Los Angeles Department of Water & Power

2012
POWER INTEGRATED RESOURCE PLAN

December 2012

LADWP's Pine Tree Solar and Wind farms - Tehachapi, CA

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Los Angeles Department of Water & Power

2012 Power Integrated Resource Plan

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December 3, 2012

Integrated Resource Planning

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Los Angeles Department of Water and Power

2012 Power Integrated Resource Plan

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Preface

This 2012 Integrated Resource Plan (IRP) document revises and builds upon last year's 2011 IRP. Major changes from 2011 include expanded discussion regarding the Power Reliability Program, more detailed information on transmission planning and projects, a new subsection on the impacts of climate change on power system operations, and new case options that analyze higher levels of energy efficiency and solar distributed generation.

The current load forecast used in this IRP is lower than the one used in 2011. Compared to the prior forecast, electricity sales for year 2020 decreased by approximately 5.3 percent mostly due to increasing levels of energy efficiency.

Early coal replacement continues to be a key strategy to reduce greenhouse gas emissions. As with last year's IRP, this 2012 IRP recommends divestiture of the Navajo coal plant by 2015, four years ahead of the scheduled 2019 end date. LADWP will replace the loss of Navajo with energy efficiency, renewable energy, and natural gas generation. LADWP's other coal source – the Intermountain Power Project—is undergoing discussions which could enable a future conversion to lower emitting resources. Because LADWP is one of thirty-six purchasers of IPP energy, any future plans must be agreed to by all project participants. Proposed amendments to the existing contracts are being considered by the purchasers which would require IPP to switch fuel from coal to natural gas no later than July 1, 2025 (two-years before the legal deadline). These amendments require unanimous approval and final purchaser decisions are expected by the end of 2013. Since the results of these discussions are not available for this 2012 IRP, we are hopeful that the plan will be in place for inclusion into next year's IRP process.

This 2012 IRP process included public outreach. Stakeholder meetings were held early in the year to solicit input towards the development of strategic case options. After the case options were analyzed, preliminary results were presented to the public for comment at meetings and through the LADWP website. This 2012 IRP documents the public outreach effort, and addresses the major themes that emerged from that process.

This IRP also includes a general assessment of the revenue requirements and rate effects that support the recommended resource plan through 2032. While this assessment was not as detailed and exhaustive as the financial analysis within the just completed rate case, it does show clearly the general requirements.

The recently concluded rate process confirmed LADWP's revenue requirements, over the next two years, to meet its mandated obligations and responsibilities. As a long-term planning process, the IRP looks at a 20-year horizon to secure adequate supplies of electricity. In that respect, it is our desire that the IRP contribute towards future rate processes by presenting and discussing the programs and projects required to fulfill our City Charter mandate to delivery reliable electric power to the City of Los Angeles.

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1. Introduction and Purpose

This document represents the Los Angeles Department of Water and Power (LADWP) Integrated Resource Plan (IRP) for 2012. 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.

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 20% of renewable energy sales in 2010 – significant challenges lie ahead. Increasing renewable energy to 33% by 2020, the continued rebuilding of coastal generation units, replacement of coal, infrastructure reliability investments, and ramping up energy efficiency and other demand side programs are all critical and concurrent strategic actions that LADWP will have to carry out over the coming decade.

The 2012 integrated resource planning process developed alternative strategic cases that assess different replacement options for coal-fired generation, as well as different projected levels of energy efficiency and distributed generation. 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, expanded electrification of processes to reduce emissions and greenhouse gases, and growing wide-spread use of information technology equipment will require a stable, resilient power grid that delivers affordable power. By adopting energy efficiency, promoting solar rooftop and supporting other clean technologies that mitigate the need to build new fossil-fueled power plants, our customers are embracing the vision of a greener resource portfolio that sustains 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 renewables, energy efficiency, and distributed generation. Today we have the same electricity consumption as we had in 2000 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 utility to achieve 20 percent renewable generation in 2010. Since 1990, we have divested of 2 coal plants and repowered several natural gas in-basin generating stations using cleaner and more efficient new combustion technology, resulting in 21 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 by next year we will use 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 2011 IRP include expanded discussion on the Power Reliability Program, more detailed information on transmission planning and projects, a new sub-section on the future impacts of climate change on power generation and operations, and new case options that analyze higher levels of Energy Efficiency (EE) and Distributed Solar Generation (Solar DG).

This 2012 IRP incorporates updates to reflect the latest load forecast, fuel price and projected renewable price forecasts, and other numerous modeling assumptions. Compared to the prior forecast, projected electricity sales in calendar year 2020 decreased by 5.3 percent, mostly due to increased levels of energy efficiency. The new forecast reduces the overall need for renewable energy (assuming 33% RPS) by approximately 461 GWh in 2020 and 745 GWh in 2030.

Long term natural gas price forecasts have been revised downwards from last year with recent prices reaching very low levels over the last year. Compared to last year's 2011 IRP, Opal and SoCal expected gas prices are 16% lower on average in the short term (2011-2020) and 8-9% lower on average in the long term (2021-2030). Coal price forecasts are also lower; with IPP coal at 4% lower for the period 2012-2027, and Navajo coal at 14% lower for the period 2012-2019.

Other changes include lower cost assumptions for solar and geothermal, reflecting price competition for both resources, and updates regarding legislative and regulatory issues. See Section 3 and Appendix N for more details.

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 keeping rates competitive. See Section 1.5 for more details.

Table ES-1. LADWP RECENT ACCOMPLISHED PROJECTS/PROGRAMS

Project/Program	Time Period	Accomplishment
Renewable Portfolio Standard	2003 to 2010	Increased renewable energy percentage from 3% to 20%
Adelanto Solar	2012	10 MW solar project built, put in-service
Energy Efficiency Program	2012	Recommitment goals adopted: 10% by 2020, with target of 15%
Solar Incentive Program	1999 to Present	Provided funding that has enabled the installation of 55 MW of solar to date
Solar Feed-in-Tariff	2012	Pilot program conducted, followed by full scale re-launch for up to 150 MW
Milford II Wind Project	2011	Supply over 100 MW of wind energy
CO_2 Emissions Reduction	1990 to 2010	CO_2 emission 22% lower than 1990 level
Once-through Cooling	1990 to Present	OTC reduced by 17% from 1990 level
Haynes 5&6	2011-12	Repowering project initiated, new turbines installed. In-service scheduled for 2013
Castaic Upgrade	2004 to 2014	Project adds up to 80 MW of renewable capacity
Power Reliability Program	Ongoing	In 2011-12, replaced 1,813 poles, 2,054 transformers, and 51 miles of UG cable
Navajo Generation Station Replacement	Ongoing	Process to divest initiated. RFP for replacement capacity issued.
Southern Transmission System Upgrade	2011	Increased capacity of 480 MW was added to the existing transmission line
Green Power Program	1999 to 2011	Participants receive 104 GWh of renewable energy annually
Electric Vehicles Incentive	2011	Provide a $2000 rebate for home EV charging systems
Demand Response Program	1999 to Present	Signed up 60 MW of load shifting and interruptible load
Alternative Marine Power Program	Through 2012	Signed up 13.8 MW of load to offset diesel motor emissions at the Port of LA

3. 2012 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 represents 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 heads. Preliminary results were analyzed and presented to the public for review and input. Final recommendations incorporating public feedback were then forwarded to the General Manager and Board of Water and Power Commissioners.

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 Heads. The approval process for recommendations was based on consensus from the managers of each area of responsibility.

4. Public Outreach

The 2012 IRP process includes a public outreach effort to provide information and gather public input.

Public outreach began with two stakeholder meetings held in early 2012. LADWP staff met with key major customers and business representatives in February; and in March with key environmental organization representatives. Comments received during these stakeholder meetings were considered in the development of the preliminary cases that were analyzed.

The preliminary results were documented in the 2012 Draft IRP that was made available at www.ladwp.com/lapowerplan on October 5, 2012. The draft IRP was presented at three stakeholder meetings and one public workshop held on October 11, 2012. Comments were accepted through November 5, 2012.

Comments received were synthesized into the following major themes. Each theme is considered of equal importance. The following list is not presented in any order of importance

Eliminate Coal from LADWP's Energy Portfolio

Incorporate More Renewables

Incorporate More Local Solar

Incorporate More Distributed Generation

Incorporate More Energy Efficiency

Reduce Greenhouse Gas Emissions

Look at New Case Scenarios

Financial and Rate Concerns

Maintain Power Reliability

LADWP Should Take a Leadership Role

Public comment and input received was considered prior to finalizing this 2012 IRP.

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

5. Challenges and Critical Issues

LADWP faces a number of concurrent issues and 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: adequate funding to support programs; ensuring reliability; greenhouse gas 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. Due to the delay of the rate action that was previously anticipated in 2011, many of the programs were scaled down, delayed or deferred. The rate process that concluded on October 5, 2012 is a positive step towards LADWP's fulfillment of its responsibilities and regulatory obligations that are discussed throughout this 2012 IRP.

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 use of local distributed solar generation and combined heat and power to support State goals.
- Through the Power Reliability Program, reduce the number and duration of distribution outages and improve system reliability.
- Implement necessary transmission improvements to maintain reliability and support new resources, including renewables.
- Provide energy efficiency and customer solar programs for participation by our customers through the Customer Opportunities Program.
- Achieve energy efficiency and other demand-side-resource target levels.
- Implement Smart Grid initiatives.
- Comply with FERC-approved reliability and Cyber-security standards.

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.

5.2 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 poles, power cables, transformers and other elements of the local distribution system.

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 to 2029 that will eliminate the use of once through cooling and provide modern units that are more reliable, efficient, and community-friendly than the units they are replacing.

To maintain grid reliability, LADWP's Ten-Year Transmission Assessment Plan has identified a number of necessary improvements that are needed to avoid potential overloads on key segments of the Basin transmission system. These overload conditions, if encountered, could lead to load shedding events (intentional power outages) to minimize the overall impact on the Power 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 generator units to compensate for significant and often rapid swings in energy production. These swings present operational challenges and must be leveled by controllable generation capable of equally rapid changes of generation in the opposite direction.

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 measurable improvement.

5.3 Greenhouse Gas Emissions Reduction

While LADWP has multiple and concurrent GHG emissions reduction strategies, the primary focus is 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 AB 32's upcoming cap and trade program.

During calendar year 2011, 41 percent of the energy delivered to LADWP customers was

[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.

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 with natural gas. Accordingly, this 2012 IRP focuses 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 state 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 CO_2 emissions performance standard. The CO_2 emissions level must be equal, or below the emissions performance standard of 1,100 lbs. per 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 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 will begin January 1, 2013. LADWP has been granted an administrative allocation of emission allowances that reflects its resource projections through 2020. At this time, it is uncertain if the program will extend beyond 2020.

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 of energy sales in 2010. Major legislation affecting LADWP's renewable policy are SB 1, SB 32, and SB 2 (1X).

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 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.

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. 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 renewable requirement.

SB 2 (1X)

Following the passage of SB 2 (1X) in 2011, LADWP's renewable energy policy is now largely driven by those requirements of SB 2 (1X).

SB 2 (1X) – which was passed in April 2011 and became effective on December 10, 2011, subjects all utilities to procurement of 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

In December 2011, LADWP amended its Renewable Portfolio Standard Policy and Enforcement Program to comply with the requirements of SB 2 (1X). However, LADWP's policy continues to include some requirements that are not a part of SB 2 (1X) 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.

As LADWP expands its renewable resource portfolio, it is important that it do so in a cost effective manner to minimize the impact on ratepayers. Some of the considerations in selecting these resources are as follows:

- Cost differences for different renewable technologies
- Cost trends that reflect decreasing prices
- Variable integration costs and operational impacts
- 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
- Qualification as "Bucket 1" energy according to CEC RPS regulation and guidelines
- Assessing projects on the basis of value to maximize benefits and minimize risks

In this 2012 IRP, the overall base renewable portfolio levelized cost is $98/MWh, which represents an $11/MWh decrease from last year. This cost reduction was achieved by selecting a more optimized and diverse portfolio that accounts for changing price trends and market developments. By maintaining flexibility in the selection of cost-effective renewable resources, LADWP is able to secure the best pricing as market conditions evolve.

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 Clean Water Act Section 316(b) and administered locally by the State Water Resources Control Board (SWRCB).

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 use ocean water. The amount of generation capacity affected by OTC is significant – approximately 2,600 MW of LADWP's total in-basin plant capacity of 3415 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 to 2029. Figure ES-1 is a timeline of the program target dates. More information regarding OTC is provided in Section 1.6.6.

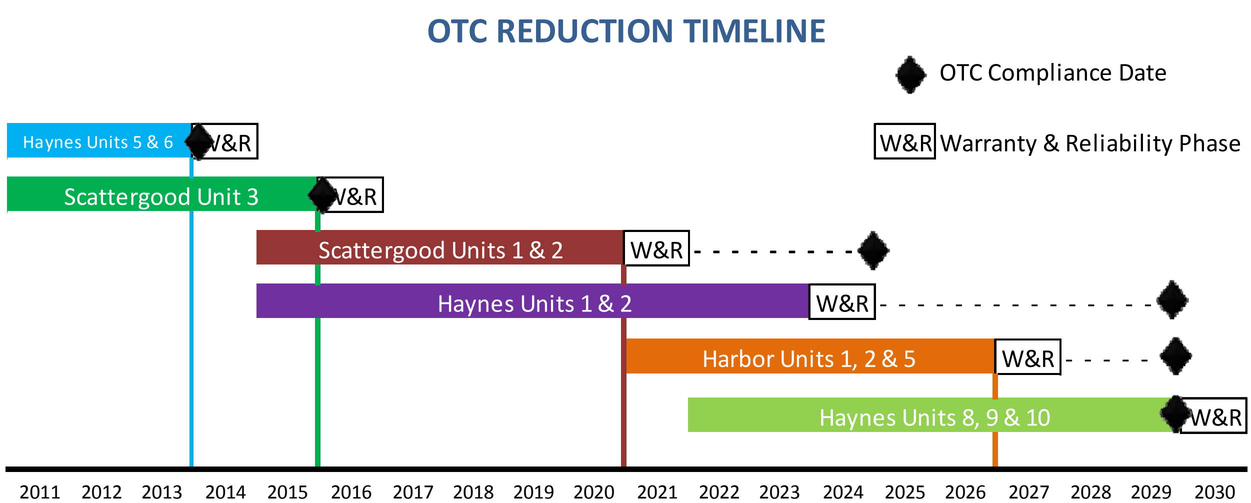

Figure ES-1. Timeline for OTC compliance.

5.6 Workforce Development

To effectively implement the programs and projects recommended in this IRP, an effective human resources strategy is required. The Power System is challenged to develop a sustainable workforce development plan that addresses the following human resource elements:

Staffing
Adequate staffing is needed to meet mandated deadlines and regulatory obligations, to execute new and expanded work functions, and to manage the volume of retirements expected over the next 3-5 years.

Proper Skill Sets
New work areas such as renewable energy facility operations, solar distributed generation, and smart grid deployment will require analysis to identify the skills, knowledge and abilities required to perform these functions in a safe, effective and efficient manner.

Training/Professional Development and New Technologies
LADWP supports employee development by providing various computer-based training programs, and offers tuition reimbursement for those who return to school to enroll in work-related courses and advanced degree programs. Across the Power System, different work groups are encouraged to develop training specific to their particular functions and needs. This is especially important as new and emerging technologies become applicable to various work functions. Applied correctly, technology increases employee productivity, enhances safety, and enables new and expanded customer services.

Recruitment
Recruiting the best qualified employees assures an effective workforce capable of meeting the near term and long term challenges identified in this IRP. Continued use of LADWP's website and social media to promote career opportunities will help ensure that the best qualified individuals consider joining the LADWP workforce.

5.7 Other Challenges

Additional challenges that LADWP must address in the coming years include:

- Managing potential natural gas price volatility
- Incorporating higher levels of Distributed Generation (DG) that 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
- 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
- Load factor improvement
- Acquisition of replacement resources for coal-fired generation

6. Strategic Case Alternatives

The 2012 IRP strategic cases incorporate the latest developments in legislation and regulation, and tactical plans developed by the Power System. This 2012 IRP also includes updated assumptions that 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 2012 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, 2 and 3 are similar to the cases analyzed in last year's 2011 IRP. The replacement date of December 2023 for IPP (Case 4) is new for this year.

In addition to the coal cases, this 2012 IRP also analyzes four additional cases to consider higher levels of energy efficiency and solar distributed generation.

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 updated energy efficiency goals including 10 percent by 2020.

Section 3 of this IRP provides more information surrounding the development of the cases, including resource adequacy and net-short 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.

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

Table ES-2. CANDIDATE RESOURCE PORTFOLIOS FOR 2012 IRP

COAL CASES

		GHG or SB1368 Compliance Date		2020	2010 thru 2020	2010 thru 2032	New Renewables Installed Capacity (MW) 2012 - 2020					New Renewables Installed Capacity (MW) 2012-2032				
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	12/1/2019	6/15/2027	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
2	Navajo Early Replacement	12/31/2015	6/15/2027	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
3	Navajo and IPP Early	12/31/2015	12/31/2020	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
4	Navajo and IPP Early (Alt.)	12/31/2015	12/31/2023	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
2011 Recommended	Navajo Early Replacement	12/31/2015	6/15/2027	33%	1443	2183	243	492	401	325	0	308	492	451	466	162

ENERGY EFFICIENCY AND DISTRIBUTED GENERATION CASES

		2020	2010 thru 2020	2010 thru 2032	New Renewables Installed Capacity (MW) 2012 - 2020					New Renewables Installed Capacity (MW) 2012-2032				
Case ID	Resource Strategy[1]	RPS Target	EE (Net GWh)	EE (Net GWh)	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
5 (Base Case)	Base EE , Base Solar DG	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
6	Advanced EE, Base Solar DG	33%	2300	4000	242	0	887	337	39	283	0	915	496	114
7	Base EE, High Solar DG	33%	2300	3500	242	0	847	485	39	258	0	876	852	95
8	Advanced EE, High Solar DG	33%	2300	4000	242	0	847	485	39	258	0	876	852	0

[1]EE percentages are as follows:

	By 2020	By 2032
Base EE	10%	15.2%
Advanced EE	10%	17.4%

The feasibility of attaining EE levels greater than 10% are uncertain at this time, but will be addressed in the upcoming EE Potential Study to be completed in 2013.

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 ratepayers hinges mainly upon the load forecast, price of fuel, and CO_2 emission levels. All cases meet the mandated RPS percentage targets and reliability standards. The analytics performed for this IRP examined the associated costs of each strategic case.

The key modeling results are summarized below:

7.1 CO_2 Emissions Considerations

Current GHG emissions levels are approximately 14.1 MMT which is 21 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 gas-fired replacements, and increased renewable generation from 3% in 2003 to 20% of overall sales in 2010. Using Case 1 (Navajo divestiture in 2019, IPP replacement in 2027) as a baseline, early divestiture of Navajo in Cases 2, 3 and 4 results in approximately 7.2 MMT less GHG emissions between 2016 and 2019. For Case 3 (IPP replaced in 2020) there is an additional post-2020 cumulative reduction of 19.5 MMT. For Case 4, the post-2020 reduction is 9.3 MMT. These GHG emission reductions are shown below in Table ES-3 and Figure ES-2.

Table ES-3 GHG EMISSIONS REDUCTION LEVELS IN MMT

Case	Reduction 2016-19	Reduction 2020-27	Total Reduction 2016-27
1	Baseline	Baseline	Baseline
2	7.2	0.0	7.2
3	7.2	19.5	26.7
4	7.2	9.3	16.3

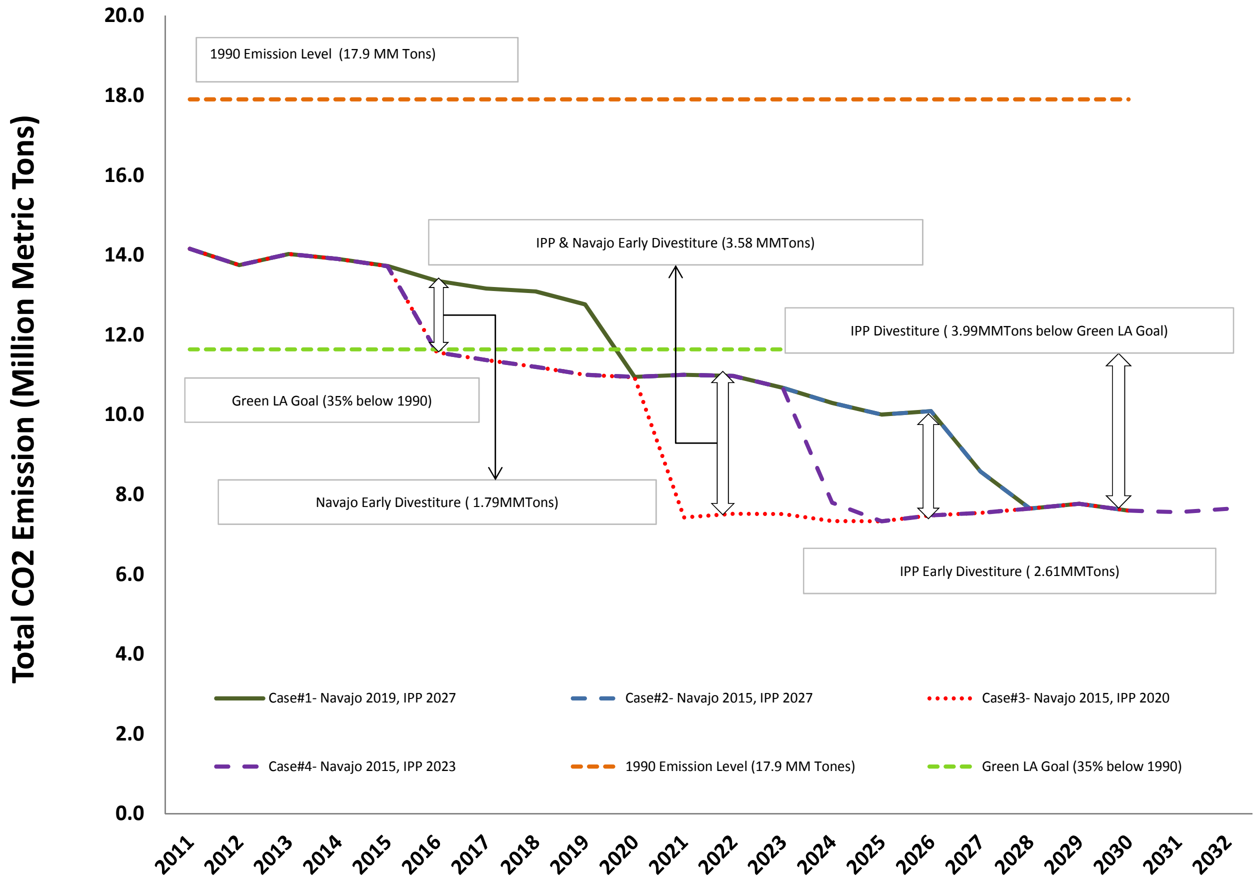

Figure ES-2. GHG emissions comparison by calendar year.

Emissions levels for energy efficiency and solar distributed generation, Cases 5 thru 8, were also evaluated and are shown in Figure ES-3. Advanced levels of EE were found to result in slightly lower emissions of CO_2 as compared to the Base EE cases. Higher levels of Solar DG were found to have little effect on reducing CO_2 emissions since Solar DG would have been replaced with other zero emissions resources. Although these higher levels of EE and distributed generation have a small impact on emissions compared to the base EE, it is important to note that the base level of energy efficiency in itself has a very significant impact on reducing overall CO_2 levels as shown by the “No More EE” curve illustrated in Figure ES-2. If no additional EE were implemented, annual GHG emissions levels would be approximately 2.0 MMT higher by 2032. This is equivalent to removing 385,000 cars from the road. For reference purposes, the CARB emissions allocation for LADWP as part of the AB 32 Cap and Trade program being implemented in 2013 and ending in 2020 is included in Figure ES-3.

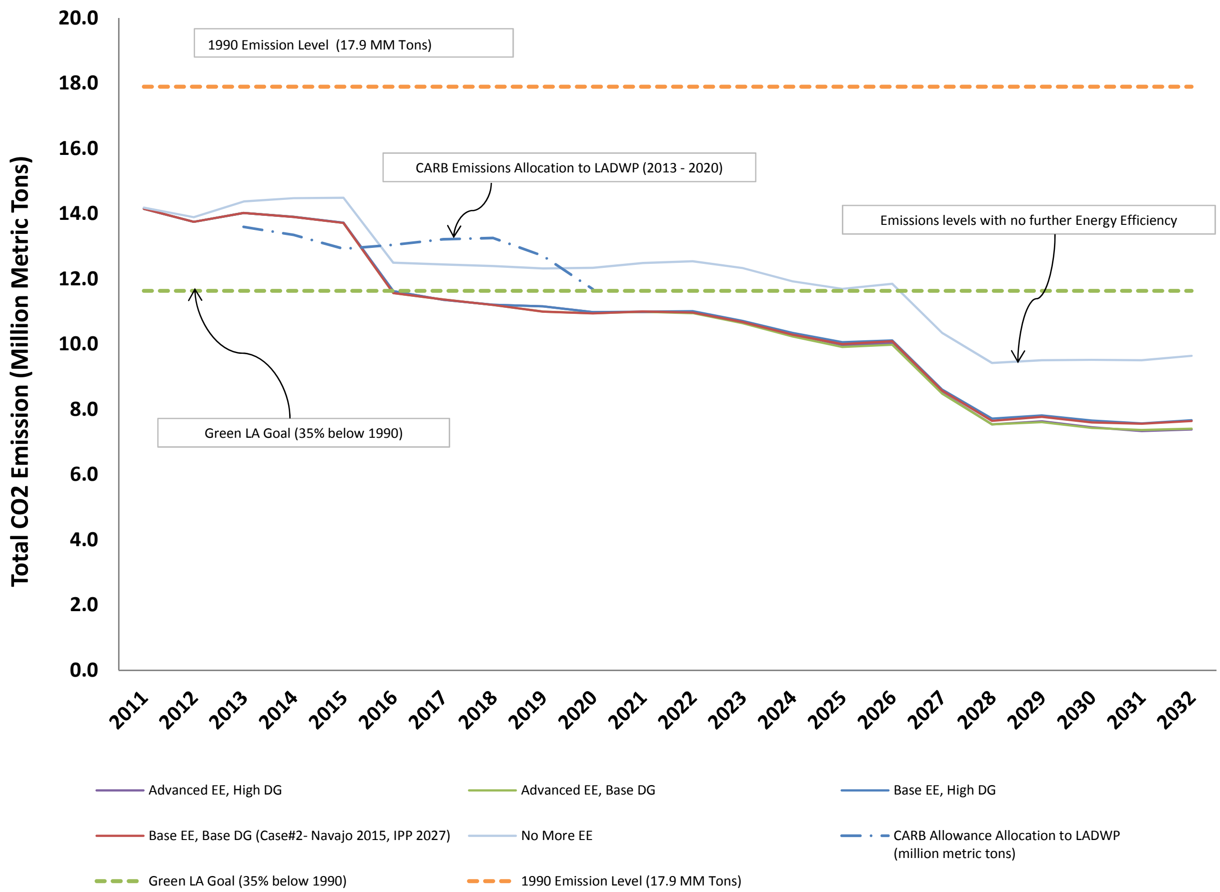

Figure ES-3. GHG emissions comparison for Energy Efficiency and Solar Distributed Generation cases by calendar year.

7.2 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 Reliability Program and Energy Efficiency programs among others. Total annual Power System costs are shown in Figure ES-4 and reflect short-term spending reductions through 2011-12 fiscal year with subsequent years reflecting a restoration of funding levels to ensure that the longer term IRP recommendations can be implemented. To the extent that energy efficiency costs are lower than the costs of generation it is replacing, its effect is to lower total costs. The costs shown in Figure ES-4 do not attempt to represent a thorough analysis of Power System finances, but they do illustrate the general trend of Power System costs relative to the 4 coal and 4 EE/DG cases analyzed.

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

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

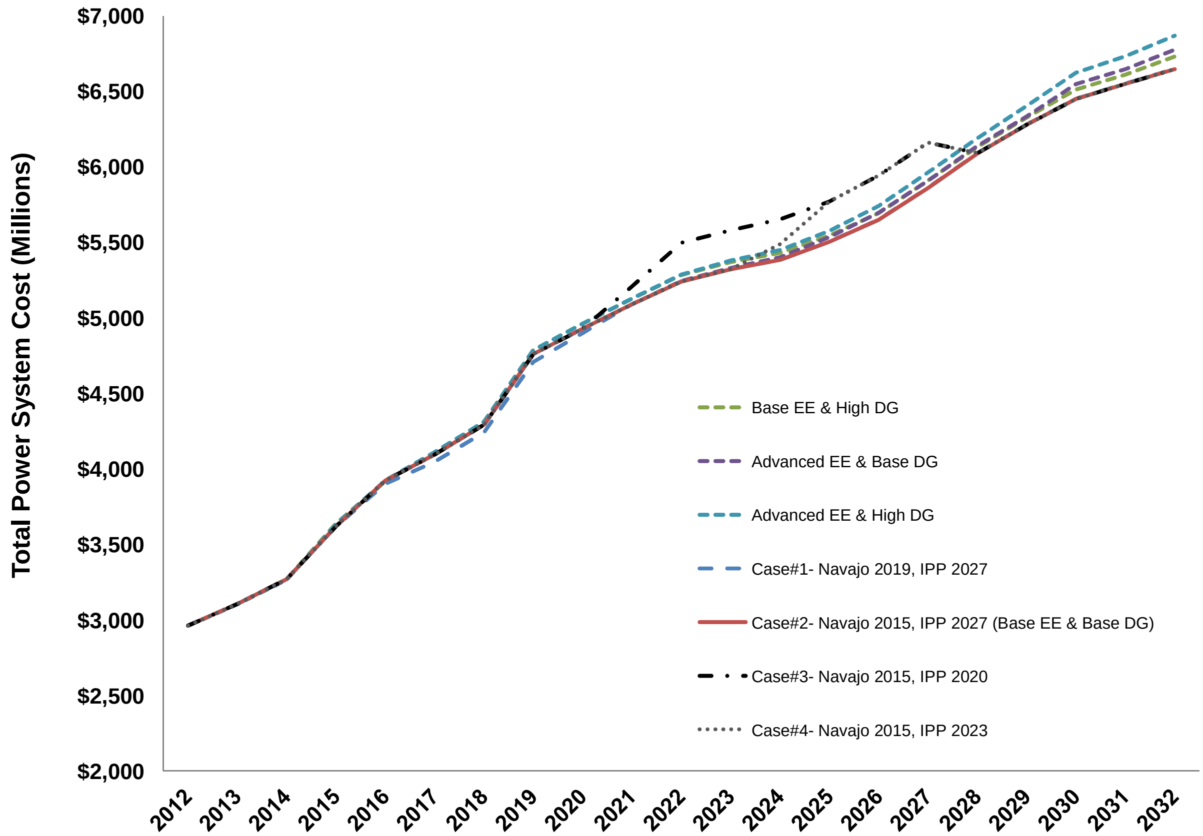

Figure ES-4. Comparison of annual Power System costs over the next 20 fiscal years.

The cost differences between the cases are highlighted in Table ES-4, which presents the incremental costs of the 4 coal cases and the 4 EE/DG cases. For the coal cases, the values listed under the Case 2 column represent the incremental costs between Cases 1 and 2 – i.e., the cost of early divestment of Navajo. The values listed under Case 3 and Case 4 represent the additional incremental costs of early IPP replacement in 2020 and 2023, respectively.

All EE & DG cases assume Navajo divestment in 2015 and IPP replaced in 2027. The values shown for Cases 6, 7, and 8 represent each case's incremental costs when compared to Case 5.

TABLE ES-4 INCREMENTAL COST COMPARISONS BETWEEN CASES

Coal Case Summary

	Case 1	Case 2	Case 3	Case 4
Case Description	Navajo 2019, IPP 2027	Navajo 2015	IPP 2020	IPP 2023
Total Incremental Revenue $M	$0	$205	$1,790	$980
Average Incremental Revenue ($M/yr)	$0	$51	$275	$280

EE & DG Case Summary

	Case 5 (Baseline) *	Case 6	Case 7	Case 8
Case Description	Base EE & Base DG	Base EE & High DG	Advanced EE & Base DG	Advanced EE & High DG
Total Incremental Revenue $M	$0	$669	$494	$1,247
Average Incremental Revenue ($M/yr)	$0	$32	$24	$59

7.3 Sensitivity Analyses

An analysis of the effects of fuel price volatility was performed for the four coal cases and is shown in Figure ES-5. With the early divestiture of Navajo in 2015 and the IPP coal contract ending in June 2027, 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. 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 and so warrants careful evaluation when comparing the different case scenarios.

It is important to note that bulk power costs shown in Figure ES-5 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 could result in large cost increases should fuel prices remain at higher than expected levels. Conversely, lower than expected fuel prices could 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. LADWP is in the process of developing a revised hedging strategy based on the newly approved rate ordinance.

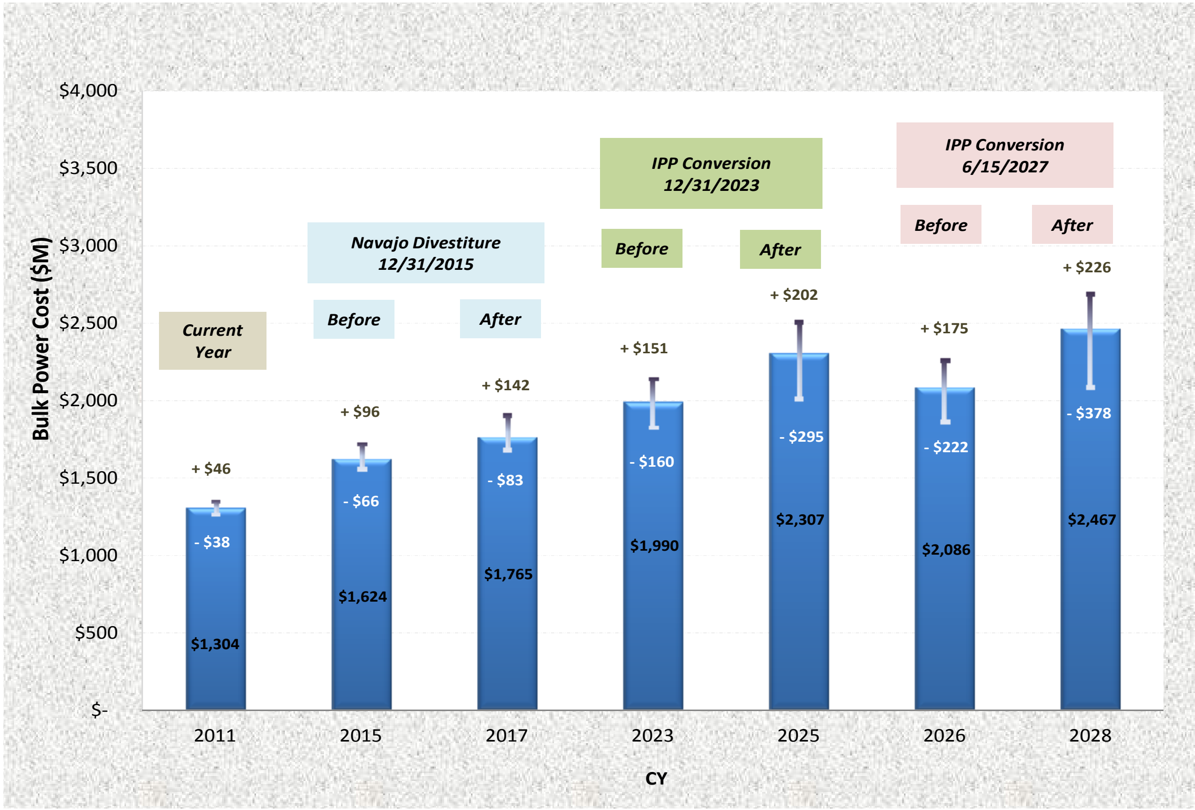

Figure ES-5. Bulk power cost before and after coal replacement with potential cost impacts from high (+$) and low (-$) fuel prices.

Increased risk exposure from high fuel costs may translate into higher customer electric rates. Figure ES-6 shows the potential rates that could be experienced under the 4 coal cases given high, expected, and low fuel ranges for both gas and coal fuel types. Today, overall coal costs represent approximately 65 percent of overall fuel expenditures. Once Navajo coal is replaced in 2015, this percentage will drop to 50 percent of overall fuel expenditures. From 2023 thru 2026, coal expenditures will gradually drop to 30 percent before reaching zero percent in 2027 when IPP coal is replaced, and future fuel price increases will be based solely on natural gas and nuclear.

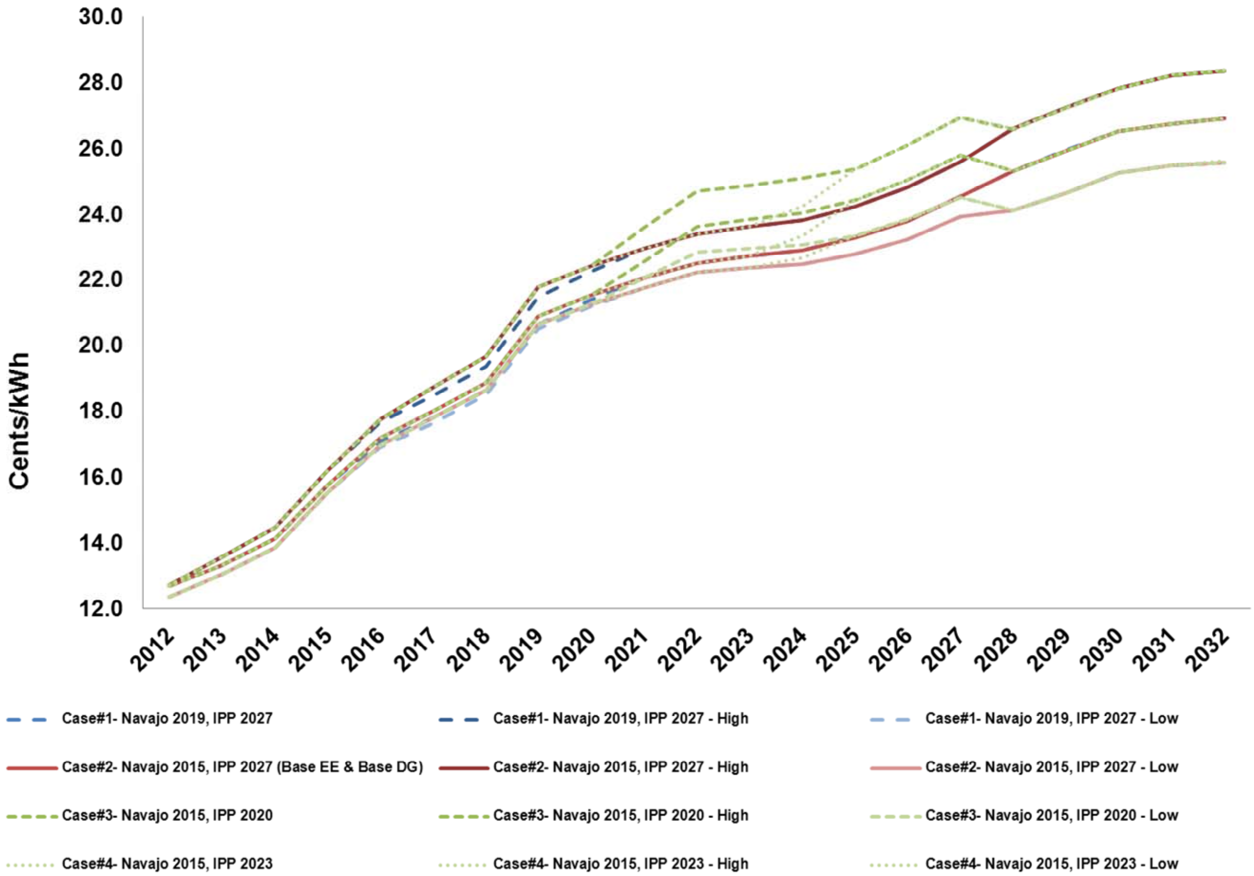

Figure ES-6. Estimated electric rate comparison with fuel price sensitivity over 20 years by fiscal year-ending

7.4 Rate Contributions Breakdown

Figure ES-7 presents the fiscal year breakdown for Case 5 comprising rate contributions from reliability, energy efficiency, renewable energy, reliability, coal replacement, OTC repowering, other Generation, Transmission and Distribution (GT&D), and fuel costs between 2012 and 2032. These individual contributions represent incremental adders to the rates. For analysis purposes, the Reliability Program has been segmented into the basic program and preferred program. The preferred program contribution shown is incremental to the basic program.

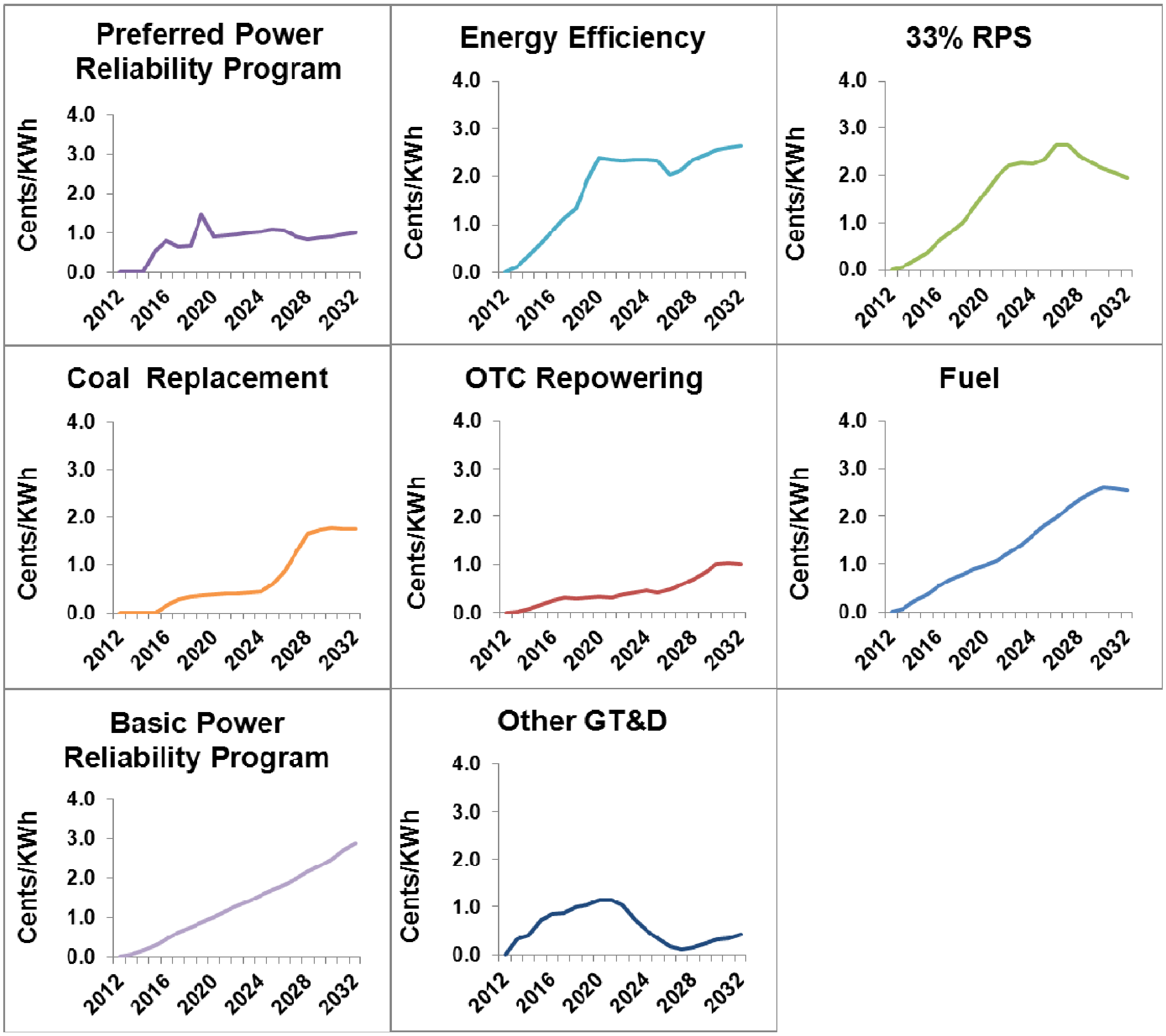

Figure ES-7. Retail electric rate contributions breakdown, based on the 2012-13 budget forecast (Case 5).

Figure ES-8 shows the total retail rate impact after combining all of the program components. One can draw the conclusion that rising fuel costs and complying with various regulatory requirements are the primary drivers of the growth in rates.

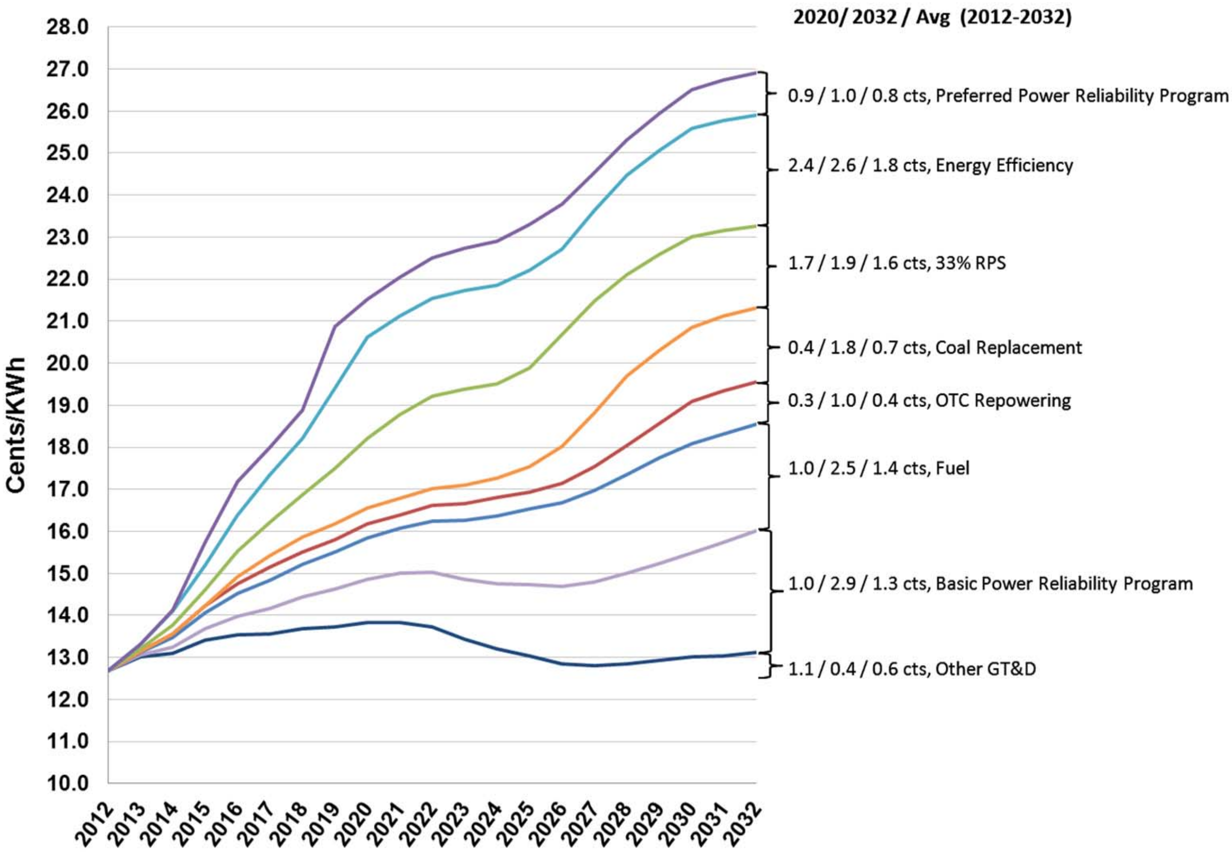

Figure ES-8. Total retail electric rate composite by fiscal year, based on the 2012-13 budget forecast (Case 5).

A few observations from Figures ES-7 and ES-8[3] can be made regarding the RPS and EE programs. Firstly, the influence of the RPS program on rates increases substantially through 2020 after the RPS percentage of sales reaches 33% and the RPS component of rates begins to decline as fuel savings increases over time with escalating fuel prices. In 2027, the RPS component of rates increases as new renewable projects are added to replace expiring PPA agreements and then the RPS component of rates resumes a downward trend due to fuel savings. Secondly, the EE program component of rates increases over time as program incentive payments and net revenue loss attributable to the EE program are recovered. Like RPS, EE has

[3] Figures ES-7 and ES-8 represent forecasted rate increases based on system averages, and do not account for rate structure variations across and within customer classes.

savings beyond 2020 due to fuel savings. Thirdly, general inflation in fuel costs and GT&D costs represents a significant growth in rates.

Preferred levels of funding for the Power Reliability Program (PRP) include capital and O&M expenditures to replace over age 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 preferred PRP and EE curve occurs when capital borrowing limits are reached around 2019-20 and cash is needed to fund capital expenses. This quickly subsides as the capacity to borrow resumes shortly thereafter.

The GT&D component of rates rises in the early years because of general inflationary pressure. After 2023 when the IPP debt is fully paid, the GT&D component of rates lowers slightly and goes slightly negative until IPP is replaced with new gas-fired generation and then resumes the familiar inflationary path.

Figures ES-9 and ES-10[4] 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 14% savings. While LADWP's overall energy efficiency program is evolving and much will depend on the new potential study to be conducted in 2013, these figures illustrate what may reasonably be achievable by customers who have not already implemented significant energy efficiency measures to reduce their electricity consumption.

[4] Figures ES-9 and ES-10 are general representations only, and do 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.

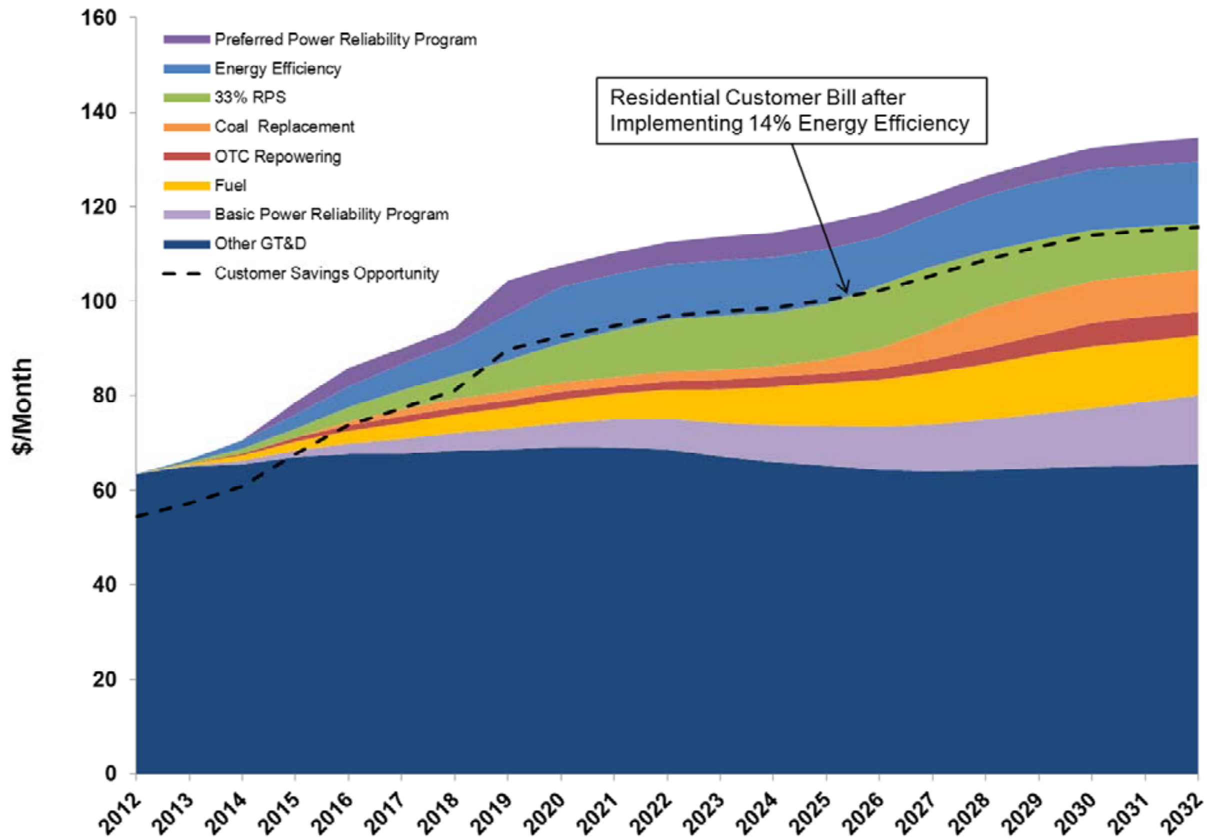

Figure ES-9. Average residential customer bill (500 kWh/month) with environmental and reliability programs by fiscal year based on the 2012-13 budget forecast (Case 5).

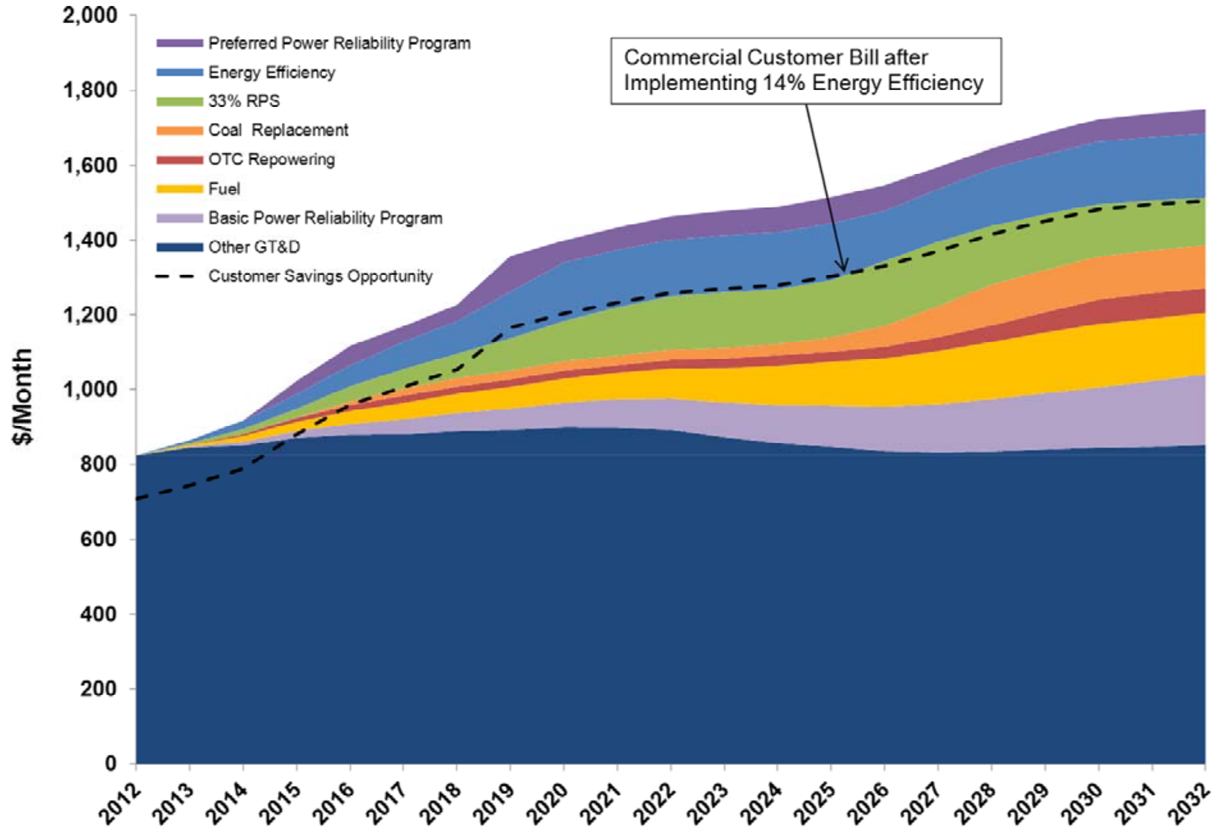

Figure ES-10. Average commercial/industrial customer bill (6,500 kWh/month) with environmental and reliability programs by fiscal year based on the 2012-13 budget forecast (Case 5).

8. Recommendations

8.1 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, energy efficiency targets, social and economic development goals, early compliance with SB 1368, and investing in local solar distributed generation.

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. SB 2 (1X) also establishes interim targets to ensure progress towards the 33 percent goal. 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 will exceed this mandate and provide 150 MW by 2016).

- Power Reliability Program (PRP) and System Infrastructure Investment

  To ensure system reliability, LADWP must re-establish sustained funding to invest in replacing transmission and distribution infrastructure that are contributing to outages. Recent funding shortfalls have resulted in an increase in the frequency and duration of system outages. Section 1.6.3 of this IRP discusses the importance of fully funding the Power Reliability Program (PRP). As discussed in Section 2.4.6, the PRP will also increase the resiliency of the distribution infrastructure to better withstand the higher future wear-and-tear effects that are expected due to climate change.

- 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 ocean water cooling.

- AB 32 – GHG Cap and Trade

  LADWP will participate in the mandated greenhouse cap-and-trade system which is scheduled to start January 1, 2013. LADWP has been granted an administrative allocation of emission allowances that reflects its resource projections through 2020. At this time, it is uncertain if the program will extend beyond 2020, and if so, what LADWP obligations would be.

- Energy Efficiency (EE)

  LADWP will continue to pursue and implement EE programs per AB 2021 standards and as directed by the Board of Water and Power Commissioners, who have adopted a goal of achieving 10 percent EE by 2020, with a target of up to 15% by 2020 pending the results of an upcoming new EE Potential Study. The Base EE cases evaluated in this 2012 IRP have all incorporated 10% EE by year 2020, with higher levels of up to 15% by 2032. Next year's IRP will incorporate the findings and recommendations of the potential study as they are finalized and approved.

- 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

  Per AB 2514, LADWP is investigating Energy Storage (ES) technologies and will establish targets for implementation by October 1, 2014. LADWP will look for programs and projects that support its unique electric grid, resource plan, and projects that will facilitate renewable integration, distributed generation and demand response. As these projects are identified and scoped, they will be incorporated into and analyzed in future IRPs. See Section 2.4.5 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 joint 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. 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 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

Regarding the Navajo Generating Station (NGS), while power imports can legally continue until 2019, LADWP recommends divestiture from NGS four years earlier, in 2015. There are many strategic advantages to early divestiture, including:

1. Better sales terms and conditions than waiting until the 2019 deadline.
2. Avoiding the risk of pending federal regulations that could potentially encumber the plant with expensive mitigation requirements.
3. Better availability and pricing for replacement generation (including existing plants), and lower fuel costs.
4. Reduced CO_2 emissions, alleviating LADWP from subsequently having to purchase emission credits for native load.
5. Transmission network for importing additional solar and geothermal resources becomes available.
6. Low load growth and increased renewable energy place less reliance on the plant for energy.
7. Provides time to handle contingencies, and to ensure that competition for replacement resources is going to benefit our ratepayers.

Regarding the Intermountain Power Project (IPP), LADWP recommends modeling and planning to be compliant with SB 1368 by 2027. However, LADWP, the Intermountain Power Agency (IPA), and the other 36 participants are considering the conversion of IPP from coal to natural gas. A new contractual arrangement is in process, which will establish a firm conversion date that will be no later than, and possibly sooner, than 2027. Until a firm conversion date is established and for analysis purposes, Case 4 was developed for this IRP which has IPP coal replacement in 2023. Once a firm date is determined, it will be incorporated into the IRP base case model runs.

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.

- 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 allow 340 MW of its solar resources be sited locally by 2016, through initiatives including the Solar Incentive Program, feed-in tariffs, and installation of solar on City-owned properties.

- Demand Response

  LADWP should accelerate its evaluation and implementation of Demand Response programs that will initially provide 5 MW of new peak demand capacity beginning in 2013 and gradually build to 200 MW by 2020 and 500 MW by 2026. Ramping the program in this manner 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.

- 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.

- Provide Sufficient Generation

  Provide sufficient generation, demand response, and limited short term purchases in peak season Q3 to cover operating and replacement reserves in accordance to applicable federal and regional reliability requirements.

- 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 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 its credit rating, the following financial targets have been adopted:
    - Maintain debt service coverage at 2.25 times
    - Minimum operating cash target of $300 million
    - Debt-to-capitalization ratio less than 68 percent

8.2 Recommended Strategic Case

Achieving the goals of reliability and environmental stewardship, while maintaining competitive rates, requires that costs be closely managed. Considering these factors, Case 5 with early Navajo coal divestiture in 2015, Base EE and Base DG with additional local solar Feed in Tarrif (FiT) DG becomes the Recommended Case for the 2012 IRP. Whereas Case 5 has 75 MW of local solar FiT by 2016, the new recommendation is to adopt an additional 75 MW for a total of 150 MW by 2016 based on input that was received from the public outreach efforts. The increase in cost for the additional 75 MW of FiT is an average of 0.018 cents/kWh or a 9 cent increase in the typical residential monthly bill (500 kWh/month). Although Case 5 with the added FiT represents additional cost as compared to the 2011 Recommended Case, the additional costs to rate payers appears to be reasonable in light of the benefits of job growth and support of the local economy from adopting higher levels of DG solar. As described in the 2011 IRP, the environmental benefits of reducing GHG emissions by 7.2 MMT are still present with the early Navajo replacement. The cost to implement Navajo divestiture in terms of metric tons of GHG removed is $28/MMT. This represents a reasonable cost in line with the range of expected AB 32 cap and trade allowance prices. Other benefits of early Navajo divestiture include a better sales price than waiting until 2019, and better availability (lower costs) of replacement energy. With Case 5 and the noted addition of FiT and Navajo divestiture in place, LADWP can begin to focus its attention on early replacement of IPP coal generation, prior to 2027, by working with the other power purchasers and the IPP plant owner.

The 2011 IRP included the same recommendation to accelerate divestiture of Navajo and this 2012 IRP further clarifies and supports this prior recommendation. This 2012 IRP recommended case presents a reasonable approach to achieving environmental goals and promoting job growth in the local economy without excessive costs to our ratepayers while limiting potential exposure to possible fuel price volatility to within manageable limits.

Table ES-5. 2012 IRP RECOMMENDED CASE

	2020	SB 1368 Compliance Date		New Renewables Installed (MW) 2012-2020				New Renewables Installed (MW) 2012-2032				
Case ID	RPS Target	Navajo End Date	IPP End Date	Geo/ Biomass	Non-DG Solar	Dist. Solar	Generic	Geo/ Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
Case 5	33%	12/31/2015	6/15/2027	242	842	382	39	283	54	915	496	114

Figure ES-11 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.

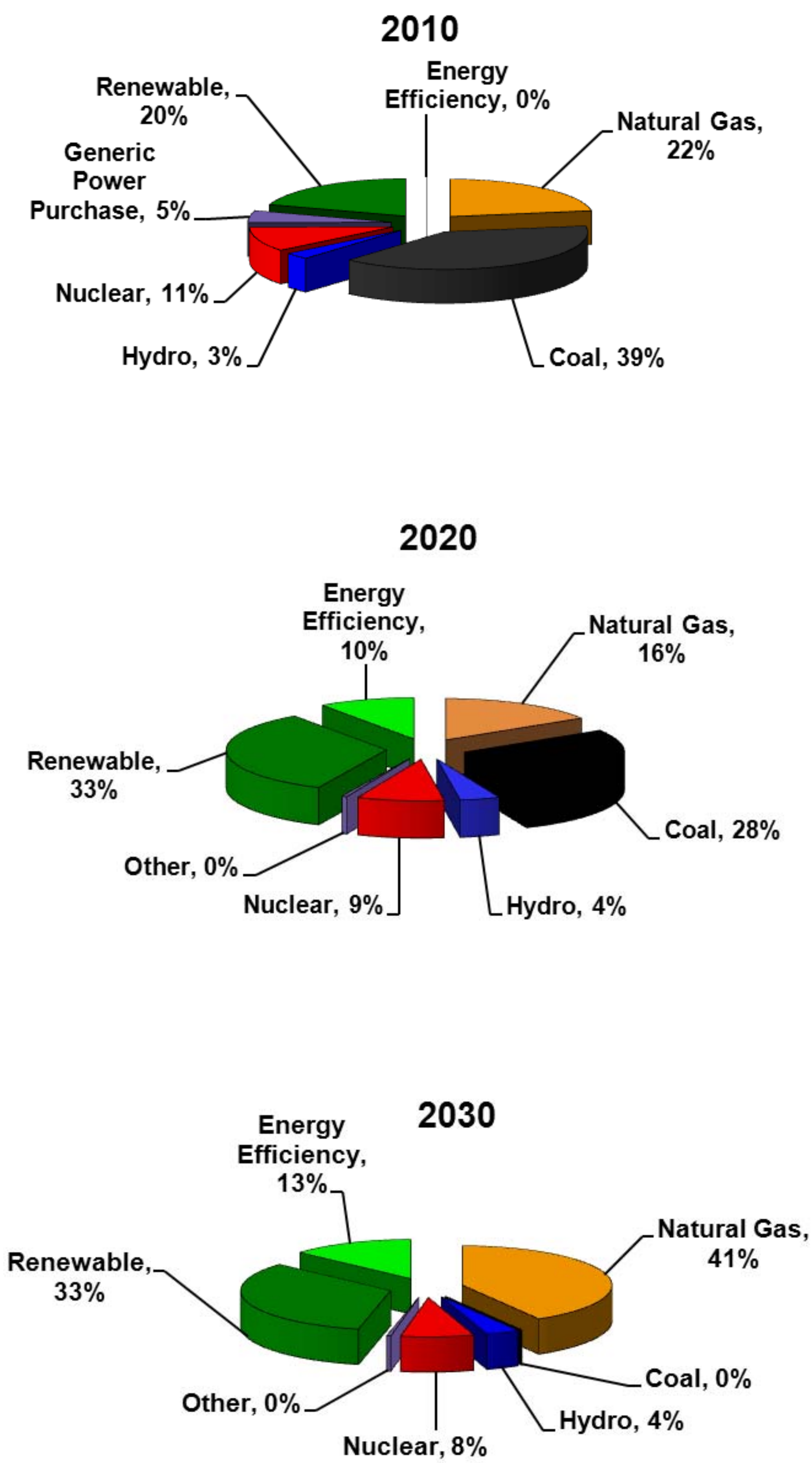

Figure ES-11. Recommended case generation resource percentages for 2010, 2020, and 2030.

Figure ES-12 shows the breakdown of renewable generation by technology, and Figure ES-13 illustrates the dependable capacity mix for the recommended case.

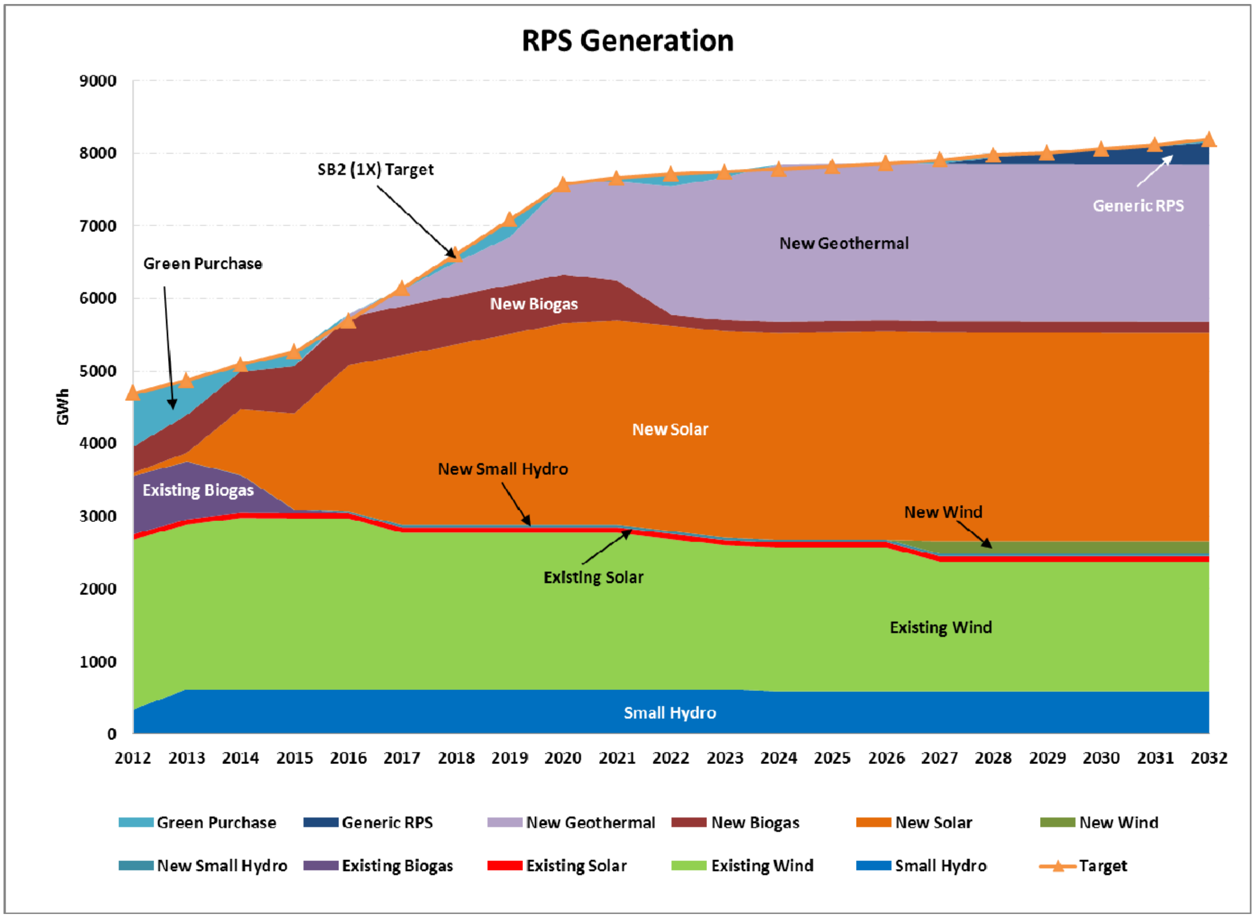

Figure ES-12. Recommended case renewable generation by technology.

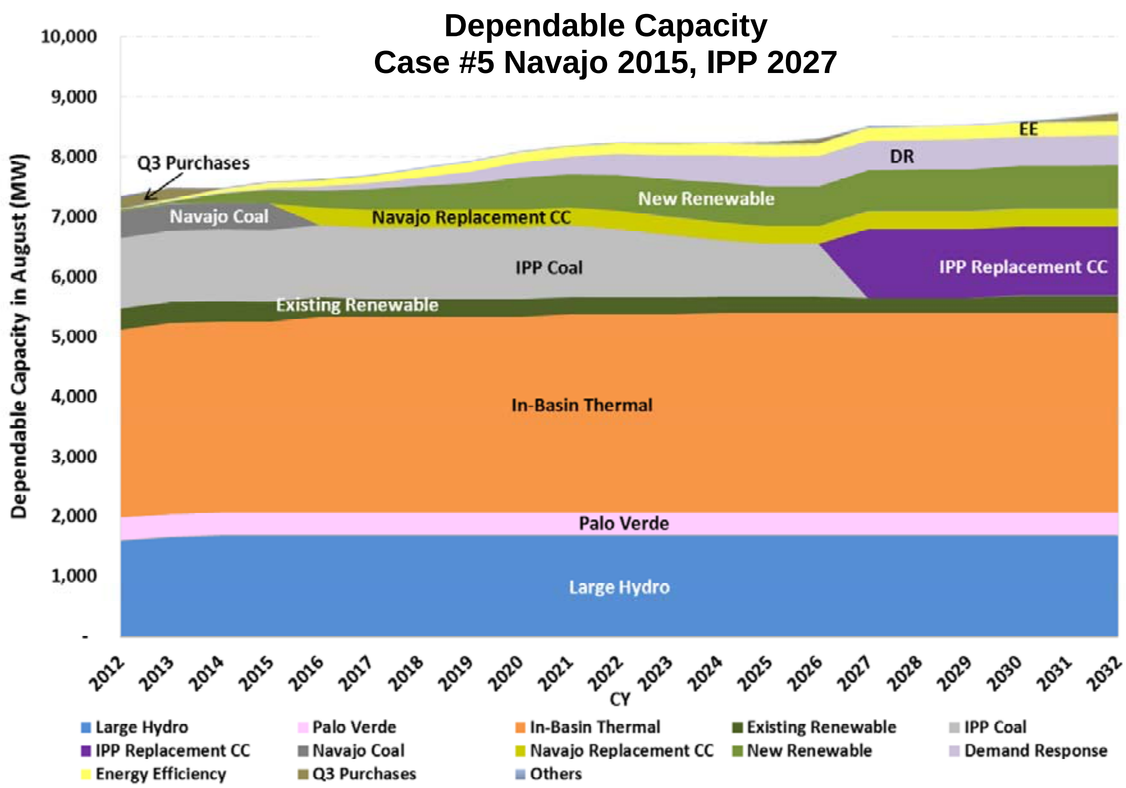

Figure ES-13. Dependable capacity profile, recommended case.

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.

8.3 Recommended Near Term Actions

Except for early Navajo divestiture, the actions needed to be taken by LADWP in the next two to four years are very similar no matter what resource strategy is chosen. 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 Haynes and Scattergood Generating Stations, and pre-development plans for the Harbor Generating Station.
2. Continue to investigate the technical and contractual options for coal-fired generation to be compliant with SB 1368.
3. Divest from the Navajo Coal Plant by 2015.

4. Continue the implementation of existing energy efficiency efforts, in anticipation of an expanded program pending the results of a new energy efficiency potential study to be conducted in 2013.
5. Continue to implement the Power Reliability Program (PRP) to replace aging infrastructure components. Develop electric modeling capability to better define the necessary investments and to prioritize the expenditures.
6. Develop/update a sustainable workforce development plan that addresses staffing needs, skill set identification for new and evolving work areas, training/professional development, application of new technologies, and recruitment strategy.
7. Implement recommendations contained in the Ten-Year Transmission Assessment Plan.
8. Develop a Demand Response Program to initially provide 5 MW of new peak load reduction capability by 2013 which will ramp up incrementally to 200 MW by 2020 and 500 MW 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). Sign Power Purchase Agreements for an additional 300-400 MW of cost effective renewable energy projects by 2014
10. Complete a comprehensive study of 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.
11. Develop and incorporate strategies to:
    a. Fully utilize existing transmission assets;
    b. Locate renewables as close as practical to the load center to reduce transmission losses;
    c. Preserve existing brown field sites to be repurposed for renewable or natural gas generation;
    d. Incorporate the concept of O&M cluster zones[5] to maximize operational efficiencies;
    e. Assess and develop necessary transmission facilities to deliver electricity generated from new facilities.
12. Develop a renewable energy feed-in tariff program to encourage 150 MW of renewable generation resources to be developed by 2016.
13. Encourage the development of an additional 50 MW of customer net-metered solar projects before 2015.
14. Develop up to 30 MW of solar capacity on existing properties under public/private partnership projects before 2015.
15. Investigate the use of term physical gas supply arrangements, either with contracts for physical supplies or futures contracts to limit LADWP's exposure to volatile gas prices. Evaluate and potentially implement any recommendations in the Fuel Hedging Plan.
16. Investigate and develop energy storage targets by October 1, 2014, per AB 2514.

[5] 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.

17. 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.

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TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Overview of the 2012 Integrated Resource Plan

This document represents the Los Angeles Department of Water and Power (LADWP) Integrated Resource Plan (IRP) for 2012. 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 key 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.

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 20% of renewable energy sales in 2010 – significant challenges lie ahead. Increasing renewable energy to 33% by 2020, the continued rebuilding of coastal generation units, replacement of coal, infrastructure reliability investments, and ramping up energy efficiency and other demand side programs are all critical and concurrent strategic actions that LADWP will have to carry out over the coming decade.

The 2012 integrated resource planning process developed alternative strategic cases that assess different replacement options for coal-fired generation, as well as different projected levels of energy efficiency and distributed generation. 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 and recommends the appropriate near-term actions and long-term plan 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, expanded electrification of processes to reduce emissions and greenhouse gases, and growing wide-spread use of information technology equipment will require a stable, resilient power grid that delivers affordable power. By adopting energy efficiency, promoting solar rooftop and supporting other clean technologies that mitigate the need to build new fossil-fueled power plants, our customers are embracing the vision of a greener resource portfolio that sustains 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 renewables, energy efficiency, and distributed generation. Today we have the same electricity consumption as we had in 2000 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 utility to achieve 20 percent renewable generation in 2010. Since 1990, we have divested of 2 coal plants and repowered several natural gas in-basin generating stations using cleaner and more efficient new combustion technology, resulting in 21 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 by next year we will use 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 2011 IRP include expanded discussion on the Power Reliability Program, more detailed information on transmission planning and projects, a new sub-section on the future impacts of climate change on power generation and operations, and new case options that analyze higher levels of Energy Efficiency (EE) and Distributed Solar Generation (Solar DG).

This 2012 IRP incorporates updates to reflect the latest load forecast, fuel price and projected renewable price forecasts, and other numerous modeling assumptions. Compared to the prior forecast, projected electricity sales in calendar year 2020 decreased by 5.3 percent, mostly due to increased levels of energy efficiency. The new forecast reduces the overall need for renewable energy (assuming 33% RPS) by approximately 461 GWh in 2020 and 745 GWh in 2030.

Long term natural gas price forecasts have been revised downwards from last year with recent prices reaching very low levels over the last year. Compared to last year's 2011 IRP, Opal and SoCal expected gas prices are 16% lower on average in the short term (2011-2020) and 8-9% lower on average in the long term (2021-2030). Coal price forecasts are also lower; with IPP coal at 4% lower for the period 2012-2027, and Navajo coal at 14% lower for the period 2012-2019.

Other changes include lower cost assumptions for solar and geothermal, reflecting price competition for both resources, and updates regarding legislative and regulatory issues. See Section 3 and Appendix N for more details.

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 energy efficiency and solar distributed generation 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 and Demand-side Management
Appendix C: Environmental Issues
Appendix D: Renewable Portfolio Standard
Appendix E: Power 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: Abbreviations and Acronyms

1.3 Objectives of the IRP

This 2012 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.

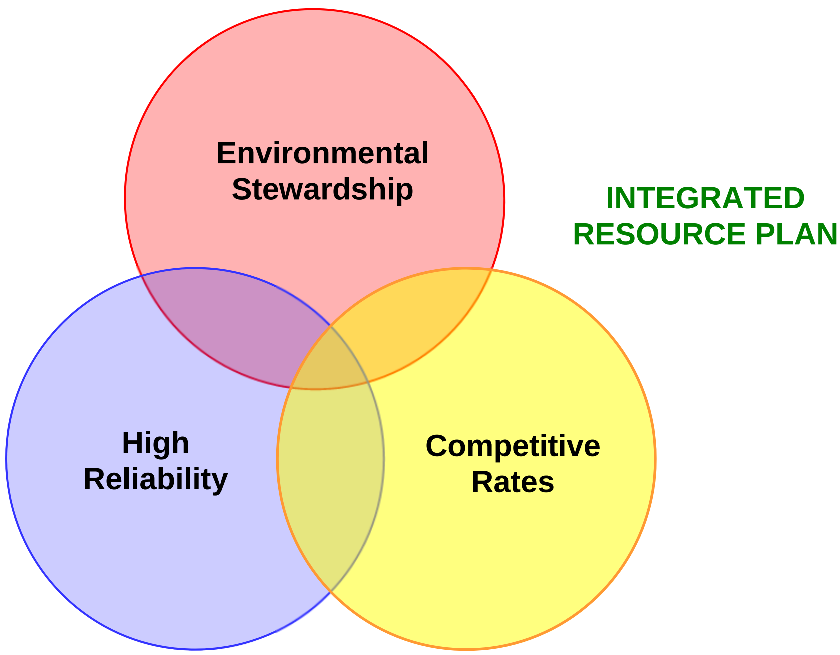


Figure 1-1. Objectives of this IRP.

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:

- <u>Reliability Standards</u>

  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 3rd quarter purchases acquired from the electricity market.

- Coastal Power Plants

  LADWP operates three coastal natural gas-fired power plants that are critical to its operations. These plants were built from the 1940s up to the 1970s. One of these plants 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.

- Power Reliability Program

  In response to an increase in power outages between 2003–2005, 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. See Section 1.6.3 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. See Appendix L for more information.

- 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.

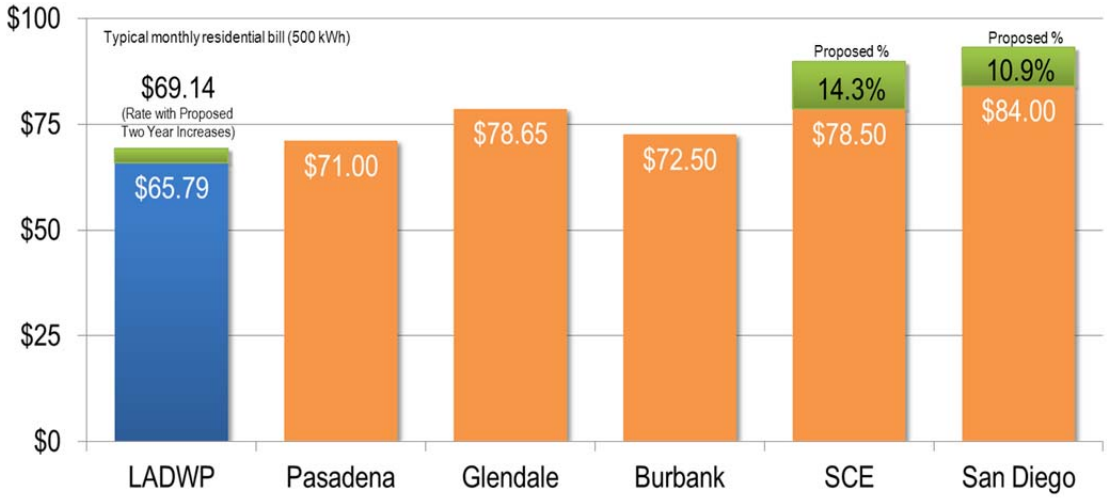
1.3.2 Competitive Rates Consistent With Sound Business Principles

Historically, LADWP's electric rates have been consistently among the lowest in California. As utilities throughout the industry address renewable energy, greenhouse gas emissions, ocean water 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.

LADWP Average Residential Customer Annualized Monthly Power Bill Comparison with Neighboring Cities (without Utility User Tax) As of January 2012



Green bar represents annouced proposed increases. Allocation to various usage levels not known for SCE, San Diego, so assumed allocation is pro-rata.

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 Ordinance 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 debt service coverage ratio of at least 2.25

- Cash on hand

  Maintain a cash balance of $300 Million

- 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 and thereafter. For more information, see Sections 1.5, 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 2012 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, and the transition towards increasing amounts of energy generated from renewable resources. 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 has 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. This IRP considers higher levels of energy efficiency than was previously considered in past IRPs. LADWP is committed to developing comprehensive programs with measurable, verifiable goals as well as implementing robust, cost-effective energy efficiency programs. 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 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.

  Additionally, LADWP is implementing a separate SB 32 Feed-in Tariff (FiT) program, 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, most will 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 Net-metering scheme.

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

- Demand Response Program

  This IRP recommends the implementation of a Demand Response (DR) program, which 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. For a full discussion of DR and details regarding LADWP plans, see Section 2.3.2.

  > *"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.*

1.4 LADWP's Power System

LADWP's Power System serves approximately 4.1 million people and is the nation's largest municipal electric utility. LADWP experienced an all-time net energy-for-load peak demand of 6,142 megawatts (MW), which occurred on September 27, 2010, and has an installed net dependable generation capacity greater than 7,125 MW. Its service territory covers the City and many areas of the Owens Valley, with annual sales exceeding 23 million megawatt-hours (MWh). LADWP is the third largest California electric utility in terms of consumption, behind Southern California Edison and Pacific Gas & Electric—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).

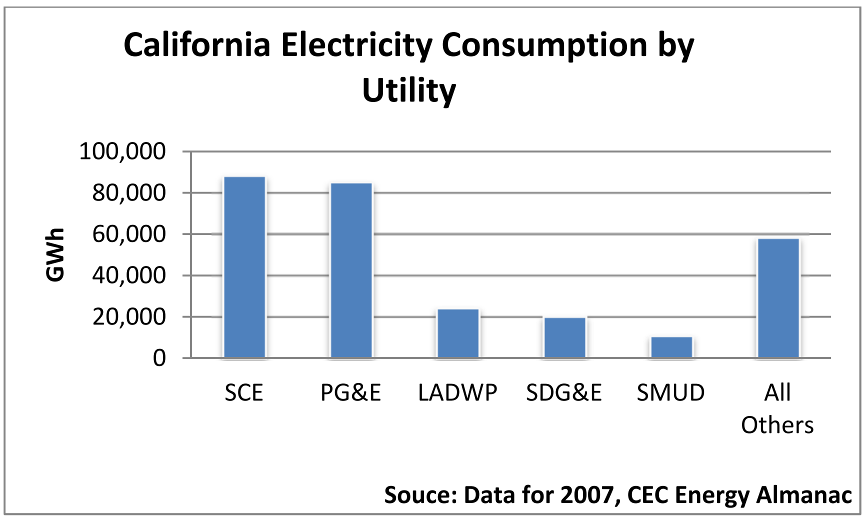


Figure 1-3. Comparison of California utilities by consumption.

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.

While LADWP customers represent roughly 10 percent of California's electrical load, approximately 25 percent of the state's total transmission capacity is owned by LADWP. LADWP's transmission reach also extends beyond California, enabling the transport of power from a diversified set of generation resources from across the Western United States.

[1] Prior to energy efficiency and distributed generation, which will reduce load growth to an approximate yearly average of 0.3% between 2012 and 2032.

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

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.

- 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. In 2011, the renewable percentage slightly decreased to 19% due to less wind and small hydro generation.

- Adelanto Solar Power Project

  On July 23, 2012, the Adelanto Solar Power Project was commissioned as LADWP's first utility-scale solar power plant. The 10 MW(AC) project was built by LADWP crews and is owned and operated by LADWP, making it the largest municipally-owned solar project in the nation. The project makes use of existing LADWP land and ties directly to an existing electrical switching station. The project will provide valuable experience and data regarding solar plant operations, the integration of variable renewable resources, and the financial requirements (capital costs, O&M costs, etc.) associated with building and operating a large solar facility. The experience gained from this project will facilitate the construction of future solar projects.

- Energy efficiency

  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 1,377 GWh of energy savings, or over 5% of energy sales.

  In 2012, the Board of Water and Power Commissioners adopted a goal of 10% energy efficiency by 2020, with a target of 15% pending the results of a new potential study to be conducted in 2013.

- Solar Incentive Program and Feed-in-Tariff (FiT)

  As of September 1, 2012, LADWP has encouraged the installation of over 56 MW of solar capacity at over 6,200 customer locations through its ratepayer-funded Solar Incentive Program. Separately, a FiT pilot program was conducted, which will enable a full-scale program launch for 150 MW by 2016.

- Emissions reduction

  As of 2011, CO_2 emissions from power generation are 21% 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 are at least 90 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 17% 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, will be replaced with efficient modern units that will facilitate the integration of intermittent renewable energy. This project is expected to be in service by May 2013, and is one of many projects that that will eliminate the use of ocean water for cooling by 2029.

- Castaic

  The seven units of the Castaic Hydroelectric Plant are currently being rotated out of service for modernization. This multi-phase process began in 2004 and is expected to continue through 2014. To date, five 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 Reliability Program (PRP)

  The 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 2011-12, 1,813 poles, 2,054 transformers, and 51 miles of underground cable were replaced. See Section 1.6.3 and Appendix E 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 2011, 17,700 LADWP customers participated in the program, receiving approximately 74,000 MWh of renewable energy. Since program inception in 1999 to the end of 2011, 872,131 MWh of renewable energy was procured, making it one of the largest voluntary green pricing programs in the nation.

- Upgraded capacity on the Southern Transmission System (STS)

  In May 2011, the 488-mile Intermountain Power Project DC Line was upgraded from 1920 MW to 2400 MW, allowing the import of additional amounts of renewable energy from Utah. Of the 2400 MW total capacity, LADWP's share is 1428 MW.

- Navajo Generating Station (NGS) retrofitted with low NO_X burners

  In March 2011, NGS completed a three-year project that retrofitted the boilers of all three units with low NO_X burners and separated over-fire air systems. This project was successful in reducing NO_X emissions by 40% which represents an annual NO_X emission reduction of 14,000 tons per year.

- Barren Ridge Switching Station

  The Barren Ridge Switching Station, located 15 miles north of Mohave, 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 Mohave 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. For more information see Section 2.4.4.

- Milford II Wind Project

  In May 2011, LADWP began receiving over 100 MW of new wind energy. Milford II is an expansion of the 200 MW Milford I wind farm project. Together, Milford I and II are providing approximately 2.6% of LADWP's total energy sales.

- 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.

- Initiated Coal Replacement

  Processes to replace coal generation from the IPP and Navajo stations have been initiated and are in progress. At Navajo, LADWP is planning to divest from the project by the end of 2015, which is four years ahead of the date required by SB 1368. At IPP, LADWP is working with the other participants to establish the contractual structure to enable a conversion from coal to natural gas. The date of conversion will likely be established before next year's 2013 IRP.

- 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. Program managers and support staff have been established to move these programs forward, and appropriate resources have been budgeted.

1.6 Key Issues and Challenges

LADWP faces a number of concurrent issues and 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. Due to the delay of the rate action that was previously anticipated in 2011, many of the programs were scaled down, delayed or deferred. The rate process that concluded on October 5, 2012 is a positive step towards LADWP's fulfillment of its responsibilities and regulatory obligations which are discussed throughout this 2012 IRP.

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 distributed solar generation and combined heat and power to support State goals.
- Through the Power Reliability Program, reduce the number and duration of distribution outages and improve system reliability.
- Implement necessary transmission improvements to maintain reliability and support new resources, including renewables.
- Provide energy efficiency and customer solar programs for participation by our customers through the Customer Opportunities Program.
- Achieve energy efficiency and other demand-side resource target levels.
- Implement Smart Grid initiatives.
- Comply with FERC-approved reliability and Cyber-security standards.

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 poles, power cables, transformers and other elements of the local distribution system (distribution 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. The new repowered units will be substantially cleaner, more reliable, community-friendly, and efficient 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 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, if encountered, could lead to load shedding events (intentional power outages) to minimize the overall impact on the Power System.

Integration of Intermittent Renewable Energy

The integration of renewable energy into the grid poses major challenges. Integrating renewables will, paradoxically, require additional gas–fired generation to provide reserves and maintain system reliability. 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 to regulate delivery of energy and reduce the severity of integration problems. For regulation, LADWP currently uses gas-fired combustion turbines and hydro resources, including pumped water storage. Batteries and compressed air offer alternative storage solutions, but those technologies are still in development and have not yet been proven commercially viable. See Section 2.4.5 for a discussion of LADWP's energy storage development activities.

"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.

LADWP is conducting studies to determine the maximum levels of intermittent energy resources that can be integrated reliably and to identify the investments necessary to maintain power grid reliability with intermittent resources contributing significantly to its energy portfolio.

1.6.3 Power Reliability Program (PRP)

Between 2003 and 2005, LADWP experienced a growing number of distribution outages due to, among other things, aging infrastructure (poles, lines, transformers, etc.), and deferred maintenance and asset replacement. To illustrate, Figure 1-4 shows the number of electrical distribution poles categorized by age. As shown, more than 50 % of the poles are 50 years or older and more than 25% already exceed the average life span of 60 years.

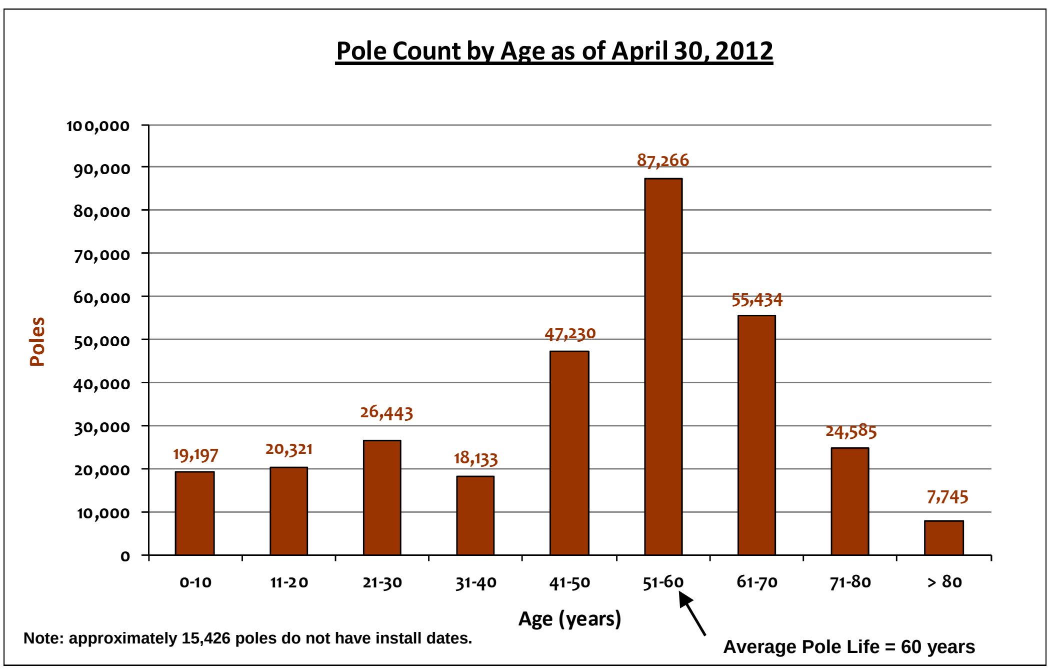


Figure 1-4. Pole count by year range installed.

Like all other electricity utilities in the US, LADWP uses a number of metrics to measure the performance and reliability of its electric power system. The two primary metrics are called SAIFI and SAIDI.

The System Average Interruption Frequency Index (SAIFI), is the average number of sustained service interruptions per customer during the year. It is the ratio of the annual number of interruptions to the number of customers. In other words, it measures how many times the average customer has been out of service. 1.1 is the recent national average. In 2002, LADWP's SAIFI index was 0.49; in 2011 it was 1.03.

The System Average Interruption Duration Index (SAIDI), is the average duration of interruptions per customer during the year. It is the ratio of the annual duration of interruptions (sustained) to the number of customers. In other words, it measures how long the average customer was without power. 90 minutes is the recent national average. In 2002 LADWP's SAIDI index was 59.29; in 2011 it was 214.44.

The trends for both SAIDI and SAIFI are shown in Figure 1-5.

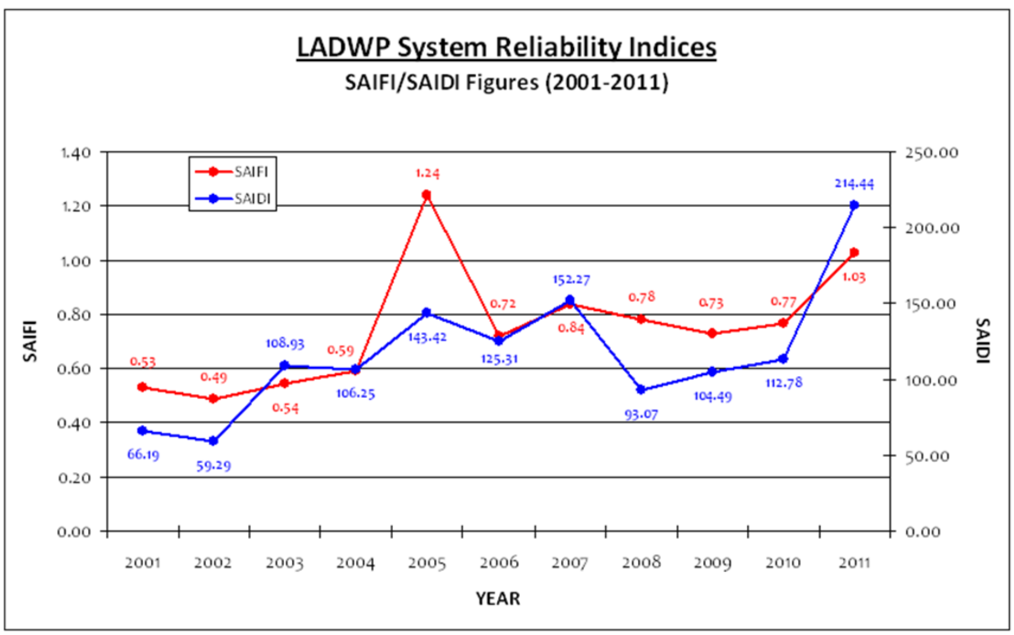


Figure 1-5. LADWP's reliability indices.

In response to the decline in service reliability, LADWP established a comprehensive Power Reliability Program (PRP) in 2006 which provided increased funding to address the growing maintenance backlog. 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 avert problems before they occur, and (3) establishing replacement cycles for facilities that are in alignment with equipment life cycle.

PRP funding has been inconsistent since its inception. As shown in Figure 1-6, the initial years of the program resulted in some reliability gains as outages decreased from 6,323 in 2006 to 4,523 in 2009. Funding levels since then, however, have declined and the number of outages has remained above 4,500 per year.

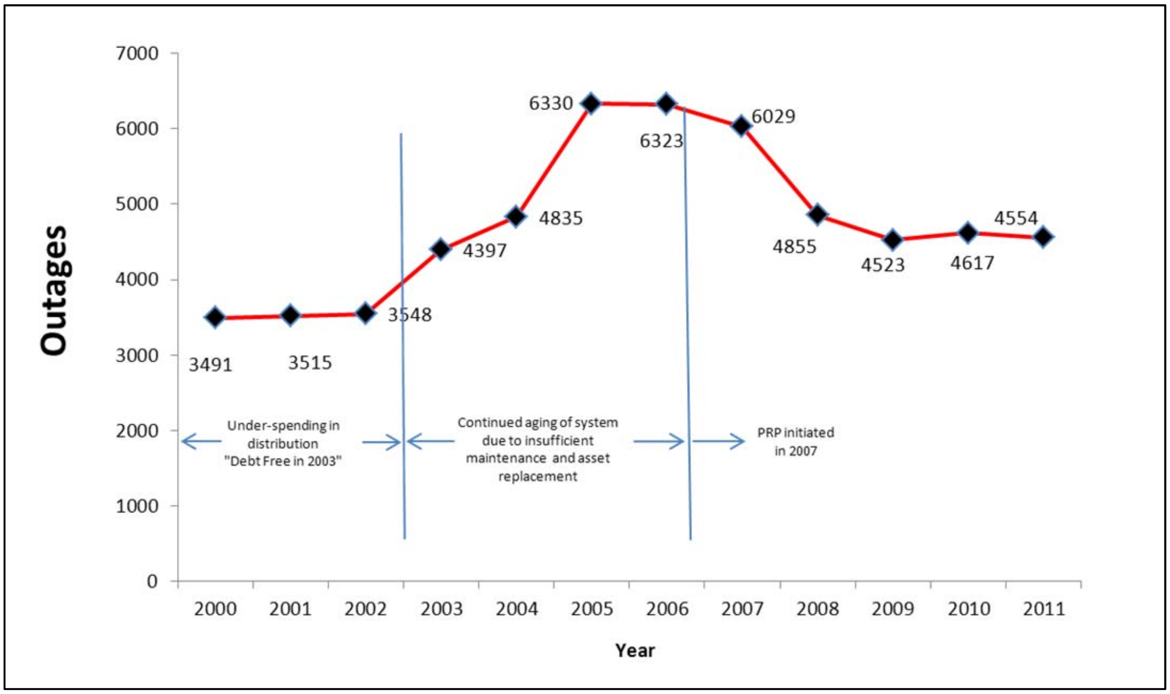


Figure 1-6. Total outages between 2000-2011.

Adequate funding is necessary to get the PRP back on track towards its goal of reducing outage levels. Additional information on LADWP's PRP can be found in Appendix E.

1.6.4 GHG Emissions Reduction

The focus of LADWP's GHG 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 AB 32's upcoming 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).

- Assembly Bill (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 will begin January 1, 2013. LADWP has been granted an administrative allocation of emission allowances that reflects its resource projections through 2020.

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. The NGS's operating agreement and land lease expires in 2019 but has a stipulation for a 25-year extension. IPP's Power Purchase Agreement (PPA) contract is in effect until 2027. 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 2012 IRP focuses on early coal replacement options 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 case 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 33 percent renewables by 2020 and maintain this level in all subsequent years.

- SB 32, signed into law on October 11, 2009, 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 33 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 1-1.

Table 1-1. 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.

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 Clean Water Act Section 316(b) and administered locally by the State 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 use ocean water. The amount of generation capacity affected by OTC is significant – approximately 2,600 MW of LADWP's total in-basin plant capacity of 3415 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 1-7).

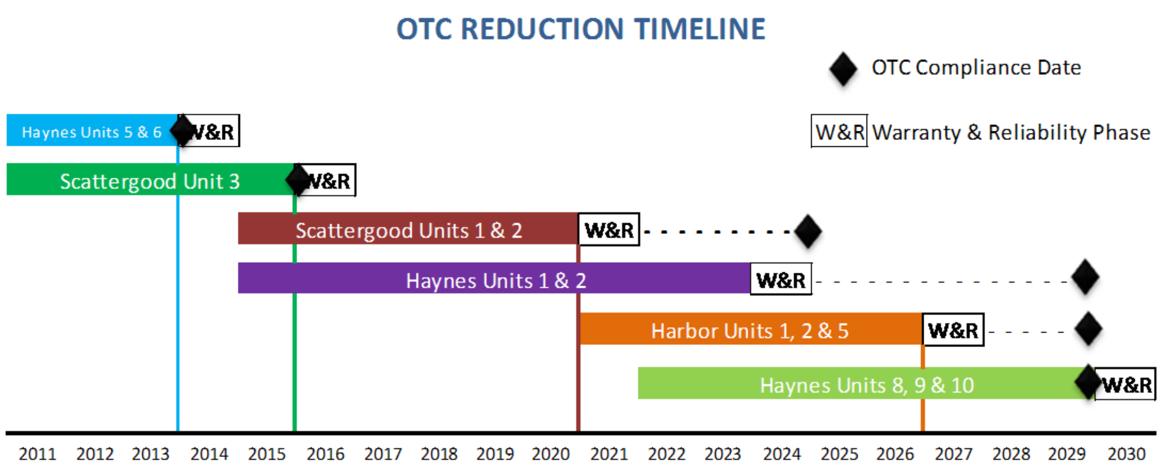


Figure 1-7. Timeline for OTC compliance.

