Los Angeles Department of Water & Power

2011
POWER INTEGRATED RESOURCE PLAN

December 22, 2011

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Los Angeles Department of Water & Power

2011 Power Integrated Resource Plan

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December 22, 2011

Integrated Resource Planning

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Preface

This 2011 IRP represents an update of last year's 2010 IRP document, and addresses, among other things, updated renewable energy requirements, the latest load forecast, early divestiture of the Navajo coal plant, revenue and rate impacts, and the incorporation of public input.

The recent passage of legislation SB 2 (1X) establishes specific renewable energy requirements, enabling more near-term certainty on the near-term need and the associated plan for renewable energy resources. As a result, the strategic case options evaluated in this IRP reflect updated quantities and mix of renewables based on the recent load forecast and availability of renewable resources and their related transmission.

The current load forecast used in this IRP is lower than the one used in 2010. Compared to the prior forecast, electricity sales for year 2020 decreased by approximately 7 percent mostly due to updated econometric studies that indicate a more prolonged recovery from the recession. The lower load forecast results in less electricity demand and fewer replacement resources when compared to last year.

This IRP update recommends divestiture of the Navajo coal power plant by 2015, 4 years ahead of the 2019 end date. Regarding early Navajo coal divestiture, the analysis and findings of this IRP update are generally consistent with conclusions developed from last year's 2010 IRP process with more details of specific replacement resources and costs. Early divestiture of LADWP's other coal source—the Intermountain Power Project—while analyzed in greater detail in this IRP, will be subjected to further investigation and analysis in next year's 2012 IRP.

Also included in this 2011 IRP is an assessment of the revenue requirements and rate effects that support the recommended plan through 2020. The rate process which began earlier in 2011 is expected to conclude in 2012, from which a final budget and rate schedule will result. LADWP supports the City Council's efforts towards this process, and looks forward to the appointment of the Ratepayer Advocate so that these budget and revenue issues can be properly addressed in a collaborative and expeditious manner. Establishing the proper rate structure will allow LADWP to implement its plan and stay on track towards meeting its long-term goals and obligations.

Lastly, many of the recommendations contained in this IRP update address concerns raised during last year's IRP public outreach process, as well as from the summer 2011 rate process. Accelerating coal replacement, emphasizing energy efficiency, and expanding local solar were among the major issues that emerged from the public processes; these and others have been incorporated into the case analysis and long-term recommendations. Next year's 2012 IRP process will include a new outreach program that will build upon these themes, as well as identify any new concerns or issues that may emerge.

I INTRODUCTION AND PURPOSE

The Los Angeles Department of Water and Power (LADWP) is currently facing some of the most serious environmental, regulatory, and economic challenges in its 100-year plus history. LADWP finds itself at a crossroads in terms of how the utility operates that will require revamping its power generation portfolio to continue providing the same reliable, low-cost electricity to the residents and businesses of Los Angeles. As the largest municipally owned utility in the nation, LADWP must continue to ensure reliable electricity service as it reduces greenhouse gas (CO_2) emissions and transitions from energy sources based on fossil fuels to sustainable forms of renewable energy.

This 2011 Power Integrated Resources Plan (IRP) is an update of last year's 2010 IRP, and reflects evolving environmental, regulatory, and economic developments since 2010. The purpose of this IRP remains as before—to provide a framework to assure the future energy needs of LADWP customers are met in a manner that balances the key objectives of:

- Maintain a high level of electric service reliability
- Maintain competitive rates
- Exercise environmental stewardship, including a reduced carbon footprint

In balancing these key objectives, LADWP's integrated resource planning efforts must be deliberate, comprehensive, and clear to our ratepayers as well as all other City stakeholders. LADWP's goal—and primary challenge—is to develop a long-term resource plan that is informative, sensitive to the local and regional economy, and adaptable to changes in state and federal regulations, fuel prices, and advances in power generation technologies.

This IRP presents several potential strategies for meeting LADWP's regulatory requirements and policy objectives, maintaining electric power service reliability, and minimizing any financial impact on ratepayers. LADWP rigorously evaluated each potential strategy to identify and recommend the best overall plan to meet its key objectives at the least cost.

