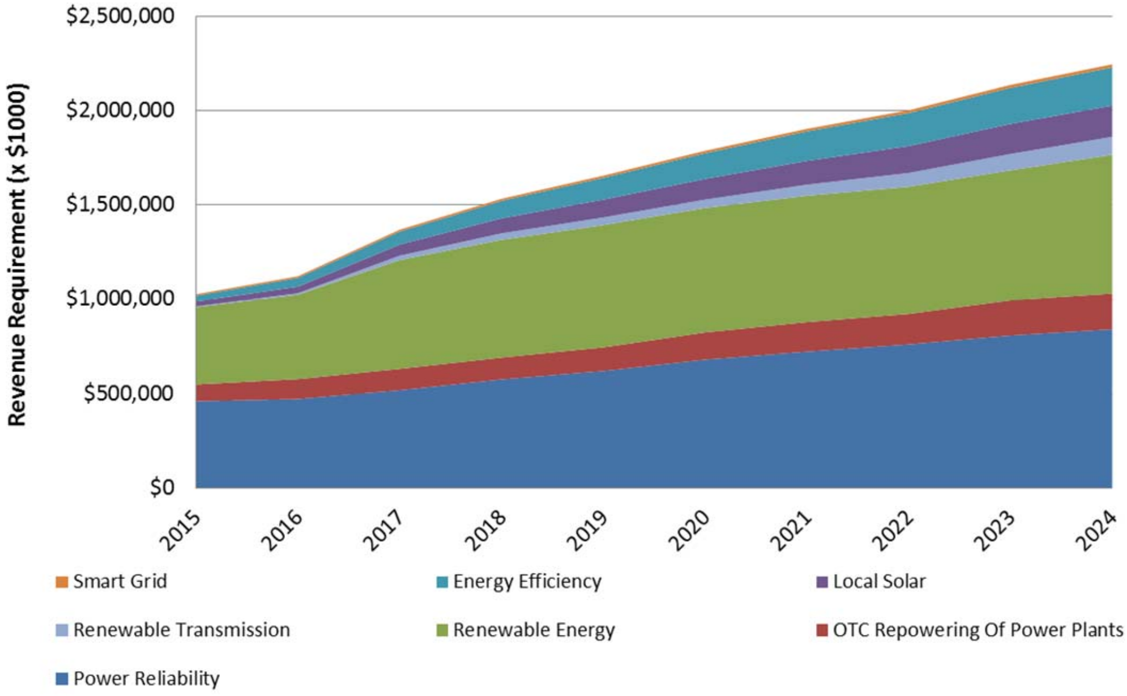


Figure 4-21. Annual revenue requirement for reliability and regulatory programs for fiscal year ending 2015 through 2025.

Note: Chart is subject to change due to technology development, commodity price fluctuations, and policy changes

Table 4-5. Annual revenue requirements of Power System programs, fiscal year ending 2015 through 2024 (x$1000) – Recommended Case

(FYE)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Power Reliability										
Debt Service	$139,722	$162,867	$200,598	$239,306	$274,576	$309,608	$341,266	$370,389	$396,558	$423,433
O&M	$320,583	$309,170	$317,991	$336,703	$346,413	$371,123	$382,014	$391,408	$412,450	$418,637
	$460,305	$472,037	$518,588	$576,009	$620,989	$680,731	$723,279	$761,797	$809,009	$842,070
Sum Total 2015-2024	**$6,464,815**									
OTC Repowering Of Power Plants										
Debt Service	$88,847	$105,474	$113,692	$115,756	$125,055	$144,516	$156,658	$161,876	$186,422	$188,719
	$88,847	$105,474	$113,692	$115,756	$125,055	$144,516	$156,658	$161,876	$186,422	$188,719
Sum Total 2015-2024	**$1,387,016**									
Renewable Energy										
Debt Service	$50,411	$53,898	$59,176	$64,110	$67,669	$70,990	$74,421	$80,143	$92,447	$107,118
O&M	$27,418	$28,455	$38,693	$38,939	$40,394	$42,412	$43,155	$43,605	$42,569	$44,033
Purchased Power	$332,468	$365,165	$478,988	$521,265	$540,497	$546,654	$552,825	$550,485	$554,659	$585,253
	$410,297	$447,518	$576,857	$624,314	$648,560	$660,057	$670,402	$674,232	$689,674	$736,404
Sum Total 2015-2024	**$6,138,315**									
Renewable Transmission										
Debt Service	$3,782	$7,747	$23,294	$34,776	$40,504	$44,275	$58,670	$73,001	$86,455	$95,174
	$3,782	$7,747	$23,294	$34,776	$40,504	$44,275	$58,670	$73,001	$86,455	$95,174
Sum Total 2015-2024	**$467,679**									
Local Solar										
SB1 Debt Service	$8,818	$10,525	$12,816	$13,780	$13,996	$14,205	$14,407	$14,606	$14,789	$14,980
Community Solar Debt Service	$11,498	$12,066	$13,303	$14,807	$16,217	$17,663	$19,036	$20,440	$21,677	$22,961
FiT (Purchased Power)	$5,493	$12,484	$32,405	$50,635	$64,160	$77,984	$92,636	$107,554	$123,400	$127,945
	$25,809	$35,076	$58,523	$79,222	$94,373	$109,852	$126,079	$142,600	$159,866	$165,886
Sum Total 2015-2024	**$997,285**									
Energy Efficiency										
Debt Service	$30,813	$46,762	$68,967	$92,778	$115,571	$136,406	$156,083	$175,346	$191,118	$202,992
	$30,813	$46,762	$68,967	$92,778	$115,571	$136,406	$156,083	$175,346	$191,118	$202,992
Sum Total 2015-2024	**$1,216,836**									
Smart Grid										
Debt Service	$7,817	$8,311	$9,845	$10,961	$11,858	$12,776	$13,695	$14,622	$15,286	$15,818
	$7,817	$8,311	$9,845	$10,961	$11,858	$12,776	$13,695	$14,622	$15,286	$15,818
Sum Total 2015-2024	**$120,988**									
Basic Gen, Trans, Dist	$2,389,112	$2,385,822	$2,336,528	$2,321,959	$2,402,594	$2,441,662	$2,448,804	$2,521,527	$2,582,625	$2,482,112
	$2,209,330	$2,290,075	$2,131,234	$2,149,182	$2,164,090	$2,230,387	$2,281,134	$2,291,526	$2,314,170	$2,386,937
Sum Total 2015-2024	**$22,448,066**									
Total Power System Revenue Requirement										
	$3,237,000	$3,413,000	$3,501,000	$3,683,000	$3,821,000	$4,019,000	$4,186,000	$4,295,000	$4,452,000	$4,634,000
Sum Total 2015-2024	**$39,241,000**									

4.3.3.5 Total Power System Cost Comparisons

The total Power System cost for each case includes bulk power costs, depreciation costs related to transmission, distribution, and generation, bond debt-service, and city transfer[9] costs. These costs assume full funding of the Power System programs, including the Power Reliability Program and Energy Efficiency programs among others. Total annual Power System costs are shown in Figure 4-22 and reflect funding levels needed to ensure that the longer term IRP recommendations can be realized. The costs shown in Figure 4-22 do not attempt to represent a thorough analysis of Power System finances. The main goal of this section is to illustrate the general trend of Power System costs relative to the two coal and five advanced renewable and energy efficiency cases analyzed. With fuel being a large driver of overall future Power System costs, a sensitivity analysis was performed on Cases 1 and 2 to determine the potential range of

[9] The city transfer payment is 8% of the previous year's gross operating revenue.

costs that could be experienced. For comparison purposes, the 33 percent expected costs are included.

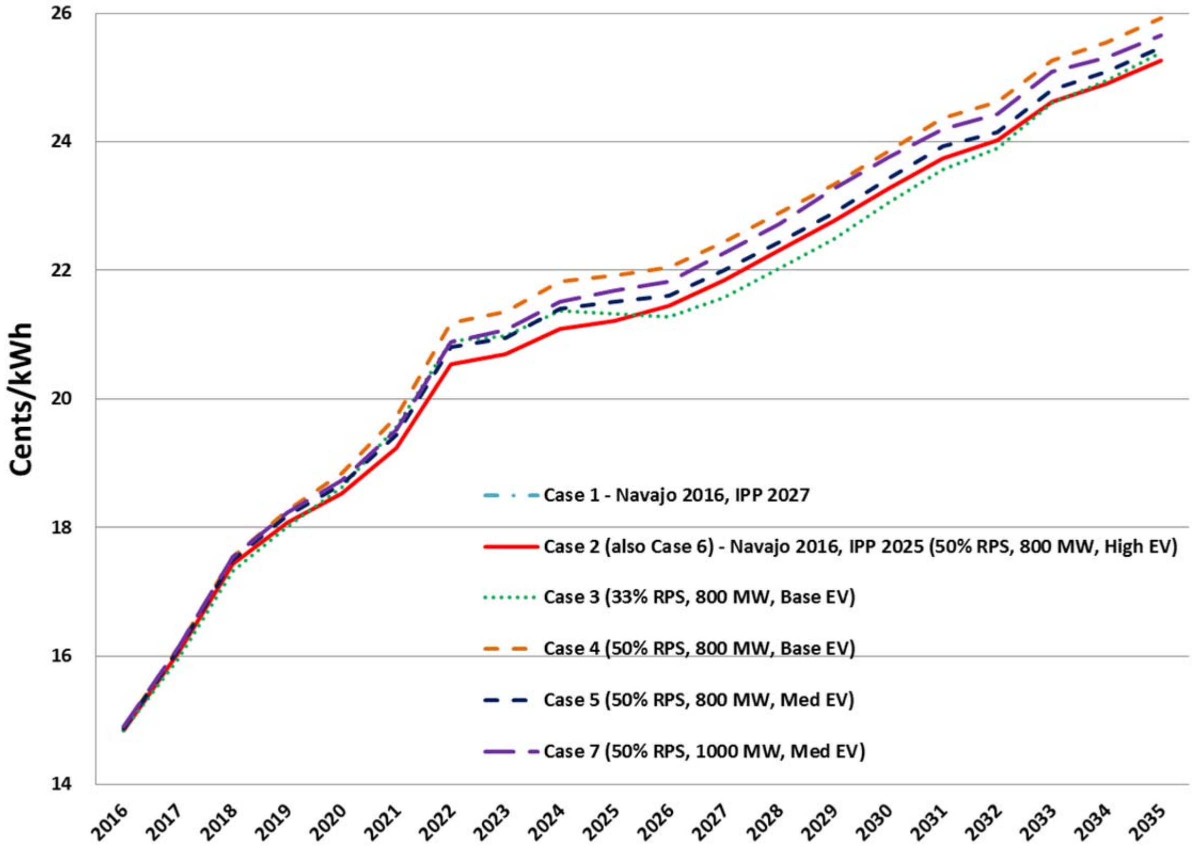


Figure 4-22. Comparison of annual Power System costs over the next 20 fiscal years.

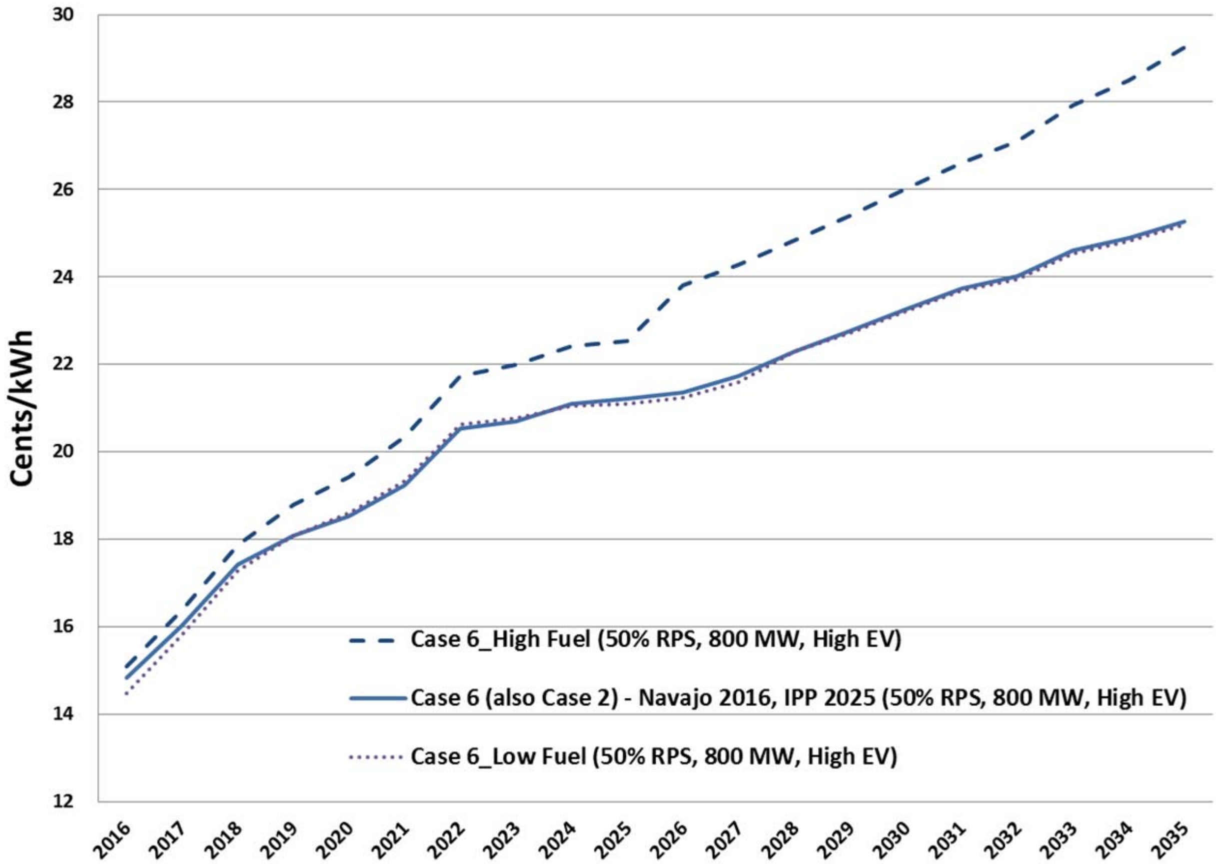


Figure 4-23. Comparison of annual Power System costs with High, Low, and Expected Fuel Price Sensitivity. (Note: Low Fuel cost and Expected Fuel Cost obtained from different forecast dates)

The cost differences between the cases are highlighted in Table 4-6, which presents the incremental revenue requirements of the two coal cases and the five advanced renewable and energy efficiency cases. For the coal cases, the values listed under the Case 2 column represent the incremental revenue requirements between Cases 1 and 2—the cost of early replacement of IPP in 2025.

All Advanced RPS and Energy Efficiency cases assume Navajo divestment in 2016 and IPP replaced in 2025. The values shown for Cases 3 through 7 represent each case's incremental revenue requirements when compared to Case 3.

TABLE 4-6 - INCREMENTAL COST COMPARISONS BETWEEN CASES

Coal Case Summary

		Early IPP Replacement
	Case 1 (Baseline)	Case 2 (2026-2027)
Case Description	Navajo 2016, IPP 2027, Adv EE	Navajo 2016, IPP 2025, Adv EE
Total Incremental Revenue $M	$0	$49
Average Incremental Revenue ($M/yr)	$0	$25

RPS Case Summary

	Case 3 (Baseline) *	Case 4	Case 5	Case 6 (same as Case 2)	Case 7
Case Description	33% RPS, 800 MW, Base EV	50% RPS, 800 MW, Base EV	50% RPS, 800 MW, Med EV	50% RPS, 800 MW, High EV	50% RPS, 1000 MW, Med EV
Total Incremental Revenue $M	$0	$2,612	$3,591	$4,300	$3,963
Average Incremental Revenue ($M/yr)	$0	$137	$189	$226	$209

The total incremental revenue requirement to replace IPP two years earlier than contractually obligated, by 2025, amounts to $49 million. Compared to early coal replacement, the total revenue requirement for the RPS cases range from $2,612 to $4,300 million.

Figure 4-24 illustrates the net present value of the total Power System costs for Cases 1 through 7 with low, expected, and high fuel costs.

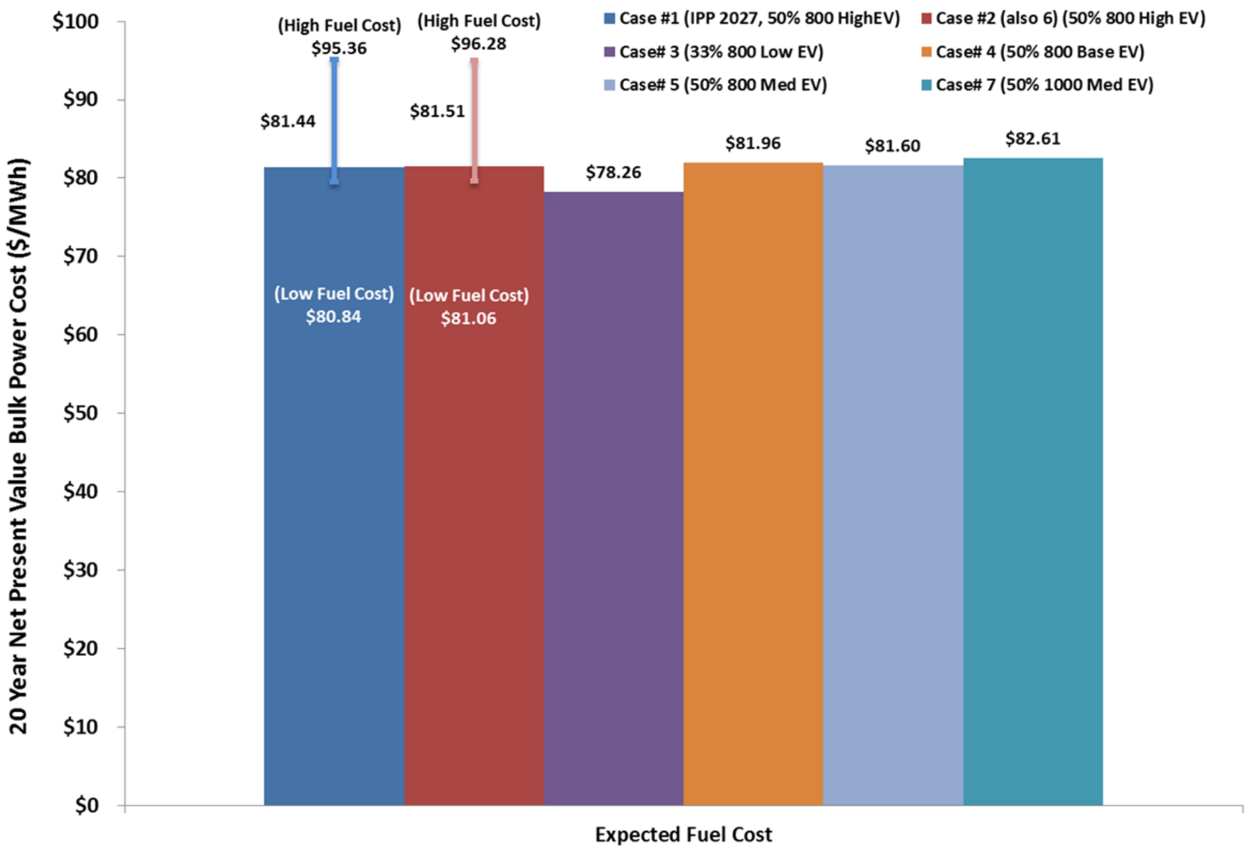


Figure 4-24. Total net present value comparison of Power System costs of Case 1-7.

4.4 Strategic Case Conclusions and Recommendations

4.4.1 Reliability

All two coal cases were designed to satisfy Power System reliability requirements. Based on the loss of load probability and resource adequacy analysis discussed in Section 4.3.1, the two coal cases are considered equal in terms of meeting reliability. To ensure that reliability is maintained during the replacement of Navajo and IPP, specific replacement strategies should be employed to assure a smooth transition. Further analysis may be required to refine the appropriate blend of renewable, gas-fired, energy efficiency, and demand response resources to replace Navajo and IPP based on reliability considerations.

4.4.2 GHG Emissions Reduction

As expected, the sooner generation from coal is removed from LADWP's portfolio, the greater the reduction of GHG emissions. Case 2 includes the divestment of IPP coal two years earlier than in Case 1, resulting in 5.07 million metric tons less GHG emissions over the 2-year period, from 2025 thru 2027 See Figure 4-8.

4.4.3 Economic

While the Base Case (Case 1) appears the least cost assuming moderate GHG emission costs, it fails to make significant progress toward the reduction of GHG emissions goals set forth by LADWP. The choice between coal replacement options of either Case 1 or 2 depends on the level of rate increases customers are willing to support while achieving the 50% required RPS by 2030, repowering of in-basin gas fired generation, funding and implementing local solar, Demand Response and Energy Efficiency programs, and providing additional external generation to supplement the lost generation resulting from coal replacement.

Considering the early replacement of IPP, revenue increase of approximately $25 million per year or $49 over 2 years would be necessary to achieve additional GHG reductions of 5.07 million metric tons, between the years 2025 and 2027, due to the replacement of IPP. This equates to a cost of $9.66 to remove 1 metric ton of GHG emissions. However, with potentially higher natural gas fuel prices, additional revenue increases to replace coal could be higher if gas prices were to remain at these higher levels.

4.4.4 Recommended Case

Decisions to fund coal replacement strategies, energy efficiency, or distributed generation cannot take place independent of other Power System programs. Maintaining reliability and meeting regulatory requirements are primary considerations before any discretionary coal replacement or advanced renewable and energy efficiency cases can be considered. However, this IRP presupposes funding of these programs so that the recommended case can be implemented.

Achieving the goals of reliability and environmental stewardship, while maintaining competitive rates, requires that program costs be closely managed. Considering these factors, the Recommended Strategy Case is Case 6 with early Navajo coal divestiture in 2016, early IPP coal replacement in 2025, 50 percent RPS, 15 percent EE by 2020, and a high electrification of the transportation sector. The Recommended Strategic Case includes a goal of 800 MW local solar by 2023 based on input that was received from the 2014 IRP public outreach efforts that advocated greater local solar and this does not preclude further consideration of expanding local solar up to potentially 1,200 MW by 2029. LADWP must first address concerns regarding cost effectiveness and reliability. The recommendation of 800 MW by 2023 will allow flexibility over time for LADWP to examine and demonstrate whether the local solar potential exists within reasonable cost and gauge levels of customer and solar developer participation; however, this goal is subject to change based on technology development, commodity price fluctuations, policy changes, and customer participation. In addition, reliability concerns must be addressed and LADWP is in the process of performing studies to determine the maximum level of local solar that can be reliably incorporated onto LADWP's distribution system. If the 800 MW local solar program is shown to be successful, in terms of participation and cost-effectiveness, and if the study concludes that high levels of local solar can be incorporated reliably onto LADWP's distribution system, LADWP would still be on track to install 1,200 MW of local solar by 2029. Future IRPs may consider greater levels of FiT and customer net-metered solar beyond 2023, based on the success of the 800 MW local solar program. The 2015 IRP allocates a "Generic RPS" category in its resource plan to allow flexibility and it is possible for the expansion of local solar to account for the planned "Generic RPS." A local solar program with a goal of up to 800 MW by 2023 will provide flexibility for LADWP to learn and grow based on experience gained from the program, and potentially further expand the local solar program up to 1,200 MW by 2029. The current recommendation of 800 MW of local solar by 2023 would allow for 50 MW of FiT installations per year, providing optimal, cost effective deployment and administration of the program. The additional cost to customers appears to be reasonable in light of the benefits of job growth and support of the local economy from adopting higher levels of local solar.

The 2014 IRP included the same recommendation to accelerate divestiture of Navajo and replacement of IPP and this 2015 IRP further clarifies and supports this prior recommendation. However, this 2015 IRP is potentially the most far reaching since the decision to replace coal fired generation back in 2010. The recommendation to increase the RPS to 50 percent by 2030, increase energy efficiency to 15 percent by 2020, increase local solar levels up to 800 MW by 2030, and promote high electrification of the transportation sector is far reaching but also a reasonable approach to achieving environmental goals while promoting job growth in the local economy without excessive costs to our customers, and while limiting potential exposure to possible fuel price volatility to within manageable limits.

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5.0 RECOMMENDATIONS

5.1 Strategic Overview

LADWP's recommended strategy set forth in this IRP for meeting its key objectives can be separated into two areas: (1) Regulatory and Reliability Initiatives, and (2) Strategic Initiatives. Regulatory and Reliability Initiatives are required actions to ensure system reliability and compliance with regulatory and legislative mandates. Strategic Initiatives are policy actions to achieve objectives established by the LADWP Board of Water and Power Commissioners and the Los Angeles City Council, and reflect their vision and leadership. These policies include, for example, establishment of LADWP's Energy Efficiency targets, social and economic development goals, early compliance with SB 1368, and investing in infrastructure reliability.

Regulatory and Reliability Initiatives

- RPS

  LADWP must increase its percentage of renewable energy per recently enacted state law, from the current 20 percent, to 33 percent by the end of 2020, and 50 percent by the end of 2030. SB 2 (1X) and SB 350 also establishes interim targets to ensure progress towards the 33 and 50 percent goal, respectively. In addressing this mandate, it is important that LADWP expand its renewable portfolio in the most cost-effective manner as possible. As two subsets of the RPS program, SB 1 requires $313 Million of expenditures towards solar incentives (Customer Net Metered), and SB 32 mandates a Feed in Tariff program of 75 MW (although LADWP, by choice, plans to exceed this mandate and provide 150 MW by 2016).

- Power System Reliability Program (PSRP) and System Infrastructure Investment

  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), which includes the establishment of metrics and indices to help prioritize infrastructure replacement expenditures from all major functions of the Power System, including generation, transmission, distribution, and substations. The PSRP assesses all power system assets affecting reliability in a truly integrated manner, and proposes corrective actions designed to minimize future outages. As funding priorities constantly shift, especially from the demands of mandated regulatory programs, competition for the remaining limited pool of resources necessitates an expanded reliability program and planning process. More detailed discussion on the PSRP is found in Section 1.6.3 of this IRP.

- Re-powering for Reliability and to Address OTC

  LADWP will continue to re-power older, gas-fired generating units at its coastal generating station for the reasons discussed in Section 2.4.2. The repowering program is a long-term series of projects through 2029 that will increase generation reliability and efficiency, reduce NO_X emissions, and eliminate the need for once-through cooling.

- Energy Efficiency (EE)

  LADWP will continue to pursue and implement EE programs per AB 2021 standards which have an adopted goal of achieving 10 percent EE by 2020. In 2014, the Board of Water and Power Commissioners adopted a new goal of achieving 15 percent EE by 2020 which exceeds the AB2021 goal based on the results of the fiscal year 2013-14 EE Potential Study.

- SB 1368 Compliance

  LADWP's two coal-fired generation sources, the Navajo Generating Station (NGS), and the Intermountain Power Project (IPP), must be compliant with the mandates established in SB 1368 by 2019 and 2027, respectively. IRP modeling determined that these units will be replaced earlier with a combination of renewable energy, demand response, EE, short-term market purchases, and conventional gas-fired generation.

- Energy Storage

  LADWP investigated Energy Storage (ES) technologies in accordance with AB 2514 and has established implementation targets prior to October 1, 2014 as required under AB 2514. LADWP has identified potential projects that support its unique electric grid, resource plan, and has identified projects that will facilitate renewable integration, distributed generation, and demand response. On August 5, 2014, the Board of Water and Power Commissioners approved an energy storage procurement of 154 MW by 2021, in addition to the previously Board approved target of 26 MW by 2016. As these projects are further developed, they will be incorporated into and analyzed in future IRPs. See Section 2.4.5.2 for more information.

- Castaic FERC Re-licensing Program

  On January 31, 2022, the Federal Energy Regulatory Commission's (FERC) license to operate Castaic Pumped-storage Hydroelectric Plant will expire. The license is a co-license between LADWP and the Department of Water Resources and includes a number of hydro power plants along the California Aqueduct. Both parties have initiated the re-licensing process that, on average, requires ten years to complete. Through 2015, LADWP expects to complete preliminary studies, contract negotiations, and prepare a new application strategy. In 2016, LADWP expects to file a notice-of-intent (NOI) and initiate the formal studies and applications.

- Transmission

  LADWP's Ten-Year Transmission Plan is prepared each year to ensure that LADWP remains compliant with NERC Transmission Planning Standards. LADWP's 2015 plan identified a number of transmission improvements that are needed to maintain reliability. The planning process involves complex modeling of the LADWP system, and concludes with findings and recommendations to maintain operational flexibility and avoid potential future overload conditions. LADWP will continue to implement the recommended projects, including construction of a new 230 kV transmission line between Scattergood

Generating Station and Receiving Station K, and upgrades at various other receiving and switching stations.

Strategic Initiatives

- Early Compliance with SB 1368

  Navajo Generating Station (NGS): while power imports can legally continue until 2019, LADWP has acted on prior recommendations to divest from NGS four years earlier, in 2015, through the sale of its share in NGS and adding additional resource capacity through the purchase and commissioning of APEX generating station in January 2014. The sale of NGS is expected to close on July 1, 2016.

  Intermountain Power Project (IPP): LADWP must be compliant with SB 1368 no later than June 30, 2027. LADWP, the Intermountain Power Agency (IPA), and the other 36 participants have approved the conversion from coal to natural gas no later than July 1, 2025 which is two years earlier than required by SB1368. Strategically, it is important for LADWP to remain a participant at IPP to retain geographic diversity in its resource mix, access the regional fuel supply, and retain the project's transmission lines to access renewable energy from the region

- Increasing Renewable Resources

  LADWP's recommended strategy regarding RPS is not only to comply with SB 2 (1X) and meet the required 33 percent RPS by the end of 2020, but also expand to 50 percent RPS by the end of 2030 per SB 350. Advanced RPS is one of several strategies that LADWP plans to employ to assist with meeting long-term greenhouse gas emission reduction goals.

- Local Solar

  Comments received at prior public workshops indicate local solar development should be a priority in LADWP's renewables procurement strategy. LADWP is recommending a policy action to encourage up to 800 MW of local solar installations to be sited locally by 2023, through initiatives including 310 MW of Customer Net Metered solar (a.k.a. Solar Incentive Program), 450 MW of feed-in tariff solar (375 MW more than required under SB 32), and installation of 40 MW of Community Solar on City-owned properties. In 2013, Mayor Garcetti announced a proposal for a 1,200 MW solar rooftop program, after the successful launch of L.A.'s 100 MW solar rooftop pilot program. Consistent with this goal, this IRP is recommending a goal of 800 MW local solar by 2023, subject to change based on technology development, commodity price fluctuations, policy changes, and customer participation. Although this recommendation appears to be short of the 1,200 MW goal, it does not preclude further consideration of expanding local solar up to potentially 1,200 MW by 2029. LADWP must first address concerns regarding cost effectiveness and reliability. The recommendation of 800 MW by 2023 will allow flexibility over time for LADWP to examine and demonstrate whether the local solar potential exists within reasonable cost and gauge levels of customer and solar developer participation. In addition, reliability concerns must be addressed and LADWP is currently performing studies to determine the maximum level of local solar that can be reliably incorporated onto LADWP's distribution system. If the 800 MW local solar program is shown to be successful, in terms of participation and cost-effectiveness, and if the study concludes that high levels of local solar can be incorporated reliably onto LADWP's distribution system, LADWP would still be able to meet the schedule of installing 1,200 MW of local solar by 2029. Future IRPs may consider greater levels of FiT and customer net-metered solar beyond 2023, based on the success of the 800 MW local solar program. Figure 5-2 illustrates that the expansion of local solar could potentially replace renewable requirements listed under "Generic RPS" or even "New Geothermal" if geothermal resources cannot be acquired.

- Demand Response

  In 2014, LADWP finalized its Demand Response (DR) Strategic Implementation plan, which serves as LADWP's near term and long term plan for developing 200 to 500 MW of measureable, cost-effective, and customer friendly DR portfolio by 2026. The DR implementation plan details the estimated DR resources, measurement and verification methods for load and billing impacts, cost-effectiveness methodology and results, enabling hardware and software requirements, customer outreach plans, and program staffing requirements.

- Advanced Technologies/Research and Development

  LADWP is looking ahead to technologies that will enhance the reliability of its system, including smart grid, energy storage, enhanced information and management systems, automation of system functions, advanced methods of outage management, and weather forecasting. These system enhancements will increase reliability, facilitate the integration of local solar generation and other variable renewable resources into the distribution network, enable smart charging of electric vehicles, and advanced demand-side management technologies. LADWP should continue to pursue grants, cost-sharing opportunities, and joint projects that promote the use and deployment of new technologies that meet its strategic goals.

- Rate Design

  As the RPS portfolio continues to increase, energy prices will have less value during the afternoon period, when the over-generation is expected to take place. Contrarily, energy will have more value once the sun sets and gas-fired generation and larger hydro are expected to quickly ramp up within a few hours to meet the evening peak. Future IRPs will investigate the need for a new rate design, in which time-of-use pricing may be considered as a strategy to shave the evening peak and encourage customers to consume during over-generation events. Next year's 2016 IRP will include an IRP Advisory Committee that will stimulate discussion on future strategies for rate design as well as smart metering.

- Electrification of the Transportation Sector

  LADWP is continuing to implement programs to support the electrification of the transportation sector. The Electric Vehicle (EV) Incentive, in which LADWP issued $2000 rebates for home EV charging systems, resulted in over 700 residential charger installations in Los Angeles. LADWP expanded its EV Program and implemented a $2 million "Charge Up L.A." rebate program to the first 2,000 approved EV customers for large businesses, small businesses, multi-family buildings, and public use. In 2015, LADWP expanded its transportation electrification plan to meet IRP electrification goals. This 2015 IRP continues to investigate higher levels of electrification/fuel switching of the transportation sector as a strategy to substantially reduce transportation sector greenhouse gases and associated criteria pollutants including NOx, CO, among others, and as a potential solution to absorb over-generation from solar.

- Provide Sufficient Generation

  In order to cover operating and replacement reserves in accordance with applicable federal and regional reliability requirements, LADWP will procure sufficient generation to meet long-term capacity requirements. Limited short-term purchases in peak season Q3 of each year will be secured to supply short-term capacity shortfalls, as needed.

- Control of Transmission Assets

  In addition to the regulatory requirement to remain compliant with NERC Transmission Planning Standards, LADWP will maintain its policy of maintaining control of its transmission assets and continue to augment those assets commensurate with load growth, reliability needs, and renewable energy opportunities.

- Collaborate with the Water System

  The LADWP Power System will continue to work with the Water System to develop programs that reduce the usage of electricity and conserve water, as well as optimizing hydroelectric energy production.

- Financial Targets

  To preserve and maintain LADWP's credit rating, the following financial targets are being utilized:

    - Maintain a full obligation coverage ratio of at least 1.70
    - Minimum operating cash target of 170 days
    - Debt-to-capitalization ratio less than 68 percent

5.2 Incorporating Public Input

Through its public outreach efforts in 2014, LADWP received various suggestions from the community, including eliminating coal and decreasing natural gas from LADWP's energy portfolio, reducing greenhouse gas emissions, promoting electrification of the transportation sector, considering new cases, and incorporating more renewables, local solar, energy efficiency, and energy storage. This input played a key role in shaping the recommendations set forth in this IRP. The major themes that emerged from the public input are listed below. Each theme is considered of equal importance and the themes are not listed in any order of priority.

Major Discussion Themes

Eliminate Coal from LADWP's Energy Portfolio

The majority of comments favored the early removal of coal from LADWP's resource portfolio and favored Case 2 – Navajo divestiture by 2015 and IPP replacement by 2025. Greenhouse gas emissions, along with other pollutants associated with coal energy were noted.

Decrease Natural Gas from LADWP's Energy Portfolio

Many public comments opposed LADWP's projected increase in natural gas resulting from the replacement of coal resources. Major concerns surrounded the issue of fracking, air quality, potential water quality issues, methane leakage from transport and storage, greenhouse gas emissions, and other pollutants associated with natural gas.

Incorporate More Renewables

The majority of the attendees of the Public Outreach Workshops was from the Environmental Community and supported Case 5 – 50% renewables, and some even promoted 100% renewables. LADWP's approach regarding this is to proceed cautiously until more is known about the operational and financial implications of higher levels of renewables, especially pertaining to system reliability and over-generation issues. Next year's IRP will include a reliability analysis regarding higher levels of renewables and its operational and financial impact on the Power System.

Incorporate More Local Solar

A majority of the comments promoted Case 5 with 1,200 MW of local solar. Many comments promoted the adoption of higher levels of local solar, noting the abundance of sunshine in the Southern California region. The benefit of providing local jobs was also noted as a supporting argument to increase penetration levels. One comment suggested investing to install solar on every house and building in Los Angeles. Regarding LADWP's current customer incentive program, multiple comments recommended hiring more inspectors to streamline the process which many see as too slow, especially when compared to other utilities.

Incorporate More Energy Efficiency

LADWP's Energy Efficiency (EE) targets, based on year 2020, have increased significantly, from 8.6% approved in December 2011; to 10% approved in May 2012; to 15% approved in July 2014. Comments received supported more EE incorporated into LADWP future plans. Some comments suggested maximizing EE and even proposed 20% EE by 2020. Many questions were directed towards specific EE programs and how customers can participate, such as trading in refrigerator and window mounted air conditioning units. Some comments suggested adding educational programs and energy efficiency home assessment programs to increase EE savings.

Promote Electrification of the Transportation Sector

Many of the public comments showed interest and support in LADWP promoting the electrification of the transportation sector. Comments advocated support for the greenhouse gas reduction levels that would primarily take place through the electrification of transportation sector. Some questions were raised regarding the matching of electrification cases to RPS cases—40 percent RPS included high electrification, whereas 50 percent RPS included medium electrification.

Incorporate More Energy Storage

The majority of the public comments supported incorporating energy storage as a means to support renewables and reduce greenhouse gases. Some comments even advocated 100 percent renewables backed with energy storage. LADWP's approach regarding this is to proceed cautiously until energy storage solutions are proven to be cost-effective and dependable for integrating renewables and maintaining system reliability.

Reduce Greenhouse Gas Emissions

This was an overarching theme of the public comments received. Indirect societal costs, health effects, and global warming were cited as reasons for accelerating the timelines to reduce GHGs. Eliminating natural gas was promoted as a means to reduce CO_2. Comments pointed out the need for considering increased renewables, energy efficiency, electrification of the transportation sector, and energy storage as strategies to reduce greenhouse gas emissions to 80 percent below 1990 levels by 2050.

Look at New Case Scenarios

Many comments suggested including additional cases to analyze more aggressive renewables and energy efficiency cases. Some suggested matching high electrification with Case 5- 50 percent renewables.

For further discussion of the themes and the overall public outreach process, see Appendix O.

5.3 Recommended Strategic Case

As discussed in Section 4.4.4, the Recommended Strategic Case for this 2015 IRP includes the following key attributes:

- At least 15 percent of Los Angeles' electric needs will be met through new customer energy efficiency measures by 2020.
- Implement 200 to 500 MW of capacity reduction through Demand Response programs by 2026.
- Generate at least 33 percent of its electricity from renewable resources by 2020 and expand that level to at least 50 percent by 2030. Although this IRP incorporates one combination set of renewable resources to achieve 50% RPS by 2030, LADWP will not limit itself to only these types and amounts of resources to achieve its goals and needs flexibility in resource development for the best fit for the electrical system.
- Promote a high level of electrification of the transportation sector by 2030 in support of renewable resources and decreasing overall greenhouse gases in the City of Los Angeles. A high level of electrification is expected to consume 2,344 GWh of energy to power approximately 580,000 electric vehicles by 2030 and thereby reducing the same amount of gasoline vehicles on the road.
- Procure 154 MW of Energy Storage Systems by 2021 and investigate the feasibility and cost-effectiveness of various energy storage technologies to enhance the integration of renewables and system reliability.
- Diversify LADWP's RPS through incorporating 799 MWs of generic renewable resources by 2035. Some of these resources could include technologies such as biomass, ocean tidal power or other emerging technologies.
- Diversify LADWP's energy portfolio through a variety of fuels, technologies and power plant sites throughout the western United States to maintain a high level of reliability.
- Implement advanced reliability improvements through Smart Grid.
- Emphasize local solar by proposing a goal of up to 800 MW solar capacity to be locally sited in Los Angeles by 2023. This will be accomplished through programs such as the Customer Solar Incentive Program, an expanded feed-in tariff goal of 450 MW by 2023, and Solar on Los Angeles properties under public/private partnership (a.k.a. Community Solar).

The additional cost to customers appears to be reasonable and offers associated benefits of job growth and support of the local economy from adopting higher levels of local solar. The environmental benefits of reducing GHG emissions by 5.07 MMT are clearly present with the early replacement of IPP. The cost to implement IPP replacement in terms of metric tons of GHG removed is $9.66 per metric ton. This represents a reasonable cost, being one of the lowest cost solutions available to reduce GHG emissions over the long-term. Other benefits of early IPP replacement include better availability (less costs) of replacement energy. With the Recommended Case and the noted addition of FiT and Navajo divestiture complete, LADWP can begin to focus its attention on early replacement of IPP coal generation no later than July 1, 2025, by working with the other power purchasers and the IPP plant owner.

Increasing the renewable portfolio standard to reach the currently mandated 50 percent, advancing energy efficiency above the required 10% by 2020, and promoting electrification of the transportation sector are all strategies that can be employed by LADWP to reduce greenhouse gas emissions that come with significant investments. In addition, these strategies are intertied and highly dependent on one another; for example, an increased renewable portfolio standard would benefit from high electrification as a strategy to absorb energy during times of over-generation. Increased energy efficiency also directly impacts the optimum levels of renewables and electrification. Therefore, these strategic programs must be evaluated as a whole to maximize LADWP's return on investment while maintaining superior reliability. The environmental benefit from combining an expanded renewable portfolio standard of 50 percent by 2030 and 15 percent energy efficiency by 2020 is equivalent to an annual GHG emissions reduction of 5.1 MMT beyond 2030. Promoting a high level of electrification as a GHG reduction strategy would further reduce the annual GHG emissions by 2.6 MMT beyond 2030; collectively, these strategies provide an annual GHG emissions reduction of 7.6 MMT beyond 2030. The combination of strategies in the Recommended Strategic Case, which includes early coal replacement, advanced renewables and energy efficiency, increased local solar, and high electrification provides the optimal solution for meeting long-term environmental goals, while providing reliable electric service in a cost effective manner.

The incremental cost to remove one metric ton of GHG through implementing 50 percent RPS ranges from \$150 to \$180 per metric ton, whereas the cost of GHG reduction through a high scenario of transportation electrification ranges from \$30 to \$40 per metric ton, considering only utility incentive costs; the GHG removal cost of 50 percent RPS is almost five times more expensive than that of transportation electrification. Transportation electrification is a cost effective strategy that can assist in reducing overall GHG emissions, depending on customer participation and regulatory relief for promoting transportation electrification. Although the cost of 50 percent renewables is significantly higher than coal replacement, it is mandated by state law. The GHG reduction costs are purely economic estimates and do not fully consider all of cost ramifications from increased levels of regulating and load following reserves associated with increased renewables.

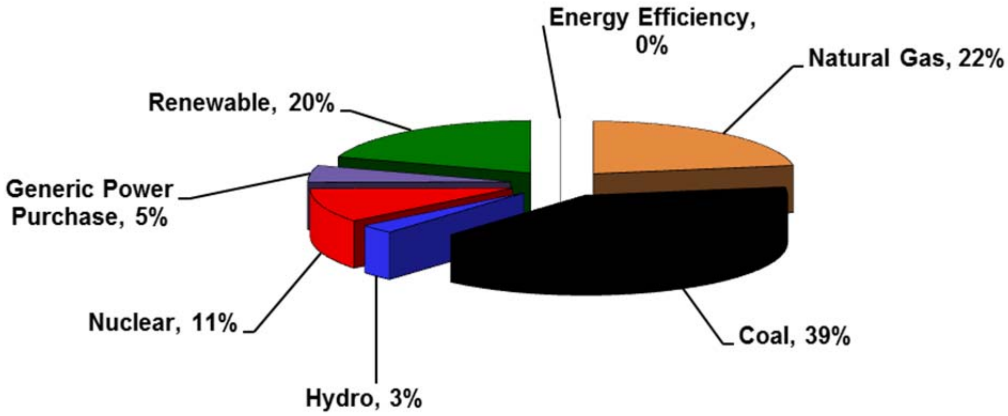
The Recommended Case for 2015 is summarized in Table 5-1.

Table 5-1. 2015 IRP RECOMMENDED STRATEGIC CASE

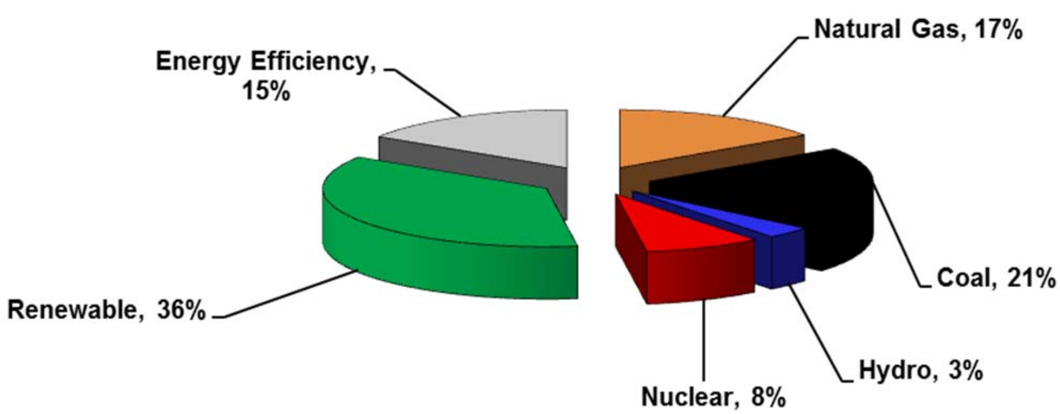
2020	2030	SB 1368 Compliance Date		New Renewables Installed (MW) 2015-2020				New Renewables Installed (MW) 2015-2035				
RPS Target	RPS Target	Navajo	IPP	Geo/ Biomass	Wind	Non-DG Solar	Dist. Solar	Geo/ Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
33%	50%	7/1/2016	7/1/2025	95	0	1,088	509	293	670	1,813	653	799

Figure 5-1 illustrates the changing generation resource percentages for 2010, 2020, and 2030 based on the Recommended Case. Because energy efficiency forecasts are forward-looking, the savings of 1,256 GWh or 5.5 percent of sales that was implemented between 2000 and 2010 are embedded into the load forecast and are not included as part of the generation resource mix shown below.

2010



2020



Note: Chart is subject to change due to technology development, commodity price fluctuations, and policy changes.

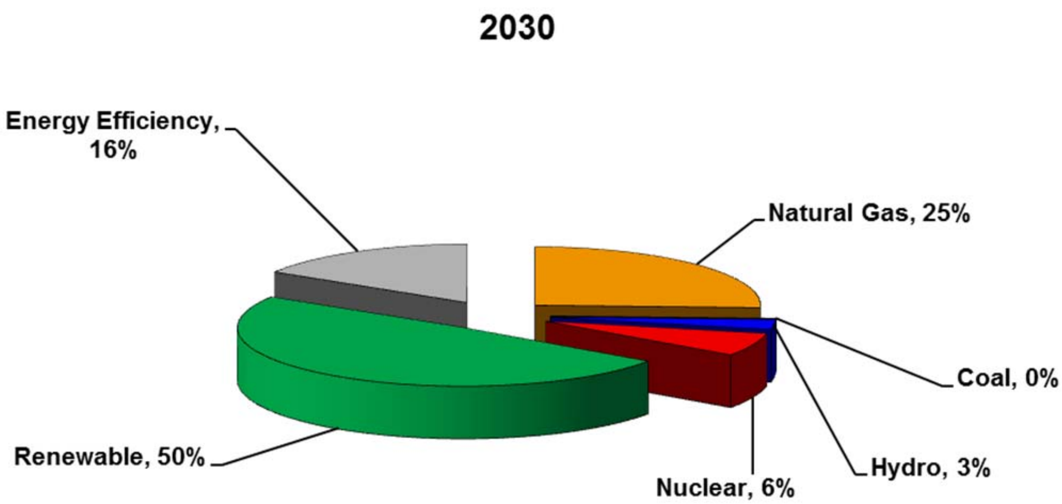


Figure 5-1. Generation resource percentages for 2010, 2020 and 2030.

Figure 5-2 shows the renewable energy resource mix of the Recommended Case. The major changes from the 2014 IRP is an expanded renewable portfolio standard from 40 percent by 2030 to 50 percent by 2030.

Note: Chart is subject to change due to technology development, commodity price fluctuations, and policy changes

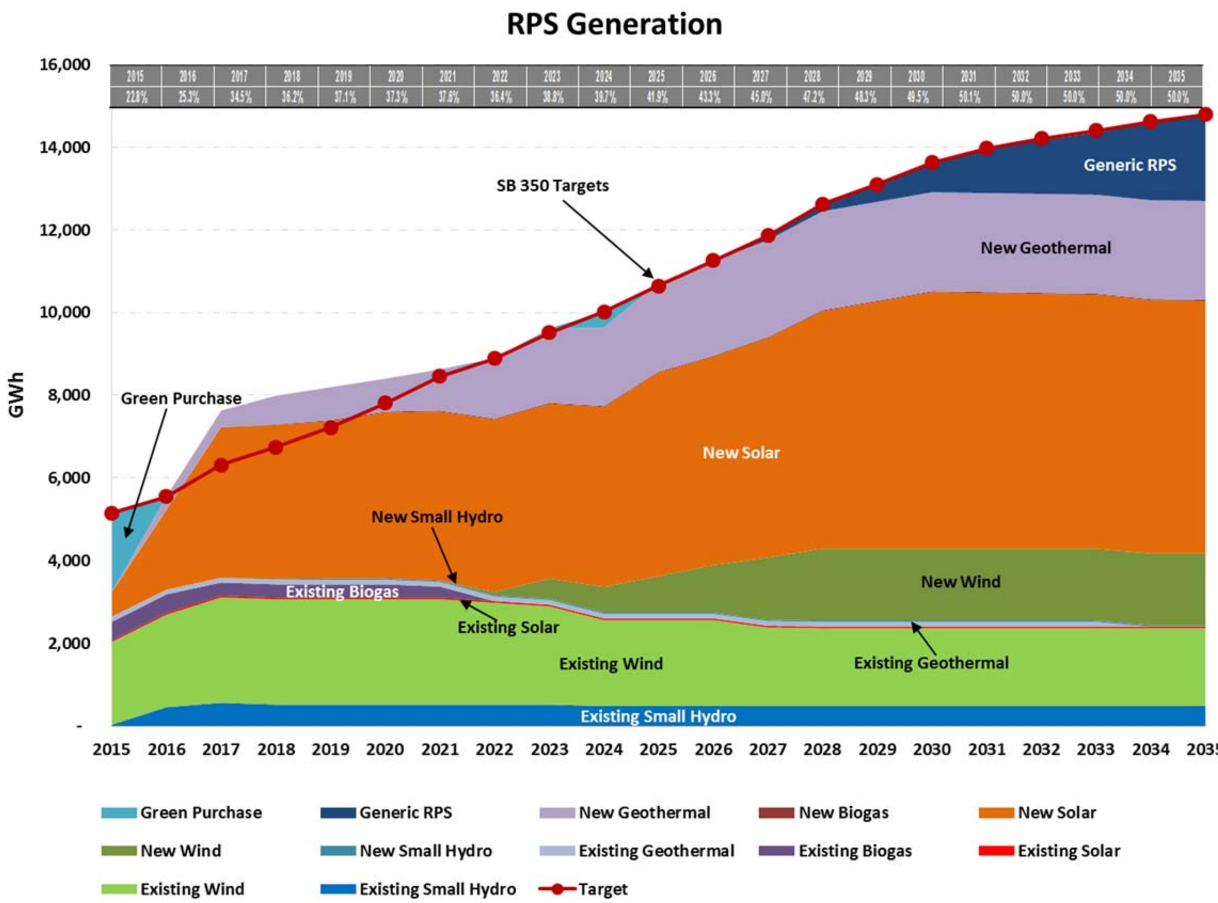


Figure 5-2. Recommended case renewable generation by technology.

The Recommended Strategic Case will meet the LADWP combined objectives of maintaining a reliable Power System, environmental stewardship, and minimizing ratepayer impacts. The Recommended Case provides a roadmap for the LADWP to achieve its long-term planning goals, while providing the required reliability and necessary flexibility to adapt to dynamic economic, environmental, and regulatory conditions. The Recommended Strategic Case will put upward pressure on retail rates, but should maintain adequate reliability and avoid fines and penalties that may otherwise result from violations in state and federal laws. The Recommended case also successfully reduces the amount of GHG emissions released into the environment and provides for additional job growth and economic benefits through the increased use of local solar.

5.4 Revenue Requirements

A brief discussion is in order here regarding budget shortfalls over the past few years. These shortfalls have prevented LADWP from fully funding existing and new programs during that timeframe. The delays surrounding resolution of the Power System budget have the potential of impeding LADWP's ability to meet its long-term plans and obligations.

Based on the 2010 IRP, a multi-year rate increase was recommended beginning fiscal year 2011-12. The rate increase would have supported elements of the 2010 IRP, all of which remain as the foundation for LADWP's short and long-term plans. Because the rate increase was not realized in July 2011, many of the programs that required funding were scaled down, delayed or deferred.

The last rate action began in early 2011 was approved by the Board, the City Council, and the Mayor, with the rates going into effect on November 11, 2012. A new rate action is under development in 2015 and is expected to conclude in 2016.

Although somewhat outside LADWP's control, future *multiyear* funding plans are desirable to provide consistent and sustainable project and program development. Funding that is based on annual budgets are subject to year-to-year fluctuations which introduces uncertainty for our customers and the inefficient use of staff and financial resources that are necessary to meet LADWP's objectives and compliance requirements.

Properly funded programs will enable LADWP to achieve the following objectives:

- Modernize its coastal generation units to replace aging equipment and to satisfy once-through cooling regulatory requirements.
- Implement early coal divestiture and replacement.
- Secure the state-mandated amounts of renewable energy.
- Through the Power System Reliability Program, reduce the number of outages and improve system reliability pertaining to generation, transmission, substations, and distribution.
- Implement necessary transmission improvements to maintain reliability.
- Implement recommended levels of local solar programs.
- Achieve energy efficiency target levels.
- Achieve demand response target levels.
- Achieve energy storage target levels
- Achieve transportation electrification target levels
- Implement Smart Grid initiatives.
- Comply with FERC-approved reliability standards.

Securing adequate multi-year funding will help to ensure LADWP's ability to stay on track towards meeting its future long-term goals and obligations.

5.5 Electric Rates

LADWP currently uses an Excel-based financial model that has been developed and used for over a decade. This financial model has been used to develop forward-looking Power System financials for the Board of Water and Power Commissioners' annual budget approval and for rating agency presentation for debt issuances.

The model is modified to analyze fuel expense, purchased power expense, and additional capital and O&M expenses for any new LADWP-owned resource additions as well as off-balance sheet resource additions. The strategic cases are overlaid on existing capital and O&M expenses for the approved FY14-15 budget data, which contains forward-looking budget data up until FY24-25. For years beyond FY24-25, general capital and O&M expenses are escalated at 2.5 percent per annum.

Effective November 11, 2012, LADWP retail revenue shall be funded primarily from the then existing Electric Rate Ordinance and the Incremental Electric Rate Ordinance through the following billing components:

(1) Base Rates and Electric Subsidy Adjustment (ESA)
(2) Energy Cost Adjustment (ECA) and Reliability Cost Adjustment (RCA)
(3) Incremental adjustments:
    Variable Energy Adjustment (VEA),
    Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA),
    Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA),
    Incremental Reliability Cost Adjustment (IRCA), and
    Incremental Base Rates

These components are described briefly below.

Effective November 11, 2012, the Base Rates and ESA under the then existing Electric Rate Ordinance shall remain fixed at their levels as of November 3, 2010. The Base Rates cover a portion of a rate other than the adjustments and are used to cover expenses from debt service arising from capital projects except RPS projects, operational and maintenance expense except RPS related, public benefit spending, property tax, and pro-rated portion of the city transfer.

The ECA under the existing Electric Rate Ordinance is used to cover fuel, purchased power, RPS and energy efficiency-related expenses. Effective November 11, 2012 under the Incremental Electric Rate Ordinance, the ECA factor shall be known as the Capped Energy Cost Adjustment Factor and shall not exceed $0.0569/kWh, which was the level applied as of November 3, 2010.

The RCA under the existing Electric Rate Ordinance is used to cover power reliability related expenses. Effective November 11, 2012, under the Incremental Electric Rate Ordinance the RCA factor applied to residential customers shall be known as the Capped Residential Capped Reliability Cost Adjustment Factor and shall not exceed $0.0030/kWh, and the RCA factor applied to general service customers shall be known as the General Service Capped Reliability Cost Adjustment Factor and shall not exceed $0.96 per kW, which were the levels applied as of November 3, 2010.

The Incremental Electric Rate Ordinance provides incremental charges to provide funding of expenditures unmet by the existing ordinance. These incremental charges are in addition to charges paid in corresponding rates of the existing Electric Rate Ordinance. These incremental charges provide more granularity and transparency for LADWP and our customers and include the following:

- Variable Energy Adjustment (VEA): Recovers costs associated with fuel non-renewable portfolio standard power purchase agreements, economy purchases, legacy ECA Factor under-collection, and base rate decoupling from energy efficiency impact.
- Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA): Recovers costs associated with renewable portfolio standard O&M, debt service, and energy efficiency programs.
- Variable Renewable Portfolio standard Energy Adjustment (VRPSEA): Recovers costs associated with renewable portfolio standard market purchases and costs above and beyond any O&M and debt service payments.
- Incremental Reliability Cost Adjustment (IRCA): Recover costs associated with O&M, debt service expense of the Power System Reliability Program (PRP), and RCA under-collection.
- Incremental Base Rates: Recovers costs of providing electric utility service that are not recovered by the above adjustments and Base Rates. These costs include labor costs, real estate costs, costs to rebuild and operate local power plants, equipment costs, operation and maintenance costs, expenditures for jointly owned plants and other inflation-sensitive costs.

To sustain LADWP's financial strength while mitigating rate impacts to customers, maintain existing "AA-" credit rating or equivalent bond ratings to minimize financing costs, and obtain funding needed for Power System capital programs, the LADWP utilizes the following financial metric targets: (1) maintain a full obligation coverage ratio of at least 1.70, (2) unrestricted operating cash target providing 170 days of cash flow, and (3) capitalization ratio of less than 68.

Full obligation coverage ratio is the ratio of cash available from operation to debt service amount. The debt service amount contains only LADWP's direct debt. Capitalization ratio is the ratio of the total direct debt divided by the total asset.

To achieve these various financial coverage parameters, the base rates will need to be increased as necessary to meet the objectives of this IRP.

5.5.1 Rates Analysis for Cases

The retail electric rates, including estimated CO_2 emission expenses, for all strategies are discussed in this subsection. Factors driving the increases over the twenty-year period include: rising fuel price, increased power system reliability program spending, replacement of aging basin generating units to meet once-through cooling and South Coast Air Quality Management District emission requirements, replacement of coal generation to lower CO_2 emissions, installation of renewables generation according to legislative mandates, and program costs for energy efficiency, demand response, local solar and other programs.

The capital cost and the associated O&M expense of any new generation resource is priced at 2015 dollars with 2.5 percent escalation except for certain solar projects, which are priced at levelized 2015 dollars due to anticipated pricing declines.

For each year, the retail rate through either the base rate or the energy cost adjustment and its related adjustments is raised sufficiently high enough to meet the various financial ratios recommended by financial advisors to maintain LADWP's "AA-" bond rating.

Using the current recommended case, customer rates are estimated to increase on average 4 percent to 6 percent per year over the next five years, and 3 percent to 5 percent per year over the next 20 years.

Assumptions used to model rate impacts can change. In order to reflect the variability in model assumptions, a sensitivity analysis was performed to determine a realistic range of rate impact trajectories. Figure 5-3 shows the retail price impact comparison of the 2015 IRP recommended case bounded by a high and low range fuel price. The high range assumes higher natural gas and coal costs while the low range assumes minimal natural gas and coal costs.

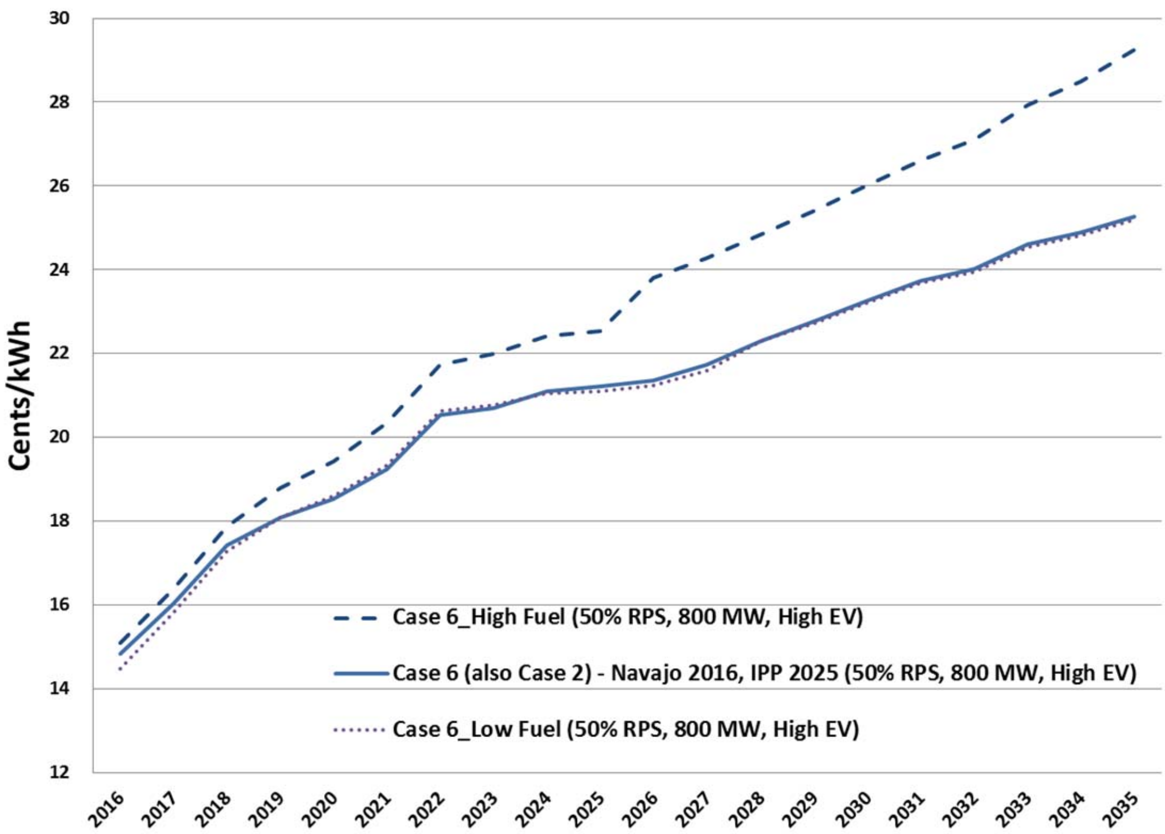


Figure 5-3. Recommended Case – expected retail price impact bounded by high and low range fuel.

Figure 5-4 presents the fiscal year breakdown for the Recommended Strategic Case comprising rate contributions from the power system reliability program, energy efficiency, renewable energy, coal replacement, OTC repowering, fuel costs, transportation electrification, and local solar from fiscal year 2015 to 2035. These individual contributions represent incremental adders to the rates. The power system reliability program, fuel increases, and OTC repowering programs result in relatively linear rate increases. On the other hand, energy efficiency and renewable energy programs result in high initial rate increases and tapers off in later years; energy efficiency targets 15 percent savings by 2020 and tapers off, whereas renewable energy targets 33 percent by 2020 and 50 percent by 2030 without tapering off. The Power System Reliability Program (PSRP) includes capital and O&M expenditures to replace over age distribution, transmission, substation, and generation components that have exceeded their life expectancy, and ensure levels of funding to reduce the backlog of “fix-it” tickets which are temporary repairs that need to be corrected.

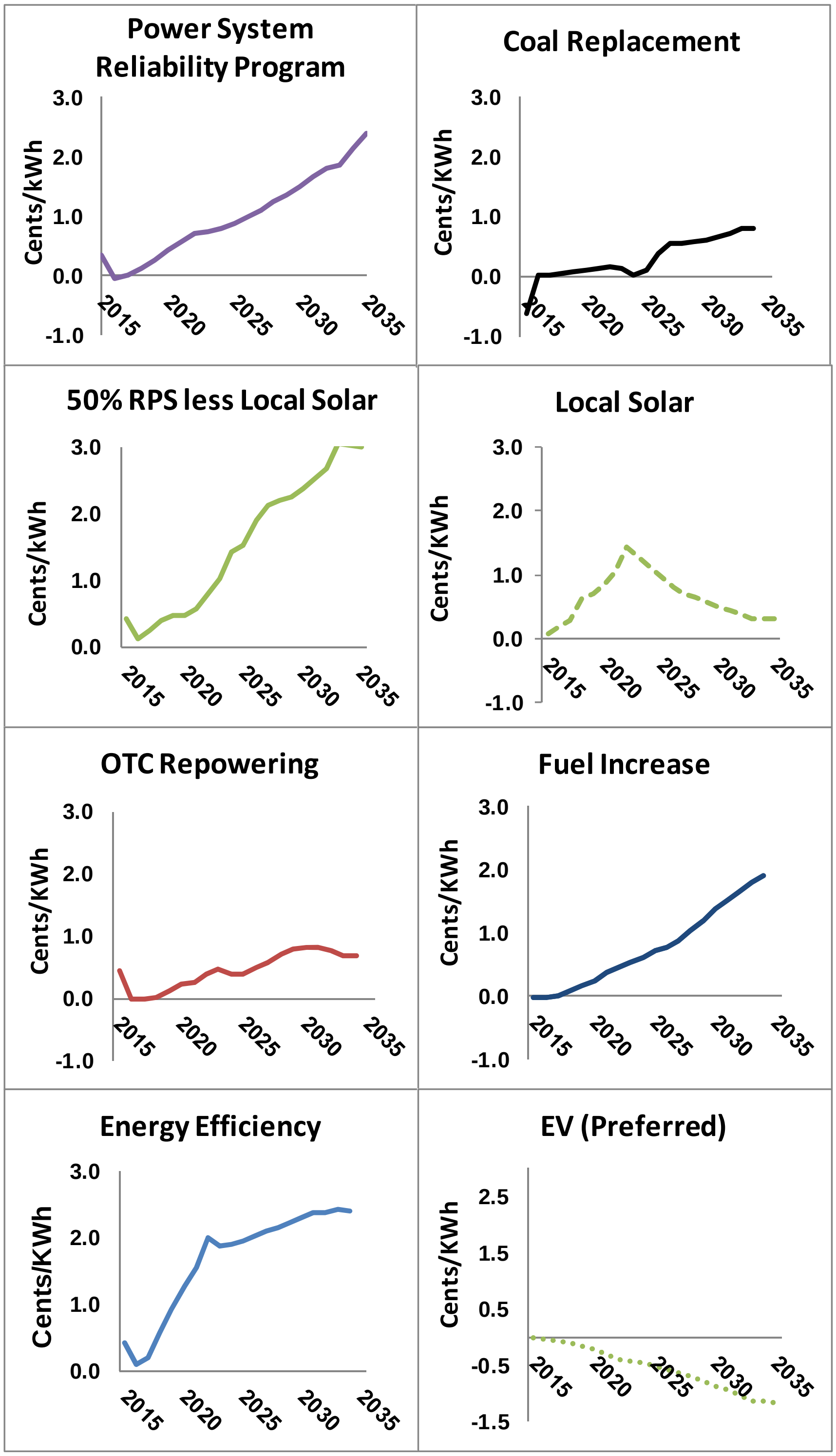


Figure 5-4. **Retail electric rate contributions breakdown, based on the 2015-16 budget forecast (Recommended Case).**

Figure 5-5 shows the total retail rate impact after combining all of the program rate components. The time period 2015 through 2020 reflects the current Rate Action. One can draw the conclusion that rising fuel costs and complying with various regulatory requirements are the primary drivers of the growth in rates.

Note: Chart is subject to change due to technology development, commodity price fluctuations, and policy changes

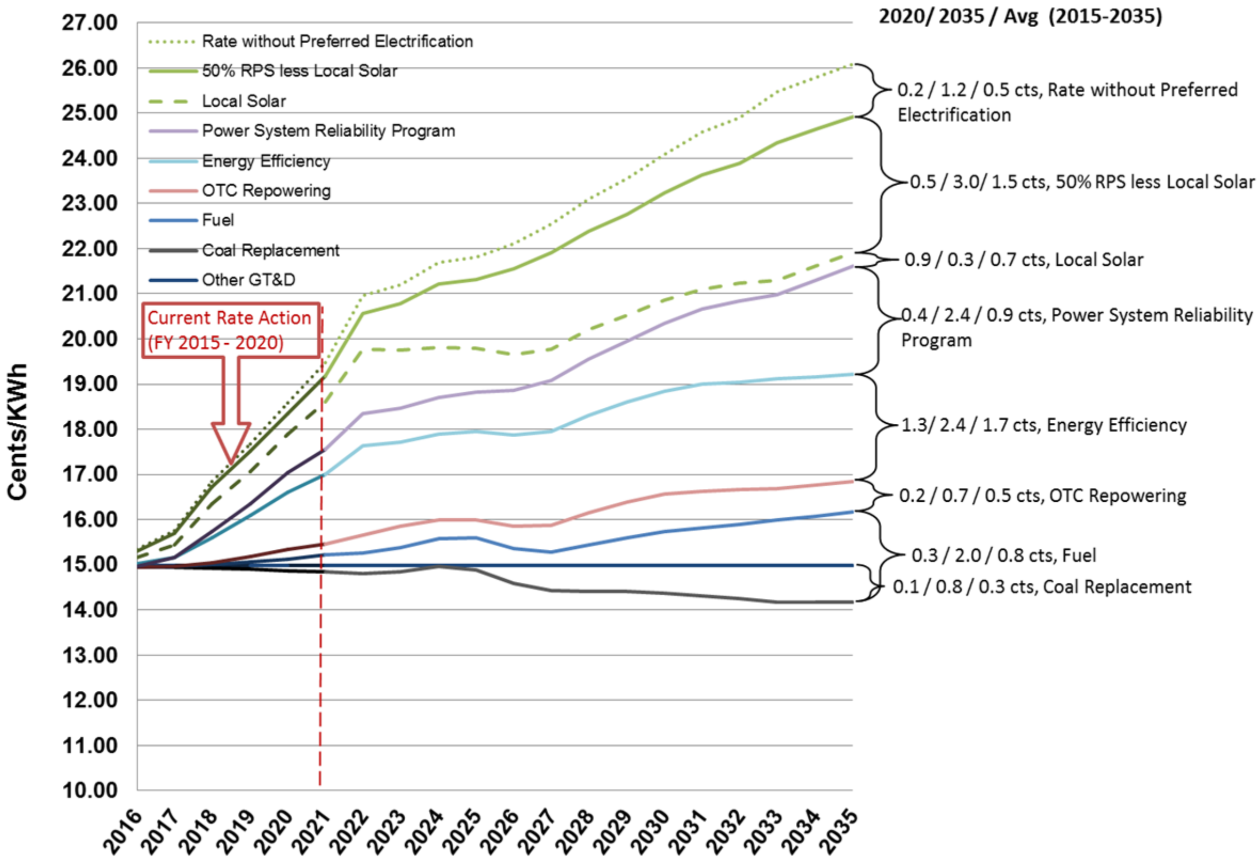


Figure 5-5. Total retail electric rate composite by fiscal year, based on the 2015-16 budget forecast (Recommended Case).

A few observations from Figures 5-4 and 5-5[10] can be made regarding the RPS, EE, OTC Repowering programs, fuel costs, local solar, and preferred electrification. The EE program component of rate increases over time as program incentive payments and net revenue loss attributable to the EE program are recovered. The RPS and local solar component of rates steeply increases through 2021 in order to reach 33 percent renewables and the rates continues to increase slowly through 2030 to reach 50 percent renewables by 2030. OTC Repowering results

[10] Figures 5-4 and 5-5 represent forecasted rate increases based on system averages, and does not account for rate structure variations across and within customer classes.

in savings beyond 2029 due to fuel and emissions savings resulting from implementation of modern, highly efficient natural gas-fired generation when the repowering program is complete. The preferred high level of transportation electrification would result in a decrease in rates compared to the base level of transportation electrification due to increased sales. Also, general inflation in fuel costs represents a significant growth in rates. The local solar component of rate decreases after 2023 due to avoided fuel emissions savings, after the expanded FiT program has reached the 450 MW build out.

Funding for the Power System Reliability Program (PSRP) includes capital and O&M expenditures to replace over age generation, substation, distribution, and transmission system components that have exceeded their life expectancy, and ensure levels of funding to reduce the backlog of "fix-it" tickets which are temporary repairs that need to be corrected. The spikes in the OTC Repowering, RPS, and EE curve occurs when capital borrowing limits are reached around 2021-2022 as additional cash is needed to fund capital expenses. This quickly subsides as the capacity to borrow resumes shortly thereafter.

The cost contributions from various environmental and reliability programs towards the retail rates are summarized in Table 5-3. A preferred electrification program is expected to decreases rates through increased electric sales.

Table 5-3. Cost contributions from various environmental and reliability programs

Program	Retail Rate Impact at FY2020 (cents/kWh)	Retail Rate Impact at FY2035 (cents/kWh)	Average Retail Rate Impact 2015-2035 (cents/KWh)
50% RPS by 2030	0.5	3.0	1.5
Energy Efficiency (15% by 2020)	1.3	2.4	1.7
Power System Reliability Program	0.4	2.4	0.9
Coal Replacement	0.1	0.8	0.3
OTC Repowering	0.2	0.7	0.5
Local Solar	0.9	0.3	0.7
Total – Recommended Case	**3.4**	**9.6**	**5.6**

Figures 5-6 and 5-7[11] further illustrate the impact to average residential and commercial/industrial customer monthly bills from these environmental and reliability programs. To show the potential effect of energy efficiency on customer bills, the dashed lines on these figures represents what a total monthly bill would amount to after implementing energy efficiency measures that result in a 20% savings. While LADWP's overall energy efficiency program is evolving and much will depend on which programs customers elect to participate in, these figures illustrate what may reasonably be achievable by customers who have not already implemented significant energy efficiency measures to reduce their electricity consumption.

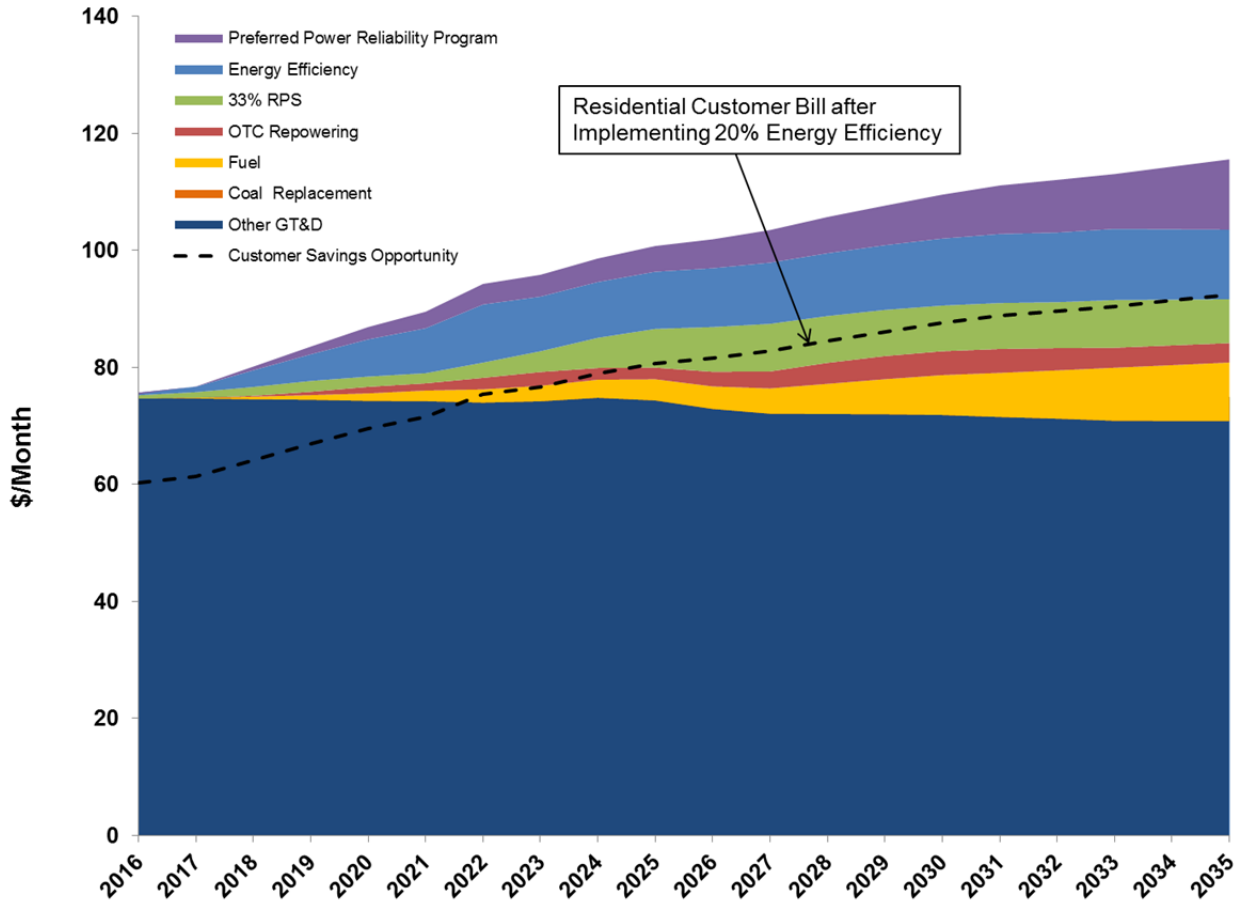


Figure 5-6. Average residential customer bill (500 kWh/month) with environmental and reliability programs by fiscal year based on the 2015-16 budget forecast (Recommended Case).

[11] Figures 5-6 and 5-7 are general representations only, and does not account for rate structure variations across and within customer classes, such as the effect of tiered rates, minimum charges, time-of-use, etc. The figures provide an indication of the relative contributions of the individual program areas toward a typical monthly bill.

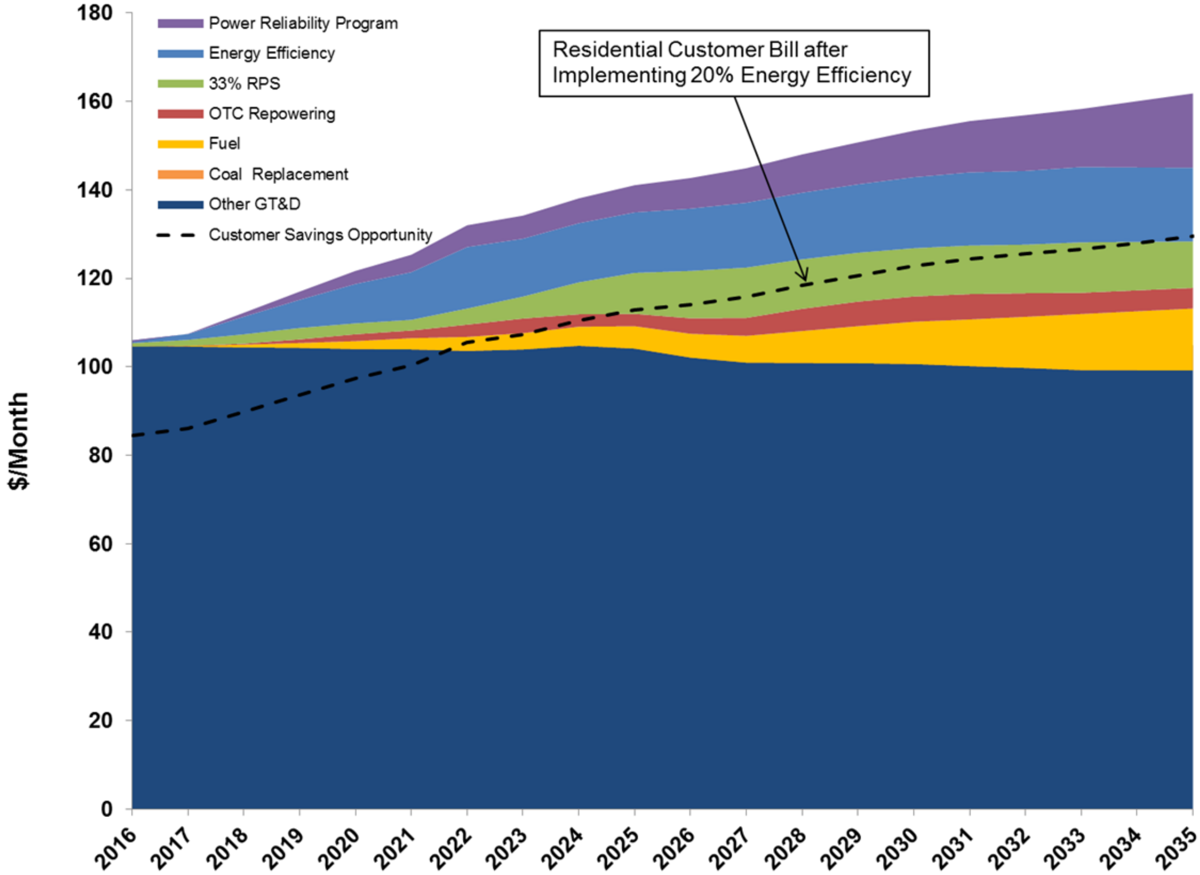


Figure 5-8. Average Valley home with air conditioning, residential customer bill (700 kWh/month) with environmental and reliability programs by fiscal year based on the 2015-16 budget forecast (Recommended Case).

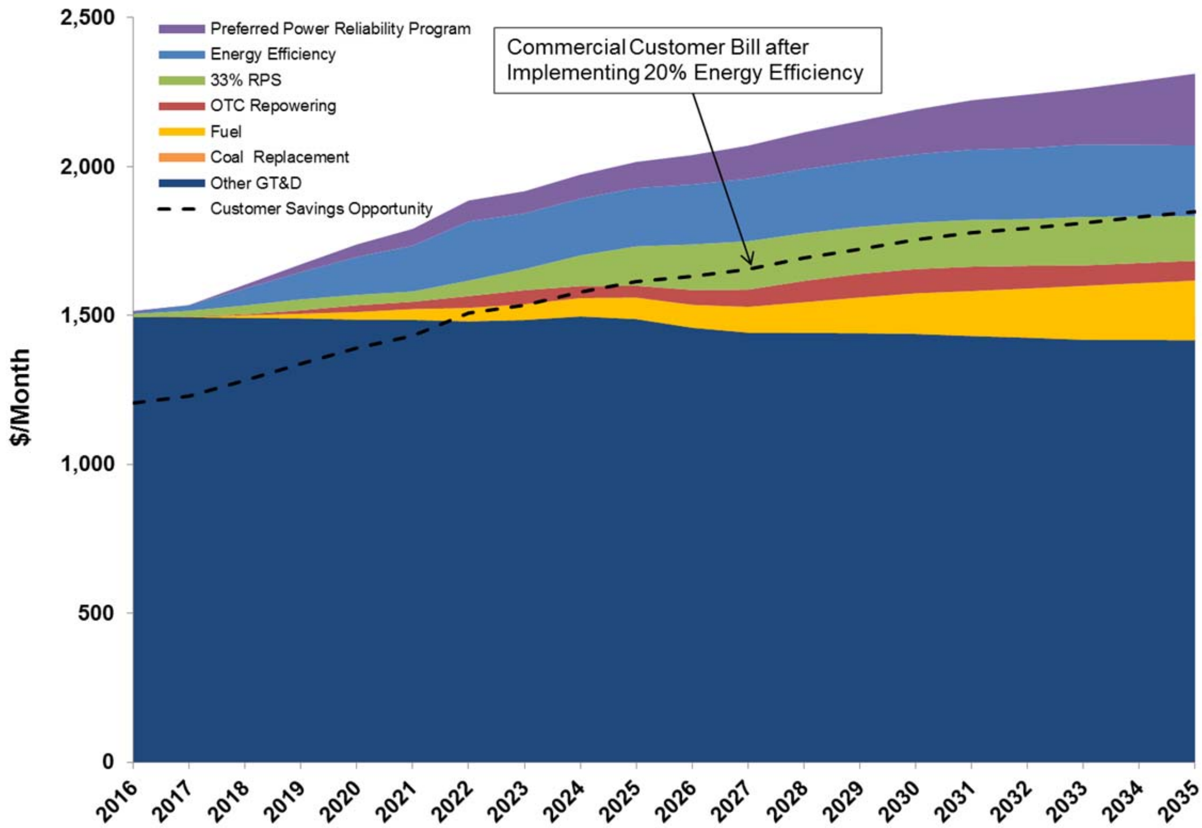


Figure 5-9. Average commercial/industrial customer bill (10,000kWh/month) with environmental and reliability programs by fiscal year based on the 2015-16 budget forecast (Recommended Case).

Aside from the environmental and reliability improvement programs, increased fossil fuel expenses also drive the rate increase, for example: (1) coal that feeds IPP is projected to climb by 35 percent from 2015 to 2023, and (2) natural gas at SoCal border is projected to climb from 2015's $3.04 per MMBtu to 2035's $6.29 per MMBtu. If these low fuel prices do not materialize, then the average rate and cost curves shown in Figures 5-3 thru 5-7 will shift upward; however, the cost of environmental and reliability programs will remain substantially unchanged.

Because the analysis and conclusion are heavily dependent on a number of assumptions, LADWP will continually update its long-term plan. As expectations change (e.g., due to technology development, commodity price fluctuations, and policy changes), they will be analyzed and incorporated into subsequent IRPs.

5.6 Recommended Near-term Actions

Based on the strategic requirements presented earlier and projected resource procurement needs, the following actions are recommended to be taken in the near-term:

1. Proceed with re-powering plans for generation units at the Scattergood Generating Station, and pre-development plans for Haynes and Harbor Generating Stations to meet OTC goals.
2. Continue to investigate the technical and contractual options for IPP coal-fired generation to be compliant with SB 1368.
3. Close the sale of Navajo Coal Plant by mid-2016.
4. Continue the implementation of existing energy efficiency efforts to reach 15 percent energy efficiency savings by 2020. Perform a new energy efficiency potential study in 2017.
5. Implement the Power System Reliability Program (PSRP) to replace aging infrastructure components. The PSRP includes periodic assessments of the program's effectiveness and identify modifications to provide continuous improvement and to serve as the backbone for transportation electrification and integration of renewables.
6. Implement the Integrated Human Resources Plan by creating a demand forecast of staffing needs, establishing measurable indicators using the five steps of the critical path, and make critical path improvements that will improve job classification, recruitment, selection, training, and placement. Continue to make improvements on the Customer Care and Billing System.
7. Implement recommended electric system upgrades contained in the 2015 Ten-Year Transmission Assessment Plan.
8. Implement a Demand Response Program based on the Demand Response Strategic Implementation Plan, which will reach 200 to 500 MW of new peak load reduction capability by 2026.
9. Implement renewable strategies for geothermal, biogas, solar, and wind resources to ensure increasing levels of renewable procurement in accordance with SB 2 (1X) and increase renewable levels to 50 percent by 2030 as required by SB 350.
10. Complete a comprehensive study of issues associated with RPS procurement strategies and integrating increasing amounts of variable energy resources such as wind and solar. Determine possible megawatt limits and mitigation strategies of various resources to achieve 33 percent renewables by 2020 and to reach the longer term goal of 50 percent by 2030.
11. Develop and incorporate strategies to:
    a. Fully utilize existing transmission assets;
    b. Preserve existing brown field sites to be repurposed for renewable or natural gas generation;
    c. Incorporate the concept of O&M cluster zones[12] to maximize operational efficiencies;

[12] Clustering renewable projects in relative proximity will decrease O&M expenditures due to economies of scales and personnel efficiencies. This would need to be balanced with the need for geographic diversity.

d. Assess and develop necessary transmission facilities to deliver electricity generated from new facilities.