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 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 1-7.

There are many challenges to meeting the target dates. The limited space available within some 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 1-7 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 ocean water use are shown in Figure 1-8. As individual units are replaced with new units that do not use ocean water, 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.

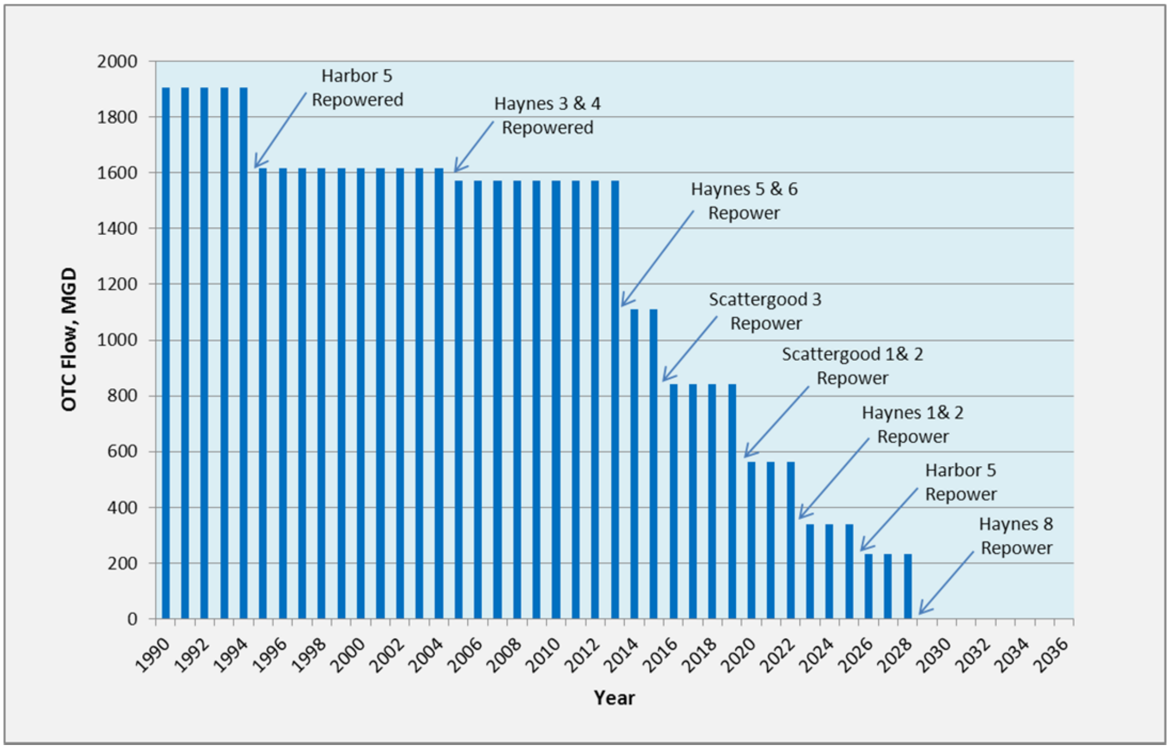


Figure 1-8. LADWP's reduction in once-through cooling from 1990 to 2029.

1.6.7 Workforce Development

To effectively implement the programs and projects recommended in this IRP, an effective human resources strategy is required. The Power System is challenged to develop a sustainable workforce development plan that addresses the following human resources elements:

Adequate Staffing
Ensure adequate staffing so that LADWP can comply with mandated deadlines and fulfill its regulatory obligations. The Power System employs approximately 4,000 employees in 150 civil service classifications who perform core work related to generation, transmission and distribution of electricity. Workload requirements and competencies are continuously reviewed to determine the composition and number of employees needed. Achieving and maintaining proper staffing levels is complicated by the fact that a significant number of employees are expected to retire in the next 3-5 years.

Proper Skill Sets
New and expanded work areas such as renewable energy facility operations, energy efficiency, solar distributed generation, power reliability and smart grid deployment will require analysis to identify the skills, knowledge, abilities, and staffing levels required to perform these functions in a safe, effective and efficient manner. New job classifications may be required for new or specialty areas.

Training/Professional Development and New Technologies
Developing and promoting the development of both new and existing employees is a key human resource management objective. LADWP supports employee development by providing various computer-based training programs, and offers tuition reimbursement for those who return to school to enroll in work-related courses and advanced degree programs. Across the Power System, different work groups are encouraged to develop training specific to their particular functions and needs. This is especially important as new and emerging technologies become applicable to various work functions. Applied correctly, technology increases employee productivity, enhances safety, and enables new and expanded customer services.

Recruitment
Recruiting the best qualified employees assures an effective workforce capable of meeting the near term and long term challenges identified in the IRP. Working with source institutions such as colleges and vocational schools will expand LADWP's candidate pool, from which the highest qualified individuals can be offered positions. To promote the local economy, strategic recruiting is planned in areas of the City which have historically been untapped as sources for entry-level craft jobs. Continued use of LADWP's website and social media to promote career opportunities will sustain public awareness and help ensure that the best qualified individuals consider joining the LADWP workforce.

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/DSM 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. These strategies are designed to protect LADWP from potential future price fluctuations, and include financial hedging products, ownership of gas reserves to supply a portion of its fuel needs, and other potential products and contractual arrangements.

- Distributed Generation

  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 investigates higher levels of distributed generation (see Cases 7 and 8 in Section 3 and 4), a number of complicating factors could make this a difficult goal to attain. Having adequate reserves, addressing operational impacts, and loss revenues 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 the ratepayers.

- Cyber Security Legislation & Regulation

  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 which 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 standards.

NERC is currently working with industry on version 5 of these standards in order to prevent cyber incidents that could lead to misoperation or instability in the bulk electric system.

- 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 joint 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.

1.7 Public Process

The 2012 IRP process includes a public outreach effort to provide information and gather public input.

Public outreach began with two stakeholder meetings held in early 2012. LADWP staff met with key major customers and business representatives in February; and in March with key environmental organization representatives. Comments received during these stakeholder meetings were considered in the development of the preliminary cases that were analyzed.

These preliminary results were documented in the 2012 Draft IRP document and were presented at three additional stakeholder meetings with major account customers, environmental organizations, and neighborhood councils; and discussed at an additional general public workshop held on October 11, 2012. The 2012 Draft IRP was made available for public comment through the LADWP website:

www.ladwp.com/lapowerplan

Comments were accepted through November 5, 2012. 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 2012 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 efforts is to produce a long term plan that ensures a future supply of electricity that is reliable, competitively priced, and is secured 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, 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, energy efficiency, and distributed generation; 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 acceptance. 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 Heads. 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 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 2012 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 2012-2017

Program Areas in Progress

- **Haynes 5&6 Repowering** (Sections 1.6.6, 2.4, 3.3; 5.3; Table 5-4; Appendix F)
- **Scattergood Repowering** (same as Haynes 5&6 references)
- **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 2.4.2.2; Appendix E)
- **RPS procurement** (Sections 1.6.5, 2.4.3, 3,4, 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, 5.3, and 5.6; Table 4-2)
- **New EE program elements** (Section 2.3; Table 4-6; Appendix B)
- **Smart Grid Implementation** (Section 2.4.5; Table 4-6; Appendix L)
- **Transmission Line Improvements** (Sections 2.4.4; Appendix I)
- **Grid Reliability Improvements** (Sections 2.4.4 and 5.1)
- **Haynes 1&2 Repowering** (Sections 1.6.6 and 3.3, Table 4-6)
- **Distributed Generation** (Sections 2.3.3, 3.5, 4.3.3.1: Appendices G and N)

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2.0 LOAD FORECAST AND RESOURCES

2.1 Overview

Through an IRP, utilities 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 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 IRP utilizes LADWP's 2012 Load Forecast, dated March 7, 2012, of customer demand for energy over the next 20 years (the complete 2012 Load Forecast is included in Appendix A). Econometric models are used to forecast retail sales and peak demand. Net Energy for Load (NEL) is defined as the production necessary to serve retail sales. NEL, and its allocation across various times of the day, are functions of the retail sales and peak demand forecasts. The retail sales forecast is the sum of seven separate customer class forecasts. The classes are residential, commercial, industrial, plug-in electric vehicle (PEV), intradepartmental, streetlight, and Owens Valley. The drivers in the retail sales models include normalized weather, population, employment, construction activity, and personal consumption. The NEL forecast is derived from the retail sales forecast by applying a normalized loss factor of 11.5 percent. Losses can vary depending on the sources of energy production. NEL load growth becomes a driver of the peak demand forecast. Peak demand is also a function of temperature, heat buildup, and time of year. The NEL forecast is allocated using the Loadfarm algorithm developed by Global Energy. The inputs into the algorithm are NEL, peak demand, minimum demand, and system load shape.

2.2.1 2012 Retail Electrical Sales and Demand Forecast

The effect of the recent recession and slower than normal recovery combined effective energy efficiency programs depressed electricity sales by approximately 6.4 percent off their fiscal year 2007-08 peak. Economic activity in commercial sectors such as construction, real estate, retail, and leisure are forecasted to recover as the economy expands.

The electricity consumption within LADWP's service territory is forecasted to rise 0.8% over the next five years as energy efficiency and solar rooftop expansion offset growth from economic activity. The growth in annual peak demand over the next twenty years is predicted to be about 0.6 percent—approximately 40 MW per year—with less growth over the next few years due to the current recession. After 2018, some of the growth will not be realized at the meter depending on the adoption of energy efficiency and distributed generation technologies.

The 2012 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 2-1 summarizes the data sources used to develop the forecast and where these data sources have been updated from previously published forecasts.

Table 2-1: LOAD FORECAST DATA SOURCES

Data Sources	Updates
1. Historical Sales through December 2011 are reconciled to the General Accountings Consumption and Earnings Report.	*Historical Sales, Net Energy for Load and weather data is updated through December 2011.*
2. Historical NEL, peak demand and losses through December 2011 are reconciled to energy accounting data.	
3. Historical weather data is provided by the National Weather Service and Los Angeles Pierce College.	*Weather is updated through December 2011.*
4. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2010 benchmark.	*Employment data is updated through December 2011 using the March 2010 benchmark.*
5. Historical population and forecasts is provided by the State of California Department of Finance.	Population data is updated through January 2012.
6. The long-term Los Angeles County economic forecast is provided by UCLA Anderson Forecast.	
7. The construction activity forecast is provided by McGraw-Hill Construction.	*Building permit data is updated through December 2011.*
8. The plug-in electric vehicle (PEV) forecast is based on the California Electric Vehicle Coalition which has been adopted as the statewide PEV forecast.	
9. The port electrification forecast is provided by the Port of Los Angeles.	
10. The housing forecast is informed by the City of Los Angeles "Housing that Works" plan.	

2.2.2 Five-year Sales Forecast

The Retail Sales Forecast represents sales that will be realized at the meter through Fiscal Year Ending (FYE) 2017. After FYE 2017, some of the forecasted sales will not be realized at the meter due to the incremental impacts of LADWP-sponsored energy efficiency programs.

The historical accumulated energy efficiency and solar savings are from 1999 forward and only include LADWP installed savings. Since July 1, 2008, LADWP installed energy efficiency savings are 715 GWh for which LADWP recovers lost revenue. In the forecast, energy efficiency and solar savings are expected to occur uniformly throughout the year as a simplifying assumption. Installation schedules are difficult to prepare because they rely on the customers allowing the installation to occur.

Retail sales decrease of 0.6 percent in FYE 2014, as shown in Figure 2-1, is attributed to the full ramp up of the lighting efficiency requirements of AB 1109 (approved in 2007 and known as the "Huffman Bill") and accelerated incremental savings rates in

LADWP's energy efficiency programs. Beginning January 2012, the Huffman Bill significantly raises the efficiency standard of light bulbs. The 0.5 increase in FYE 2015 is due to the projected completion of port electrification projects and a decline in the LADWP incremental energy efficiency savings rate.

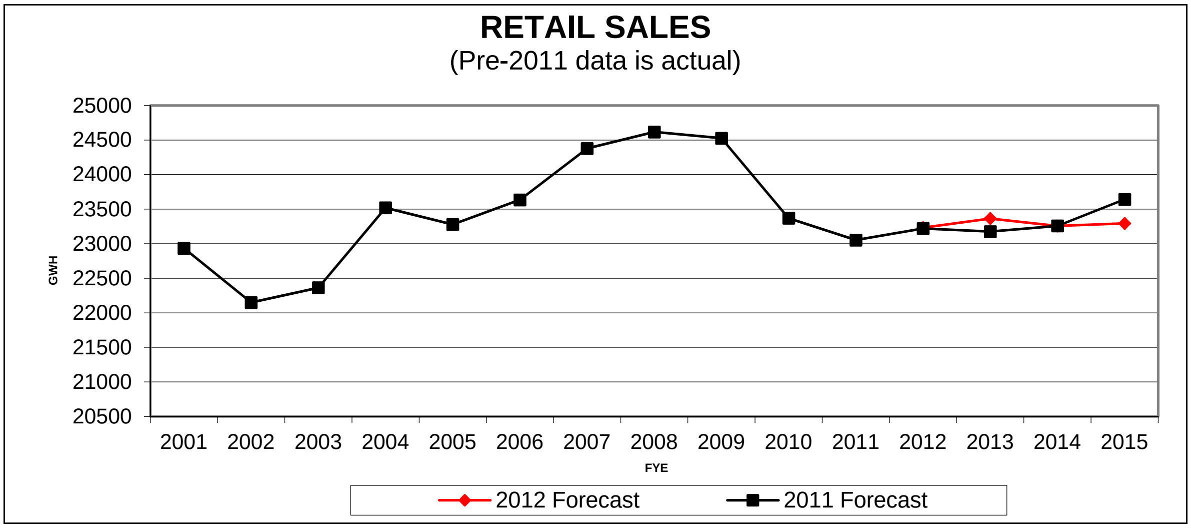


Figure 2-1. Retail sales net of energy efficiency and distributed generation.

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

Table 2-2. SHORT-TERM GROWTH

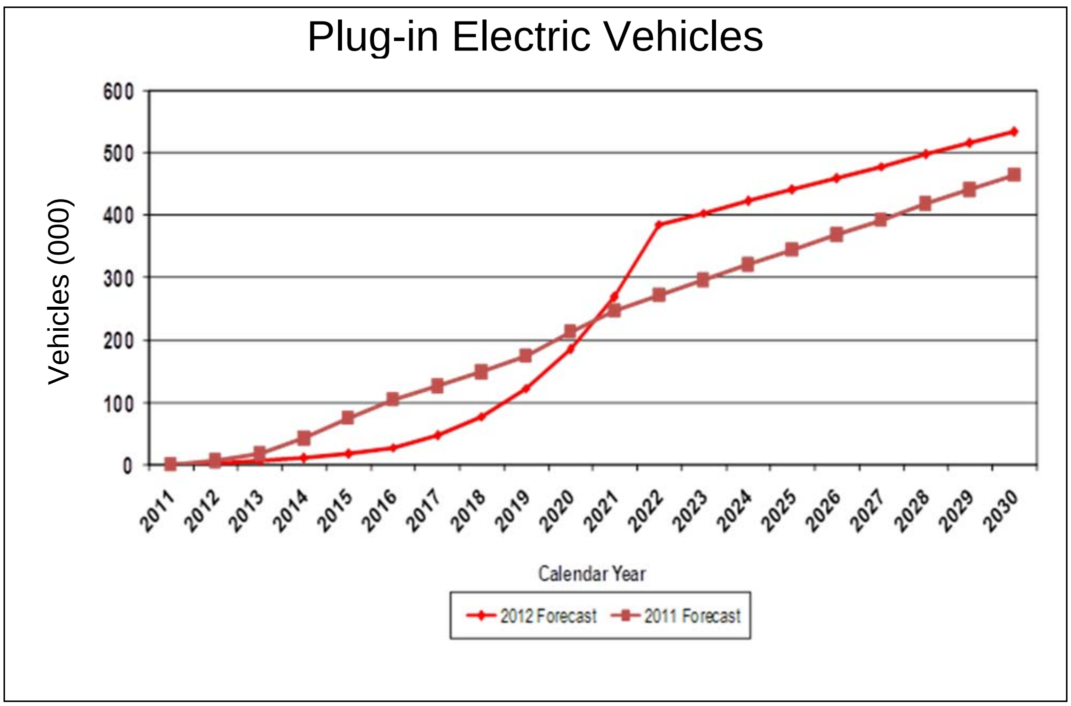
Fiscal Year	Retail Sales		Additional Load if not for EE & Solar Savings
Ending June 30	(GWH)	Growth Rate (Year-Over-Year)	(GWH)
2010-11	23,053	-1.50%	0
2011-12	23,232	0.8%	255
2012-13	23,364	-0.4%	592
2013-14	23,256	-0.6%	928
2014-15	23,294	0.2%	1302

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

A result of AB 32 will be to encourage increased electrification as a means to reduce GHG emissions. 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 2-2 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. Supporting the City's electric vehicle infrastructure, LADWP is also in the process of retrofitting 117 vintage chargers on City property.



Based on 2011 CEC Forecast

Figure 2-2. Forecasted number of 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 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 factor. 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.

2.2.4 Peak Demand Forecast

Growth in annual peak demand over the next ten years is 1.0 percent as shown in Table 2-3.

Table 2-3: 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)
2011-12	5635[1]		6046
Forecast			
2015-16	5591	0.8%	6028
2020-21	5791	1.0%	6244
2030-31	6381	1.1%	6885
2040-41	6992	1.1%	7546

[1] Weather-normalized. Actual peak was 5907 MW

In 2010, the System set its all-time annual net energy for load peak at 6142 MW on September 27, 2010 on a day that was a one-in-thirty-five year weather event. The weather-adjusted one-in-two peak for 2011 is 5635 MW. Figure 2-3 presents the one-in-ten peak demand forecast, which is used for integrated resource planning. In the 1990s through 2005, annual system load factors were trending slowly upward. Since 2006, 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.

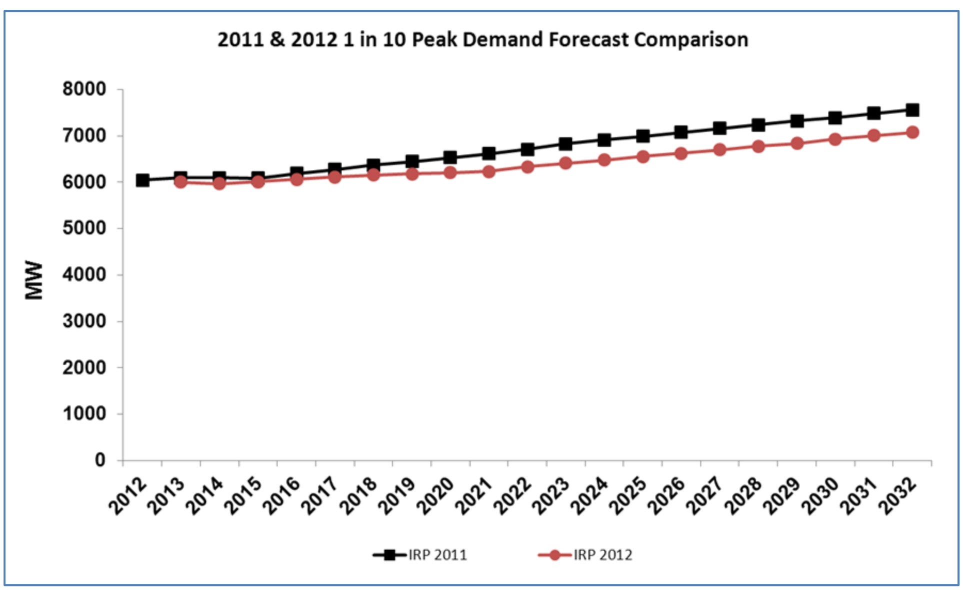


Figure 2-3. One-in-ten peak demand forecast comparison.

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 AB 2021 objectives, 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.
- An assessment of existing and developing technological improvements in large scale battery systems for energy storage.

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. One of the most widely recognized examples of an EE program 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 $315.2 million in capital and O&M on its energy efficiency (EE) programs and these programs have reduced consumption by approximately 1,377 GWh. LADWP is committed to implementing comprehensive programs with measurable, verifiable goals as well as implementing robust, cost effective energy efficiency programs.

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 "Potential" studies to update their forecasts and targets. LADWP's most recent study, carried out in late 2010, is the basis for the EE recommendations contained in last year's 2011 IRP and was used to develop the initial financial plan and proposed rates for fiscal year ending (FYE)[2] 2013 and FYE 2014. LADWP is currently proceeding with the 2013 EE Potential Study, to be completed in 2013.

2.3.1.1 Recommended Target – 10% by 2020

The base plan for energy efficiency programs established in December 2011 puts 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 latest energy efficiency potential study and was approved by the LADWP's Board of 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 targeted 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.

LADWP's baseline EE spending in the initial financial plan for FYE 2013 and 2014 (based on the 8.6% target) is $87M and $99M, respectively. In order to achieve the 10% level of GWh savings, LADWP recommended increasing spending on EE programs. This change would add funding to existing programs, modify existing programs or develop new programs that provide additional GWh savings necessary to put the utility on a projected path to achieve 10% savings by 2020. Other changes included reallocating costs from support functions to programs, capitalizing the vast majority of the programs, and updating assumptions related to other programs. The Board adopted the increased EE budget for 2013-14 at the same time as the 10% savings goal, on May 14, 2012.

On May 24, 2012 the Board also acknowledged plans to conduct a new updated energy efficiency potential study to be completed by June 30, 2013. The new potential study will be used to develop a long-term plan for the scope and estimated costs to achieve 10%, 12.5%, and 15% savings by 2020. The energy efficiency planning scenarios resulting from the new study will be considered for inclusion into future IRPs.

2.3.1.2 Total Additional EE Investment Required to Reach Required 10% GWH Savings

As shown in Figure 2-4 and Table 2-4 below, LADWP recommended an additional $41 million and $40 million in expenditures in FYEs 2013 and 2014 respectively. This level of additional spending is well above LADWP's historic and current levels and produces

[2] FYE 2013 refers to 2012-13 and FYE 2014 refers to 2013-14. LADWP's fiscal year begins on July 1 and ends on June 30.

the GWh savings required in the next two fiscal years to put LADWP on a path which, if continued beyond FYE 2014, would reach at least the 10% required by year 2020 per AB 2021. 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. Moving forward with this level of commitment then allows LADWP to prepare plans beyond the next two fiscal years to achieve the 10% energy efficiency savings by 2020, or to consider even further energy efficiency improvements beyond 10% if deemed appropriate.

The yellow line in Figure 2-4 represents the level of energy savings required to pace LADWP towards the 10% reduction target. Expenditures for this level of savings were approved in the recently concluded rate process.

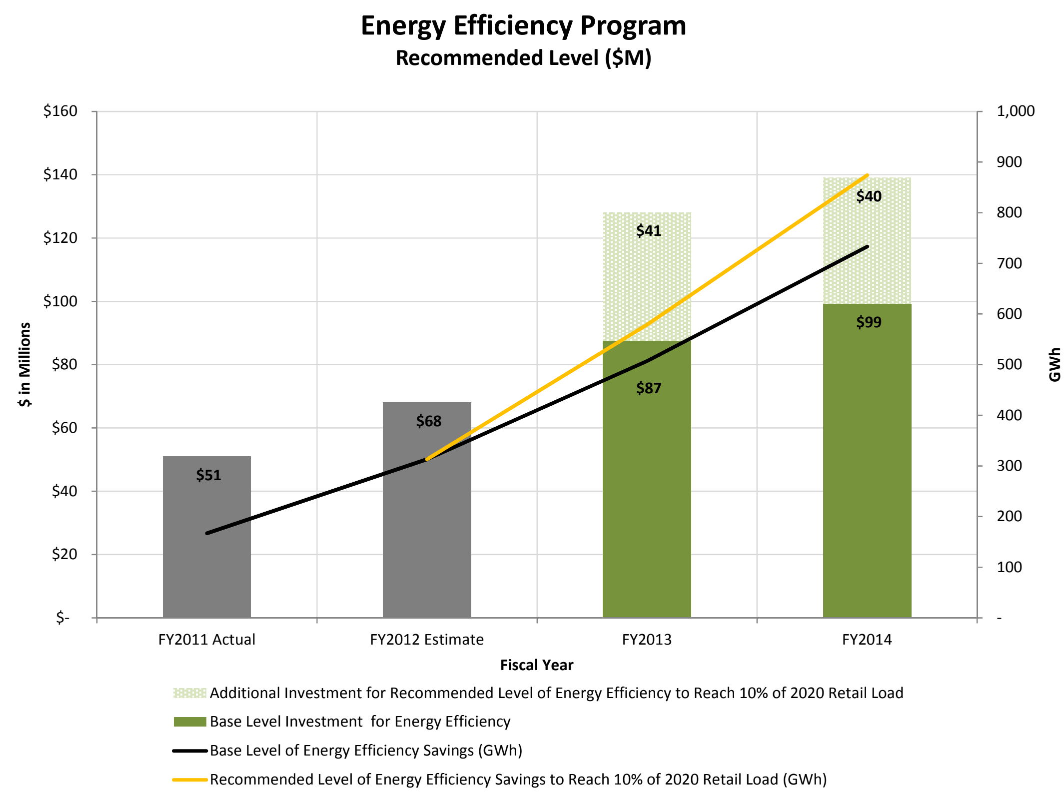


Figure 2-4. Energy efficiency recommended investment and energy savings through FYE 2014.

Table 2-4 below shows proposed spending for the next two years, along with an extended outlook through FYE 2017.

Table 2-4. TOTAL ENERGY EFFICIENCY EXPENSES AND USAGE SAVINGS

Energy Efficiency Program	Proposed Rate Period Cost ($000s)		Extended Outlook Cost ($000s)			Total Five Years FY 2013 to FY 2017		
	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	Cost ($000s)	GWh Savings	Cost ($/kWh)
Residential Programs								
Refrigerator Recycling Program	1,033	1,212	1,440	1,683	2,400	7,768	100.0	0.016
Refrigerator Exchange Program	6,200	6,323	14,126	15,451	21,879	63,979	59.9	0.076
Consumer Rebate Program	2,067	3,161	3,260	4,414	5,470	18,372	13.5	0.105
Income Qualified and Multi-Family Program	12,380	12,678	6,540	6,738	6,850	45,186	10.6	0.327
Residential Lighting Program	723	1,054	1,630	2,207	4,102	9,717	71.6	0.026
Residential Home Electronics Program	0	0	543	1,104	1,367	3,014	6.0	0.100
Behavioral Programs	2,067	2,108	2,173	2,207	2,735	11,290	113.5	0.099
Energy Upgrade California	1,033	2,108	1,087	1,104	1,367	6,699	7.0	0.095
AC/Tune-Up	2,067	2,108	2,173	2,207	2,735	11,290	5.2	0.215
Residential Subtotal	**$27,570**	**$30,750**	**$32,973**	**$37,115**	**$48,905**	**$177,313**	**387.4**	**0.118**
Non-Residential Programs								
Commercial Lighting Efficiency Offer	10,333	10,538	7,607	7,725	8,205	44,408	165.9	0.024
Chiller Efficiency Program	2,583	3,161	3,803	3,863	4,786	18,197	23.4	0.039
Refrigeration Program	1,033	1,581	1,630	1,655	2,051	7,951	75.5	0.026
HVAC Program (5 to 20 tons)	2,067	2,181	2,336	2,456	3,138	12,178	15.1	0.054
Custom Performance Plus	10,333	10,906	11,627	12,250	15,725	60,843	92.4	0.041
Custom Performance-Based Efficiency	12,400	14,753	15,213	15,451	19,144	76,961	365.3	0.018
New Construction	1,292	1,844	2,173	2,207	2,735	10,251	82.7	0.008
LAUSD	11,327	11,569	12,047	12,453	12,586	59,982	136.1	0.043
Lighting Direct Install Program	36,183	36,987	37,979	38,924	39,649	189,721	101.7	0.170
Retrocommissioning (RCx)	4,133	4,215	4,347	4,414	4,102	21,212	77.9	0.027
Demand Response Pgm Dev/Program Support	258	738	1,304	2,207	5,470	9,977	0.0	0.00
Non-Residential Subtotal	**91,943**	**98,473**	**100,066**	**103,606**	**117,591**	**511,680**	**1,136.1**	**0.045**
Subtotal General Program Support	7,684	8,512	10,341	11,313	13,250	51,100	N/A	0.00
TOTAL ENERGY EFFICIENCY PROGRAM	**$127,197**	**$137,736**	**$143,379**	**$152,034**	**$179,747**	**$740,094**	**1,523.5**	**0.079**

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 needs.

The spending shown in Table 2-4 results in cumulative savings of 1,523.5 GWh in FYE 2013 through FYE 2017 combined at an average cost per kWh of $0.079.

2.3.1.3 Program Descriptions

The different EE program elements are briefly described as follows:

Residential Programs

Refrigerator Recycling Program: The program provides free pick-up and recycling of old, inefficient refrigerators, along with a cash incentive of $50 for each recycled refrigerator.

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.

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.

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.

Residential Lighting Program: This program is currently under development.

Behavioral Programs: Provides residential end-users with information on their energy use, comparisons with usage by others, goal setting, rewards and additional tactics that encourage efficient energy use. This is a new program not included in the base energy efficiency program.

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 energy efficiency program.

AC/Tune-Up: Provides qualifying residential customers with Air Conditioning refrigerant charge adjustments and condenser coil cleaning. Program is currently in development.

Non-Residential Programs

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.

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.

Refrigeration Program: The new Refrigeration Efficiency Program encourages best practices and retrofit measures and technologies to reduce energy in food store refrigerator cases and cold storage facilities.

HVAC Program (5 to 20 tons): Offers incentives for replacing inefficient package units with high efficiency units. This is a new program not included in the base energy efficiency program.

Custom Performance Plus: An enhanced version of the Custom Performance Program that is in the base level EE plan, targeting industrial process efficiency improvements with minimum energy saving requirement of one GWh. Program is currently in development. This is a new program not included in the base energy efficiency program.

Custom Performance Based 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, HVAC, other).

New Construction Program: This program is being redeveloped. Plans are underway to offer incentives for projects exceeding current Title 24 requirements for energy efficiency.

Energy Efficiency Measures for LAUSD: Los Angeles Unified School District (LAUSD) is the largest power customer of the utility. LADWP is presently working with LAUSD to develop a focused energy efficiency program to reduce energy use at LAUSD facilities that are within the City of Los Angeles[3]. LADWP has proposed to LAUSD undertaking specific energy efficiency measures in FYE 2013 while LADWP works with LAUSD to develop a detailed energy usage and energy efficiency potential study of LAUSD facilities that will provide the basis for a multi-year energy efficiency plan that LADWP and LAUSD would collaboratively undertake as part of LADWP's overall energy efficiency investment program. The Energy Efficiency Alternative Plan presented herein provides for an allocation of funding and target energy savings for the next two fiscal years. This plan will be developed in more detail in cooperation with LAUSD.

Small Business Direct Install Program (SBDI): This program will retrofit 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.

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

[3] Some of the LAUSD facilities are located outside of the boundaries of the City of Los Angeles and are served by Southern California Edison.

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.

Other Programs

Other programs in support of residential and industrial energy efficiency programs includes: (1) development of an on-bill financing mechanism for third party financing and LADWP collection of payments for such financing; (2) program outreach and community partnerships; (3) marketing to increase awareness of energy efficiency programs; and (4) measurement and verification of energy efficiency program savings.

2.3.1.4 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 the 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 dispatch 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. A new potential study is planned for completion in 2013 and will provide updated information to modify the overall EE program.

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

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 objective of DR is to lower energy usage at critical peak demand periods, in a manner which decreases overall system costs. LADWP's DR programs will be based on incentives to encourage customer participation based on lower rates, rebates, or other financial incentives.

The benefits of demand response are many:

> ***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.
>
> ***Lower 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 keeps rates low.

Less 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.

Help Integrate Renewables. Under certain circumstances, DR can enable customer loads to respond to fluctuations in generation from wind and solar power.

DR is a relatively new demand-side resource, and LADWP plans to develop an active program over the next several years. As discussed in Section 5, one of the recommendations of this 2012 IRP is to provide funds to develop and implement DR. The analysis of all strategic cases considered in this 2012 IRP (discussed in more detail in Section 4) calls for a small 5 MW DR program beginning in 2013 that will build to 200 MW by 2020 and 500 MW by 2026. This gradual expansion will facilitate the development of in-house expertise that will ensure a sound DR program by the end of this decade, and will also allow time to deploy the supporting IT infrastructure and to implement required IT systems and processes.

A variety of program elements are being considered for LADWP's DR program. The following are some of the offerings that are commonly adopted in the industry. Depending on the circumstances of how energy is used, certain programs will be more suitable to particular customer segments than others. LADWP's initial planning focus is on items 1 and 2 below.

1- Curtailable/Interruptible – Commercial/Industrial customers who sign up are on-call for curtailment of power, and are provided credit even if an event is not triggered. However, curtailments are firm and mandatory; penalties are assessed for under performance or non-performance.

2- Direct Load Control – Customers sign up and agree to be subjected to demand reductions as-needed based on power system needs and constraints. The typical example is a customer's central air conditioning system which may be remotely shut down by the utility during high peak conditions. In exchange, the customer gets an incentive payment or bill credit.

3- Peak Rebate Pricing – Customers who participate in the Peak Rebate Pricing are notified in advance in which the retail electric rates are temporarily adjusted up, typically as a response to events or conditions such as extreme high peak load. The customer receives a rebate for reducing or shifting their load during the peak load event, but there is no penalty if the customer does not reduce load during the peak load event.

4- Critical Peak Pricing – Similar to the Peak Rebate Pricing, customers who participate are notified in advance of the event and can avoid the higher prices by decreasing their energy use during this time period. The customer incentive to participate is a lower base rate throughout the year.

5- Real Time Pricing – Retail rates are varied on an hourly basis or other short-term basis and are typically tied to variations in the commodity market prices for wholesale power supplies. Consumers are provided with access to the changing market prices on a continuous basis, and can change their usage patterns accordingly to lower their energy costs. The premise is that customers will reduce usage during the expensive high peak periods.

6- Demand Bidding – Commercial/Industrial customers are given the opportunity to receive a credit for voluntarily reducing load when an event is called. The customer is not penalized if they are unable to meet their reduction target.

7- Aggregation Programs – DR aggregators are third party contractors who work with groups of customers to make combined loads available for reduction or interruption. The aggregator works with LADWP and the combined load is assigned to the appropriate DR program. Customers work directly with the aggregator. Terms, conditions and payment may vary per aggregator.

In designing the overall program, a number of parameters need to be established, such as the specific program elements to offer, and for each program element: customer eligibility, the type and size of incentives, contract duration, event duration, number of events, notification lead times, automation, billing requirements, etc.

This 2012 IRP recommends funding to initiate a formal DR program with the capacity targets as shown in Table 2-6:

Table 2-6. DEMAND RESPONSE TARGET SCHEDULE (NEW MW CAPACITY)

Yr.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Target	5	10	20	40	75	100	150	200	250	300	350	400	450	500

DR will play a significant long-term role in securing adequate system capacity, especially in the case of early coal replacement. Section 4 discusses the strategic cases in detail. As shown in the case analysis, DR is a strategic component of LADWP's future resource portfolio.

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.

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 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 2-5 shows LADWP's Power System capacity and energy breakdown as of December 31, 2011 as well as what the capacity and energy mix was at the end of 2006.[4] The largest change between these two periods is the decrease in coal-fired energy from 47 percent in 2006 to 41 percent in 2011, and the corresponding increase in energy from renewable resources, from 7 percent in 2006 to 19 percent in 2011.

[4] "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).

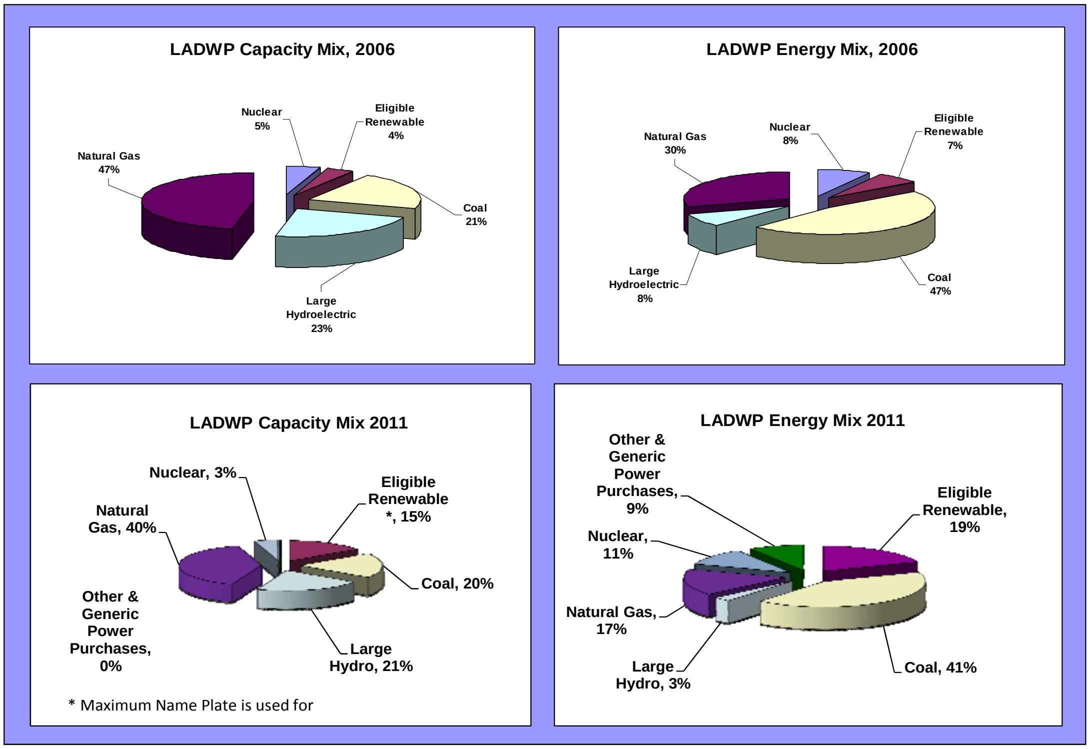


Figure 2-5: LADWP capacity and energy mix for 2006 and 2011.

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 APRIL 2012)

Name of Plant	Fuel Source	Unit No.	In Service Date	Age (Years)	Net Maximum Unit Capability (MW) [2]	Net Maximum Plant Capability (MW) [3]	Net Dependable Plant Capability (MW) [4]	Comments
Harbor Generating Station	Natural Gas	1	1995	17	82	466	452	Units 1, 2 and 5 operate as a combined cycle unit. Once-through cooling (OTC)
		2	1995	17	82			
		5	1995	17	65			
		10	2002	10	47.4			
		11	2002	10	47.4			
		12	2002	10	47.4			
		13	2002	10	47.4			
		14	2002	10	47.4			
Haynes Generating Station	Natural Gas	1	1962	50	222	1,555.6	1,525	Units 8, 9 and 10 operate as a combined cycle unit. Unit 7 is used for auxiliary power only. OTC
		2	1963	49	222			
		5	1966	45	292			
		6	1967	45	243			
		7	1970	42	1.6			
		8	2005	7	250			
		9	2005	7	162.5			
		10	2005	7	162.5			
Scattergood Generating Station	Natural Gas	1	1958	54	183	817	796	Includes 16 MW for Hyperion digester gas. OTC
		2	1959	53	184			
		3	1974	38	450			
Valley Generating Station	Natural Gas	5	2001	11	43	576	556	Units 6, 7 and 8 operate as a combined cycle unit.
		6	2003	9	159			
		7	2003	9	159			
		8	2003	9	215			
Total Net Capability of Natural Gas Stations						**3,415**	**3,329**	
Intermountain Generating Station	Coal	1	1986	26	900	1175	1175	Reduced by current recall
		2	1987	25	900			
Navajo Generating Station	Coal	1	1974	38	750	477	477	
		2	1974	38	750			
		3	1975	37	750			
Total Net Capability of Coal Stations						**1,652**	**1,652**	
Palo Verde Generating Station	Nuclear	1	1986	27	1,333	387	380	
		2	1986	27	1,336			
		3	1988	25	1,334			
Total Net Capability of Nuclear Stations						**387**	**380**	
Castaic Power Plant	Hydro	Various	1972-1978	34-40	1,635	1,247	1,175	Pumped Storage
Hoover Power Plant	Hydro	Various	1936	76	491	491	468	
Total Net Capability of "Large" Hydro Stations						**1,738**	**1,643**	
Aqueduct System	Hydro	Various	1917-1987	25-95	126.7	83.1	24.2	11 Units total
Owens Valley System	Hydro	Various	1908-1958	54-104	16	12.5	1.2	7 Units total
Owens Gorge System	Hydro	Various	1952-1953	59-60	112.5	112.5	109.5	3 Units total
Owned & Contracted Renewables	Renewable/ DG	Various	2002-2012	2-10	1,141	1,109	330	Note [5]
Total Net Capability of Small Hydro and Renewable / Distributed Generation						**1,317**	**465**	
Total Net Capability of LADWP Resources						**8,509**	**7,469**	
California State Capacity Entitlement						-120	-56	Note [6]
Total Net Capability of LADWP System						**8,389**	**7,413**	Note [7]

Notes:

1. Power source data are based on Power System Engineering Division's January 2012 Generation Ratings and Capabilities Sheet and power purchase agreements for contract sources.
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, sum of unit output at in-basin thermal or renewable plants, or LADWP contract entitlement of external thermal plants.
4. Reflects: year- round outputs adjusted for low-generation season. For hydro plants, winter is the low-generation season.
5. Owned or contracted renewable projects in wind, solar, hydro, landfill gas, biomass, and distributed generation in-service as of April 2012.
6. The maximum State (CDWR) Capacity Entitlement from Castaic Power Plant is 120 MW. The average for FY 09-10 was approximately 55 MW. The actual amount varies weekly.
7. Total Net Capability of LADWP System may vary due to unit outages, de-ratings and sales obligations.

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 2-6.

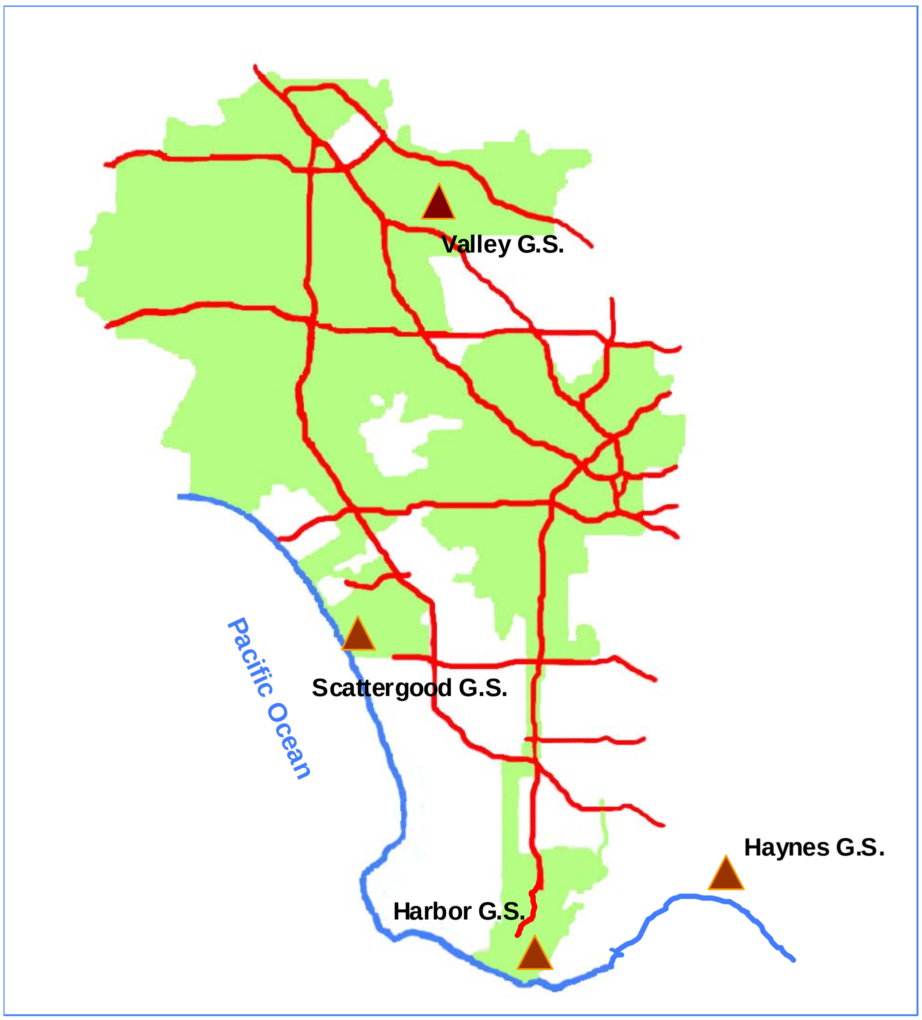


Figure 2-6. LADWP in-basin generating stations.

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 agreement enabling this arrangement will end by 2015, but will be extended to account for a potential physical plant reconfiguration at the Hyperion Plant Facility.

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. 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 ocean water 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 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 are considering plans to convert the facility to natural gas. LADWP is one of thirty-six purchasers of IPP energy, and any future plans must be agreed to by all parties involved. Proposed amendments to the existing contracts are being considered by the purchasers which would require IPP to switch fuel from coal to natural gas no later than July 1, 2025 (two-years before the legal deadline). These amendments require unanimous approval and final purchaser decisions are expected by the end of 2013. Although the results of these discussions will not be available for this 2012 IRP, it is hopeful that the plan will completed in time for inclusion into next year's IRP process

NGS operates under a co-tenancy agreement that remains effective throughout the initial term of its land lease until December 31, 2019. LADWP has been working with its partners on arrangements that would allow it to divest early from NGS, in 2015. 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 a facility which consists 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 1,200 MW of capacity, and consist of wind, small hydro, solar, biogas, and geothermal resources. More detailed information is presented in Section F.2.5 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 Point
    - Milford I
    - Milford II

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

- Solar
    - LADWP In-Basin
    - Customer Net Metered
    - Adelanto Solar Project

- Biogas/Biomass
    - Bradley
    - Lopez Canyon
    - Toyon
    - Atmos and Shell
    - Hyperion Digester Gas

Additional renewable energy comes from market purchases.

Figure 2-7 presents the profile for LADWP's renewable resources portfolio as of 2011.

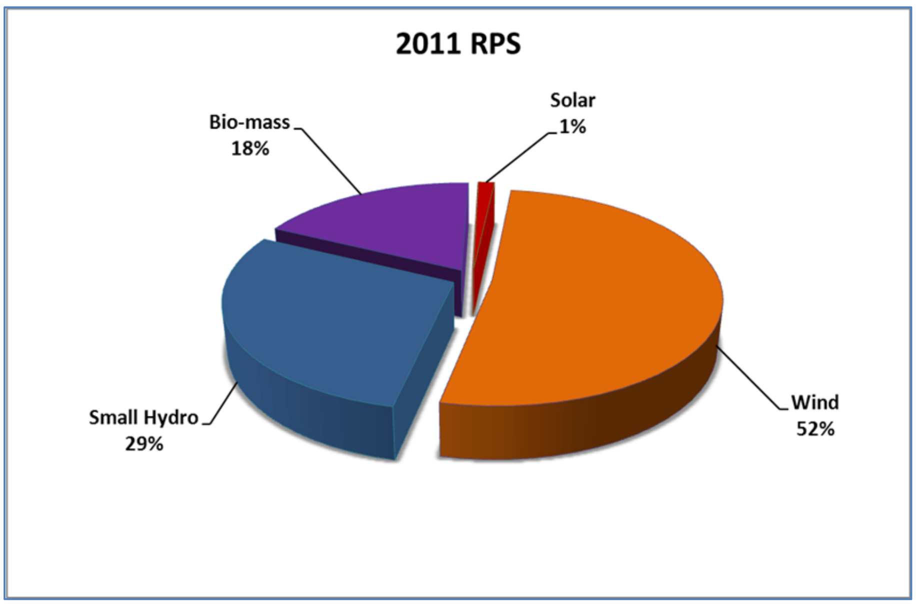


Figure 2-7: 2011 LADWP renewable energy mix.

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 a cost which is less than which LADWP can produce such energy. Periodically, capacity and energy is purchased from providers within the Western Electricity Coordinating Council (WECC) jurisdiction under short-term "spot" arrangements to be delivered to the

LADWP transmission system. These purchases are used by LADWP in conjunction with other resources for economical Power System operation.

The cost and availability of economical energy on the spot market has fluctuated greatly in recent years. While LADWP currently continues to execute economical spot purchase opportunities, it cannot guarantee the future availability of economic 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 within the WECC at prices above LADWP's production costs. This way, LADWP's ratepayers 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.

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 the Haynes and 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 Haynes and Scattergood Generating Stations are between 44 and 53 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, Haynes and 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 less 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 – that 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 with 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.

- NOX 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 the LADWP ratepayers.
- 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, a new power purchase contract is being drafted to construct a natural gas replacement facility located at the IPP site. The in-service date for the new facility will likely be sometime between the debt payment completion schedule at the end of 2023 and the end date for the existing power contracts in June 2027. For modeling purposes, until the contract is finalized a date of December 31, 2023 will be used as an assumed early conversion date (see Case 4 in Section 3.5).

As of this writing, the IPP participants are considering the conversion to natural gas. 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.
2. Amend the IPP Organization Agreement between the 23 Utah municipal members.
3. Adopt the Second Amendatory Power Sales Contract between all 36 power purchasers
4. Adopt Renewal Power Sales Contracts
5. Adopt Renewal Excess Power Sales Agreements

Assuming the timely completion of the new agreements, the new conversion date will be incorporated into the 2013 IRP model runs.

<u>Navajo Generating Station</u>

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 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, significant progress has been made to exit from the project by 2015. 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, relieving LADWP from having to purchase emission credits within the soon-to-be implemented statewide cap and trade program.
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 ratepayers.

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 with the required amount of renewable resources. The 2012 recommended Case 5 with 150 MW of FiT includes the following targets for new renewable acquisitions between 2011 and 2020[5]:

New Renewable Installed Capacity (MW) 2012-2020			
Geothermal & Biomass	Non-DG Solar	Distributed Solar	Generic
242	842	382	39

Furthermore, maintaining at least 33% of renewables beyond 2020 requires additional renewables to account for system loading, project turnover, and output degradation as projects age. The 2012 recommended Case 5 with 150 MW of FiT includes the following additional targets for new renewable acquisitions between 2021 and 2030[4]:

New Renewable Installed Capacity (MW) 2021-2030			
Geothermal & Biomass	Wind	Distributed Solar	Generic
41	54	114	75

[5] The DG/EE Cases 5-8 have alternative renewable mixes due to higher levels of Solar DG and EE.

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, 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. 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 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 and N.

2.4.4 Transmission and Distribution Facilities/Grid Reliability

Electricity from LADWP's power generation sources is delivered to customers over an extensive transmission and distribution 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 2-8. 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 ratepayers 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, while the nearby San Onofre Nuclear Generating Station remains offline without a set return-to-service date, the California Independent System Operator is attempting to secure the delivery of replacement energy from other potentially available generation sources.

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. Following is 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 2200 MW. As of May 2012, approximately 3085 MW from a combination of wind and solar 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 Haskell Canyon to the Castaic Power Plant
- Reconductor the existing 230-kV transmission line from the Barren Ridge Switching Station to the existing Rinaldi Receiving Station, through the 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 PDCI partners are considering increasing the capacity of the PDCI from 3100 MW to as much as 3650 MW. The benefit of such an undertaking would be a higher-capacity corridor for renewable wind and hydro energy from the Pacific Northwest to Los Angeles. LADWP, as the PDCI operator, is currently developing a cost estimate for the project that considers transmission and station upgrades and the increased dispatch and energy costs during construction to cover the reserve margin. Toward that end, preliminary estimates based on a Light Detection and Ranging study in 2011 indicate the transmission component of the project may cost up to $150 million and require as much as six years to construct. Less aggressive options with lower capacity benefits are also being investigated to facilitate an informed decision by the PDCI partners.

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 convert the 115-kV towers to a single circuit 230-kV transmission line from the new Haskell Canyon Switching Station to the existing Olive 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.

The Victorville-Los Angeles (Vic-LA) Project

The Vic-LA Project involves making infrastructural and operational improvements to the existing system between the Victorville area and the Los Angeles Basin in three phases which will allow LADWP to add 500-600 MWs of transfer capacity, subject to operational requirements. The Vic-LA Project can be defined in short, mid, and long term actions, as follows:

- Short-term actions
    - Upgrade the terminal equipment at Rinaldi and Toluca Receiving Stations and modify system protection of the line transformers.
    - Add a second Victorville 500/230-kV transformer (Bank K).
    - Upgrade Victorville-Century transmission system.
    - Upgrade the terminal equipment at the Century and Velasco Receiving Stations.
    - Trip non-firm resources to maintain the post-contingency flow within the existing Vic-LA system operating limit.

- Mid-term actions
  - Re-conductor the Victorville-Century 287-kV transmission lines to increase the rating.
  - Upgrade Banks F & G at Century Receiving Station to increase emergency rating.

- Long-term actions
  - Convert the Victorville-Century 287-kV transmission lines to DC, which is described below.

Conversion of the Victorville-Century 287-kV Circuit

Conversion of the Victorville-Century 287-kV AC lines is a potential future project that would increase the transfer capacity by converting the lines from AC to DC. The existing Victorville-Century circuit spans about 84 miles between Victorville and South LA. Converting the lines to DC would require a change-out of insulators along the line, and the installation of AC to DC converter equipment at each end. The transmission towers themselves will not require any modification. Preliminary studies indicate a potential 4-fold increase in power transfer capacity as a result of this project.

Regional transmission plans have shown that in order for LADWP and its Western counterparts to meet their renewable energy goals at minimal cost, additional transmission improvements will be needed. While the projects listed in this subsection have a high priority and a high likelihood of construction, they may not be sufficient to meet future needs. LADWP will continue to evaluate transmission needs and opportunities as necessary.

Grid Reliability

LADWP annually performs a Ten-Year Transmission Assessment Plan, in compliance with the North American Electricity Reliability Corporation (NERC) Compliance Enforcement Program. LADWP's 2012 plan identified a number of transmission improvements that are needed to maintain reliability. These projects include:

- Installation of a new Scattergood-Olympic 230-kV Line 1.
- Upgrade circuit breakers and disconnects at RS-U.
- Install a variable 90-MVAR shunt reactor bank at Scattergood 230 kV and a variable 90-MVAR shunt reactor bank at RS-K 230 kV.
- Relocate the 230/115 kV Banks from Olive Switching Station (SS) to Haskell Canyon SS.
- Convert the existing twin 115 kV circuits between Haskell Canyon SS and Olive SS with a new double 230 kV circuit along existing right-of-way.

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

FERC Order 1000 - The California Transmission Planning Group

With the release of Federal Energy Regulatory Commission (FERC) Order 1000 in July 2011, to direct regional and interregional transmission planning and cost allocation, FERC-jurisdictional (investor-owned) electric utilities are now required to reorganize transmission planning functions to collectively achieve state and federal public policy goals. Order 1000 builds upon the directives of FERC Order 890, issued in February 2007, to open regional and local planning to stakeholders to ensure transparency and non-discriminatory access to transmission service.

LADWP has a longstanding history of working with its Western Electricity Coordinating Council counterparts on regional transmission planning to ensure bulk power reliability and to leverage economies of scale; regional transmission plans are reviewed and approved through a formal process. Since the California Transmission Planning Group (CTPG) was formed in 2009, LADWP has been active in that transmission planning forum. CTPG was formed to comply with Order 890 by providing the increased coordination and public participation mandated while ensuring the electric needs and goals of Californians are reliably and efficiently met. In February 2011, the 2010 California Transmission Plan (California Plan) was released http://www.ctpg.us/images/stories/ctpg-plan-development/2011/02-Feb/2011-02-09_final_statewide_transmission_plan.pdf.

The CTPG was not able to reorganize quickly enough to meet Order 1000's deadline for FERC-jurisdictional entities to join a specific type of regional planning group and to file a regional planning methodology with FERC. In order to meet this timeline, CTPG members resorted to membership in additional regional organizations. CTPG members inside the CAISO footprint joined the CAISO Region, while other CTPG utilities joined the WestConnect Region. LADWP joined the WestConnect Region in November 2012. Other CTPG members in the WestConnect Region include the Sacramento Municipal Utility District, the Imperial Irrigation District, and the Western Area Power Administration.

Because of the large geographical extent of the LADWP transmission system, LADWP's planning takes place in various forums for sub-regional, regional, and inter-regional issues. Membership in WestConnect will allow LADWP to engage with the changes to regional planning caused by Order 1000. At the same As CTPG member utilities evaluate their options, they continue to press forward with their current transmission assessment to ensure California's electric power policy goals are reached efficiently and without undue hardship to the consumer or to the electric grid. California's electric power policy goals include:

- Attainment of renewable portfolio standard goals as promulgated by SB 2 (1X), which was passed in April 2011 and became effective December 10, 2011
- Satisfaction of repowering/retirement deadlines of fossil-fueled Once-Through Cooling power plant units as negotiated with the State Water Resources Board to comply with Federal Clean Water Act §326(b)

As a municipal utility, LADWP is outside FERC jurisdiction, so, in a technical sense, Order 1000 is not a mandate. Consistent with its response to other FERC Orders, however, LADWP is seeking to conform to this order, with the same consideration as it would to an industry standard.

LADWP's extensive network of transmission resources is described in Appendix I; Figure 2-8 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.

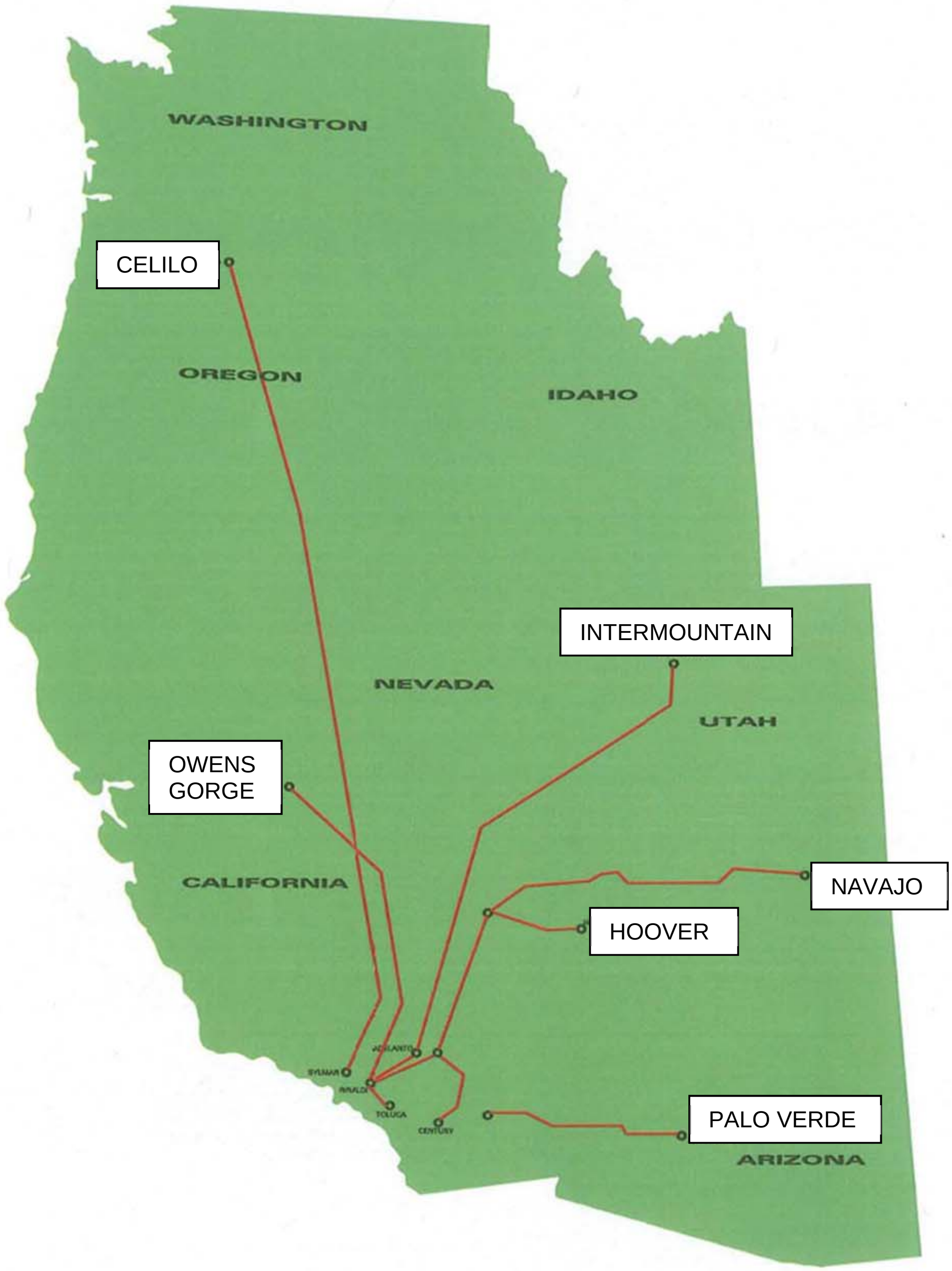


Figure 2-8: Major out-of-basin generating stations and major transmission lines.

2.4.5 Advanced Technologies and Research and Development

LADWP is looking ahead to technologies that will benefit operations and enhance reliability, including smart grid applications and energy storage systems. Many programs, such as demand response and electric vehicles, will rely on deployment of Advance Metering Infrastructure to support their functionality and effectiveness. The implementation of Smart Grid technologies will provide enhanced information systems, automation of system functions, and advanced methods of outage management. Although energy storage technologies (except for Pumped Water Storage) are still being developed and are not currently cost effective for large scale applications, their potential for altering how electricity is generated and consumed is high.

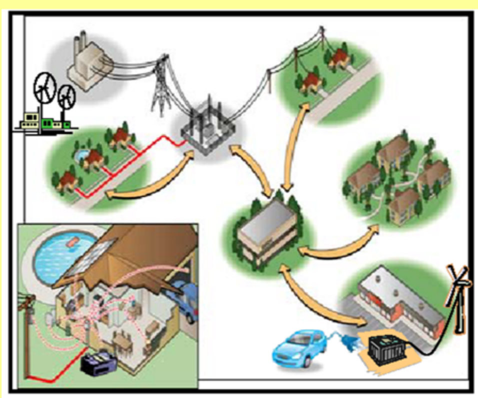
2.4.5.1 Smart Grid

"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, and is a major enabler for many existing and potentially new DSR/EE programs.

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 utilities 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 consumer to make decisions to optimize the use of energy, improve reliability, and reduce the consumption of fossil fuels.

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*



LADWP is implementing nine major Smart Grid initiatives:

1. Renewable Integration to support the adoption and utilization of renewable resources.
2. Transmission Automation to better monitor the transmission system to predict instability and take corrective actions before they escalate into major problems.
3. Substation Automation to enable remote monitoring and control of substation feeder lines.
4. Distribution Automation to optimize operational efficiency.
5. Advanced Metering Infrastructure which will enable a number of demand-side capabilities.
6. Demand Response is a tool that will provide reduction of peak loads at critical times to relieve system stress during periods of overload.
7. Advance Telecommunications will enable real-time control and observation of deployed automation equipment.
8. System and Data Integration will optimize the communications and integration of separate systems and sub-networks.
9. Cyber Security to protect the Smart Grid from physical and cyber attacks.

Demonstration Program

In addition to the Smart Grid initiatives, LADWP, through a US Department of Energy grant awarded in 2009 is leading a group of local research institutions in a regional demonstration program. The program includes pilot projects in four interrelated areas – Demand Response, Consumer Behavior, Cyber Security and Electric Vehicle Integration.

More information on this 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, including LADWP, to identify and procure viable and cost-effective Energy Storage (ES) Systems. The targets must be formally approved by the Board of Water and Power Commissioners by October 1, 2014, and be implemented in two phases – by the end of 2016 and the end of 2021. Accordingly, LADWP has initiated a process to develop an ES plan which will include the appropriate ES targets per AB 2514.

Although LADWP does not currently have a formal ES plan, it has been practicing energy storage since 1973 through its daily operation of the Castaic Pump Storage Power Plant. In developing its formal Energy Storage Plan (ES Plan), LADWP's investigation will include options to leverage and/or augment the ES capabilities of the Castaic facility.

Some of the key considerations for the ES Plan are as follows:

- LADWP will look for ES programs and projects that will support its unique electric grid, resource plan, and projects that will facilitate renewable integration, distributed generation and demand-side management; and programs that address resource adequacy and reliability issues.

- A review of the current state of ES technologies will be required, including current cost projections.

- Per AB 2514, the ES systems shall be cost-effective.

To support its ES planning efforts, LADWP will consider the following two initiatives as a means to provide valuable technical information:

1. LADWP is participating in a working group with the US 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 LADWP to evaluate the performance of ES and to make more informed decisions as potential applications are consider for implementation.

2. DWP is planning to incorporate into its ES Plan the results from three ES research projects conducted by the Electric Power Research Institute:

    a. Strategic Intelligence and Technology Assessments of Energy Storage and Distributed Generation, Project 94.001 – 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 – 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- This project provides information and guidelines for using bulk ES to shift off-peak energy and integration of variable renewable generation.

A status update of the ES Plan will be provided in next year's 2013 IRP document. Per AB 2514, the ES targets are to be approved no later than October 1, 2014.

For more information, see Appendix K.

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.

Energy Consumption

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 2012 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

[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

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 Reliability Program is fully funded to optimize the resiliency of its infrastructure to better withstand the more volatile weather patterns that will be expected.

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.

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 and 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 Contingency Reserve as well as the Replacement Reserve requirements. Based on current NERC Standards, at least 50 percent of the Contingency Reserves must be Spinning Reserve. The Replacement Reserve requirement is to restore Operating 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. Given LADWP's current total generation portfolio, the system reserve requirement is approximately 1,100 MW. Therefore, if the system demand is 5,000 MW, LADWP must have a total of 6,100 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.

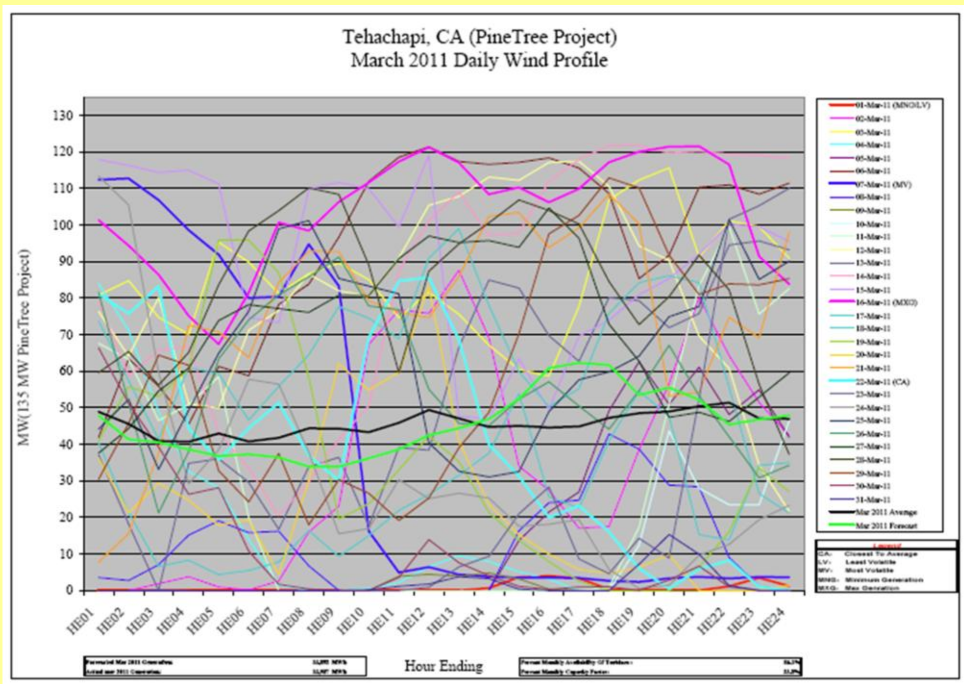
This local requirement is particularly important in the context of deciding how to schedule the repowering of units that use once through cooling. It is for this reason that no unit will be taken out of service before an equivalently-sized, locationally-equivalent replacement unit is constructed, tested 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. These PV systems can experience variations in output of ± 50 percent in 30 to 90 seconds, and ± 70 percent in five to 10 minutes. 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 size of a single PV facility.

See Appendix J for more details regarding integrating intermittent resources.

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3.0 STRATEGIC CASE DEVELOPMENT

3.1 Overview

IRP planning is an on-going process and as such, the development of the 2012 IRP strategic cases incorporates the latest changes that have occurred in the regulatory landscape and tactical plans developed by the Power System. This 2012 IRP also includes many updated 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 2012 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, 2 and 3 are similar to the cases analyzed in last year's 2011 IRP. The replacement date of December 2023 for IPP (Case 4) is new for this year.

In addition to the coal cases, this 2012 IRP also analyzes four additional cases to consider higher levels of energy efficiency and solar distributed generation.

The 2012-13 fiscal-year financial planning process included many of the assumptions and recommendations that were used in the 2012 IRP. This is a continual process that requires the budget and the IRP model to be guided by the same assumption set although 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.

Primary regulations and state laws affecting the Power System, including AB 32, SB 1368, SB 1, SB 2 (1X), SB 32, and US EPA 316(b), have become more certain over the last 2 years although many details are still being finalized mainly involving existing renewable projects and their applicability towards meeting in-state or out-of-state qualifications. This 2012 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 for this IRP. 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 2012 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 this 2012 IRP.

3.2.1 Major Changes From the 2011 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 new load forecast is lower than the previous forecast used in the 2011 IRP. Compared to the prior forecast, electricity sales in the calendar year 2020 decreased by 5.3 percent mostly due to increased levels of energy efficiency. The new forecast reduces the overall need for renewable energy (assuming 33% RPS) by approximately 461 GWh in 2020 and 745 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 – 2012 IRP	22,958	24,424
Old Forecast – 2011 IRP	24,239	26,665
Difference	-1,281	-2,241

Energy Efficiency

The Energy Efficiency (EE) forecast used in the 2012 IRP includes higher levels of funding for the 2012/13 thru 2019/20 fiscal years to achieve 10 percent EE from 2010 thru 2020. This represents 1,084 GWh of additional EE savings by 2020 as compared to the 2011 IRP. Higher funding levels required to achieve this target were approved through the recent rate action for the 2012/13 and 2013/14 fiscal years. As a comparison, the 2011 IRP forecasted a 6 percent EE achievement during the same period 2010 thru 2020.

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 June 30, 2013. The potential study will 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. Inclusion of the 12.5 percent, and 15 percent energy efficiency savings by 2020 will be considered for inclusion in future IRP's.

The cumulative EE savings incorporated in the 2012 IRP will reach 2,705 GWh (Net 2,300 GWh) from 2010 thru 2020 and 4,117 GWh (Net 3,500 GWh) from 2010 thru 2032. Using The Total Sales to Ultimate Customers for 2010/11 fiscal year as the baseline and using net EE savings, the 2012 IRP forecasts a 10 percent energy efficiency savings by 2020 and 15 percent energy efficiency savings by 2032. Historical efficiency savings of 1,256 GWh from 2000 to 2010, equivalent to 5.5 percent of customer sales, are already embedded in the load forecast. Figure 3-1 below shows the projected cumulative gross savings from 2001 through 2032.

Federal and State efficiency standards create fewer opportunities to give financial incentives to customers to install products that exceed the higher efficiency standards. This reduces the effectiveness of incentives to realize incremental energy savings targets. To combat this natural decline, additional programs requiring direct installation of energy efficiency measures at customer sites will be required to implement these higher savings. Although savings from Federal and State efficiency standards cannot be counted in the achievements made by the utility, these savings are nevertheless accounted for in the sales load forecast and do contribute to reducing overall sales and load growth.

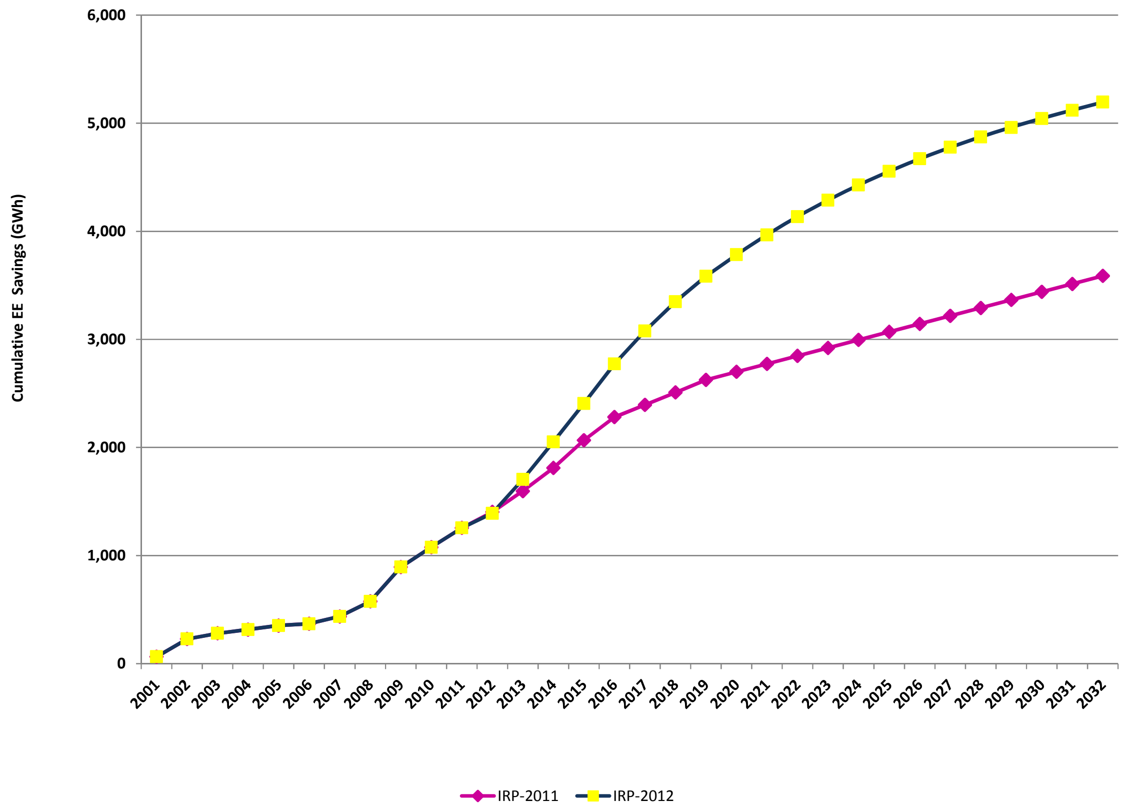

Figure 3-1. Comparison of 2011 and 2012 IRP gross energy efficiency forecasts by fiscal year.

Solar C-N-M and FiT

The solar Customer-Net-Metered (CNM) program (a.k.a. Solar Incentive Program) and Feed-In-Tariff (FiT) programs used in the 2012 IRP are shown in Figure 3-2. CNM solar starts out lower than last year's forecast, but quickly catches up and surpasses it, reflecting the recent program delay followed by a re-commitment of funding. Continued strong interest in the program is expected. FiT is lower in 2012-2014 due to a delay in implementation of the program due to budget constraints, but quickly reaches 150 MW or 210 GWh by 2016, reflecting the plan to accelerate the program to take advantage of tax benefits available through 2016.

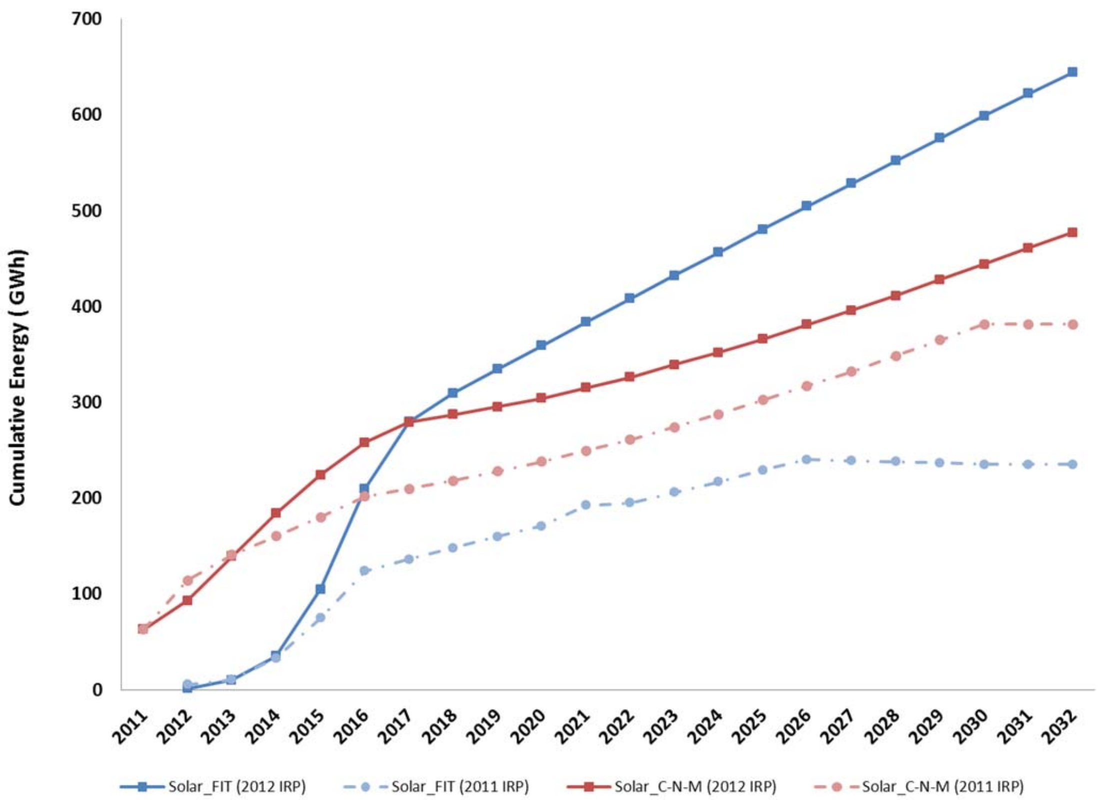

Figure 3-2. Comparison of FiT and CNM (SIP) solar projections, 2012 vs. 2011.

Renewables

Table 3-2 is a comparison of the overall renewable additions planned for the 2012 IRP vs. the 2011 IRP:

Table 3-2. RENEWABLE ADDITIONS, 2011 VS. 2012

		2020	New Renewable Installed Capacity (MW) 2012 – 2020					New Renewable Installed Capacity (MW) 2012 – 2032				
Case ID	Resource Strategy	RPS Target	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biogas	Wind	Non-DG Solar	Dist. Solar	Generic
All Cases in 2011 IRP	33% RPS SB 2 (1X) Compliant	33%	243	492	401	325	0	308	492	451	466	162
Base Case in 2012 IRP	33% RPS SB 2 (1X) Compliant	33%	242	0	887	337	39	283	54	915	496	114

Compared to last year's IRP, solar now holds a more prominent position in the overall portfolio mainly replacing future planned wind projects as prices for solar PPAs have dropped significantly over the last year while the availability of competitively priced in-state wind projects has decreased. Solar is also well suited to utilize the Navajo and

Barren Ridge transmission line capacity that will become available in 2016. Increased use of solar will further diversify the renewable resource mix which already contains a strong wind focus.

GHG Costs

Projected GHG cost assumptions resulting from the California Air Resources Board's Cap and Trade Regulation have been lowered. The forecast assumes GHG pricing will start at $15 per metric ton in 2013 and escalate to $36 per metric ton in 2020 with a $3 per metric ton increase for every year in between. In the 2011 IRP, GHG pricing started at $24 per metric ton in 2013 and escalated to $45 per metric ton in 2020.

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 2012 IRP were 16 percent lower on average, in the short term (2011-2020), and were 8 and 9 percent lower on average, respectively, in the long term (2021-2030) as compared to the 2011 IRP. The Pinedale gas reserves owned by LADWP continue to provide a low cost source of gas and hedge against future gas volatility and estimates of gas volumes to be produced from Pinedale have not been revised since the 2011 IRP.

Coal Prices

IPP forecasted coal prices are 4 percent lower for the period 2012 thru 2027 as compared to the 2011 IRP. Navajo coal prices are 14 percent lower for the period 2012-2019 as compared to the 2011 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 put to LADWP by Utah participants has risen from 222 MW assumed in the 2011 IRP to 318 MW in the 2012 IRP thereby increasing our share of the IPP capacity entitlement. This raised the energy and capacity expected from IPP generation in the 2012 IRP. This trend is believed to be occurring because of the lower gas prices relative to coal.

3.2.2 General Price Inputs

General price assumptions are presented here for supply side resources, fuel, and GHG allowances. 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. Generally lower prices for solar and geothermal have been incorporated into the 2012 IRP modeling as price competition has lowered 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

Resource	Levelized Cost[1] ($/MWh)	Capacity Factors	Dependable Capacity
Solar Photovoltaic – PPA	$116	25% - 32%	27%
Solar Photovoltaic - LA Solar – Public/Private Partnership In-Basin	$154	20-23%	27%
Solar Photovoltaic – LA Solar – Public/Private Partnership Owens	$153	25%	27%
Solar Customer-Net-Metered	$130	18%	27%
Solar Feed-In-Tariff	$152	19%	27%
Wind	$105	24% - 37%	10%
Geothermal	$109	91%-95%	90%
New Combined Cycle Gas (310 MW)	$80	59%	100%
New Simple Cycle Gas (50/100 MW)	$225	9%	100%

[1]Net Present Value (annual costs, 2012-2032) / 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 3-3, are fundamental forecasts obtained from Wood Mackenzie that consider a range of future assumptions including economic growth, supply and demand, and environmental regulations.

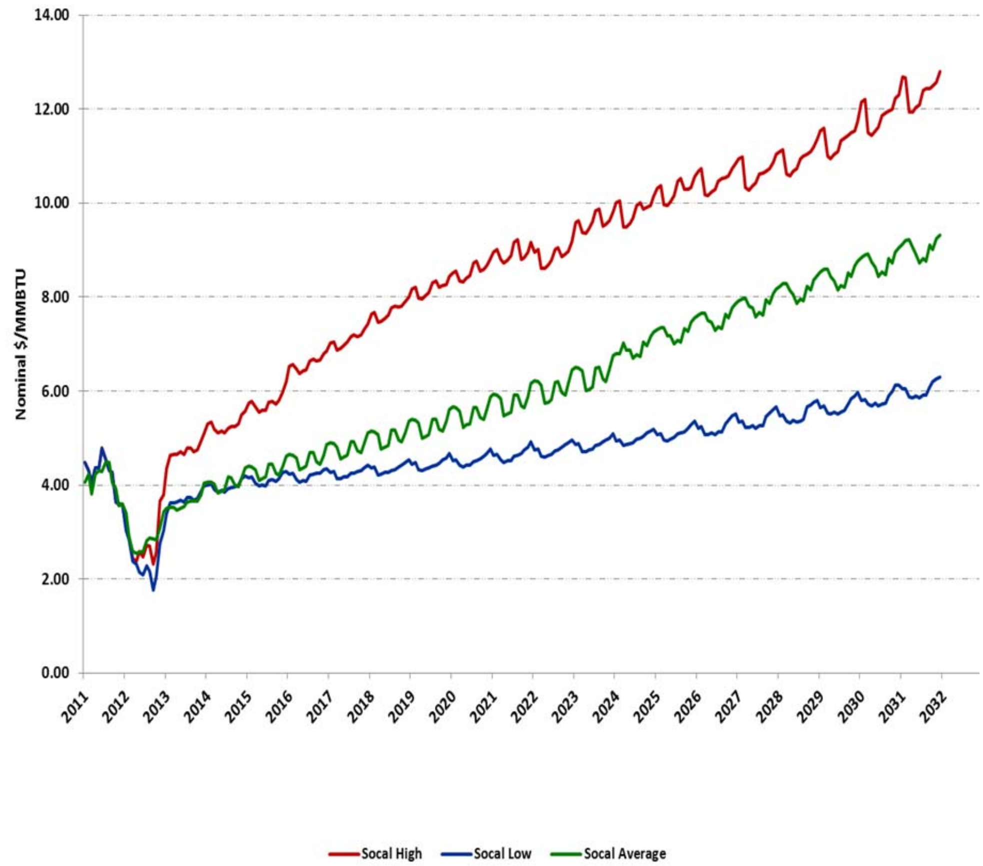

Figure 3-3. Natural gas price forecast (SoCal).

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

Coal Prices

A ±20 percent 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

Price scenarios were also developed and tested for GHG allowance prices using staff estimates and price forecasts available from recent brokerage transactions. The forecast assumes GHG pricing will start at $15 per metric ton in 2013 and escalate to $36 per metric ton in 2020 with a $3 per metric ton increase for every year in between. Forecasts of further GHG costs beyond 2020 and sensitivity around GHG allowance prices were not considered for the 2012 IRP. Considering the allocation administratively provided to LADWP and the planned divestiture of Navajo and implementation of further renewables reducing our overall GHG emissions, the overall cost impact of the CARB Cap and Trade Regulations is expected to be relatively neutral when considering the entire 8 year program (it should be noted that the initial years of the Cap and Trade program may require the purchase of allowances).

The likelihood of a future Federal Carbon Tax or a continuation of the CARB Cap and Trade regulations beyond 2020 are speculative at this time and will be addressed in future IRP's as necessary.

Figure 3-4 depicts the GHG allowance prices used to evaluate the portfolios.

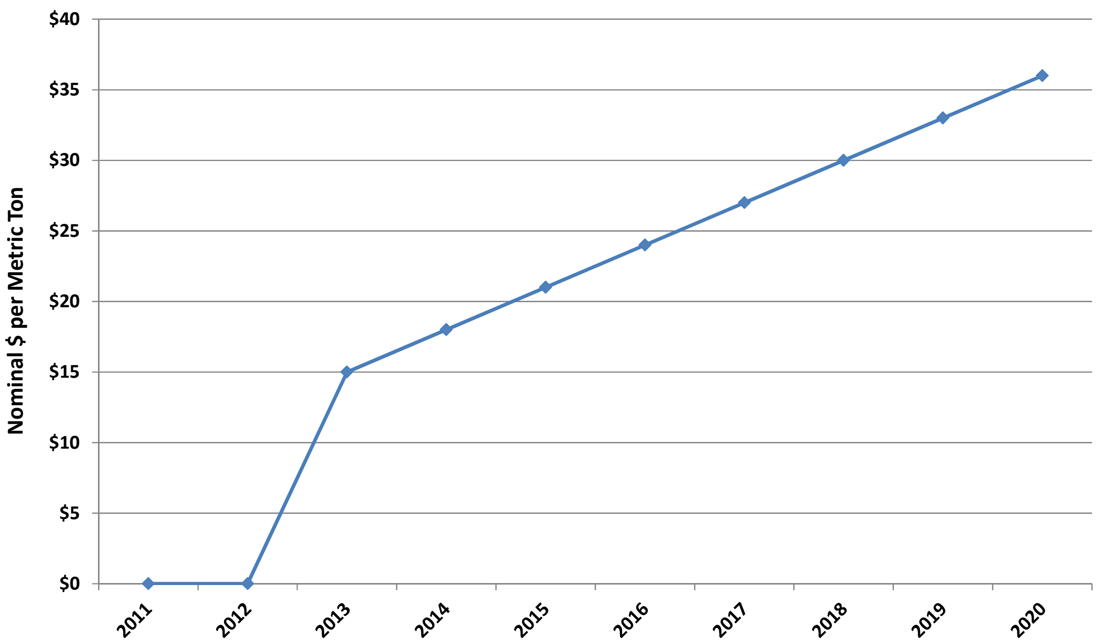

Figure 3-4. Assumed GHG emissions allowance prices.

3.3 Addressing Legislative and Regulatory Mandates

The 2012 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 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, four coal replacement cases have been considered in this 2012 IRP to define the costs and operational impacts that 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 prior to 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 Figure 3-5 below:

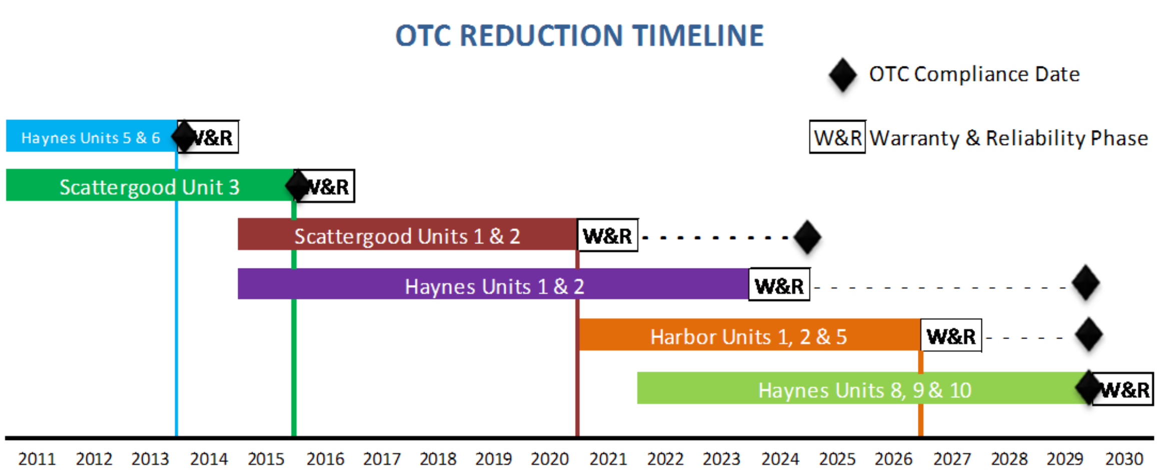

Figure 3-5. Timeline for OTC repowering projects.

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 on the amount of out-of-state renewable generation and renewable energy credits that can be used to meet renewable portfolio standards. Wind, small hydro, and biogas provide the largest contributions to LADWP's current portfolio as shown in Figure 2-7. Future renewable generation will rely heavily on solar PV and wind resources 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 2011 IRP established a diversified resource mix for the next 20 years including goals for estimated MW's installed for each renewable technology. The 2012 IRP retains the same diversified renewable mix goals set forth in the 2011 IRP recommended case while including a more solar-focused portfolio.

As shown in Table 3-2, all Coal Replacement cases being considered in the 2012 IRP use the base renewable resource plan. However, the energy efficiency and distributed generation cases described in Table 3-4 include different potential renewable portfolios for the High DG and Advanced EE options to account for the effects these demand resources have on reducing customer sales. Future IRP's will likely address different renewable resource mixes as the CEC further develops specific qualifying criteria for meeting in-state and out-of-state category requirements.

The 2012 IRP Strategic Cases were developed to assist policymakers and ratepayers 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.

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

Before developing candidate portfolios, LADWP met with and gathered input from key major customer and business representatives, as well as key environmental organization representatives. Comments received from these early discussions 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.

3.4.2 Net Short and Resource Adequacy

The first step in developing the 2012 IRP candidate portfolios was to determine how LADWP can meet and maintain its renewable energy policy goals: 20 percent renewables in 2010 and 33 percent renewables by 2020. 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 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 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
- 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 1.6.5)

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.

In this 2012 IRP, the overall renewable portfolio levelized cost is $98/MWh, which represents an $11/MWh decrease from last year. This cost reduction was achieved by selecting a more optimized and diverse portfolio that increases the contribution from cost-effective large central solar projects and biogas resources. Although LADWP continues to evaluate and develop wind and geothermal resources, they tend to be very site specific and typically lie a greater distance from existing transmission, or require transmission that must be purchased from other utilities. Another factor considered were solar tax credits which extend beyond those for wind and geothermal. Biogas uses the existing gas delivery infrastructure and existing combined cycle generating units making this a very cost effective and fully dependable resource. By maintaining flexibility in the selection of cost-effective renewable resources, LADWP is able to secure the best pricing for its ratepayers, as market conditions evolve.

3.4.4 Distributed Generation Levels

This year's IRP considers higher levels of Distributed Generation (DG), partly in response to the Governor's State-wide initiative for 12,000 MW of local renewable DG. Due to reliability and operational concerns, the maximum amount of DG 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 impacts intermittent resources will have on its distribution grid. Potential impacts include cost increases for infrastructure enhancements, the need for curtailment during

[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

high generation/low load periods, and new procedures 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 DG levels

3.5 2011 IRP Strategic Cases

The 2012 IRP analyses a focused set of strategic cases, expanding on the results from the 2011 IRP. A streamlined set of 4 coal replacement cases and 4 energy efficiency and solar distributed generation cases were evaluated for the 2012 IRP. Unlike other areas that are constrained by mandated regulatory requirements (such as renewable resources), the decision to divest from coal earlier than legally required, and accelerate energy efficiency programs or solar distributed generation programs is discretionary and thus appropriate for analysis. The 2012 IRP strategic cases are designed to assist policymakers and ratepayers to make informed decisions regarding these major initiatives particularly with regard to the environmental benefits and resulting resource and financial impacts.

Tables 3-4 and 3-5 provided a detailed description of each of the strategic cases.

It should be noted that the same renewable resource plan applies to Cases 1 thru 5. Cases 6 thru 8 include different renewable resource plans to adjust for increasing amounts of solar distributed generation and reductions in forecasted sales resulting from additional energy efficiency and CNM solar distributed generation. Table 3-5 summarizes each renewable portfolio. For comparison purposes, the recommended case from the 2011 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, 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 included measurements of power costs, emissions, and fuel usage. High and low scenarios based on fuel prices were also modeled for the coal replacement cases to quantify the risk associated with fuel price volatility. Section 4 discusses the modeling results to facilitate a dialogue with our stakeholders and ratepayers with a goal of selecting the recommended case for the 2012 IRP.

Section 5 discusses in greater detail Case 5 with early Navajo divestiture which is a variation of the recommended case from the 2011 IRP with updates including 10% energy efficiency, enhanced solar focus including increased local distributed solar, and other updated assumptions. This discussion primarily involves the impact on Power System revenue requirements, rates, and customer bills.

Table 3-4. DESCRIPTION OF STRATEGIC CASES

Case ID	Description
Case 1 (Coal Base Case)	No Early Coal Replacement – This case assumes coal resources will be replaced with combined cycle natural gas and renewable resources upon the expiration of coal contracts with no early compliance with SB 1368. Maintains the 33 percent standard renewables mix recommended to comply with SB 2 (1X) and the 10 percent energy efficiency savings by 2020 to comply with AB 2021.
Case 2	Navajo Early Divestiture Strategy – This case considers early divestment of Navajo on 12/31/2015, or 4 years prior to contract expiration, with IPP replacement at the end of contract expiration in 2027. Maintains the recommended 33 percent standard renewables mix to comply with SB 2 (1X) and the 10 percent energy efficiency savings by 2020 to comply with AB 2021.
Case 3	Navajo and IPP Early Replacement Strategy – This case considers early divestment of Navajo on 12/31/2015, 4 years prior to contract expiration, and early replacement of IPP on 12/31/2020 or 7 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix to comply with SB 2 (1X) and the 10 percent energy efficiency savings by 2020 to comply with AB 2021.
Case 4	Navajo and IPP Early Replacement Strategy (Alternate) – This case considers early divestment of Navajo on 12/31/2015, 4 years prior to contract expiration, and early replacement of IPP on 12/31/2023 when the IPP debt burden is fully paid 3.5 years prior to contract expiration. Maintains the recommended 33 percent standard renewables mix to comply with SB 2 (1X) and the 10 percent energy efficiency savings by 2020 to comply with AB 2021.
Case 5 (EE and DG Base Case)	Base Energy Efficiency and Base Solar Distributed Generation - Indentical to Case 2 and used as a baseline comparison to Cases 6 thru 8.
Case 6	Advanced Energy Efficiency and Base Solar Distributed Generation - Considers early divestment of Navajo with 10 percent energy efficiency savings by 2020 and an additional 500 GWh of energy efficiency savings between 2020 thru 2032.

Case 7	Base Energy Efficiency and High Solar Distributed Generation - Considers early divestment of Navajo with 10 percent energy efficiency savings by 2020. Increases solar distributed generation thru the FiT program from 75 MW to 150 MW by 2016 and 150 to 305 MW by 2026 and increases CNM (SIP) solar from 145 to 183 MW by 2020 and 252 to 363 MW by 2032.
Case 8	Advanced Energy Efficiency and High Solar Distributed Generation - Considers early divestment of Navajo with 10 percent energy efficiency savings by 2020 and an additional 500 GWh of energy efficiency savings between 2020 thru 2032. Increases solar distributed generation thru the FiT program from 75 MW to 150 MW by 2016 and 150 to 305 MW by 2026 and increases CNM (SIP) solar from 145 to 183 MW by 2020 and 252 to 363 MW by 2032.

Table 3-5. CANDIDATE RESOURCE PORTFOLIOS FOR 2012 IRP

COAL CASES

		GHG or SB1368 Compliance Date		2020	2010 thru 2020	2010 thru 2032	New Renewables Installed Capacity (MW) 2012 - 2020					New Renewables Installed Capacity (MW) 2012-2032				
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	12/1/2019	6/15/2027	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
2	Navajo Early Replacement	12/31/2015	6/15/2027	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
3	Navajo and IPP Early	12/31/2015	12/31/2020	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
4	Navajo and IPP Early (Alt.)	12/31/2015	12/31/2023	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
2011 Recommended	Navajo Early Replacement	12/31/2015	6/15/2027	33%	1443	2183	243	492	401	325	0	308	492	451	466	162

ENERGY EFFICIENCY AND DISTRIBUTED GENERATION CASES

		2020	2010 thru 2020	2010 thru 2032	New Renewables Installed Capacity (MW) 2012 - 2020					New Renewables Installed Capacity (MW) 2012-2032				
Case ID	Resource Strategy[1]	RPS Target	EE (Net GWh)	EE (Net GWh)	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic	Geo / Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
5 (Base Case)	Base EE , Base Solar DG	33%	2300	3500	242	0	887	337	39	283	54	915	496	114
6	Advanced EE, Base Solar DG	33%	2300	4000	242	0	887	337	39	283	0	915	496	114
7	Base EE, High Solar DG	33%	2300	3500	242	0	847	485	39	258	0	876	852	95
8	Advanced EE, High Solar DG	33%	2300	4000	242	0	847	485	39	258	0	876	852	0

[1]EE percentages are as follows:

	By 2020	By 2032
Base EE	10%	15.2%
Advanced EE	10%	17.4%

The feasibility of attaining EE levels greater than 10% are uncertain at this time, but will be addressed in the upcoming EE Potential Study to be completed in 2013.

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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 8 cases being considered for study. This Section 4 presents the analysis of the 8 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 10 percent energy efficiency, reliable integration of renewables, etc.

The 2012 IRP continues to evaluate the coal replacement strategies considered in the 2010 and 2011 IRPs with updated cost and assumptions information. Additionally, a new case (Case 4) was also developed with the goal of divesting of Navajo on December 31, 2015 and replacing IPP by the end of 2023. The date of 2023 was selected because this is the earliest practical transition point considering that the capital bonds to build IPP will be paid in full at the end of 2023. Any earlier divestiture would significantly increase ratepayer costs by expending debt payments on a facility that was not providing energy. Every year, LADWP purchases a percentage (~60%) of IPP generation from its owner, Intermountain Power Agency (IPA). LADWP's obligations to make payments with respect to IPP are unconditional "take-or-pay" obligations, obligating LADWP to make such payments as operating expenses of the Power System whether or not the applicable project is operating or operable, or the output thereof is suspended, interfered with, reduced, curtailed, or terminated in whole or in part. Since LADWP is just one of 36 utilities purchasing energy from IPA, any agreement to replace IPP will need the cooperation of all power purchasers involved. This new Case 4 also targeted an early IPP replacement date of 2023 so LADWP can avoid the financial burden of paying for both the replacement CC units and the IPP associated cost from 2024 to 2027. The actual replacement date may vary based on the final agreement with the other power purchasers. However, for evaluation purposes, this is a reasonable transition point to consider.

As a new addition for the 2012 IRP, four new scenarios (Cases 5 – 8) have been developed, focusing on alternative energy efficiency (EE) and solar distributed generation (DG) strategies over the next 20 years. These four new EE/DG scenarios include the same coal replacement timeline with Navajo divested in 2015 and IPP replaced in 2027. The detailed discussion on the scenarios and the analyzed results can be found in Sections 3 and 4.3.

All 8 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. All of the strategic cases meet electric system reliability requirements per WECC and NERC standards.

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 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 distributed solar generation and energy efficiency.

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 2012 IRP were introduced in Section 3.5 and are briefly discussed here. The timing of coal replacement and the variations in energy efficiency and distributed generation quantities and the resultant changes in resource mix are the key parameters that differentiate the 8 cases evaluated. Table 3-5 summarizes the portfolios for each case.

The following inter-related resource parameters were assumed to occur in the 8 coal and EE/DG potential resource strategies:

- OTC Repowering Schedule per Figure 1-15
- Net Energy efficiency penetration of approximately 3500 GWh by FY 2032 for base EE and 4000 GWh by FY 2032 for advanced EE
- RPS Resource Mix, schedule per Table 3-5
- GHG allowance allocations and prices shown in Appendix N
- Gas and Coal Fuel prices, as discussed in Section 3.2.2.
- IPP capacity and recall schedule shown in Appendix N

Coal strategic cases were also subjected to high and low scenario runs, which were based on high and low values for natural gas and coal prices. High and low fuel scenario runs were not performed for the EE/DG cases evaluated. 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 and other demand side management programs), 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 for RPS percentage (see Section 1.6.5 for details) which includes meeting the RPS portfolio content categories as shown in Table 1-1. Other considerations included costs, resource and geographical diversity, 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	27%
Solar Thermal	68%
Geothermal	90%

The specific RA analyses for each of the four 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 totally avoid the chance of a power outage due to inadequate supply resources. Such a strategy would be very expensive and would mean that some resources would be built with a small chance 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 chance that load will not be served.