This IRP is not a technical plan nor a compact to pursue all of the initiatives identified in this document. Instead, this plan establishes the overall vision for the power system and a broad discussion of the finances necessary to support that vision. LADWP needs to be free to react to market conditions and make corrections in its shorter term tactical plans. Additionally, short-term budgets will be refined and financial analysis published as they are recommended for approval by LADWP's Governing Board and the City Council.

II PUBLIC OUTREACH

LADWP conducts a public review process on their IRP every other year. A review process was held last year in support of the 2010 IRP, and the results of that process are considered applicable to the 2011 IRP. A full scale public outreach program, similar to the one held in 2010, is planned for next year's 2012 IRP. In summary, following are the themes that emerged.

LADWP should:

- Emphasize a variety of energy resources
- Maximize energy efficiency and conservation
- Eliminate coal from its generation portfolio
- Emphasize local solar generation
- Avoid adverse impacts to vulnerable communities
- Clarify costs of IRP implementation and potential impacts to ratepayers
- Reduce environmental impacts
- Provide proactive leadership and transparency

For details regarding the 2010 Public Outreach effort, refer to Appendix N. The recommended strategy for addressing these themes is presented in Section 5.2.

III 2011 IRP DEVELOPMENT PROCESS

The IRP is prepared by a group of engineers dedicated to LADWP resource planning and preparation of the IRP. This group is managed by a Supervising Engineer, with a direct reporting staff of four. While this group performs the production model and report preparation for the IRP, the bulk of the work is collaborative across the different work groups and functional areas of the Power System.

The IRP is developed in multiple stages, including:

1. Identifying and approving key assumptions
2. Establishing clear goals and objectives
3. Establishing strategic case alternatives
4. Completing computer modeling of power system operations
5. Recommending and approving a preferred case

Each of these stages includes coordination between multiple LADWP organizations responsible for different aspects of power system operations, preparing recommended positions for each stage, presenting recommendations to LADWP's leadership team, including Division and Section Heads, and ultimately presenting recommendations to the General Manager. At each of these presentations, modifications to recommendations are noted. The approval process for recommendations is based on consensus from the managers of each area of responsibility.

IV 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
Milford II Wind Project	2011	Supply over 100 MW of wind energy
Electric Vehicles Incentive	2011	Provide a $2000 rebate for home EV charging systems
Southern Transmission System Upgrade	2011	Increased capacity of 480 MW was added to the existing transmission line
Navajo Generation Station Retrofits	2011	Retrofit burners reduce NO_X emission by 40% or 14,000 tons per year
Energy Efficiency Program	2000 to 2011	Reduced long-term peak period demand by 303 MW, 1,256 GWh of energy savings
Renewable Portfolio Standard	2003 to 2010	Increased renewable energy percentage from 3% to 20%
Castaic Upgrade	2004 to 2014	Project adds up to 80 MW renewable capacity
Green Power Program	1999 to 2011	Participants receive 104 GWh of renewable energy annually
Power Reliability Program	Ongoing	Improve reliability of Power System infrastructure
Solar Incentive Program	1999 to 2011	Provided funding that has enabled the installation of 41 MW of solar
CO_2 Emissions Reduction	1990 to 2010	CO_2 emission 23% lower than 1990 level
Once-through Cooling	1990 to 2011	OTC reduced by 17% from 1990 level

V 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 initiatives, programs and projects; ensuring reliability; greenhouse gas emission reduction; increasing the amounts of renewable generation resources; and addressing once-through cooling.

Adequate Multi-year Funding to Support Programs

Based on last year's 2010 IRP, a multi-year rate increase was recommended beginning fiscal year 2011-12. The rate increase would have supported elements of last year's 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.

A multi-year funding plan is necessary 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.
- 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.

A rate process that began earlier this year is addressing the revenue needs for LADWP. A proposed 3-year rate adjustment that would support the programs listed above is being considered. The expectation is that the rate process will conclude sometime in 2012. 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.