12. Implement a renewable energy feed-in tariff program to encourage 150 MW of renewable generation resources to be developed by 2016 and to expand the feed-in tariff program to reach 450 MW by 2023.
13. Promote high levels of electrification in the transportation sector as a strategy to decrease overall greenhouse gas emissions in the City of Los Angeles. A high level of electrification is expected to provide fuel switching for approximately 580,000 vehicles by 2030, reduce overall GHG emissions in Los Angeles by 3.0 million metric tons by 2030, and increase load growth by 2,344 GWh by 2030 and pursue associated GHG credits.
14. Continue to refine and optimize strategic cases with the goal of balancing environmental stewardship, superior reliability, and competitive rates.
15. Encourage the development of 190 MW incremental, for a total of 310 MW of customer net-metered solar projects to be installed before 2019.
16. Develop up to 40 MW of Community Solar capacity on existing city owned property before 2020.
17. Implement recommendations from the Fuel Hedging Plan finalized in 2014 to limit LADWP's exposure to volatile natural gas prices.
18. Review the energy storage plan of 154 MW by 2021 in conformance to AB2514 for technical and economic viability with SB 350 targets.
19. Refine and implement a Smart Grid strategy that can assist in the procurement and development of advanced technologies to support areas such as: weather forecasting/ energy scheduling, customer kWh metering, high speed communications and information systems, and energy storage systems. Deployment of these technologies will increase operational efficiency, help reduce system losses, improve outage response times, increase utilization of predictive/proactive maintenance techniques for improved grid reliability, enable better management of the Power System, and lower costs.

5.7 Long-Term Planning Considerations

The analysis and conclusions contained in this IRP are heavily dependent on a number of assumptions, such as the projected fuel and purchase power costs, RPS target goals, renewable generation costs, proposed state and federal mandates, and GHG emissions costs. If these assumptions were to change, LADWP's long-term strategies will need to change accordingly.

As the RPS portfolio continues to increase, energy prices will have less value during the afternoon period, when the over-generation is expected to take place. Contrarily, energy will have more value once the sun sets and gas-fired generation and larger hydro are expected to quickly ramp up within a few hours to meet the evening peak. Future IRPs will investigate the need for a new rate design, in which time-of-use pricing may be considered as a strategy to encourage customers to reduce the evening peak and consume more during over-generation events when excess energy from renewables is plentiful. Next year's 2016 IRP will include an

IRP Advisory Committee that will stimulate discussion on future strategies for rate design as well as smart metering.

Integrated resource planning is an on-going process. LADWP will continue to adapt and refine the IRP as the uncertainties are better understood, and policy direction and requirements are solidified. Last year's 2014 IRP process includes a public outreach process and the next IRP public outreach will be undertaken in 2016.

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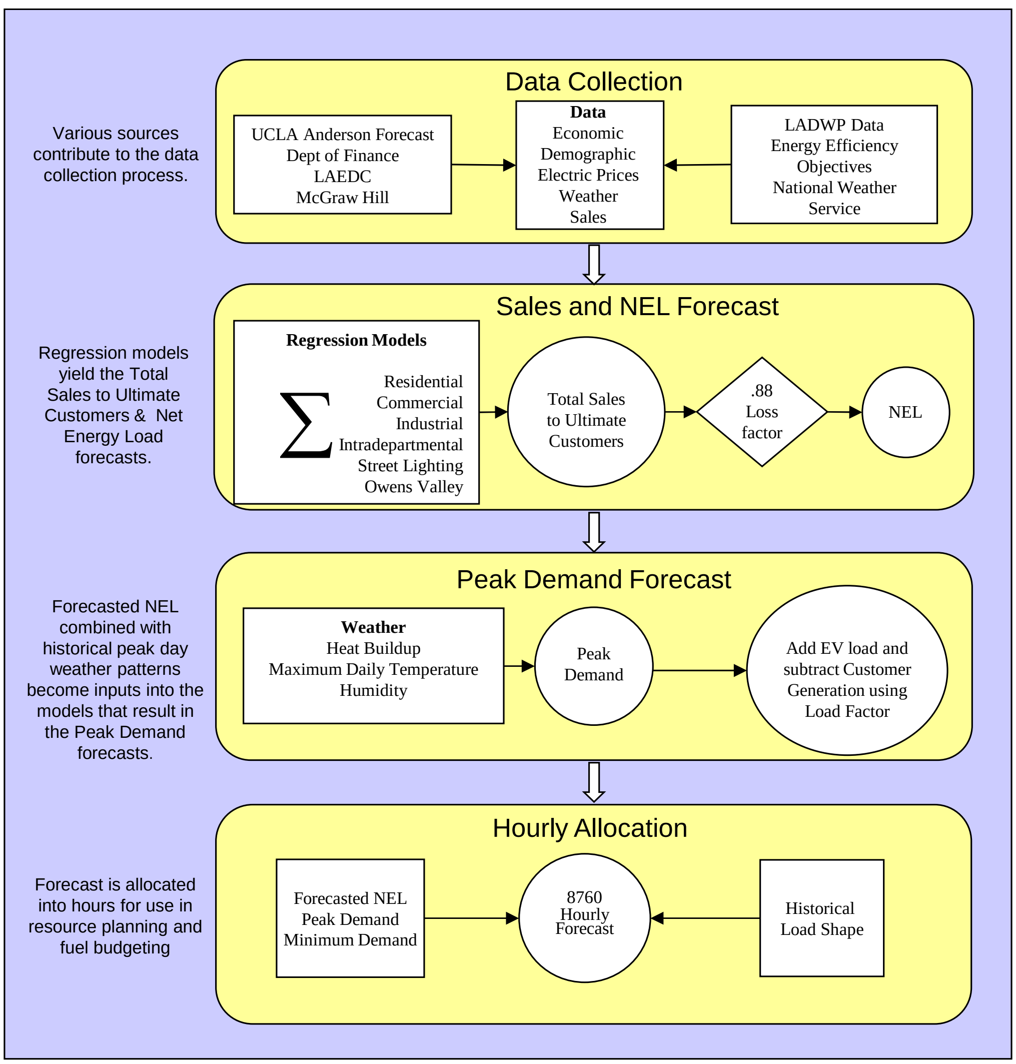
Appendix A. Load Forecasting

A.1 Overview

The 2015 Retail Sales and Demand Forecast (2015 Forecast) is a long-run projection of electrical energy sales, production, and peak demands for the City of Los Angeles (City) and Owens Valley. Los Angeles Department of Water and Power (LADWP) adopted the 2014 Retail Electric Sales and Demand Forecast (Appendix A) as the 2015 Retail Electric Sales and Demand Forecast. 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 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 purchases a construction forecast from McGraw-Hill Construction service. 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 is 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 seven separate customer classes; residential, commercial, industrial, plug-in electric vehicle (PEV), intradepartmental, 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. Intradepartmental sales are sales to the Water System and are primarily related to water pumping activities.

In September 2013, LADWP implemented a new Customer Care & Billing System (CCB). CCB classified retail customers into six classes that include residential, apartment, commercial, industrial, municipal (City of Los Angeles government including Water System), and government (other non-City of Los Angeles governments like State, Federal and Public Universities). As CCB experienced technical issues the raw sales data was not made available until February of 2015. At least five years of consistent historic sales data from these new customer classes is required to provide a statistically viable time series forecast that projects sales 20 years out. Therefore, the load forecasting group will continue to forecast utilizing the previous classifications utilizing a back-casting method that remaps electric sales to the previous classifications.

The California Energy Commission's 2013 Plug-in Electric Vehicle (PEV) forecast has been adapted to the LADWP service area. Further, PEV load is forecasted as a separate class, which will facilitate financial modeling due to the expected subsidies and production modeling as PEV 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 six single equations plus the adapted PEV 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, and the California Energy Crisis. The equations fit historical data quite accurately, producing coefficients of determination (R-Squared) statistics greater than 80 percent. For the streetlight, intradepartmental, and the Owens Valley sales classes, time series trend models are used. The results of the six equations plus the PEV 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 System is run. Electricity generated in distant places will have a higher loss factor than electricity generated located locally. The change in loss factor is accounted for in resource planning models.

The 2015 Forecast includes committed energy efficiency and customer self-generation. Committed energy efficiency includes budgeted utility programs and expected energy efficiency gains from the Huffman Bill lighting standards. Expected Huffman Bill energy efficiency savings were developed by Global Energy for the 2013 LADWP Energy Potential study. Since the 2015 Forecast is created early in the planning process, budgeted utility energy efficiency programs are subject to change. Planners using the 2015 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 similar to the 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 forty-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 40 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 ninety percent of the time the actual peak day temperature is expected to be below it and ten percent 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 the alternative peak demand forecasts.

In the Integrated Resource Plan, LADWP uses the One-in-Ten Case Peak Demand forecast rather than the Base Case forecast. LADWP's policy regarding obligation to serve is to be self-sufficient in supplying native load and not rely on external energy markets. The Base Case Peak Demand forecast falls short of this standard since it is expected that fifty percent of the time actual peak demands will exceed the Base Case Peak Demand forecast. The One-in-Ten Case provides LADWP ninety percent confidence that the forecasted peak demand will not be exceeded in any given year.

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 forecast 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 2014 Appendix A Forecast.

Fiscal Year	SECTOR SALES Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	PHEV Sales (GWh)	Total Sales to Ultimate Customers (GWh)	Net Energy for Load (GWh)	Peak Demand (MW)
1990-91	6,805	11,457	3,051	501		21,814	24,399	3,595
1991-92	6,699	11,343	2,979	500		21,521	24,088	3,854
1992-93	7,026	11,589	2,682	472		21,769	24,428	4,114
1993-94	6,572	10,903	2,485	453		20,413	23,066	4,373
1994-95	6,711	10,858	2,404	501		20,475	22,929	4,633
1995-96	6,855	11,336	2,537	486		21,214	23,894	4,892
1996-97	6,975	11,314	2,579	531		21,399	24,467	5,111
1997-98	7,141	11,402	2,642	525		21,710	24,656	5,492
1998-99	7,298	11,523	2,556	552		21,929	25,069	5,630
1999-00	7,187	11,858	2,637	546		22,227	25,601	5,368
2000-01	7,542	12,107	2,754	531		22,934	25,688	5,299
2001-02	7,282	11,843	2,496	528		22,149	24,903	4,805
2002-03	7,358	12,077	2,383	545		22,363	25,370	5,185
2003-04	8,061	12,408	2,485	565		23,520	26,701	5,410
2004-05	7,907	12,374	2,447	551		23,279	26,338	5,418
2005-06	8,051	12,580	2,451	551		23,634	26,828	5,667
2006-07	8,495	12,984	2,332	567		24,378	27,502	6,102
2007-08	8,540	13,134	2,366	576		24,617	27,928	6,071
2008-09	8,578	13,084	2,303	560		24,526	27,447	5,647
2009-10	8,300	12,467	2,073	532		23,373	26,526	5,709
2010-11	8,068	12,342	2,189	464		23,062	26,252	6,142
2011-12	8,162	12,507	1,924	444		23,037	26,552	5,907
2012-13	8,442	12,759	1,947	401		23,548	27,086	5,782
2013-14	7,959	12,586	1,842	484		22,871	26,765	5,862
2014-15	8,327	12,990	2,008	375	104	23,804	27,221	6,343
2015-16	8,314	12,986	2,020	400	144	23,863	27,116	5,741
2016-17	8,206	12,760	1,985	426	224	23,601	26,878	5,721
2017-18	8,215	12,586	1,989	440	270	23,500	26,714	5,671
2018-19	8,242	12,413	1,994	442	350	23,442	26,638	5,650
2019-20	8,279	12,251	1,997	444	429	23,399	26,695	5,634
2020-21	8,328	12,339	1,997	446	512	23,622	26,859	5,638
2021-22	8,411	12,576	1,998	448	592	24,024	27,297	5,730
2022-23	8,510	12,772	1,997	449	675	24,403	27,728	5,812
2023-24	8,613	12,989	1,996	451	755	24,803	28,253	5,899
2024-25	8,710	13,230	1,994	453	834	25,221	28,649	5,991
2025-26	8,798	13,476	1,995	455	897	25,621	29,109	6,084
2026-27	8,886	13,718	1,996	457	963	26,020	29,561	6,174
2027-28	8,977	13,967	1,996	458	1,018	26,417	30,085	6,265
2028-29	9,069	14,223	1,997	460	1,073	26,822	30,471	6,357
2029-30	9,161	14,482	1,998	462	1,119	27,222	30,930	6,449
2030-31	9,255	14,744	1,999	464	1,172	27,634	31,395	6,543
2031-32	9,351	15,006	2,000	466	1,220	28,043	31,931	6,637
2032-33	9,448	15,269	2,001	468	1,272	28,457	32,330	6,746
2033-34	9,545	15,535	2,002	469	1,320	28,871	32,801	6,827
2034-35	9,640	15,802	2,003	471	1,372	29,288	33,274	6,922
2035-36	9,738	16,071	2,004	473	1,420	29,706	33,821	7,018
2036-37	9,835	16,342	2,005	475	1,472	30,128	34,229	7,129
2037-38	9,930	16,616	2,006	477	1,521	30,549	34,709	7,211
2038-39	10,028	16,892	2,007	478	1,571	30,976	35,193	7,309
2039-40	10,128	17,168	2,008	480	1,621	31,405	35,749	7,407

Table updated through December 2014

Annual Percent Change								
1991-2001	1.03%	0.55%	-1.02%	0.58%		0.50%	0.52%	3.96%
2001-11	1.03%	0.41%	-1.31%	-1.29%		0.40%	0.53%	2.49%
2012-17	-0.57%	0.00%	0.39%	1.23%		0.04%	-0.15%	-0.21%
2012-22	-0.04%	-0.14%	0.26%	1.11%		0.20%	0.08%	-0.09%
2012-32	0.51%	0.81%	0.13%	0.76%		0.88%	0.83%	0.69%
2012-40	0.65%	1.07%	0.11%	0.65%		1.03%	1.00%	0.89%

*** Includes Streetlighting, Owens Valley, and Intra-Departmental**
PHEV Sales & Program Impacts are embedded in historic sector sales

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CITY OF LOS ANGELES

DEPARTMENT

OF

WATER AND POWER

2014 RETAIL ELECTRIC SALES AND DEMAND FORECAST

APPENDIX A

Randy S. Howard
Senior Assistant General Manager
Power System

Philip Leiber
Chief Financial Officer

September 26, 2014
Load Forecasting, Room 956
Financial Services Organization

Table of Contents

TABLES 3
Peak Demand—Fiscal Year *3*
Minimum Demand— Fiscal Year *4*
Net Energy for Load— Fiscal Year *5*
Total Sales to Ultimate Customers— Fiscal Year *6*
Residential Sales— Fiscal Year *7*
Commercial Sales— Fiscal Year *8*
Industrial Sales— Fiscal Year *9*
Intradepartmental Sales— Fiscal Year *10*
Streetlight Sales— Fiscal Year *11*
Owens Valley Sales— Fiscal Year *12*
Electric Vehicle Sales— Fiscal Year *13*
R-1A & B Sales—Fiscal Year *14*
R-1 Lifeline Sales—Fiscal Year *15*
R-1 Low Income Sales—Fiscal Year *16*
A-1 Sales—Fiscal Year *17*
A-2 Sales—Fiscal Year *18*
A-3 Sales—Fiscal Year *19*
Experimental and Contract Rate Sales—Fiscal Year *20*
Residential Accumulated Energy Efficiency Savings—Fiscal Year *21*
Commercial Accumulated Energy Efficiency Savings—Fiscal Year *22*
Cross Cutting Accumulated Energy Efficiency Savings—Fiscal Year *23*
Huffman Bill Accumulated Energy Efficiency Savings—Fiscal Year *24*
Solar Rooftop Accumulated Energy Efficiency Savings—Fiscal Year *25*

PEAK DEMAND - MW
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2001-02	4799	4805	4681	4604	3694	3626	3632	3576	3421	3599	4177	4493	4805
2002-03	4910	4874	5185	4463	4039	3735	3878	3724	3932	3860	4782	4522	5185
2003-04	5337	5410	5273	4159	3825	3887	3632	3606	4080	5161	5316	4448	5410
2004-05	5402	5123	5418	4087	3701	3956	3848	3698	3583	3815	4629	4524	5418
2005-06	5667	5405	5093	4692	4040	3732	3709	3702	3677	3592	4587	5498	5667
2006-07	6102	5305	5656	4529	4406	3965	4023	3694	4214	4059	4840	4729	6102
2007-08	5341	6071	5917	4557	4052	3908	3908	3778	3868	4769	5303	6006	6071
2008-09	5128	5384	5472	5647	3997	4176	3707	3672	3706	5064	4761	4304	5647
2009-10	5569	5553	5709	4510	3794	3918	3925	3756	3597	3523	3818	4322	5709
2010-11	5511	5592	6142	4900	4457	3786	3766	3628	4114	4246	4518	4387	6142
2011-12	5340	5348	5907	5039	3591	3887	3575	3525	3457	4071	4288	4343	5907
2012-13	5001	5782	5775	5585	4111	3807	3854	3546	3620	3712	5224	5226	5782
2013-14	5300	5856	5862	3964	3892	3798	3472	3458	3649	4320	5612	4576	5862

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2014-15	5517	5327	5445	4641	4082	4051	3944	3917	3917	4247	4576	4846	5517
2015-16	5448	5741	5450	4646	4083	4052	3928	3901	3901	4233	4561	4830	5741
2016-17	5430	5721	5431	4631	4066	4035	3895	3868	3868	4196	4521	4787	5721
2017-18	5382	5671	5383	4590	4032	4001	3881	3855	3854	4179	4503	4769	5671
2018-19	5361	5650	5363	4572	4018	3987	3872	3846	3846	4166	4490	4755	5650
2019-20	5346	5634	5348	4558	4009	3978	3878	3853	3851	4168	4492	4758	5634
2020-21	5350	5638	5351	4561	4015	3984	3944	3917	3917	4236	4565	4835	5638
2021-22	5437	5730	5439	4635	4083	4052	4005	3978	3978	4295	4629	4903	5730
2022-23	5515	5812	5516	4700	4146	4115	4069	4042	4041	4357	4697	4975	5812
2023-24	5597	5899	5598	4769	4213	4181	4138	4102	4109	4424	4769	5052	5899
2024-25	5684	5991	5686	4842	4283	4251	4205	4177	4176	4490	4841	5129	5991
2025-26	5771	6084	5773	4916	4353	4320	4271	4242	4242	4556	4913	5205	6084
2026-27	5857	6174	5859	4989	4422	4388	4337	4307	4307	4621	4984	5280	6174
2027-28	5942	6265	5944	5061	4490	4455	4403	4357	4373	4688	5056	5358	6265
2028-29	6030	6357	6032	5134	4559	4524	4470	4440	4439	4756	5129	5435	6357
2029-30	6117	6449	6119	5208	4627	4592	4537	4506	4506	4824	5203	5513	6449
2030-31	6206	6543	6208	5283	4697	4661	4605	4574	4573	4892	5277	5592	6543
2031-32	6295	6637	6297	5359	4767	4731	4673	4615	4641	4961	5351	5671	6637
3032-33	6384	6746	6386	5434	4838	4801	4741	4709	4709	5030	5426	5751	6746
2033-34	6474	6827	6476	5510	4909	4871	4810	4777	4777	5099	5501	5830	6827
2034-35	6564	6922	6566	5586	4980	4942	4879	4846	4846	5169	5576	5910	6922
2035-36	6655	7018	6657	5663	5051	5013	4949	4880	4915	5239	5652	5991	7018
2036-37	6747	7129	6749	5740	5123	5084	5018	4984	4984	5310	5729	6072	7129
2037-38	6838	7211	6840	5818	5195	5156	5088	5054	5054	5380	5805	6154	7211
2038-39	6930	7309	6933	5896	5268	5228	5159	5124	5124	5452	5883	6236	7309
2039-40	7024	7407	7026	5975	5341	5300	5230	5149	5194	5523	5960	6318	7407

MINIMUM DEMAND - MW
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2001-02	1933	1944	1985	1927	1879	1988	2010	1936	1881	1932	1879	1942	1936
2002-03	2009	1986	2015	1940	1917	1984	1996	1996	1913	1858	1892	1996	1959
2003-04	2140	2187	2163	1808	1982	2030	2107	2103	1931	1926	1912	2095	2032
2004-05	2071	2171	2161	2061	2057	2108	1984	2083	1982	1944	1925	2035	2049
2005-06	2100	2187	2043	2083	2085	2128	2109	2074	2114	2041	2068	2122	2096
2006-07	2406	2246	2196	2093	2088	2242	2276	2170	2080	2036	2050	2152	2170
2007-08	2287	2289	2173	2146	2106	2114	2229	2190	2121	2125	2078	2192	2171
2008-09	2262	2347	2229	2182	2091	2155	2131	2135	2117	2022	2062	1997	2144
2009-10	2041	2172	2155	2049	2050	2170	2142	2107	2047	2015	2000	2066	2085
2010-11	2084	1925	1981	2029	2045	2091	2126	2151	2094	2061	2031	2055	2056
2011-12	2114	2207	2134	2056	2062	2144	2033	2042	2016	2108	2058	2150	2094
2012-13	2039	2244	2176	2091	2024	2101	2077	2037	2020	2039	2116	2024	2082

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2013-14	2189	2108	2034	2086	2053	2076	2108	2044	2149	2087	2201	2230	2114
2014-15	2354	2327	2074	2178	2128	2202	2189	2167	2054	2046	1970	2036	2144
2015-16	2095	2223	2075	2179	2128	2203	2180	2235	2045	2038	1962	2027	2116
2016-17	2087	2213	2066	2170	2120	2194	2161	2140	2028	2021	1945	2010	2096
2017-18	2069	2195	2049	2151	2102	2175	2154	2133	2021	2014	1939	2003	2084
2018-19	2062	2187	2042	2144	2094	2168	2149	2128	2017	2009	1934	1999	2078
2019-20	2057	2182	2037	2139	2090	2163	2152	2208	2019	2012	1937	2001	2083
2020-21	2060	2185	2040	2142	2093	2166	2189	2167	2054	2046	1970	2035	2096
2021-22	2095	2222	2075	2178	2128	2203	2223	2201	2086	2078	2001	2067	2130
2022-23	2128	2257	2107	2212	2161	2237	2258	2236	2119	2111	2033	2100	2163
2023-24	2162	2293	2141	2248	2196	2273	2296	2351	2155	2147	2067	2136	2205
2024-25	2198	2332	2177	2285	2233	2311	2334	2311	2190	2182	2100	2170	2235
2025-26	2234	2370	2212	2323	2269	2349	2370	2347	2224	2216	2134	2205	2271
2026-27	2269	2407	2247	2359	2305	2386	2407	2383	2258	2250	2166	2238	2306
2027-28	2304	2444	2281	2396	2340	2422	2444	2497	2293	2285	2199	2273	2348
2028-29	2339	2481	2316	2432	2376	2459	2480	2456	2328	2319	2233	2307	2377
2029-30	2374	2519	2351	2469	2412	2496	2518	2493	2363	2354	2266	2342	2413
2030-31	2410	2557	2387	2506	2448	2534	2555	2530	2398	2389	2300	2377	2449
2031-32	2446	2595	2422	2544	2485	2572	2593	2645	2433	2425	2334	2412	2492
3032-33	2482	2633	2458	2581	2522	2610	2631	2606	2469	2460	2368	2447	2522
2033-34	2519	2672	2494	2619	2559	2648	2669	2643	2505	2496	2403	2483	2559
2034-35	2555	2711	2530	2657	2596	2686	2708	2681	2541	2532	2437	2518	2596
2035-36	2592	2750	2567	2695	2633	2725	2746	2796	2577	2568	2472	2554	2640
2036-37	2629	2789	2603	2733	2670	2764	2785	2758	2613	2604	2507	2590	2670
2037-38	2666	2828	2640	2772	2708	2803	2824	2796	2650	2640	2542	2626	2708
2038-39	2703	2867	2677	2811	2746	2842	2863	2835	2687	2677	2577	2663	2746
2039-40	2741	2907	2714	2850	2784	2882	2902	2951	2723	2714	2612	2699	2790

NET ENERGY FOR LOAD- GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2000-2001 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2206	2338	2138	2109	1965	2044	2100	1830	1972	1966	2068	2168	24903
2002-03	2391	2324	2306	2096	2005	2076	2077	1854	2069	1957	2104	2111	25370
2003-04	2581	2621	2352	2262	1983	2139	2119	1964	2136	2069	2253	2221	26701
2004-05	2460	2444	2440	2175	2051	2187	2166	1912	2101	2020	2209	2172	26338
2005-06	2582	2572	2232	2221	2076	2154	2141	1927	2143	2015	2238	2527	26828
2006-07	2935	2589	2398	2187	2142	2227	2178	1972	2200	2091	2267	2318	27502
2007-08	2664	2760	2420	2267	2119	2222	2251	2079	2144	2132	2288	2580	27928
2008-09	2701	2703	2528	2406	2115	2240	2187	1962	2131	2069	2253	2152	27447
2009-10	2597	2523	2542	2176	2030	2201	2151	1917	2087	1985	2078	2239	26526
2010-11	2373	2424	2311	2171	2069	2165	2193	1953	2185	2068	2157	2183	26252
2011-12	2514	2570	2333	2201	2038	2164	2094	1916	2084	2111	2264	2262	26552
2012-13	2448	2845	2600	2288	2032	2178	2163	1885	2048	2077	2290	2231	27086
2013-14	2534	2523	2436	2160	2017	2124	2077	1860	2166	2118	2398	2353	26765

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	2691	2631	2406	2285	2116	2214	2193	1975	2157	2086	2223	2244	27221
2015-16	2569	2626	2407	2286	2117	2215	2184	2037	2148	2078	2214	2235	27116
2016-17	2559	2615	2397	2276	2108	2206	2166	1950	2130	2060	2195	2216	26878
2017-18	2537	2593	2376	2257	2090	2187	2158	1944	2123	2053	2187	2208	26714
2018-19	2528	2584	2368	2249	2083	2179	2154	1939	2118	2048	2183	2203	26638
2019-20	2523	2579	2363	2244	2078	2175	2157	2012	2121	2051	2186	2206	26695
2020-21	2526	2582	2366	2248	2081	2178	2193	1975	2157	2086	2223	2244	26859
2021-22	2569	2626	2406	2286	2116	2215	2227	2006	2191	2118	2257	2279	27297
2022-23	2609	2667	2444	2321	2149	2249	2263	2038	2226	2153	2294	2315	27728
2023-24	2651	2710	2483	2359	2184	2285	2301	2142	2263	2189	2332	2354	28253
2024-25	2696	2755	2525	2398	2220	2324	2339	2106	2300	2224	2370	2393	28649
2025-26	2740	2800	2566	2437	2257	2361	2375	2139	2336	2259	2408	2430	29109
2026-27	2783	2844	2606	2476	2292	2399	2412	2172	2372	2294	2444	2467	29561
2027-28	2825	2888	2646	2514	2327	2435	2449	2275	2408	2329	2482	2505	30085
2028-29	2869	2932	2687	2552	2363	2473	2486	2239	2445	2364	2519	2543	30471
2029-30	2912	2976	2727	2591	2399	2510	2523	2272	2481	2400	2557	2581	30930
2030-31	2956	3021	2768	2630	2435	2548	2561	2306	2519	2436	2596	2620	31395
2031-32	3000	3066	2810	2669	2471	2586	2599	2410	2556	2472	2634	2659	31931
2032-33	3044	3112	2851	2708	2508	2624	2637	2375	2593	2508	2672	2698	32330
2033-34	3089	3157	2893	2748	2545	2663	2675	2409	2631	2544	2711	2737	32801
2034-35	3134	3203	2935	2788	2581	2701	2713	2444	2669	2581	2750	2776	33274
2035-36	3179	3249	2977	2828	2618	2740	2752	2548	2707	2618	2789	2816	33821
2036-37	3224	3295	3019	2868	2656	2779	2791	2513	2745	2654	2829	2855	34229
2037-38	3269	3342	3062	2909	2693	2818	2830	2548	2783	2692	2868	2895	34709
2038-39	3315	3388	3105	2949	2731	2857	2869	2584	2822	2729	2908	2935	35193
2039-40	3361	3436	3148	2990	2769	2897	2909	2689	2860	2766	2948	2976	35749

TOTAL SALES TO ULTIMATE CUSTOMERS- GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1971	1948	2055	1903	1845	1794	1827	1798	1738	1724	1657	1888	22149
2002-03	1977	1932	1977	2037	1819	1918	1849	1872	1678	1755	1691	1860	22363
2003-04	1948	2164	2200	2110	2027	1891	2006	1810	1735	1852	1843	1933	23520
2004-05	1991	2120	2116	2070	1895	1977	1969	1852	1778	1798	1756	1956	23279
2005-06	1998	2176	2151	2055	1874	2038	1985	1863	1831	1828	1781	2053	23634
2006-07	2234	2390	2304	2137	1953	1959	1983	1932	1852	1853	1850	1932	24378
2007-08	2147	2253	2365	2187	1986	1979	2005	2015	1896	1899	1855	2031	24617
2008-09	2383	2143	2300	2270	2079	1964	2007	2002	1799	1819	1836	1926	24526
2009-10	1982	2127	2253	2289	1867	1881	1947	1925	1760	1745	1712	1884	23373
2010-11	1944	1988	2069	2110	1892	1961	1958	1941	1789	1826	1780	1803	23062
2011-12	1981	2043	2176	2074	1885	1895	1881	1814	1745	1798	1813	1932	23037
2012-13	1951	2079	2322	2294	2031	1940	1921	1879	1760	1717	1770	1884	23548
2013-14	2017	2088	2214	2119	1945	1926	2004	1909	1844	1813	1843	1944	23666

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	2080	2149	2213	2110	1981	1949	2005	1906	1838	1804	1834	1936	23804
2015-16	2088	2157	2221	2118	1987	1954	2010	1911	1842	1806	1835	1936	23863
2016-17	2068	2135	2201	2099	1970	1937	1992	1890	1818	1779	1807	1906	23601
2017-18	2055	2123	2194	2092	1963	1930	1986	1883	1810	1771	1798	1896	23500
2018-19	2045	2114	2188	2087	1960	1928	1985	1880	1807	1767	1792	1889	23442
2019-20	2038	2108	2184	2083	1956	1925	1983	1878	1804	1765	1790	1885	23399
2020-21	2038	2112	2192	2094	1969	1938	2007	1903	1831	1795	1823	1923	23622
2021-22	2077	2151	2230	2130	2004	1973	2034	1932	1861	1825	1854	1955	24024
2022-23	2110	2184	2262	2162	2034	2003	2064	1962	1892	1856	1886	1988	24403
2023-24	2145	2219	2297	2195	2066	2035	2096	1995	1924	1889	1919	2024	24803
2024-25	2181	2256	2333	2231	2101	2069	2130	2028	1958	1922	1953	2059	25221
2025-26	2217	2292	2368	2265	2133	2100	2161	2060	1990	1955	1987	2093	25621
2026-27	2253	2328	2403	2299	2166	2132	2193	2092	2021	1987	2019	2127	26020
2027-28	2288	2364	2437	2332	2198	2163	2224	2124	2053	2019	2053	2162	26417
2028-29	2324	2400	2473	2366	2231	2196	2257	2156	2086	2052	2086	2196	26822
2029-30	2359	2435	2507	2400	2263	2227	2289	2188	2118	2085	2119	2231	27222
2030-31	2396	2472	2543	2435	2297	2260	2321	2221	2151	2118	2153	2267	27634
2031-32	2432	2508	2579	2469	2330	2292	2354	2254	2184	2151	2187	2302	28043
3032-33	2468	2545	2615	2504	2363	2326	2387	2287	2218	2185	2222	2337	28457
2033-34	2505	2582	2651	2539	2397	2358	2420	2320	2251	2219	2256	2373	28871
2034-35	2542	2619	2687	2575	2431	2392	2453	2353	2284	2252	2291	2409	29288
2035-36	2579	2656	2723	2610	2465	2425	2486	2387	2318	2286	2325	2445	29706
2036-37	2616	2694	2760	2646	2499	2459	2520	2421	2352	2321	2360	2481	30128
2037-38	2653	2731	2796	2681	2533	2492	2554	2455	2386	2355	2395	2518	30549
2038-39	2691	2769	2833	2717	2568	2526	2588	2489	2421	2390	2431	2554	30976
2039-40	2729	2807	2870	2753	2603	2560	2622	2523	2455	2425	2466	2591	31405

RESIDENTIAL SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	608	659	640	661	582	622	653	654	568	559	520	557	7282
2002-03	600	673	670	678	595	618	652	647	560	560	530	576	7358
2003-04	639	773	787	746	641	682	701	688	596	595	578	635	8061
2004-05	630	726	745	731	620	680	724	687	600	606	552	606	7907
2005-06	640	772	771	712	610	659	701	685	625	649	583	644	8051
2006-07	774	919	838	750	629	669	724	733	631	624	576	628	8495
2007-08	694	812	838	799	646	694	734	761	664	634	593	670	8540
2008-09	758	859	815	816	692	706	731	735	636	616	581	634	8578
2009-10	665	793	820	819	675	696	712	725	629	598	560	607	8300
2010-11	635	710	720	765	659	697	720	719	631	631	581	600	8068
2011-12	647	753	806	760	651	698	713	698	616	628	575	618	8162
2012-13	648	772	854	902	721	686	721	753	617	592	553	622	8442
2013-14	697	759	794	790	674	666	744	726	664	625	607	630	8377

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	704	775	802	757	683	677	734	715	652	612	596	621	8327
2015-16	702	775	801	756	681	675	733	715	651	610	594	620	8314
2016-17	693	766	793	748	673	666	724	706	641	600	584	610	8206
2017-18	692	766	793	749	674	667	726	708	643	601	585	611	8215
2018-19	694	767	796	752	676	670	729	711	645	603	587	613	8242
2019-20	696	770	799	755	680	673	733	714	648	606	590	615	8279
2020-21	699	774	804	761	685	676	736	717	651	609	594	621	8328
2021-22	705	781	810	766	689	682	743	725	660	618	602	629	8411
2022-23	714	790	819	774	697	690	751	734	668	626	610	638	8510
2023-24	723	799	828	783	706	698	760	742	676	634	619	646	8613
2024-25	732	808	837	792	714	705	768	750	683	641	626	654	8710
2025-26	740	817	845	799	721	712	775	757	690	648	633	661	8798
2026-27	748	824	852	807	728	719	782	764	698	655	640	669	8886
2027-28	756	833	861	815	735	726	789	772	705	663	648	676	8977
2028-29	764	841	869	822	742	733	796	779	712	670	655	684	9069
2029-30	772	849	877	830	750	741	804	787	720	677	662	692	9161
2030-31	780	858	885	838	757	748	812	794	727	685	670	700	9255
2031-32	789	867	894	847	765	756	819	802	735	693	678	708	9351
3032-33	797	875	902	855	773	763	827	810	743	700	686	716	9448
2033-34	805	884	911	863	781	771	835	818	751	708	693	724	9545
2034-35	814	893	920	871	788	778	843	826	758	716	701	732	9640
2035-36	822	902	928	880	796	786	851	834	766	724	709	740	9738
2036-37	831	911	937	888	804	793	858	842	774	731	717	748	9835
2037-38	839	919	945	896	812	801	866	850	782	739	724	756	9930
2038-39	848	928	954	905	820	809	874	858	789	747	732	764	10028
2039-40	857	937	963	913	828	816	882	866	798	755	740	773	10128

COMMERCIAL SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1086	1025	1147	975	1020	952	916	887	936	931	902	1067	11843
2002-03	1141	983	1050	1091	989	1065	951	969	885	959	958	1036	12077
2003-04	1023	1140	1154	1101	1084	969	1073	862	943	979	1017	1064	12408
2004-05	1084	1124	1129	1099	989	1046	1013	934	956	954	964	1082	12374
2005-06	1097	1151	1121	1115	1019	1081	1027	958	959	952	984	1116	12580
2006-07	1201	1216	1181	1134	1093	1085	1009	968	999	997	1039	1063	12984
2007-08	1169	1171	1254	1130	1090	1062	1051	1022	1002	1023	1048	1111	13134
2008-09	1369	1035	1225	1200	1144	1055	1031	1033	950	958	1025	1061	13084
2009-10	1097	1066	1190	1240	980	1007	1016	984	925	958	964	1040	12467
2010-11	1084	1062	1125	1119	1025	1011	1018	992	938	959	1004	1005	12342
2011-12	1122	1092	1146	1112	1039	1009	977	936	967	981	1042	1084	12507
2012-13	1107	1117	1250	1176	1122	1076	981	939	958	956	1010	1067	12759
2013-14	1120	1103	1209	1126	1075	1064	1060	990	985	998	1035	1106	12872

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	1159	1159	1195	1143	1095	1069	1062	991	985	997	1033	1103	12990
2015-16	1162	1161	1198	1146	1097	1071	1063	990	982	993	1027	1095	12986
2016-17	1144	1142	1181	1129	1081	1055	1047	972	963	971	1005	1071	12760
2017-18	1128	1126	1167	1115	1068	1043	1035	958	948	956	989	1054	12586
2018-19	1110	1109	1152	1101	1055	1030	1022	945	935	942	974	1037	12413
2019-20	1094	1092	1137	1087	1042	1017	1010	932	922	931	962	1024	12251
2020-21	1084	1084	1133	1085	1042	1019	1023	947	939	950	984	1049	12339
2021-22	1110	1110	1158	1109	1065	1043	1037	961	954	965	999	1066	12576
2022-23	1127	1128	1175	1125	1081	1058	1052	976	969	981	1016	1084	12772
2023-24	1146	1147	1193	1143	1098	1075	1069	993	987	999	1035	1104	12989
2024-25	1167	1168	1214	1163	1117	1094	1088	1012	1006	1019	1056	1126	13230
2025-26	1189	1190	1235	1184	1137	1113	1107	1032	1026	1039	1076	1147	13476
2026-27	1211	1212	1257	1205	1157	1132	1126	1051	1045	1058	1096	1169	13718
2027-28	1233	1234	1278	1225	1177	1152	1145	1070	1065	1079	1117	1191	13967
2028-29	1256	1257	1300	1247	1198	1172	1165	1090	1085	1099	1139	1213	14223
2029-30	1279	1280	1323	1269	1219	1193	1186	1111	1106	1121	1161	1236	14482
2030-31	1303	1304	1345	1291	1240	1213	1206	1131	1127	1142	1183	1259	14744
2031-32	1327	1327	1368	1313	1261	1234	1227	1152	1148	1163	1204	1282	15006
3032-33	1350	1351	1391	1335	1282	1255	1247	1173	1169	1185	1227	1305	15269
2033-34	1374	1374	1414	1357	1304	1276	1268	1194	1190	1206	1249	1328	15535
2034-35	1398	1398	1437	1380	1325	1297	1289	1215	1212	1228	1271	1352	15802
2035-36	1422	1422	1461	1403	1347	1318	1310	1236	1233	1250	1294	1375	16071
2036-37	1446	1447	1484	1425	1369	1340	1332	1257	1255	1272	1316	1399	16342
2037-38	1471	1471	1508	1448	1391	1362	1353	1279	1277	1294	1339	1423	16616
2038-39	1495	1496	1532	1472	1414	1384	1375	1301	1299	1317	1362	1447	16892
2039-40	1520	1520	1556	1495	1436	1406	1397	1322	1321	1339	1385	1471	17168

INDUSTRIAL SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	232	217	219	217	199	182	217	213	195	194	194	218	2496
2002-03	187	225	205	219	189	199	192	212	195	195	163	203	2383
2003-04	237	202	210	229	242	197	186	213	152	231	199	187	2485
2004-05	229	218	192	190	245	208	190	188	182	195	193	218	2447
2005-06	209	198	216	180	206	251	207	175	204	187	173	245	2451
2006-07	209	205	233	203	187	166	204	188	175	186	187	190	2332
2007-08	232	214	220	209	206	176	175	184	185	195	167	202	2366
2008-09	206	201	210	202	194	158	201	188	171	203	185	184	2303
2009-10	171	218	196	180	163	134	177	174	167	148	147	199	2073
2010-11	181	175	184	183	171	214	185	195	184	200	160	156	2189
2011-12	173	153	185	162	159	150	155	147	129	154	168	188	1924
2012-13	157	155	182	176	157	147	186	153	156	132	184	160	1947
2013-14	167	196	178	172	167	167	170	165	163	161	165	170	2042

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	177	176	175	170	164	165	168	162	161	158	163	168	2008
2015-16	176	176	176	171	166	166	169	164	162	160	164	169	2020
2016-17	176	174	173	168	163	163	166	161	159	156	161	165	1985
2017-18	174	174	174	169	163	164	167	161	160	157	161	166	1989
2018-19	174	174	174	169	164	164	167	162	160	157	162	166	1994
2019-20	175	174	175	169	164	164	167	162	160	157	162	166	1997
2020-21	175	175	175	169	164	164	167	162	160	157	162	166	1997
2021-22	175	175	175	170	164	165	167	162	160	158	162	167	1998
2022-23	175	175	175	170	164	164	167	162	160	157	162	166	1997
2023-24	175	175	175	169	164	164	167	162	160	157	162	166	1996
2024-25	175	174	174	169	164	164	167	162	160	157	162	166	1994
2025-26	175	174	175	169	164	164	167	162	160	157	162	166	1995
2026-27	175	174	175	169	164	164	167	162	160	157	162	166	1996
2027-28	175	175	175	169	164	164	167	162	160	157	162	166	1996
2028-29	175	175	175	169	164	164	167	162	160	157	162	166	1997
2029-30	175	175	175	170	164	165	167	162	160	158	162	167	1998
2030-31	175	175	175	170	164	165	167	162	160	158	162	167	1999
2031-32	175	175	175	170	164	165	167	162	160	158	162	167	2000
3032-33	175	175	175	170	164	165	168	162	161	158	162	167	2001
2033-34	175	175	175	170	164	165	168	162	161	158	162	167	2002
2034-35	175	175	175	170	164	165	168	162	161	158	162	167	2003
2035-36	175	175	175	170	165	165	168	162	161	158	163	167	2004
2036-37	175	175	175	170	165	165	168	162	161	158	163	167	2005
2037-38	175	175	175	170	165	165	168	163	161	158	163	167	2006
2038-39	176	175	175	170	165	165	168	163	161	158	163	167	2007
2039-40	176	175	176	170	165	165	168	163	161	158	163	167	2008

INTRADEPARTMENTAL SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
1995-1996 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	13	14	17	16	12	5	9	10	8	9	10	12	136
2002-03	16	17	18	17	14	13	12	11	7	8	8	12	153
2003-04	16	15	16	15	14	13	12	12	10	9	8	10	150
2004-05	13	14	16	14	9	8	7	8	7	8	13	13	128
2005-06	13	14	13	11	8	10	8	9	8	7	7	10	119
2006-07	12	13	16	14	12	10	11	9	12	11	12	14	146
2007-08	13	13	15	13	10	10	10	10	9	11	12	10	135
2008-09	12	12	14	12	12	10	9	10	8	8	9	11	126
2009-10	11	11	10	12	9	10	9	9	9	9	7	7	115
2010-11	8	8	8	9	6	8	6	5	5	7	7	9	87
2011-12	10	10	10	9	8	8	7	6	7	5	6	9	95
2012-13	9	8	9	8	7	5	9	6	7	6	6	8	86

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2013-14	8	8	9	9	7	7	7	6	6	6	6	9	88
2014-15	9	8	9	9	7	7	7	6	6	6	6	9	89
2015-16	9	8	9	9	7	7	7	6	6	6	6	9	89
2016-17	9	8	9	9	7	7	7	6	6	6	6	9	89
2017-18	9	8	9	9	7	7	7	6	6	6	6	9	89
2018-19	9	8	9	9	7	7	7	6	6	6	6	9	89
2019-20	9	8	9	9	7	7	7	6	6	6	6	9	89
2020-21	9	8	9	9	7	7	7	6	6	6	6	9	89
2021-22	9	8	9	9	7	7	7	6	6	6	6	9	89
2022-23	9	8	9	9	7	7	7	6	6	6	6	9	89
2023-24	9	8	9	9	7	7	7	6	6	6	6	9	89
2024-25	9	8	9	9	7	7	7	6	6	6	6	9	89
2025-26	9	8	9	9	7	7	7	6	6	6	6	9	89
2026-27	9	8	9	9	7	7	7	6	6	6	6	9	89
2027-28	9	8	9	9	7	7	7	6	6	6	6	9	89
2028-29	9	8	9	9	7	7	7	6	6	6	6	9	89
2029-30	9	8	9	9	7	7	7	6	6	6	6	9	89
2030-31	9	8	9	9	7	7	7	6	6	6	6	9	89
2031-32	9	8	9	9	7	7	7	6	6	6	6	9	89
3032-33	9	8	9	9	7	7	7	6	6	6	6	9	89
2033-34	9	8	9	9	7	7	7	6	6	6	6	9	89
2034-35	9	8	9	9	7	7	7	6	6	6	6	9	89
2035-36	9	8	9	9	7	7	7	6	6	6	6	9	89
2036-37	9	8	9	9	7	7	7	6	6	6	6	9	89
2037-38	9	8	9	9	7	7	7	6	6	6	6	9	89
2038-39	9	8	9	9	7	7	7	6	6	6	6	9	89
2039-40	9	8	9	9	7	7	7	6	6	6	6	9	89

STREETLIGHT SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	25	25	25	25	25	25	25	25	25	25	25	25	297
2002-03	25	25	25	25	25	14	35	25	25	25	24	25	295
2003-04	25	24	24	11	38	25	25	24	25	24	25	24	294
2004-05	24	24	24	24	24	24	24	25	25	24	25	24	294
2005-06	25	25	24	25	24	25	30	24	25	24	25	25	300
2006-07	25	23	24	25	24	24	25	24	25	25	25	25	293
2007-08	25	25	25	25	25	25	25	25	25	25	24	24	298
2008-09	24	24	24	43	24	24	24	24	24	24	24	24	310
2009-10	24	24	24	24	24	21	21	21	21	21	21	21	269
2010-11	20	20	20	20	20	19	19	19	19	19	18	18	232
2011-12	18	18	18	18	17	17	17	17	17	17	16	16	204
2012-13	16	15	14	14	14	14	13	13	13	12	11	11	160
2013-14	10	10	10	10	10	10	10	10	10	10	10	10	118

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	11	11	11	11	11	11	11	11	11	11	11	11	132
2015-16	13	13	13	13	13	13	13	13	13	13	13	13	156
2016-17	15	15	15	15	15	15	15	15	15	15	15	15	180
2017-18	16	16	16	16	16	16	16	16	16	16	16	16	193
2018-19	16	16	16	16	16	16	16	16	16	16	16	16	193
2019-20	16	16	16	16	16	16	16	16	16	16	16	16	193
2020-21	16	16	16	16	16	16	16	16	16	16	16	16	193
2021-22	16	16	16	16	16	16	16	16	16	16	16	16	193
2022-23	16	16	16	16	16	16	16	16	16	16	16	16	194
2023-24	16	16	16	16	16	16	16	16	16	16	16	16	194
2024-25	16	16	16	16	16	16	16	16	16	16	16	16	194
2025-26	16	16	16	16	16	16	16	16	16	16	16	16	194
2026-27	16	16	16	16	16	16	16	16	16	16	16	16	194
2027-28	16	16	16	16	16	16	16	16	16	16	16	16	194
2028-29	16	16	16	16	16	16	16	16	16	16	16	16	195
2029-30	16	16	16	16	16	16	16	16	16	16	16	16	195
2030-31	16	16	16	16	16	16	16	16	16	16	16	16	195
2031-32	16	16	16	16	16	16	16	16	16	16	16	16	195
3032-33	16	16	16	16	16	16	16	16	16	16	16	16	195
2033-34	16	16	16	16	16	16	16	16	16	16	16	16	195
2034-35	16	16	16	16	16	16	16	16	16	16	16	16	196
2035-36	16	16	16	16	16	16	16	16	16	16	16	16	196
2036-37	16	16	16	16	16	16	16	16	16	16	16	16	196
2037-38	16	16	16	16	16	16	16	16	16	16	16	16	196
2038-39	16	16	16	16	16	16	16	16	16	16	16	16	196
2039-40	16	16	16	16	16	16	16	16	16	16	16	16	196

OWENS VALLEY SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	8	9	8	8	7	8	8	9	7	8	7	9	94
2002-03	9	9	9	8	7	8	8	9	7	8	7	9	97
2003-04	8	9	9	9	8	5	10	11	10	13	16	13	121
2004-05	12	14	11	12	8	10	11	11	9	10	9	13	128
2005-06	14	15	6	13	7	12	11	11	11	9	10	13	132
2006-07	13	14	12	11	7	4	11	11	10	11	11	12	128
2007-08	14	18	13	10	10	11	10	13	10	11	11	13	143
2008-09	13	13	11	-2	11	11	11	13	10	11	11	12	125
2009-10	14	14	12	13	15	12	11	12	10	12	13	11	148
2010-11	15	12	12	14	12	12	11	11	12	10	10	14	145
2011-12	13	16	11	13	11	13	12	9	10	14	7	17	145
2012-13	14	12	13	17	10	13	11	14	10	19	6	16	155
2013-14	14	12	14	12	12	11	12	11	13	10	14	14	152

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	15	13	14	12	13	11	13	11	13	10	15	14	153
2015-16	15	13	14	12	13	12	13	11	13	10	15	15	155
2016-17	15	13	14	13	13	12	13	11	13	11	15	15	157
2017-18	15	13	14	13	13	12	13	11	14	11	15	15	158
2018-19	15	13	15	13	13	12	13	11	14	11	15	15	160
2019-20	15	13	15	13	13	12	13	11	14	11	15	15	162
2020-21	15	13	15	13	13	12	13	12	14	11	15	15	163
2021-22	16	14	15	13	14	12	14	12	14	11	15	15	165
2022-23	16	14	15	13	14	13	14	12	14	11	16	16	167
2023-24	16	14	15	13	14	13	14	12	14	12	16	16	168
2024-25	16	14	15	14	14	13	14	12	15	12	16	16	170
2025-26	16	14	15	14	14	13	14	12	15	12	16	16	171
2026-27	16	14	16	14	14	13	14	12	15	12	16	16	173
2027-28	16	14	16	14	14	13	14	13	15	12	16	16	175
2028-29	17	14	16	14	14	13	15	13	15	12	16	16	176
2029-30	17	15	16	14	15	14	15	13	15	12	17	17	178
2030-31	17	15	16	14	15	14	15	13	15	13	17	17	180
2031-32	17	15	16	15	15	14	15	13	16	13	17	17	181
3032-33	17	15	16	15	15	14	15	13	16	13	17	17	183
2033-34	17	15	17	15	15	14	15	13	16	13	17	17	185
2034-35	17	15	17	15	15	14	15	14	16	13	17	17	186
2035-36	17	15	17	15	15	14	15	14	16	13	17	17	188
2036-37	18	16	17	15	16	14	16	14	16	13	18	18	190
2037-38	18	16	17	15	16	15	16	14	16	13	18	18	191
2038-39	18	16	17	16	16	15	16	14	17	14	18	18	193
2039-40	18	16	17	16	16	15	16	14	17	14	18	18	195

PHEV SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
1995-1996 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1995-96	0	0	0	0	0	0	0	0	0	0	0	0	0
1996-97	0	0	0	0	0	0	0	0	0	0	0	0	0
1997-98	0	0	0	0	0	0	0	0	0	0	0	0	0
1998-99	0	0	0	0	0	0	0	0	0	0	0	0	0
1999-00	0	0	0	0	0	0	0	0	0	0	0	0	0
2000-01	0	0	0	0	0	0	0	0	0	0	0	0	0
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	0
2002-03	0	0	0	0	0	0	0	0	0	0	0	0	0
2003-04	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-05	0	0	0	0	0	0	0	0	0	0	0	0	0
2005-06	0	0	0	0	0	0	0	0	0	0	0	0	0
2006-07	0	0	0	0	0	0	0	0	0	0	0	0	0
2007-08	0	0	0	0	0	0	0	0	0	0	0	0	0
2008-09	0	0	0	0	0	0	0	0	0	0	0	0	0
2009-10	0	0	0	0	0	0	0	0	0	0	0	0	0
2010-11	0	0	0	0	0	0	0	0	0	0	0	0	0
2011-12	0	0	0	0	0	0	0	0	0	0	0	0	0
2012-13	0	0	0	0	0	0	0	0	0	0	0	0	0
2013-14	0	0	0	0	0	1	1	2	2	3	4	5	18

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	6	6	7	8	9	9	10	10	10	10	10	10	104
2015-16	10	10	11	11	11	11	12	12	13	14	14	15	144
2016-17	16	16	17	18	18	19	19	20	20	20	20	20	224
2017-18	21	21	21	21	21	22	22	23	24	24	25	25	270
2018-19	26	27	27	28	28	29	30	30	31	31	32	32	350
2019-20	33	33	34	34	35	35	36	37	37	38	38	39	429
2020-21	40	40	41	41	42	43	43	44	44	45	45	46	512
2021-22	46	47	47	48	48	49	50	50	51	51	52	52	592
2022-23	53	54	54	55	55	56	57	57	58	58	59	59	675
2023-24	60	60	61	61	62	63	63	64	64	65	65	66	755
2024-25	67	67	68	68	69	70	70	70	71	71	72	72	834
2025-26	72	73	73	74	74	74	75	75	76	76	77	77	897
2026-27	78	78	79	79	80	80	81	81	81	82	82	82	963
2027-28	83	83	83	84	84	85	85	85	86	86	87	87	1018
2028-29	87	88	88	89	89	89	90	90	90	91	91	91	1073
2029-30	91	92	92	92	93	93	93	94	94	95	95	95	1119
2030-31	96	96	96	97	97	98	98	98	99	99	99	100	1172
2031-32	100	100	100	101	101	101	102	102	103	103	103	104	1220
3032-33	104	104	105	105	106	106	106	107	107	107	108	108	1272
2033-34	108	108	109	109	109	110	110	111	111	111	112	112	1320
2034-35	112	113	113	113	114	114	115	115	115	116	116	116	1372
2035-36	116	117	117	117	118	118	119	119	119	120	120	120	1420
2036-37	121	121	121	122	122	122	123	123	123	124	124	124	1472
2037-38	125	125	126	126	126	127	127	127	128	128	128	129	1521
2038-39	129	129	130	130	130	131	131	131	132	132	132	133	1571
2039-40	133	134	134	134	135	135	135	136	136	136	137	137	1621

R-1 wo LOW INCOME AND LIFE LINE SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	442	492	470	490	423	454	470	482	407	406	370	403	5310
2002-03	432	503	492	505	427	449	469	472	432	435	406	447	5469
2003-04	499	616	627	596	498	531	542	539	460	462	453	501	6324
2004-05	500	583	599	589	487	534	570	545	467	476	431	477	6258
2005-06	507	624	625	574	482	520	557	551	496	520	461	515	6431
2006-07	630	759	687	610	503	536	577	589	501	492	458	510	6852
2007-08	558	663	685	649	512	551	584	610	527	500	468	534	6841
2008-09	609	702	660	660	547	553	567	574	490	475	445	487	6769
2009-10	513	621	640	640	514	530	535	549	472	449	414	450	6327
2010-11	470	535	537	578	486	519	519	528	454	462	415	436	5939
2011-12	464	559	612	575	472	515	511	513	436	455	403	448	5964
2012-13	464	573	627	679	518	498	507	548	431	425	386	449	6106
2013-14	497	557	577	574	489	484	539	528	482	454	441	458	6080

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	511	564	582	550	496	491	533	519	473	444	433	451	6049
2015-16	510	563	581	549	495	490	533	519	473	443	432	450	6039
2016-17	504	556	576	544	489	484	526	513	466	436	425	443	5960
2017-18	503	556	576	544	490	485	528	514	467	437	425	444	5967
2018-19	504	557	578	546	491	486	530	516	469	438	427	445	5987
2019-20	505	559	580	548	494	489	532	519	471	440	428	447	6014
2020-21	508	562	584	552	497	491	535	521	473	443	432	451	6049
2021-22	512	567	588	556	501	495	540	527	479	449	437	457	6109
2022-23	519	574	595	562	507	501	546	533	485	455	443	463	6181
2023-24	525	581	601	569	513	507	552	539	491	460	449	469	6256
2024-25	532	587	608	575	518	512	558	545	496	466	455	475	6326
2025-26	538	593	613	581	523	517	563	550	502	471	460	480	6391
2026-27	543	599	619	586	529	522	568	555	507	476	465	486	6454
2027-28	549	605	625	592	534	527	573	561	512	481	470	491	6521
2028-29	555	611	631	597	539	533	579	566	517	487	476	497	6587
2029-30	561	617	637	603	545	538	584	572	523	492	481	503	6654
2030-31	567	623	643	609	550	543	589	577	528	498	487	508	6723
2031-32	573	630	649	615	556	549	595	583	534	503	492	514	6793
3032-33	579	636	655	621	561	554	601	589	540	509	498	520	6862
2033-34	585	642	662	627	567	560	606	594	545	514	504	526	6933
2034-35	591	649	668	633	573	565	612	600	551	520	509	532	7002
2035-36	597	655	674	639	578	571	618	606	557	526	515	538	7073
2036-37	604	661	681	645	584	576	624	612	562	531	521	543	7144
2037-38	610	668	687	651	590	582	629	617	568	537	526	549	7213
2038-39	616	674	693	657	595	587	635	623	573	542	532	555	7284
2039-40	622	681	699	663	601	593	641	629	579	548	538	561	7356

LIFELINE SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	30	36	32	36	29	34	33	37	28	31	26	30	382
2002-03	29	36	33	36	29	33	32	35	27	30	26	31	376
2003-04	31	40	38	38	30	36	34	37	29	32	27	33	406
2004-05	30	38	36	37	30	36	36	37	29	32	26	31	398
2005-06	30	39	36	36	28	34	33	36	30	34	28	32	398
2006-07	35	46	38	36	28	34	34	38	30	31	26	31	408
2007-08	32	41	39	40	30	35	35	40	32	32	28	34	419
2008-09	36	44	39	41	33	37	37	41	33	34	30	35	439
2009-10	34	43	43	46	38	41	41	44	37	36	32	36	473
2010-11	37	43	42	46	39	43	45	47	39	40	35	38	493
2011-12	39	47	37	38	33	38	39	39	33	36	31	35	446
2012-13	35	44	47	51	40	39	42	45	36	35	30	36	480
2013-14	39	45	46	46	39	39	43	42	38	36	35	37	485

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	41	45	46	44	40	39	43	41	38	35	34	36	482
2015-16	41	45	46	44	39	39	42	41	38	35	34	36	482
2016-17	40	44	46	43	39	39	42	41	37	35	34	35	475
2017-18	40	44	46	43	39	39	42	41	37	35	34	35	476
2018-19	40	44	46	44	39	39	42	41	37	35	34	35	477
2019-20	40	45	46	44	39	39	42	41	38	35	34	36	480
2020-21	40	45	47	44	40	39	43	42	38	35	34	36	482
2021-22	41	45	47	44	40	40	43	42	38	36	35	36	487
2022-23	41	46	47	45	40	40	44	42	39	36	35	37	493
2023-24	42	46	48	45	41	40	44	43	39	37	36	37	499
2024-25	42	47	48	46	41	41	44	43	40	37	36	38	504
2025-26	43	47	49	46	42	41	45	44	40	38	37	38	510
2026-27	43	48	49	47	42	42	45	44	40	38	37	39	515
2027-28	44	48	50	47	43	42	46	45	41	38	38	39	520
2028-29	44	49	50	48	43	42	46	45	41	39	38	40	525
2029-30	45	49	51	48	43	43	47	46	42	39	38	40	531
2030-31	45	50	51	49	44	43	47	46	42	40	39	41	536
2031-32	46	50	52	49	44	44	47	46	43	40	39	41	542
3032-33	46	51	52	50	45	44	48	47	43	41	40	41	547
2033-34	47	51	53	50	45	45	48	47	43	41	40	42	553
2034-35	47	52	53	50	46	45	49	48	44	41	41	42	558
2035-36	48	52	54	51	46	46	49	48	44	42	41	43	564
2036-37	48	53	54	51	47	46	50	49	45	42	42	43	570
2037-38	49	53	55	52	47	46	50	49	45	43	42	44	575
2038-39	49	54	55	52	47	47	51	50	46	43	42	44	581
2039-40	50	54	56	53	48	47	51	50	46	44	43	45	587

LOW INCOME SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	66	62	69	62	66	62	75	67	66	56	60	56	767
2002-03	69	66	76	68	71	64	78	68	34	30	34	31	688
2003-04	40	43	50	41	42	40	47	41	39	33	32	30	477
2004-05	31	34	39	34	34	34	41	34	34	30	29	28	402
2005-06	33	35	38	30	30	29	32	27	27	25	26	25	358
2006-07	34	37	37	29	27	24	33	32	29	27	27	26	362
2007-08	31	33	37	33	30	30	34	34	32	27	28	29	379
2008-09	36	37	39	35	35	37	47	43	41	37	40	40	466
2009-10	48	52	61	55	51	49	57	52	51	43	47	48	613
2010-11	58	58	68	63	62	59	73	66	67	58	62	55	747
2011-12	70	70	83	70	73	68	85	70	72	63	68	61	852
2012-13	76	78	100	89	86	69	90	80	78	61	67	64	939
2013-14	86	80	90	90	77	76	86	83	76	71	70	72	956

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	80	88	92	87	78	77	84	82	74	70	68	71	950
2015-16	80	88	91	86	78	77	84	82	74	70	68	71	949
2016-17	79	87	90	85	77	76	83	81	73	69	67	70	937
2017-18	79	87	91	86	77	76	83	81	73	69	67	70	938
2018-19	79	88	91	86	77	76	83	81	74	69	67	70	941
2019-20	79	88	91	86	78	77	84	82	74	69	67	70	945
2020-21	80	88	92	87	78	77	84	82	74	70	68	71	951
2021-22	81	89	92	87	79	78	85	83	75	71	69	72	960
2022-23	82	90	93	88	80	79	86	84	76	71	70	73	971
2023-24	83	91	94	89	81	80	87	85	77	72	71	74	983
2024-25	84	92	95	90	81	81	88	86	78	73	71	75	994
2025-26	84	93	96	91	82	81	88	86	79	74	72	75	1004
2026-27	85	94	97	92	83	82	89	87	80	75	73	76	1014
2027-28	86	95	98	93	84	83	90	88	80	76	74	77	1025
2028-29	87	96	99	94	85	84	91	89	81	76	75	78	1035
2029-30	88	97	100	95	86	85	92	90	82	77	76	79	1046
2030-31	89	98	101	96	86	85	93	91	83	78	76	80	1057
2031-32	90	99	102	97	87	86	94	92	84	79	77	81	1068
3032-33	91	100	103	98	88	87	94	92	85	80	78	82	1078
2033-34	92	101	104	99	89	88	95	93	86	81	79	83	1090
2034-35	93	102	105	99	90	89	96	94	87	82	80	84	1100
2035-36	94	103	106	100	91	90	97	95	87	83	81	84	1112
2036-37	95	104	107	101	92	91	98	96	88	83	82	85	1123
2037-38	96	105	108	102	93	91	99	97	89	84	83	86	1134
2038-39	97	106	109	103	94	92	100	98	90	85	84	87	1145
2039-40	98	107	110	104	94	93	101	99	91	86	85	88	1156

A-1 SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	256	253	256	253	236	227	233	224	222	218	218	234	2829
2002-03	250	258	249	245	231	300	170	235	211	254	179	238	2820
2003-04	252	271	269	251	243	233	244	218	225	226	233	241	2906
2004-05	246	260	258	244	221	239	238	215	218	218	219	239	2816
2005-06	249	268	254	246	226	240	240	221	225	219	221	251	2861
2006-07	268	276	262	244	233	236	239	222	222	225	230	213	2871
2007-08	253	264	274	243	237	232	232	227	223	229	215	238	2866
2008-09	260	264	250	250	234	232	227	225	210	209	214	226	2802
2009-10	238	252	256	348	123	224	227	224	205	214	206	226	2743
2010-11	237	238	248	244	221	227	234	225	215	215	218	224	2746
2011-12	245	252	253	247	233	235	238	224	224	224	227	244	2846
2012-13	251	265	282	276	250	241	245	236	230	229	235	254	2996
2013-14	269	263	283	267	250	248	252	238	233	233	239	254	3028

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	268	272	281	268	254	249	252	237	232	232	237	252	3035
2015-16	269	273	281	268	254	249	252	237	232	231	237	251	3034
2016-17	265	269	277	265	251	246	248	233	227	226	232	245	2984
2017-18	262	266	275	262	249	244	246	231	225	223	229	242	2953
2018-19	259	263	272	260	247	242	244	229	223	221	226	240	2925
2019-20	256	260	270	258	244	240	242	227	221	219	224	238	2898
2020-21	254	259	269	258	245	240	245	229	224	223	228	242	2917
2021-22	259	264	274	262	249	245	248	232	227	226	232	246	2965
2022-23	263	268	278	266	252	248	251	236	230	229	235	250	3006
2023-24	267	272	282	270	256	251	254	239	234	233	239	254	3051
2024-25	271	276	286	274	260	255	258	243	238	237	243	258	3100
2025-26	276	280	290	278	264	259	262	247	242	241	247	262	3150
2026-27	280	285	295	282	268	263	266	251	246	245	251	267	3199
2027-28	285	289	299	286	272	267	270	255	250	249	256	271	3249
2028-29	289	294	304	291	276	271	274	259	254	253	260	276	3301
2029-30	294	299	308	295	280	275	278	263	258	258	264	280	3353
2030-31	299	303	313	299	285	279	282	267	262	262	269	285	3406
2031-32	303	308	317	304	289	284	287	272	267	266	273	290	3459
3032-33	308	313	322	308	293	288	291	276	271	271	278	294	3513
2033-34	313	318	327	313	298	292	295	280	275	275	282	299	3566
2034-35	318	323	331	318	302	296	299	284	279	279	287	304	3620
2035-36	323	328	336	322	307	301	304	289	284	284	291	308	3675
2036-37	327	332	341	327	311	305	308	293	288	288	296	313	3730
2037-38	332	337	346	331	315	309	312	297	293	293	300	318	3785
2038-39	337	342	350	336	320	314	317	302	297	297	305	323	3840
2039-40	342	347	355	341	324	318	321	306	302	302	310	328	3896

A-2 SALES - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	327	321	383	266	302	298	264	253	285	257	303	289	3549
2002-03	314	330	328	323	289	299	292	286	262	271	274	306	3574
2003-04	342	342	345	332	312	296	291	276	270	293	307	325	3732
2004-05	325	346	345	329	293	306	296	274	282	283	288	319	3686
2005-06	327	351	340	327	300	310	302	276	283	274	288	335	3713
2006-07	357	375	349	334	310	301	309	271	289	287	297	312	3792
2007-08	344	346	365	336	314	291	294	294	281	288	302	320	3775
2008-09	356	345	361	346	326	299	289	291	270	269	294	300	3745
2009-10	301	274	317	319	291	272	267	265	246	256	259	283	3349
2010-11	287	288	303	305	279	282	269	259	244	252	264	265	3298
2011-12	295	290	297	274	249	230	227	220	257	273	292	299	3203
2012-13	276	296	317	304	277	249	259	227	234	241	252	269	3201
2013-14	280	282	304	285	270	268	269	252	250	252	260	277	3250

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	291	292	301	288	275	269	269	252	249	251	259	276	3273
2015-16	292	293	302	289	275	270	270	252	249	250	258	274	3273
2016-17	287	288	297	284	271	266	265	248	244	245	252	268	3217
2017-18	284	285	294	282	269	263	263	245	241	242	249	265	3179
2018-19	280	281	291	278	266	260	260	242	238	239	246	261	3142
2019-20	276	277	288	275	263	257	258	239	235	236	243	258	3107
2020-21	274	276	287	275	263	258	261	242	239	240	248	264	3128
2021-22	280	282	293	281	268	263	264	246	243	244	252	268	3182
2022-23	284	286	297	284	272	267	267	249	246	248	256	272	3228
2023-24	288	290	301	289	276	271	271	253	250	252	260	277	3278
2024-25	293	295	306	293	281	275	276	258	255	256	265	282	3334
2025-26	298	300	311	298	285	280	280	262	259	261	269	287	3390
2026-27	303	305	316	303	290	284	284	266	264	265	274	291	3446
2027-28	309	310	321	307	294	289	289	271	268	270	279	297	3503
2028-29	314	316	326	312	299	293	293	276	273	275	284	302	3562
2029-30	319	321	331	317	304	298	298	280	278	280	289	307	3622
2030-31	325	326	336	323	309	303	303	285	283	285	294	312	3682
2031-32	330	332	341	328	314	307	308	290	287	290	299	317	3743
3032-33	335	337	347	333	319	312	312	295	292	294	304	323	3803
2033-34	341	343	352	338	323	317	317	299	297	299	309	328	3865
2034-35	346	348	357	343	328	322	322	304	302	304	314	333	3926
2035-36	352	354	363	348	333	327	327	309	307	309	319	339	3988
2036-37	357	359	368	354	339	332	332	314	312	315	325	344	4050
2037-38	363	365	374	359	344	337	337	319	317	320	330	350	4113
2038-39	369	371	379	364	349	342	342	324	322	325	335	355	4177
2039-40	374	376	385	370	354	347	347	329	327	330	341	361	4241

2014 APPENDIX A ENERGY AND DEMAND FORECAST
2015 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	731	660	724	676	677	615	615	618	622	647	565	754	7905
2002-03	785	606	680	727	669	671	677	638	596	613	683	678	8023
2003-04	641	746	748	731	736	640	733	556	627	642	660	686	8146
2004-05	705	726	720	711	669	695	662	610	626	630	641	706	8101
2005-06	715	733	720	730	680	719	668	633	623	630	649	735	8236
2006-07	776	770	780	743	737	727	656	653	663	659	683	703	8552
2007-08	790	763	821	754	725	727	699	682	680	700	699	732	8774
2008-09	952	624	814	803	769	705	684	697	633	669	691	708	8749
2009-10	750	721	806	779	744	677	716	689	650	659	670	721	8582
2010-11	753	718	770	763	700	696	703	706	670	700	680	689	8548
2011-12	756	722	774	756	724	693	682	642	622	647	686	738	8442
2012-13	724	721	803	768	735	721	639	617	628	619	662	693	8331
2013-14	710	716	769	721	686	680	681	638	634	640	662	706	8244

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	740	740	760	728	696	682	681	638	633	637	660	703	8299
2015-16	741	742	763	730	698	684	682	638	632	636	657	699	8301
2016-17	731	730	751	720	688	674	672	626	620	622	643	684	8159
2017-18	721	720	744	712	681	667	665	619	612	614	634	674	8064
2018-19	711	711	736	705	674	660	659	611	604	607	626	666	7970
2019-20	703	702	728	697	667	653	652	605	598	600	620	659	7882
2020-21	697	698	726	696	667	654	659	613	607	611	632	673	7932
2021-22	711	713	740	709	680	667	667	621	615	619	641	682	8066
2022-23	721	722	749	719	689	676	675	629	624	628	650	692	8176
2023-24	732	733	760	729	698	685	685	639	634	639	661	704	8298
2024-25	744	745	771	740	709	696	696	650	645	650	672	716	8433
2025-26	756	758	783	752	721	707	707	661	656	661	684	728	8573
2026-27	769	770	795	763	732	718	717	671	667	672	695	740	8709
2027-28	781	782	808	775	743	729	728	682	678	684	707	752	8850
2028-29	794	795	820	787	755	740	739	694	690	695	719	765	8994
2029-30	807	808	833	800	767	752	751	705	701	707	731	778	9140
2030-31	820	822	846	812	779	764	763	717	713	719	744	791	9288
2031-32	834	835	858	824	791	775	774	729	725	731	756	804	9436
3032-33	847	848	871	837	803	787	786	740	737	743	769	817	9585
2033-34	860	862	884	850	815	799	798	752	749	756	781	830	9735
2034-35	874	875	897	862	827	811	809	764	761	768	794	843	9886
2035-36	887	889	911	875	839	823	821	776	773	780	807	856	10038
2036-37	901	902	924	888	852	835	833	788	785	793	819	870	10191
2037-38	915	916	937	901	864	847	846	800	798	805	832	883	10346
2038-39	929	930	951	914	877	860	858	813	810	818	845	897	10502
2039-40	943	944	964	927	890	872	870	825	823	831	858	910	10658

CONTRACT RATES - ELECTRICITY SALES - GWH
(Includes Real Time Pricing, Contract Demand, and Guarantee Load Factor)
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	85	89	89	87	80	72	105	83	76	77	83	87	1014
2002-03	64	99	86	100	71	80	89	105	84	89	56	94	1017
2003-04	110	72	89	100	120	85	79	107	51	126	90	79	1109
2004-05	118	94	83	88	129	97	89	101	88	94	87	118	1184
2005-06	98	84	105	75	96	148	111	83	111	92	73	122	1199
2006-07	96	90	113	103	83	73	98	92	83	97	91	99	1119
2007-08	100	100	105	97	103	77	90	89	85	87	80	108	1121
2008-09	96	91	101	94	98	65	120	95	88	91	87	93	1119
2009-10	60	124	93	65	65	54	72	68	68	55	50	88	863
2010-11	67	73	70	76	73	58	83	79	70	69	75	63	856
2011-12	82	67	90	82	70	84	69	77	74	69	81	73	918
2012-13	94	72	116	94	97	95	111	96	99	74	118	92	1156
2013-14	108	122	120	114	110	110	111	106	105	104	108	113	1331

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	118	117	118	114	110	109	110	105	104	103	107	111	1326
2015-16	117	117	119	115	110	110	110	105	104	104	107	112	1330
2016-17	116	116	117	113	109	108	108	103	102	102	105	109	1307
2017-18	115	115	117	112	108	107	108	103	102	101	104	109	1302
2018-19	114	114	116	112	108	107	108	103	102	101	104	108	1297
2019-20	114	114	116	111	107	107	107	102	101	100	103	108	1291
2020-21	113	113	115	111	108	107	108	103	102	101	104	109	1295
2021-22	115	115	117	112	109	108	109	103	102	102	105	109	1305
2022-23	115	115	117	113	109	108	109	104	103	102	106	110	1313
2023-24	116	116	118	114	110	109	110	105	104	103	106	111	1321
2024-25	117	117	119	115	111	110	111	105	104	104	107	112	1331
2025-26	118	118	120	115	111	111	111	106	105	105	108	113	1341
2026-27	119	119	121	116	112	111	112	107	106	106	109	114	1351
2027-28	120	120	121	117	113	112	113	108	107	106	110	115	1362
2028-29	121	121	122	118	114	113	114	109	108	107	111	116	1373
2029-30	122	122	123	119	115	114	115	110	109	108	112	117	1384
2030-31	123	123	124	120	116	115	116	110	110	109	113	118	1395
2031-32	124	124	125	121	117	116	117	111	111	110	114	119	1406
3032-33	125	125	126	122	118	117	117	112	111	111	114	120	1418
2033-34	126	126	127	123	119	118	118	113	112	112	115	120	1429
2034-35	127	127	128	124	119	118	119	114	113	113	116	122	1440
2035-36	128	128	129	125	120	119	120	115	114	114	117	123	1452
2036-37	129	129	130	126	121	120	121	116	115	115	118	124	1464
2037-38	130	130	131	127	122	121	122	117	116	116	119	125	1475
2038-39	131	131	132	128	123	122	123	118	117	117	120	126	1487
2039-40	132	132	133	129	124	123	124	119	118	118	121	127	1499

RESIDENTIAL ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2	2	2	3	3	3	3	3	3	3	3	3	34
2002-03	3	4	4	4	4	4	3	4	4	4	4	4	45
2003-04	4	5	4	4	4	4	4	4	4	4	5	5	53
2004-05	5	5	5	5	5	5	5	5	5	5	6	6	62
2005-06	6	6	6	6	6	6	5	6	6	6	6	7	71
2006-07	7	7	7	7	7	7	7	7	7	7	8	8	86
2007-08	9	9	9	9	9	9	9	9	10	10	11	12	115
2008-09	13	13	13	13	12	12	14	16	21	22	23	25	195
2009-10	25	26	24	24	23	22	22	22	23	23	24	26	283
2010-11	27	27	25	25	24	23	22	23	24	24	26	28	297
2011-12	29	29	27	27	26	25	24	25	26	26	28	30	322
2012-13	30	31	29	28	27	26	25	26	27	27	29	31	336
2013-14	32	32	30	29	28	27	27	27	28	29	30	33	353

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	34	34	32	32	30	30	29	31	31	32	34	37	386
2015-16	38	39	37	36	35	35	34	35	36	37	40	43	446
2016-17	45	46	43	43	41	41	40	42	43	44	47	51	526
2017-18	53	54	51	50	48	48	47	49	50	52	55	60	618
2018-19	62	63	59	58	56	55	54	56	58	59	63	68	713
2019-20	71	71	67	66	63	62	61	63	65	66	70	76	802
2020-21	78	78	73	71	67	66	64	66	66	67	71	76	842
2021-22	78	78	73	71	67	66	64	66	66	67	71	76	842
2022-23	78	78	73	71	67	66	64	66	66	67	71	76	842
2023-24	78	78	73	71	67	66	64	66	66	67	71	76	842
2024-25	78	78	73	71	67	66	64	66	66	67	71	76	842
2025-26	78	78	73	71	67	66	64	66	66	67	71	76	842
2026-27	78	78	73	71	67	66	64	66	66	67	71	76	842
2027-28	78	78	73	71	67	66	64	66	66	67	71	76	842
2028-29	78	78	73	71	67	66	64	66	66	67	71	76	842
2029-30	78	78	73	71	67	66	64	66	66	67	71	76	842
2030-31	78	78	73	71	67	66	64	66	66	67	71	76	842
2031-32	78	78	73	71	67	66	64	66	66	67	71	76	842
3032-33	78	78	73	71	67	66	64	66	66	67	71	76	842
2033-34	78	78	73	71	67	66	64	66	66	67	71	76	842
2034-35	78	78	73	71	67	66	64	66	66	67	71	76	842
2035-36	78	78	73	71	67	66	64	66	66	67	71	76	842
2036-37	78	78	73	71	67	66	64	66	66	67	71	76	842
2037-38	78	78	73	71	67	66	64	66	66	67	71	76	842
2038-39	78	78	73	71	67	66	64	66	66	67	71	76	842
2039-40	78	78	73	71	67	66	64	66	66	67	71	76	842

COMMERCIAL ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	26	27	26	26	26	26	27	28	30	31	33	37	343
2002-03	38	39	36	36	34	34	33	34	35	36	38	41	436
2003-04	43	43	40	39	37	37	36	37	38	38	40	44	472
2004-05	45	45	42	41	40	39	38	39	40	40	43	46	498
2005-06	47	48	45	44	42	41	40	41	42	43	45	49	525
2006-07	50	50	47	46	44	43	42	44	45	46	48	53	559
2007-08	54	55	51	51	48	47	46	48	49	51	55	62	618
2008-09	65	67	64	64	62	61	61	64	66	68	72	78	790
2009-10	82	83	78	77	74	73	72	74	77	78	85	93	946
2010-11	97	98	93	92	87	86	84	87	89	91	99	108	1112
2011-12	111	111	105	103	99	97	95	98	100	102	108	117	1246
2012-13	121	121	113	111	106	104	102	105	108	111	118	128	1350
2013-14	131	132	124	122	117	115	113	117	119	123	130	142	1485

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	147	148	140	138	132	130	127	132	135	138	147	159	1673
2015-16	165	167	158	156	150	148	146	152	156	160	170	185	1913
2016-17	192	195	184	182	175	173	170	177	182	187	199	217	2233
2017-18	225	228	215	212	204	201	198	206	212	217	231	251	2601
2018-19	260	263	248	244	235	231	227	236	241	247	263	285	2980
2019-20	295	297	279	275	264	259	254	263	269	275	292	316	3338
2020-21	324	324	301	294	279	272	265	272	276	279	294	316	3496
2021-22	324	324	301	294	279	272	265	272	276	279	294	316	3496
2022-23	324	324	301	294	279	272	265	272	276	279	294	316	3496
2023-24	324	324	301	294	279	272	265	272	276	279	294	316	3496
2024-25	324	324	301	294	279	272	265	272	276	279	294	316	3496
2025-26	324	324	301	294	279	272	265	272	276	279	294	316	3496
2026-27	324	324	301	294	279	272	265	272	276	279	294	316	3496
2027-28	324	324	301	294	279	272	265	272	276	279	294	316	3496
2028-29	324	324	301	294	279	272	265	272	276	279	294	316	3496
2029-30	324	324	301	294	279	272	265	272	276	279	294	316	3496
2030-31	324	324	301	294	279	272	265	272	276	279	294	316	3496
2031-32	324	324	301	294	279	272	265	272	276	279	294	316	3496
3032-33	324	324	301	294	279	272	265	272	276	279	294	316	3496
2033-34	324	324	301	294	279	272	265	272	276	279	294	316	3496
2034-35	324	324	301	294	279	272	265	272	276	279	294	316	3496
2035-36	324	324	301	294	279	272	265	272	276	279	294	316	3496
2036-37	324	324	301	294	279	272	265	272	276	279	294	316	3496
2037-38	324	324	301	294	279	272	265	272	276	279	294	316	3496
2038-39	324	324	301	294	279	272	265	272	276	279	294	316	3496
2039-40	324	324	301	294	279	272	265	272	276	279	294	316	3496

CROSS CUTTING ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	0
2002-03	0	0	0	0	0	0	0	0	0	0	0	0	0
2003-04	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-05	0	0	0	0	0	0	0	0	0	0	0	0	0
2005-06	0	0	0	0	0	0	0	0	0	0	0	0	0
2006-07	0	0	0	0	0	0	0	0	0	0	0	0	0
2007-08	0	0	0	0	0	0	0	0	0	0	0	0	0
2008-09	0	0	0	0	0	0	0	0	0	0	0	0	0
2009-10	0	0	0	0	0	0	0	0	0	0	0	0	0
2010-11	0	0	0	0	0	0	0	0	0	0	0	0	0
2011-12	0	0	0	0	0	0	0	0	0	0	0	0	0
2012-13	1	1	1	2	2	3	3	4	4	5	5	6	36
2013-14	7	7	7	8	8	8	8	9	10	10	12	13	108

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	14	15	14	14	14	14	14	15	16	16	18	20	184
2015-16	21	21	20	20	20	20	20	21	22	22	24	26	258
2016-17	28	28	27	27	26	26	25	27	27	28	30	33	332
2017-18	34	35	33	33	32	31	31	32	33	34	36	40	406
2018-19	41	42	40	39	38	37	37	38	39	40	43	46	479
2019-20	48	49	46	45	44	43	42	44	45	46	49	53	553
2020-21	54	54	51	49	47	46	44	46	46	47	49	53	587
2021-22	54	54	51	49	47	46	44	46	46	47	49	53	587
2022-23	54	54	51	49	47	46	44	46	46	47	49	53	587
2023-24	54	54	51	49	47	46	44	46	46	47	49	53	587
2024-25	54	54	51	49	47	46	44	46	46	47	49	53	587
2025-26	54	54	51	49	47	46	44	46	46	47	49	53	587
2026-27	54	54	51	49	47	46	44	46	46	47	49	53	587
2027-28	54	54	51	49	47	46	44	46	46	47	49	53	587
2028-29	54	54	51	49	47	46	44	46	46	47	49	53	587
2029-30	54	54	51	49	47	46	44	46	46	47	49	53	587
2030-31	54	54	51	49	47	46	44	46	46	47	49	53	587
2031-32	54	54	51	49	47	46	44	46	46	47	49	53	587
3032-33	54	54	51	49	47	46	44	46	46	47	49	53	587
2033-34	54	54	51	49	47	46	44	46	46	47	49	53	587
2034-35	54	54	51	49	47	46	44	46	46	47	49	53	587
2035-36	54	54	51	49	47	46	44	46	46	47	49	53	587
2036-37	54	54	51	49	47	46	44	46	46	47	49	53	587
2037-38	54	54	51	49	47	46	44	46	46	47	49	53	587
2038-39	54	54	51	49	47	46	44	46	46	47	49	53	587
2039-40	54	54	51	49	47	46	44	46	46	47	49	53	587

HUFFMAN BILL ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	0
2002-03	0	0	0	0	0	0	0	0	0	0	0	0	0
2003-04	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-05	0	0	0	0	0	0	0	0	0	0	0	0	0
2005-06	0	0	0	0	0	0	0	0	0	0	0	0	0
2006-07	0	0	0	0	0	0	0	0	0	0	0	0	0
2007-08	0	0	0	0	0	0	0	0	0	0	0	0	0
2008-09	0	0	0	0	0	0	0	0	0	0	0	0	0
2009-10	0	0	0	0	0	0	0	0	0	0	0	0	0
2010-11	0	0	0	0	0	0	0	0	0	0	0	0	0
2011-12	0	0	0	0	0	0	1	1	1	2	2	2	9
2012-13	3	3	4	4	5	6	7	8	9	10	10	9	77
2013-14	10	11	13	14	17	20	20	19	20	20	19	17	201

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014-15	18	18	21	22	25	29	29	26	27	27	25	22	287
2015-16	23	23	27	27	31	35	35	32	32	33	30	27	354
2016-17	27	27	32	32	36	41	40	36	37	37	34	29	408
2017-18	30	30	34	34	38	43	42	38	38	38	35	31	431
2018-19	31	31	35	36	39	45	44	40	40	40	36	32	448
2019-20	32	32	37	37	41	46	46	41	41	42	38	33	466
2020-21	34	34	39	39	43	49	49	44	44	44	40	35	494
2021-22	36	36	41	41	45	52	51	46	46	46	42	37	518
2022-23	37	37	43	43	47	54	53	47	47	48	43	38	536
2023-24	38	38	44	44	48	55	54	48	48	49	44	39	549
2024-25	39	39	44	44	49	56	55	49	49	49	45	39	556
2025-26	39	39	45	45	50	57	56	50	50	50	46	40	566
2026-27	40	40	46	46	50	57	56	51	51	51	46	41	575
2027-28	41	41	46	47	51	58	57	51	51	52	47	41	583
2028-29	41	41	47	47	52	59	58	52	52	52	48	42	592
2029-30	42	42	48	48	53	60	59	53	53	53	48	42	600
2030-31	42	42	48	49	53	61	60	54	54	54	49	43	609
2031-32	43	43	49	49	54	62	60	54	54	54	50	43	617
3032-33	43	44	50	50	55	62	61	55	55	55	50	44	625
2033-34	44	44	50	51	56	63	62	56	56	56	51	45	634
2034-35	45	45	51	51	56	64	63	57	57	57	52	45	642
2035-36	45	45	52	52	57	65	64	57	57	57	52	46	651
2036-37	46	46	53	53	58	66	65	58	58	58	53	46	659
2037-38	46	46	53	53	59	67	65	59	59	59	54	47	667
2038-39	47	47	54	54	59	68	66	60	60	60	54	48	676
2039-40	48	48	55	55	60	68	67	60	60	60	55	48	684

SOLAR ROOFTOP ACCUMULATED SAVINGS - GWH
2014 APPENDIX A ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2000-01	0	0	0	0	0	0	0	0	0	0	0	0	0
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	1
2002-03	1	1	1	1	1	1	0	0	0	0	0	0	5
2003-04	1	1	1	1	1	1	1	1	1	1	1	1	12
2004-05	1	1	1	1	1	1	1	1	1	1	1	1	12
2005-06	2	1	1	1	1	1	1	1	1	1	1	1	14
2006-07	2	2	1	1	1	1	1	1	1	1	1	1	15
2007-08	2	2	2	1	1	1	1	1	1	2	2	2	18
2008-09	2	2	2	2	1	1	1	1	2	2	2	2	21
2009-10	3	3	3	2	2	2	2	2	2	3	3	3	29
2010-11	4	4	4	3	3	3	3	4	4	5	5	6	48
2011-12	7	7	6	5	4	4	4	5	7	8	9	9	75
2012-13	10	10	9	8	7	6	6	8	10	12	12	13	110

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2013-14	15	14	13	12	10	9	9	12	15	18	18	19	163
2014-15	22	22	19	17	15	13	14	17	21	26	26	27	239
2015-16	31	30	27	23	20	17	19	23	29	34	35	36	324
2016-17	41	40	35	31	26	23	25	29	37	43	44	44	417
2017-18	50	48	42	36	31	27	28	34	41	48	48	48	481
2018-19	54	51	45	38	32	27	29	34	42	49	49	49	500
2019-20	55	52	45	38	32	28	29	35	42	49	49	49	505
2020-21	55	52	45	38	32	28	29	35	42	49	49	49	505
2021-22	55	52	45	38	32	28	29	35	42	49	49	49	505
2022-23	55	52	45	38	32	28	29	35	42	49	49	49	505
2023-24	55	52	45	38	32	28	29	35	42	49	49	49	505
2024-25	55	52	45	38	32	28	29	35	42	49	49	49	505
2025-26	55	52	45	38	32	28	29	35	42	49	49	49	505
2026-27	55	52	45	38	32	28	29	35	42	49	49	49	505
2027-28	55	52	45	38	32	28	29	35	42	49	49	49	505
2028-29	55	52	45	38	32	28	29	35	42	49	49	49	505
2029-30	55	52	45	38	32	28	29	35	42	49	49	49	505
2030-31	55	52	45	38	32	28	29	35	42	49	49	49	505
2031-32	55	52	45	38	32	28	29	35	42	49	49	49	505
3032-33	55	52	45	38	32	28	29	35	42	49	49	49	505
2033-34	55	52	45	38	32	28	29	35	42	49	49	49	505
2034-35	55	52	45	38	32	28	29	35	42	49	49	49	505
2035-36	55	52	45	38	32	28	29	35	42	49	49	49	505
2036-37	55	52	45	38	32	28	29	35	42	49	49	49	505
2037-38	55	52	45	38	32	28	29	35	42	49	49	49	505
2038-39	55	52	45	38	32	28	29	35	42	49	49	49	505
2039-40	55	52	45	38	32	28	29	35	42	49	49	49	505

Appendix B Energy Efficiency

Energy Efficiency (EE) is a key strategic element in the Los Angeles Department of Water and Power's (LADWP) Integrated Resource Planning (IRP) efforts. EE is a very cost-effective supply-side resource, and serves an important and multi-faceted role in meeting customer demand. One of the most widely recognized examples of EE is the replacement of incandescent lights with compact fluorescent lamp (CFL) or light-emitting diode (LED) bulbs. CFLs consume up to 75 percent less energy than incandescent bulbs while producing an equivalent amount of illumination, and last up to 10 times longer; LEDs consume up to 85 percent less energy than incandescent bulbs while producing an equivalent amount of illumination, and last up to 42 times longer.