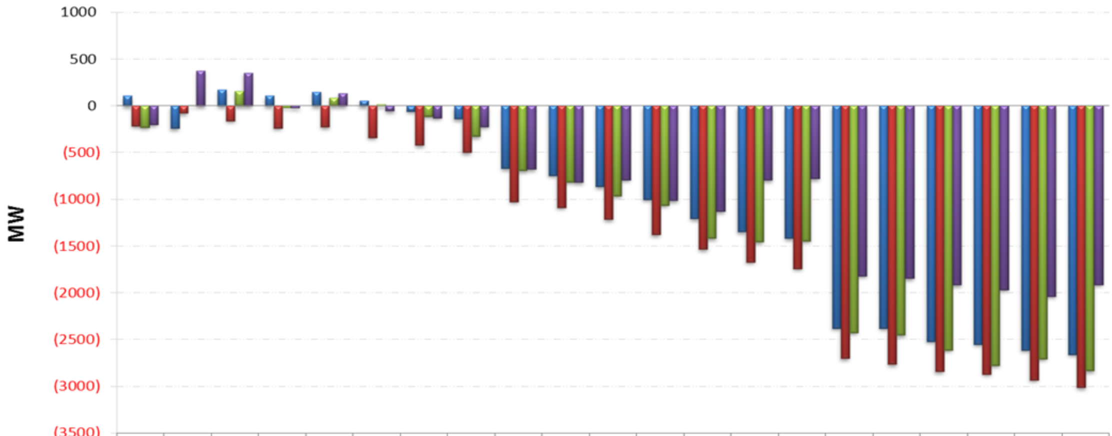
Based on the reliability calculation, no single resource strategy is significantly more or less reliable than another strategy, and all strategies meet this criteria. The economic aspects of each of the resource strategies are only valid if the resource strategy meets the NERC reliability standard of "1 day in 10 years." For this evaluation on reliability, each resource strategy was considered equal in terms of the reliability criteria.

4.3.1.1 Resource Adequacy

The process of ensuring resource adequacy for each strategic case is iterative. Initially, a model run 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 and Solar DG on the demand side. Figure 4-1 presents the resource shortfalls for the four coal replacement cases prior to any resource additions. For planning purposes, the figures focus on the most critical months of each year – July through October.

Resource Shortfall

Case #1 (Navajo 2019, IPP 2027)

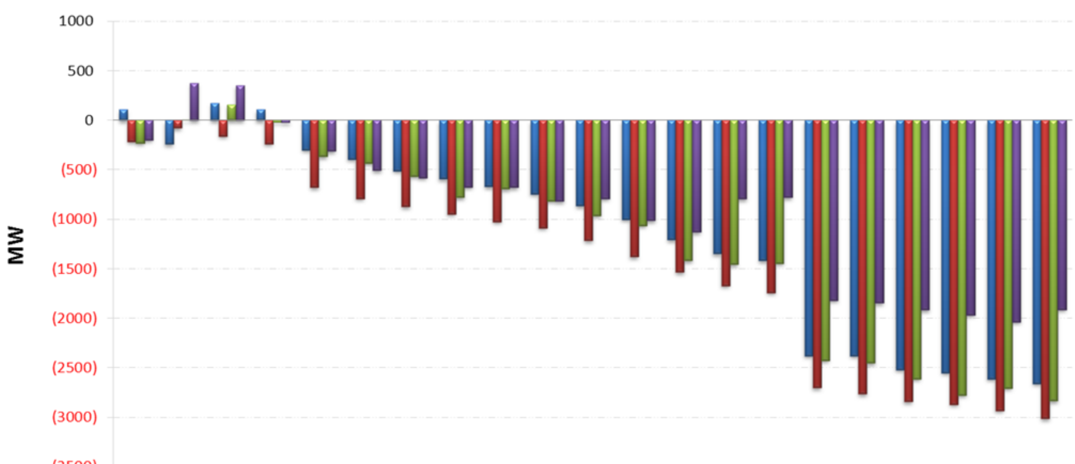


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
July	107	(241)	176	109	150	59	(59)	(140)	(672)	(744)	(865)	(1001)	(1207)	(1349)	(1418)	(2379)	(2380)	(2517)	(2550)	(2613)	(2660)
August	(213)	(78)	(159)	(236)	(227)	(339)	(420)	(497)	(1024)	(1087)	(1215)	(1378)	(1533)	(1672)	(1742)	(2701)	(2766)	(2842)	(2870)	(2930)	(3013)
September	(231)	2	160	(19)	84	19	(114)	(329)	(693)	(813)	(960)	(1064)	(1418)	(1454)	(1446)	(2427)	(2452)	(2613)	(2776)	(2707)	(2834)
October	(197)	379	354	(25)	138	(56)	(130)	(223)	(678)	(819)	(790)	(1013)	(1128)	(796)	(779)	(1818)	(1847)	(1914)	(1966)	(2036)	(1912)

Year/Month

Resource Shortfall

Case #2 (Navajo 2015, IPP 2027)



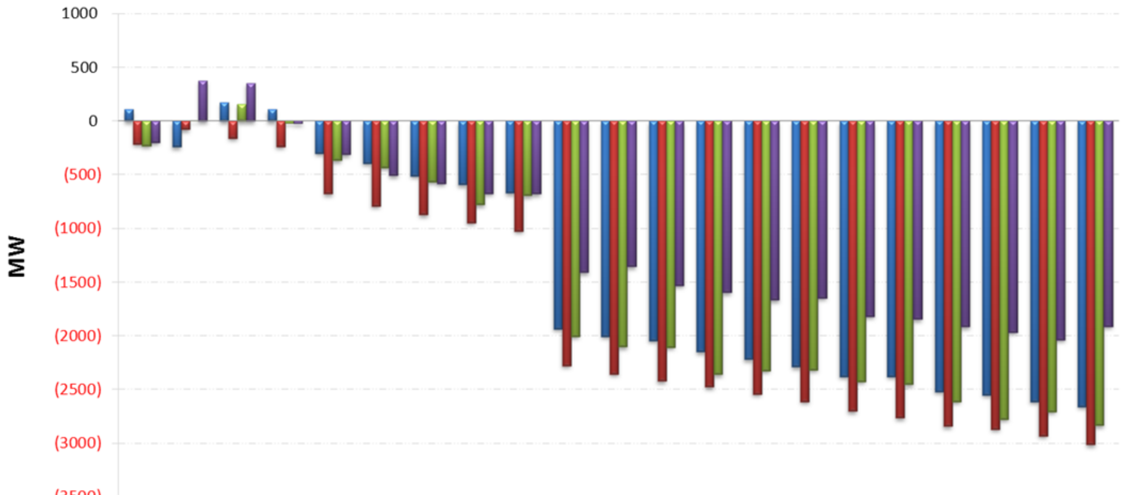
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
July	107	(241)	176	109	(301)	(392)	(510)	(591)	(672)	(744)	(865)	(1001)	(1207)	(1349)	(1418)	(2379)	(2380)	(2517)	(2550)	(2613)	(2660)
August	(213)	(78)	(159)	(236)	(678)	(789)	(870)	(948)	(1024)	(1087)	(1215)	(1378)	(1533)	(1672)	(1742)	(2701)	(2766)	(2842)	(2870)	(2930)	(3013)
September	(231)	2	160	(19)	(366)	(432)	(564)	(779)	(693)	(813)	(960)	(1064)	(1418)	(1454)	(1446)	(2427)	(2452)	(2613)	(2776)	(2707)	(2834)
October	(197)	379	354	(25)	(313)	(507)	(581)	(674)	(678)	(819)	(790)	(1013)	(1128)	(796)	(779)	(1818)	(1847)	(1914)	(1966)	(2036)	(1912)

Year/Month

Figure 4-1. Summer months resource adequacy shortage for Cases 1-4, by calendar year ("1 in 10" reliability criteria)

Resource Shortfall

Case #3 (Navajo 2015, IPP 2020)

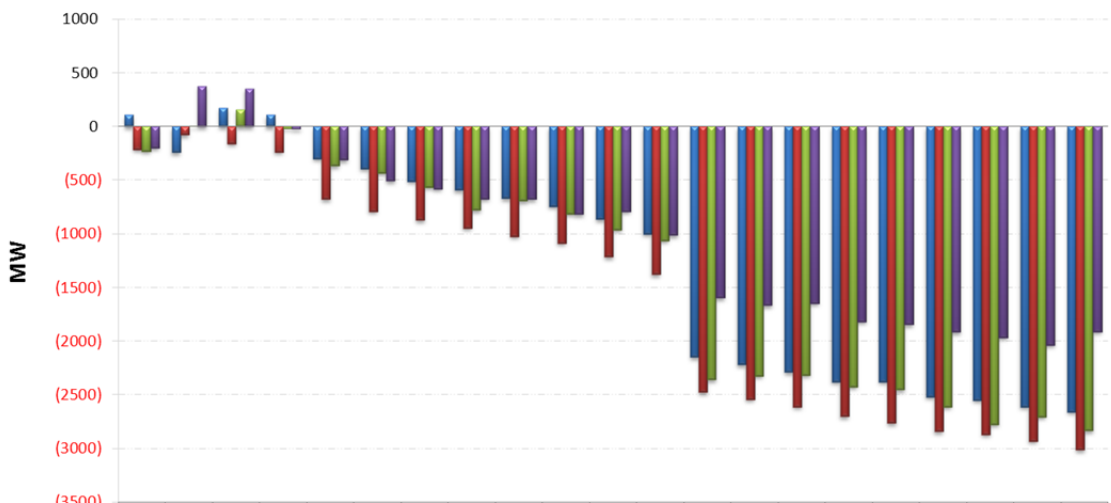


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
July	107	(241)	176	109	(301)	(392)	(510)	(591)	(672)	(1934)	(2006)	(2043)	(2149)	(2218)	(2288)	(2379)	(2380)	(2517)	(2550)	(2613)	(2660)
August	(213)	(78)	(159)	(236)	(678)	(789)	(870)	(948)	(1024)	(2278)	(2356)	(2420)	(2475)	(2541)	(2612)	(2701)	(2766)	(2842)	(2870)	(2930)	(3013)
September	(231)	2	160	(19)	(366)	(432)	(564)	(779)	(693)	(2004)	(2101)	(2105)	(2361)	(2324)	(2315)	(2427)	(2452)	(2613)	(2776)	(2707)	(2834)
October	(197)	379	354	(25)	(313)	(507)	(581)	(674)	(678)	(1410)	(1355)	(1529)	(1594)	(1666)	(1649)	(1818)	(1847)	(1914)	(1966)	(2036)	(1912)

Year/Month

Resource Shortfall

Case #4 (Navajo 2015, IPP 2023)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
July	107	(241)	176	109	(301)	(392)	(510)	(591)	(672)	(744)	(865)	(1001)	(2149)	(2218)	(2288)	(2379)	(2380)	(2517)	(2550)	(2613)	(2660)
August	(213)	(78)	(159)	(236)	(678)	(789)	(870)	(948)	(1024)	(1087)	(1215)	(1378)	(2475)	(2541)	(2612)	(2701)	(2766)	(2842)	(2870)	(2930)	(3013)
September	(231)	2	160	(19)	(366)	(432)	(564)	(779)	(693)	(813)	(960)	(1064)	(2361)	(2324)	(2315)	(2427)	(2452)	(2613)	(2776)	(2707)	(2834)
October	(197)	379	354	(25)	(313)	(507)	(581)	(674)	(678)	(819)	(790)	(1013)	(1594)	(1666)	(1649)	(1818)	(1847)	(1914)	(1966)	(2036)	(1912)

Year/Month

Figure 4-1. (continued)

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).

- 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 and briefed the General Manager. 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. Table 4-2 shows the breakdown of the replacement resources recommended for the four coal cases. Replacement resources for the 4 EE/DG cases were also developed and are shown in Appendix N.

Table 4-2. RESOURCES RECOMMENDED FOR RESOURCE ADEQUACY BY CALENDAR YEAR

Case#1 (Navajo 2019, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	25	75	0	0	0	0	50	125
Total Replacement	**244**	**257**	**165**	**342**	**460**	**563**	**675**	**784**	**1245**	**1313**	**1426**	**1513**	**1600**	**1686**	**1747**	**2835**	**2854**	**2867**	**2880**	**2943**	**3030**

Case #2 (Navajo 2015, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	25	75	0	0	0	0	50	125
Total Replacement	**244**	**257**	**165**	**342**	**760**	**863**	**975**	**1084**	**1245**	**1313**	**1426**	**1513**	**1600**	**1686**	**1747**	**2835**	**2854**	**2867**	**2880**	**2943**	**3030**

Case #3 (Navajo 2015, IPP 2020)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	125
Total Replacement	**244**	**257**	**165**	**342**	**760**	**863**	**975**	**1084**	**1245**	**2463**	**2576**	**2663**	**2750**	**2811**	**2822**	**2835**	**2854**	**2867**	**2880**	**2943**	**3030**

Case #3A (Navajo 2015, IPP 2024)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	125
Total Replacement	**244**	**257**	**165**	**342**	**760**	**863**	**975**	**1084**	**1245**	**1313**	**1426**	**1513**	**2750**	**2811**	**2822**	**2835**	**2854**	**2867**	**2880**	**2943**	**3030**

Figure 4-2 shows the net dependable capacity profiles for the 4 coal cases after including the recommended resources to satisfy resource adequacy requirements. In each case, Navajo is replaced with new renewable generation and a 300 MW replacement combined cycle gas-fired unit upon divestiture. Energy efficiency, demand response, and Q3 term purchases supply capacity that primarily contributes to peak load growth. Figure 4-3 presents the generation profiles for the same 4 coal cases.

When IPP energy ceases in 2027 for Cases 1 and 2, 2020 for Case 3, and 2023 for Case 4, that production is replaced entirely with two 575 MW combined cycle natural gas units. The larger combined cycle units will be necessary to reduce Q3 term purchases and to provide energy and capacity for additional load growth. By 2020, most of the renewable portfolio will have already been built to replace Navajo, with continued load growth being offset by renewables, energy efficiency, demand response, Q3 term purchases, and a portion of the two 575 MW combined cycled gas-fired units.

Q3 term purchases are meant to satisfy peak load growth 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 peak load growth. 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 Cases 2, 3 and 4 with the Navajo Generating Station (NGS) divested in 2015, the 300 MW combined cycle gas-fired unit and demand response resources are fulfilling two purposes, (1) replacing 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.

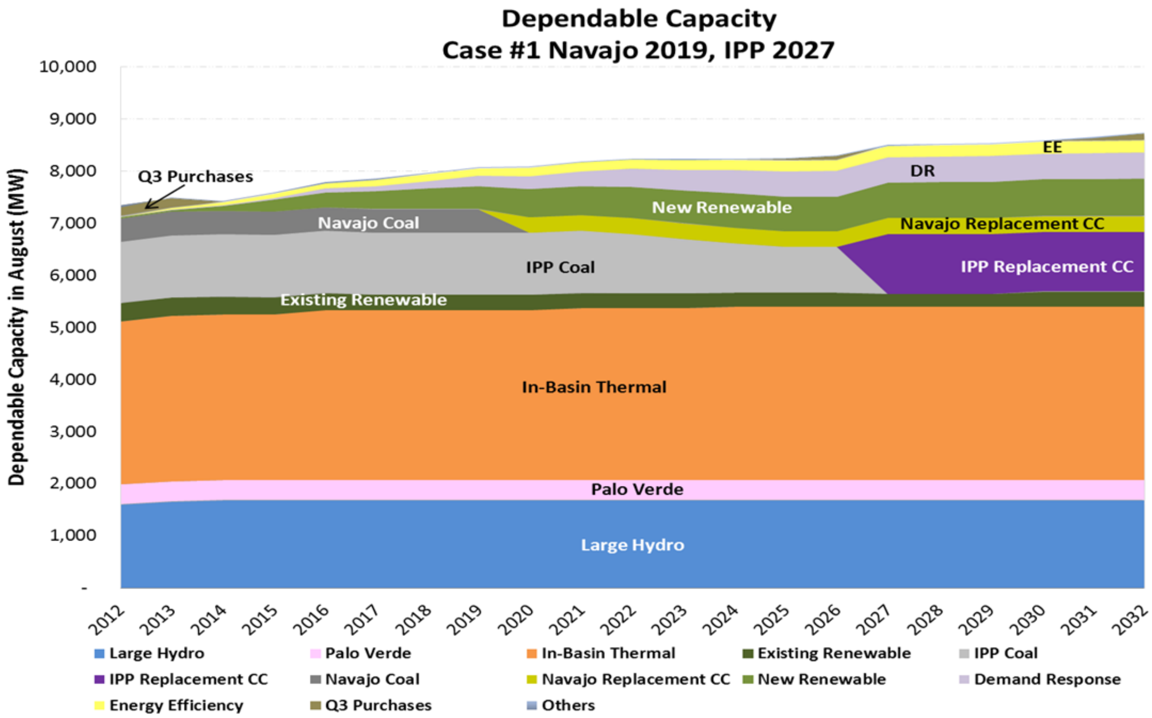
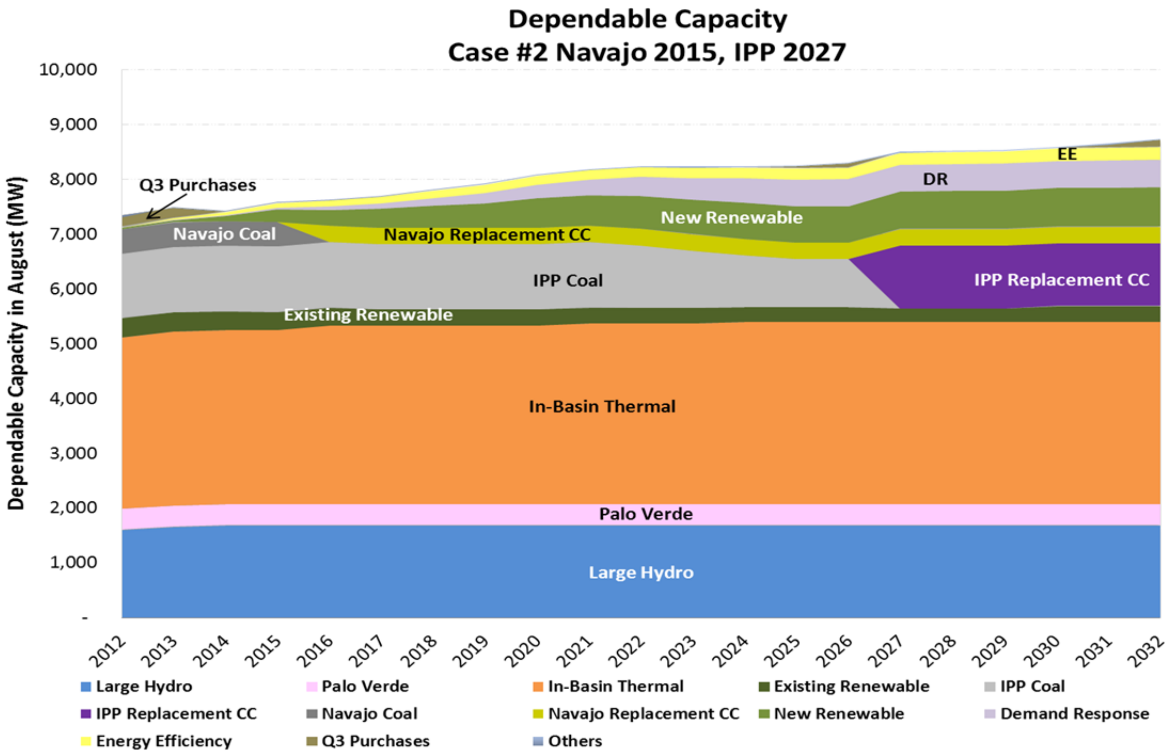


Figure 4-2. Dependable capacity profiles, Cases 1 - 4.



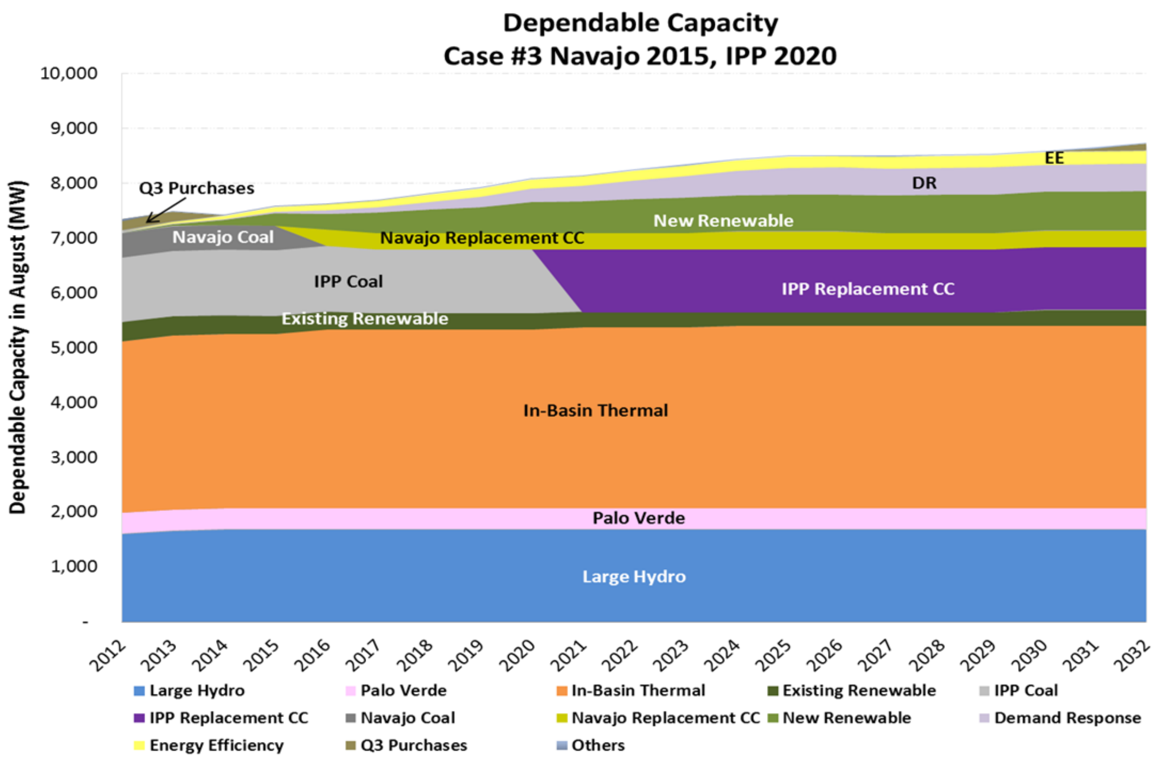


Figure 4-2. (continued)

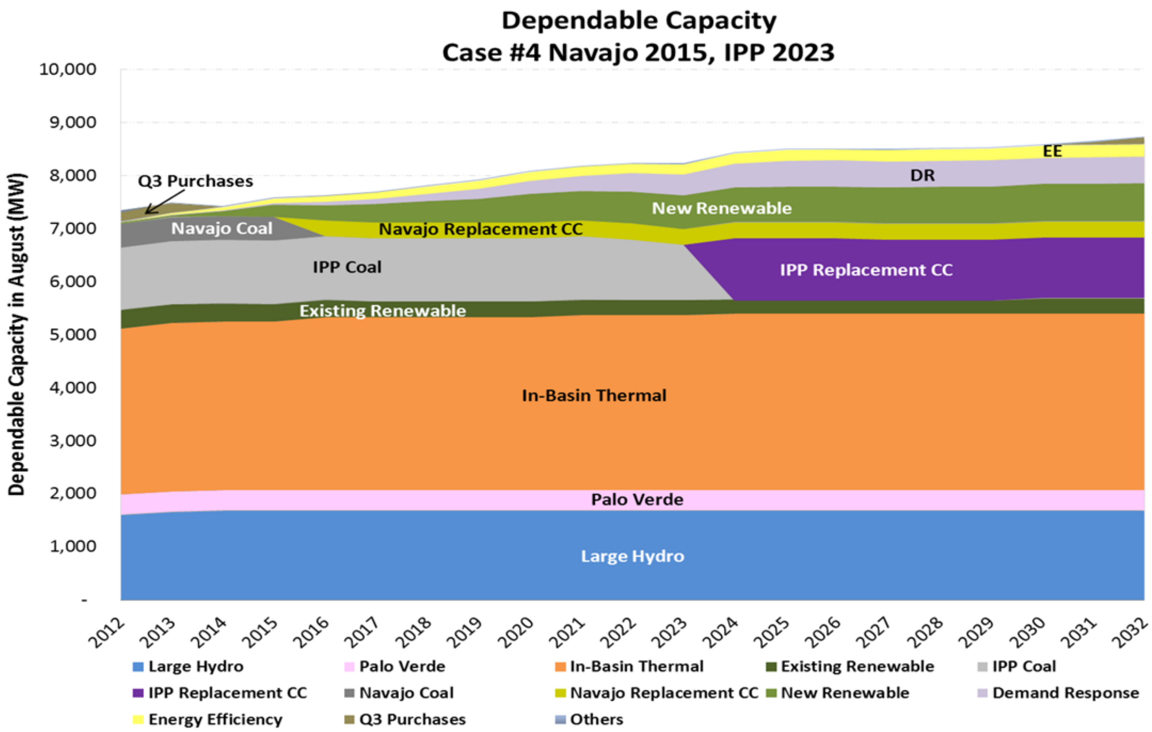
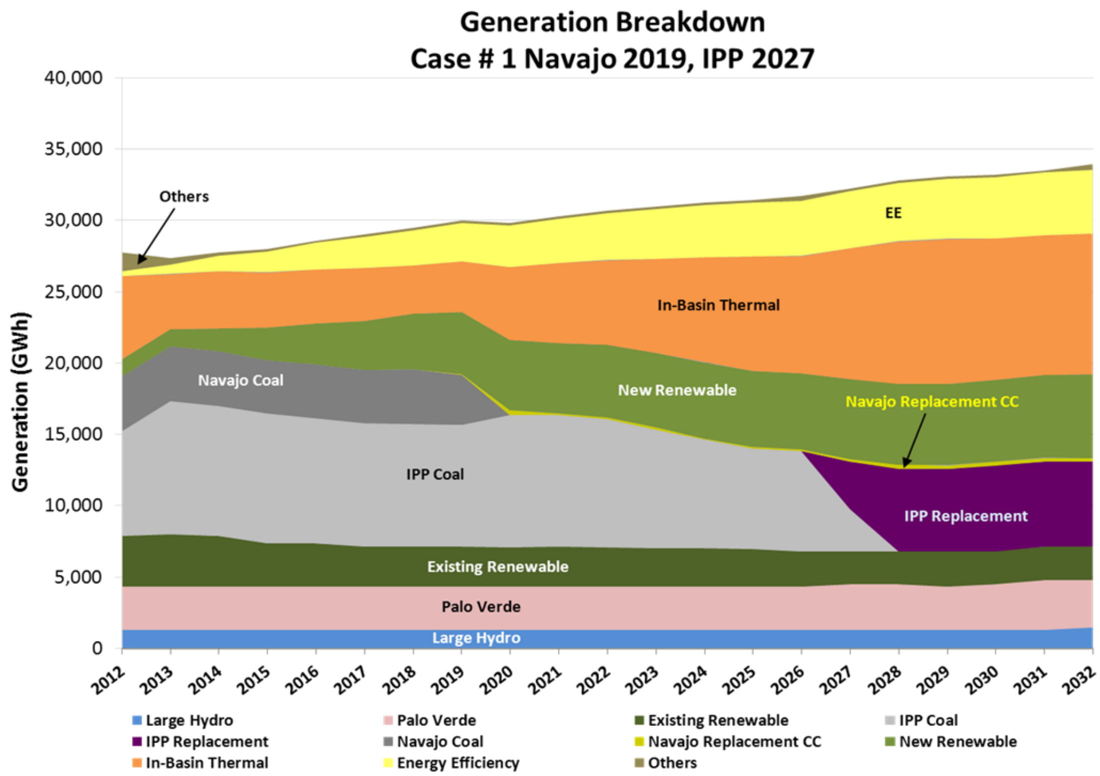


Figure 4-2. (continued)



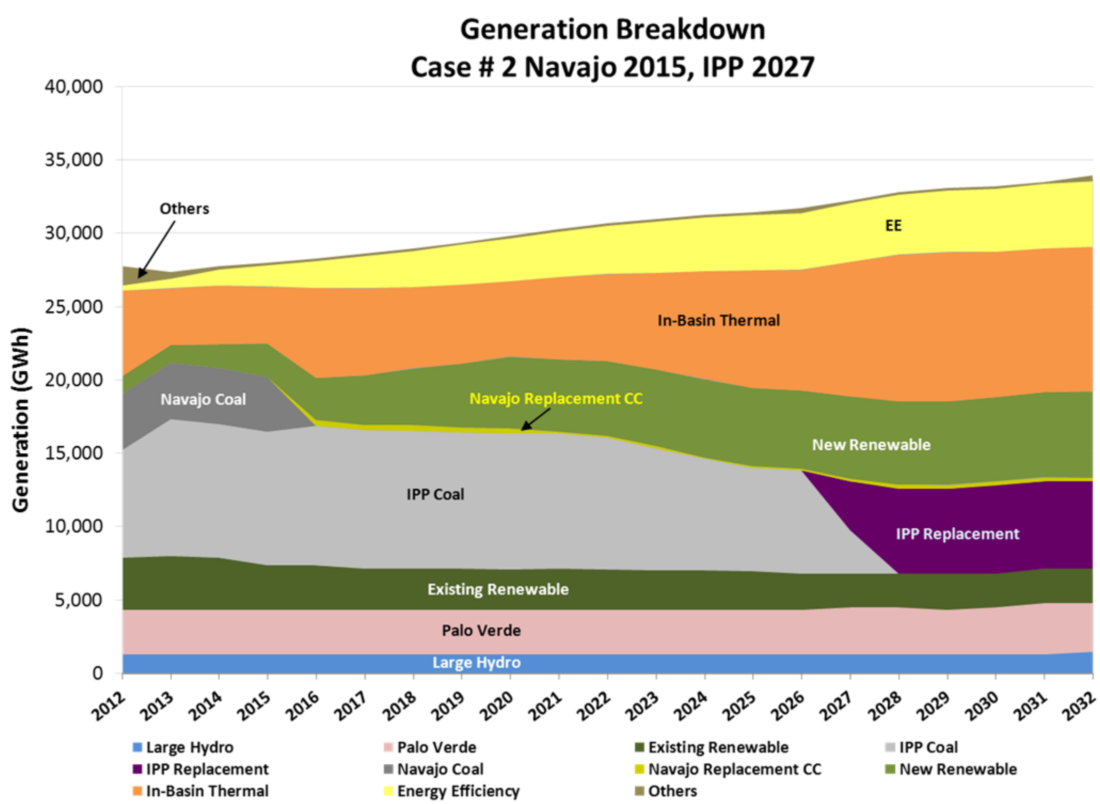
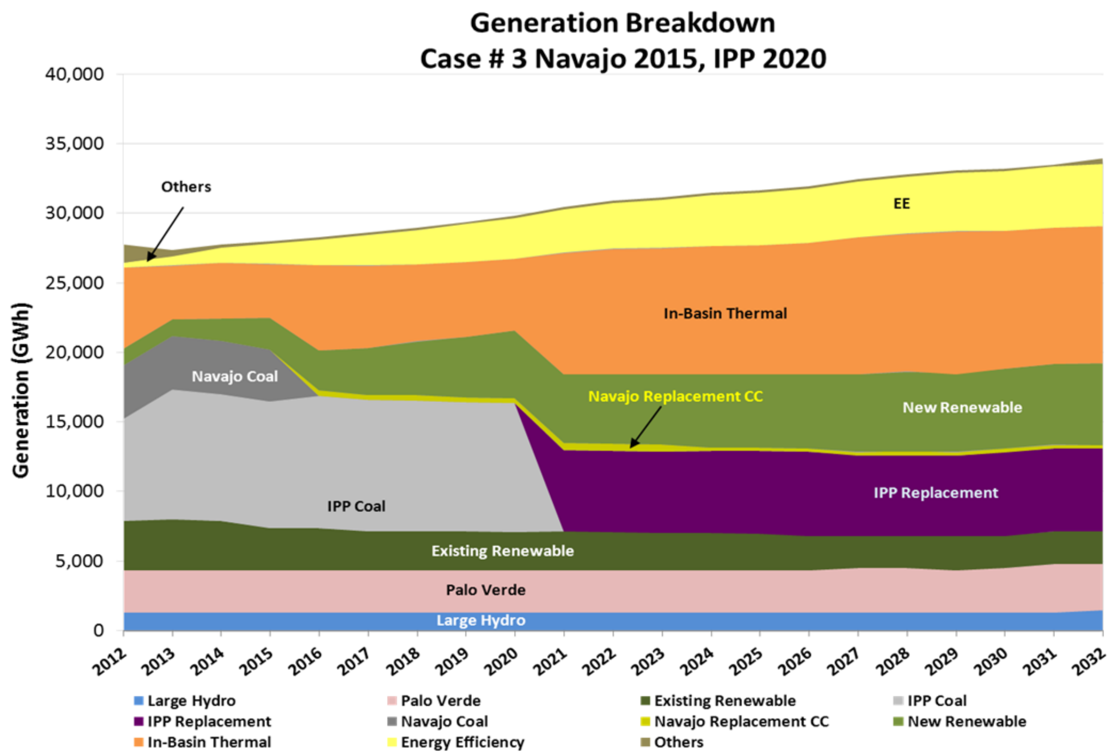


Figure 4-3. Generation mix profiles, Cases 1 - 4.



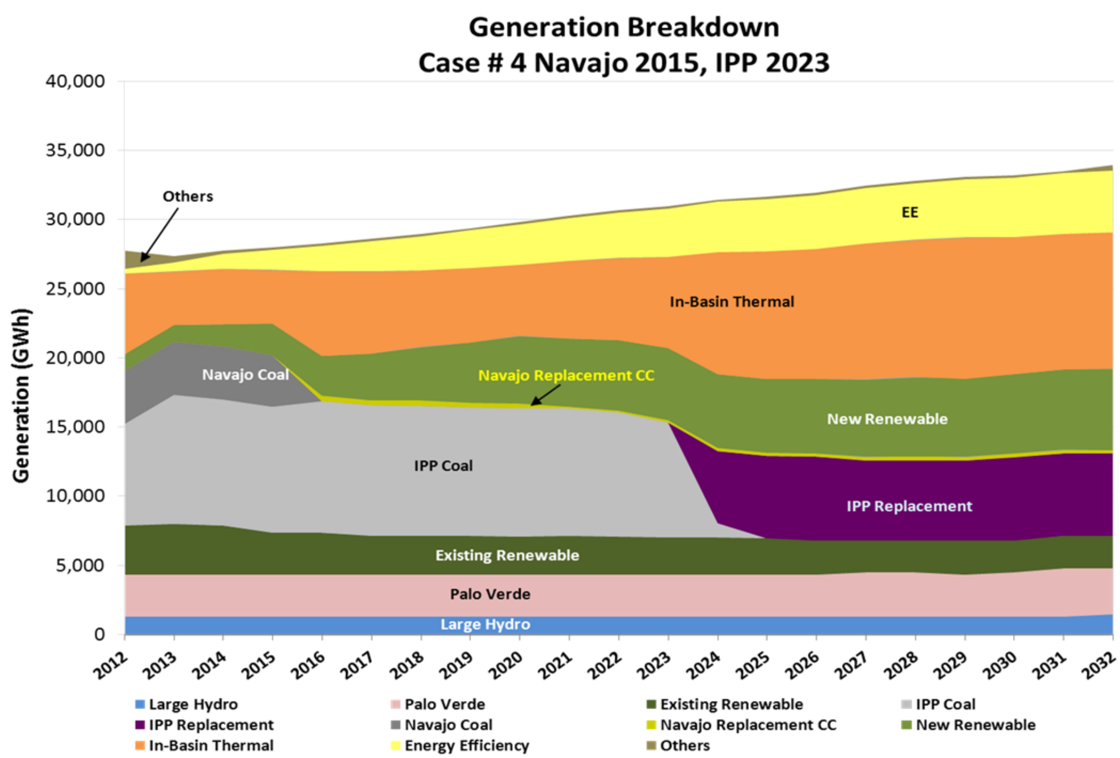


Figure 4-3. (continued)

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, when compared to energy produced from natural gas. The reductions of GHG emissions are reflected in the production cost model simulations. Figure 4-4 illustrates a comparison of the resulting GHG emission levels of the four cases. Divestiture of Navajo results in an average 1.81 Million Metric Tons (MMT) reduction in GHG each year while IPP results in an average 2.78 MMT reduction each year. GHG reductions are accelerated in Cases 2, 3 and 4 with the replacement of Navajo and 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 all cases in 2019 and then again in 2027 when SB 1368 essentially prohibits the importation of energy produced from coal when the existing power contracts expire.

Current total GHG emissions levels are approximately 14.1 MMT which is 21 percent below 1990 levels due to the elimination of Mojave and Colstrip Coal, completed repowering of units at Haynes and Valley generating stations with cleaner gas-fired replacements, and increased renewable generation from 3% in 2003 to 20% in 2010. Using Case 1 (Navajo divestiture in 2019, IPP replacement in 2027) as a baseline, early divestiture of Navajo in Cases 2, 3 and 4 results in approximately 7.2 MMT less GHG emissions between 2016 and 2019. For Case 3 (IPP replaced in 2020) there is an additional post-2020 cumulative reduction of 19.5 MMT. For Case 4, the post-2020 reduction is 9.3 MMT. These GHG emission reductions are shown below in Figure 4-4 and Table 4-3.

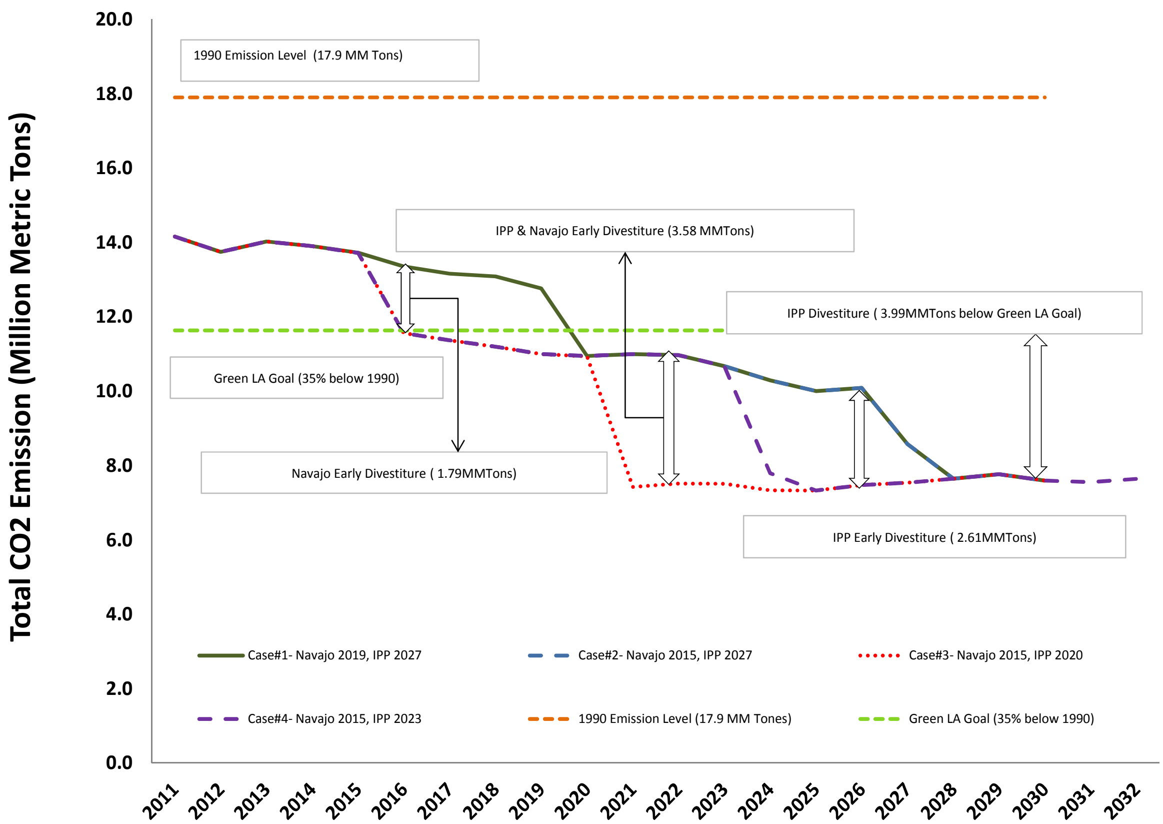


Figure 4-4. GHG emissions comparison by calendar year.

Table 4.3 GHG EMISSIONS REDUCTION LEVELS IN MMT

Case	Reduction 2016-19	Reduction 2020-27	Total Reduction 2016-27
1	Baseline	Baseline	Baseline
2	7.2	0.0	7.2
3	7.2	19.5	26.7
4	7.2	9.3	16.3

Emission levels for the energy efficiency and solar distributed generation, Cases 5 thru 8 were also evaluated as shown in Figure 4-5. Advanced levels of EE were found to result in slightly lower emissions of CO_2 as compared to the Base EE cases. Higher levels of Solar DG were found to have little effect on reducing CO_2 emissions since Solar DG would have been replaced with other zero emissions resources. Although these higher levels of EE and distributed generation have a small impact on emissions compared to the base EE, it is important to note that the base level of energy efficiency in and of itself has a very significant impact on reducing overall CO_2 levels as shown by the "No More EE" curve illustrated in Figure 4-4. If no additional EE were implemented, annual GHG emissions levels would be approximately 2.0 MMT higher by 2032. This is equivalent to removing 385,000 cars from the road. For reference purposes, the CARB emissions allocation for LADWP as part of the AB 32 Cap and Trade program being implemented in 2013 and ending in 2020 is shown in Figure 4-5.

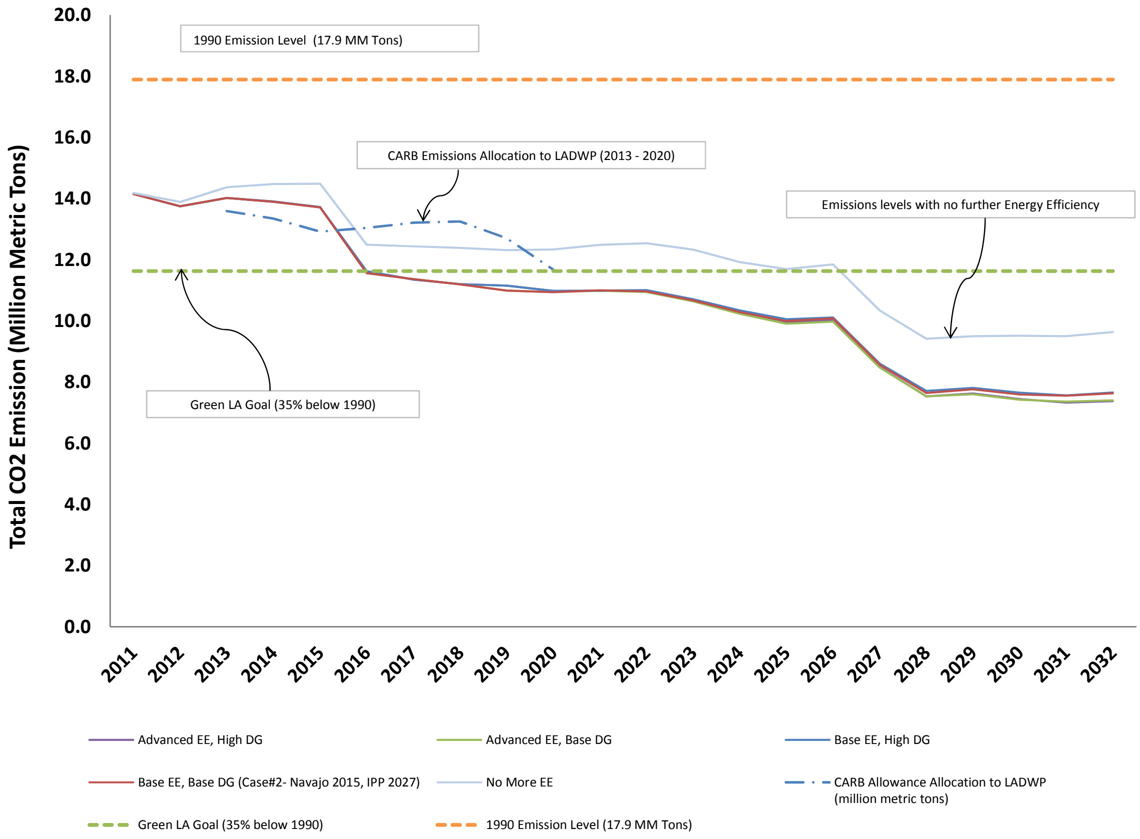


Figure 4-5. GHG emissions comparison for Energy Efficiency and Solar Distributed Generation cases by calendar year.

In addition to GHG, Oxides of Nitrogen (NO_X) were also measured within the production model. Figure 4-6 summarizes NO_X emissions for each of the four cases. With the installation of SCR equipment since 1989, NO_X emissions of in-basin generation has been reduced by 90 percent.

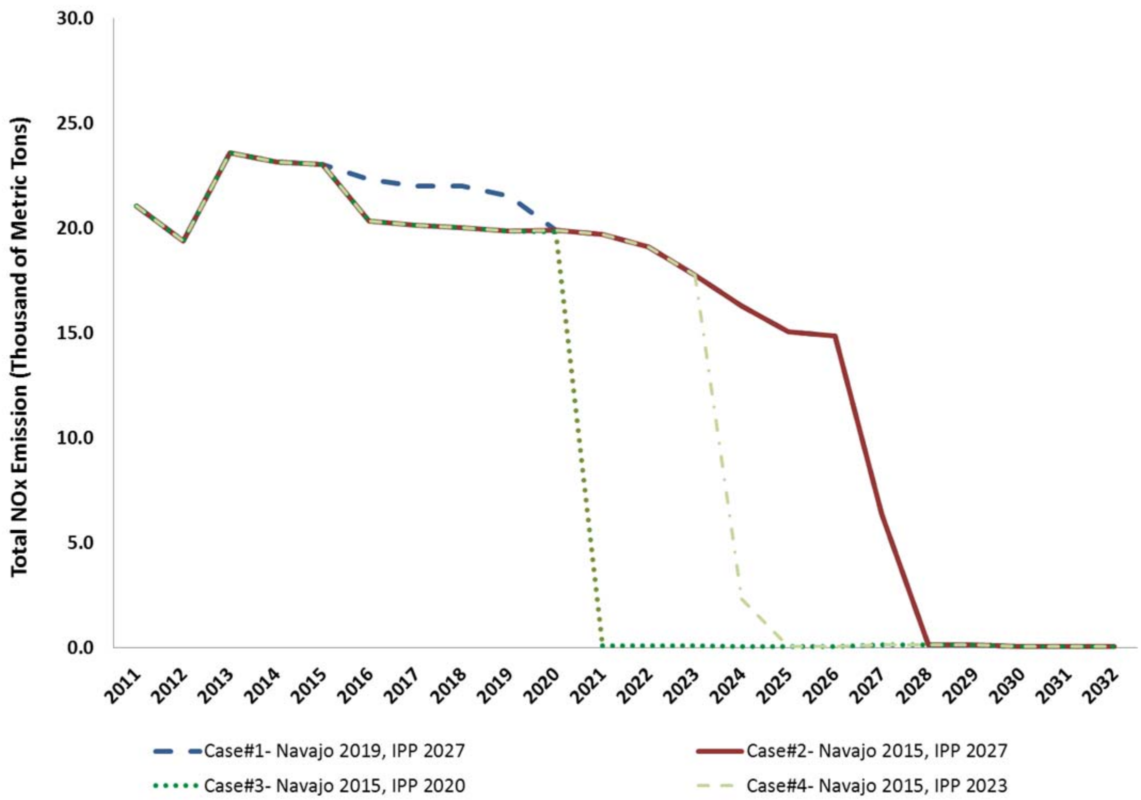


Figure 4-6. NO_X emissions comparison by calendar year

4.3.3 Economic Considerations

The economic considerations for the eight coal and EE/DG 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 EE and DG Cases 5 thru 8

Two scenarios of Energy Efficiency (EE) were considered including a Base EE case and an Advanced EE case. By using FY 2010-11 Total Sales to Ultimate Customers (23,053 GWh) to calculate the energy savings percentage, the Base EE case forecasts LADWP will achieve 10% of Net EE savings by 2020 and 15% EE savings by 2032. The Advanced EE case forecasts the same EE savings up to and including 2020 as in the Base EE case, but gradually adds another 500 GWh of savings by 2032. The Net EE savings in GWh for the two scenarios along with the projected budget are shown below in Figures 4-7 and 4-8.

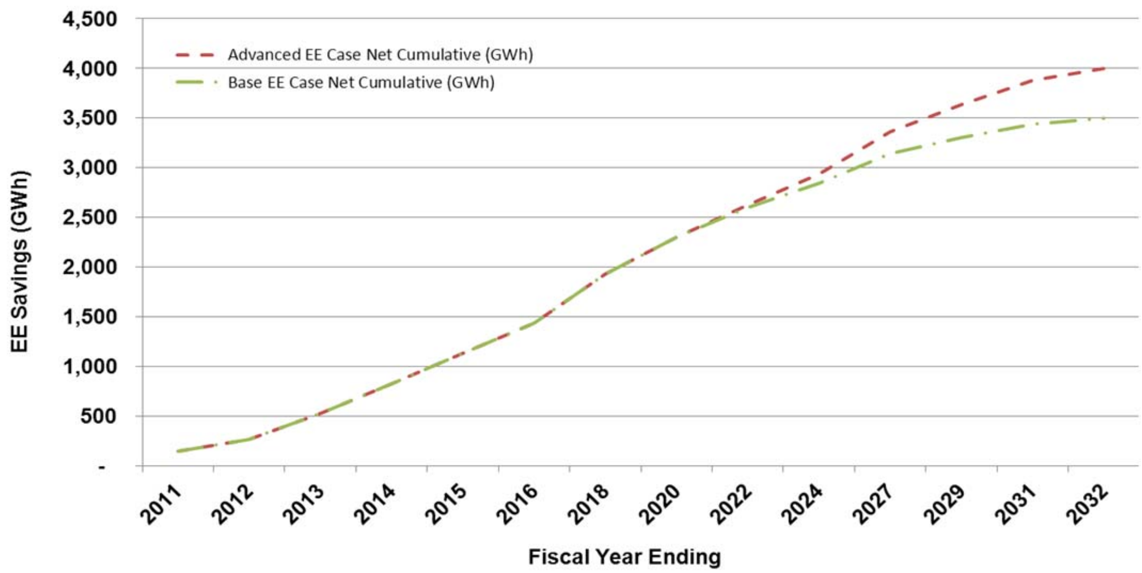


Figure 4-7. Advanced EE and Base EE GWh Comparison

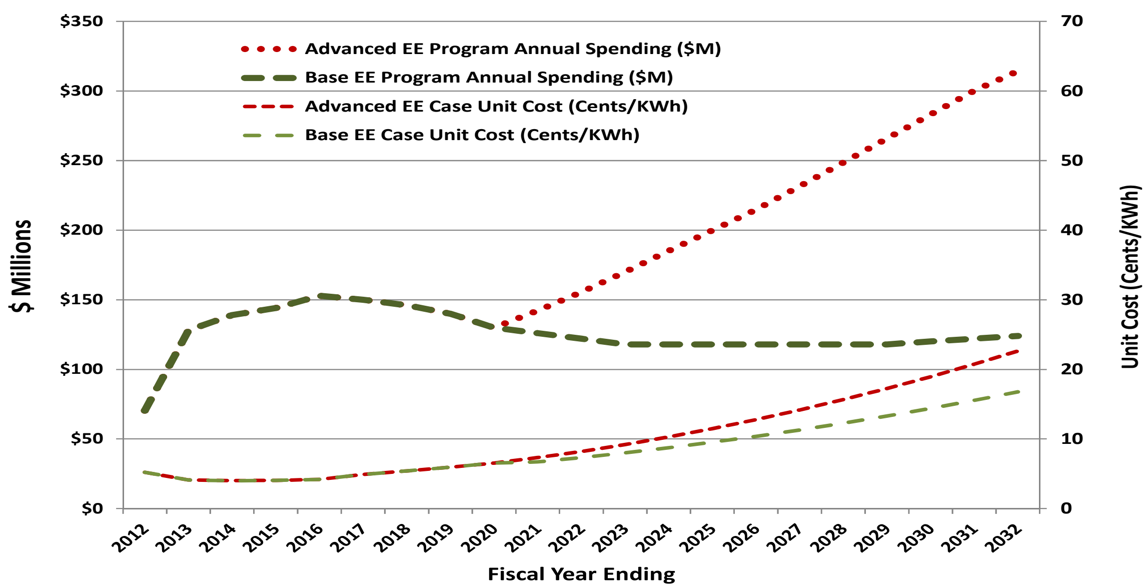


Figure 4-8. Advanced EE and Base EE Program Cost Comparison

Solar Distributed Generation (DG) includes local solar generation that is directly interconnected to the distribution system. Distributed generation comprises solar generation from the Feed in Tariff (FiT), Utility Built Solar (UBS), and customer net metered programs. UBS are solar projects that would be built and operated by LADWP, and may be located in the city or out-of-basin. The detailed Solar DG scenarios in GWh and unit cost are shown in

Figure 4-9, along with curves for LADWP's Utility Built Solar (UBS) program. The two scenarios for Solar DG consist of one Base DG case and one High DG case.

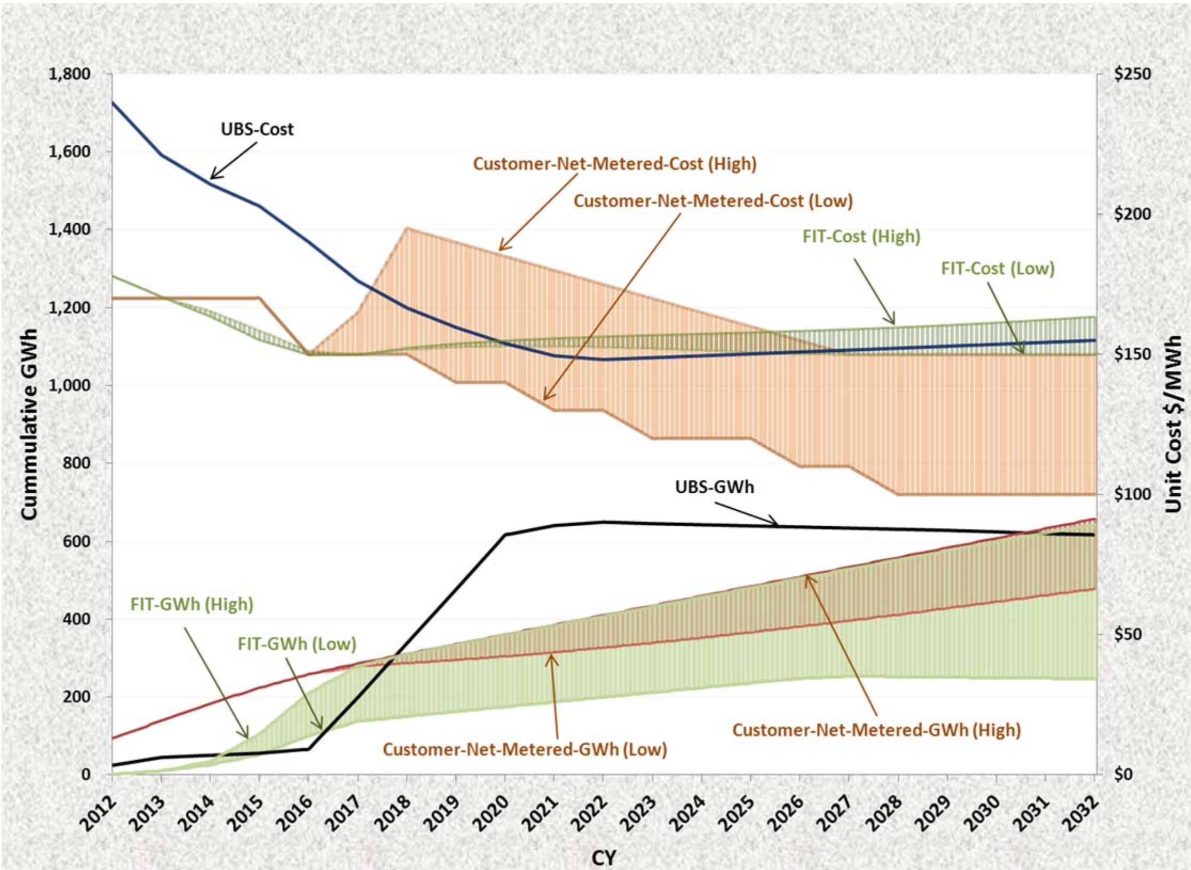


Figure 4-9. High and Base DG solar program cost assumptions and GWh comparison

The Base EE and Base DG energy forecasts are used in all four coal strategic cases evaluated in the 2012 IRP. The Base Case assumes divestment of Navajo Generating Station by December 31, 2015 and Intermountain Generating Station will be replaced by natural gas generation by June 15, 2027. Different combinations of EE and DG cases were analyzed in the production model simulations including: (1) Base EE with Base DG, (2) Base EE with High DG, (3) Advanced EE with Base DG, and (4) Advanced EE with High DG. The detailed analysis was conducted using the PROSYM production cost modeling software .

There are various resource changes associated with different EE and DG combinations due to RPS mandatory and system reliability requirements. For example, when the High DG and Advanced EE case is modeled, the more aggressive EE reduces both customer energy sales and load demand which relaxes the requirements on RPS and peak demand. Also, with higher Solar DG some non-solar-DG renewable resources were reduced or even eliminated to avoid unnecessary expenditures on renewable energies beyond the amount mandated by SB 2 (1X).

Demand-Side Resources – Total Revenue Requirements

Due to the load reduction nature of energy efficiency and solar customer-net-metered "demand-side" programs, analysis of the revenue requirements of these specific programs must be handled in a different manner than other distributed generation programs such as solar feed-in-tariff and utility built solar. The modeling results were analyzed to determine the net revenue loss due to reduced sales and the program costs which consist mainly of incentive payments paid to customers to subsidize the cost of these demand-side measures. While the program costs are relatively straight forward to evaluate, determining the net revenue loss is a more complex process that requires first determining the costs that the utility avoids by implementing these programs which is simply described as "avoided costs."

Determining Net Revenue loss involves first determining the avoided costs from implementation of demand-side energy savings, including: fuel, variable O&M, emissions, transmission and distribution deferred upgrades, capital investments for new generation, fixed O&M, and energy transport losses. The avoided costs and fixed billing charges from demand and minimum billing charges are then subtracted from the gross revenue loss to determine the net revenue loss as shown in Figures 4-10 through 4-13 below. A full detailed discussion of avoided costs and revenue loss results are included in Appendix N.

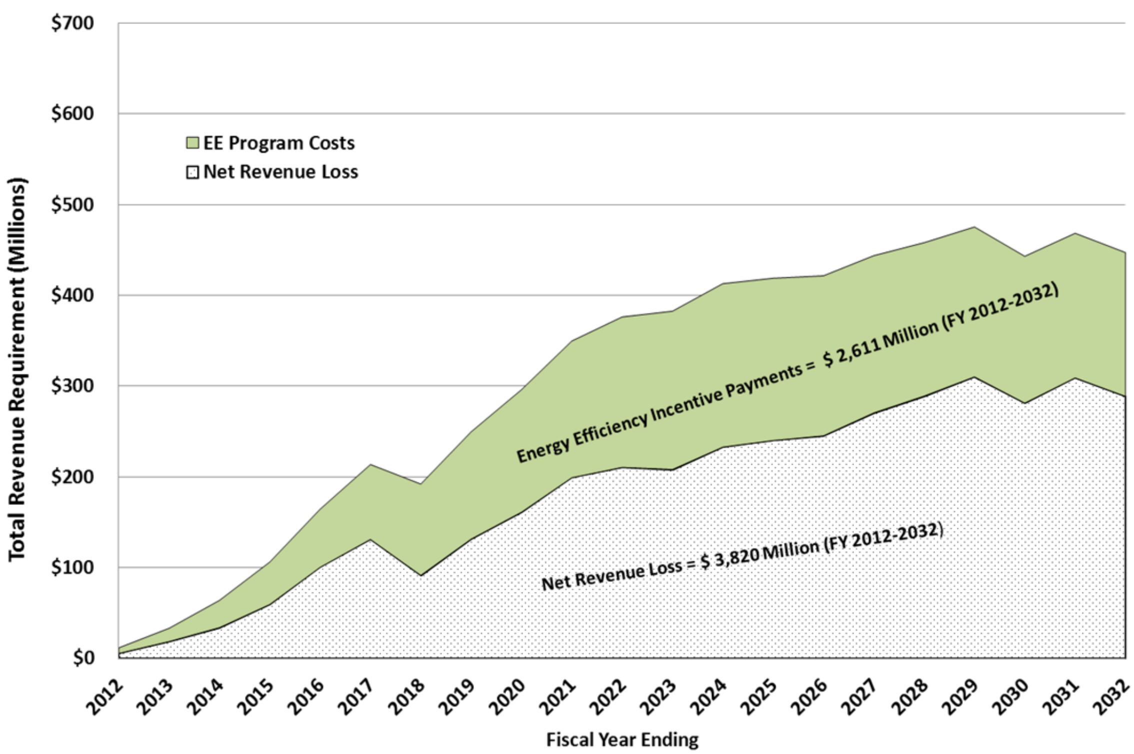


Figure 4-10. Base EE - Total Revenue Requirement

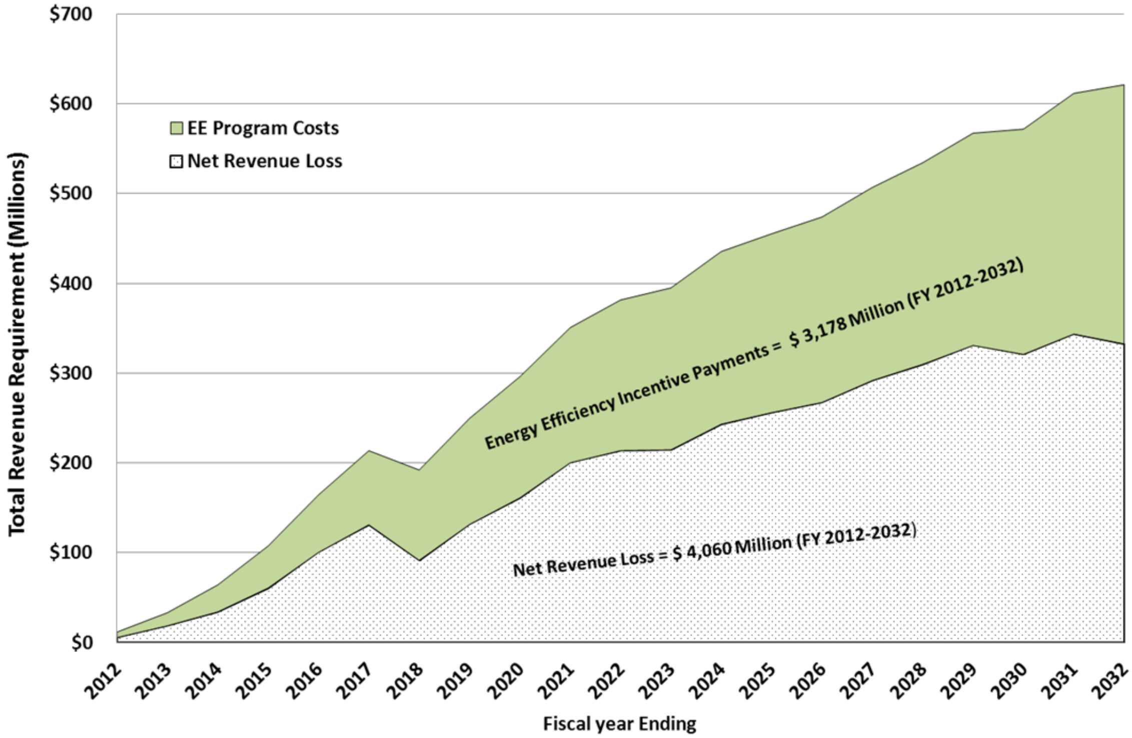


Figure 4-11. Advanced EE - Total Revenue Requirement

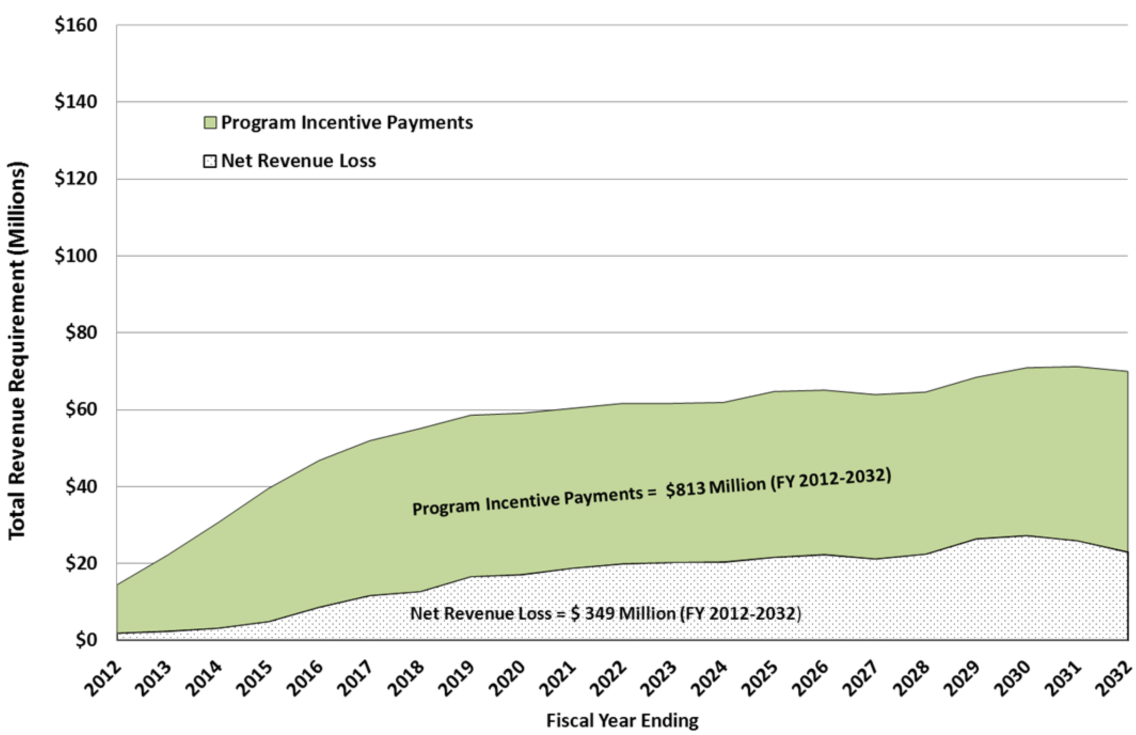


Figure 4-12. Base CNM Solar - Total Revenue Requirement

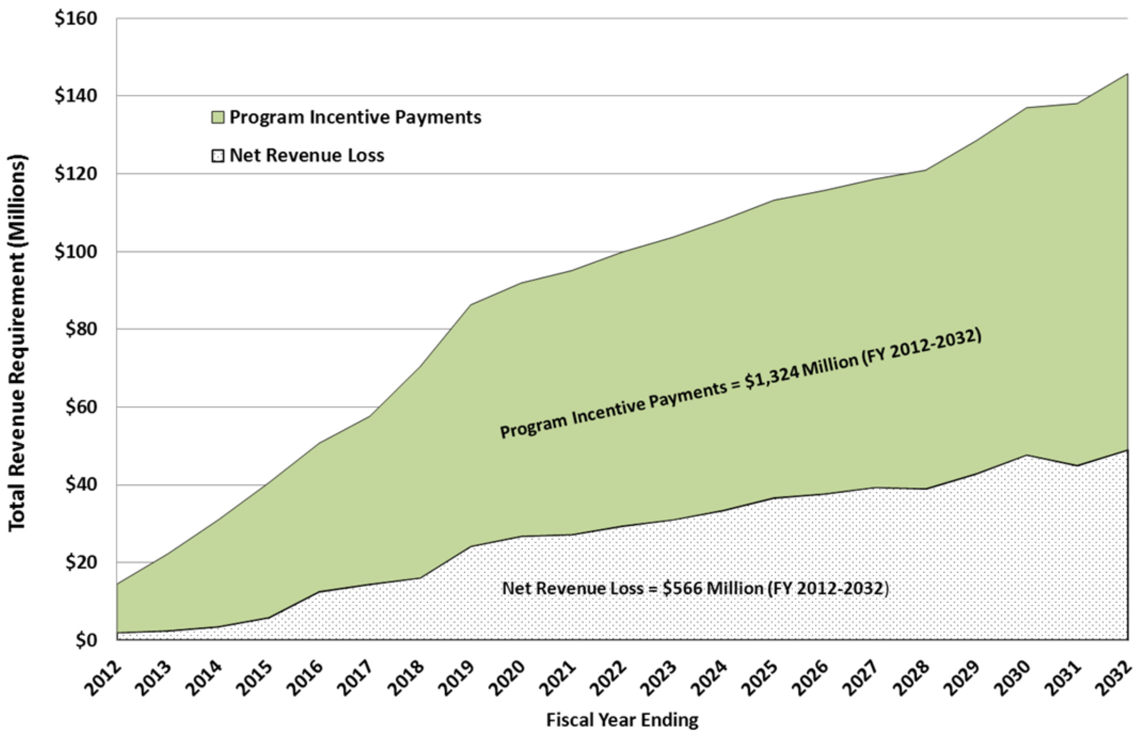


Figure 4-13 High CNM Solar - Total Revenue Requirement

Solar DG resources including Solar Feed-In-Tariff and Utility Built Solar do not result in revenue losses because these programs do not reduce customer sales. Therefore, the energy costs offset by the avoided costs savings of these programs must be calculated separately and then added to the demand-side EE and CNM costs to arrive at the final bulk power costs for the different cases as shown in Figure 4-14 below. FiT and UBS also result in avoided costs similar to EE and CNM with only slight differences. Although the evaluation considered the entire period of 2012 thru 2032, only the years 2020 thru 2032 are shown in Figure 4-14. The reason for this is that all cases have the same EE savings from 2012 thru 2020 and only slightly higher solar DG savings for this time period. Increased levels of EE and solar DG mostly occur in the later period from 2020 thru 2032 in the cases evaluated. Integration costs for solar resources, assumed to be $7/MWh based on recent studies performed by outside consultants, and all other bulk power resource costs were aggregated together to determine the total bulk power costs of the 4 EE/DG cases evaluated. The incremental differences between these 4 EE/DG cases can be seen in Table 4-4 below.

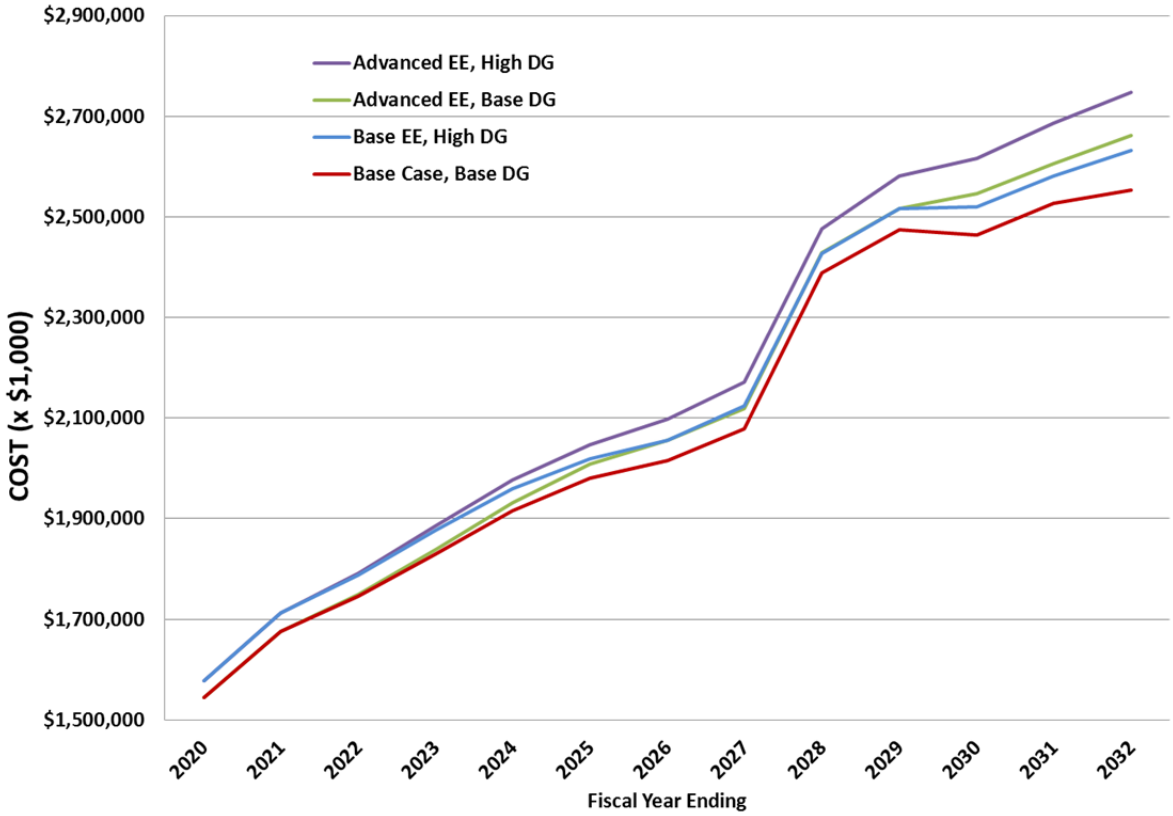


Figure 4-14. Bulk Power Cost Comparison of EE/DG cases (2020 thru 2032)

Table 4-4. Incremental Cost vs. Base EE, Base DG Comparison

	Base EE & Base DG	Base EE & High DG	Advanced EE & Base DG	Advanced EE & High DG
Fuel & Program Costs $M	$0	$428	$254	$766
DG Integration Costs - DG $M	$0	$39	$0	$39
T&D Savings - FIT, UBS $M	$0	($15)	$0	($15)
Net Lost Revenue - EE CNM $M	$0	$217	$240	$457
Total Incremental Revenue $M	$0	$669	$494	$1,247
Average Incremental Revenue ($M/yr)	$0	$32	$24	$59
Average Incremental Cost (Cents/kWh)	0.00	0.14	0.10	0.26

The results show that both higher levels of EE and DG must be carefully considered in the utilities overall finances as these programs tend to require higher levels of revenue as compared to other alternatives. For customers that implement both EE programs and Solar CNM, the opportunity to realize savings in their use of electricity and associated savings can be substantial and should be encouraged. However, from the utility perspective, it is important that cost recovery mechanisms are established to recover reduced revenues that come from Solar CNM and Energy Efficiency to minimize the impact on other programs that require appropriate funding levels to maintain reliability of the electric grid and comply with existing laws and regulations. Careful planning of these resources must also be evaluated periodically as new cost information becomes available (e.g., Energy Efficiency Potential Study) to provide the most economical mix of future resources.

4.3.3.2 Cost Comparison Between Coal Cases 1 thru 4

The total fuel and variable costs for the 4 coal replacement cases are shown in Figure 4-15 below. The natural gas price used in the production model was the 20-yr long-term natural gas price forecast from Platts and is also considered as the expected natural gas price in the stress test study in Section 4.3.3.3.

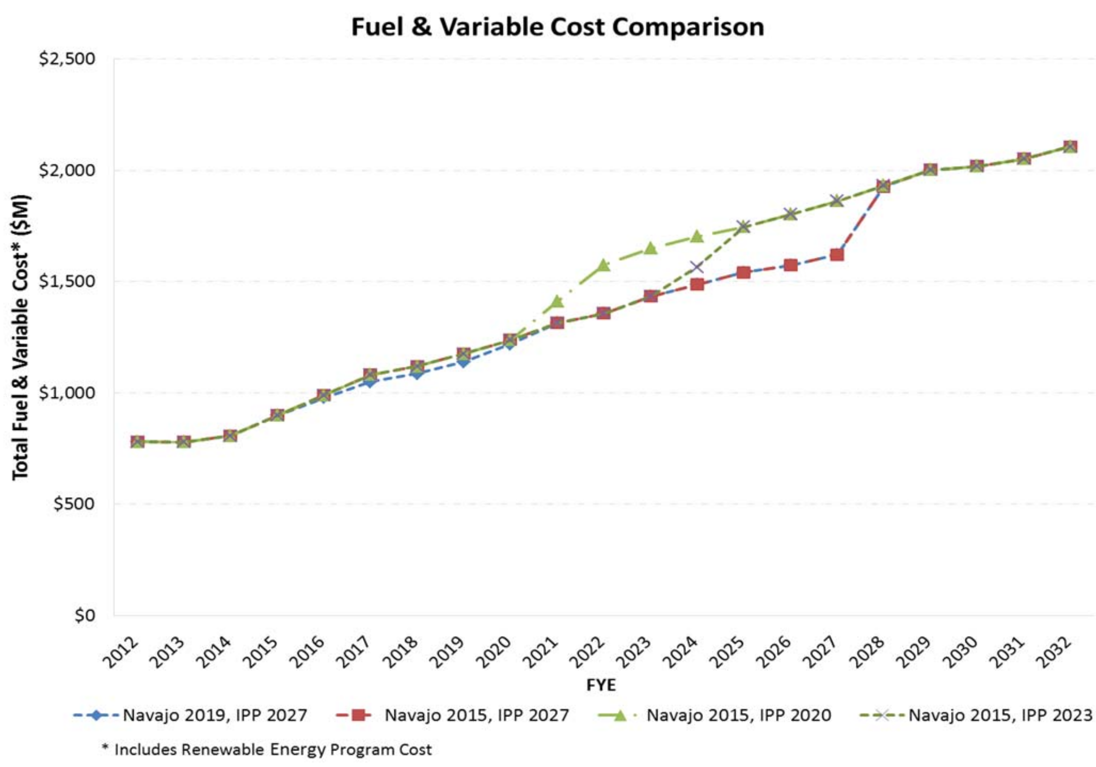


Figure 4-15. Total fuel and variable cost comparison by fiscal year (Includes renewable project costs).

Replacement of IPP and Navajo results in higher fuel and variable O&M costs, as less expensive coal is replaced with relatively higher cost gas-fired energy. The resulting increase in fuel costs from the Navajo divestiture is due to a blended increase of in-basin and out-of-basin gas fired generation. In reality, resources replacing Navajo consist of a blend of new energy efficiency, new renewable energy, and new replacement gas-fired combined cycle units. The gas-fired replacement resources for Navajo can be better seen in Table 4-5. Because all 4 coal cases analyzed have the same renewable portfolio, the cost differences between the cases can only be attributed to increased gas cost; therefore, the costs shown in Table 4-5 do not include any incremental costs associated with new renewable resources.

Table 4-5. Increased incremental capital, fuel, and variable O&M costs related to replacement of Navajo and IPP by fiscal year

Delta -Navajo Early Divestiture Study (Case 2 - Case 1) ($M) [FYE]	2016	2017	2018	2019	2020	Total
Capital & Fixed OM Cost						
300 MW Navajo Replacement Cost	$9 M	$18 M	$18 M	$18 M	$12 M	$74 M
Fuel Cost	$12 M	$28 M	$32 M	$33 M	$17 M	$121 M
VOM Cost	$0 M	$3 M	$2 M	$3 M	$1 M	$9 M
Total Cost Delta	**$22**	**$48**	**$52**	**$53**	**$30**	$205 M

Delta - IPP 2020 Conversion Study (Case 3 - Case 2) ($M) [FYE]	2021	2022	2023	2024	2025	2026	2027	Total
Capital & Fixed OM Cost								
IPP Replacement Cost	$19 M	$38 M	$43 M	$52 M	$61 M	$64 M	$59 M	$337 M
Natural Gas Pipe line Cost *	$4 M	$4 M	$4 M	$4 M	$4 M	$4 M	$4 M	$30 M
SubTotal	$23 M	$43 M	$47 M	$56 M	$65 M	$69 M	$63 M	$366 M
Fuel Cost	$80 M	$177 M	$176 M	$178 M	$167 M	$190 M	$204 M	$1,173 M
VOM Cost	$18 M	$39 M	$39 M	$39 M	$38 M	$39 M	$38 M	$250 M
Total Cost Delta	**$121**	**$259**	**$262**	**$273**	**$270**	**$298**	**$305**	$1,790 M

Note: * Pipeline installation cost is based on $60 M one-time cost amortized over 25 year period with 5.5% interest.

Delta - IPP 2023 Conversion Study (Case 4 - Case 2) ($M) [FYE]	2021	2022	2023	2024	2025	2026	2027	Total
Capital & Fixed OM Cost								
IPP Replacement Cost				$24 M	$61 M	$64 M	$59 M	$208 M
Natural Gas Pipe line Cost *				$4 M	$4 M	$4 M	$4 M	$17 M
SubTotal				$28 M	$65 M	$69 M	$63 M	$225 M
Fuel Cost				$65 M	$167 M	$190 M	$204 M	$627 M
VOM Cost				$13 M	$38 M	$39 M	$38 M	$128 M
Total Cost Delta				$106	$270	$298	$305	$980 M

*Note: * Pipeline installation cost is based on $60 M one-time cost amortized over 25 year period with 5.5% interest.*

4.3.3.3 Fuel Price Stress Test

The importance of stress testing the model results of the 4 coal cases is to determine the range of exposure to economic risk due to fuel price volatility. Historically, natural gas prices have 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 eliminates the fuel cost for 20 percent of our current fuel supply.

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. Therefore, natural gas prices become the primary concern when assessing future cost impacts. Replacing Navajo and IPP Generating Stations with gas fired generation would expose our ratepayers to fuel markets which may result in higher or lower fuel costs which are much less predictable.

Realizing the need for accurate fuel price forecasts, LADWP contracted with Wood Mackenzie Research and Consulting to provide natural gas price high and low forecasts to stress test future power production costs as shown in Figure 4-16. Also included in the high and low range forecasts were coal prices received from LADWP's External Generation Group. Based on the expertise and experience of the Coal Supply Group, a ±20 percent factor was applied to the expected coal fuel price to determine a high and low range for coal prices.

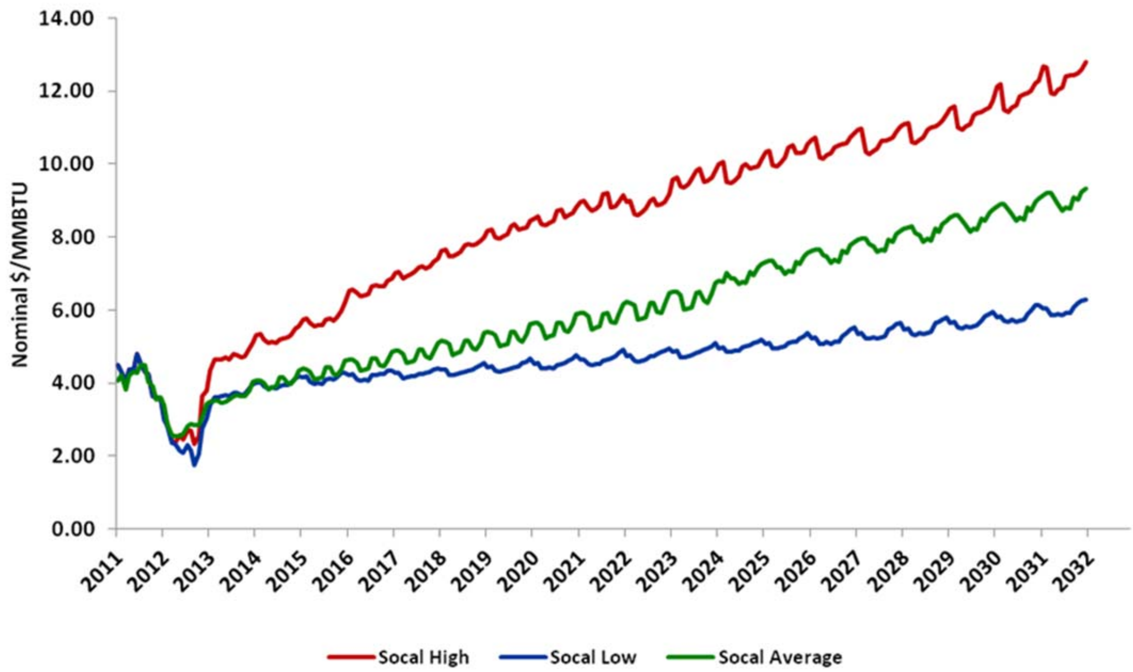


Figure 4-16. High, low, and expected natural gas price forecasts (So Cal Gas).

The natural gas price curves furnished by Wood Mackenzie Research and Consulting show a greater propensity towards higher than 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 4-17 – the relative shape of the curve is asymmetrical with the forward tail (higher prices) extending further away from the mean of the curve.

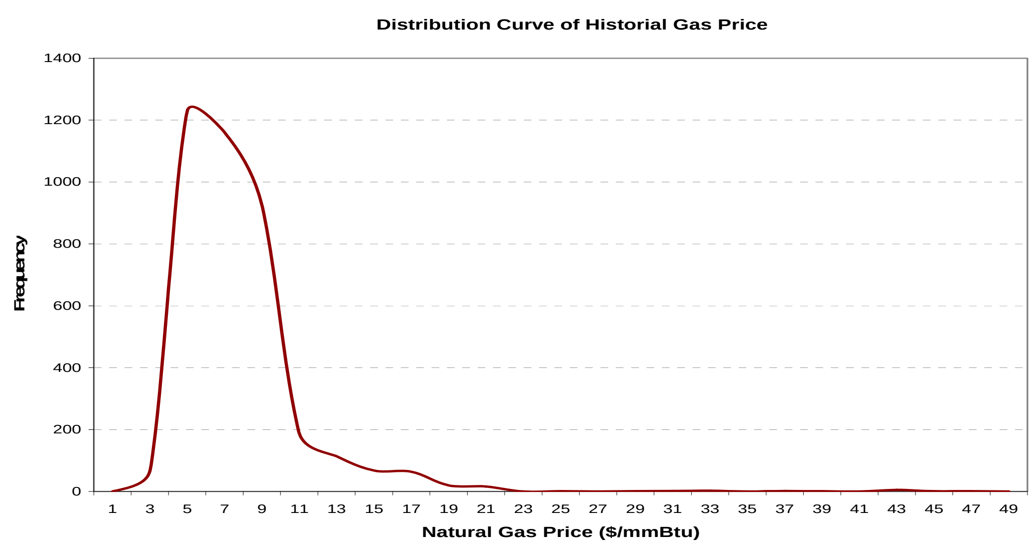
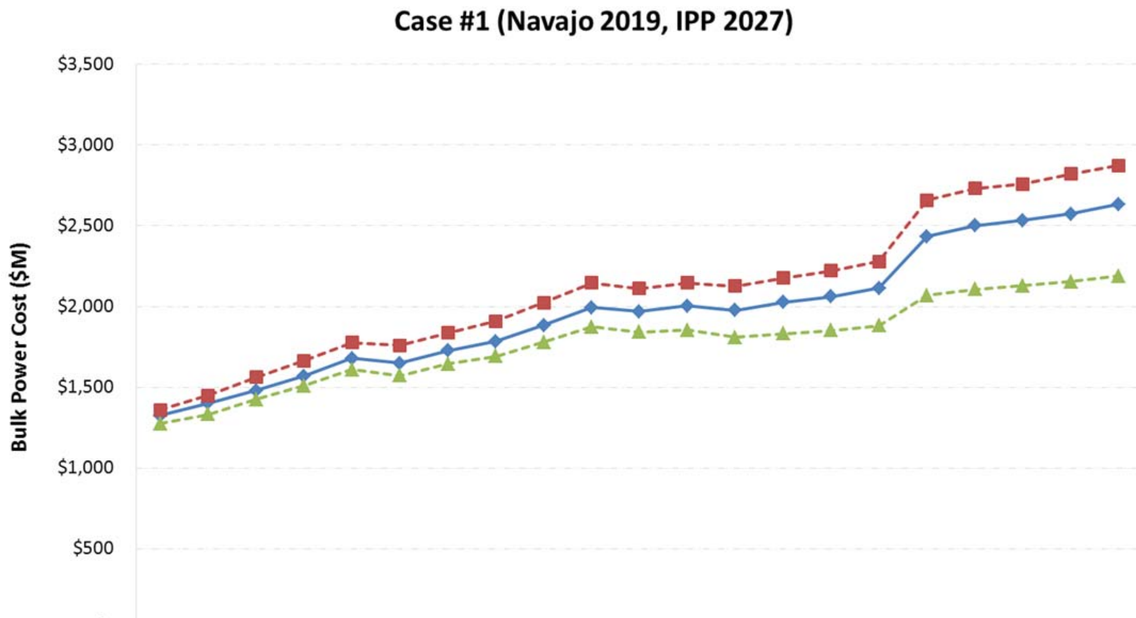


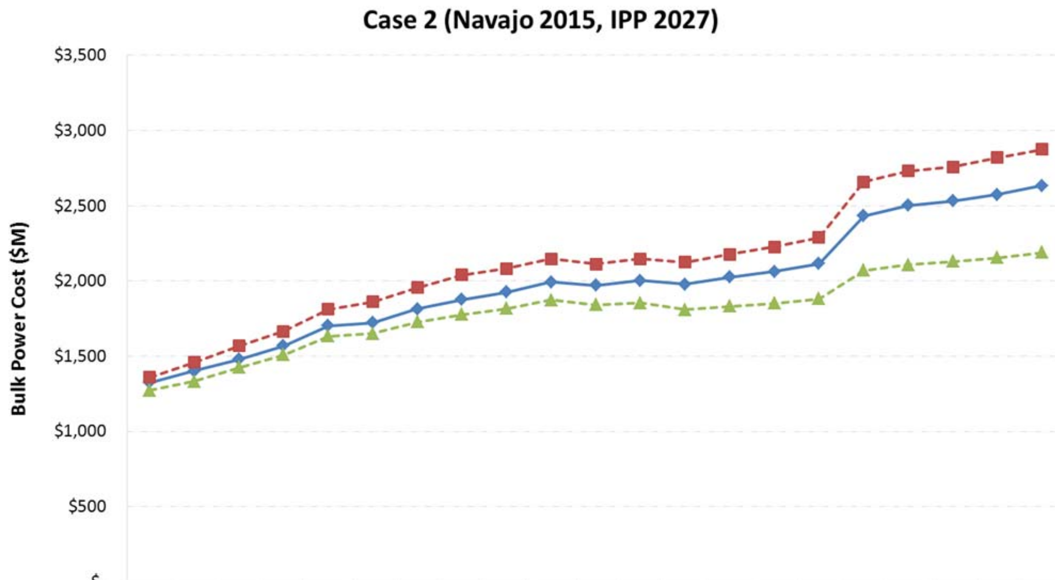
Figure 4-17. Historical distribution of natural gas prices (SoCal, 2005 through 2010).

The high and low fuel price ranges were then incorporated into the four strategic case model runs. The four charts shown in Figure 4-18 display the results of bulk power costs for each of the 4 coal cases. The wider the range from the high fuel case to the medium fuel case indicates increased exposure to risk from the higher fuel costs.

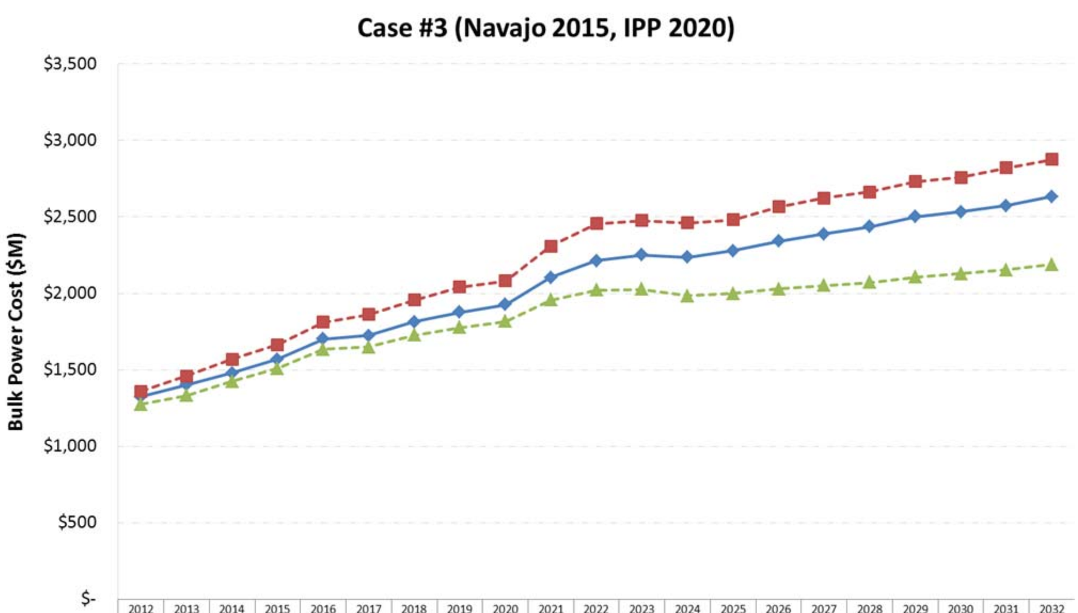


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Case #1	$1,324	$1,400	$1,479	$1,568	$1,678	$1,647	$1,727	$1,783	$1,884	$1,993	$1,969	$2,003	$1,977	$2,025	$2,061	$2,113	$2,433	$2,501	$2,532	$2,573	$2,634
Case #1_H	$1,358	$1,449	$1,560	$1,663	$1,776	$1,759	$1,837	$1,909	$2,023	$2,146	$2,112	$2,147	$2,125	$2,175	$2,221	$2,278	$2,659	$2,730	$2,757	$2,821	$2,873
Case #1_L	$1,272	$1,331	$1,424	$1,508	$1,608	$1,571	$1,644	$1,691	$1,779	$1,873	$1,840	$1,853	$1,809	$1,830	$1,850	$1,881	$2,069	$2,106	$2,129	$2,153	$2,189

Figure 4-18. Bulk power cost comparison - high, low, and expected fuel prices.

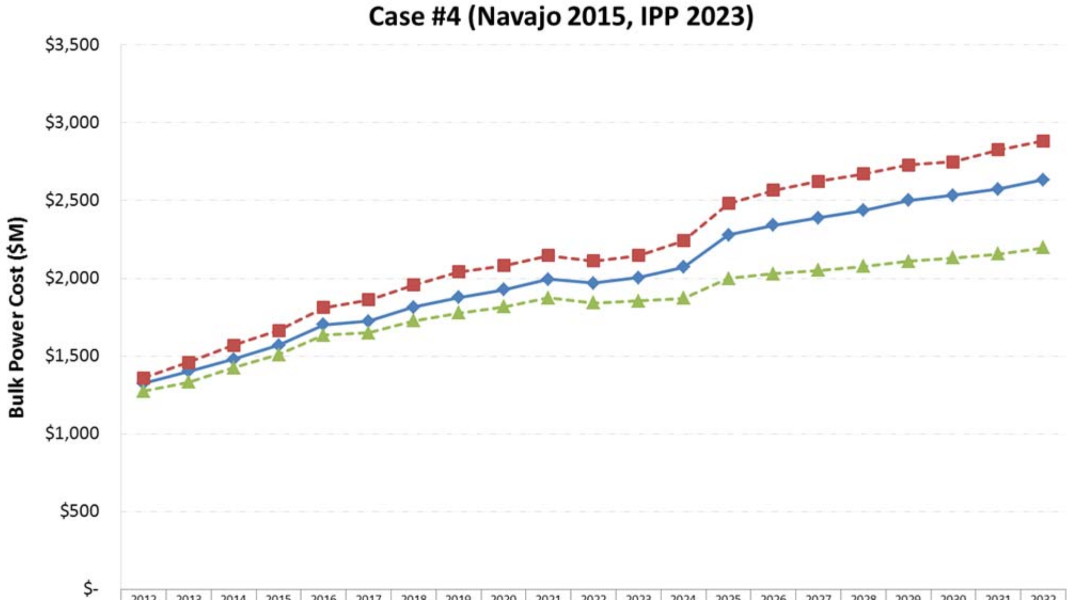


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Case #2	$1,324	$1,400	$1,479	$1,568	$1,701	$1,722	$1,813	$1,875	$1,925	$1,993	$1,969	$2,003	$1,977	$2,025	$2,061	$2,113	$2,433	$2,501	$2,532	$2,573	$2,634
Case #2_H	$1,359	$1,458	$1,568	$1,664	$1,810	$1,861	$1,955	$2,040	$2,081	$2,146	$2,112	$2,147	$2,125	$2,175	$2,225	$2,288	$2,659	$2,730	$2,757	$2,821	$2,875
Case #2_L	$1,272	$1,331	$1,424	$1,508	$1,633	$1,648	$1,726	$1,776	$1,815	$1,873	$1,840	$1,853	$1,809	$1,830	$1,850	$1,881	$2,069	$2,106	$2,129	$2,153	$2,189



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Case #3	$1,324	$1,400	$1,479	$1,568	$1,701	$1,722	$1,813	$1,875	$1,925	$2,104	$2,214	$2,251	$2,235	$2,278	$2,341	$2,389	$2,436	$2,501	$2,532	$2,573	$2,634
Case #3_H	$1,359	$1,458	$1,568	$1,664	$1,810	$1,861	$1,955	$2,040	$2,081	$2,307	$2,456	$2,475	$2,462	$2,480	$2,565	$2,624	$2,663	$2,730	$2,757	$2,821	$2,875
Case #3_L	$1,272	$1,331	$1,424	$1,508	$1,633	$1,648	$1,726	$1,776	$1,815	$1,957	$2,021	$2,027	$1,982	$1,998	$2,027	$2,050	$2,071	$2,106	$2,129	$2,153	$2,189

Figure 4-18. (continued)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Case #4	$1,324	$1,400	$1,479	$1,568	$1,701	$1,722	$1,813	$1,875	$1,925	$1,993	$1,969	$2,003	$2,072	$2,278	$2,341	$2,389	$2,436	$2,501	$2,532	$2,573	$2,634
Case #4_H	$1,359	$1,458	$1,568	$1,664	$1,810	$1,861	$1,955	$2,040	$2,081	$2,146	$2,112	$2,147	$2,240	$2,480	$2,565	$2,624	$2,670	$2,728	$2,748	$2,825	$2,883
Case #4_L	$1,272	$1,331	$1,424	$1,508	$1,633	$1,648	$1,726	$1,776	$1,815	$1,873	$1,840	$1,853	$1,871	$1,998	$2,027	$2,050	$2,075	$2,107	$2,131	$2,156	$2,197

Figure 4-18. (continued)

An analysis of the effects of fuel price volatility was performed for the four coal cases and is shown in Figure 4-18. With the early divestiture of Navajo in 2015 and the IPP coal contract ending in June 2027, 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 so warrants careful evaluation when comparing the different case scenarios.

It is important to note that bulk power costs shown in Figure 4-19 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 could result in large cost increases should fuel prices remain at higher than expected levels. Conversely, lower than expected fuel prices could 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. LADWP is in the process of developing a revised hedging strategy based on the newly approved rate ordinance.

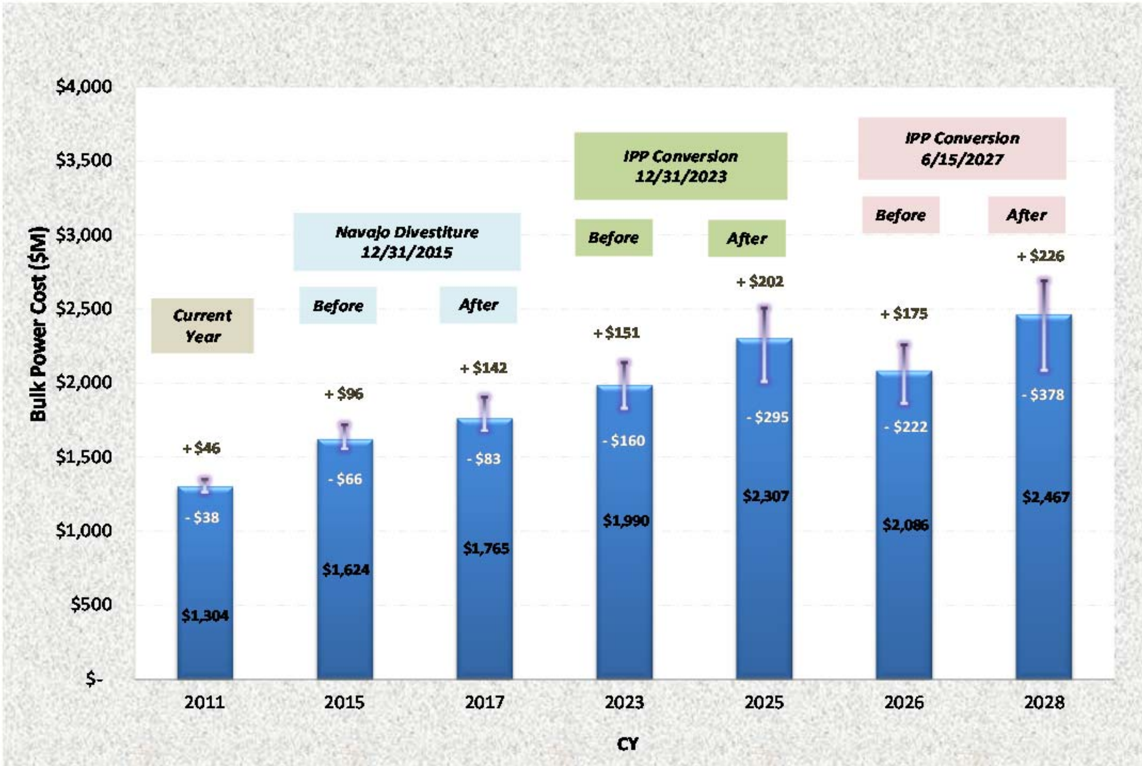


Figure 4-19. Bulk power cost with high and low fuel costs by calendar year.