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, and will provide modern units that are more reliable than the units they are replacing.

To maintain grid reliability, LADWP's Ten-Year Transmission Assessment Plan has identified a number of necessary improvements. In addition, a recently completed Reactive Power Management Study recommends improvements to optimize grid performance and reduce system losses. More information can be found in Section 2.4.4.

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 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. This stabilization is known as "regulation." A preferred solution would use energy storage to regulate delivery of energy and reduce the severity of integration problems. LADWP currently uses, among other resources, pumped water storage and hydro resources for regulation.

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.[1] In response, 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.

Greenhouse Gas Emissions Reduction

LADWP's CO_2 emissions reduction strategy must comply with state and federal regulations. At the time of this writing, key legislation and regulations either promulgated or proposed include:

[1] To illustrate the age of the distribution system, over 50 percent of the City's 308,000 distribution poles are greater than 50 years old.

- 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 trading 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. Electric distribution utilities, including LADWP, will receive an administrative allocation of emission allowances that reflects their respective annual emissions as they implement aggressive energy efficiency measures and the 33 percent Renewable Portfolio Standard. The ARB will continue to work with stakeholders to monitor the impacts of the regulation on all sectors, including the electricity sector.
- SB 1368, the California Greenhouse Gas Emissions Performance Standard Act, also 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, 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.

LADWP has historically relied upon coal for base load generation. Currently, 39 percent of the energy delivered to LADWP customers is 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 land lease expires in 2019 but has a stipulation for a 25-year extension. IPP's contract is in effect until 2027. These stations provide dependable, low cost base load generation to Los Angeles. Coal-fired generation, however, emits about twice as much CO_2 as energy generated with natural gas. Accordingly, this 2011 IRP focuses on early coal divestiture options as a means to comply with AB 32 and lower LADWP's CO_2 emission levels. Sections 3 and 4 discuss the alternative strategic case options in detail.

Increasing Renewable Resources

Initiatives to utilize renewable resources to generate electricity support the goal of reducing CO_2 emissions and lessen our reliance on fossil fuels.

State legislation – SB 2 (1X) – which was passed in April 2011 and became effective on December 10, 2011, will subject 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

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.

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 major 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 total generation capacity affected by OTC is significant – approximately 2,162 MW, or roughly 35 percent of LADWP's annual peak demand in 2010. The total expenditures required are also significant, on the order of $2.4 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 1.6.5.

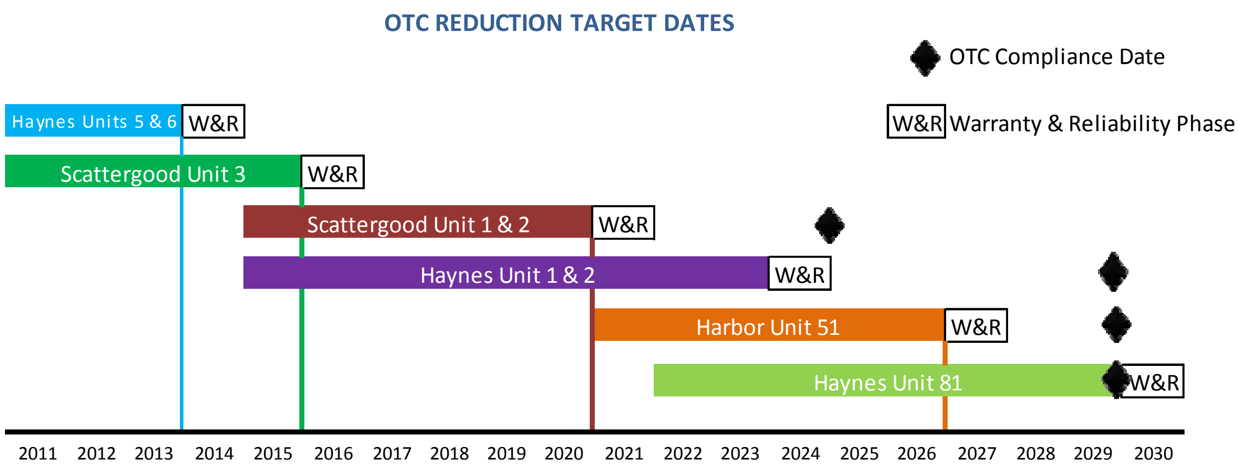


Figure ES-1. Timeline for OTC compliance.