The reduction in energy demand that EE enables, translates into a number of benefits:

- Deferred need to build physical generation assets
- Reduced Renewable Portfolio Standard (RPS) compliance costs
- Reduced environmental footprint, including lower Greenhouse Gas (GHG) emissions
- Potential for local job creation opportunities

The following subsections provide a background of LADWP's EE program, and evaluates the most recently completed EE potential study that was conducted in 2013. Based on the study results, a plan is recommended with identified savings and costs targets. For more specific details regarding the 2013 study, see the references listed at the end of this appendix.

All cases evaluated in this 2015 IRP incorporates 15% EE by year 2020.

B.1 Background

LADWP has active EE programs that have been in place for several years. Since 2000, LADWP spent approximately $423.8 million on its EE programs, which has reduced consumption by approximately 1,756 GWh. LADWP continues its commitment to developing robust, cost-effective EE programs with measurable and verifiable goals.

LADWP offers numerous EE programs and services for residential, commercial, industrial, governmental, and institutional customers to promote the efficient use of energy through the installation of energy efficient equipment. Examples include:

- The Commercial Lighting Efficiency Offer (CLEO), which provides rebates for a variety of high efficiency lighting measures to retrofit existing buildings. The CLEO program enjoys sustained high rates of participation and has achieved 507 GWh of energy savings since 2000.
- The Chiller Efficiency Program, which provides incentives for customers to replace old

electric chillers with new, high-efficiency units. Chillers provide space conditioning for larger buildings and the program has reduced associated peak electrical demand by more than 61 MW since 2001.
- The Small Business Direct Install (SBDI) Program, which assists eligible small businesses (A1 rate customers) in Los Angeles in becoming more energy efficient through free lighting assessments and free lighting retrofits (up to $2,500 in cost). SBDI began in 2008 and has achieved 190 GWh of energy savings since its inception.
- The Custom Performance Program, which provides performance-based incentives for energy efficiency measures not included on LADWP's menu-based EE programs. Measures supported include controls and control systems, high efficiency motors, and data server virtualization. The Custom Performance Program has achieved 324 GWh of energy savings since 2006.
- The Refrigerator Exchange Program, which delivers new Energy Star refrigerators to eligible residential customers, and picks-up/recycles customers' old, inefficient refrigerators. This program has replaced and recycled more than 53,000 refrigerators since 2007, achieving an energy savings of 61 GWh.

B.2 Energy Efficiency Potential Study

On December 6, 2011, the Board of Water and Power Commissioners approved an advanced EE program with a goal of 8.6 percent of sales by the end of fiscal year 2019-20 and beginning fiscal year 2010-11. Subsequently, on May 24, 2012, the Board of Water and Power Commissioners approved a target of 15 percent energy efficiency, subject to the results of an updated energy efficiency potential study to be completed by March 2014. The potential study would be used to develop a long-term plan for the scope and estimated costs for additional programs, to achieve 10 percent, 12.5 percent, and 15 percent energy efficiency savings by 2020. In Fiscal Year 2013-14, LADWP hired Nexant, Inc to conduct the potential study to determine the achievable potential for energy savings. On August 5, 2014, the results of the potential study, recommending 14.8 percent in energy efficiency savings targets by 2020, was presented and approved by the Board of Water and Power Commissioners. Per Assembly Bill 2021 (AB 2021), publically owned utilities such as LADWP, must identify and develop all potential achievable, cost-effective EE savings and establish annual targets. Furthermore, utilities are required to conduct periodic "Potential" studies to update their forecasts and targets. The most recent study was carried out in 2013 and is the basis for the EE recommendations contained in this 2015 IRP.

For more in-depth information, see the study referenced at the end of this appendix. This section presents a brief summary of the methodology and findings.

The 2013 Potential Study objectives were as follows:

- To estimate savings possible through utility programs and other interventions (such as the American Recovery and Reinvestment Act)
- Identify energy-efficiency technologies and measures that will produce savings
- Link the energy saving measures with utility programs to achieve savings
- Provide guidance for setting 10-year targets for CEC

Some of the key factors that were considered in the study include:

- Changes in the customer base since the last study
- Building codes
- Adoption of new appliance standards
- Naturally-occurring conservation
- Trends in appliance saturations
- How customers use electricity today
- Technological changes in appliances and equipment

The potential through 2023, including 2011-13 achievements is shown in Figure B-1.

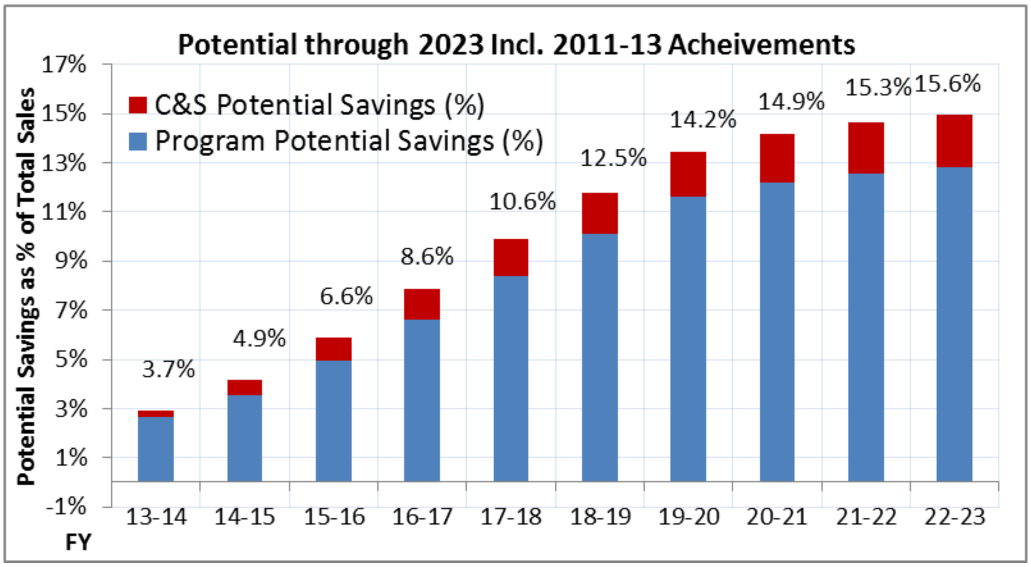


Figure B-1. Energy Efficiency Potential through 2023.

Segmented forecasts for the industrial, commercial, and residential sectors are shown in Figure B-2.

Sector	Baseline Sales (GWh)	Technical Potential			Economic Potential				
		GWh	% of Base Sales	MW	GWh	% of Base Sales	MW	Percent of Technical Potential - Energy	Percent of Technical Potential - Demand
Residential	9,985	3,334	33%	1,940	1,625	16%	471	49%	24%
Commercial	14,798	3,332	23%	851	2,188	15%	505	66%	59%
Institutional	756	143	19%	37	110	15%	27	77%	72%
Industrial	2,195	314	14%	66	265	12%	56	84%	85%
Codes and Standards[a]	N/A	1,690	N/A	312	1,690	N/A	312	100%	N/A
Other[b]	838	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	28,571	8,813	31%	3,205	5,877	21%	1,371	67%	43%

[a]Includes savings from Huffman Bill, Title 24 codes, and Title 20 standards, as well as federal standards not covered by California standards.
[b]Other includes components for which energy efficiency potential was not considered, such as port electrification and rooftop solar. Plug-in electric vehicles were excluded from baseline forecasts

Figure B-2. Technical and Economic Potential forecast results.

The study evaluated a multitude of measures for potential inclusion into LADWP's EE program, including:

- Existing program elements
- High-efficiency air conditioners (higher efficiency levels, variable refrigerant flow systems)
- High-efficiency lighting (CFLs, LED lamps)
- Upgraded insulation in buildings
- Retrocommissioning and routine maintenance
- Programmable Communicating Thermostats and Energy Management Systems

B.3 EE Study Results and Plan

To understand the study results the following terms are defined:

2013 Potential Study Definitions

Term	Definition
Technical Potential	The quantification of savings that can be realized if energy efficiency measures passing the qualitative screening are applied in all feasible instances, regardless of cost.
Economic Potential	A subset of technical potential, where measures are cost-effective from the Total Resource Cost ("TRC") perspective, without regard to cross-subsidies.
Maximum Achievable Potential	The energy savings that can possibly be achieved through assuming maximum market penetration of all measures. Individual measures are not necessarily cost-effective in this scenario, though measures with a low TRC benefit-cost ratio are excluded.
Program Potential	The energy savings that can possibly be achieved through utility programs or codes and standards. Individual measures are not necessarily cost-effective in this scenario, though measures with a low benefit-cost ratio, as determined through the Total Resource Cost (TRC) test, are excluded.

This study estimated program potential for five top-down policy intervention scenarios, corresponding to varying incentive levels provided to end-use consumers and an acquisition rate of 10 years for retrofit measures, as well as two additional scenarios that considered accelerated acquisition rates under the advanced and extreme scenarios:

- ***Low scenario***: Monetary incentives to customers equaling 25% of incremental costs of energy efficiency improvements[1], and administration and marketing costs equaling 20% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Moderate scenario***: Monetary incentives to customers equaling 50% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 35% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***High scenario***: Monetary incentives to customers equaling 75% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 40% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Advanced scenario***: Monetary incentives to customers equaling 90% of incremental costs of energy efficiency improvements and administration and marketing costs equaling 65% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Advanced accelerated scenario:*** Same incentives and administration and marketing costs as the "advanced scenario", but retrofit opportunities are assumed to be acquired in 8 years.

The study found that there is a realistic potential to reduce energy consumption from the baseline forecast by 15% by year 2019-20. Figure B-4 shows the cumulative % energy savings and cumulative savings through fiscal year 2022-23,

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	207	233	357	437	479	470	427	202	127	90
2	**Cumulative Program Potential (GWh)**	207	440	798	1,235	1,714	2,184	2,610	2,812	2,940	3,029
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	643	876	1,234	1,671	2,150	2,620	3,047	3,248	3,376	3,465
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**278**	**310**	**442**	**515**	**541**	**520**	**471**	**240**	**161**	**118**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.7%	3.6%	5.1%	6.8%	8.7%	10.4%	12.0%	12.6%	13.0%	13.2%
9	**Savings as % of Baseline (with Standards)**	**3.7%**	**5.0%**	**6.8%**	**8.8%**	**10.9%**	**12.8%**	**14.5%**	**15.3%**	**15.8%**	**16.1%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.7%	5.0%	6.8%	8.8%	10.9%	12.8%	14.5%	14.4%	14.1%	13.7%
11	**Incremental Demand Savings (MW)**	52	57	89	110	119	118	106	50	31	24
12	**Cumulative Demand Savings (MW)**	52	109	198	307	426	544	650	701	731	755
13	**Total Budget ($000)**	$84,597	$94,742	$144,932	$177,633	$193,758	$189,789	$171,939	$80,876	$50,648	$35,723
14	**TRC Levelized Cost ($/kWh)**	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620
15	**UCT Levelized Cost ($/kWh)**	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394

Figure B-4. Cumulative energy savings as a percentage of the baseline forecast.

B.4 References

1. "LOS ANGELES DEPARTMENT OF WATER AND POWER ENERGY EFFICIENCY AND DEMAND RESPONSE POTENTIAL STUDY
VOLUME 1 – ENERGY EFFICIENCY POTENTIAL" prepared by: Nexant Inc.

2. Assembly Bill: "BILL NUMBER: A.B. No. 2021, AUTHOR : Levine, TOPIC : Public utilities: energy efficiency." - "Assembly Bill No. 2021, CHAPTER 734, An act to add Section 25310 to the Public Resources Code, and to amend Section 9615 of the Public Utilities Code, relating to energy efficiency."

Appendix C Environmental Issues

C.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:

- Increasing the use of renewable energy to meet the needs of LADWP's customers (20 percent by December 31, 2010, 33 percent by December 2020, and 50 percent by December 2030) through the development of wind, solar, geothermal, and biomass energy sources and acquiring the associated transmission required to transmit such energy to Los Angeles.

- Prioritizing the use of Energy Efficiency (EE), Demand Side Management (DSM), renewable Distributed Generation (DG), and other renewable resources.

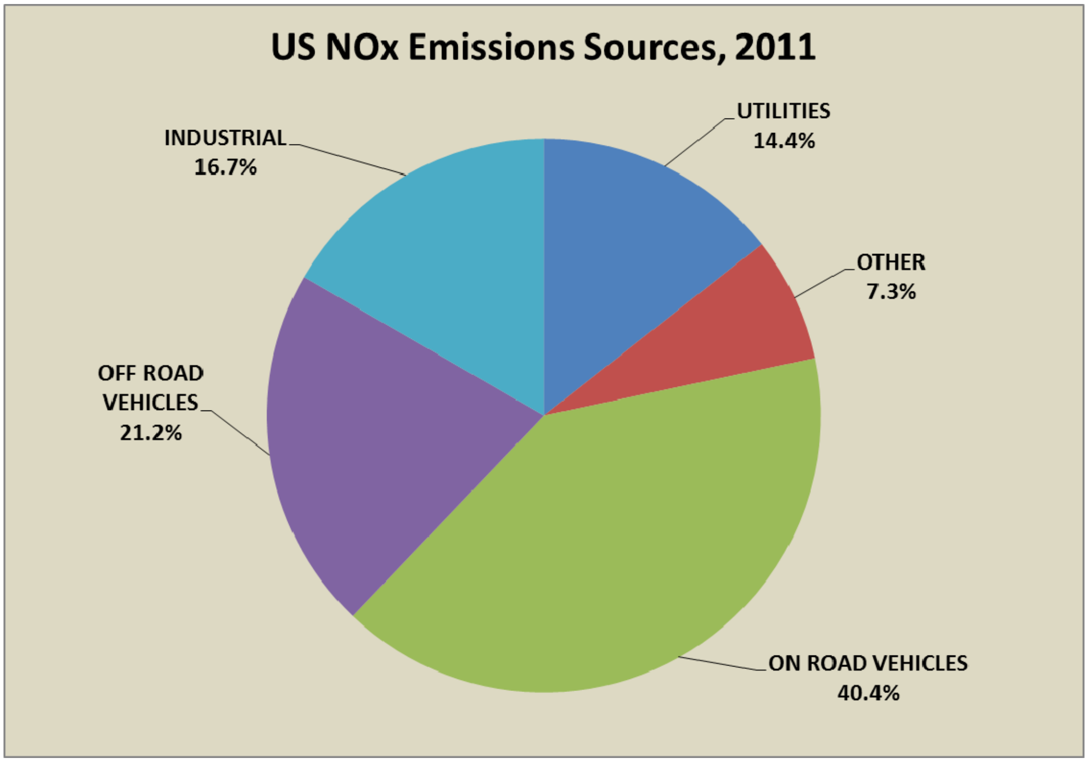
- Continuing the modernization of LADWP's in-basin generating stations, including the repowering of four older, less-efficient utility steam boiler units with advanced gas turbine generating units.

This Appendix provides information on a number of environmental issues and policies including oxides of nitrogen (NO_X) emissions, Greenhouse Gases (GHGs), climate change, power plant once-through cooling, (OTC), and mercury emissions.

C.2 Emissions of Oxides of Nitrogen (NO_X)

Oxides of nitrogen, or NO_X, is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. Many of the oxides of nitrogen are colorless and odorless. Oxides of Nitrogen is a precursor to the formation of ozone, and the South Coast Air Basin (SCAB), in which Los Angeles is situated, has the one of the highest ozone levels in the United States.

NO_X forms when fuel is burned at high temperatures, as in a combustion process. Figure C-1 shows the primary man-made sources of NO_X as reported by the United States Environmental Protection Agency (U.S. EPA) in 2011. The U.S. EPA first set standards for 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 2010, EPA established a new 1-hour standard at a level of 100 ppb to supplement the existing annual standard.



Source: U.S. Environmental Protection Agency

Figure C-1. NO_X emission sources in the U.S.

The SCAB (including Los Angeles, Orange, San Bernardino, and Riverside 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.

The South Coast Air Quality Management District (SCAQMD) estimated in its 2012 Air Quality Management Plan (AQMP) that 2012 emissions in the SCAB were 485 tons of NO_X per day. In the 2012 AQMP, SCAQMD projects that SCAB NO_X emissions will continue to decrease to 319 tons per day in 2023 and 276 tons per day in 2032. The majority of this reduction is expected to be attributed from a reduction in vehicle emissions. Figure C-2 shows the estimate 2014 NO_X emission sources.

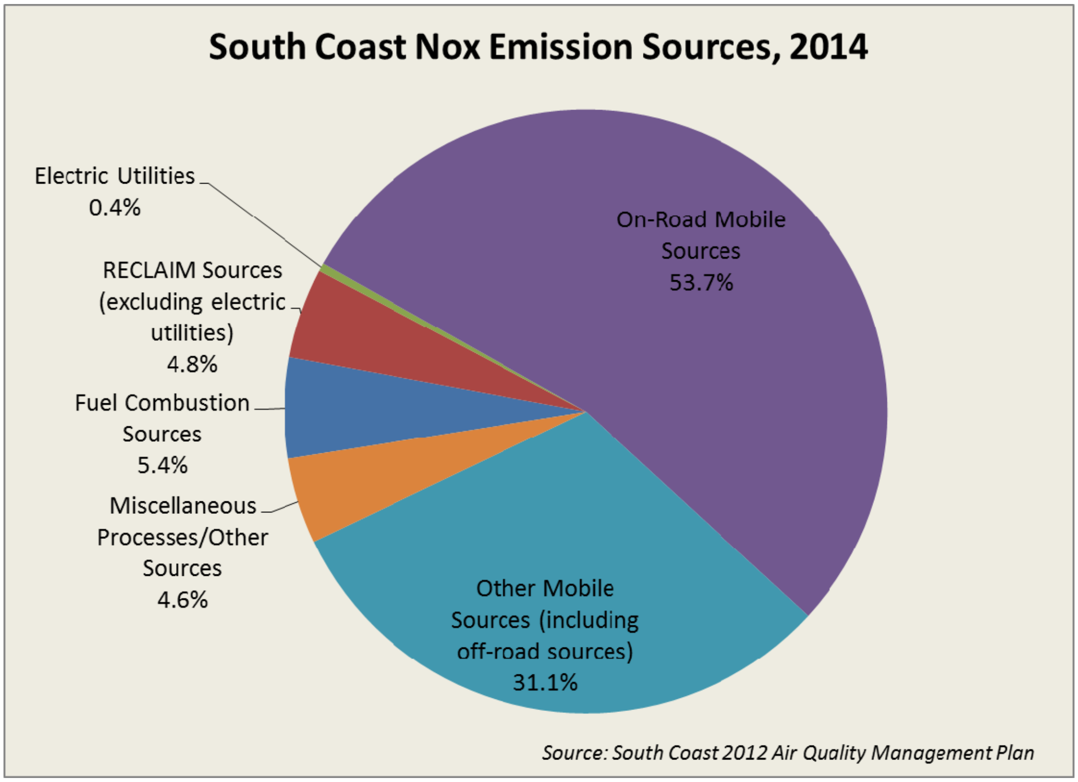


Figure C-2. Projected Local NO_X sources in 2014.

For comparison, the combined average daily NO_X emissions from LADWP's in-basin generating stations (Harbor, Haynes, Scattergood, and Valley) was 0.6 short tons of NO_X per day in 2014, which represents 0.12 percent of the 2014 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 at all facilities and the installation of advanced emissions control systems.

A key regulation employed by the South Coast Air Quality Management District (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 superseded the SCAQMD's existing NO_X rules for facilities with NO_X emissions exceeding 4 tons per year. These "command and control" rules limited the emission rates of stationary combustion equipment and have been replaced by a facility-wide emissions cap, which gradually declines each year. Facilities receive 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. RECLAIM is a market-driven program because the RTCs can be purchased and sold, which allows for the emissions reductions to be made in the most cost-effective manner.

All of LADWP's in-basin power plants now have advanced pollution control equipment, which reduces NO_X emissions by at least 90 percent. Thus, all of LADWP's in-basin power plants meet Best Available Retrofit Control Technology or the more stringent Best Available Control Technology requirements (applicable to repowered units). However, SCAQMD is proposing a 49 percent reduction, or "shave" in the power plant sector's allocation of RTCs by 2022. SCAQMD is scheduled to adopt amendments to its NOx RECLAIM regulation at its December 2015 Governing Board meeting.

C.3 Greenhouse Gas Emissions and Climate Change

C.3.1 Federal Efforts to Address Climate Change

Federal Regulation of Greenhouse Gases Under the Clean Air Act

In the absence of federal legislation, 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 regulating 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 amount of tons per year on a CO2e 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 GHG requirements. LADWP's future repowering efforts will be subject to the new permitting requirements under EPA's Tailoring Rule. Also, LADWP has existing Title V operating permits which will be required to be amended to incorporate any federal GHG applicable regulatory requirements (e.g. GHG BACT requirements) when they are renewed.

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 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 repowering projects will be subject to GHG regulation under BACT since they are "anyway" sources.

In addition to the PSD permit program, EPA is also in the process of developing a GHG regulatory program under the New Source Performance Standards ("NSPS") provisions of the Clean Air Act. On December 23, 2010, the EPA entered a settlement agreement and agreed to issue NSPS and emissions guidelines for GHG emissions from new and modified fossil fuel fired electric generating units ("EGUs"). On April 13, 2012, the EPA published in the Federal Register its proposed rule for CO2 NSPS for new EGUs. EPA received over 2.5 million comments, the most ever for a proposed EPA rule.

On June 25, 2013, President Obama announced initiatives addressing climate change. In his announcement, he directed EPA to re-propose CO2 emission standards for new EGUs by September 20, 2013. He also directed EPA to propose guidelines for existing EGUs by June 2014, and finalize them a year later.

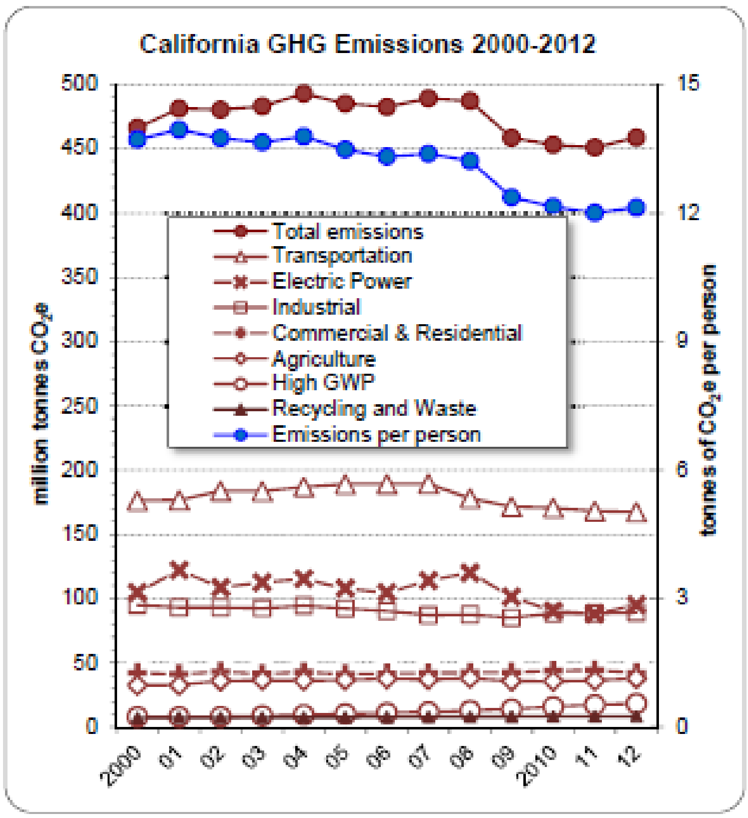
EPA released the re-proposed standards on September 20, 2013, solicited public comments, and released its final rule on August 3, 2015. For new and reconstructed natural gas base load units, the CO2 standard is 1,000 lb per MWh gross and for non-base load natural gas units, the standard is a natural gas heat input standard of 120 lb CO2 per MMBTU. LADWP's future repowerings of its in-basin generating units will be in compliance with EPA's required levels.

On June 18, 2014, EPA's proposed Clean Power Plan for reducing CO2 from existing electric generating units (EGUs) was published in the federal register. The proposal required each state with fossil fuel-fired EGUs to meet state-specific rate-based (lb/MWh) CO2 emission goals by 2030 as well as an interim reduction target, which is an average emission rate required to be met over the period 2020 to 2029. The proposal also allows states to convert their emission rate goals to a mass-based limit (tons CO2/year) and provides guidelines for states to follow in developing plans to achieve the state-specific goals. Clean Air Act Section 111(d) provides states with the primary responsibility and authority to establish and implement performance standards for existing sources and states will have broad discretion to develop their plans.

On August 3, 2015, EPA released its final Clean Power Plan rule which establishes state-specific CO2 emission reduction goals for existing EGUs starting in 2022 and directs each state to submit to EPA approval a plan demonstrating how the state will meet its reduction goals. EPA's guideline goals are formulated as rate-based limits and also provides mass-based limits that EPA deems equivalent. States are required to submit a plan or initial plan and request for an extension by September 6, 2016. Because there are multiple compliance pathways a state can take, at this time, LADWP cannot predict how the Clean Power Plan will specifically impact its EGUs.

C.3.3 California Efforts to Address Climate Change

This section presents an overview of the California greenhouse gas emissions inventory and trends from 2000 through 2012. A new edition of California's greenhouse gas emission inventory was released in May 2014. It includes emissions estimates for years 2000 to 2011. Figure C-3 depicts the general trend in emissions from 2000 to 2012 by economic sector, and per capita.



Source: California Air Resources Board

Figure C-3. California GHG emissions by Economic Sector, 2000-2010.

As California strives to achieve its GHG emission reduction goals under Assembly Bill (AB) 32, the California GHG emissions inventory is the tool to track statewide GHG emissions and progress towards the GHG emission reduction target. In 2007, the California Air Resources Board adopted 427 MMT CO2e as the 1990 statewide GHG emissions level and 2020 emission limit. According to the latest edition of the inventory, California's 2012 GHG emissions were 458.7 million metric tons of carbon dioxide equivalent (MMT CO_{2e}), which is 1.6 percent less than 2000 emissions (466.3 MMT

CO2e) and 7.4 percent higher than 1990 emissions (427 MMT CO2e). Figure C-4 depicts the 2012 statewide GHG emissions by sector.

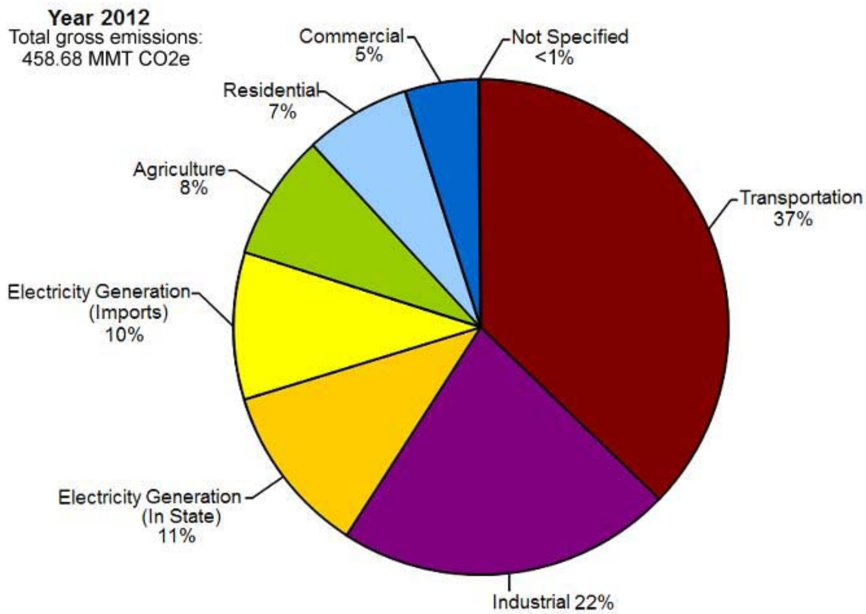


Figure C-4. California GHG Emissions by Sector, 2012

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. Strategies implemented by the CPUC and CEC under SB 1368 are expected to result in a combined GHGs emissions reduction of over 15 million metric tons (MMT) CO_{2e} by 2020. The GHG emissions performance standard is based on the emissions profile of combined-cycle, natural gas fired generating units. The CEC's regulations established an emissions performance standard of 1,100 pounds (0.5 metric tons) of CO_2 per megawatt hour (MWh) of electricity. 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, currently set at 1,100 pounds per MWh.

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 that encompassed the various issues raised by the Petitioners and other stakeholders.

At its January 12, 2012 business meeting, the Commission adopted an order instituting rulemaking (OIR) 12-0112-7, which initiated a proceeding to discuss, and if warranted, implement possible changes to the Emissions Performance Standards regulations.

The CEC issued a proposed Final Decision on April 5, 2013 with modifications to the EPS regulations. The CEC proposed to modify Section 2908 of the EPS to require local publicly owned electric utilities to inform the CEC and all persons on the CEC's Climate Change service list on any expenditure over $2.5 million at a non-EPS compliant baseload facility to meet environmental regulatory requirements.

To date, the CEC has not formally proceeded with adoption of the proposed modifications to the EPS.

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 2020 GHG emissions reduction goal that would require the reduction of statewide emissions of GHGs[1]. In 2007, the ARB established a 1990 statewide GHG emissions baseline of 427 MMT of carbon dioxide equivalent (CO_{2e})[2] and adopted a regulation for mandatory emissions reporting from the most significant sources that contribute to statewide emissions, including all electricity consumed in the state as well as imported electricity. The 2020 target was set at the 1990 baseline level of 427 MMT $CO_{2e.}$

The AB 32 Scoping Plan

AB 32 requires CARB to develop and approve a Scoping Plan, which serves as California's blueprint for reducing greenhouse 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 percent.
- Developing a California cap-and-trade program to ensure the target is met, while providing flexibility to California businesses to reduce emissions at low cost. Establishing targets for transportation-related GHG emissions for regions throughout California, and pursuing policies and incentives to achieve those targets.
- Adopting and implementing measures pursuant to existing State laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard.

In May 2014, the CARB adopted the First Update to the AB 32 Scoping Plan (Update). The 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 states 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 October 2015, the California Environmental Protection Agency, California State Transportation Agency, California Energy Commission, California Public Utilities Commission, California Natural Resources Agency, California Department of Food and Agriculture, CARB, and Governor's Office of Planning and Research hosted a community workshop to begin the process of updating the Scoping Plan to reflect California's goal to reduce GHG emissions 40 percent below 1990 levels by 2030, as directed in Executive Order B-30-15. It is anticipated that a Final 2030 Target Scoping Plan will be presented to the CARB Board in Fall 2016.

[1] GHGs covered by AB 32 include the following: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.
[2] Carbon dioxide equivalent ($CO2_e$) means the amount of carbon dioxide by weight that would produce the same global warming impact as a given weight of another greenhouse gas, based on the best available science, including from the Intergovernmental Panel on Climate Change.

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 Commissions to ensure that a regulation adopted under authority of AB 32 to encourage the creation and use of renewable energy sources shall build upon the RPS program, developed to reduce GHG emissions in California and shall regulate all California publicly owned utilities, such as LADWP. In addition, Executive Order S-21-09 provides that CARB may delegate policy development and implementation to 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.

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 percent 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 program covers about 350 businesses, representing 600 facilities and it starts in 2013 for electric utilities and large industrial facilities, while distributors of transportation, natural gas and other fuels join in 2015. The ARB linked carbon markets with Quebec in 2014 and is in the process of linking with Ontario.

Although the program commenced on January 1, 2012, the enforceable compliance obligation starts with 2013 GHG emissions. CARB held its first auction of California carbon allowances in November 2012 and has been holding auctions on a quarterly basis since then.

Combined Heat and Power

Assembly Bill 1613 (Blakeslee, 2007) as amended by AB 2791 (Blakeslee, 2008), created the Waste Heat and Carbon Emissions Reduction Act of 2007, which requires among other things that a local publicly owned electric utility serving retail end-use customers establish a program that allows retail end-use customers to utilize combined heat and power (CHP) systems that reduce emissions of greenhouse gases by achieving improved efficiencies utilizing heat that would otherwise be wasted in separate energy applications and that provides a market for the purchase of excess electricity generated by a combined heat and power system, at a just and reasonable rate, to be determined by the governing body of the utility. LADWP is in compliance with this requirement as it offers a Standard Energy Credit for distributed generation, including CHP.

As part of the ARB's 2008 Climate Change Scoping Plan, a CHP measure was included that calls for 4,000 MW of new CHP capacity that would result in an estimated reduction of 6.7 million metric tons of annual GHG emission reductions and displace 30,000 GWh of electricity demand by 2020. Governor Brown's Clean Energy Jobs Plan includes a target of 6,500 MW of additional installed CHP capacity over the next 20 years.

The Energy Commission updated its CHP market assessment to update the potential for new CHP and to understand the amount of new CHP the current policy may provide, and the emissions reductions gained from old, retiring CHP and its associated capacity. This information will be used to develop policies and regulations to encourage CHP and support the state's GHG emissions reduction goals. Market penetration estimates of CHP were presented for three market development scenarios—a Base Case reflecting continuation of existing state policies and two additional cases (Medium and High) that show the market impacts of additional CHP policy actions and incentives. The updated 2012 assessment suggests that the LADWP service territory's share of new CHP under the base case market penetration scenario is 15 percent overall. The assessment suggested a range for LADWP's new CHP capacity (MW) starting with the base case at 224 MW by 2020 increasing to 281 MW by 2030, up to the high case of 557 MW by 2020 increasing up to 698 MW.[3]

C.3.4 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 discontinuation of involvement in the development of Unit 3 at Intermountain Generating Station. Table C-1 shows the downward trajectory in LADWP's power generation portfolio CO_2 emissions and CO_2 emissions intensity between 1990 and 2014.

[3] California Energy Commission, "Consultant Report: Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment," ICF Consulting, February 2012, Publication No. CEC, 200-2012-002, Appendix D.

Table C-1. HISTORICAL LADWP POWER GENERATION CO_2 EMISSIONS

Year	CO2 Emissions from Total Owned & Purchased Generation including wholesale transactions (metric tons)	CO2 Emissions from Total Owned & Purchased Generation excluding wholesale transactions (metric tons)	Total Owned & Purchased Generation (Net MWh)	LADWP Power System CO2 Intensity Metric (lbs CO2/MWh)
1990	17,925,410	17,764,874	25,481,532	1,551
2000	18,464,480	16,992,238	28,806,750	1,413
2001	18,086,034	16,663,305	28,032,375	1,422
2002	16,873,841	16,237,832	26,808,569	1,388
2003	17,274,623	16,710,232	27,337,694	1,393
2004	17,609,759	16,604,943	28,138,391	1,380
2005	16,928,681	15,854,278	28,301,700	1,319
2006	16,838,147	15,885,136	29,029,883	1,279
2007	16,461,774	15,523,035	29,141,703	1,245
2008	16,232,608	15,650,115	29,394,809	1,217
2009	14,646,410	13,829,395	28,041,998	1,151
2010	13,771,186	12,844,288	27,490,878	1,104
2011	14,169,324	13,631,178	27,025,925	1,156
2012	14,053,029	13,414,528	28,311,079	1,094
2013	14,314,083	13,813,895	27,792,649	1,135
2014	14,917,314	14,192,577	28,268,228	1,163
Difference between 1990 and 2014	-3,008,096	-3,572,297	2,786,696	-387
% Change from 1990	-17%	-20%	11%	-25%

Notes:
1) Calculated CO2 emissions for specified sources using fuel data and fuel-specific emission factors from 40 CFR Part 98 Subpart C Table C-1.
2) Calculated CO2 emissions for unspecified purchased power using CARB's default emission factor for unspecified electricity (0.428 MT CO2e/MWH) x 2% transmission loss factor.

SF6 Emissions

In February 2010, CARB adopted a new regulation to reduce SF6 emissions from gas insulated electrical switchgear as part of the AB 32 program. The CARB SF6 regulation imposes a declining limit on each equipment owner's annual average SF6 emissions rate starting at 10 percent in 2011 and decreasing to 1 percent in 2020, as well as new recordkeeping and reporting requirements.

Over the past decade, LADWP has been proactive in reducing SF6 emissions by implementing its own internal program to reduce emissions through equipment replacement, repair, and process improvements. This voluntary effort to reduce SF6 emissions demonstrates LADWP's commitment to environmental stewardship and puts

LADWP in a good position to comply with the emission limits imposed by the CARB SF6 regulation.

C.4 Power Plant Once-Through Cooling Water Systems

Power plants with "once-through cooling" (OTC) systems draw or take in water from coastal/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 7, reducing ocean water use from 1904 MGD to 1110 MGD, an overall reduction of ocean water usage by 42%.

- LADWP has spent over $1.3 billion dollars to replace the older generating units with more efficient generating units (known as "repowering") at its Haynes and Harbor Generating Stations. This has resulted in a reduced use of coastal waters.

To further reduce impacts and completely eliminate OTC, LADWP plans to do the following:

- By December 31, 2015, the Scattergood Unit 3 Repowering Project will be complete, further reducing the number of OTC units to 6 and decreasing ocean water use from 1110.2 MGD to 839.8 MGD, an overall reduction of 56% from 1990 ocean water usage levels.

- By 2020, the Scattergood Units 1&2 Repowering Project will be complete, further reducing the number of OTC units to 4 and decreasing ocean water use from 839.8 MGD to 563.3 MGD; an overall reduction of 68% from 1990 ocean water usage levels.

- By 2024, the Haynes Units 1&2 Repowering Project will be complete, further reducing the number of OTC units to 2 and decreasing ocean water use from 563.3 MGD to 338.7 MGD, an overall reduction of 82% from 1990 ocean water usage levels.

- By 2026 the Harbor Unit 5 repowering project will be complete, further reducing the number of OTC units to 1 and decreasing ocean water use from 338.7 MGD to 230 MGD, an overall reduction of 87% from 1990 ocean water usage levels.

- By 2029, the final repowering project, Haynes Unit 8 will be complete, reducing the number of OTC units to 0, resulting in 100% elimination of OTC.

Figure C-4 shows LADWP's reduction in OTC usage from 1990 through 2029.

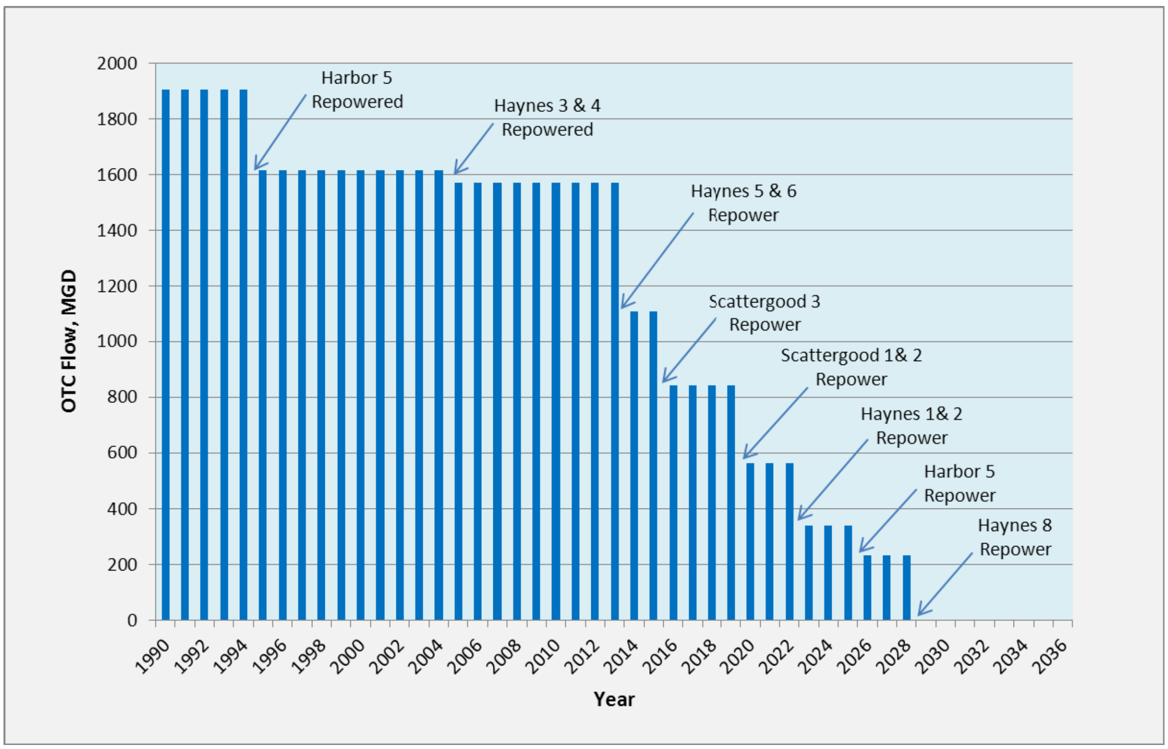


Figure C-4: LADWP OTC reduction from 1990 to 2029.

C.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 method. 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 has been awaiting 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 is now 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) becomes effective 60 days after it is noticed in the Federal Register. The new Rule allows for the IM and E 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 alternatives, 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.

C.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 retrofitted with IM and Entrainment (E) impact control technology; 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 percent 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 percent) what would exist with CCC. New consecutive 36-month IM and E baseline studies will be required if 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, LADWP must commit to complete elimination of OTC and in the interim must prepare a mitigation plan and fund projects to offset impacts until each unit is fully compliant. In addition, LADWP 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 is in the process of developing its mitigation plan and submitting the alternative technologies studies proposal for the State Board's approval.. The Haynes Units 5&6 repowering project has been completed and the new units are in operation. Also, the construction phase for the Scattergood Unit 3 project has commenced in is nearly complete to meet the 2015 deadline.

C.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 percent 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.

C.6 Coal Combustion Residuals

On May 4, 2010, the U.S. Environmental Protection Agency released pre-publication co-proposals to regulate the management of coal ash from coal-fired power plants.

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. There are almost 900 landfills and surface impoundments nationwide.

Due to the metal constituents of the CCRs, EPA's co-proposals will establish control measures, such as liners and groundwater monitoring, which would be in place at new landfills to protect groundwater and human health. Existing surface impoundments would also require liners, with incentives to close the impoundments and transition to landfills, which store coal ash in dry form.

The proposed regulations may change the way CCRs are handled and stored at Intermountain Power Plant and Navajo generating station. If implemented, the rules would require the phase-out of wet handling systems and surface impoundments of bottom ash and the subsequent permitting and installation of lining under fly ash landfills. The facilities would have to conduct additional groundwater monitoring, and provide closure and post-closure care of the surface impoundments and landfills. For Mohave generating station, the rules, as proposed are expected to have minimal impacts because the facility did not operate any surface impoundment.

Appendix D Renewable Portfolio Standard

D.1 Overview

LADWP has historically maintained that its major objectives concerning integrated resource planning are; (1) providing reliable service to its customers; (2) remaining committed to environmental leadership; and (3) maintaining a competitive price.

Since its 2007 IRP, LADWP has made great strides towards achieving the 2010 goal of increasing its supply of electricity from "eligible" renewable resources to 20 percent, measured by the amount of electric energy sales to retail customers, and has met the 20 percent goal for calendar year 2010.

On April 12, 2011, the California governor signed into law the Senate Bill 2 (1X) which extends the 20 percent target to 2013, and ramps up the target to 25 percent by December 31, 2016 and 33 percent by December 31, 2020.

On December 6, 2011, the LADWP Board approved the Renewables Portfolio Standard Policy and Enforcement Program, which is included in Reference D-1 and D-2.

On October 7, 2015, the California governor signed into law the Senate Bill 350 which extends the RPS target, increasing the requirement to 40 percent by December 31, 2024, 45 percent by December 31, 2027, and 50 percent by December 31, 2030.

This 2015 IRP documents how LADWP expects to maintain 20 percent renewable energy and describes the process for LADWP's continuing commitment to increase the renewable energy to reach 33 percent by 2020 and 50 percent by 2030. Additionally, LADWP will continue to encourage voluntary contributions from customers to fund renewable resources above the stated Renewable Portfolio Standard (RPS) goal, as part of its Green Power for a Green LA Program (GREEN).

D.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 Request 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.

D.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.

D.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 per year to meet the then RPS interim goal of 13 percent 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.

D.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 percent 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.

D.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 percent by 2010 and 35 percent by December, 31, 2020.

The 2008 RFP process resulted in two contracts, which provide 834 GWhs/yr of renewable energy from wind resources.

D.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. LADWP participated in the evaluations of the RFP proposals. LADWP evaluated proposals through a structured process. The evaluation included a 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 the Desert, and biogas from Shell. The results are summarized in the table below:

Renewable Project		Integration Cost
Geothermal	Salton Sea	$0/MWh
Wind	STS Wind	$7-15/MWh
Solar	PV_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 a RFP for renewable projects and the response deadline was December 31, 2013. In February 2014, SCPPA issued a RFP for renewable and energy storage projects and the response deadline was December 31, 2014. In January 2015, SCPPA issued a new RFP for renewable and energy storage projects. The response deadline is December 31, 2015.

D.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 IRP, 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.

This IRP describes several fundamental principles for the RPS progression from the current 20 percent renewable energy to a potentially higher goal of 33 percent by 2020. Issues and principles affecting the future of the RPS plans are discussed below:

D.3.1 Issues

- The "Ramp Rate", i.e., the annual rate of progress from 20 percent to 33 percent renewables, will be subject to several factors. The time frame is 10 years, which would equate to a constant ramp of 1.33 percent per year. 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 maintain a 20 percent RPS between 2010 and 2012, ramp to 33 percent between 2013 and 2020, and ramp to 50 percent between 2020 and 2030. There are several reasons for this path forward: Between 2010 and 2012, the projects maintaining the 20 percent RPS will become fully integrated into the system; reflecting 2010 economic conditions and allowing time for pricing adjustments and efficiencies of certain renewable industries such as solar PV to reach the marketplace. For budgeting and planning purposes, the assumed RPS implementation strategy is 1 percent annual RPS increases from 2013 thru 2015 and 2 percent from 2016 thru 2020. Of course, all of this strategy is dependent on adequate funding.

- 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.

D.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.

D.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 tax advantages; thereby lowering the ultimate cost to LADWP.

Subject to further studies, given the wind and solar projects coming on-line, limitations on the percentage of intermittent resources may be required. There may be more stringent limitation in certain resource areas, or along certain transmission systems. It is possible that no more than 15-20 percent intermittent energy can be ultimately integrated in the current electric grid. Of the 20 percent renewable energy consumed in 2010, less than 1/5th of that amount was of an intermittent type. Most renewable resources are base-load sources having a predictable energy pattern or wind projects that have their energy output firmed and shaped by outside balancing authorities before delivery to LADWP. The total amount of intermittent energy obtained will not be increased beyond current levels unless studies demonstrate that these resources can be reliably integrated.

Wind, as shown elsewhere in this IRP, 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 2014 is shown on Figure D-1.

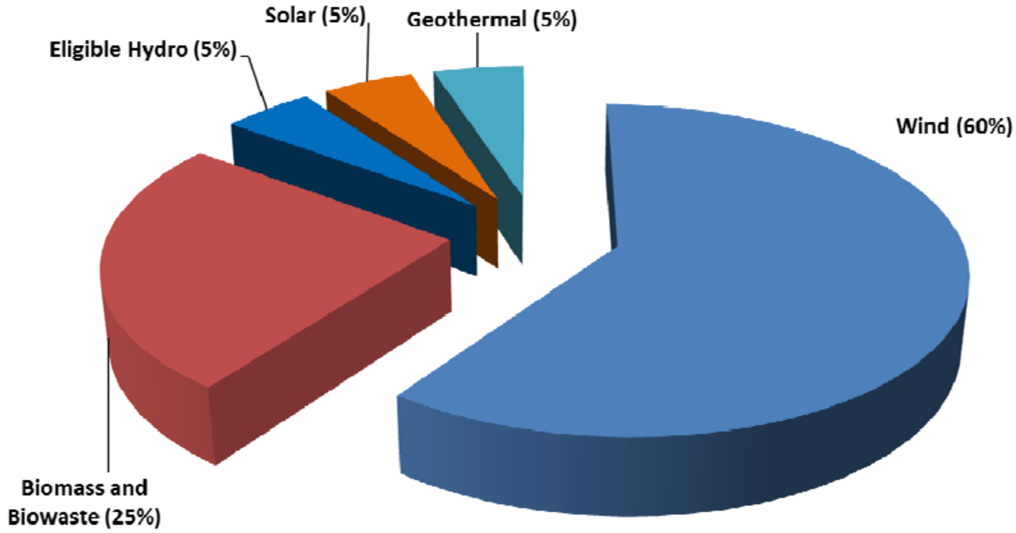


Figure D-1: 2014 LADWP Renewable Energy Mix

D.3.4 Impacts of CA Senate Bill SB 2 (1X) and Senate Bill SB 350

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 percent 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 have 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 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).	**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 Sixth Edition Renewable Energy Program Overall Program Guidebook and the Seventh Edition Renewable Portfolio Standard Eligibility Guidebook were adopted by the CEC on April 30, 2013.

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 adopted Regulations have placed additional criteria to the procurement targets for each compliance period:

1. For the compliance period beginning January 1, 2011, and ending December 31, 2013, POUs are required to meet or exceed an average of 20 percent RPS over the three calendar years in the compliance period.
2. 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.
3. 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.

In December 2013, LADWP amended its Renewable Portfolio Standard (RPS) Policy and Enforcement Program to comply with the requirements of SB 2 (1X) and the Regulations. However, LADWP's policy continues to include some requirements that are not a part of SB 2 (1X) or the Regulations but were in place prior to enactment of the State legislation. These additional requirements include the provision for LADWP to own at least 50 percent of its renewable energy resources, and to give preference to projects located within the City.

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.

D.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

[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

greenhouse-gas (GHG) attributes, associated with the production of electricity from the eligible renewable energy resource.

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 2011.

D.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 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 is ongoing. The target in-service data is 2016.

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 build-out in the Owens Valley, additional new transmission may be required.

3. The joint Southern California Edison (SCE)/Imperial Irrigation District (IID) upgrade of Path 42 is critical for delivery of renewable generation from the IID area into the California ISO. Upgrading Path 42 requires improvements to facilities under the control of SCE and the California ISO as well as facilities under IID control. The IID upgrades consist of replacing the 220 kV circuits between the Coachella Valley Substation and the Mirage Substation with bundled circuits, two conductors per circuit. The IID portion of the upgrades would increase the capacity of IID's portion of the path by around 800 MW. The total renewable potential for the California ISO/IID Path 42 upgrades is approximately 1,400 MW.

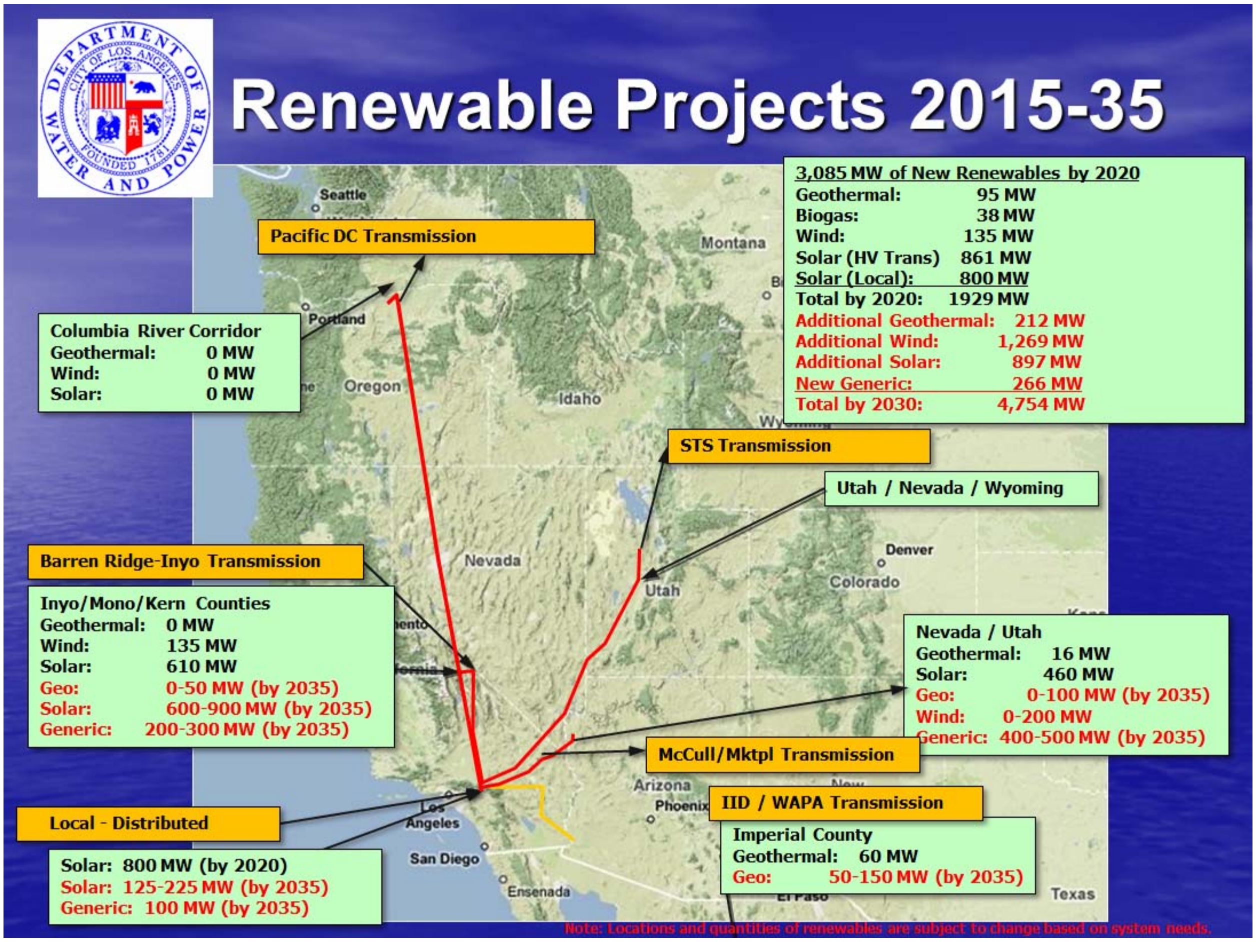


Figure D-2: Renewable Transmission Paths and Potential Resources, 2015 – 2035

D.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 a 50 percent RPS goal will vary depending on the mix of resource types and associated costs. Generally, renewable energy costs more than traditional energy sources such as natural gas and coal. However, a diversified energy portfolio, including a larger mix of renewables, may also reduce the risk of price spikes due to fuel supply shortages.

Estimated RPS revenue requirements to comply with SB 2 (1X) compliance targets of 25 percent renewable in 2016 and 33 percent in 2020 are shown in Figure D-3. Revenues required for an additional 2600 GWh for 2020 will require increasing annual renewable portfolio costs from 400 million to 600 million over the next 7 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. As can be seen in Figure D-4, the deficit of renewable projects will reduce from 1,069 MW to 0 MW between 2015 and 2017 but will grow to 392 MW by 2020. Filling this deficit with viable projects is a constant challenge especially since the selection of each project must fulfill multiple criteria including being economically attractive, located near existing transmission lines, and achieving geographically and technologically diversity.

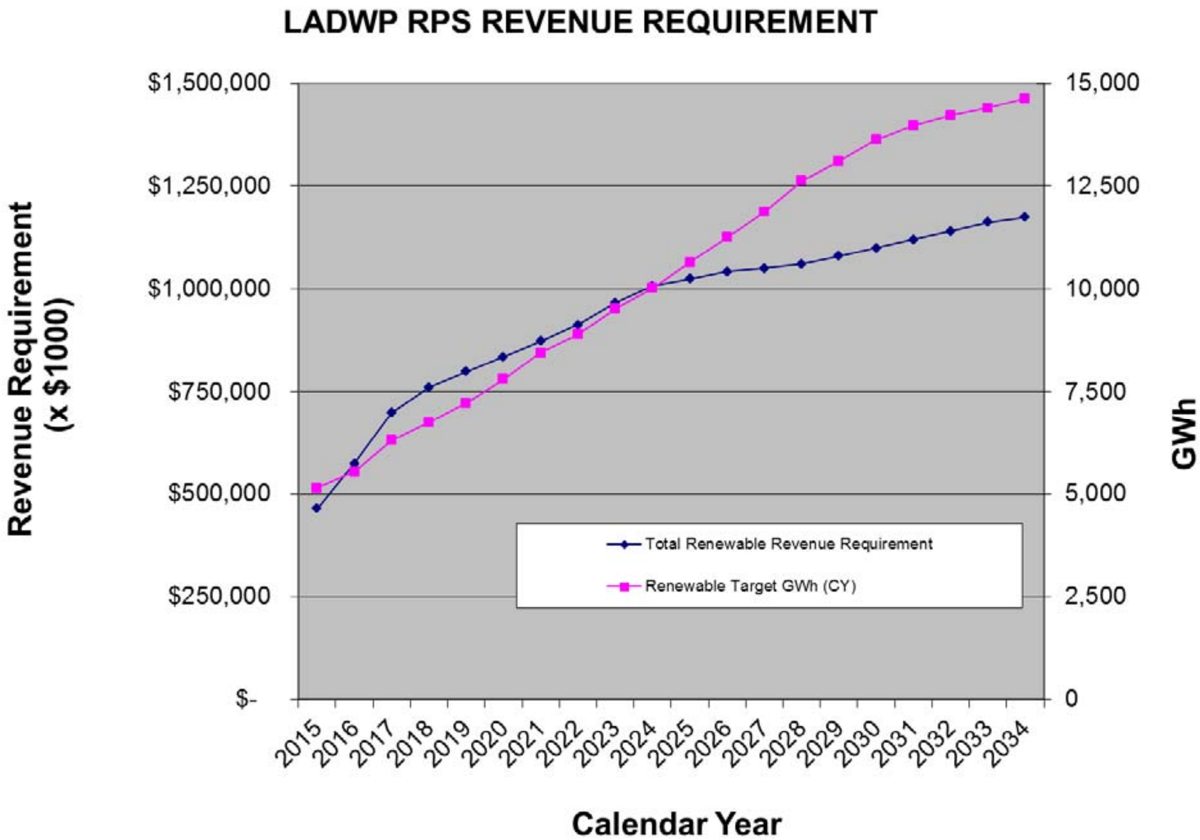
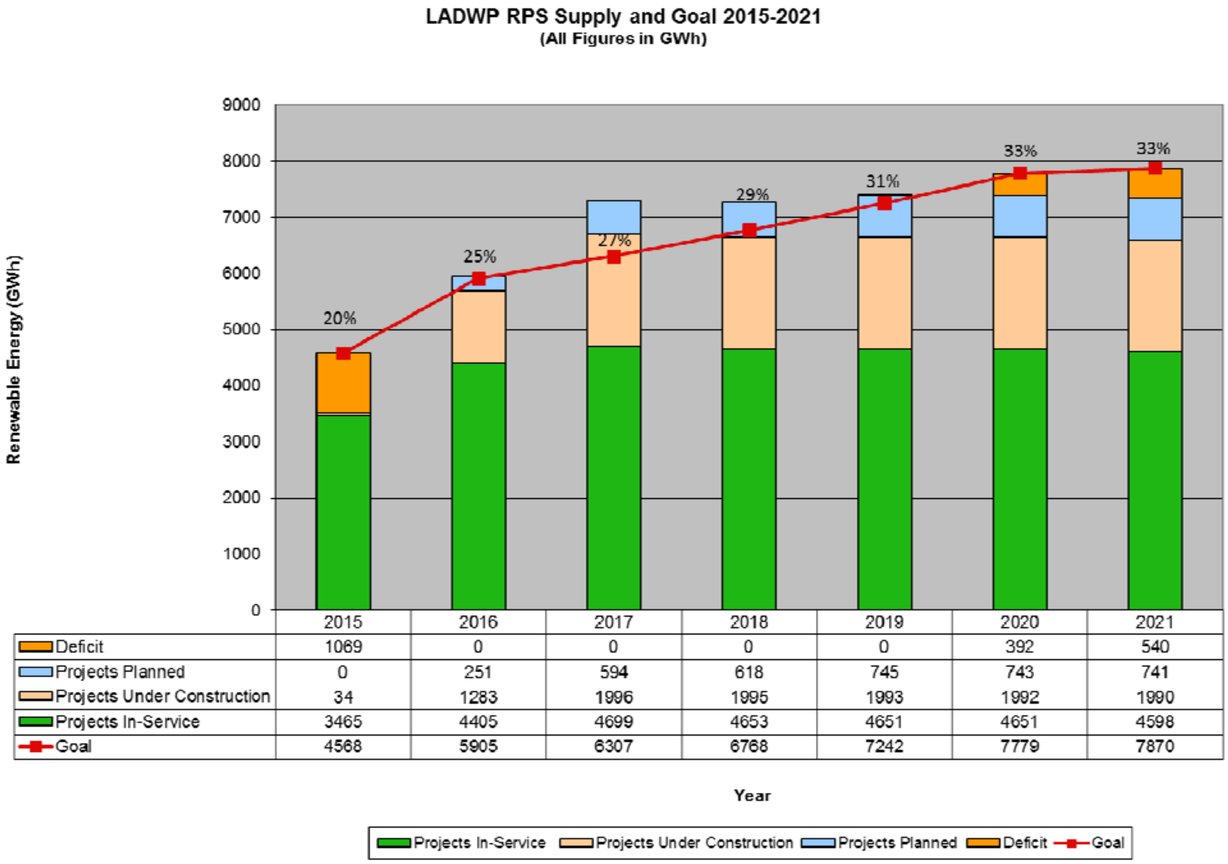


Figure D-3 – LADWP RPS Revenue Requirement 2015-2034.



	2015	2016	2017	2018	2019	2020	2021
Deficit	1069	0	0	0	0	392	540
Projects Planned	0	251	594	618	745	743	741
Projects Under Construction	34	1283	1996	1995	1993	1992	1990
Projects In-Service	3465	4405	4699	4653	4651	4651	4598
Goal	4568	5905	6307	6768	7242	7779	7870

Figure D-4. LADWP RPS supply and goals for 2015-2021.

D.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.

D.6.1 Biogas and Biomethane

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.

D.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 of 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 percent 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.

D.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 2014 Power Content Label is shown in Table D-1. As LADWP has two separate renewable programs, the RPS policy and GREEN, both of these programs are reported on the Power Content Label.

Table D-1: LADWP's 2014 Power Content Label

POWER CONTENT LABEL			
ENERGY RESOURCES	2014 Power Mix	2014 Green Power for Green LA Power Mix	2014 CA POWER MIX**
Eligible Renewable	**20%**	**100%**	**20%**
Biomass & waste	5%	100%	3%
Geothermal	1%	0%	4%
Small hydroelectric	1%	0%	1%
Solar	1%	0%	4%
Wind	12%	0%	8%
Coal	**40%**	**0%**	**6%**
Large Hydroelectric	**2%**	**0%**	**6%**
Natural Gas	**22%**	**0%**	**45%**
Nuclear	**9%**	**0%**	**9%**
Other	**0%**	**0%**	**0%**
Unspecified sources of power*	**7%**	**0%**	**14%**
TOTAL	**100%**	**100%**	**100%**

* "Unspecified sources of power" means electricity from transactions that are not traceable to specific generation sources.

** Percentages are estimated annually by the California Energy Commission based on the electricity sold to California consumers during the previous year.

For specific information about this electricity product, contact:	**LADWP** 1-800-DIAL-DWP
For general information about the Power Content Label, contact:	California Energy Commission 1-844-217-4925 http://www.energy.ca.gov/sb1305/

Reference D-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 D-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 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

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

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 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. RPS Procurement Targets

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. Voluntary Program – Green L.A.

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. Eligible Renewable Energy Resources to be Counted in Full Towards RPS

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).	**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 – 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 – 2020):** 10% of RPS maximum from this category. **Post 2020:** 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

[8] Public Utilities Code §399.15(b)(5); Regulation §3206(a)(2)(A)

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 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

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Appendix E Power System Reliability Program

1. Introduction

The Power System Reliability Program (PSRP) was launched in July 2014 as a comprehensive asset rehabilitation program, covering the four major asset classes: Generation, Transmission, Substations, and Distribution.

It is funded by base rates, a pass-through Reliability Cost Adjustment (RCA) passed by the City Council on April 9, 2008 as Los Angeles City Ordinance 179801, and the Incremental Reliability Cost Adjustment (IRCA) enacted as Ordinance 182273 and passed on October 2, 2012. The ordinances had been established to fund the Power Reliability Program (PRP) which is now the distribution component of the PSRP.

By refreshing its aging infrastructure, the PSRP is positioning the power system so that compliance-driven system expansions are prudent investments, rather than extensions of a crumbling foundation. Table E-1 summarizes the target replacements through Fiscal Year (FY) 16-17.

	Asset	Target FY 15-16	Target FY 16-17
	GENERATION		
1	Generator Transformer (GSU & AUX)	0	2
2	Major Inspection (Thermal)	1	0
3	Major Inspection (Hydro)	0	2
4	Major Inspection (Pump)	1	1
	TRANSMISSION		
1	138kV UG Transmission Circuit	2	2
2	138kV Stop Joints	5	5
3	Maintenance Hole Restraints	20	30
	SUBSTATION		
1	RS Transformer. Voltage > 138kV	0	0
2	RS Transformer. Load Bank. Secondary Voltage 34.5kV	3	3
3	DS Local Substation Transformer	12	16
4	>100kV Circuit Breaker	0	0
5	34.5kV Circuit Breaker	4	21
6	4.8kV Circuit Breaker	5	16
	DISTRIBUTION		
1	Pole	2,000	2,500
2	Crossarm	7,000	7,000
3	Cable (Miles)	46	48
4	Transformer	600	700
5	Substructure	12	12

Table E-1. Target Replacement Summary

2. System Description

LADWP has built a vast power system that spans five Western states, and delivers electricity to about 4 million people in Los Angeles via thousands of miles of overhead wires and underground cables. Its major wholly-owned assets are listed below.

Generation include:

- ✓ 14 individual plants wholly-owned and operated hydroelectric power plants;
- ✓ 7 units wholly-owned and operated Castaic Pump Storage;
- ✓ 24 units wholly-owned and operated Los Angeles Basin thermal plants;
- ✓ 1 wholly-owned wind plant and solar station in the Tehachapi Mountains; and
- ✓ 1 wholly-owned solar station in Adelanto.

Transmission System infrastructure include:

- ✓ 3,507 miles of overhead transmission circuits spanning five Western states;
- ✓ 124 miles of underground transmission circuits; and
- ✓ 15,452 transmission towers.

Substations include:

- ✓ 162 distributing stations in the Los Angeles Basin;
- ✓ 21 receiving stations in the Los Angeles Basin; and
- ✓ 10 wholly owned transmission substations in the Los Angeles Basin, Owens Valley, and at Adelanto and Victorville;

Distribution System infrastructure include:

- ✓ 321,516 distribution poles;
- ✓ 1.3 million distribution cross-arms;
- ✓ 6,800 miles of overhead distribution lines;
- ✓ 3,597 miles of underground distribution cables;
- ✓ 126,000 distribution transformers; and
- ✓ 50,636 substructures.

3. Historical Heat Storm Performance

All-time peak demands were set on two consecutive days during this past Summer 2014's lengthy heat storm. Remarkably, 99.8% of the 78,766 customers who lost service were re-energized within 24 hours. This is the best performance in recent years and can be attributed to PRP investments; in the years immediately preceding the PRP, only 70% of the disrupted customers were reconnected within 24 hours. Table E-2, reprised from the *State at the Start*, shows virtually every metric has improved with the PRP.

Table E-2. Summary of Major Heat Storms for July 2007 – June 2012 time frame

Weather	2006, past peak	2007	2008	2010, past peak	2014, all-time peak
Peak Demand, NPL	6165MW @ 5pm Mon 7/24	6107MW @ 4pm Fri 8/31	6053MW @ 4pm Fri 6/20	6177MW @ 4pm Mon 9/27	**6396MW** @ 5pm Tue 9/16 6196MW @ 5pm Mon 9/15
Civic Center Temps ≥ 90°F	Sat 7/22 – Fri 7/28	Thu 8/30 – Tue 9/4	Thu 6/19 – Sun 6/22	Fri 9/24 – Sat 10/2	Fri 9/12 – Wed 9/17
Highest Civic Center Temp	101°F, Sat 7/22	101°F, Sun 9/2	97°F, Fri 6/20 97°F, Sat 6/21	112°F, Mon 9/27	103°F, Tue 9/16
Distribution	**2006,past peak**	**2007**	**2008**	**2010, peak peak**	**2014, all-time peak**
Elevated Trouble, start	5:53pm, Fri 7/21	3:05pm, Thu 8/30	9:29pm, Thu 6/19	8am, Mon 9/27	4:30pm, Sat 9/13
Elevated Trouble, end	6:28am, Fri 7/28	10:59pm, Fri 9/7	10:12pm, Mon 6/23	6am, Thu 9/30	11pm, Thu 9/18
#Customers Out	78,340	102,749	43,712	28,198	78,766
Peak #Customers Out	29,355 @ 12:55am Sun 7/23	28,668 @ 10:57pm Mon 9/3	21,701@ 6:58pm Fri 6/20	19,838 @ 11:57pm Mon 9/27	14,146 @ 9:59pm Mon 9/15
%Customers, 24hr Restoration	71.5%	72.3%	99.5%	92.3%	99.8%
Max #Crews Utilized	142 on Sat 7/22	110 on Mon 9/3	74 on Fri 6/20	121 on Mon 9/27	76 on Mon 9/15
Crews Utilized/Day	86	89	60	83	50
Incidents	1,017	945	261	238	480
Ave# Incidents/Day	159	113	65	82	91
Partial #4.8kV Outages	66	83	48	29	40
Partial 4.8kV Outages/Day	10	10	12	10	8
Transformer Outages	852	674	161	161	189
Transformer Outages/Day	131	81	40	55	36
Forced Outages	**2006, past peak**	**2007**	**2008**	**2010, peak peak**	**2014, all-time peak**
Basin Generation	Castaic 6 PP2 1	Haynes 5 PP2 1 Scattergood 2	PP2 1 Scattergood 2	Castaic 6, Haynes 6, San Fernando, PP2 1, Scattergood 1	Haynes 15/16, PP2 1, Franklin, Sawtelle, San Fernando 1
External Generation	None	None	None	None	None
Transmission	Unavailable	Unavailable	PP1-Olive Line 1	None	None

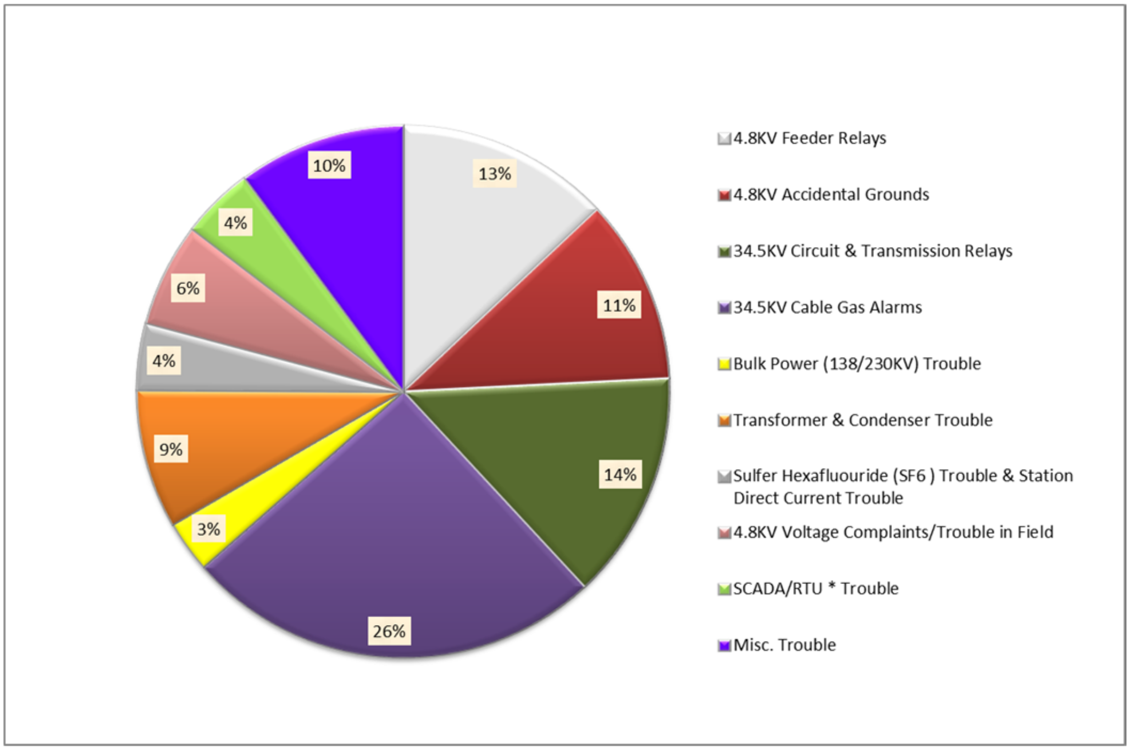
4. Reliability Assessment

Substation Outage Causes. Table E-3 and Figure E-1 is an annual count of the trouble conditions within the Substation system.

Table E-3. Substation trouble condition, by calendar year

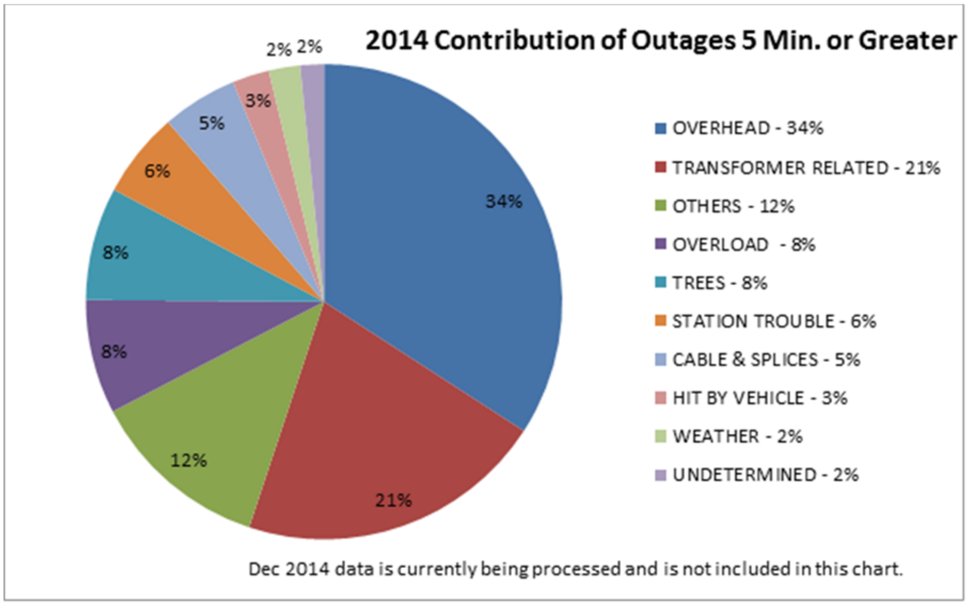
Description	Metro	South	WLA	EV	WV	Total
4.8KV Feeder Relays	7.4	10.2	9.4	12.1	11.2	**50.3**
4.8KV Accidental Grounds	6.4	5.4	11.3	7.4	9.5	**40.0**
34.5KV Circuit & Transmission Relay	7.9	5.8	9.8	5.3	6.7	**35.5**
34.5KV Cable Gas Alarms	14.5	1.9	14.5	2.4	13.0	**46.3**
Bulk Power (138/230KV) Trouble	1.8	1.0	6.5	2.8	7.3	**19.4**
Transformer & Condenser Trouble	4.8	2.8	13.0	4.7	11.5	**36.8**
Sulfer Hexafluouride (SF_6) Trouble & Station Direct Current	2.3	0.9	3.9	3.7	17.0	27.8
4.8KV Voltage Complaints/Trouble in Field	3.6	1.3	6.4	5.6	8.2	25.1
SCADA/RTU * Trouble	2.5	0.8	1.9	2.2	14.2	21.6
Misc. Trouble	5.8	2.4	7.8	7.5	12.5	**36.0**
Total	**57.0**	**32.5**	**84.5**	**53.7**	**111.1**	**338.8**

Figure E-1. Chart of substation trouble condition, by Calendar Year



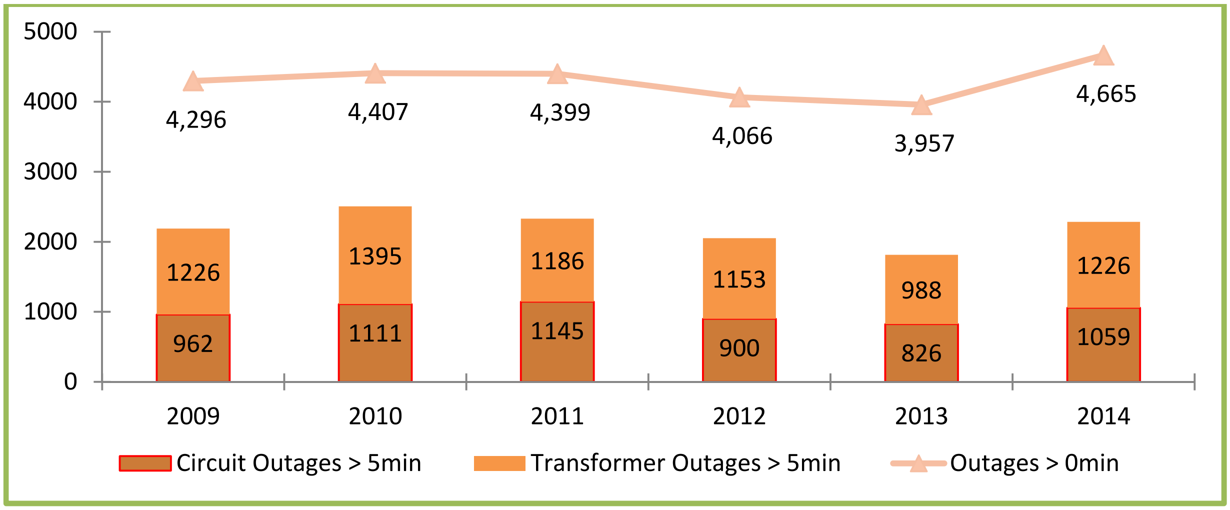
Distribution Outage Causes. Figure E-2 highlights the Distribution system outage causes.

FIGURE E-2. CHART OF DISTRIBUTION OUTAGES, BY CALENDAR YEAR



Distribution Outage History. The 2014 Summary Report - State at the Start, the 2013 Power System Reliability Plan, the Integrated Resource Plan, and other reports have reported customer outages of any duration and for any cause not related to customer equipment. Because customer outages of longer than five minutes is generally attributed to power reliability, Figure E-3 of this report highlights this subset of outages, extracting this information from the monthly Board Outage Reports posted on our intranet. The shorter duration outages ascribed to power quality concerns are represented in the gap between the total outages and outages exceeding five minutes. Outages of this kind may the result of faults that are subsequently cleared by automatic system protection schemes. Figure E-3 also shows the number of power quality and reliability outages are roughly equal.

Figure E-3. Distribution Outages, by Calendar Year



Reliability Indices. The CPUC requires the IOUs to annually file their most recent historical system reliability data and apply Institute of Electrical and Electronic Engineers Standard P1366 (IEEE 1366) criteria when excluding major events. As a municipal utility, LADWP has the freedom to apply its own criteria, which it does. LADWP defines as a major event any event in which more than 10% of its customers are out of service for 24 hours or more.

The metrics calculated and tracked by the Distribution Reliability Group (DRG) on a monthly and annual basis are:

- ✓ ***System Average Interruption Frequency Index*** (SAIFI), which measures the average number of interruptions per customer
- ✓ ***System Average Interruption Duration Index*** (SAIDI), which measures the average outage duration in minutes per customer

DRG does not currently monitor these indices on a daily basis, making conforming to IEEE 1366, which is based on a study of the most recent five years of daily SAIDI values cumbersome. This industry standard, also known as the 2.5 Beta Method, defines major events as being those events more than 2.5 standard deviations away from the mean daily SAIDI in the five-year pool. That is, days that exceed this threshold are considered Major Event Days and excluded in developing normalized indices. Prior to the CPUC adopting the IEEE standard, excludable events were limited to those that affected 15% of the system facilities or 10% of utility customers, which is similar to LADWP's practice.

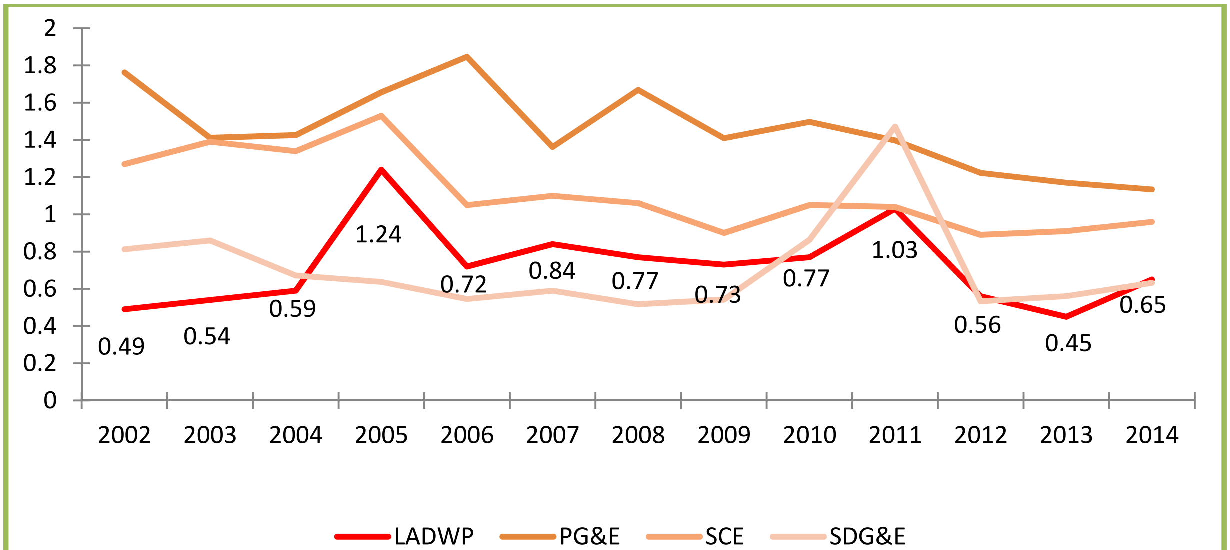
While the use of different methodologies undermines strict comparisons of normalized reliability indices with those of its IOU counterparts when one methodology cannot be considered more conservative than the other and other simplifying generalizations don't apply, comparisons are still worthwhile. Information was culled from annual IOU filings to the CPUC, including any revisions to past data to develop the comparison charts for this report.