By the year 2020 NGS will retire in all four cases, with Case 3 and 4 showing IPP being replaced in 2020 and 2023, respectively, with two 575 MW combined cycle units.

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. Figure 4-20 shows the potential rates that could be experienced under the 4 coal cases given high, expected, and low fuel ranges for both gas and coal fuel types. Today, overall coal costs represent approximately 65 percent of overall fuel expenditures. Once Navajo coal is replaced in 2015, this percentage will drop to 50 percent of overall fuel expenditures. From 2023 thru 2026, coal expenditures will gradually drop to 30 percent before reaching zero percent in 2027 when IPP coal is replaced, and future fuel price increases will be based solely on natural gas and nuclear.

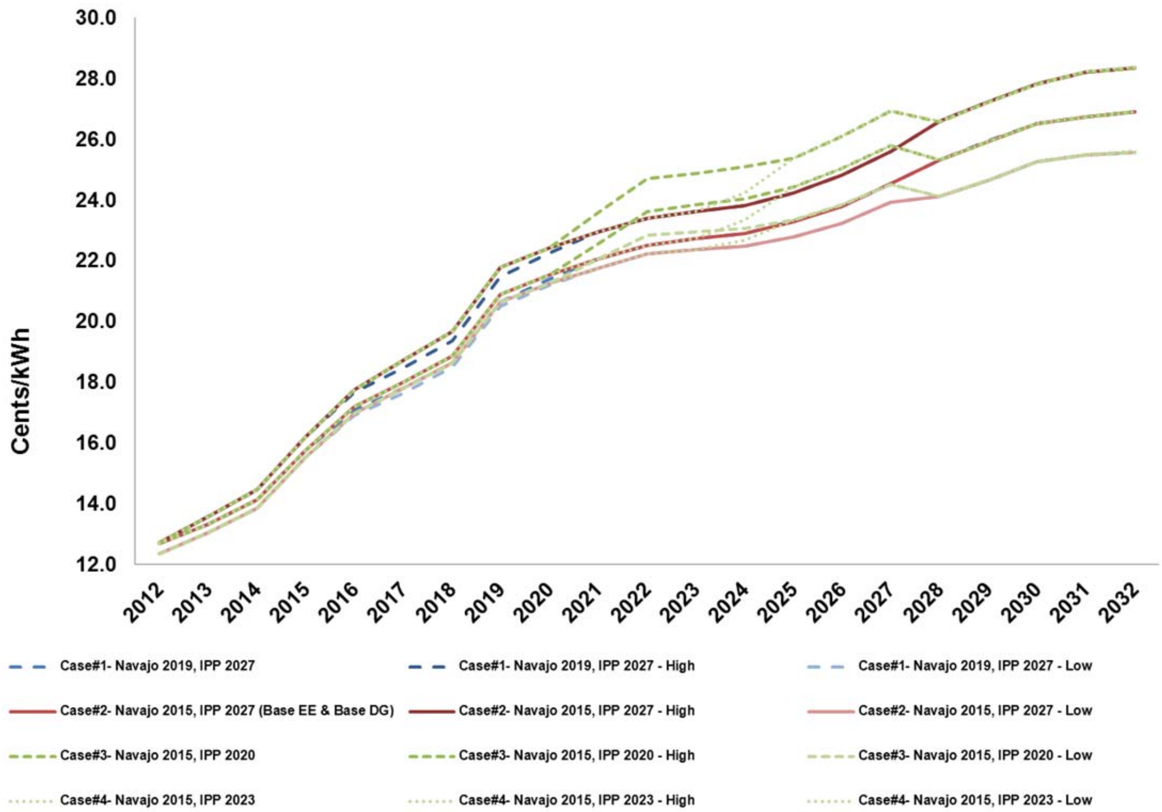


Figure 4-20. Estimated electric rate comparison with fuel price sensitivity over 20 years by fiscal year-ending

4.3.3.4 Reliability and Regulatory Revenue Requirements

Bulk Power costs discussed previously make up less than half of the cost to operate 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 PRP attract the most attention, investments in these programs are a subset of the generation, transmission, 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 4-6. Today, these reliability and regulatory programs comprise 28% of all Power System costs and in 2020 these same programs will grow to approximately 42%.

Table 4-6 shows the breakdown of these reliability and regulatory costs with RPS and PRP 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.

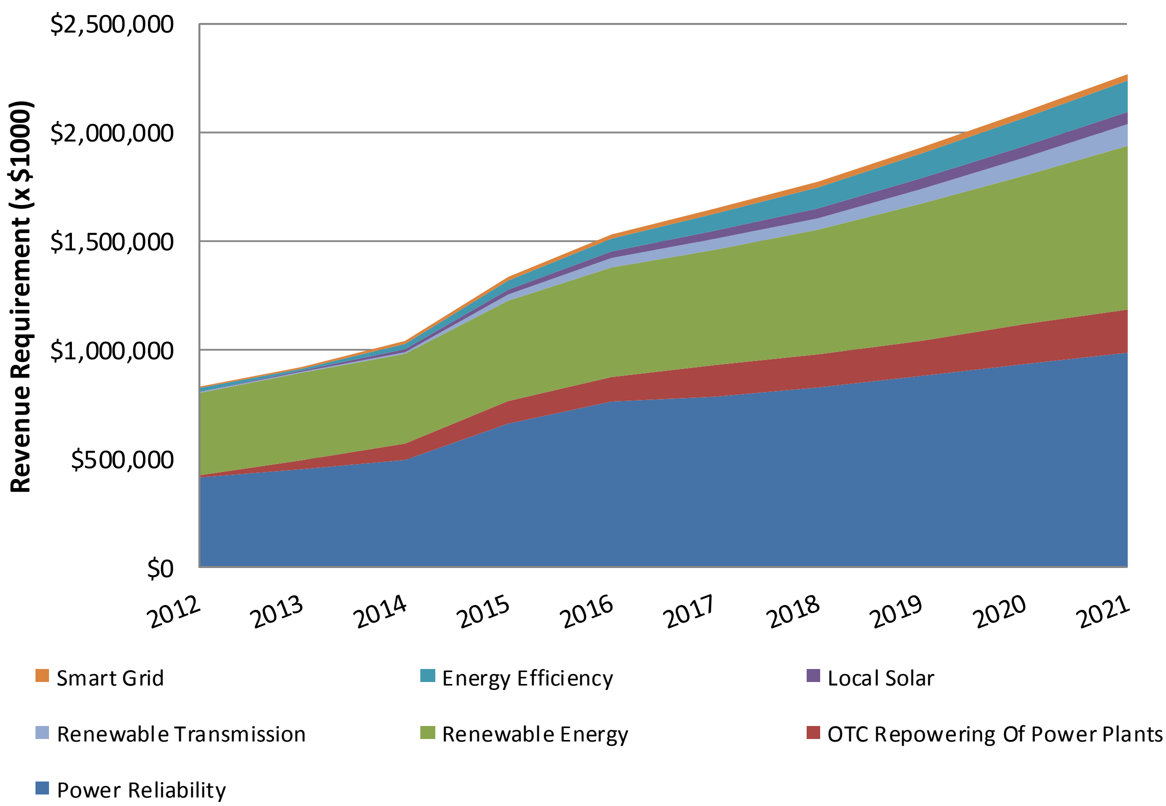


Figure 4-21. Annual revenue requirement for reliability and regulatory program for fiscal year ending 2012 through 2021.

Table 4-6. Annual revenue requirements of Power System programs, fiscal year ending 2012 through 2021 (x$1000) – Case 2

Power Reliability										
Debt Service (Less Smart Grid)	$70,450	$95,292	$122,219	$157,222	$190,430	$230,056	$272,729	$311,882	$351,889	$389,690
O&M	**$342,642**	**$356,509**	**$372,302**	**$504,000**	**$572,000**	**$554,000**	**$554,000**	**$567,850**	**$582,046**	**$596,597**
	$413,092	$451,800	$494,520	$661,222	$762,430	$784,056	$826,729	$879,732	$933,935	$986,288
Sum Total 2011-2020	**$7,193,805**									
OTC Repowering Of Power Plants										
Debt Service	$9,834	$41,196	$74,347	$103,562	$112,068	$145,782	$152,050	$160,646	$184,236	$198,432
	$9,834	$41,196	$74,347	$103,562	$112,068	$145,782	$152,050	$160,646	$184,236	$198,432
Sum Total 2011-2020	**$1,182,154**									
Transition from Coal Early (NGS)										
Debt Service	$0	$0	$0	$0	$9,000	$18,000	$18,000	$18,000	$12,000	$0
Fuel & VOM	$0	$0	$0	$0	$12,509	$30,463	$34,126	$35,447	$17,923	$0
	$0	$0	$0	$0	$21,509	$48,463	$52,126	$53,447	$29,923	$0
Sum Total 2011-2020	**$205,468**									
Renewable Energy										
Debt Service	$37,499	$34,862	$30,676	$27,790	$28,120	$29,511	$56,038	$91,118	$110,338	$128,456
O&M	$33,415	$34,703	$36,880	$39,563	$40,272	$41,564	$44,009	$46,030	$47,107	$47,878
Purchased Power (PPA's)	$306,641	$331,676	$344,494	$392,655	$434,915	$458,146	$472,365	$493,257	$524,059	$575,341
	$377,554	$401,241	$412,050	$460,009	$503,307	$529,221	$572,413	$630,404	$681,504	$751,675
Sum Total 2011-2020	**$5,319,379**									
Renewable Transmission										
Debt Service	$4,104	$4,700	$7,989	$29,209	$43,541	$50,497	$52,095	$67,444	$83,257	$99,896
	$4,104	$4,700	$7,989	$29,209	$43,541	$50,497	$52,095	$67,444	$83,257	$99,896
Sum Total 2011-2020	**$442,731**									
Local Solar										
SB1 Debt Service	$11	$1,582	$5,708	$9,746	$11,050	$12,043	$12,931	$13,240	$13,501	$13,758
UBS Debt Service	$794	$3,264	$4,801	$5,716	$6,651	$7,477	$10,999	$12,172	$13,217	$14,247
FIT (PPA)	$0	$967	$3,157	$6,530	$12,124	$18,154	$21,840	$23,976	$26,006	$27,819
	$806	$5,813	$13,665	$21,992	$29,826	$37,674	$45,769	$49,387	$52,724	$55,824
Sum Total 2011-2020	**$313,480**									
Energy Efficiency										
Debt Service	$1,061	$7,919	$24,368	$41,939	$58,797	$77,731	$96,317	$113,235	$129,247	$143,535
O&M	$17,512	$0	$0	$0	$0	$0	$43	$41	$0	$0
	$18,574	$7,919	$24,368	$41,939	$58,797	$77,731	$96,360	$113,276	$129,247	$143,535
Sum Total 2011-2020	**$711,747**									
Smart Grid										
Debt Service (Operation Support)	$2,502	$3,983	$8,017	$9,803	$11,043	$12,314	$13,217	$14,001	$14,791	$15,543
Debt Service (PRP)	$3,272	$4,265	$5,478	$6,875	$8,565	$10,733	$13,060	$14,066	$14,172	$14,273
	$5,775	$8,249	$13,495	$16,679	$19,608	$23,048	$26,277	$28,067	$28,963	$29,816
Sum Total 2011-2020	**$199,977**									
Basic Gen, Trans, Dist	$2,107,365	$2,191,782	$2,231,555	$2,324,597	$2,436,454	$2,476,026	$2,557,276	$2,889,040	$2,938,467	$2,978,430
	$2,107,365	$2,191,782	$2,231,555	$2,324,597	$2,436,454	$2,476,026	$2,557,276	$2,889,040	$2,938,467	$2,978,430
Sum Total 2011-2020	**$25,130,991**									
Total Power System Revenue Requirement										
	$2,933,000	$3,108,000	$3,264,000	$3,630,000	$3,944,000	$4,122,000	$4,329,000	$4,804,000	$4,979,000	$5,144,000
Sum Total 2011-2020	**$40,257,000**									

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 preferred Power Reliability Program and Energy Efficiency programs among others. Total annual Power System costs are shown in Figure 4-22 and reflect short-term spending reductions through 2011-12 fiscal year with subsequent years reflecting a restoration of funding levels to ensure that the longer term IRP recommendations can be realized. To the extent that energy efficiency costs are lower than the costs of generation it is replacing, its effect is to lower total costs. 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 4 coal and 4 EE/DG cases analyzed.

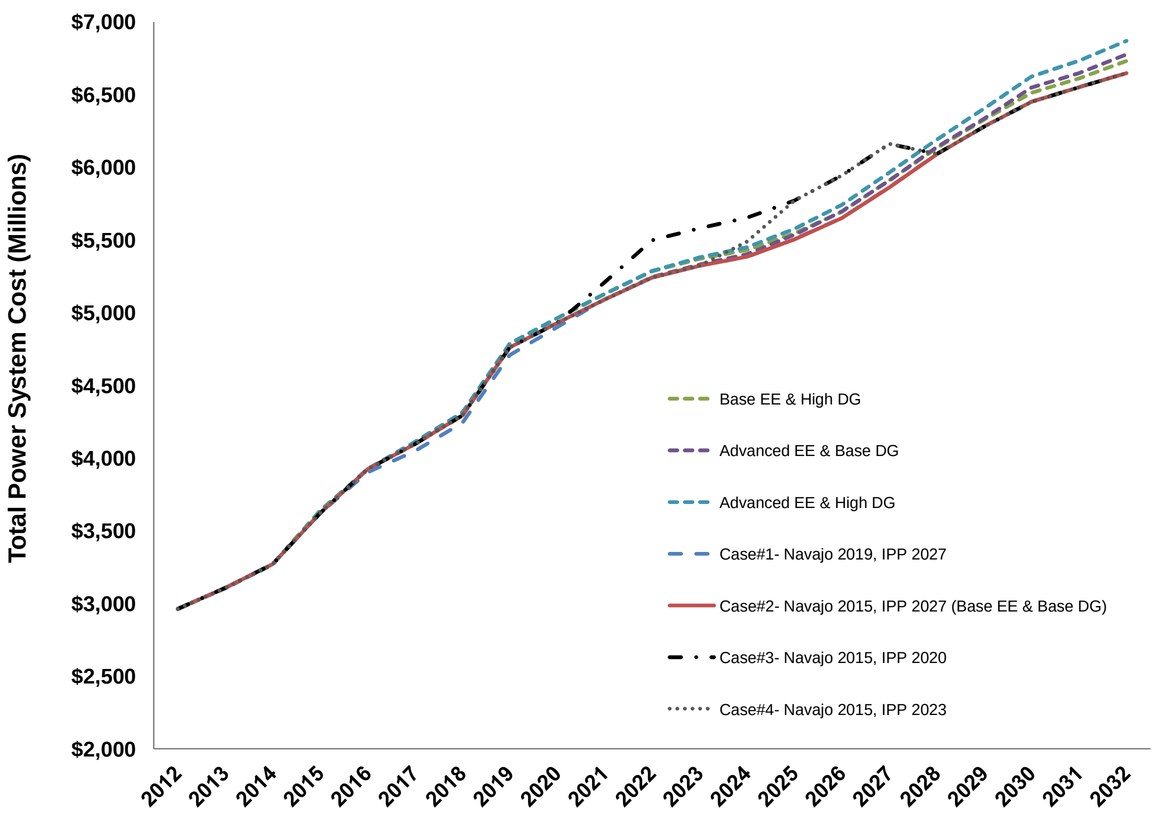


Figure 4-22. Comparison of annual Power System costs over the next 20 fiscal years.

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

The cost differences between the cases are highlighted in Table 4-7, which presents the incremental costs of the 4 coal cases and the 4 EE/DG cases. For the coal cases, the values listed under the Case 2 column represent the incremental costs between Cases 1 and 2 – i.e., the cost of early divestment of Navajo. The values listed under Case 3 and Case 4 represent the additional incremental costs of early IPP replacement in 2020 and 2023, respectively.

All EE & DG cases assume Navajo divestment in 2015 and IPP replaced in 2027. The values shown for Cases 6, 7, and 8 represent each case's incremental costs when compared to Case 5.

TABLE 4-7 - INCREMENTAL COST COMPARISONS BETWEEN CASES

Coal Case Summary

	Case 1	Case 2	Case 3	Case 4
Case Description	Navajo 2019, IPP 2027	Navajo 2015	IPP 2020	IPP 2023
Total Incremental Revenue $M	$0	$205	$1,790	$980
Average Incremental Revenue ($M/yr)	$0	$51	$275	$280

EE & DG Case Summary

	Case 5 (Baseline) *	Case 6	Case 7	Case 8
Case Description	Base EE & Base DG	Base EE & High DG	Advanced EE & Base DG	Advanced EE & High DG
Total Incremental Revenue $M	$0	$669	$494	$1,247
Average Incremental Revenue ($M/yr)	$0	$32	$24	$59

Figure 4-23 illustrates the net present value of the total Power System costs for each of the coal strategic cases.

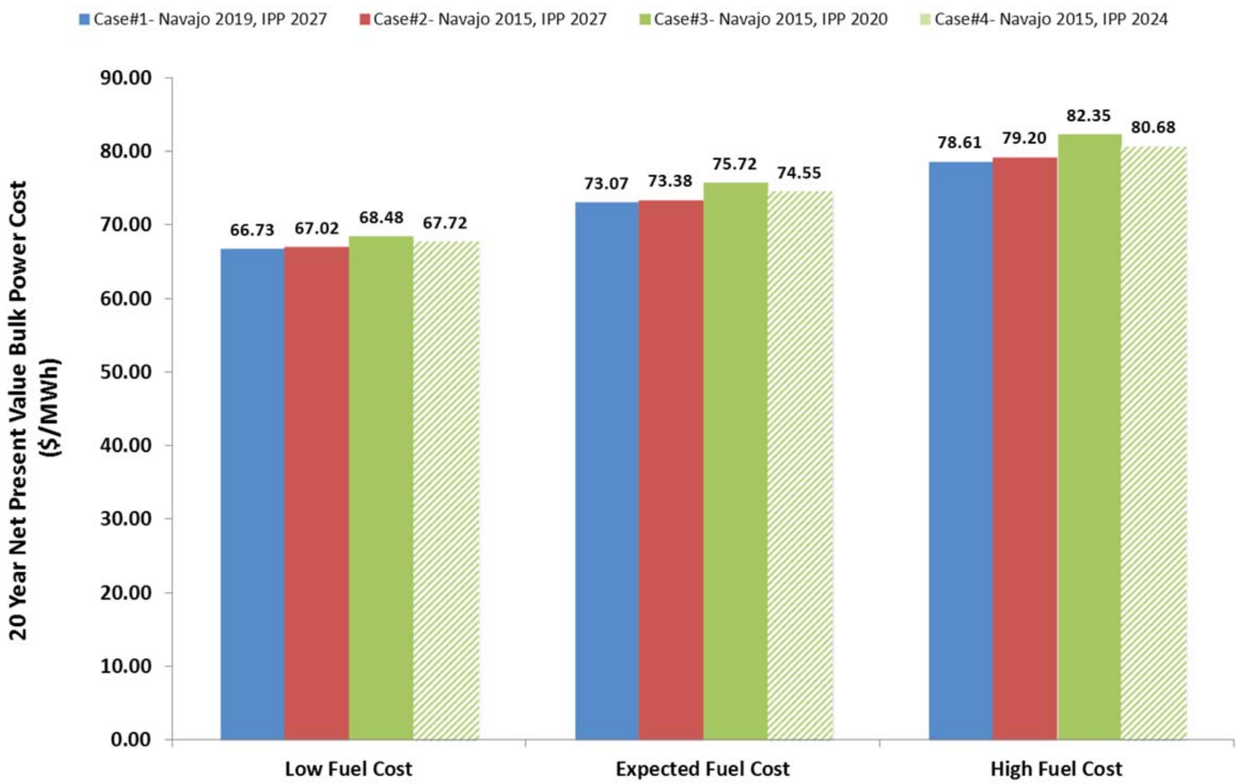


Figure 4-23. Total net present value comparison of Power System costs of 4 coal cases.

4.4 Strategic Case Conclusions and Recommendations

4.4.1 Reliability

All four 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, all four 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 is achieved. Case 2 removes NGS energy four years earlier than in Case 1 and results in 7.2 million metric tons less GHG emissions over the 20-year study period. In addition to early NGS divestiture, Case 3 accelerates the replacement of IPP seven years earlier than Case 2, results in a further reduction of 19.5 million metric tons over the 20-year period whereas Case 4 replaces IPP four years earlier which reduces an additional 9.3 million metric tons of GHG emissions. See Figure 4-4 and Table 4-3.

4.4.3 Economic

While the Base Case 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 2, 3 and 4 depends on the level of rate increases ratepayers are willing to support while achieving the 33% required RPS by 2020, 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.

With early divestiture of Navajo, an additional revenue increase of $51 million per year or $205 million over four years would be necessary to achieve GHG reductions of 7.2 million metric tons between years 2016 and 2019. This equates to a cost of $28 to remove 1 metric ton of GHG. However, as previously discussed in Section 4.3.3.3, the early divestiture of Navajo will expose ratepayers to potentially higher natural gas fuel prices that may result in further revenue increases up to $141 million per year if gas prices were to remain at these higher levels.

Considering Case 3 with early replacement of IPP and Navajo, revenue increases of approximately $275 million per year or $1,790 million over 6.5 years would be necessary to achieve additional GHG reductions of 19.5 million metric tons between the years 2021 and 2027 due to the replacement of IPP. This equates to a cost of $92 to remove 1 metric ton of

GHG. With potentially higher natural gas fuel prices, additional revenue increases could be as high as $214 million per year if gas prices were to remain at these higher levels.

The new Case 4 presents a new scenario with early divestiture of Navajo and replacement of IPP in 2023 with a better financial plan as discussed in the beginning of this section, at the same time yielding significantly reduced GHG emissions. Case 4 will result in an increase of $245 million per year or $980 million over a four year period and would result in a cost of $105 to remove 1 metric ton of GHG.

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 EE/DG 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 costs be closely managed. Considering these factors, Case 5 with early Navajo coal divestiture in 2015, Base EE and Base DG with additional Local Solar FiT DG becomes the Recommended Case for the 2012 IRP. Whereas Case 5 has 75 MW of local solar FiT by 2016, the new recommendation is to adopt an additional 75 MW for a total of 150 MW by 2016 based on input that was received from the public outreach efforts. The increase in cost for the additional 75 MW of FiT is an average of 0.018 cents/kWh or a 9 cent increase in the typical residential monthly bill (500 kWh/month). Although Case 5 with the added FiT represents additional cost as compared to the 2011 Recommended Case, the additional costs to rate payers appears to be reasonable in light of the benefits of job growth and support of the local economy from adopting higher levels of DG solar. As described in the 2011 IRP, the environmental benefits of reducing GHG emissions by 7.2 MMT are still present with the early Navajo replacement. The cost to implement Navajo divestiture in terms of metric tons of GHG removed is $28/MMT. This represents a reasonable cost in line with the range of expected AB32 cap and trade allowance prices. Other benefits of early Navajo divestiture include a better sales price than waiting until 2019, and better availability (lower costs) of replacement energy. With Case 5 and the noted addition of FiT and Navajo divestiture in place, LADWP can begin to focus its attention on early replacement of IPP coal generation, prior to 2027, by working with the other power purchasers and the IPP plant owner.

The 2011 IRP included the same recommendation to accelerate divestiture of Navajo and this 2012 IRP further clarifies and supports this prior recommendation. This 2012 IRP recommended case presents a reasonable approach to achieving environmental goals and promoting job growth in the local economy without excessive costs to our ratepayers 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. SB 2 (1X) also establishes interim targets to ensure progress towards the 33 percent goal. 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 will exceed this mandate and provide 150 MW by 2016).

- Power Reliability Program (PRP) and System Infrastructure Investment

  LADWP must re-establish sustained funding to invest in replacing transmission and distribution infrastructure that are contributing to outages to ensure system reliability Recent funding shortfalls have resulted in an increase in the frequency and duration of system outages. Section 1.6.3 of this IRP discusses the importance of fully funding the Power Reliability Program (PRP). As discussed in Section 2.4.6, the PRP will also optimize the resiliency of the distribution infrastructure to better withstand the more volatile weather patterns that are expected due to climate change.

- 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 ocean water cooling.

- AB 32 – GHG Cap and Trade

  LADWP will participate in the mandated greenhouse cap-and-trade system which is scheduled to start January 1, 2013. LADWP has been granted an administrative allocation of emission allowances that reflects its resource projections through 2020. At this time, it is uncertain if the program will extend beyond 2020, and if so, what LADWP obligations would be.

- Energy Efficiency (EE)

  LADWP will continue to pursue and implement EE programs per AB 2021 standards and as directed by the Board of Water and Power Commissioners, who have adopted a goal of achieving 10 percent EE by 2020, with a target of up to 15% by 2020 pending the results of an upcoming new EE Potential Study. The Base EE case evaluated in this 2012 IRP includes 10% EE by the year 2020, with higher levels of up to 15% by 2032. Next year's IRP will incorporate the findings and recommendations of the potential study as they are finalized and approved.

- SB 1368 Compliance

  LADWP's two coal-fired generation sources, the Navajo Generating Station 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

  Per AB 2514, LADWP is investigating Energy Storage (ES) technologies and will establish targets for implementation by October 1, 2014. LADWP will look for programs and projects that support its unique electric grid, resource plan, and projects that will facilitate renewable integration, distributed generation and demand response. As these projects are identified and scoped, they will be incorporated into and analyzed in future IRPs. See Section 2.4.5 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 joint 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. The planning process involves complex modeling of the LADWP system, and concludes with findings and recommendations to avoid potential future overload conditions. LADWP will continue to implement the recommended projects, including construction of a new 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

  Regarding the Navajo Generating Station (NGS), while power imports can legally continue until 2019, LADWP recommends divestiture from NGS four years earlier, in 2015. There are many strategic advantages to early divestiture, including:

  1. Better sales terms and conditions than waiting until the 2019 deadline.
  2. Avoiding the risk of pending federal regulations that could potentially encumber the plant with expensive mitigation requirements.
  3. Better availability and pricing for replacement generation.
  4. Reduced CO_2 emissions, alleviating LADWP from subsequently having to purchase emission credits within the soon-to-be implemented statewide cap and trade program.
  5. Transmission network for importing additional solar and geothermal resources becomes available.
  6. Low load growth and increased renewable energy place less reliance on the plant for energy.
  7. Provides time to handle contingencies, and to ensure that competition for replacement resources is going to benefit our ratepayers.

Regarding the Intermountain Power Project (IPP), LADWP recommends modeling and planning to be compliant with SB 1368 by 2027. However, LADWP, the Intermountain Power Agency (IPA), and the other 36 participants are considering the conversion of IPP from coal to natural gas. A new contractual arrangement is in process, which will establish a firm conversion date that will be no later than, and possibly sooner, than 2027.

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.

- Demand Response

LADWP should accelerate its evaluation and implementation of Demand Response programs that will initially provide 5 MW of new peak demand capacity beginning in 2013 and gradually build to 200 MW by 2020 and 500 MW by 2026. Ramping the program in this manner will provide the development of in-house expertise, and will also allow time to deploy the supporting information systems necessary to implement these systems successfully.

- 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 allow 340 MW of its solar resources be sited locally by 2016, through initiatives including the Solar Incentive Program, feed-in tariffs, and installation of solar on City-owned properties. Local solar costs an estimated additional \$36/MWh over utility-scale solar located outside the Los Angeles Basin, estimated to cost \$116/MWh, primarily due to economies of scale and about 30% better solar insolation, even when considering transmission and distribution costs.

- Advanced Reliability Improvements

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 advanced 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 advance the use and deployment of new technologies that meet its strategic goals.

- Provide Sufficient Generation

  Provide sufficient generation, demand response, and limited short term purchases in peak season Q3 to cover operating and replacement reserves in accordance to applicable federal and regional reliability requirements.

- 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 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 its credit rating, the following financial targets have been adopted:

    - Maintain debt service coverage at 2.25 times
    - Minimum operating cash target of $300 million
    - Debt-to-capitalization ratio less than 68 percent

5.2 Incorporating Public Input

Through its public outreach efforts in 2012, LADWP received various suggestions from the community including increasing energy efficiency and conservation, eliminating coal from LADWP's resource mix, emphasizing local solar generation, maintaining competitive rates, and addressing infrastructure reliability issues. 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. Some were concerned that Navajo would continue to operate after LADWP divestiture, and suggested the plant be shut down. Greenhouse gas emissions, along with other pollutants associated with coal energy were noted.

Incorporate More Renewables

Many public comments suggested higher levels of renewables, beyond the mandated 33% by 2020. Some promoted the idea of 50% and even 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. The IRP is prepared annually, and it is possible that future IRPs will include cases that incorporate higher levels of renewables.

Incorporate More Local Solar

Many comments promoted the adoption of higher levels of local solar, noting the abundance of sunshine in southern California region. The benefit of providing local jobs was also noted as a supporting argument to increase penetration levels. One comment suggested installing solar on every house and building in Los Angeles. Regarding LADWP's current solar 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 Distributed Generation

Since the majority of LADWP's new Distributed Generation (DG) will come from local solar, this theme is somewhat associated with the More Local Solar theme. Most of the comments regarding more DG point to the governor's statewide goal for 12,000 MW, of which LADWP' proportionate share is assumed to be 1,200 MW. Within this 2012 IRP, the highest levels of new DG considered for analysis were 485 MW by 2020, and 852 MW by 2032. LADWP's concern with DG levels is maintaining reliability (see Section 3.4.4). Numerous utility studies have recommended a limit of 15% of the peak load circuit capacity, which for LADWP is approximately 900 MW. As LADWP adopts more DG per its current plan, and as more experience is gained along with more industry-wide research in this area, it is possible that future IRPs will consider higher DG levels.

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; with a further anticipated increase to 15%, pending completion of an updated potential study in 2013. Comments received supported incorporating more EE and Demand Response into LADWP future plans. As presented in this 2012 IRP, EE and DR is a vital component within all long term resource planning options. As the results of the upcoming potential study are developed and finalized, they will be adopted into the IRP planning strategy.

Reduce Greenhouse Gas Emissions

This was an overarching theme of the public comments received. Indirect societal costs, health effects, global warming, and super storm Sandy were cited as reasons for accelerating the timelines to reduce GHGs. In considering the GHG impacts of fuel consumption for electricity generation, many comments pointed to the additional impacts resulting from fuel production (coal mining and gas drilling). Comments pointed out the need for considering energy efficiency, demand response, load shifting, and other technologies such as shunt reactive support to offset future additions of gas-fired capacity.

Look at New Case Scenarios

Many comments suggested a scenario that contained no new gas-generation resources, an eventual portfolio of 100% renewables, and investments in EE, conservation, renewables and demand response. Some felt that multiple sets of potential renewable resource mixes should be considered. LADWP prepares a new IRP annually and will consider new scenarios within subsequent case option development processes.

Financial and Rate Concerns

Some comments expressed concern that LADWP needs to ensure its financial stability and integrity. Many comments presented concerns with rising electricity rates wanting to ensure that the cost and benefits were clearly presented; and recommended a comparison of costs with other regional and out-of-state utilities. One comment suggested that LADWP keep coal for as long as possible explaining that other forms of energy were not mature and too costly. Conversely, other comments suggested that rate increases were acceptable if EE options are made available to help customers reduce their bills. One comment suggested that LADWP rates are too low and the tiers are too generous – resulting in disincentives for EE and renewables.

Maintain Power Reliability

Some comments expressed concern about the state of the LADWP infrastructure, noting that the reliability program continues to be subject to budgets cuts - unlike mandated areas such as renewables. They point to the 2011 windstorm and 2006 heat storm as evidence that the infrastructure is getting older and more costly to maintain, and suggest that paying more now to address this problem will save money later.

LADWP s Should Take a Leadership Role

Regarding renewable resources and other green energy matters, many suggested that LADWP, as a municipal utility, should lead by example; consider unconventional business models, and through its governance, garner the political will to do something different.

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, Case 5 with the addition of 150 MW of FiT by 2016 has emerged as the Recommended Case for this 2012 IRP. The key attributes of Case 5 includes the following:

- At least 10 percent of Los Angeles' electric needs will be met through new customer energy efficiency measures by 2020.
- At least 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 maintain that level through 2032. Although this IRP incorporates one combination set of renewable resources to achieve a 33% RPS, 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.
- Diversify LADWP's RPS through incorporating 114 MWs of generic renewable resources by 2032. These resources could be 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 thru Smart Grid.
- Emphasize local solar by proposing approximately 340 MW of solar capacity to be locally sited in Los Angeles by 2016. This will be accomplished through programs such as the Customer Solar Incentive Program, a feed-in tariff goal of 150 MW by 2016, and Solar on Los Angeles properties under public/private partnership (a.k.a. UBS).

Benefits of early Navajo divestiture include a better sales price than waiting until 2019, and better availability (less costs) of replacement energy. With Case 5 and the noted addition of FiT and Navajo divestiture in place, LADWP can begin to focus its attention on early replacement of IPP coal generation, prior to 2027, by working with the other power purchasers and the IPP plant owner.

The Recommended Case for 2012 is summarized in Table 5-1.

Table 5-1. 2012 IRP RECOMMENDED CASE

	2020	SB 1368 Compliance Date		New Renewables Installed (MW) 2012-2020				New Renewables Installed (MW) 2012-2032				
Case ID	RPS Target	Navajo End Date	IPP End Date	Geo/ Biomass	Non-DG Solar	Dist. Solar	Generic	Geo/ Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
Case 5	33%	12/31/2015	6/15/2027	242	842	382	39	283	54	915	496	114

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.

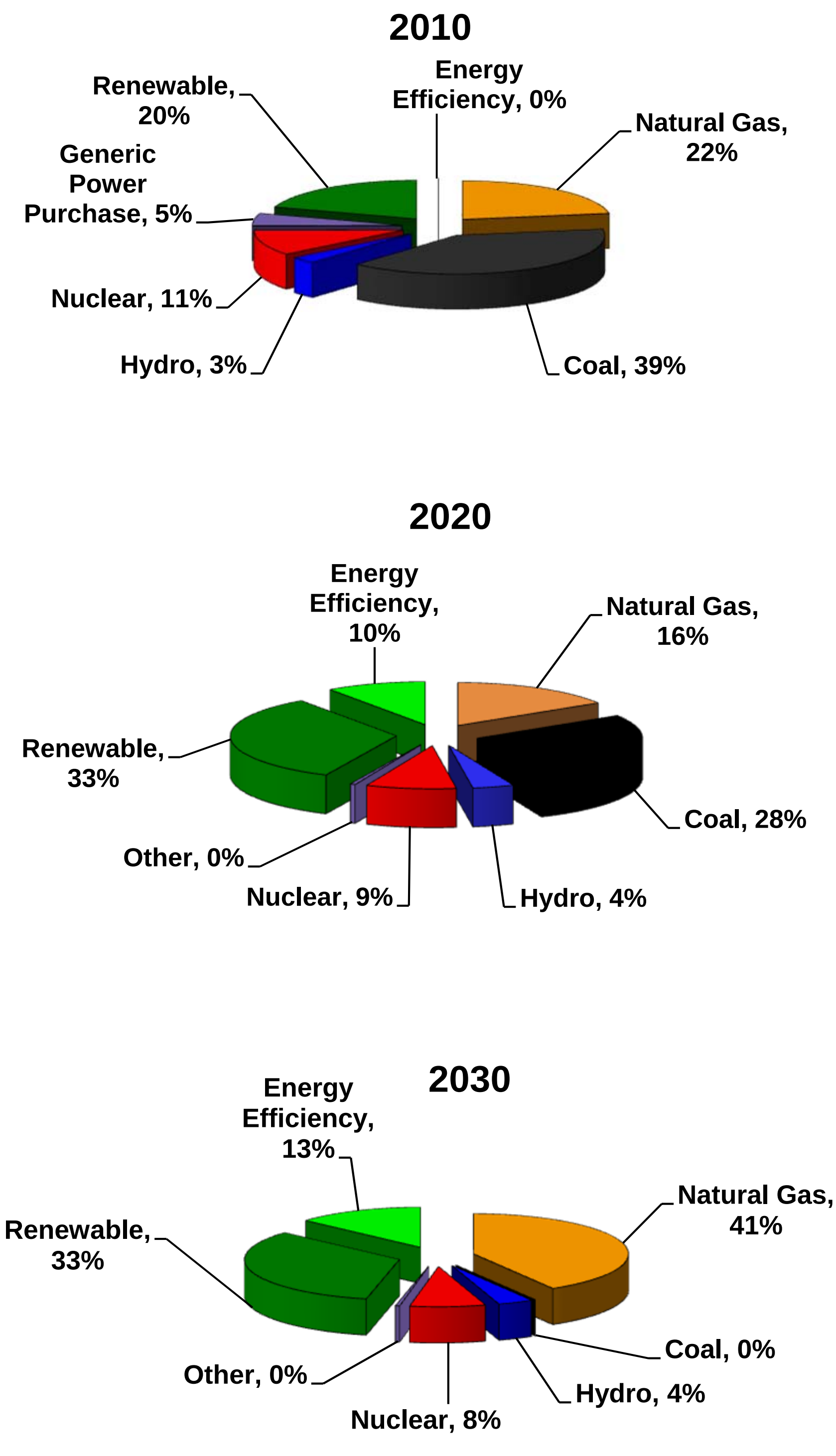

Figure 5-1. Generation resource percentages for 2010, 2020, and 2030.

Figure 5-2 shows the renewable energy resource mix of the Recommended Case. The major change from the 2011 IRP is expanded levels of new solar over the next 20 years and lower amounts of new wind.

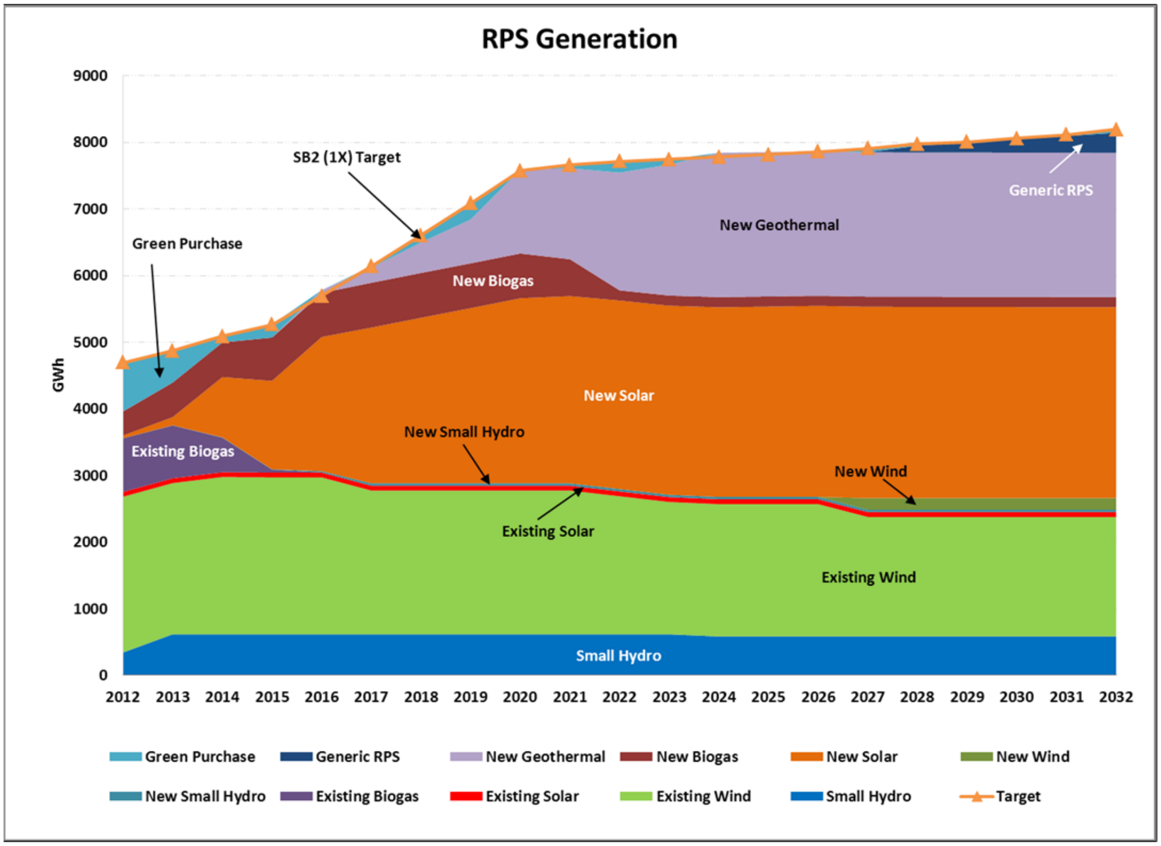

Figure 5-2. Recommended case renewable generation by technology.

The Table 5-2 below illustrates the revenue requirements necessary to supply the recommended resources required to meet future load growth, achieve energy efficiency targets, secure the necessary demand response capabilities, reach and maintain the RPS requirement of 33% by 2020 and thereafter, and ensure that the necessary replacement resources are in-service before divestiture of Navajo in 2015 and replacement of IPP in 2027 can occur.

Table 5-2. Revenue and resources recommended to replace coal and load growth ($ million)

(FY)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy & Capacity Cost											
Energy Efficiency	$ 6	$ 15	$ 30	$ 47	$ 64	$ 83	$ 101	$ 118	$ 135	$ 151	$ 166
Demand Response	$ -	$ 2	$ 2	$ 2	$ 3	$ 5	$ 7	$ 10	$ 14	$ 15	$ 16
New Renewable											
Solar	$ 8	$ 20	$ 57	$ 125	$ 204	$ 267	$ 294	$ 318	$ 343	$ 357	$ 362
Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Geo	$ -	$ -	$ -	$ -	$ -	$ 12	$ 30	$ 42	$ 72	$ 128	$ 155
Small Hydro	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Generic RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Purchase	$ 13	$ 26	$ 14	$ 7	$ 5	$ 1	$ 4	$ 10	$ 8	$ 1	$ 7
New Renewable Subtotal	**$ 21**	**$ 46**	**$ 71**	**$ 132**	**$ 209**	**$ 281**	**$ 330**	**$ 372**	**$ 425**	**$ 488**	**$ 526**
Q3 Term Purchase	$ 1	$ 8	$ 7	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Replacement CC Capital Cost											
Navajo Replacement CC	$ -	$ -	$ -	$ -	$ 1	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18
IPP Replacement CC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 27**	**$ 62**	**$ 103**	**$ 181**	**$ 278**	**$ 386**	**$ 455**	**$ 519**	**$ 591**	**$ 671**	**$ 725**

(FY)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy & Capacity Cost										
Energy Efficiency	$ 181	$ 195	$ 209	$ 223	$ 237	$ 252	$ 266	$ 280	$ 294	$ 309
Demand Response	$ 18	$ 20	$ 21	$ 23	$ 24	$ 24	$ 24	$ 24	$ 24	$ 24
New Renewable										
Solar	$ 365	$ 369	$ 372	$ 374	$ 376	$ 378	$ 377	$ 379	$ 380	$ 382
Wind	$ -	$ -	$ -	$ -	$ 15	$ 26	$ 26	$ 26	$ 26	$ 26
Geo	$ 199	$ 229	$ 246	$ 248	$ 252	$ 252	$ 256	$ 259	$ 261	$ 265
Small Hydro	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Generic RPS	$ -	$ -	$ -	$ -	$ -	$ 5	$ 18	$ 27	$ 34	$ 43
Green Purchase	$ 9	$ 3	$ -	$ -	$ 2	$ 3	$ 2	$ 1	$ 2	$ 3
New Renewable Subtotal	**$ 575**	**$ 602**	**$ 620**	**$ 624**	**$ 647**	**$ 666**	**$ 681**	**$ 695**	**$ 705**	**$ 722**
Q3 Term Purchase	$ -	$ -	$ 0	$ 3	$ 8	$ -	$ -	$ -	$ -	$ 2
Replacement CC Capital Cost										
Navajo Replacement CC	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18
IPP Replacement CC	$ -	$ -	$ -	$ -	$ 6	$ 133	$ 133	$ 133	$ 133	$ 133
Total	**$ 791**	**$ 834**	**$ 867**	**$ 887**	**$ 932**	**$1,093**	**$1,121**	**$1,149**	**$ 1,174**	**$ 1,206**

The Recommended 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 Case will put upward pressure on retail rates, but will 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 thru 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.

Last year's 2011 IRP was prepared concurrent to the rate process that began in early 2011, and recognized that the process would likely conclude in 2012. As of this writing, the rate ordinance has been completed having received City Council and Mayor approval on October 5, 2012.

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 Reliability Program, reduce the number of distribution outages and improve system reliability.
- Implement necessary transmission improvements to maintain reliability.
- Achieve energy efficiency 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 FY12-13 budget data, which contains forward-looking budget data up until FY21-22. For years beyond FY22-23, general capital and O&M expenses are escalated at 2.5 percent per annum.

Effective November 11, 2012 LADWP retail revenue shall be funded from the existing Electric Rate Ordinance and the Incremental Electric Rate Ordinance through the following billing factors:

(1) Base Rate
(2) Energy Cost Adjustment (ECA) and Reliability Cost Adjustment (RCA) factors
(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 factors are described briefly below.

Effective November 11, 2012, the Base Rate under the existing Electric Rate Ordinance shall be capped and remain fixed at their levels as of November 3, 2010. The Base Rate covers a portion of a rate other than the adjustments and is 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 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 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 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 ECAF 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 adjustment factors and Base Rate. 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 has adopted the following financial metric targets: (1) maintain debt service coverage of at least 2.25 (2) unrestricted operating cash target of $300 million and (3) capitalization ratio of less than 68.

Debt service coverage is the amount of cash available from operation divided by the 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 rate factor 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 reliability program spending, replacement of aging basin generating units to meet once-through cooling and South Coast Air Quality 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, and other programs, and payment for emission allowances due to anticipated CO_2 cap and trade requirements.

The capital cost and the associated O&M expense of any new generation resource is priced at 2012 dollars with 2.5 percent escalation except for certain solar projects, which are priced at levelized 2012 dollars due to anticipated pricing declines.

For each year, the retail rate through either the base rate or the energy cost adjustment factor is raised sufficiently high enough to meet the various financial ratios recommended by financial advisors to maintain LADWP's "AA-" bond rating.

Using Case 5 as an example, which is very similar to the 2011 Recommended Case except for additional energy efficiency of 10% by 2020 and slightly higher amounts of solar DG, customer rates are estimated to increase on average 6 percent to 7 percent per year over the next five years, and 3 percent to 4 percent per year over the next 20 years.

The CO_2 emission allowance price is estimated to range from $15 per Metric Ton in 2013 to $36 per Metric Ton in 2020. The California Air Resources Board established an allocation cap, and emissions exceeding this cap will require purchases of additional allowances or in some cases, emissions below the cap can be used in future compliance periods.

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 2012 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.

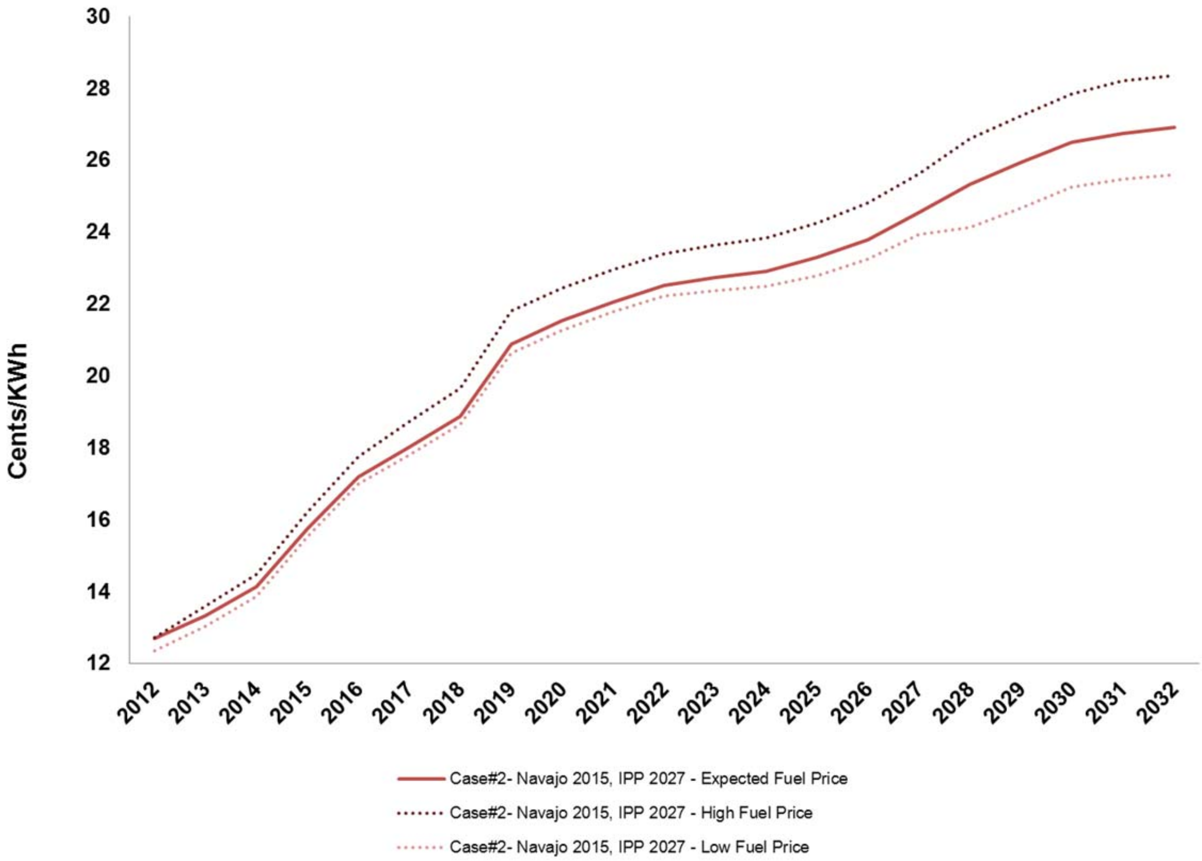

Figure 5-3. Recommended Case - retail price impact bounded by high and low range fuel.

Figure 5-4 presents the fiscal year breakdown for Case 5 comprising rate contributions from reliability, energy efficiency, renewable energy, coal replacement, OTC repowering, other General Transmission and Distribution (GT&D), and fuel costs between 2012 and 2032. These individual contributions represent incremental adders to the rates. For analysis purposes, the Reliability Program has been segmented into the basic program and preferred program. The preferred program contribution shown is incremental to the basic program.

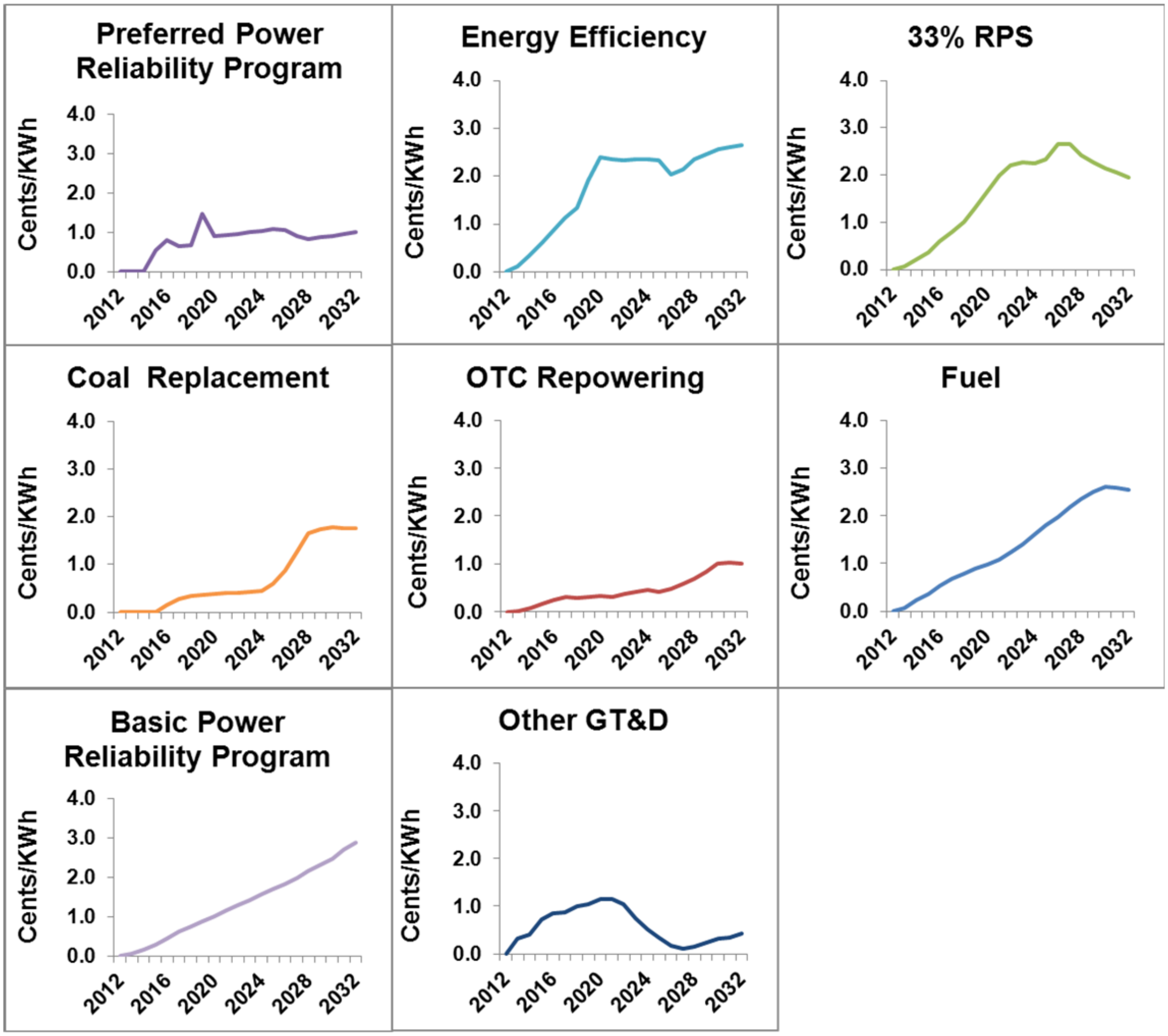

Figure 5-4. Retail electric rate contributions breakdown, based on the 2012-13 budget forecast (Case 5).

Figure 5-5 shows the total retail rate impact after combining all of the program components. One can draw the conclusion that rising fuel costs and complying with various regulatory requirements are the primary drivers of the growth in rates.

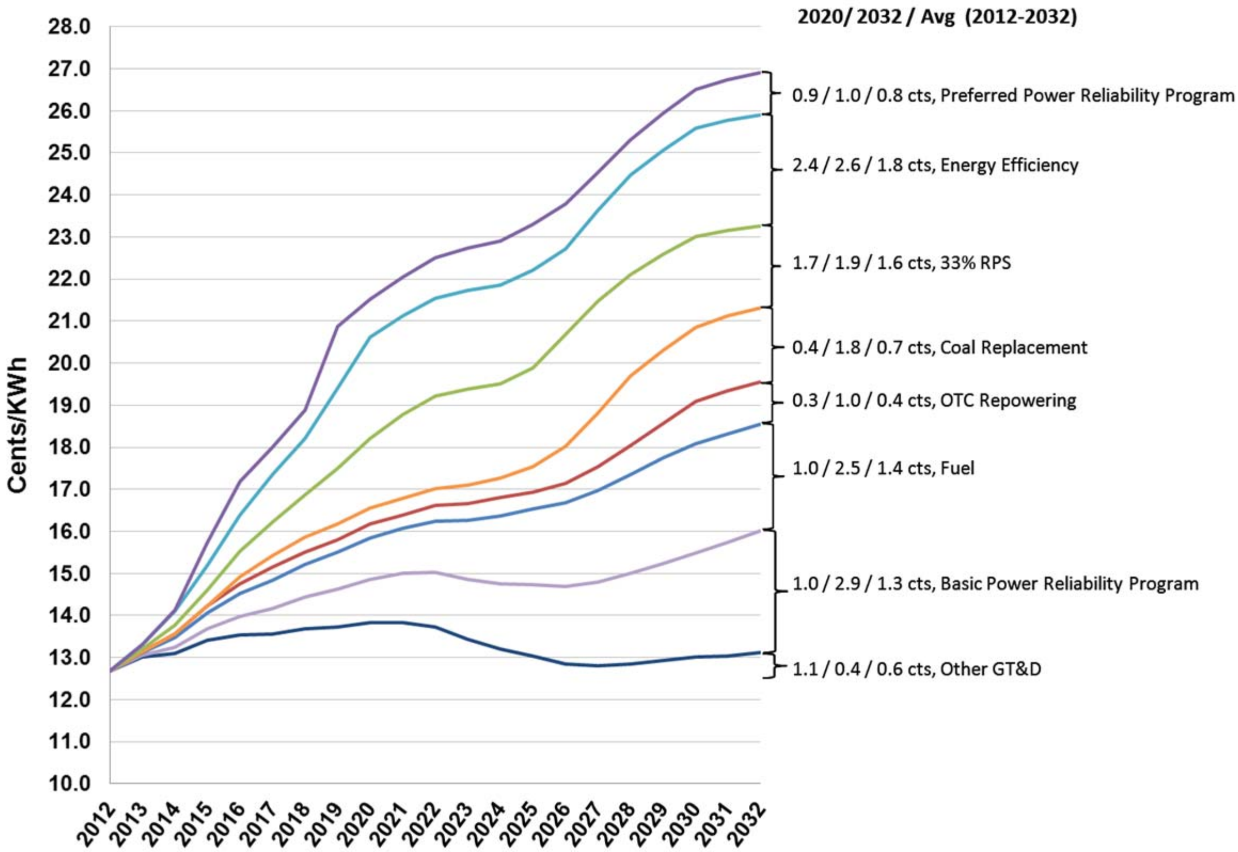

Figure 5-5. Total retail electric rate composite by fiscal year, based on the 2012-13 budget forecast (Case 5).

A few observations from Figures 5-4 and 5-5[10] can be made regarding the RPS and EE programs. Firstly, the influence of the RPS program on rates increases substantially through 2020 after the RPS percentage of sales reaches 33% and the RPS component of rates begins to decline as fuel savings increases over time with escalating fuel prices. In 2027, the RPS component of rates increases as new renewable projects are added to replace expiring PPA agreements and then the RPS component of rates resumes a downward trend due to fuel savings. Secondly, the EE program component of rates increases over time as program incentive payments and net revenue loss attributable to the EE program are recovered. Like RPS, EE has savings beyond 2020 due to fuel savings. Thirdly, general inflation in fuel costs and GT&D costs represents a significant growth in rates.

Preferred levels of funding for the Power Reliability Program (PRP) include capital and O&M expenditures to replace over age distribution and transmission system components that have exceeded their life expectancy, and ensure levels of funding to reduce the backlog of “fix-it”

[10] Figures 5-4 and 5-5 represent forecasted rate increases based on system averages, and do not account for rate structure variations across and within customer classes.

tickets which are temporary repairs that need to be corrected. The spikes in the preferred PRP and EE curve occurs when capital borrowing limits are reached around 2019-20 and cash is needed to fund capital expenses. This quickly subsides as the capacity to borrow resumes shortly thereafter.

The GT&D component of rates rises in the early years because of general inflationary pressure. After 2023 when the IPP debt is fully paid, the GT&D component of rates lowers slightly and goes slightly negative until IPP is replaced with new gas-fired generation and then resumes the familiar inflationary path.

The cost contributions from various environmental and reliability programs towards the retail rates are summarized in Table 5-3.

Table 5-3. Cost contributions from various environmental and reliability programs

Program	Retail Rate Impact at FY2020 (cents/kWh)	Retail Rate Impact at FY2032 (cents/kWh)	Average Retail Rate Impact 2012-2032 (cents/KWh)
33% RPS from 20%	1.7	1.9	1.6
Preferred EE (10% by 2020)	2.4	2.6	1.8
Preferred Power Reliability Program	0.9	1.0	0.8
Basic Power Reliability Program	1.0	2.5	1.4
Coal Replacement	0.4	1.8	0.7
OTC Repowering	0.3	1.6	1.0
Total – Recommended Case	**6.7**	**11.5**	**7.2**

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 14% savings. While LADWP's overall energy efficiency program is evolving and much will depend on the new potential study to be conducted in 2013, these figures illustrate what may reasonably be achievable by customers who have not already implemented significant energy efficiency measures to reduce their electricity consumption.

[11] Figures 5-6 and 5-7 are general representations only, and do 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.

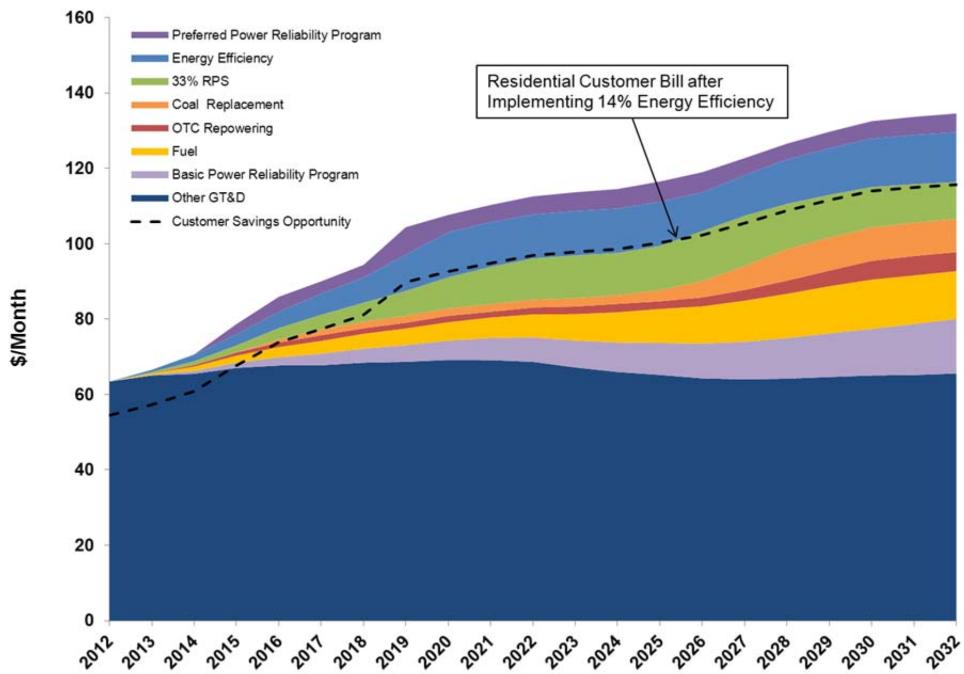

Figure 5-6. Average residential customer bill (500 kWh/month) with environmental and reliability programs by fiscal year based on the 2012-13 budget forecast (Case 5).

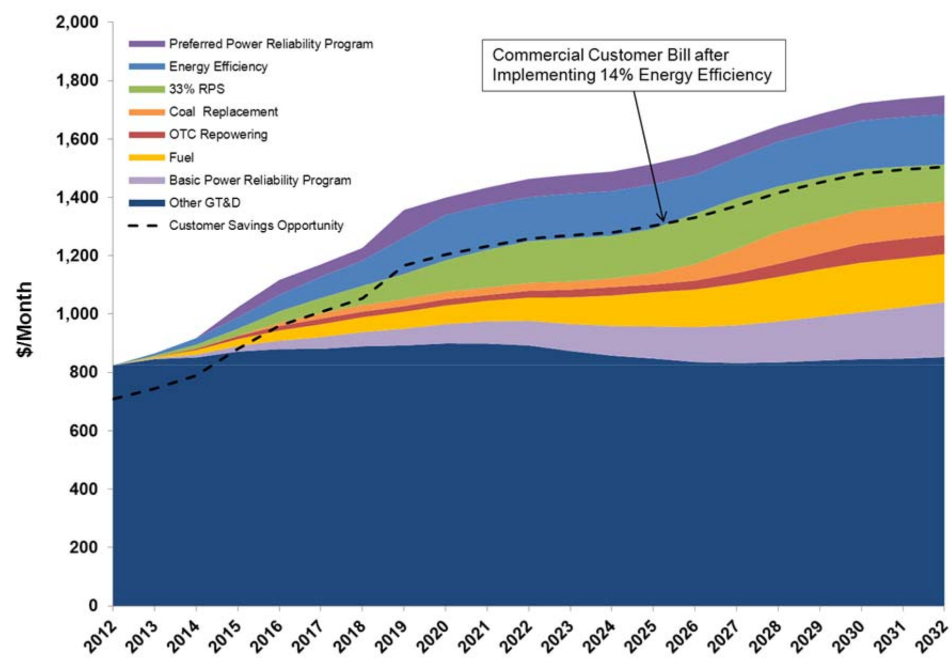

Figure 5-7. Average commercial/industrial customer bill (6,500 kWh/month) with environmental and reliability programs by fiscal year based on the 2012-13 budget forecast (Case 5).

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 76 percent from 2012 to 2027, and (2) natural gas at SoCal border is projected to climb from 2013's $3.62/MMBtu to 2032's $9.31/MMBtu. If these fuel increases do not materialize, then the average rate and cost curves shown in Figures 5-3 thru 5-7 will shift downward; 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

Except for early Navajo divestiture, the actions needed to be taken by LADWP in the next two to four years are very similar no matter what resource procurement strategy is chosen. Base 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 Haynes and Scattergood Generating Stations, and pre-development plans for the Harbor Generating Station.
2. Continue to investigate the technical and contractual options for coal-fired generation to be compliant with SB 1368.
3. Divest from the Navajo Coal Plant by 2015.
4. Continue the implementation of existing energy efficiency efforts, in anticipation of an expanded program pending the results of a new energy efficiency potential study to be conducted in 2013.
5. Continue to implement the Power Reliability Program (PRP) to replace aging infrastructure components. Develop electric modeling capability to better define the necessary investments and to prioritize the expenditures.
6. Develop/update a sustainable workforce development plan that addresses staffing needs, skill set identification for new and evolving work areas, training/professional development, application of new technologies, and recruitment strategy.
7. Implement recommendations contained in the Ten-Year Transmission Assessment Plan.
8. Develop a Demand Response Program to initially provide 5 MW of new peak load reduction capability by 2013 which will ramp up incrementally to 200 MW by 2020 and 500 MW 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). Sign Power Purchase Agreements for an additional 300-400 MW of cost effective renewable energy projects by 2014
10. Complete a comprehensive study of 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.
11. Develop and incorporate strategies to:
    a. Fully utilize existing transmission assets;
    b. Locate renewables as close as practical to the load center to reduce transmission losses;
    c. Preserve existing brown field sites to be repurposed for renewable or natural gas generation;
    d. Incorporate the concept of O&M cluster zones[12] to maximize operational efficiencies;
    e. Assess and develop necessary transmission facilities to deliver electricity generated from new facilities.

[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.

12. Develop a renewable energy feed-in tariff program to encourage 150 MW of renewable generation resources to be developed by 2016.
13. Encourage the development of an additional 50 MW of customer net-metered solar projects before 2015.
14. Develop up to 30 MW of solar capacity on existing properties under public/private partnership projects before 2015.
15. Investigate the use of term physical gas supply arrangements, either with contracts for physical supplies or futures contracts to limit LADWP's exposure to volatile gas prices. Evaluate and potentially implement any recommendations in the Fuel Hedging Plan.
16. Investigate and develop energy storage targets by October 1, 2014, per AB 2514.
17. 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.

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. A new IRP process will be undertaken in 2013.

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Appendix A. Load Forecasting

A.1 Overview

The 2012 Retail Sales and Demand Forecast (2012 Forecast) is a long-run projection of electrical energy sales, production, and peak demands in the City of Los Angeles (City) and Owens Valley. A flowchart of the forecast process is illustrated on Figure A-1. The sections which follow 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.

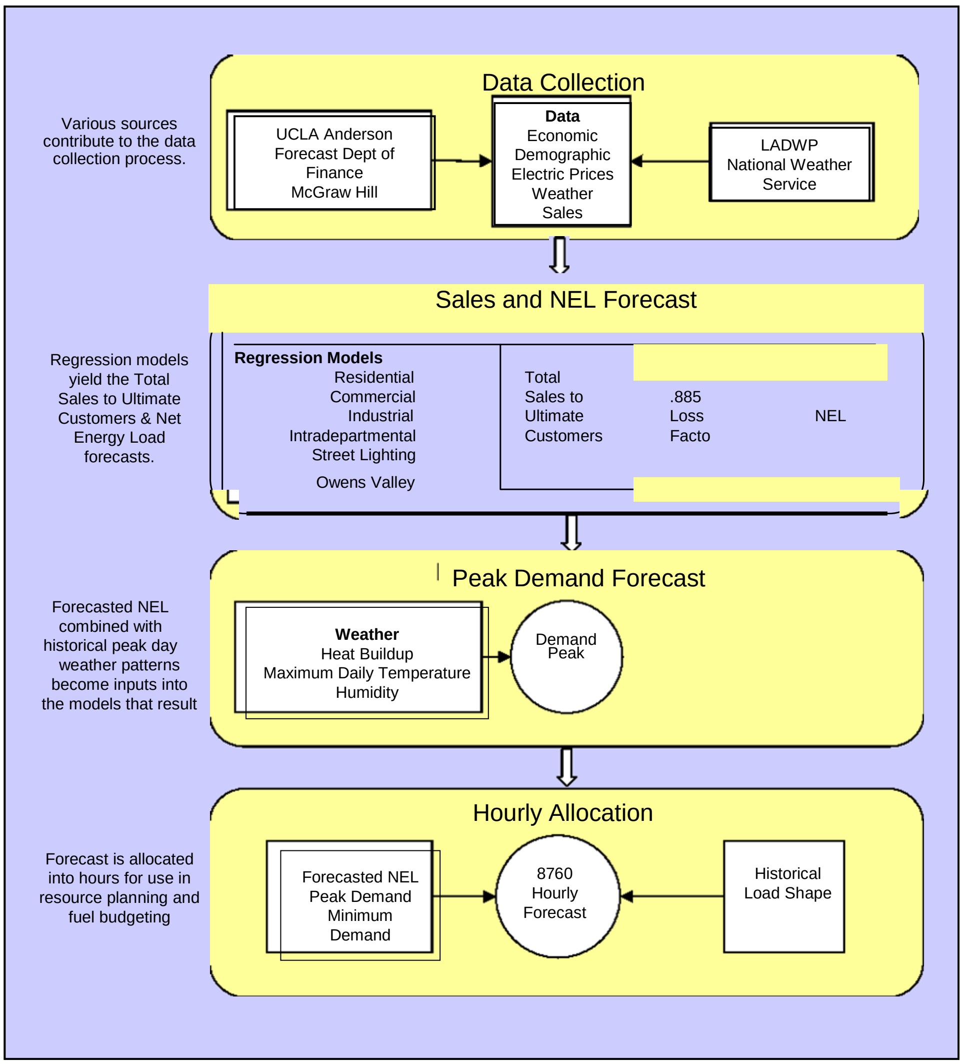

Figure A-1. Overview of the load forecasting process

A.2 Data Collection

Data collection is the first step in the process. LADWP purchases 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 the 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.

The California Energy Commission's PEV forecast has been adapted to the LADWP service area. Further, PEV load is forecast 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 such, Owens Valley sales are rolled into a single class and forecast 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 like 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 trend models are used. The results of the six equations plus the PEV forecast are summed to forecast Total Sales to Ultimate Customers (Sales).

The Retail Sales Forecast represents sales that will be realized at the meter. The NEL forecast is a function of the Sales forecast. The NEL is forecast by adjusting annual forecasted Sales upward by a historic average loss factor and then allocating a portion of the annual energy to each calendar month based on historical proportions. Loss factor has the potential to change 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 the resource planning models.

The 2012 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 2010 LADWP Energy Potential study. Since the 2012 Forecast is created early in the planning process, budgeted utility energy efficiency programs are subject to change. Planners using the 2012 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. The temperature variable 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 the numerical 2012 Forecast.

Table A-1. TREND CASE ENERGY SALES AND PEAK DEMAND

	SECTOR SALES					Total Sales to Ultimate Customers	Net Energy for Load	Peak Demand
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	PHEV (GWh)	(GWh)	(GWh)	(MW)1
2000-01	7,542	12,107	2,754	531	0	22,934	25,688	5,299
2001-02	7,282	11,843	2,496	528	0	22,149	24,903	4,805
2002-03	7,358	12,077	2,383	545	0	22,363	25,370	5,185
2003-04	8,061	12,408	2,485	565	0	23,520	26,701	5,410
2004-05	7,907	12,374	2,447	551	0	23,279	26,338	5,418
2005-06	8,051	12,580	2,451	551	0	23,634	26,828	5,667
2006-07	8,495	12,984	2,332	567	0	24,378	27,502	6,102
2007-08	8,540	13,134	2,366	576	0	24,617	27,928	6,071
2008-09	8,578	13,084	2,303	560	0	24,526	27,447	6,006
2009-10	8,300	12,463	2,073	532	0	23,369	26,526	5,709
2010-11	8,068	12,333	2,189	464	0	23,053	26,252	6,142
2011-12	8,353	12,474	1,932	473	1	23,232	26,458	5,907
2012-13	8,407	12,513	1,947	493	4	23,364	26,360	5,606
2013-14	8,290	12,545	1,927	485	8	23,256	26,310	5,577
2014-15	8,279	12,588	1,936	479	12	23,294	26,311	5,604
2015-16	8,257	12,557	1,937	480	22	23,253	26,312	5,591
2016-17	8,239	12,532	1,938	482	34	23,224	26,235	5,590
2017-18	8,288	12,607	1,938	484	61	23,378	26,392	5,597
2018-19	8,381	12,764	1,939	486	97	23,667	26,705	5,658
2019-20	8,474	12,920	1,940	488	151	23,973	27,115	5,725
2020-21	8,555	13,122	1,940	490	223	24,330	27,451	5,791
2021-22	8,638	13,312	1,941	492	328	24,711	27,878	5,881
2022-23	8,718	13,442	1,941	494	402	24,997	28,199	5,942
2023-24	8,805	13,572	1,942	496	416	25,230	28,537	5,995
2024-25	8,896	13,702	1,942	498	429	25,467	28,739	6,050
2025-26	8,985	13,831	1,943	500	452	25,710	29,010	6,105
2026-27	9,076	13,960	1,943	502	467	25,948	29,283	6,160
2027-28	9,168	14,089	1,944	503	489	26,193	29,626	6,216
2028-29	9,260	14,217	1,945	505	505	26,431	29,828	6,271
2029-30	9,351	14,344	1,945	507	526	26,673	30,101	6,326
2030-31	9,447	14,480	1,946	509	542	26,925	30,385	6,381
2031-32	9,545	14,623	1,946	511	562	27,188	30,749	6,441
2032-33	9,643	14,765	1,947	513	580	27,448	30,975	6,515
2033-34	9,741	14,907	1,947	515	599	27,710	31,271	6,560
2034-35	9,840	15,048	1,948	517	617	27,971	31,566	6,619
2035-36	9,940	15,189	1,949	519	636	28,233	31,931	6,679
2036-37	10,039	15,329	1,949	521	654	28,493	32,156	6,753
2037-38	10,139	15,470	1,950	523	674	28,756	32,452	6,798
2038-39	10,240	15,610	1,950	525	692	29,017	32,748	6,858
2039-40	10,341	15,751	1,951	527	711	29,280	33,114	6,917

Table updated through December 2011

Annual Percent Change								
1991-2001	1.03%	0.55%	-1.02%	0.53%		0.50%	0.48%	-0.02%
2001-11	0.68%	0.18%	-2.27%	-1.34%		0.05%	0.22%	1.49%
2011-17	0.35%	0.27%	-2.01%	0.65%		0.12%	-0.01%	-1.56%
2011-21	0.59%	0.62%	-1.20%	0.55%		0.54%	0.45%	-0.59%
2011-31	0.79%	0.81%	-0.59%	0.47%		0.78%	0.73%	0.19%
2011-40	0.86%	0.85%	-0.40%	0.44%		0.83%	0.80%	0.41%

*** Includes Streetlighting, Owens Valley, and Intra-Departmental**
1 Weather normalized

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CITY OF LOS ANGELES

DEPARTMENT

OF

WATER AND POWER

2012 RETAIL ELECTRIC SALES AND DEMAND FORECAST

Ronald O. Nichols
General Manager

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March 7, 2012
Load Forecasting, Room 956
Financial Services Organization

Document reflects previous 8.6% energy efficiency goal by 2020.
Forecast will be updated to incorporate revised goal.

Table of Contents

2012 Retail Electric Sales and Demand Forecast

Overview

The 2012 Retail Electric Sales and Demand Forecast (Forecast) supersedes the 2011 Retail Electric Sales and Demand Forecast as the City of Los Angeles Department of Water and Power's (LADWP) official Power System Forecast. The Forecast is the basis for LADWP Power System planning activities including but not limited to Financial Planning, Integrated Resource Planning (IRP), Transmission and Distribution Planning and Wholesale Marketing.

Because the Forecast is a public document, only publically available information is used in its development. (This practice has become a standard among California electric utilities.) LADWP Planners wishing to use their own proprietary data should adjust the Forecast accordingly. The Load Forecast Group (LFG) is available to help Planners make adjustments and produces an Unmitigated and Gross Forecast to facilitate those adjustments.

Data Sources

1. Historical Sales reconciled to the Consumption and Earnings Report prepared by General Accounting.
2. Historical NEL, Peak Demand and Losses reconciled to the PowerMaster database maintained by the Power System Planning & Development Group.
3. Historical weather data is provided by the National Weather Service and Los Angeles Pierce College.
4. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2010 Benchmark.
5. Historical population estimates and projections are provided by the State of California Department of Finance.
6. The long-term Los Angeles County economic forecast with quarterly short-run updates is provided by UCLA Anderson Forecast.
7. The construction activity forecast is provided by McGraw-Hill Construction.
8. The Electric Vehicle forecast is based on the California Energy Commission (CEC) statewide forecast. The California Electric Transportation Coalition of which LADWP is a member prepared the CEC forecast.
9. The port electrification forecast is provided by the Port of Los Angeles.
10. The LADWP program energy efficiency forecast is based on the LADWP Energy Efficiency projected budget through Fiscal year 2016-17 dated February 21, 2012. Historical installation rates are provided by the Energy Efficiency group.
11. The forecasted impacts of the Energy Independence Security Act (EISA) and the Huffman Bill on residential lighting rely on the Energy Efficiency Potential Study prepared in 2010 by Global Energy.
12. Historical and projected solar rooftop installations are the draft 2011 Integrated Resources Planning Assumptions document dated October 14, 2011.
13. Electric Price Forecast is developed by Financial Services organization.
14. Historical data is current through December 2011.

Five-Year Sales Forecast

The Retail Sales Forecast represents sales that will be realized at the meter through Fiscal Year End 2017. After FYE 2017, some of the forecasted sales will not be realized at the meter due to the incremental impacts of LADWP-sponsored energy efficiency programs. After FYE 2017, LADWP-sponsored energy efficiency programs will be accounted for in the Integrated Resource Plan.

The historical accumulated Energy Efficiency and Solar Saving are from 1999 forward and only include LADWP installed savings. Since July 1, 2008, LADWP-installed Energy Efficiency savings are 715 GWH for which LADWP recovers lost revenue. In the Forecast, energy efficiency and solar savings are expected to occur uniformly throughout the year as a simplifying assumption. Installation schedules are difficult to prepare because they rely on the customers allowing the installation to occur.

Retail sales decrease of 0.6 percent in Fiscal Year 2013-14 is attributed to the full ramp up of the Huffman Bill and accelerated incremental savings rates in LADWP's energy efficiency programs. Beginning January 2012, the Huffman Bill significantly raises the efficiency standard of light bulbs. The 0.5 increase in FYE 2014-15 is due to the projected completion of port electrification projects and a decline in the LADWP incremental energy efficiency savings rate.

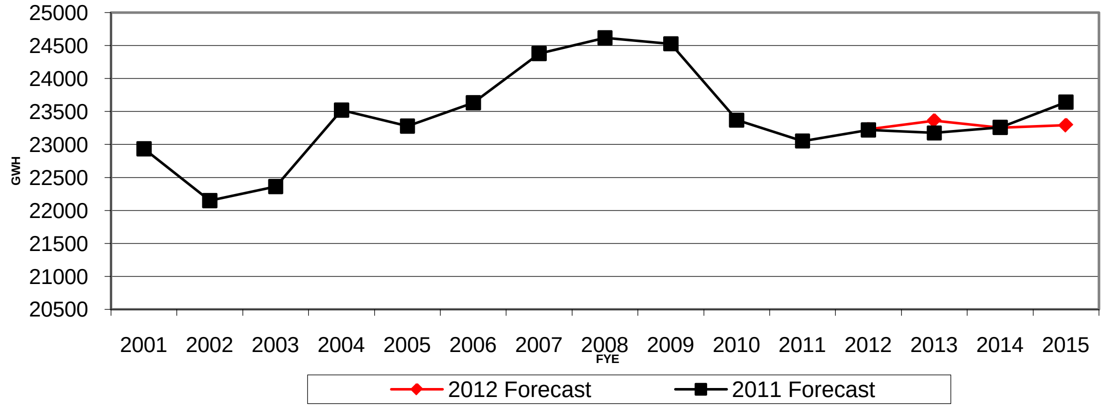
Forecasted Energy Efficiency is based LADWP Board-approved AB 2021 goal of saving 2161 GWH from FYE 2011 through FYE 2020 and forecasted Huffman bill savings. The targeted goal for rooftop solar installations is 242 MW by 2030.

Short-Run Growth

Fiscal Year	Retail Sales		Accumulated EE & Solar Savings	Gross Sales
Ending June 30	(GWH)	YOY Growth Rate	(GWH)	(GWH)
2010-11	23053		1470	24523
Forecast				
2011-12	23232	0.8%	1725	24957
2012-13	23364	-0.4%	2062	25426
2013-14	23256	-0.6%	2428	25684
2014-15	23294	0.2%	2772	26066
2015-16	23253	-0.1%	3113	26366
2016-17	23224	-0.1%	3448	26672

[1] Actual sales through December 2011

Retail Sales Net of Energy Efficiency and Distributed Generation



Peak Demand Forecast

Growth in annual peak demand over the next ten years is 0.3 percent.

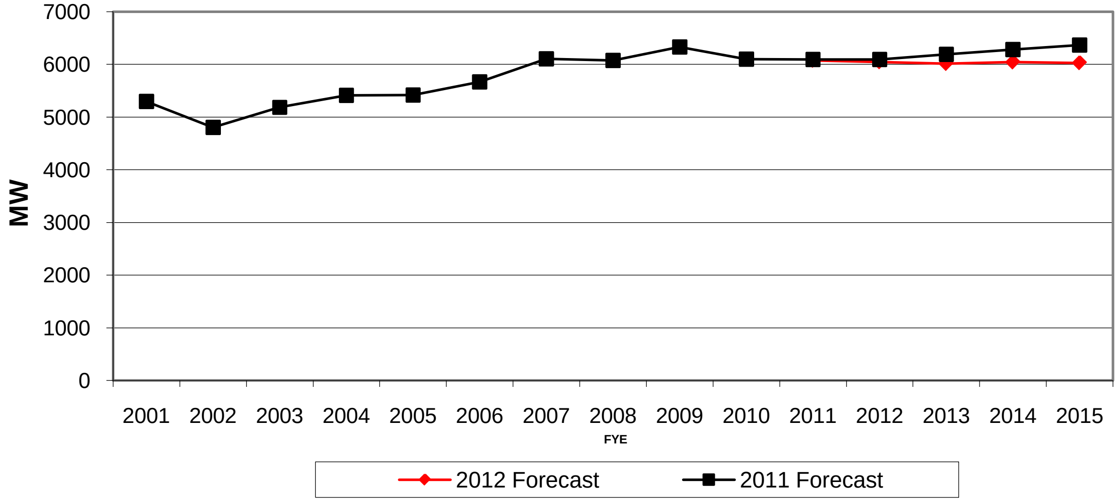
Long-Run Growth

Fiscal Year End June 30	Base Case Peak Demand (MW)	Growth Rate Base Year 2011-12	One-in-Ten Peak Demand (MW)
2011-12	5631[1]		6073
Forecast			
2016-17	5590	-0.1%	6026
2021-22	5881	0.4%	6342
2031-32	6441	0.7%	6885
2040-41	6992	0.7%	7546

[1]Weather-normalized. Actual peak was 5907 MW.

In 2011, the System set its calendar annual peak at 5907 MW on September 7, 2011 on a day that was a 1-in-2.3 weather event. The weather-adjusted one-in-two peak for 2011 is 5631 MW. The following graph of the One-in-Ten peak demand forecast is used for the Integrated Resource Plan (IRP). In the 1990s through 2005, annual System load factors were trending slowly upward. Since 2006, System load factors are trending down. Three 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. Solar rooftops peak production is between 1200 and 1300 hours and declines to 40 to 50 percent of capacity at 1600 hours when the peak occurs. In contrast, the load factor will rise due to significant load growth from the greater use of electric vehicles. The new electric vehicle forecast adopted from the California Electric Transportation Coalition has less impact on the peak than the 2011 Forecast.

One-in-Ten Peak Demand Comparisons



The Peak Demand Forecast is primarily used in the following areas:

1. Integrated Resource Planning
2. Wholesale Energy Marketing
3. Distribution Planning
4. Transmission Planning

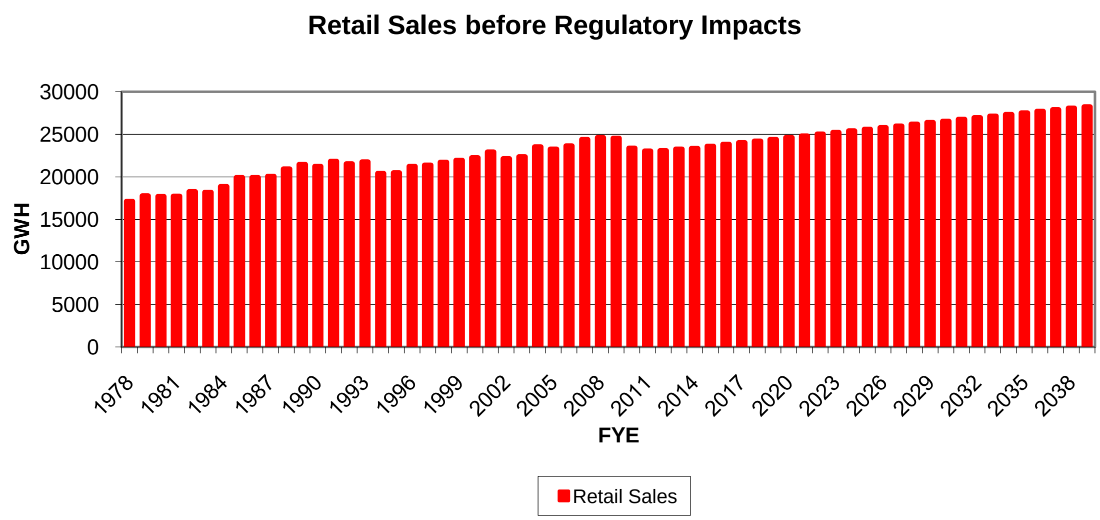
In Integrated Resource Planning, LADWP uses the One-in-Ten Case Peak Demand forecast rather than the Base Case forecast. LADWP's policy is to ensure reliability in times of volatility by controlling its own generation capacity. Planning generation resources at the one-in-ten level has proven over the years to be an effective tool in meeting the reliability policy.   The one-in-ten case is based on historical peak day weather events and uses a statistical model and the underlying retail sales forecast to forecast an annual peak demand.   The peak demand is adjusted for lighting energy efficiency and electric vehicle impacts.

Plausibility

To measure plausibility we compare the current forecast to historical periods. Data is available electronically from 1978 forward. A direct comparison is not appropriate because the forecast period includes programs that reduce all forms of energy consumption due to an aggressive regulatory agenda primary aimed at reducing greenhouse emissions. Instead the unmitigated forecast is compared against history. The unmitigated forecast is the forecast that would occur before the impacts of AB 32 and AB 2021 are considered. It might also be considered a "business-as-usual" case.

The decline in forecasted sales 2008 through 2010 is most directly compared to the decline in sales between 1992 and 1994. The 1992 through 1994 time period was difficult for Los Angeles in many aspects. An economic slump occurred mostly created by the downsizing of the aerospace industry but it also was time of civil unrest and natural disaster. The combination of events caused a major migration of people leaving Los Angeles. Peak-to-Trough sales declined 7 percent in the 1992 through 1994 time period. The following table shows all the peak-to-through declines since 1978. The chart then gives visual evidence of the long-term perspective.

Peak-to-Trough Analysis		
Years	GWH Decline	Percent Decline
2008-2010	1,910	8.3%
1992-1994	1,421	7.0%
2000-2002	572	2.6%
1979-1980	322	1.8%
1981-1982	145	0.8%



Primarily due to the recession that began in December 2007 and ended in June 2009, the historical sales experienced a decline of 8.3 percent in the 2008 through 2010 time period. While the 1992-94 sales decline was specific to Los Angeles and the aerospace industry, in 2008-2010 the decline in Los Angeles mirrored the malaise in the national economy. Going forward, there are conflicting trends in the economic forecast for Los Angeles County going forward. On the positive note, Real Personal Income is increasing. Per capita energy consumption is historically positively correlated with increases in personal income and consumption. The negative trends are population out-migration and fewer jobs in Los Angeles County. Population out-migration means smaller demand for housing infrastructure. Fewer jobs imply that vacant commercial floor space will not be absorbed. Based on economic variables sales will not reach 2008 levels until 2021. The next decade will be much like the 1990s.

Variables in the Forecast

Population: The 2010 United States Census reported 3,792,621 residents in the City of Los Angeles. This number was far lower than the previous 4,094,764 estimated by State of California Department of Finance Demographic unit. The State relies on birth-death records and driver license data to estimate population between censuses. The 2000 United States Census reported 3,694,742. The population growth rate was only 0.2 percent per annum in the first decade of the 21st century. This data seems contrary to other data such as new residential accounts for example. New residential accounts increased at a 0.5% rate in the same time period. This Forecast relies less on the population data since it gives us an unexpected result.

SB 375: SB 375 layers statewide guidelines onto local planning decisions. It favors redevelopment, known as brown field development, near transportation centers over new (green field) development. The goal is to reduce vehicle miles traveled thereby reducing emissions. Most development in Los Angeles is brown field development. However, brown field development is more complicated and expensive than green field development so overall development could slow. The City of LA's "Housing that Works" plan fits well into the SB 375 structure. Residential construction activity is forecast to rebound to normal levels within the next three years.

Emission Allowances: AB 32 seeks to reduce emissions to 1990 levels using a cap-and – trade scheme. Originally the program was to begin in 2012 but has been delayed. Program is designed to protect utilities and consumers. Ultimate impacts are unknown.

Electric Vehicles: LADWP is making electric vehicles a key strategic initiative. The Forecast uses the 2011 California Energy Commission mid-level forecast for electric load growth. This forecast was developed by the California Plug-in Electric Vehicle Coalition of which LADWP is a member. Demand response strategies are intrinsic to this forecast whereas in the 2011 Forecast Demand Response strategies for electric vehicles were external to the electric vehicle forecast. Alternative forecasts for load growth from electric vehicles vary widely.

Energy Efficiency: According to the State of California Strategic Plan, achieving the energy efficiency goals relies on new emerging technologies. The timing of the market availability and the adoption rates for the new technologies is unknown.

Smart Grid: It is unknown when LADWP will complete its Smart Grid program. Some believe that developing a Smart Grid system is a necessary precondition towards a successful electric vehicle program. Also Smart Grid is an important component towards achieving energy efficiency goals in the residential sector.

Vacancy Factor in Residential Sector: Vacancy rose faster than expected in the recession. Some of the vacancy rate was due to households combining and living in the same structure. Vacancy could rapidly swing lower as the economy begins to expand. The Forecast has vacancy rate returning to five percent which is the long-term average by 2015.

Vacancy Factor in Commercial Sector: High vacancy factor is expected to remain more persistent in the commercial sector as models for delivery of services especially in retail change. The rise of big-box retail stores and the Internet have crowded out the small retail shop owner over the past twenty years. There is a smaller need for a physical presence.

Panama Canal Widening: Panama is widening its canal to accommodate the modern larger container ships. It is expected to be completed by 2014. Eastern seaports are also dredging to allow the larger container ships to dock. Currently the larger container ships dock in Los Angeles and Long Beach and the goods are shipped by rail to the East Coast. A decline in this business would hurt the Los Angeles economy. Wholesale Trade and Transportation represent about ten percent of the employment in Los Angeles County.

2012 RETAIL ENERGY AND DEMAND FORECAST

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

	SECTOR SALES					Total Sales to Ultimate	LOSSES		Net Energy		Service	Peak		Service
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	Electric Vehicles (GWh)	Customers (GWh)	Total (GWh)	DC Line (GWh)	for Load (GWh)	Cogen (GWh)	Area Load (GWh)	Demand (MW)	Cogen (MW)	Area Peak (MW)
2000-01	7,542	12,107	2,754	531	0	22,934	2,753	407	25,688	1,294	26,981	5,299	184	5,483
2001-02	7,282	11,843	2,496	528	0	22,149	2,755	350	24,903	1,059	25,962	4,805	181	4,986
2002-03	7,358	12,077	2,383	545	0	22,363	3,006	444	25,370	1,069	26,438	5,185	184	5,369
2003-04	8,061	12,408	2,485	565	0	23,520	3,181	239	26,701	1,073	27,774	5,410	186	5,596
2004-05	7,907	12,374	2,447	551	0	23,279	3,059	216	26,338	1,075	27,413	5,418	187	5,605
2005-06	8,051	12,580	2,451	551	0	23,634	3,194	482	26,828	1,076	27,903	5,667	188	5,855
2006-07	8,495	12,984	2,332	567	0	24,378	3,125	377	27,502	1,077	28,579	6,102	191	6,293
2007-08	8,540	13,134	2,366	576	0	24,617	3,311	425	27,928	1,080	29,007	6,071	193	6,264
2008-09	8,578	13,084	2,303	560	0	24,526	2,921	350	27,447	1,084	28,531	5,647	196	5,843 [1]
2009-10	8,300	12,463	2,073	532	0	23,369	3,157	262	26,526	1,092	27,617	5,709	203	5,912
2010-11	8,068	12,333	2,189	464	0	23,053	3,200	598	26,252	1,105	27,357	6,142	212	6,354
2011-12	8,353	12,474	1,932	473	1	23,232	3,226	411	26,458	1,116	27,574	5,907	224	6,131
2012-13	8,407	12,513	1,947	493	4	23,364	2,996	411	26,360	1,184	27,544	5,606	232	5,837
2013-14	8,290	12,545	1,927	485	8	23,256	3,054	411	26,310	1,208	27,518	5,577	238	5,815
2014-15	8,279	12,588	1,936	479	12	23,294	3,017	411	26,311	1,227	27,538	5,604	243	5,847
2015-16	8,257	12,557	1,937	480	22	23,253	3,058	411	26,312	1,248	27,560	5,591	248	5,840
2016-17	8,239	12,532	1,938	482	34	23,224	3,011	411	26,235	1,263	27,498	5,590	252	5,842
2017-18	8,288	12,607	1,938	484	61	23,378	3,014	411	26,392	1,271	27,663	5,597	254	5,851
2018-19	8,381	12,764	1,939	486	97	23,667	3,038	411	26,705	1,280	27,985	5,658	256	5,914
2019-20	8,474	12,920	1,940	488	151	23,973	3,143	411	27,115	1,290	28,405	5,725	258	5,983
2020-21	8,555	13,122	1,940	490	223	24,330	3,122	411	27,451	1,301	28,752	5,791	261	6,052
2021-22	8,638	13,312	1,941	492	328	24,711	3,167	411	27,878	1,312	29,190	5,881	264	6,145
2022-23	8,718	13,442	1,941	494	402	24,997	3,202	411	28,199	1,315	29,514	5,942	267	6,209
2023-24	8,805	13,572	1,942	496	416	25,230	3,307	411	28,537	1,338	29,875	5,995	270	6,265
2024-25	8,896	13,702	1,942	498	429	25,467	3,271	411	28,739	1,352	30,091	6,050	274	6,324
2025-26	8,985	13,831	1,943	500	452	25,710	3,300	411	29,010	1,367	30,377	6,105	277	6,383
2026-27	9,076	13,960	1,943	502	467	25,948	3,334	411	29,283	1,382	30,665	6,160	281	6,441
2027-28	9,168	14,089	1,944	503	489	26,193	3,432	411	29,626	1,397	31,023	6,216	284	6,500
2028-29	9,260	14,217	1,945	505	505	26,431	3,396	411	29,828	1,414	31,242	6,271	288	6,559
2029-30	9,351	14,344	1,945	507	526	26,673	3,427	411	30,101	1,430	31,531	6,326	292	6,618
2030-31	9,447	14,480	1,946	509	542	26,925	3,460	411	30,385	1,430	31,815	6,381	292	6,674
2031-32	9,545	14,623	1,946	511	562	27,188	3,562	411	30,749	1,430	32,179	6,441	292	6,733
2032-33	9,643	14,765	1,947	513	580	27,448	3,527	411	30,975	1,430	32,405	6,515	292	6,807
2033-34	9,741	14,907	1,947	515	599	27,710	3,560	411	31,271	1,430	32,701	6,560	292	6,852
2034-35	9,840	15,048	1,948	517	617	27,971	3,595	411	31,566	1,430	32,996	6,619	292	6,912
2035-36	9,940	15,189	1,949	519	636	28,233	3,698	411	31,931	1,430	33,361	6,679	292	6,971
2036-37	10,039	15,329	1,949	521	654	28,493	3,663	411	32,156	1,430	33,586	6,753	292	7,046
2037-38	10,139	15,470	1,950	523	674	28,756	3,696	411	32,452	1,430	33,882	6,798	292	7,090
2038-39	10,240	15,610	1,950	525	692	29,017	3,731	411	32,748	1,430	34,178	6,858	292	7,150
2039-40	10,341	15,751	1,951	527	711	29,280	3,834	411	33,114	1,430	34,544	6,917	292	7,210

Table updated through December 2012

Electric Vehicle Sales before January 2012 included in Residential and Commercial Sales

Annual Percent Change

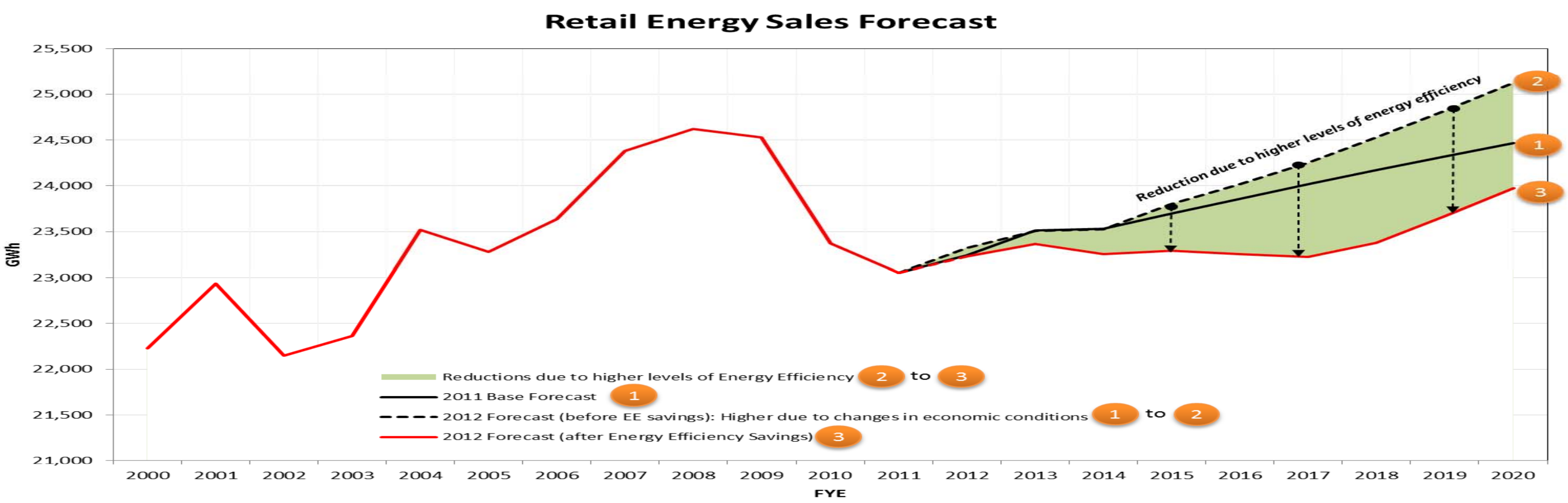
	Residential	Commercial	Industrial	Miscellaneous*	Electric Vehicles	Total Sales	Losses Total	DC Line	Net Energy for Load	Cogen (GWh)	Service Area Load	Peak Demand	Cogen (MW)	Service Area Peak
1991-2001	1.03%	0.55%	-1.02%	0.53%		0.50%			0.48%		0.57%	-0.02%		0.10%
2001-11	0.68%	0.18%	-2.27%	-1.34%		0.05%			0.22%		0.14%	1.49%		1.49%
2011-17	0.35%	0.27%	-2.01%	0.65%		0.12%			-0.01%		0.09%	-1.56%		-1.39%
2011-21	0.59%	0.62%	-1.20%	0.55%		0.54%			0.45%		0.50%	-0.59%		-0.48%
2011-31	0.79%	0.81%	-0.59%	0.47%		0.78%			0.73%		0.76%	0.19%		0.25%
2011-40	0.86%	0.85%	-0.40%	0.44%		0.83%			0.80%		0.81%	0.41%		0.44%

*****'Miscellaneous' includes Streetlighting, Owens Valley, and Intra-Departmental.

Retail Sales

Key Change Factors from 2011 to 2012 forecast:

- ✓ EE included through FYE 2017
- ✓ EE has contributed to the reduction in the retail sales forecast as part of implementing AB 2021. LADWP has targeted an additional 8.6% reduction by 2020.
- ✓ Construction activity remains at low level for extended period. Construction jobs concentrated on rebuilding infrastructure rather than adding housing units or commercial floor space which would have greater impact on electricity sales.



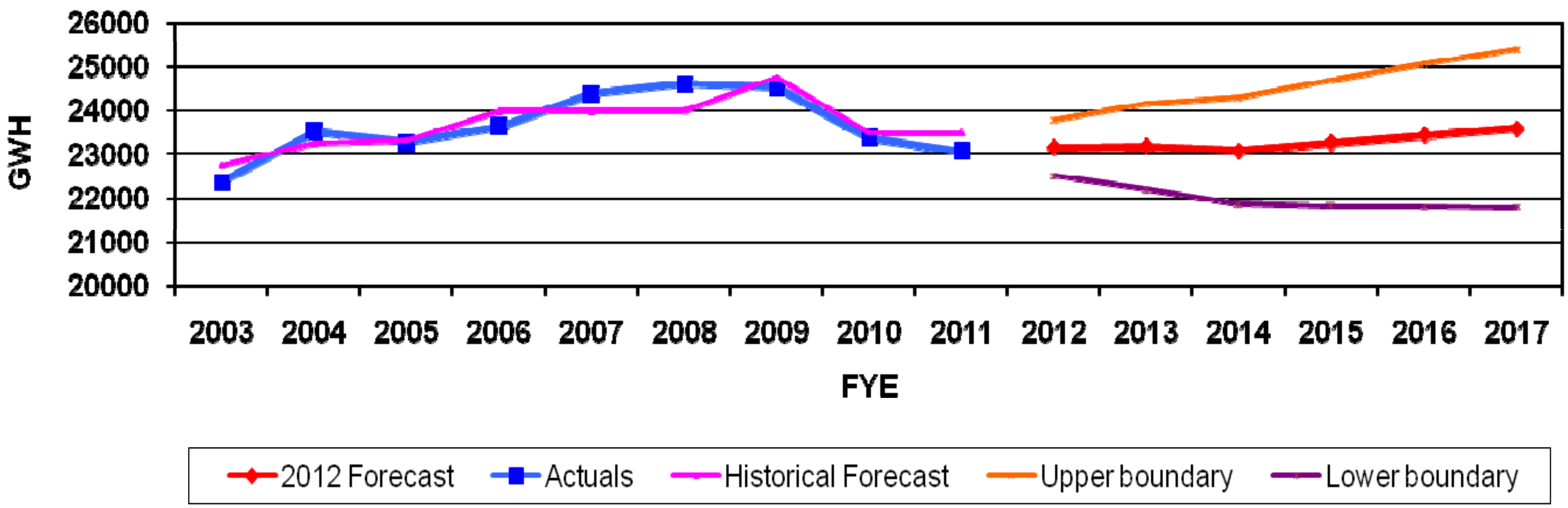
Retail Sales

Accuracy:

✓EE and Solar were not modeled explicitly in Historical Forecasts.

✓Historical accuracy is 0.2% with a 1.6% deviation. However expect larger variation in accuracy due uncertainty of new programs.

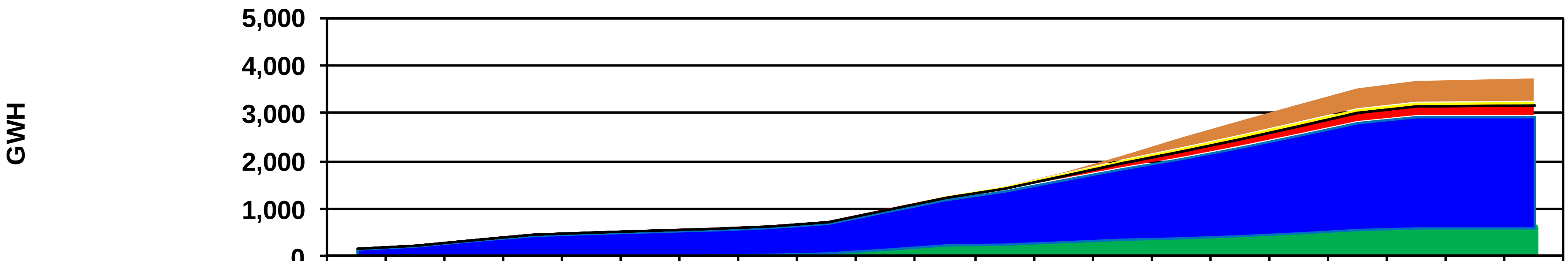
✓Forecast variation is a function of weather, economic forecasts, meeting program goals and model specification.



Energy Efficiency and Solar Rooftops

Historical and Forecasted Accumulated Savings

- ✓ EE before 2008 not included in ECAF Lost Revenue calculation.
- ✓ Energy Efficient Light Bulbs savings are the result of a new State appliance standard. (Huffman)

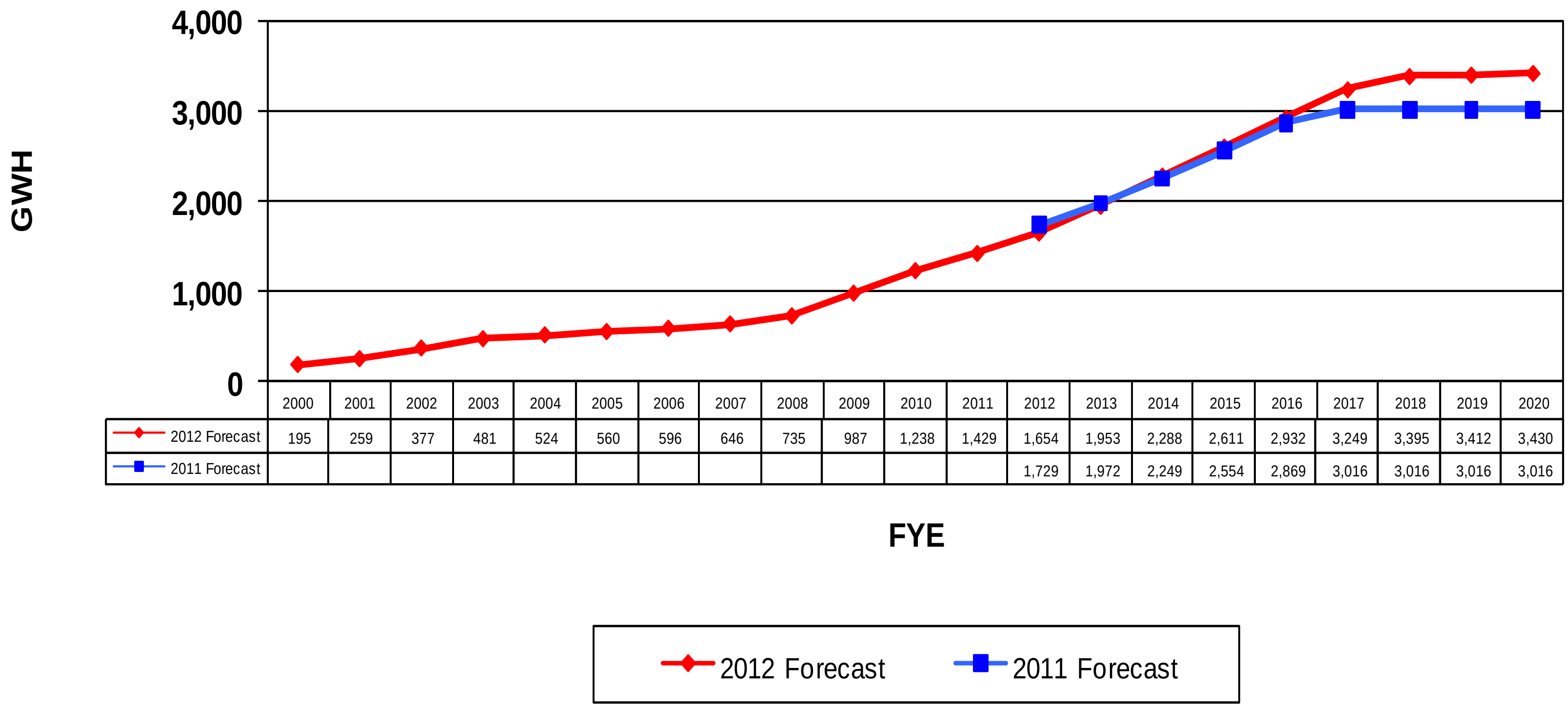


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Energy Efficient Light Bulbs	0	0	0	0	0	0	0	0	0	0	0	0	9	77	201	287	354	408	431	448	466
LADWP Street Light	0	0	0	0	0	0	0	0	0	0	5	15	25	35	45	50	50	50	50	50	50
LADWP Traffic Light	0	0	0	0	0	0	0	1	2	2	3	4	4	4	4	4	4	4	4	4	4
LADWP Rooftop Solar	0	0	2	9	12	13	14	16	18	22	30	42	70	109	140	161	181	199	210	219	228
LADWP Commercial	179	238	343	436	472	498	525	559	618	790	946	1,112	1,295	1,475	1,656	1,848	2,042	2,236	2,325	2,325	2,325
LADWP Residential	15	21	34	45	53	62	71	86	115	195	283	297	350	400	432	476	535	605	639	639	639

FYE

LADWP Residential | LADWP Commercial | LADWP Rooftop Solar
LADWP Traffic Light | LADWP Street Light | Energy Efficient Light Bulbs

Energy Efficiency Program Change



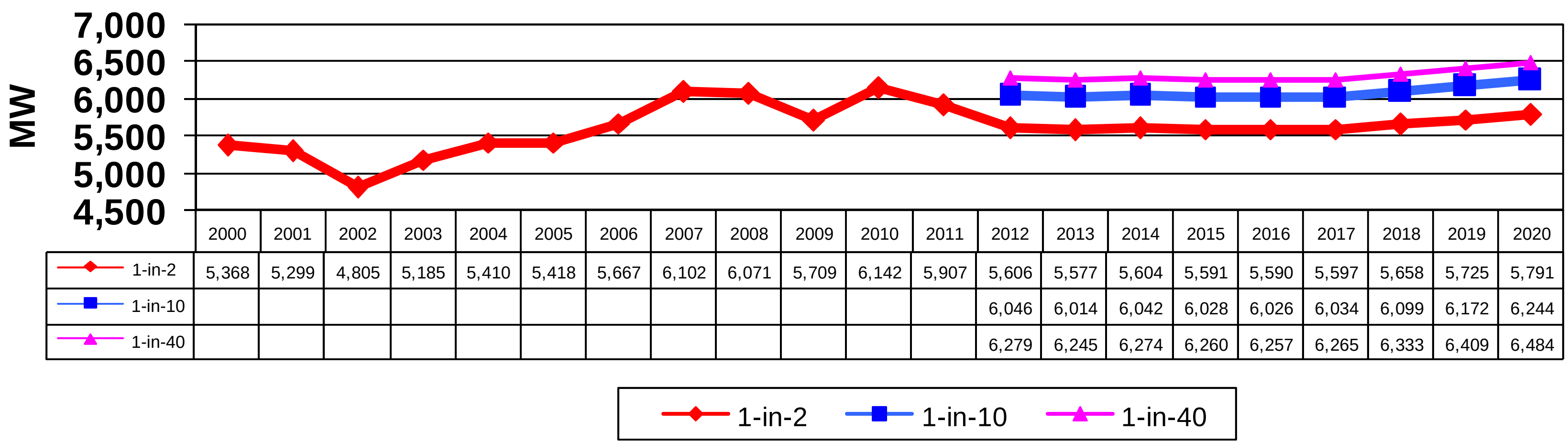
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2012 Forecast	195	259	377	481	524	560	596	646	735	987	1,238	1,429	1,654	1,953	2,288	2,611	2,932	3,249	3,395	3,412	3,430
2011 Forecast													1,729	1,972	2,249	2,554	2,869	3,016	3,016	3,016	3,016

Peak Demand

Cases:

✓The variance around the 1-in-2 forecasted peak has widened based on events since 2006.

✓Based on the climate change finding, it is now expected that the System will approach its potential more frequently so the distance between the 1-in-10 and 1-in-40 forecasts is compressed.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1-in-2	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	5,907	5,606	5,577	5,604	5,591	5,590	5,597	5,658	5,725	5,791
1-in-10													6,046	6,014	6,042	6,028	6,026	6,034	6,099	6,172	6,244
1-in-40													6,279	6,245	6,274	6,260	6,257	6,265	6,333	6,409	6,484

Peak Demand

✓Annual peak demand is dependent on the severity of the heat storms that are encountered during the year.

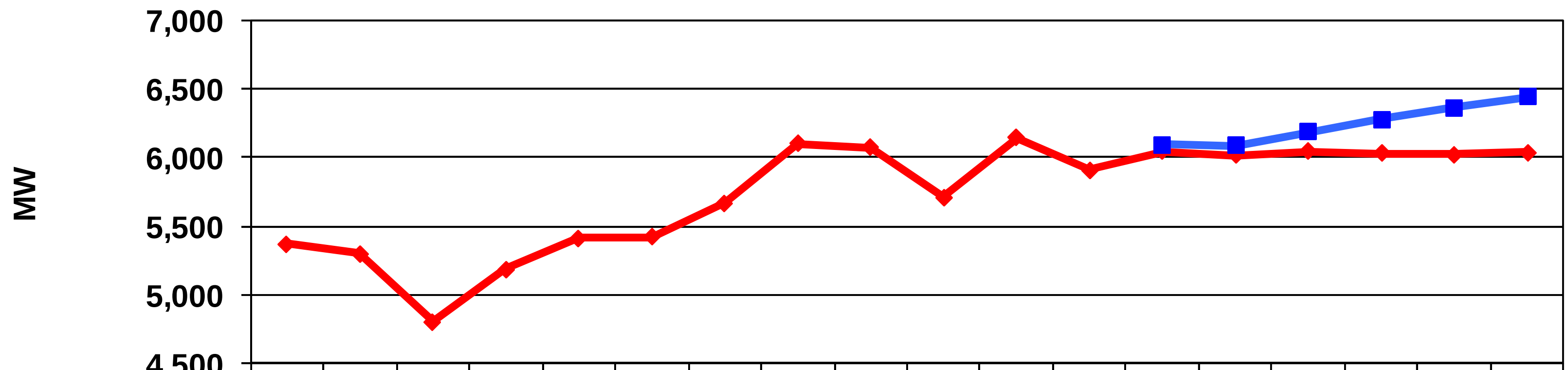
✓The cases are built on the probability of a weather event occurring in a given year.

NEL (MW) Fiscal Year Annual Peak Demand				
Fiscal Year	Base Case	1 in 5	1 in 10	1 in 40 Hot
2012-13	5,606	5,894	6,046	6,279
2013-14	5,577	5,863	6,014	6,245
2014-15	5,604	5,891	6,042	6,274
2015-16	5,591	5,878	6,028	6,260
2016-17	5,590	5,876	6,026	6,257
2017-18	5,597	5,884	6,034	6,265
2018-19	5,658	5,947	6,099	6,333
2019-00	5,725	6,018	6,172	6,409
2020-21	5,791	6,088	6,244	6,484
2021-22	5,881	6,184	6,342	6,586
2022-23	5,942	6,248	6,409	6,656
2023-24	5,995	6,305	6,467	6,716
2024-25	6,050	6,363	6,526	6,779
2025-26	6,105	6,421	6,586	6,840
2026-27	6,160	6,478	6,645	6,902
2027-28	6,216	6,537	6,705	6,965
2028-29	6,271	6,595	6,765	7,027
2029-30	6,326	6,653	6,824	7,088
2030-31	6,381	6,712	6,885	7,151

1-in-10 Peak Demand

1-in-10 peak used in Integrated Resource Planning process:

- ✓2011 Actual Peak = 5907 MW.
- ✓2011 Weather-Normalized peak = 5631 MW.
- ✓2011 Forecasted Weather-normalized peak = 5589 MW.
- ✓Peaks after 2006 have tended to spike.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2012 Forecast	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	5,907	6,046	6,014	6,042	6,028	6,026	6,034
2011 Forecast													6,092	6,089	6,188	6,277	6,365	6,442

FYE

2012 Forecast 2011 Forecast

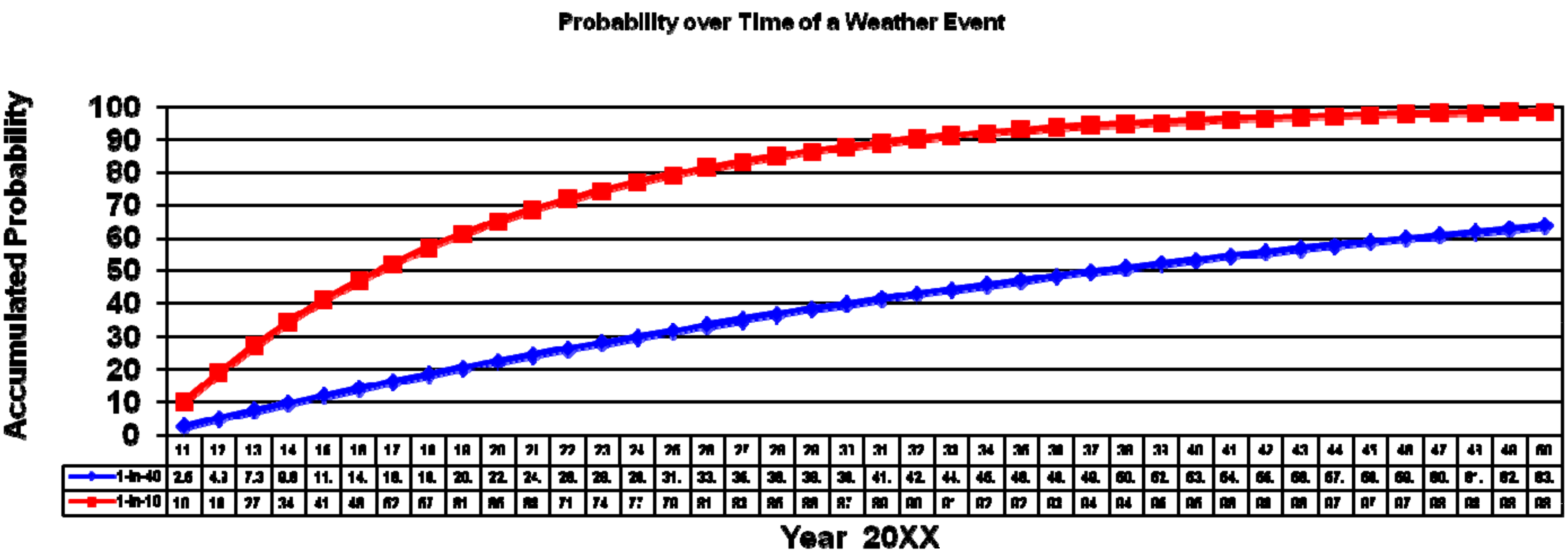
1-in-10 Peak Demand

Probability accumulates over time:

✓There is a 65% chance of having a 1-in-10 weather event by 2020.

✓There is a 22% chance of having a 1-in-40 weather event by 2020.

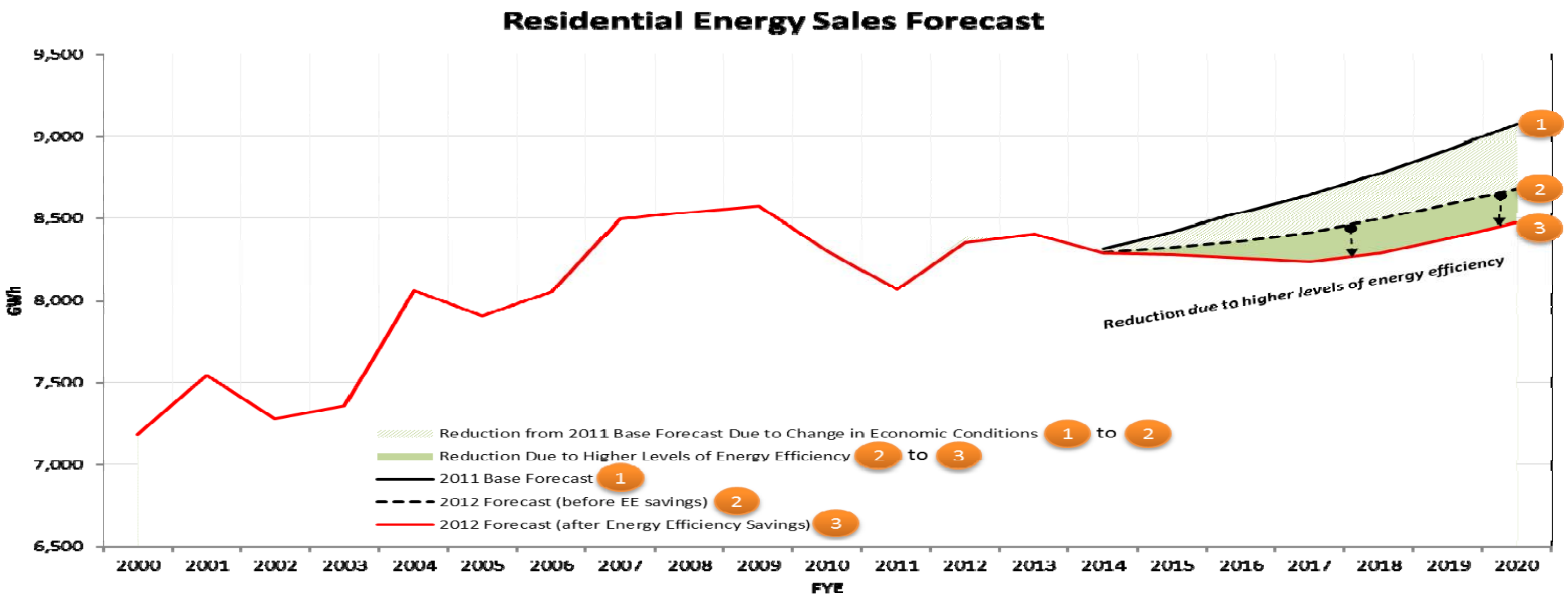
✓$P_t=1-(1-P_e)^t$



Residential Energy Sales

Components of Change

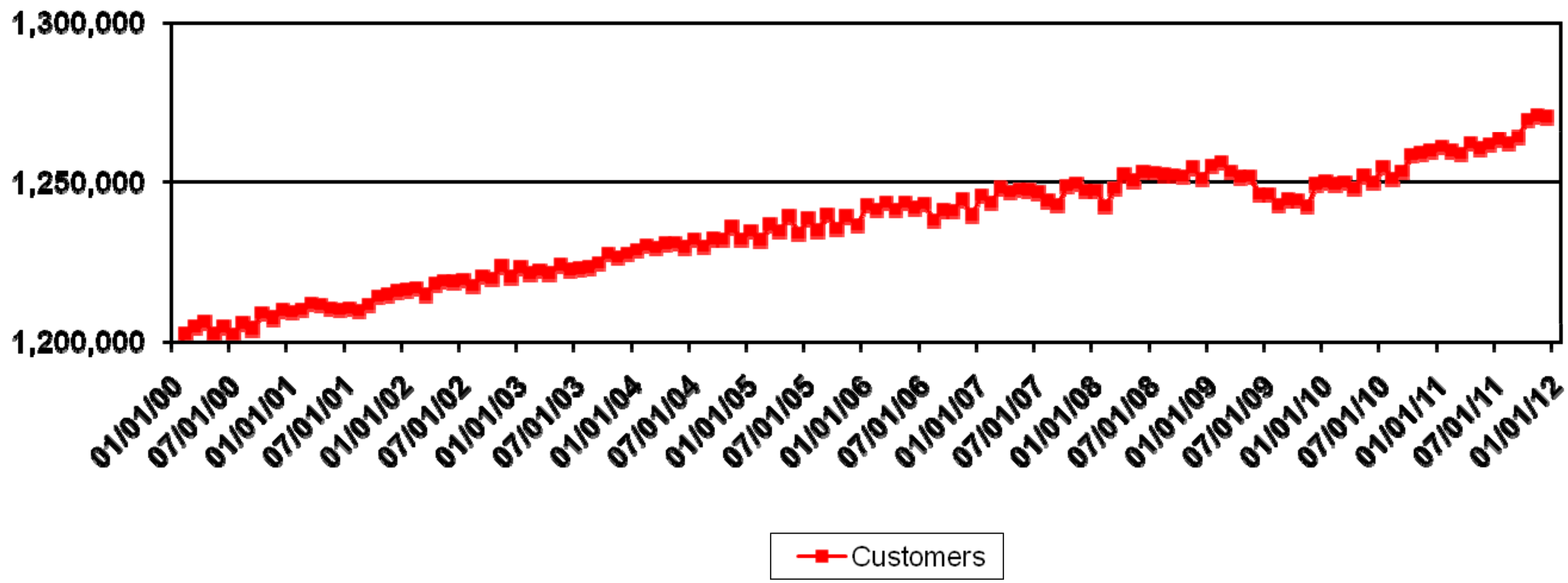
- ✓ Lowered new-units-built forecast
- ✓ Lower economic forecast



Residential Energy Sales
Number of Residential Customers

Recent Evidence

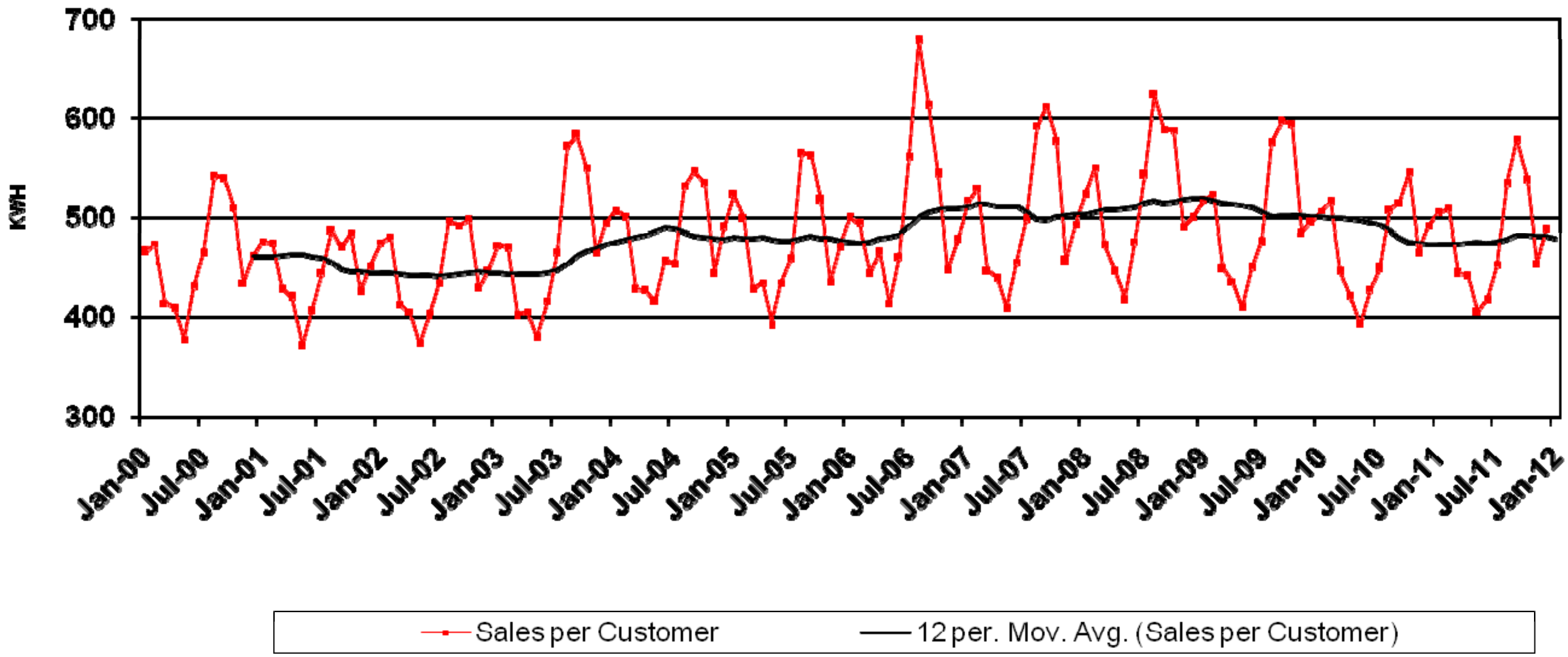
- ✓ 10,000 active meters added in 2011.
- ✓ Returning to long-term trend quickly.
- ✓ The majority of residential customers are renters and live in multi-family units.
- ✓ The attractiveness of downtown living has increased due to the “Housing that Works” plan.



Residential Energy Sales
Average Sales per Customer

Recent Evidence

- ✓Sales per residential customer reached an all-time high of 519 KWH per month in December 2008.
- ✓The December 2011 rate is 482 KWH per Month.
- ✓Weather -normalized September 2011 rate is 495 kWh per Month.

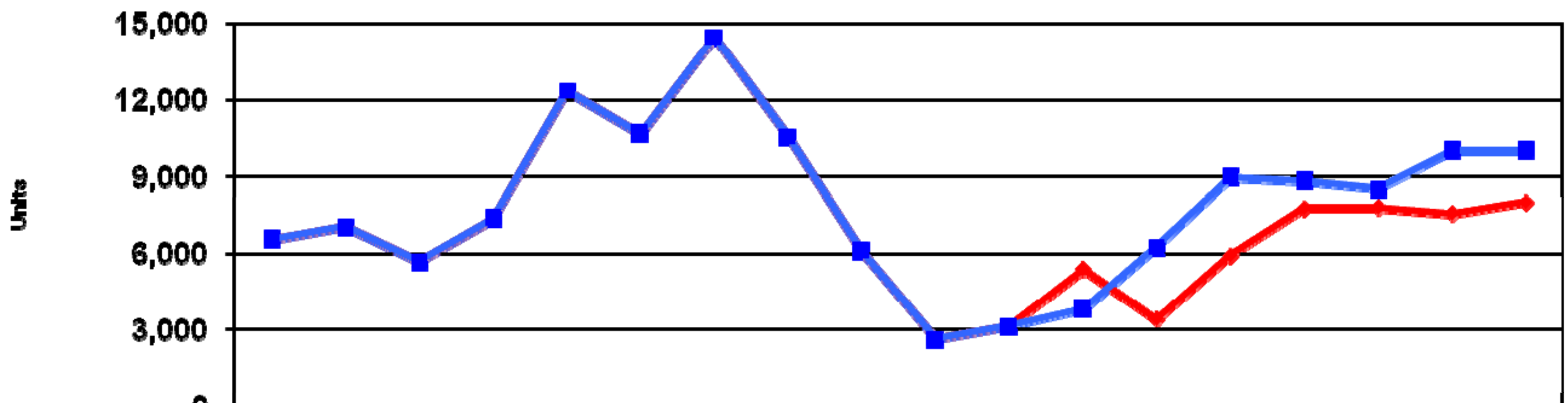


Residential Energy Sales

New Residential Building Units

Recent Evidence

- ✓ New units are 20% Single-Family and 80% Multi-family which lowers future average consumption per household.
- ✓ Recent Housing Starts are at historical lows.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2012 Forecast	6,567	7,062	5,673	7,361	12,340	10,666	14,446	10,554	6,080	2,607	3,129	5,360	3,404	5,911	7,754	7,760	7,544	8,000
2011 Forecast	6,567	7,062	5,673	7,361	12,340	10,666	14,446	10,554	6,080	2,607	3,129	3,820	6,239	8,961	8,814	8,512	10,000	10,000

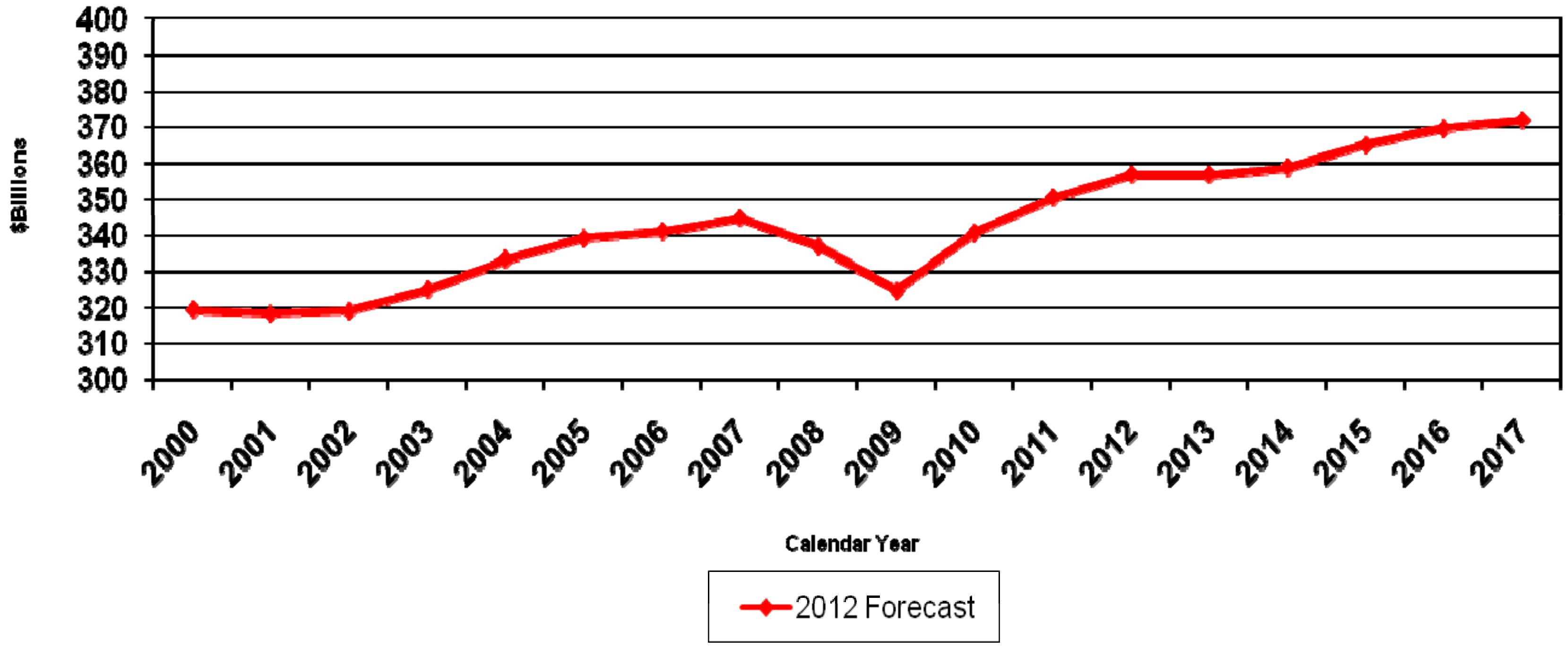
Calendar Year

2012 Forecast　2011 Forecast

Residential Energy Sales
Recent Economic Impact

Real Personal Consumption

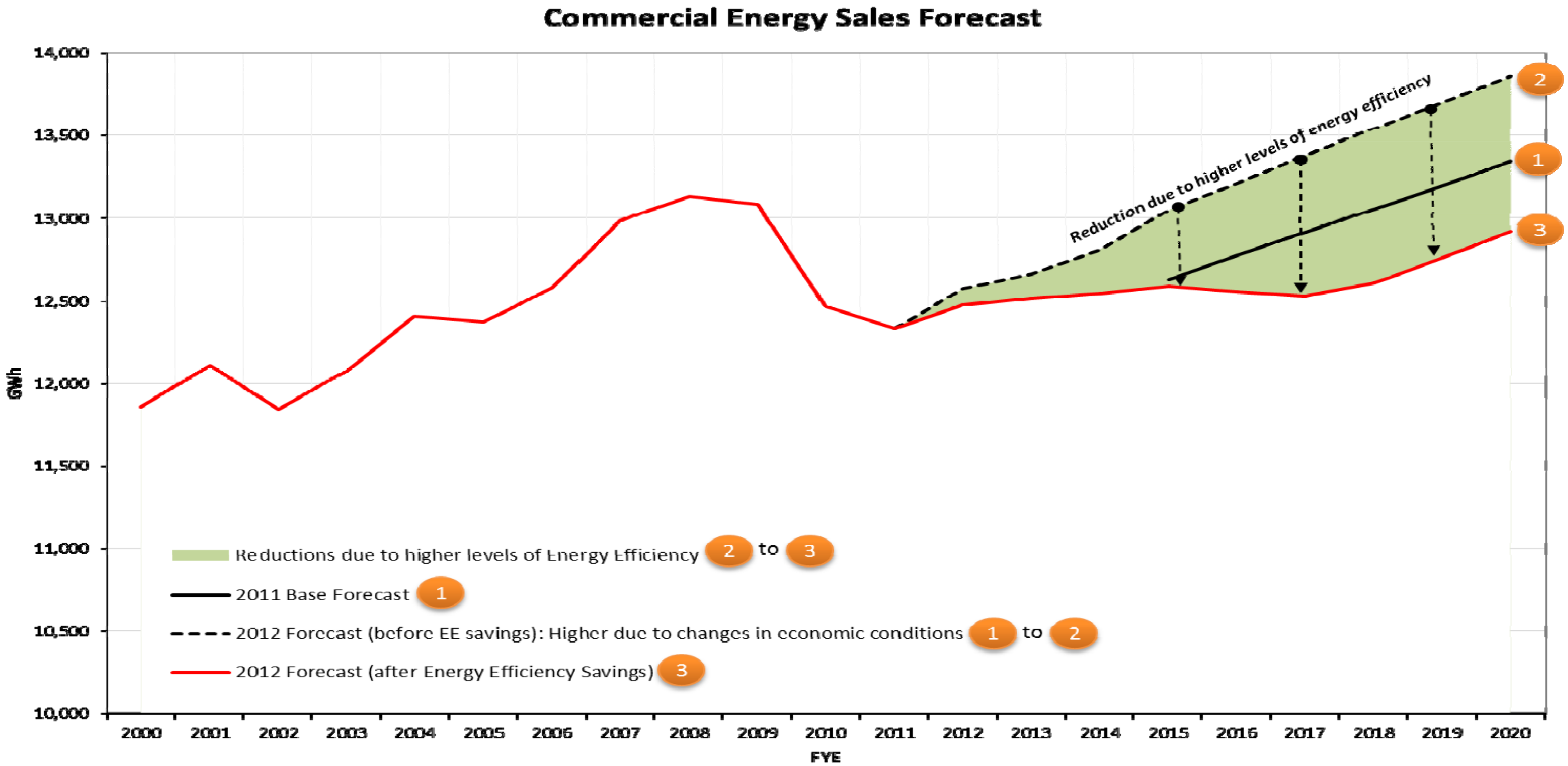
- ✓ Recovery ends and expansion begins in 2012.
- ✓ 1% growth - Below historical mean growth.



Commercial Energy Sales

Components of Change

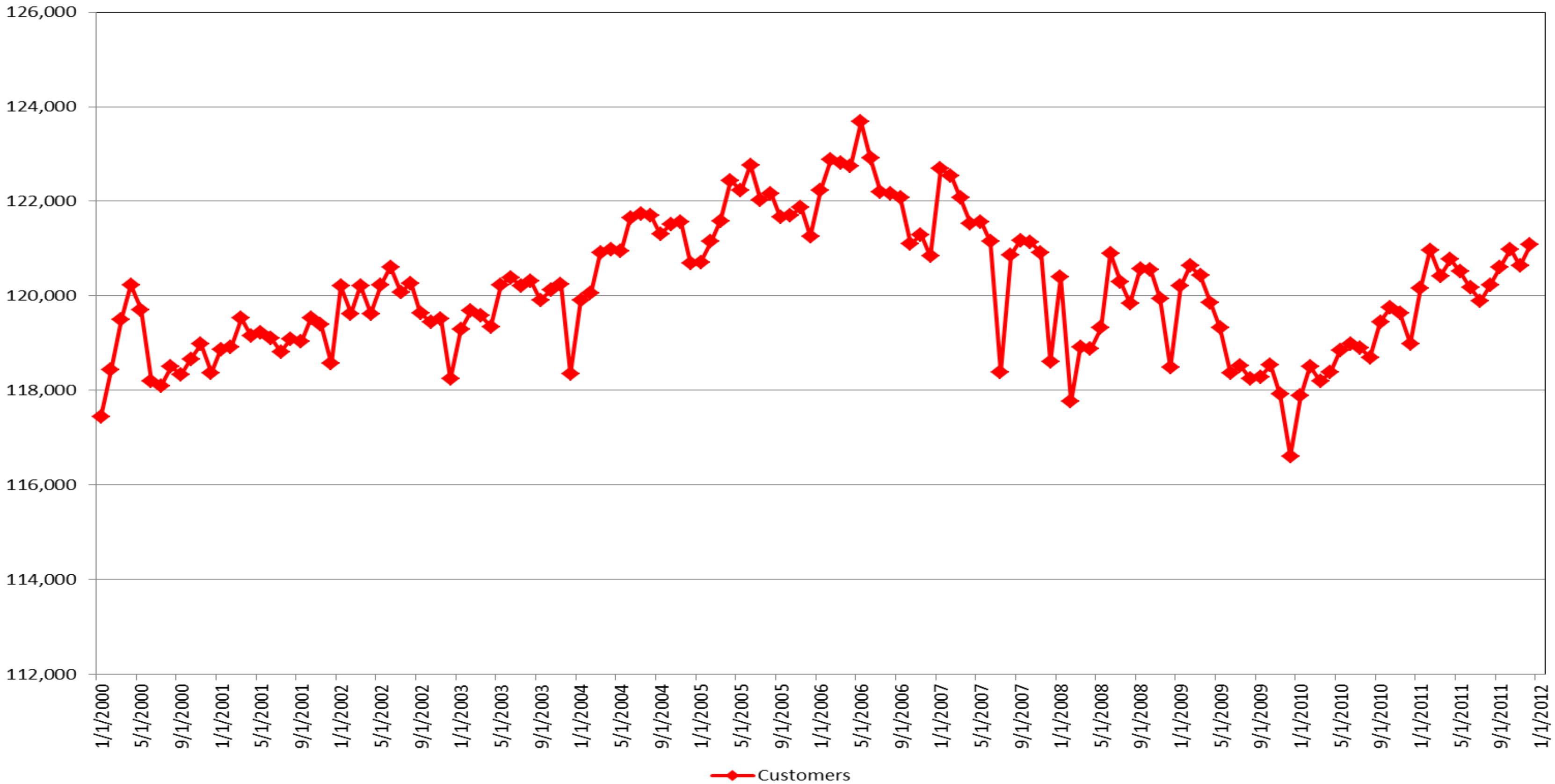
- ✓ Service employment forecast slightly higher.
- ✓ Commercial construction activity down but positive absorption.



Commercial Energy Sales
Number of Commercial Customers

Recent Evidence

✓ There is a delay in bill collection. There are approximately 750 accounts past due, as result of the AMI implementation. LADWP is working to resolve this issue.

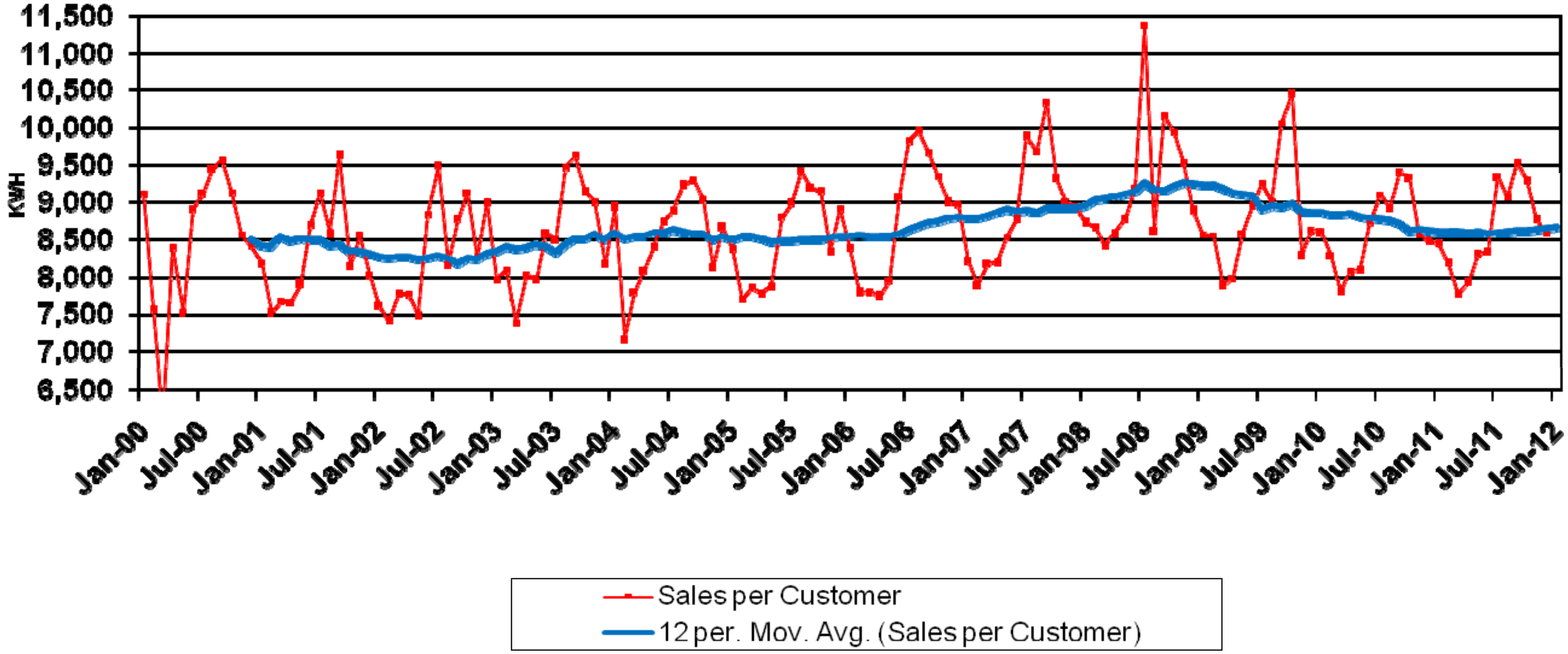


Commercial Energy Sales

Average Sales per Customer

Recent Evidence

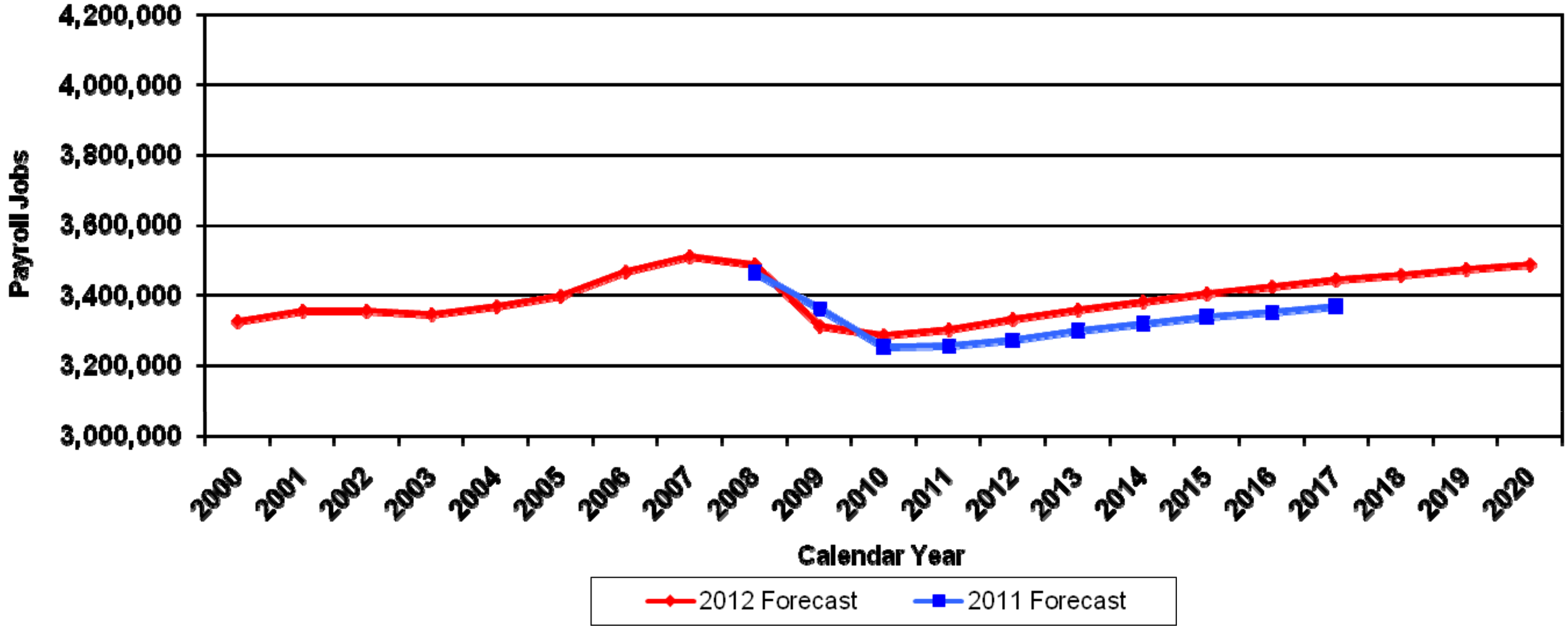
- ✓ Sales per customer per month peaked in July 2008 at 9265 KWH per month.
- ✓ Currently sales per customer per month are 8614 KWH.
- ✓ Weather normal sales per customer per month is 8690 KWH.



Commercial Energy Sales
Local Employment in Service Sector

LA County Commercial Services Employment

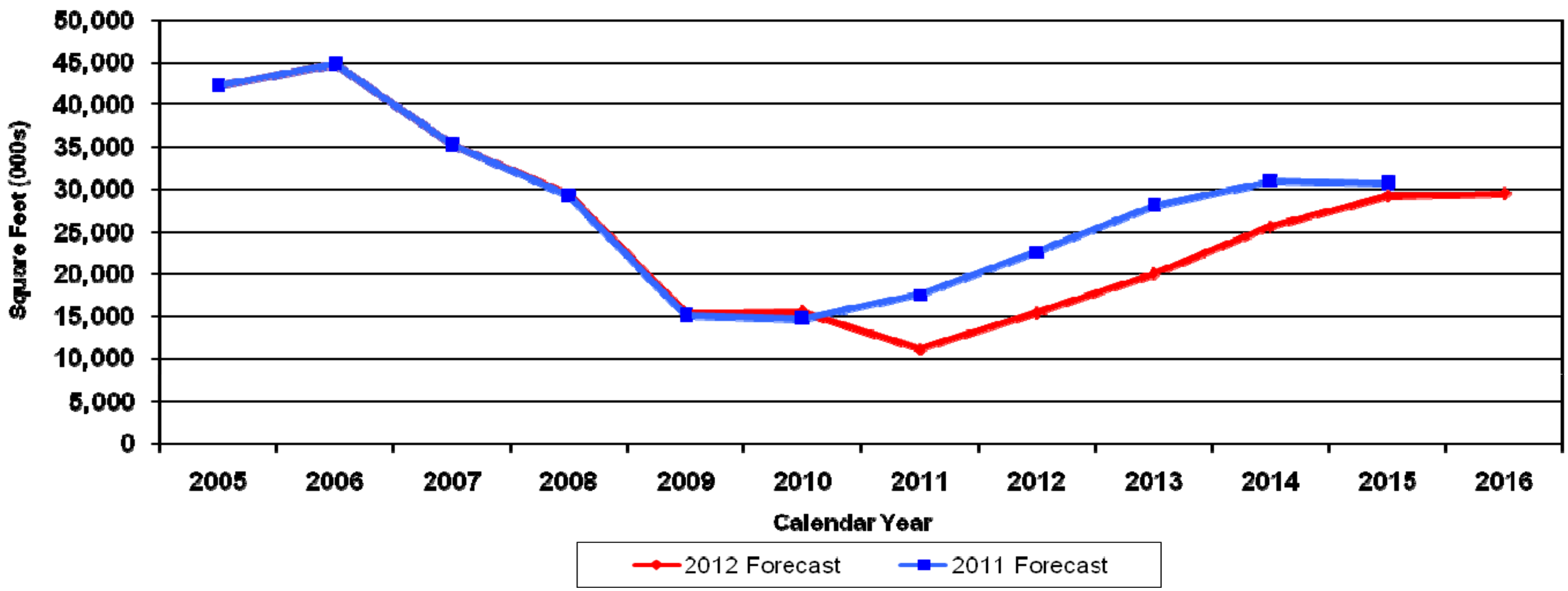
- ✓ Changing service delivery models – Internet and Big box retailers are two examples.
- ✓ Employment does not return to former high by 2020.



Commercial Energy Sales
McGraw-Hill Construction Forecast

Commercial Floorspace Additions

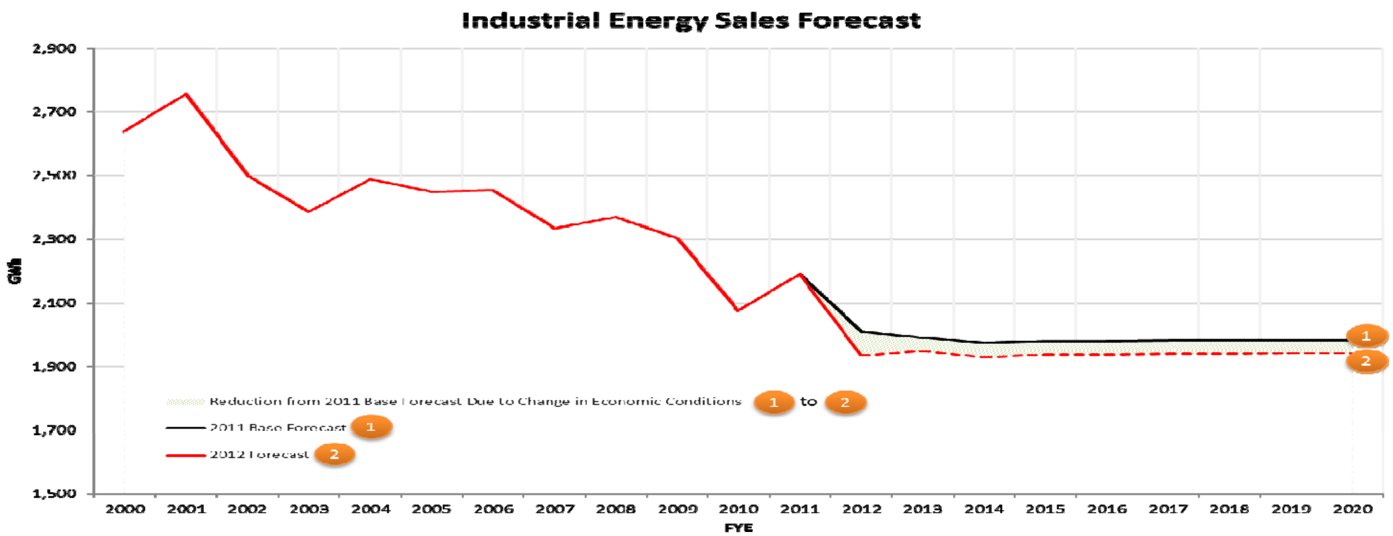
- ✓ Construction activity at historically low levels.
- ✓ Office vacancy rates in San Fernando Valley at 18 percent.
- ✓ New models for delivering commercial services require smaller physical presence.



Industrial Energy Sales

Components of Change

- ✓ Land use issue: Once industrial land is vacated, residential and commercial buildings tend to replace it. 3 to 4 percent vacancy rates in the industrial sector.
- ✓ Manufacturing that is staying tends to be high-value added manufacturing and process industries.
- ✓ Other manufacturing continues to move offshore or to the States with better business climate.
- ✓ No EE or rooftop solar in the Industrial Forecast. All EE and solar assigned to Residential, Commercial and Streetlight sectors.



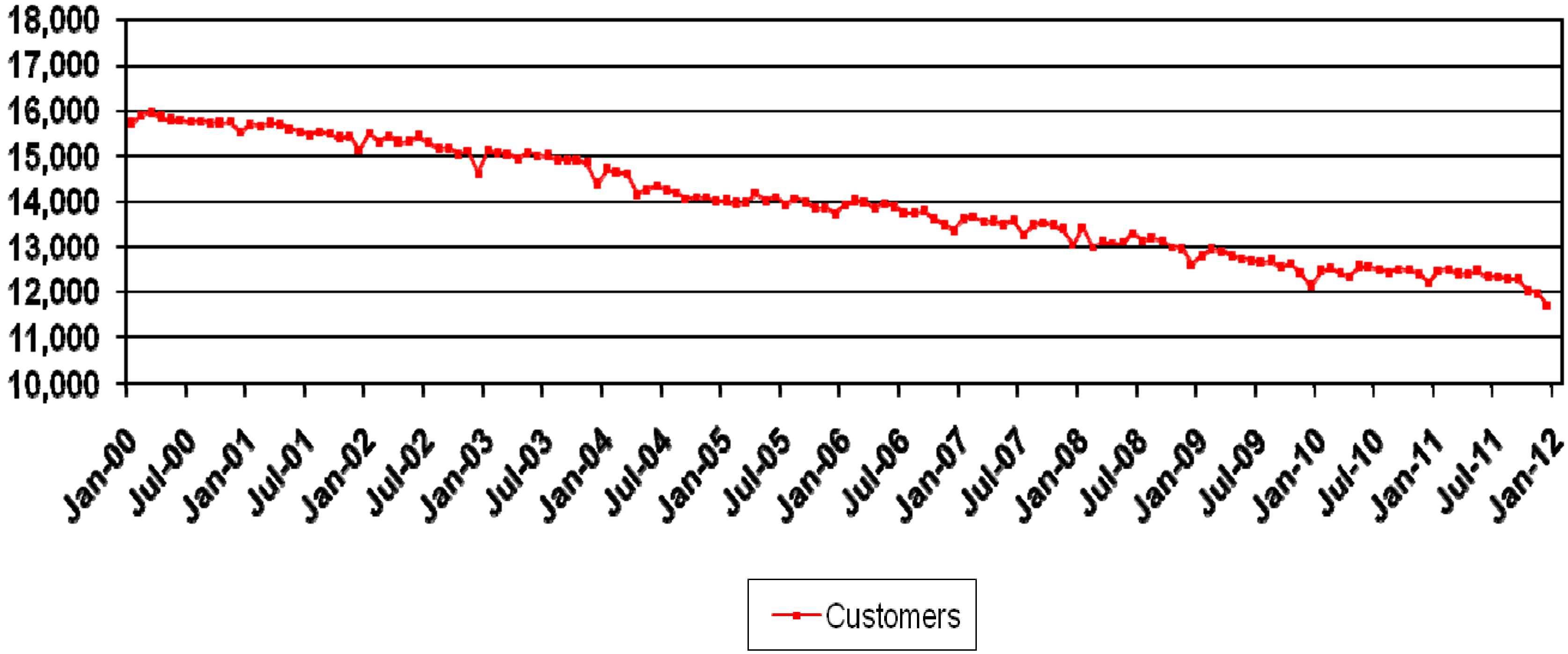
Industrial Energy Sales
Number of Industrial Customers

Recent Evidence

✓The number of Industrial customers is continually and relentlessly declining.

✓The decline began in the 1970s**.**

✓The forecast is for the heavy process industries to remain although no new heavy industry will be built. It is the light industry and assembly jobs that are disappearing.

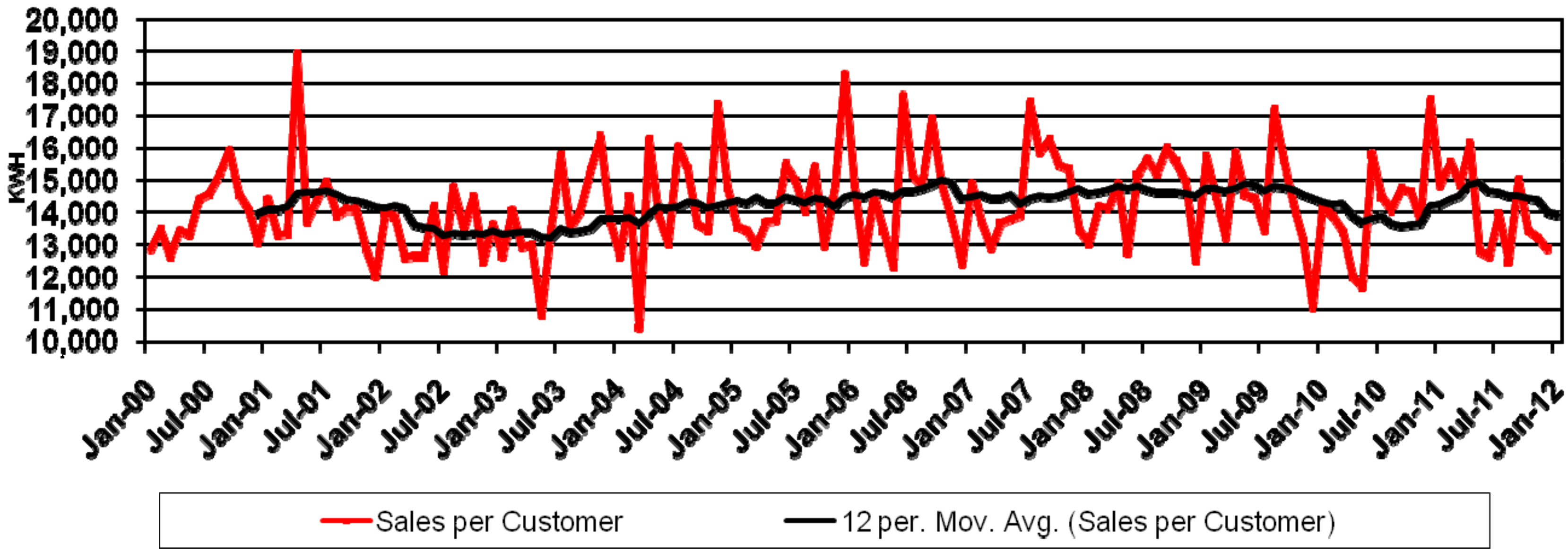


Industrial Energy Sales
Average Sales per Customer

Recent Evidence

✓Sales per customer per month peaked in October 2006 at 15026 KWH per month. High consumption partially attributed to a large self-generation unit being off-line at a refinery.

✓Currently sales per customer per month are 14000 KWH.

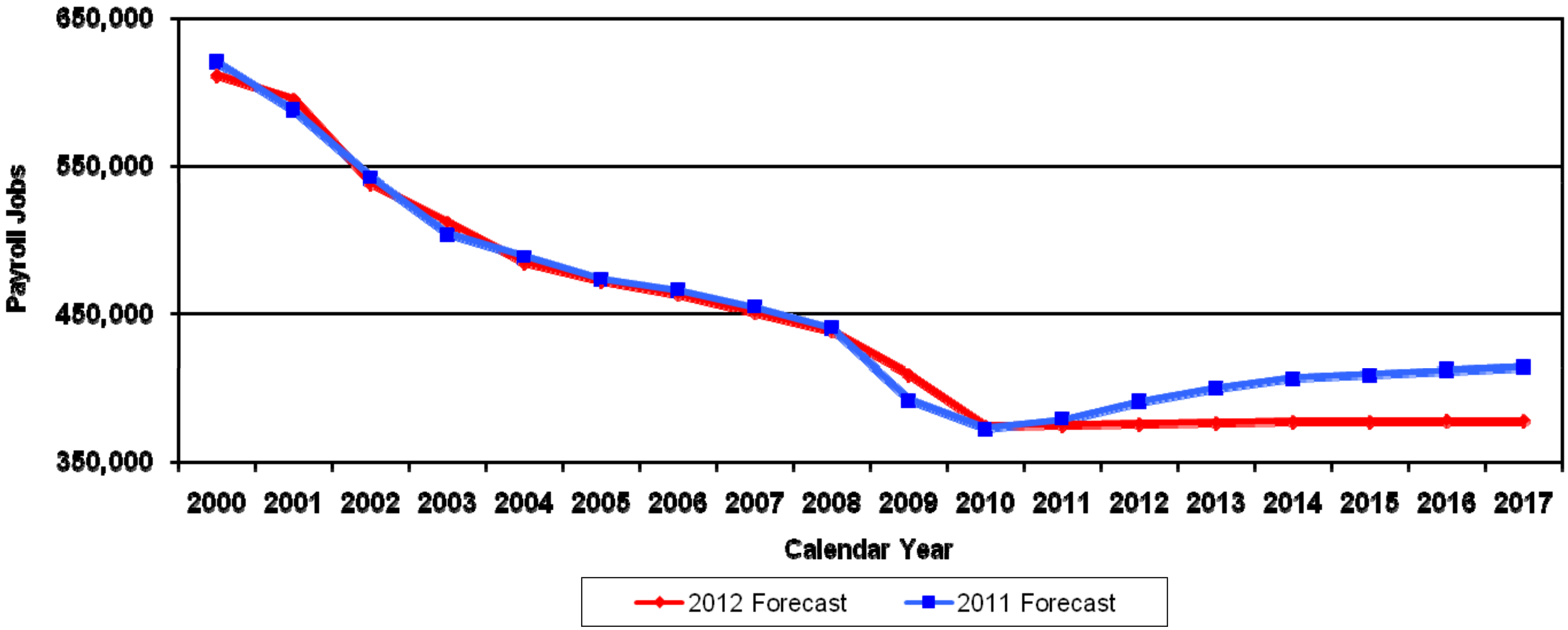


Industrial Energy Sales

Local Manufacturing Employment

LA County Manufacturing Employment

✓Future employment forecast is flat. If Los Angeles continues to lose manufacturing jobs then there will be a mismatch with the education level of the population and available high paying jobs. It could lead to significant population out-migration.

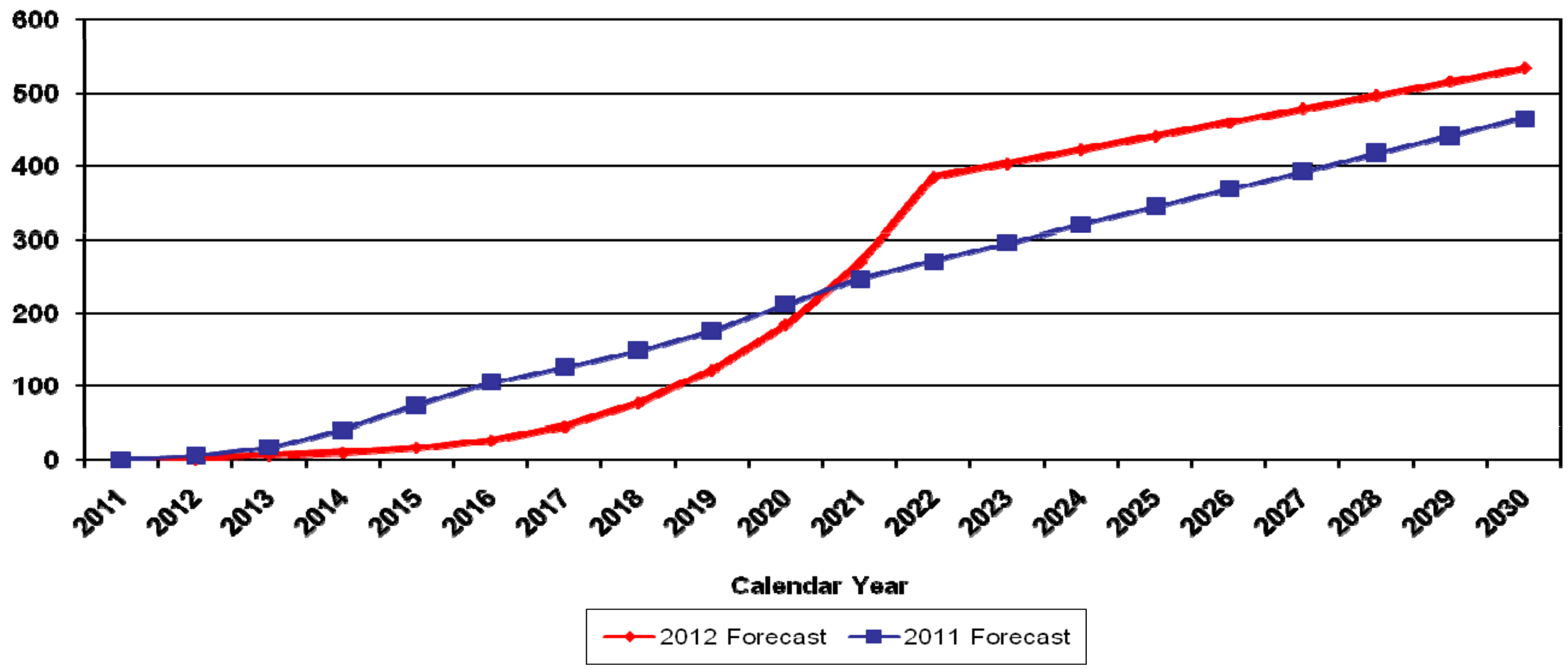


Electric Vehicle Sales

Load Growth

✓2012 forecast developed by the Plug-in Electric Vehicle Collaborative.

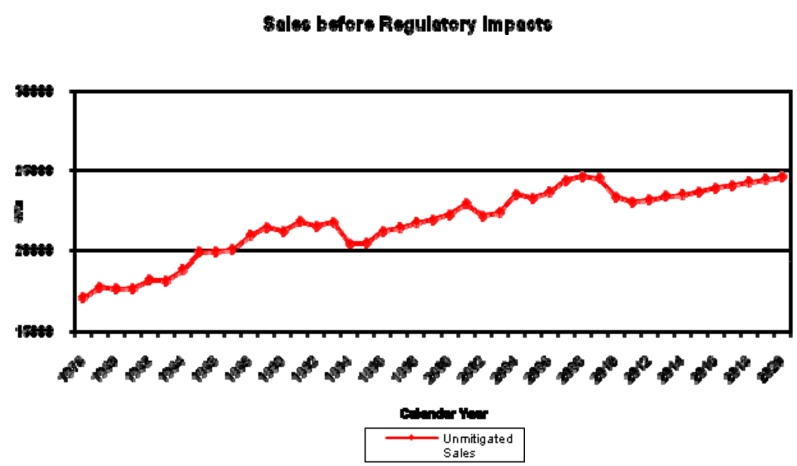
✓Also adopted by California Energy Commission



Plausibility

- Comparing unmitigated 2012 Sales Forecast to historical sales.
  - Unmitigated means forecasting sales based on economics alone before the impacts of environmental programs are considered.
  - Forecasted sales decline from 2008 to 2011 is largest in the past 30 years but smaller in scale.
  - No growth from economic factors in the next ten years. Next decade similar to what occurred in the 1990s before additional regulation.
  - LA is a mature economy.

Peak-to-Through Analysis		
Years	GWH Decline	Percent Decline
2008-2011	1,564	6.4%
1992-1994	1,421	7.0%
2000-2002	572	2.6%
1979-1980	322	1.8%
1981-1982	145	0.8%



Appendix B Energy Efficiency

Energy Efficiency (EE) is a key strategic element in LADWP IRP planning 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) 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.

The reduction in energy demand that EE enables, translates into a number of benefits:

- Deferred need to build physical generation assets
- Reduced RPS compliance costs
- Reduced environmental footprint, including lower GHG emissions
- Potential for local job creation opportunities

The following subsections summarize the background of LADWP's EE program, and then review the most recently completed EE potential study that was conducted in 2010 and finalized in February 2011. Based on the study results, a plan is recommended with identified savings and costs targets. For more specific details regarding the 2010 study, see the reference at the end of this appendix.

It should be noted that efforts are in progress to commission a new EE Potential Study that will supersede the 2010 study. In 2012, the Board of Water and Power Commissioners adopted a goal of achieving 10 percent EE by 2020, with a target of up to 15% by 2020 pending the results of the new study. The cases evaluated in this 2012 IRP have all incorporated 10% EE by year 2020, with higher levels of up to 17% by 2032. Next year's IRP will incorporate the findings and recommendations of the new potential study as they are finalized and approved.

B.1 Background

LADWP has active EE programs that have been in place for several years. Since 2000, LADWP has spent approximately $315.2 million on its EE programs, which have reduced consumption by approximately 1,377 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 433 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 52 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 149 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 200 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 49 GWh.

However successful LADWP's EE program has been, for a variety of reasons it did not meet targets that were set back in 2006. A summary the program since 2006 is presented in Table B-1.

Table B-1. LADWP EE PROGRAM PROGRESS-TO-DATE

	FY 06-07	FY 07-08	FY 08-09	FY 09-10	FY 10-11	FY 11-12	Cumulative FY 06-12
LADWP Adopted Targets (2006) - Net GWh	58	275	315	300	280	255	1,483
Actual Energy Savings Achieved - Net GWh	58	118	270	156	154	107	863
Actual % of Adopted Target	100%	43%	86%	52%	55%	42%	58%
Actual Energy Savings - Gross GWh	68	139	318	184	181	126	1016
Approved EE Budget ($million)	28	79	77	93	69	70	416
Revised EE Budget ($million)	n/a	n/a	n/a	>50	50	55	
Actual EE Funds Spent ($million)	14	38	68	44	50	37	251
Actual % of Budget	51%	48%	88%	48%	72%	68%	62%
Effective Cost - $/kWh	$0.018	$0.023	$0.018	$0.020	$0.023	$0.035	$0.291

Some key points regarding Table B-1 are as follows:

- The economic outlook in 2006, which the targets were based on, was more elevated then what actually transpired. As the higher outlook in 2006 failed to materialize, in retrospect the prior EE targets were overly ambitious.
- Since 2006, regulatory requirements have increased (OTC, RPS, GHG, etc.), resulting in additional demands outside of the EE program.

- Revenue streams required to support EE programs did not materialize. A spending freeze in 2009 and spending cutback in 2010 resulted in underfunding which hindered the attainment of program goals.
- Actual load profiles were less than forecasted, further affecting program performance.

An assessment of LADWP's EE program was undertaken in 2010. The assessment, also known as an Energy Efficiency Potential Study, includes an updated plan for moving forward.

B.2 Energy Efficiency Potential Study

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 late 2010 and is the basis for the EE recommendations contained in this 2011 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 2010 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

The analysis methodology is shown in Figure B-1.

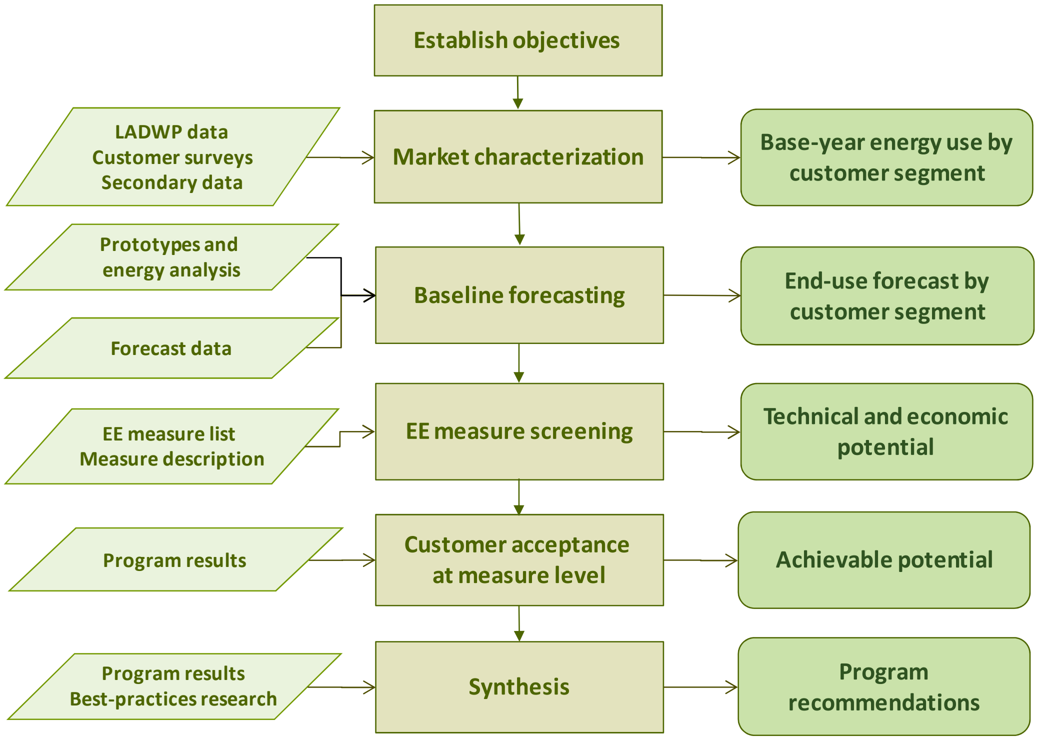


Figure B-1. 2010 Energy Efficiency Potential Study analysis approach.

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-occuring conservation
- Trends in appliance satuations
- How customers use electricity today
- Technological changes in appliances and equipment

The resulting baseline forecast for the overall customer base is shown in Figure B-2.

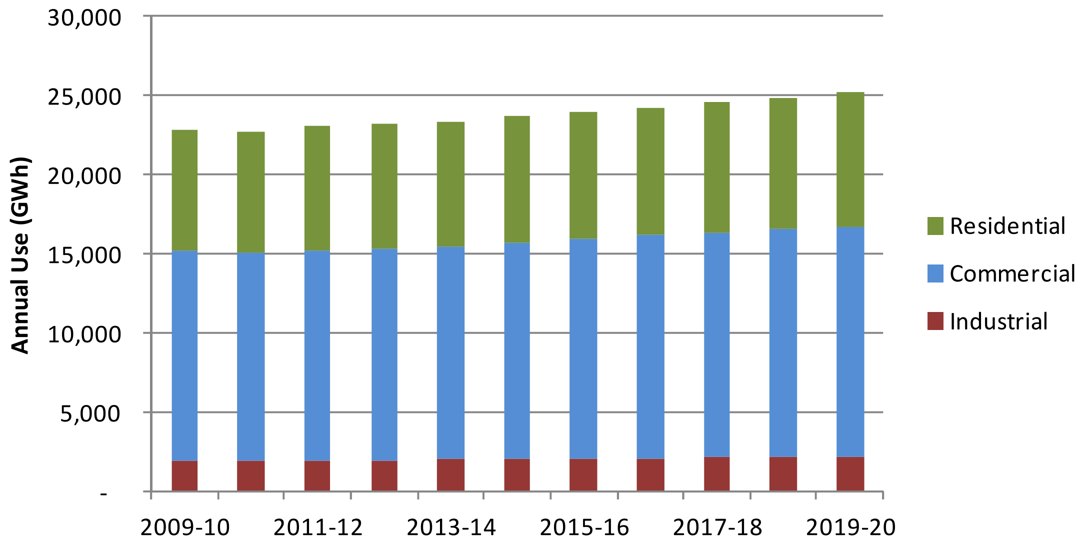


Figure B-2. Baseline forecast results through 2019-20.

Segmented forecasts for the industrial, commercial, and residential sectors are shown in Figures B-3, B-4, and B-5.

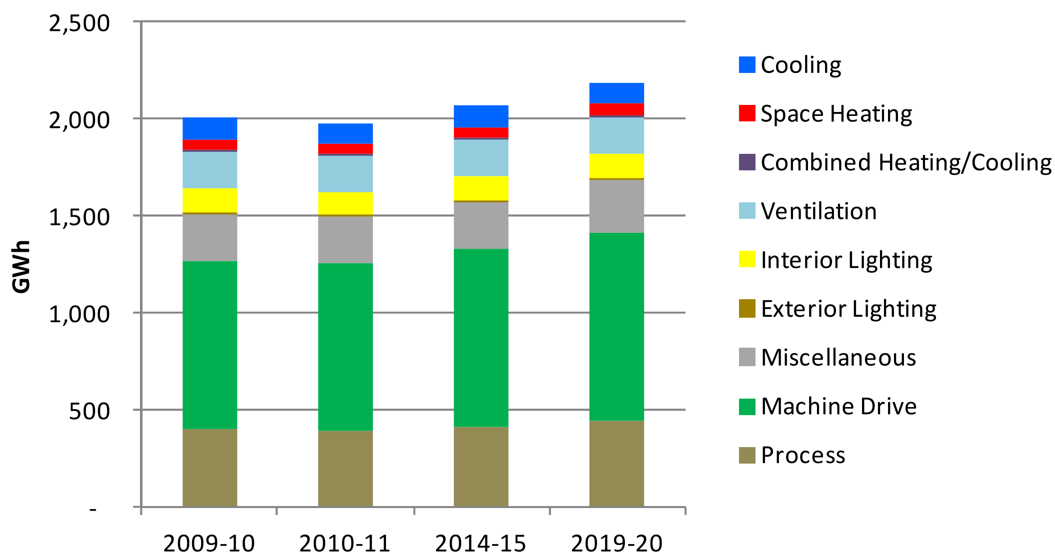


Figure B-3. Industrial sector baseline forecast results.

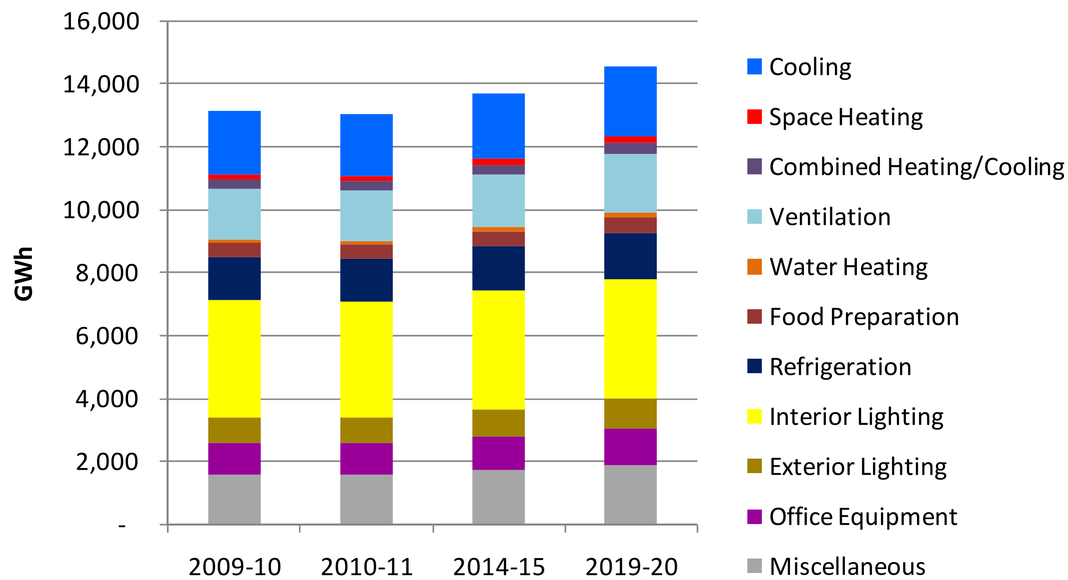


Figure B-4. Commercial sector baseline forecast results.

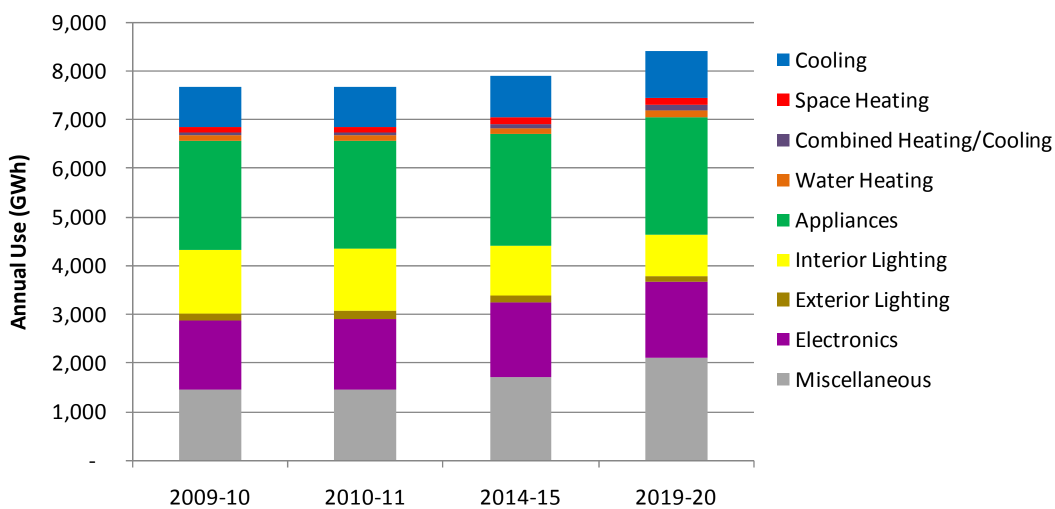


Figure B-5. Residential sector baseline forecast results.

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
- Retrocommissiong 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:

2010 Potential Study Definitions

Term	Definition
Technical Potential	Customers are assumed to install most efficient option regardless of costs.
Economic Potential	Customers are assumed to install most efficient cost-effective option.
Maximum Achievable Potential	Sets maximum targets for savings. Assumes "ideal" implementation conditions and customer preferences.
Realistic Achievable Potential	Includes realistic parameters for implementation; incorporates real-world limitations: Advance program potential: Utility pays 100% of incremental cost to upgrade to EE measures. Base program potential: Utility pays 50% of incremental cost.

Key drivers/assumptions influencing EE potential levels are:

- Program budgets are assumed to grow over time
  - Financing impacts
  - Federal grants impact
- Staffing levels and other required resources will increase with program expansion
- Avoided costs will rise with changes to the generations mix

The study found that there is a realistic potential to reduce energy consumption from the baseline forecast by 8.6% by year 2019-20. Figure B-6 shows the cumulative % energy savings through fiscal year 2019-20, and Figure B-7 shows the cumulative absolute savings.

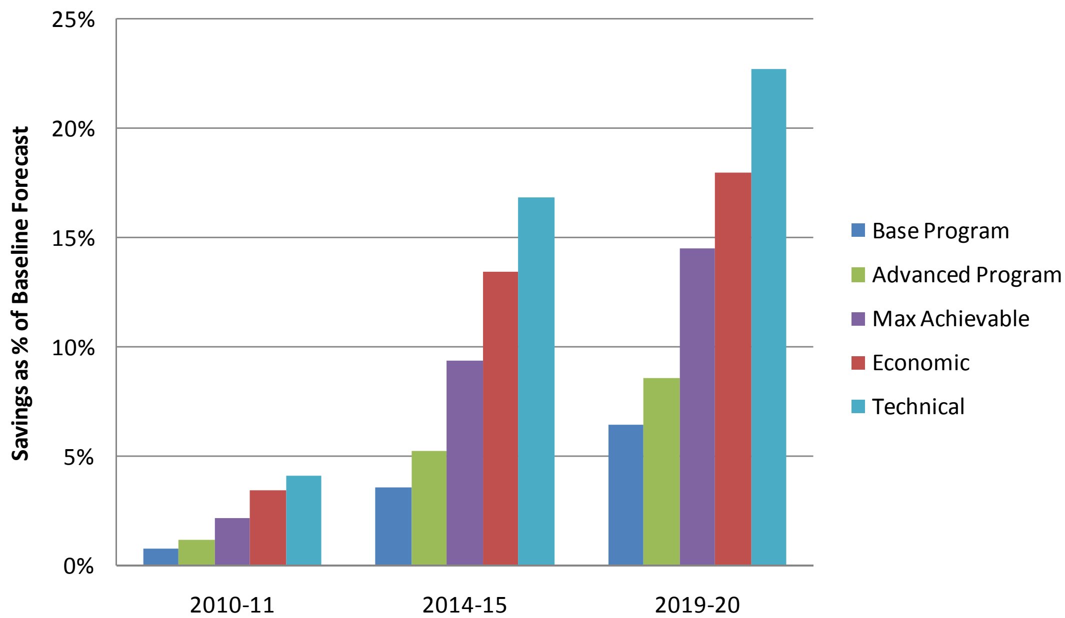


Figure B-6. Cumulative energy savings as a percentage of the baseline forecast.

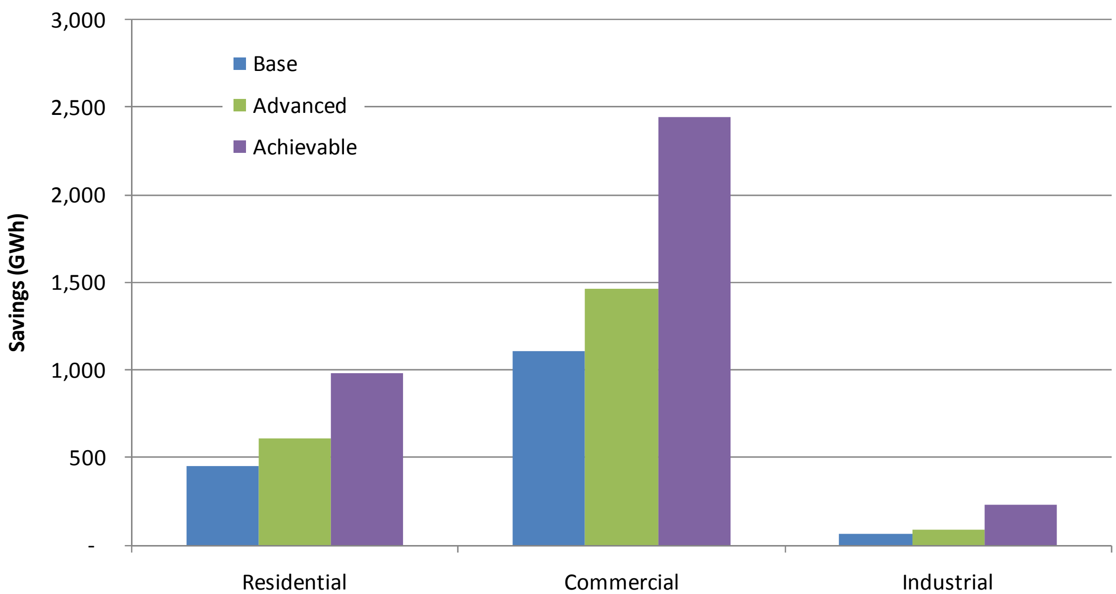


Figure B-7. Cumulative energy savings in GWh.

The Potential Study found that the net present value of avoided energy costs exceeds the NPV of program costs (including incentive payments, administrative costs and customer contributions) in both the Base and Advanced programs. Table B-2 and Figure B-8 illustrate the cost and benefit findings.

Table B-2. Financial Metrics

	Total Savings (GWh)	Total Cost ($Million)	Total Benefits ($Million)	Net Benefits ($Million)	Benefit/ Cost	Cost of Conserved Energy (cents/kWh)
Base Program	18,719	$1,073	$1,092	$18	1.02	5.73
Advanced Program	25,290	$1,411	$1,483	$72	1.05	5.58
Max Achievable	46,209	$2,139	$2,681	$542	1.25	4.63

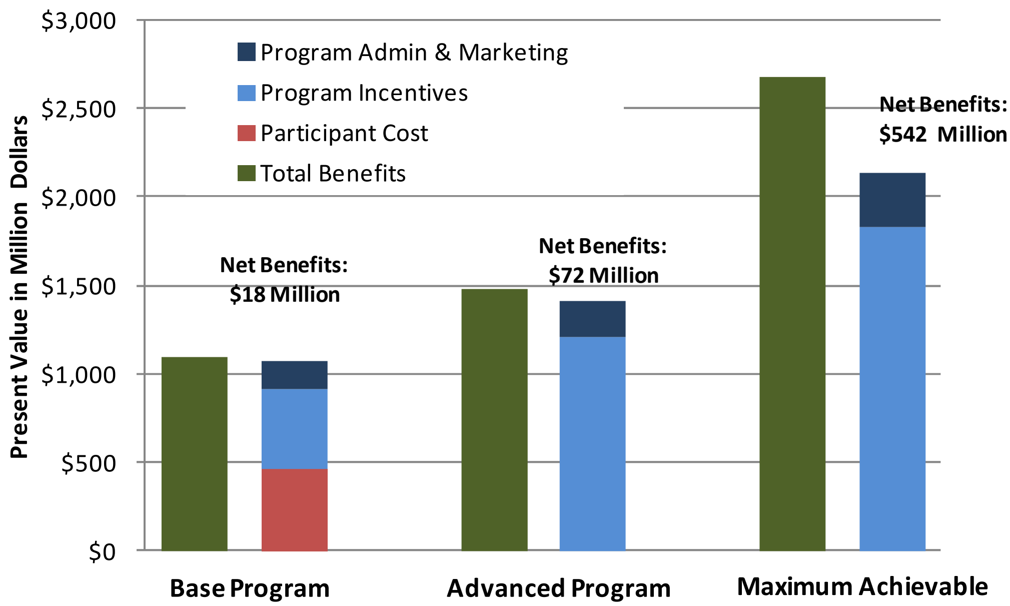


Figure B-8. Cost and benefits for base and advanced programs.

The analysis includes an assessment of the current program portfolio and the development of recommended changes.

<u>Residential Programs</u>

LADWP currently has the following existing residential EE programs:

Consumer Rebate
Refrigerator Turn-In and Recycle
Low Income Refrigerator Exchange
Compact Fluorescent Lamp (CFL) Distribution

The following recommendations resulted from the 2010 potential study:

1. LADWP should keep its existing programs, with the exception of CFL Distribution which should be replaced with a broader lighting initiative adapted to revised lighting standards.
2. Two new programs should be adopted, (1) Low-income, and (2) Whole House Performance.

A continued effort towards public outreach is also recommended to maintain and broaden public awareness of available EE benefits, and to promote participation.

Figure B-9 illustrates potential residential EE program savings for fiscal year 2019-20.

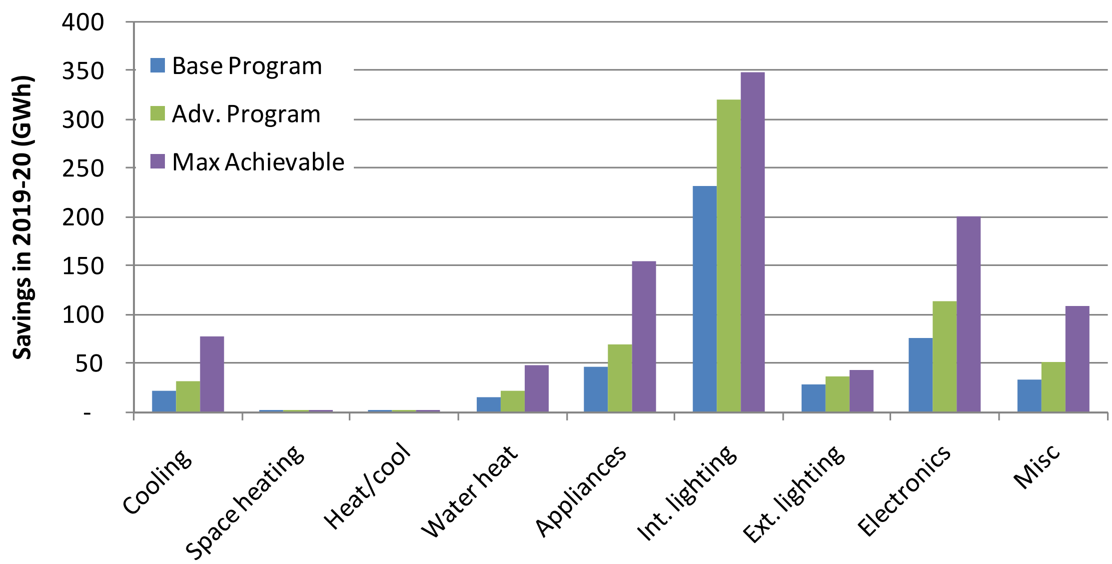


Figure B-9. Potential residential EE program savings in 2019-20.

Commercial and Industrial (C&I)

LADWP currently has the following existing C&I EE programs:

Commercial Lighting Efficiency
Chiller Efficiency
Refrigeration
Customer Performance
Small Business Direct Install
New Construction Incentive
Financing Programs
Energy Audits
Technical Assistance

The following recommendations resulted from the 2010 potential study:

1. LADWP should keep its existing program elements, but should adapt the lighting program to educate customers on the expanded choices in energy efficiency bulbs available that will comply with new lighting standards.

Figures B-10 and B-11 illustrate potential commercial and industrial savings for year 2019-20.

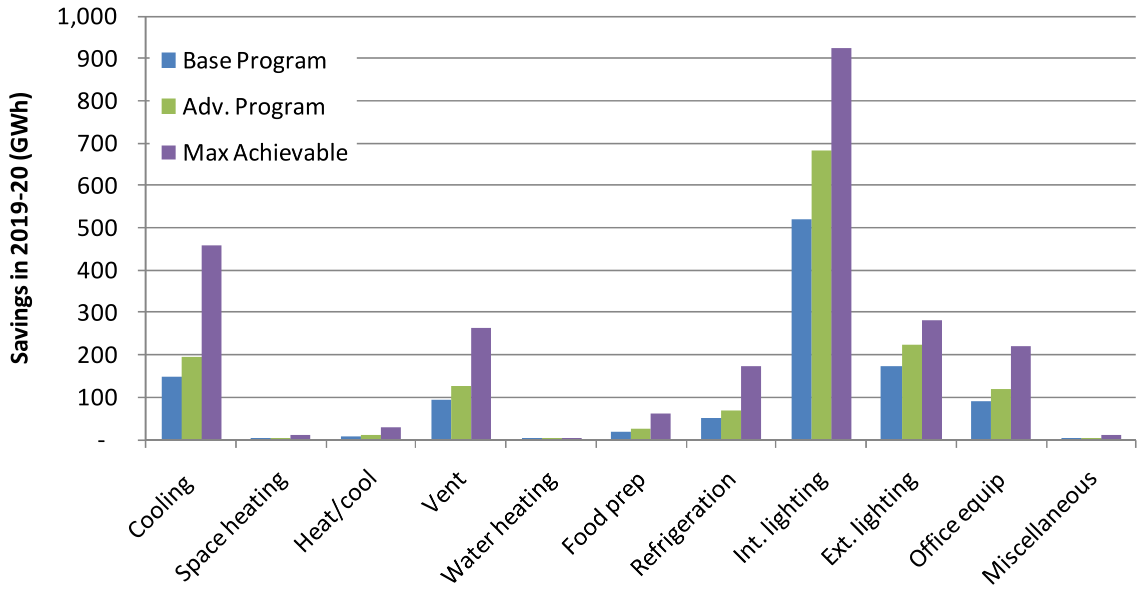


Figure B-10. Projected commercial EE savings in 2019-20.

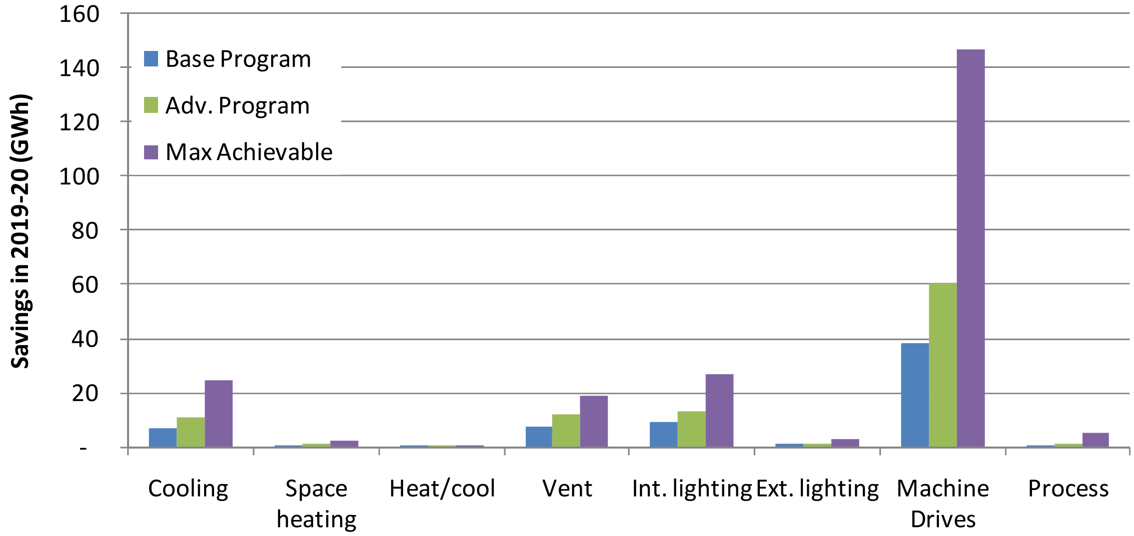


Figure B-11. Projected industrial EE savings in 2019-20.

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: Global Energy Partners, February 2011.

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 and 33 percent by December 2020 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.

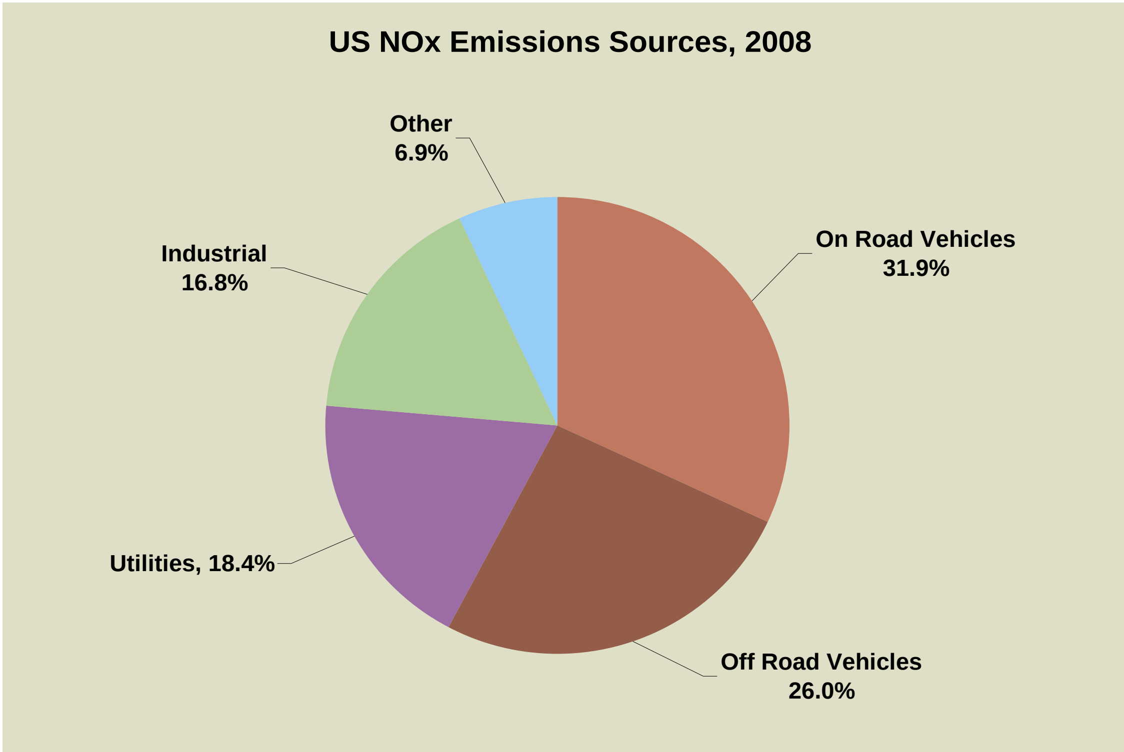
- Continuing the modernization of LADWP's in-basin generating stations, including the repowering of four older, less-efficient utility steam boiler units with advanced gas turbine generating units.