The SAIFI chart, presented in Figures E-4, show that LADWP compares favorably with the

IOUs in terms of outage frequency regardless of whether major events are included. Of the three IOUs, only San Diego Gas & Electric (SDG&E) betters LADWP with any consistency in this regard. Aside from recent performance, LADWP has bettered its normalized SAIFI target of 0.68 outages/customer since 2012.

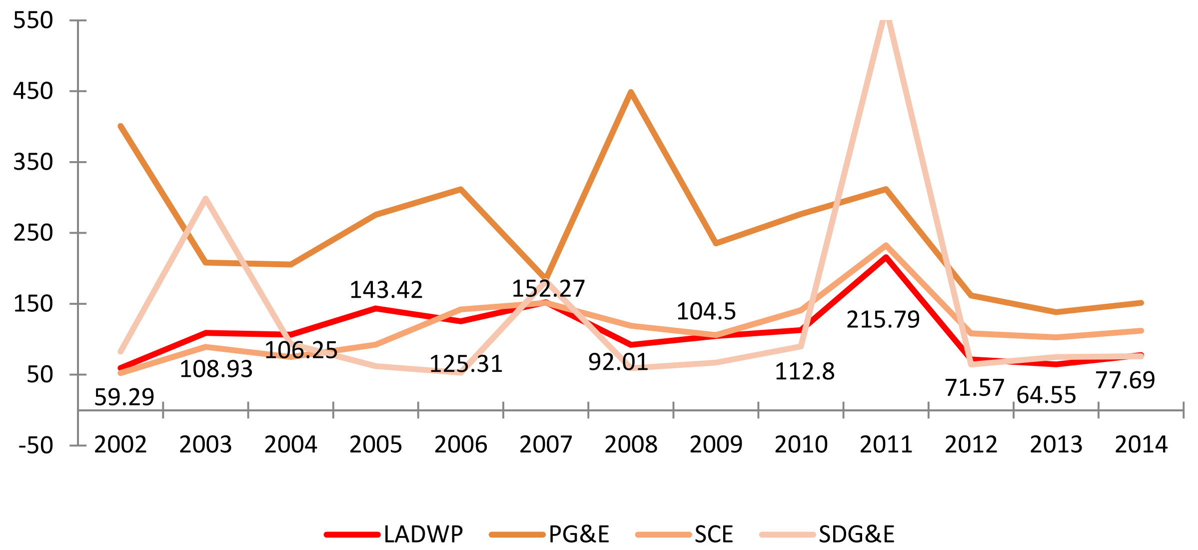
The SAIDI chart, presented in Figures E-5, suggest that LADWP, while comparable to neighboring Southern California Edison (SCE), has been consistently outperforming its counterpart since the PRP was launched in July 2007. In recent years, LADWP has generally been able to re-energize customers more quickly than SCE, at the system level. LADWP has bettered its normalized SAIDI target of 90 minutes/customer since 2011. For the upcoming fiscal year, the SAIDI target is 85 minutes/customer.

Figure E-4. SAIFI Including Major Events (Interruptions/Customer)



Note: included are Sept 2005 LADWP Field-triggered Incident and Fall 2011 Windstorn

Figure E-5. SAIDI Including Major Events (minutes/Customer)



Note: included are Sept 2005 LADWP Field-triggered Incident and Fall 2011 Windstorn

Fix-It Tickets. The CPUC's GO-165 guides the Power System's inspections of distribution equipment and facilities. As of this writing, nearly 50,000 Fix-It Tickets have been amassed as a result of GO-165 inspections. Figure E-6 shows the inventory of Fix-It Tickets has been steadily increasing over the years. Table E-4 details totals by category and priority. Although this might suggest neglect, more often than not, it suggests that many of these tickets are for low priority work that has no bearing on the loading, safety, or performance of equipment. Critical repairs are always attended to with the appropriate urgency.

In coming years, the backlog of Fix-It Tickets is expected to eventually decline as a result of the following:

- ✓ Equipment and facility replacements will eliminate Fix-It Tickets that had been previously logged for those facilities and that equipment.
- ✓ The recent launch of inspection software that associates Fix-It Tickets to the facilities and equipment requiring remediation and the ability to link historical activity based on such identifiers has suggested that a nontrivial number of these tickets are duplicates. This occurs when multiple inspection cycles have identified the same problems but the issue goes uncorrected. The Power System may either elect to apply resources to identify and eliminate these duplicate tickets; eliminate the tickets by performing the needed work; or both.

In the short-term, the number of Fix-It Tickets is expected to increase because conforming to GO-165 requires that documented inspections increase. Field crews have traditionally inspected job site facilities and equipment as part of each job, but the practice of crediting themselves with their due diligence is new.

Figure E-6. Backlog of Fix-It Tickets

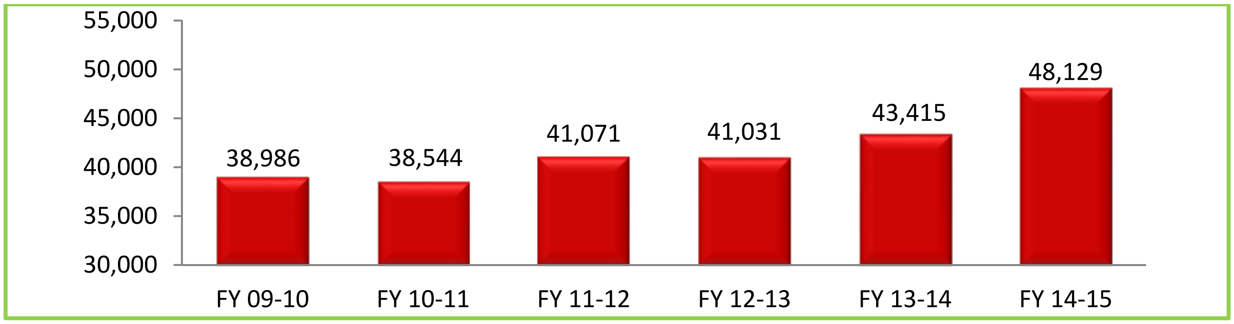
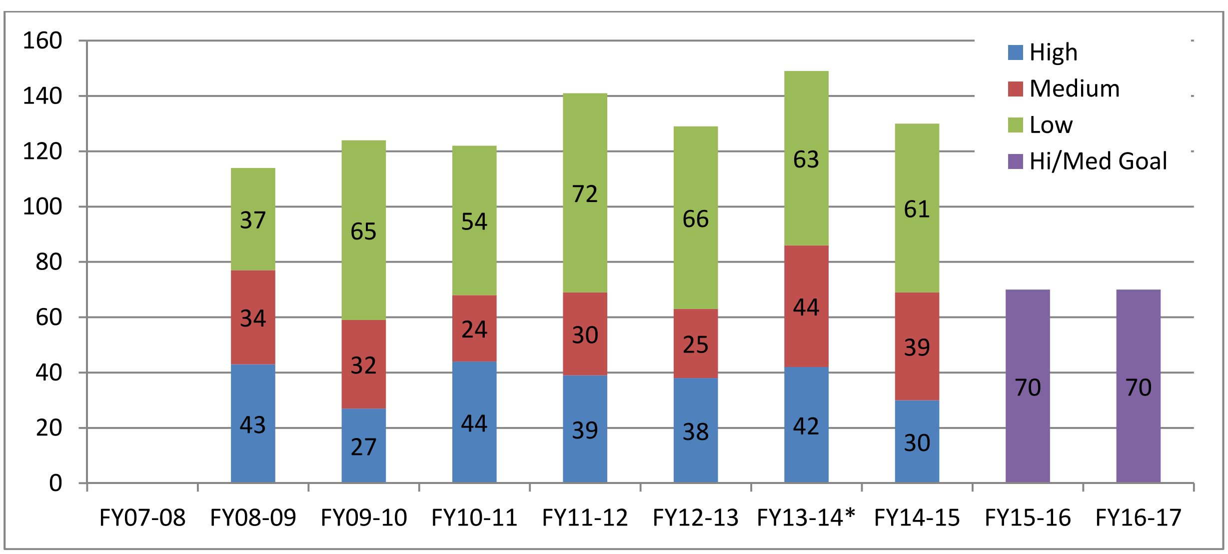


TABLE E-4. Backlog of Fix-It Tickets by category and Priority

Priority	Poles & Crossarms	Cables & Conductors	Transformers	Substructures	Others OH/UG Equipments	Total
High	2,705	1,030	120	2,572	9,593	**16,020**
Medium	4,659	8	227	314	4,047	**9,255**
Low	6,520	1,632	695	4,996	9,011	**22,854**
Total	**13,884**	**2,670**	**1,042**	**7,882**	**22,651**	**48,129**

Abnormal & Temporary Distribution Circuits. These circuits are a result of temporary repairs made during one circuit failure due to switching of loads onto another circuit. However, the new configuration is not within the original circuits. FY 14-15 had 69 Priority A and B circuits with the target of keeping the total of such circuits at 70. Figure E-7 details totals by FY.

Figure E-7. Backlog of Abnormal & Temporary Distribution Circuits



*Note *: FY 2013-2014 has 85 distinct High and Medium Abnormal Circuits*

Abnormal/Temporary Circuits are prioritized in the following manner:

- Priority A—High…circuits carrying additional load until the failed components on a connecting circuit have been replaced;
- Priority B—Medium…circuits with failed components; and
- Priority C—Low…circuits carry additional load because of field work.

Worst-Performing Circuits. Table E-5 lists 21 worst-performing distribution circuits based on logged electric troubles. Because five of these circuits were attended to in FYE 2015, 16 are being carried over into FYE 2016.

Table E-5. Worst-Performing Circuits, as of June 30, 2015

Circuit	Overhead/Underground	District	FY Listed	Status
103-02	OH	WLA	2009-2010	Completed
018-09	OH	P	2011-2012	Completed
044-08	OH	WLA	2011-2012	76%
122-07	OH	NR, VN	2012-2013	91%
124-05	UG	WLA	2012-2013	91%
091-03	UG	NR	2012-2013	Completed
029-06	UG	WLA	2012-2013	83%
018-03	OH	LH, P	2013-2014	Completed
115-02	UG	VN	2013-2014	Completed
086-11	UG	NR, VN	2013-2014	87%
041-04	OH	C	2013-2014	83%
088-17	UG	NR	2013-2014	78%
058-03	OH	WLA	2013-2014	64%
002-05	OH	LH	2013-2014	17%
046-04	OH	WLA	2013-2014	12%
066-02	OH	WLA	2014-2015	80%
041-02	OH	C	2014-2015	42%
135-23	UG	WLA	2014-2015	21%
58-1	OH	WLA	2014-2015	55%
122-3	OH	NR	2014-2015	12%
27-6	OH	CEN	2014-2015	0%

5. Equipment Replacement Cycle and Unit Cost

Table E-6. Replacement Cycles

	Asset	Average Expected Asset Life	Replacement Cycle FY 14-15	Replacement Cycle FY 19-20 (Estimated)	Unit Cost Benchmark (2013 Report)	Unit Cost Benchmark (2015 Analysis)	Total Asset Replacement FY 15-16 to FY 19-20 (Estimated)
	GENERATION						
1	Generator Transformer (GSU & AUX)	45	50	45	$5,000,000	No Data	14
2	Major Inspection (Thermal)	30	n/a	n/a	$4,000,000	No Data	13
3	Major Inspection (Hydro)	55	n/a	n/a	$3,000,000	No Data	8
4	Major Inspection (Pump)	55	n/a	n/a	$4,000,000	No Data	5
	TRANSMISSION						
1	138kV UG Transmission Circuit (Miles)	40	70	65	$12,600,000	$15,000,000	10
2	138kV Stop Joints	50	75	50	$300,000	$300,000	25
3	Maintenance Hole Restraints	n/a	n/a	n/a	$27,000	$50,000	170
	SUBSTATION						
1	RS Transformer. Voltage > 138kV	45	70	45	$4,000,000	No Data	4
2	RS Transformer. Load Bank. Secondary Voltage 34.5kV	45	70	45	$4,500,000	$4,400,000	9
3	DS Local Substation Transformer	50	70	50	$1,200,000	$700,000	82
4	> 100kV Circuit Breaker	30	30	30	$550,000	No Data	19
5	34.5kV Circuit Breaker	30	45	30	$200,000	$220,000	85
6	4.8kV Circuit Breaker	30	60	30	$80,000	$60,000	141
	DISTRIBUTION						
1	Pole	60	145	80	$45,000	$50,000	22,500
2	Crossarm	30	No Data	No Data	$4,000	$3,000	44,000
3	Cable (Miles)	Lead 75 & Synthetic 40	No Data	No Data	$1,000,000	$700,000	274
4	Transformer	40	45	40	$20,000	$15,000	3,700
5	Substructure	50	No Data	No Data	$400,000	$160,000	84

6. Programs and Projects

Generation Transformer. Fund and personnel were not available to perform the work in FY 14-15. The target for FY 15-16 will also not be met since it takes a couple of years to design, procure, and install. Plans for Generator Step Up (GSU) transformer are to install two reconditioned transformers at Harbor Generating Station in FY 16-17, one new transformer at Castaic Power Plant in FY 16-17, and one new transformer at Castaic Power Plant in FY 17-18. For Auxiliary (AUX), install one new transformer in FY 17-18 and one new transformer in FY 18-19 at Castaic Power Plant.

Generation Major Inspection. Generation reliability depends on regular inspections, faithful maintenance, and timely repairs of generation assets. LADWP, either wholly or jointly, owns 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. The contribution of LADWP's wholly owned in-Basin thermal assets cannot be overstated, because every one of them (Harbor, Haynes, Scattergood, and Valley Generating Stations) has been designated RMR by ECC's 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.

For FY 14-15 actuals are summarized as referenced from the 2014-2015 Scheduled Maintenance and Repair (SIR) schedule – 1) Thermal Inspection target met with Scattergood Unit 1 returning to service on 5/11/15. 2) Hydro Major Inspection target met through Upper, Middle, and Control Gorge project. 3) Pump Major Inspection partially met at Castaic Unit 2 with completion estimated in October 2015.

Transmission LA Basin Tower Painting Program. Previously a multi-year contract was issued for services to protect existing galvanized towers from corrosion and extend the useful service life. The program began in 1993 and went dormant after 2006. Currently, 247 towers have been assessed and selected for painting of the 1,400 total. A new contract is to be advertised for bid in December 2015.

138kV Cables and Stop Joints. Every cable failure since 2009 has involved stop joints along either Fairfax-Gramercy Line 1 or Fairfax-Olympic Cable A. Both oil-filled 138kV cables were installed in 1946 and 1955, respectively, but root cause analyses of the most recent failures have shown that compromised oil reservoirs, rather than wear and tear, were at fault. LADWP's oil-filled 138kV cables, every one of them installed between 1943 and 1959 and now either exceeding or nearing their 60 year useful lives, are vulnerable to oil starvation from faulty reservoir equipment and cable oil deterioration from insulation breakdown. It has been documented that oil leaks from 30% of these stop joints. Since 2000, the Power System has replaced seven such 138kV cables with synthetic XLPE cable.

ECC typically approves construction outage periods from October 16 of one year through May 14 of the following year. Gramercy-Harbor L2 was scheduled to be replaced FY 14-15 but due to purchase of material delays it will now begin construction by October 2015. Both Fairfax-Gramercy Line 1 and Fairfax-Olympic Cable A are scheduled to be replaced in FY 16-17.

Stop joints can either be rebuilt or replace. This effort is still done in existing cable in order to maintain the existing circuit functioning. Three stop joints have been purchased in 2015. The target will be to replace 5 stop joints FY 15-16.

Maintenance Hole Restraints. Previously the circuit was de-energized prior to the work. Now the crews can make these replacements in energized circuits. Also FLIR cameras will be used to check for "Hotspots" which are areas that is substantially hotter than the rated temperature of the equipment. The target of 10 was not met in FY 14-15. Only 6 replacements were completed. However, the new entrance policy allowing work to be done in energized condition will facilitate meeting the target of 20 replacements in FY 15-16.

Substation Transformers. The Transformer, Replacement, & Availability Program 2014 (XARAP 2014) provided a prioritized list for recommend transformer replacement. The study developed a scoring methodology in order to rank each transformer based on the unit's condition and system impact. It prioritizes which substation transformer to replace based on specialized tests, including critical location, power factor, dissolved gas tests, and age. This data analysis resulted in the following Distribution station rank in the top 10 – DS-8, 9, 17, 18, 20, 26, 28, 34, 38, and 43. Table E-7 will provide recent substation transformer replacements and upgrades.

Table E-7. Substation Transformer replacement plan

Asset Type	**Actuals** **FY 14-15**
RS Transformer. **Voltage > 138-kV**	None
RS Transformer. Load Bank. **Secondary Voltage 34.5-kV**	RS H, N, and U
DS Transformer.	DS 32 and 51

Substation Circuit Breakers. The useful design life of the Power System's circuit breakers is 30 years, the majority of the distribution and sub-transmission circuit breakers, with median ages of 49 years and 44 years, respectively, are operating well-beyond their expected lifespans. The longevity of the vintage circuit breakers, however, bears silent testimony to the durability of quality workmanship, design, and materials. Priorities are based on outage history, maintenance record, and location. Table E-8 will provide recent circuit breaker replacements and upgrades.

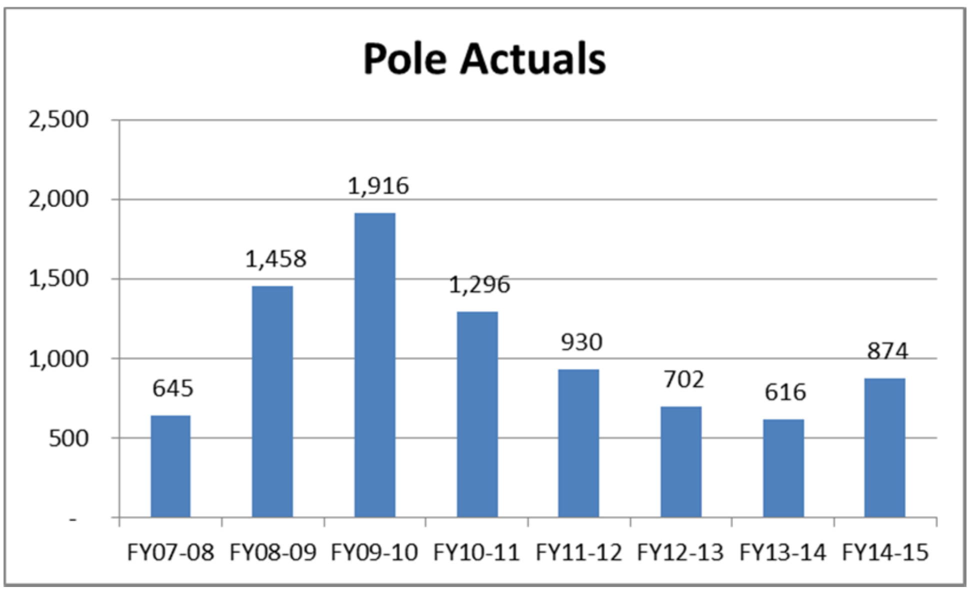
TABLE E-8. SUBSTATION CIRCUIT BREAKER REPLACEMENT PLAN

Asset Type	Actuals FY 14-15
Substation Circuit Breaker	Delayed due to circuit breaker availability
34.5-kV Circuit Breaker	RS A (10 breakers)
4.8-kV Circuit Breaker	DS 29 (5 breakers)

Distribution Pole Replacements. Poles are replaced based on age and condition. When a pole is deemed unreliable and subject to replacement, it is the entire support that is replaced. Typically the pole is replaced with a taller pole, fiberglass cross arm, and new equipment. With each change, it gives an opportunity to replace, resize or readjust the line conductors. This new configuration will eventually result in less outage. Currently, 64% of our pole inventory is 60 years or older. See Figures E-8 for the history of pole replacement.

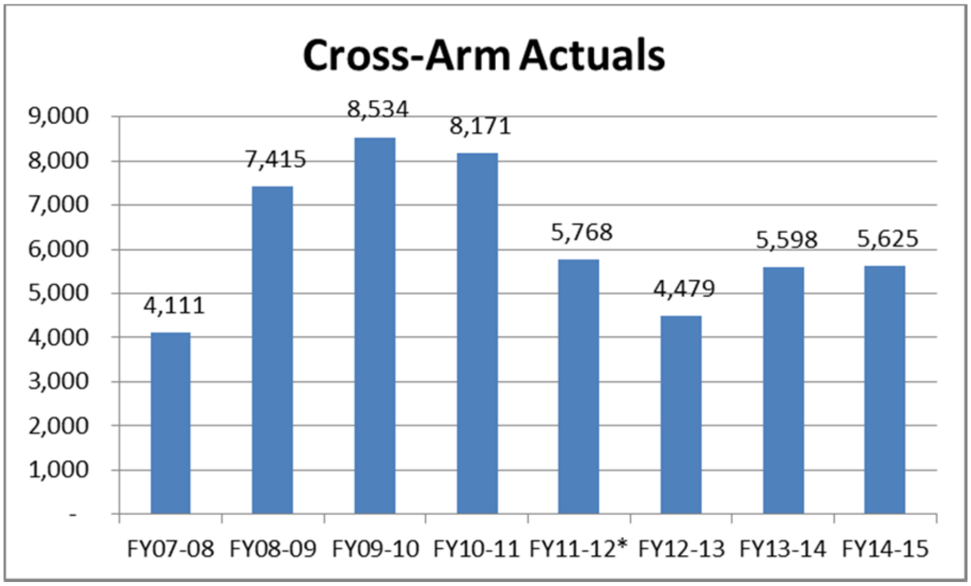
The FY 14-15 target of replacing 1560 poles was not met. This was partly due to the pole contracts not starting until towards the end of the fiscal year. Contract 540R1 for facilities north of Mulholland Drive and within City boundaries started in 12/29/14 has replaced 280 poles. Similarly contract 532R2, a service contract for overhead distribution facilities south of Mulholland Drive and within City boundaries started in 3/23/15 has replaced 97 poles.

Figure E- 8. Pole Replacement Actuals



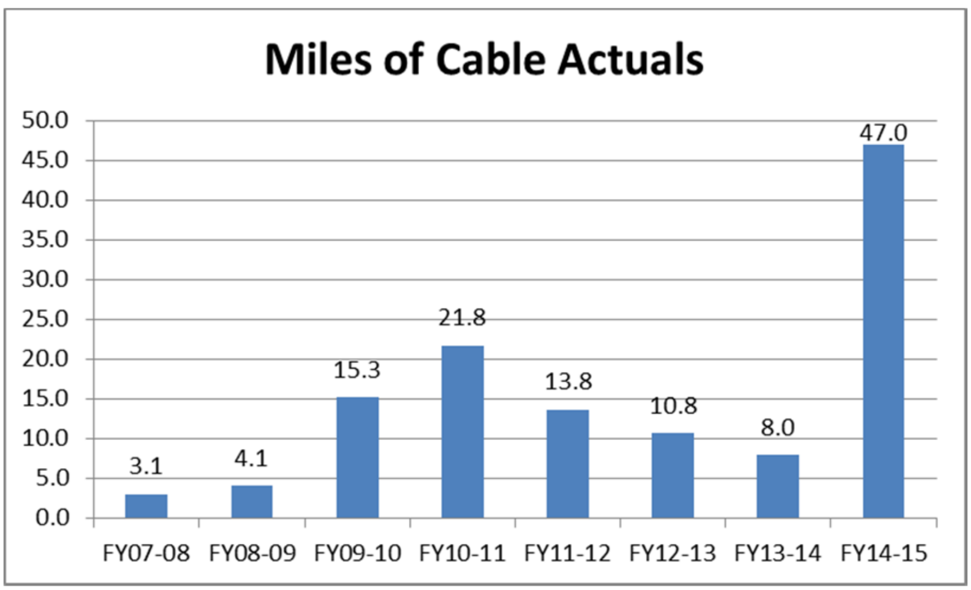
Crossarms Replacements. If a pole is still in good condition then just replacing the crossarms is an economic way of increasing reliability. Replacing crossarms is about one tenths of the cost of replacing a pole. See Figure E-9 for the history of crossarms replacement.

Figure E-9. Cross-Arm Replacements



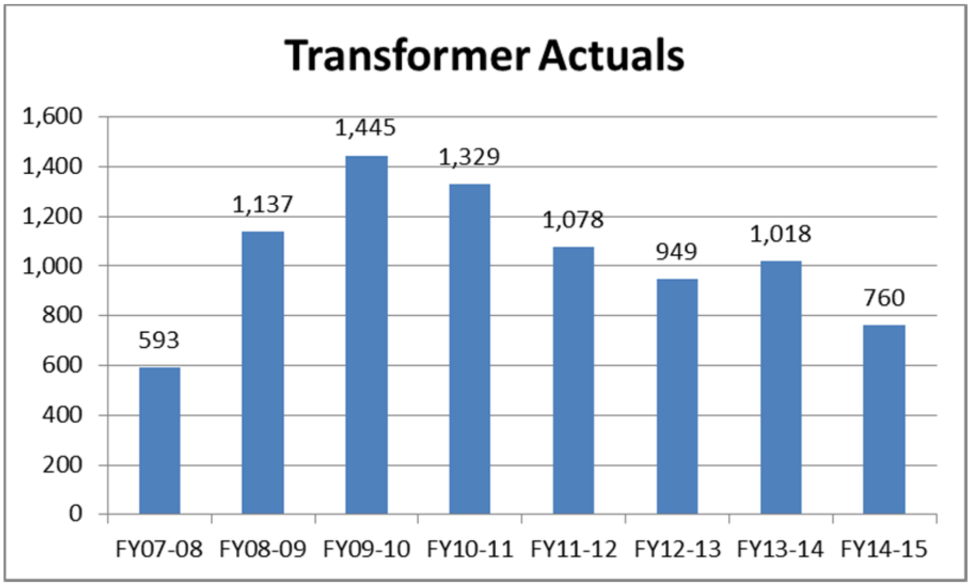
Distribution Cable Replacements. Cable replacement involves both the cable replacements and the associated cabling within a substructure. The replacement gives an opportunity to resize or change cable type. See Figure E-10 for the history of cable replacement. Contract 531 which started in 10/9/14 has pulled 36.7 miles so far.

Figure E-10. Miles of Cable Replaced/Installed



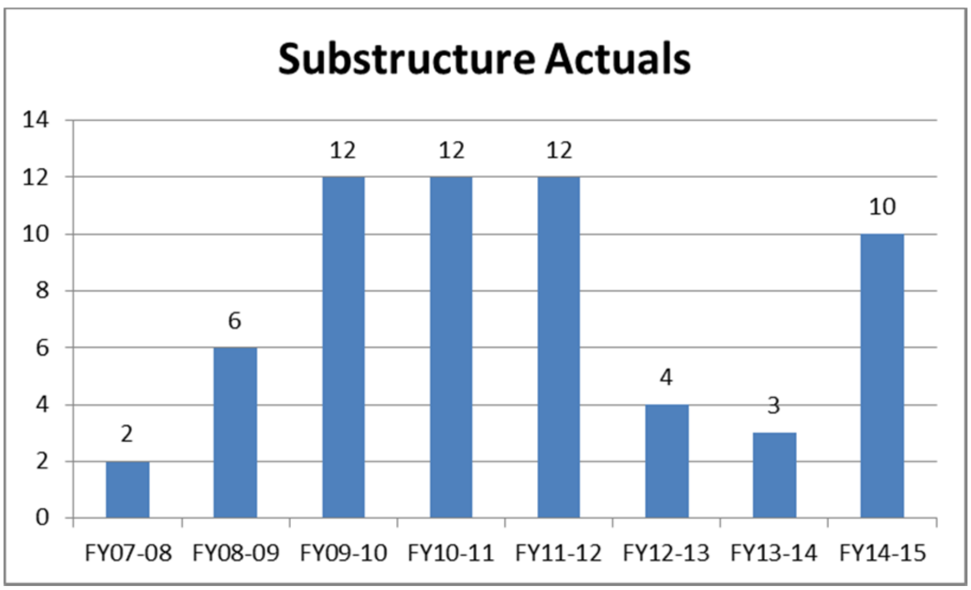
Distribution Transformers Replacements. The distribution transformers replacement program was initiated in 2007. Currently, the system has benefited through the aggressive replacements and withstood the recent heat storms. The pace must continue in order to keep the reliability benefits. See Figure E-11 for the history of distribution transformer replacements.

FIGURE E-11. TRANSFORMER REPAIRS/REPLACEMENTS, UNDERGROUND AND OVERHEAD



Substructure Repairs and Restorations. This program identified 54,099 substructure that need repairs. See Figures E-12 for the history of substructure repair or replacements.

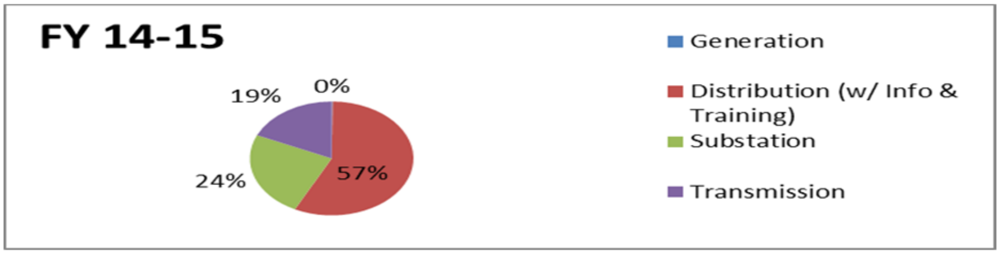
Figure E-12. Substructure Repairs/Restorations/Replacements



7. Budget

FY 14-15 overall actual budget was Capital $318M and O&M $321M totaling to $639M. Figure E-13 shows the dollar breakdown per segment.

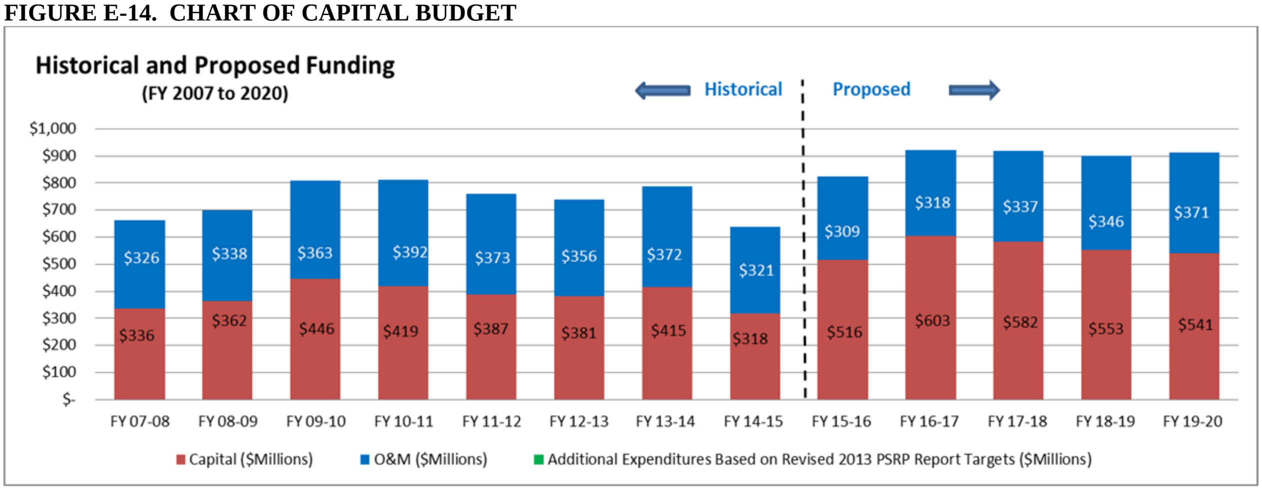
FIGURE E-13. PERCENTAGE BREAKDOWN FOR FY 14-15 BUDGET



Capital Underspend for FY 14-15. PSRP as a whole accomplished a lot, but these underspend areas highlights the difficulty of matching up money, materials, and labor. In Substation, FI 21195 under spending of $35M were in the following jobs: C5145 Install voltage support equipment, O1322 Construction new outdoor DS-104, O9768 34.5 kV circuit breakers, O9780 HV transformer replacement program, and P6193 Substation automation system. The explanations for variances were due to environment process, vendor delays, and procurement of materials. For Transmission, FI 21212 under spending of $30M in the following jobs: O1346 Construction new Scattergood-Olympic cable A, O1373 Sylmar CS AC filter replacement project, and O1376 Form Gramercy-Harbor Lines 1&2. The explanations for variances were due to permit issues and contract delays.

Budget for Slower Ramp Up. Lessons learned from the initial FY 14-15 launch is that it will take time to coordinate all the different facets as we go towards the FY 19-20 targets.

FIGURE E-14. CHART OF CAPITAL BUDGET



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Appendix F Generation Resources

F.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.

F.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

F.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 capability of 3,466 megawatts (MWs) and a combined net dependable generating capability of 3,389 MWs. Natural gas and digester gas are used as fuel for the Los Angeles Basin Stations. Low-sulfur, low-ash residual distillate is used for emergency back-up fuel for some of the stations.

LADWP's natural gas-fueled generating plant capabilities are shown in Table F-1.

Table F-1. NATURAL GAS GENERATING RESOURCES

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Capability (kW)	Net Dependable Capability (kW)
Harbor	1 2 5 10 11 12 13 14	1995 1995 1995 2002 2002 2002 2002 2002	85,340 85,340 75,000 60,500 60,500 60,500 60,500 60,500	78,000 78,000 65,000 47,400 47,400 47,400 47,400 47,400	452,000[2]
Haynes	1 2 7 8 9 10 11 12 13 14 15 16	1962 1963 1970 2005 2005 2005 2013 2013 2013 2013 2013 2013	230,000 230,000 2,000 264,350 182,750 182,750 108,190 108,190 108,190 108,190 108,190 108,190	222,000 222,000 1,599 250,000 162,500 162,500 99,367 99,367 99,367 99,367 99,367 99,367	1,585,200[3]
Scattergood	1 2 3	1958 1959 1974	163,200 163,200 496,800	183,000 184,000 450,000	796,000
Valley	5 6 7 8	2001 2003 2003 2003	60,500 182,750 182,750 264,350	43,000 162,000 162,000 209,000	556,000[4]
Total				3,466,202	3,389,200

Notes:

1. COD refers to Commercial Operation Date.
2. Harbor Generating Station Net Dependable Plant Capability is 452 MW, reflecting Units 1 and 2 reduced performance during hot-weather conditions.
3. Haynes Generating Station Net Dependable Capability is 1,585.2 MW reflecting 8, 9, and 10 reduced performances during hot weather conditions; and Unit 7 used for auxiliary power only.
4. Valley Generation Station Net Dependable Capability limited to 556 MW reflecting reduced performance during hot weather conditions.

Haynes Generating Station

The largest of the Los Angeles Basin Stations is the Haynes Generating Station, located in the City of Long Beach, California. The Haynes Station currently consists of eleven generating units (Unit 7 is used for auxiliary power only) with a combined net maximum capability of 1,639 MWs and a net dependable capability of 1,585 MWs. This station includes a 575 MW combined-cycle generating unit installed in February 2005. The combined-cycle generating unit includes two combustion turbines and a common 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). LADWP completed the repowering of Unit 5 and 6 with six 100 MW simple cycle gas turbine units. The new Units 11, 12, 13, 15, and 16 were placed in-service on June 19, 2013 and Unit 14 was place in-service on June 29, 2013.

Valley Generating Station

The Valley Generating Station is located in the San Fernando Valley. The Valley Station began its repowering in 2001 with a simple-cycle, 60.5 MW gas–turbine generator. Repowering was completed in 2004 with the installation of a combined-cycle generating unit consisting of two gas turbines with heat recovery steam generators, which supplies one steam turbine with a combined net maximum capability of 576 MWs. The total net dependable capacity for the Valley Station is 556 MWs.

Harbor Generating Station

The 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 capability of 458 MWs and a net dependable capability of 452 MWs.

Scattergood Generating Station

The Scattergood Generating Station is located in Playa del Rey, California and is comprised of three steam generating units with a net maximum capability of 817 MWs and a net dependable capability of 796 MWs. Units 1 and 2 is also capable of burning digester gas from the adjacent Hyperion Wastewater Treatment Plant. LADWP is in the process of repowering 460 MWs of Scattergood Unit 3 with a combined cycle generating unit and two simple cycle gas turbines by December 2015. In addition, Scattergood Units 1 and 2 are planned to be repowered with a combined cycle generating unit that will utilize air-cooling in lieu of ocean water to comply with the California State Once-Through Cooling requirements. Scattergood Unit 3 will be demolished to create the construction area for the replacement combined cycle generating unit between January 2016 and December 2017 and the subsequent construction project is scheduled for completion by December 2020.

All of these generating stations are certified to burn biogas. This will allow the electricity produced from the biogas to be qualified for the Renewable Portfolio Standard.

F.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. SCPPA then purchased AGS, which completed the implementation of this strategy. At this point, LADWP is the sole participant and purchaser of power from Apex Generating Station through SCPPA.

Apex Generating Station is located in Clark County, north of Las Vegas, Nevada. AGS includes combined-cycle generating units consisting of two gas turbines with heat recovery steam generators, which supplies one steam turbine with a combined net maximum capability of 531.8 MWs. The total net dependable capacity for the Apex Generating Station is 479.9 MW. Apex Generating Station also includes the heat recovery equipment, air inlet filtering, air cooled condenser, emission control system, exhaust stack, and distributed control systems.

Apex Generating Station capabilities are shown in Table F-2.

Table F-2. NATURAL GAS GENERATING RESOURCES

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Plant Capability (kW)	Net Dependable Capability (kW)
Apex	1A 1B STG	2014[2] 2014[2] 2014[2]	203,150 203,150 237,600	531,860	479,900[3]

Notes:

1. COD refers to Commercial Operation Date, when SCPPA acquired ownership.
2. LADWP officially took ownership of Apex Generating Station on March 26, 2014 and the units first carried load on March 28, 2014. Units1A and STG were originally put in-service by the original owner on 1/13/2003 and Unit 1B was originally put in-service on 1/20/2003.
3. Apex Generating Station Net Dependable Capability limited to 479.9 MW reflecting reduced performance during hot weather conditions. This will require using in-duct firing and augmentation, which will substantially increases the heat rate.

F.2.3. Coal-Fired Thermal Generation

LADWP's coal generating capacity comes from the Navajo Generating Station and the Intermountain Generating Station (IGS). IGS is also referred to as the Intermountain Power Project (IPP). Coal generating resources are summarized in Table F-2.

Table F-3: COAL GENERATING RESOURCE

Plant Name	Unit	COD[1]	Net Max Capability (Total kW)	Net Max Capability (LADWP kW)	Net Dependable Capability (LADWP kW)	LADWP Expiration	LADWP Share
Intermountain	1 2	1986 1987	900,000 900,000	401,553 401,553	401,553 401,553	15Jun2027	44.617%
Intermountain	1 2	1986 1987	900,000 900,000	36,000 36,000	36,000 36,000	15Jun2027	4% (UP&L)
Intermountain	1 2	1986 1987	900,000 900,000	163,512 163,512	163,512 163,512	15Jun2027	18.168% (Recallable)
Total				1,202,130[2]	1,202,130[2]		
Navajo	1 2 3	1974 1974 1975	750,000 750,000 750,000	159,000 159,000 159,000	477,000[3]	31Dec2019	21.2%
Total				1,679,130	1,679,130		

Notes:

1. COD refers to Commercial Operation Date.

2. IPP's Net Capacity available maybe less than 1202 MW due to Excess Power Recall. The LADWP entitlement is 44.617% direct ownership plus a 4% purchase from Utah Power & Light Company, plus 86.281% of up to 21.057% of muni's and co-op's recallable entitlement which can vary (shown is that of summer 2013). The nominal net Maximum Unit Capability and Net Dependable of both Units 1 and 2 is 900 MW.

3. LADWP's contract entitlement is 21.2% of Navajo's total net generation.

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 MWs 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 three separate agreements.

- Pursuant to a Power Sales Contract with IPA (the "IPP Contract") and a Lay-Off Power Purchase Contract with Utah Power & Light Company ("UP&L") and IPA, LADWP is entitled to 44.617 percent of the capacity of the IPP (currently equal to 803 MWs). The IPP Contract terminates in 2027 and may be renewed by LADWP under certain circumstances, subject, in addition, to legal and regulatory mandates.

- Pursuant to a Power Purchase Agreement with UP&L, LADWP purchases capacity and energy equivalent to the capacity and energy made available to UP&L pursuant to its 4 percent entitlement in the IPP (currently equal to approximately 72 MWs) until 2027, subject to certain renewal rights, which are dependant upon certain factors including the renewal of the IPP Contract.

- 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 percent of the capacity of IPP (equal to approximately 327 MWs). 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 2014 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 percent of the coal requirements for the IPP. Spot market and opportunity purchases provide the balance of the fuel requirements for the facility. Additional information regarding IPP's fuel procurement strategy is found in Appendix H.

Navajo Generating Station (NGS)

The NGS is located near the City of Page, Arizona. Salt River Project (SRP) is the operating agent for the Navajo Station. The Navajo Station is a coal-fired electric generating station and consists of three units with a combined net maximum capacity of 2,250 MWs. LADWP's entitlement of the Navajo Generating Station capability is 21.2 percent. On March 23, 1976, LADWP, Arizona Public Service Company (APS), Nevada Power Company (NPC), SRP, Tucson Electric Power Company (TEP), and the U.S. Department of Interior executed the Navajo Project Co-Tenancy Agreement effecting the co-owners' participation, and the operation and maintenance of the Navajo Project for as long as the land lease with the Navajo Nation is in effect until December 22, 2019 and throughout the lease extension thereafter. Negotiations are currently under way between the Navajo Nation and SRP, on behalf of the NGS participant owners, to renew the terms of the lease and all rights of way (ROWs) and grants related to the NGS site, transmission, and railroad until December 31, 2044.

The station's sulfur dioxide (SO_2) scrubbers, which were installed in 1999, continue to operate in full compliance with federal regulations for SO_2. The plant-wide compliance number has been under the emission limit of 0.10 pounds per million Btu.

NGS also completed its Low NO_x burner/Separated Overfire Air (SOFA) retrofit project in late March 2011. The Low NO_x/SOFA installation on all three units' boilers has contributed to a successful reduction of NO_x emissions by 40%, representing an annual NOx emissions reduction of 14,000 tons/year. The NOx emission is now under the limit of 0.24 pounds per million Btu.

In February 2013, the Environmental Protection Agency (EPA) issued a proposed Best Available Retrofit Technology (BART) rule for NGS under the Regional Haze Rule of the Clean Air Act. The EPA's proposal would require an emission control technology called

Selective Catalytic Reduction (SCR) to be installed and operational on all three NGS units by 2018, which carry a capital cost of approximately $550 million (or $117 million for LADWP). Should the new regulations require the installation of baghouses in addition to the SCRs, the combined capital cost of both SCRs and baghouses would amount to $1.13 billion (or $240 million for LADWP). The EPA also proposed an alternative that would give the NGS owners credit for early installation of low-NOx burners at NGS and allow SCR to be installed on one unit per year between 2021 and 2023. Due to credits given to the early installation of the Low-NOx Burners, installation of the SCR will not be required until 2023 with the requirement for installation of the baghouse still undetermined. NGS may postpone the SCR installation even further, possibly until 2030, by removing one of the three units out of service permanently. After 2030, installation of a compact SCR may be required to continue operation. EPA invited stakeholders to suggest additional BART alternatives which would meet the proposed framework described in the February 2013 proposal. A group of NGS stakeholders called the Technical Work Group (TWG) submitted a proposed BART alternative to EPA in July 2013. In September 2013, EPA issued a Supplemental Proposal that requests public comment on the TWG Alternative. The current deadline for public comments is January 6, 2014.

In March 2011, the Environmental Protection Agency (EPA) released another proposed rule called the Utility Maximum Achievable Control Technology (MACT) that sets the national emissions standards for hazardous air pollutants (HAP) for electric generating units (EGUs). This rule calls for compliance of monitoring systems for Hg, particulate matter, and SO_2 (or HCl), hourly data collection, quarterly submission of emissions data, and new work practice standards for dioxins, furans, and other organic HAPs that would require regular “tune ups” of boilers to optimize combustion. These MACT modifications could be as much as $148.5 million (or $31.5 million for LADWP) or less depending on the required compliance systems.

The EPA also proposed federal regulations governing the disposal of coal ash and other coal combustion byproducts (CCBs) under the Resource Conservation and Recovery Act (RCRA). Under this rule, CCBs may be classified as either RCRA Subtitle C hazardous waste or RCRA Subtitle D non-hazardous waste. The regulation of CCBs under RCRA Subtitle C would impose staggering compliance costs on the power industry including NGS. An unfavorable ruling would jeopardize fly ash sales, trigger significant capital improvement to minimize environmental releases of coal ash and other byproducts, involve additional manpower to manage new programs, and require additional monitoring of the ash disposal landfill. Such coal ash disposal initiatives could amount to approximately $10 million (or $2.1 million for LADWP).

On May 19, 2015, the Board of Water and Power Commissioners at the Los Angeles Department of Water and Power approved an agreement under which LADWP will sell its 21 percent share of NGS to Salt River Project (SRP). Under the agreement with SRP, LADWP will stop receiving its 477 megawatt share of coal power from Navajo when the sale closes on July 1, 2016.

F.2.4. Nuclear-Fueled Thermal Generation

LADWP's nuclear-fueled generating plant capabilities are shown in Table F-3.

Table F-4. NUCLEAR GENERATING RESOURCES

Plant Name	Unit	COD[1]	License Expiration	Net Max Capability (Total kW)	Net Max Capability (LADWP kW)	Net Dependable Capability (LADWP kW)	LADWP Share[2]
LADWP Direct Ownership Interest:							
Palo Verde	1 2 3	1986 1986 1988	2045 2046 2047	1,333,000 1,336,000 1,334,000	75,981 76,152 76,038	74,727 74,898 74,784	5.7%
LADWP Entitlement Interest Through SCPPA:							
Palo Verde	1 2 3	1986 1986 1988	2045 2046 2047	1,333,000 1,336,000 1,334,000	52,787 52,906 52,826	51,916 52,034 51,955	3.96% (SCPPA)
Total					386,690	380,314	

Notes:

1. COD refers to Commercial Operation Date.
2. LADWP's contract entitlement is 9.66 percent of generation comprised of 5.7 percent direct ownership in Palo Verde and another 67 percent power purchase of SCPPA's 5.91 percent ownership of Palo Verde.

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 ended June 30, 2011, PVNGS provided over 3.1 million megawatt-hours ("MWhs") of energy to the Power System. LADWP has a 5.7 percent direct ownership interest in the PVNGS (approximately 224 MW of dependable capacity). LADWP also has a 67.0 percent generation entitlement interest in the 5.91 percent ownership share of PVNGS that belongs to SCPPA through its "take-or-pay" power contract with SCPPA (totaling approximately 156 MWs 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 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. While evaluations are still in progress, among the initial recommendations are plans to accelerate fuel removal from the spent fuel pools and possibly purchase a standby diesel generator as reinforcement to the existing back-up power sources.

F.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 capabilities are shown in Table F-4.

Table F-5. LARGE HYDROELECTRIC GENERATING RESOURCES

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Capability (LADWP kW)	Net Dependable Capability (LADWP kW)	LADWP Expiration	LADWP Share
Castaic[2]	1 2 3 4 5 6 7	1973 1974 1976 1977 1977 1978 1972	271,000 271,000 271,000 271,000 271,000 271,000 56,000	271,000 271,000 271,000 271,000 271,000 265,000 56,000	1,175,000	Owned Asset	100%
Hoover[3]		1936	2,074,000	491,000	400,000	30Sep2017	25.16%
Total				2,140,000	1,575,000		

Notes:

1. Commercial Operation Date.
2. Castaic Power Plant is re-rated at 1,175 MW. Castaic Power Plant Units 2, 4, 5, 6 modernizations were completed September 2004, June 2006, July 2008, and December 2005 respectively. Unit 3 modernization was completed in June 2009.
3. LADWP's entitlement is 25.16% of the plant's contingent capability of 1,951 MW (or 491 MW). The reduced entitlement is due to lower lake levels resulting from the western drought. The current Hoover net plant capability as of June 30, 2014 is 1,592 MW.

Castaic Pump Storage Power Plant.

The Castaic Pump Storage Power Plant (the "Castaic Plant") is located near Castaic, California. The Castaic Plant is LADWP's largest source of hydroelectric capacity and consists of seven units with a net dependable capacity of 1,175 MWs. The Castaic Plant provides peaking and reserve capacity for LADWP's load requirements.

Hoover Power Plant.

General. The 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 1935 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 MWs. LADWP has a power purchase agreement with the United States Department of Energy Western Area Power Administration ("Western") for 491 MWs of capacity (calculated based on 25.16 percent of 1,951 MWs of total contingent capacity) and energy from the Hoover Plant through September 2017. On December 20, 2011, the 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. Due to the long drought conditions and decreasing lake levels recently, LADWP's capacity entitlement at the Hoover Plant has decreased to 440 MWs (calculated based on 25.16 percent of 1,592 MW output capability as of June 30, 2014).

F.2.6 Renewable Resources and Distributed Generation

LADWP's Renewable Resources and Distributed Generation consists of

- Eligible renewable small hydro resources as shown in Tables F-5, F-6, and F-7.
- Renewable and distributed generation resources as shown in Table F-8.

Table F-6. OWENS VALLEY SMALL HYDROELECTRIC GENERATING RESOURCES

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capability (LADWP kW)	Net Max Plant Capability (LADWP kW)	Net Dependable Capability (LADWP kW)
Haiwee[3]	1 2	1927 1927	2,800 2,800	2,500 2,500	3,500	0
Cottonwood[3]	1 2	1908 1909	750 750	1,200 1,200	1,900	400
Division Creek	1	1909	600	680	680	400
Big Pine[4]	1	1925	3,200	3,050	3,050	400
Pleasant Valley[5]	1	1958	3,200	2,700	2,700	0
Total					11,830	1,200[2]

Note:

1. Commercial Operation Date.
2. Owens Valley combined Net Dependable Plant Capability is 1.2 MW based on 20-years of historical data. 1.2 MW consists of 0 MW from Haiwee and Pleasant Valley and 0.4 MW each from Cottonwood, Division Creek, and Big Pine.
3. Haiwee maximum unit capability is 3.6 MW each when feed is taken from North Haiwee Reservoir. Cottonwood Power Plant Units 1 and 2 were re-wound to higher Net Maximum Unit Capability of 1.2 MW.
4. Big Pine Net Maximum Unit Capability 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 F-7. OWENS GORGE SMALL HYDROELECTRIC GENERATING RESOURCES

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capability (kW)	Net Max Plant Capability (kW)	Net Dependable Capability (kW)
Upper Gorge	1	1953	37,500	37,500	37,500	36,500
Middle Gorge	1	1952	37,500	37,500	37,500	36,500
Control Gorge	1	1952	37,500	37,500	37,500	36,500
Total[2]					112,500	109,500

Notes:

1. Commercial Operation Date.
2. Owens Gorge Net Dependable Plant Capability was decreased to 109.5 MW to reflect re-watering flow.

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 is currently working with Voith Hydro, Inc., to recondition and refurbish selected components of the Upper, Middle, and Control Gorge Power Plant to extend the life of the three units, increase reliability, and improve efficiency. The work consists 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

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. The net aggregate dependable plant capability of these smaller units is 24 MWs under average water conditions. Table F-7 summarizes these 12 units.

Table F-8. RENEWABLE AND DISTRIBUTED GENERATING RESOURCES[1]

Includes only Projects in Service as of January 2014

Plant Name	PPA/Own	COD	Net Max Capability[2] (Installed kW)	Net Max Capability[3] (LADWP kW)	Net Dependable Capability[4] (LADWP kW)	LADWP Share
PPM SW Wyoming	PPA	2006	144,000	82,200	8,220	57%
Willow Creek	PPA	2008	72,000	72,000	36,000	100%
PPM Pebble Springs	PPA	2009	98,700	68,695	34,000	70%
Pine Tree	Own	2009	120,000	120,000	12,000	100%
Milford Wind Phase I	PPA/Own	2009	200,000	185,000	18,500	93%
Windy Flats	PPA/Own	2010	262,200	262,200	73,000	100%
Pine Tree Expansion	Own	2010	15,000	15,000	1,500	100%
Linden	Own	2010	50,000	50,000	25,000	100%
Milford Wind Phase II	PPA/Own	2011	102,000	102,000	10,200	100%
Manzana	PPA	2012	189,000	39,000	3,900	21%
Wind Subtotal				**996,095**	**222,320**	
DWP Built Solar	Own	1999-2012	2,100	2,100	567	100%
Solar CNM (SB1)	Own (REC's only)	1999-2012	54,000	54,000	14,580	100%
Solar Subtotal				**56,100**	**15,147**	
Small Hydro	Own	1908-1987	208,080	208,080	134,930	100%
MWD Sepulveda	PPA	2008	8,540	8,540	8,540	100%
Castaic U3&U5 Upgrade	Own	2008-2009	30,000	30,000	30,000	100%
North Hollywood PS Power Plant	Own	2010	1,000	1,000	1,000	100%
Small Hydro Subtotal				**247,620**	**174,470**	
Hyperion Digester Gas	Own	1995	16,000	16,000	14,600	100%
Lopez Microturbine	Own	2002	1,500	1,500	1,500	100%
WM Bradley	PPA	2006	6,400	6,400	6,400	100%
Shell Energy Landfill Gas	PPA	2009	n/a	n/a	n/a	n/a
Atmos Energy Landfill Gas	PPA	2009	n/a	n/a	n/a	n/a
Toyon Power Plant	PPA	2010	3,600	3,600	3,600	100%
Shell Renewable Biomethane	PPA	2012	n/a	n/a	n/a	n/a
Biomass/Landfill Gas Subtotal				**27,500**	**26,100**	
Customer Cogenerations	PPA	1998-2000	303,000	45,000	45,000	15%
Distributed Generation Subtotal				**45,000**	**45,000**	
Don A. Campbell	PPA	2013	16,200	13,710	12,339	85%
Geothermal Subtotal				**13,710**	**12,339**	
Total In Service Renewables & DG				**1,386,025**	**495,376**	

Notes:

[1] Table include LADWP's renewables and distributed generating sources from LADWP-owned and contracted projects. This table is based on data from the January, 2013 RPS Master Project List and contract sources.

[2] The full-load continuous rating of a generator unit under specified conditions as designated by the manufacturer.

[3] Maximum Plant Capability reflects water flow limits at hydro plants; or aggregation of units at renewable plants.

[4] Net Dependable Plant Capability reflects the amount of generating capability that can be depended on during the peak demand hours of a day. Dependable capacity of a plant using a specific renewable technology is estimated by applying a Dependable Capacity Factor (DCF) to the plant nameplate capacity. The dependable capacity factor may change as LADWP gains more operating experience with renewable technologies. DCFs currently used are as follow:

- Digester Gas 1.00
- Geothermal 0.90
- Landfill Gas 1.00
- Muncipal Solid Waste Conversion 1.00
- Small Hydroelectric 1.00
- Solar Photovoltaic 0.27
- Wind 0.10 (projects with firming contracts are rated at firming levels)

[5] LADWP's share for Don A. Campbell is 13,710 kW or 84.62%; Burbank's share is 2,490 kW or 15.38%

Table F-8 CONTINUED. RENEWABLE AND DISTRIBUTED GENERATING RESOURCES [2]

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capability (LADWP kW)	Net Max Plant Capability (LADWP kW)	Net Dependable Capability (LADWP kW)
Pine Tree Wind Power Plant	1-90	2009	1,500	1,500	135,000	[1]
Pine Tree Solar Power Plant	1-17	2013	500	500	8,500	[2]
Adelanto Solar Power Plant	1-13	2012	770	770	10,000	[3]

Note:

1. Pine Tree Wind Power Plant was commissioned in June 2009. Wind Generation is not considered to be dispatchable and dependable.
2. Pine Tree Solar Power Plant was commissioned in March 2013. Solar generation is not considered to be dispatchable and dependable.
3. Adelanto Solar Power Plant was commissioned in June 2012. Solar generation is not considered to be dispatchable and dependable.

Table F-9. AQUEDUCT SMALL HYDROELECTRIC GENERATING RESOURCES

Plant Name	Unit	COD[1]	Generator Nameplate (kW)	Net Max Unit Capability (kW)	Net Max Plant Capability (kW)	Net Dependable Capability (kW)
Foothill (PP4)	1	1971	11,000	9,900	83,050	24,230[2]
Franklin (PP5)	1	1921	2,000	2,000		
San Francisquito 1 (PP1)	1A 3 4 5A	1983 1917 1923 1987	22,500 7,500 10,000 22,500	27,000 10,000 12,000 27,000		
San Francisquito 2 (PP2)	1 2 3	1919 1919 2006	14,000 14,000 18,000	0 14,000 18,000		
San Fernando 1 (PP3)	1 2	1922 1922	2,800 2,800	3,200 2,900		
Sawtelle (PP6)	1	1986	640	650		
Total[3]					83,050	24,230

Note:

1. Commercial Operation Date.
2. San Francisquito Power Plant 2 Unit 1 is out of service; however LADWP has plans to refurbish the unit. San Francisquito Power Plant 2 Unit 2 stator heating limits capacity to 8 MW during hot weather conditions. San Francisquito Power Plant 2 Unit 3 has a new generator with refurbished turbine as of December 2, 2006. Contract specification is 18 MW output but unit was tested to only 16 MW due to low water flows and restricted downstream capacity. Assumed maximum actual output is 18 MW.

4. Aqueduct combined Net Dependable Plant Capability reflects low water availability during winter.

5. 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.

6. LADWP has applied to the CEC for certification of the Gorge Units and PP1 and PP2; however, CEC has not yet acted on the applications.

Appendix G Distributed Generation

G.1 Overview

Distributed Generation (DG) is a concept of installing and operating small-scale electric generators, typically less than 20 megawatts MW, at or near an electrical load and interconnected to the electric utility distribution system. Many of these operate in cogeneration mode to utilize the produced heat. The most common technologies used today for DG are turbines and internal combustion engines (ICEs). Newer technologies are now entering the field, such as fuel cells, microturbines, and solar photovoltaic (PV), as their cost and reliability have improved significantly in recent years. In addition to providing environmental, cost, and reliability benefits, DG provides the potential to improve power quality, increase reliability, and defer transmission or distribution system upgrades.

DG can be customer installed or utility installed. The benefits for customer installed DG include waste heat utilization, backup power and improved power quality. The benefits for utility installed DG include central station generation, transmission and distribution infrastructure deferral, and reduction of delivery losses.

This Appendix describes DG on the grid, ICE technologies, fuel cells, and PV technologies.

G.2 Distributed Generation on the Grid

The introduction of deregulation and competition into the electric marketplace has led to the commercialization of DG technologies. Most technologies being commercialized for DG applications are currently more costly than traditional generating resources. However, it is anticipated that, with advances in the technologies and a greater demand for DG, costs will become more competitive, and more systems will be installed.

As of 2015, LADWP has approximately 139 GWh of combined heat and power and 320 GWh coming from landfill or process gas that is put into the electrical 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 and lower natural gas prices, distributed generation is becoming more in demand. Additionally, as of October 1, 2015, over 17,500 LADWP customers have installed over 140 MW of solar PV energy systems with the help of LADWP's Solar Incentive Program.

LADWP has installed 24.8 MW of solar PV energy systems on LADWP and City of Los Angeles (City) facilities to generate clean, renewable energy for the LADWP grid. LADWP has also installed fuel cells and microturbines for demonstration purposes to understand their operating issues and benefits.

Tables G-1 and G-2 provide projections of Cogeneration and PV capacity and energy used in the 2013 IRP. Cogeneration forecast is from 2012 Retail Energy and Demand Forecast.

Table G-1. PROJECTED DISTRIBUTED GENERATION COGEN - CUMULATIVE

Calendar Year		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Customer generated	MW	235	241	246	250	253	255	257	260	263	265	268	272
	GWh	1,196	1,218	1,238	1,256	1,267	1,276	1,285	1,296	1,307	1,314	1,327	1,345

Table G-2. PROJECTED SOLAR PV DISTRIBUTED GENERATION - CUMULATIVE

Calendar Year		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Customer generated	MW	95	122	152	192	212	227	237	245	250	255	260	265
	GWh	131	201	277	317	350	375	391	404	413	421	429	437
Utility generated	MW	2.4	4	8	14	20	26	32	40	40	40	39	39
	GWh	2	5	12	23	33	44	54	70	70	69	69	69

NOTE: Solar Distributed generation includes the Solar Incentive Program (SIP) and Community Solar

G.3 Internal Combustion Engines

ICEs include reciprocating engines and combustion turbines. Improvements have been seen recently in the emissions and efficiencies of reciprocating engines and combustion turbines. Combustion turbines have typically been in the multi-MW size, but recently small-scale combustion turbines, or microturbines, have been developed.

Microturbines are machines ranging in size from 28 kilowatts (kW) to 500 kW. They have the potential to be located on sites that have space limitations to produce power. The advantages of microturbines are their ability to operate on a variety of fuels and that they are compact in size.

LADWP has installed nearly 2 MW of microturbines, the first of which was located at LADWP's Main Street Center in 1999. Additional microturbines were installed and tested at LADWP facilities and the Lopez Canyon landfill.

G.4 Fuel Cells

A fuel cell combines hydrogen and oxygen to produce electricity through an electrochemical process like a battery. Besides electricity, fuel cells produce water and heat. If the oxygen source is air, then small amounts of NO_X may also be emitted. Fuel cells produce energy at relatively higher efficiencies and emit far fewer air pollutants, including particulates, than combustion technologies. Fuel-cell power plants are now becoming commercially available for use by electric power producers, industrial facilities, and large commercial buildings. Smaller systems for residential, small commercial buildings and transportation applications are expected to be commercially available in the near future. The pricing for these products is expected to become competitive due to several factors:

- Significant recent investments in the technology are accelerating the development of more reliable and efficient fuel cells, and costs have been decreasing.
- Support equipment, such as fuel processing and power conditioning equipment can add significant cost to fuel cells, but cost reductions are taking place as more fuel cells are installed and operated.

Under a pilot project, LADWP installed a total of four 200-250 kW fuel cell power plants in various locations in Los Angeles that have provided considerable experience and data. All four fuel cell plants, which were pre-commercial and developmental accomplished their purpose and have been decommissioned.

G.5 Photovoltaics

Solar energy is harnessed and converted to electricity using two power conversion technologies: PV systems and solar thermal power systems. PV systems convert sunlight directly into electricity. PV systems are modular, portable, highly reliable, and have low environmental impact, 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. Many utilities are installing these systems on the rooftops of schools and their customers are installing them on the rooftops of their houses. LADWP has seen the popularity of local customer owned solar generation increase due to the combination of utility paid incentives and recent federal tax law changes, as well as declining solar equipment costs.

In 2006 state legislation SB1 required all utilities to offer incentives to customers to install solar energy systems through 2016. LADWP's Solar Incentive Program (SIP) has been 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 is available to residential customers, has seen tremendous growth in the last four years due to drastic drops in solar panel costs, availability of a 30 percent Investment Tax Credit from the Federal government, and solar-equipment-leasing opportunities. In 2009, the SIP administration team received about 90 applications a month. In 2015, the SIP administration team is receiving 300 plus applications a month. Additional information on the SIP can be found at www.ladwp.com/solar. LADWP incentives have supported the installation of 140 MW MW on its customers' properties, through September 2015. A typical 5 kW alternating current (AC) residential rooftop solar power system produces 8,250 kW-hours per year.

LADWP's Community Solar Program has installed 24.8 MW of PV at LADWP facilities and other City facilities, utilizing LADWP construction forces.

After three years of extensive public outreach to our customers and stakeholders, the LADWP developed a Feed-in Tariff (FiT) program. Through the FiT Program, the LADWP will purchase energy from eligible renewable projects from 30 kilowatts up to three megawatts (MW) in capacity within its service territory. FiT is a DG program, meaning that the power is generated close to where it is consumed. It provides LADWP customers the opportunity to sell energy to the LADWP by using their property as the DG site. LADWP's 150 MW FiT Program is the largest FiT offered by any city in the Nation. The comprehensive FiT Program will comprise of two FiT programs – FiT100 and FiT50. The LADWP first launched a 10 MW FiT Demonstration Program in April 2012 to fine-tune the processes that LADWP created for the program, and learn about consumer sensitivity pricing for solar generation in Los Angeles. With lessons-learned from the FiT Demonstration, the LADWP launched the first phase of FiT100 in February 2013. FiT100 is a 100-MW program with a set pricing structure – designed to provide price certainty for the solar industry so they can commit to building projects. The goal is to have 20 MW of renewable energy installed every six months and have all 100 MW installed before 2016. Although this program is open to all forms of eligible renewable energy, most systems will be solar PV. Additional information can be found at www.ladwp.com/fit.

FiT50 has a goal of acquiring 50 MW of solar energy from systems built within the Los Angeles city limits. It has a unique and innovative structure, since LADWP has competitively procured both 50 MW of local solar energy along with 200 MW of solar energy from the Beacon Project. LADWP was able to garner overall reduced prices on proposals, likely due to economies of scale and the financing power of large-scale developers. The Request for Proposal was issued on July 1, 2013 and contracts were awarded to two developers.

G.6. Combined Heat and Power (CHP) Program

Combined heat and power (CHP) systems, or also known as thermal cogeneration, simply capture and utilize excess heat generated during the production of electric power. CHP systems can reach a combined fuel utilization levels of up to 80% and offer economic, environmental, and reliability-related advantages compared to power generation facilities that produce only electricity. Distributed power generation systems, which are frequently located near thermal loads, are particularly well suited for CHP applications.

Currently CHP installed in the LADWP Power System consists primarily of cogeneration projects of industrial and commercial customers. This totaled to approximately 265 MWs nameplate capacity operating in the LADWP's service area. Some cogeneration projects sell excess energy to the LADWP under interconnection agreements.

Current barriers to the expansion of CHP can be attributed to:

- Natural gas price volatility in recent years has caused uncertainty in the economic feasibility of CHP projects.
- Diminishing industrial customer base in recent years has reduced CHP developable potential.
- Reliability and economic issues made small systems infeasible.
- Added cost from utility replacement reserve requirements.
- Uncertain Greenhouse Gas emissions add costs to CHP electric generation.
- Air quality sitting restriction for new carbon-based CHP electric generation.

LADWP is developing CHP target goals to incorporate CHP generation in its future resource mix. LADWP is currently considering development of the following self-owned CHP projects:

- Terminal Island Renewable Energy Project is a fuel cell plant to produce 4 MW of electricity and process heat using methane gas.
- Los Angeles Bureau of Sanitation Alternative Technologies Projects to convert waste to heat.

To encourage customer-developed CHP, shift demand from electric grid, and provide accurate price signals to customer, LADWP is currently offering a Standard Energy Credit (SEC) to its customers for excess energy they sell to LADWP. The SEC is based on LADWP marginal generation cost, and is updated and posted monthly. In the future, for renewable CHP, LADWP may provide a renewable premium based on the energy market plus the SEC. For non-renewable CHP, LADWP will continue to purchase CHP excess energy at the SEC.

Current Incentives offered to customers require:

- Customer must purchase electric services from LADWP to be eligible for interconnection

- Customer submits completed Standard Offer Agreement for interconnection and qualification for a CG Rate
- Customers pay for all costs associated with time-of-use metering, interconnection, and safe grid-parallel operation of the generation facilities
- For cogeneration facilities equal to or greater than one megawatt, the customer is required to install remote monitoring equipment for LADWP
- Customer maintains adequate insurance on generating facilities
- Excess power reimbursements are made to the customer at end of billing period using the Energy Credit
- The interconnection agreement has a three year term and requires approval by the General Manager initially and for renewal and extension

Inclusion of the CHP goals under the IRP process will help communicate CHP program information and facilitate stakeholder feedback.

Appendix H Fuel Procurement Issues

H.1 Overview

This Appendix presents issues and strategies related to LADWP procurement of both natural gas and coal.

H.2 Natural Gas

LADWP generates about 22 percent of energy from natural gas-fired generation. Or, in other words, almost one-fourth of LADWP's energy generation is exposed to the risks of gas price volatility. This percentage will increase in the future as coal is removed from LADWP's resource portfolio, and with the integration of additional variable energy resources. Figure H-1 below graphically illustrates the daily natural gas spot market price (including delivery charges to LADWP's gas plants) and the large price fluctuations from the year 2000 to 2014.

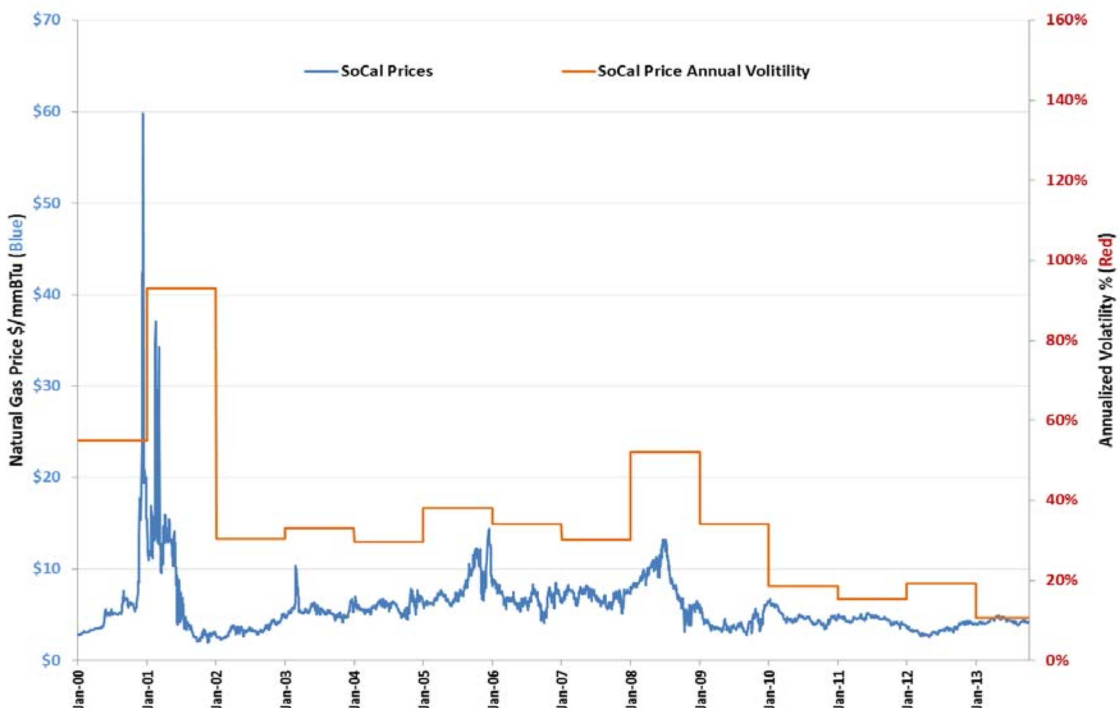

Figure H- 1. Natural gas daily spot prices

As is shown on Figure H-1, the natural gas market has been very volatile with extreme variations of prices but appears to be settling down. 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 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 also replaced 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 that were replaced, resulting in a 30 percent to 40 percent decreased usage of natural gas to generate the same amount of electricity. LADWP has also added 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 pricing issues is provided in the following subsections.

H.2.1 Natural Gas Pricing Issues

Gas delivered to the burner tip for electric generation in California is comprised of three elements: 1) commodity costs; 2) interstate transportation; and 3) intrastate transportation. Other concerns include regulatory/legal issues, gas price volatility, support for renewables, and gas supply issues.

Commodity Costs

Natural gas for electric generation is produced primarily outside California in areas known as basins, such as the Green River Basin near Opal, Wyoming; the San Juan Basin near San Juan, New Mexico; and the Permian Basin in west Texas. Gas produced from individual wells is gathered by small pipeline systems and delivered into a gas plant that processes the raw gas into pipeline quality gas for delivery to markets. Prior to the 1980s, this pipeline gas was sold as a bundled product by various interstate pipelines to distribution companies in the individual states, such as the Southern California Gas Company (SoCal) and the Pacific Gas & Electric Company (PG&E). Eventually interstate gas rates were restructured so that interstate pipelines became transport-only businesses with the gas marketing function spun off to the market via unregulated affiliates or independent marketers.

Intensified exploration in non-traditional producing areas of the country, chiefly the so-called shale gas, has produced a surplus of gas, which has pressured prices lower recently and will continue to do so in the foreseeable future. The development of Liquefied Natural Gas (LNG) import terminals in the United States has been delayed by a number of factors, including burgeoning domestic supply, regulatory requirements, environmental issues, safety concerns, and economic uncertainty. Development of resources known to exist in the United States offshore continental shelf, especially in view of the blowout of a deep underwater well near the coast of Louisiana, continues to experience similar issues. The U.S. has become the world's number one oil and gas producer, and consequently, most LNG import terminals have applied to the Federal Energy Regulation Commission (FERC) to convert to export terminals.

Interstate Transportation

The interstate pipeline companies that formally sold bundled gas along with their transportation services have now focused primarily on the transportation of gas from producing basins to interconnections with the individual state's local distribution companies. The jurisdiction for the regulation of these companies falls under the authority of the FERC. California is currently served by seven interstate pipelines (and two pipelines from Mexico) although only four are actually directly connected to supply basins. The other three redistribute gas from other interstates. Volatility in gas prices into California has arisen because of various supply-related issues, variations in liquidity stemming from fewer suppliers in the aftermath of the market adjustment following 2000-2001, financial trading of commodities by funds, maintenance issues, and weather-related events throughout the country. Limited price discovery has also added an element of uncertainty in gas transactions. Additional pipeline capacity to California is readily available through expansions of existing pipelines and interruptible capacity. One major interstate pipeline has indicated its interest in building laterals to Mexico to supply burgeoning demand for gas to feed its growing industrial sector. This has raised some concern over the effect of gas supplies to the southern part of California, which the local distribution companies are starting to address. LADWP has firm capacity on the Kern River pipeline approximately equal to its forecasted average gas requirement although there is a certain amount of uncertainty in this forecast depending upon the degree of implementation of renewables, the operational use of the Apex power plant in Nevada, and potential retirement of IPP.

The LADWP has rollover rights to extend its contracts with Kern River when they expire in 2016 and 2018. In addition, Kern River has expressed a willingness to expand its pipeline system to serve increased demand.

SoCal is the sole provider of intrastate gas transportation services in Southern California. These services consist primarily of delivering gas from the interconnections with interstate pipelines near the California border, but also include storage, balancing, wheeling, parking, loaning of gas, and recent operational changes stemming from the CPUC's approval of SoCal's use of the Low Operational Flow Order (Low OFO) process. Ever since May 1988, SoCal has been relieved of its obligation to serve the so-called non-core customers, those who are able to make their own arrangements for procuring their natural gas. All electric generators such as LADWP are deemed non-core or transport-only customers. The rate charged by SoCal for this transportation only service is regulated by the California Public Utilities Commission (CPUC). This rate is the lowest for any customer class (outside of any special negotiated rate) because it provides the minimum service and approaches as close to cost-of-service pricing as possible. LADWP's active participation in SoCal's rate cases at the CPUC was instrumental in achieving this distinction.

Additional services relating to the delivery of gas are available from SoCal, but the rates are subject to negotiation and, usually, CPUC approval. Generally speaking, these services are of more value to marketers than to municipal generators, but in any case would add to the cost of delivered gas.

One issue that has emerged from the recent price volatility in Southern California is whether or not SoCal has the ability to accept all the gas that will be filling the expanded interstates over the next few years. The CPUC has addressed this issue in a recent proceeding into the adequacy of SoCal's system to serve the expected load on its system. So far no conclusions can be made but SoCal is confident that they have the problem in hand because of their recent completion of various system upgrades increasing takeaway capacity by approximately 11 percent. SoCal has been able to settle rate allocation issues to allow its intrastate transmission system to accommodate the delivery of LNG Gas supplies into its system. In addition SoCal is planning system upgrades to provide more reliability in the southern part of their system which should increase overall system reliability. SoCal has indicated it is studying supply issues in the southern part of their system. Because of the interest by interstates to serve burgeoning markets in Mexico, SoCal is studying an expansion of its system to enhance its ability to move gas from north to south and avoid curtailments. SoCal has also announced its intention to improve reliability with a Pipeline Safety Enhancement Program which will, among other things, replace significant portions of older transmission lines and bring them up to modern standards.

Regulatory/Legal Issues

Several issues at the CPUC and FERC also impact pricing. SoCal revised its rates on October 2008 to accommodate the delivery of LNG into California, through the implementation of what is known as the Firm Access Rights (FAR) decision, now termed

Basic Transportation Service or BTS. It appears now that importation of LNG will be a long way off. Implementation of BTS has affected the role of transportation pricing and the distribution of receipt point allocations for deliveries into the California market. The BTS program has been renewed for another three years. LADWP has obtained BTS rights that match with its firm Kern River Interstate capacity. Another issue regarding the SoCal system is the desire by SoCal to provide bio-conditioning and compression services to customers in California who wish to introduce Renewable Portfolio Standard (RPS) qualifying gas into SoCal's system. Also SoCal is attempting to change its allocation of storage resources for balancing services in order to make more unbundled storage available for transportation customers. The RPS market for this gas will increase in prominence as electric utilities strive to reach their goal of generating 33% of their electricity with renewables by 2020.

The FERC has approved new tariff sheets for the Kern River pipeline in which LADWP has a substantial interest. Kern River had applied for a significant rate increase, but lost after a long proceeding at the FERC. The rate case was settled by most of the interested parties and refunds were distributed. LADWP recently obtained approval from the City Council and is in the process of seeking approval of restated transportation contracts to reflect the newly approved tariffs which will make the LADWP's contracts consistent with the contracts of all the other Kern River shippers and insure rollover rights when the contracts eventually expire in 2016 and 2018.

Gas Price Volatility

During the winter of 2000-2001, gas prices were highly volatile. This was somewhat repeated in milder form briefly in early 2003, in the second half of 2005, and most recently in early December 2013 and February 2014. For the most part, extreme volatility has subsided with prices remaining at substantially lower levels than in previous years due to the recession and plentiful supplies from shale plays throughout the country. Forward pricing indicates that gas prices will move relatively sideways with a slight bias upward, in part due to the competing effects of the economy and increased supplies of shale gas. The industry has endeavored to reduce volatility through a massive effort of injecting gas into storage for winter use, thereby eliminating the perception of a huge overhang of expected gas purchases during the winter heating season. Due to the abundance of shale gas production, storage levels at the end of injection seasons have continually reached record levels.

Gas Supply Issues

- New drilling techniques make it possible to extract natural gas from deep shale rock formations. The advances mean the United States has more abundant natural gas resources than previously believed. Gas advocates say it could significantly alter the future U.S. energy markets and affect geopolitical relationships.
- Horizontal drilling ($1.06-$1.34 /thousand cubic feet (Mcf)) vs. vertical drilling ($1.71 Mcf): horizontal wells open up much larger areas of the resource-bearing formation.

- Hydraulic Fracturing (or fracking): Injecting a mixture of water, sand, and other chemicals at high pressure to create multiple fractures throughout the rock, liberating trapped gas. Environmental issues have become more prominent.
- Combination of the horizontal drilling and fracking.
- With more drilling experience, U.S natural gas reserves are likely to rise dramatically in the next few years. At current level of demand, U.S. has about 90 years of proven and potential supply.
- Preliminary estimates suggest that shale gas resources around the world could be equivalent to or even greater than current proven conventional natural gas reserves.
- Re-treating conventional exhausted oil and gas formations with the newer fracking techniques has revealed the potential for extracting additional oil and gas out of those same formations.

H.2.2 Natural Gas Procurement Strategy

LADWP retained the services of PriceWaterhouse Coopers (PwC) in 2003 to assess, validate, and verify LADWP's current gas procurement strategy. Their report assessed the current strategy, suggested changes and enhancements to that strategy, and prepared a preliminary plan and timetable for implementing the changes.

As a result of PwC's review of gas operations, LADWP decided to adopt a program of protecting its gas costs from price volatility through financial hedging. The appropriate authority was sought and received by the City Council to employ financial hedges for up to ten years and physical hedges for up to five years, and to limit spending for this effort to no more than $15 million per year.

In addition, an Executive Risk Policy Committee was formed with senior management as members to provide oversight over the energy risk management activities of LADWP, including natural gas. Several actions have taken place.

First, LADWP's Financial Services Organization (FSO) negotiated individual International Swaps and Derivatives Association (ISDA) agreements with potential counterparties for the swaps to hedge gas prices. Fiscal Year 03-04 was the first complete year for using financial hedging to cap gas prices over a portion of forecasted gas requirements.

Second, LADWP obtained approval of two ordinances from the Council authorizing the Board of Water and Power Commissioners to delegate its award authority to the General Manager for approving gas procurement contracts. Subsequently the Board approved two separate pro forma North American Energy Standards Board (NAESB) contracts for use in procuring natural gas for up to one year, and for up to five years in duration. A number of the one-year NAESB agreements are now being used to buy gas. Five year strips of gas for physical risk management purposes were completed in late 2008 using the 5-Year NAESB authority. In addition, in mid-2009 the 5-Yr NAESB was used to obtain strips of biogas which contributes to the LADWP's Renewable Portfolio Standard goal. Additional hedging with natural gas is on hold due to the reduced gas usage and current hedge status limit set by the City Charter.

Third, LADWP participated through SCPPA in a Request for Proposal (RFP) process soliciting proposals for a term supply of natural gas for 30 years for up to an average of 27,500 MMBtu/Day with a discount to index. The agreements were negotiated but the deal was never completed because difficulties with the economy greatly reduced the anticipated discount offered under the prepaid terms.

Fourth, LADWP has participated with the SCPPA in purchasing an active gas reserve in the Pinedale anticline area of Wyoming. Savings from this purchase have totaled approximately $32,000,000 for the ten years of ownership. Further production is indicated by virtue of the fact that neighboring production has been approved for drilling on 10-acre spacing, up from the current 20-acre spacing, by the Wyoming Division of Oil, Gas and Conservation. Other production adjacent to the SCPPA properties has already shown promise although development depends upon a number of environmental challenges.

PwC noted that LADWP's previous gas procurement strategy was highly dependent on spot market purchases and lacked the flexibility necessary to appropriately manage the price risk involved in gas buying, trading, and transportation activities. They argued at the time that price risk was a critical issue because gas was playing an increasingly important role in LADWP's future due to increased reliance on natural gas-fired generation. (Note that the 2000 IRP had recommended repowering four natural gas-fired generating stations and adding six gas-fired simple cycle combustion turbines to make up for a sale of a portion of LADWP's interest in the coal-fired Mohave plant, to replace units that were over 40 years old, and to meet anticipated load growth). Additionally, the increased use of renewables, such as wind and solar projects, may require higher levels of reserve margins because of their variable and intermittent nature, with the higher reserve margins being provided by gas-fired generation. Also, gas price volatility and constraints on the SoCal intrastate transportation system required LADWP to place more importance on gas supply management.

PwC was retained again in the fall of 2013 to develop a hedge plan for gas purchases. PwC was instructed to take into account hedging strategies such as prepays, strips, options and reserves acquisition. As a follow-on to the PwC report, the Natural Gas Procurement group began an initial program of forward purchases to hedge FY 15-16. Subsequent hedge purchases beyond have yet to be approved by the Energy Services Executive Risk Policy Committee pending approval of policies and procedures that are Dodd-Frank compliant.

Of major significance, LADWP has sought a minor change in its hedging authority to allow it to purchase up to 10 year supplies of biogas only. Using this authority the LADWP was able to purchase a maximum of 10,000 MMBtu/day of landfill gas from Shell Energy North America. This amounts accounts for about 2% of the LADWP's committed goal of achieving 33 % renewables by 2020.

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. Additional administrative procedures were put in place to further strengthen deal tracking and audit trails.

An important initiative was put into play to obtain delegated authority from the City Council to allow LADWP management to execute SoCal's Master Service Contracts. This contract allows the LADWP to take advantage of additional services offered by SoCal such as storage, parking, loaning and wheeling. The initiative was completed in early 2008.

Additional Actions To Be Considered

With respect to transportation and storage options, LADWP will need to evaluate its options in view of the aggressive schedule adopted by the Board of Commissioners in meeting its goals for implementation of renewable technologies for generation and elimination of coal-fired generation. The successful completion of both these goals will significantly impact the need for natural gas generation. To this end, LADWP has begun to develop standardized methods for evaluating capacity projects. Factors to consider in evaluating options including:

- Cost of being short gas supply
- The amount of fuel carried in inventory for emergencies
- The type of fuel carried in inventory for emergencies
- Cost of alternatives
- Demand Side Management (DSM)
- Spot power purchases
- Alternative generation costs
- Service interruptions and preparation for emergency fuel supply
- Political and budget impacts
- Cost of being over-contracted for off-peak periods
- Cost of new capacity (initial capital and demand and charges)
- Value of excess capacity sold on short-term basis

These factors are applied to the contracting options that range from meeting base load requirements to meeting peak requirements.

SoCal is LADWP's only available intrastate transportation supplier by virtue of its authorized franchise. Since SoCal provides 100 percent firm full requirements service, LADWP's transportation need is met. Storage is being developed by others. In the meantime, LADWP may participate in SoCal's auction to acquire an appropriate amount of inventory space, injection rights, and withdrawal capacity on a year to year basis. Storage is most effective contiguous to load centers. However, the most geologically effective sites in the greater Los Angeles area have already been developed by SoCal Storage service. Storage is primarily useful for minor load balancing and, to some extent, hedging. Given the robustness of SoCal's distribution system in particular, and the interstate transportation system in general, storage is not necessary for emergency backup supply for power generation.

In 2014, LADWP finalized its Natural Gas Hedging Program, which has the goal of managing 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. Full implementation is pending approval of a Dodd-Frank compliant policy.

H.2.3 Proposed Actions

LADWP proposes to take the following actions to provide additional flexibility in implementing its natural gas procurement strategy:

- Increase the long-term natural gas hedging price cap. LADWP's authority for purchasing financial swaps for long-term natural gas is currently limited to $10.00 per MMBtu.
- Increase the short-term physical natural gas purchase price cap. LADWP's authority for purchasing short-term natural gas is currently limited to a rolling twelve months at $20.00 per MMBtu.
- Obtain delegated authority to execute SoCal's Master Services Contracts (MSC) along with the attachments for ancillary services as soon as the new MSC is published by SoCal after several regulatory proceedings have been concluded which may affect the form of MSC. Delegation would be made on an operational basis so execution would be made by management.
- Increase the term limitation for its short-term power purchases. LADWP's authority for purchasing short-term power is currently limited to a rolling eighteen months from date of execution. And likewise increase to eighteen months the 1-year gas NAESB contracts for short term gas purchases as has been done for electric deals.
- Seek authority to enter into long-term power purchase hedging contracts. LADWP is currently not authorized to enter into such arrangements.

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 repowering over 1,000 MW of electrical generation with more efficient combined cycle technology.

H.2.4 Liquefied Natural Gas

LADWP has been carefully monitoring for years the development of LNG throughout the country, and in particular the many projects aimed at California. Generally, LADWP has been supportive of the concept but has not taken an active role in any proposed project. LADWP supports making additional supplies available to the market in California for reliability and cost reasons. This will be especially true as more states implement environmental regulations that will limit the amount of electricity produced from coal resources and shift much of the energy production to natural gas.

Currently there are no active LNG projects in California though several have been planned. Environmental issues and price containment from non-conventional shale gas have made project development a challenge. In fact the current trend is to build or convert existing import terminals to export terminal due to the expanding production of shale gas nationwide. It is expected that LNG will not have a role in LADWP's resource mix in the foreseeable future.