This Appendix provides information on a number of environmental issues and policies including oxides of nitrogen (NO_X) emissions, GHGs and 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. However, one common pollutant, nitrogen dioxide (NO_2), is a major precursor for "smog," which can be seen as a reddish-brown layer over many urban areas. Oxides of Nitrogen is also 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 2008. 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. The Agency has reviewed the standards twice since that time, but chose not to revise the standards at the conclusion of each review. All areas in the U.S. meet the current (1971) NO_2 standards.

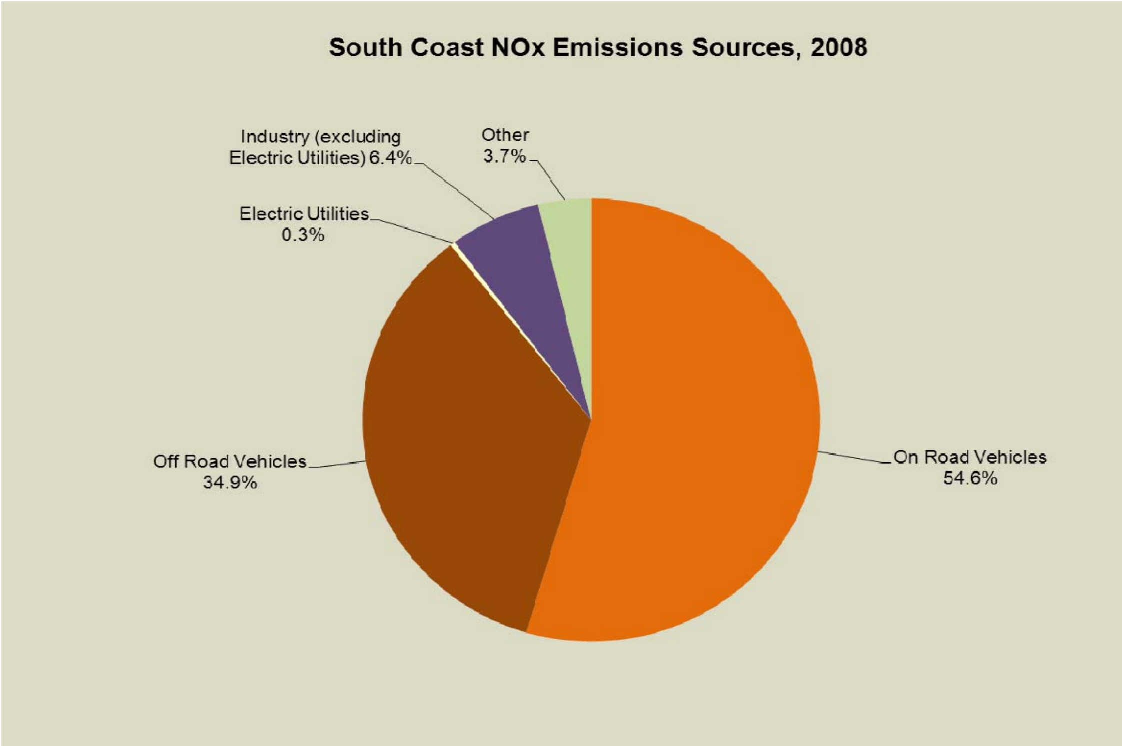


Source: U.S. Environmental Protection Agency

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 California Air Resources Board (CARB) estimates in its 2010 Almanac of Emissions and Air Quality that emissions in the SCAB were 742 tons of NO_X per day. This is down from 820 tons per day in 2008 due to additional regulatory requirements for stationary sources, and more efficient cars. CARB projects in their Almanac that SCAB NO_X emissions will continue to decrease from 56 tons per day to 52 tons per day. Figure C-2 shows the estimate 2008 NO_X emission sources.



Source: California Air Resources Board

Figure C-2. Local NO_X sources in 2010.

For comparison, the average daily NO_X emissions from LADWP's in-basin generating stations (Harbor, Haynes, Scattergood, and Valley) combined was 0.65 short tons of NO_X per day in 2008, which represents 0.08 percent of the 2008 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.

Forecasts project that South Coast Air Basin NO_X emissions will continue to decrease over the next decade. Targets for 2015 are 580 tons per day, while the 2020 target is 468 tons per day. The majority of this reduction is expected to come from a reduction in vehicle emissions; total tons emitted from stationary sources during this time period are only projected to decrease from 56 tons per day to 52 tons per day.

A major tool employed by the SCAQMD to reduce NO_X emissions from stationary sources is the RECLAIM (Regional Clean Air Incentives Market) 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 bought 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. However, the allocation of RTCs to each of LADWP's power plants declines over time, and the entire future allocation of RTCs was reduced about 22.5 percent by the SCAQMD in 2005. Using the resource planning studies and other considerations, the environmental assessment results show that the projections meet LADWP's NO_X goals.

C.3 Greenhouse Gas Emissions and Climate Change

C.3.1 Federal Efforts To Address Climate Change

Federal Climate Change Legislation

Several Congressional bills have been proposed in recent years to regulate GHG emissions under a federal cap-and-trade program, but none have garnered enough support for passage by both the House of Representatives and the Senate. In 2010, focus shifted to the U.S. EPA and the authority it has to regulate GHG emissions under the Clean Air Act (discussed in more details below).

Federal Regulation of Greenhouse Gases Under the Clean Air Act

In the absence of federal legislation, GHG emissions may still be regulated through the U.S. EPA through its authority under the Clean Air Act. In April 2007, the Supreme Court ruled in *Massachusetts v. EPA* that the U.S. EPA must make a determination when it comes to regulating motor vehicle emissions. The Supreme Court ruling gives the U.S. EPA 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 threatens public health and welfare.

In December 2009, U.S. EPA published its findings in the *Federal Register*, stating: "The Administrator finds that greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare." The impacts of climate change that will cause harm to human health and welfare of current and future generations include but are not limited to: increased drought; more heavy downpours and flooding; more frequent and intense heat waves and wildfires; greater sea level rise; more intense storms; and harm to water resources, agriculture, wildlife, and ecosystems.

EPA Tailoring Rule for Regulating Stationary Sources under the Clean Air Act

The Environmental Protection Agency finalized its "Tailoring Rule," which establishes a phased timetable for implementing Clean Air Act permitting requirements for GHG emissions from large stationary sources. The rule provides that Prevention of Significant Deterioration (PSD) requirements will first apply to GHG emissions effective January 2, 2011. This initial phase will apply to new and modified facilities that would already be required to obtain PSD permits as a result of their non-GHG emissions, and whose construction will result in an increase in GHG emissions of at least 75,000 tons CO_{2e} per year. A second phase of the program will commence on July 1, 2011, and will impose PSD requirements on new facilities that emit at least 100,000 tons CO_{2e} per year, as well as modified facilities whose emissions will increase by at least 75,000 tons CO_{2e} per year. In addition to these PSD requirements, the Tailoring Rule sets comparable emission thresholds and timetables for new and existing facilities to obtain operating permits under Title V of the Clean Air Act. It is anticipated that LADWP's Scattergood generating station will be subject to the new permitting requirements under the EPA's Tailoring Rule.

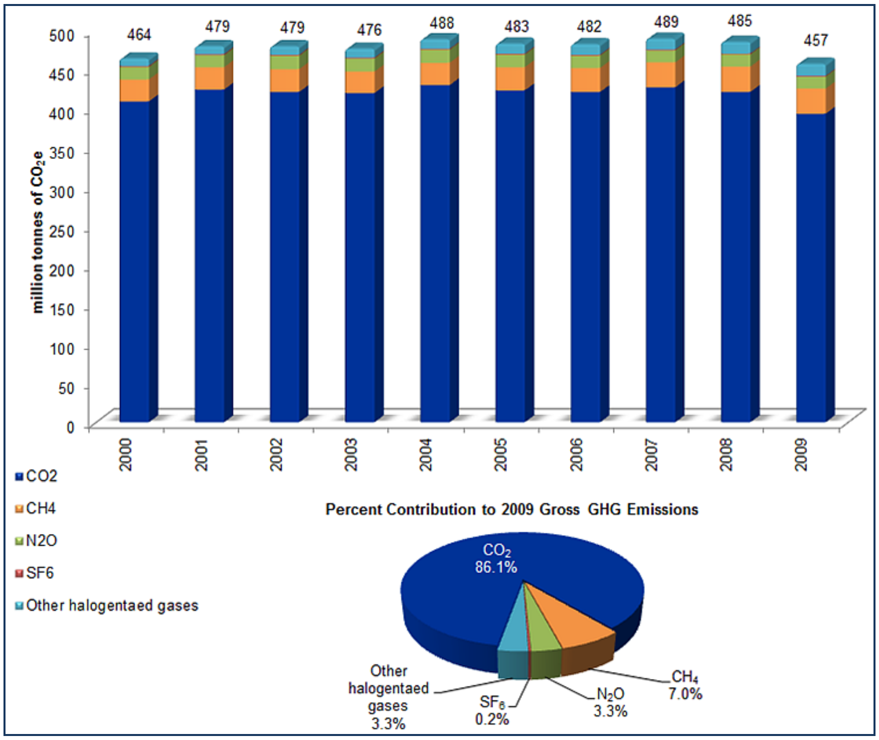
C.3.2 Western Climate Initiative (WCI)

Originally established by the Western Governor's Association in February 2007, the WCI has been reduced to a collaboration of only California and Quebec to reduce GHG emissions 15 percent below 2005 levels by 2020. The primary mechanism for achieving these reductions will be through a regional cap-and-trade program.

CARB is in the process of developing regulations to link California's market with Quebec.

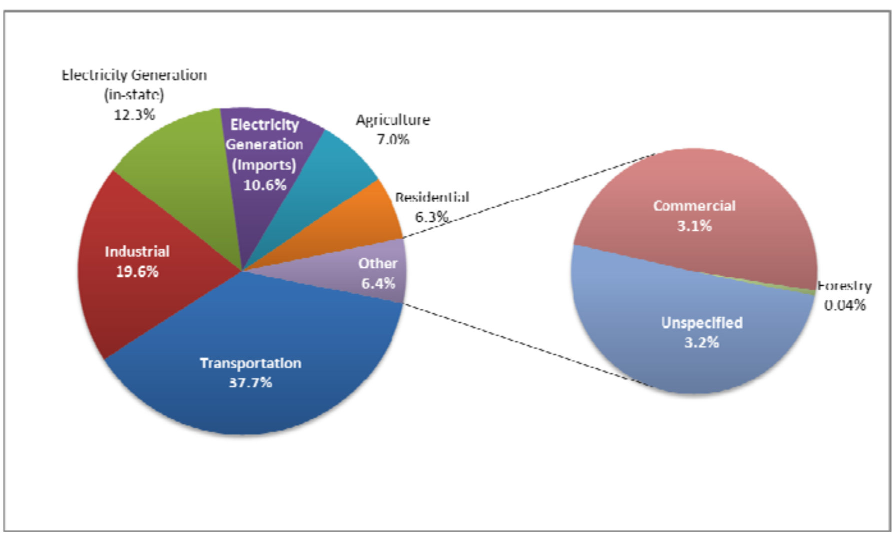
C.3.3 California Efforts to Address Climate Change

This section presents an overview of the California greenhouse gas emissions inventory and trends from 2000 through 2009. A new edition of California's greenhouse gas emission inventory was released April 6, 2012. It includes emissions estimates for years 2000 to 2009. Figure C-3 depicts the general trend in emissions from 2000 to 2009, and Figure C-4 displays 2009 statewide emissions by economic sector.



Source: California Air Resources Board

Figure C-3. California GHG emissions, 2000-2009.



Source: California Air Resources Board

Figure C-4. 2009 California GHG emissions by Economic Sector.

As California strives to achieve its benchmark goals under AB 32, the California inventory will become an increasingly valuable tool to keep track of greenhouse gas emissions from each sector. Maintaining and updating greenhouse gas inventory methodologies and data are imperative for a successful greenhouse gas reduction program. In 2009, total California GHG emissions were 457 million tons of carbon dioxide equivalent (MMT CO_{2e}); net emissions were 453 MMT CO_{2e}, reflecting the influence of sinks (net CO_2 flux from forestry). While total emissions have increased by 5.5 percent from 1990 to 2009, emissions decreased by 5.8 percent from 2008 to 2009 (485 to 457 MMT CO_{2e}). The total net emissions between 2000 and 2009 decreased from 459 to 453 MMT CO_{2e}, representing a 1.3 percent decrease from 2000 and a 6.1 percent increase from the 1990 emissions level. The transportation sector accounted for approximately 38 percent of the total emissions, while the industrial sector accounted for approximately 20 percent. Emissions from electricity generation were about 23 percent with almost equal contributions from in-state and imported electricity.

California Governor's Executive Order S-3-05

On the state level, Governor Schwarzenegger signed Executive Order #S-3-05 on June 1, 2005 which established the following GHG targets:

- By 2010, reduce emissions to 2000 levels
- By 2020, reduce emissions to 1990 levels
- By 2050, reduce emissions to 80 percent below 1990 levels.

California SB 1368: Greenhouse Gas Emissions Performance Standard

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 establish 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 California Energy Commission 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 EPS regulations.

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 greenhouse gas 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

In December 2008, the CARB adopted the AB 32 Scoping Plan, which serves as California's blueprint for reducing greenhouse GHG emissions. 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 renewables energy mix of 33 percent.
- Developing a California cap-and-trade program that links with other Western Climate Initiative partner programs to create a regional market system.
- Expand use of Combined Heat and Power (CHP) by 30,000 GWh statewide.

[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.

- 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.
- Creating targeted fees, including a public goods charge on water use, fees on high global warming potential gases, and a fee to fund the administrative costs of the state's long term commitment to AB 32 implementation.

All programs developed under AB 32 contribute to the reductions needed to achieve this goal, and will deliver an overall 15% reduction in greenhouse gas emissions compared to the 'business-as usual' scenario in 2020 if nothing was done at all. In 2010, the ARB made revisions to the expected 2020 emission reductions in consideration of the economic recession and the availability of updated information from development of measure-specific regulations. ARB staff re-evaluated the baseline in light of the economic downturn and updated the projected 2020 emissions to 545 $MMTCO_{2e}$. Two reduction measures (Pavley I and the Renewables Portfolio Standard (12% - 20%)) not previously included in the 2008 Scoping Plan baseline were incorporated into the updated baseline, further reducing the 2020 statewide emissions projection to 507 $MMTCO_{2e}$. The updated forecast of 507 $MMTCO_{2e}$ is referred to as the AB 32 2020 baseline. Reduction of an estimated 80 $MMTCO_{2e}$ are necessary to reduce statewide emissions to the AB 32 Target of 427 $MMTCO_{2e}$ by 2020.

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, like 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 (Adopted October 20, 2011)

The cap-and-trade program is a key element in California's climate plan. The cap-and-trade program sets a statewide limit on sources responsible for 85 percent of California's greenhouse gas emissions, and establishes a price signal needed to drive long-term investment in 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 expects to link with Quebec in 2013.

Although the program commenced on January 1, 2012, the enforceable compliance obligation starts with the 2013 GHG emissions. The first auction of California carbon allowances occurred in November 2012

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 to 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. Faced with the slow development of new CHP in California, 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. Understanding the full range of opportunities, motivations, policy successes, and remaining regulatory barriers for CHP across industrial, commercial, and residential sectors will help determine where the opportunities for development of new facilities are the greatest. This information will be used to develop policies and regulations to encourage CHP and support the state's GHG emissions reduction goals.

The California Energy Commission provided an update in February 2012 for a CHP Market Assessment that was originally conducted in 2009. 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 CEC's report suggests that the cumulative statewide market penetration for the base case is 1,888 MW, down from 2,998 MW as originally projected in 2009. The 2011 market scenarios, in general, show lower cumulative market penetration than the 2009 scenarios. The Base Case results show that, under the current policy landscape, CHP will fall short of the ARB Scoping Plan market penetration target. The report suggests that "additional policy measures, represented in the Medium and High Cases, are needed to raise market penetration up to the Scoping Plan target." 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 generating resources, including the divestiture of power purchase agreements with Colstrip and Coronado Generating Stations, 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 2011.

Table C-1. HISTORICAL LADWP POWER GENERATION CO_2 EMISSIONS

Year	Total CO_2 Emissions from Owned & Purchased Generation (metric tons)	Total CO_2 Emissions from Owned & Purchased Generation minus Wholesale Power Sales (metric tons)	Total Owned & Purchased Generation (MWh)	LADWP System CO_2 Intensity Metric (lbs CO_2/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
Difference between 1990 and 2011	-3,756,086	-4,133,696	1,544,393	-395
% Change from 1990	-21%	-23%	6%	-25%

Notes:
1. Calculated CO_2 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 power purchases using MWh purchased x default emission factor (1,100 lbs CO_2/MWh).

[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.

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. This new regulation imposes a declining limit on a utility'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 new emission limits imposed by the 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 new state wide OTC Policy and upcoming 316 b Federal Rule 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 Statewide OTC policy and upcoming Federal rule.

In addition, LADWP has already 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 IM. In 2006, LADWP conducted an effectiveness study on its velocity cap and the results showed that it is 96% effective.

- To date, LADWP has reduced the number of power plant units that utilize OTC from 14 to 9, reducing ocean water use from 1904 MGD to 1571 MGD, an overall reduction of ocean water usage by 17%.

- LADWP has spent over $600 million 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 2013, the Haynes 5&6 repowering project will be completed, reducing the number of OTC units to 7. This will decrease ocean water use from 1571 MGD to 1110.2 MGD, an overall reduction of 42% from 1990 ocean water usage levels.

- By 2015, the Scattergood 3 repowering project will be completed, further reducing the number of OTC units to 6 and decreasing ocean water use from 1110.2 MGD to 839.8MGD, an overall reduction of 56% from 1990 ocean water usage levels.

- By 2020, the Scattergood 1&2 repowering project will be completed, further reducing the number of OTC units to 4 and decreasing ocean water use from 839.8 MGD to 563.3MGD; an overall reduction of 70% from 1990 ocean water usage levels.

- By 2024, the Haynes 1&2 repowering project will be completed, 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 5 repowering project will be completed, 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 completed, reducing the number of OTC units to 0, resulting in 100% elimination of OTC.

Figure C-5 shows LADWP’s reduction in OTC usage from 1990 to 2029.

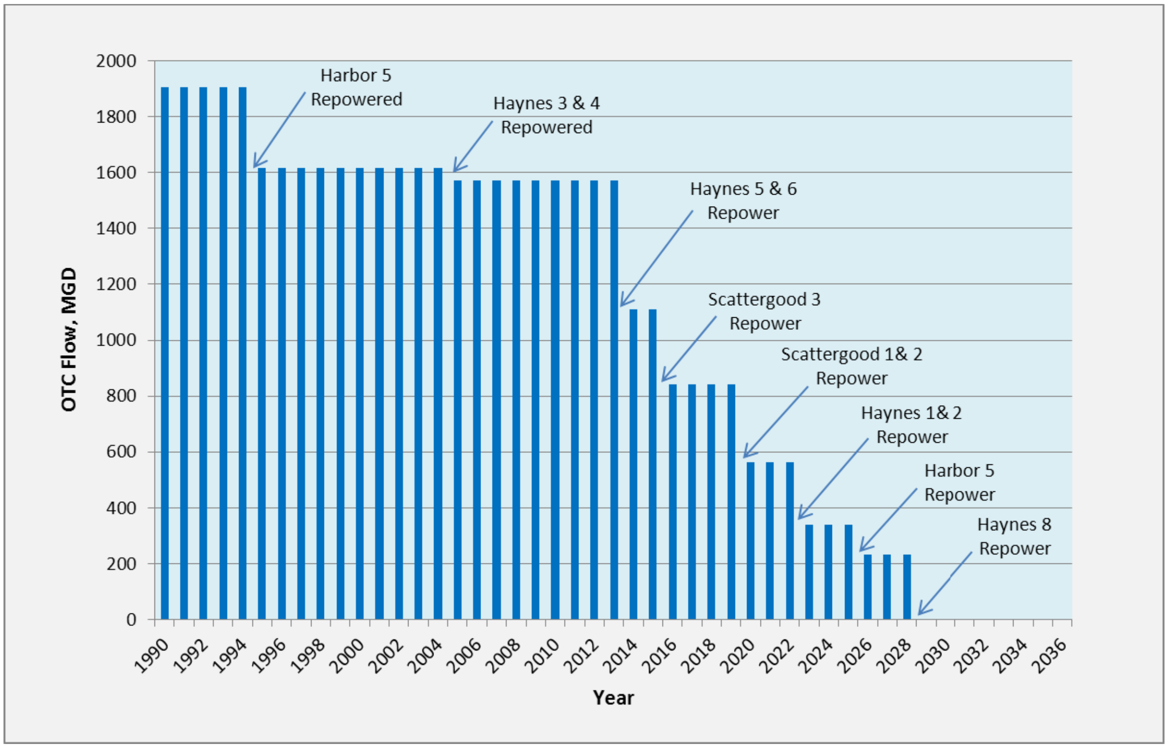


Figure C-5: LADWP OTC reduction from 1990 to 2029.

C.4.1 USEPA 316(b) Requirements for Cooling Water Intake Structures

EPA's Clean Water Act Section 316(b) Phase II Cooling Water Intake Structure Rule (Rule) 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 were unlawful and that other fundamental components of the 2004 Rule, 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 316(b) regulations. On April 1, 2009, the Supreme Court affirmed that a cost-benefit analysis can 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 Clean Water Act 316 (b) requirements using "Best Professional Judgment (BPJ) when reauthorizing facility National Pollutant Discharge Elimination System (NPDES) permits.

During this period, LADWP completed the required Characterization Study to identify baseline biological impacts in order to determine an appropriate impingement mortality (IM) and entrainment (E) reduction method. However, when the Rule was remanded to U.S. EPA to re-study and then re-propose a rule, it essentially remanded the Rule 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 and has been awaiting the outcome of U.S. EPA's effort to re-propose a new rule. The UP EPA publicly noticed the new proposed rule for existing facilities on April 19, 2011 and the comment period ended on August 18, 2011. The US EPA is under a settlement agreement with the Riverkeeper to have a final rule by no later than July 2012. In the meantime, EPA has given the State Permitting Authorities permission to continue with the regulation of Section 316 B with the use of BPJ.

C.4.2 SWRCB 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 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) or a 93 percent flow reduction and essentially requires the installation of cooling towers. If Track I can be demonstrated as "not feasible" a Track II compliance option is available. A 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 a 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's implementation plan 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. 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 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 commencing the alternative technologies studies. The Haynes Units 5&6 repowering project has broken ground and is in its construction phase in order to meet the 2013 deadline. Also, the conceptual planning and design for the Scattergood Unit 3 project has commenced in order to meet the 2015 deadline.

C.5 Mercury Emissions

Mercury (Hg) emissions are 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.

Coal-burning power plants are the largest human-caused source of Hg emissions to the air in the United States, accounting for over 50 percent of all domestic human-caused Hg emissions (Source: 2005 National Emissions Inventory). The EPA estimates that less than ½ of all Hg deposited within the U.S. comes from U.S. sources.

The 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.

On March 15, 2005 U.S. EPA promulgated the Clean Air Mercury Rule (CAMR), which established a nationwide cap-and-trade program for mercury emissions. CAMR was designed to reduce mercury emissions by 60 percent between 2010 and 2018. Several legal challenges of the CAMR ensued. As a result, the D.C. Circuit vacated U.S. EPA's Clean Air Mercury Rule on February 18, 2008. On May 3, 2011, EPA proposed NESHAPs for coal- and oil-fired EGUs under Clean Air Act (CAA) section 112(d) and proposed revised NSPS for fossil fuel-fired EGUs under CAA section 111(b). The proposed NESHAP would protect air quality and promote public health by reducing emissions of the hazardous air pollutants (HAP) listed in CAA section 112(b). In addition, these proposed amendments to the NSPS are in response to a voluntary remand of a final rule. EPA finalized its rule in December 2011.

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 and is included in Reference D-1 and D-2.

This 2012 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 goal to 25 percent by 2016 and 33 percent by 2020. 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 five 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. The 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.

The Pine Tree wind farm was expanded with ten new 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. Several other proposals that were received are currently being negotiated.

D.2.5 2011 SCPPA RFP

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. 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, SCPPA issued another RFP for renewable resources. The response deadline is November 30, 2012.

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 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. 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 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 and to ramp to 33 percent between 2013 and 2020. 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 either small hydro or biogas 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 on line in the next few years, and limitations of the 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 2011 is shown on Figure D-1

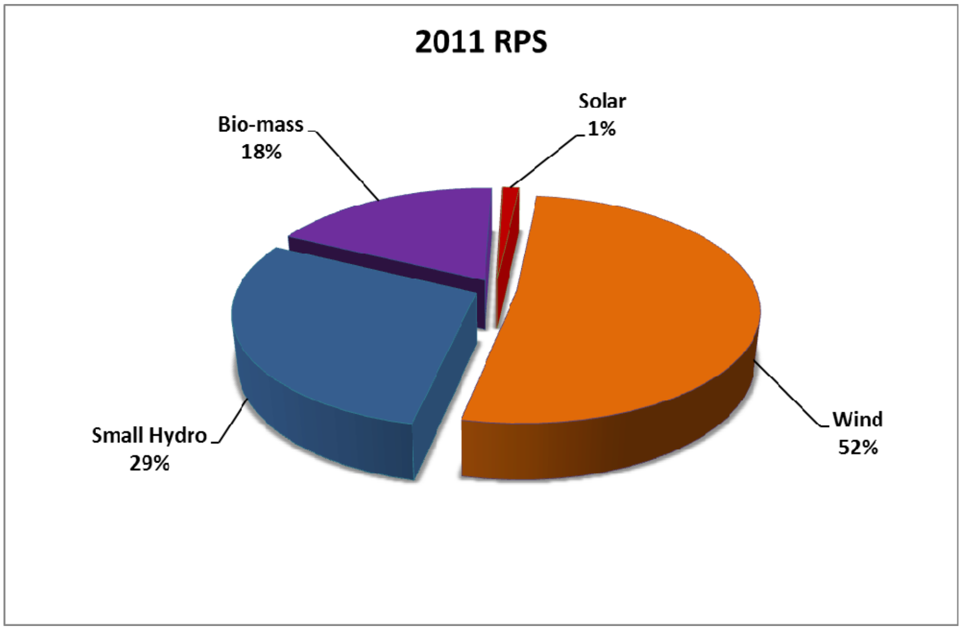


Figure D-1: 2011 Renewable Energy Mix

D.3.4 Impacts of CA Senate Bill SB 2 (1X)

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 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.

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. Either: Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source [PUC Section 399.16(b)(1)(A)]. Or, have an agreement to dynamically transfer electricity to a California balancing authority. [PUC Section 399.16(b)(1)(B)]	**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. Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority. [PUC Section 399.16(b)(2)]	Shall be calculated as the remainder of resources which are not in either Category 1 or Category 3.
3. Eligible renewable energy resource electricity products or any fraction of the electricity generated, including unbundled RECs that do not qualify under Bucket 1 or 2. [PUC Section 399.16(b)(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 CEC over POUs were finalized. The Fourth Edition Renewable Energy Program Overall Program Guidebook and the Fifth Edition Renewable Portfolio Standard Eligibility Guidebook were adopted by the CEC on May 9, 2012.

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 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 buy, sell, or trade RECs without the associated energy (unbundled). This procurement approach will be limited by the percentage requirements established by 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. 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, which total 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 currently underway on this project.
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/Imperial Irrigation District 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.

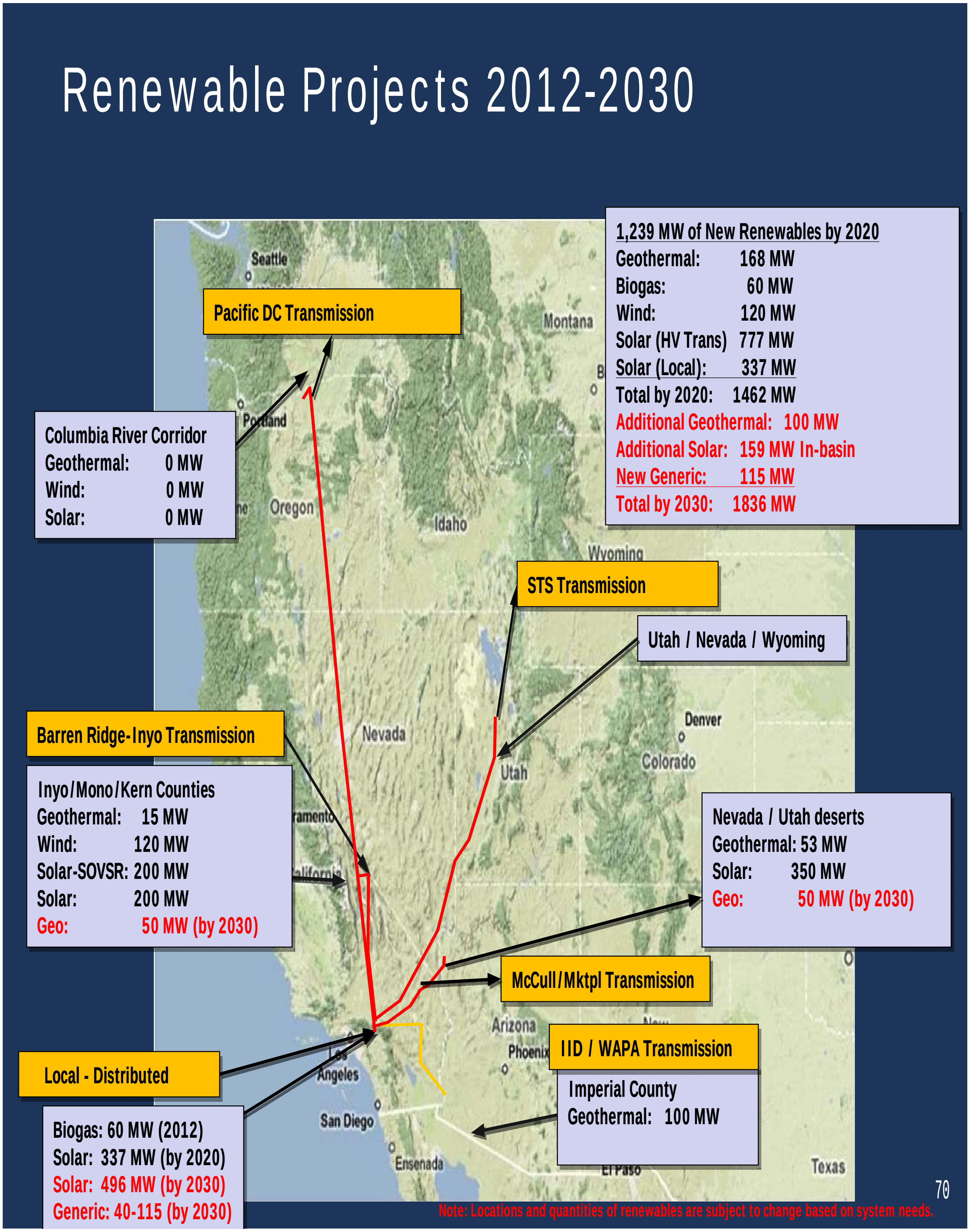


Figure D-2: Renewable Transmission Paths and Potential Resources, 2010 - 2030

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 33 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 4000 GWh annually for 2020 and beyond will require increasing annual renewable portfolio costs from 387 million to 848 million over the next 9 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 used to comply with RPS standards as other lower cost alternatives have been largely exhausted. As can be seen in Figure D-4, contracts for renewable projects totaling 548 GWh or 12 percent of the renewable energy supply will expire over the next 4 years and will need to be replaced with higher cost renewable resources. Maintaining the current 20 percent RPS will require additional revenue to compensate for these higher cost replacement resources.

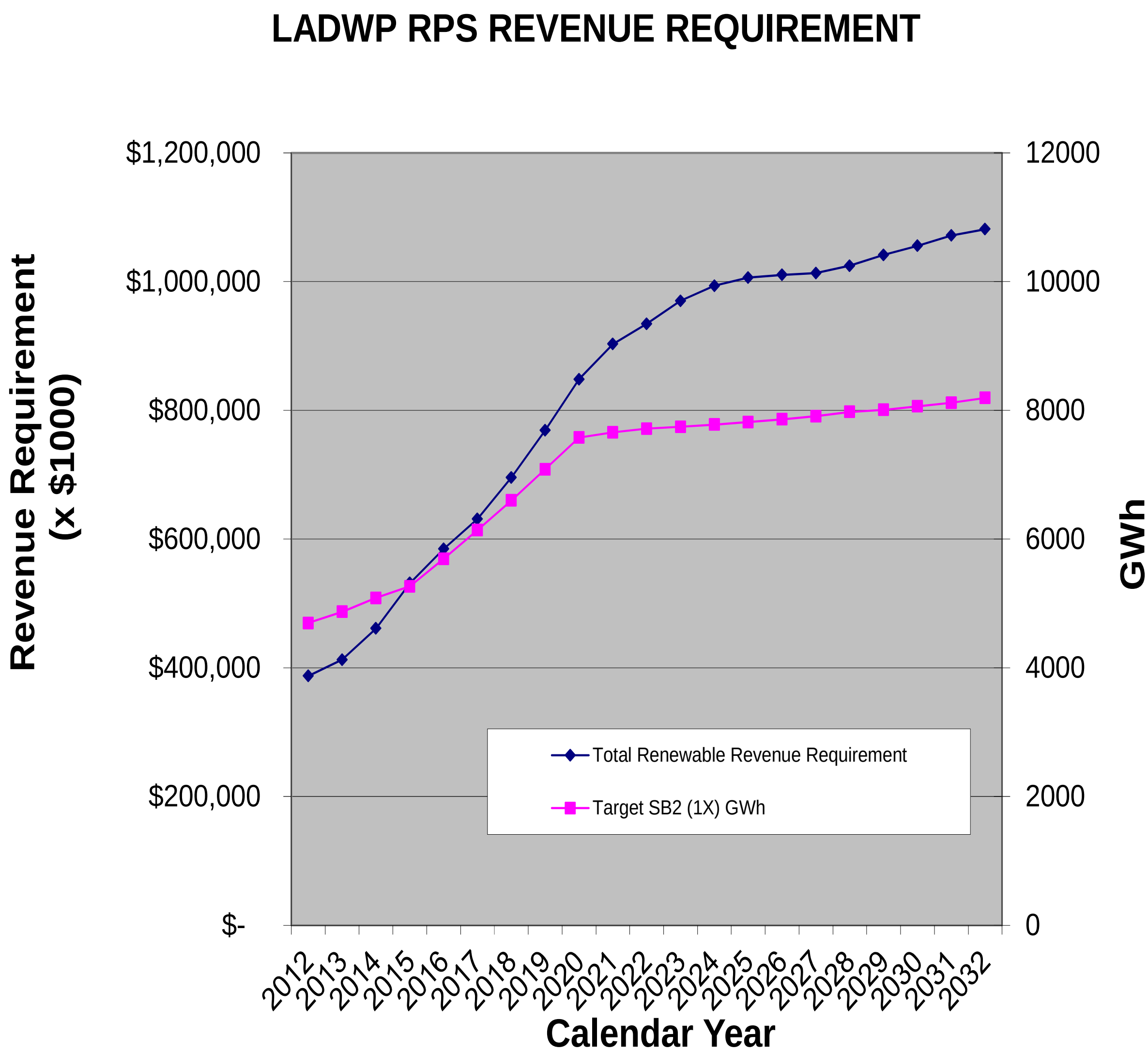
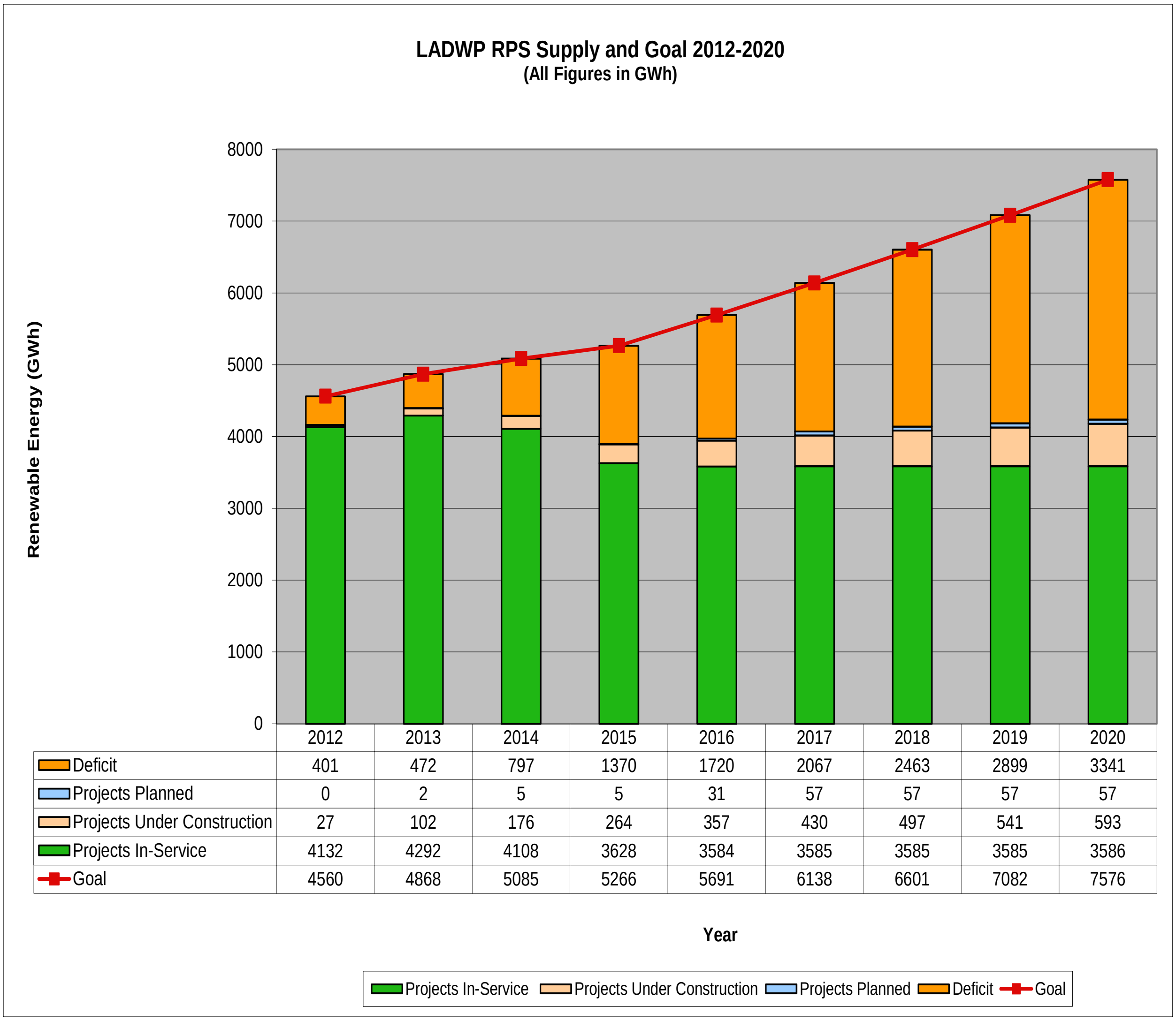


Figure D-3 – LADWP RPS Revenue Requirement 2012-2030.



	2012	2013	2014	2015	2016	2017	2018	2019	2020
Deficit	401	472	797	1370	1720	2067	2463	2899	3341
Projects Planned	0	2	5	5	31	57	57	57	57
Projects Under Construction	27	102	176	264	357	430	497	541	593
Projects In-Service	4132	4292	4108	3628	3584	3585	3585	3585	3586
Goal	4560	4868	5085	5266	5691	6138	6601	7082	7576

Figure D-4. LADWP RPS supply and goals for 2011-2020.

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 current California Energy Commission (CEC) Overall Program Guidebook of May, 2012 defines 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.”

Digester gas is typically derived from the anaerobic digestion of agricultural or 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.

In its latest edition of the RPS Eligibility Guidebook (5th Edition)[1], the CEC has noted that it has suspended the RPS eligibility related to biogas and put certain conditions of suspension and eligibility limitations in place, as described in Resolution No. 12-0328-3[2]. The suspension, which took effect on March 28, 2012, was adopted by the CEC Commissioners to provide the CEC staff with additional time to evaluate issues surrounding the continued eligibility of biomethane as a result of changes in law under SB 2 (1X). The suspension will remain in effect until the Energy Commission takes subsequent action to lift the suspension.

The California Legislature is currently proposing legislation that will revise the current eligibility requirements of biogas for entities who procured this resource prior to the effective date of the suspension. If legislation is executed, the CEC will subsequently modify its RPS Eligibility Guidebook to comply with such new requirements pertaining to the eligibility of Biogas.

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

[1] Renewables Portfolio Standard Eligibility, Fifth Edition, California Energy Commission, Efficiency and Renewable Energy Division. Publication Number: CEC-300-2012-002-CMF.

[2] Notice of Correction to Resolution on Suspension of the RPS Eligibility Guideline related to Biomethane, issued April 5, 2012. Available at: http://www.energy.ca.gov/portfolio/notices/2012-04-05_Notice_of_Correction_to_Resolution_on_Suspension_Biomethane_TN-64618.pdf

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 MSW 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 2011 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 2011 Power Content Label

POWER CONTENT LABEL

Annual Report of Actual Electricity Purchases for LADWP
Calendar Year 2011

ENERGY RESOURCES	LADWP Power ACTUAL MIX	LADWP Green Power ACTUAL MIX	2011 CA POWER MIX** (for comparison)
Eligible Renewable ***	**19%**	**100%**	**14%**
-- Biomass & waste	3%	0%	2%
-- Geothermal	0%	0%	5%
-- Small hydroelectric	6%	0%	2%
-- Solar	0%	0%	0%
-- Wind	10%	100%	5%
Coal	41%	0%	8%
Large Hydroelectric	3%	0%	13%
Natural Gas	17%	0%	37%
Nuclear	11%	0%	16%
Other	0%	0%	0%
Unspecified sources of power*	**9%**	**0%**	**12%**
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.

*** This is in accordance with Los Angeles City Council's action on 10-5-04 for File No. 03-2688 (RPS)

For specific information about this electricity product, contact LADWP at 1-800-DIAL-DWP. For general information about the Power Content Label, contact the California Energy Commission at 1-800-555-7794 or www.energy.ca.gov/consumer.

Reference D-1 – LADWP Renewables Portfolio Standard Policy and Enforcement Program Amended December 2011 - 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 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 publicly-owned utilities 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 a LADWP 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, 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 the RPS goal to obtain 20 percent renewables by 2010, which recommendation included updating LADWP's Integrated Resource Plan to include 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 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 date of the goal that required 20 percent of energy sales to retail customers be generated from renewable resources 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 will become effective on December 10, 2011, and requires the governing board of a local publicly owned electric utility, such as LADWP, to adopt a program for enforcement, in accordance with Public Utilities Code Section 399.30(e), by January 1, 2012.

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 2011, 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 2011:

City of Los Angeles Department of Water and Power Renewables Portfolio Standard Policy and Enforcement Program Amended December 2011

1. Purpose:

On April 12, 2011, Governor Jerry Brown 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 local Publicly Owned Electric Utilities (POUs). It is anticipated that SB 2 (1X) becomes effective on December 10, 2011, ninety days after the end of the special legislative session (1X) in which it was enacted.

This RPS Renewables Portfolio Standard 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. It is being adopted in accordance with the newly added Section 399.30 (e) of the Public Utilities Code (PUC), requiring the governing boards of POUs to adopt "a program for enforcement of this article" on or before January 1, 2012.

The SB 2 (1X) also requires the California Energy Commission (CEC) to "adopt regulations specifying procedures for enforcement of this article", which include a public process under which the CEC may issue a notice of violation and correction against a POU for failure to comply. The CEC is further required to refer violations of its regulations to the California Air Resources Board which may impose penalties to enforce the Act consistent with California Assembly Bill 32, (AB32 - California Global Warming Solutions Act of 2006).

It is the intent of LADWP to comply with the provisions of the Act, and with applicable enforcement regulations adopted by the CEC pursuant to the Act. It is also the intent of LADWP to update this RPS Policy, as necessary, after the CEC adopts regulations specifying procedures for enforcement.

The Board of Water and Power Commissioners of the City of Los Angeles (Board) retains its jurisdiction to enforce the RPS Policy in accordance with PUC Section 399.30 (e).

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 investor-owned electric utilities.

SB 1078 provided that each governing board of a local POU be responsible for implementing and enforcing a 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 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 a LADWP 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 Los Angeles 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 a RPS Policy, as amended 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.

3. RPS Compliance Targets:

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, the following RPS compliance targets are hereby adopted:

1. For the period of January 1, 2011 to December 31, 2013, LADWP will procure sufficient electricity products from eligible renewable energy resources to achieve an average of 20 percent of retail sales during such period.
2. LADWP will increase its procurement of electricity products from eligible renewable energy resources to achieve 25 percent of retail sales by December 31, 2016, based on an average percentage of retail sales calculations for the period of January 1, 2016 to December 31, 2016.
3. LADWP will increase its procurement of electricity products from eligible renewable energy resources to achieve 33 percent of retail sales by

December 31, 2020, based on an average percentage of retail sales calculations for the period of January 1, 2020 to December 31, 2020.

4. For each calendar year after 2020, LADWP will procure sufficient electricity products from eligible renewable energy resources to achieve a minimum 33 percent of retail sales based on an average percentage of retail sales calculations for the period of January 1 to December 31 in each such calendar year.

The LADWP will continue to encourage voluntary contributions from customers to fund renewable energy resources in addition to the stated RPS compliance targets, in accordance with its Green Power for a Green L.A. Program or any successor program.

4. Eligible Renewable Energy Resources:

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, and the Los Angeles Aqueduct hydro power plants; 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 on Appendix A, will continue to be eligible renewable energy resources. These renewable energy resources will count in full towards LADWP's RPS targets adopted in section 3 under this updated RPS Policy.

For RPS resources procured after the effective date of SB 2 (1X), "eligible renewable energy resource" means a generation facility that meets eligibility criteria under applicable law, including a "Renewable Electrical Generation Facility" as defined in Section 25741 (a) of the Public Resources Code and "Eligible Renewable Energy Resource" as defined in PUC Sections 399.12 (e) and 399.12.5.

5. Long-Term Resource and Procurement Plan:

The LADWP will integrate the RPS Policy into its long-term resource planning process, and the RPS Policy will not compromise LADWP's IRP objectives of service reliability, competitive electric rates, and environmental leadership. Future IRPs will incorporate and expand upon RPS compliance targets, and further define plans for procuring eligible renewable energy resources by technology type and geographic diversity.

Each year, 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, will comprise the LADWP Renewable Energy Resources Procurement Plan, as required under SB 2 (1X).

6. Procurement of Eligible Renewable Energy Resources:

The LADWP will procure eligible renewable energy resources based on a competitive method and least-cost, best-fit evaluations. 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 a Distributed Generation Feed-In-Tariff, Senate Bill 1 (SB1) Customer Net Metered Solar PV, 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 the 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 optioned 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.

7. Portfolio Content Categories

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, commonly known as "buckets". 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) for each bucket in each compliance period.

These buckets and percentage requirements are summarized in Table 1 below:

Table 1: Procurement Content Categories and Percentage Requirements

Category (aka "Buckets")	Percentage of RPS Target
4. Either: Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source [PUC Section 399.16(b)(1)(A)]. Or, have an agreement to dynamically transfer electricity to a California balancing authority. [PUC Section 399.16(b)(1)(B)]	**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.
5. Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority. [PUC Section 399.16(b)(2)]	Shall be calculated as the remainder of resources which are not in either Category 1 or Category 3.
6. Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled RECs, that do not qualify under Bucket 1 or 2. [PUC Section 399.16(b)(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 maximum from this category.

The LADWP will define the specific scheduling methods, including firming services, as needed, to maintain transmission system reliability and compliance with these procurement content categories and specified percentage requirements.

Subject to the provisions of PUC Section 399.16 (d), renewable electricity products procured prior to June 1, 2010, are exempt from these portfolio content categories and will continue to count in full toward LADWP's RPS compliance targets.

8. System Rate Impact:

The LADWP may not make any major financial commitment to procure renewable resources prior to evaluating the rate impact and any potential adverse financial impact on the City transfer.

9. Compliance Considerations:

In accordance with this RPS Policy, the Board will review the annual fiscal year budget and Renewable Energy Resources Procurement Plan, and will ensure that reasonable progress is being made towards compliance with the RPS compliance targets.

Reasonable progress may include activities that further the development and procurement of eligible renewable energy resources. Such activities may include, but are not limited to: real estate purchases for future project development, project planning and environmental permitting for either renewable energy projects or transmission in support of renewable energy projects, and other engineering, planning, budgeting, contracting and regulatory compliance activities.

In accordance with PUC Section 399.30 (d) (2), under exceptional circumstances the Board may adopt conditions that allow for delaying timely compliance with the RPS compliance targets, consistent with PUC Section 399.15 (b). Such conditions may include permitting, interconnection or environmental delays; transmission constraints; resource availability; or operational limitations.

In accordance with PUC Section 399.30 (d) (3), under exceptional circumstances the Board may adopt cost limitations for procurement expenditures consistent with PUC Sections 399.15 (c) and 399.15 (d).

In accordance with PUC Section 399.30 (d) (1), under exceptional circumstances the Board may adopt rules permitting LADWP to apply excess procurement in one compliance period to subsequent compliance periods in the same manner as allowed for retail sellers pursuant to PUC Section 399.13.

10. Reporting and Notice Requirements:

The LADWP will provide a monthly RPS Progress Report to the Board of Commissioners. Additionally an annual report will be provided to its customers and the CEC, containing all information required to be reported pursuant to SB 2 (1X), SB 1078, SB 107, and related regulations.

Per PUC Section 399.30 (e), the Board will adopt the program for enforcement at a publicly noticed Board meeting offering all interested parties an opportunity to comment. No less than 30 days' notice shall be given to the public of any meeting held for purposes of adopting the program. No less than 10 days' notice shall be given to the public before any meeting is held to make a substantive change to the program.

Per PUC Section 399.30 (f), LADWP will post notice whenever the Board will deliberate in public on its Renewable Energy Resources Procurement Plan. LADWP will either 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, or provide the CEC with the uniform resource locator (URL) that links to this information. 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, or provide the Uniform Resource Locator (URL) that links to the documents or information regarding other manners of access to the documents.

Per PUC Section 399.30 (g), LADWP shall annually submit to the CEC documentation regarding eligible renewable energy resources procurement contracts that it executed during the prior year.

Per PUC Section 399.30 (l), LADWP shall report, on an annual basis, information on: (1) expenditure of public goods funds for eligible renewable energy resources development, (2) the resource mix used to serve its retail customers by energy source, and (3) status in implementing the RPS and progress toward attaining the RPS.

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.

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) provides the REC definition.

In order for RPS compliance targets to be managed effectively, LADWP may buy, sell, or trade RECs without the associated energy (unbundled). This procurement approach will be limited by the percentage requirements established by PUC Section 399.16 (b) (3), and as described in section 7 above.

RPS Policy & Enforcement Program
Appendix A – List of LADWP RPS Resources prior to SB 2 (1X)

PPM SW Wyoming – Pleasant Valley Wind	Cottonwood Power Plant
Linden Wind	Division Creek P. P.
PPM Pebble Springs Wind	Big Pine Power Plant
Willow Creek Wind	Pleasant Valley P. P.
Pine Tree Wind Power Project	Upper Gorge P. P.
Milford Wind Phase I	Middle Gorge P. P.
Milford Wind Phase II	Control Gorge P. P.
Windy Point Phase II	North Hollywood Pump Station PP
Powerex - BC Hydro	Castaic Hydro Plant – Efficiency Upgrades
MWD Sepulveda	SB-1 Customer Net Metered Solar PV
Lopez Canyon Landfill	DWP Built Solar:
WM Bradley Landfill	Silverlake Library
Penrose Landfill	LA Convention Center Canopy
Toyon Landfill	Sun Valley Library
Valley Generating Station (GS) – Multi-fuel	Lake View Terrace Library
Scattergood GS – Multi-fuel	Canoga Park Library
Haynes GS – Multi-fuel	North Central Animal Shelter
Harbor GS – Multi-fuel	Ascot Library
Shell Energy Landfill Gas	Hyde Park Library
Atmos Energy Landfill Gas	Ducommon Fitness Center
Hyperion Digester Gas – Scattergood GS	Truesdale Warehouse
LADWP Small Hydro Power Plants (PP):	Van Nuys Truck Shed
San Francisquito Power Plant 1	Distribution Station 3 (Vincent Thomas Bridge)
San Francisquito Power Plant 2	Main Street Yard
San Fernando Power Plant 2	Exposition Park Library
Foothill Power Plant	Granada Hills Yard
Franklin Power Plant	LADWP JFB Parking Lot
Sawtelle Power Plant	LA Convention Center Cherry St Parking Lot
Haiwee Power Plant	Council District 6 Field Office

Appendix E Power Reliability Program

Reliability represents one of the three main objectives of LADWP (see Figure 1-1). However, many people have trouble understanding what reliability is and why it so important.

The reliability discussed in this section refers to the electricity delivery infrastructure, and its job of delivering electricity to its customers in a safe and effective manner.

A good analogy would be one's car – how reliable it is at performing its job depends on how well it is maintained. As the years go by, certain components of a car began to fail (e.g., brakes, battery, water pump, etc.) and need to be replaced. Likewise, certain components of the electrical distribution infrastructure (e.g., poles, cables, transformers, etc.) eventually reach the end of their service lives. Unless they are replaced, they will begin to fail, causing various problems including power outages. As discussed later in this section, the level of outages caused by aging system components has reached an unacceptable level.

Ironically, the more successful a utility is in terms of reliability, the less awareness and attention it is given. For the general public, the historically high level of electric service has engrained an expectation of high reliability, to the extent that it is not given much thought – when a light switch is flipped, we expect the lights to turn on. It is only when the light doesn't turn on (or goes off during a power outage) that much public notice is given to the electricity delivery infrastructure.

The difficulties in managing reliability include the following:

- Because the consequences of deficient reliability are not experienced until electricity delivery is compromised, the need to allocate appropriate capital resources to better maintain system integrity – before problems occur – may not be fully appreciated by those outside the utility.
- External regulatory mandates are demanding a growing share of LADWP's limited financial resources. As rate actions have been delayed over recent years, inadequate revenues have resulted in underfunding for reliability programs.
- Reliability levels that become unacceptable due to deferral of infrastructure upkeep and replacement are more difficult to recover from and in the end are more costly.

History of High Reliability

Reliable electric power has been a cornerstone objective of LADWP since it began offering municipal electricity in 1917. Historically, LADWP's Power System reliability has consistently placed in the top quartile of the electric utility industry. However, as a result of aging electrical distribution infrastructure, reliability levels started to decrease in the early to mid-2000s. There are significant challenges for LADWP to halt the decline and to restore reliability to acceptable levels.

The City of Los Angeles (City) was founded in 1781 and incorporated in 1850. Since then, Los Angeles has grown to the Nation's second largest City with a population of almost 4 million residents. Most of this growth occurred between 1920 (when there were roughly 580,000 residents) and 1970 (when the City had grown to over 2.8 million residents). This incredible growth of 2.2 million residents – roughly 56 percent of today's population – coincided with the mass electrification of homes and businesses throughout the country. During this time, LADWP installed tremendous amounts of electrical infrastructure to ensure that these growing numbers of new homes and businesses were supplied with reliable electric service. Figure E-1 shows the number of electrical distribution poles categorized by age, and illustrates that the bulk of the installations were made within the timeframe of this growth period.

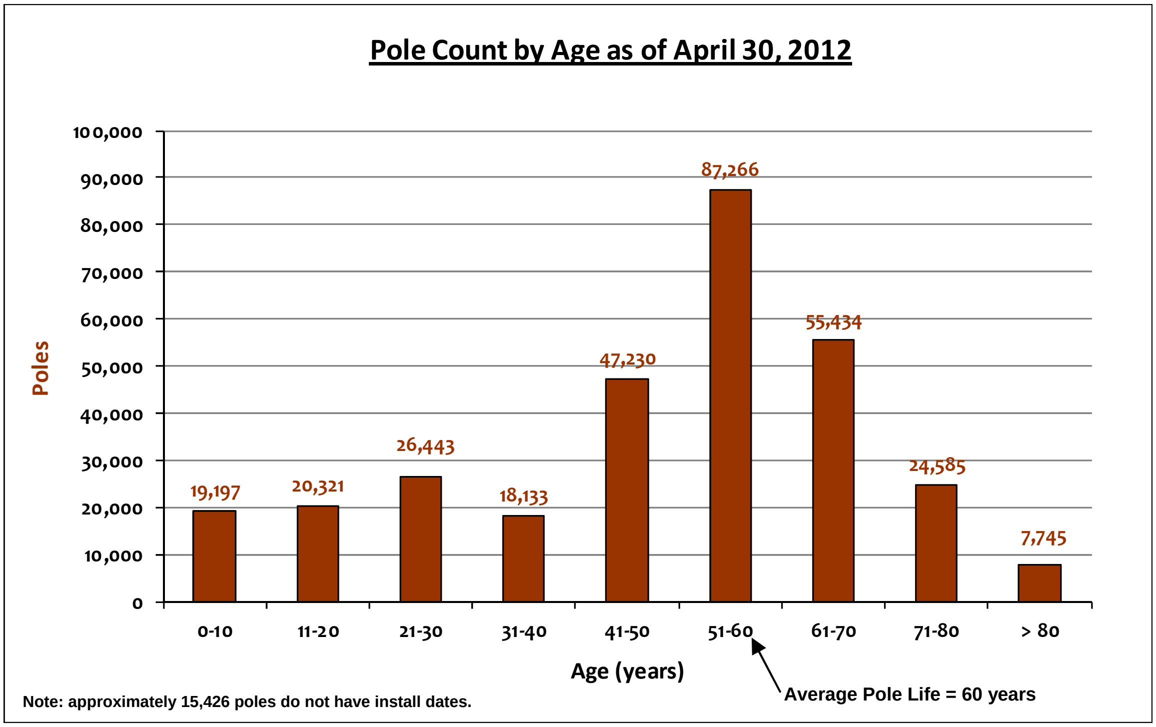


Figure E-1. Pole count by year range installed.

Reliability Levels Decrease

As a testimony to the initial design and installation of this electrical infrastructure, it had reliably served the residents of the City for 40 to 70 years. However, as stated previously, reliability began to deteriorate in the early to mid-2000’s. Increasing outage rates, including several high profile outages, have resulted in service reliability concerns.

Table E-1 below summarizes several significant service interruptions since FY 2005-06.

Table E-1. MAJOR POWER OUTAGES SINCE FY 2005-06

Date of Event	Type	Duration (days)	Outages (sustained)	Customers Affected (sustained)
December 31, 2005 - January 4, 2006	Wind/Rain	3.56	189	79,918
July 21-28, 2006	Heat	6.89	1033	46,981
January 5-8, 2007	Wind	2.92	150	62,725
April 12-16, 2007	Wind / Rain	3.57	218	105,796
August 30 - September 7, 2007	Heat	7.33	858	60,891
September 21-24, 2007	Rain	2.11	86	42,452
January 4-7, 2008	Rain	3.02	129	57,981
January 24-28, 2008	Rain	4.66	119	54,236
November 15-17, 2008	Fire/Wind	2.08	200	133,524
October 13-16, 2009	Rain	2.95	156	93,754
October 27-30, 2009	Wind	2.81	176	87,763
January 18-24, 2010	Wind/Rain	5.84	319	172,883
September 27-30, 2010	Heat	2.92	228	32,010
October 4-7, 2010	Rain	2.83	116	103,112
December 19-23, 2010	Rain	4.96	139	52,786
March 20-22, 2011	Wind/Rain	2.22	196	106,491
November 30 - December 4, 2011	Wind	3.75	419	222,567

The increase in problems appears to be the result of an aging infrastructure and a significant amount of deferred maintenance and deferred reliability-enhancing capital work. Several years of limited funding and reduced staffing levels are underlying contributors to the deferred infrastructure replacement cycle, maintenance, and capital improvements.

Reliability Performance Indicators – SAIFI and SAIDI

Like all other electricity utilities in the US, LADWP uses a number of metrics to measure the performance and reliability of its electric power system. The two primary metrics are called SAIFI and SAIDI.

System Average Interruption Frequency Index (SAIFI): SAIFI is the average number of sustained service interruptions per customer during the year. It is the ratio of the annual number of interruptions to the number of customers. In other words, it measures how many times the average customer has been out of service. 1.1 is the recent national average. In 2002, LADWP's SAIFI index was 0.49; in 2011 it was 1.03.

System Average Interruption Duration Index (SAIDI): SAIDI is the average duration of interruptions per customer during the year. It is the ratio of the annual duration of interruptions (sustained) to the number of customers. In other words, it measures how long the average customer was without power. 90 minutes is the recent national average. In 2002 LADWP's SAIDI index was 59.29; in 2011 it was 214.44.

The trends for both SAIDI and SAIFI are shown in Figure E-2.

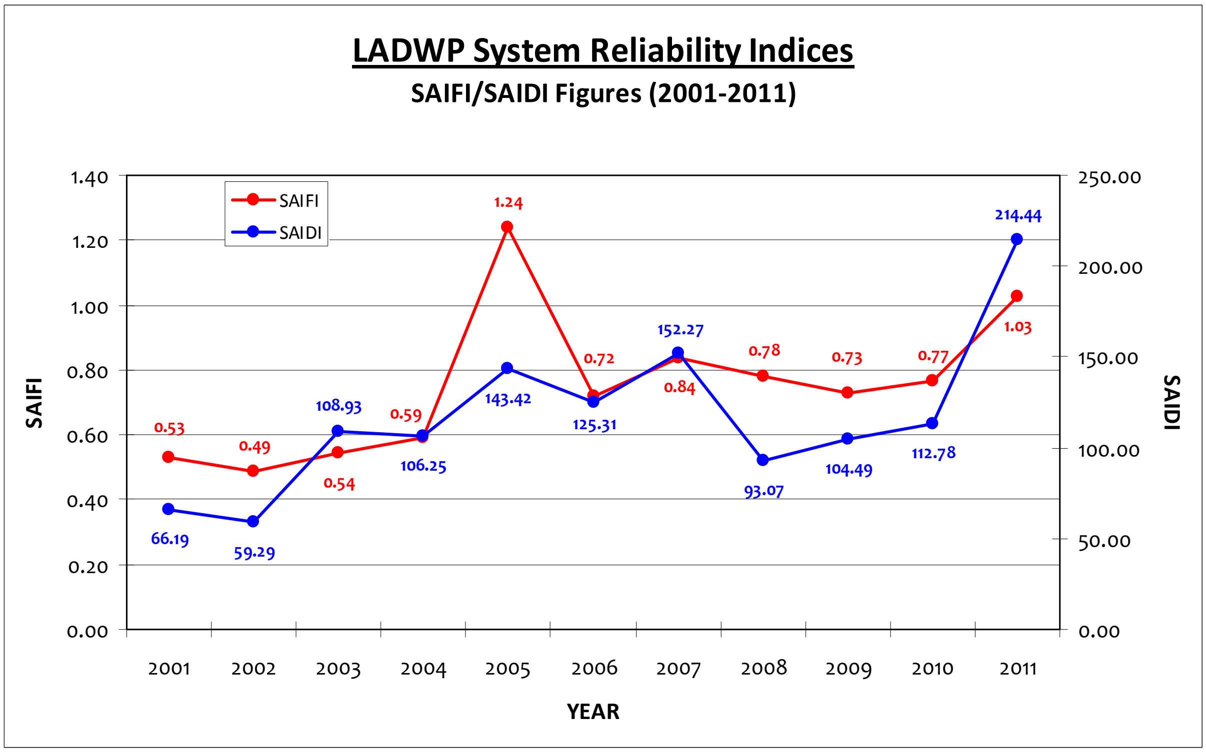


Figure E-2. LADWP's reliability indices.

The PRP is Initiated

As a result of deteriorating service, in 2007 Power System staff and independent industry expert consultants developed recommendations encapsulated in an initiative called the Power Reliability Program (PRP). The PRP is recognition that an infrastructure based industry, such as an electric utility, requires substantial re-investments in the infrastructure to have a viable and reliable system, and that these investments need to be stepped up on a permanent ongoing basis to support reliability in the long term.

The goals of the PRP include:

- Mitigating problem circuits and stations based on the types of outages specific to the facility

- Implementing proactive maintenance and capital improvements that take into account system load growth and the inspections and routine maintenance that must take place to identify problems before they occur
- Establishing replacement cycles for system components that are in alignment with the equipment's life cycle

The system components that are being replaced include the following (see Figure E-3.):

- Power Poles
- Underground Cable
- Distribution and Substation Transformers
- Substation Circuit Breakers
- Overhead Transmission

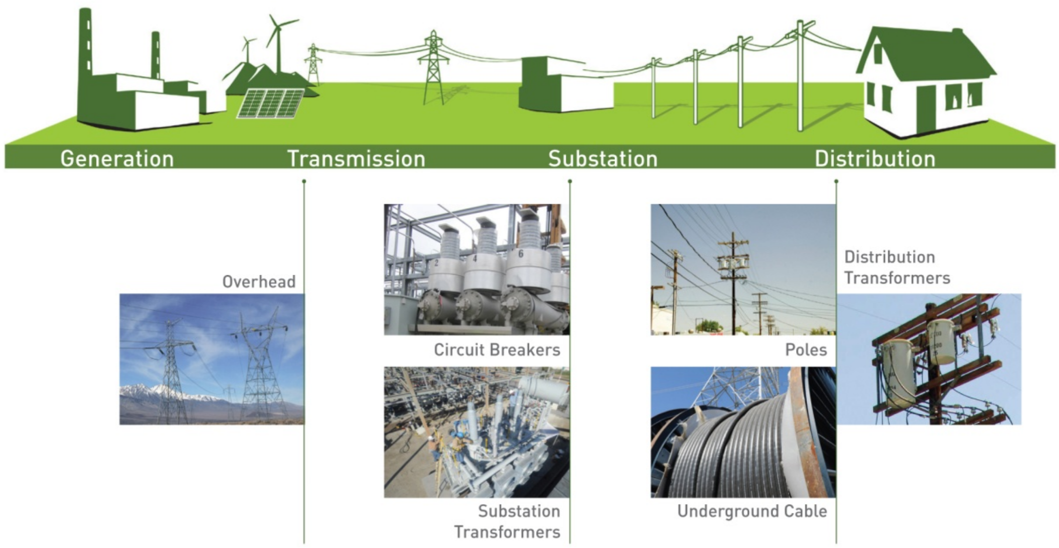


Figure E-3. Power System infrastructure assets for electricity delivery.

Infrastructure Replacement

Through the PRP, LADWP has moved forward with increased infrastructure replacement in key areas to reduce the average age of the critical components of its power system. While improvements have been made to reduce the age of certain equipment, more investment is required.

Increased investment in transformer and underground cable replacement in recent years has reduced outages related to these aspects of the distribution system; however, investment in overhead facilities has continued to lag targeted levels with a corresponding increase in overhead-related outages. Despite recent investments, there is an increasing amount of critical infrastructure components that are operating beyond their useful life.

Asset Replacement Cycles

LADWP utilizes metrics to track the age, condition and impact on reliability for each major type of asset in its infrastructure. Table E-2 presents proposed and actual replacement cycles for PRP asset elements. Given the number and age of each asset element, a key consideration is to replace these assets at a rate that corresponds to their respective service lives. Replacement cycles that exceed the average service life by a factor of 2 or 3 puts the system at increased risk of service interruption.

Table E-2. REPLACEMENT CYCLES FOR INFRASTRUCTURE ASSETS

		Recommended		Actuals	Projected	Budgeted FY 2012-13	
Asset	Count	Replacement Cycle (years)	Proposed Replacement Rate (units/year)	FY 2010-11	CY 2011-12	Actual Replacement Rate	Replacement Cycle (years)
Poles	321,780	60	5,000	2,481	2,100	1,820	166
Underground Cable (miles)	4,500	75	50	68	52	28	161
Distribution Transformers	126,000	60	2,400	2,606	2,400	2,400	53
Large Substations Transformers	88	45	2	1	1	2	45
Local Substation Transformers	360 (approx.)	50	7	3	7	7	50
Substation Circuit Breakers	4,934	50	100	33	33	0	∞
Overhead Transmission (miles)	3,623	Maintenance & Capital Upgrade	100	0	1	0	∞
Underground Transmission (miles)	124	75	1 ckt./yr. (approx.. 2 mi. each)	1	0	0	∞

Pole Replacement Program

Since approximately 70% of LADWP's system is overhead, pole and cross arm replacements are a major driver of reliability. As shown in the Figure E-4, the majority of LADWP's poles currently exceed their useful 60 year life. While the recommended replacement rate is 60 years, over 80,000 poles (26%) are more than 60 years old. Therefore, additional investment in pole replacement is warranted.

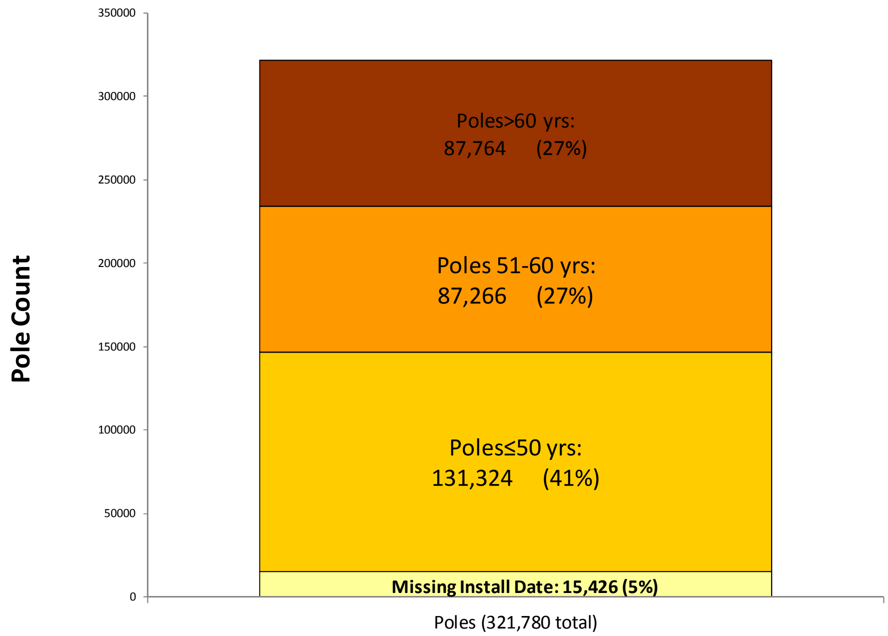


Figure E-4. Pole aging.

A growing number of these poles are in need of expeditious replacement. The following picture illustrates the poor condition of some of LADWP's older poles.

Picture: Pole condition illustrative.

LADWP identifies the poles that are most critically in need of replacement and replaces them as soon as possible. However, LADWP is not replacing poles and cross-arms at a pace that is keeping up with the aging of the system.

Funding for pole replacement has LADWP on a 166 year replacement cycle which is more than double the ideal 60 year cycle. Figure E-5 below shows the recent pole replacement amounts and target levels to 2017.

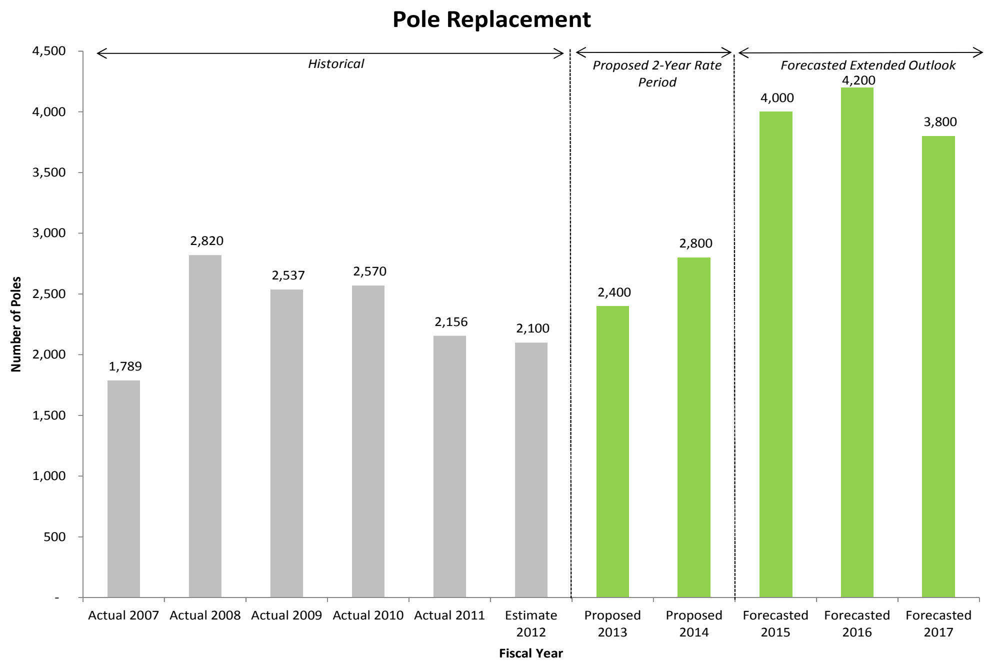


Figure E-5. Historical and forecasted pole replacement (FY 2007 – 2017).

To move towards the ideal life cycle, replacements will need to ramp up to around 5,000 per year over the next several years, pending available funds.

Underground Cable (UG) Replacement Program

LADWP has replaced on average 53 miles per year of UG cable over the past five years. Replacements have targeted cable failures that have caused outages contributing 27% to overall SAIFI. A pilot cable replacement program focused on the 5 worst performing UG circuits and produced a better than 50% reliability improvement; these circuits reflected 66% of common outage causes. LADWP's recent program compare favorably with best practices for utilities with aging underground cable. In an attempt to balance spending and rate levels, the proposed expenditures target replacement of 27 miles of UG cable per year for the next two years. While recent gains should help mitigate any short term decrease in reliability, over time it is likely that reliability could decrease.

Following LADWP's current replacement schedule, cable will be replaced every 159 years compared to a more ideal level of 72 years. In the past five years, the PRP has provided funding for the replacement of cable as shown in Figure E-6. Due to limited funding, the cable replacement program targets were reduced in order to more fully address replacement of other infrastructure assets.

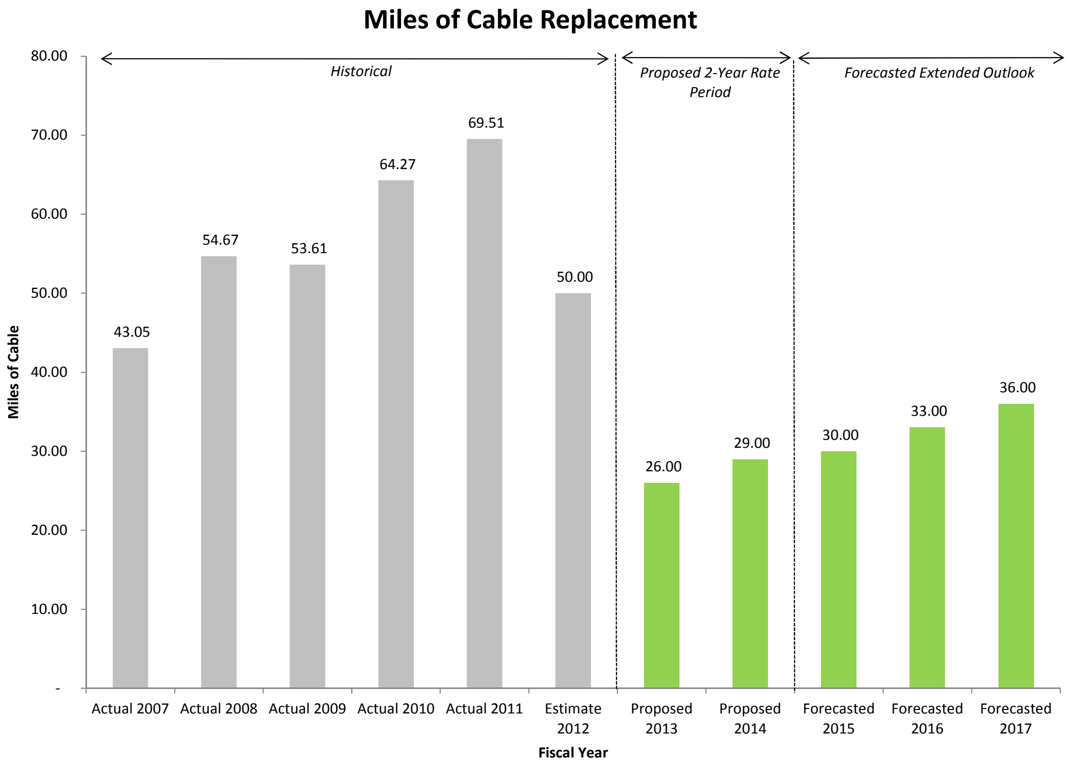


Figure E-6. Historical and forecasted cable replacement (FY 2007-2017).

Notwithstanding this decreased replacement target, cables identified as in critical need of replacement, like the one shown in picture below, are scheduled for replacement as soon as possible.

Picture: Illustrative of Cable Scheduled for Replacement.

Distribution Transformer Replacement Program

Transformers play a critical role in the delivery of electricity to the city of Los Angeles. Many factors shorten the life of a transformer including: corrosion; moisture; physical damage; electrical surges; heat; loading; and, age. Transformer failures have been trending up in the past four years. With respect to age, overhead transformers have an average age to failure of 35 years; underground transformers at 23 years; and PAD transformers at 27 years. As shown in Figure E-7, the vast majority of LADWP's 957 transformer banks are over 40 years old with a significant number of those over 50 years old.

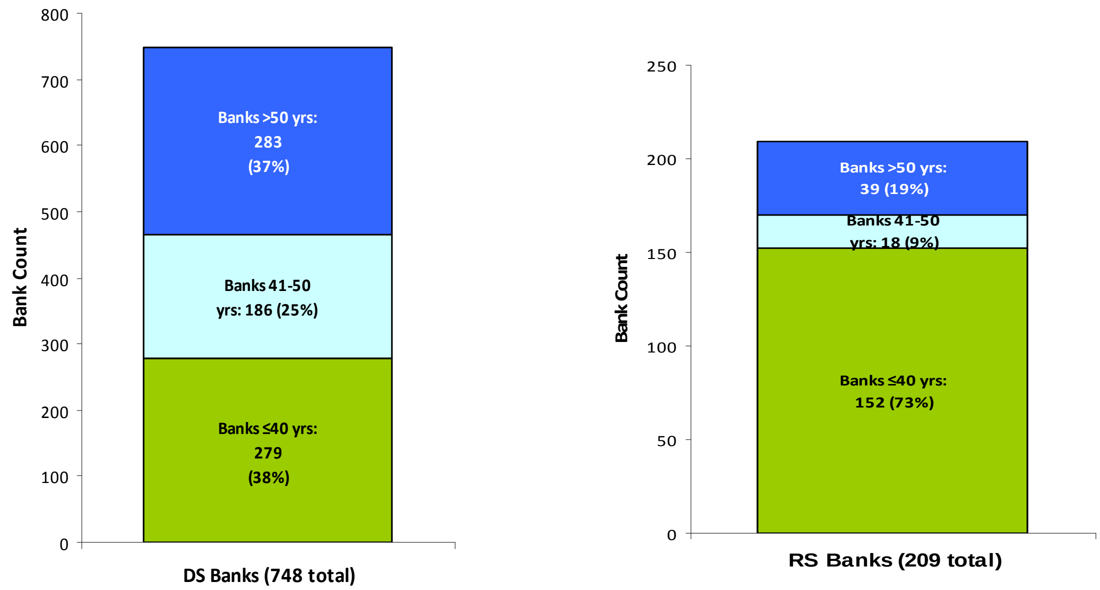


Figure E-7. DS and RS bank aging.

In recent years the PRP has provided funding to replace significant numbers of transformers as shown in Figure E-8.

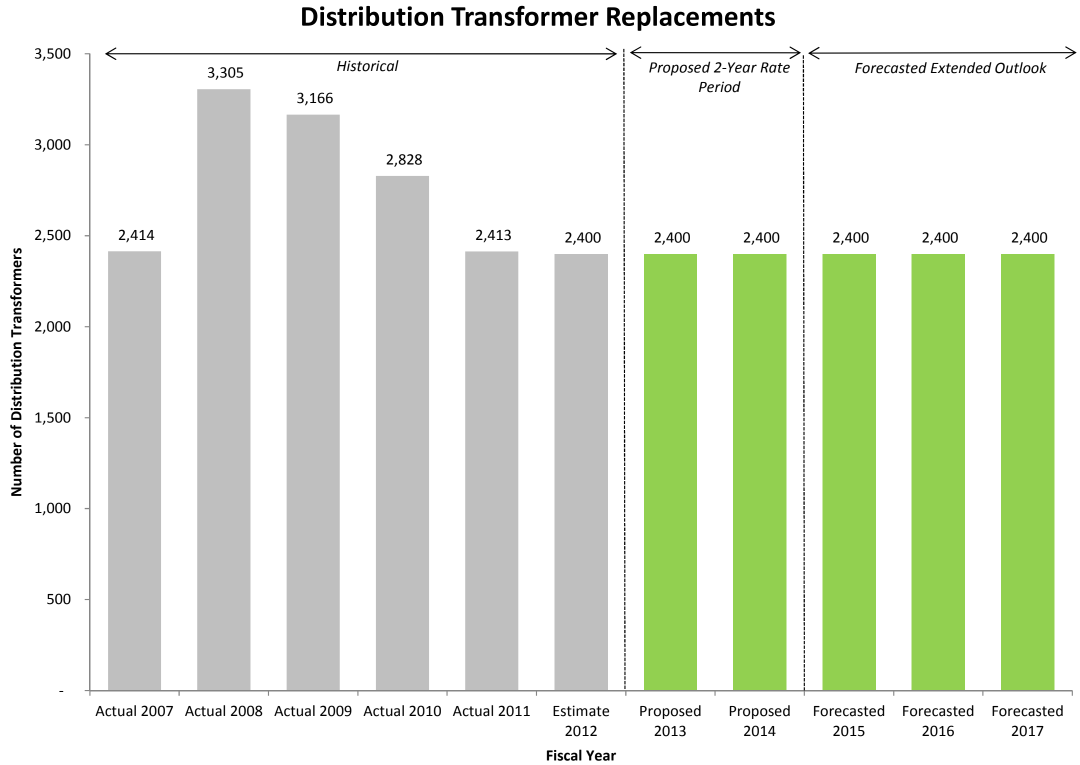


Figure E-8. Historical and forecasted distribution transformer replacements (FY 2007-2017).

Expected transformer replacements are expected to average 2,400 for the next five-years. Existing units may be run until closer to overload status, but new business related installations will continue as in the past. However, the risks of additional failures will be at least partially mitigated by maintaining an appropriate replacement inventory to permit prompt corrective actions.

Work Backlog

Another objective of the PRP is to reduce the backlog of needed work on the distribution system.

LADWP maintains a list of known required distribution system repairs and replacements that have not been completed. The size of this backlog has grown in recent years, as illustrated in Figure E-9. To bring down the nearly 41,000 repair orders in the queue to a desired base or on-going level of 2,000-5,000 would take 3 million work hours to catch up. Proposed funding levels do not provide enough for this catch-up. Based on forecasted PRP investment levels, the repair order backlog is projected to increase to approximately 44,000 tickets in 2017.

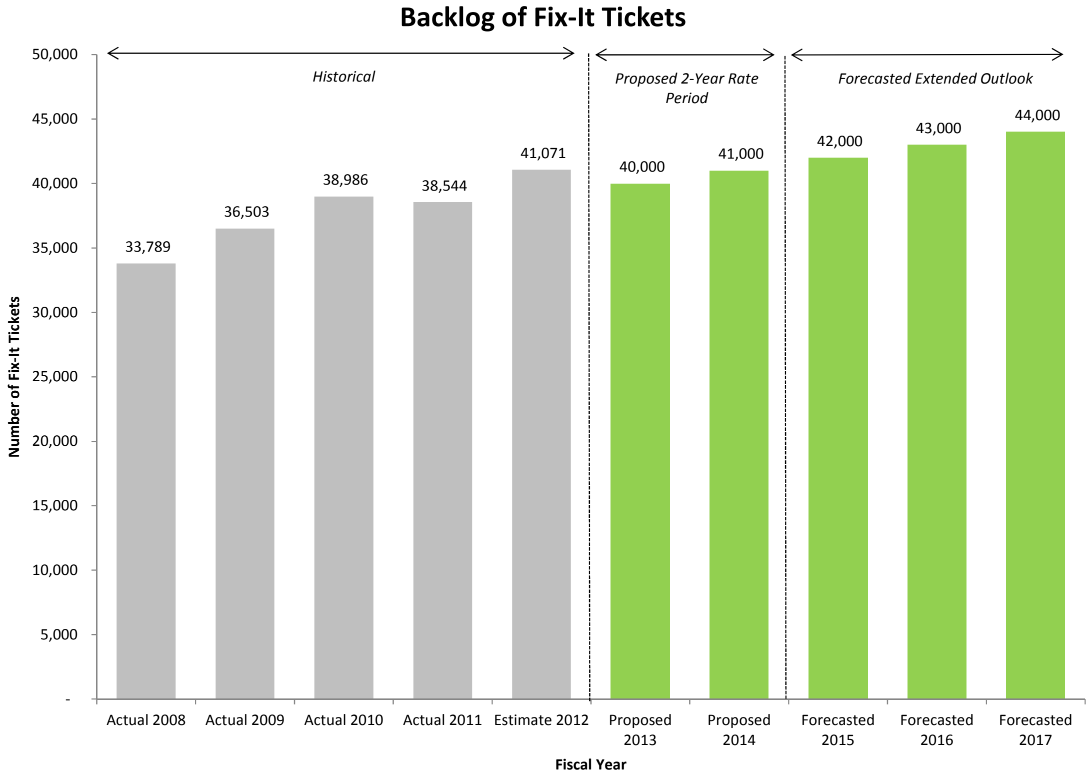


Figure E-9. Historical and forecasted backlog of repair orders (FY 2008 – FY 2017).

Funding Challenges

Funding of the PRP has been inconsistent since its inception. As shown in Figure E-10, the initial years of the program resulted in some reliability gains as outages decreased from 6,323 in 2006 to 4,523 in 2009. Funding levels since then, however, were below levels proposed when the PRP was initially designed in 2007. The numbers of outages are no longer declining. During FYE 2012, funding was cut by over $100 million from the previous year, given the limited resources available without the rate action proposed during 2011.

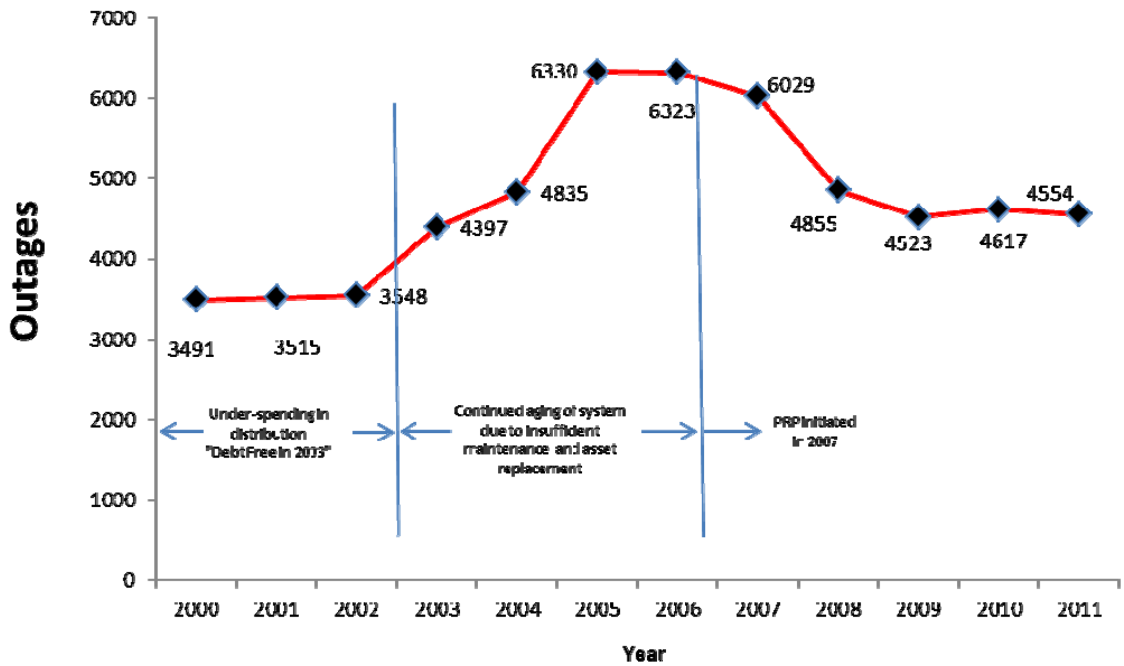


Figure E-10. Total outages between 2000-2011.

Asset Management Process

Reliability improvement in light of aging infrastructure and limited resources has become a critical issue for many utilities including 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 that attempts to maintain overall reliability.

PRP - Summary and Recommendations

Reliability of the electricity delivery infrastructure is a key objective of LADWP. Historically, LADWP had attained adequate levels of reliability relative to the utility industry. However, beginning in the mid 2000's reliability began to decrease, the main cause being aging infrastructure. Deferred maintenance and investment did not keep pace with replacement needs, and the number and duration of outages began to increase. In response, LADWP initiated the Power Reliability Program in 2007 to address infrastructure reliability and lower the replacement cycles of infrastructure components to acceptable ranges that account for their expected service lives.

The PRP experienced initial successes, but as funding levels became constrained, outage levels, which had been decreasing, reversed and began to increase. Adequate funding is critical to restoring reliability to levels that LADWP customers expect and deserve. Figure E-11 presents the actual annual expenditures from FY 2008 to FY 2012, along with proposed spending levels through FY 2017. While the "Preferred T&D Reliability Expenditures" shown on the figure is the level of expenditure required to fully fund the PRP, the "Basic T&D Reliability Expenditures" is the projected expenditures to be available for the program.

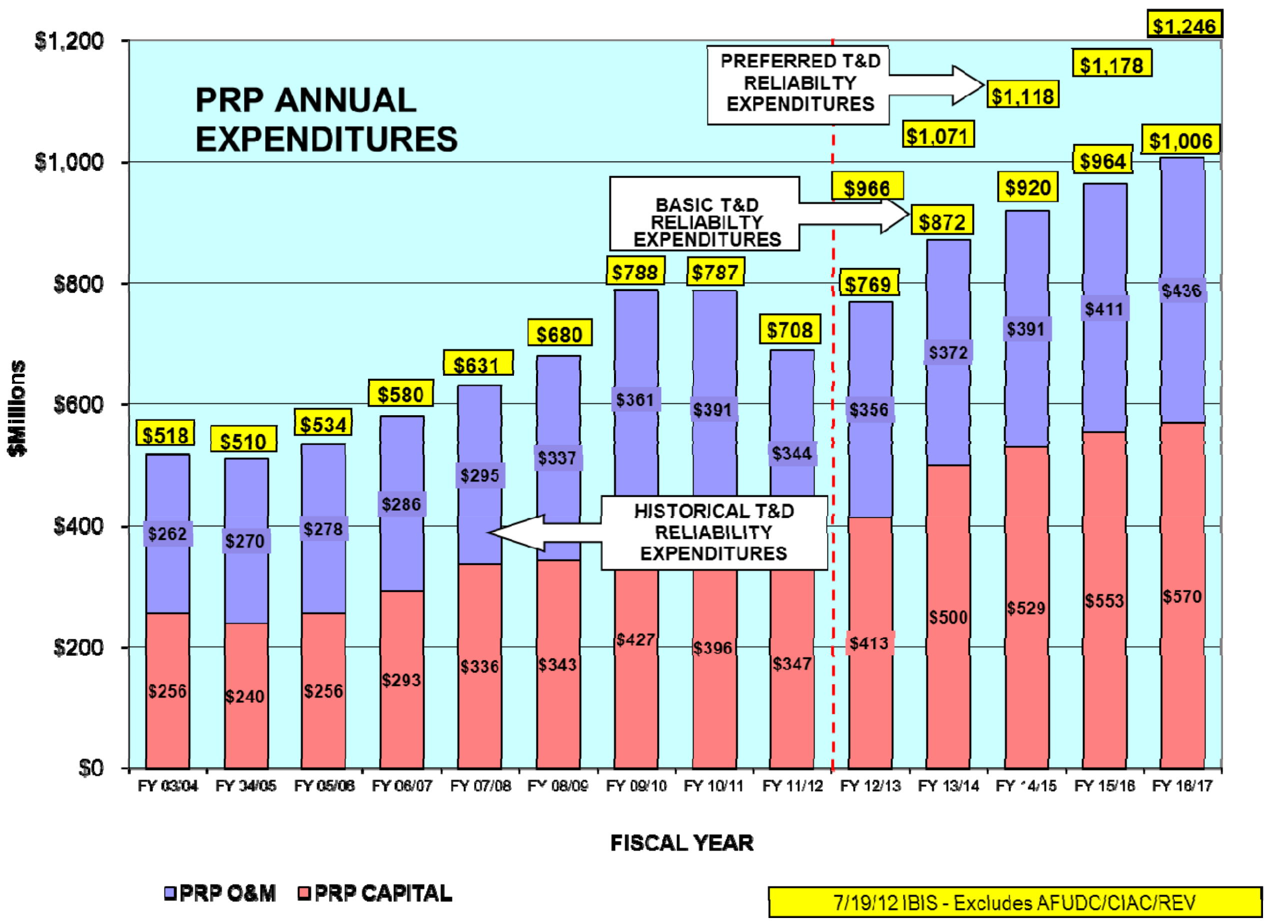


Figure E-11. Historical and proposed replacement targets and funding through FY 2017.

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
- 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 3,415 megawatts (MWs) and a combined net dependable generating capability of 3,329 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	1995	85,340	82,000	452,000[2]
	2	1995	85,340	82,000	
	5	1995	75,000	65,000	
	10	2002	60,500	47,400	
	11	2002	60,500	47,400	
	12	2002	60,500	47,400	
	13	2002	60,500	47,400	
	14	2002	60,500	47,400	
Haynes	1	1962	230,000	222,000	1,525,000[3]
	2	1963	230,000	222,000	
	5	1966	343,000	292,000	
	6	1967	343,000	243,000	
	7	1970	2,000	1,599	
	8	2005	264,350	250,000	
	9	2005	182,750	162,500	
	10	2005	182,750	162,500	
Scattergood	1	1958	163,200	183,000	796,000
	2	1959	163,200	184,000	
	3	1974	496,800	450,000	
Valley	5	2001	60,500	43,000	556,000[4]
	6	2003	182,750	159,000	
	7	2003	182,750	159,000	
	8	2003	264,350	215,000	
Total				3,414,599	3,329,000

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 1,525 MW reflecting 8, 9, and 10 reduced performances during hot weather conditions; and Unit 7 used for auxiliary power only. Unit 5 Net Maximum Unit Capability was decreased to 292 MW to reflect LP hot-reheat piping derating. Unit 6 Net Dependable Unit Capability is 238 MW reflecting 243 MW transformer derating during hot weather conditions. Unit 4 was decommissioned in November 2003 and Unit 3 was decommissioned in September 2004.
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 eight generating units (Unit 7 is used for auxiliary power only) with a combined net maximum capability of 1,556 MWs and a net dependable capability of 1,525 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 plans to repower unit 5 and 6 with six 100 MW simple-cycle gas turbine units targeted by June 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 466 MWs and a net dependable capability of 452 MWs.

Scattergood Generating Station

The Scattergood 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 also burn digester gas from the adjacent Hyperion Wastewater Treatment Plant.

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. 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-2: 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	149,500 149,500	15Jun2027	18.168% (Recallable)
Total				1,202,130[2]	1,174,106[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	1,651,106		

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 2012). 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 Authority (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 299 MW is the summer 2012 entitlement amount.

Fuel Supply. IPA sold its 50 percent undivided interest in the Crandall Canyon Mine in Emery County, Utah and 50 percent undivided interest in the West Ridge Mine in Carbon County, Utah, in 2010. As part of the sale, a continued long term contract for fuel from the West Ridge Mine for IPP was agreed to at about 20 percent of the annual 6,000,000 ton coal requirement. 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 60 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.

Over the past several years, the IPP units have had several substantial modifications, including cooling tower additions, high pressure turbine replacements, boiler capacity additions, distributed control system replacement, scrubber outlet modifications and rebuilds, and induced draft fan drive replacement. These modifications have decreased emissions and increased plant efficiency. They have also increased the plant's capacity by 140 MW, resulting in a 68 MW increase in capacity for LADWP.

Navajo Generating Station

The Navajo Generating Station (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 31, 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 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.

Stringent NO_x emissions control standards currently being considered by the federal government for the pending Regional Haze Best Available Retrofit Technology (BART) ruling may require Navajo Generating Station to install Selective Catalytic Reduction (SCR) systems 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 installation of these SCRs and baghouses could begin as early as 2017 and as late as 2029. On the other hand, if only Non-Selective Catalytic Reduction (NSCR) is required, the capital cost will be $40 million (or $8.5 million for LADWP).

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).

F.2.3. Nuclear-Fueled Thermal Generation

LADWP's nuclear-fueled generating plant capabilities are shown in Table F-3.

Table F-3. 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) 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. 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.2.4 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.

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Table F-4. 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	212,500 265,000 265,000 265,000 265,000 265,000 56,000	250,000 265,000 270,000 265,000 265,000 265,000 55,000	1,175,000	Owned Asset	100%
Hoover[3]		1936	2,079,000	491,000	468,000	30Sep2017	25.16%
Total				2,126,000	1,643,000		

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, which has abated recently. The current Hoover net plant capability as of April 20, 2012 is 1,861 MW. The 15.4229% is LADWP's share of total Hoover generation.

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 2,080 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. The facility is owned and operated by the United States Bureau of Reclamation.

Drought Conditions. The long drought conditions and low lake levels have been improved recently, consequently LADWP's capacity entitlement at the Hoover Plant has increased to 468 MWs (calculated based on 25.16 percent of 1,861 MW output capability as of April 20, 2012).

F.2.5 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-5. 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	3,600 3,600	4,200	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					12,530	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-6. 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 a network 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.

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-7. 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	9,900	2,900
Franklin (PP5)	1	1921	2,000	2,000	2,000	400
San Francisquito 1 (PP1)	1A 3 4 5A	1983 1917 1923 1987	25,000 9,375 10,000 25,000	27,000 10,000 12,000 27,000	46,500	13,000
San Francisquito 2[2] (PP2)	1 2 3	1919 1919 1912	14,000 14,000 14,000	0 14,000 18,000	18,000	5,700
San Fernando 1 (PP3)	1 2	1922 1922	2,800 2,800	3,200 2,900	6,000	2,100
Sawtelle (PP6)	1	1986	640	650	650	130
Total[3]					83,050	24,230

Note:
1. Commercial Operation Date.
2. San Francisquito Power Plant 2, Unit 1 has been out of service since 1996. The plant's Unit 2 stator heating limits capacity to 8 MW during hot weather condition. The plant's Unit 3 has a new generator with refurbished turbine as of the end of 2006. The contract specification is 18 MW output, but the unit was tested to only 16 MW due to low water flow and restricted downstream capacity. Assumed maximum actual output is 18 MW.
3. Aqueduct combined Net Dependable Plant Capability reflects low water availability during winter.

Table F-8. RENEWABLE AND DISTRIBUTED GENERATING RESOURCES[1]

Includes only Projects in Service as of April 2012

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 Point Phase II	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%
Wind Subtotal				**957,095**	**218,420**	
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	16,000	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**	**27,500**	
Customer Cogenerations	PPA	1998-2000	303,000	45,000	45,000	15%
Distributed Generation Subtotal				**45,000**	**45,000**	
Total In Service Renewables & DG				**1,333,315**	**480,537**	

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 April 10, 2012 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 sum of each unit at renewable plants.

[4] Net Dependable Plant Capability reflects the amount of generating capability that can depend on during the peak demand hours of a day. Dependable capacity of a renewable technology plant is estimated by applying a Dependable Capacity Factor (DCF) to the plant nameplate capacity. The conservative factor is used until LADWP gains more actual amount of 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)

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. The most common technologies used today for DG are turbines and internal combustion engines (ICEs). However, new technologies including fuel cells, microturbines, and solar PVs are now being developed. The promise of DG is to provide electricity to customers at a reduced cost and more efficiently than the traditional utility central generating plant with transmission and distribution wire losses. Other benefits that DG could potentially provide, depending on the technology, include reduced emissions, utilization of waste heat, improved power quality and reliability and deferral of transmission or distribution upgrades.