H.3 Coal Procurement Strategy for the Intermountain Generating Station

H.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 date 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.

H.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 contains a combination of long-term, mid-term, and short-term coal supply contracts, which are either market price-based, fixed price-based, or cost of production price-based. Similar portfolio practices would be used to procure natural gas should the above-described IGS site fuel switch be achieved.

H.3.3 Coal Portfolio

The current coal procurement portfolio mix is as follows:

Long-term fixed pricing (with contracts beyond 2016):	50 percent
Short-term market pricing (spot market purchases):	50 percent

The Operating Agent procures between five and six million tons of coal per year for IGS based on recent annual capacity factors. At present, IPA has in place coal contracts which can supply all of the coal needs of IGS through 2016, with a significant portion of the coal needs beginning 2017 also already in place.

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 in a similar manner as described above, with the percentages of the pricing methodologies in the portfolio mix being determined with pricing and security of supply in mind. While Utah coal is expected to remain a key part of the IGS coal supply for the next 12 years, Utah sources of coal are diminishing. Thus, it is prudent for to the Operating Agent (with IPPCC and IPA Board of Directors guidance and approval) to seek out sources from new Utah mines and from other Rocky Mountain States. For several years the Operating Agent has procured short-term contract coal from more than a half dozen sources in Colorado and Wyoming. This will have to be done to a greater extent in the future. Since travel time using IPA-owned unit-trains increases while traveling greater distances to the out-of-state sources, the Operating Agent has already made arrangements to lengthen IPA's unit-trains, obtain additional railcar capacity, and expand IPA's railcar operation and maintenance facility.

H.4 Alternative Fuels for Basin Generation

Although there will be ample supplies and delivery capacity for natural gas to power all Basin generation for the foreseeable future, there is some concern that 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 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 put on line. No power was brought in from the Pacific Intertie and minimal power from Palo Verde, Navajo, Mohave or Intermountain power 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 quake, but some were temporarily taken off line until the situation stabilized. All generation was eventually brought on line within a few hours of the quake. If the quake were much more severe, damage to the power plants' turbines would have necessitated them to be taken off line. The gas delivery system, both SoCal's 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 move all the time, but rarely cause delivery outages. Thus it would appear that the gas delivery infrastructure is more robust than the power plants that depend on it.

We can conclude from this that although it might seem 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 being actively studied by the Fuels and Risk Advisory Working Group.

Appendix I. Transmission System

I.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 in Utah/Wyoming, Washington and Oregon. To lower transmission losses, AC/DC conversion equipment is utilized to interconnect its long distance DC lines with the AC system. Table I-1 lists LADWP's transmission resources.

Table I-1. TRANSMISSION LINE LENGTHS

Voltage	AC/DC	Circuit-Miles
Out-of-Basin		
±500kV	DC	1,068
500kV	AC	1,056
345kV	AC	101
287kV	AC	343
230kV	AC	512
Sub-Total		3,080 (85%)
In-Basin		
230kV	AC	349
138kV	AC	158
115kV	AC	45
Sub-Total		552 (15%)
TOTAL		**3,632 (100%)**

As Table I-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 33% RPS goal by 2020 and50% RPS goal by 2030. 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.

The transmission capabilities of the different systems are summarized in Table I-2.

Table I-2. TRANSFER CAPABILITY OF TRANSMISSION SYSTEMS

Transmission System	Transfer Limit (MW)	LADWP Share (MW)
Victorville-to-LA Basin	3,950[1]	3,950
West-of-the-Colorado River	11,200	3,373
East-of-the-Colorado River	9,300	1,109
Pacific DC Intertie	3,100	1,196
Owens Valley Transmission	450	450
Intermountain Power Project DC Line	2,400	1,428

[1] Victorville-to-LA Basin Transmission System has seasonal ratings of 3800 MW and 4050 MW in the summer and winter months, respectively.

I.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 20 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 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 Ten-Year Transmission Assessment released in November 2015, 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 double contingencies.

Further, the annual Ten-Year Transmission Assessments have consistently identified the need to install Scattergood-Olympic 230kV Cable A for many years now. With each passing year, the urgency becomes more apparent so that now even remedial actions have limited benefit. For this reason, LADWP is moving forward with the installation. With construction that began in 2012, the new 15-mile long Scattergood-Olympic 230kV Cable A in the Westside is under construction. Information on this project is available at the following website: http://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-projects/a-p-p-scattergood-olympictransmissionline

I.3 Victorville-to-LA Basin Transmission System

The Victorville-to-LA Basin System (see Table I-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 I-3. VICTORVILLE-to-LA BASIN TRANSMISSION SYSTEM

Transmission Line	Transfer Limit (MW)	LADWP Ownership (%)	LADWP Scheduling (%)
Victorville-Century 287kV Lines 1 & 2 Victorville-Rinaldi 500kV Line 1 Adelanto-Toluca 500kV Line 1 Adelanto-Rinaldi 500kV Line 1	3,950	100	100

I.4 WECC's West-of-the-Colorado River System

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). Path 46 facilitates transportation of electricity from 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 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 Both systems are also related in that the capacity ratings are seasonally adjusted according to the Southern California Import Transmission (SCIT) Operating nomogram.

The WOR system is summarized on Table I-4 and shown on Figure I-1.

Table I-4. WOR TRANSMISSION SYSTEM

	Transmission Line	Net WOR Line Allocation (MW)	LADWP Entitlement (MW)
North	McCullough-Victorville 500kV Lines 1 & 2 Mead-Victorville 287kV Line 1	2,592	2,592
North	Marketplace-Adelanto 500kV Line 1	1,291	313
North	Eldorado-Lugo Eldorado-Cima-Pisgah Lines 1 & 2 Mohave-Lugo 500kV Line 1 Julian Hinds-Mirage 230kV Line 1	3,031	0
North	Northern System Sub-total	6,914	2,905
South	Palo Verde-Devers 500kV Line 1	2,102	368
South	Ramon-Mirage 230kV Line 1 Coachella-Devers 230kV Line 1	600	0
South	North Gila-Imperial Valley 500kV Line 1 El Centro-Imperial Valley 230kV Line 1	1,584	0
South	Southern System Sub-total	4,286	368
	WOR Total	11,200	3,273

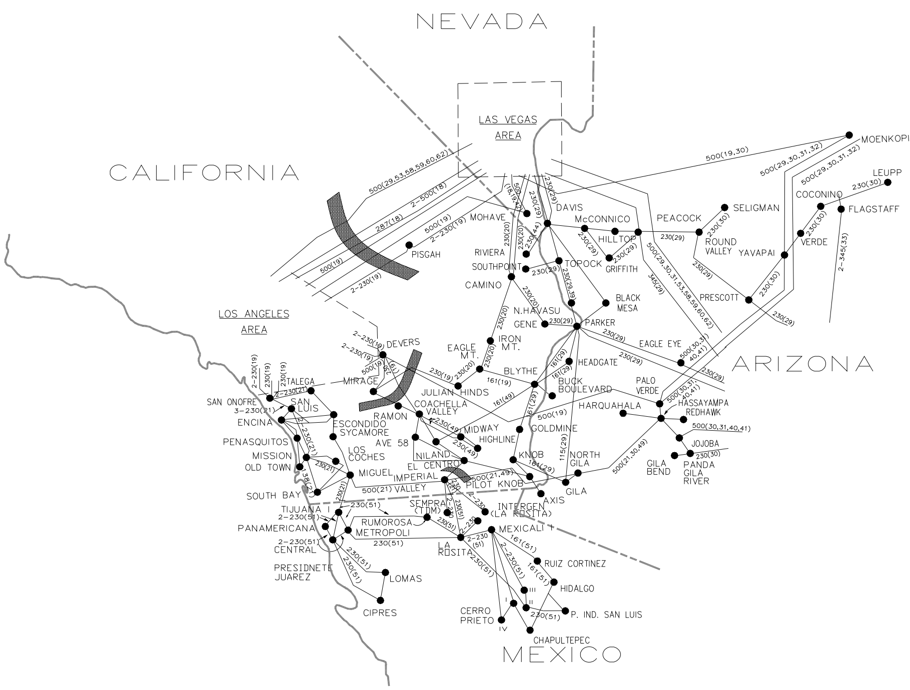

Figure I-1. WECC's West-of-the-Colorado River Transmission System.

I.5 WECC's East-of-the-Colorado River (EOR) 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). Path 49 facilitates transportation of electricity from Navajo Generating Station (Page, Arizona) and Palo Verde Generating Station (Wintersburg, Arizona) to Southern Nevada and to Southern California, respectively. 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 West-of-River System and the East-of-River System. Both systems are also related in that the capacity ratings are seasonally adjusted according to the Southern California Import Transmission (SCIT) Operating Nomogram.

The EOR system is summarized on table I-5 and shown on Figure I-2.

Table I-5. EOR TRANSMISSION SYSTEM

Transmission Line	Allocation (MW)	LADWP Entitlement (MW)
Navajo-Crystal 500kV Line 1 Moenkopi-Eldorado 500kV Line 1 Liberty-Peacock-Mead 345kV Line 1 Palo Verde-Devers 500kV Line 1 Hoodoo Wash-North Gila 500kV Line 1 Perkins-Mead 500kV Line 1	9,300: East to West	1,109

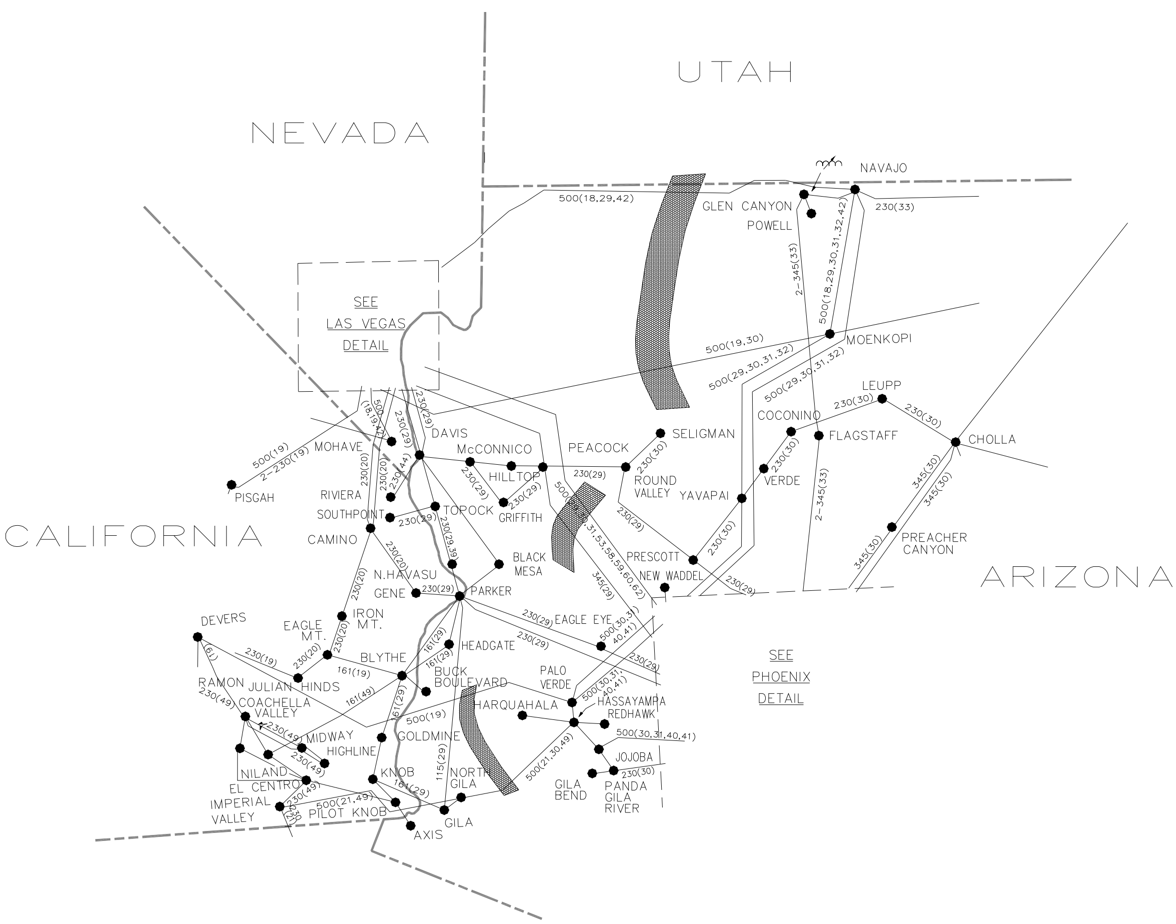

Figure I-2. WECC's East-of-the-Colorado River Transmission System

I.6 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 RPS goals. Developers have proposed interconnecting renewable resource projects totaling more than 2,950 MW. These projects have been placed in the interconnection queue but require the construction of LADWP's Barren Ridge Renewable Transmission Project, described in Section 2.4.4 of this IRP.

The Owens Valley transmission system is summarized on Table I-6 and shown on Figure I-3.

Table I-6: Owens Valley Transmission System

Transmission Line	Approximated Allocation (MW)	LADWP Expiration	LADWP Entitlement (MW)
Owens Gorge-Inyo 230kV Line 1 Inyo-Barren Ridge 230kV Line 1 Barren Ridge-Rinaldi 230kV Line 1	450[1]	Owned Asset	450

[1] The normal rating of the line is 459 MVA,

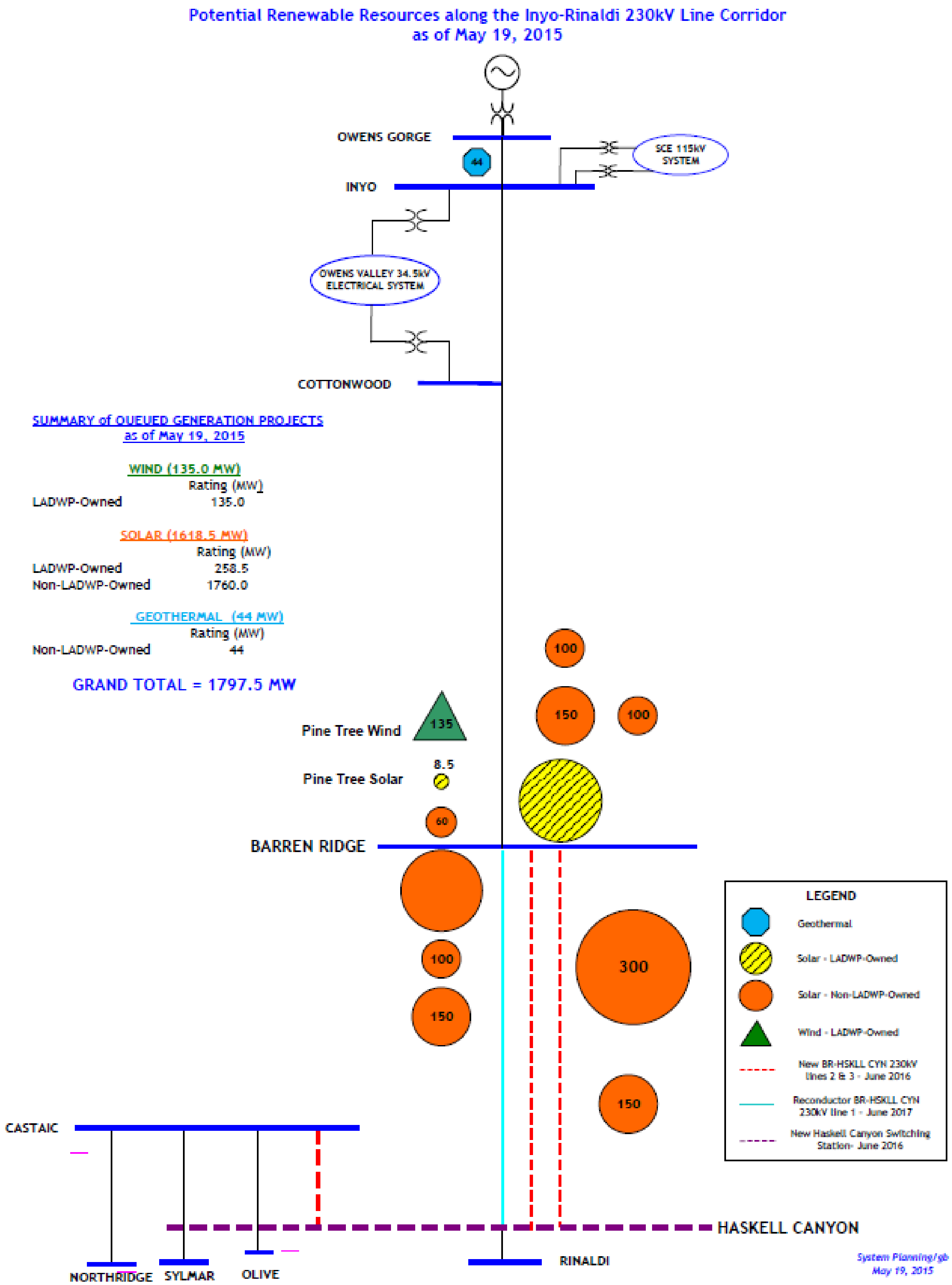

Figure I-3. Owens Valley Transmission System.

I.7 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 DC Line, was upgraded from 1920 MW to 2400 MW in May 2011. The increased capacity has been accommodating transmission of wind energy from Utah (see Table I-7 and Figure I-4).

- WECC Path 28, the 50-mile Intermountain-Mona 345kV line ties Pacificorp to LADWP's Balancing Authority Area (see Table I-8 and Figure I-5).

- WECC Path 29, the 144-mile Intermountain-Gonder 230kV line ties NV Energy to LADWP's Balancing Authority Area (see Table I-9 and Figure I-6).

Table I-7. INTERMOUNTAIN POWER PROJECT DC LINE

Transmission Line	Allocation (MW)	LADWP Expiration	LADWP Share (%)	LADWP Scheduling (%)
Intermountain-Adelanto (NE-SW) Adelanto-Intermountain (SW-NE)	2400 1400	15Jun2027	59.5	59.5

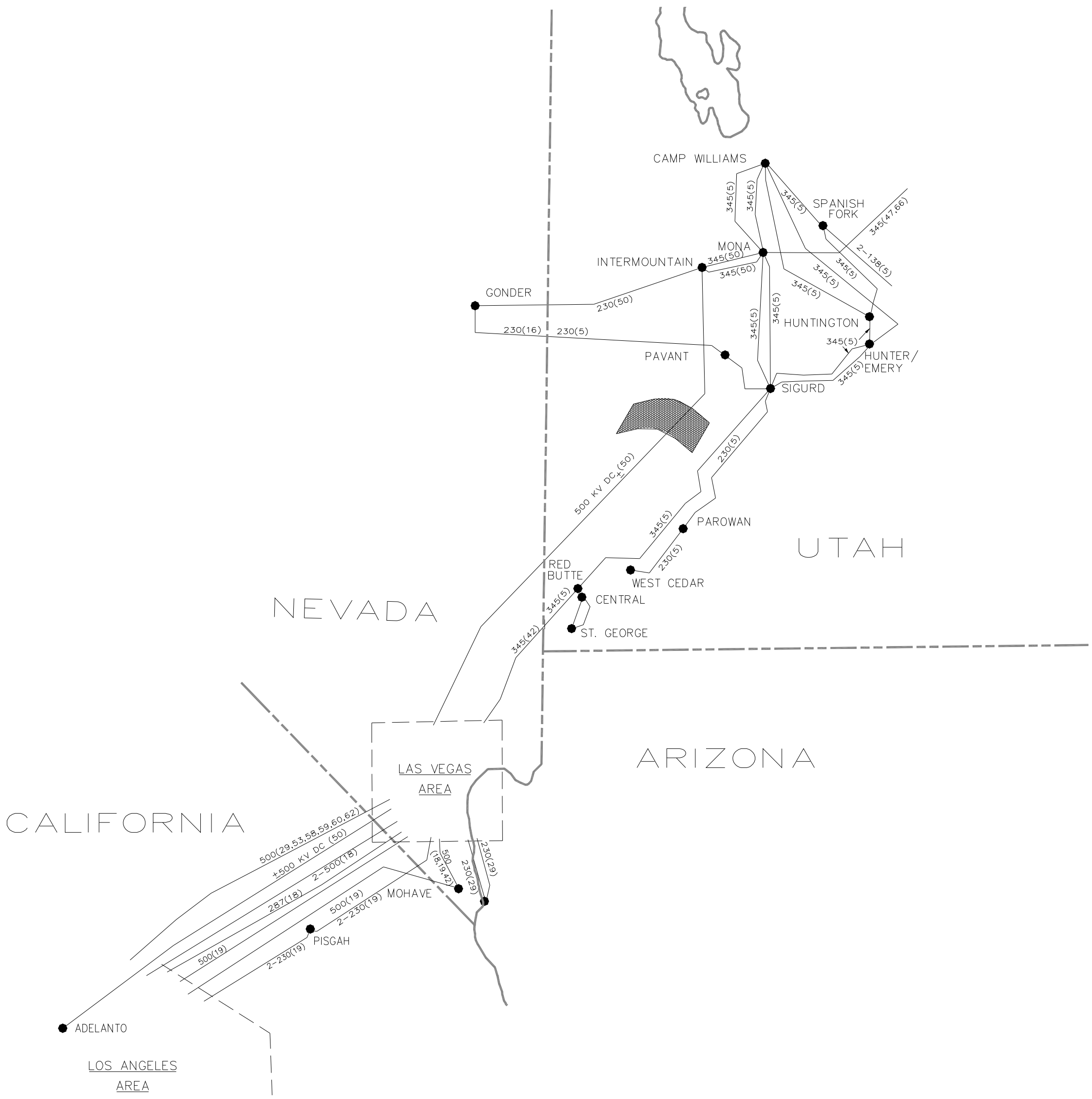

Figure I-4. WECC Path 27.

Table I-8: INTERMOUNTAIN-MONA

Transmission Line	Allocation (MW)	LADWP Expiration	LADWP Share (%)	LADWP Entitlement (MW)
Intermountain-Mona (East to West) Mona-Intermountain (West to East)	1200 1400	n/a	0	0

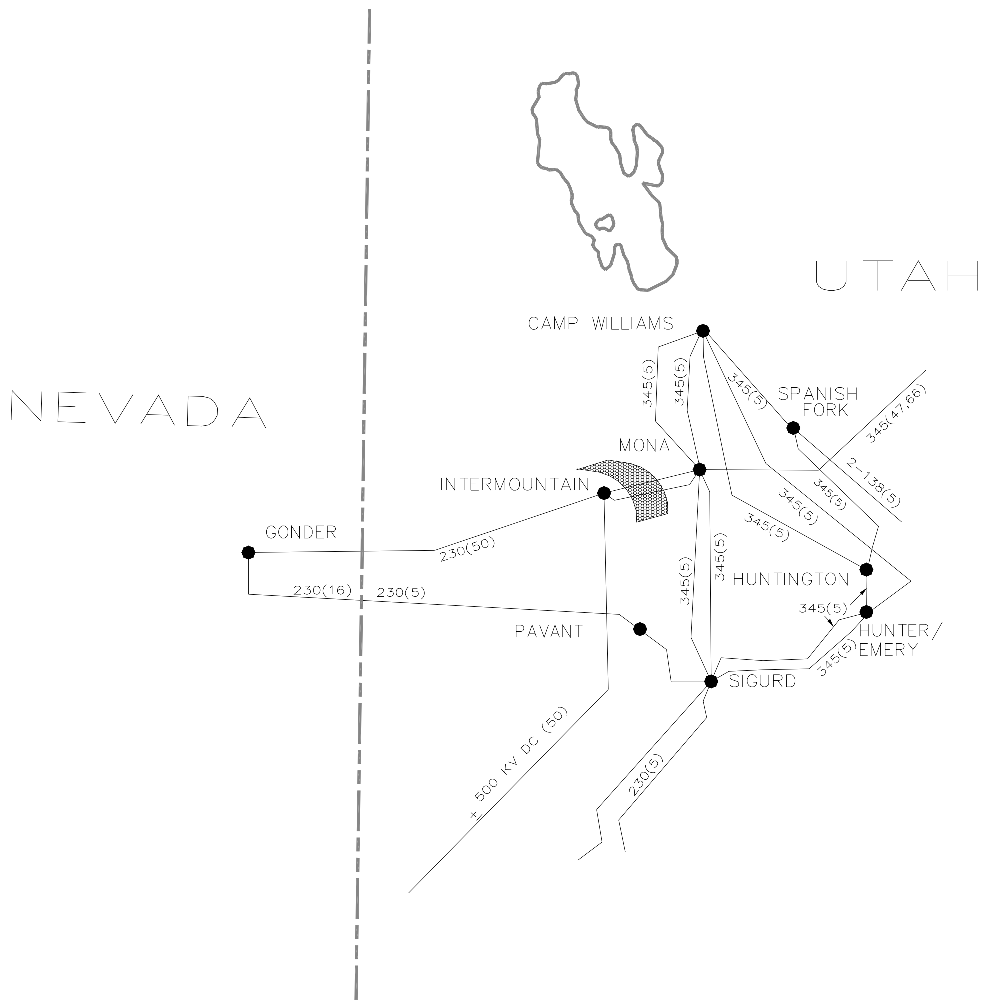

Figure I-5. WECC Path 28.

Table I-9: INTERMOUNTAIN-GONDER

Transmission Line	Allocation (MW)	LADWP Expiration	LADWP Share (%)	LADWP Entitlement (MW)
Intermountain-Gonder 230kV Line 1 (East to West)	200 MW (non-simultaneous)	n/a	0	0

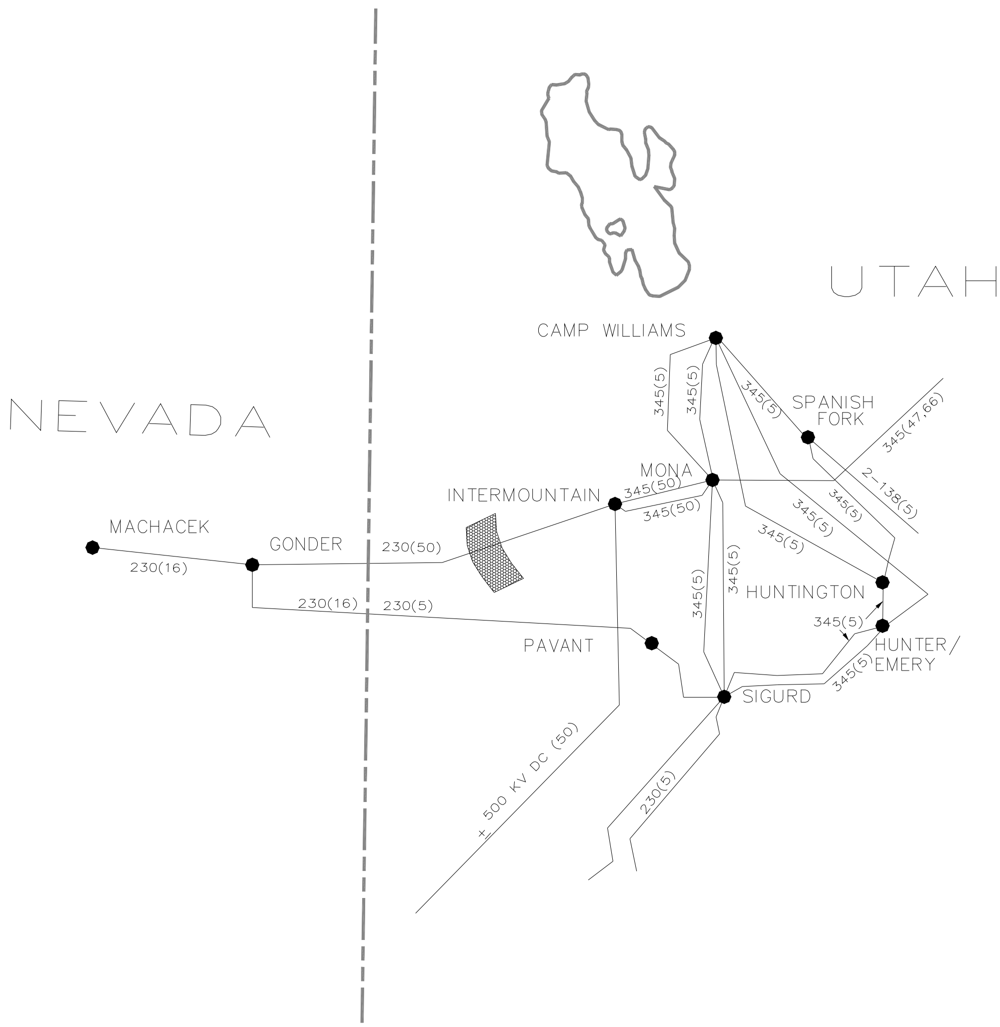

Figure I-6. WECC Path 29.

I.8 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. As described in 2.4.8 of this IRP, research into the various technological options to increase the capacity of the Pacific DC Intertie is being conducted.

Table I-10. WECC PATH 65

Transmission Line	Voltage (kV)	Allocation (MW)	LADWP Ownership (%)	LADWP Scheduling (%)
Sylmar-Celilo	+/- 500 kV DC	975[2]	40	40
Celilo-Sylmar	+/- 500 kV DC	3100	40	40

Figure I-7. WECC Path 65.

[2] Although the path rating of 3100 MW is bi-directional, the Sylmar to Celilo transmission line has a 2990 MW limitation due to losses at the scheduled point of Interconnection.

I.9 Scheduling Points with Other Utilities

A number of utilities interconnect with LADWP's transmission system. The tie points are listed in Table I-11.

Table I-11. TRANSMISSION TIE POINTS WITH OTHER UTILITIES

Utility	Regional Transmission Organization	Location	Voltage (kV)
Arizona Public Service	--	Marketplace Switching Station	500
Bonneville Power Administration	--	Pacific DC Intertie @ North of 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, after 15Jun2027	500
NV Energy	--	McCullough Switching Station Gonder, until 15Jun2027	500 and 230 230
Pacificorp	--	Mona, until 15Jun2027	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 J Integration of Intermittent Energy from Renewable Resources

J.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 the power system operators throughout the day to maintain instantaneous balance between demand and generation.

However, some renewable resources generate energy following the vagaries of nature in a variable and intermittent manner, and 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.

J.2 Findings of System Integration Studies

In the last several years, LADWP has been increasing its efforts to acquire renewable resources. In 2003, three percent of energy sold to its customers was generated from renewable energy resources. This increased substantially to 20 percent by 2010, and 33 percent is mandated by 2020. Senate Bill 350 further increases this mandate to 50 percent by 2030. 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.

J.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 through 2020 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. LADWP conducted analysis in 2014 to estimate the over-generation for various RPS scenarios – 33%, 40%, and 50%, to determine what percentage of hours over-generation is forecasted to occur and what percentage of RPS energy will result in over-generation.

   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 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 (see Figure J-1, which illustrates the power output from the Pine Tree Wind Farm, rated at 135 MW with 90 wind turbines located over 7,100 acres).
- 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 (see Figures J-2 and J-3).

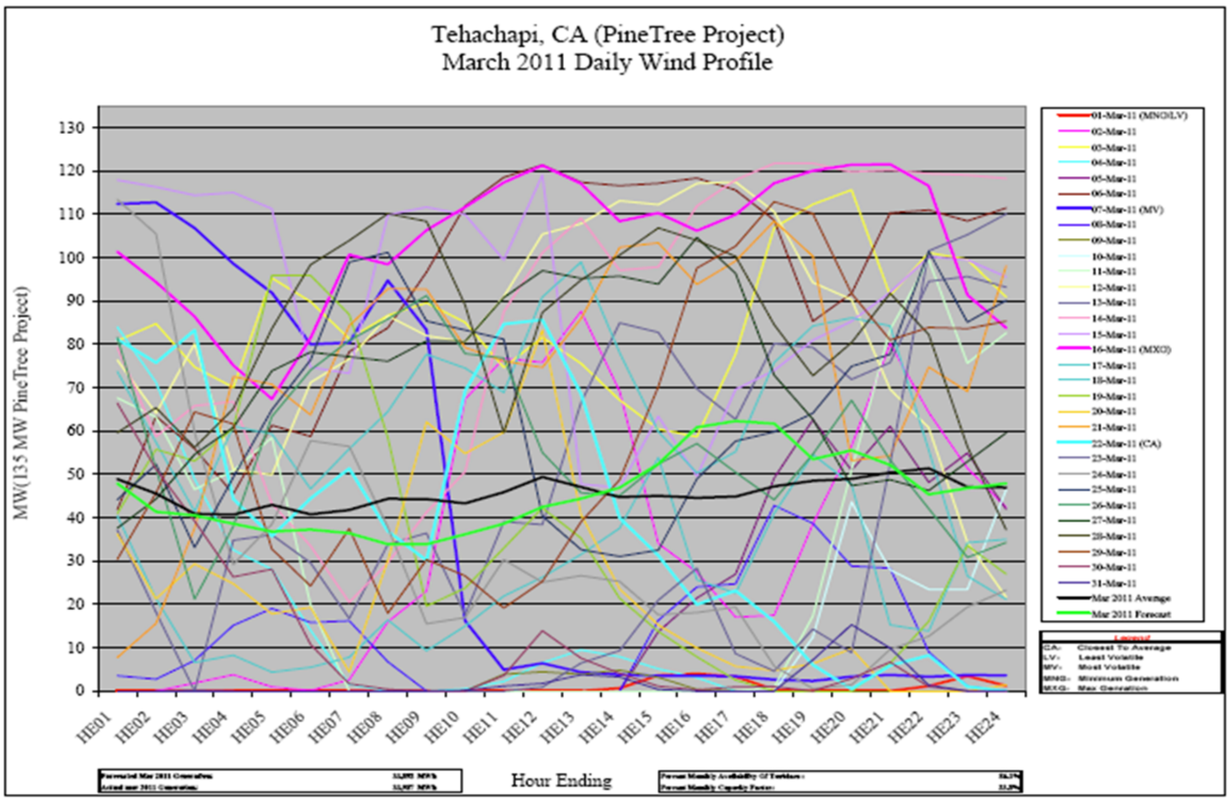
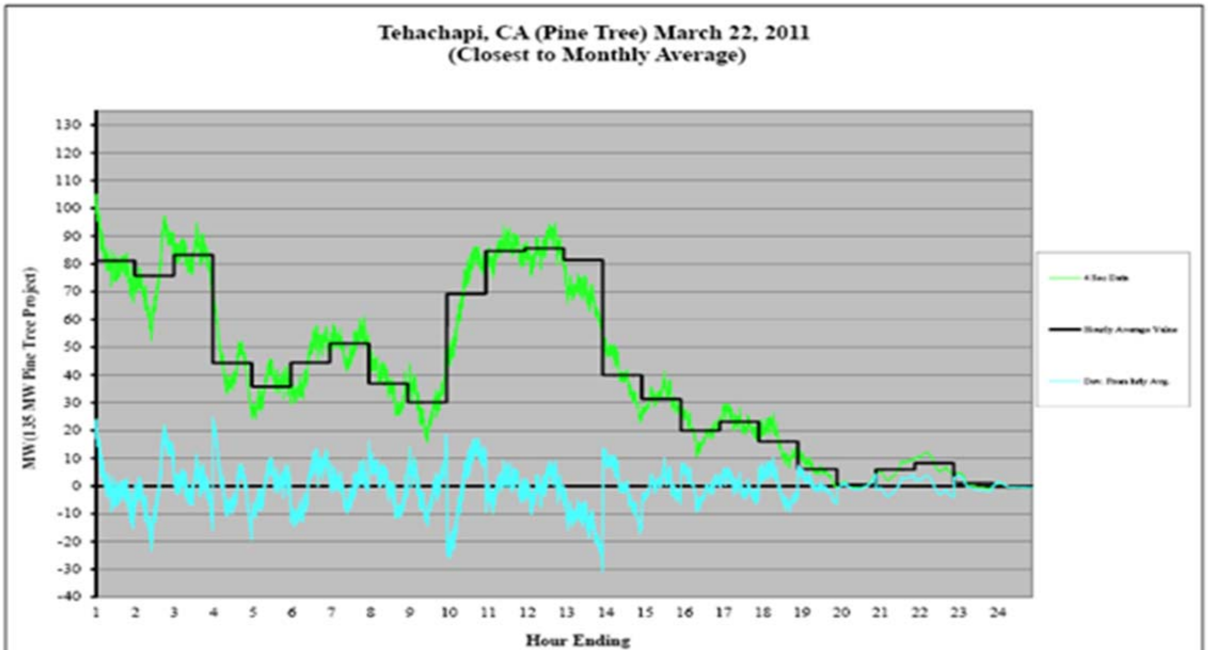


Figure J-1. Wind farm daily wind profiles.



Maximum Hour Deviation (Absolute Value)											
HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
39.34	45.28	27.56	44.23	21.77	28.20	19.81	27.86	33.15	43.06	19.43	19.53
HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
30.70	30.89	17.92	18.14	12.84	19.96	13.95	5.76	7.94	8.03	5.88	2.38

Figure J-2. Wind farm variability measured instantaneously.

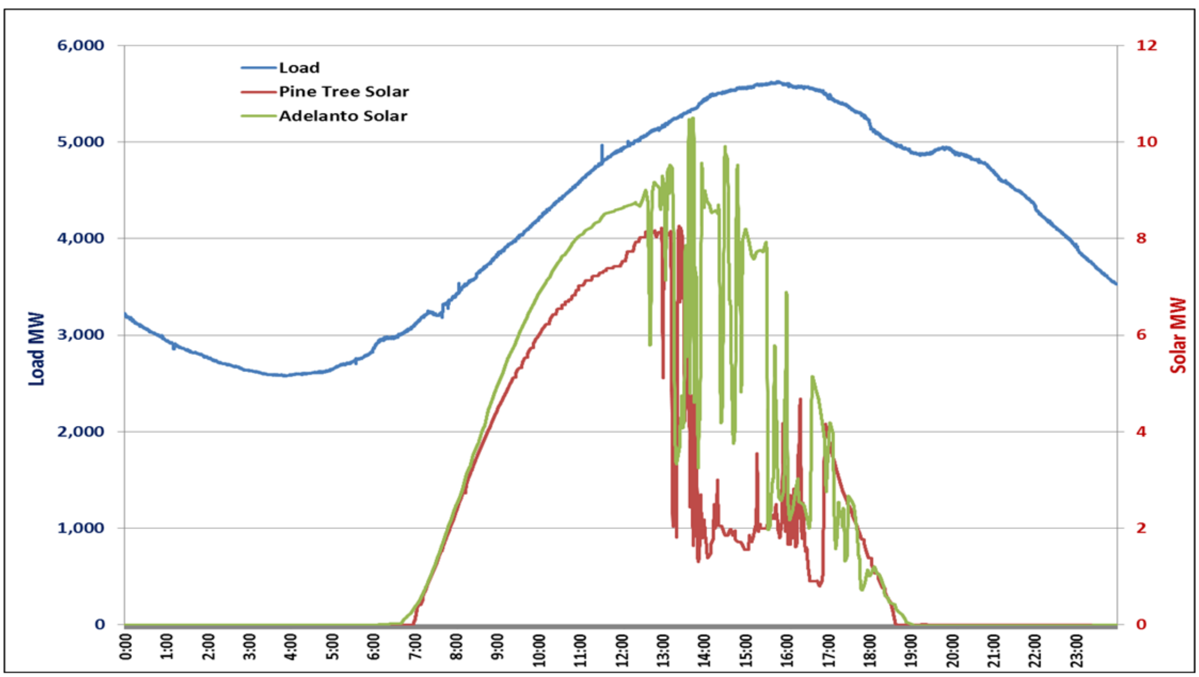


Figure J-3. Solar photovoltaic power generation at the 10 MW Adelanto facility and 9 MW Pine Tree facility.

J.2.2 Potential Solutions and Cost Impact

Discussions to identify potential solutions and cost impacts associated with the operational challenges resulting from a 50% RPS 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 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 50 percent renewables on LADWP's Power System and provide recommendations for actions and further study of cost-effective, reliable methods of variable energy resources integration. The results of this study are detailed in the MGREPS report attached as follows:

MAXIMUM GENERATION RENEWABLE ENERGY PENETRATION STUDY (MGREPS)

Final Report – Executive Summary

Los Angeles Department of Water and Power

Report No.: 20530005, Rev. B
Document No.: 20530005-01-B
Date: November 24, 2015

Project name:	Maximum Generation Renewable Energy Penetration Study (MGREPS)	DNV GL Energy Advisory Market and Policy Development 155 Grand Avenue Oakland, CA 94612 (510) 891 0446
Report title:	Final Report	
Customer:	Los Angeles Department of Water Power	
Contact person:		
Date of issue:	November 24, 2015	
Project No.:	20530005	
Organization unit:	**MPD / WAS**	
Report No.:	20530005-01, Rev. B	
Document No.:	20530005-01-B	

Applicable contract(s) governing the provision of this Report:

Objective: Analyze the impact of the anticipated high penetration of variable renewable energy resources on LADWP's system.

Prepared by:	Verified by:	Approved by:
Emily Fertig Consultant	Farnaz Farzan Senior Consultant	Olof Bystrom Head of Section MPD / WAS

ACKNOWLEDGMENTS

The Maximum Generation Renewable Energy Penetration Study (MGREPS) was commissioned by LADWP to analyze the impacts and mitigation strategies associated with high Renewable Portfolio Standard (RPS) scenarios in the LADWP system. A consortium of consultants, headed by URS Corporation Americas (URS) with sub-consultant firms DNV GL and Navigant, completed the study. This report was executed primarily by DNV GL, with the Executive Summary of the Navigant report included as Appendix 6. DNV GL, Navigant, and URS would like to acknowledge strong collaboration with the operational and planning teams at LADWP as a critical component of successfully completing this study.

1 EXECUTIVE SUMMARY

California recently increased its renewable energy mandates from achieving 33 percent renewable electricity consumption by 2020 to reaching 50 percent by 2030[1]. The present study, entitled the Maximum Generation Renewable Energy Penetration Study (MGREPS) analyzes the impact of 40-50 percent penetration of variable energy resources (VERs) on LADWP's system balancing requirements, including reserve requirements, ramp rate requirements, system reliability and operation requirements (system inertia and frequency response), and generation dispatch strategies.

Increased amounts of wind and solar power in LADWP's system will pose new operational challenges for existing generators in the system, including the Castaic pumped hydropower plant. Increasing VERs also have implications for long term resource planning and the amount of operating reserves needed to maintain reliability. LADWP requested a consulting team consisting of URS, DNV GL (Kema) and Navigant to examine the impacts of large amounts of VER on a range of system metrics and provide recommendations for actions and further study on cost-effective, reliable methods of VER integration. The study examines a large number of alternative scenarios over the 2015-2030 period, including VER penetrations of up to 50 percent, and contains a detailed sub-hourly analysis of operating reserves and system stability.

High VER penetrations, especially solar power, exacerbate the "duck curve" effect of very low load-less-VER mid-day and a strong evening ramp. Analyzing these effects on an hourly basis gives insight into the potential for over-generation as well as the necessary hourly schedules of thermal generation. However, the duck curve also has sub-hourly effects that are crucial to system planning on both long-range and operational time scales. VERs add variability that increases regulation and load following requirements as well as the potential for violation of NERC standards. The results of this study indicate that for uncommon days, in particular during the winter and spring, LADWP will face overgeneration that may necessitate periodically significant curtailment of solar PV generation capacity.

Figure 1 shows both an hourly and a sub-hourly duck curve simulated for February 16, 2025. While system planning analyses typically take place at hourly time scales (left panel), increased VER penetration introduces sub-hourly variability (right panel) that has a substantial impact on system flexibility needs, dispatch costs, and reliability risks. For example, the hourly curve on the left implies a maximum load-less-VER ramp of 19 MW/min, in the late afternoon. A sub-hourly ramping analysis, however, shows that 28 MW/min is necessary to match the first 30 minutes of the afternoon ramp, showing that LADWP must account for sub-hourly effects to ensure adequate ramping capability, and system performance, under high VER penetrations. Figure 1 also highlights the

[1] Clean Energy and Pollution Reduction Act of 2015. California Legislature, Senate Bill no. 350.

3,000 MW ramp that takes place over 4 hours in the afternoon, an event that would not be unusual in LADWP's system given proposed additional solar capacity. Using a portfolio of methods, this study provides a detailed analysis of the effects of the duck curve, at both hourly and sub-hourly time scales.

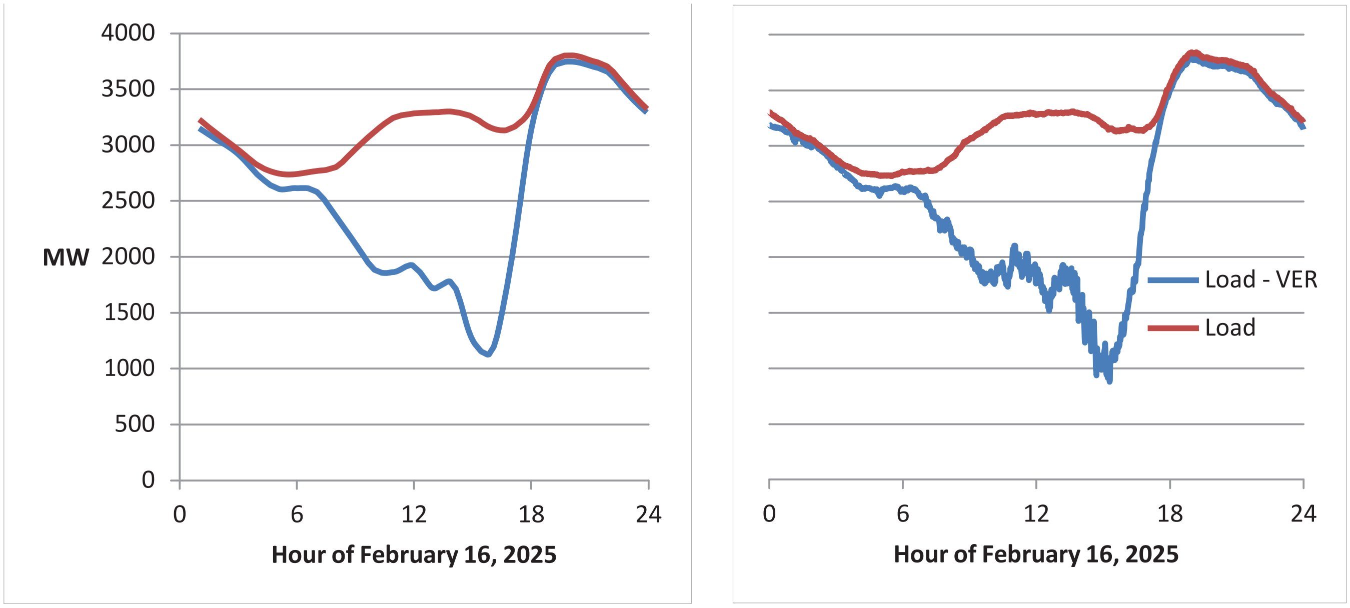


Figure 1. Hourly (left) and sub-hourly (right) duck curves.

A Resource Adequacy analysis was first performed on long-term production cost simulation results from the integrated resource planning (IRP) process. Results show that the planned LADWP system is sufficiently flexible to integrate a high level of renewables, even at a 50% RPS requirement, although stresses increase towards the end of the 20-year forecast period. A full report on the resource adequacy analysis is given in Appendix 6.

Ramping Reserve Violations and renewables curtailment can largely be mitigated by operating the existing and planned resources differently than what is forecast in the IRP.

- Dispatch of available Hoover capacity and re-dispatch (startup or maintain online) of available thermal capacity would provide significant mitigation of Ramping Reserve Violations. Additional dispatch of Castaic and DR would provide nearly complete mitigation. This result is driven to a large extent by the planned replacement of coal resources with flexible gas.
- Re-dispatch of available thermal capacity (turndown instead of shutdown) and use of Castaic in pumping mode would provide significant mitigation of renewables curtailment. Castaic would need to pump during the mid-day and generate during the evening peak for 4-5 hours a day while remaining within operating limits.

- Castaic units will have a more significant role in controlling frequency and ACE in LADWP's system. More frequent deployment of these aging plants will increase wear and tear including accelerated aging, hydraulic actuator reliability, cavitation of runner blades, and failure of transformers, which will in turn drive up O&M costs for these units. These adverse impacts can be mitigated by creating appropriate proactive maintenance energy strategies. A more detailed analysis of Castaic O&M costs and replacement needs is therefore warranted.

Thermal turn down would be constrained by RMR minimums and by the output of units that are online to provide regulation capacity. As the transmission system evolves over time, LADWP should reconsider the RMR minimums in light of the support that lower levels can give to mitigating curtailment.

In addition to system operational changes, strong time-of-use incentives for EV charging are important to keep charging away from the early evening ramp and mitigate Ramping Reserve Violations. If EV load increases as expected, early evening charging (post-commute) in combination with the natural evening loss of solar generation will increase System load and the potential for violations.

Given the ability of the planned system to provide significant mitigation, LADWP can continue to monitor how loads and VERs actually evolve over the next few years and evaluate the need for new flexible resources. These new resources include energy storage, increased DR, additional flexible thermal generation and smart demand response.

In parallel with the resource adequacy analysis, an analysis of the sub-hourly effects of increased VER penetration, including the effect on load-following and regulation requirements, was conducted. As indicated in Figure 2, several scenarios were considered, including a 40 percent RPS, a 50 percent RPS, as well as two alternative 50 percent scenarios – Accelerated Local Solar and High Solar. These are described in detail in Section 2.

Hourly load following capacity will need to increase under all scenarios from today's level of about 150 MW per hour during average winter conditions to 1,000 MW per hour under a 50% RPS scenario containing a large solar plant. Taking uncertainty into account, hourly load following requirements could occasionally reach as high as 1,400 MW by 2030, from 350 MW in 2014 (Figure 2), at the 99th percentile (equivalent to 3 or 4 events per year). 1,400 MW corresponds to the combined capacity of Apex and both Utah combined cycle units starting up and ramping to full capacity within an hour, frequently followed by similar ramping requirements the following hour. Even the lowest future RPS scenario could require up to 1,100 MW to meet hourly afternoon ramping needs at the 99th percentile. The 99th percentile requirements, used frequently as a metric in this study, refer to the capacity that results indicate will be adequate over 99% of hours. Load-following and regulation requirements refer to total required capacity (not incremental to the current system).

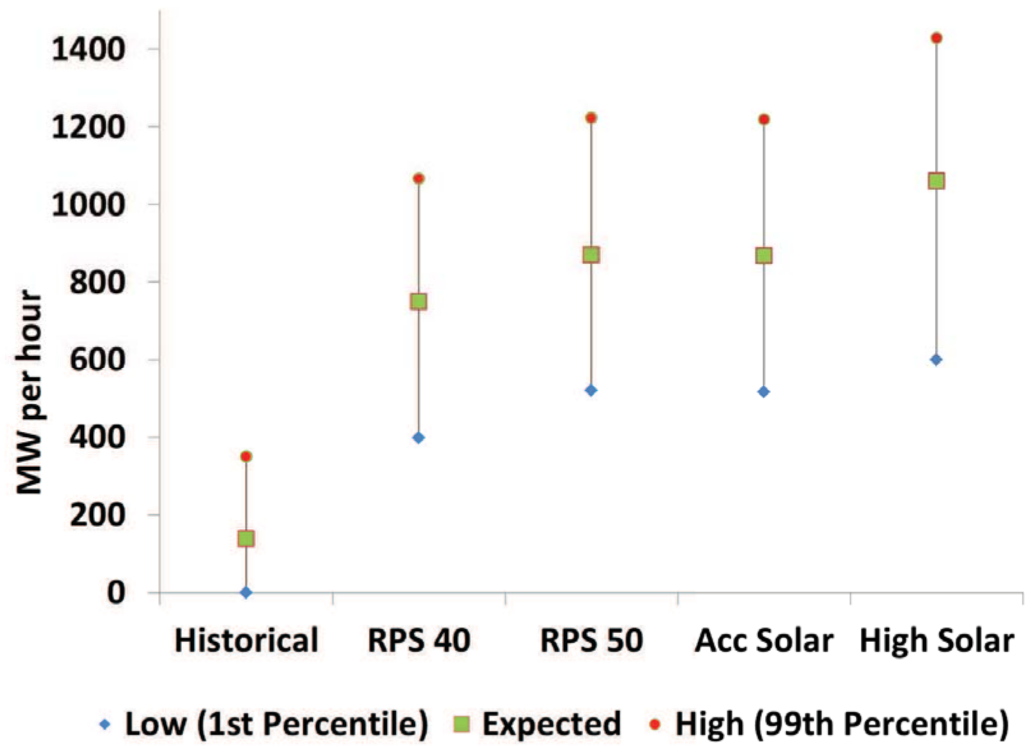


Figure 2. Hourly load-following requirements: afternoon ramp, winter 2030.

The total load-following requirement during the afternoon ramp (from the trough to the peak of the "duck curve") will increase significantly as well. Load-following requirements over the afternoon ramp would reach an average of 2,600 MW in 2030 for the highest renewables scenario. At the 99^{th} percentile, the total afternoon ramp in this scenario is 3,600 MW, exceeding LADWP's current in-basin gas-fired capability of 3414 MW.

Regulation requirements are poised to increase significantly, even under the most conservative 40 percent RPS scenario. By 2030, up regulation is expected to increase to 220 MW for the 40 percent RPS scenario and 360 MW for the 50 percent RPS scenarios at the 99^{th} percentile, up from 60 MW in 2014 (Figure 3). Down-regulation requirements are similar.

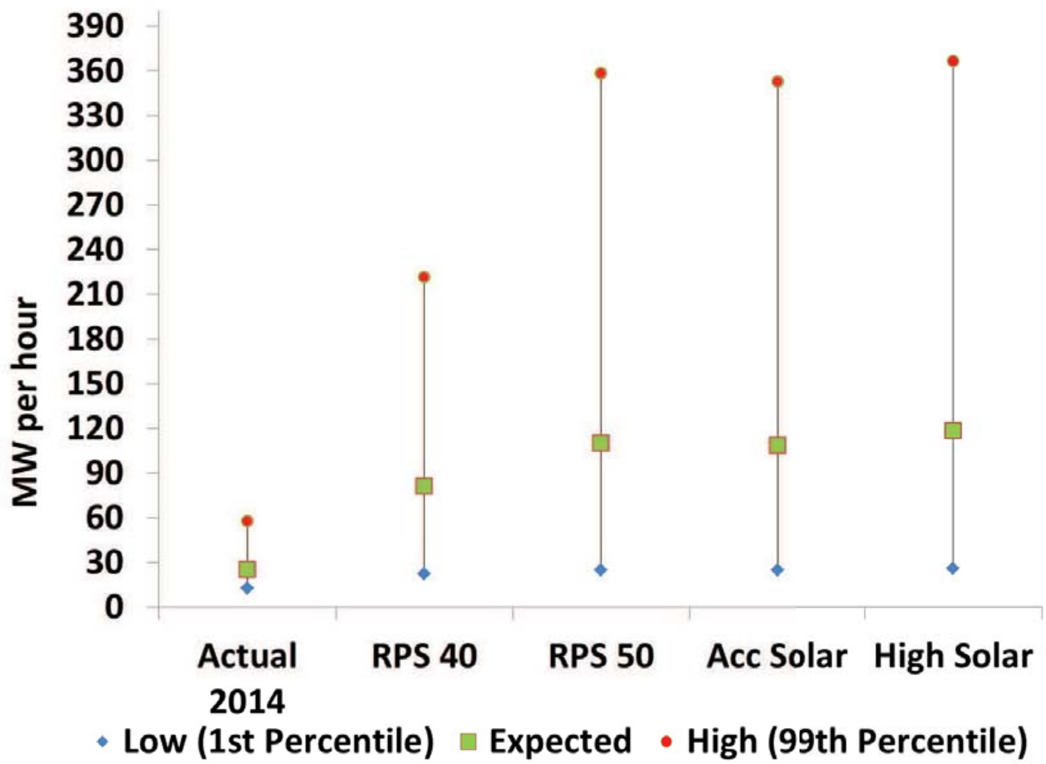


Figure 3. Hourly up-regulation requirements: peak solar hour, summer 2030.

The LADWP system currently requires almost no downward load-following in the morning. An increase in solar penetration will introduce substantial requirements, up to 860 MW per hour for 3 to 4 hours of the year (99th percentile) for the High Solar case in 2030. This result highlights a challenge associated with integrating an additional large solar plant at Barren Ridge (present only in the High Solar scenario).

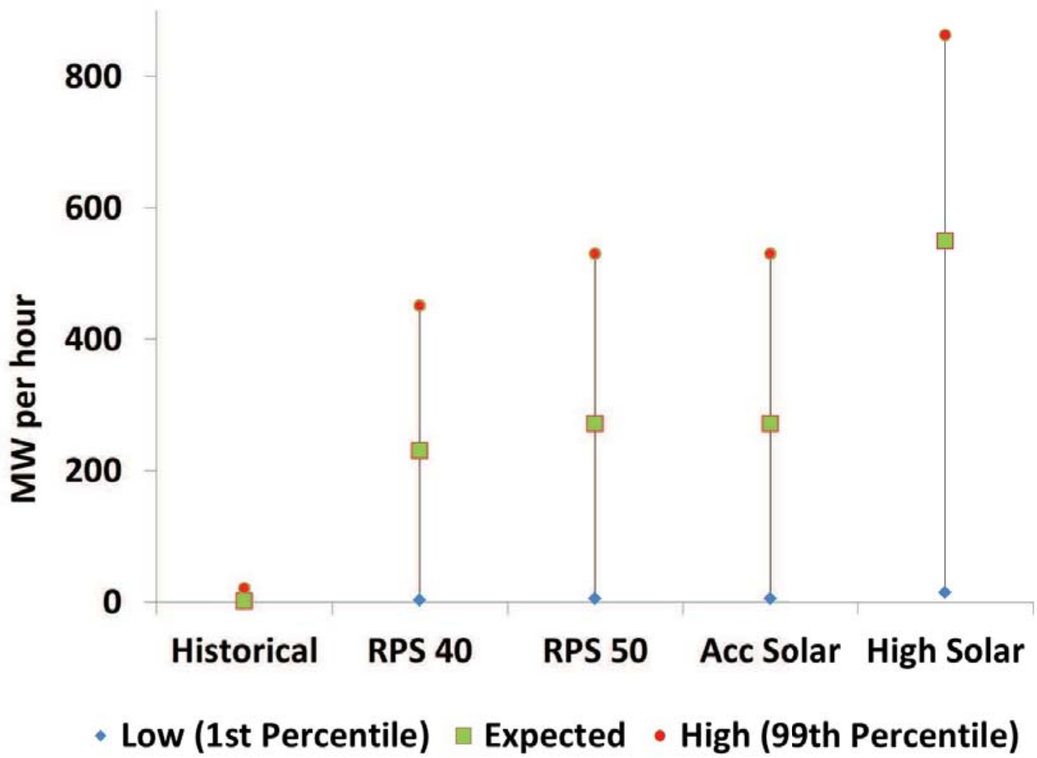


Figure 4. Hourly downward load-following requirements in the morning (0800-0900), winter 2030.

A comparison with results of the headroom analysis indicates that LADWP will face shortfalls in system ramping capability, especially over the 10-minute timeframe and for the 2030 High Solar scenario, when about 22 percent of the total LADWP demand is served by solar PV.

Figure 5 shows 10-minute, 30-minute, and 60-minute shortfalls in ramping capability for the 2030 High Solar scenario. Shortfalls of 10-minute ramping capability are expected for 220 hours of this year, at a level of 90 MW on average and 400 MW at the 99th percentile. For the other 50% RPS scenarios, 10-minute ramping shortfalls are expected only half as often.

60-minute ramping shortfalls are expected for 47 hours of the 2030 High Solar scenario, or about once per week. In contrast, only three or fewer hours of 60-minute ramping shortfall are expected for other RPS scenarios in 2030. This result again highlights the potentially high additional cost of integrating an additional large solar plant in the 50% RPS scenario.

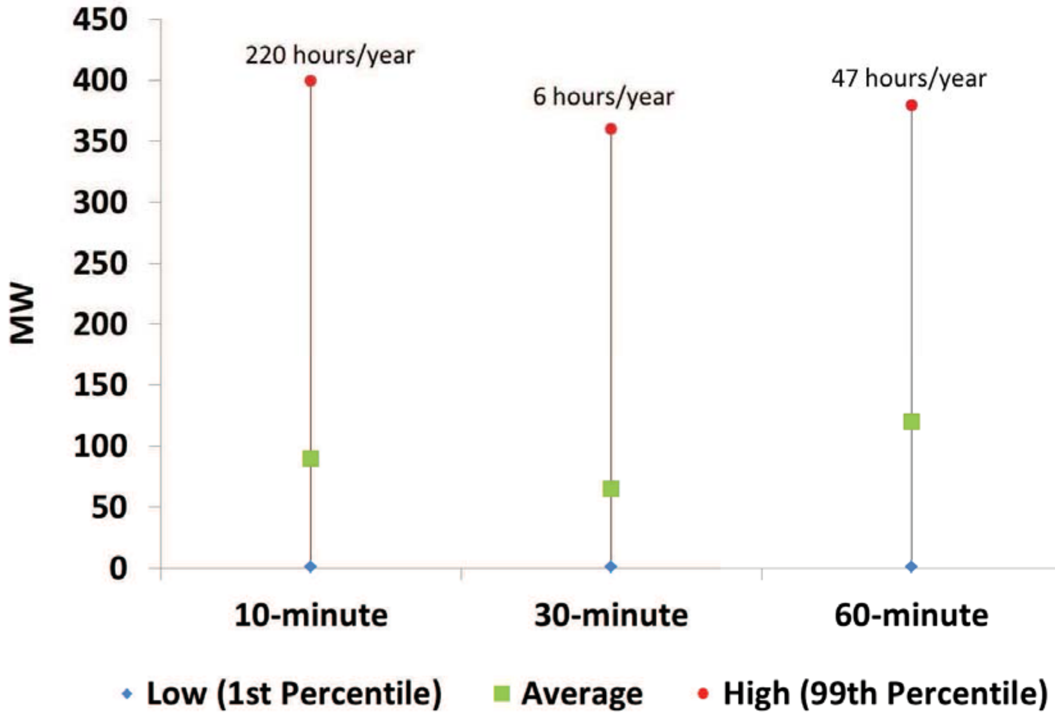


Figure 5. Average and maximum shortfalls in ramping capacity for the 2030 High Solar scenario (and total number of hours in which shortfall exists).

The load-following and regulation requirements give statistical descriptions of what can be expected over the course of the year as VER penetration increases. In the day-ahead and hour-ahead space, VER forecast error becomes important for system operations, requiring additional load-following reserves to be online to compensate for unexpected changes in load and VER output.

Results of the forecast error analysis indicate that:

- Solar power forecast error is the primary driver of additional load-following requirements. Approximately 245 MW per hour—the capacity of a large Castaic unit—are needed to cover 99th percentile forecast errors during the peak-solar hour in the 2030 High Solar scenario (Figure 6).
- Planning for the 95th percentile, rather than the 99th percentile, consistently cuts additional load-following requirements by about one third.

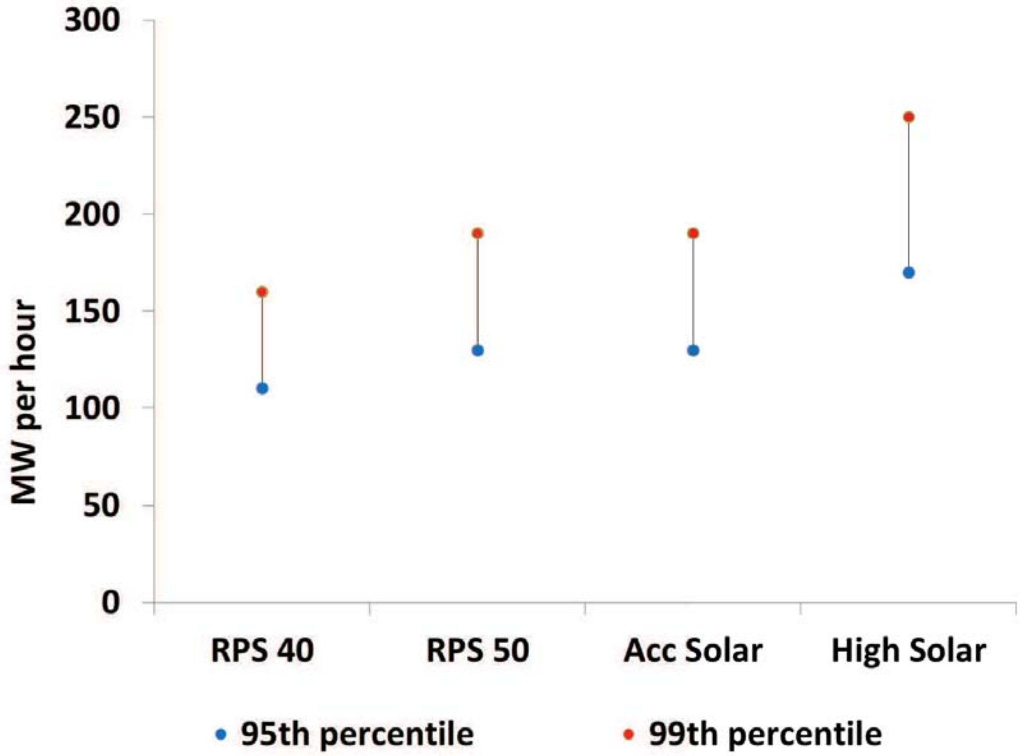


Figure 6. Upward load-following requirements introduced by forecast error for the peak solar hour (1300-1400), 2030.

The consulting team also simulated key system performance metrics under normal operating conditions (non-contingency) as well as under a contingency event (for example, the tripping of a large generating unit). Under normal (non-contingency) conditions, LADWP's existing and planned IRP resources are generally adequate to cope with variability in VER and load:

- Reliability Based Control (RBC) performance is within NERC's maximum 30 minute excursion requirement (Figure 7).[2] Individual ACE excursions outside the RBC limits last up to 18 minutes (i.e., for the uncommon winter scenario-day in the 2025 High Solar scenario.)[3] Operational challenges involving ACE and RBC are shifted to spring and winter days, due to increased VER in these seasons.
- CPS 1 performance shows a decreasing trend over time in all scenarios (Figure 8). CPS1 is acceptable year-round in 2018 and 2021, but falls below acceptable levels at higher VER penetrations and future scenario-

[2] Although a 30 minute RBC excursion limit is currently in use during the NERC/WECC trial use period. DWP has chosen to set an outer target of 10 minutes.

[3] While excursions up to 30 minutes may be acceptable from a NERC compliance viewpoint, the report discusses mitigation options to improve this performance in Task 2.4.

years. Low-load winter and spring days account for the majority of the CPS1 degradation brought on by increased VER. In particular, for low-load winter and spring days at high VER penetration CPS1 falls below the minimum level of 100 percent in some cases.

- The study was conducted for days that are considered common and uncommon from the point of view of power-systems operation. Very rare conditions, representing “a perfect storm,” were not considered in this study.

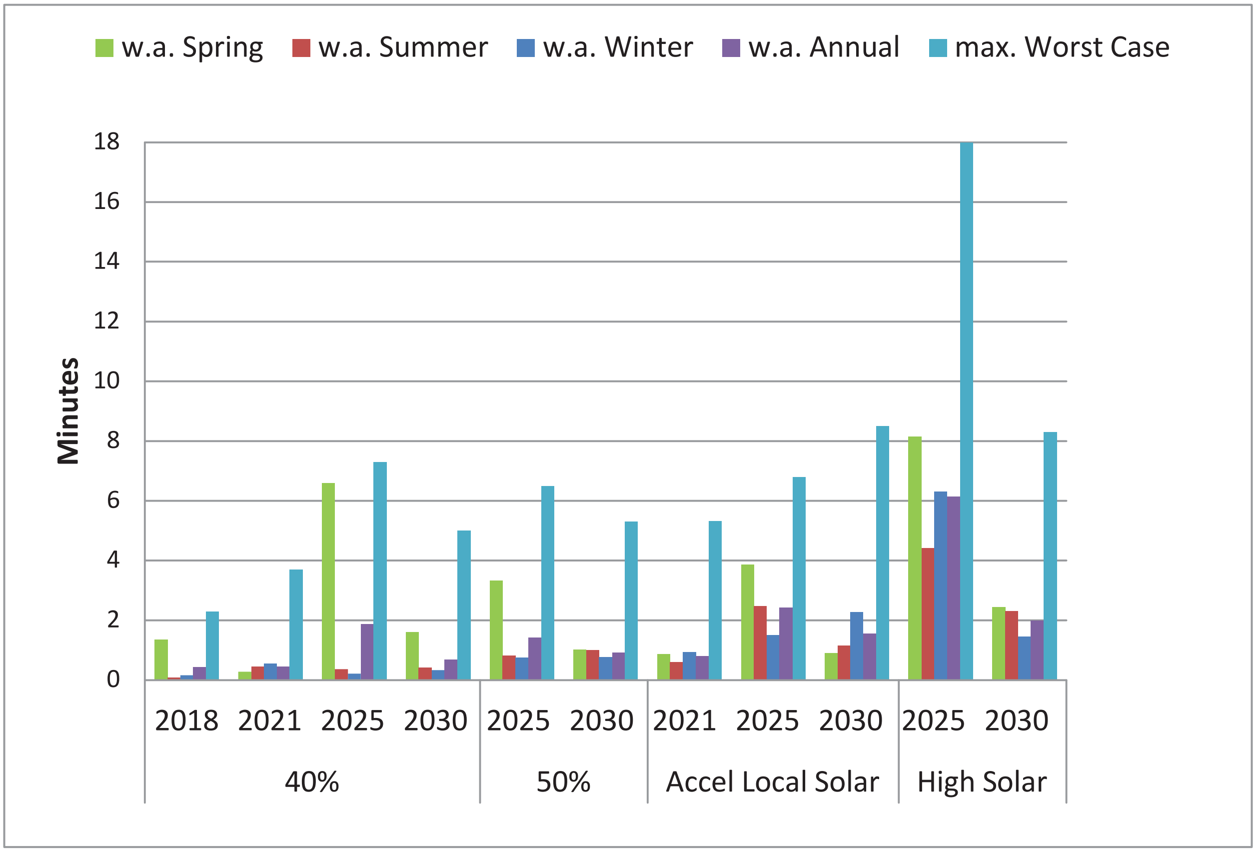


Figure 7. Worst RBC excursions for each scenario-year. The plot shows seasonal weighted averages (w.a.) of common and uncommon days as well as the single worst RBC excursion for the given scenario-year.

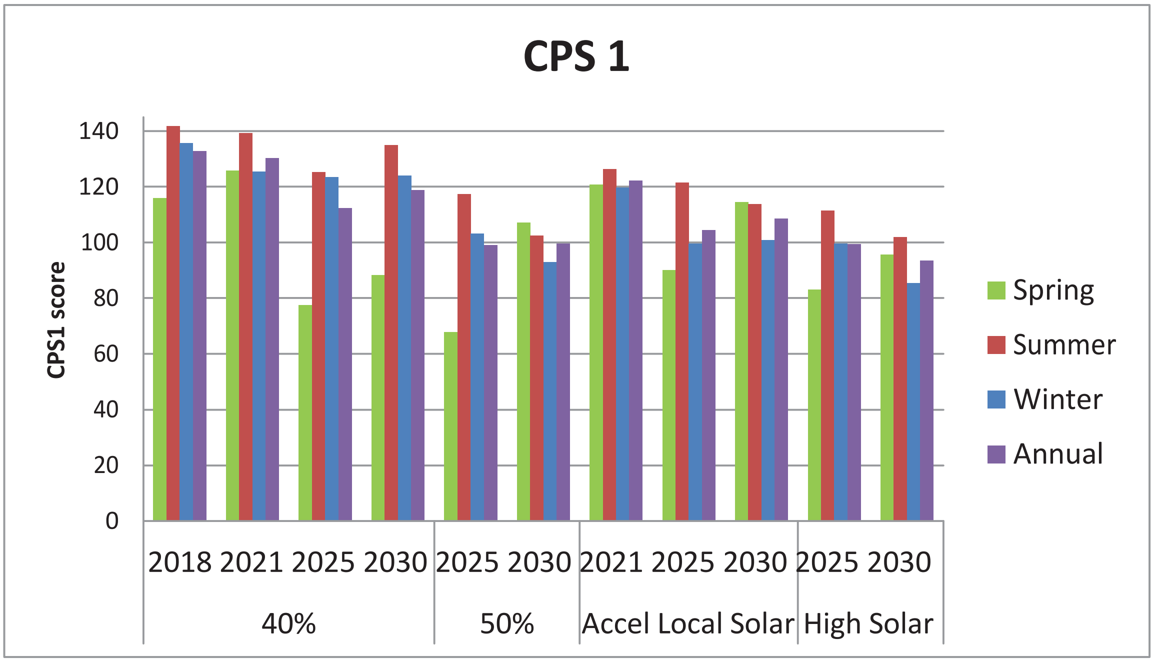


Figure 8: CPS1 results for each scenario-year (weighted average of common and uncommon days).

Under a contingency event, the analyses show that the system still meets minimum performance requirements. Results of the contingency analysis show that:

- Typical area control error (ACE) recovery time is around 6 to 7.5 minutes.
- Castaic is a critical resource for restoring DWP's resource balance/reserves.
- Absent Castaic, the recovery time could stretch to more than 15 minutes (introducing a risk of NERC Disturbance Control Standard (DCS) violations).
- Three percent of the selected scenario-days did not have adequate generation resources to fully recover from the contingency event unless Castaic continues to operate for more than one hour following the event.

It should be noted that these results cover only the specific scenarios analyzed and do not represent a worst case scenario. The assessment does not include any analysis of composite days wherein challenging system conditions compound or persist over longer periods of time.

To improve and restore the system's ability to handle higher levels of VERs, energy storage was examined as an option to mitigate the impact of VERs on LADWP's system. Operation of a 50 MW/1 MW-hour device was simulated to respond to increased regulation requirements. In the modeling of system frequency and ACE, both the baseline energy storage portfolio proposed in the IRP (110 MW for 1 hour) and a range of energy storage sizes were considered in order to quantify the storage size necessary to address future system performance needs. The results show that:

- A 50 MW/1hour energy storage system can fulfill the majority of hourly regulation requirements (measured by energy), except for up-regulation during the afternoon ramp.
- The proposed IRP portfolio for energy storage improves ACE and RBC performance, but under contingency conditions, the improvement is marginal due to the limited size (110MW or less) of the energy storage.
- 30 MW of battery energy storage (BES) would be needed to reduce the maximum RBC excursion time from 18 minutes down to 8 minutes, well below the 10 minutes set as a target by LADWP (Figure 9). Systems greater than 50 MW provide limited additional reduction in RBC.
- A 60 MW (or smaller) storage device is not sufficient to impact contingency recovery.

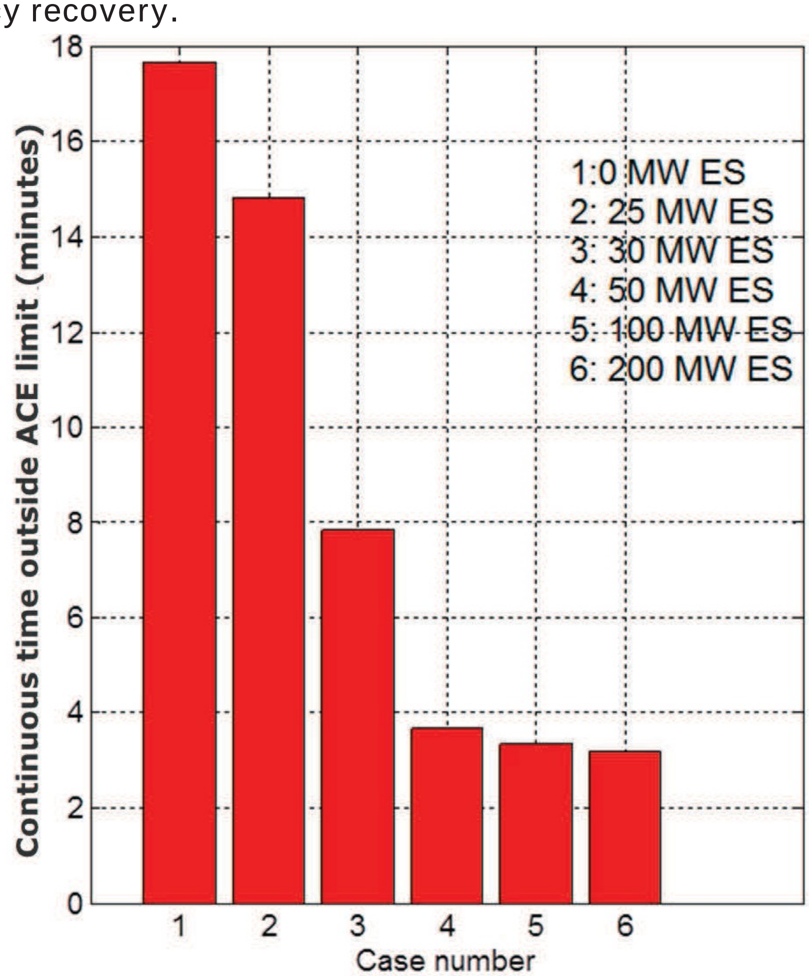


Figure 9. The effect of battery energy storage on RBC excursions.

Based on the analyses and findings in this study, the consulting team offers the following recommendations:

- It is recommended that LADWP adopt a multi-dimensional metric for flexibility reserves and implement ECC tools that will allow ongoing assessment of hourly needs and availability of such reserves. By having access to such tools, the ECC is likely to better anticipate real-time changes in the need for flexible resources, load following and ramping needs, and thereby be able to reduce the amount of committed resources relative to a situation without such real-time tools. The metric would incorporate real-time system parameters such as VER forecast (both energy and variability), system headroom and legroom, ramping capability, transmission constraints, unit availability, and demand-response capability, on an hour-ahead or better time-resolution.
- The cost-effectiveness of adopting 30-50 MW of battery storage should be considered for regulation. This level of storage can significantly reduce large RBC excursions and fulfill the majority of regulation requirements introduced by increased VER. This level of storage cannot, however, fulfill load-following requirements or contribute in a meaningful way to manage contingencies.
- Consider the cost-effectiveness of alternative flexible resources such as
    - Fast-start gas generation to compensate for extreme afternoon ramps in load-less-VER and provide regulation
    - Two-way demand response (providing the ability to both increase and decrease load)
    - VER curtailment, to the point at which the cost of forgone energy production outweighs the benefit of avoided regulation requirements
    - Smart EV charging with strong time-of-use incentives to discourage charging during the early evening ramp
    - Behind-the-meter energy conservation programs with a storage component
    - New software tools at the LADWP control center to analyze sub-hourly operational requirements.

  The best mitigation portfolio, from the perspectives of both cost and reliability, will consist of a balance of these options. While some of them fulfill the same role—with fast-start generators and demand response both mitigating drops in VER output, for example—others are complementary. Energy conservation programs and storage, for example, would help shift and decrease peak load on a day-to-day basis rather than mitigating the fast fluctuations introduced by VER.

- Evaluate participation in CAISO's Energy Imbalance Market (EIM) as an additional means of managing VER variability.
- Evaluate the optimal location of mitigation devices such as storage in LADWP's system. For example, locating storage near renewables can alleviate transmission congestion but sacrifices the smoothing effect of aggregating VER system-wide.
- Investigate the system frequency and ACE under a longer lasting and possibly compound set of system challenges (composite days) in order to gain further insight into the stability of the system under challenging conditions.
- Reconsider RMR minimums in light of the support that lower levels can give to mitigating curtailment and quantify the benefit of reduced RMR in the future high-VER system when planning transmission investments

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Appendix K Energy Storage

K.1 Introduction

This Appendix K provides an overview of grid-scale energy storage (ES) systems followed by a copy of a September 2014 resolution by the Water and Power Board of Commissioners regarding energy storage procurement targets.

K.2 Background

On February 7, 2012, the LADWP's Board of Commissioners (Board) initiated a process by directing LADWP to determine appropriate targets, if any, for LADWP to procure viable and cost-effective Energy Storage System (ESS) by December 31, 2016 and December 31, 2021 pursuant to AB 2514 which became effective on January 1, 2011. In addition, LADWP shall report back to the Board prior to October 1, 2014, regarding potential procurement targets, if any, for LADWP to procure technologically viable and cost-effective ESS, at which time the Board may determine whether it is appropriate to adopt such targets.

K.3 Scope and Objectives

To conform to AB 2514 Requirements, LADWP has developed an analytical framework from which energy storage targets will be deduced which includes an evaluation of existing eligible energy storage systems and two energy storage procurement target development approaches. The first approach referred to as "Selected Location Energy Storage Evaluation" identifies specific locations in the power system where ESS may be the most useful and will be used to set ESS procurement targets for 2016, and if any, preliminary ESS procurement targets for 2021. The second approach called "Whole Power System Energy Storage Evaluation", will be used to refine the ESS procurement target for 2021, including an investigation as to whether ESS can be integrated at all levels of the power system namely, generation, transmission, distribution, and behind-the-meter for the purposes of (i) integrating renewable energy, (ii) reducing peak load demand, (iii), deferring power system upgrades, and (iv) improving the overall system reliability. LADWP energy storage development timeline and strategy are presented in Figure K-1 and Table 1 below, respectively.

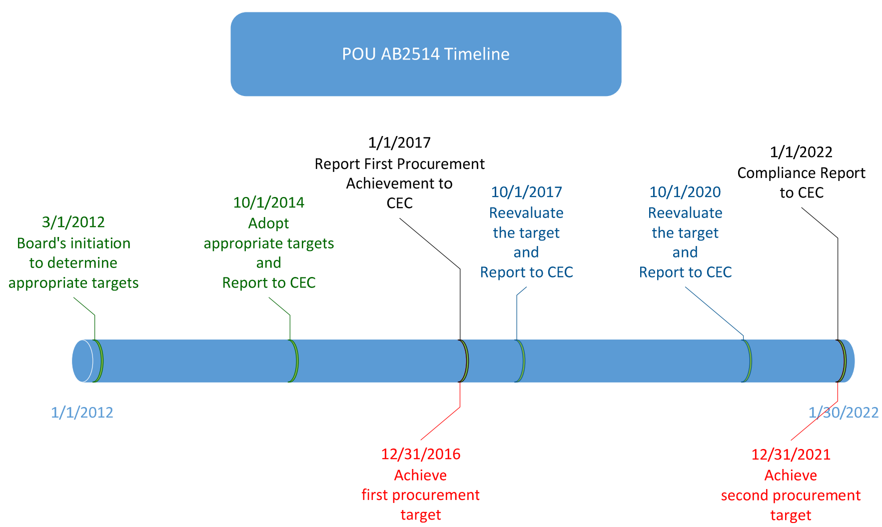

Figure K-1: POU AB2514 Timeline.

Table K-1: Energy Storage System Development Strategy

STRATEGY	TASK
LADWP Efforts	➢ Discussion with Subject Matter Experts ➢ Research relevant topics ➢ Participate with Industry working groups ➢ Working with Consultants, EPRI and B&V o Selected Location Energy Storage Evaluation • Generation Level • Transmission Level • Distribution Level • Behind-the-Meter Level o Power System Evaluation • Maximum Distributed Renewable Energy Penetration • Maximum Generation Renewable Energy Penetration o 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

K.4 Description of Existing Energy Storage System

K.4.1 Large Hydroelectric Plant (Castaic)

Castaic power plant is a seven unit Pump Storage Hydroelectric (PSH) plant owned and operated by LADWP located near the Castaic Lake, California approximately 22 miles north of the Los Angeles upper city limits. Castaic Power Plant is the largest LADWP's hydroelectric resource and the most widely used form of energy storage within the utility sector. It provides energy storage in the form of water stored in Pyramid Lake reservoir on the west bank 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 (1 through 6) rated at 250-MW each before recent upgrades and one conventional unit (Unit 7) rated at 56 MW. Units 1 through 6 function as pumps as well as generators, whereas Unit 7 is an auxiliary unit. Prior to recent upgrades, Castaic Power Plant was rated at 1,175 MW however, these recent upgrades have increased the plant installed capacity to 1,247 MW. This large capacity reflects the nature of Castaic Power Plant as an effective resource to manage variations in supply and demand. Table 2 below provides additional information on recent upgrades to Castaic Power Plant.

Table K-2: 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. As an LSE, LADWP utilizes Castaic Power Plant to store hundreds of megawatts, which makes it an ideal technology for load leveling and peak shaving. Castaic Power Plant provides valuable ancillary services to LADWP as a BA to ensure the reliability of power system and especially during LADWP's most challenging hours (hot summers), including (i) the ability to help balance load with generation, (ii) the ability to integrate intermittent energy resources, and (iii) the ability to provide crucial ancillary services to the grid namely, reactive power support, regulation and frequency support service, operating reserve services (both spinning and supplemental). Because Castaic Power Plant is such a large plant with enormous dependable generating capacity, representing nearly 1.25-GW, it plays a crucial role in meeting LADWP resource adequacy, improving system-wide reliability, and integrating renewable energy resources now and in the future, its presence in LADWP's generating mix will significantly impact LADWP future ESS procurement targets.

K.4.2 Thermal Energy Storage (TES) System

The LADWP has promoted TES technology to its customers since the early 1990s and has paid incentives for the successful installations of TES systems during the last ten years. Two specific examples include the University of Southern California (USC) and the University of California at Los Angeles (UCLA), together representing 9 megawatts of peak demand reduction. The result was an improvement to LADWP's load factor, shifting customer load from the peak to the base period. In addition, this technology reduced peak in-basin generation, and accompanying emissions of Nitrous Oxide (NOx). Table 3 below provides a list and size of existing thermal ice storage systems in LADWP's service territory.

Table K-3: Completed TES Pilot Projects

Facility Name	System Requirements	Project In-Service Date	Peak Reduction Capacity
McDonalds	(2) 10 Ton RTU (2) 12.5 Ton RTU	7/7/2008	30 kW
Taix Restaurant	(1) 3.5 Ton RTU (1) 4.5 Ton RTU	12/1/2005	4 kW
LADWP Boyle Heights Facility	(1) 10 Ton RTU	10/27/2005	6 kW
University of Southern California (USC)	(1) TES Tank (4) Pumps	1/30/2006	4,375 kW
University of California, Los Angeles (UCLA)	(1) TES Tank (6) Pumps	6/15/2004	4,668 kW
		Total =	9,083 kW

K.5 Description of Eligible Energy Storage System

K.5.1 Eligibility Criteria

AB 2514 establishes a statutory definition of “energy storage system,” which will mean “commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy.” The system must use “mechanical, chemical or thermal processes to store energy” or store thermal energy for direct use for heating and cooling at a later time. The system may be centralized or distributed, and may be owned by a load-serving entity, a customer, or a third party. To be an eligible ESS, the system has to be installed and first becomes operational after January 1, 2010. Pumped hydroelectric systems, may not be greater than 50 MW. In addition, ESS 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 the above eligibility criteria, LADWP has identified the following ESS that will be used toward 2016 procurement target deadline.

K.5.2 Castaic Hydroelectric Power Plant Unit 1

Although Castaic Hydroelectric Power Plant is larger than 50 MW, it 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 that reason, LADWP will only claim incremental Castaic Power Plant upgrades in excess of the existing capacity provided that such excess (i) does not exceed a 50 MW capacity limit on pumped storage, and (ii) first became operational after January 1, 2010. Table K-4 below provides a summary of Castaic Hydroelectric Power Plant Unit 1 capacity gain and performance improvements.

Table K-4: 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

K.5.3 Approved Thermal Energy Storage (TES) Project

The LADWP's commitment to achieving aggressive energy efficiency goals emphasizes a compelling need to promote innovative programs that save both energy and reduce demand. The proposed TES incentive amount is $750 per kilowatt of demand shifted, a level that will encourage customers to install TES systems while comparing favorably to both the cost of adding generation capacity and to implementing demand response programs. Additionally, a TES system, unlike added generation capacity, is owned, operated, and maintained by the customer. Based on marginal cost studies, the average benefit-to-cost savings ratio (value achieved for every dollar spent) for the proposed program incentive is approximately 3:1. Examples of customers under the TES incentive program used as a Permanent Load Shifting (PLS) are listed in Tables K-5. In line with this, LADWP has approved a onetime incentive plan for the Los Angeles International Airport (LAX), a large customer in LADWP's service territory, to use thermal energy ice storage system to achieve PLS. The approved project requires that a TES be installed to reduce electrical demand. Table K-5 below provides a summary of LAX's approved TES age.

Table K-5: Approved LAX TES Project Summary

Owner/Operator	LAX
Utility	LADWP
System	TES
Location	LAX
Shifted Capacity	3,025 kW
Operational Status	No later than 2016
Primary Benefit	Annual energy saving of 2,477,681 kWh
Secondary Benefit	Minimize LADWP Peak demand
Incentive Level Cost	$750/kW shifted or 50% of TES Installed Cost = $2,022,000

LADWP is conducting a series of studies to investigate ESS applications in LADWP's service territory. In one of these studies, LADWP will assess the impact of deploying behind-the-meter TES on LADWP's resource adequacy and system reliability while taking into consideration the Renewable Portfolio Standards (RPS) goal which requires electric utility to provide 33% of electric energy sales from renewable by 2020. Findings from this study will provide among other things (i) a measure of the avoided cost of acquiring a new gas-fired power plant as a result of generation capacity displaced by TES, (ii) the cost benefit of deploying behind-the-meter TES in LADWP's service territory, and (iii) the means to design a standardized PLS program based on a standard offer (similar to the LAX project above) with common design rules. The purpose of the PLS incentive program is to help offset the cost of initial implementation of PLS technologies. Table 6 below provides a summary of all eligible energy storage systems that will be used towards LADWP's 2016 ESS procurement target.

K.5.4 Pilot Energy Storage Project

LADWP is currently conducting two pilot projects in the LADWP's service territory on Battery Energy Storage System (BESS). The first project is a 25 kW BESS called "Garage of the Future" located at UCLA. The second project called "La Kretz Innovation Campus Project (LA Downtown)" is a 50 kW to 200 kW BESS project located at the 525 S. Hewitt Street construction site. The purpose of these projects is to investigate how well BESS can be applied to the micro grid system to integrate distributed renewable energy resources for the purpose of promoting energy savings for LADWP's customers and increasing energy efficiency.

Table K-6: ESS 2016 Target Summary

Connection Level	System Type	Capacity
Transmission	Pump Hydroelectric Storage	21 MW
Distribution	None	0
Customer	Thermal Energy Storage Sytem	3 MW
	Battery Energy Storage System	75 Kw
	Total =	24.08 MW

K.6 Energy Storage System Evaluation Methodology

To determine whether a ESS is cost-effective and viable, LADWP first evaluated the existing and eligible ESS's that could be counted toward LADWP ESS procurement targets and then selected two approaches to determine whether additional ESS procurement targets are technologically viable and cost-effective.

1. Selected Location Energy Storage Evaluation – Identifies specific locations within the Power System where ESS may be the most useful and will contribute towards ESS procurement targets. To accomplish this evaluation, LADWP contracted with Black & Veatch, Electric Power Research Institute (EPRI), and consulted with Southern California Public Power Authority (SCPPA) subject matter experts.

   Whole Power System Energy Storage Evaluation – Will be used to refine the ESS procurement target for 2021, investigate whether ESS can be integrated at all levels within the Power System namely, generation, transmission, distribution, and behind-the-meter for the purposes of (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 is in the process of issuing two study task scopes to third parties.

The process described above and detailed in the LADWP Energy Storage Development Plan is illustrated in Figure K-2 below. This plan forms the analytical framework from which LADWP will determine its ESS procurement targets for 2016 and 2021 with a reevaluation process occurring once every three years aimed at refining proposed ESS targets.

Energy Storage System Target Development Process

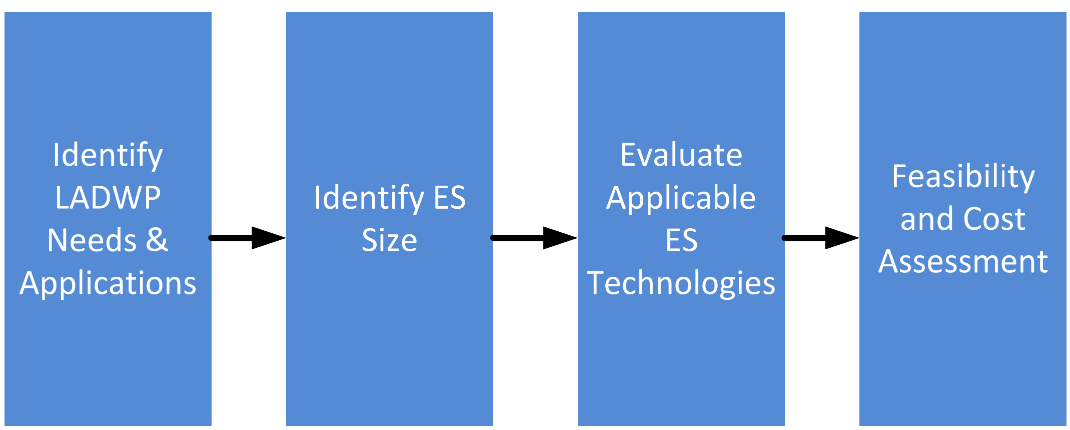

Figure K-2: ESS Target Development Process.

Each ESS technology will be selected based on connection level and type of the application.

K.7 Energy Storage System Technology

The value of energy storage technologies lies in the services that they provide at different locations within theLADWP power system, including electricity to electricity, electricity to thermal, and thermal to electricity applications. This Appendix K includes discussion of storage technologies in the context of these applications. Locations in the power system are termed as generation (supply), transmission and distribution, and end-use (demand). In addition to Castaic pump storage and TES described above, the following energy storage system will also be considered.

K7.1 Generation Thermal Energy Storage Solutions

During the summer peak demand, Combustion Turbines and Combined Cycle plants operate at lower capacity due to higher temperature of inlet air. Generation TES would chill stored water during off-peak night hours when the cost of energy is cheaper. The chilled water would be stored in a TES tank. During on-peak hours Combustion Turbine and Combined Cycle plants would produce more electricity by reducing inlet temperature using stored chilled water. The flow of the water can be adjusted to provide regulation up and down. Valley Generating units 5, 6, and 7 have been identified as potential candidates to be retrofitted with a Generation TES capacity of 60 MW to offer the following benefits:

- Capacity contribution
- Capital deferment for new fossil fuel-power peaking generation
- Peak shaving
- Peak shifting
- Ancillary services
- Reduced cycling cost at thermal generation plants
- Renewable energy integration support

K7.2 Flow Battery Energy Storage Solutions

Flow battery, or Redox flow battery, is a type of rechargeable battery where rechargeability is provided by two chemical components fully dissolved at all times in liquids contained within the system and separated by a membrane. Flow batteries essentially comprise two key elements: cell stacks, where power is converted from electrical form to chemical form, and tanks of electrolytes where energy is stored. The most popular flow battery on the market uses vanadium redox technology - using charged vanadium in a diluted sulfuric acid solution to store energy. Potential candidates for flow battery ESS deployments include Beacon Solar and Q09 Solar projects estimated at 50-MW combined and a smaller distribution system project estimated at 4-MW at present. The appeal of flow batteries for grid applications is that they combine the strengths of both conventional batteries and fuel cells and include the following benefits:

- Ramping

- Peak shaving
- Time shifting
- Frequency Regulation
- Power quality

K7.3 Lithium-Ion Battery Energy Storage Solution

A lithium-ion battery (sometimes referred to as Li-ion battery or LIB) is a member of a family of rechargeable battery types in which lithium ions move from the negative electrode to the positive electrode during discharge and back when charging. Li-ion batteries use an intercalated lithium compound as the electrode material, in contrast to the metallic lithium used in a non-rechargeable lithium batteries. The electrolyte which allows for ionic movement and the two electrodes are the primary components of a lithium-ion cell. Lithium-ion applications include:

- Power quality
- Deferral distribution infrastructure upgrade
- Peak shifting downstream of distribution system
- Intermittent Distributed generation integration
- Micro-Grid formation

Potential locations for deploying Li-Ion battery ESS include:

- Transmission Connected ESS (Beacon Solar and Q09 Solar Projects)
- Distribution Connected ESS (Receiving and Distribution Stations) 4-MW

K7.4 Distributed Thermal Energy Storage System

TES systems use conventional air conditioning equipment and a storage tank to shift the majority of electricity used for space cooling in customer facilities from peak to off-peak periods. TES systems produce ice or chilled water during off-peak periods that is stored in a tank and then circulated during peak periods to produce the desired cooling. TES system installations can be an effective alternative to supply side strategies (adding generation capacity) and/or demand response programs needed to reliably meet the LADWP's peak electrical load growth. LADWP is currently evaluating a TES Incentive Program with a capacity of 40-MW. The TES Incentive Program is consistent with LADWP's Board-approved efficiency programs that promote the efficient use of electrical energy.

Creating incentives for customers that combines Energy Efficiency and Demand Response will add greater value to behind-the-meter TES. Customers may earn additional savings by being on the Time-of-Use program. Behind-the-meter TES is fully dispatchable and utilities can use this form of ESS to mitigate over-generation during high penetration levels of variable energy resources (See Figure K-3).

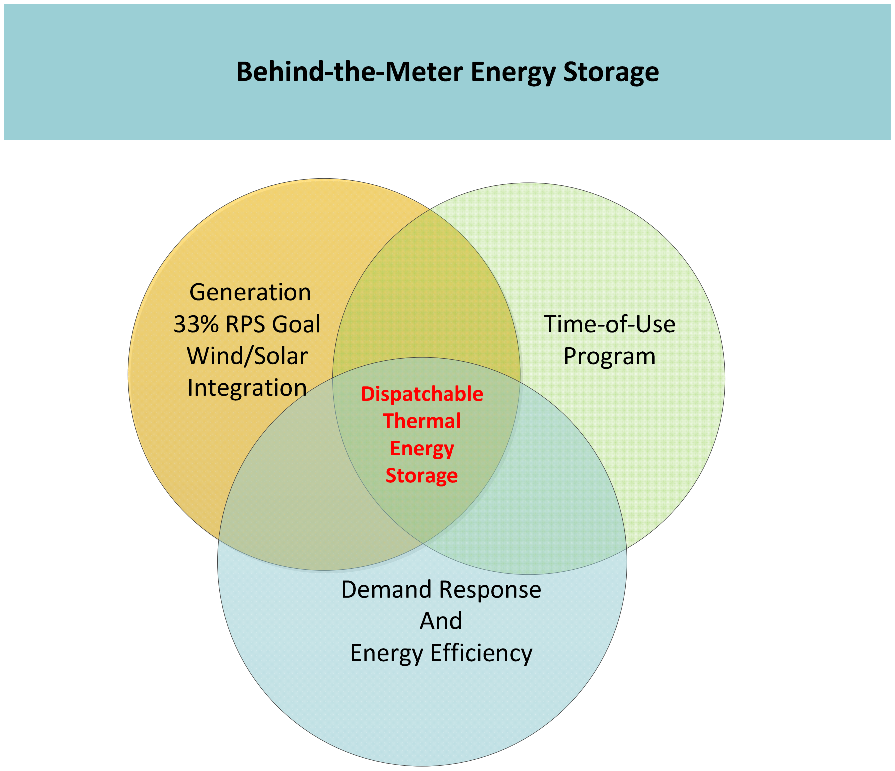

Figure K-3: Multiple Usage of Behind-the-Meter-Energy Storage

K.8 ESS Summary Targets

Table K-7: ESS Summary of Targets

CONNECTION LEVEL	Existing TARGETS			PROPOSED TARGETS					
	PRE 2010			2016 TARGETS			2021 TARGETS		
	Project Name	Energy Storage Type	Capacity	Project Name	Energy Storage Type	Capacity	Project Name	Energy Storage Type	Capacity
GENERATION	Castaic	Pump Storage Hydro	1275 MW	Castaic	Pump Storage Hydro	21 MW	Valley Generating Station	Thermal Energy Storage	60 MW
		Sub-Total	1275 MW		Sub-Total	21 MW		Sub-Total	60 MW
TRANSMISSION	None			None			Beacon Solar Project	Battery Energy Storage	30 MW
							Q09 Solar Project	Battery Energy Storage	20 MW
								Sub-Total	50 MW
DISTRIBUTION	None			None			Distribution Circuit	Battery Energy Storage	4MW
								Sub-Total	4 MW
CUSTOMER	UCLA	Thermal Energy Storage	4.375 MW	LAX	Thermal Energy Storage	3 MW	Distributed Energy Storage System	Thermal Energy Storage	40 MW
	USC	Thermal Energy Storage	4.668 MW						
	TAIX	Thermal Energy Storage	.004 MW	LA Downtown (Pilot)	Battery Energy Storage	.05 MW			
	LADWP Boyle Heights Facilities	Thermal Energy Storage	.006 MW	Garage of the Future (Pilot)	Battery Energy Storage	.025 MW			
	McDonald	Thermal Energy Storage	.03 MW						
		Sub-Total	9.08 MW		Sub-Total	3.08 MW		Sub-Total	40 MW
		TOTAL	1284.08 MW		TOTAL	24.08 MW		TOTAL	154 MW

K8.1 Energy Storage Targets for 2021

Generation

Thermal Energy Storage

Location: Valley Generating Station

Capacity: 60MW or greater

Completion by December 2017

Estimated Cost: $24 Million

Key Applications:

- Increase CT output during hot weather 10%-20%
- Peak Shifting
- May eliminate need for a new power plant
- Ramping Regulation Capacity

Key Actions:

- Complete Maximum Generation Renewable Energy Penetration Study (MGREPS)
- Complete Feasibility Study
- Seek Managerial Approval of Proposal
- Award Contract
- Construction and Installation
- Measurements and Commissioning

Transmission

Battery Energy Storage System

Location: Beacon & Springbok Area Solar

Capacity: 50MW or greater

Completion by December 2020

Estimated Cost: $95.6 Million

Key Applications:

- Regulation Service (ramping up & down)
- Solar Power Output Leveling

Key Actions:

- Complete Maximum Generation Renewable Energy Penetration Study (MGREPS)
- Complete Feasibility Study

- Peak Shaving

- Seek Managerial Approval of Proposal
- Award Contract
- Construction and Installation
- Measurements and Commissioning

Distribution

Battery Energy Storage System

Location: Distributing and Receiving Stations (DS and RS)

Capacity: 4MW or greater

Completion by March 2019 for DS and September 2020 for RS

Estimated Cost: $7.7 Million

Key Applications:

- Peak Shaving
- Distributed PV Solar Integration
- Distribution Infrastructure Upgrade Deferral

Key Actions:

- Complete Maximum Generation Renewable Energy Penetration Study (MGREPS)
- Complete Feasibility Study
- Seek Managerial Approval of Proposal
- Award Contract
- Construction and Installation
- Measurements and Commissioning

Customer

Thermal Energy Storage

Location: Overloaded Feeders and Circuits

Capacity: 40MW or greater

Completion by July 2020

Estimated Cost: $33 Million

Key Applications

- Permanent Load Shifting
- Dispatchable Peak Shifting
- Differing Distribution Infrastructure Upgrades
- Demand Response
- Energy Efficiency

Key Actions

- Complete Feasibility Study
- Seek Managerial Approval of Proposal
- Award Contact
- Conduct Survey
- Construction and Installation
- Measurements and Commissioning

Pilot Project—JFB Energy Storage System

Battery Energy Storage System

Location: John Ferraro Building (JFB)

Capacity: 300KW/1MWH

Completion by June 2016

Estimated Cost: $4 Million

Key Applications	Key Actions
• Demand Response	• Feasibility Study ✓
• Dispatchable Peak Shifting	• Managerial Approval of Proposal
• Energy Management System	• Award Contact
• Technology Evaluation	• Construction and Installation
• Research and Development	• Measurements and Commissioning

K8.1 2021 Energy Storage Procurement Roadmap Targets

The 20121 Energy Storage Procurement Roadmap highlights key phases of the LADWP Energy Storage Procurement Plan.

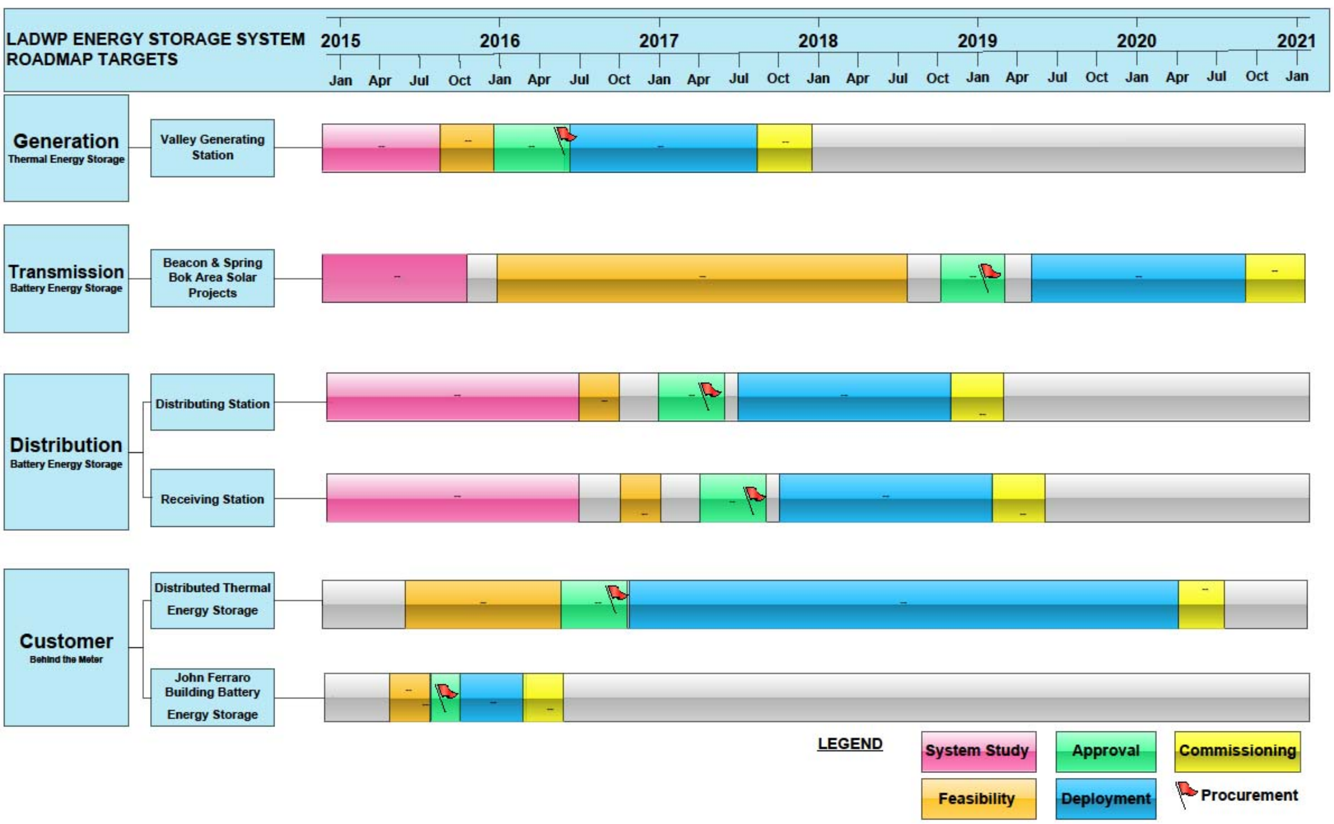

Figure K-5: ESS Procurement Roadmap Targets

K.9 Procurement Mechanism

LADWP may procure ESS through three main mechanisms:

- Utility-Owned
- Customer Incentive Programs
- Collaborative Ownership

1. Utility-Owned

LADWP may procure generation, transmission, and distribution connected ESS primarily through its competitive solicitation process. Under this process, LADWP will make a solicitation through a bidding process by issuing a Request for Proposal (RFP) to potential suppliers to submit ESS procurement proposals. The RFP outlines the bidding process and contract terms, and provides guidance on how the bid should be formatted and presented. A RFP is typically open to a wide range of bidders, creating open competition between companies looking for business opportunities. To issue an RFP, LADWP follows the following guidelines including, but 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 distribution and responses, (iv) ensuring the vendors are responsive to the bid and ensuring that vendors response is consistent with the identified requirements, and (v) following LADWP's evaluation and selection procedure to ensure impartiality in the awarding process.

2. Customer Incentive Program

LADWP may acquire behind-the-meter ESS primarily through its TES incentive program to permanently shift load. As defined by CPUC Resolution E-4586, "Permanent Load Shifting" refers to the shifting of energy usage from one period of time to another on a recurring basis, often by storing energy produced during off-peak hours and using the energy during peak hours to support loads. PLS technology of interest under this incentive program is mostly ice storage. Ice storage systems use a standard chiller to produce ice overnight which is stored in tanks. The stored ice is used to cool buildings the following day. This type of energy storage is especially important since conventional cooling equipment consumes significant amounts of energy and inopportune electricity demands during summer peaks. It is anticipated that the TES incentive program will provide more efficient use of underutilized night time generation and enhance the integration of variable energy resources by absorbing over-generation when loads are low. Energy from ice is fully dispatchable and can offset intermittent availability associated with variable energy resources. Under the current incentive program, the customer receives $750 per kW shifted when the ESS permanently displaces customer demand peak to other times. The incentive is capped at 50% of the total eligible project costs. However, this TES incentive program may need to be restructured to maximize its value to both customers and the utility by combining efforts from both Energy Efficiency and Demand Response programs.

3. Collaborative Ownership

LADWP has successfully procured many projects through SCPPA which encourages joint ownership among its members.

SCPPA's Request for Proposal was issued on February 1, 2014 with a response deadline of December 31, 2014. LADWP will be actively looking for collaborative opportunities with SCPPA members for ESS procurement projects. RFP responders may propose:

- Project ownership by SCPPA
- Power purchase agreement or an equivalent commercial agreement with an ownership option, or
- Power purchase agreement or an equivalent commercial agreement without an ownership option

As a "rolling RFP" SCPPA reserves the right to contact proposers at any time to start negotiations, and to execute one or more agreements before the proposal deadline.

K.10 Rate Recovery

The procurement of ESSs described herein will have a significant impact on LADWP's power system both operationally and financially. On the one hand the integration of these ESSs into the grid may improve the overall system reliability especially with the integration of renewable energy resources. On the other hand these systems may add complexity to the day to day operation of the LADWP bulk power system. ESS procurement also requires significant capital investment. Securing these investments in turn may require a rate increase for LADWP customer. While the rates and charges of investor-owned utilities (such as PG&E, SCE, and SDG&E) are approved at the state level, those decisions for LADWP are made at the local government level by the Los Angeles City Council. To seek the approval of the energy storage procurement targets from LADWP's Board of Commissioners, LADWP has to 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 saddle ratepayers with unnecessary costs for ESSs that do not have direct utility or customer benefits. These guidelines form the basis for LADWP energy storage procurement targets.

LA DWP Los Angeles Department of Water & Power

RESOLUTION NO. ____________

BOARD LETTER APPROVAL

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DATE: August 25, 2014

SUBJECT: Los Angeles Department of Water and Power's (LADWP's) Energy Storage System (ESS) Procurement Targets

SUMMARY

California Assembly Bill 2514 (AB 2514) requires that all California Electric Utilities, such as LADWP establish technologically viable and cost-effective ESS Procurement Targets to be achieved by December 31, 2016, and December 31, 2021. LADWP will report to the California Energy Commission (CEC) the adoption of these targets, if any, by October 1, 2014.

City Council approval is not required.

RECOMMENDATION

It is recommended that the Board of Water and Power Commissioners (Board) adopt the attached Resolution authorizing the implementation of the LADWP ESS Targets for procurement in 2016 and 2021 delineated in Table 1 below. Staff also recommends procurement targets be revisited every three years. Energy storage is a viable technology to allow greater penetration of renewable energy integration LADWP has considered the use of energy storage in its Integrated Resource Plan (IRP) and operates Castaic Power Plant (one of the largest pump-storage projects in the Country).

Table 1: Procurement Targets to be established by the Board

CONNECTION LEVEL	PROPOSED TARGETS					
	2016 TARGETS			2021 TARGETS		
	Project Name	**Energy Storage Type**	**Capacity**	**Project Name**	**Energy Storage Type**	**Capacity**
GENERATION	Castaic	Pump Storage Hydro	21 MW	Valley Generation Station	Thermal Energy Storage	60 MW
		Sub-Total	**21 MW**		**Sub-Total**	**60 MW**
TRANSMISSSION	None			Beacon Solar Project	Battery Energy Storage	30 MW
				Q09 Solar Project	Battery Energy Storage	20 MW
					Sub-Total	**50 MW**
DISTRIBUTION	None			Distribution Circuit	Battery Energy Storage	**4 MW**
					Sub-Total	**4 MW**
CUSTOMER	LAX	Thermal Energy Storage	3 MW	Distributed Energy Storage System	Thermal Energy Storage	40 MW
	Garage of the Future (Pilot)	Battery Energy Storage	.025 MW			
	LA Downtown (Pilot)	Battery Energy Storage	.05 MW			
		Sub-Total	**3.08 MW**		**Sub-Total**	**40 MW**
		TOTAL	**24.08 MW**		**TOTAL**	**154 MW**

All 2016 ESS procurement targets were approved by the Board on February 7, 2012, Resolution No. 012-168 (attached).

ALTERNATIVES CONSIDERED

Historically, it has been difficult to evaluate benefits that ESS provides to the grid, not only due to high costs, but also because of the array of services it provides and the challenges posed in quantifying the value of these services, particularly the operational benefits such as ancillary services, and the overall improvement to system reliability. The challenge of modeling energy storage in the grid, estimating its total value, and actually recovering those value streams continue to be a major barrier. However, ESS could be beneficial to the grid especially when short-term demand is high by shaving or shifting peak load, and providing regulation services with increasing variable renewable energy resource penetration. As with the alternative generation technologies, cost will be the primary factor for determining which ESS technologies are suitable for LADWP's grid. Technologies that offer cost-effective applications are proposed for installation at LADWP. Preliminary cost-benefit analyses performed suggests that ESS technologies for procurement by December 31, 2021, are cost-effective when compared to the cost of acquiring a similar size simple cycle turbine. A tabular summary of ESS preliminary analysis is presented in Table 2 below.

Table 2: ESS Installation Cost vs. Small Simple Cycle Installation Cost

TECHNOLOGY TYPE	INSTALLED COST ($/kW)	PROJECT NAME
Small Simple Cycle	1385	N/A
Generation Thermal Energy Storage	400	Valley Generating Station
Thermal Energy Storage (Ice)	825	Distributed ESS
Battery Energy Storage System	1930	Beacon Solar
Battery Energy Storage System	1930	Q09 Solar

Note: Battery ESS is only viable if regulation service is added (see LADWP Energy Storage Development Plan).

FINANCIAL INFORMATION

Funding for the 2016 targets have been already approved by the Board. Therefore, no additional funding is required to reach these targets. Table 3 below is a summary of ESS costs incurred by LADWP:

Table 3: Procurement Cost for 2016 ESS Targets

Project Name	Cost Incurred	Board Resolution Numbers	Date
Castaic Power Plant Unit 1 Upgrade	$41,000,000	001-318	June 19, 2001
		003-102	November 2, 2002
		010-142	November 3, 2009
		010-275	April 6, 2010
		011-309	June 21, 2011
		013-056	September 18, 2012
LAX Thermal Energy Storage Incentive	$2,022,000	009-081	October 7, 2008
Total	**$43,022,000**		

At this present time, actual costs to be incurred by LADWP to achieve the 2021 ESS targets is pending completion of feasibility studies, including procurement costs that might be recommended based on findings from ongoing system studies (see background below). Once these feasibility and system studies are completed, LADWP will reevaluate the established 2021 ESS Procurement Targets and report to the Board and CEC pursuant to Section 2836(b)(4) of AB 2514. Table 4 below, provides estimated installation costs for 2021 ESS procurement targets.

Table 4: Estimated 2021 ESS Installation Costs

CONNECTION LEVEL	PROJECT NAME	STORAGE TYPE	ESTIMATED COST	CAPACITY Megawatt (MW)
GENERATION	Valley Thermal Plant	Generation Thermal Energy Storage	$24,000,000	60 MW
TRANSMISSSION	Beacon Solar	Battery Energy Storage	$57,000,000	30 MW
	Q09	Battery Energy Storage	$38,600,000	20 MW
DISTRIBUTION	34.5 kV Circuit	Battery Energy Storage	$7,720,000	4 MW
CUSTOMER	Customer Side	Distributed Thermal Energy Storage	$33,000,000	40 MW
		TOTAL =	$160,320,000	154 MW

Note: Battery ESS is only viable if regulation service is added (see LADWP Energy Storage Development Plan attached).

No additional funding is required at this present time.

BACKGROUND

AB 2514 became effective January 1, 2011. Under this bill, local publicly owned electric utilities (POUs) such as LADWP are required to initiate a process by March 1, 2012, to determine appropriate targets, if any, to procure viable and cost-effective ESS by certain dates. AB 2514 further requires that if determined viable and cost-effective ESS, this Board shall adopt procurement targets by October 1, 2014, directing LADWP to procure economically viable ESS by the first target date of December 21, 2016, and second target date of December 31, 2021.

On February 7, 2012, the Board approved Resolution No. 012-168 (attached) initiating a process directing LADWP to determine appropriate targets, if any, to procure viable and cost-effective ESS by December 31, 2016, and December 31, 2021. In addition, LADWP shall report to the Board prior to October 1, 2014, regarding potential procurement targets, if any, for LADWP to procure technologically viable and cost-effective ESS, at which time the Board may determine whether it is appropriate to adopt such targets.

LADWP first evaluated the existing and eligible ESS that could be counted toward LADWP ESS procurement targets and then selected two approaches to determine whether additional ESS procurement targets are technologically viable and cost-effective:

1. Selected Location Energy Storage Evaluation - Identifies specific locations within the Power System where ESS may be the most useful and will be used to set ESS procurement targets. To accomplish this approach, LADWP contracted with Black & Veatch, Electric Power Research Institute (EPRI), and consulted with Southern California Public Power Authority (SCPPA) subject matter experts.

2. Whole Power System Energy Storage Evaluation – Will be used to refine the ESS procurement target for 2021, investigates whether ESS can be integrated at all levels within the Power System, namely generation, transmission, and distribution and behind-the-meter for the purposes of (i) integrating renewable energy, (ii) reducing peak load demand, (iii) deferring power system upgrade, and (iv) improving the overall system reliability. To accomplish this approach, LADWP is in the process of issuing two study task scopes to a third party:

   Task Scope 1: <u>Maximum Distribution Renewable Energy Resource Penetration Study</u>

   This study evaluates the impact of the maximum distributed photovoltaic (PV) solar into LADWP distribution system from now through 2020. The study will address whether ESS could be used cost-effectively to eliminate or minimize technical concerns resulting from integrating higher penetration of PV system including, but not limited to grid stability, voltage regulation, power quality (voltage rise, sag, flicker, harmonics, and frequency fluctuation), reverse power flow, and system protection and coordination.

   Task Scope 2: <u>Maximum Generation Renewable Energy Resource Penetration Study</u>

   This study will analyze the impact of high penetration of large scale variable energy resources and distributed solar PV generation on LADWP system balancing requirements including reserve requirements, ramp rate requirements, system reliability and operation requirements (system inertia and frequency response), and generation dispatch strategies. The study will assess whether ESS is an economically and viable alternative to acquiring a simple cycle unit in the event that additional generation capacity is needed to integrate renewable energy resources or improve overall system reliability.

Any viable and cost-effective ESS solutions recommended for procurement from studies described above whether from the first approach or the second will proceed to a feasibility study. The purpose of feasibility is to evaluate whether proposed ESS projects from studies recommendations are technically feasible (electrical, spatial, and environmental constraints) and feasible within the estimated cost.

The process described above forms the analytical framework from which LADWP will determine its ESS targets for procurement in 2016 and 2021 with a reevaluation process occurring once every three years aimed at refining proposed ESS targets described herein. The first reevaluation cycle is scheduled for 2017.

Study and Preliminary Analysis Findings

Selected Location Energy Storage Evaluation Findings

- Studies performed under this category indicate that there is no ESS need within the LADWP system that could be used for the 2016 ESS Procurement Target.

- Findings from the Black & Veatch study indicate that Battery Energy Storage System (BESS) is cost-effective if used to provide regulation service for each large scale solar projects namely, Beacon Solar Project and Q09 Solar Project. For that reason, Beacon Solar Project and Q09 Solar Project are recommended for a feasibility study.

- EPRI study findings which only evaluate one 34.5kV circuit, suggest that a small BESS is not cost-effective. Although it is not cost-effective for the selected circuit, LADWP anticipates that ESS might be viable for other circuits under consideration in the Whole Power System Energy Storage Evaluation. For that reason, a moderate size ESS is recommended for further study.

- Preliminary assessment from LADWP indicates that Generation Thermal Energy Storage if installed at Valley Generating Station is the most cost-effective ESS (Table 2). For that reason, Valley Generating Station is recommended for a feasibility study.

- Preliminary assessment from LADWP shows that thermal energy storage incentive program for Distributed Thermal Energy Storage capped at $750 per Kilowatt (kW) of shifted demand capacity is a cost-effective ESS (Table 2). For that reason, Thermal Energy Storage is recommended for a feasibility study.

Whole System Energy Storage Evaluation Findings

- All studies under this category are still pending. Once completed, identified viable and cost-effective ESS, if any, will proceed to a feasibility study. LADWP anticipates completing studies under this category no later than end of 2015.

Outputs from all feasibility studies described above will be used to revise the LADWP ESS Targets for procurement in 2021 in accordance with 2836(b)(3). LADWP anticipates completing all feasibility studies no later than December 2016.

LADWP ESS Procurement Targets assessment and methodology along with completed, pending study task scopes, and findings are compiled in the LADWP Energy Storage Development Plan attached hereto for your review.

ENVIRONMENTAL DETERMINATION

In accordance with the California Environmental Quality Act (CEQA), it has been determined that establishing ESS Procurement Targets is exempt pursuant to the General Exemption described in CEQA Section 15061(b)(3). General Exemptions apply in situations where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment. Any action or activity that is planned as a result of or to meet said targets will undergo its own, independent CEQA review.

CITY ATTORNEY

The Office of the City Attorney reviewed and approved the Resolution as to form and legality.

ATTACHMENTS

- Resolution
- LADWP Energy Storage Procurement Plan
- Board Letter/Reso No. 012-168

Resolution No. 015 033

WHEREAS, California State Assembly Bill 2514 (AB 2514) became law on January 1, 2011, requiring the governing board of a local publicly owned electric utility, such as the Los Angeles Department of Water and Power (LADWP), to initiate a process by March 1, 2012, to determine appropriate targets, if any, for LADWP to procure viable and cost-effective energy storage systems by certain dates; and

WHEREAS, if determined to be appropriate, the Board of Water and Power Commissioners (Board) shall adopt procurement targets by October 1, 2014, for LADWP to procure viable and cost-effective energy storage systems to be achieved by a first target date of December 31, 2016, and a second target date of December 31, 2021; and

WHEREAS, the Board on February 7, 2012, initiated a process 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 AB 2514; and

WHEREAS, to conform to AB 2514 and consistent with Board Resolution No. 012-168 LADWP has developed an analytical framework from which its energy storage system targets for procurement in 2016 and 2021 will be deduced, which include system and feasibility studies aimed at investigating economically viable energy storage systems at four points of interconnection: generation, transmission, distribution and behind the meter or customer; and

WHEREAS, LADWP declares that, based on the assessment of existing eligible energy storage systems, there are two projects that are deemed eligible energy storage systems namely, a generation connected storage with a net incremental capacity of 21 Megawatt (MW) and an incentivized customer connected storage with a rated peak demand shift of 3 MW, and LADWP will primarily rely on these two projects to fulfill its 2016 procurement targets totaling 24 MW; and

WHEREAS, LADWP states that, based on preliminary assessments and findings from studies performed thus far, there are five projects that are deemed relatively cost-effective namely, generation connected thermal energy storage with an incremental rated capacity approximated at 60 MW, two transmission connected battery energy storages with a combined capacity of 50 MW, one distribution connected battery energy storage rated at 4 MW, and one customer connected storage with a potential rated peak demand shift of 40 MW for a total of 154 MW; and

WHEREAS, pursuant to AB 2514, the Board shall re-evaluate the determinations made regarding energy storage system procurement not less than once every three years; and

WHEREAS, LADWP shall report to the California Energy Commission (CEC) regarding any energy storage system procurement targets and policies that may be adopted by the Board, and any modifications made to those targets as a result of the Board's reevaluations.

NOW, THEREFORE, BE IT RESOLVED that the Board of Water and Power Commissioners of the City of Los Angeles hereby adopts the procurement targets of 24 MWs of energy storage systems for December 31, 2016 and 154 MWs of energy storage systems for December 31, 2021 pursuant to AB 2514.

BE IT FURTHER RESOLVED that LADWP shall report to the CEC regarding these adopted energy storage system procurement targets and report any modifications made to those targets as a result of reevaluation.

BE IT FURTHER RESOLVED that LADWP shall report back to the Board prior to September 2, 2017, for the Board to reevaluate the determinations made regarding the energy storage system procurement targets and shall report to the CEC any modifications made to those targets as a result of the Board's reevaluations.

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 SEP 02 2014

Barbara E. Moschos

Secretary

APPROVED AS TO FORM AND LEGALITY
MICHAEL N. FEUER, CITY ATTORNEY

AUG 15 2014

BY

VAUGHN MINASSIAN
DEPUTY CITY ATTORNEY

Appendix L Smart Grid

LADWP's Smart Grid Program is described in the following components of the "Smart Grid Deployment Plan"

SMART GRID PROGRAM

DEPLOYMENT PLAN

Prepared by:
Power System Engineering Division
Power System Information and Advanced Technologies (PSIAT) Section

Table of Contents

1. Background ... 4
2. LADWP's Approach to Smart Grid ... 5
2.1. Why do we need a Smarter Grid? ... 5
2.2. LADWP's Vision for Smart Grid ... 6
2.3. Smart Grid Benefits and Value Proposition ... 7
2.4. Benefits to the LADWP Customer ... 8
3. Smart Grid Roadmap ... 9
3.1. Smart Grid Regional Demonstration Program (SGRDP) ... 9
3.2. Smart Grid functions ... 10
3.3. Implementation plan ... 10
4. SGIP Benefit Assessment ... 15

1. Background

The electric and water utility industry is currently undergoing a major transformation. This is driven by a number of economic, regulatory, and strategic challenges that utilities are facing today. In order to effectively tackle the challenges arising from the need to address 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) is 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. In addition, LADWP aims to enhance customer choice and experience, increase operational efficiency, reduce energy loss, and improve employee safety, on top of meeting future operational and regulatory requirements - such as increased distributed generation (DG) and Renewable Portfolio Standards (RPS). To address these challenges, LADWP must adopt new Smart Grid technologies to manage the operations and our electric and water grid.

The objective of adopting the Smart Grid technologies is to provide a framework to assure the future energy needs of LADWP customers are met in a manner that balances the key objectives of maintaining a high level of electric service reliability, maintain competitive rates, and exercise environmental stewardship, including a reduced carbon footprint.

The Smart Grid Investment Program (SGIP) involves implementation of these technologies in a prudent, cost-effective, and phased manner to achieve the objectives described above while minimizing the cost to our stakeholders. The roadmap and plan described herein have been developed using a benefits driven approach that maximizes the value of LADWP's investments by driving operational benefits for the Department and its customers.

LADWP's Approach to Smart Grid

1.1. Why do we need a Smarter Grid?

LADWP faces a number of concurrent issues and challenges that may impact reliability, compliance, and strategy. The drivers summarized below require implementation of technology and potentially changes in business processes to be able to continue providing high quality customer service while maintaining reliability and cost-effectiveness. The strategy to identify Smart Grid projects for the Roadmap has been driven by these factors.

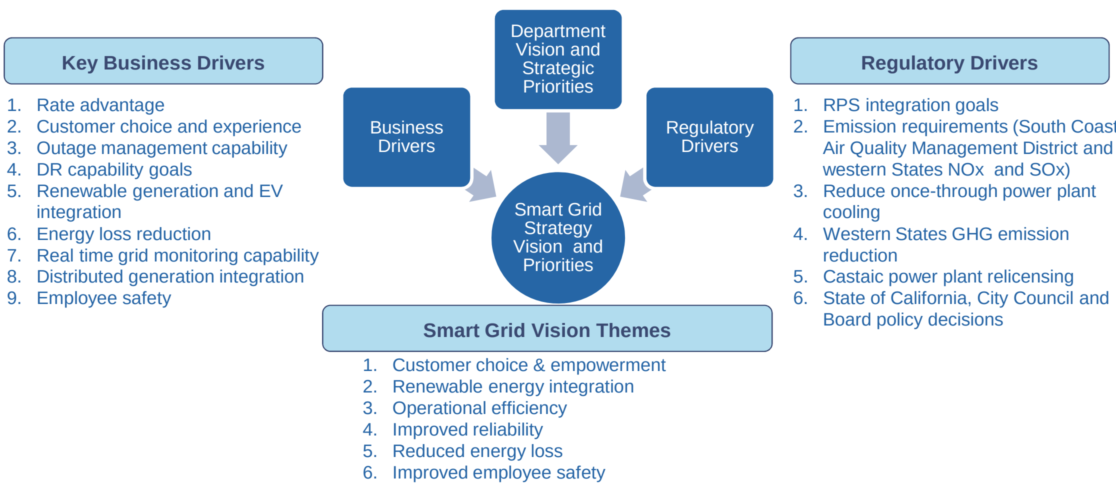
Increasing costs impacting Customer rate advantage - Historically, LADWP's electric rates have been consistently among the lowest in California. As utilities address renewable energy, greenhouse gas emissions, ocean water cooling and other issues, it can be expected that rates for most, if not all utilities, will rise. Smart Grid technologies can help LADWP lower operational costs in a number of business areas such as meter reading, field operations, and customer support. This will allow us to maintain a low cost structure and thus provide low rates to customers.	**Increasing solar, other Distributed Energy Resources (DER) and Electric Vehicles (EV) impacting reliability -** LADWP is committed to achieving a 33% renewable energy target by 2020. Renewable resources like wind and solar produce electricity variably and intermittently. EVs pose a similar challenge for the load- where a customer load will vary based on when, where and how they charge their EVs. Rapid changes in load and generation can destabilize the grid and requires LADWP to develop capability to monitor and manage these resources in real-time.
Customer choice and experience - Engaging customers to participate in managing the grid and managing their electricity costs is a primary objective of Smart Grid at the national level and for LADWP. Smart Grid technologies can enable us to provide real-time usage information, more rate options, and other customer service options such as pre-payment and remote service connect. This will contribute to enhancing customer choice, participation, and experience.	**Managing peak energy demand -** In the last six years, due to a number of factors, the peak power demand has been going up relative to our off-peak demand. It is imperative that LADWP implements tools to shift load from peak hours to off peak hours to reverse this trend and improve system performance. Smart Grid technologies will allow us to roll-out and effectively manage the demand response programs. This will also enable our customers to participate in our peak demand conservation efforts.
Outage management capability - The LADWP is continually improving its ability to minimize frequency and duration of outages. Smart Grid technologies will dramatically increase our ability to sense and monitor voltage and other system health metrics which will allow LADWP System Operators and Electric Trouble Dispatchers to foresee potential problems and minimize chances of outage. In case of outages, the smart meters will provide more accurate location information than is currently available.	**System efficiency and energy losses -** Reduction in energy losses improves the overall efficiency and effectiveness of delivering energy to customers, reducing overall energy costs. Energy losses have both a technical component (physical energy lost through transmitting electricity over long distances) and a non-technical component (theft, unrecovered revenue). Smart Grid applications have the potential to reduce both of these components through different monitoring technologies.

In addition to business drivers, regulatory requirements drive the need for an LADWP Smart Grid. From a Smart Grid perspective, the most important regulatory drivers include:

- **RPS integration goals.** The State Legislature passed legislation (SBx1-2) which subjects all utilities in California to Renewable Energy Standards. LADWP is required to achieve 20 percent renewables on average between 2011 and 2013, 25% in 2016, and 33 percent in 2020 and beyond. **State Legislature passed legislation SB 350, which further increases this requirement to 50 percent RPS by 2030 and beyond.** Significant penalties can be imposed by the California Air Resources Board (CARB) for failure to achieve these targets. The LADWP Board of Commissioners has adopted a policy to achieve these compliance requirements.
- **Emission requirements.** The LADWP is required to reduce Green House Gas (GHG) emissions by an order of the South Coast Air Quality Management District (SCAQMD) and by Assembly Bill (AB) 32. Specifically, the SCAQMD Order requires that three LADWP in-basin generators be repowered over the next several years. AB 32 requires that LADWP reduce its GHG emissions to 1990 levels by 2020. The LADWP has already accomplished this goal. In addition, SB 1368 places limitations on LADWP and other California utilities on the GHG emissions associated with power imported from outside California – limitations that will impact existing contracts for imported power. The LADWP intends to meet these targeted reductions.

1.2. LADWP's Vision for Smart Grid

The LADWP's vision of a Smart Grid is to deploy advanced technologies to its electric and water system that will provide better information about usage, increase operational efficiency by lowering costs, help reduce system losses, and enable us to better control and manage the grid in real-time.



This vision covers all facets of energy from its transmission to distribution, and finally its efficient use in homes, businesses and vehicles. This Smart Grid will incorporate high-tech digital devices throughout the transmission, substation and distribution systems and integrate advanced intelligence to provide the information necessary to both optimize electric service and empower customers to make informed energy decisions. Furthermore, the LADWP will be able to optimize the systems' performance, improve service reliability and help customers better manage their electric and water use. The Smart Grid will also enable us to better manage integration of renewable generation resources, such as solar and wind energy, and will also provide an important new tool in managing the influx of electric vehicles anticipated in Los Angeles, and their impact on our electric delivery system.

1.3. Smart Grid Benefits and Value Proposition

Key objectives of LADWP's SGIP program include pursuit of technologies that provide significant customer value that exceeds the cost of implementation, as well as identifying best fit solutions to meet policy objectives that may not have direct operational benefits. The SGIP projects involve a mix of both incremental and replacement investments that not only expand existing capabilities, but also build new capabilities that will help achieve the goals of the program.

The LADWP has taken a benefit driven approach to identifying which technology investments and the SGIP projects will deliver a combination of economic and customer service benefits. In addition, there are substantial benefits that are societal in nature and include achieving national and state priorities such as energy independence, reducing greenhouse gas emissions and increasing grid security, safety and reliability. In addition, these benefits need to be considered within the context of the portfolio of Smart Grid technologies to be deployed at different times over the next twenty years and beyond. The SGIP projects will deliver benefits to LADWP and our customers across the following four categories.

Economic	•Revenue enhancement by reduced theft, improved metering, reduced write offs •Avoided capacity investment, energy cost, transmission & distribution loss, and ancillary cost due to demand response •Avoided capital costs on scheduled meter replacement, distribution & sub-transmission investment, transformer maintenance, handheld device for field representatives, and vehicles •Workforce efficiency savings on meter reading, field services, call center, credit management, financial operation, and equipment maintenance
Reliability	•Reduced overall outage and outage time •Enhanced power system monitoring •Enhanced capabilities to support high DG & EV penetration
Environmental & Regulatory	•Reduced emission from generation & gasoline vehicles •Reduced energy and water usage through conservation •Improved grid visibility to avoid hazardous conditions
Other	•Reduced customer bill amount through conservation and new rate option •Customer incentives for participating in demand-side management programs •Improved worker safety

1.4. Benefits to the LADWP Customer

Currently, LADWP delivers power and water to its customers, and in about 30 to 60 days, we determine how and who used the electricity and water. With the automated metering infrastructure, LADWP will be able to monitor and communicate the usage patterns and other related detailed information to our customers close to real-time. In the current process, customers typically call LADWP when there is a local outage. With Smart Grid technologies such as automated meters and sensors on the lines, LADWP will instantly know whether an electric line failed and who is affected. Water customers could be automatically notified of a potential leak on their property.

Furthermore, we will be able to optimize the systems' performance, improve service reliability and help customers better manage their electric and water use. Smart Grid will also enable us to more efficiently and accurately integrate renewable generation, such as solar and wind energy. It will also provide an important new tool in managing the influx of electric vehicles anticipated in Los Angeles. For instance, automated systems will help us monitor the effects of EV charging on the grid, and customers will know how their EV impacts their electricity use.

Smart Grid Roadmap

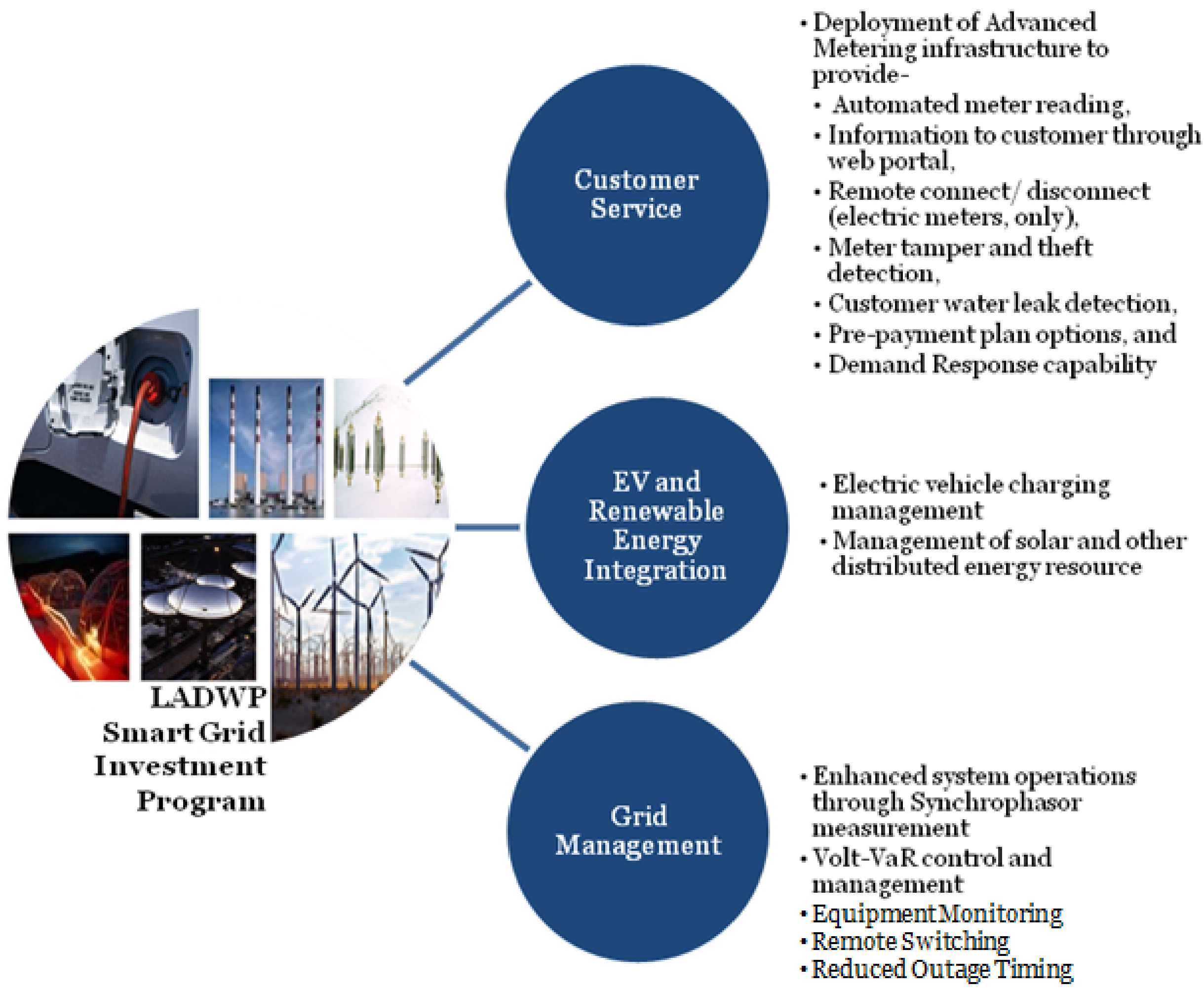
1.5. Smart Grid Regional Demonstration Program (SGRDP)

Funded by a DOE grant, Smart Grid technology will be demonstrated on a regional electric grid. This program will create the foundation for the SGIP with implementation of Advanced metering Infrastructure (AMI). The SGRDP projects are listed below:

#	Project	Key Highlights
1	Demand Response/ Advanced metering Infrastructure (AMI)	• Demonstration of Smart Grid operations and technology as applied to load curtailment and customer participation for a full range of user infrastructure environments. • Test bed sites will provide for the investigation of a full range of user infrastructure environments including residential, commercial, institutional, medical, retail, and light industrial.
2	Electric Vehicle	Integration of EVs into LADWP grid and demonstrate: • Smart charging; battery aggregation and backfill; renewable and EV battery integration; • A fully operational Microgrid; and, • A ride/car share program at LADWP.
3	Customer Behavior Studies	Demonstrate a comprehensive portfolio of studies and focused surveys to determine: • The impact of smart grid communication systems and processes on customer usage patterns; • Energy savings resulting from the use of smart grid enabled interfaces, pricing options and programs; and, • Effective messaging strategies and incentives to educate and interest different target customer groups.
4	Next Generation Cyber Security	Demonstrate technologies to show: • <u>Grid Resilience</u> - how the Smart Grid can operate resiliently against physical and cyber-attack; • <u>Operational Effectiveness</u> - to demonstrate a complete cyber security testing approach for components and installed systems; and, • <u>Redefinition of the security perimeter</u> - to demonstrate new cyber security measures that address the expansion of this perimeter by smart grid technologies to the meter in residential and commercial sites.

1.6. Smart Grid functions

Based on a thorough evaluation of proven technologies available, their benefit to our operations, and the cost-benefit assessment of implementation, LADWP has identified the following areas for implementation of Smart Grid technologies:



1.7. Implementation plan

The SGIP projects have been assessed for technologies required, implementation dependencies, strategic or regulatory priorities, and benefits to the customer and LADWP. The implementation roadmap shown below takes into account all these factors and outlines the overall schedule for implementation of these projects.

The SGIP roadmap consists of 12 projects for implementing the functions described in the graphic above. The project implementation is planned over a period of 10 years with a priority on foundational and high-value projects. The Advanced Metering Infrastructure (AMI) is foundational to seven projects. However, the SGIP program includes a number of areas where improvements can be realized without investing in AMI.

1.7.1. Advanced Metering Infrastructure (AMI) for Water and Power

Advanced Metering Infrastructure (AMI) for Water and Power

The AMI infrastructure is a foundational and enabling component for seven of the SGIP projects. The first project involves phased installation of AMI components. This project consists of procuring and installing the AMI components necessary to provide a set of Smart Grid metering functions that are comprehensive but are initially deployed on a limited scale. LADWP does not plan to roll out AMI meters to all customers universally in the near term. First deployments will focus on areas where the remote connect and disconnect capabilities are useful, where meters are hard to read or where special customer options such as prepayment are selected. These will be followed by deployments of meters appropriate to the other projects in the AMI work stream. The scope of this project includes both electric and water customers. Installation of AMI electric and water meters will provide these capabilities:

- **Remote meter reading** - Capability to remotely read each electricity or water meter on a daily basis, and record data within the meter in time-of-use intervals.
- **Customer web portal** - Presenting customers who have AMI meters with their amount of energy or water consumed for their billing period and for each time-of-use recording interval.
- **Customer display** - The ability to send usage and account information to a customer display device, e.g. home display, cell phone etc.
- **Remote connect/disconnect** - The ability to remotely connect, disconnect or limit the amount of electric service to the customer premise thereby reducing wait time for customer.
- **Outage management** - The ability to utilize the "last gasp" feature of AMI meters to provide indication of a power outage and allow LADWP to more accurately determine the scope of an outage and narrow the location to send repair crews, without reliance on customers reporting of a "lights out" condition.
- **Meter tamper detection** - The ability to remotely detect meter tampering by logging when a meter is removed from its socket, when it is re-installed (distinct from when it is initially provisioned), when there is voltage on the load side of an energy meter even though service is disconnected, when the meter is physically tampered with or the seal is broken, when the meter ring is removed, when the cover is removed or when the meter is inverted.
- **Energy/water theft and leak analysis** - This function includes the ability to analyze water or energy usage data and compare the current profile against previously recorded or typical profiles for the appropriate type of customer. The applications shall apply appropriate algorithms to distinguish between water theft and water leaks and to suggest possible causes other than theft e.g. old meters or defective meters.

Further, the AMI infrastructure will enable LADWP to deliver the following customer programs and operational improvements.

Customer Service Programs	Grid Management Capabilities
a. Customer pre-payment The AMI metering will enable us to allow customers to pre-pay for electric and water service, enable LADWP to send automated messages to pre-pay customers once the balance approaches a minimum threshold, allow customers to setup auto-payments for replenishing account balance, and provide usage data and account balance information through the LADWP website or in-premises display device. ***b. Demand response(DR) for small customers*** The AMI infrastructure will enable LADWP to provide a DR program for residential and other small customers allowing them to earn benefits by reducing their load during peak load situations. Using smart meter infrastructure, LADWP will be able to offer DR programs for residential customers such as - Peak Time Rebate (PTR) enabled by Programmable Communicating Thermostats (PCT), and voluntary Air Conditioner cycling program. ***c. Electric vehicle (EV) charging management*** High penetration of electric vehicles may cause demand fluctuations and reliability issues. In order to manage such events, the SGIP includes implementation of technologies to communicate with customers and control/optimize EV charging during periods of high demand or reliability problems. Implementation of these technologies will also enable LADWP to potentially use EVs as source of energy storage and ancillary services in the future once the technologies mature.	***d. Distributed generation monitoring and management*** Integration of increased levels of renewable generation to 33% and beyond requires changes to distribution planning as well as weather forecasting to assist with generation scheduling, control and dispatch. AMI meters with interval and voltage measurement can provide LADWP with data at the distribution system level that can assist in measuring distributed generation impacts. Communications with customer devices can permit the development of voluntary customer programs that permit LADWP output control of these distributed energy resources to alleviate localized voltage or VAR fluctuations. ***e. Advanced Voltage, Power Quality and Volt/VAR Control*** The AMI meter data will provide LADWP a detailed view of the voltage profile of distribution lines at a level that is currently not available. This will provide LADWP greater visibility into our distribution system; visibility that is increasingly important at higher penetration levels of solar and other distributed energy resources. This function builds upon the 'System Voltage/VAR Control' project described separately in the next section, as that will provide the automation for capacitor banks and voltage regulators to enable voltage/VAR control based on the AMI voltage data. ***f. Distribution modeling and planning*** The AMI meter data will provide detailed information about LADWP's distribution system, and the SGIP plan involves installing software applications to use AMI data for system modeling and planning purposes. Specifically, LADWP will potentially be able to use this information to improve transformer utilization, better forecast load growth, and manage circuit loading more effectively.

1.7.2. Large customer demand response

Consistent with national and state policy, LADWP is focused on enabling customer participation in the energy supply chain through DR. While, the SGIP plan incorporates implementing the foundational AMI technology to enable DR for all customers, a separate project for large customers is envisioned to quickly move forward with high value target customers where minimal investment will enable LADWP to develop large demand response capability without the need for AMI implementation. This project is unique to Commercial & Industrial customers (>100kW demand) and focuses on allowing these resources to be dispatchable and visible to the LADWP system operators. The DR programs for Commercial & Industrial customers can be implemented independent (i.e. sooner) of the residential customer demand response solution and with fewer system requirements. This will be achieved by interfacing with such customers that have existing Building Automation & Control Systems (BACS) and Industrial Control Systems. A combination of Rates and Programs will be designed to incentivize participation.

1.7.3. Enhanced system operations

To enhance visibility into grid operations and empower its power system operators with more detailed, accurate, and real-time information about power flow, LADWP plans to invest in enabling advanced features of the existing energy management systems by resolving the metering and communications system gaps, staffing and training system operators to maintain the operational system model, and utilizing the advanced functionality (state estimation, contingency analysis, training simulator) of existing IT systems. These investments in personnel and enhancement of current IT infrastructure will provide greatly improved visibility with little incremental investment. Additionally, this project also incorporates the use of phasor measurement units to transition to a state measurement capability and to perform dynamic line rating for the transmission system. Extending system operators' visibility into both the 34.5kV sub-transmission system and into neighboring utility systems is planned. These investments will help LADWP mitigate risk of major outages, maintain compliance with NERC requirements, and support real-time contingency analysis.

1.7.4. System voltage/VAR control (Non-AMI)

The LADWP proposes to install distribution automation devices to improve the measurement and control of voltage and VARs, improving reliability, power quality, and system efficiency. The project involves installation of remotely controlled capacitor banks, adding controls to existing capacitor banks and voltage regulators on targeted distribution circuits. This project is applicable to both LADWP's 34.5-kV sub-transmission and 4.8-kV distribution networks. The project anticipates that additional visibility and control of voltage and VARs will be required in the future as distributed generation and electric vehicles reach higher levels of penetration. The distribution/sub-transmission system project is a required precursor to the "Advanced Volt/VAR Control System" which uses the AMI system to provide additional detailed voltage measurements within the distribution system.

1.7.5. Asset Condition Monitoring

Advanced sensors and communication devices can provide LADWP with information on the health of assets in our power system. For example, we may be able to predict equipment failure before it happens by installing such sensors on high value equipment such as large transformers. The LADWP plans to install and use on-line condition monitoring devices for transmission transformers with the objective of maximizing the life and utilization of the asset and optimizing maintenance activities while avoiding unplanned outages and damage to the equipment. The solution requires the use of communication equipment used to collect the on-line data, a historian database to store data, condition analysis applications, and dashboard applications with integration to existing LADWP grid management applications. The implementation of the proposed solution reduces the risk of unplanned asset failure while performing maintenance activities on an "as needed" basis (i.e., prior to asset failure).

1.7.6. *Enhanced forecasting of renewable generation*

The integration of increased levels of renewable generation to 50% and beyond requires changes to distribution planning as well as weather forecasting to assist with generation scheduling, control and dispatch. In order to develop capabilities in this area, the LADWP plans to conduct an advanced distribution study on our distribution system connected generation sources with distribution system modeling to validate the system impact. Moreover, current industry studies and pilot efforts will result in mature tools allowing us to implement a weather forecasting capability providing localized data to manage solar and wind generation.

2. *SGIP Benefit Assessment*

2.1. SGIP Benefit Assessment

The LADWP believes that strategic Smart Grid investments will produce long term benefits for our customers, the environment, and society as a whole. The assessment of Smart Grid technology reveals a number of these benefits as described below.

2.1.1. Revenue Enhancement

The Core AMI project involves installation of new advanced meters across LADWP's service territory that will not only be more accurate, but will also provide theft and leakage detection capability, leading to revenue enhancement opportunity. For example, revenue loss will be reduced with increased meter accuracy, mitigation of unregistered meters, and reduced unmetered usage (e.g. theft). The LADWP estimate for these benefits over the 20 year period is up to $363.5 million approximately.

2.1.2. Avoided Capital Costs

The proposed SGIP projects can help LADWP avoid certain capital costs in the future. For example, these include: the handheld device and vehicle costs related to the reduced need for field services and meter reading; distribution and transmission investments; and the cost of the scheduled non-AMI meter installation. The LADWP estimate for these benefits over the 20 year period is up to $144.1 million approximately.

2.1.3. Demand Response Benefits

The large and small customer demand response program, and electric vehicle charging program can create significant savings from reduced generation capacity investments, reduced energy costs, avoided transmission & distribution losses, and reducing ancillary costs. The LADWP estimate for these benefits over the 20 year period is up to $1,065.7 million approximately.

2.1.4. Workforce Efficiency

The SGIP projects involve automation of a number of operational functions thereby creating significant workforce efficiencies throughout the Department. These functions include: Meter Reading, Field Services, Call Center Operations, Customer Credit Management, Back Office Financial Operations, and Transformer Maintenance. The LADWP estimates that the automation will help realize up to 4.25 million efficiency labor hours over the 20 year period that can be redeployed in other advanced functions.

2.1.5. Reduced Emissions

A number of SGIP projects will help reduce GHG emissions through conservation or operation efficiency. For example, energy conservation and increased renewable resources penetration will require less in-basin and overall fossil generation, thereby reducing emission. Also, the increased utilization of renewable generation resources will help LADWP achieve the RPS goals. We estimate that implementation of SGIP projects will help LADWP reduce its GHG emission by up to 3.7 million metric tons over the 20 year period.

2.1.6. Reduced Energy and Water Usage Through Conservation

By providing customers with increased access to information related to their impact on the energy system, carbon footprint, energy and water consumption, and the related cost, LADWP believes the overall energy/ water usage of its customer will be reduced. The LADWP estimate the reduction of electricity and water usage over the 20 year period is approximately 8,660.3 GWh and 144,766 AF respectively.

2.1.7. Customer Incentives

The LADWP customers may receive monetary incentives for participating in the small customer demand response, large customer demand response, and electric vehicle charging management programs. The peak load requirements, generation costs, energy cost, and ancillary cost can be reduced with such programs and is beneficial for both LADWP and its customers. Based on the preliminary assessment, the LADWP estimates that its customers will receive participation incentives of up to $221.4 million over the 20 year period by opting to participate in these programs.

2.2. Other Key Benefits

The SGIP projects are expected to deliver significant additional benefits that were not estimated as part of the analysis above, but are highly valuable to the LADWP, and our customers. The following is a list of the non-quantified benefits derived from SGIP:

2.2.1. Reduced overall outage and outage time

The proposed Smart Grid applications can help reduce both the occurrence of major and localized outages, as well as the duration of outages when they occur. For instance, asset condition monitoring capability will help reduce equipment failure-related outages by allowing LADWP to take remedial action prior to failure; more accurate planning data, real-time information about system instability, and demand-side management capabilities will help reduce chances of system overload-related outages; and increased monitoring capabilities will help reduce time taken by LADWP to respond to outage situations thereby help reduce the outage times.

2.2.2. Improved grid visibility and enhanced power system monitoring

In the future, higher penetration of distributed energy resources and EVs will increase load variability across LADWP's electric grid. The proposed Smart Grid applications will provide real-time and more accurate monitoring of grid operations, and thereby allow LADWP to anticipate and respond to disturbances in the grid. By utilizing on-line diagnosis and reporting of equipment condition, LADWP could identify and mitigate equipment problems that could otherwise result in hazardous conditions. For instance, transformer explosions may be reduced with asset condition monitoring, avoiding the leak of toxic oil to the environment and the surrounding residents.

2.2.3. Reduced customer bill amount through conservation and new rate options

With improved usage information, the customers will be able to understand how their water and energy consumption habits affect their monthly bills. This will allow the customers to reduce their overall usage (conservation) by changing their consumption behavior or shifting usage to cheaper time periods, resulting in a lower bill amount. In addition, customers will also have the option to reduce their bills under the new rate plans (such as time-of-use pricing) enabled by the AMI infrastructure.

2.2.4. Improved worker safety

With reduced field services, meter reading, and equipment maintenance activities, workers are at less risk of motor vehicle accidents and other potentially dangerous incidents. In addition, more up-to-date and accurate system condition information will help provide a safer working condition for the field crew.

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Appendix M - Climate Change Effects on Power Generation

The association of power generation and climate change usually centers on the industry's contribution towards atmospheric Greenhouse Gas (GHG) emissions and its efforts to reduce such emissions. This Integrated Resource Plan (IRP) discusses various Los Angeles Department of Water and Power (LADWP) programs and projects whose key objective is to lower GHG emissions. However, an important factor to also consider in resource planning is how climate change *affects* electricity demand, or consumption, and how it impacts the process of generating electricity. Rising average temperatures, changes in precipitation amounts and patterns, more frequent extreme weather events and a rise in sea level are some of the effects that may be expected from global warming. Understanding how these effects impact power generation and incorporating that knowledge into the planning process facilitates adaptation of the power system to respond in a way that mitigates potential problems and takes advantage of any opportunities.

The effects of climate change on resource planning can be addressed on two levels: (1) how it affects *energy consumption*, and thus how much generation should be planned for and secured, and (2) how it affects *power generation* operations and the siting of new facilities.

Energy Consumption

The effects of rising temperatures on energy consumption will vary by region and season. In traditionally cooler regions, net energy use may actually decrease due to less heating requirements. In warmer regions, an increase in cooling demand will mean an increase in energy usage, specifically electricity. Within LADWP's service territory, a net increase in electricity for cooling can be expected. Along with increased temperatures, there is also an increased potential for extreme weather events, such as heat storms of longer duration. Preliminary findings are as follows:

Global Warming Impacts Affecting Energy Consumption

1. Mean temperatures will continue to rise in Los Angeles, increasing Cooling Degree Days and decreasing Heating Degree Days.[1]
2. Extreme heat conditions, such as heat waves and very high temperatures, may last longer and become more commonplace.[2]
3. Air conditioning saturation will increase with the rise of mean temperatures.[3]

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1 Climate Scenarios for California, California Energy Commission, CEC-500-2005-203-SF

2 Global Climate Change, California Energy Commission, CEC-600-2005-007, page 2

3 Air conditioning market saturation and long-term response of residential cooling energy demand to climate change, D.J. Sailor, Energy 28 (2003) pages 941-951

These effects have been incorporated into LADWP's load forecast. Due to the ongoing nature of climate change studies and advancements, it is important that LADWP stay abreast of current findings and conclusions, and incorporate such findings as appropriate.

A recent study by the UCLA Department of Atmospheric and Oceanic Sciences[4] focuses on temperature changes in the Los Angeles region in years 2041-2060. A key attribute of the study is its high resolution perspective for the Los Angeles region, including unique predictions for individual areas such as San Pedro, Woodland Hill, San Fernando and Downtown LA. Due to the region's varied topology, some areas are expected to experience more warming than others.

The UCLA study results for the City of Los Angeles show annual average temperature increases of between 3.7 and 4.3 °F (an average increase of 4.0 °F), depending on location within the city.[5] The number of days per year in which temperatures will surpass 95 °F are shown to increase – at worst by a factor of 4.0, but again depending on location as shown in Table M-1 below:

Table M-1 – NUMBER OF DAYS WITH TEMPERATURES ABOVE 95 °F

	Number of Days Baseline	Number of Days, Study Results, Mean	Increase Factor over Baseline
Downtown	1.4	4.6	3.3
San Pedro	0.6	1.4	1.4
Venice	0.1	0.1	1.0
Sylmar	6.8	25.5	3.8
San Fernando	7.9	26.3	3.3
Woodland Hills	4.2	16.7	4.0
El Sereno	2.3	6.8	3.0
Eagle Rock	2.0	6.0	3.0
Porter Ranch	8.0	30.1	3.8

While the UCLA study looks at temperature changes in the 2041-2060 timeframe (which is beyond the 20-yr planning horizon for the 2014 IRP), the findings corroborate other studies and supports the expectation of higher future temperatures which will increase electricity use. As this study is specific to the Los Angeles region, it provides detailed information which local government, utilities (including LADWP), hospitals and other institutions can use to help prepare for the future.

[4] Hall, et al., 2012: Mid-Century Warming in the Los Angeles Region. Available at: www.c-change.LA
[5] The study includes two GHG emission scenarios – a business-as-usual scenario and an aggressive emissions mitigation scenario. The data noted here is from the business-as-usual scenario.

Power Generation

The impacts of climate change on power generation go beyond the need to meet increased loads and higher peak demands. The potential expressions of global warming that are the major areas of concern for power generation are extreme weather events, water availability, and rising sea levels; consequences include decreased thermal efficiencies and siting impacts for new facilities.

Extreme Weather

From a national perspective, an increase in “extreme weather conditions” usually refers to an increase in the number, intensity and duration of hurricanes, such as on the East Coast and Gulf of Mexico, tornadoes in the Mid-West, floods, droughts, etc. These extreme events have the power to disrupt and damage power generating facilities. Fortunately, such events affecting LADWP generation sources have been relatively less frequent. However, extreme weather conditions in other areas of the country can impact LADWP by disrupting fuel supply production and transportation.

Locally, an increase in frequency of weather anomalies can be a cause for concern. In July 2006, a prolonged heat wave resulted in major service disruptions. And in November 2011, a severe wind storm resulted in extensive damage and power outages across the region, affecting over 220,000 LADWP customers. Such events stretch available resources and expose vulnerabilities in the electric delivery system. To the extent climate change contributes to an increase in such events, more human and capital resources must be provided to increase the resiliency of the electricity infrastructure to better withstand these extreme conditions; and, when outages do occur, to restore interrupted service in an expeditious manner that adequately addresses public health and safety needs.

Water Availability

Changes in weather patterns due to climate change will likely result in increased variations of water availability, with some regions experiencing more drought conditions and other areas becoming more subject to flooding. This affects power generation in a number of different ways. A decline in water levels behind hydro dams will decrease generation capacity which would have to be made up elsewhere. Changes in stream and river flows will affect the output of run-of-the river hydro facilities, which may be positive or negative. Flooding conditions could threaten the operation of generating stations, including renewable wind and solar facilities. In drought stricken areas, a scarcity of cooling water availability will increase the demand and price for water. Increased competition for water can be expected from other water consumers, including the agriculture, mining, industrial, residential and commercial sectors within the affected region.

For California, the research to date indicates a potential of reduced snowpack in the Sierras, which would decrease hydro-electric output. An increased likelihood of drought conditions in the US Southwest would also impact hydro generation in addition to constraining sources for cooling water. Developments such as these will have negative implications for LADWP's hydro-electric and thermal generation operations.

Sea Level Rise

Sea Level Rise (SLR) is another area of ongoing study. While projections vary, the October 2010 State of California Sea-Level Rise Interim Guidance Document uses a baseline that estimates a 5-8 inch rise by year 2030. Within the 20-year planning horizon of this IRP, SLR in this range will not present a problem to LADWP's coastal generating facilities. Longer-term effects, such as what may be projected for the end of the century, would be addressed over time. Because the more pronounced effects of SLR are not anticipated to occur until 60+ years into the future, strategies to mitigate possible negative impacts can be developed and implemented in a deliberate and methodical manner. For example, generating stations are expected to be replaced every 30-35 years, and if warranted due to extreme SLR, consideration can be given to relocate inland as part of the replacement process.

Decreased Thermal Efficiency and Output

An increase in temperature due to global warming will impact the thermodynamic efficiency for power plant generating equipment. An increase in ambient temperature decreases efficiency, resulting in less output per unit of fuel. On average, an increase of 5 °F decreases efficiency by approximately 0.4 to 0.8 percent. Higher temperatures would also decrease the amount of energy capable of being generated – a 5 °F increase reduces available output by about 1.0 to 2.6 percent.[6]

New Facility Siting

The potential impacts of water availability and extreme weather events could impact the siting of new energy generation and transmission infrastructure. This would be more pronounced in areas where water availability is expected to decrease, such as the US Southwest. This doesn't necessarily preclude potential sites as candidate locations, but it may necessitate higher construction and operation costs, and incorporation of engineering designs and processes that are more weather-hardened and use less water.

Actions to Address Climate Change

Reducing GHG emissions to minimize its impact on climate change/global warming is a key LADWP strategic objective. As discussed in other parts of this IRP, LADWP is modifying its resource mix to adopt more renewable resources such as wind and solar, which do not emit GHG emissions. Replacing older inefficient gas-fired units at its in-basin generating stations will reduce the amount of fuel needed to generate electricity,

[6] The ranges shown reflect differences across different generation methods, e.g., combined cycle vs. combustion turbine. Values shown are approximations. Relative humidity is also an influencing factor.

which also decreases emissions. Ensuring the adoption of energy efficiency programs will offset the amount of emissions in direct proportion to the resulting energy savings: every unit of electricity saved also eliminates the corresponding amount of GHG that would otherwise be emitted. And, to further reduce GHG emissions, LADWP is actively working to divest itself from its two coal power plants –the Navajo Generating Station and the Intermountain Power Project – although contractual, legal and financial issues present challenges that need to be worked out.

To prepare for and adapt to climate change, LADWP incorporates into its load forecast increases in electricity demand resulting from expected higher future temperatures. Implementation of LADWP's Power Reliability Program will increase the resiliency of its electricity delivery infrastructure, better preparing it to withstand the more frequent and prolong weather events (heat waves) that will be expected. Other considerations include a heightened awareness and accounting of potential effects on water availability, new facility siting, thermal efficiencies, and sea level rise. Although this IRP document addresses only the power side of LADWP, it is worth noting here that water conservation will play a large role in both reducing GHG emissions and as a means of adapting to the effects of climate change.

Conclusion

Global warming is a major environmental concern that warrants continuous attention. LADWP's efforts to reduce GHG emissions should continue, as should planning activities to prepare for and adapt to the future consequences of climate change. As a responsible municipal utility, LADWP should base its recommendations and actions on sound scientific studies and principles, and in concurrence with City policy.

As the science of climate change continues to evolve, LADWP should stay abreast of the latest findings and conclusions. Subsequent IRPs will monitor developments in climate change and develop/refine recommendations to mitigate any negative impacts as part of the resource planning process.

Appendix N Model Description and Assumptions

N.1 Overview

The study horizon for the model analysis is the 20 year period 2015 through 2035. In performing this modeling, it is necessary to assume certain actions will be taken in each of the next 20 years. However, it must be understood that the Integrated Resource Plan (IRP) is an ongoing process. A new IRP is developed every two years. Between each 2-year interval, the most recent IRP is modified if appropriate. The key results from this IRP analysis is the action plan that will be put in place for the next 1 to 5 years. These near-term actions are important recommendations that will enable and support the goals and objectives of the long term plan.

This Appendix presents the Model Analysis and is organized as follows:

- Section N.2, Model Description, provides a description of the model selected by LADWP to simulate the operation of its power system under different futures and with different resource portfolios.
- Section N.3, Resource Selection Process/Gap Analysis, describes the method used to assess the amount of future renewables and other replacement resources required to satisfy resource adequacy requirements including a description of the valuation process used in selecting the future renewable resource portfolio.
- Section N.4, Avoided Costs and Net Revenue Losses, describes the analysis and results to determine the net revenue loss used in the evaluation of the advanced renewable and local solar case comparisons (Cases 3 thru 7) found in Section 4.3.3.1.
- Section N.5, Model Inputs and Assumptions, presents the major input parameters that were used in the production cost model runs.

N.2 Model Description

LADWP has chosen a widely used and industry accepted hourly chronological unit commitment and dispatch model to simulate the operation of the LADWP power system under different futures and with different resource portfolios. The model is the Planning & Risk model (PaR) licensed from Ventyx (an Atlanta based software firm). It uses the PROSYM unit commitment and dispatch algorithm.

PROSYM is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour investigation of the operations of electric utilities. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. PROSYM considers a complex set of operating constraints to simulate the least-cost operation of the utility. This simulation, respecting chronological, operational, and other constraints, is the essence of the model.

This model looks at the LADWP load for each hour and then dispatches LADWP generation supplies on an economic basis (lowest variable cost units first) until the load is met. The model output reflects all the variable costs incurred in meeting the load for each study performed. The fixed costs for the resources are added to the modeled variable costs to develop the total power cost incurred in meeting the load.

The model is also capable of representing certain transmission constraints on a utility system. LADWP load is generally confined to the geographic area of Los Angeles. An IRP would not generally be a replacement for transmission planning activities needed in the service area. However, LADWP does have generation outside of Los Angeles and has transmission rights to other areas of the Western Interconnect. To better represent the constraints and opportunities related to these remote facilities, the modeling topology depicted on Figure N-1 was developed for this IRP.

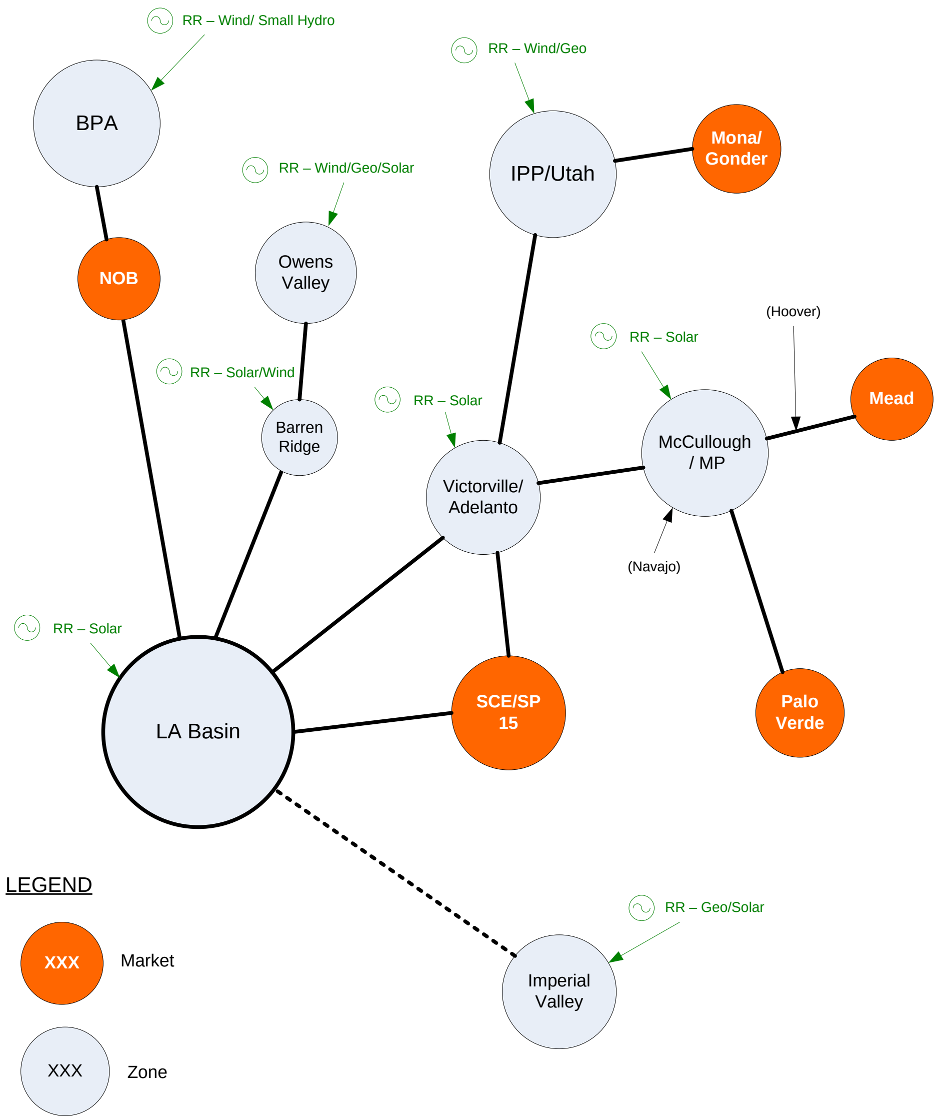


Figure N-1: LADWP Modeling Topology.

On a day-to-day basis, LADWP will buy power in spot markets if such a purchase can be done both without causing reliability issues and if the price of the spot market power is less than the operating cost of its own power plants. Similarly, on a day-to-day basis, LADWP will sell power in spot markets if the price of power in the spot market is greater than the cost of operating an LADWP resource and the power is not needed to meet LADWP load. In an IRP analysis, it may or may not be desirable to attempt to reflect spot market activity. For this IRP, short term and long term market purchases and sales were included in the overall energy mix. For resource adequacy, some limited Q3 purchases were included to supply short term capacity deficits in future years resulting from coal divestment and load growth.

N.3 Resources Selection Process/Gap Analysis

The gap analysis in this IRP evaluated both a Resource Adequacy (RA) need as well as a need to meet certain goals for renewables as a percentage of billed energy (renewable need). The RA need compares available generation supplies to the load that needs to be served. For LADWP, this comparison was based on the annual peak load plus a planning reserve margin. In addition to a system wide demonstration of RA, a certain amount of generation needs to be located in the Los Angeles service territory to assure local reliability. Sections 2.4.7, 3.4.2, 4.2.1.4 and 4.3.1 of this report discuss the LADWP approach to RA.

N.3.1 Resources recommended for Resource Adequacy

The displaced energy from early coal replacement is generally replaced with a combination of renewable energy and new gas-fired combined cycle generation. Energy efficiency, demand response, and short term 3rd quarter market purchases are used to primarily satisfy load growth. Table N-1 summarizes the different replacement resources for the different cases that were evaluated.

Case #2 (Navajo 2015, IPP 2025, 50% RPS, Adv EE, 800MW Local Solar, High EV)

Capacity (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy Efficiency	29	52	79	108	135	160	172	181	187	191	193	194	196	198	199	202	204	206	206	206	206
Demand Response	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500	500	500
New Renewable	79	348	411	485	535	584	667	753	849	961	1132	968	1049	1075	1123	1182	1225	1246	1267	1311	1332
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600
Capacity Shortfall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	70	192	268	292	284
Total Replacement	128	440	566	692	820	943	1089	1233	1386	1552	2374	2262	2345	2373	2422	2532	2600	2743	2841	2909	2922

Table N-1. Resources recommended for resource adequacy by calendar year

N.3.3 Amount of Renewables Needed

To determine the amount of renewable energy necessary to meet future targets, forecasts were made for the future power demand and the amount of existing renewable capacity available to meet these requirements. The difference between the projected amount required and the amount currently being utilized is the net short that will need to be acquired to meet RPS guidelines. A description of the methodology undertaken to define the future renewable needs is outlined below.

LADWP Renewable Net Short

The net short is the generation target to be met with resources identified in this project. The calculation for the net short was performed using the following equation:

Net Short(GWh) = (Forecasted Energy Sales) x (Annual Renewable Percent Goal) – (Operating Renewable Resources – Under Construction and Pre-construction Renewable Resources - Renewable Energy Purchases)

SB 2 (1X) has established the level of renewables required by 2020 and beyond, and also sets interim targets between now and 2020. SB 350 further extends the renewable targets to 50 percent by 2030 with interim targets between 2020 and 2030. These levels and targets represent the *Annual Renewable Percent Goal* parameter in the equation. By incorporating forecasted sales, existing renewable projects, and current and forecasted renewable energy purchases, the net short can be calculated.

N.3.3 Renewable Resources Selection Process

Over the last ten years, LADWP has issued several requests for proposals for renewable energy and gained a thorough understanding of the nature and availability of the different renewable resource technologies. This knowledge was used in developing the renewable portfolio. Additionally, LADWP largely considered renewable resources within the Western Governors' Association's Western Renewable Energy Zones (WREZ). In the WREZ initiative, Qualified Resource Areas were defined as areas of dense, high-quality renewable energy resources, meeting various resource size, quality, environmental, and technical criteria. LADWP screened all resources to ensure they are located near available LADWP transmission infrastructure. Assumptions were made for the cost and performance of each technology used to convert the renewable resources to electricity. These assumptions were used in calculating the levelized cost of electricity.