DG can be customer installed or utility installed. The benefits for customer installed DG include waste heat recovery, backup power and power quality. The benefits for utility installed DG include 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 competition into the electric marketplace has driven the development of new electrical generation technologies. Most technologies being developed for DG applications are more costly than traditional generating resources. However, it is anticipated that, with advances in the technologies and a greater demand for DG, costs will decrease, and more systems will be installed.

As of 2010, LADWP has approximately 161 GWh of combined heat and power and 79 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 stable electricity prices and high natural gas prices, customer generation becomes less attractive. Additionally, as of September 1, 2012, about 6,200 LADWP customers have installed over 56 MW of solar PV energy systems with the help of LADWP's Solar Incentive Program.

LADWP has installed 3 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 various other DG technologies for demonstration purposes to understand the operating issues and benefits associated with various equipment and to promote the development of new clean, efficient technologies.

Tables G-1 and G-2 provide projections of Cogeneration and PV capacity and energy used in the 2012 IRP. Cogeneration forecast is from 2012 Retail Energy and Demand Forecast.

Table G-1. PROJECTED DISTRIBUTED GENERATION COGEN - CUMULATIVE

Calendar Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Customer generated	MW	224	232	238	243	248	252	254	256	258	261	264	267
	GWh	1,116	1,184	1,208	1,227	1,248	1,263	1,271	1,280	1,290	1,301	1,312	1,315

Table G-2. PROJECTED SOLAR PV DISTRIBUTED GENERATION - CUMULATIVE

Calendar Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Customer generated	MW	72	108	145	187	241	154	266	279	292	307	321	337
	GWh	94	149	210	276	358	416	437	458	479	502	526	551
Utility generated	MW	3	6	9	12	21	37	54	71	88	101	100	100
	GWh	4	8	13	19	29	52	81	111	141	167	178	177

NOTE: Solar Distributed generation includes the Solar Incentive Program (SIP), Feed in Tariff program (FiT) and Utility Built Solar (UBS)

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, which include a compressor, combustor, turbine, alternator, recouperator, and generator. They have the potential to be located on sites that have space limitations to produce power. The advantages of microturbines are that there are a small number of moving parts, are compact in size, are lightweight, and can utilize waste fuels.

LADWP has installed nearly 2 MW of microturbines, the first of which was located at LADWP's Main Street Center in 1999. Additional microturbines have been installed 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. 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 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:

- A fuel cell is a fairly simple technology with reasonably priced components.
- Significant recent investments in the technology are accelerating the development of fuel cells, and costs are decreasing.
- Integrating fuel processing and power conditioning equipment can be a significant cost with regard to fuel cells, but reductions are likely as more fuel cells are manufactured and installed.

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 have accomplished the task and the fuel cells have been removed from service.

G.5 Photovoltaics

Solar energy is converted to electricity using two power 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 hundreds 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 recently seen the popularity of local customer owned solar generation skyrocket due to the combination of utility paid incentives and recent federal tax law changes, as well as declining solar equipment costs.

A typical 4 kW alternating current (AC) residential rooftop solar power system produces 6,600 kW-hours per year. Presently, LADWP has installed about 1.3 MW of PV at LADWP facilities and other City facilities. LADWP incentives have supported the installation of over 51 MW on its customers' properties, as of May 1, 2012. 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 has been developed with a goal of encouraging the installation of 280 MW of customer installed solar PV systems by 2016 with a budget of $313 million over 10 years, however because of LADWP's lower electric rates, a higher incentive amount has been offered which will reduce the expected amount of customer installed solar to approximately 165MW. An additional 150MW of distributed solar is expected to be installed through a new feed-in tariff program.

The energy generation characteristics of a typical PV installation are that the output peaks around 1:00 p.m., and that 90 percent of a solar PV system's energy is produced from 10:00 a.m. to 4:00 p.m. during a typical summer day in California. Another point worth noting is that a solar PV system can be designed to coincide more closely to the system load profile by altering the module's orientation. While this will increase the energy produced during the peak load of the utility, it will result in an overall lower amount of energy produced for the day. Cloud cover also affects the energy output of a solar photovoltaic installation. The type of clouds will either raise or lower the output of the PV system. Darker rain clouds will lower PV output, but a light marine layer may actually produce more energy than the nameplate rating of the modules due to light reflecting off of the modules, back to the atmosphere, and then back to the modules. This does not happen often but does cause design issues that must be taken into account.

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 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 Green House 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 will 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 Net Metering 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 the 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 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 at the CG Rate
- 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.

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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 2002 to 2006.

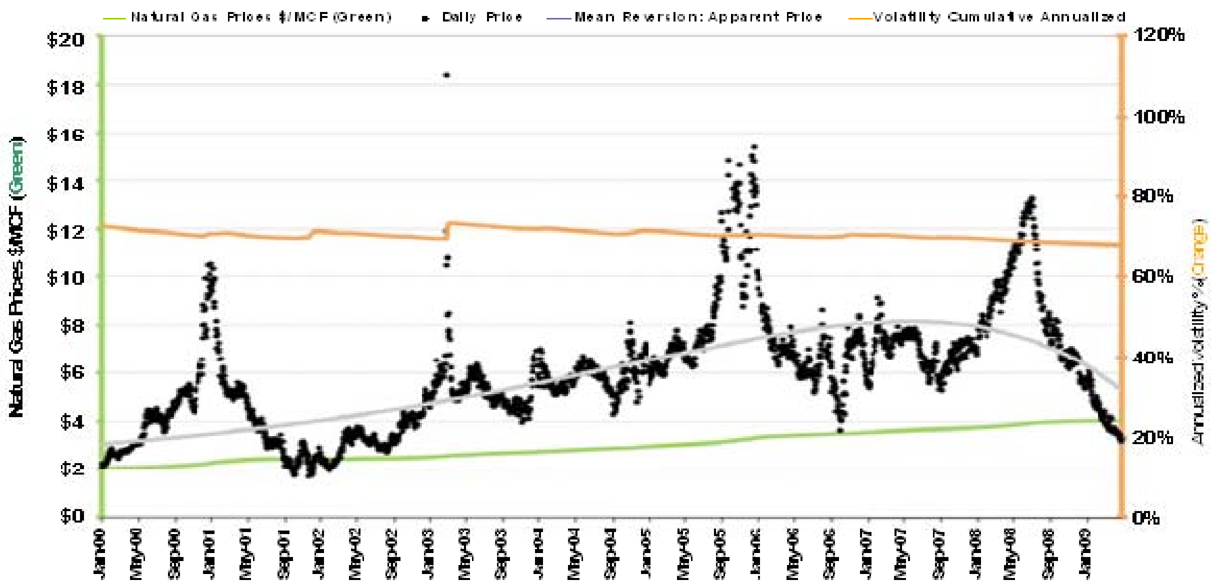


Figure H- 1. Natural gas daily spot prices.

As is shown on Figure H-1, the natural gas market has been very volatile with extreme variations of prices. 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 gas reserve in the Pinedale anticline area of Wyoming. This reserve is currently producing for SCPPA over 50,000 million British thermal units (MMBtu)/day, of which LADWP receives approximately 83 percent of the project.
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.
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 burnertip 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 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. In light of the burgeoning supply of shale gas some LNG import terminals have applied to the 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 Federal Energy Regulatory Commission (FERC). California is currently served by seven interstate pipelines 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, 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. 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.

Intrastate Transportation

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, and loaning of gas. 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 own 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 provides 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 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 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.

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. 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. The Department has obtained BTS rights that match with its firm Kern River Interstate capacity. Another issue regarding the SoCal system, is the Wobbe Index. The Wobbe Index relates to the energy content of the natural gas delivered into SoCal's system which affects operating characteristics of gas turbines and emission levels. The Wobbe Index has risen to prominence due to environmental concerns which may substantially affect SoCal's service to electric generators. The CPUC has already allowed SoCal to set sufficiently high limits on the Wobbe Index for gas coming into its system. This will chiefly benefit LNG sourced gas although there is a challenge being mounted by the South Coast Air Quality Management District (SCAQMD). The SCAQMD has adopted a new rule, Rule 433, which proposes to monitor the effects of any increase in the Wobbe Index and could be interpreted as an attempt to regulate the distribution of natural gas. It is anticipated that the CPUC will oppose this initiative, and at this point in time, SoCal has filed a lawsuit to set aside Rule 433.

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. The Department is in the process of seeking approval of restated transportation contracts to reflect the newly approved tariffs which will make the Department's contracts consistent with the contracts of all the other Kern River shippers and insure rollover rights when the contracts eventually expire.

Gas Price Volatility

During the winter 2000-2001 gas prices were highly volatile. This was somewhat repeated in milder form briefly in early 2003 and the second half of 2005 For the most part, extreme volatility has subsided with prices remaining at substantially lower levels than in previous years due to the recession. 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 the injection season have typically 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 market.
- Horizontal drilling ($1.06-$1.34 /thousand cubic feet (Mcf)) vs. vertical drilling ($1.71 Mcf): horizontal wells open up much larger area of the resource-bearing formation.
- Hydraulic Fracturing (or fracking): Injecting a mixture of water and sand 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 natural gas reserves.

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 ISDA (International Swaps and Derivatives Association) 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 NAESB (North American Energy Standards Board) 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 prepay.

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 $52,000,000 for the six and a half 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.

Of major significance, the Department 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 Department 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 Department'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 baseload 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.

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.
- 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. And 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.

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. 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 is 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.

H.3.3 Coal Portfolio

The current coal procurement portfolio mix is as follows:

Long-term fixed pricing (with contracts beyond 2013):	60 percent
Short-term market pricing (spot market purchases):	40 percent

In all, the Operating Agent procures up to six million tons of coal per year for IGS based on current capacity factors. At present, IPA has in place coal contracts which can supply all of the coal needs of IGS through 2013, with a significant portion of the coal needs beginning 2014 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 20 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 greatest disaster that could possibly affect the 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 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 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. BREAKDOWN OF TRANSMISSION RESOURCES

Voltage Class	AC/DC	Circuit-Miles
Out-of-Basin		
±500kV	DC	1,068
500kV	AC	1,069
345kV	AC	189
287kV	AC	350
230kV	AC	353
Out-of-Basin Circuit-Miles		3,029 (81%)
In-Basin		
230kV	AC	521
138kV	AC	153
115kV	AC	44
In-Basin Circuit-Miles		718 (19%)
Total Circuit-Miles		**3,747 (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. Excess transmission capacity is sold on a non-discriminatory basis in a wholesale market under an open-access transmission tariff largely conforming to FERC Order 890.

A one-line diagram of the key bulk power transmission lines is shown in Figure I-1. The transmission capabilities of the different systems are summarized in Table I-2.

Table I-2. IMPORT CAPABILITY OF TRANSMISSION RESOURCES

Transmission System	Transfer Rating (MW)	LADWP Share (MW)
East-to-LA Basin	4,000	3,566
West-or-River	10,623	3,273
East-of-River	9,256	1,456[1]
Pacific DC Intertie @ NOB	2,990	1,196
Owens Valley Transmission	450	450
Intermountain	2,400	1,428

[1]As of 6/1/2012

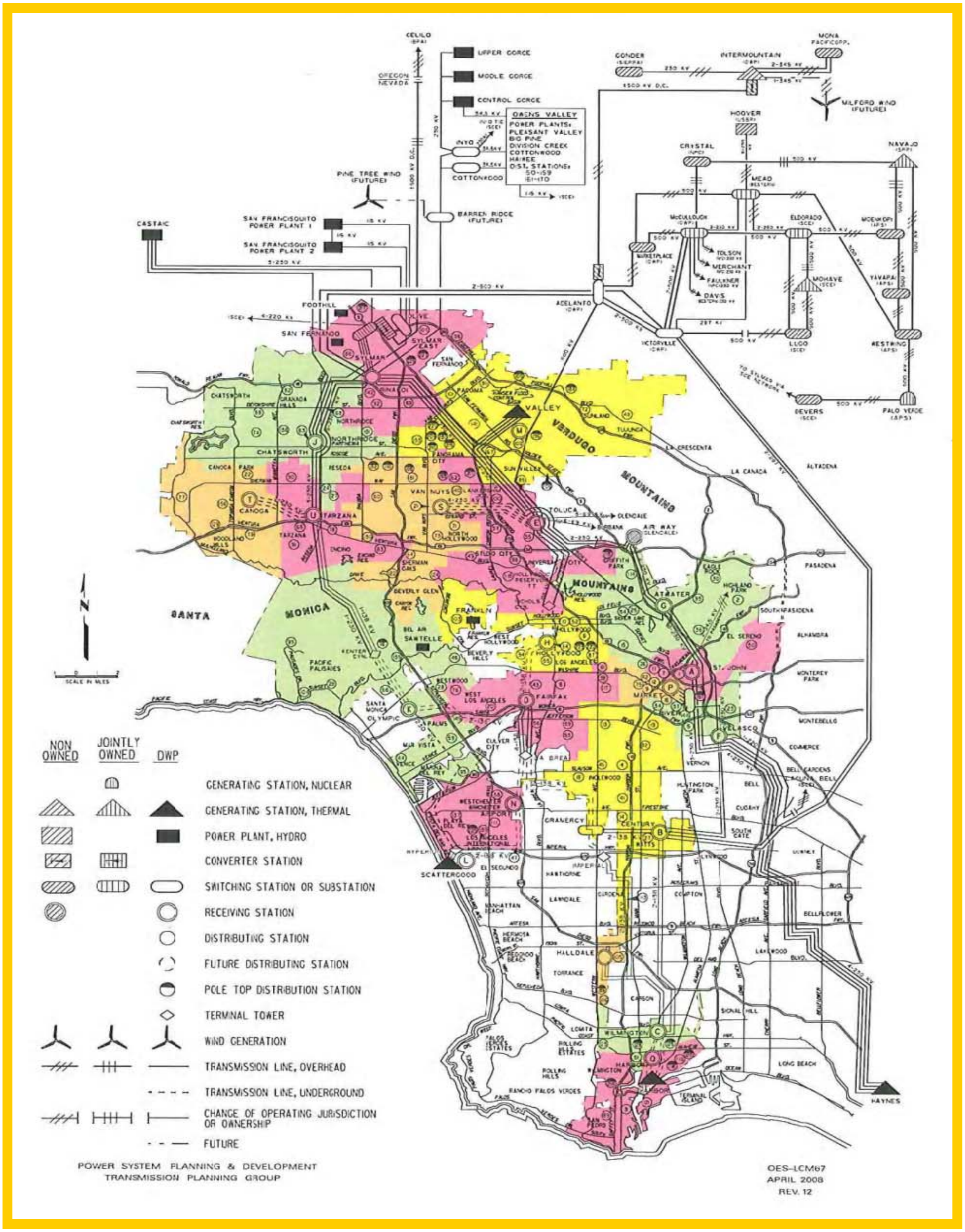


Figure I-1. LADWP Power System diagram.

I.2 Basin Transmission System

LADWP's basin transmission network is comprised of overhead and underground lines ranging from 115kV to 230kV; 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 so 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 2010, 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 Line 1 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 slated to begin in 2012, the new 15-mile long Scattergood-Olympic 230kV Line 1 in the Westside should be in-service before Summer 2015. Information on this project is available at the following website: http://www.ladwp.com/ladwp/cms/ladwp013744.jsp.

I.3 East-to-LA Basin Transmission System

The East-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. EAST TO LA BASIN TRANSMISSION SYSTEM

Transmission Line	Voltage Class (kV)	Transfer Limit (MW)	LADWP Ownership (%)	LADWP Scheduling (%)
Victorville-Century Lines 1&2 Victorville-Rinaldi Adelanto-Toluca Adelanto-Rinaldi	287 500 500 500	4,000	100	100

I.4 West-of-the-River System

LADWP's West-of-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 1580 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 No. 1, of which LADWP has 368MW of bi-directional transmission service rights, and 368MW 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 WOR system is summarized on Table I-4 and shown on Figure I-2.

Table I-4. WOR TRANSMISSION SYSTEM

	Transmission Line	Voltage Class (kV)	Allocation (MW)	LADWP Entitlement (MW)
North	McCullough-Victorville Lines 1&2 Hoover-Victorville	500 287	2,592	2,592
North	Marketplace-Adelanto	500	1,291	313
North	Eldorado-Lugo Eldorado-Pisgah Eldorado-Cima-Pisgah Mohave-Lugo Julian Hinds-Mirage	500 230 230 500 230	2,754	0
North		North Subtotal	6,637	2,905
South	Palo Verde-Devers	500	1,802	368
South	Ramon-Mirage Coachella-Devers	230 230	600	0
South	North Gila-Imperial Valley El Centro-Imperial Valley	500 230	1,584	0
South		South Subtotal	3,986	368
		WOR Total	10,623	3,273

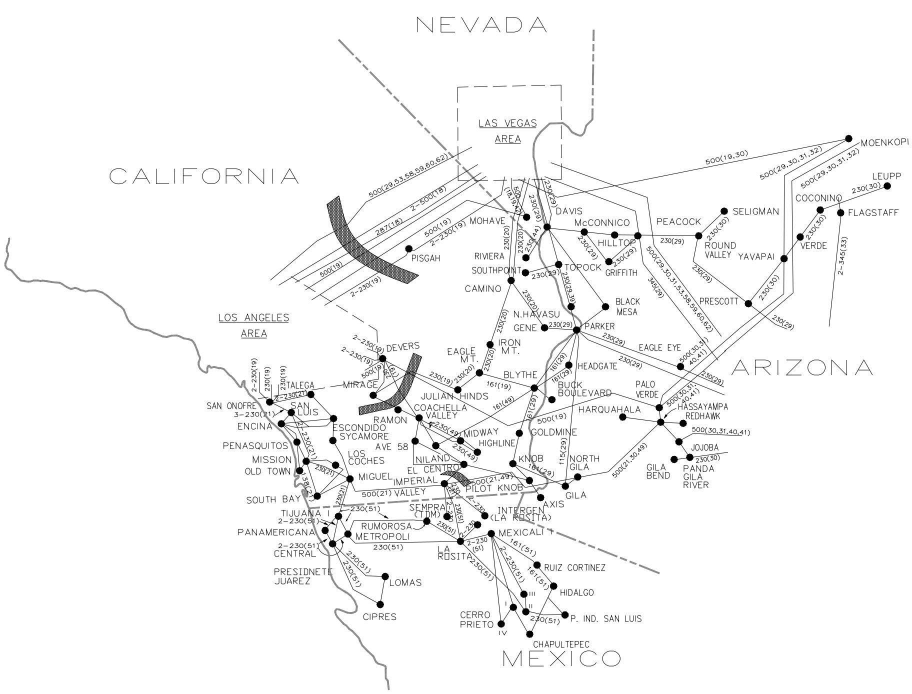


Figure I-2. LADWP West-of-Colorado transmission resources.

I.5 East-of-the-River (EOR) System

LADWP's East-of-the 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 No. 1, of which LADWP has 368MW of bi-directional transmission service rights, and 368MW 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-3.

Table I-5. EOR TRANSMISSION SYSTEM

Transmission Line	Voltage Class (kV)	Allocation (MW)	LADWP Entitlement (MW)
Navajo-Crystal Moenkopi-Eldorado Liberty-Peacock-Mead Palo Verde-Devers Hassayampa-North Gila Perkins-Mead	500 500 345 500 500 500	9,256, east to west non-simultaneous	1,456

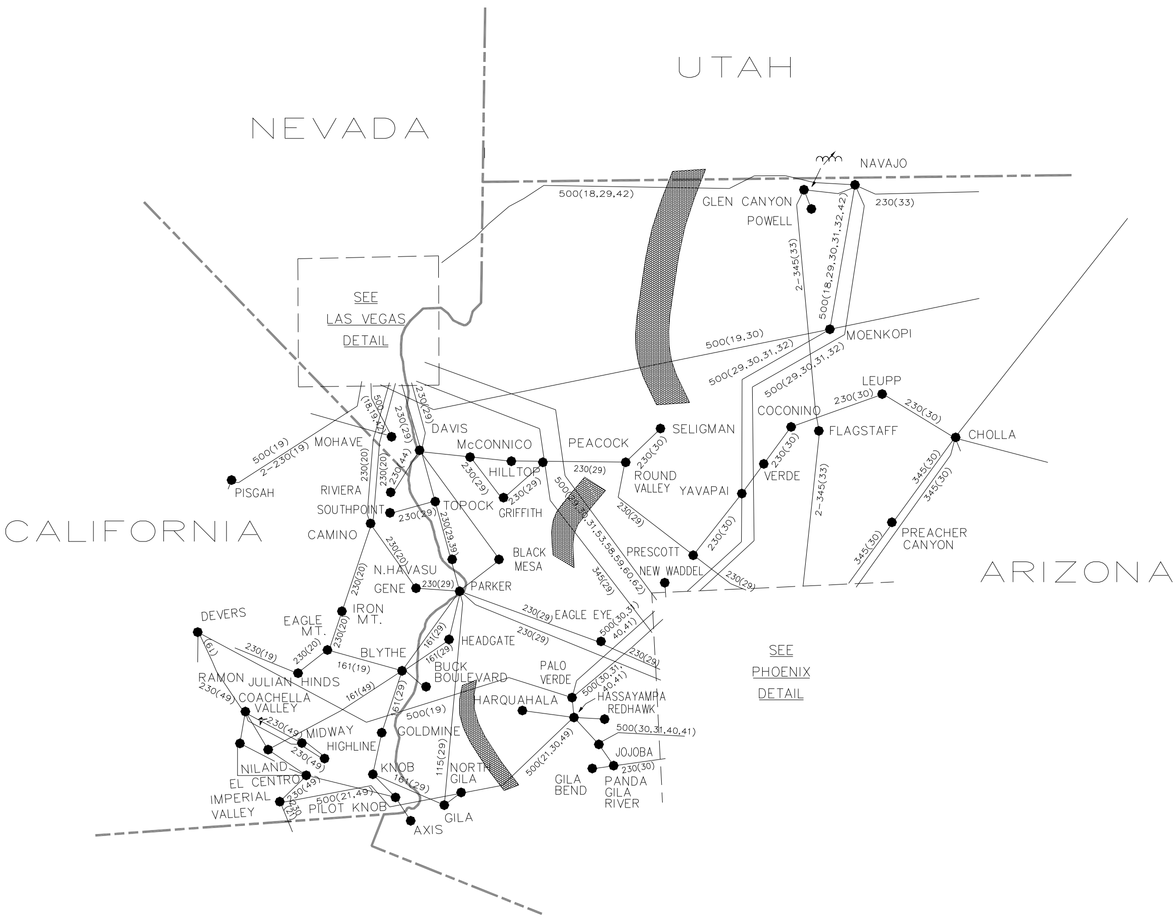


Figure I-3. LADWP East-of-Colorado River transmission resources.

I.6 Owens Valley Transmission Line

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 2950MW. These projects have been placed in the interconnection queue but require the construction of LADWP's Barren Ridge Renewable Transmission Project, described in Section 2.4.8 of this IRP.

The Owens Valley transmission system is summarized on Table I-6 and shown on Figure I-4.

Table I-6: Owens Valley Transmission System

Transmission Line	Voltage Class (kV)	Approximated Allocation (MW)	LADWP Expiration	LADWP Entitlement (MW)
Owens Gorge-Inyo Inyo-Cottonwood Cottonwood-Barren Ridge Barren Ridge-Rinaldi	230 230 230 230	450[1]	Owned Asset	450

[1] The normal rating of the line is 459 MVA,

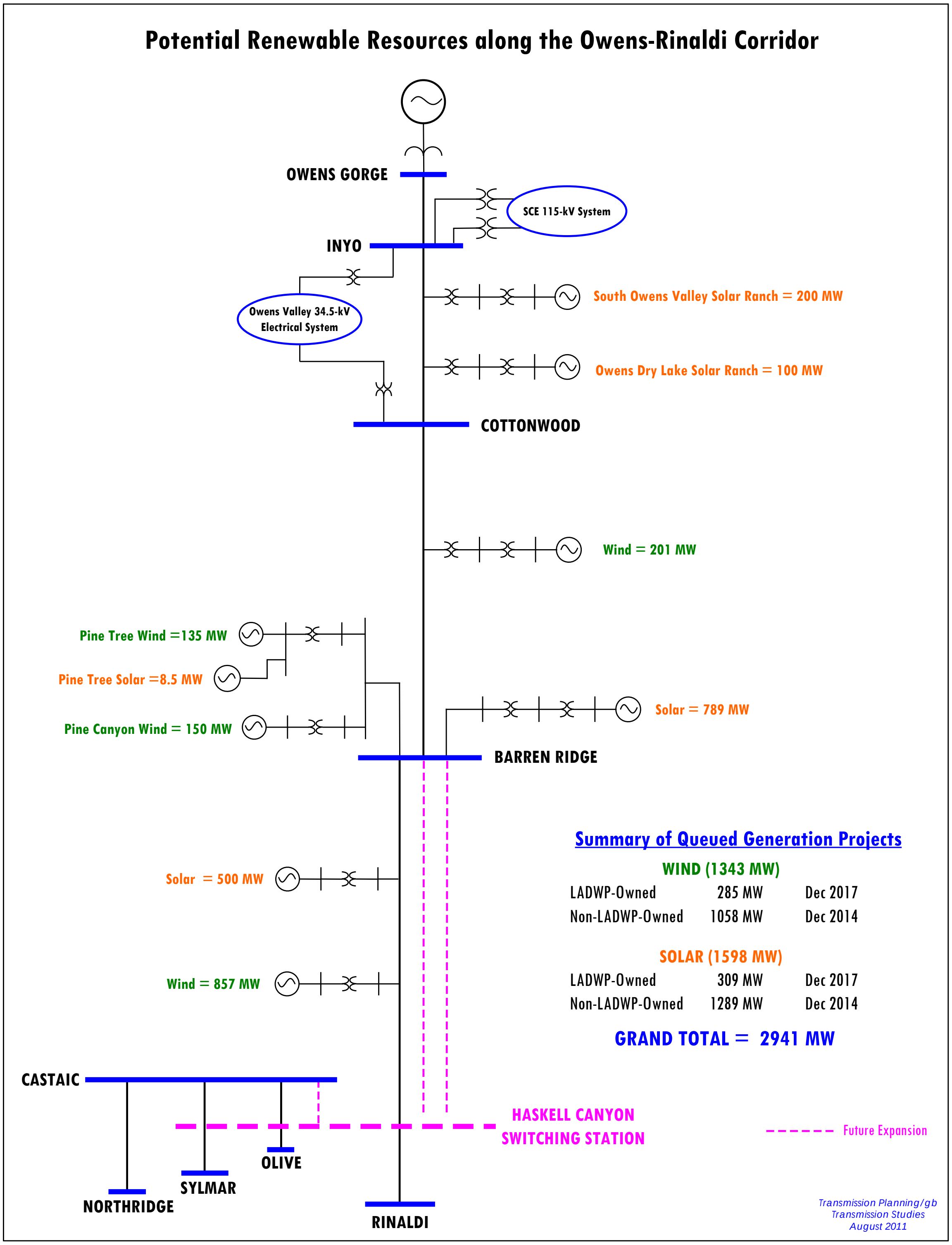


Figure I-4. Owens Valley transmission resources.

I.7 Intermountain System

The Intermountain System is comprised of three WECC paths operated by LADWP on behalf of the Intermountain Power Authority:

- WECC Path 27, the 488-mile Intermountain Power Project DC Line, was upgraded from 1920MW to 2400MW in May 2011. The increased capacity has been accommodating transmission of wind energy from Utah (see Table I-7 and Figure I-5).

- 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-6).

- 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-7).

Table I-7. WECC PATH 27

Transmission Line	Allocation (MW)	LADWP Expiration	LADWP Share (%)	LADWP Scheduling (%)
Intermountain-Adelanto Adelanto-Intermountain	2400 1400	15Jun2027	59.5	59.5

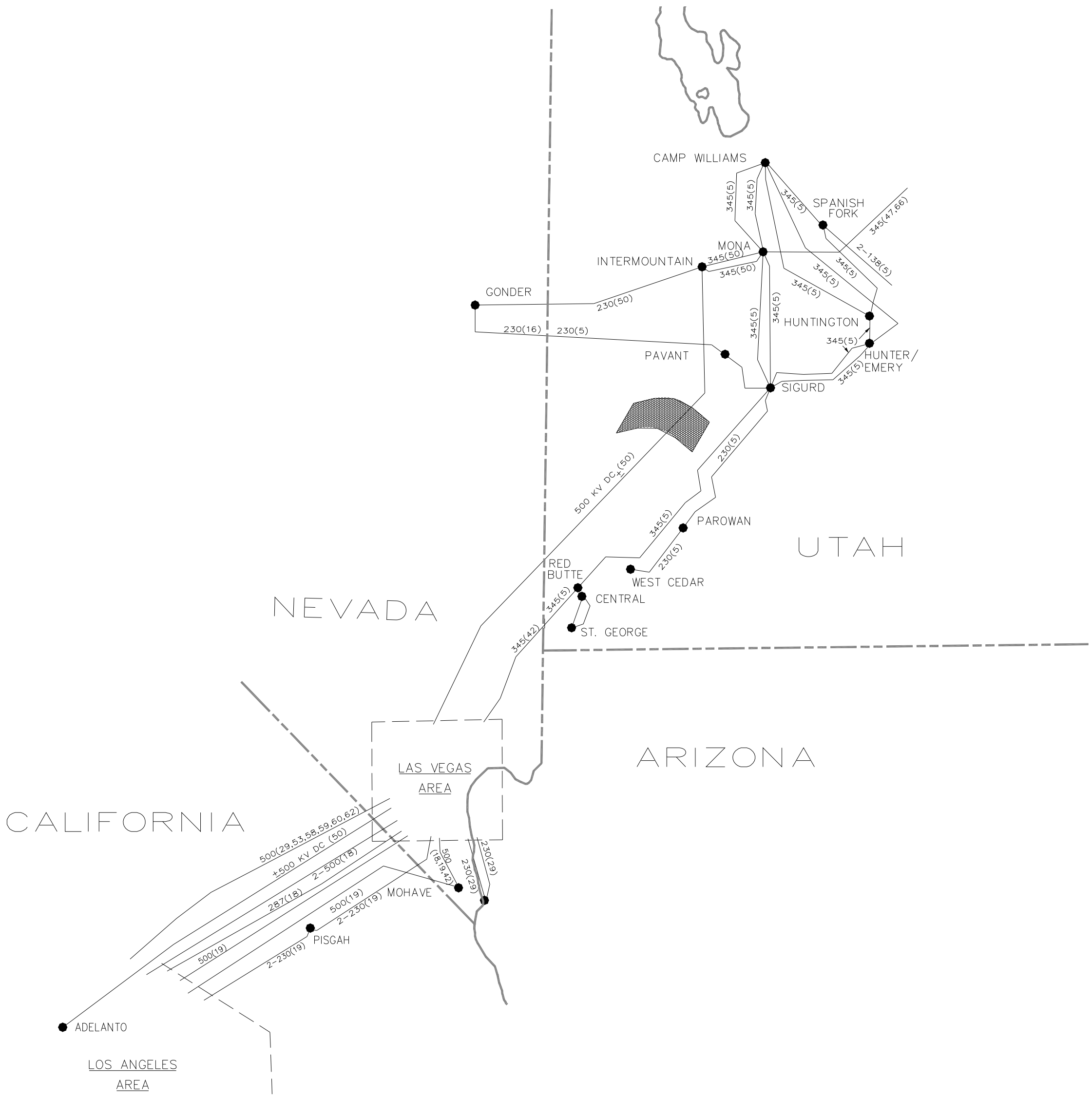


Figure I-5. WECC Path 27.

Table I-8: WECC PATH 28

Transmission Line	Allocation (MW)	LADWP Expiration	LADWP Share (%)	LADWP Entitlement (MW)
Intermountain-Mona Mona-Intermountain	1200 1400	n/a	0	0

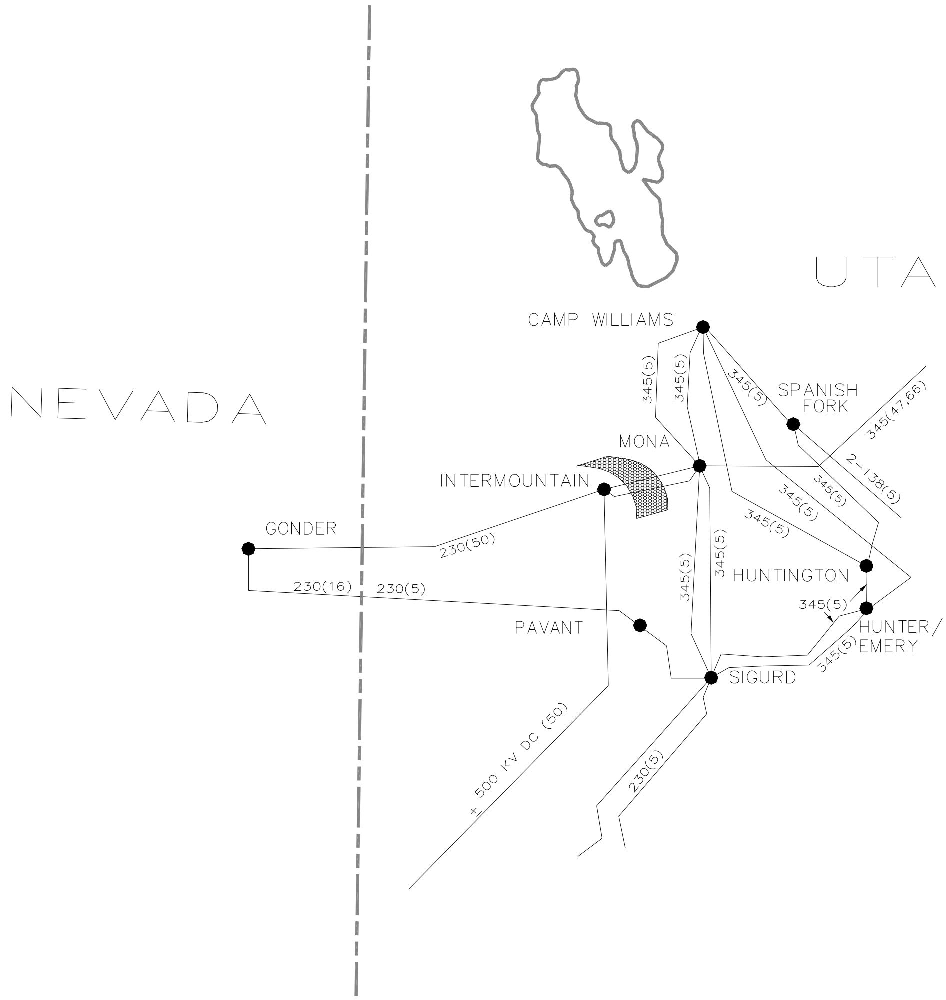


Figure I-6. WECC Path 28.

Table I-9: WECC PATH 29

Transmission Line	Allocation (MW)	LADWP Expiration	LADWP Share (%)	LADWP Entitlement (MW)
Intermountain-Gonder	200 non-simultaneous bi-directional	n/a	0	0

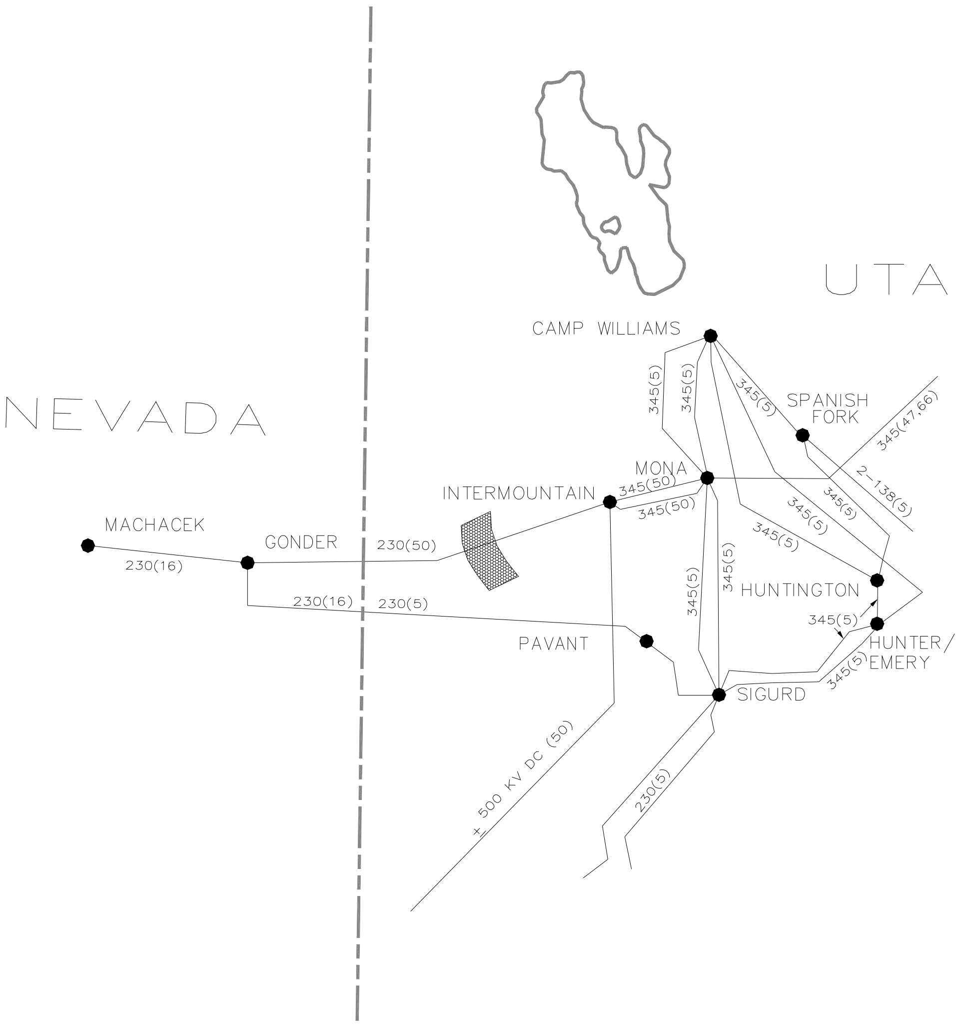


Figure I-7. WECC Path 29.

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 Class (kV)	Allocation (MW)	LADWP Ownership (%)	LADWP Scheduling (%)
Sylmar-Celilo	+/- 500 kV DC	3100, both directions	40	40

Figure I-8. WECC Path 65.

I.9 Interconnections 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 Class (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

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 this 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 renewable resources are often referred to as variable and intermittent renewable generation technologies.

It is anticipated that the amounts of energy generated from solar and wind resources will be substantial and increasing over time. The percentage of solar and wind resources compared to the total capability of a utility's power system may also be defined as "percent penetration." Percent penetration can be measured either by a capacity or energy method. Either measurement method is important; since a utility may use this information to determine the maximum amount of intermittent resources 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 most 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 variable and intermittent renewable generation, the conventional controllable generation resources of a power system must become more flexible in their ability to rapidly ramp up or ramp down their output in order to successfully and reliably integrate new renewable generation.

J.2 Findings of System Integration Studies

In the last several years, LADWP has been increasing its efforts to acquire renewable resources. In 2003, 3 percent of energy sold to its customers was generated from renewable energy resources. This increased substantially to 20 percent in 2010, and 33% is mandated in 2020. 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.

These studies have yielded some common observations and recommendations regarding the integration of intermittent renewable resources into power system generation portfolios. Some common observations of these studies include the following:

1. Larger power systems with robust transmission systems tend to have a greater ability to integrate intermittent wind and solar resources.
2. 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).
3. Wind energy production impacts a power system's regulation (minute to minute generation variability), load following (hourly variability), and unit commitment decisions (day-ahead flexibility) (see Figure J-2, which illustrates the instantaneous generation for the Pine Tree Wind Farm for a single day).
4. Wind is usually categorized primarily as an energy resource. The dependable capacity value of a wind farm to the power system is much lower than the rated capacity of the wind turbines.
5. There is a financial cost to integrate intermittent wind and solar renewable projects into existing power systems, and this cost increases with increasing amounts of intermittent renewable resources.
6. Wind energy production patterns are not usually aligned with daily load patterns. Wind production tends to be greatest in the evenings when the daily load is near its minimum.

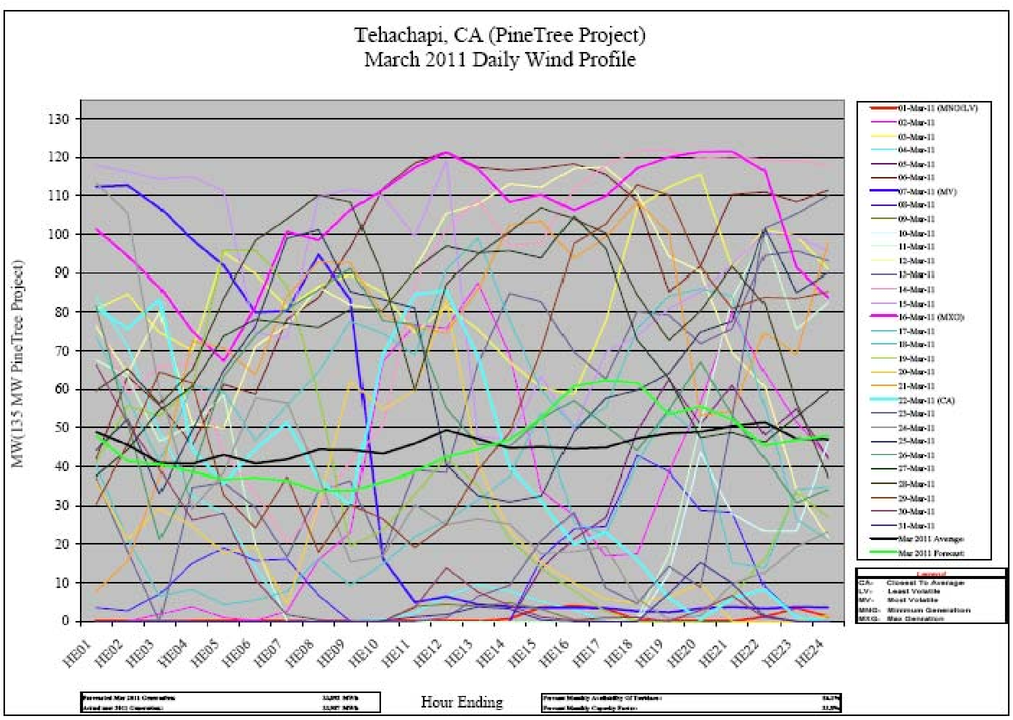
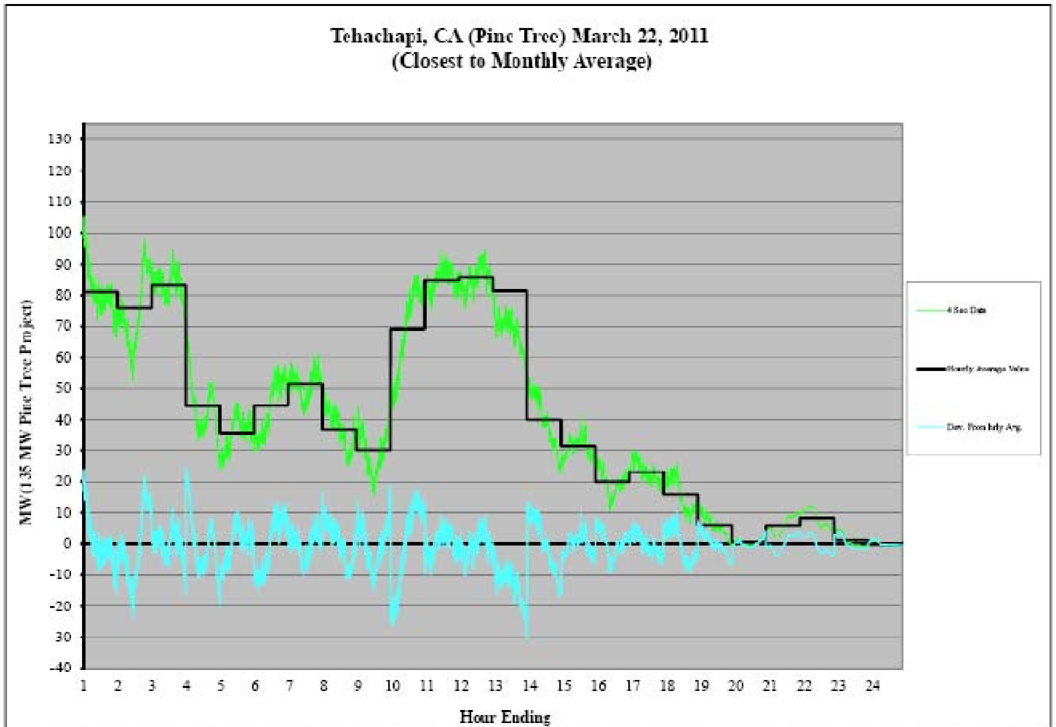


Figure J-1. Wind farm daily wind profiles.



Maximum Hour Deviation (Absolute Value)																							
HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
39.34	45.28	27.56	44.23	21.77	28.20	19.81	27.86	33.15	43.06	19.43	19.53	30.70	30.89	17.92	18.14	12.84	19.95	13.95	5.76	7.94	8.03	5.88	2.38

Figure J-2. Wind farm variability measured instantaneously.

7. In many cases high wind energy production during low power system energy demand hours represents the greatest challenge for power system operations.
8. Average daily and monthly wind energy production profiles are not representative of actual hourly production, due to the high variability in hourly energy production (see Figure J-1).
9. Solar energy production patterns are more closely aligned with daily load patterns than with wind energy production patterns, yet also exhibit variable and intermittent characteristics (see Figure J-3, which illustrates instantaneous output from LADWP's 10 MW Solar Photovoltaic facility located at Adelanto, California. Output tends to be smooth (about 40% of the days), or semi-volatile or volatile (about 60% of the days).
10. Energy generated from Solar PV technology is highly sensitive to cloud cover. These PV systems can experience variations in output of + 50 percent in 30 to 90 seconds, and + 70 percent in five to 10 minutes. 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 capabilities of a power system's dispatchable resources will limit the size of a single utility scale solar PV facility.
11. In the current energy market, the energy from renewable resource generation will tend to displace the marginal resource, which is typically natural gas. However, if future financial burdens are applied to carbon fuels such as coal, and coal becomes the marginal resource,

then coal energy may tend to be displaced by renewable resources.

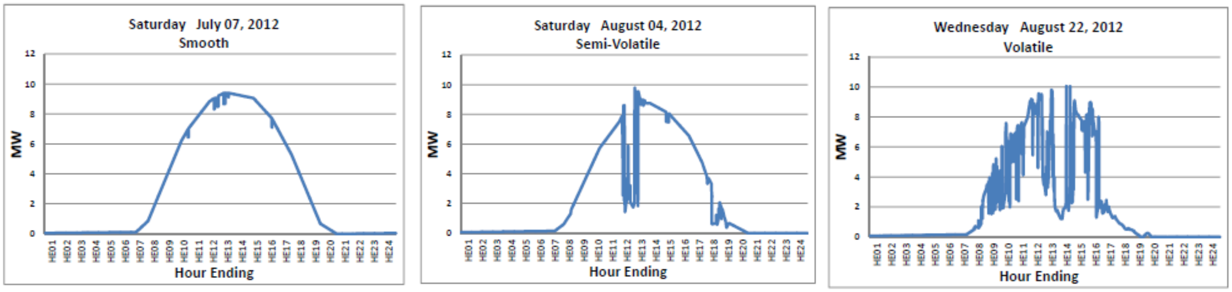


Figure J-3. Solar photovoltaic power generation days at the 10 MW Adelanto facility.

Some common recommendations from these renewable energy integration studies include the following:

1. Successful integration of intermittent renewable resources requires an investment in transmission and generation resources and cooperative operational agreements between power system operators and energy providers.
2. New generation should be able to operate flexibly, meaning it should be able to start and stop quickly and to cycle on and off many times throughout the year. It should also be able to ramp (change the amount of energy it produces) quickly and operate at low generation levels.
3. State-of-the-art forecasting, particularly for wind resources, needs to be made available to power system operators.
4. Variable generators need to have NERC reliability standard compliant features, including low-voltage ride-through, voltage control, and reactive power control.
5. Wind and solar energy production must be curtailable by power system operators if variable energy production negatively affects power system reliability. The power system operators also must have the ability to set power ramp rates for wind and solar projects if needed to ensure power system reliability.
6. Natural gas fired combustion turbines and pump-storage hydro plants are effective tools for integrating intermittent renewable resources into existing power systems. Other energy storage devices described in Appendix K may also assist in integrating intermittent renewable resources.
7. Customer demand response programs may work well in integrating intermittent renewable resources.

Further studies, planning and system modeling will be needed as additional renewable resources come on-line to maintain power system reliability.

Appendix K Energy Storage

K.1 Overview

This Appendix provides a review of the general requirements of grid-scale energy storage systems (ESSs) and ESS technologies, followed by a copy of a February 2012 resolution by the Water and Power Board of Commissioners regarding energy storage targets, and a copy of AB 2514.

K.2 Requirements of Grid-Scale Energy Storage Systems

LADWP plans to meet its 33 percent renewable generation goal by acquiring and self-developing eligible renewable resources including wind and solar. Because wind and solar are intermittent resources by nature, integrating them into the power system is a major challenge. One method of integrating these intermittent generating resources will be large-scale ESSs. The LADWP currently has electrical storage capacity of 1175 megawatts (MW) of pumped storage at the Castaic Lake Hydroelectric Pumped Storage Plant. The ESSs used in the system should be cost effective and provide economical benefit to LADWP.

The ESS power and energy requirements vary widely with the particular grid support application (Figure K-1). Power quality applications require ESSs with high power capability and short storage capacity, while grid support systems require high power output and medium storage capability. Grid-connected renewable energy generation requires large-scale energy storage and large power capability.

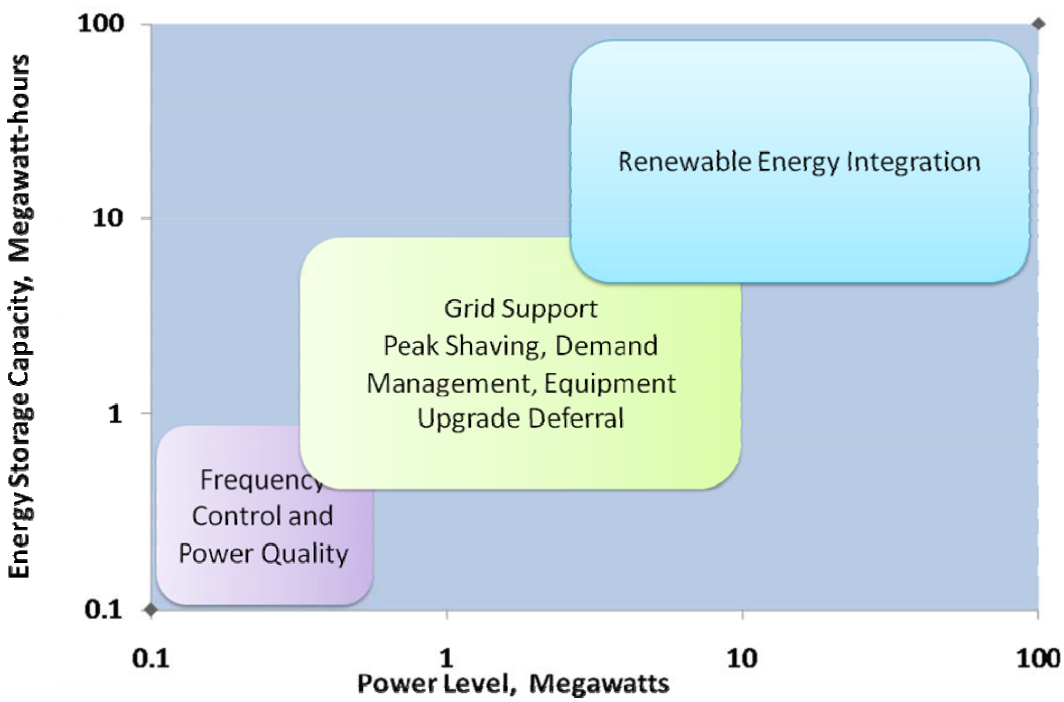


Figure K-1. Requirements of grid-scale ESS.

Electrical ESSs are critical for the integration of intermittent renewable energy sources, load shifting, and improving the stability and reliability of the electricity grid. Such electrical ESSs must be capable of storing hundreds of megawatt-hours (MWhs) and operating without significant degradation for 15-20 years at a cost comparable to today's power plants.

K.3 Energy Storage System Technologies

LADWP is presently in the process of assessing various advanced electrical energy storage technologies to meet its renewable energy program goals. The technologies that look promising for grid-scale energy storage are rechargeable batteries, compressed-air energy storage (CAES), pumped hydro-storage, flywheels energy storage (FES), and supercapacitors. Table K-1 summarizes the salient characteristics of the various energy storage technology options. Among these options, CAES and pumped hydroelectric systems are the technologies most suited for storing large quantities of electrical energy for long periods of time. Rechargeable batteries can support applications requiring a few minutes to a few hours of energy storage. However, hybrid ESSs consisting of rechargeable batteries and other electrical storage systems are likely to meet a wide range of requirements.

Table K-1. COMPARISON OF VARIOUS ESS TECHNOLOGIES

Electrical Storage Technology	Power	Energy Storage Capacity	Duration of Discharge	Advantages	Challenges / Issues
Lead Acid	< 1 MW	0.1 kWh - 1 MWh	1 - 5 hours	low cost, mature technology	limited cycle life low energy density
Lithium-Ion	< 2 MW	0.1 kWh - 10 MWh	1 - 8 hours	high energy density, high power density	high cost, safety in large systems, life,
Sodium Sulfur	< 40 MW	< 250 MWh	1 - 24 hours	high energy density, modest power density	high temperature operation, cost, safety of large systems, life
Redox Flow	< 5 MW	< 15 MWh	1 - 24 hours	long life, safe, easily scalable, medium cost	low energy density, low power density
Compressed Air	25 MW - 3000 MW	1 GWh	1 - 24 hours	high capacity, low cost	special site requirements
Pumped Hydro	100 MW - 4000 MW	15 GWh	4 - 24 hours	mature, high capacity, low cost	special site requirements
Flywheels	< 1 MW	< 10 MWh	< 1 hour	high power density	low energy density, high cost
Supercapacitors	< 1 MW	< 100 kWh	< 1 minute	high power density, long life, high efficiency	low energy density, high cost
Superconducting Magnetic Storage	< 10 MW	< 1 MWh	< 30 minutes	high power density, high efficiency	high cost

K.3.1 Rechargeable Batteries

Rechargeable batteries, upon being charged, convert electrical energy into chemical energy within reactant materials. The chemical energy can be returned as electrical energy upon discharge of the batteries. The rechargeable batteries being considered for the grid support applications described in this appendix are Lithium-Ion Batteries, Sodium-Sulfur (NaS) Batteries, and Redox Flow Batteries. The key challenges for these battery systems are summarized in Table K-2.

Lithium-Ion Batteries

The basic chemistry of these batteries is the same as that of the batteries used in cell phones, laptops, and other portable electronic devices. Large batteries can be fabricated using the same chemistry to provide ESSs for the grid. These batteries consist of carbon-based anode materials and lithiated metal oxide (metals such as cobalt, nickel, and manganese) cathode materials along with an organic electrolyte. Other material choices include lithium titanate for the anode and lithium iron phosphate for the cathode. The cells are sealed to prevent exposure of the battery chemistry to moisture and oxygen. These batteries offer specific energy values as high as 200 watt hour per kilogram (Wh/kg) and 400 watt hour per liter (Wh/L). They are three to six times lighter than lead acid batteries for the equivalent capacity and allow for fast charging and discharging. Operational life of about five years has been demonstrated. Further research is currently being done to improve battery-life characteristics for automotive applications. Cost and safety are the key challenges for widespread deployment of these types of batteries. Lithium iron phosphate and lithium titanate are particularly attractive for automotive applications because of their lower cost and higher abuse tolerance, albeit at a moderate reduction in energy density to 100 Wh/kg. AES Energy Storage is current installing a 32 MW lithium-ion storage system to regulate the 100-MW Laurel Mountain Wind Farm in West Virginia. Similarly, A123 Systems and AES have jointly deployed a 2 MW system (see Figure K-2). The current cost for lithium-ion batteries is between \$650-\$1000/kWh and \$400-\$2000/kW. Current costs of lithium-ion batteries are coming down because of ongoing developments in the automotive industry and are expected to reach \$250/kwh by 2020.

Figure K-2. Lithium-ion batteries.

Sodium-Sulfur Battery

This type of battery was developed prior to lithium ion batteries and uses metallic sodium and elemental sulfur. A sodium-ion conductive ceramic separates both electrodes. Redox and Lithium-Ion batteries can operate at ambient temperatures, but NaS batteries must operate at about 450°C and must be maintained at this high temperature by appropriate thermal insulation. Repeated heating and cooling cycles will reduce the life of NaS batteries. Since NaS batteries consist of reactive materials maintained at high-temperatures, engineering measures are required to ensure safe operations. Notwithstanding these challenges, large-scale NaS battery installations have been demonstrated worldwide, with the largest installed unit being 34 MW, 245 MWh for a wind power stabilization application in Northern Japan by NGK Insulators Inc. (see Figure K-3). Thus far in the U.S., about 40 MWs have been deployed for grid support and integration with wind energy systems. General Electric USA has recently announced its intention to develop and manufacture NaS batteries for renewable energy system integration. The projected cost of large-scale NaS batteries is $450/kW and $400/kWh.

Figure K-3. Sodium-sulfur batteries.

Redox Flow Batteries

In a redox flow battery (see Figure K-4), the chemicals produced in the cell stack during electrical charging are pumped out of the cell stack and stored as a solution in tanks. The solutions are then re-circulated through the cell stack when the energy needs to be regenerated. Since large amounts of energy can be stored as solutions in tanks, the redox flow battery concept is particularly suitable for large-scale energy storage applications. The Vanadium Redox Battery (VRB) is one of the best known examples of a redox flow battery that has been scaled up to MWh sizes; systems with the power level of 2 MW and storage capacity of 12 MWh have been demonstrated. Many units based on VRB technology are in operation worldwide. Some of the flow battery systems have been in operation for over 30 years with minimal maintenance. The life cycle emission from these batteries is less than 25 percent of that of lead-acid batteries. The capital cost for these batteries is in the range of $1000/kW and $300/kWh. With a 15-year life span, the amortized cost of this system is comparable to that of lead acid batteries.

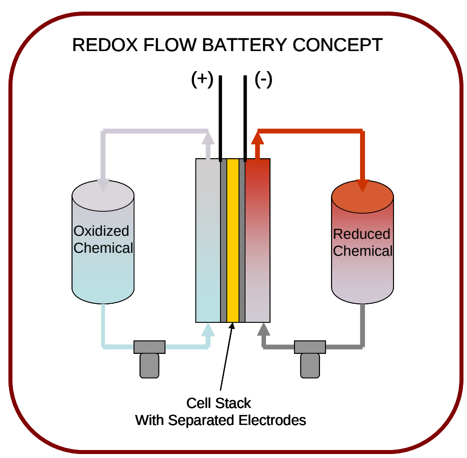


Figure K-4. Redox flow batteries.

Table K-2: KEY CHALLENGES OF BATTERY SYSTEMS

Vanadium Redox Battery	Lithium Ion Battery	Sodium-Sulfur Battery
High cost of vanadium Negative environmental impact of using large quantities of a biologically active heavy metal such as vanadium Low-efficiency Low to Moderate power density Loss of efficiency by cross diffusion of constituents, Low storage capacity of solutions	Operational safety of large-scale batteries Degradation after 2000 cycles on deep discharge which translates to about 3-4 years of operation. High cost of materials to achieve high-energy density.	High temperature operation of the battery (400^{o}C) adds to cost, maintenance and safety Rapid degradation of sealing elements when subjected to thermal cycling. Degradation of battery over 1000 cycles High cost arising from materials and manufacturing methods.

K.3.2 Compressed Air Energy Storage

CAES systems compress large masses of air during periods of low energy demand (off-peak) and then expand the air in turbogenerators to produce power during periods of peak demand. Heating the compressed air before sending it through the turbogenerator results in a three-fold increase in the power that could otherwise be generated without the heater. Compressed air stores mechanical energy that can be released very rapidly. However, the stored energy density of CAES systems is relatively small compared to liquid fuel (gasoline, diesel). Currently, about 80-85 percent of the mechanical work for compressing the air is lost as waste heat during the compression. New air compressor devices that recover the heat generated will substantially increase the efficiency.

K.3.3 Pumped Hydroelectric Storage

Pumped Hydroelectric Storage (PHS) is one of the most widely used ESS technologies. The PHS system involves pumping water from a lower reservoir to a higher reservoir when electricity is available (generally at night) and then flowing water down through hydroelectric generators to produce electricity when additional power capacity is needed (typically at midday during periods of peak demand). PHS systems require a particular geographical topology where reservoirs can be situated at different elevations and where sufficient water is available. PHS systems constitute 3-4 percent of the current worldwide power generation capacity. The typical size of these PHS systems is around 1000 MW, and the storage capacity can exceed thousands of MWhs based on the size of the reservoirs and the hydroelectric generator assets involved. The round-trip efficiency of these systems usually exceeds 70 percent. Installation costs of these systems tend to be high because of the geographical siting requirements. System cost is estimated to be \$4000/kW and \$200/kWh.

K.3.4 Flywheel Energy Storage

FES systems work by using an electric motor to accelerate a rotor (flywheel) to a very high speed, maintaining the energy in the system as rotational energy using very low-friction bearings and engaging an electric generator to convert the rotational energy back to electricity by decelerating the flywheel. FES technology is a good fit for managing relatively limited amounts of electricity for short periods of time and is being considered as a strong contender for frequency control of the grid. Beacon Power Corporation has developed a flywheel system for frequency control of the grid and is currently testing several installations of prototype equipment.

K.3.5 Supercapacitor Energy Storage

Supercapacitor Energy Storage (SES) and Ultracapacitor Energy Storage (UES) systems are targeted to fill the gap between capacitors and batteries. These devices can deliver large amounts of power for short periods of time and can be used to dampen the in-rush current noise caused by the start-up and shut down of large motors and generators in large power system facilities. However, these devices are not likely to be good candidates for large-scale energy storage.

K.3.6 Superconducting Magnetic Energy Storage

Superconducting Magnetic Energy Storage (SMES) systems store energy in the magnetic field created by the flow of direct current in a superconducting coil, which has been cryogenically cooled to a temperature below its superconducting critical temperature. SMES technology is highly efficient, but manufacture of actual commercial equipment has been hard to achieve. This technology appears to be too immature for large scale commercialization.

K-4 Benefits

Quantifiably advances in ESS technologies, and implementation will result in several benefits as shown on Table K-4.

Table K-4. BENEFITS OF ENERGY STORAGE SYSTEMS

LADWP Approach	Benefits	Metrics
Use Battery Energy Storage to supply energy when the generation dips from the wind or solar generators during peak demand periods or demand increases	Lower electricity cost	Lowering peak demand needed from expensive combustion turbine generators with wind and solar generation
Use Battery Energy Storage to supply energy when the generation dips from the wind or solar generators or during system disturbances	Reduced power interruptions and increase reliability	Fewer and Shorter outages
	Reduced costs from better power quality	Fewer momentary outages
		Fewer severe sags and swells
		Lower harmonic distortion
Use Battery storage energy from green power reduces CO_2 Emissions	Reduced damages as a result of lower GHG/carbon emissions	Percentage of green power relative to total power generated.
Increase of battery storage from green power to reduce need for oil or gas		
Reduce reliance on non renewable resources	Greater energy security from reduced oil consumption	Percentage of green energy utilized

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19

LOS ANGELES DEPARTMENT OF WATER AND POWER (LADWP) BOARD APPROVAL LETTER

TO: BOARD OF WATER AND POWER COMMISSIONERS	DATE: February 2, 2012
ARAM BENYAMIN, Senior Assistant General Manager – Power System; RONALD O. NICHOLS, General Manager	SUBJECT: LADWP Energy Storage Targets
	FOR COMMISSION OFFICE USE: RESOLUTION NO. 012 168 FEB 0 7 2012 COPY RESO TO: 3-SR. AGM-Power System 2-17-12
CITY COUNCIL APPROVAL REQUIRED: Yes ☐ No ☒ / IF YES, BY WHICH CITY CHARTER SECTION:	

PURPOSE

To comply with State Assembly Bill 2514 (AB 2514), which became law on January 1, 2011, the Board of Water and Power Commissioners (Board) must take action by March 1, 2012, to initiate a process to determine appropriate targets, if any, for the LADWP to procure viable and cost-effective energy storage systems.

BACKGROUND

The AB 2514 became law on January 1, 2011. The bill requires the governing board of a local publicly owned electric utility, such as 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. AB 2514 further requires that if determined to be appropriate, this 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.

Furthermore, AB 2514 requires the Board to re-evaluate the determinations made regarding the energy storage system procurement not less than once every three years and for LADWP to report to the California Energy Commission regarding the 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 re-evaluations.

The LADWP's 2011 Power System Integrated Resource Plan provides a review of the general requirements of grid-scale energy storage systems and technologies, which may serve as an initial framework to determine appropriate targets, if any, for LADWP to procure viable and cost-effective energy storage systems.

RECOMMENDATION

It is recommended that your Honorable Board adopt the attached Resolution initiating a process to determine appropriate energy storage system targets, if any, consistent with AB 2514.

TA:nsh
e-c/att: Ronald O. Nichols
Richard M. Brown
Aram Benyamin
James B. McDaniel
Lorraine A. Paskett
Philip R. Leiber
Ann M. Santilli
Gary Wong
Randy S. Howard
Oscar A. Alvarez
Than Aung

RESOLUTION NO. 012 168

WHEREAS, 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, LADWP's 2011 Power Integrated Resource Plan (IRP) provides a review of the general requirements of grid-scale energy storage systems and technologies and includes a proposed energy storage demonstration project, which may serve as an initial framework to determine appropriate targets, if any, for LADWP to procure viable and cost-effective energy storage systems; 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 regarding any energy storage system procurement targets and policies that may be adopted by this 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 initiates 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.

BE IT FURTHER RESOLVED that LADWP shall report back to this Board prior to October 1, 2014, regarding potential procurement targets, if any, for LADWP to procure viable and cost-effective energy storage systems, at which time this Board may determine whether it is appropriate to adopt such targets.

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 FEB 07 2012

APPROVED AS TO FORM AND LEGALITY
CARMEN A. TRUTANICH, CITY ATTORNEY

FEB 02 2012

BY [signature]
VAUGHN MINASSIAN
DEPUTY CITY ATTORNEY

Barbara E. Moschos

Secretary

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Assembly Bill No. 2514

CHAPTER 469

An act to amend Section 9620 of, and to add Chapter 7.7 (commencing with Section 2835) to Part 2 of Division 1 of, the Public Utilities Code, relating to energy.

[Approved by Governor September 29, 2010. Filed with Secretary of State September 29, 2010.]

LEGISLATIVE COUNSEL'S DIGEST

AB 2514, Skinner. Energy storage systems.

Under existing law, the Public Utilities Commission (CPUC) has regulatory authority over public utilities, including electrical corporations, as defined. The existing Public Utilities Act requires the CPUC to review and adopt a procurement plan for each electrical corporation in accordance with specified elements, incentive mechanisms, and objectives. The existing California Renewables Portfolio Standard Program (RPS program) requires the CPUC to implement annual procurement targets for the procurement of eligible renewable energy resources, as defined, for all retail sellers, including electrical corporations, community choice aggregators, and electric service providers, but not including local publicly owned electric utilities, to achieve the targets and goals of the program.

The existing Warren-Alquist State Energy Resources Conservation and Development Act establishes the State Energy Resources Conservation and Development Commission (Energy Commission), and requires it to undertake a continuing assessment of trends in the consumption of electricity and other forms of energy and to analyze the social, economic, and environmental consequences of those trends and to collect from electric utilities, gas utilities, and fuel producers and wholesalers and other sources, forecasts of future supplies and consumption of all forms of energy.

Existing law requires the CPUC, in consultation with the Independent System Operator (ISO), to establish resource adequacy requirements for all load-serving entities, as defined, in accordance with specified objectives. The definition of a "load-serving entity" excludes a local publicly owned electric utility. That law further requires each load-serving entity to maintain physical generating capacity adequate to meet its load requirements, including peak demand and planning and operating reserves, deliverable to locations and at times as may be necessary to provide reliable electric service. Other existing law requires that each local publicly owned electric utility serving end-use customers to prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers. That law additionally requires the utility, upon request, to provide the Energy Commission with any information the Energy Commission determines is necessary to evaluate the progress made by the local publicly owned electric utility in meeting those planning requirements, and requires the Energy Commission to report the progress made by each utility to the Legislature, to be included in the integrated energy policy reports. Under existing law, the governing body of a local publicly owned electric utility is responsible for implementing and enforcing a renewables portfolio standard for the utility that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.

This bill would require the CPUC, by March 1, 2012, to open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems and, by October 1, 2013, to adopt an energy storage system procurement target, if determined to be appropriate, to be achieved by each load-serving entity by December 31, 2015, and a 2nd target to be achieved by December 31, 2020. The bill would require the governing board of a local publicly owned electric utility, by March 1, 2012, to open a proceeding to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems and, by October 1, 2014, to adopt an energy storage system procurement target, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a 2nd target to be achieved by December 31, 2021. The bill would require each load-serving entity and local publicly owned electric utility to report certain information to the CPUC, for a load-serving entity, or to the Energy Commission, for a local publicly owned electric utility. The bill would make other technical, nonsubstantive revisions to existing law. The bill would exempt from these requirements an electrical corporation that has 60,000 or fewer customers within California and a public utility district that receives all of its electricity pursuant to a preference right adopted and authorized by the United States Congress pursuant to a specified law.

Under existing law, a violation of the Public Utilities Act or any order, decision, rule, direction, demand, or requirement of the CPUC is a crime.

Because certain of the provisions of this bill require action by the CPUC to implement, a violation of these provisions would impose a state-mandated local program by creating a new crime. Because certain of the bill's requirements are applicable to local publicly owned electric utilities, the bill would impose a state-mandated local program.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for specified reasons.

The people of the State of California do enact as follows:

SECTION 1. The Legislature finds and declares all of the following:

(a) Expanding the use of energy storage systems can assist electrical corporations, electric service providers, community choice aggregators, and local publicly owned electric utilities in integrating increased amounts of renewable energy resources into the electrical transmission and distribution grid in a manner that minimizes emissions of greenhouse gases.

(b) Additional energy storage systems can optimize the use of the significant additional amounts of variable, intermittent, and offpeak electrical generation from wind and solar energy that will be entering the California power mix on an accelerated basis.

(c) Expanded use of energy storage systems can reduce costs to ratepayers by avoiding or deferring the need for new fossil fuel-powered peaking powerplants and avoiding or deferring distribution and transmission system upgrades and expansion of the grid.

(d) Expanded use of energy storage systems will reduce the use of electricity generated from fossil fuels to meet peak load requirements on days with high electricity demand and can avoid or reduce the use of electricity generated by high carbon-emitting electrical generating facilities during those high electricity demand periods. This will have substantial cobenefits from reduced emissions of criteria pollutants.

(e) Use of energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities will reduce emissions of carbon dioxide and criteria pollutants.

(f) There are significant barriers to obtaining the benefits of energy storage systems, including inadequate evaluation of the use of energy storage to integrate renewable energy resources into the transmission and distribution grid through long-term electricity resource planning, lack of recognition of technological and marketplace advancements, and inadequate statutory and regulatory support.

SEC. 2. Chapter 7.7 (commencing with Section 2835) is added to Part 2 of Division 1 of the Public Utilities Code, to read:

Chapter 7.7. Energy Storage Systems

2835. For purposes of this chapter, the following terms have the following meanings:

(a) (1) "Energy storage system" means commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy. An "energy storage system" may have any of the characteristics in paragraph (2), shall accomplish one of the purposes in paragraph (3), and shall meet at least one of the characteristics in paragraph (4).

(2) An "energy storage system" may have any of the following characteristics:

(A) Be either centralized or distributed.

(B) Be either owned by a load-serving entity or local publicly owned electric utility, a customer of a load-serving entity or local publicly owned electric utility, or a third party, or is jointly owned by two or more of the above.

(3) An "energy storage system" shall be cost effective and either reduce emissions of greenhouse gases, reduce demand for peak electrical generation, defer or substitute for an investment in generation, transmission, or distribution assets, or improve the reliable operation of the electrical transmission or distribution grid.

(4) An "energy storage system" 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.

(b) "Load-serving entity" has the same meaning as defined in Section 380.

(c) "New" means, in reference to an energy storage system, a system that is installed and first becomes operational after January 1, 2010.

(d) "Offpeak" means, in reference to electrical demand, a period that is not within a peak demand period.

(e) "Peak demand period" means a period of high daily, weekly, or seasonal demand for electricity. For purposes of this chapter, the peak demand period for a load-serving entity shall be determined, or approved, by the commission and shall be determined, or approved, for a local publicly owned electric utility, by its governing body.

(f) "Procure" and "procurement" means, in reference to the procurement of an energy storage system, to acquire by ownership or by a contractual right to use the energy from, or the capacity of, including ancillary services, an energy storage system owned by a load-serving entity, local publicly owned electric utility, customer, or third party. Nothing in this chapter, and no action by the commission, shall discourage or disadvantage development and ownership of an energy storage system by an electrical corporation.

2836. (a) (1) On or before March 1, 2012, the commission shall open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems to be achieved by December 31, 2015, and December 31, 2020. As part of this proceeding, the commission may consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems.

(2) The commission shall adopt the procurement targets, if determined to be appropriate pursuant to paragraph (1), by October 1, 2013.

(3) The commission shall reevaluate the determinations made pursuant to this subdivision not less than once every three years.

(4) Nothing in this section prohibits the commission's evaluation and approval of any application for funding or recovery of costs of any ongoing or new development, trialing, and testing of energy storage projects or technologies outside of the proceeding required by this chapter.

(b) (1) On or before March 1, 2012, the governing board of each local publicly owned electric utility shall initiate a process to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2021. As part of this proceeding, the governing board may consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems.

(2) The governing board shall adopt the procurement targets, if determined to be appropriate pursuant to paragraph (1), by October 1, 2014.

(3) The governing board shall reevaluate the determinations made pursuant to this subdivision not less than once every three years.

(4) A local publicly owned electric utility shall report to the Energy Commission regarding the energy storage system procurement targets and policies adopted by the governing board pursuant to paragraph (2), and report any modifications made to those targets as a result of a reevaluation undertaken pursuant to paragraph (3).

2836.2. In adopting and reevaluating appropriate energy storage system procurement targets and policies pursuant to subdivision (a) of Section 2836, the commission shall do all of the following:

(a) Consider existing operational data and results of testing and trial pilot projects from existing energy storage facilities.

(b) Consider available information from the California Independent System Operator derived from California Independent System Operator testing and evaluation procedures.

(c) Consider the integration of energy storage technologies with other programs, including demand-side management or other means of achieving the purposes identified in Section 2837 that will result in the most efficient use of generation resources and cost-effective energy efficient grid integration and management.

(d) Ensure that the energy storage system procurement targets and policies that are established are technologically viable and cost effective.

2836.4. (a) An energy storage system may be used to meet the resource adequacy requirements established for a load-serving entity pursuant to Section 380 if it meets applicable standards.

(b) An energy storage system may be used to meet the resource adequacy requirements established by a local publicly owned electric utility pursuant to Section 9620 if it meets applicable standards.

2836.6. All procurement of energy storage systems by a load-serving entity or local publicly owned electric utility shall be cost effective.

2837. Each electrical corporation's renewable energy procurement plan, prepared and approved pursuant to Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1, shall require the utility to procure new energy storage systems that are appropriate to allow the electrical corporation to comply with the energy storage system procurement targets and policies adopted pursuant to Section 2836. The plan shall address the acquisition and use of energy storage systems in order to achieve the following purposes:

(a) Integrate intermittent generation from eligible renewable energy resources into the reliable operation of the transmission and distribution grid.

(b) Allow intermittent generation from eligible renewable energy resources to operate at or near full capacity.

(c) Reduce the need for new fossil-fuel powered peaking generation facilities by using stored electricity to meet peak demand.

(d) Reduce purchases of electricity generation sources with higher emissions of greenhouse gases.

(e) Eliminate or reduce transmission and distribution losses, including increased losses during periods of congestion on the grid.

(f) Reduce the demand for electricity during peak periods and achieve permanent load-shifting by using thermal storage to meet air-conditioning needs.

(g) Avoid or delay investments in transmission and distribution system upgrades.

(h) Use energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities.

2838. (a) (1) By January 1, 2016, each load-serving entity shall submit a report to the commission demonstrating that it has complied with the energy storage system procurement targets and policies adopted by the commission pursuant to subdivision (a) of Section 2836.

(2) By January 1, 2021, each load-serving entity shall submit a report to the commission demonstrating that it has complied with the energy storage system procurement targets and policies adopted by the commission pursuant to subdivision (a) of Section 2836.

(b) The commission shall ensure that a copy of each report required by subdivision (a), with any confidential information redacted, is available on the commission's Internet Web site.

2838.5. Notwithstanding any provision of this chapter, the requirements of this chapter do not apply to either of the following:

(a) An electrical corporation that has 60,000 or fewer customer accounts within California.

(b) A public utility district that receives all of its electricity pursuant to a preference right adopted and authorized by the United States Congress pursuant to Section 4 of the Trinity River Division Act of August 12, 1955 (Public Law 84-386).

2839. (a) (1) By January 1, 2017, a local publicly owned electric utility shall submit a report to the Energy Commission demonstrating that it has complied with the energy storage system procurement targets and policies adopted by the governing board pursuant to subdivision (b) of Section 2836.

(2) By January 1, 2022, a local publicly owned electric utility shall submit a report to the Energy Commission demonstrating that it has complied with the energy storage system procurement targets and policies adopted by the governing board pursuant to subdivision (b) of Section 2836.

(b) The Energy Commission shall ensure that a copy of each report or plan required by subdivisions (a) and (b), with any confidential information redacted, is available on the Energy Commission's Internet Web site, or on an Internet Web site maintained by the local publicly owned electric utility that can be accessed from the Energy Commission's Internet Web site.

(c) The commission does not have authority or jurisdiction to enforce any of the requirements of this chapter against a local publicly owned electric utility.

SEC. 3. Section 9620 of the Public Utilities Code is amended to read:

9620. (a) Each local publicly owned electric utility serving end-use customers, shall prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers. Customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218, shall not be subject to these requirements if the customer generation, or the load it serves, meets one of the following criteria:

(1) It takes standby service from the local publicly owned electric utility on a rate schedule that provides for adequate backup planning and operating reserves for the standby customer class.

(2) It is not physically interconnected to the electric transmission or distribution grid, so that, if the customer generation fails, backup power is not supplied from the electricity grid.

(3) There is physical assurance that the load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

(b) Each local publicly owned electric utility serving end-use customers shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

(c) Each local publicly owned electric utility shall prudently plan for and procure energy storage systems that are adequate to meet the requirements of Section 2836.

(d) A local publicly owned electric utility serving end-use customers shall, upon request, provide the Energy Commission with any information the Energy Commission determines is necessary to evaluate the progress made by the local publicly owned electric utility in meeting the requirements of this section.

(e) The Energy Commission shall report to the Legislature, to be included in each integrated energy policy report prepared pursuant to Section 25302 of the Public Resources Code, regarding the progress made by each local publicly owned electric utility serving end-use customers in meeting the requirements of this section.

SEC. 4. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act or because costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

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Appendix L Smart Grid

LADWP's Smart Grid Program is described in the following
"Smart Grid Deployment Plan" dated October 31, 2011

Smart Grid

Deployment Plan

Prepared by: Power System Engineering Division
Power System Information and Advanced Technologies (PSIAT) Section

Smart Grid Team

Version 1.0

Contents

1 Introduction

1.1 Purpose of this document

The Los Angeles Department of Water and Power (LADWP) Smart Grid Deployment Plan represents a roadmap to address the anticipated future needs of the people of the City of Los Angeles. By meeting the requirements of both SB 17 and Title XIII, LADWP's Smart Grid Deployment Plan outlines the coordinated and integrated approach in implementing new technologies while maintaining or improving safety and reliability.

1.2 Smart Grid Initiative Background

Smart Grid is a national policy that grew as a response to The Energy Policy Act of 2005, which called for advanced metering. It, however, has been insufficient to achieve the desired goals of energy conservation, migration to renewable energy, and reduction of CO2 emissions from power plants. The federal Energy Independence and Security Act of 2007 called for the implementation of Smart Grid systems as a "Policy of the United States". The new Energy Independence and Security Act of 2007 authorizes $100 M each year from 2008 through 2012 to be divided between five Smart Grid demonstration projects throughout the nation. The Department of Energy is required to report within one year on the status of Smart Grid deployments and identify any regulatory or government obstacles.

Additionally, utility executives and regulators have become increasingly concerned about multiple issues that can only be addressed through an enterprise wide Smart Grid solution. The four main concerns are:

(a) Cost and uncertainty about New Generation and Transmission

(b) Environmental impacts ("Green House" gases emitted from fossil fuel power plants and proposed right-of-ways for transmission lines crossing through pristine forests, deserts and wild life areas to service urban areas) such as those proposed in AB 32, the *California Global Warming Solutions Act, 2006*.

(c) Increasing requirements for the use of Renewable and Distributed Generation (Wind, Solar, Geothermal, Hydro, and Biomass)

(d) Demographics: aging workforce

Regulated utilities in California are now responding to regulatory direction to submit plans for large-scale AMI and Smart Grid initiatives with full delineation of costs and benefits. This regulatory initiative is an aggressive step, seeking to promote customer awareness of peak load periods, and response to peak-sensitive pricing. The Smart

Grid deployments and the associated utility customer features are proceeding through out the State of California.

1.3 Smart Grid Definition

The Los Angeles Department of Water and Power maintains that the definition of a smart grid is a system which facilitates the integration of advanced technologies in existing networks to improve system performance, power flow control, and reliability. Such a system is characterized by the following:

(a) Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.

(b) Dynamic optimization of grid operations and resources, with cost-effective full cyber security.

(c) Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

(d) Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficiency resources.

(e) Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation.

(f) Integration of cost-effective smart appliances and consumer devices.

(g) Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning.

(h) Provide consumers with timely information and control options.

(i) Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

(j) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

1.4 Stakeholders

1.4.1 Customer

LADWP ratepayers are the Customers and will realize the monetary, social, and environmental benefits of the plan.

2 LADWP Smart Grid Initiatives

2.1 Smart Grid Objectives

Currently, the Department is involved in two strategic initiatives related to Smart Grid. The first is the Smart Grid Regional Demonstration Project and the second is the Smart Grid Investment Program.

The Smart Grid Regional Demonstration Project began in December of 2009, when LADWP was awarded 60.2 million dollars grant from the Department of Energy for the American Reinvestment and Recovery Act for Smart Grid Demonstrations. As a result of the award, LADWP is managing a consortium of Los Angeles metropolitan area research institutions with established energy and technology transfer programs. Together, the team is carrying out a regionally unique demonstration by using innovative technology test beds located at LADWP's partner university campuses and technology transfer laboratories to prove the viability of the demonstration technology. Additional research is being conducted to explore options for informed, enabled customers based on historical usage and pricing data. This research uses a multi-tiered rate approach to address the diversity of customer demands by exploring time-varying and time-of-use products for the end consumer. The regional demonstration project includes four interrelated project initiatives, which will be incorporated into the long term investment program:

(a) A fully integrated demonstration of Smart Grid operation and technology as applied to Demand Response.

(b) A comprehensive portfolio of research empoying a unique test bed structure to identify historical usage and consumer adoption obstacles essential for succesful adoption of Smart Grid Technologies and improved energy usage patterns.

(c) Demonstration of next generation cyber security technologies using the Regional Project as the driving source of specific system architecture and models.

(d) The integration of electric vehicles into the LADWP managed grid, addressing solutions to overcome both technical and social impediments.

The Smart Grid investment plan is a 10-year project that incorporates 11 strategic initiatives.

2.1.1 Links with the Department's Strategic Objectives

The Smart Grid Implementation Plan continues to align LADWP's efforts to implement the technology with the goal of increasing LADWP's Power System monitoring, control and reliability while decreasing operating costs and gaining significant efficiencies.

2.2 LADWP Smart Grid Initiatives in Progress

"Smart Grid" is a term used to describe a variety of advanced information-based utility improvements. Smart Grid is a major enabler for many existing and potentially new Demand Side Resource programs. Smart Grid is a national policy evolving from the Energy Policy Act of 2005. 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 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 utilities 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 consumer to make decisions to optimize the use of energy, improve reliability, and reduce the consumption of fossil fuels.

Section 8360 of the Senate Bill 17 defines the policy that governs the way utilities modernize transmission and distribution systems. LADWP's eleven Smart Grid Initiatives are designed to be collectively compliant with SB17. The following is the list of the initiatives:

(a) Renewable Integration

(b) Transmission Automation Initiative

(c) Substation Automation Initiative

(d) Distribution Automation Initiative

(e) AMI Metering Initiative

(f) Demand Response Initiative

(g) Communications Initiative

(h) Cyber Security Initiative

(i) System and Data Integration Initiative

(j) Feed-In Tariff Initiative

(k) Solar Incentives Program

2.3 Renewable Integration

LADWP has a comprehensive Integrated Resource Plan where new Wind, Solar, and Geothermal Power Plants, as well as Energy Storage, and Electric Vehicles will be incorporated into the power generation mix. Currently, the ECS/Historian Servers have been installed at Pine Tree Generation Station, and there are plans to install more of these servers at each of the power plants. These servers allow for real-time monitoring and control of renewable sources, which will be equipped with automation equipment in order to facilitate peak shaving activities and to better support the adoption and utilization of renewables.

2.4 Transmission Automation Initiative

For years, LADWP has worked in substations to meter the transmission lines and record Phasor Measurement Units (PMU). These measurements are used to determine the health of the Electrical System. LADWP will install PMUS, and upgrade Tie-Line Meters to improve measurement, provide backup metering at Tie Points, collect dynamic reads, and reroute power. The real-time data provided by PMU will be used for predicting instability in the transmission system and undertaking preventive actions.

2.5 Substation Automation Initiative

For the past five years, LADWP has implemented a comprehensive program to install a new Power System Substation Automation System (SAS) from the Energy Control Center to the Substations, transmission, and Generation Stations. Currently, 80 of the approximate 200 substations and generation stations have been updated to the new Substation Automation, and a new SCADA system has been implemented. There are approximately 70 more stations in the inventory that will be implemented over the next two to three years. Approximately 840 feeders now have remotely controlled circuit breakers and remote monitoring of megawatt loading of wire/cables. A significant amount of data is already being processed through the SCADA system and is available to the load dispatchers and other personnel on an as needed basis. At the conclusion of this project, the vast majority of feeders at all substations will be observable and controllable from the Energy Control Center.

2.6 Distribution Automation Initiative

There have been several pilot projects for the Distribution Automation relating to devices outside the substation walls (Current's Broadband over Power Line project, Ricochet Spread Spectrum project, and Telemetric Cellular project). These projects were never rolled out as the industry was still being developed and LADWP's decision was to wait until more robust solutions were available. Additionally, some of the pilot programs were never considered industry standard since it was using obsolete technology. The LADWP is currently evaluating fault indicators, remotely controlled switches and automatic cap banks. These devices can be used for dynamic optimization of the distribution system.

2.7 AMI Metering Initiative

LADWP has been progressing over the past few years with the AMI Metering Initiative.

- As of 6/01/11, the LADWP has installed 162,200 AMR meters
  - Residential Meters (F meters) – 85,000 (using RF Technology and one way communication providing billing information for walk or drive by meter reading)
  - Small Commercial Demand Meters (FM meters) – 68,000 (using RF Technology and one way communication providing billing information)
  - Large Commercial Wireless Meters (A meters) – 9,000 (using Cellular Technology and two way communication providing billing information and load profile information)
- AMR meters represent approximately 10.6% of the total meters in the system but over 45% of the power revenue

Wireless meter reading and real-time pricing are available for 9,000 Large Commercial Customers with demand greater than 200kW. The newest AMI meters have the capability of short range connectivity. This feature will be used by the Home Area Network devices that display various real-time energy consumption data to the customers.

2.8 Demand Response Initiative

LADWP has had a Demand Response (DR) rate for years for large industrial users. Currently, there are 30 Megawatts of interruptible load, but very rarely has this been used because LADWP has had a philosophy to cover all its loads. This pilot program is also voluntary in that when a load reduction is required, the customer has the option to not participate and pay for the higher cost of energy. Currently, the LADWP is planning to develop a formal demand response program that will allow the Department to reduce generation cost and distribution system strain during peak consumption periods.

2.9 Communications Initiative

The component that pulls all of the initiatives together is the common communication network. Over the past ten years, thousands of miles of fiber optic cable has been installed in over 72 substations as part of a fiber optic broadband infrastructure. The plan is for all substations to have fiber optic connections within the next two years.

LADWP evaluates different communication protocols that can be used for the real-time control and observation of deployed automation equipment.

2.10 Cyber Security Initiative

The implementation of Smart Grid will involve a wide deployment of smart remotely controlled network capable devices. These devices can be potential points of cyber attack due to network connectivity. This is why NERC and FERC have developed strict procedures and guidelines that require utilities to treat any critical cyber asset (CCA) with great attention. The breach of CCA can result in critical damage to the power distribution system.

Due to the importance of Cyber Security, the Smart Grid will need to better understand and improve the cyber security, and more importantly, three key items will be developed:

- Grid Resilience: this effort will show how the Smart Grid can operate resiliently against physical and cyber attack.
- Operational Effectiveness: this effort will demonstrate a complete cyber security testing approach for components and installed systems.
- Redefinition of Security Perimeter: this effort will demonstrate new cyber security measures that address the expansion of this perimeter by Smart Grid technologies to the meter in residential and commercial sites.

2.11 System and Data Integration Initiative

Significant progress has been made in the Power System in implementing the best of breed systems (see **Figure 2.11-1** Power System Technology Architecture). These systems are the backbone of the business and information processes in the Power System. Additionally, significant integration between these and the corporate systems is in place.

In particular, OSIsoft's Pi Historian is a fast real time data processing system that has been purchased and installed by LADWP. The next Pi Historian initiative is to use it as a central repository for all of LADWP's real-time data and to allow access to the appropriate users of the data throughout the utility. LADWP has currently installed the Pi Historian in two locations (ECC and JFB) with a tag count of 20,000 data points. There are three pilot Pi Historian applications running at this time: 1) door/gate alarm; 2) Operation logger; and 3) Power System Dashboard real time data. Five user groups (Reliability, Planning, Station Operators, Grid Operations, and Meter) are also currently developing new applications.

In addition, LADWP is working on integrating the Meter Data Management System (MDMS), Outage Management System (OMS), and Customer Information System

(CIS) with various Web services. These services will be designed to provide accurate and timely information to customers regarding their consumption, billing, any pending outages and restoration statuses. The customers will have the option to adjust their accounts to set up their profile and notification preferences.

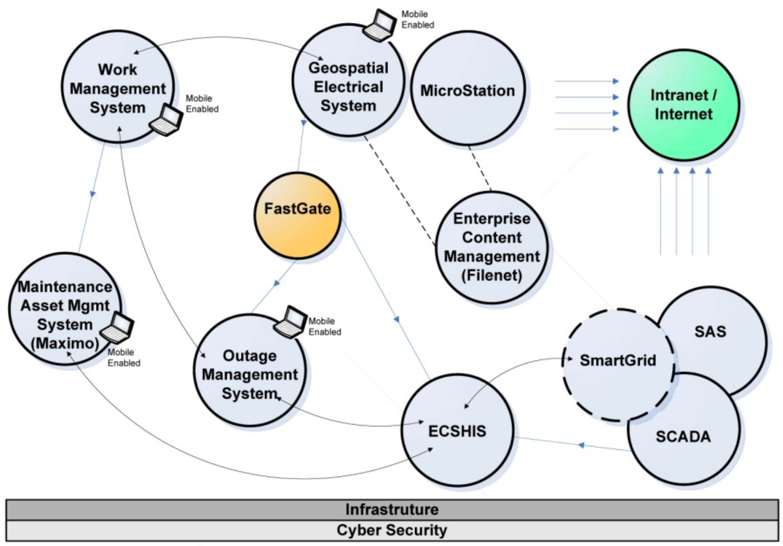

Figure 2.11-1 Power System Technology Architecture

2.12 Feed-In Tariff Initiative (FiT)

FiT seeks to purchase energy from small and medium-scale renewable energy projects (from 30 kilowatts up to one megawatt in AC capacity) within the service territory of LADWP under a long-term Standard Offer Power Purchase Agreements (SOPPA). The SOPPA terms are standard for all participants, can be up to 20 years in duration, and participants will be paid the bid base price of energy plus Time-of-Delivery (TOD) multipliers. FIT is a distributed generation (DG) program designed for the local Los Angeles market, and gives LADWP customers the opportunity to sell energy to LADWP from using their property as the DG site.

2.13 Solar Incentive Program (SIP)

The LADWP Solar Photovoltaic Incentive Program provides financial incentives to LADWP customers who purchase and install their own solar power systems. LADWP currently also provides an additional incentive payment for systems using PV modules manufactured in the City of Los Angeles.

LADWP currently provides a Los Angeles Manufacturing Credit (LAMC) for qualifying photovoltaic equipment manufactured in Los Angeles as approved by the LADWP guidelines. The goal of the LAMC is to promote local economic development through manufacturing and job creation within the City of Los Angeles and to reduce costs through increased volume and competition.

3 Proposed Deployment Plan

The overall scope of the Smart Grid Deployment Plan includes the following three overlapping phases:

3.1 Implement a short term plan (one year horizon)

This plan includes the following coordinated activities:

- Create a Smart Grid System Architecture (**Table 3.1-1** *SG Architecture (Phase 1) Schedule* & **Table 3.1-2 SG Architecture (Phase 2) Schedule**)
- Create a Comprehensive Business Plan/Case (**Table 3.1-3 SG Business Plan Schedule**)
- Integration of Various Information Systems
- Participate in Standard Development
- Creation of a Multi Disciplinary matrix team

Tasks	Schedule															
	Week of May 16	Week of May 23	Week of May 30	Week of Jun 6	Week of Jun 13	Week of Jun 20	Week of Jun 27	Week of Jul 11	Week of Jul 18	Week of Jul 25	Week of Aug 1	Week of Aug 8	Week of Aug 15	Week of Aug 22	Week of Aug 29	Week of Sep 5
Program Scoping																
1. Assist in communication management																
a. Assist LADWP Program Director in drafting Smart Grid Program Sponsor communication bulletin																
Deliverable D1: Program sponsor communication bulletin	D1															
b. Assist in preparation of kick off document for Phase 2																
Deliverable D2: Kick off document for Phase 2			D2													
2. Identify focus areas for Smart Grid program																
a. Conduct discussions with Steering Committee members to identify Smart Grid focus areas for LADWP based on expected benefits																
b. Prepare high level mapping of focus areas to benefit areas, expected value of benefit, and KPIs for LADWP																
Deliverable D3: Draft list of Smart Grid focus areas, and identification of expected benefits						D3										
c. Discuss and obtain feedback from LADWP Program Director on focus areas and expected benefits																
Deliverable D4: Finalized list of Smart Grid focus areas, and identification of expected benefits							D4									
Requirements Analysis																
3. Use case analysis																
a. Prepare list of proposed use cases																
b. Discuss use cases with LADWP Program Director and obtain sign off																
Deliverable D5: List of use cases								D5								
c. Prepare agenda and schedule for requirements sessions																
4. Requirements identification																
a. Prepare strawman requirements for each use case																
b. Conduct requirements interviews for each use case to confirm requirements																
c. Update and finalize requirement documents including functional, technical, data, and interface requirments																
d. Deliver draft requirements document for each use case																
Deliverable D6: Draft requirements document for use cases													D6			
e. Obtain feedback from LADWP Smart Grid program director and update requirements document as needed																
Deliverable D7 Final requirements document for use cases																D7

Table 3.1-1 SG Architecture (Phase 1) Schedule

Tasks	Schedule															
	Week of Sep 12	Week of Sep 19	Week of Sep 26	Week of Oct 3	Week of Oct 10	Week of Oct 17	Week of Oct 24	Week of Oct 31	Week of Nov 7	Week of Nov 14	Week of Nov 21	Week of Nov 28	Week of Dec 5	Week of Dec 12	Week of Dec 19	Week of Jan 9
5. Develop roadmap																
1. Technology Assessment																
a. Perform technology assessment for each use case application																
2. Develop Roadmap																
a. Prepare draft roadmap																
b. Present to LADWP Program Director																
***Deliverable D8: Draft Smart Grid Roadmap document				D8												
c. Obtain feedback and update roadmap																
***Deliverable D9: Smart Grid Roadmap document						D9										
6. Develop architecture																
a. Requirements Analysis																
b. Develop Architecture																
***Deliverable D10: Draft Smart Grid Architecture document										D10						
c. Obtain LADWP feedback and update Smart Grid Architecture Definition document																
d. Deliver final Smart Grid Architecure Def. Doc																
***Deliverable D11: Smart Grid Architecture document															D11	
e. Prepare draft deployment plan per SB17 guidance																
***Deliverable D12: Draft SB17 deployment plan document															D12	
7. Prepare program strategy document																
a. Prepare draft of LADWP Smart Grid program definition document including key Smart Grid focus areas, and their mapping to expected benefits and KPIs																
***Deliverable D13: Draft Program strategy document										D13						
b. Validate program definition document for the Smart Grid project with LADWP Program Director and Manager and obtain feedback																
c. Finalize program definition document to include list of Smart Grid initiatives, agreed upon focus areas, and expected benefits																
***Deliverable D14: Finalized Program strategy document																D14

Table 3.1-2 *SG Architecture (Phase 2) Schedule*

Tasks	Schedule																				
	May 16 - Aug 15	Week of Aug 22	Week of Aug 29	Week of Sep 5	Week of Sep 12	Week of Sep 19	Week of Sep 26	Week of Oct 3	Week of Oct 10	Week of Oct 17	Week of Oct 24	Week of Oct 31	Week of Nov 7	Week of Nov 14	Week of Nov 21	Week of Nov 28	Week of Dec 5	Week of Dec 12	Week of Dec 19	Week of Jan 9	Week of Jan 16
1. Develop and agree business plan template																					
a. Discuss Business Plan template and requirements with LADWP Program Director																					
b. Prepare draft template for LADWP's Business Plan																					
***Deliverable D1: Draft Business Plan template				D1																	
c. Discus template with LADWP Program Director and obtain sign off																					
***Deliverable D2: Finalized template for Business Plan						D2															
2. Identify benefits and metrics / KPIs																					
a. Refine mapping of benefit areas and metrics / KPIs to each use case																					
***Deliverable D3: Draft list of benefits and KPIs for use cases				D3																	
b. Discuss benefits areas and KPIs for each use case with LADWP																					
c. Refine and finalize specific benefits and appropriate KPIs for each use case																					
***Deliverable D4: Final list of benefits and KPIs for use cases							D4														
3. Develop cost model																					
a. Identify solution components based on requirements																					
b. Identify cost drivers for the solution																					
c. Develop breakdown of cost components																					
d. Identify data requirements and prepare cost data request																					
***Deliverable D5: Cost data request									D5												
4. Develop benefit model																					
a. Prepare benefit calculation model for each use case																					
b. Identify data requirements and prepare data request for benefit calculation																					
***Deliverable D6: Benefit data request									D6												
5. Develop business plan																					
a. Receive cost and benefits data from LADWP and update financial data																					
b. Develop proposed organizational structure and resource requirements for projects included in business plan																					
c. Prepare draft business plan document																					
***Deliverable D7 Draft Business Plan document including supporting organization															D7						
d. Receive feedback from LADWP Program Director and update business plan document																					
***Deliverable D8: Final Business Plan document including supporting organization																					D8

Table 3.1-3 *SG Business Plan Schedule*

3.2 Implement a mid term plan (up to five years horizon)

This plan includes the following coordinated activities:

- Complete and implement LADWP's ARRA Smart Grid Regional Demonstration Project, which focuses on Customer and Behavioral Studies, Cyber Security, Demand Response, and Electric Vehicles.

Figure 3.2-1 ***Smart Grid Regional Demonstration Project Schedule*** below shows the implementation schedule of the Smart Grid Regional Demonstration Project.

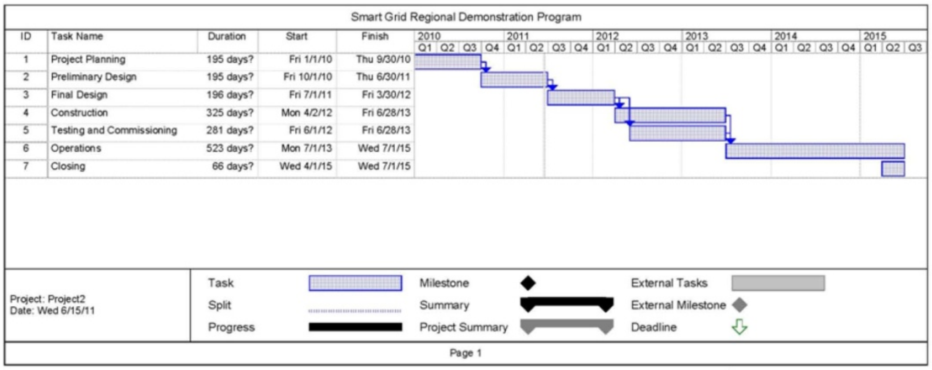

Figure 3.2-1 Smart Grid Regional Demonstration Project Schedule

- Implement the balance of the SAS project to automate all generation, substation, and transmission with the SCADA system. **Table 3.2-1** ***Substation Automation Project Installation Progress Schedule*** below shows the overall schedule of activities to implement the SAS project.

Stations for Site Acceptance Test (SAT)			
RS-T	Monday, January 25, 2012	Friday, February 12, 2012	3 Weeks
IS-1221	Monday, February 15, 2012	Friday, February 26, 2012	2 Weeks
IS-1263	Monday, March 01, 2012	Friday, March 12, 2012	2 Weeks
RS-N	Monday, March 15, 2012	Friday, April 02, 2012	3 Weeks
DS-24	Monday, April 05, 2012	Friday, April 16, 2012	2 Weeks
RS-C	Monday, April 19, 2012	Friday, May 07, 2012	3 Weeks
DS-135	Monday, May 10, 2012	Friday, May 21, 2012	2 Weeks
RS-E	Monday, May 24, 2012	Friday, June 25, 2012	5 Weeks
DS-81	Monday, June 28, 2012	Friday, July 09, 2012	2 Weeks
DS-30	Monday, July 12, 2012	Friday, July 23, 2012	2 Weeks
RS-M	Monday, July 26, 2012	Friday, August 06, 2012	2 Weeks
DS-36	Monday, August 09, 2012	Friday, August 20, 2012	2 Weeks
DS-76	Monday, August 23, 2012	Friday, September 03, 2012	2 Weeks
RS-U	Monday, September 06, 2012	Friday, September 24, 2012	3 Weeks
DS-21	Monday, September 27, 2012	Friday, October 08, 2012	2 Weeks
RINALDI	Monday, October 11, 2012	Friday, October 29, 2012	3 Weeks
DS-26	Monday, November 01, 2012	Friday, November 12, 2012	2 Weeks
HALLDALE	Monday, November 15, 2012	Friday, December 03, 2012	3 Weeks
DS-143	Monday, December 06, 2012	Friday, December 17, 2012	2 Weeks
DS-15	Monday, December 20, 2012	Friday, December 31, 2012	2 Weeks
RS-J	Monday, January 03, 2013	Friday, January 21, 2013	3 Weeks

DS-2	Monday, January 24, 2013	Friday, February 04, 2013	2 Weeks
RS-Q	Monday, February 07, 2013	Friday, February 25, 2013	3 Weeks
DS-95	Monday, February 28, 2013	Friday, March 11, 2013	2 Weeks
RS-L	Monday, March 14, 2013	Friday, April 01, 2013	3 Weeks
DS-50	Monday, April 04, 2013	Friday, April 15, 2013	2 Weeks
RS-S	Monday, April 18, 2013	Friday, May 06, 2013	3 Weeks
DS-58	Monday, May 09, 2013	Friday, May 20, 2013	2 Weeks
RS-R	Monday, May 23, 2013	Friday, June 10, 2013	3 Weeks
DS-105	Monday, June 13, 2013	Friday, June 24, 2013	2 Weeks
RS-F	Monday, June 27, 2013	Thursday, June 30, 2013	1 Weeks
RS-Q	Sunday, July 03, 2013	Thursday, July 21, 2013	3 Weeks
IS-3115	Sunday, July 24, 2013	Thursday, July 28, 2013	1 Weeks
IS-3130	Sunday, July 31, 2013	Thursday, August 04, 2013	1 Weeks
IS-1671	Sunday, August 07, 2013	Thursday, August 11, 2013	1 Weeks

Table 3.2-1 Substation Automation Project Installation Progress Schedule

- Implement the balance of the projects at ECC to use all of the features and upgrades of the SAS and other systems with the new technology. **Figure 3.2-2** ***ECC Plans to be Implemented*** below shows the activities and systems to be implemented.

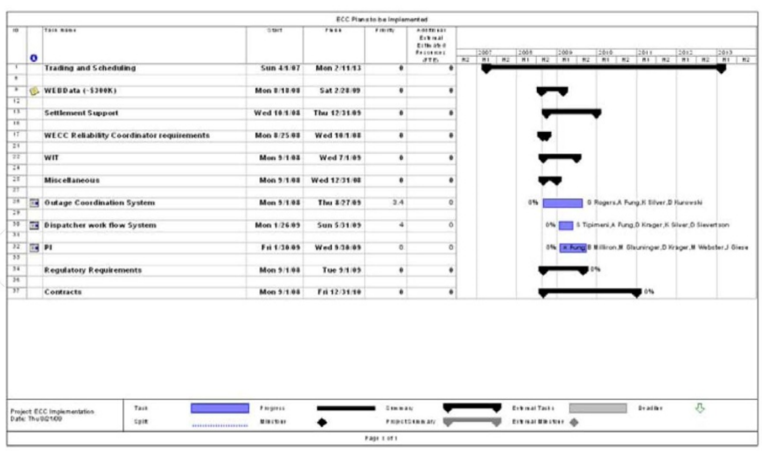

Figure 3.2-2 ECC Plans to be Implemented

- Implement the balance of the projects at ETC to use all of the features and upgrades of the Smart Grid systems with the new technology. **Figure 3.2-3** ***ETC Plan and Enhancements*** below shows the various activities to be implemented.

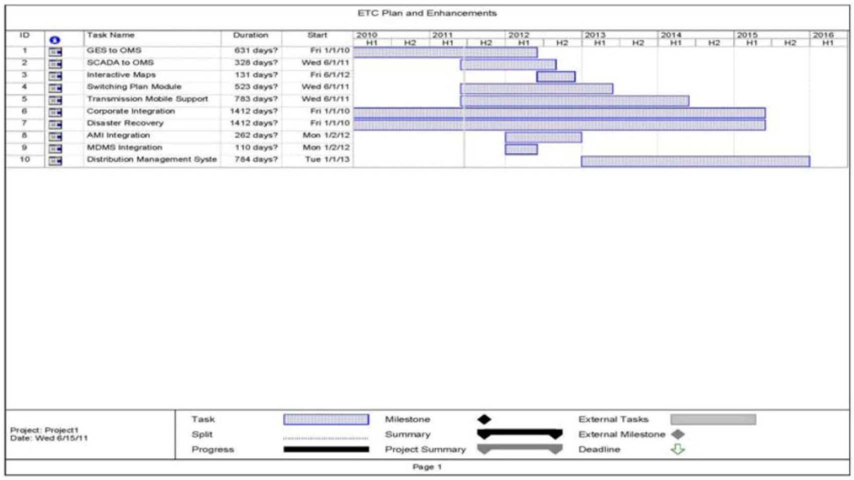

Figure 3.2-3 ETC Plan and Enhancements

- Implement a new CIS and Supply Chain System

The effort must be made to implement a new CIS, and a new Supply Chain Corporate System. These systems will be able to manage the new information and transaction of a Smart Grid system.

Other activities to be implemented during this phase are as follows:

- Implement the balance of the electric model with the GIS system and engineering design tools
- Create and advertise Multiple RFPs as needed to start the implementation of the Smart Grid components
- Create Multiple contracts as needed to bring the vendors on-board

3.3 Implement the full Smart Grid Features (up to 10 years)

Implement all the remaining features indicated in this plan in various phases based on the requirements and needs identified, and with the dynamics of the utility and technology environment. The phases of this significant program could include two large pilot periods where various telecommunication technologies will be tested while Smart Grid technology will be utilized to cover overhead, underground, single family residences, multi-family residences, and medium and large customers in a couple of neighborhoods. The final phase would be the full city wide implementation assuming the data and results from the pilot programs are satisfactory.

The full functionality of the Smart Grid could include all of the following aspects:

(a) Outage Notifications

(b) Transformer Monitoring

(c) Capacitor Controls

(d) Line Switch Controls

(e) Automatic Meter Reading

(f) Load Control of residential and commercial devices (DSM Program)

(g) Video Surveillance via Smart Grid

(h) Fault Management

(i) Transformer Deterioration

(j) Transformer Overloading

(k) Current Monitoring

(l) Cable Management

(m) Surge Protection

(n) Lighting Controls

(o) Weather

(p) Municipal Applications

(q) Other applications as they become available.

Other features could include:

- Installation of Smart Grid equipment in the City of Los Angeles Facilities
- Installation of Smart Grid equipment and potentially replacement all of the water meters
- Access to broadband capabilities (Internet access, VoIP, video) for City of Los Angeles Municipality
- Access to City of Los Angeles Municipal information via broadband connections

- Set up an internal LADWP organization to maintain and operate the Smart Grid equipment
- Maintain, install, and operate the Smart Grid equipment through the following organization and service components:
  1. Services
  2. Customer response center
  3. Network Operation Center (NOC)

3.4 Related Projects

The following projects are related to the Smart Grid as follows:

1. Substation Automation System: Extension and upgrade of the remaining Switching, Receiving, and Distribution Systems
2. Telecommunications system: Extension and upgrade of the telecommunications to support the Power System operations through the implementation of a fiber optic broadband network.
3. Subtransmission and distribution switches: Automation of subtransmission and distribution switches, implementing line monitoring, line switch control, and 4.8 kV line capacitor bank control.
4. Fault and outage detectors: Installation of remotely monitored fault and outage detectors which would provide a means to locate faults and outages on selected 4.8 kV distribution lines.
5. Operating orders, procedures, and processes: Re-engineering of operating orders and processes as required for monitoring and controlling changes of the Power System.

3.5 Constraints

The following are potential constraints:

- Budget/Cost
- Regulatory environment which may limit Smart Grid installations
- Internal Resources
- Political environment (City/State/Federal)

3.6 Urgency

The timing of LADWP's Smart Grid Deployment coincides with the initiatives by other major U.S. utilities. Additionally, the Department of Energy is encouraging utilities to invest in Smart Grid by offering grants and the regulatory environment seems to support Smart Grid as an alternative to the existing utility practice.

3.7 Procurement Process

The Smart Grid Plan will utilize the procurement process as follows:

(a) Determination of requirements

(b) Preparation of RFP(s)

(c) Vendor(s) Selection

(d) Preparation of Agreements

(e) Initial Implementation – Phase 1

(f) Phase 1 Evaluation

(g) Multi-phase Implementation over the next 10 years.

4 Critical Milestones

4.1 Schedules and Critical Milestones

The Smart Grid Plan assumes a 1-year, 5-year, and 10-year implementation.

4.1.1

4.1.2 Critical Milestones

Table 4.1.2-1 Critical Milestones illustrates the critical milestones:

Milestone or Event	Significance
Smart Grid Business/Project Plan and Architecture Presentation	Get concurrence from Management
Setup of Smart Grid Project Committee	Establish Project Committee
Preparation of Smart Grid Project Requirements	Establish project requirements
Advertise Request for Proposals	Request for Proposals
Vendors Selection	Selection of qualified bidder
Board Approval	Contract approval by LADWP Board of Commissioners

City Council Approval	Contract approval by City of Los Angeles
Contracts Award	Execution of contract award
Implementation Phase 1	Implement Smart Grid Phase 1 (Pilot Programs)
Evaluation of Phase 1	To continue Full Implementation
Begin full deployment	Implement city wide

Table 4.1.2-1 Critical Milestones

5 Budget

Smart Grid equipment costs are expected to continue to drop due to technology advances and significant market changes, **Table 4.1-1** Budget Estimates for various Systems given below is our best estimate for various alternatives at this point. As RFPs are produced and responses are received, we will have a better idea as to the cost of these types of systems and process.

	Single Unit				Total			
	P2P	**Single Unit RF**	**RF Mesh**	**BPL/PLC**	**P2P**	**RF**	**RF Mesh**	**BPL/PLC**
AMI (w/o communications)								
Residential	200.00	160.00	200.00	220.00	248,992,000.00	199,193,600.00	261,992,000.00	273,891,200.00
Commercial	317.50	347.50	387.50	337.50	57,029,032.50	62,417,602.50	89,602,362.50	60,621,412.50
Industrial	367.50	367.50	367.50	376.50	17,050,897.50	17,050,897.50	48,485,525.50	17,468,470.50
					323,071,930.00	**278,662,100.00**	**400,079,888.00**	**351,981,083.00**
DA 4.8 kv (w/o communications)								
switches	950.00	-	950.00	1,150.00	12,831,650.00	-	12,831,650.00	15,533,050.00
capacitors	950.00	-	950.00	1,150.00	2,998,200.00	-	2,998,200.00	3,629,400.00
transformers	950.00	-	950.00	1,150.00	96,215,050.00	-	96,215,050.00	116,470,850.00
DA 35.5 kv (w/o communications)								
switches	1,700.00	-	1,700.00	-	8,746,500.00	-	8,746,500.00	-
capacitors	950.00	-	950.00	-	-	-	-	-
					120,791,400.00	**-**	**120,791,400.00**	**135,633,300.00**
DR (w/o communications)								
Residential	77.00	-	77.00	77.00	95,861,920.00	-	95,861,920.00	95,861,920.00
Commercial	77.00	-	77.00	77.00	13,830,663.00	-	13,830,663.00	13,830,663.00
					109,692,583.00	**-**	**109,692,583.00**	**109,692,583.00**
Communications					**7,671,847.47**	**10,407,798.40**	**10,407,798.40**	**49,624,600.00**

SAS					60,000,000.00	60,000,000.00	60,000,000.00	60,000,000.00
Applications					110,000,000.00	110,000,000.00	110,000,000.00	110,000,000.00
				TOTAL	731,227,760.47	459,069,898.40	746,537,041.40	816,631,566.00

Table 4.1-1 Budget Estimates for various Systems

The pie chart below (**Figure 4.1-1** P2P Cost Graph) depicts the P2P estimated cost in the nine different categories of the smart Grid.

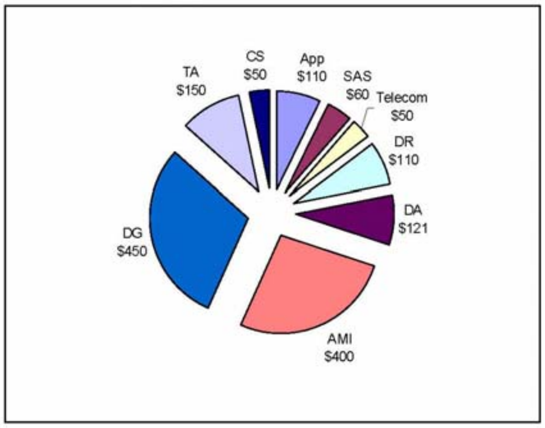

Figure 4.1-1 P2P Cost Graph

6 Impacts

6.1 Internal

The Smart Grid equipment will impact several areas within LADWP. **Table 6.1-1** Potential Impacts within LADWP shows some potential impacts on these organizations:

Area within LADWP	Nature of impact
Meter Reading	Automated method reading of electric meters
Control System Operations	may gain capability to control devices at all levels
Customer Service	Establish direct communications with customer
Electric Trouble Dispatch	Will process trouble calls using Smart Grid information
Engineering Design	Power network design process (OH/UG)
Distribution Line Crews	Maintain and operate new Smart Grid equipment
ITS	Provides support of Smart Grid network equipment
Water Meters	Automated method of reading water meters

Table 6.1-1 Potential Impacts within LADWP

Area within the department	Nature of impact
Energy Control Center	Will use SAS for real-time data instead of current RTU
Electric Trouble Center	Will use real-time data
Plant Control System Operations	Will use real-time data access and archived data
Substation Operations	Selected station status information will be available
Substation Maintenance	Will access intelligent relay settings and logs without having to connect directly to the devices
ITS	Provides support of ECS WAN network.
Power Systems Operation and Maintenance	Provides support of SAS application software and hardware
Engineering	Will use archived data

Table 6.1-2 Potential Impacts within department

6.2 External

Table 6.2-1 Potential Impacts external to LADWP shows some potential impacts on organizations that are external to LADWP:

Area external to LADWP	Nature of impact
City of Los Angeles	Gain fiber optic broadband infrastructure
Broadband Companies	May perceive competition from LADWP and receive services.
Gas Utility	Opportunities to collaborate with LADWP
State of California (CPUC)	May encourage Smart Grid installation at Los Angeles

Table 6.2-1 Potential Impacts external to LADWP

7 Smart Grid Business Plan & Evaluation Strategy

A Smart Grid business plan will be developed in conjunction with the roadmap and architecture development activities which will include cost-benefit analysis of projects for implementation of the functionality identified in the Smart Grid architecture and roadmap. The business plan documentation will outline the project description; costs associated with the implementation; and expected benefits. The financial analysis will be based on estimated benefits and costs information and will be updated throughout the course of the implementation of the projects as the actual cost data become available. The business plan development process will include an assessment to identify the benefit areas and develop an estimate of actual quantifiable benefits expected from investment into particular Smart Grid area. The benefits resulting from LADWP's Smart Grid investments could be in various areas including but not limited to better customer service, reduced operational costs, higher operational efficiency, and achievement of environmental goals. The benefit estimation will be developed using LADWP KPIs and other relevant metrics. The business plan will also include a cost model to estimate the implementation costs of each project. The cost estimates will be based on assumptions of the technology and implementation choices, and will be updated during implementation of the projects with actual costs and implementation plans.

8 Smart Grid Safety

Smart Grid Deployment Plan requires specific installation, maintenance, and operation procedures, which LADWP personnel will need training on. Additionally, the Smart Grid equipment will require compliance and resolution of issues relating to the following state regulations:

(a) California Public Utilities Commission - General Order 128 – Construction of underground electric supply and communication systems.

(b) California Public Utilities Commission - General Order 95 – Overhead electric line construction.

(c) California Public Utilities Commission - General Order 165 – Inspection Cycles for electric distribution facilities

(d) The Smart Grid vendors and utilities are currently handling all of these issues with success.

9 Smart Grid Operational issues

LADWP intends to own and operate the Smart Grid equipment. The ownership entails the support and ability to operate the Smart Grid network by LADWP personnel.

The following are potential operational issues:

- 24/7 operational support of the Smart Grid equipment
- Training of Crews for the operation and maintenance of the Smart Grid equipment
- 24/7 operational support of the telecommunications and fiber optic broadband infrastructure access

10 Smart Grid Performance Measurement

The critical success factors essential for plan success are as shown in **Table 10-1** Critical Success Factors:

Critical Success Factors	Measurement method
Plan Buy-in from LADWP Board	LADWP Board Approval
Plan Buy-in from City	City Council approval
Appropriate plan budget	Budget approval
Smart Grid Technical Feasibility	Market proven Smart Grid technology
Secure staffing resources	Appropriate resource leveling based on project scope
Regulatory Support for Smart Grid	City, State legislative approvals for Smart Grid implementation

Table 10-1 Critical Success Factors

11 Smart Grid Product Benefits Realization

The benefits will be measured as shown in **Table 11-1** Benefits:

Potential Benefits	Measurement method
Municipal fiber optic broadband Capability	No. of City of Los Angeles Broadband users
Smart Grid enabled Automated meter reading	No. of automated meter reads
Customer Energy Management Programs	No. of devices under Direct load control
Improved reliability	No. of Utility applications in service
Additional Revenue Sources	Capitalize on revenue generating opportunities

Table 11-1 Benefits

12 Conclusion

The Los Angeles Department of Water and Power is dedicated to integrating new technologies to improve system performance, power flow control, safety and reliability. By maintaining a high level of commitment and service for the City of Los Angeles, LADWP is taking the necessary steps to:

(a) Coordinate efforts across multiple stakeholders

(b) Integrate new technologies to supplement the power system

(c) Deliver safe, secure, and efficient electrical service well into Los Angeles's future

LADWP's overall strategic plan is inclusive of the Smart Grid Deployment plan. LADWP's focus is the City of Los Angeles, customer enhancement, utility services, and operations. LADWP looks forward to further collaborate with policymakers, customers, and stakeholders as the process of Smart Grid implementation unfolds.

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. Throughout this IRP is discussion of various 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 common place.[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 2012 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

[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.

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, 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.

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Appendix N Model Description and Assumptions

N.1 Overview

The study horizon for the model analysis is the 20 year period 2012 through 2032. In performing this modeling, it is necessary to assume certain actions are 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 energy efficiency and distributed generation case comparisons (Cases 5 thru 8) 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.

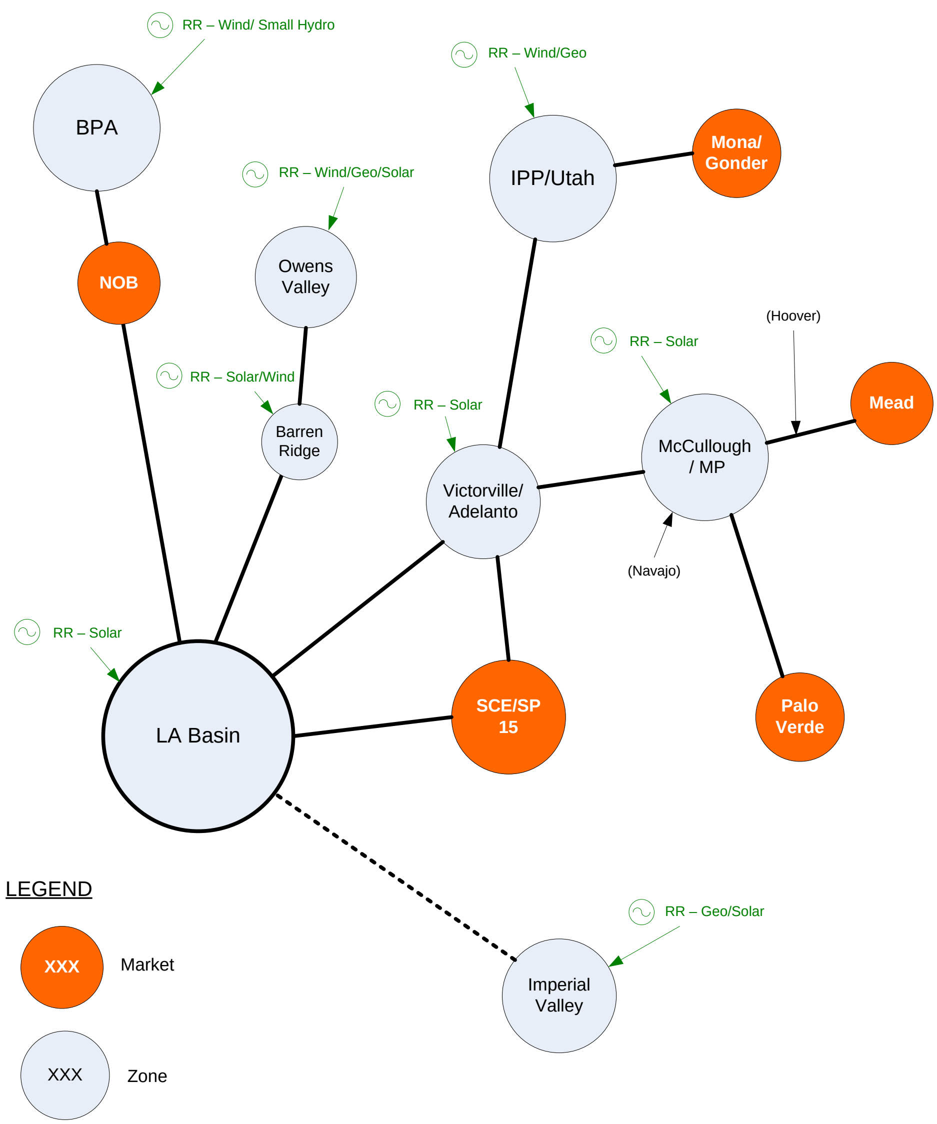


Fig N-1: LADWP Modeling Topology.

On a day-to-day basis, LADWP will buy power in spot markets if such a purchase can be done both without causing a reliability problem 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.

Table N-1. Resources recommended for resource adequacy by calendar year

Case#1 (Navajo 2019, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	25	75	0	0	0	0	50	125
Total Replacement	244	257	165	342	460	563	675	784	1245	1313	1426	1513	1600	1686	1747	2835	2854	2867	2880	2943	3030

Case #2 (Navajo 2015, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	25	75	0	0	0	0	50	125
Total Replacement	244	257	165	342	760	863	975	1084	1245	1313	1426	1513	1600	1686	1747	2835	2854	2867	2880	2943	3030

Case #3 (Navajo 2015, IPP 2020)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	125
Total Replacement	244	257	165	342	760	863	975	1084	1245	2463	2576	2663	2750	2811	2822	2835	2854	2867	2880	2943	3030

Case #4 (Navajo 2015, IPP 2023)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	87	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	125
Total Replacement	244	257	165	342	760	863	975	1084	1245	1313	1426	1513	2750	2811	2822	2835	2854	2867	2880	2943	3030

Case#5 Base EE & Base DG (Navajo 2019, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	22	36	141	223	286	347	393	440	540	547	600	629	658	662	666	673	687	695	703	711	719
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	175	0	0	0	0	0	0	0	0	0	0	0	25	75	0	0	0	0	50	125
Total Replacement	244	257	219	342	760	863	975	1084	1245	1313	1426	1513	1600	1686	1747	2835	2854	2867	2880	2943	3030

Case #6 Advanced EE & Base DG (Navajo 2015, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	156	167	178	189	199	210	219	229	238	247	256	264	273
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	25	35	141	223	286	347	393	440	539	547	600	629	658	662	666	668	682	690	698	706	714
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	150	0	0	0	0	0	0	0	0	0	0	0	0	75	0	0	0	0	25	75
Total Replacement	247	232	218	342	760	863	974	1084	1245	1314	1428	1518	1607	1671	1760	2847	2870	2887	2904	2945	3011

Case #7 Base EE & High DG (Navajo 2015, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	155	166	175	184	192	199	206	212	217	222	227	231	236
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	25	35	143	225	295	362	413	518	569	580	638	670	678	686	694	701	720	734	742	755	769
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	150	0	0	0	0	0	0	0	0	0	0	0	25	100	0	0	0	0	0	0
Total Replacement	247	232	221	344	769	878	995	1162	1274	1346	1463	1554	1620	1710	1799	2863	2888	2906	2918	2936	2954

Case #8 Advanced EE & High DG (Navajo 2015, IPP 2027)

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy Efficiency	17	37	58	79	99	116	131	144	156	167	178	189	199	210	219	229	238	247	256	264	273
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500	500	500	500
New Renewable	25	35	143	225	295	362	413	518	569	580	638	670	678	686	694	701	709	717	724	732	740
Navajo Replacement CC	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1150	1150	1150	1150	1150	1150
Q3 Term Purchase	200	150	0	0	0	0	0	0	0	0	0	0	0	25	75	0	0	0	0	0	25
Total Replacement	247	232	221	344	769	878	995	1162	1274	1347	1466	1559	1628	1721	1788	2880	2897	2914	2930	2947	2988

N.3.2 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. 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:

*Capacity Value ($/MWh) = (Dependable Capacity Factor) x (Baseline Capacity Value) / (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:

Energy Value ($/MWh) =
Σ [(Energy Value in Time Period) x (Energy Output in Time Period)] / 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. This base portfolio was used in all 4 coal cases considered in this IRP and the Base EE, Base DG case which is identical to Coal Case #2. Figures N-2 and N-3 show the renewable capacity and energy production schedules for the base portfolio. To accommodate advanced levels of EE and higher levels of Solar DG for the 3 additional EE/DG Cases evaluated (6 thru 8), certain renewable projects were delayed or eliminated to accommodate the advanced levels of EE and higher levels of DG to maintain consistency with the procurement targets established by SB 2 (1X).

RPS Capacity (MW)

Base Case 2012 IRP (MW)																							
Station Group	Item	Technology	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Existing Wind	Wind_Linden	Wind	50	47	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
	Wind_PebbleSprings	Wind	69	69	69	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	82	82	82										
	Wind_Willow Crk	Wind	72	72	72	72	72																
	Wind_WindyPoint	Wind	262	244	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242
	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	100	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Existing Small Hydro	AQ & OV& OG	Hydro	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
	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	9	9	9									
	Castaic3&5 Upgrade	Hydro	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Existing Solar	Solar_DWP_Basin_E	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Solar_C-N-M	Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Existing Biogas	Bio_Bradley	Bio	6	6	6	6																	
	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	4	4																			
	Atmos & Shell Gas Credit	Bio	71	70	39																		
	Hyperion Digester Gas	Bio	15	15	15																		
	Existing Subtotal		**1,304**	**1,281**	**1,241**	**1,184**	**1,178**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,024**	**1,015**	**1,015**	**1,015**	**947**	**947**	**947**	**947**	**947**	**947**
New Geo	Geo PPA 2016 O	New_Geo					15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Geo PPA 2017 T	New_Geo									53	53	53	53	53	53	53	53	53	53	53	53	53
	Imperial County Joint Geothermal Project -1,2,3,4	New_Geo						25	50	75	100	100	100	100	100	100	100	100	100	100	100	100	100
	Generic_Geo	New_Geo											50	75	100	100	100	100	100	100	100	100	100
	Subtotal		**0**	**0**	**0**	**0**	**15**	**40**	**65**	**90**	**168**	**168**	**218**	**243**	**268**	**268**	**268**	**268**	**268**	**268**	**268**	**268**	**268**
New Solar	Solar_DWP_Ow ens	New_Solar						50	100	150	200	199	198	197	196	195	194	193	192	191	190	189	188
	Solar_DWP_Basin_Planned	New_Solar	2	5	8	11	20	36	53	70	87	100	99	99	98	98	97	97	96	96	95	95	94
	Adelanto Solar	New_Solar	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Solar_PineTree	New_Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Solar_FIT	New_Solar	2	10	20	40	75	83	90	98	105	113	120	128	135	143	150	150	150	150	150	150	150
	Solar_C-N-M (SB1)	New_Solar	28	55	82	104	124	129	134	139	145	152	159	167	175	184	193	202	212	222	232	242	252
	Solar PPA 2015 B	New_Solar				150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Solar PPA 2015 R	New_Solar				53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	Solar PPA 2014 K	New_Solar			200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	Solar PPA 2015 CM	New_Solar			150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Solar PPA 2015 FM	New_Solar					155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155
	Subtotal		**50**	**89**	**478**	**726**	**945**	**1,023**	**1,103**	**1,182**	**1,263**	**1,289**	**1,302**	**1,316**	**1,330**	**1,346**	**1,361**	**1,368**	**1,377**	**1,385**	**1,394**	**1,402**	**1,411**
New Wind	Wind_PineCYN	New_Wind																54	54	54	54	54	54
	Wind PPA 2012 M	New_Wind																					
	Subtotal		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**54**	**54**	**54**	**54**	**54**	**54**
New Biogas	Hyperion Gas Extension	New_Bio				15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Shell Renew albe Biomethane	New_Bio	41	59	59	59	59	59	59	59	59	46											
New Small Hydro	WSHydro	New_Hydro					4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Castaic U1 update	New_Hydro		15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Aqueduct PP Improvement	New_Hydro					4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Generic_RPS	Generic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	38	57	76	95	114
	GreenPurchase	Purchase																					
	Total RPS		**1,395**	**1,444**	**1,794**	**2,000**	**2,235**	**2,267**	**2,371**	**2,476**	**2,634**	**2,647**	**2,664**	**2,621**	**2,652**	**2,667**	**2,682**	**2,674**	**2,721**	**2,749**	**2,776**	**2,804**	**2,831**

Figure N-2. Renewable resource capacity in MW for all Coal cases and the Base EE, Base DG case.

RPS Energy (GWh)

	Base Case 2012 IRP (GWh)																					
Station Group	**Item**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Existing Wind	Wind_Linden	140	136	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Wind_PebbleSprings	169	169	193	193	193	193	193	193	193	193	193	193	193	193	193						
	Wind_PineTree	322	326	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
	Wind_PPMWyoming	207	197	171	171	171	171	171	171	171	171	86										
	Wind_Willow Crk	185	185	197	197	197																
	Wind_WindyPoint	693	645	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641
	Wind_Milford1	412	404	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434
	Wind_Milford2	209	208	212	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206
Existing Small Hydro	AQ & OV& OG	300	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
	North Hollyw ood	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Sepulveda	30	34	33	33	33	33	33	33	33	33	33	33									
	Castaic3&5 Upgrade	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Existing Solar	Solar_DWP_Basin_E	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Solar_C-N-M	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Existing Biogas	Bio_Bradley	43	44	44	44																	
	Bio_Lopez	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Bio_Toyon	6	7																			
	Atmos & Shell Gas Credit	626	610	343																		
	Hyperion Digester Gas	130	131	131																		
	Existing Subtotal	**3,559**	**3,751**	**3,568**	**3,088**	**3,044**	**2,847**	**2,847**	**2,847**	**2,847**	**2,847**	**2,761**	**2,676**	**2,643**	**2,643**	**2,643**	**2,451**	**2,451**	**2,451**	**2,451**	**2,451**	**2,451**
New Geo	Geo PPA 2016 O					42	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
	Geo PPA 2017 T									330	441	441	441	441	441	441	441	441	441	441	441	441
	Imperial County Joint Geothermal Project -1,2,3,4						100	333	533	800	800	800	800	800	800	800	800	800	800	800	800	800
	Generic_Geo											400	600	800	800	800	800	800	800	800	800	800
	Subtotal					**42**	**225**	**458**	**658**	**1,255**	**1,366**	**1,766**	**1,966**	**2,166**	**2,166**	**2,166**	**2,166**	**2,166**	**2,166**	**2,166**	**2,166**	**2,166**
New Solar	Solar_DWP_Ow ens						110	220	330	440	438	436	433	431	429	427	425	423	421	418	414	412
	Solar_DWP_Basin_Planned	1.6	6	11	17	27	50	79	109	139	165	176	175	174	174	173	172	171	170	169	168	167
	Adelanto Solar	11	20	20	20	20	20	20	19	19	19	19	19	19	19	19	19	19	18	18	18	18
	Solar_PineTree	4	17	17	17	17	17	17	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	Solar_FIT	1	10	26	52	100	137	150	163	175	187	200	212	224	236	248	253	252	251	249	248	246
	Solar_C-N-M (SB1)	23	69	113	154	188	208	216	225	234	245	256	268	282	296	311	325	341	358	374	391	407
	Solar PPA 2015 B				170	337	335	332	329	327	324	321	319	316	314	311	309	306	304	301	299	297
	Solar PPA 2015 R				73	145	144	143	141	140	139	138	137	136	135	134	133	132	130	129	128	127
	Solar PPA 2014 K			518	561	556	552	547	543	539	534	530	526	522	517	513	509	505	501	497	493	489
	Solar PPA 2015 CM			198	263	327	325	322	320	317	314	312	309	307	305	302	300	297	295	293	290	288
	Solar PPA 2015 FM					296	441	438	435	432	429	426	423	420	417	414	411	408	405	402	400	397
	Subtotal	**41**	**122**	**904**	**1,326**	**2,014**	**2,338**	**2,485**	**2,630**	**2,777**	**2,811**	**2,830**	**2,837**	**2,846**	**2,856**	**2,867**	**2,872**	**2,870**	**2,869**	**2,868**	**2,866**	**2,864**
New Wind	Wind_PineCYN																175	175	175	175	175	175
	Wind PPA 2012 M																					
	Subtotal PPA's																					
	Subtotal																**175**	**175**	**175**	**175**	**175**	**175**
New Bio Gas	Hyperion Gas Extension				131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Shell Renew albe Biomethane	361	520	520	520	520	520	520	520	520	400											
New Small Hydro	WSHydro					11	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	Castaic U1 update		2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Aqueduct PP Improvement					15	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	Generic_RPS																	100	150	200	250	300
	GreenPurchase	718	458	73	179		1	84	218		22	145	53				32	3				26
	Total RPS	**4,679**	**4,853**	**5,070**	**5,249**	**5,782**	**6,119**	**6,581**	**7,060**	**7,587**	**7,634**	**7,690**	**7,719**	**7,843**	**7,853**	**7,864**	**7,883**	**7,952**	**7,998**	**8,047**	**8,095**	**8,170**

Figure N-3. Renewable energy production in GWh for all Coal cases and Base EE, Base DG case.

N.4 Avoided Costs and Net Revenue Losses – Energy Efficiency and Distributed Generation Case Comparisons (Cases 5 thru 8)

Due to the load reduction nature of energy efficiency and solar customer-net-metered (CNM) programs, generally referred to as "demand side programs" or "customer opportunity programs", customer sales are reduced leaving the utility with a potential loss of revenue if the cost savings experienced by the utility from these programs does not fully offset the lost sales revenue. The cost savings experienced by the utility from demand side programs are typically referred to as "avoided costs". The difference between the lost sales revenue and the avoided costs is referred to as the "net revenue loss". Modeling of net revenue loss addresses ratepayer concerns that the impact to customer bills and rates due to changes in utility revenues and operating costs be fully considered when comparing the cost of these demand side programs to other resource alternatives. Avoided costs described herein include only those costs that can be avoided by LADWP thru implementing demand side programs and does not consider avoided costs experienced by the customer participating in these programs nor does it consider the wider societal cost benefits of these programs.

Avoided costs are sometimes difficult to quantify since it is not always fully understood what the effect these demand side programs will have on reducing utility costs. There exists a wide range of opinions on the types of avoided costs that should be considered and how those costs are calculated. The larger avoided cost savings components of fuel, emissions, capacity savings, and reduced transfers of surplus revenue (city transfers), are fairly well understood and estimating these cost savings can be effectively performed using production cost modeling software. The production cost model program PROSYM was employed in this analysis and is further described in Section M.2. Less well understood are the system wide savings associated with deferred transmission and distribution upgrades. Distribution savings in the form of deferred upgrades to the distribution system will require further study and were not included in this analysis. Cost savings associated with deferred transmission upgrades were included and are based on upgrades that have recently occurred. Emissions cost savings from CARB's Cap and Trade program were included in this analysis where costs exceeded the emissions allocation to LADWP. Additional work to identify and further quantify avoided costs will be addressed in future IRP's.

Calculations of avoided costs and net revenue losses can vary among utilities because each utility has different cost structures and rate recovery mechanisms. Current methodologies used to calculate avoided costs for an investor-owned utility such as the Ratepayer Impact Measure (RIM) Test may not necessarily apply for vertically-integrated utilities such as LADWP that have direct control over generation, transmission, and distribution resources. It is still unclear whether this same test can be used to evaluate avoided costs for LADWP. Future IRP's will examine the appropriateness of this model for use in evaluating future avoided costs.

Demand side programs such as energy efficiency and solar CNM programs primarily reduce the fuel and variable operating and maintenance costs of marginal gas-fired generation. These programs can also offset lower cost resources such as coal or hydro depending on the size of the demand side resource and the hours over which the energy savings occur. Besides fuel savings, the utility will also experience other fixed and variable cost savings associated with generating, transmitting, and distributing electricity, and lowered compliance obligations of renewables which are typically based on a percentage of overall customer sales, and city transfers which are based on a percentage of the Power System's gross revenues. As fuel prices rise, these avoided costs will increase so loss of net revenue experienced by the utility will be reduced. Because fuel market price forecasts can vary considerably from year to year, it is important that avoided costs be reexamined periodically.

N.4.1 Analysis of Avoided Costs and Net Revenue Loss - Base EE and Advanced EE

While implementation of the EE program dramatically reduces customer sales, it is important to capture the effects of this loss in revenue. A portion of this loss in revenue can be recovered from demand charges from commercial customers which is a significant portion of a commercial or industrial customer's bill. Residential minimum bill charges were not considered since EE programs would typically offset electrical usage above minimum thresholds. There are also avoided costs of supplying additional generation resources to meet load growth because the EE program reduces system load and to a smaller extent, peak demand as well. Net Revenue Loss is the remaining loss after deducting fixed demand charges from commercial and industrial customers and savings associated with avoided costs. Table N-2 lists all the avoided costs associated with EE programs considered including a brief explanation of each component of the total avoided cost.

Table N-2: EE Program Avoided Costs Considered

List of Avoided Cost	Reasons
Avoided Energy- Fuel, Renewable	**Fuel:** EE reduces customer load, which results in less generation primarily from gas units so there will be less fuel and variable O&M cost. **Renewable:** EE reduces customer sales, and at the same time RPS % is calculated based on the customer sale. Lower customer sales results in less renewable energy procurement to meet the mandated RPS percentage.
Avoided Emissions	Lower generation levels will result in lower greenhouse gas emissions. Per AB32, utilities will be charged for the CO2 emission amount beyond their allocation of allowances.
Avoided City Transfer	EE reduces customer sales which reduces total revenue thereby lowering the transfer to the City which is currently 8 percent of total revenue.
Avoided Transmission & Distribution	With reduced peak load from EE, less MW's will be needed during peak hours so some transmission and distribution upgrades can be deferred.
Avoided Capacity	With reduced peak demand due to EE, fewer peaker units will be built to meet system reserve requirements resulting in deferred capital spending.
Avoided O&M	With lower peak demand and fewer peaker units being built, there will be a savings of fixed O&M costs.
Avoided Losses	EE reduces customer sales thereby lowering the amount of energy we will need to generate to cover distribution and transmission losses.

Figure N-4 shows the avoided costs, fixed billing charges recovered and net revenue loss for the Base EE case. The gross revenue loss shown is $12,227 Million from FY 2012 to FY 2032 and is determined by using the forecasted average customer electricity rate in $/kWh multiplied by the EE energy savings in kWh. The total avoided cost is $6,187 Million over the next 20 years, and the recovered fixed billing charges is $2,220 Million. The small dotted area at the top of Figure N-4 shows the final net revenue loss due to the implementation of Base EE program. An observation from our study was that the net revenue loss was found to be more significant as EE GWh achievement increases.

As mentioned in the previous section, EE program reduces customer sales which means less renewable energy will be needed to meet RPS targets. With the Base EE case, the forecasted customer sales will stay below FY 2010-11 levels over the next 10 years with minimal growth thereafter. This lowered growth rate expected with the Base EE reduces the need to build ~ 800 GWh of renewable energy beginning in 2018 and will save approximately $110 Million assuming the renewable energy that is offset comes from a combination of geothermal and wind. These savings also apply to years beyond 2018 as well. This explains the large increase in avoided energy starting in 2018 (avoided fuel and renewable costs shown in the blue area in Figure N-4).

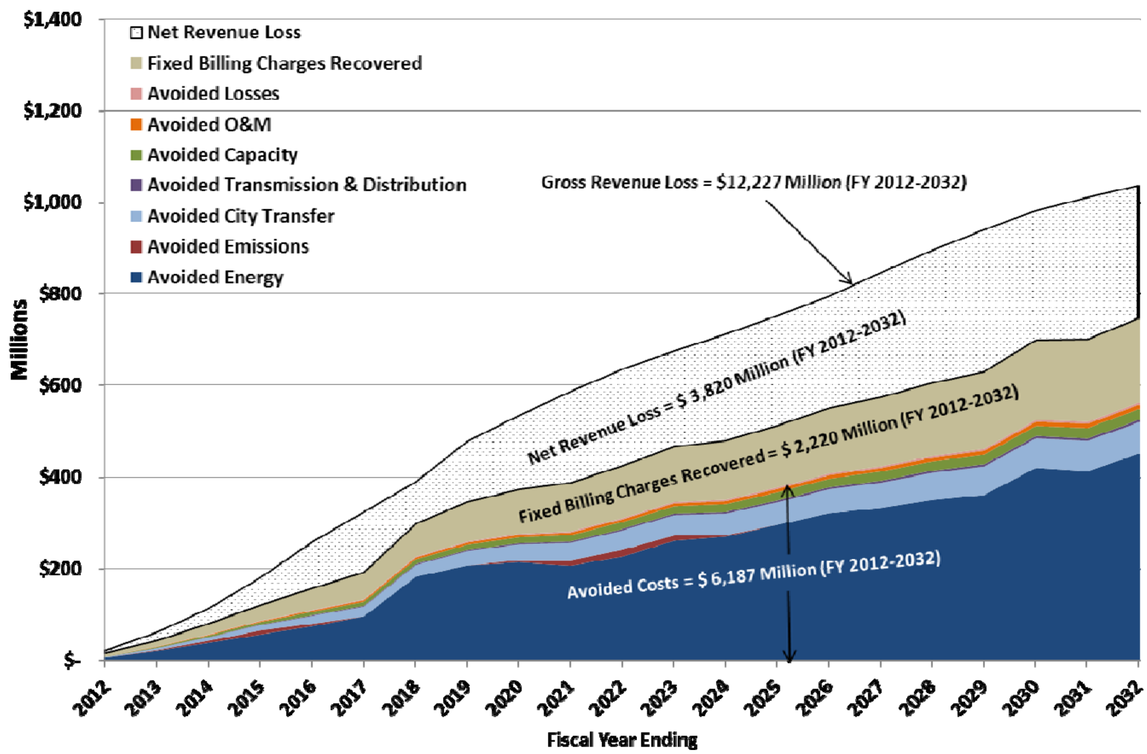


Figure N-4: Base EE Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss

The associated rates breakdown associated with Figure N-4 is shown in Figure N-5.

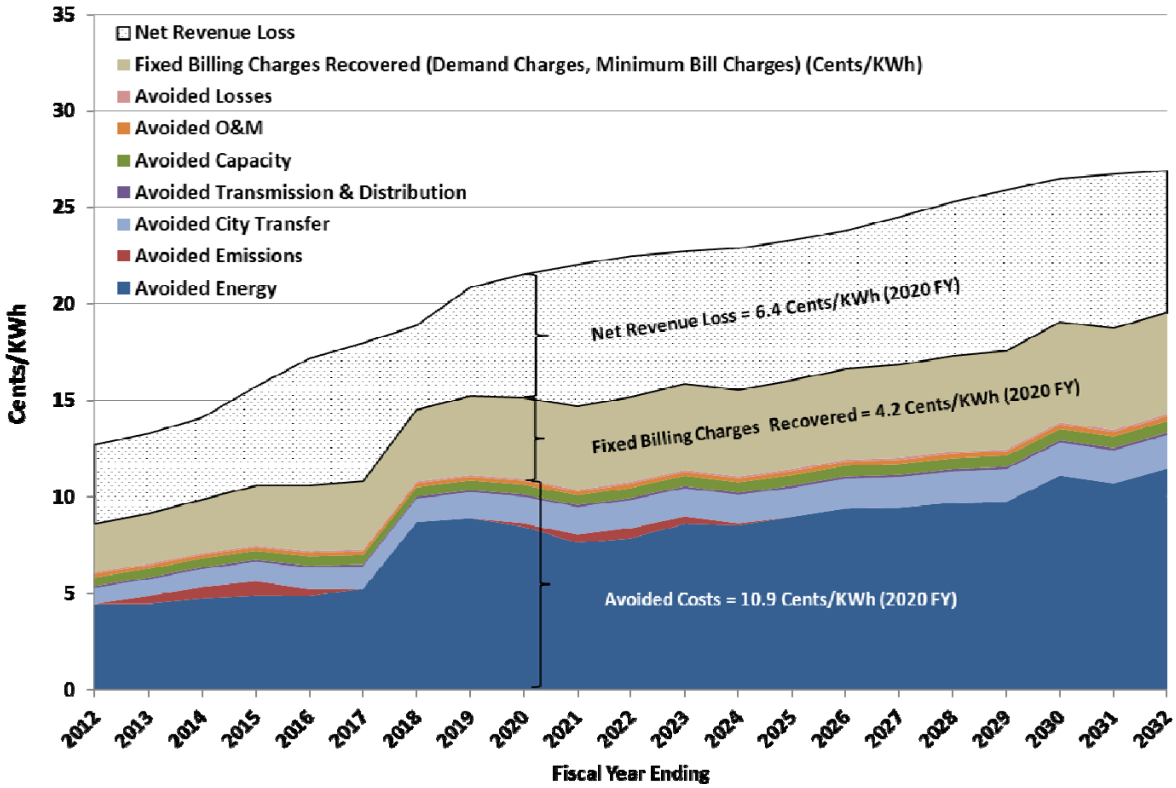


Figure N-5: Base EE Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss (in Cents/kWh)

For the Advanced EE case discussed in previous section, similar figures are shown below. The total Net Revenue Loss for this Advanced EE case is $4.06 Billion, which is $240 Million higher than the Base EE case because of the higher level of energy savings (500 GWh) in the last decade. Similar to the Base EE case, the rapid increase of Avoided Energy cost in 2018 as shown in Figure N-6 is also due to the considerable savings in procuring additional renewables resulting from the lowered sales.

The associated rates breakdown associated with Figure N-6 is shown in Figure N-7.

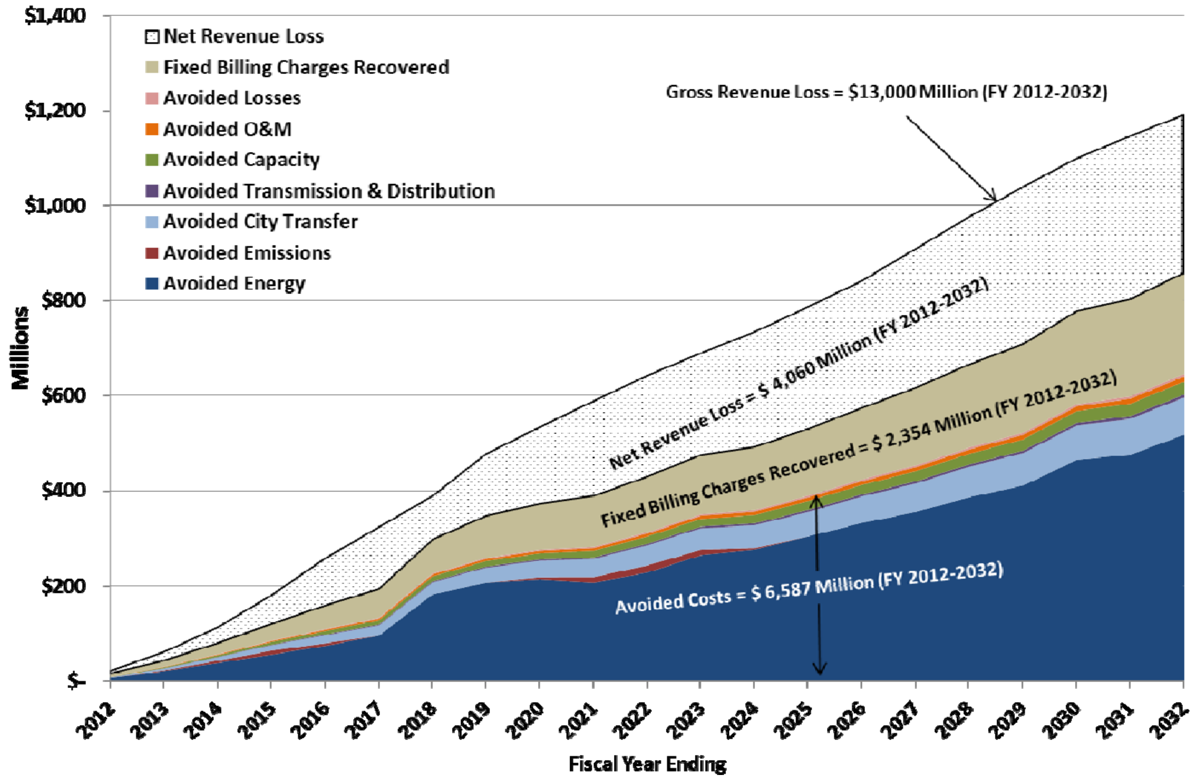


Figure N-6: Advanced EE Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss

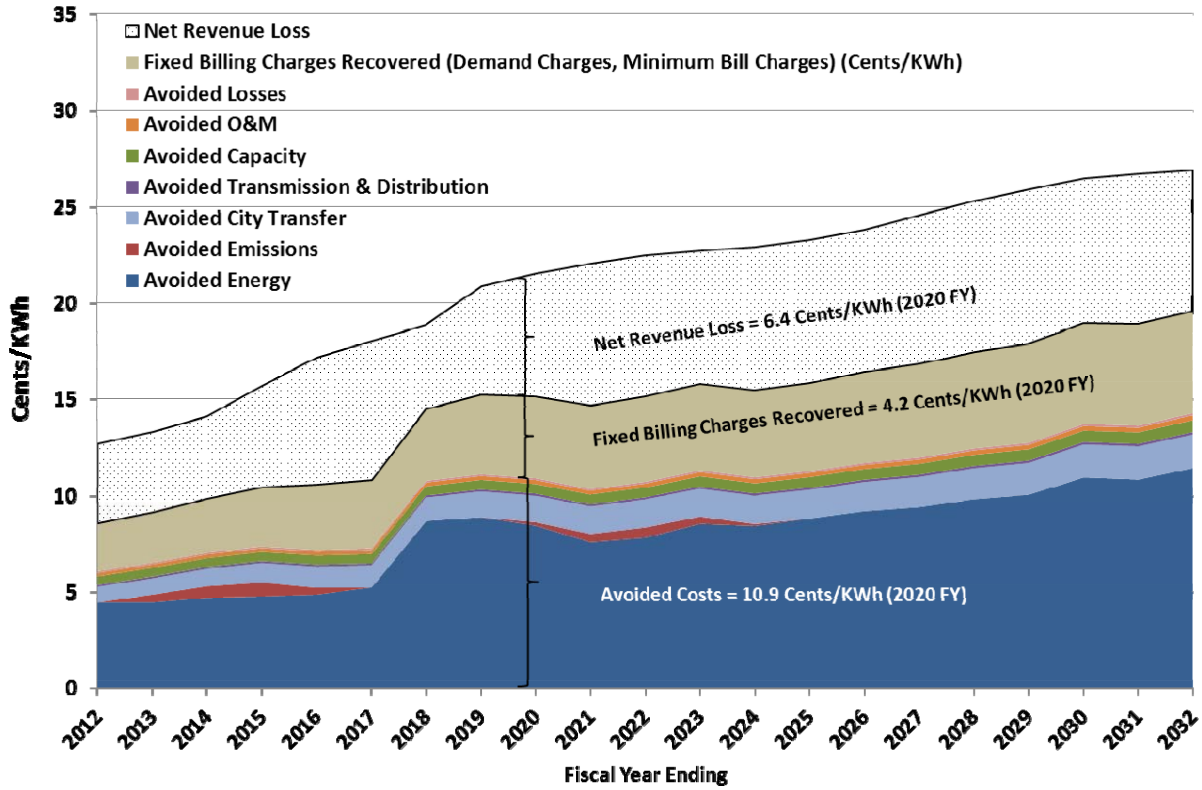


Figure N-7: Advanced EE Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss (in Cents/kWh)

N.4.2 Analysis of Avoided Costs and Net Revenue Loss – Base and High Solar CNM

Two Solar DG Cases were evaluated which comprise several internal programs including Customer Net Metered (CNM) Solar (a.k.a. Solar Incentive Program), Feed In Tariff (FIT), and Utility Built Solar on City Properties. The analysis presented below is intended to represent the avoided costs and net revenue loss for the Solar CNM program only. However, in the final comparison of distributed generation and energy efficiency cases discussed in Section 4.3.3.1, many of the same avoided costs were considered with the exception that avoided renewable, avoided capacity, and avoided O&M only apply to Solar CNM due to the unique feature that demand side resources possess which is reducing peak load and reduced customer sales.

Similar to the EE programs described previously, revenue loss offset by the avoided costs described in Table N-3 and fixed billing charges recovered from minimum bill charges for residential customers must be considered in the evaluation of costs for the Solar CNM program. A smaller portion of this loss in revenue can be offset with fixed bill charges as compared to EE programs primarily because demand charges for commercial customers cannot easily be reduced using solar resources that require the utility to fully back up the customer when solar production plummets during cloudy days.

Table N-3: Solar CNM Program Avoided Costs

List of Avoided Cost	Reasons
Avoided Fuel	Solar DG (Customer-Net-Metered solar) reduces customer load, which results in less generation primarily from gas units. A solar generation profile is similar to the system load profile and will be displace more expensive peaker generation resulting in less fuel and variable O&M cost.
Avoided Renewable	Solar-CNM program reduces customer sales which reduces renewable energy expenditures to meet the mandated RPS %.
Avoided Emissions	Lower generation levels will result in lower greenhouse gas emissions. Per AB32, utilities will be charged for the CO2 emission amount beyond their allocation of allowances.
Avoided City Transfer	Solar-CNM reduces customer sales which reduces total revenue thereby lowering the transfer to the City which is currently 8 percent of total revenue.
Avoided Transmission & Distribution	With reduced peak load from EE, less MW's will be needed during peak hours so some transmission and distribution upgrades can be deferred.
Avoided Capacity	With reduced peak demand due to Solar DG, fewer peaker units will be built to meet system reserve requirements resulting in deferred capital spending.
Avoided O&M	With lower peak demand and fewer peaker units being built, there will be a savings of fixed O&M costs.
Avoided Losses	EE reduces customer sales thereby lowering the amount of energy we will need to generate to cover distribution and transmission losses.

Among Solar DG programs, the Solar CNM program impacts system costs in a similar manner as energy efficiency, so the same methodology was employed. Figure N-8 shows avoided costs, recovered fixed billing charges, and net revenue loss for the Base Solar CNM case. Over the next 20 years for the Base Solar CNM, the gross revenue loss will be $1,484 Million, the total avoided cost is $878 Million, and the fixed billing charges are $257 Million. The small dotted area at the top of Figure N-8 shows the final net revenue loss as $349 Million due to the implementation of Base Solar CNM program. Like EE programs, the net revenue loss of Base Solar CNM increases as Solar CNM generation increases, however, the avoided cost is more evenly distributed throughout time since Solar CNM is a smaller program and reductions in RPS generation are less significant. The rate breakdown associated with Figure N-8 for the Base Solar CNM case is shown in Figure N-9 below.

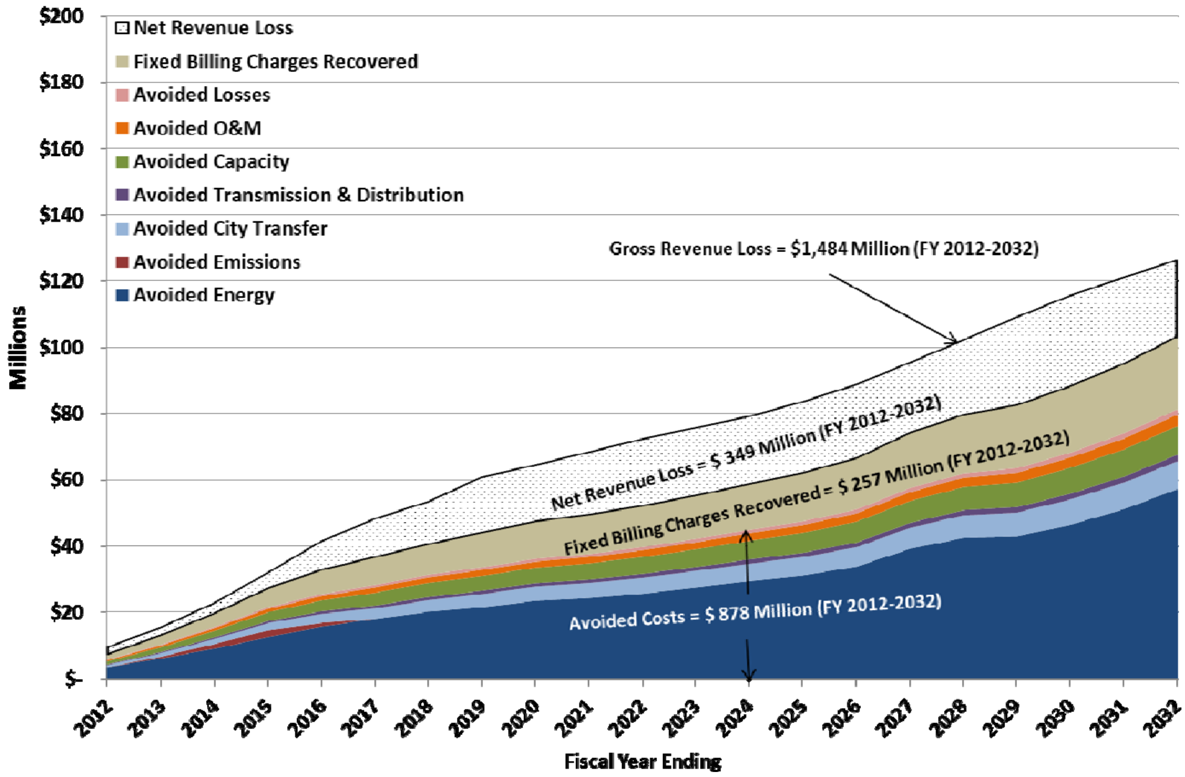


Figure N-8: Base Solar CNM Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss

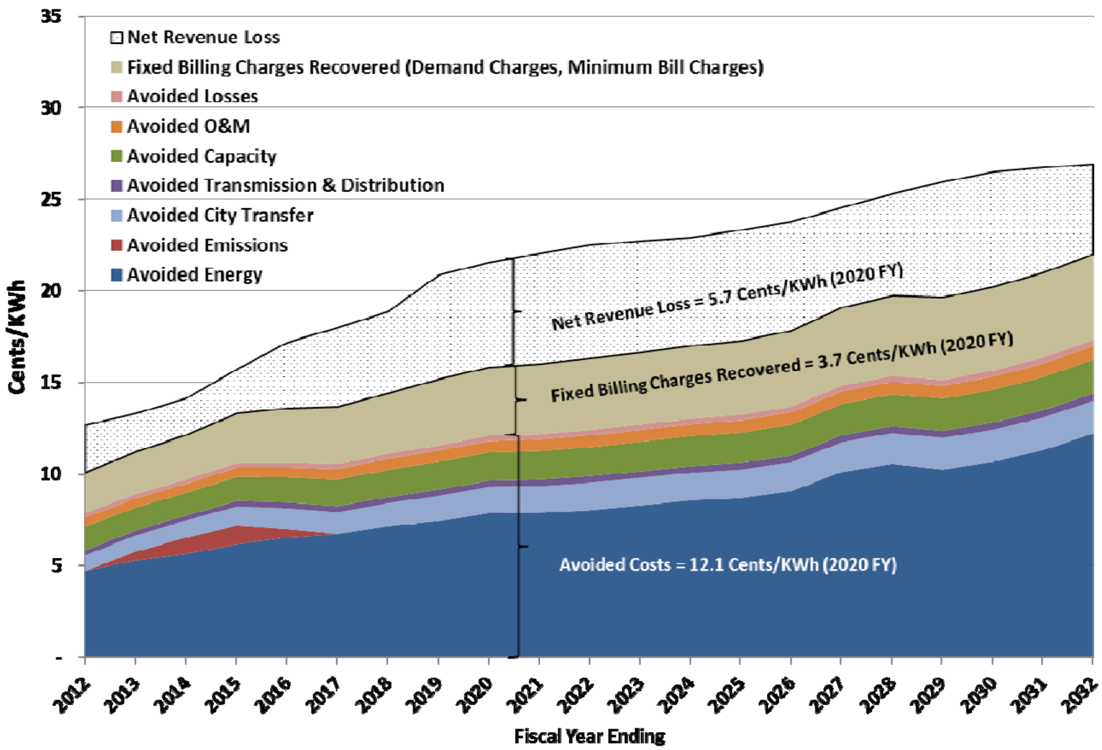


Figure N-9: Base Solar CNM Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss (in Cents/kWh)

For High Solar CNM, similar figures are shown below in Figures N-10 and N-11. The total net revenue loss for the High Solar CNM is $566 Million, which is $217 Million more than the Base Solar CNM. The Solar CNM program results in net revenue losses so more Solar CNM generation with result in a greater loss of revenue.

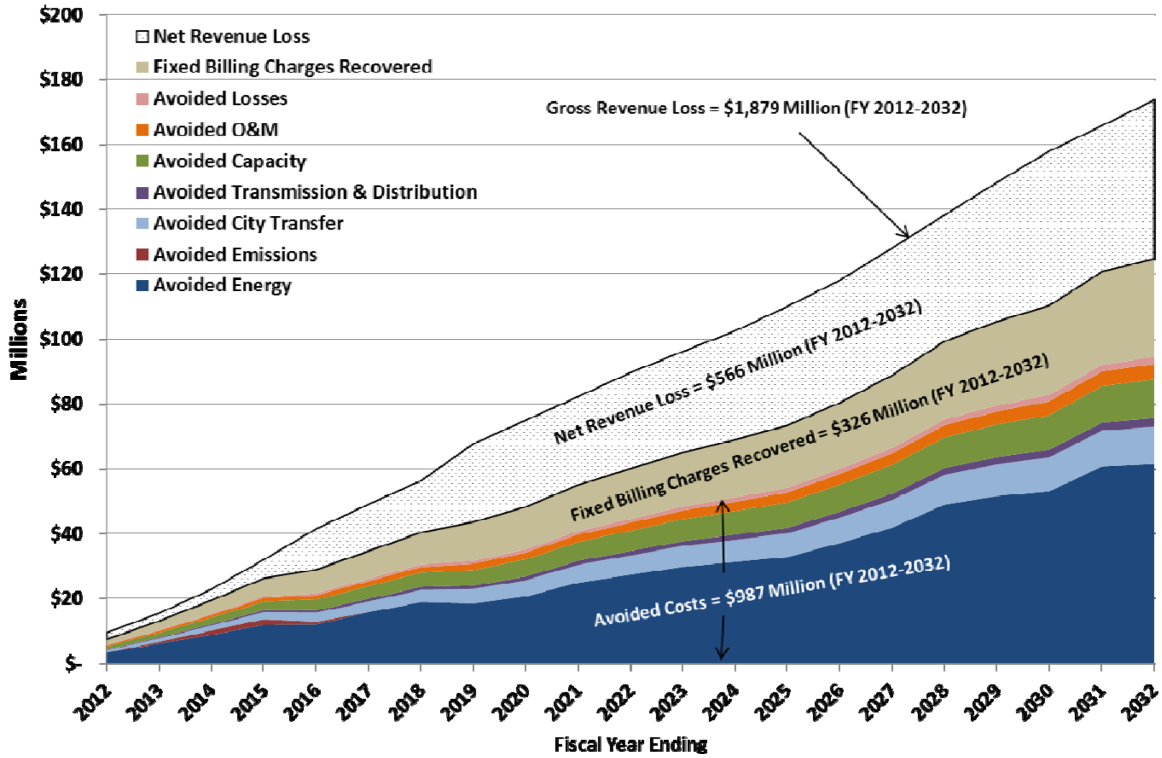


Figure N-10: High Solar CNM Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss

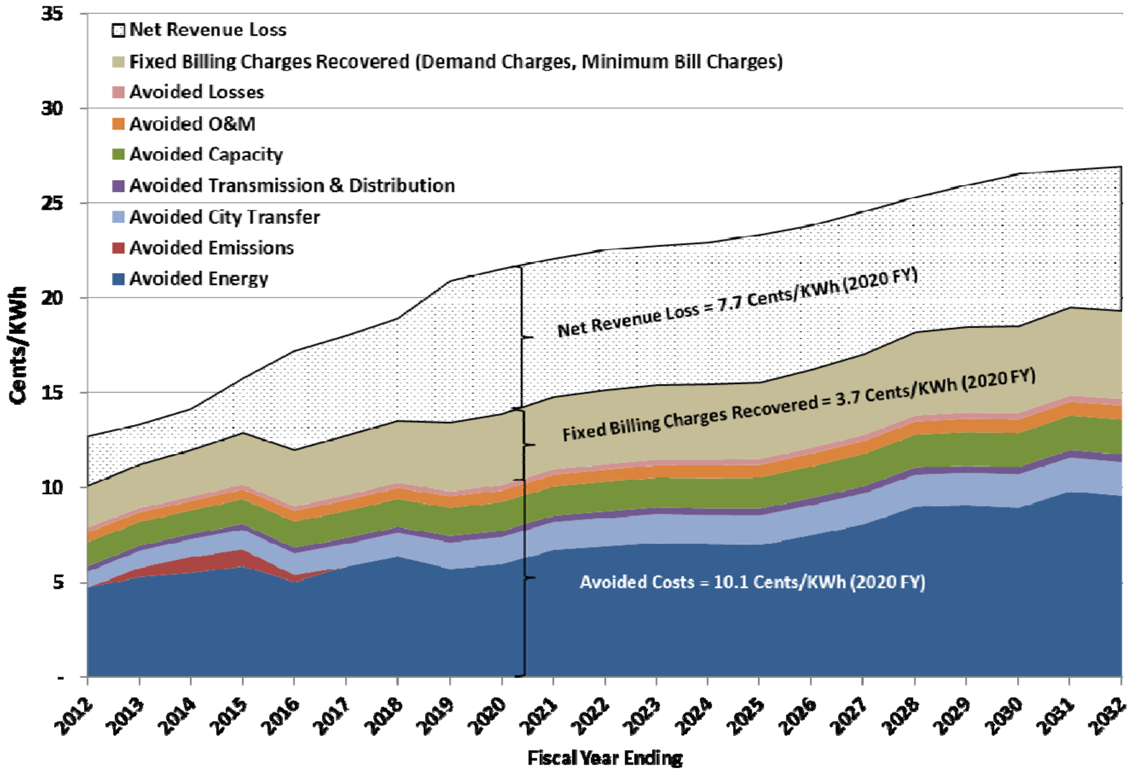


Figure N-11: High Solar CNM Program annual Avoided Cost savings, Fixed Billing Charges Recovered and Net Revenue Loss (in Cents/kWh)

N.7 Model Input and Assumptions

The following pages present the major input parameters and assumptions that were incorporated into the production cost model for this 2012 IRP.

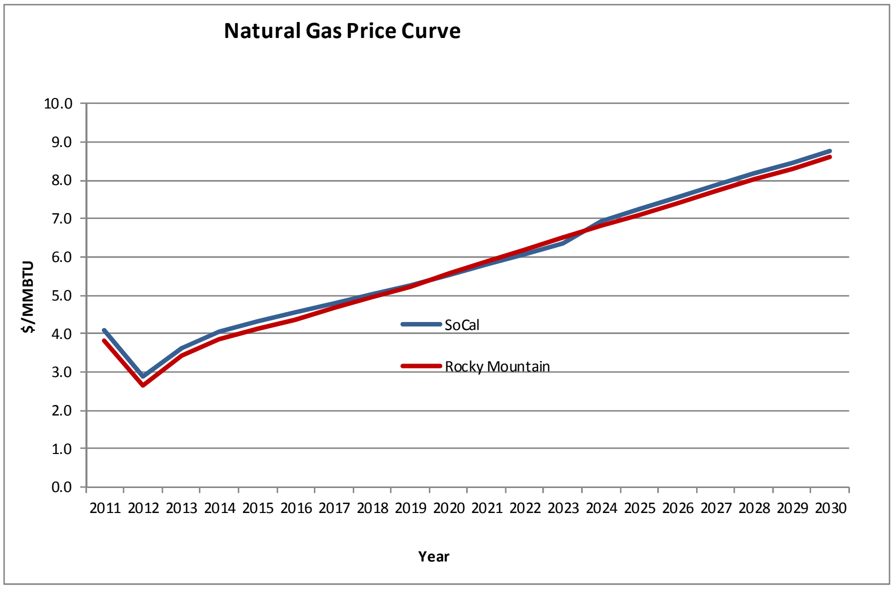
Load Forecast

	2012 Forecast						2012 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
2012	26,409	259	90	23,436	2.67%	1.55%	26,803	42	230	23,482	2.75%	1.8%
2013	26,335	464	127	23,280	0.21%	-0.67%	27,002	77	509	23,344	0.59%	-0.6%
2014	26,311	693	151	23,359	1.30%	0.34%	27,264	102	822	23,237	0.87%	-0.5%
2015	26,312	936	171	23,276	0.67%	-0.36%	27,562	124	1159	23,142	1.00%	-0.4%
2016	26,274	1,196	191	23,237	0.91%	-0.17%	27,841	148	1509	23,015	0.92%	-0.5%
2017	26,314	1,425	206	23,266	1.06%	0.12%	28,156	165	1858	22,928	1.07%	-0.4%
2018	26,549	1,451	214	23,526	1.16%	1.12%	28,430	174	2189	22,830	0.94%	-0.4%
2019	26,910	1,451	223	23,823	1.19%	1.26%	28,802	185	2491	22,847	1.27%	0.1%
2020	27,283	1,451	233	24,128	1.21%	1.28%	29,186	196	2763	22,904	1.30%	0.3%
2021	27,665	1,451	244	24,547	1.64%	1.74%	29,580	208	2962	23,041	1.31%	0.6%
2022	28,039	1,451	256	24,879	1.28%	1.35%	29,967	221	3100	23,232	1.27%	0.8%
2023	28,368	1,451	268	25,111	0.88%	0.93%	30,311	235	3227	23,396	1.10%	0.7%
2024	28,638	1,451	282	25,354	0.91%	0.97%	30,596	251	3342	23,517	0.89%	0.5%
2025	28,875	1,451	296	25,592	0.89%	0.94%	30,848	267	3448	23,619	0.77%	0.4%
2026	29,147	1,451	311	25,835	0.90%	0.95%	31,137	283	3544	23,761	0.88%	0.6%
2027	29,455	1,451	326	26,074	0.88%	0.93%	31,462	300	3632	23,944	0.99%	0.8%
2028	29,727	1,451	341	26,318	0.89%	0.94%	31,752	318	3712	24,102	0.86%	0.7%
2029	29,965	1,451	357	26,556	0.86%	0.90%	32,008	337	3786	24,236	0.75%	0.6%
2030	30,243	1,451	372	26,798	0.86%	0.91%	32,302	356	3857	24,408	0.86%	0.7%

Notes:
1. Net Energy for Load model run (E) = Net Energy for Load (A) + Energy Efficiency (B)/0.885 + Solar Rooftop (C)/0.885
2. Energy Efficiency in 2012 IRP differs from Energy Efficiency in Forecast. IRP treats EE as a variable resource.
3. IRP Calculated Sales (H) = [E – (F/.885) – (G/.885) + 37] / 0.885

Natura Gas Prices

Gas Price used in IRP 2012		
Year	SoCal	Rocky Mountain
2011	4.1	3.8
2012	2.9	2.7
2013	3.6	3.4
2014	4.0	3.8
2015	4.3	4.1
2016	4.6	4.4
2017	4.8	4.7
2018	5.0	5.0
2019	5.3	5.2
2020	5.5	5.6
2021	5.8	5.9
2022	6.1	6.2
2023	6.3	6.5
2024	6.9	6.8
2025	7.3	7.1
2026	7.6	7.4
2027	7.9	7.7
2028	8.2	8.0
2029	8.5	8.3
2030	8.7	8.6



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

LADWP Generator Ratings and Capabilities of Power Sources (as of April 2012)[1]

NAME OF PLANT	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE[2] (kVA)	GENERATOR NAMEPLATE[2] (kW)	NET MAXIMUM UNIT CAPABILITY[3] (kW)	NET Maximum PLANT CAPABILITY[4] (kW)	NET DEPENDABLE PLANT CAPABILITY[5] (kW)
	1A	12/10/1983	25,000	25,000	27,000		
San Francisquito	3	4/16/1917	11,719	9,375	10,000		
Power Plant 1	4	5/21/1923	12,500	10,000	12,000		
(PP1)	5A	4/9/1987	25,000	25,000	27,000	46,500	13,000
San Francisquito	1	7/6/1919	17,500	14,000	0		
Power Plant 2	2	8/7/1919	17,500	14,000	14,000		
(PP2)	3	9/26/1932	17,500	14,000	18,000	18,000	5,700
San Fernando	1	10/22/1922	3,500	2,800	3,200		
Power Plant (PP3)	2	10/22/1922	3,500	2,800	2,900	6,000	2,100
Foothill Power Plant (PP4)	1	10/6/1971	11,000	11,000	9,900	9,900	2,900
Franklin Power Plant (PP5)	1	6/3/1921	2,500	2,000	2,000	2,000	400
Sawtelle Power Plant (PP6)	1	6/5/1986	711	640	650	650	130
Aqueduct Hydro Subtotal					**126,650**	**83,050**	**24,230**
Haiwee Power Plant	1	7/18/1927	3,500	2,800	3,600		
	2	7/18/1927	3,500	2,800	3,600	4,200	0
Cottonwood	1	11/13/1908	937	750	1,200		
Power Plant	2	10/13/1909	937	750	1,200	1,900	400
Division Creek P. P.	1	3/22/1909	750	600	680	680	400
Big Pine Power Plant	1	7/29/1925	4,000	3,200	3,050	3,050	400
Pleasant Valley P. P.	1	2/5/1958	4,000	3,200	2,700	2,700	0
Owens Valley Hydro Subtotal					**16,030**	**12,530**	**1,200**
Upper Gorge P. P.	1	6/15/1953	37,500	37,500	37,500	37,500	36,500
Middle Gorge P. P.	1	5/11/1952	37,500	37,500	37,500	37,500	36,500
Control Gorge P. P.	1	4/1/1952	37,500	37,500	37,500	37,500	36,500
Owens Gorge Hydro Subtotal					**112,500**	**112,500**	**109,500**
	1	7/11/1973	250,000	212,500	250,000		
	2	7/9/1974	287,500	265,000	265,000		
	3	7/13/1976	287,500	265,000	270,000		
Castaic Power Plant	4	6/16/1977	287,500	265,000	265,000		
	5	12/16/1977	287,500	265,000	265,000		
	6	8/11/1978	287,500	265,000	265,000		
	7	1/27/1972	70,000	56,000	55,000	1,247,000	1,175,000
Castaic Hydro Subtotal					**1,635,000**	**1,247,000**	**1,175,000**
Hoover Power Plant (Capacity and energy purchase from WAPA through Sep					**491,000**	**491,000**	**468,000**
TOTAL HYDRO (Based on average hydro conditions)					**2,381,180**	**1,946,080**	**1,777,930**
	1	1/31/1995	100,400	85,340	82,000	82,000	76,500
	2	1/31/1995	100,400	85,340	82,000	82,000	76,500
	5	1/31/1995	93,750	75,000	65,000	65,000	62,000
Harbor Generating	10	1/4/2002	71,176	60,500	47,400	47,400	47,400
Station	11	1/4/2002	71,176	60,500	47,400	47,400	47,400
	12	1/4/2002	71,176	60,500	47,400	47,400	47,400
	13	1/4/2002	71,176	60,500	47,400	47,400	47,400
	14	1/4/2002	71,176	60,500	47,400	47,400	47,400
Harbor Generating Station Subtotal					**466,000**	**466,000**	**452,000**
	5	8/17/2001	71,176	60,500	43,000	43,000	43,000
Valley Generating	6	9/4/2003	215,000	182,750	159,000	159,000	156,000
Station	7	9/9/2003	215,000	182,750	159,000	159,000	156,000
	8	11/13/2003	311,000	264,350	215,000	215,000	201,000
Valley Generating Station Subtotal					**576,000**	**576,000**	**556,000**
Scattergood	1	12/7/1958	192,000	163,200	183,000	183,000	174,000
Generating Station	2	7/1/1959	192,000	163,200	184,000	184,000	177,000
	3	10/6/1974	552,000	496,800	450,000	450,000	445,000
Scattergood Generating Station Subtotal					**817,000**	**817,000**	**796,000**
	1	9/2/1962	270,000	230,000	222,000	222,000	222,000
	2	4/7/1963	270,000	230,000	222,000	222,000	222,000
	3	7/14/1964	270,000	230,000	0	0	0
	4	2/9/1965	270,000	230,000	0	0	0
Haynes Generating	5	8/12/1966	381,000	343,000	292,000	292,000	292,000
Station	6	3/18/1967	381,000	343,000	243,000	243,000	238,000
	7	9/1/1970	2,500	2,000	1,599	1,599	0
	8	1/25/2005	311,000	264,350	250,000	250,000	235,000
	9	1/25/2005	215,000	182,750	162,500	162,500	158,000
	10	1/25/2005	215,000	182,750	162,500	162,500	158,000
Haynes Generating Station Subtotal					**1,555,599**	**1,555,599**	**1,525,000**
Total Basin Thermal					**3,414,599**	**3,414,599**	**3,329,000**
Mohave Generating	1	4/1/1971	909,000	818,000	0	0	0
Station	2	10/1/1971	909,000	818,000	0	0	0
Mohave Generating Station Subtotal					**0**	**0**	**0**
Navajo Generating	1	2/1/1974	892,400	803,000	750,000	159,000	159,000
Station	2	12/2/1974	892,400	803,000	750,000	159,000	159,000
	3	11/29/1975	892,400	803,000	750,000	159,000	159,000
Navajo Generating Station Subtotal					**2,250,000**	**477,000**	**477,000**
Intermountain	1	6/9/1986	991,000	820,000	900,000	587,290	587,290
Generating Station	2	4/30/1987	991,000	820,000	900,000	587,290	587,290
Intermountain Generating Station Subtotal					**1,800,000**	**1,174,580**	**1,174,580**
Palo Verde Nuclear	1	1/30/1986	1,550,000	1,403,000	1,333,000	128,768	126,643
Generating Station	2	9/19/1986	1,550,000	1,403,000	1,336,000	129,058	126,932
	3	1/19/1988	1,550,000	1,403,000	1,334,000	128,864	126,739
Palo Verde Generating Station Subtotal					**4,003,000**	**386,690**	**380,314**
Total External Thermal (Coal and nuclear fuels)					**8,053,000**	**2,038,270**	**2,031,894**
TOTAL THERMAL					**11,467,599**	**5,452,869**	**5,360,894**
NET MAXIMUM AND NET DEPENDABLE SYSTEM CAPABILITY w/o CDW						**7,398,949**	**7,138,824**
Transfer	State's Capacity Entitlement					**-120,000**	**-56,000**
NET MAXIMUM AND NET DEPENDABLE SYSTEM CAPABILITY						**7,278,949**	**7,082,824**
Renewables/Distributed Generation as of April 10, 2012 [6]						**1,109,235**	**329,607**
NET MAXIMUM AND NET DEPENDABLE SYSTEM CAPABILITY w/ RE/DG						**8,388,184**	**7,412,431**

Notes:

[1] This table is based on data from Power System Engineering Division January 1, 2012 Generation Rating and Capabilities of Power Sources sheet. This table also include data for the renewables and distributed generating resources owned and contracted by LADWP. The data are from the April 10, 2012 RPS Master Project List and project contracts.

[2] Nameplate capability is the full-load continuous rating of a generating unit under specified conditions as designated by the manufacturer.

[3] Unit can attained Maximum Capability when the weather and equipment are simultaneously at optimal conditions.

[4] Maximum Plant Capability reflects water flow limits at hydro plants; or sum of each unit at in-basin thermal plans; or entitlements from external thermal plants.

[5] Net Dependable Plant Capability reflects year-round outputs adjusted for low generation season. For hydro plants, winter is the low generation season. Thermal plants experience reduced performance during hot weather conditions.

[6] Dependable capacity of renewable technology plants are estimated by applying a Dependable Capacity Factor (DCF) to the plant nameplate capacity. The conservative factor is used until LADWP gains more actual amount of 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 1.0
- Solar Photovoltaic 0.27
- Solar Thermal 0.27
- Wind 0.10 (projects with firming contracts are rated at firming levels)

IPP Capacity for LADWP

IPP Capacity (MW)								
CY	Season	DWP's Excess Share (MW)	DWP's Excess Share Recalled via Long-Term Letter (MW)	Short Term Recall	DWP's Excess Shares Recalled via Short-Term Letter (MW)	DWP's Excess Shares via UP&L Purchase (MW)	DWP's Own Entitlement (MW)	Total IPP Capacity (MW)
2011	Summer	327	(153)	43	217	72	803	1092
	Winter	327	(136)	43	234	72	803	1109
2012	Summer	327	(66)	39	299	72	803	1175
	Winter	327	(58)	43	312	72	803	1187
2013	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2014	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2015	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2016	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2017	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2018	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2019	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2020	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2021	Summer	327	(42)	39	324	72	803	1199
	Winter	327	(58)	43	312	72	803	1187
2022	Summer	327	(92)	39	274	72	803	1149
	Winter	327	(108)	43	262	72	803	1137
2023	Summer	327	(192)	39	174	72	803	1049
	Winter	327	(208)	43	162	72	803	1037
2024	Summer	327	(292)	39	74	72	803	949
	Winter	327	(308)	43	62	72	803	937
2025	Summer	327	(327)	0	0	72	803	875
	Winter	327	(327)	0	0	72	803	875
2026	Summer	327	(327)	0	0	72	803	875
	Winter	327	(327)	0	0	72	803	875
2027	Summer	327	(327)	0	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 Expense
	Principal (M$)			Interest (M$)			Debt Service (M$)			(M$)	(M$)	(M$)
	Regular	Subord.	Total	Regular	Subord.	Total	Principal	Interest	Total			
2008									$310.2	$174.7	$484.90	$283.1
2009									$271.2	$156.3	$427.50	$244.5
2010	$104.5	$34.0	$138.5	$57.6	$59.6	$117.2	$138.5	$117.2	$255.7	$167.3	$423.00	$250.5
2011	$128.3	$80.4	$208.7	$51.1	$56.0	$107.1	$208.7	$107.1	$315.9	$170.8	$486.70	$292.7
2012	$83.2	$104.2	$187.4	$46.9	$49.6	$96.5	$187.4	$96.4	$283.8	$167.8	$451.60	$276.9
2013	$104.0	$68.6	$172.6	$42.9	$41.3	$84.2	$172.6	$84.3	$256.9	$169.0	$425.90	$259.6
2014	$137.6	$76.8	$214.4	$38.9	$38.2	$77.1	$214.4	$77.0	$291.5	$172.4	$463.90	$282.7
2015	$130.9	$73.2	$204.1	$34.7	$32.6	$67.3	$204.1	$67.4	$271.5	$175.8	$447.30	$272.6
2016	$154.0	$90.5	$244.5	$30.5	$32.2	$62.7	$244.5	$62.7	$307.2	$179.3	$486.50	$297.3
2017	$98.4	$26.9	$125.3	$25.9	$29.5	$55.4	$125.3	$55.4	$180.6	$182.9	$363.50	$221.5
2018	$152.2	$53.3	$205.5	$19.6	$30.5	$50.1	$205.5	$50.0	$255.5	$186.6	$442.10	$269.4
2019	$113.8	$124.7	$238.5	$13.0	$24.2	$37.2	$238.5	$37.2	$275.7	$190.3	$466.00	$284.0
2020	$61.3	$161.2	$222.5	$9.5	$15.6	$25.1	$222.5	$25.1	$247.6	$194.1	$441.70	$269.9
2021	$66.0	$158.5	$224.5	$7.7	$6.4	$14.1	$224.5	$14.1	$238.5	$198.0	$436.50	$266.0
2022	$102.9	$73.1	$176.0	$4.9	$2.6	$7.5	$176.0	$7.5	$183.5	$202.0	$385.50	$232.1
2023	$53.0	$73.9	$126.9	$1.8	-$2.5	-$0.7	$126.9	-$0.7	$126.2	$206.0	$332.20	$188.3
2024	$7.1	$6.2	$13.3	$0.2	$0.0	$0.2	$13.3	$0.2	$13.5	$210.1	$223.60	$115.7
2025	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$214.3	$214.30	$104.2
2026	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$218.6	$218.60	$106.3
2027	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$223.0	$223.00	$108.4

Demand Response Schedule

Fiscal Year	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027	2027/2028
MW	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500
Total Annual Budget ($000)	1,650	1,889	2,230	3,092	4,924	6,792	10,235	13,544	14,876	16,278	17,722	19,509	21,041	22,919	23,515	24,128

LADWP Solar Program

SB1 Solar Rooftop Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012	70	93	170
2013	98	139	170
2014	125	184	170
2015	147	224	170
2016	166	258	150
2017	171	279	150
2018	176	287	150
2019	181	295	140
2020	187	304	140
2021	194	315	130
2022	201	326	130
2023	209	339	120
2024	217	352	120
2025	226	366	120
2026	235	381	110
2027	244	396	110
2028	254	411	100
2029	264	428	100
2030	274	444	100
2031	284	461	100
2032	294	477	100

DWP Build In Basin Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012	3	4	240
2013	6	8	221
2014	9	13	211
2015	12	19	203
2016	21	29	190
2017	37	52	176
2018	54	81	167
2019	71	111	160
2020	88	141	154
2021	101	167	150
2022	100	178	148
2023	100	177	149
2024	99	176	149
2025	99	176	150
2026	99	175	151
2027	98	174	152
2028	98	173	152
2029	97	172	153
2030	97	171	154
2031	96	170	154
2032	96	169	155

DWP Build Out Basin Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012	19	21	150
2013	19	37	150
2014	19	37	150
2015	19	37	150
2016	19	37	150
2017	19	37	150
2018	19	37	150
2019	19	35	150
2020	19	35	150
2021	19	35	150
2022	19	35	150
2023	19	35	150
2024	19	35	150
2025	19	35	150
2026	19	35	150
2027	19	35	150
2028	19	35	150
2029	19	35	150
2030	19	35	150
2031	19	35	150
2032	19	35	150

Feed-In Tariff Solar Program

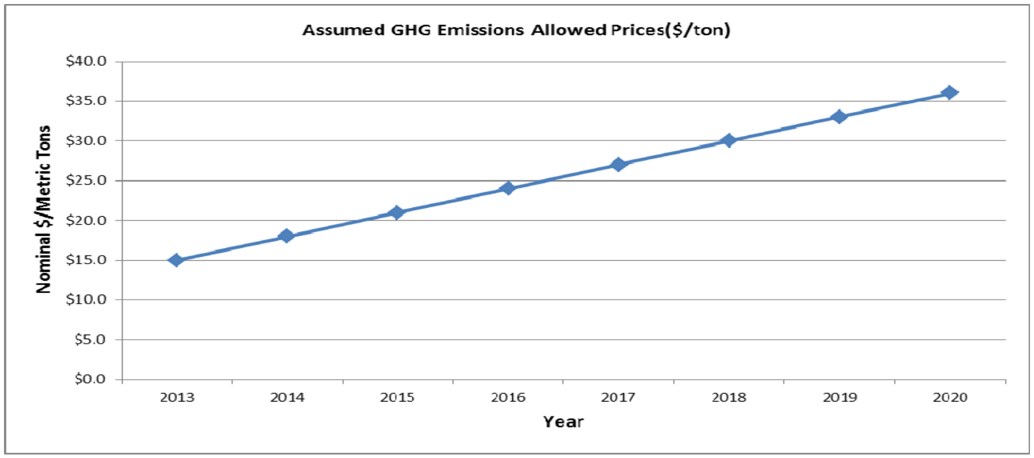
CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012	2	1	178
2013	10	10	171
2014	20	26	165
2015	40	52	159
2016	75	100	151
2017	83	137	150
2018	90	150	152
2019	98	163	153
2020	105	175	153
2021	113	187	153
2022	120	200	152
2023	128	212	152
2024	135	224	151
2025	143	236	151
2026	150	248	150
2027	150	253	150
2028	150	252	150
2029	150	251	150
2030	150	249	150
2031	150	248	150
2032	150	246	150

Owens Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017	50	110	153
2018	100	220	153
2019	150	330	153
2020	200	440	153
2021	200	438	153
2022	200	436	153
2023	200	433	153
2024	200	431	153
2025	200	429	153
2026	200	427	153
2027	200	425	153
2028	200	423	153
2029	200	421	153
2030	200	418	153
2031	200	414	153
2032	200	412	153

CO_2 Allocations and Costs Assumptions

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electrical Sector Total	95.8437	94.0851	92.2288	90.3725	88.6139	86.7576	84.9013	83.1427	83.1427	83.1427	83.1427	83.1427	83.1427	83.1427	83.1427	83.1427	83.1427	83.1427
DWP factor	0.14183509	0.14189282	0.14008639	0.14434701	0.14914139	0.15281658	0.14963257	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137	0.14048137
DWP Allocation (MMT)	13.594	13.350	12.920	13.045	13.216	13.258	12.704	11.680	11.680	11.680	11.680	11.680	11.680	11.680	11.680	11.680	11.680	11.680
Cost Assumption ($/ton)	$15.0	$18.0	$21.0	$24.0	$27.0	$30.0	$33.0	$36.0	$39.0	$42.0	$45.0	$48.0	$51.0	$54.0	$57.0	$60.0	$63.0	$66.0



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Appendix O Public Outreach

This Appendix O describes the public outreach that was carried out as part of the 2012 IRP process to involve the public in the development of this LADWP 2012 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 2012 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 stakeholder meetings, a public workshop, and a dedicated website (www.ladwp.com/lapowerplan). Comments were gathered at the stakeholder meetings and public workshop, and were also provided through an online comment form, direct e-mail, and the US mail.

The public outreach began with two stakeholder meetings held in early 2012. Comments received at these meetings were considered in the development of the preliminary planning cases which were subsequently modeled and were analyzed.

The preliminary results were documented in the 2012 Draft IRP that was made available on the website on October 5, 2012. The draft IRP was presented at three stakeholder meetings and one public workshop held on October 11, 2012. Comments were accepted through November 5, 2012.

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 2012 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 2012 IRP. Community involvement opportunities were provided through a website, stakeholder meetings, and a general public workshop. 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.

- **Pre-Draft Stakeholder Meetings**: LADWP conducted meetings targeting specific stakeholders in early 2012, including business and industry representatives on February 9, and environmental groups on March 1. The purpose of these meetings was to discuss and collect public inputs for consideration in the development of the 2012 Draft IRP. Input collected at these meetings is included in the discussion themes found in the next section of this appendix. Discussion notes can also be found in Exhibit A.

- **Draft IRP Stakeholder Meetings and Public Workshop**: LADWP conducted three meetings targeting specific stakeholders in the fall of 2012, including environmental groups on September 21, commercial/business customer representatives on October 4, and Neighborhood Council members on October 22. A general public workshop was also held, on October 11. The purpose of the workshop and meetings was to present the 2012 Draft IRP and collect public input for consideration prior to preparing the 2012 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/lapowerplan) was utilized for the 2012 IRP. The website included an announcement of the public workshop, 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 2012 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, stakeholder meetings, online survey, and comment forms yielded a significant amount of information from LADWP customers related to the 2012 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, attendees at the stakeholder meetings and public workshop, and members of the public who completed the online comment form, or submitted comments through e-mail or the US mail. 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. Some were concerned that Navajo would continue to operate after LADWP divestiture, and suggested the plant be shut down. Greenhouse gas emissions, along with other pollutants associated with coal energy were noted.

Related LADWP Actions:

- LADWP is proceeding with plans to replace Navajo Generating Station by 2015—four years ahead of the SB 1368 requirement.
- The Intermountain Power Project is modeled in this IRP through 2027, but LADWP is working with the project participants to convert the IPP facility from coal to natural gas, and is hopeful that a firm conversion date can be established in time for next year's IRP analysis.

Theme: Incorporate More Renewables

Discussion

Many public comments suggested higher levels of renewables, beyond the mandated 33% by 2020. Some promoted the idea of 50% and even 100% renewables. LADWP's approach regarding this is to proceed cautiously until more is known about the operational and financial implications of higher levels. The IRP is prepared annually, and it is possible that future IRPs will include cases that incorporate higher levels of renewables.

Related LADWP Actions:

- LADWP will increase its levels of renewable resource generation in accordance with SB 2 (1X).
- LADWP will complete a study 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

Incorporate More 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:

- Develop a renewable energy feed-in tariff program to encourage 150 MW of renewable generation resources to be developed by July, 2016.
- Encourage the development of an additional 50 MW of customer net-metered solar projects before 2015.
- Develop up to 30 MW of solar capacity on existing properties under public/private partnership projects before 2015.

Theme: Incorporate More Distributed Generation

Discussion

Since the majority of LADWP's new Distributed Generation (DG) will come from local solar, this theme is somewhat associated with the More Local Solar theme. Most of the comments regarding more DG point to the governor's statewide goal for 12,000 MW, of which LADWP's proportionate share is assumed to be 1,200 MW. Within this 2012 IRP, the highest levels of new DG are 485 MW by 2020, and 852 MW by 2032. LADWP's concern with DG levels is maintaining reliability (see Section 3.4.4). Numerous utility studies have recommended a limit of 15% of the peak load circuit capacity – for LADWP this is approximately 900 MW. As LADWP adopts more DG per its current plan, and as more experience is gained along with more industry-wide research in this area, it is possible that future IRPs will consider higher DG levels.

Related LADWP Actions:

- LADWP will continue its study of issues associated with integrating increasing amounts of variable energy resources to assess possible megawatt limits for the LADWP electric power system.

- LADWP will further develop its Smart Grid plans, which will facilitate the adoption of increasing levels of distributed generation.
- LADWP will investigate applications for energy storage, including those that may enable higher levels of local distributed generation.

Theme: Incorporate More Energy Efficiency and Demand Response

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; with a further anticipated increase to 15%, pending completion of an updated potential study in 2013. Comments received supported more EE and Demand Response (DR) incorporated into LADWP future plans. As presented in this 2012 IRP, EE and DR are vital components within all long-term resource planning options. As the results of the upcoming potential study are developed and finalized, they will be adopted into the IRP planning strategy.

Related LADWP Actions:

- In May 2012, the Board of Water and Power Commissioners approved a revised target of 15% of energy efficiency by 2020, subject to an updated potential study.
- Implement 200 MW of demand response by 2020 and 500 MW of demand response by 2026.

Theme: Reduce Greenhouse Gas Emissions

Discussion

This was an overarching theme of the public comments received. Indirect societal costs, health effects, global warming and super storm Sandy we cited as reasons for accelerating the timelines to reduce GHGs. Rooftop gardens were promoted as a means to absorb CO_2. In considering the GHG impacts of fuel consumption for electricity generation, many comments pointed to the additional impacts resulting from fuel production (coal mining and gas drilling). Comments pointed out the need for considering energy efficiency, demand response, load shifting, and other technologies such as shunt reactive support to offset future additions of gas-fired capacity.

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, demand response, and other load shifting strategies.
- Provide financial incentives to encourage customers to shift their load away from peak hours to reduce 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

<u>Discussion</u>

Many comments suggested a scenario that contained no new gas-generation resources, an eventual portfolio of 100% renewables, and investments in EE, conservation, renewables and Demand Response. Some felt that multiple sets of potential renewable resource mixes should be considered.

<u>Related LADWP actions</u>

- LADWP prepares a new IRP annually and will consider new scenarios within subsequent case option development processes.

Theme: Financial and Rate Concerns

<u>Discussion</u>

Some comments expressed concern that LADWP needs to ensure its financial stability and integrity. Many comments presented concerns with rising electricity rates and wanted to ensure that the cost and benefits were clearly presented; and recommended a comparison with other regional and out-of-state utilities. One comment suggested that LADWP keep coal for as long as possible, and that other forms of energy are not mature and are too costly. Conversely, other comments suggested that rate increases were acceptable if EE options are made available to help reduce customer bills. One comment suggested that LADWP rates are too low and the tiers are too generous – resulting in disincentives for EE and renewables.

<u>Related LADWP actions</u>

- LADWP will continue to work with our stakeholders including the Office of the Ratepayer Advocate (ORA) to ensure that the financial requirements of meeting its mandated obligations and discretionary goals are clearly delineated and understood.

- Provide EE and CNM solar incentives to help customers reduce the impact that rates have on their bills.
- Encourage demand response incentives and time-of-use rates to encourage shifting of load away from peak hours and reduce customer bills.

Theme: Maintain Power Reliability

Discussion

Some comments expressed concern about the state of the LADWP infrastructure, noting that the reliability program continues to be subject to budgets cuts - unlike mandated areas such as renewables. They point to the 2011 wind storm and 2006 heat storm as evidence that the infrastructure is getting older and more costly to maintain, and suggest that paying more now to address this problem will save money later.

Related LADWP actions

- Continue to prioritize those infrastructure elements that are in urgent need of repair/replacement, and try to extend reliable operations with the (less than fully funded) budget provided. See Section 1.6.3 and Appendix E for more information.
- LADWP will continue to work with our stakeholders and the Office of the Ratepayer Advocate (ORA) to ensure that the financial requirements of meeting its mandated obligations and discretionary goals are clearly delineated, and understood.

Theme: LADWP Should Take a Leadership Role

Discussion

Regarding renewable resources and other green energy matters, many suggested that LADWP, as a municipal utility, should lead by example, consider unconventional business models, and through its governance garner the political will to do something different.

Related LADWP actions

- LADWP's first and foremost responsibility is to its ratepayers, and will continue to pursue its balanced strategy of reliability, competitive rates, and environmental stewardship. To the extent that new ideas or unconventional approaches to long term planning could potentially benefit the ratepayers, they should and will be considered.
- LADWP will continue to provide transparency in its resource planning activities to encourage input from all stakeholders.

- Advocate for consistency and clarity in regulations that affect our ratepayers while meeting environmental objectives.

O.4 Exhibits

- **A – Stakeholder Meeting Notes and Survey/Comment Forms**
- **B – Public Workshop Notes and Survey/Comment Forms**
- **C – Website Online Survey/Comment Forms**
- **D – Other Survey/Comment Inputs**

To view these exhibits, please visit www.ladwp.com/lapowerplan

Appendix P Abbreviations and Acronyms

P.1 Overview

This appendix presents acronyms for agencies and other entities, facilities and locations, electric industry terms, miscellany, and units of measure.

P.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
CPUC	California Public Utilities Commission
DOD	U.S. Department of Defense
DOE	U. S. Department of Energy
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

P.3 Facilities and Locations

BPA	Bonneville 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
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

P.4 Electric Industry Terms

A/C	air conditioning
AC	Alternating Current
AEDP	Advanced ESS Demonstration Project
AMI	Advanced Metering Infrastructure
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
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
DG	distributed generation
DNI	direct normal insolation
DR	Demand Response
DSM	Demand Side Management
E&L	Environment and Lands
ECAF	Energy Cost Adjustment Factor
EDS	Energy Dissipation Station
EE	Energy Efficiency
EHV	Extra-High Voltage
ESPs	energy service providers
ESS	energy storage system
ETD	Electric Trouble Dispatch
FAR	Firm Access Rights
FES	flywheel energy storage
FiT	Feed-in Tariff
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
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
OASIS	open-access same-time information systems
OATTS	open-access transmission tariffs
OTC	once-through cooling
PFCs	perfluorcocarbons
PHEV	plug-in hybrid electric vehicle
PHS	pumped-hydro storage
PMU	power measurement units
POUs	publicly-owned electric utilities
PTC	production tax credit
PV	photovoltaic
QRAs	Qualified Resource Areas
RASS	Residential Appliance Saturation Survey
RECLAIM	Regional Clean Air Incentive Market
RETI	Renewable Energy Transmission Initiative
RPS	Renewable Portfolio Standard
RS	receiving station
RTCs	RECLAIM Trading Credits
Rule	Cooling Water Intake Structure 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
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
VRB	Vanadium Redox Battery
WEC	Wave Energy Converter
XRT	experimental demand response contract
ZITA	Zone Identification and Technical Analysis
ZNE	Zero Net Energy

P.5 Miscellany

A	Category of Flow Meter
AB	Assembly Bill
AMR	Automatic Meter reading
CFL	compact fluorescent light
CI	commercial/industrial
CIS	Customer Information System
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
JFB	John Ferraro Building
LED	light-emitting diode
MFR	multi-family residence
NLC	net levelized cost
OH	overhead
QRAs	Qualified Resource Areas
RF	Radio Frequency
RFP	Request for Proposal
SB	Senate Bill
SBDI	Small Business Direct Install
SFR	single family residence
UG	Underground

P.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

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