A valuation process designed to provide a single ranking value to a resource was then applied. The valuation process is a method to rank the total value of separate renewable resource projects, and accounts for such parameters as transmission costs, integration costs, supply curves, load shapes, the capacity benefit provided by the resource, capital and O&M costs, financial factors and other measures This step is intended to identify resources with the combination of lowest cost and highest value. The valuation approach is similar to the bid evaluation process many utilities use when procuring renewable resources.

After applying the appropriate constraints, resources were selected and added progressively to the renewable resource mix based on lowest rank cost and transmission availability until the net short was mitigated. To assess and rank projects consistently, a method must be developed to measure the economics of all resources on a consistent basis. Renewable technologies all have different characteristics, with different cost requirements and energy delivery patterns. Resource valuation is a way to measure different renewable resources on a comparable basis.

N.3.4 Renewable Generation Cost

The cost of generation is calculated as a levelized cost of energy ("LCOE") at the point at which the project will interconnect to the existing transmission system. The LCOE for a project is the total life-cycle cost of generating electricity at the facility normalized by the total generation from the facility and is calculated in terms of dollars per megawatt hour ($/MWh). LCOE provides a consistent basis for comparing the economics of disparate projects across all technologies and ownership.

For each project or resource class, a pro forma financial analysis was conducted to determine the life-cycle cost. This pro forma model uses input assumptions for key project variables to determine expected revenues, costs, and year-by-year after-tax cash flow over the project life. The pro forma model used is consistent with the model used in CEC's Cost of Generation model, as well as those used in WREZ and California's Renewable Energy Transmission Initiative. It is also very similar to the model used by the CPUC to calculate the Market Price Referent (MPR), with the necessary modifications to make the calculations appropriate for renewable resources, including the modeling of tax incentives, accelerated depreciation, and other incentives.

The analysis included appropriate assumptions for each project. Some assumptions were tailored to be technology specific, such as financing terms and appropriate tax incentives. Other assumptions such as capacity factor and capital cost depended on geography and the available natural resource. Specific costs included in the generation costs were:

- Capital costs
- Generation interconnection costs ("gen-tie")
- Fixed operation and maintenance
- Variable operation and maintenance
- Heat rate (if applicable)
- Fuel costs (if applicable)
- Incentives
- Net plant output
- Capacity factor
- Economic life

N.3.5 Renewable Generation Cost

The integration cost of a project is the indirect operational cost to the transmission system to accommodate the generation from the project into the grid. The addition of substantial amounts of intermittent and as-available renewable resources could result in substantial generation swings on the transmission system, and the grid operator must accommodate these swings by ensuring there is sufficient regulation service, modifications to current daily ramps, additional reserve capacity, and voltage support. Additional integration costs will include wear-and-tear on resources if they are required to repeatedly cycle to adjust for the intermittent resource output.

N.3.6 Renewable Resource Capacity Value

The capacity value of a generating resource is based on its ability to provide dependable and reliable capacity during peak periods when the system requires reliable resources for stable operation. Resources that can provide firm dependable capacity will have a higher capacity value than resources that cannot. In the WREZ model, the ability of a renewable resource to generate power during the top 10 percent of the model's yearly load was used as the capacity credit. LADWP uses a more conservative approach by considering the dependable capacity which varies depending on the resource type and is a fraction of the total available capacity as shown in Table 3-4.

The baseline value of capacity is the cost of the next most likely addition of low-cost capacity, defined as the fixed carrying costs of a simple cycle gas turbine generator. This includes the capital costs, fixed operations and maintenance costs, and other fixed charges associated with the gas turbine generator capacity, expressed as a dollar per kilowatt per year ($/kW-year). The fixed carrying cost assumed in the model is $100/kW-yr. The baseline capacity value does not include variable costs, such as fuel purchases. For new projects, the capacity factor is derived from the projected generation profile for the resource. The formula for calculating capacity value ($/kW-yr) is:

$$\textit{Capacity Value (\$/MWh)} = \textit{(Dependable Capacity Factor)} \times \textit{(Baseline Capacity Value)} / \textit{(Project Capacity Factor} * 8760/1000)$$

N.3.7 Renewable Resource Energy Value

The energy value of a resource assesses the value of its hourly output to the energy markets. Resources that produce more power during high-price, peak demand periods will have a higher energy value than resources that provide power primarily during low demand periods.

The formula for calculation of energy value is:

$$\textit{Energy Value (\$/MWh)} = \Sigma\, [\textit{(Energy Value in Time Period)} \times \textit{(Energy Output in Time Period)}] / \textit{Total Energy Output}$$

N.3.8 Renewable Energy Portfolio

Utilizing the methodology described in the previous subsections, a best-value portfolio of renewable resources was developed. The base portfolio, which includes 50 percent RPS by 2030, 15 percent energy efficiency by 2020, 800 MW local solar, and high electrification, was used in both coal cases considered in this IRP and the Advanced Renewable and Local Solar Case 6 which is identical to Coal Case 2. The base portfolio is nearly identical to the 2014 IRP recommended case with the exception of 50 percent RPS instead of 40 percent RPS due to SB 350 mandates. Figures N-2 and N-3 show the renewable capacity and energy production schedules for the base portfolio. The four additional advanced renewable and local solar cases (Cases 4 thru 7) analyzed varied amounts of local solar, ranging from 800 to 1,000 MW, and a base, medium, and high cases of transportation electrification. Along with these cases, a 33 percent RPS by 2030 base case was analyzed and used for cost and greenhouse gas comparison purposes.

RPS Capacity (MW)

Station Group	Item	Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Wind	Wind_Linden	Wind	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Wind_PebbleSprings	Wind	69	69	69	69	69	69	69	69	69	69	69	69									
	Wind_PineTree	Wind	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
	Wind_PPMWyoming	Wind	82	82	82	82	82	82	82	82													
	Wind_Willow Crk	Wind	72	72	72	72	72	72	72	72	72												
	Wind_WindyPoint	Wind	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
	Wind_Milford1	Wind	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
	Wind_Milford2	Wind	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
	Wind_Manzana	Wind	39	39	39	39	39	39	39	39	39												
Existing Small Hydro	AQ & OV& OG	Hydro	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
	North Hollyw ood	Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Sepulveda	Hydro	9	9	9	9	9	9	9	9	9												
Existing Solar	Solar_FiT_E	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	3
	Solar_DWP_Basin_E	Solar	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Solar_CNM_RPS_E	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar_CNM_nonRPS	Solar_non RPS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
	Solar_PPA_CopperMountain	Solar	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
	Solar_DWP_PineTree	Solar	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	Solar_DWP_Adelanto	Solar	10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9	9	9	9	9
Existing Biogas	Bio_Bradley	Bio																					
	Bio_Lopez	Bio	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Bio_Toyon	Bio																					
	Atmos & Shell Gas Credit	Bio																					
	Hyperion Digester Gas	Bio	16	16																			
	Shell Renew able Biomethane	Bio	36	37	37	37	37	37	30														
Existing Geo	Geo_DonCamb	Geo	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14		
	Geo_Hudson Ranch	Geo	55	55	55	55	55	55	55														
Existing Subtotal			**1,567**	**1,568**	**1,552**	**1,552**	**1,552**	**1,552**	**1,545**	**1,460**	**1,378**	**1,258**	**1,258**	**1,258**	**1,189**	**1,189**	**1,189**	**1,189**	**1,189**	**1,188**	**1,188**	**1,176**	**1,176**
New Geo	Geo_Herber1	New_Geo		23	23	23	35	35	35	35	35	35	35										
	Geo_Imperial	New_Geo						0	0	0	25	38	44	50	50	50	50	50	50	50	50	50	50
	Geo_Imperial_Ext	New_Geo							0	0	0	0	25	38	44	50	50	50	50	50	50	50	50
	Geo_DonCamb2	New_Geo		17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Geo_PPA_2017 OR	New_Geo				30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	Geo_PPA_2017 OT	New_Geo				13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	Geo_PPA_2026 OH	New_Geo												33	33	33	33	33	33	33	33	33	33
	Geo_Generic (50%)	New_Geo							25	75	100	100	100	100	100	100	100	100	100	100	100	100	100
	Subtotal		**0**	**40**	**40**	**83**	**95**	**95**	**120**	**170**	**220**	**233**	**264**	**281**	**287**	**293**	**293**	**293**	**293**	**293**	**293**	**293**	**293**
New Solar	Solar_Ow ens	New_Solar							0	0	0	50	100	150	200	199	198	197	196	195	194	193	192
	Solar_DWP_Basin_P	New_Solar	2	5	8	11	14	17	20	23	26	29	32	35	37	37	37	37	36	36	36	36	36
	Solar_FiT_150	New_Solar	50	121	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Solar_FiT_300	New_Solar	0	0	25	75	125	175	225	275	300	300	300	300	300	300	300	300	300	300	300	300	300
	Solar_CNM_RPS_P	New_Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar_CNM_nonRPS_P	New_Solar_non RPS	13	50	111	153	160	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167
	Solar_PPA_SG	New_Solar			150	149	149	148	147	146	146	145	144	143	143	142	141	141	140	139	138	138	137
	Solar_PPA_SG2	New_Solar						50	50	50	49	49	49	49	48	48	48	48	47	47	47	47	46
	Solar_PPA_SG3	New_Solar											150	149	149	148	147	146	146	145	144	143	143
	Solar_PPA_VicLA	New_Solar													146	250	250	250	250	250	250	250	250
	Solar_PPA_Springbok	New_Solar	0	43	100	100	99	99	98	98	97	97	96	96	95	95	94	94	93	93	92	92	91
	Solar_PPA_Springbok2	New_Solar			150	149	149	148	147	146	146	145	144	143	143	142	141	141	140	139	138	138	137
	Solar_PPA_Springbok3	New_Solar			90	90	90	90	90	90	90	89	89	88	88	87	87	86	86	86	85	85	84
	Solar_PPA_Beacon	New_Solar		250	249	248	246	245	244	243	241	240	239	238	237	235	234	233	232	231	230	228	227
	Solar_PPA_RecurrentBR	New_Solar	0	60	60	59	59	59	59	58	58	58	57	57	57	56	56	56	56	55	55	55	55
	Solar_PPA_K.Moapa	New_Solar	7	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
	Solar_Generic (50%)	New_Solar															100	200	200	200	200	200	200
	Subtotal		**59**	**729**	**1,231**	**1,281**	**1,331**	**1,430**	**1,479**	**1,529**	**1,553**	**1,601**	**1,800**	**1,849**	**2,042**	**2,140**	**2,234**	**2,328**	**2,322**	**2,316**	**2,310**	**2,304**	**2,299**
New Wind	Wind_PineCYN	New_Wind					0	0	0	0	70	70	70	70	70	70	70	70	70	70	70	70	70
	Wind_Ext	New_Wind									100	150	150	150	200	200	200	200	200	200	200	200	200
	Wind_ISO	New_Wind											100	200	200	200	200	200	200	200	200	200	200
	Wind_STS	New_Wind													100	200	200	200	200	200	200	200	200
	Subtotal		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**170**	**220**	**320**	**420**	**570**	**670**	**670**	**670**	**670**	**670**	**670**	**670**	**670**
New Small Hydro	WSHydro	New_Hydro				4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Aqueduct PP Improvement	New_Hydro				4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
eneric_RPS (50%_800_High	Generic_RPS (50%_800_High)	Generic	0	0	0	0	0	0	0	0	0	0	0	0	38	76	152	266	419	495	571	723	799
GP_(50%_800_High)	GP_(50%_800_High)	Purchase																					
Total RPS			**1,626**	**2,336**	**2,823**	**2,924**	**2,985**	**3,085**	**3,153**	**3,167**	**3,329**	**3,320**	**3,650**	**3,815**	**4,134**	**4,376**	**4,546**	**4,754**	**4,900**	**4,971**	**5,041**	**5,174**	**5,246**

Figure N-2. Renewable resource capacity in MW for 2015 IRP recommended case.

RPS Energy (GWh)

Station Group	Item	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Wind	Wind_Linden	130	142	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
	Wind_PebbleSprings	138	157	193	193	193	193	193	193	193	193	193	193	16								
	Wind_PineTree	152	201	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
	Wind_PPMWyoming	186	205	171	171	171	171	171	86													
	Wind_Willow Crk	155	173	197	197	197	197	197	197	197												
	Wind_WindyPoint	616	685	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694
	Wind_Milford1	352	378	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434
	Wind_Milford2	178	190	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231
	Wind_Manzana	95	108	104	104	104	104	104	104	104												
Existing Small Hydr	AQ & OV& OG	31	427	523	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478
	North Hollywood		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Sepulveda		22	33	33	33	33	33	33	33												
Existing Solar	Solar_FiT_E	10	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13	13
	Solar_DWP_Basin_E	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Solar_CNM_RPS_E																					
	Solar_CNM_nonRPS	200	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233
	Solar_PPA_CopperMountain	511	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515
	Solar_DWP_PineTree	11	13	17	17	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	Solar_DWP_Adelanto	20	20	20	20	19	19	19	19	19	19	19	19	19	19	18	18	18	18	18	18	18
Existing Biogas	Bio_Bradley																					
	Bio_Lopez																					
	Bio_Toyon	6																				
	Atmos & Shell Gas Credit																					
	Hyperion Digester Gas	132	131																			
	Shell Renewable Biomethane	311	320	320	320	320	320	267														
Existing Geo	Geo_DonCamb	127	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114		
	Geo_Hudson Ranch	272	438	438	438	438	438	438														
Existing Subtotal		3,438	4,263	4,555	4,510	4,508	4,508	4,454	3,664	3,578	3,244	3,244	3,244	3,067	3,051	3,050	3,050	3,050	3,049	3,049	2,935	2,935
New Geo	Geo_Herber1		187	187	187	291	291	291	291	291	291	291										
	Geo_Imperial									200	300	350	400	400	400	400	400	400	400	400	400	400
	Geo_Imperial_Ext											200	300	350	400	400	400	400	400	400	400	400
	Geo_DonCamb2		143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
	Geo_PPA_2017 OR			21	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
	Geo_PPA_2017 OT			48	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
	Geo_PPA_2026 OH												287	287	287	287	287	287	287	287	287	287
	Geo_Generic (50%)							200	600	800	800	800	800	800	800	800	800	800	800	800	800	800
	Subtotal		330	399	694	798	798	998	1,398	1,798	1,898	2,148	2,294	2,344	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394
New Solar	Solar_Owens										132	262	393	522	519	517	514	512	509	507	504	501
	Solar_DWP_Basin_P	4	9	14	20	25	30	35	41	46	51	56	62	65	65	64	64	64	63	63	63	63
	Solar_FIT_150	52	183	263	263	261	260	259	257	256	255	253	252	251	250	248	247	246	245	243	242	241
	Solar_FIT_300			22	109	197	284	372	458	522	521	518	516	513	511	508	506	503	501	498	496	493
	Solar_CNM_RPS_P																					
	Solar_CNM_nonRPS_P	18	44	136	221	261	273	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
	Solar_PPA_SG		109	435	433	431	429	426	424	422	420	418	416	414	412	410	408	406	403	401	399	397
	Solar_PPA_SG2						125	124	124	123	123	122	121	121	120	119	119	118	118	117	117	116
	Solar_PPA_SG3											450	448	446	443	441	439	437	434	432	430	428
	Solar_PPA_VicLA													156	608	608	608	608	608	608	608	608
	Solar_PPA_Springbok		117	270	268	267	266	264	263	262	261	259	258	256	256	254	253	251	251	249	249	248
	Solar_PPA_Springbok2			407	405	403	401	399	397	395	393	391	389	387	385	383	381	379	378	376	374	372
	Solar_PPA_Springbok3			240	239	238	236	235	234	233	232	231	229	228	227	226	225	224	223	222	220	219
	Solar_PPA_Beacon		346	617	613	610	607	604	601	598	595	592	589	586	583	581	578	575	572	569	566	563
	Solar_PPA_RecurrentBR		110	182	181	180	179	178	177	177	176	175	174	173	172	171	171	170	169	168	167	166
	Solar_PPA_K.Moapa	18	527	664	664	664	664	664	664	664	664	664	664	664	664	664	664	664	664	664	664	664
	Solar_Generic (50%)															250	500	500	500	500	500	500
	Subtotal	74	1,401	3,113	3,195	3,276	3,482	3,561	3,641	3,698	3,822	4,391	4,511	4,783	5,216	5,445	5,676	5,656	5,637	5,617	5,600	5,580
New Wind	Wind_PineCYN								76	227	227	227	227	227	227	227	227	227	227	227	227	228
	Wind_Ext									263	394	394	394	526	526	526	526	526	526	526	526	526
	Wind_ISO											263	526	526	526	526	526	526	526	526	526	526
	Wind_STS													231	462	462	462	462	462	462	462	462
	Subtotal								76	490	621	884	1,147	1,509	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,741
New Small Hydro	WSHydro				11	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	Aqueduct PP Improvement				15	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
ic_RPS (50%_800	Generic_RPS (50%_800_High)													100	200	400	700	1,100	1,300	1,500	1,900	2,100
P_(50%_800_Hig	GP_(50%_800_High)	1,637							60		385		9	10		25	17		40	50	3	
Total RPS		5,149	5,995	8,067	8,425	8,633	8,840	9,066	8,891	9,616	10,022	10,719	11,257	11,865	12,653	13,106	13,628	13,992	14,213	14,402	14,623	14,802

Figure N-3. Renewable energy production in GWh for 2015 IRP recommended case.

N.4 Model Input and Assumptions

The following pages present the major input parameters and assumptions that were incorporated into the production cost model for this 2015 IRP.

Load Forecast

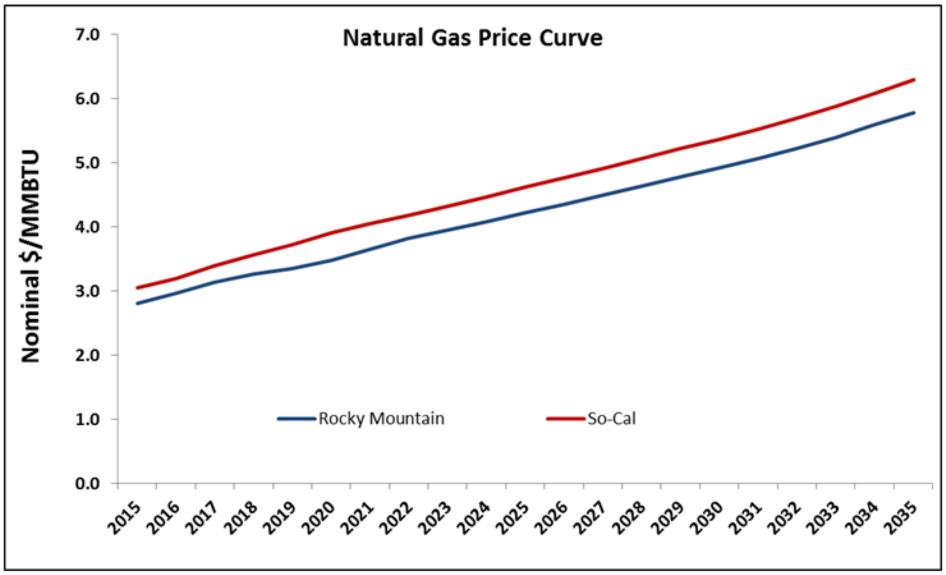
	May 2015 Forecast						2015 IRP					
Year	Net Energy for Load (A)	Energy Efficiency (B)	Solar Rooftop Program (C)	Forecasted Sales (D)	% Annual Sales Change before EE	% Annual Sales Change after EE	Net Energy for Load for model run (E)	Solar Rooftop Program (F)	Energy Efficiency (G)	IRP Calculated Sales (H)	% Annual Sales Change before EE	% Annual Sales Change after EE
2015	26,898	438	141	23,670	1.03%	-0.05%	27,556	277	517	23,488	1.03%	-0.2%
2016	26,932	711	233	23,639	1.00%	-0.13%	28,005	369	914	23,394	1.26%	-0.4%
2017	26,794	988	317	23,579	0.89%	-0.25%	28,277	454	1,372	23,090	0.64%	-1.3%
2018	26,894	1,274	355	23,666	1.52%	0.37%	28,745	494	1,847	22,987	1.52%	-0.4%
2019	27,070	1,514	365	23,822	1.59%	0.66%	29,205	506	2,295	22,932	1.58%	-0.2%
2020	27,545	1,541	366	24,178	1.51%	1.49%	29,712	512	2,608	23,059	1.74%	0.6%
2021	27,955	1,541	366	24,600	1.64%	1.75%	30,122	512	2,773	23,255	1.41%	0.8%
2022	28,356	1,541	366	24,953	1.35%	1.43%	30,523	512	2,881	23,500	1.36%	1.1%
2023	28,778	1,541	366	25,325	1.40%	1.49%	30,945	512	2,962	23,790	1.41%	1.2%
2024	29,297	1,541	366	25,720	1.47%	1.56%	31,464	512	3,015	24,194	1.71%	1.7%
2025	29,671	1,541	366	26,110	1.43%	1.52%	31,838	512	3,049	24,489	1.21%	1.2%
2026	30,105	1,541	366	26,493	1.39%	1.47%	32,272	512	3,080	24,840	1.39%	1.4%
2027	30,535	1,541	366	26,871	1.35%	1.43%	32,702	512	3,114	25,184	1.36%	1.4%
2028	31,043	1,541	366	27,256	1.36%	1.43%	33,210	512	3,149	25,596	1.58%	1.6%
2029	31,409	1,541	366	27,640	1.33%	1.41%	33,576	512	3,187	25,880	1.12%	1.1%
2030	31,851	1,541	366	28,029	1.33%	1.41%	34,018	512	3,231	26,225	1.34%	1.3%
2031	32,297	1,541	366	28,421	1.33%	1.40%	34,464	512	3,267	26,582	1.33%	1.4%
2032	32,814	1,541	366	28,815	1.31%	1.39%	34,981	512	3,286	27,018	1.52%	1.6%
2033	33,195	1,541	366	29,212	1.31%	1.38%	35,362	512	3,291	27,348	1.11%	1.2%
2034	33,646	1,541	366	29,609	1.29%	1.36%	35,813	512	3,296	27,740	1.30%	1.4%
2035	34,101	1,541	366	30,009	1.28%	1.35%	36,268	512	3,301	28,135	1.29%	1.4%

Notes:

1. Net Energy for Load for model run (E) = [Net Energy for Load (A) + Energy Efficiency (B)/0.88 + Solar Rooftop Program (C) /0.88]
2. IRP Calculated Sales (H) = [E – F /0.88 – G /0.88 + 37] * 0.88

Natural Gas Prices

Gas Price used in IRP 2015		
Year	Rocky Mountain	So-Cal
2015	2.80	3.04
2016	2.96	3.19
2017	3.13	3.39
2018	3.26	3.56
2019	3.35	3.72
2020	3.48	3.90
2021	3.65	4.05
2022	3.82	4.18
2023	3.94	4.32
2024	4.08	4.47
2025	4.23	4.63
2026	4.35	4.77
2027	4.49	4.91
2028	4.63	5.06
2029	4.78	5.22
2030	4.92	5.37
2031	5.06	5.53
2032	5.22	5.69
2033	5.40	5.88
2034	5.59	6.08
2035	5.77	6.29



Natural Gas Prices and Volume for Pinedale Reserves

Pinedale Gas Price	
Date	$/MMBTU
7/1/2011	3.45
7/1/2012	4.00
7/1/2013	4.17
7/1/2014	4.20
7/1/2015	4.24
7/1/2016	4.28
7/1/2017	4.32
7/1/2018	4.36
7/1/2019	4.40
7/1/2020	4.44
7/1/2021	4.48
7/1/2022	4.48
7/1/2023	4.48
7/1/2024	4.48
7/1/2025	4.48
7/1/2026	4.48
7/1/2027	4.48
7/1/2028	4.48
7/1/2029	4.48

Pinedale Gas Volume	
Date	GBTU/Day
7/1/2011	30.65
7/1/2012	32.25
7/1/2013	23.54
7/1/2014	19.68
7/1/2015	18.27
7/1/2016	15.97
7/1/2017	14.49
7/1/2018	13.22
7/1/2019	12.34
7/1/2020	11.47
7/1/2021	10.66
7/1/2022	10.66
7/1/2023	10.66
7/1/2024	10.66
7/1/2025	10.66
7/1/2026	10.66
7/1/2027	10.66
7/1/2028	10.66
7/1/2029	10.66

LADWP Existing Generation Resources

CITY OF LOS ANGELES - DEPARTMENT OF WATER AND POWER
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Based on Information Available as of July 1, 2015

NAME OF PLANT	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPABILITY [2] (kW)	NET MAXIMUM PLANT CAPABILITY [3] (kW)	NET DEPENDABLE PLANT CAPABILITY [4] (kW)
			(kVA)	(kW)			
San Francisquito Power Plant 1	1A	12/10/1983	25,000	22,500	27,000	83,050	[A] [B] 24,230
	3	4/16/1917	9,375	7,500	10,000		
	4	5/21/1923	12,500	10,000	12,000		
	5A	4/9/1987	25,000	22,500	27,000		
San Francisquito Power Plant 2	1	7/6/1919	17,500	14,000	0		
	2	8/7/1919	17,500	14,000	14,000		
	3	12/2/2006	20,000	18,000	18,000		
San Fernando Power Plant	1	10/22/1922	3,500	2,800	3,200		
	2	10/22/1922	3,500	2,800	2,900		
Foothill Power Plant	1	10/6/1971	11,000	11,000	9,900		
Franklin Power Plant	1	8/3/1921	2,500	2,000	2,000		
Sawtelle Power Plant	1	6/5/1986	711	640	650		
Haiwee Power Plant	1	7/18/1927	3,500	2,800	2,500	[D] 11,830	[C] [E] [F] 1,200
	2	7/18/1927	3,500	2,800	2,500		
Cottonwood Power Plant	1	11/13/1908	937	750	1,200		
	2	10/13/1909	937	750	1,200		
Division Creek Power Plant	1	3/22/1909	750	600	680		
Big Pine Power Plant	1	7/29/1925	4,000	3,200	3,050		
Pleasant Valley Power Plant	1	2/5/1958	4,000	3,200	2,700		
Upper Gorge Power Plant	1	6/15/1953	37,500	37,500	37,500	112,500	[G] 108,500
Middle Gorge Power Plant	1	5/11/1952	37,500	37,500	37,500		
Control Gorge Power Plant	1	4/1/1952	37,500	37,500	37,500		
Hoover Power Plant (Energy Purchase from WAPA through Sept. 2017) [H]						491,000	390,000
TOTAL HYDRO						**698,300**	**524,930**
Castaic Power Plant	1	7/11/1973	287,500	271,000	271,000	1,247,000	[I] [J] 1,175,000
	2	7/9/1974	287,500	271,000	271,000		
	3	7/13/1976	287,500	271,000	271,000		
	4	6/16/1977	287,500	271,000	271,000		
	5	12/16/1977	287,500	271,000	271,000		
	6	8/11/1978	287,500	271,000	271,000		
	7	1/27/1972	70,000	56,000	56,000		
TOTAL PUMP STORAGE						**1,247,000**	**1,175,000**
Harbor Generating Station	1	1/31/1995	100,400	85,340	78,000	458,000	[K] 452,000
	2	1/31/1995	100,400	85,340	78,000		
	5	1/31/1995	93,750	75,000	66,000		
	10	1/4/2002	71,176	60,500	47,400		
	11	1/4/2002	71,176	60,500	47,400		
	12	1/4/2002	71,176	60,500	47,400		
	13	1/4/2002	71,176	60,500	47,400		
	14	1/4/2002	71,176	60,500	47,400		
Valley Generating Station	5	8/17/2001	71,176	60,500	43,000	576,000	[L] 556,000
	6	9/4/2003	215,000	182,750	162,000		
	7	9/9/2003	215,000	182,750	162,000		
	8	11/13/2003	311,000	264,350	209,000		
Scattergood Generating Station	1	12/7/1958	192,000	163,200	183,000	817,000	796,000
	2	7/1/1959	192,000	163,200	184,000		
	3	10/6/1974	552,000	496,800	450,000		
Haynes Generating Station	1	9/2/1962	270,000	230,000	222,000	[V] 1,615,202	[M] 1,585,200
	2	4/7/1963	270,000	230,000	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	99,367		
	12	6/12/2013	127,282	108,190	99,367		
	13	6/12/2013	127,282	108,190	99,367		
	14	6/19/2013	127,282	108,190	99,367		
	15	6/12/2013	127,282	108,190	99,367		
	16	6/12/2013	127,282	108,190	99,367		
TOTAL BASIN THERMAL (Based on gas fuel ratings)						**3,466,202**	**3,389,200**
Navajo Generating Station	1	2/1/1974	892,400	803,000	750,000	477,000	[N] 477,000
	2	12/2/1974	892,400	803,000	750,000		
	3	11/29/1975	892,400	803,000	750,000		
Intermountain Generating Station	1	6/9/1986	991,000	820,000	900,000	1,202,000	[O] 1,202,000
	2	4/30/1987	991,000	820,000	900,000		
Palo Verde Nuclear Generating Station	1	1/30/1986	1,550,000	1,413,000	1,333,000	386,690	[P] 380,314
	2	9/19/1986	1,550,000	1,413,000	1,336,000		
	3	1/19/1988	1,550,000	1,413,000	1,334,000		
Apex Generating Station [S] [T]	1A	3/28/2014	239,000	203,150	162,000	531,860	[U] 479,900
	1B	3/31/2014	239,000	203,150	162,000		
	STG	3/28/2014	264,000	237,600	207,860		
TOTAL THERMAL						**2,597,550**	**2,539,214**
SUBTOTAL NET DEPENDABLE SYSTEM CAPABILITY						**8,009,132**	**7,628,344**
Transfer	State's Capacity Entitlement [Q]					(120,000)	(43,720)
NET DEPENDABLE SYSTEM CAPABILITY						**7,889,132**	**7,584,624**

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NAME OF PLANT	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPABILITY [2] (kW)	NET MAXIMUM PLANT CAPABILITY [3] (kW)	NET DEPENDABLE PLANT CAPABILITY [4] (kW)
			(kVA)	(kW)			
Pine Tree Wind Power Plant	1 - 90	6/14/2009	1,667	1,500	1,500	**135,000**	[R]
Pine Tree Solar Power Plant	1 - 17	3/15/2013	500	500	500	**8,500**	[W]
Adelanto Solar Power Plant	1 - 13	6/30/2012	770	770	770	**10,000**	[X]

(1) Power from Power Purchase Agreements and fuel cells is not included in this table.
(2) All units can attain maximum capability only when the weather and equipment are simultaneously at optimum conditions.
(3) Reflects water flow limits at hydro plants; or sum of each unit at in-basin thermal or wind power plants; or entitlements from external thermal plants.
(4) Reflects year-round outputs adjusted for low-generation season. For hydro plants, winter is the low generation season.
[A] Aqueduct combined Net Dependable Plant Capability reflects low water availability during winter.
[B] San Francisquito Power Plant 2, Unit 1 has been out of service since 1996. San Francisquito Power Plant 2, Unit 2 stator heating limits capacity to 8 MW during hot weather conditions. San Francisquito Power Plant 2, Unit 3 has a new generator with refurbished turbine as of December 2, 2006. Contract specification is 18 MW output, but unit was tested to only 16 MW due to low water flows and restricted downstream capacity. Assumed maximum actual output is 18 MW.
[C] Owens Valley combined Net Dependable Plant Capability is 1.2 MW based on 20 years of historical data. 1.2 MW consists of 0 MW from Haiwee and Pleasant Valley and 0.4 MW each from Cottonwood, Division Creek, and Big Pine.
[D] Haiwee maximum unit capability is 2.5 MW each when only one unit is in service; when both units are in service, the Net Maximum Plant Capability is 3.6 MW when feed is taken from North Haiwee Reservoir. Cottonwood Power Plant, Units 1 and 2 Net Maximum Unit Capability is 1.2 MW each. Cottonwood Net Maximum Plant Capability is 1.8 MW.
[E] Big Pine and Cottonwood Net Maximum Unit Capability is limited to a maximum flow through penstock.
[F] Pleasant Valley Power Plant output is limited by Division of Safety of Dams (DOSD) reservoir level restriction.
[G] Owens Gorge Net Dependable Plant Capability reflects re-watering flow.
[H] LADWP's entitlement is 25.16% of the plant capability of 1,951 MW. The reduced entitlement is due to lower lake levels resulting from the drought which causes plant capability to constantly vary. The most recent available average Net Plant Capability is 390 MW for FY 2014-2015.
[I] Castaic Power Plant is re-rated at 1,175 MW, but is capable of generating 1,247 MW for short periods or for extended periods if sufficient flow-through water schedules are received.
[J] Castaic Power Plant, Units 1-6 have completed modernization improvements: 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, and Unit 1 in October 2013.
[K] Harbor Generating Station Net Dependable Plant Capability is 452 MW due to Units 1, 2, and 5 reduced performance during hot weather conditions. Units 1 and 2 were de-rated to 78 MW due to gas turbine wear.
[L] Valley Generating Station Net Dependable Capability is limited to 556 MW reflecting reduced performance during hot weather conditions. This includes operating Units 6 and 7 with duct burners in service. Units 6, 7, and 8 can only produce power in a combine cycle combination (1+1, 2+1).
[M] Haynes Generating Station Net Dependable Capability is 1,585 MW reflecting reduced performance during hot weather conditions. This includes operating Units 9 and 10 with duct burners in cycle. Unit 4 was decommissioned in November 2003 and Unit 3 was decommissioned in September 2004. Units 5 and 6 were decommissioned in June 2013. Units 8, 9, and 10 can only produce power in a combine cycle combination (1+1, 2+1).
[N] LADWP's entitlement is 21.2% of total Navajo net generation.
[O] IPP Net Dependable Plant Capability may be less than 1,202 MW due to Excess Power Recall. For FY 2014-2015, the Dependable Capability is approximately 1,202 MW. The LADWP 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. The nominal Net Maximum Unit Capability and Net Dependable Capability of both Units 1 and 2 is 900 MW.
[P] LADWP's 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.
[Q] The maximum State (CDWR) Capacity Entitlement from Castaic Power Plant is 120 MW. The average for FY 2014-2015 was approximately 43.72 MW.
[R] Pine Tree Wind Power Plant was commissioned in June 2009. Wind generation is not considered to be dispatchable and dependable.
[S] Apex Generating Station Net Dependable Capability is limited to 479.9 MW reflecting reduced performance during hot weather conditions. This includes operating Units 1A and 1B with duct burners in service. Units can only produce power in a combine cycle combination (1+1, 2+1).
[T] SCCPA owns Apex Generating Station. Units 1A and STG were originally placed in-service by the original owner on January 13, 2003, and Unit 1B was originally placed in-service on January 20, 2003. SCCPA took ownership of Apex Generating Station on March 26, 2014, and maintains a sales agreement for the Station's generated power.
[U] Currently LADWP purchases one-hundred percent of Apex Generating Station's production of power.
[V] For Haynes Generating Station, Units 11-16, the net maximum unit capability occurs when all 6 units are in-service as this is when the lowest average auxiliary power is being drawn per unit.
[W] Pine Tree Solar Power Plant was commissioned in March 2013. Solar generation is not considered to be dispatchable and dependable.
[X] Adelanto Solar Power Plant was commissioned in June 2012. Solar generation is not considered to be dispatchable and dependable.

A.AK ALV LBB/ALV DKY
Reviewed by: Anton L. Vu, Lars B. Black, and Daryl K. Yonamine

Approved by:
Kenneth A. Silver

Kenneth A. Silver
Director of Power Supply Operations Division

IPP Capacity for LADWP

IPP Capacity (MW)								
CY	Season	DWP's Excess Share (MW)	Short Term Recall	DWP's Excess Share Recalled via Long-Term Letter (MW)	DWP's Excess Share Recalled via Short-Term Letter (MW)	DWP's Excess Share Recalled via UP&L Purchase (MW)	DWP's Own Entitlement (MW)	Total IPP Capacity (MW)
2015	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2016	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2017	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2018	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2019	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2020	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2021	Summer	327	0	0	327	72	803	1202
	Winter	327	0	0	325	72	803	1202
2022	Summer	327	0	-50	277	72	803	1152
	Winter	327	0	-50	275	72	803	1152
2023	Summer	327	0	-150	177	72	803	1152
	Winter	327	0	-150	175	72	803	1152
2024	Summer	327	0	-250	77	72	803	952
	Winter	327	0	-250	75	72	803	952
2025	Summer	327	0	-327	0	72	803	875
	Winter	327	0	-327	0	72	803	875
2026	Summer	327	0	-327	0	72	803	875
	Winter	327	0	-327	0	72	803	875
2027	Summer	327	0	-327	0	72	803	875

IPP Debt Service and O&M, and Generation Expenses

FY	IPA Generation Debt Service									IPA Generation O&M	IPA Generation D/S O&M	DWP's Share of IPA Generation	DWP's Share of IPA D/S & O&M
	Principal (M$)			Interest (M$)			Debt Service (M$)			M$	M$	M$	M$
	Regular	Subord.	Total	Regular	Subord.	Total	Regular	Subord.	Total				
2008										$174.7	$174.7	58.39%	$102.0
2009										$156.3	$156.3	57.18%	$89.4
2010	$104.5	$34.0	$138.5	$57.6	$59.6	$117.2	$138.5	$117.2	$255.7	$167.3	$423.0	59.21%	$250.5
2011	$128.3	$80.4	$208.7	$51.1	$56.0	$107.1	$208.7	$107.1	$315.9	$170.8	$486.7	60.14%	$292.7
2012	$83.2	$104.2	$187.4	$46.9	$49.6	$96.4	$187.4	$96.4	$283.8	$167.8	$451.6	62.54%	$282.4
2013	$72.4	$68.6	$141.0	$42.5	$41.3	$83.7	$141.0	$83.7	$224.8	$169.0	$393.7	65.86%	$259.3
2014	$67.2	$76.8	$144.0	$26.1	$38.3	$64.4	$144.0	$64.4	$208.4	$165.7	$374.1	66.17%	$247.5
2015	$64.3	$73.2	$137.5	$23.5	$28.7	$52.2	$137.5	$52.2	$189.7	$161.9	$351.7	66.17%	$232.7
2016	$146.9	$90.5	$237.4	$22.0	$24.6	$46.6	$237.4	$46.6	$283.9	$159.3	$443.2	66.35%	$294.1
2017	$79.4	$26.9	$106.3	$18.9	$24.4	$43.2	$106.3	$43.2	$149.5	$162.5	$312.0	66.17%	$206.4
2018	$137.2	$53.3	$190.5	$14.3	$12.5	$26.8	$190.5	$26.8	$217.3	$165.7	$383.0	66.17%	$253.5
2019	$87.1	$124.7	$211.8	$9.3	$20.5	$29.8	$211.8	$29.8	$241.6	$169.0	$410.6	66.17%	$271.7
2020	$58.8	$161.2	$220.0	$6.5	$5.8	$12.3	$220.0	$12.3	$232.3	$172.4	$404.8	66.35%	$268.6
2021	$54.8	$158.5	$213.3	$5.0	-$7.0	-$1.9	$213.3	-$1.9	$211.3	$175.9	$387.2	66.17%	$256.2
2022	$81.3	$73.1	$154.4	$3.2	-$8.8	-$5.5	$154.4	-$5.5	$148.9	$179.4	$328.2	65.42%	$214.7
2023	$36.4	$73.9	$110.4	$1.2	-$3.6	-$2.4	$110.4	-$2.4	$107.9	$183.0	$290.9	61.90%	$180.1
2024	$4.9	$6.2	$11.1	$0.1	-$0.6	-$0.4	$11.1	-$0.4	$10.7	$186.6	$197.3	56.50%	$111.5
2025	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$190.4	$190.4	51.13%	$97.3

Demand Response Schedule

Fiscal Year Ending	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	25-26	26-27
MW	20	40	65	100	150	200	250	300	350	400	450	500
Total Annual Budget ($000)	6,763	11,098	11,461	14,312	16,737	21,170	26,103	27,925	30,386	32,939	35,573	36,000

LADWP Solar Program

Customer Net Metered Solar Program

CY	Cumulative Total Installed CNM (MW AC)	Cumulative Total Effective Install (GWh)	Equiv Ann Incentive Pmts $M/Yr ($370M Total)
2015	156	218	
2016	193	277	$25.0
2017	254	369	$27.0
2018	296	454	$28.0
2019	303	494	$29.0
2020	310	506	$30.0
2021	310	512	$30.0
2022	310	512	$30.0
2023	310	512	$30.0
2024	310	512	$30.0
2025	310	512	$30.0
2026	310	512	$30.0
2027	310	512	$30.0
2028	310	512	$30.0
2029	310	512	$30.0
2030	310	512	$25.0
2031	310	512	$18.0
2032	310	512	$16.0
2033	310	512	$13.0
2034	310	512	$13.0
2035	310	512	$13.0

Community (UBS) Solar Program

CY	Cumulative Install Target (MW AC)	Cumulative Effective Install (GWh)
2015	4.1	7
2016	8	14
2017	14	25
2018	19	33
2019	24	42
2020	29	51
2021	34	60
2022	40	70
2023	40	70
2024	40	69
2025	39	69
2026	39	69
2027	39	68
2028	39	68
2029	39	68
2030	38	67
2031	38	67
2032	38	67
2033	38	66
2034	38	66
2035	37	66

Feed-In Tariff Solar Program - 100

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)
2015	15	17
2016	78	116
2017	100	175
2018	100	175
2019	100	175
2020	100	175
2021	100	175
2022	100	175
2023	100	175
2024	100	175
2025	100	175
2026	100	175
2027	100	175
2028	100	175
2029	100	175
2030	100	175
2031	100	175
2032	100	175
2033	100	175
2034	100	175
2035	100	175

Feed-In Tariff Solar Program - 50

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)
2015		
2016	43	67
2017	50	88
2018	50	88
2019	50	88
2020	50	88
2021	50	88
2022	50	88
2023	50	88
2024	50	88
2025	50	88
2026	50	88
2027	50	88
2028	50	88
2029	50	88
2030	50	88
2031	50	88
2032	50	88
2033	50	88
2034	50	88
2035	50	88

Feed-In Tariff Solar Program - 300

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)
2015		
2016		
2017	25	22
2018	75	109
2019	125	197
2020	175	284
2021	225	372
2022	275	459
2023	300	525
2024	300	525
2025	300	525
2026	300	525
2027	300	525
2028	300	525
2029	300	525
2030	300	525
2031	300	525
2032	300	525
2033	300	525
2034	300	525
2035	300	525

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Appendix O Public Outreach

This Appendix O describes the public outreach that was carried out as part of the 2014 IRP process to involve the public in the development of the LADWP 2014 IRP. Public outreach efforts occur once every two years and were carried out for last year's 2014 IRP. The appendix is arranged into four sections:

1. Outreach Overview: Describes the purpose of the public outreach effort, and outlines the outreach process and its relationship to this IRP.
2. Community Outreach Program: Provides an overview of all aspects of the outreach, including stakeholder meetings, website, and public workshops.
3. Comments and Discussion Themes: Presents a summary of the public comments inputted during the community outreach program; and discussion of themes synthesized from the public input.
4. Exhibits: Include the notes from the stakeholder meetings and public workshops, comment forms submitted at the public meetings and online, and other comments that were submitted through the website, e-mail, and US mail.

O.1 Outreach Overview

The 2014 IRP process included a public outreach effort to provide information, increase awareness, and gather public input on LADWP's long-term power resource plan. Public outreach consisted of a series of five IRP Advisory Committee meetings, three public workshops, and a dedicated website (www.ladwp.com/powerIRP). Comments were gathered at the IRP Advisory Committee meetings and public workshops, and were also provided through an online comment form, direct e-mail, and the US mail.

The 2014 IRP includes a public review process, including the formation and active participation of a new IRP Advisory Committee (Committee). The purpose of the Committee is to further transparency and build on the collaborative dialog that was conducted in recent IRP processes. The Committee was presented with the major issues facing LADWP and weighed in on how those issues should be addressed.

While the Committee did not have approval authority for the 2014 IRP, it influenced the assumptions that were used in the case scenarios, as well as the final recommendations and near term actions. The Committee contributed to the process in a constructive manner, mutually exchanging information with LADWP for the betterment of the Power System, the ratepayers, and the environment.

The Committee represents a range of stakeholder representatives, including: Neighborhood Councils, Business Customer Representatives, Environmental Representatives, the LA City

Council and Mayor's office, and an academic representative from UCLA. The Office of Public Accountability (Ratepayer Advocate) attended most meetings as an observer of the proceedings. The Committee met five times throughout the calendar year and provided input in the development and recommendation of the final 2014 IRP cases. Comments received during these stakeholder meetings were considered in the development of the preliminary cases that were analyzed.

In addition to the IRP Advisory Committee, three Public Outreach Workshops were held in October and November 2014, to provide an overview of the 2014 IRP and collect comments from the general public regarding the final 2014 IRP cases. Surveys were distributed during the public workshops and an online form was available to collect comments. Attendees of the Public Outreach Workshops advocated greater levels of Renewables, Energy Efficiency, and Local Solar. The 2014 Draft IRP was made available for public comment. Considering the public comment and input received, a final set of recommendations was made.

The many public comments and input received were synthesized into a set of discussion themes that reflect the major ideas provided by the public. The themes were reviewed and considered in developing the final recommended plan that is incorporated in this final 2014 IRP document.

O.2 Community Outreach Program

LADWP developed a multipronged outreach approach to allow community members and stakeholders different opportunities to provide input on the 2014 IRP. Community involvement opportunities were provided through a website, IRP Advisory Committee meetings, and three general public workshops. Comments were accepted at the meetings and workshop, through the website, and via direct e-mail and the US mail. Input collected through each of these means is considered of equal importance when considered by LADWP staff.

- **IRP Advisory Committee:** In February 2014, the 2014 IRP Advisory Committee was formed, consisting of representatives from the Mayor's office, council districts, key major customers, business associations, environmental organizations, neighborhood councils, and academia. The Committee met five times between February 2014 and September 2014, and provided collaborative dialog and stakeholder feedback on major power-related issues and cases developed for the IRP. The purpose of these meetings was to discuss and collect public inputs for consideration in the development of the 2014 IRP Cases. Discussion notes can be found in Exhibit A.

- **Draft IRP Public Workshops**: Three IRP Public Outreach Workshops were held on October 28, October 30, and November 6, 2014, at the LADWP Headquarters, Pacoima, and Wilmington, respectively, in which the 2014 IRP overview and results were presented for public feedback. The Public Outreach Workshops serve as an opportunity for public stakeholders to learn about the 2014 IRP and provide their input on the future of LADWP. Information was provided during the Workshop, in regards to the various programs which customers may participate, including Environmental Efficiency, Local Solar, and Electric Vehicle Rebates. The purpose of the workshops was to present the 2014 IRP case results and collect public input for consideration prior to preparing the 2014 Final IRP. Input collected at these meetings is included in the discussion themes found in the next section of this document. Discussion notes can also be found in Exhibit B.

- **Website and Online Forms**: A project website (www.ladwp.com/powerIRP) was utilized for the 2014 IRP. The website included an announcement of the public workshops, and a section that allowed the public to submit comments and questions about the plan online. The website provided access to a complete version of the 2014 Draft IRP and associated technical appendices, as well as a stand-alone version of the Executive Summary. Comments submitted through the website can be found in Exhibit C. Comments submitted through other methods (e-mail or US mail) can be found in Exhibit D.

O.3 Discussion Themes

The public workshops, online survey, and comment forms yielded a significant amount of information from LADWP customers related to the 2014 IRP. This information has been synthesized into a set of discussion themes that reflect the major ideas provided by participants during the community outreach program.

The discussion themes listed below are not representative of the city at-large, and only encompass input from participants in the public workshops and members of the public who completed the online comment form, or submitted comments through e-mail or the US mail. The majority of the attendees represent members from the Environmental Community. All the ideas that were prioritized during the public workshops are included within the discussion themes; however, each theme is considered to be of equal importance, and the themes are not listed in any order of priority.

Theme: Eliminate Coal from LADWP's Energy Portfolio

Discussion

The majority of comments favored the early removal of coal from LADWP's resource portfolio and favored Case 2 – Navajo divestiture by 2015 and IPP replacement by 2025. Greenhouse gas emissions, along with other pollutants associated with coal energy were noted.

Related LADWP Actions:

- LADWP is proceeding with plans to divest of Navajo Generating Station by 2015—four years ahead of the SB 1368 requirement.
- LADWP is working with the IPP participants to convert the IPP facility from coal to natural gas by July 1, 20025. As of September 12, 2014, 27 of 36 participants have approved the amendment.

Theme: Decrease Natural Gas from LADWP's Energy Portfolio

Discussion

Many public comments opposed LADWP's projected increase in natural gas resulting from the replacement of coal resources. Major concerns surrounded the issue of fracking, air quality, potential water quality issues, methane leakage from transport and storage, greenhouse gas emissions, and other pollutants associated with natural gas.

Related LADWP Actions:

- Increasing renewables to 40 percent by 2030 and energy efficiency from 10 to 15 percent by 2020 will dramatically lower the use of natural gas from 43% to 32% of the energy resource mix by 2030. In comparison, coal today represents 40% of the resource mix and natural gas fired generation represents 22% so the overall reduction of fossil fuels will be from 62% to 32% by 2030.
- LADWP currently uses Castaic Pumped Hydro-electric Power Plant as an tool to integrate renewables and minimize the use of gas fired generators to provide the on-line reserves needed to support higher renewables and other system reliability needs. Additional smaller scale energy storage is also being planned to minimize gas reserves. In 2014, LADWP's Board of Water and Power Commissioners approved an Energy Storage Procurement target of 154 MW by 2021 in addition to the 26 MW approved for 2016. The technology of base-loaded generation to replace natural gas is limited at this time. LADWP is constantly evaluating technologies and alternatives to reduce greenhouse gas and dependence on fossil fuels. Future IRPs may consider replacement options for additional natural gas.

Theme: Incorporate More Renewables

Discussion

The majority of the attendees of the Public Outreach Workshops was from the Environmental Community and supported Case 5 – 50% renewables, and some even promoted 100%

renewables. LADWP's approach regarding this is to proceed cautiously until more is known about the operational and financial implications of higher levels of renewables, especially pertaining to system reliability and over-generation issues. Next year's IRP will include a reliability analysis regarding higher levels of renewables and its operational and financial impact on the Power System.

Related LADWP Actions:

- LADWP will increase its levels of renewable resource generation in accordance with SB 2 (1X) and increase to 40 percent RPS by 2030.
- LADWP will complete a maximum generation renewable energy penetration study in 2015 to consider issues associated with integrating increasing amounts of variable energy resources such as wind and solar, to reflect possible megawatt limits for the LADWP electric power system.

Theme: Incorporate More Local Solar

Discussion

A majority of the comments promoted Case 5 with 1,200 MW of local solar. Many comments promoted the adoption of higher levels of local solar, noting the abundance of sunshine in the Southern California region. The benefit of providing local jobs was also noted as a supporting argument to increase penetration levels. One comment suggested investing to install solar on every house and building in Los Angeles. Regarding LADWP's current customer incentive program, multiple comments recommended hiring more inspectors to streamline the process which many see as too slow, especially when compared to other utilities.

Related IRP Recommendations:

- Consider the expansion of the renewable energy feed-in tariff solar program up to 450 MW of to be developed by 2023.
- Continue the development of the Solar Incentive Program by 2019.
- Develop up to 40 MW of Community Solar capacity on existing properties under public/private partnership projects before 2020.

Theme: Incorporate More Energy Efficiency

Discussion

LADWP's Energy Efficiency (EE) targets, based on year 2020, have increased significantly, from 8.6% approved in December 2011; to 10% approved in May 2012; to 15% approved in July

2014. Comments received supported more EE incorporated into LADWP future plans. Some comments suggested maximizing EE and even proposed 20% EE by 2020. Many questions were directed towards specific EE programs and how customers can participate, such as trading in refrigerator and window mounted air conditioning units. Some comments suggested adding educational programs and energy efficiency home assessment programs to increase EE savings.

Related LADWP Actions:

- In July, the Board of Water and Power Commissioners approved a revised target of 15% of energy efficiency by 2020, based on the Energy Efficiency Potential Study completed in Fiscal Year 2013-14.
- Energy Efficiency Potential Studies will be performed once every three years per AB 2021, and increased EE targets may be considered for future IRPs.

Theme: Promote Electrification of the Transportation Sector

Discussion

Many of the public comments showed interest and support in LADWP promoting the electrification of the transportation sector. Comments advocated support for the greenhouse gas reduction levels that would primarily take place through the electrification of transportation sector. Some questions were raised regarding the matching of electrification cases to RPS cases—40 percent RPS included high electrification, whereas 50 percent RPS included medium electrification.

Related LADWP Actions:

- The 2014 IRP is the first year LADWP has included electrification of the transportation sector as a potential strategy to reduce overall greenhouse gas emissions in California. Future IRPs may consider matching different levels of electrification with various cases.
- LADWP will work with Local and State regulators to promote greater electrification in the Los Angeles basin to reduce GHG, NOx emissions and other criteria pollutants.
- Future IRP's will include more in-depth analysis on the cost-effectiveness of electrifying the transportation sector.

Theme: Incorporate More Energy Storage

Discussion

The majority of the public comments supported incorporating energy storage as a means to support renewables and reduce greenhouse gases. Some comments even advocated 100 percent renewables backed with energy storage. LADWP's approach regarding this is to proceed cautiously until energy storage solutions are proven to be cost-effective and dependable for integrating renewables and maintaining system reliability.

Related LADWP Actions:

- In August 2014, the LADWP Board of Water and Power Commissioners approved Energy Storage Procurement targets of 154 MW by 2021 in addition to the 36 MW previously approved for 2016. LADWP will continue to perform feasibility and cost-effectiveness studies on various energy storage technologies.
- LADWP will further develop its Smart Grid plans, which will facilitate the adoption of increasing levels of distributed generation and energy storage.

Theme: Reduce Greenhouse Gas Emissions

Discussion

This was an overarching theme of the public comments received. Indirect societal costs, health effects, and global warming were cited as reasons for accelerating the timelines to reduce GHGs. Eliminating natural gas was promoted as a means to reduce CO_2. Comments pointed out the need for considering increased renewables, energy efficiency, electrification of the transportation sector, and energy storage as strategies to reduce greenhouse gas emissions to 80 percent below 1990 levels by 2050.

Related LADWP Actions:

- LADWP is pursuing coal replacement (see above Theme)
- LADWP is repowering its coastal generation with more efficient units
- LADWP is adopting higher levels of renewables and energy efficiency, energy storage, demand response, and other load shifting strategies.
- LADWP is considering promoting the electrification of the transportation sector to reduce overall greenhouse gas emissions in Los Angeles.
- Provide financial incentives to encourage customers to shift their load away from peak hours to reduce the need for on-line generation and capacity

additions.

- Continue to investigate upgrades to the transmission and distribution system to provide voltage support and power import capabilities to minimize on-line generation.
- Consider quick start generators when repowering to reduce the need for on-line generation.

Theme: Look at New Case Scenarios

Discussion

Many comments suggested including additional cases to analyze more aggressive renewables and energy efficiency cases. Some suggested matching high electrification with Case 5- 50 percent renewables.

Related LADWP actions

- LADWP prepares a new IRP annually and will consider new scenarios within subsequent case option development processes.

O.4 Exhibits

- **A – IRP Advisory Committee Meeting Notes and Presentations**
- **B – Public Workshop Notes, Presentation, and Survey/Comment Forms**
- **C – Website Online Survey/Comment Forms**
- **D – Other Survey/Comment Inputs**

To view these exhibits, please visit www.ladwp.com/powerIRP

Appendix P Integrated Human Resources Plan (IHRP)

Los Angeles Department of Water & Power

Integrated Human Resources Plan (IHRP)

A CHAPTER IN
THE 2015 POWER INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

PAGES

1. **Executive Summary** **P-2**

2. **Supply and Demand** **P-3**

3. **Challenges and Critical Issues** **P-5**
   3.1 Demand Side Challenges
   - Decentralized planning P-5
   - Budget constraints P-5
   - Two-year planning horizons P-6
   - Support organizations P-6

   3.2 Supply Side Challenges
   - Workforce gaps P-6
   - Employee attrition P-9
   - Feeder class vacancies P-14
   - The critical path P-17
   - Labor issues P-21

4. **The Integrated Human Resources Plan (IHRP)** **P-22**
   4.1 Overview P-22
   4.2 The IHRP Demand Side Approach P-24
   - Workforce Demand Forecast Report
   - The revised JJS

   4.3 The IHRP Supply Side Approach P-24
   - Workforce Development Task Force
   - Workforce gap strategies

   4.4 Priorities and Schedule P-29
   4.5 Reporting P-34
   4.6 Conclusion P-35

Appendix
Non-cumulative attrition projection P-36
Assumptions in retirement probability P-38

1. EXECUTIVE SUMMARY

The Power System is entering a time of dramatic changes and three critical issues. First, by 2023 a significant number of current Power System workforce are expected to retire. The expected level is over 1,200 employees and may exceed 1,700. The loss of 1,200 equals a minimum of 37,400 years of experience and knowledge walking out the door. Second, most feeder class vacancies are increasing and will impede normal promotional ladders from filling positions that have routinely become vacant. Therefore alternative hiring practices will be required to fill these vacancies. Third, the time currently required to fill a position can take up to 6 years or longer. This duration puts the Power System at a significant competitive disadvantage. Others cities and private employers can make job offers to prospective DWP employees within days, not over an extended period of time.

The vast exiting of talent, knowledge, and experience places the operations of the Power System at risk. This exodus of retirees will come at a time when the Power System will be implementing significant changes in operations that utilize new, more efficient and renewable generation methods and advanced smart-grid technologies. These changes demand a larger future workforce with new skills, capabilities, and expertise. The Power System will also be grappling with a critical mass of mandated, yet unfunded, work in the Transmission and Distribution's infrastructure that may leave the Power System vulnerable to increased frequency and duration of outages.

Up to this point in time, the Power System has had no long-term program that could assure that all future vacant positions will be filled on time.

In 2013, the Power System launched the Integrated Human Resources Plan (IHRP) as a broad and systemic solution. It is a significant and far-reaching strategy that will manage the availability of the Power System's workforce for the next ten years and beyond. The IHRP is an integral part of resource planning that can make reasonable forecasts of the Power System's long-term employment needs while taking into consideration statistical retirement projections. The IHRP will ensure that trained and talented employees will always be available when needed to perform the important work that is described in this IRP document. The IHRP is a cooperative effort between the Los Angeles Department of Water and Power and the International Brotherhood of Electrical Workers (IBEW) Local 18.

PRIORITIES FOR 2013-14

DEMAND FORECAST OF THE POWER SYSTEM

- Install an effective on-line workforce demand tool that provides a ten-year forecast of staffing needs of the Power System.
- Design a Job Justification Sheet (JJS) that can yield resource loaded staffing requirements for individual projects / programs that are either funded or unfunded.

MEETING DEMANDS OF THE POWER SYSTEM

- The Workforce Planning Coordinators recommend to the JRB the gap strategies necessary for each job classification in the Power System.

- The five steps of the Critical Path have established measurable indicators of a streamlined system.

CRITICAL PATH IMPROVEMENTS

- Numerous innovations and breakthroughs are being designed or implemented that will improve Job Classification, Recruitment, Selection, Training, and Placement. These innovations are described in detail on pages 31-33.

2. SUPPLY AND DEMAND

The principles of supply and demand that operate in the business world also apply to the long-term development of human resources in the Power System. The "demand" is the need of the Power System to have a talented workforce available whenever IRP projects and programs require them. Much like a train that pulls into a station to fill its empty seats with passengers, the Power System needs all open positions to be filled on demand.

The Power System's demand is a rolling ten-year forecast of workforce requirements by specific job classifications. The "supply" is the talent pool of resources that are available on time. Figure 2-1 below represents some of these dynamics of demand and supply.

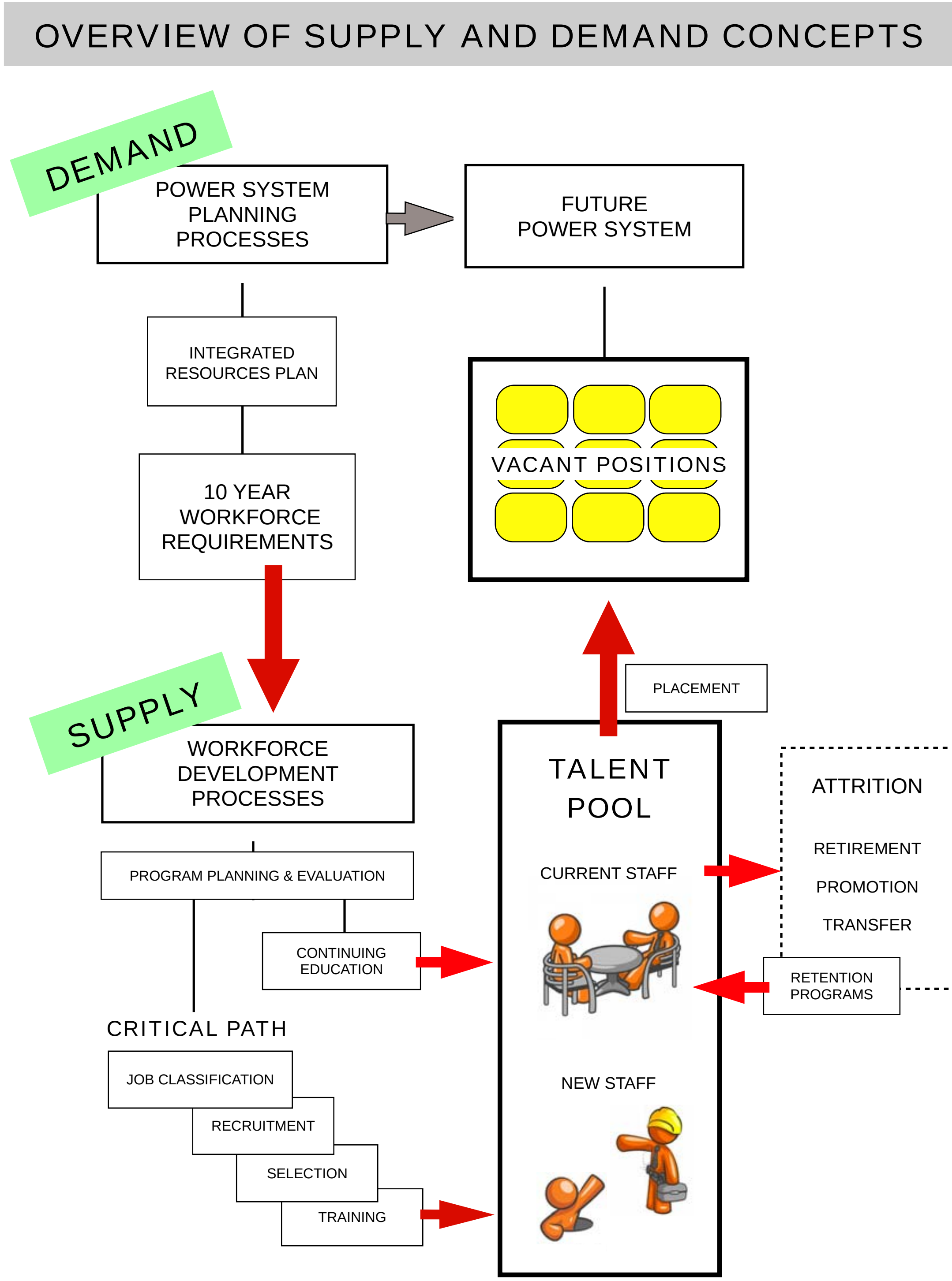

Figure 2-1. Overview of the supply and demand concepts

On the demand side, Figure 2-1 illustrates that the Power System planning processes will identify "vacant positions" in future operations. These open positions are referred to as forecasted workforce "gaps" later in this report. The forecasted demand for the next ten years is transferred to the supply side in the form of a formal report.

On the supply side, Figure 2-1 shows that workforce development processes will ensure that the talent pool is always available. The talent pool is continually eroded by attrition. It is replenished by the infusion of new staff, the continuing education of current staff and the retention of potential retirees. The talent pool is also supplemented by outside sources, such as exempt or contract labor.

3. CHALLENGES AND CRITICAL ISSUES

Over the past decade, dramatic new environmental regulations have driven the Power System to acquire and operate new technologies. During the upcoming decade, these changes in the Power System's operational mix are expected to continue and will demand new expertise. For example, the staff will need new skills to operate and maintain renewable generation facilities that are part of the Power System's future profile.

The Power System continues to seek new ways of managing its overall business more efficiently. Many of these changes will require new skills and expertise to manage smart grid deployment, solar distributed generation, renewable energy operations, and other advanced technologies.

3.1 Demand Side Challenges

There has been an insufficient integrated planning and implementation of the long-term development of the Power System's human resources. This section outlines these challenges for the demand side.

CHALLENGE #1: DECENTRALIZED PLANNING

There has been insufficient centralized and standardized methodology for forecasting the long-term human resource needs to support IRP initiatives or Power System projects / programs. The recent implementation of the Job Justification Sheet (JJS) has provided a common format for needed dialogue with Power System Divisions about their long-term plans. The JJS allows the Divisions to identify its needs and to execute capital projects and O&M activities as scheduled and within their budgets. In its current format, the JJS does not provide sufficient information for the most accurate planning of workforce requirements by job classification over a ten-year time span.

CHALLENGE #2: BUDGET CONSTRAINTS

The Power System executes all funded projects. Ideally, all long-term and mandated work drives the budget. Currently, the opposite is true for the Power System. Its short-term budget limits both the mandated work that can be done and the workforce available to do the work. Under these circumstances, significant and important unfunded work and its associated personnel remain unplanned and unbudgeted. Deferred work, especially in O&M, compounds the potential crisis in power reliability that is described above.

CHALLENGE #3: TWO-YEAR PLANNING HORIZONS

The IRP initiatives incorporate projects and programs that may take 10 to 20 years to fully implement. Unfortunately workforce planning has typically been limited to two-year forecasts that mask the labor required to complete long-term capital projects and O&M work.

CHALLENGE #4: SUPPORT ORGANIZATIONS

Some critical support organizations conduct their resource planning with inadequate long-term forecasts from the Power System's operating divisions. Many projects and programs greatly depend on the staffs from the Integrated Support Services Division (ISS), Systems Support Division (SS), and Power System Safety & Training (PSST). ISS provides staffing for internal construction, test lab, and shops support. SS provides a host of services including information technology, fleet, stores, purchasing, landscaping, custodial, and security. PSST provides a significant amount of apprentice and technical craft training to new employees of the Power System.

3.2 Supply Side Challenges

There has been an insufficient integrated planning and implementation of the long-term development of the Power System's human resources. This section describes five challenges that the IHRP must manage on the supply side:

- Workforce gaps
- Employee attrition
- Feeder class vacancies
- The critical path
- Labor issues

CHALLENGE #1: WORKFORCE GAPS

A workforce gap is composed of vacant positions. There are two causes of workforce gaps in the Power System. As Figure 3-1 shows, a gap may be the result of the increase in approved positions through business expansion and growth. Some of the current drivers for expansion of the Power System are greater service demands, the acquisition of new technologies to improve reliability, and mandated O&M repairs, upgrades, and use of renewables. A workforce gap can also result from employee attrition through retirements, promotions, and transfers. Of these, potential retirements will be the strongest driver over the next 10 years for the Power System.

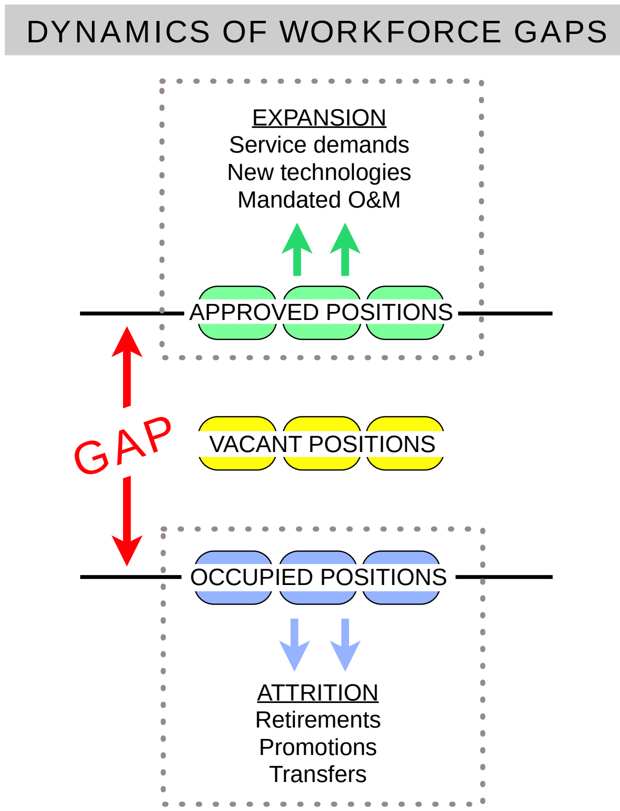

Figure 3-1. Dynamics of workforce gaps

Ideally an internal talent pool will fill all workforce gaps through training, promotion, and transfer processes, as illustrated in Figure 3-2. Unfortunately, this approach is not expected to meet the Power System's future demands for available and talented staff. For example, the Electric Distribution Mechanics duties have been contracted out in the Power Reliability Program. In these situations and others, the Power System fills these positions with less effective, alternate solutions. A significant gap will occur over the next five years in the Power System. Alternate sources will be required. They are described on later in this report.

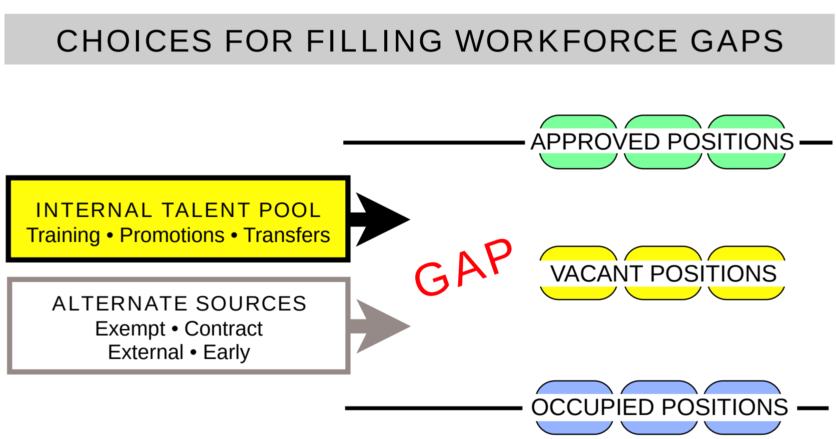

Figure 3-2. The choices for filling workforce gaps in the Power System

THE SIZE OF THE WORKFORCE GAP IN THE POWER SYSTEM

Currently there is a workforce gap of 416 unfilled positions in the Power System. The System is funded at the level of 4,264 positions and has 3,848 positions filled, as of October 18, 2013. When this gap is joined by the significant attrition that will occur over the next 10 years, the Power System will face a large shortfall of workforce availability.

WORKFORCE GAPS FOR SPECIFIC JOB CLASSES

Significant workforce gaps exist in many job classes throughout the Power System in 2013. Shown below in Table 3-4 are workforce gaps for selected positions that are integral to its core business. Their replacement lead times can be up to 6 years.

Table 3-4. Gaps in selected positions for 2013

GAPS IN SELECTED POSITIONS FOR 2013

		2013			
CLASS TITLES	CODE	APR	OCC	GAP	%
ELECTRIC DISTRIBUTION MECHANIC (a)	3879	548	430	118	22%
ELECTRICAL CRAFT HELPER	3799	362	270	92	25%
ELECTRICAL ENGINEERING ASSOC	7525	313	279	34	11%
MECHANICAL ENGINEERING ASSOC	7554	85	61	24	28%
ELECTRICAL REPAIRER	3853	62	46	16	26%
STEAM PLANT ASSISTANT	5622	134	119	15	11%
SENIOR ELECTRICAL TESTER	7515	49	38	11	22%
ELEC DISTR MECH SUPV	3873	104	95	9	9%
STM PLT OPRG SUPV	5625	31	24	7	23%
TRANS & DISTR DIST SUPV	3875	39	32	7	18%
SENIOR ELECTRICAL MECHANIC	3834	66	59	7	11%
LOAD DISPATCHER	5233	40	34	6	15%
ELECTRICAL SERVICE MANAGER	5265	41	35	6	15%
MACHINIST	3763	44	38	6	14%
STM PLT MTNC MCHC	5630	57	51	6	11%
ELECTRICAL ENGINEER	7539	58	52	6	10%
CHIEF ELECTRIC PLANT OPERATOR	5237	22	17	5	23%
SR ELTC TRBL DSPR	3829	8	5	3	38%
STM PLT MTNC SUPV	3786	15	12	3	20%
SENIOR LOAD DISPATCHER	5235	22	19	3	14%
TREE SURGEON SUPERVISOR	3117	24	22	2	8%
STEAM PLANT OPERATOR	5624	91	90	1	1%
TOTAL GAP FOR SELECTED POSITIONS				**387**	
TOTAL GAP FOR REMAINDER OF POWER SYSTEM				**29**	
TOTAL GAP FOR POWER SYSTEM				**416**	

NOTES
APR = Positions authorized through Annual Personnel Resolution
OCC = Positions currently occupied as of 10/28/13
GAP = Difference between APR and OCC
% = The percentage of positions that are not occupied as of 10/28/13
(a) = The "occupied" number has been reduced by the historical graduation rate (40%) for trainees in this job classification.

Table 3-4 shows that these positions account for 93% of the current workforce gap. The Electrical Craft Helper (ECH) classification has the second largest gap with 92 vacancies in 2013. The ECH talent pool feeds 27 other positions in the Power System as vacancies occur.

Any prolonged gap in the ECH pool has pervasive, negative consequences on workforce availability. This case example is described in greater detail later in this report.

CHALLENGE #2: EMPLOYEE ATTRITION

The greatest single cause of workforce gaps is employee attrition. Over the next 10 years, attrition will dramatically shrink the talent pool available for the Power System. The bulk of this attrition will be due to retirement. By 2023, a minimum of 1,200 Power System employees are expected to retire. This level of attrition will create a vacuum in key positions and place tremendous pressure on their feeder classes to provide promotable employees.

THE IMPACT OF RETIREMENTS ON THE POWER SYSTEM

As of October 28, 2013, the Power System had 3,848 employees in occupied positions. A significant loss of talent, knowledge, and experience could put future Power System operations and reliability at risk. Shown below in Table 3-5 are the numbers of Power System employees who will likely retire during the years 2014 to 2023 and the potential workforce gaps that could accumulate over that time. Table 3-5 displays the impacts across three possible retirement scenarios.

- "Maximum possible" level of retirement
- "High" level of retirement
- "Expected" level of retirement

Each scenario has a different set of assumptions, which are described below. Division executives will need to determine which assumptions will they make to build their forecasts of future vacancies.

MAXIMUM POSSIBLE LEVEL. This section of Table 3-5 indicates the total number of employees who will have any of the retirement eligibility criteria. This calculation has two assumptions: 1) that all retirees will retire in the year that they become eligible, and 2) that a backlog of nearly 1,300 previously eligible employees will retire in 2014.

HIGH LEVEL. This section applies to those employees who fulfill any of the eligibility criteria for retirement. This calculation has one assumption: that some (but not all) retirees will retire in the year that they become eligible. The level for each year is determined by a statistic based on historical data.

EXPECTED LEVEL. This section applies only to employees who have 30 years of service. Other eligible retirees are not included. This calculation has one assumption: that these employees will retire no later than 4 years after the year that they become eligible. The statistically expected duration of service for LADWP's employees is 34 years, corresponding approximately to a 50% chance of retiring. An employee with at least 50% chance of retiring is deemed retired. Once an employee is deemed retired with at least 50% chance of retiring, there is a residual 50% chance of not retiring. This remaining probability is decayed over three annual iterations representing approximately 30%, 10%, and 10% for these years for which chances of retiring become higher than initial 50% of retiring. This process takes approximately 4 years to ensure that a complete removal from the total count of an employee that has been deemed retired and assumes that the criteria discussed above occurs.

Table 3-5 shows that by the year 2023 the cumulative percentage of reduced Power System workforce could range from 39% to 69% of the APR positions for 2014. These percentages translate into possible workforce gaps ranging from 1,659 to 2,949 employees by the year 2023. This potential workforce gap could be nearly catastrophic and could not be filled solely by an internal talent pool

Table 3-5. Maximum possible, high, and expected levels of retirement

MAXIMUM POSSIBLE, HIGH, AND EXPECTED LEVELS OF RETIREMENT

Authorized positions for 2014 = 4,264
Occupied positions = 3,848 (as of 10/18/13)
Unoccupied positions = 416 (as of 10/18/13)

	MAXIMUM POSSIBLE				HIGH LEVEL				EXPECTED LEVEL			
FY YEARS	RETIREES	WORK-FORCE SIZE	GAP	GAP %	RETIREES	WORK-FORCE SIZE	GAP	GAP %	RETIREES	WORK-FORCE SIZE	GAP	GAP %
2014	1,366	2,482	1,782	42%	345	3,503	761	18%	125	3,723	541	13%
2015	170	2,312	1,952	46%	217	3,286	978	23%	89	3,634	630	15%
2016	153	2,159	2,105	49%	206	3,080	1,184	28%	123	3,511	753	18%
2017	165	1,994	2,270	53%	181	2,899	1,365	32%	112	3,399	865	20%
2018	146	1,848	2,416	57%	161	2,738	1,526	36%	86	3,313	951	22%
2019	133	1,715	2,549	60%	145	2,593	1,671	39%	123	3,190	1,074	25%
2020	151	1,564	2,700	63%	130	2,463	1,801	42%	151	3,039	1,225	29%
2021	101	1,463	2,801	66%	117	2,346	1,918	45%	153	2,886	1,378	32%
2022	73	1,390	2,874	67%	106	2,240	2,024	47%	148	2,738	1,526	36%
2023	75	1,315	2,949	69%	95	2,145	2,119	50%	133	2,605	1,659	39%
TOTALS	**2,533**				**1,703**				**1,243**			

ELIGIBILITY CRITERIA FOR RETIREMENT
- At least age 60 with at least 5 years of service, or
- At least age 55 with at least 10 years of service, or
- Any age with at least 30 years of service, or
- At least age 55 with at least 30 years of service

GAP = The "gap" is a cumulative total. It is the sum of the retirement forecast for that year plus the GAP of the prior year. The GAP for 2014 includes the 416 vacant or unoccupied positions in 2013.

GAP % = It is calculated by dividing the GAP for that year by 4,264 (the APR for 2014).

The numbers in Table 3-5 do not include any employee credit for years of service in other government work or the military.

THE BAND OF MOST LIKELY LEVEL OF RETIREMENTS IN THE POWER SYSTEM

The future shrinkage of the Power System workforce due to attrition is summarized in Figure 3-3 below. It interprets the data in Table 3-5 above. The blue band indicates the range of most likely retirements for each year. This chart also shows the three levels of retirement described in Table 3-5 above. It is assumed that the actual number of retirements for each year will be near the "expected level" curve and indicated by the darker blue color. Given the several years' lead time required to develop internally qualified staff, the IHRP will need more precise information about the positions and job classifications in workforce gaps than is shown by the blue band. These forecasts can be more accurate through frequent assessment of potential retirements by Division executives and continuous forecasts based on historical trends.

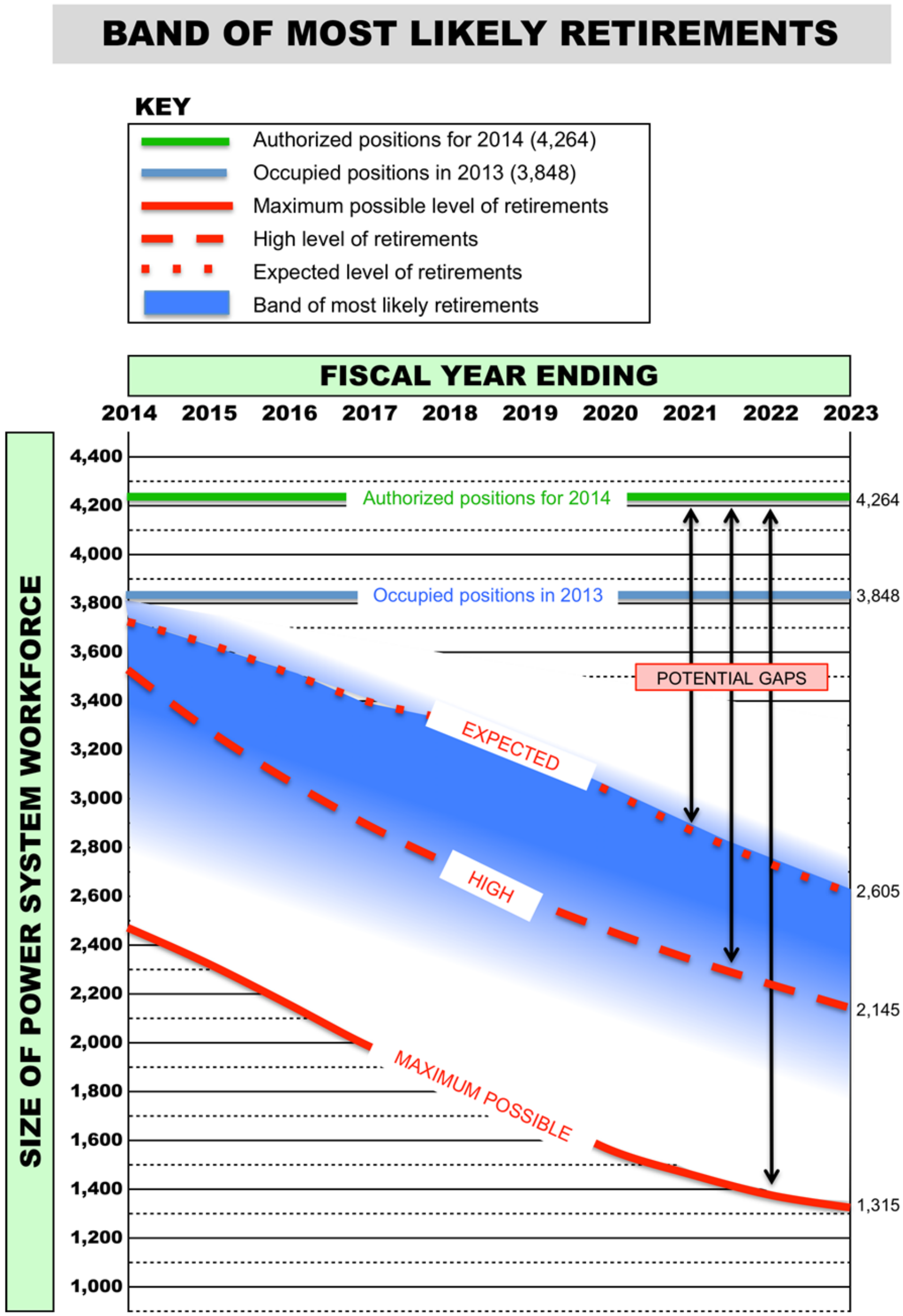

Figure 3-3. Band of most likely retirements

SIGNIFICANT ATTRITION WITHIN SPECIFIC JOB CLASSES

An examination of specific job classifications reveals some important trends. Table 3-6 below shows the potential cumulative impact of retirement that will cause attrition in 34 selected positions. These positions are integral to the core business of the Power System and can have replacement lead times of up to 6 years or longer.

Table 3-6. Forecasted gaps in 34 key positions from 2014 to 2023

[This table appears on the next page]

FORECASTED GAPS IN 34 KEY POSITIONS FROM 2014 TO 2023

CUMULATIVE PERCENTAGE OF 2013 APR
- ≥75 to 100%
- ≥50 to <75%
- ≥25 to <50%
- <25%

CLASS TITLES	CODE	2013 ACTUALS APR	2013 ACTUALS OCC	2013 ACTUALS GAP	2014 RET	2014 GAP	2014 CUM %	2015 RET	2015 GAP	2015 CUM %	2016 RET	2016 GAP	2016 CUM %	2017 RET	2017 GAP	2017 CUM %	2018 RET	2018 GAP	2018 CUM %	2019 RET	2019 GAP	2019 CUM %	2020 RET	2020 GAP	2020 CUM %	2021 RET	2021 GAP	2021 CUM %	2022 RET	2022 GAP	2022 CUM %	2023 RET	2023 GAP	2023 CUM %
ELECTRIC DISTRIBUTION MECHANIC (a)	3879	548	428	120	5	125	23%	5	130	24%	5	135	25%	7	142	26%	8	150	27%	8	158	29%	11	169	31%	10	179	33%	15	194	35%	14	208	38%
ELECTRICAL CRAFT HELPER	3799	362	270	92	1	93	26%	3	96	27%	4	100	28%	4	104	29%	5	109	30%	5	114	31%	5	119	33%	5	124	34%	7	131	36%	7	138	38%
ELECTRICAL ENGR ASSOCIATE	7525	313	279	34	5	39	12%	4	43	14%	8	51	16%	9	60	19%	4	64	20%	6	70	22%	7	77	25%	6	83	27%	5	88	28%	10	98	31%
ELECTRICAL MECHANIC (a)	3841	263	258	5	3	8	3%	1	9	3%	2	11	4%	4	15	6%	2	17	6%	6	23	9%	7	30	11%	6	36	14%	5	41	16%	9	50	19%
ELECTRIC STATION OPERATOR (a)	5224	224	206	18	1	19	8%	5	24	11%	8	32	14%	12	44	20%	6	50	22%	5	55	25%	3	58	26%	3	61	27%	4	65	29%	4	69	31%
STEAM PLANT ASSISTANT	5622	134	119	15	0	15	11%	0	15	11%	0	15	11%	1	16	12%	0	16	12%	0	16	12%	1	17	13%	1	18	13%	1	19	14%	1	20	15%
ELEC DISTR MECH SUPV	3873	104	95	9	3	12	12%	3	15	14%	3	18	17%	7	25	24%	5	30	29%	5	35	34%	9	44	42%	10	54	52%	7	61	59%	7	68	65%
ELECTRICAL TESTER	7512	102	96	6	1	7	7%	1	8	8%	1	9	9%	0	9	9%	0	9	9%	1	10	10%	1	11	11%	0	11	11%	1	12	12%	5	17	17%
STEAM PLANT OPERATOR	5624	91	90	1	3	4	4%	1	5	5%	2	7	8%	2	9	10%	2	11	12%	1	12	13%	1	13	14%	1	14	15%	3	17	19%	1	18	20%
SENIOR ELECTRICAL MECHANIC	3834	66	59	7	3	10	15%	2	12	18%	1	13	20%	1	14	21%	2	16	24%	2	18	27%	3	21	32%	1	22	33%	2	24	36%	3	27	41%
ELECTRICAL REPAIRER	3853	62	46	16	0	16	26%	1	17	27%	1	18	29%	2	20	32%	1	21	34%	3	24	39%	2	26	42%	2	28	45%	2	30	48%	3	33	53%
ELECTRICAL ENGINEER	7539	58	52	6	3	9	16%	1	10	17%	5	15	26%	4	19	33%	3	22	38%	3	25	43%	5	30	52%	4	34	59%	4	38	66%	3	41	71%
STM PLT MTNC MCHC	5630	57	51	6	1	7	12%	1	8	14%	2	10	18%	0	10	18%	2	12	21%	1	13	23%	1	14	25%	1	15	26%	3	18	32%	1	19	33%
SENIOR ELECTRICAL TESTER	7515	49	38	11	2	13	27%	2	15	31%	2	17	35%	2	19	39%	2	21	43%	1	22	45%	2	24	49%	2	26	53%	3	29	59%	2	31	63%
MACHINIST	3763	44	38	6	1	7	16%	0	7	16%	1	8	18%	1	9	20%	1	10	23%	0	10	23%	0	10	23%	2	12	27%	1	13	30%	0	13	30%
ELTC SRVC REPTV	7520	42	44	-2	1	-1	-2%	3	2	5%	2	4	10%	3	7	17%	3	10	24%	2	12	29%	2	14	33%	2	16	38%	2	18	43%	2	20	48%
ELECTRICAL SERVICE MANAGER	5265	41	35	6	5	11	27%	2	13	32%	4	17	41%	4	21	51%	2	23	56%	2	25	61%	3	28	68%	4	32	78%	2	34	83%	2	36	88%
LOAD DISPATCHER	5233	40	34	6	1	7	18%	0	7	18%	1	8	20%	1	9	23%	1	10	25%	0	10	25%	1	11	28%	1	12	30%	1	13	33%	0	13	33%
TRANS & DISTR DIST SUPV	3875	39	32	7	1	8	21%	2	10	26%	2	12	31%	3	15	38%	2	17	44%	2	19	49%	4	23	59%	4	27	69%	3	30	77%	3	33	85%
INSTRUMENT MECHANIC	3843	37	38	-1	1	0	0%	1	1	3%	2	3	8%	1	4	11%	1	5	14%	0	5	14%	1	6	16%	1	7	19%	2	9	24%	0	9	24%
STM PLT OPRG SUPV	5625	31	24	7	5	12	39%	4	16	52%	4	20	65%	2	22	71%	1	23	74%	1	24	77%	0	24	77%	1	25	81%	0	25	81%	0	25	81%
POWER ENGINEERING MANAGER	9453	25	23	2	1	3	12%	0	3	12%	3	6	24%	4	10	40%	3	13	52%	2	15	60%	2	17	68%	2	19	76%	2	21	84%	1	22	88%
TREE SURGEON SUPERVISOR	3117	24	22	2	2	4	17%	1	5	21%	1	6	25%	1	7	29%	2	9	38%	1	10	42%	2	12	50%	1	13	54%	1	14	58%	1	15	63%
CHIEF ELECTRIC PLANT OPERATOR	5237	22	17	5	2	7	32%	3	10	45%	2	12	55%	2	14	64%	1	15	68%	2	17	77%	1	18	82%	0	18	82%	0	18	82%	1	19	86%
SENIOR LOAD DISPATCHER	5235	22	19	3	0	3	14%	0	3	14%	0	3	14%	2	5	23%	2	7	32%	0	7	32%	2	9	41%	1	10	45%	2	12	55%	0	12	55%
SR ELTL MCHC SUPV	3836	22	23	-1	1	0	0%	1	1	5%	1	2	9%	1	3	14%	1	4	18%	2	6	27%	2	8	36%	1	9	41%	0	9	41%	3	12	55%
STM PLT MTNC SUPV	3786	15	12	3	1	4	27%	0	4	27%	1	5	33%	2	7	47%	1	8	53%	1	9	60%	1	10	67%	0	10	67%	2	12	80%	1	13	87%
ELECTRICAL REPAIR SUPERVISOR	3855	8	9	-1	0	-1	-13%	0	-1	-13%	0	-1	-13%	1	0	0%	1	1	13%	0	1	13%	2	3	38%	1	4	50%	1	5	63%	1	6	75%
MACHINIST SUPERVISOR	3766	8	8	0	1	1	13%	0	1	13%	0	1	13%	1	2	25%	0	2	25%	0	2	25%	0	2	25%	2	4	50%	1	5	63%	0	5	63%
SR ELTC TRBL DSPR	3829	8	5	3	0	3	38%	0	3	38%	1	4	50%	0	4	50%	0	4	50%	1	5	63%	0	5	63%	2	7	88%	1	8	100%	0	8	100%
INSTRUMENT MECHANIC SUPV	3844	6	6	0	0	0	0%	0	0	0%	0	0	0%	1	1	17%	0	1	17%	0	1	17%	1	2	33%	2	4	67%	1	5	83%	0	5	83%
SR ELTC SRVC REPTV	7521	4	5	-1	0	-1	-25%	1	0	0%	0	0	0%	1	1	25%	0	1	25%	1	2	50%	0	2	50%	0	2	50%	0	2	50%	0	2	50%
SR ELTL RPR SUPV	3856	3	3	0	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	1	1	33%	1	2	67%	0	2	67%	0	2	67%	0	2	67%
SENIOR MACHINIST SUPERVISOR	3768	1	1	0	0	0	0%	0	0	0%	0	0	0%	1	1	100%	0	1	100%	0	1	100%	0	1	100%	0	1	100%	0	1	100%	0	1	100%

OCC = Positions currently occupied as of 10/28/13
(a) = The "occupied" number has been reduced by the historical graduation rate for trainees in this job classification from 2006 to today
EDMT graduation rate = 40%
ESOT graduation rate = 47%
EMT graduation rate = 75%

This table depicts the case of forecasted retirement scenarios in each class. In the past retirement eligibility was used for workforce and succession planning. Traditionally, LADWP employees have not retired at the moment when they became eligible. The forecasting method used for Figure 3-6 was determined to be more accurate for predicting retirement. In addition, employees in each classification have not retired at an equal rate. As shown in Table 3-6, an IHRP process has forecasted these actual retirement dates based on historical analysis. More information about this calculation methodology is available in the Appendix section.

CHALLENGE #3: FEEDER CLASS VACANCIES

Attrition, unoccupied positions, and inadequate training graduation rates are the main causes of pervasive vacancies in the feeder classes for key positions throughout the Power System. These vacancies impede promotional ladders from filling unoccupied positions with internal candidates. Some examples of currently high feeder class vacancies are Steam Plant Operators, Electric Station Operators, Electrical Repairers, Electric Distribution Mechanics, and Electrical Engineers.

Feeder class vacancies can cause an additional harm to the Power System. When a large number of employees retire from a specific class, there is a significant loss of field experience and transfer of knowledge. It is mandatory that the training units in the Power System capture this knowledge and build it into their curricula.

SIGNIFICANT VACANCIES ABOVE THE ELECTRICAL CRAFT HELPER

As mentioned earlier in the chapter, the Electrical Craft Helper (ECH) position has 92 unfilled positions as of October 28, 2013. The ECH position is a talent pool that over time can feed vacancies for 27 other positions in three Power System Divisions. Figure 3-4 illustrates the ECH career ladder that has 28 positions (including ECH) are located in Integrated Support Services, Power Supply Operations, and Transmission & Distribution Divisions.

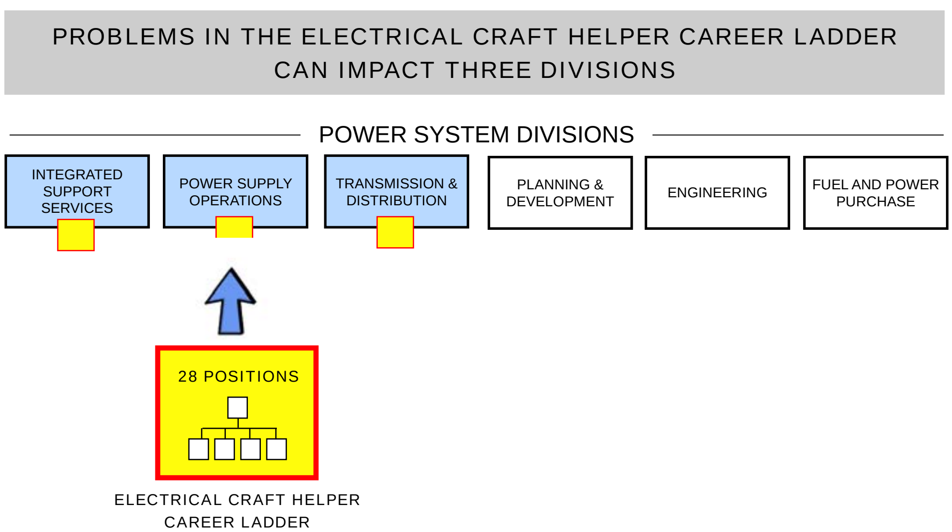

Figure 3-4. Problems in the Electrical Craft Helper career ladder can impact three Divisions

FEEDER CLASS PRESSURES THROUGHOUT THE ECH CAREER LADDER

Figure 3-5 shows the potential retirement rate for 28 positions at or above the Electrical Craft Helper (ECH). This chart shows the significant cumulative impact of eligible retirement by

2018 in many positions. These impending vacancies put great pressure on the ECH position to be the main source of promotable talent, particularly for the 10 positions that are directly above the ECH. As indicated in Figure 3-5, this problem is exacerbated because the ECH position is also vulnerable to a high degree of attrition.

In addition, some ECH workers can be less interested in promotions. They are satisfied with entry-level jobs, as they are very challenging. Promotions can require passing very difficult Civil Service exams. Promotions can require employees to travel taking them away from their families, or to incur burdensome travel expenses. ECH workers may stay in their entry-level position for an entire career for 30 years or longer.

This overall situation will force the Power System to utilize alternate methods of hiring into the open positions shown on this chart including exempt and contract labor.

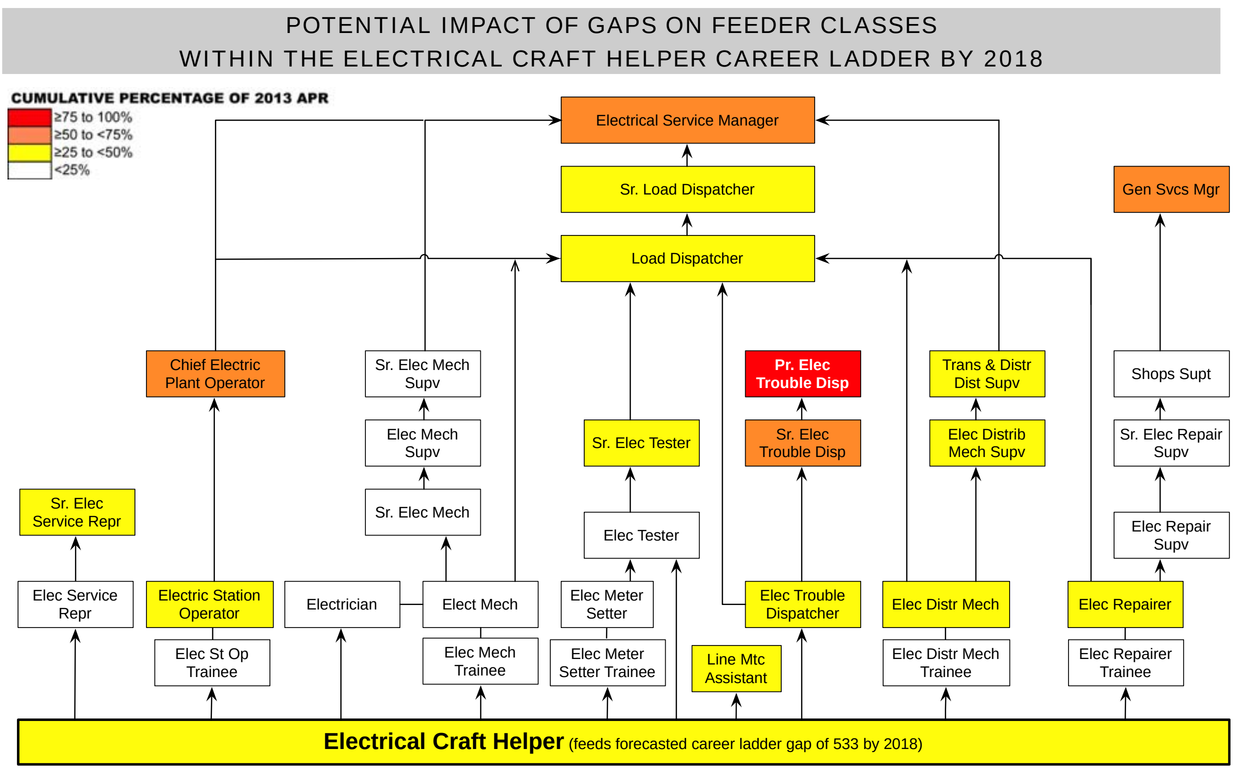

Figure 3-5. The potential impact of gaps on feeder classes within the Electrical Craft Helper career ladder by 2018

THE UPCT PROGRAM PROVIDES RELIEF

In October 2010, the LADWP and IBEW Local 18 initiated the Utility Pre-Craft Trainee (UPCT) program. It will help relieve the pressure on the ECH as the only feeder class within this career ladder. As well, the UPCT program provides a talent pool for seven other entry-level positions in LADWP. The first step for a UPCT candidate begins when he/she signs the “Exempt Book” at IBEW Local 18 for the UPCT position. IBEW Local 18 then dispatches the trainee to the LADWP. The trainees are hired for 18 months as exempt employees with the intention that they will promote to permanent jobs in higher classifications. During this period they are trained to work safely in the field. They also work alongside trained LADWP employees. They are provided with computer-based training programs, electrical training programs, and others. They are exposed to different groups in the LADWP so they can make some decisions about their promotional opportunities. The UPCT class is designed to keep journey level positions filled and promotional ladders operating smoothly.

THE POSSIBLE SIZE OF GAPS IS SIGNIFICANT

Feeder class vacancies create workforce gaps that become larger along the vertical lines of promotion within a class series. For example, Table 3-7 shows that by 2018 there could be 533 possible vacant positions at and above the Electrical Craft Helper.

Table 3-7. Forecasted gaps by 2018 for the career ladder of the Electrical Craft Helper

[This table appears on the next page]

FORECASTED GAPS BY 2018 FOR CAREER LADDER OF ELECTRICAL CRAFT HELPER

CUMULATIVE PERCENTAGE OF 2013 APR

- ≥75 to 100%
- ≥50 to <75%
- ≥25 to <50%
- <25%

28 POSITIONS IN ELECT CRAFT HELPER CAREER LADDER

CLASS TITLES	CODE	2013 ACTUALS APR	2013 ACTUALS OCC	2013 ACTUALS GAP	2018 FORECASTS RET	2018 FORECASTS GAP	2018 FORECASTS CUM %
ELECTRIC DISTRIBUTION MECHANIC (a)	3879	548	430	118	30	148	27%
ELECTRICAL CRAFT HELPER	3799	362	270	92	17	109	30%
ELECTRIC STATION OPERATOR (a)	5224	224	206	18	42	60	26%
ELEC DISTR MECH SUPV	3873	104	95	9	21	30	29%
ELECTRICAL SERVICE MANAGER	5265	41	35	6	17	23	56%
SENIOR ELECTRICAL TESTER	7515	49	38	11	10	21	43%
ELECTRICAL REPAIRER	3853	62	46	16	5	21	34%
TRANS & DISTR DIST SUPV	3875	39	32	7	10	17	44%
ELECT MECHANIC (a)	3841	263	258	5	12	17	6%
SENIOR ELECTRICAL MECHANIC	3834	66	59	7	9	16	24%
CHIEF ELECTRIC PLANT OPERATOR	5237	22	17	5	10	15	68%
ELEC MECHANIC SUPV	3835	69	60	9	6	15	22%
LINE MAINTENANCE ASSISTANT	3882	33	29	4	9	13	39%
LOAD DISPATCHER	5233	40	34	6	4	10	25%
ELEC SERVICE REPR	7520	42	44	-2	12	10	24%
ELECTRICAL TESTER	7512	102	96	6	3	9	9%
ELEC TROUBLE DISPATCHER	3828	24	22	2	6	8	33%
SENIOR LOAD DISPATCHER	5235	22	19	3	4	7	32%
SR ELTC TRBL DSPR	3829	8	5	3	1	4	50%
SR ELEC MECH SUPV	3836	22	23	-1	5	4	18%
PR ELEC TROUBLE DISP	3830	2	2	0	2	2	100%
GEN SVCS MGR	9601	2	2	0	1	1	50%
SR ELEC SERVICE REPR	7521	4	5	-1	2	1	25%
ELEC REPAIR SUPV	3855	8	9	-1	2	1	13%
SR ELEC REPAIR SUPV	3856	3	3	0	0	0	0%
ELECTRICIAN	3863	3	3	0	0	0	0%
SHOPS SUPT	3780	1	1	0	0	0	0%
ELEC METER SETTER	3822	18	50	-32	3	-29	-161%
TOTALS FOR 28 POSITIONS		**2183**	**1893**	**290**	**243**	**533**	
TOTALS FOR REST OF POWER SYSTEM		**2081**	**1955**	**126**	**249**	**375**	
TOTALS FOR POWER SYSTEM		**4264**	**3848**	**416**	**492**	**908**	

NOTES

OCC = Positions currently occupied as of 10/28/13

(a) = The "occupied" number has been reduced by the historical graduation rate for trainees in this job classification.

EDMT graduation rate = 40%
ESOT graduation rate = 47%
EMT graduation rate = 75%

CHALLENGE #4: THE CRITICAL PATH

Currently the time required to fill a position can take up to 6 years or longer. This duration puts the Power System at a significant competitive disadvantage. Others cities and private employers can make job offers to prospective employees within days, not over an extended period of time.

Two major challenges to provide a qualified workforce are its high costs and extended length of time. The cost for delivery of technical craft training can be substantial over the length of a training program. This amount includes the trainee's base salary, benefits, labor costs for training staff, materials, and other expenses.

FIVE STEPS OF THE CRITICAL PATH

A "critical path" for developing talent in the Power System has been established. It consists of five steps that are completed in sequence. Much like a supply chain, if there is a breakdown in quality or in the execution of an "upstream" step, then the "downstream" steps in the critical path have to manage these quality problems. For example, if "Selection" fails to identify quality talent, then "Training" will be forced to engage trainees who are poorly qualified candidates. This failure in "Selection" can lower the graduation rate of "Training."

Together the steps in the Critical Path can predict the length of time it can take a new employee to be on-the-job and doing full-time work in a required classification. Over time, the IHRP will streamline this path, shorten its duration, and increase its overall effectiveness. The sequence of the five steps in the Critical Path is shown in Figure 3-7 below.

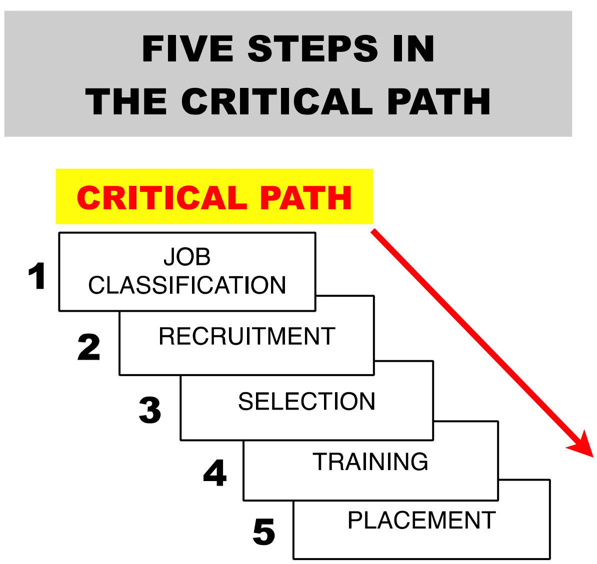

Figure 3-7. The five steps in the Critical Path help develop new employees for the Power System

Below is a brief description of each step in the IHRP Critical Path.

1. JOB CLASSIFICATION. This step is required to establish new classifications or to update current classifications. The Power System is continually acquiring new technologies that require new areas of expertise and new job classifications. Currently new supervisory classifications are needed to oversee Meter Setters and Electrical

Testers. If some job classifications have not been completed on time or not updated to current needs, the Power System will be forced to staff these operations with multiple classifications. This approach is extremely inefficient. Such was the case with the Pine Tree Wind Plant where the Wind Plant Technicians were not available when needed. Future geothermal operations may face a similar situation. Normal duration to create a new Job Classification: two years or longer.

2. RECRUITMENT. This step intends to identify the most qualified candidates who can proceed to the selection step. It includes advertisements and visits to educational institutions and technical training organizations. Currently, the Department is required to seek Engineering Associates from local colleges and is restricted from recruiting nationally. Normal duration of Recruitment: one year or longer.

3. SELECTION. This step concludes with the hiring of an employee who can be a candidate for training. Selection includes an established list of certified candidates, bulletins / notices, interviews with interested candidates, and approved candidates for hire. A significant amount of time in this step is taken up by coordination and approvals from City Personnel. Normal duration of Selection: 6 months or longer.

4. TRAINING. This step provides qualified graduates for placement in open entry-level positions. Some courses have graduation rates as low as 50% that can add significantly to the overall costs to develop full-time employees. This step in the critical path refers only to the delivery of technical training for entry-level employees. It excludes the time needed for planning and evaluation of these programs. As well, it excludes the many continuing education programs that the Department provides for employees to improve their on-the-job performance. Duration of Training: 18 months to 48 months depending on the program.

5. PLACEMENT. This step covers the period from graduation from training to being placed in a full-time position. A position may not be available at the moment of graduation. For example, Machinists and Welders may be required to take a second Civil Service exam before placement is finished. If the exam is not available, these employees can be assigned to a position where they are unable to use their training. Duration of Placement: immediate to one year or longer.

THE CRITICAL PATH CAN TAKE YEARS

In Figure 3-8 below are shown the durations of the five steps in the Critical Path. It is evident that the three steps prior to training (job classification, recruitment, and selection) can create serious delays in hiring. These durations must be reduced to allow the Department to compete effectively for talent in the marketplace.

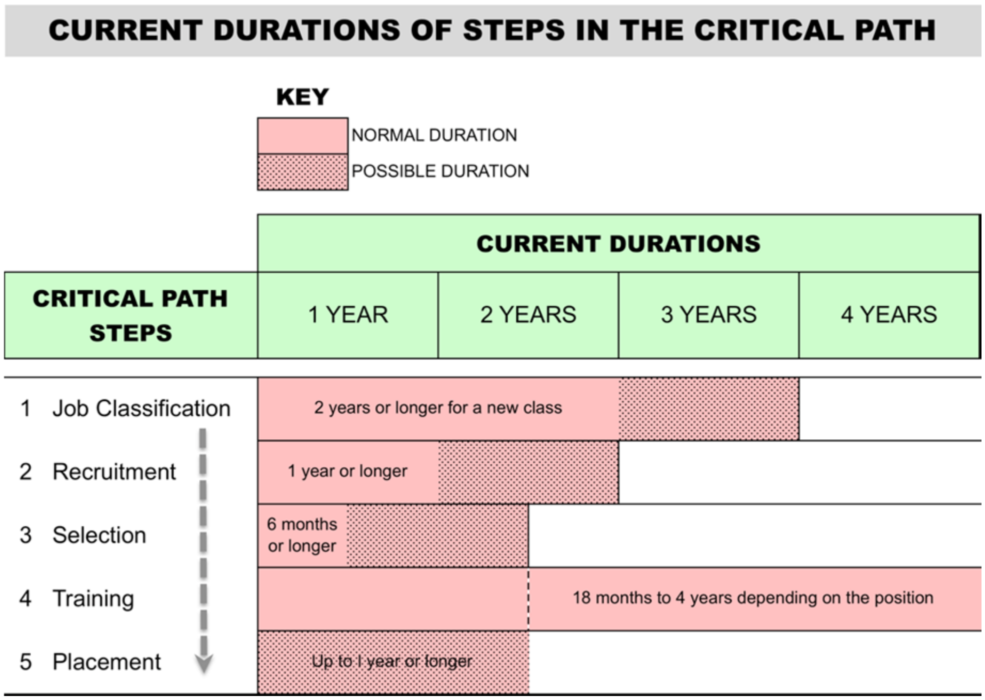

Figure 3-8. Current durations of steps in the Critical Path

MANY STAKEHOLDERS IN THE CRITICAL PATH

Streamlining this Critical Path will require breakthroughs and innovations. There are many stakeholders who participate in its five steps. Some stakeholders are responsible to manage specific steps while others are active participants. They will require unconventional approaches to their traditional procedures and methods for planning, coordinating, and executing their activities. Figure 3-9 shows these stakeholders and their general roles in each step.

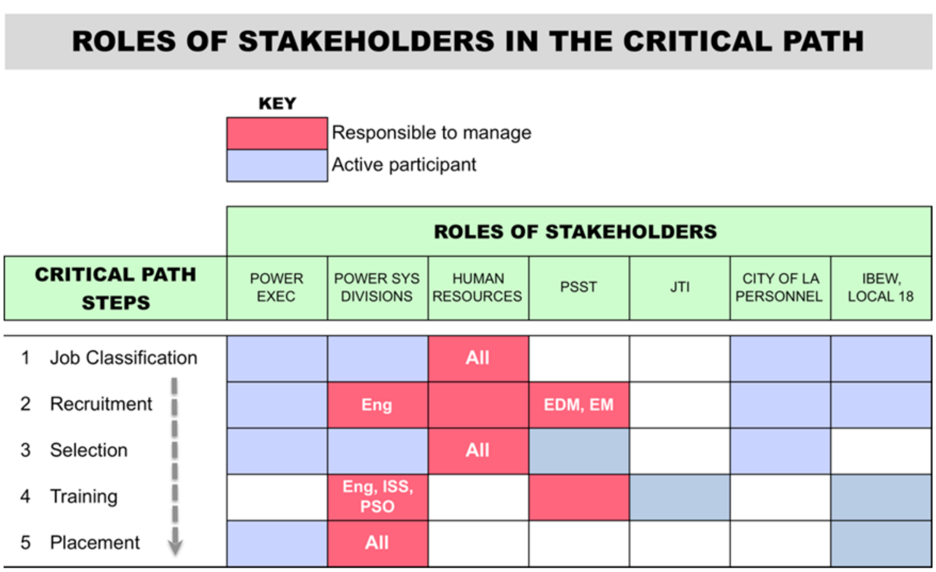

Figure 3-9. Roles of stakeholders in the Critical Path

- JOB CLASSIFICATION: While the Human Resources staff manages this step, they have to coordinate significant input and approvals from all other participants.
- RECRUITMENT: This step is executed independently by Human Resources, Engineering, and PSST for job classes that are assigned to each Division.
- SELECTION: The Human Resources staff manages this step with significant input from the operating Divisions and PSST. City Personnel Department controls the process that establishes certified lists of candidates.
- TRAINING: The technical training programs are provided by four different participating organizations: PSST, Engineering, ISS, and PSO.
- PLACEMENT: The Division that receives the graduates from training manages this step.

CHALLENGE #5: LABOR ISSUES

Both the International Brotherhood of Electrical Workers (IBEW) Local 18 and Department Management intend that workforce planning and development through the IHRP will support all existing and future labor agreements.

4. THE INTEGRATED HUMAN RESOURCES PLAN (IHRP)

The anticipated exiting of talent, knowledge, and experience places the operations of the Power System at great risk. This exodus of retirees will come at a time when the Power System will be implementing significant changes in operations that utilize new, more efficient, and renewable generation methods and advanced smart-grid technologies. These changes will demand that the future workforce is larger and that it has new skills, capabilities, and expertise. Up to this point in time, the Power System has had no disciplined and long-term means to assure that all future vacant positions will be filled on time.

In 2013, the Power System launched the Integrated Human Resources Plan (IHRP) as the broad and systemic solution. It is a significant and far-reaching strategy that will manage the availability of the Power System's workforce for the next ten years and beyond. It will ensure that trained and talented employees will always be available when needed to perform the important work that is described in this IRP document. The IHRP is a cooperative effort between the Los Angeles Department of Water and Power and the International Brotherhood of Electrical Workers (IBEW) Local 18.

4.1 IHRP Overview

This section describes these elements of the IHRP

- Program goals
- Priorities for 2013-14
- Annual deliverables
- General program benefits
- Program leadership

PROGRAM GOALS

The IHRP is a joint effort where the Department and the IBEW Local 18 are working collectively to achieve these common goals for the IHRP:

- To support the annual IRP report with a forecast of the workforce requirements needed to fulfill the strategic case for the Power System.
- To ensure that the Power System's workforce requirements for recurring ten years are fulfilled on time.

PRIORITIES FOR 2013-14

<u>DEMAND FORECAST OF THE POWER SYSTEM</u>

- Install an effective on-line workforce demand tool that provides a ten-year forecast of staffing needs of the Power System.
- Design a Job Justification Sheet (JJS) that can yield resource loaded staffing requirements for individual projects / programs that are either funded or unfunded.

MEETING DEMANDS OF THE POWER SYSTEM

- The Workforce Planning Coordinators recommend to the JRB the gap strategies necessary for each job classification in the Power System.
- The five steps of the Critical Path have established measurable indicators of a streamlined system.

CRITICAL PATH IMPROVEMENTS

- Numerous innovations and breakthroughs are being designed or implemented that will improve Job Classification, Recruitment, Selection, Training, and Placement. These innovations are described in detail on pages 26-30.

ANNUAL DELIVERABLES

The IHRP has these general deliverables each year:

- An IHRP chapter will be part of the Power System's annual IRP. This chapter will discuss the general state of workforce development in the Power System and the forecast for talent needed to support the IRP's initiatives.
- The IHRP planning process will produce an annual forecast of human resource requirements for the next ten years. This forecast will be transferred to the Workforce Development Task Force (JLMC) whose members will be accountable for achieving all workforce availability targets on schedule.
- The IHRP Workforce Development Task Force (JLMC) will produce goals and objectives that accomplish the following:
  - Achieve all workforce targets on time
  - Improve the effectiveness of the critical path for developing skilled employees
  - Demonstrate the continuous integration of knowledge transfer, best practices, and innovations in the development of the workforce

GENERAL PROGRAM BENEFITS

Over the next few years the IHRP can provide important benefits to key stakeholders. Some of these benefits are described below:

FOR LADWP / POWER SYSTEM

- Captures all personnel requirements and associated costs
- Provides ability to manage effects of changes to the budget in the areas of personnel, equipment, and materials

FOR THE POWER SYSTEM DIVISIONS

- Provides structured and comprehensive planning and budgeting processes for staffing requirements
- Identifies and fulfills personnel needs for upcoming ten years
- Forecasts workforce gaps and strategies to manage them
- Provides reporting and monitoring of status of personnel, projects, and programs
- Provides more accurate attrition data
- Streamlines the recruiting and selection process

FOR THE JRB

- Provides greater transparency
- Provides a greater ability to anticipate and resolve labor issues

FOR THE IRP

- Provides more accurate and comprehensive costs for future projects and programs in the areas of personnel, materials, etc.
- Supports the timely completion of major projects

PROGRAM LEADERSHIP

The leadership of the IHRP reflects the commitment to a cooperative effort between the Los Angeles Department of Water and Power and the International Brotherhood of Electrical Workers (IBEW) Local 18. The IHRP has two Workforce Planning Coordinators: one representing Management and the other Labor. They report to the JRB. They lead the planning processes that determine the workforce requirements of the Power System. They also chair the Workforce Development Task Force (JLMC) that utilizes the cooperative joint labor-management committee process. Mike Coia and Barry Poole have been appointed as the current Workforce Planning Coordinators.

4.2 The IHRP Demand Side Approach

THE IHRP WORKFORCE DEMAND FORECAST REPORT

This foundation report provides the estimated workforce demand as gaps for the next ten years in all job classifications of the Power System. In addition, this report contains the following data for each job classification:

- The number of positions occupied in the current year
- The estimated retirements for each year
- The estimated workforce requirements for each year
- Links between feeder classes for promotion
- Forecast of gaps for the next ten years
- Cumulative totals of the effect of retirement on the system

THE REVISED JOB JUSTIFICATION SHEET (JJS)

Within a few years it is expected that project managers will have sufficient mastery of planning for project scope, schedule, and cost. At that point, it is expected that an enhanced JJS can provide detailed resource-loaded data for the IHRP.

4.3 The IHRP Supply Side Approach

This section describes how the IHRP is ensuring that the Power System has a constant supply of human resources available when needed. The two elements described here are:

- The IHRP Workforce Development Task Force
- Workforce gap strategies

IHRP WORKFORCE DEVELOPMENT TASK FORCE

The IHRP Workforce Development Task Force (WFDTF) utilizes the cooperative joint labor-management committee process. It is a cooperative effort between the Los Angeles Department of Water and Power and the International Brotherhood of Electrical Workers (IBEW) Local 18.

The WFDTF mission is:

- Achieve all Power System work force targets on time.
- Improve the effectiveness of the critical path for developing employees.
- Demonstrate the continuous integration of knowledge transfer, best practices, and innovations in the development of the work force.

The WFDTF is the major agent for driving innovation and change especially through the Critical Path. The task force held its first meeting in July 2013. It meets monthly. It is empowered to work across the Department to achieve its goals and objectives.

Figure 4-1 shows a general overview of the WFDTF including its membership and scope of work.

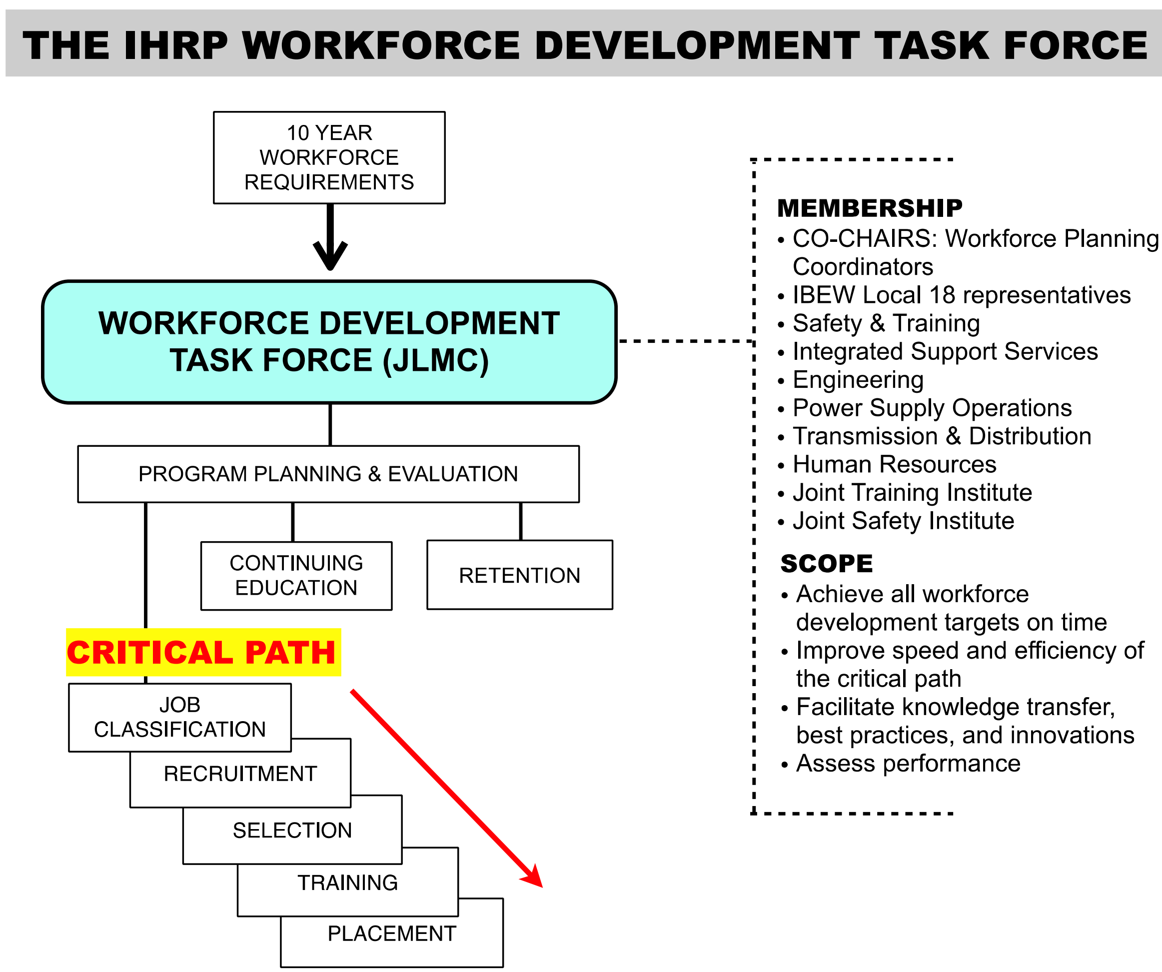

Figure 4-1. Overview of the Workforce Development Task Force (JLMC)

The WFDTF members represent all stakeholders who are responsible for the areas of: job classification, recruitment, selection, training, placement, continuing education, and retention. The task force implements actions that can streamline the Critical Path, shorten its duration, and increase its overall effectiveness.

FIVE STRATEGIES TO MEET WORKFORCE GAPS

The IHRP intends to eliminate the impact of workforce gaps for critical projects and programs that support the IRP. The "workforce gap" is a current or forecasted vacancy in a job classification. It is calculated as the difference between the resources required per class per year and the predicted availability of those resources.

Ideally, all gaps will be filled through routine hiring and internal promotion processes. Some "gap strategies" are options that the Power System can use to gain needed resources when they are unavailable in the current workforce. The utilization of all gap strategies will be approved by the JRB.

Shown below in Figure 4-2 are the five IHRP strategies for managing workforce gaps and the normal length of time that each strategy can consume.

DESCRIPTIONS OF IHRP GAP STRATEGIES

GAP STRATEGIES	DESCRIPTION	LENGTH OF TIME TO EXECUTE
1 INTERNAL	These employees fill positions through existing LADWP and City Personnel processes to transfer and/or promote qualified incumbents to fill vacancies. Candidates are made available through Power System training programs, promotions, and transfers. This process could also be utilized to hire qualified candidates from an existing civil services list to fill positions.	4 months
2 EXEMPT	These employees are exempted or occupy positions that are exempted from civil service provisions. They are hired with mechanisms for transitioning them to permanent staff. Examples: Utility Pre-craft Trainees (UPCT) and "on-the-spot" hires.	1 week
3 CONTRACT	These employees will have special expertise or will be required only for peak demands. Example: engineers for construction projects.	12-18 months
4 EXTERNAL	In limited circumstances, "Power Purchase Agreements" (PPA) are employed to meet short-term needs for procuring energy from generating facilities owned and operated by another utility. An example is the existing PPA for renewable energy from the Milford Wind Plant for an established period of time. It also gives LADWP the option to own and operate after a set amount of time.	9 months
5 EARLY	These employees will have significant work experience outside the Los Angeles Department of Water and Power. They must successfully challenge portions of Power System's training programs through written exams and practical testing processes. These employees may also qualify for hire through "early hire testing" without exemption request. Example: US Navy technicians who have experience with gas turbine engines.	TBD

Figure 4-2. Descriptions of IHRP gap strategies

The IHRP Workforce Planning Coordinators will report to the Joint Resolution Board with their recommendations of gap strategies for the future of each job classification in the Power System. An example of the format for this report is shown in Figure 4-3 below. This chart shows how IHRP gap strategies can apply to a sample of five workforce gap situations for the next five years. At the bottom of the chart are strategies for managing the workforce requirements as the Power System replaces the Navajo Generating Station with renewable energy and/or combined cycle power facilities.

The "Internal" strategy is heavily dependent on the effectiveness of the technical training programs provided by PSST. They will have to increase their capacity and graduation rate to cover the significant gaps that are shown in Figure 4-3. The average graduation rates for PSST are based on the performance of these programs from 2006 to the present:

- Electrical Distribution Mechanics Trainees (EDMT): 40% graduated
- Electrical Mechanics Trainees (EMT): 75% graduated
- Electric Station Operators Trainees (ESOT): 47% graduated

It is important to note that the "exempt" strategies for Electrical Distribution Mechanics and Electrical Mechanics will include employees from the UPCT program that was discussed earlier in this chapter. Figure 4-3 assumes that there will be an exempt class of Engineering Associates by 2015 for "on-the-spot" hires.

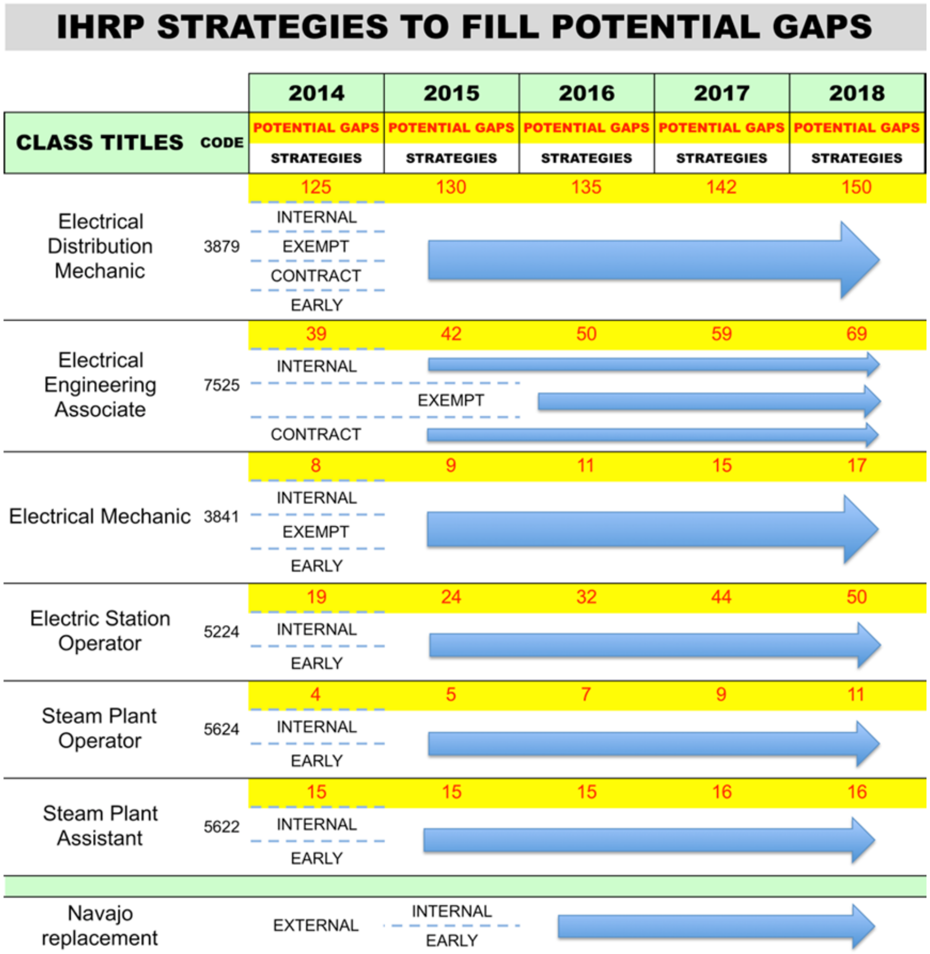

Figure 4-3. IHRP strategies to fill potential gaps

EVALUATION OF IHRP GAP STRATEGIES

It is important that the IHRP gap strategies provide broad benefits to the Power System. Each strategy plays an important role in helping the IHRP achieve its goal of workforce availability. The five IHRP gap strategies were evaluated against these criteria:

- Supports the IRP
- Supports long-term labor-management interests
- Is cost-effective
- Meets IHRP deadlines
- Is sustainable; supports long-term and stable workforce
- Provides ease of start and implementation
- Supports City Personnel policies

This evaluation is shown in Figure 4-4 below. All gap strategies were seen as effective in fulfilling the criteria to support the IRP. The criteria "ease of implementation" was the most difficult to meet for all strategies. The "Internal" strategy was generally the most effective approach followed by the "Exempt" strategy. The "Contract" strategy was the least effective although it is the only approach that can manage peak workloads.

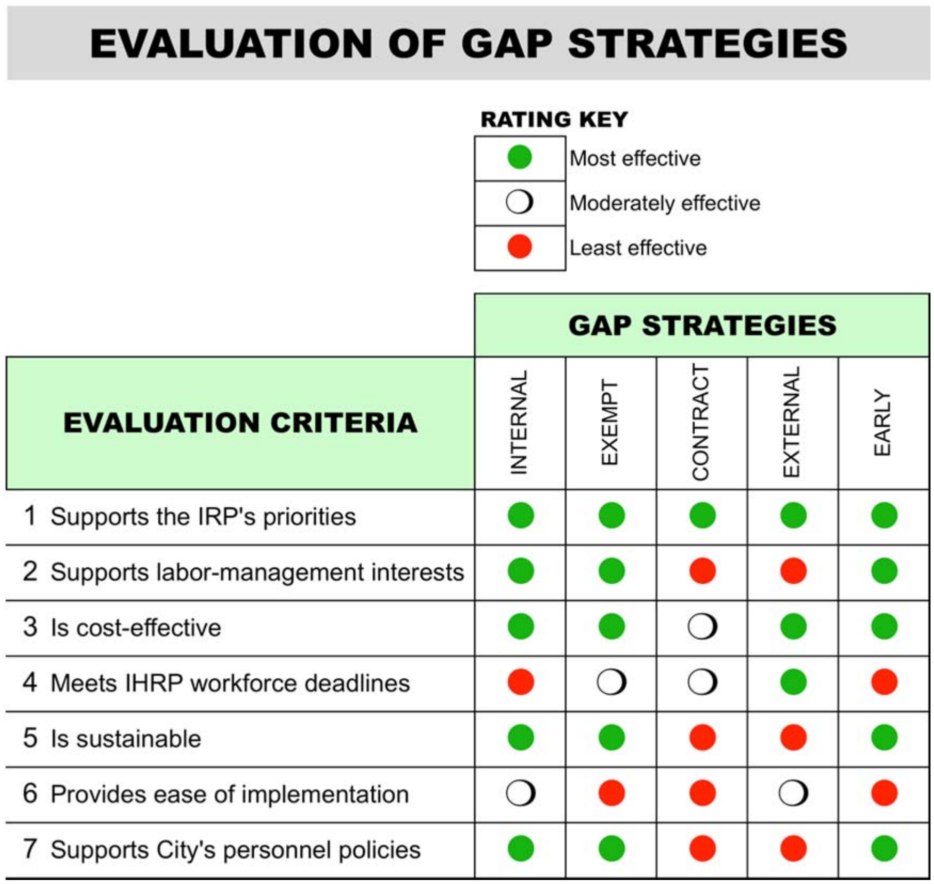

Figure 4-4. The evaluation of gap strategies

4.4 IHRP Priorities and Schedule

The IHRP has priorities that encompass the demand and the supply side of the Power System's planning for the future. The Workforce Development Task Force (WFDTF) will establish a set of goals and objectives in response to the IHRP Workforce Demand Forecast. Many of these priorities will focus on the improvement of the Critical Path. Figure 4-5 below shows a schedule that the WFDTF could implement. It includes activities located in the critical path that are currently underway in the Power System.

PRIORITIES FOR 2013-2014

DEMAND FORECAST OF THE POWER SYSTEM

1. Install an effective on-line workforce demand tool that provides a ten-year forecast of staffing needs of the Power System

2. Design a Job Justification Sheet (JJS) that can yield resource loaded staffing requirements for individual projects / programs that are either funded or unfunded

MEETING DEMANDS OF THE POWER SYSTEM

1. The Workforce Planning Coordinators recommend to the JRB the gap strategies necessary for each job classification in the Power System.
2. The five steps of the Critical Path have established measurable indicators of a streamlined system.

CRITICAL PATH IMPROVEMENTS — Numerous innovations and breakthroughs are being designed or implemented that will improve Job Classification, Recruitment, Selection, Training, and Placement including:

1. The consolidation of existing journey-level classes with their corresponding trainee/assistant/apprentice feeder class.
2. The application of the 5.30 civil service rule.
3. New classifications to ensure effective field supervision.
4. The creation of exempt positions to enable hiring to avoid losing qualified applicants.
5. An improved comprehensive recruitment process for Engineering Associates.
6. The expansion of local recruitment efforts.
7. Improving recruitment efforts of veterans.
8. Achieve 30 days for when a decision is made to hire to when the person starts work.
9. Improving job bulletins.
10. Civil Service exams test applicants for the skills, knowledge, and abilities needed for success.
11. Establishing metrics for training graduation rates.
12. New training programs for specific positions.
13. Trainer certification.
14. Knowledge capture and successor training.
15. Elimination of placement exams after training is complete.

INITIAL IHRP SCHEDULE FOR 2013-2016

KEY

(peach)	In development
(green)	Implementation

	IHRP PRIORITIES	2013	2014	2015	2016
DEMAND FORECAST					
1	Workforce Demand Forecast	In development	Implementation	Implementation	Implementation
2	Revised JJS for unfunded work		In development	In development	Implementation
MEETING DEMANDS					
1	IHRP gap strategies in place	In development	Implementation	Implementation	Implementation
2	Streamlined Critical Path	In development	In development	Implementation	Implementation
CRITICAL PATH					
1 JOB CLASSIFICATION					
CLASS CONSOLIDATION					
1.1	Machinist and Machinist Apprentice		In development	Implementation	Implementation
1.2	Welder and Apprentice Metal Trades		In development	Implementation	Implementation
1.3	Tree Surgeon and Tree Surgeon Apprentice		In development	Implementation	Implementation
1.4	Apply 5-30 rule to Meter Setters	Implementation	Implementation	Implementation	Implementation
1.5	Apply 5-30 rule to Engineering Drafting Technicians, Underground Distribution Construction Mechanics, and Electrical Service Representatives	In development	Implementation	Implementation	Implementation
NEW CLASSIFICATIONS					
1.5	Meter Setter Supervisors	In development	Implementation	Implementation	Implementation
1.6	Wind Plant Technician Supervisors	In development	Implementation	Implementation	Implementation
1.7	Electrical Tester Supervisors	In development	Implementation	Implementation	Implementation
1.8	Exempt classes	In development	Implementation	Implementation	Implementation
CITY PERSONNEL					
1.9	Bulletin improvements	In development	Implementation	Implementation	Implementation
2 RECRUITMENT					
2.1	Engineering Associates	In development	Implementation	Implementation	Implementation
2.2	EDMs	In development	Implementation	Implementation	Implementation
2.3	Military		In development	Implementation	Implementation
3 SELECTION					
DWP HUMAN RESOURCES					
3.1	HFE improvements	In development	Implementation	Implementation	Implementation
3.2	Reduce internal process to 30 days	In development	Implementation	Implementation	Implementation
CITY PERSONNEL					
3.3	Exam improvements	In development	Implementation	Implementation	Implementation
4 TRAINING					
EFFECTIVENESS					
4.1	Graduation rate at 90%	In development	In development	In development	Implementation
PROGRAM DESIGN					
4.2	On-line / CBT courses	In development	In development	Implementation	Implementation
4.3	Knowledge capture	In development	In development	In development	Implementation
NEW PROGRAMS					
4.4	Engineering Associates	In development	Implementation	Implementation	Implementation
4.5	Drafting Technicians		In development	Implementation	Implementation
4.6	Meter Setters	Implementation	Implementation	Implementation	Implementation
4.7	Underground Distr Construction Mechanics		In development	Implementation	Implementation
4.8	Formal Certification for Trainers	In development	Implementation	Implementation	Implementation
4.9	Successor Training	In development	In development	In development	Implementation
5 PLACEMENT					
5.1	Budgeted positions availability	Implementation	Implementation	Implementation	Implementation
5.2	Exam elimination		In development	Implementation	Implementation
CONTINUING EDUCATION					
1	Supervisory Training	Implementation	Implementation	Implementation	Implementation
2	New Technology Training	In development	Implementation	Implementation	Implementation
RETENTION					
	[no activities at this time]				

Figure 4-5. Initial IHRP schedule for 2013 - 2016

DESCRIPTION OF ACTIVITIES

In this section is a brief explanation of the activities in the initial IHRP priorities and schedule shown in Figure 4-5.

DEMAND FORECAST FOR THE POWER SYSTEM

1. Workforce Demand Forecast Report: An on-line assessment of Power System long-term employment needs while taking into consideration statistical retirement projections.
2. Revised JJS for Unfunded Work: A planning document that allows for resource loading staffing requirements for individual projects / programs that are unfunded. This document can be used for funded programs as well.

MEETING DEMANDS OF THE POWER SYSTEM

1. IHRP Gap Strategies: The Workforce Planning Coordinators recommend to the JRB the gap strategies necessary for each job classification in the Power System.
2. Streamlined Critical Path: The five steps of the critical path are meeting their measurable indicators of high performance.

CRITICAL PATH IMPROVEMENTS

1. JOB CLASSIFICATION: Pursue opportunities for job consolidation and new classifications.
   - 1.1. The consolidation of existing journey-level classes with their corresponding trainee/assistant/apprentice feeder class eliminates any potential delays that could be caused by the lack of a journey-level exam list at the time trainees graduate. It also reduces the number of exams that Personnel Department has to administer.
   - 1.2. The application of the 5.30 civil service rule enables the Department to better evaluate a candidate's ability and adherence to successful completion of a formal training program. The application of this rule also requires the appointing section to formally document and develop an objective, comprehensive, thorough training program that produces an excellent journey-level employee and at the same time provides for knowledge capture of the key skills, knowledge, and abilities for these positions.
   - 1.3. These new classifications are required to ensure effective field supervision for new and existing classes where clear supervision by the appropriate class that is fully knowledgeable on all the responsibilities and duties of the position. Electric Meter Setters and Electrical Testers were previously supervised by other classes (such as Transmission and Distribution District Supervisors and Electrical Engineers) that were inundated with other priorities.
   - 1.4. The creation of exempt positions for various classifications enables hiring of personnel in critical areas to avoid the situation of losing qualified applicants to other utilities due to the lack of an existing civil service list. It also provides the ability to use exempt hiring to meet peak resource requirements as a short-term gap strategy for critical projects or needs.

2. RECRUITMENT: Pursue innovations in recruiting new and existing classifications.
   2.1. An improved comprehensive recruitment process for Engineering Associates will expand the number of colleges visited, as well as ensure a qualified pool of graduates exists and is used to hire when traditional graduations in the winter and spring to capture interested applicants at the time when they make career decisions.
   2.2. The expansion of existing recruitment efforts at local high schools and community colleges, as well as specialized line worker trade schools to make potential candidates aware of the excellent job opportunities for line worker at LADWP.
   2.3. The U.S. Military provides excellent training and education to their active personnel in many areas suited to utility operations and maintenance requirements. Improving recruitment efforts of veterans with these skills, knowledge, and abilities, as well as modifying exam bulletin requirements to capture these persons exponentially increases not only the quality of the candidate but improves the probability of the trainees successfully completing the program.

3. SELECTION: Pursue innovations in the external and internal selection processes.
   3.1. HFE (Hiring Freeze Exemption) – The internal process that the Department and Power System have in place needs to be reviewed to ensure that only value added steps are used to effectively fill a vacancy from the moment a decision is made to hire to the day the person starts work.
   3.2. A target has been established to streamline this process to 30 days.
   3.3. Bulletin – Existing civil service bulletins used to establish job applicant requirements need to be extensively scrutinized to ensure the candidates who qualify and take these exams have the requisite skills, knowledge, and abilities to be successful for that specific class at LADWP. Another option to employ is to require applicants to take preparatory course work in advance to qualify for an exam either online or at a recognized school.
   3.4. Exam – Ensure that the exams administered by the Personnel Department test applicants for the skills, knowledge, and abilities they need to be successful for that specific class. Another component of this effort is to evaluate all exams used to fill Power System vacancies for the potential of these exams to be administered by LADWP to ensure the exam lists are current and in place when positions need to be filled.

4. TRAINING: Effectiveness ratings achieve their targets. New programs have been implemented. New methods and content are part of current programs.
   4.1. Effectiveness — The improvement in the graduation rate for programs is critical to meet the needs of the future Power System. Establishing an objective goal ensures all involved focus on improving the upstream processes, such as recruitment, selection, training, and placement, to improve this metric.
   4.2. New Programs —As previously identified in the initiatives related to job classifications, the development and implementation of new "formal" training programs for classes where they did not exist before improves the quality of graduates and provides a repository to capture knowledge that only was available as oral legacies from experienced employees.

4.3. Formal certification — Providing our trainees with a sound foundation on the requirements to be an effective and successful instructor increases the ability of training programs to improve the quality of the training delivery experience.
4.4. Online/Computer-Based Training (CBT) — The expansion of CBT training modules online increases the availability of training opportunities for employees to access material on their schedule 24/7. This also decreases the demand on valuable hands-on instructor time to free them up for more valuable use of their limited resources. This effort also leverages the use of best practices from other educational resources to avoid duplication of development efforts in building training programs.
4.5. Successor training — It is imperative to ensure knowledge capture and training programs are developed and implemented to cover areas requiring specialized skills and leadership/supervisor training due to the pending "vacuum effect" that will occur with the loss of experienced personnel.
4.6. Knowledge capture — see previous descriptions.

5. PLACEMENT: Barriers to immediate placement after training have been removed.
   5.1. Budgeted Position Availability – Ensure that budgeted and funded positions are available for a trainee graduate to transition into once they successfully complete the program.

CONTINUING EDUCATION

1. Supervisory Training: It is imperative to ensure knowledge capture and training programs are developed and implemented to cover areas requiring specialized skills and leadership/supervisor training due to the pending "vacuum effect" that will occur with the loss of experienced personnel.
2. New Technology Training: Programs are provided for employees to utilize new software applications and new equipment technologies.

4.5 IHRP Reporting

In 2014, the IHRP will report on its achievements against its goals. Within a few years, the IHRP will produce an annual document that can provide the following information:

- All long-term workforce requirement targets organized by classification
- Achievement of workforce development against annual targets
- All approved gap strategies for each classification
- Work rules that apply to any aspect of the IHRP
- Confidential retirement survey data, such as those done through Survey Monkey
- All reports to IRP, Power System management, the JRB, and Task Force members

4.6 Conclusion

This report provides an overview of the critical workforce issues that the Power System will face over the next 10 years. This chapter introduces the IHRP as a broad and systemic approach to address these challenges. In 2013 the IHRP successfully initiated a planning methodology that can determine the Power System's forecast for staffing needs over the next ten years. The IHRP also instituted the Workforce Development Task Force (JLMC). Over the next few years it will streamline the processes for job classification, recruiting, selecting, training, and placement of future talent for the Power System.

IHRP APPENDIX

Power SYSTEM NON CUMULATIVE ATTRITION PROJECTION for 2014-2023

AS OF OCT 28, 2013

CLASS TITLES	CLASS CODE	AVE AGE	AVE. YRS SERV.	2013 OCC	NON CUMULATIVE ATTRITION AS A RESULT OF RETIREMENT (NET OCCUPANCY) 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Survival Rate
APPRENTICE MACHINIST	3764	0.00	15.03	1	1	1	1	1	1	1	1	1	1	1	100.00%
APPRENTICE METAL TRADES	3789	47.25	12.42	8	8	8	8	8	8	8	8	8	8	8	100.00%
ARCHITECT	7925	51.00	24.94	1	1	1	1	1	1	1	1	1	1	1	100.00%
ARCHITECTURAL ASSOC.	7926	57.50	19.15	6	6	6	6	6	6	6	5	5	5	5	83.33%
ARCHITECURAL DRAFTING TECH	7922	59.00	22.53	4	4	4	4	4	4	4	4	3	2	2	50.00%
ASBESTOS SUPERVISOR	3440	0.00	22.75	2	2	2	2	2	2	2	2	2	2	2	100.00%
ASBESTOS WORKER	3435	53.67	11.84	13	13	13	13	13	13	13	13	13	13	13	100.00%
ASSISTANT ENGR GEOLOGIST	7253	0.00	4.47	1	1	1	1	1	1	1	1	1	1	1	100.00%
ASST GM WATER & POWER	151	0.00	33.71	2	1	1	1	0	0	0	0	0	0	0	0.00%
BATTERY TECHNICIAN	3725	0.00	44.62	1	0	0	0	0	0	0	0	0	0	0	0.00%
BOILERMAKER	3735	62.50	21.63	3	3	3	3	3	3	3	3	2	2	2	66.67%
BUILDING REPAIR SUPERVISOR	3338	0.00	26.90	1	1	1	1	1	1	1	1	1	0	0	0.00%
BUILDING REPAIRER	3333	56.44	26.35	8	8	8	7	6	6	6	5	4	4	4	50.00%
CABINET MAKER	3343	56.60	26.75	5	5	5	5	5	5	5	4	2	2	1	20.00%
CARPENTER	3344	55.09	17.37	40	39	39	39	39	39	39	38	38	36	34	85.00%
CARPENTER SHOP SUPERVISOR	3339	0.00	17.07	1	1	1	1	1	1	1	1	1	1	1	100.00%
CARPENTER SUPVSR	3346	53.87	19.87	20	20	20	20	20	20	19	18	17	16	16	80.00%
CEMENT FINISHER	3353	0.00	13.86	2	2	2	2	2	2	2	2	2	2	2	100.00%
CHEMIST	7833	58.31	16.66	19	18	18	18	17	17	17	17	16	16	16	84.21%
CHIEF ELECTRIC PLANT OPERATOR	5237	56.38	29.90	17	15	12	10	8	7	5	4	4	4	3	17.65%
CHIEF REAL ESTATE OFFICER	1949	0.00	38.61	1	1	1	1	1	1	1	1	1	0	0	0.00%
CHIEF SFTY ENGR PRESS VESS	4260	0.00	10.08	1	1	1	1	1	1	1	1	1	1	1	100.00%
CIVIL ENGINEER	7237	53.29	26.57	6	6	6	6	5	5	5	5	4	3	2	33.33%
CIVIL ENGINEERING ASSOCIATE	7246	53.81	17.68	35	35	34	32	32	31	31	30	29	28	27	77.14%
CIVIL ENGRNG DRAFTING TECH	7232	57.58	20.31	37	37	36	36	35	33	32	30	28	27	27	72.97%
CLERK	1141	0.00	51.04	1	0	0	0	0	0	0	0	0	0	0	0.00%
CLERK TYPIST	1358	53.83	26.63	10	9	8	7	7	6	6	5	4	4	3	30.00%
CONST & MTC SUPERINTENDENT	3129	0.00	32.78	2	2	1	1	1	1	1	1	1	1	1	50.00%
CONSTRUCTION & MTNC SUPV	3127	57.00	27.29	9	9	8	8	7	7	6	5	4	4	3	33.33%
DELIVERY DRIVER	1121	56.00	28.46	5	3	3	3	3	3	2	2	2	2	2	40.00%
ELECTRIC DISTRBN MECHC SUPV	3873	52.63	27.27	95	92	89	86	79	74	69	60	50	43	36	37.89%
ELECTRIC METER SETTER	3822	54.16	13.19	50	49	49	48	48	47	46	45	45	43	42	84.00%
ELECTRIC SERVICE REP	7520	55.32	24.72	44	43	40	38	35	32	30	28	26	24	22	50.00%
ELECTRIC STATION OPERATOR	5224	55.44	18.26	217	206	201	193	181	175	170	167	164	160	156	71.89%
ELECTRIC TROUBLE DISPATCHER	3828	52.24	27.71	22	22	20	20	18	16	15	14	12	9	8	36.36%
ELECTRICAL CRAFT HELPER	3799	54.22	14.16	270	269	266	262	258	253	248	243	238	231	224	82.96%
ELECTRICAL DISTRIBUTION MECHANIC	3879	52.47	14.40	499	494	489	484	477	469	461	450	440	425	411	82.36%
ELECTRICAL ENGINEER	7539	54.86	27.83	52	49	48	43	39	36	33	28	24	20	17	32.69%
ELECTRICAL ENGR ASSOCIATE	7525	55.46	14.91	279	274	271	263	254	244	235	228	222	214	204	73.12%
ELECTRICAL ENGR DRAFTG TECH	7532	54.00	13.03	5	5	5	5	4	4	4	4	4	4	4	80.00%
ELECTRICAL MECHANIC	3841	55.94	16.08	271	268	267	265	261	259	253	246	240	235	226	83.39%
ELECTRICAL MECHANIC SUPV	3835	54.41	24.54	60	58	58	57	56	54	51	49	46	42	40	66.67%
ELECTRICAL REPAIR SUPERVISOR	3855	55.90	26.06	9	9	9	9	8	7	7	5	4	3	2	22.22%
ELECTRICAL REPAIRER	3853	57.59	21.00	46	46	45	44	42	41	38	36	34	32	29	63.04%
ELECTRICAL SERVICE WORKER	3825	56.25	25.10	10	10	10	10	9	9	9	8	6	6	5	50.00%
ELECTRICAL SERVICES MANAGER	5265	55.79	31.50	35	30	28	24	20	18	16	13	9	7	5	14.29%
ELECTRICAL TESTER	7512	58.13	11.21	96	95	94	93	93	93	92	91	91	90	85	88.54%
ELECTRICIAN	3863	59.33	25.70	3	3	3	3	3	3	3	3	2	2	2	66.67%
ELEVATOR MECHANIC	3866	53.50	11.97	5	5	5	5	5	5	5	5	5	4	4	80.00%
ENVIRONMENTAL SPECIALIST	7310	50.00	13.05	3	3	3	3	3	3	3	3	3	3	3	100.00%
EQUIPMENT OPERATOR	3525	53.14	24.71	19	19	18	18	18	18	18	17	16	15	13	68.42%
EQUIPMENT SPECIALIST	3734	0.00	26.93	2	2	2	2	2	2	2	2	1	1	1	50.00%
GENERAL SERVICES MANAGER	9601	0.00	30.33	2	2	2	2	1	1	1	1	1	0	0	0.00%
HEAVY DUTY TRUCK OPERATOR	3584	0.00	0.00	2	2	2	2	2	2	2	2	2	2	2	100.00%
INDUSTRIAL CHEMIST	7834	0.00	24.66	1	1	1	1	1	1	1	1	1	1	1	100.00%
INSTRUMENT MECHANIC	3843	56.85	16.01	38	37	36	34	33	32	32	31	30	28	28	73.68%
INSTRUMENT MECHANIC SUPV	3844	56.17	27.97	6	6	6	6	5	5	5	4	2	1	1	16.67%
INSTRUMENT REPAIRER	3842	0.00	28.14	2	2	2	1	1	1	1	1	1	1	1	50.00%
LABOR SUPERVISOR	3126	0.00	21.91	3	3	3	3	3	3	3	3	3	3	2	66.67%
LABORATORY TECHNICIAN	7854	58.73	13.93	15	15	15	15	15	15	15	14	14	14	14	93.33%
LINE MAINTENANCE ASSISTANT	3882	57.00	27.02	29	27	25	23	21	20	19	18	15	13	12	41.38%
LOAD DISPATCHER	5233	53.89	13.86	34	33	33	32	31	30	30	29	28	27	27	79.41%
MACHINIST	3763	57.13	14.65	38	37	37	36	35	34	34	34	32	31	31	81.58%
MACHINIST SUPERVISOR	3766	59.00	28.16	8	7	7	7	6	6	6	6	4	3	3	37.50%
MAINTENANCE & CONTSTR HELPER	3115	54.87	16.85	61	60	59	58	57	57	56	55	53	51	49	80.33%
MAINTENANCE LABORER	3112	61.67	27.90	12	11	11	11	11	11	10	9	7	6	5	41.67%
MANAGEMENT ANALYST	9184	55.91	17.25	28	28	27	27	27	27	27	26	26	25	25	89.29%
MANAGEMENT ASSISTANT	1539	0.00	13.31	1	1	1	1	1	1	1	1	1	1	1	100.00%
MECHANICAL EGR DRAFTG TECH	7551	63.33	26.90	4	4	4	3	3	3	3	3	3	3	2	50.00%
MECHANICAL ENGINEER	7558	55.06	26.91	16	15	15	12	10	9	8	6	5	4	3	18.75%
MECHANICAL ENGR ASSOCIATE	7554	55.50	14.22	61	60	60	57	54	52	50	49	48	47	46	75.41%
MECHANICAL HELPER	3771	56.75	18.25	16	13	12	12	12	12	12	12	11	11	11	68.75%
MILLWRIGHT	3760	56.00	33.82	2	2	2	2	2	1	1	1	0	0	0	0.00%
OFFICE ENGINEERING TECHN	7212	56.08	22.95	14	13	13	13	12	12	11	10	9	8	7	50.00%
OPRNS & STATL RES ANALYST	1779	0.00	31.34	1	1	1	1	0	0	0	0	0	0	0	0.00%
PAINTER	3423	55.86	17.37	33	33	32	32	31	31	31	30	30	29	28	84.85%

AS OF OCT 28, 2013

CLASS TITLES	CLASS CODE	AVE AGE	AVE. YRS SERV.	2013 OCC	NON CUMULATIVE ATTRITION AS A RESULT OF RETIREMENT (NET OCCUPANCY)										Survival Rate
					2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
PAINTER SUPERVISOR	3426	0.00	31.49	2	2	2	2	2	1	1	1	1	0	0	0.00%
PIPEFITTER	3433	64.60	19.67	6	5	5	5	5	5	5	5	5	5	5	83.33%
PIPEFITTER SUPVSR	3438	58.50	17.40	2	2	2	2	2	2	2	2	2	2	2	100.00%
PL CVL ENGG DRFTG TCHN	7219	51.83	28.99	6	6	5	5	4	3	3	3	2	2	2	33.33%
PL ELTL ENGG DRFTG TCHN	7531	0.00	32.21	2	2	2	1	1	0	0	0	0	0	0	0.00%
PL MCHL ENGG DRFTG TCHN	7550	0.00	32.82	1	1	1	0	0	0	0	0	0	0	0	0.00%
PLUMBER	3443	55.44	16.60	18	18	18	17	17	17	17	16	16	16	16	88.89%
PLUMBER SUPERVISOR	3446	46.50	29.90	2	2	2	2	2	2	2	2	2	2	1	50.00%
POWER ENGINEERING MANAGER	9453	54.89	29.53	23	22	22	19	15	12	10	8	6	4	3	13.04%
PR CLERK UTILITY	1202	52.46	26.31	31	30	29	27	25	23	21	20	18	16	16	51.61%
PRINCIPAL ELECTRIC TROUBLE DISPATCHER	3830	58.00	34.72	2	1	1	0	0	0	0	0	0	0	0	0.00%
REENFORCING STEEL WORKER	3483	0.00	11.33	1	1	1	1	1	1	1	1	1	1	1	100.00%
ROOFER	3476	53.00	12.64	5	5	5	5	5	5	5	5	5	5	5	100.00%
SAFETY ENGR PRESS VESS	4261	57.75	13.81	5	5	5	5	5	5	5	5	5	5	5	100.00%
SENIOR LOAD DISPATCHER	5235	53.87	24.49	19	19	19	19	17	15	15	13	12	10	10	52.63%
SHEET METAL WORKER	3775	54.00	14.86	4	4	4	4	4	4	3	3	3	3	3	75.00%
SHOPS SUPERINTENDENT	3780	50.00	27.34	1	1	1	1	1	1	1	1	0	0	0	0.00%
SR ARCHITECURAL DRFTG TECH	7208	59.33	23.69	4	4	4	4	3	3	2	2	2	2	1	25.00%
SR CIVIL ENGR DRAFTING TECH	7207	58.07	20.66	16	15	15	13	13	12	12	11	10	10	10	62.50%
SR CLERK STENO	1323	58.00	41.31	1	1	1	0	0	0	0	0	0	0	0	0.00%
SR CLERK TYPIST	1368	54.59	21.79	142	139	135	131	128	125	122	119	115	109	102	71.83%
SR ELCTRCL ENGR DRAFTNG TECH	7209	55.22	30.82	10	9	9	7	5	5	4	4	4	4	4	40.00%
SR ELECTRIC SERVICE REP	7521	56.00	28.82	5	5	4	4	3	3	2	2	2	2	2	40.00%
SR ELECTRIC TROUBLE DISPATCHER	3829	55.43	29.87	5	5	5	4	4	4	3	3	1	0	0	0.00%
SR ELECTRICAL MECHANIC	3834	55.14	21.93	59	56	54	53	52	50	48	45	44	42	39	66.10%
SR ELECTRICAL MECHANIC SUPV	3836	53.95	26.89	23	22	21	20	19	18	16	14	13	13	10	43.48%
SR ELECTRICAL REPAIR SUPV	3856	57.67	28.12	3	3	3	3	3	3	2	1	1	1	1	33.33%
SR ELECTRICAL TESTER	7515	57.83	26.02	38	36	34	32	30	28	27	25	23	20	18	47.37%
SR MACHINIST SUPERVISOR	3768	0.00	31.57	1	1	1	1	0	0	0	0	0	0	0	0.00%
SR PAINTER	3424	62.00	26.70	4	4	4	4	4	4	4	4	4	4	4	100.00%
SR PLUMBER	3444	57.33	23.00	4	4	4	4	4	4	4	4	4	3	2	50.00%
SR ROOFER	3477	0.00	12.24	1	1	1	1	1	1	1	1	1	1	1	100.00%
SR SAFETY ENGR PRESS VESS	4262	0.00	10.78	1	1	1	1	1	1	1	1	1	1	1	100.00%
SR UG DISTRIBUTION CONSRT SUPERVISOR	3815	54.17	27.55	6	6	6	6	6	5	5	4	4	2	1	16.67%
STEAM PLANT ASSISTANT	5622	54.04	9.07	119	119	119	119	118	117	117	116	115	114	113	94.96%
STEAM PLANT MAINT MECHANIC	5630	56.75	19.88	51	50	49	47	47	45	44	43	42	39	38	74.51%
STEAM PLANT MAINT SUPV	3786	54.36	30.16	12	11	11	10	8	7	6	5	5	3	2	16.67%
STEAM PLANT OPERATING SUPV	5625	56.75	30.70	24	19	15	11	9	8	7	7	6	6	6	25.00%
STEAM PLANT OPERATOR	5624	54.85	16.93	90	87	86	84	82	80	79	78	77	74	73	81.11%
STOREKEEPER	1835	0.00	25.02	2	2	2	2	2	2	2	2	2	2	2	100.00%
STREET TREE SUPERINTENDENT	3160	0.00	38.59	2	1	1	1	1	0	0	0	0	0	0	0.00%
STRL STL FABRICATOR SUPV	3794	0.00	22.21	1	1	1	1	1	1	1	1	1	1	1	100.00%
STRUCT STEEL FABRICATOR	3793	58.09	19.67	11	10	9	8	8	8	7	6	6	6	5	45.45%
STRUCTURAL ENGINEER	7956	56.00	31.73	2	2	1	1	1	1	1	0	0	0	0	0.00%
STRUCTURAL ENGR ASSOCIATE	7957	59.00	14.94	9	8	8	8	8	8	8	7	7	7	6	66.67%
T&D DISTRICT SUPERVISOR	3875	52.63	29.27	32	31	29	27	24	22	20	16	12	9	6	18.75%
TREE SURGEON	3114	52.67	17.11	32	31	31	31	30	30	29	27	27	26	26	81.25%
TREE SURGEON ASST	3151	53.00	14.86	33	33	33	33	33	33	33	33	33	33	33	100.00%
TREE SURGEON SUPERVISOR	3117	56.64	29.56	22	20	19	18	17	15	14	12	11	10	9	40.91%
UG DISTRIBUTION CONSTR MECH	3812	53.37	19.48	88	88	88	87	87	86	86	83	78	74	70	79.55%
UG DISTRIBUTION CONSTR SUPV	3814	51.57	24.47	27	27	27	27	27	26	26	24	21	18	16	59.26%
UTILITY ADMINISTRATOR	9105	53.78	23.96	19	19	19	18	17	16	15	15	14	13	12	63.16%
UTILITY EXECUTIVE SECRETARY	1336	51.40	25.76	7	7	7	6	6	6	5	5	5	5	5	71.43%
WAREHOUSE & TOOLROOM WRKR	1832	57.83	21.70	10	10	10	10	10	10	10	9	8	7	6	60.00%
WELDER	3796	59.73	19.45	19	19	19	19	19	19	17	16	14	12	11	57.89%
WELDER SUPERVISOR	3798	0.00	27.14	2	1	1	1	1	1	1	1	1	1	1	50.00%
132 CIVIL CLASSIFICATIONS			**TOTAL**	3848	3750	3681	3576	3455	3356	3258	3130	2995	2853	2722	70.74%

LEGEND

Net Occupancy of 2013 Occupancy

(white)	<=100% and >75%
(light blue)	<75% and >50%
(magenta)	<50% and >25%
(red)	<25%
(green)	Classification for which no differentiation exists between the trainees and staff. In most cases the trainee are in majority

Assumptions in Retirement Probability

To analyze transitions from employment into retirement, a hazard based duration of model framework is used. This allows modeling the length of time spent at work before moving into retirement. A relationship is developed between the dependent variable, the amount of time that an employee spends in employment before retirement, and the hazard function (retirement probability). To achieve this relationship the following assumptions are taken:

1. Incentives for maintaining employment until at least all retirement eligibility conditions are met are considered constant. These incentives include, but not limited to:

- Work environment
- Health and pension benefits
- Salary increases

2. An employee transition from employment to retirement is the event of interest in this study for period 2002 to 2012. Therefore the spell of retirement considered in the study occurs before the proposed Memorandum of Understanding (MOU) from IBEW Local 18 which might affect an employee's decision to retire. However, the Integrated Human Resource Plan (IHRP) model has a built-in threshold to account for potential discrepancies caused by this new MOU.

3. The hazard function or the retirement probability relies heavily on the employee's years of service. Thus, any buy back years of service acquired from organizations other LADWP that qualify to participate into the LADWP outside years of service buy back program is not accounted for in this model because Retirement Office evaluation of affected employees is neither empirical nor verifiable. This condition will only make the model retirement prediction more conservative.

4. It is natural to hypothesize upfront that retirement dynamics change overtime reflecting the extent to which social, income, pension and health benefits impact the employee decision to move into retirement.

5. Entering to retirement as a result of a weakening of employee's health is assumed negligible since nearly all observed retirement spell have retired upon meeting retirement eligibility criteria.

6. Every two weeks this model will be refreshed to reflect any changes observed from payroll database.

7. This Model does not account for Tiers 2 as part of the new MOU which will affect the new recruitment with no statistical significance for at least 10 to 15 years from now.

8. The statistical Expected Duration of Service for LADWP's employees is 34 years corresponding approximately to 50% chance of retiring. An employee with at least 50% chance of retiring is deemed retired. Once an employee is deemed retired with at least 50% chance of retiring there's a residual 50% chance of not retiring. This remaining probability is decayed

over three iterations representing approximately 30%, 10%, and 10% for the later years for which chances of retiring become higher than initial 50% of retiring. The key here is to ensure that the total probability is 1 or 100% for each retiree, that is 50%+30%+10%+10% = 100%. This process takes approximately 4 years ensuring that a complete removal from the total count of an employee that has been deemed retired based on criteria discussed above occurs. At any given year of interest, a summation of all fractional probabilities is performed within the civil classification at a Division level to arrive to the retirement projection.

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Appendix Q Abbreviations and Acronyms

Q.1 Overview

This appendix presents acronyms for agencies and other entities, facilities and locations, electric industry terms, miscellany, and units of measure.

Q.2 Agencies and Other Entities

APS	Arizona Public Service Company
BPA	Bonneville Power Administration
BOS	Bureau of Sanitation
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
City	City of Los Angeles
Committee	IRP Advisory Committee
CPUC	California Public Utilities Commission
DOD	U.S. Department of Defense
DOE	U. S. Department of Energy
DWR	Department of Water Resources
EPA	U. S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FSO	LADWP Financial Services Organization
IID	Imperial Irrigation District
IOU	California investor owned utilities
IPA	Intermountain Power Agency
IPCC	Intergovernmental Panel on Climate Change
IPPCC	Intermountain Power Project Coordinating Committee
ISDA	International Swaps and Derivatives Association
JPL	NASA Jet Propulsion Laboratory
LADWP	Los Angeles Department of Water and Power
NAESB	North American Energy Standards Board
NASA	National Aeronautic Space Administration
NERC	North American Electric Reliability Corporation
NPC	Nevada Power Company
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric Company
PwC	PriceWaterhouse Coopers
RTO	Regional Transmission Organization
RWQCB	Regional Water Quality Control Board
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCPPA	Southern California Public Power Agency
SoCal	Southern California Gas Company

SRP	Salt River Project
SWRCB	State Water Resources Control Board
TEC	Tucson Electric Company
UCLA	University of California at Los Angeles
UCSD	University of California at San Diego
USC	University of Southern California
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WREZ	Western Renewable Energy Zones

Q.3 Facilities and Locations

BPA	Bonnerville Power Administration
BBRTP	Barren Ridge Renewable Transmission Project
BRSS	Barren Ridge Switching Station
COB	California-Oregon Border
COI	California-Oregon Intertie
EOR	East-of-the-River
HSS	Haskell Switching Station
IGS	Intermountain Generating Station
IPP	Intermountain Power Project
LA	Los Angeles
NGS	Navajo Generating Station
NOB	Nevada-Oregon Border
NTS	Northern Transmission System
PACI	Pacific AC Intertie
PDCI	Pacific High Voltage Direct Current Intertie
PTWPP	Pine Tree Wind Power Project
PVD2	Palo Verde-Devers Line No. 2
PVNGS	Palo Verde Nuclear Generating Station
SHARE	Scattergood-Hyperion Alternative Renewable Energy Project
SRP	Salt River Project
STS	Southern Transmission System
UGPP	Upper Gorge Power Plant
US	United States
WREZ	Western Renewable Energy Zone
WOR	West-of-the-River
WSPP	Western Systems Power Pool

Q.4 Electric Industry Terms

A/C	air conditioning
AC	Alternating Current
ACE	Area Control Error
AEDP	Advanced ESS Demonstration Project
AMI	Advanced Metering Infrastructure

AMP	Alternative Maritime Power
AQMP	Air Quality Management Plan
BACT	Best Available Control Technology
BIGCC	Biomass Integrated Gasification Combined Cycle
BPJ	Best Professional Judgment
CAES	compressed air energy storage
CAMR	Clean Air Mercury Rule
CAP	Climate Action Plan
CCC	closed cycle cooling
CH_4	methane
CHP	combined heat and power
CISCON	Customer Information System Conversion
CLEO	Commerical Lighting Efficiency Offer
CLFR	compact linear frenal reflector
CNG	compressed natural gas
CNM	Customer Net Metered
CO_2	carbon dioxide
CSI	California Solar Initiative
CSP	concentrating solar thermal power plants
CY	calendar year
DC	Direct Current
DC&M	Distribution Construction and Maintenance
DCS	Disturbance Control Standard
DG	distributed generation
DNI	direct normal insolation
DR	Demand Response
DSM	Demand Side Management
E&L	Environment and Lands
ECAF	Energy Cost Adjustment Factor
ECH	Electrical Craft Helper
EDS	Energy Dissipation Station
EE	Energy Efficiency
EHV	Extra-High Voltage
EIM	Energy Imbalance Market
ESPs	energy service providers
ESS	energy storage system
ETD	Electric Trouble Dispatch
EV	electric vehicle
FAR	Firm Access Rights
FES	flywheel energy storage
FiT	Feed-in Tariff
FYE	Fiscal Year Ending
GHG	greenhouse gas
GHGs	greenhouse gases
GREEN	Green Power for Green LA Program
GT&D	Generation, Transmission and Distribution

GWP	global warming potential
HHV	higher heating value
HRSG	heat recovery steam generator
HVAC	heating, ventilating, and air conditioning
IBEW	International Brotherhood of Electrical Workers
ICEs	internal combustion engines
IGCC	integrated gasification combined cycle
IM	impingement mortality
LCOE	levelized cost of energy
LF	Load Factor
LFG	landfill gas
LNG	liquefied natural gas.
LPG	propane
LSE	loadserving entities
NaS	sodium-sulfur
NEL	Net Energy for Load
N_2O	nitrous oxide
NO_2	nitrogen dioxide
NOx	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NPHR	net plant heat rate
O&M	operations and maintenance
OATT	Open Access Transmission Tariff
OASIS	open-access same-time information systems
OATTS	open-access transmission tariffs
OTC	once-through cooling
PAR	Planning and Risk
PCL	Power content label
PCT	Programmable Communicating Thermostats
PFCs	perfluorcocarbons
PHEV	plug-in hybrid electric vehicle
PHS	pumped-hydro storage
PMU	power measurement units
POUs	publicly-owned electric utilities
PPA	Power Purchase Agreement
PRP	Power Reliability Program
PSRP	Power System Reliability Program
PTC	production tax credit
PV	photovoltaic
QRAs	Qualified Resource Areas
RA	Resource Adequacy
RASS	Residential Appliance Saturation Survey
RBC	Reliability Based Control
RECLAIM	Regional Clean Air Incentive Market
RETI	Renewable Energy Transmission Initiative
RMR	Reliability Must Run

RPS	Renewable Portfolio Standard
RS	receiving station
RTCs	RECLAIM Trading Credits
Rule 316(b)	United States Environmental Protection Agency Clean Water Act Section 316(b) Cooling Water Intake Structures, Phase II Rule
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAS	Substation Automation System
SCADA	supervisory control and data acquisition
SEC	Standard Energy Credit
SES	super capacitor energy storage
SF_6	sulfur hexafluoride
SGIP	Smart Grid Investment Program
SGRDP	Smart Grid Regional Demonstration Program
SIP	Solar Incentive Program
SMES	Superconducting Magnetic Energy Storage
SNCR	selective non-catalytic reduction
SOx	sulfur oxide
T&T	transmission and delivery
UBS	Utility-built Solar
UES	ultra capacitor energy storage
VER	variable energy resources
VRB	Vanadium Redox Battery
WEC	Wave Energy Converter
XRT	experimental demand response contract
ZITA	Zone Identification and Technical Analysis
ZNE	Zero Net Energy

Q.5 Miscellaneous

A	Category of Flow Meter
AB	Assembly Bill
AMR	Automatic Meter reading
ARI	Air-Conditioning and Refrigeration Institute
C&S	Codes and Standards
CAHP	California Advanced Home Program
CFL	compact fluorescent light
CI	commercial/industrial
CIS	Customer Information System
CPR	Consumer Rebate Program
CS	Customer Service
CSA	Candidate Study Aras
ECC	Energy Control Center
EIR	Environmental Impact Report
F	Category of flow meter
FM	Category of flow meter
GDP	gross domestic product
IHRP	Integrated Human Resource Plan
IRP	Integrated Resource Plan
IT	Industrial Technology
JFB	John Ferraro Building
JPL	Jet Propulsion Laboratory
LED	light-emitting diode
MDREPS	Maximum Distribution Renewable Energy Penetration Study
MGREPS	Maximum Generation Renewable Energy Penetration Study
MFR	multi-family residence
NLC	net levelized cost
NOI	notice-of-intent
OH	overhead
QRAs	Qualified Resource Areas
RCx	Retrocommissioning Express
RF	Radio Frequency
RFP	Request for Proposal
SB	Senate Bill
SBDI	Small Business Direct Install
SFR	single family residence
UCLA	University of California Los Angeles
UG	Underground
USC	University of Southern California

Q.6 Units of Measure

BTU	British thermal unit

GWh	gigawatt-hour
kV	kilovolt
kW	kilowatts
MMBtu	Million British thermal units
MMT	million metric tons
$MMTCO_2E$	million metric ton CO2 equivalent
MVA	mega volt amperes
MW	megawatt
MWhs	megawatt hours
TWh	terawatt hour