VI STRATEGIC CASE ALTERNATIVES

IRP planning is an on-going process and as such, the development of the 2011 IRP strategic cases incorporates the latest changes that have occurred in the regulatory landscape, and tactical plans developed by the power system. This 2011 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.

Last year's 2010 IRP analyzed 6 strategic cases representing different potential renewable resource portfolio mixes, with and without the early divestiture of IPP, and recommended a comprehensive strategy that adopted elements of a number of the cases analyzed. The 2011-12 fiscal-year financial planning process included many of the assumptions and recommendations set forth in the 2010 IRP.

This year's IRP analyzes a focused set of strategic cases, expanding on the results from the 2010 IRP process. Cases from last year that included a variety of renewable percentage targets were eliminated, mostly due to the recent approval of SB 2(1X) which mandates a fixed set of renewable targets. Because the key remaining discretionary decision involves coal divestiture, a streamlined set of 3 new coal divestiture cases were analyzed. These cases are designed to assist policymakers and ratepayers to make informed decisions regarding accelerated coal divestiture, particularly with regard to the environmental benefits and resulting resource and electricity rate impacts. The time frames for coal divestiture for each strategic case are as follows:

- Case #1 provides a baseline without any early coal divestiture. Navajo Generating Station continues until 12/1/2019 and the Intermountain Power Project (IPP) until 6/15/2027.
- Case #2 considers an early divestiture of NGS, by 12/31/2015, with IPP until 6/15/2027.
- Case #3 considers early divestiture of both coal plants – NGS by 12/31/2015 and IPP by 12/31/2020.

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

Table ES-2. CANDIDATE RESOURCE PORTFOLIOS FOR 2011 IRP

		2020	CO_2 or SB 1368 Compliance Date		New Renewables Installed Capacity (MW) 2011 – 2020					New Renewables Installed Capacity (MW) 2011 – 2030				
Case ID	Resource Strategy	RPS Target	Navajo Replacement	IPP Replacement[1]	Geo-thermal	Bio-mass	Wind	Non-DG Solar	Dist. Solar	Geothermal/ Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
1 (Base Case)	**No Early Coal Divestiture**	**33%**	**12/1/2019**	**6/15/2027**	**183**	**60**	**492**	**401**	**325**	**308**	**492**	**451**	**466**	**162**
2	**Navajo Early Replacement**	**33%**	**12/31/2015**	**6/15/2027**	**183**	**60**	**492**	**401**	**325**	**308**	**492**	**451**	**466**	**162**
3	**Navajo and IPP Early Replacement**	**33%**	**12/31/2015**	**12/31/2020**	**183**	**60**	**492**	**401**	**325**	**308**	**492**	**451**	**466**	**162**
Rec. Case 2010 IRP	**33% RPS Balanced**	**33%**	**1/1/2014**	**6/15/2027**	**320**	**0**	**580**	**315**	**315**	**320**	**680**	**485**	**485**	**160**

[1] Early replacement for IPP will be further evaluated in the 2012 IRP

VII EVALUATION OF STRATEGIC CASE OPTIONS

Key results for each model run 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. The selection of the best case for LADWP ratepayers hinges mainly upon the load forecast, price of natural gas, 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:

CO_2 Emissions Considerations

The reductions of CO_2 emissions are reflected in the production cost model simulations. Figure ES-2 illustrates a comparison of the resulting CO_2 emission levels of the three cases. Divestiture of Navajo results in an average 1.86 Million Metric Tons (MMT) reduction in CO_2 each year while IPP results in an average 3.26 MMT reduction each year. CO_2 reductions are accelerated in Cases 2 and 3 with the divestiture 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 divestiture. 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.

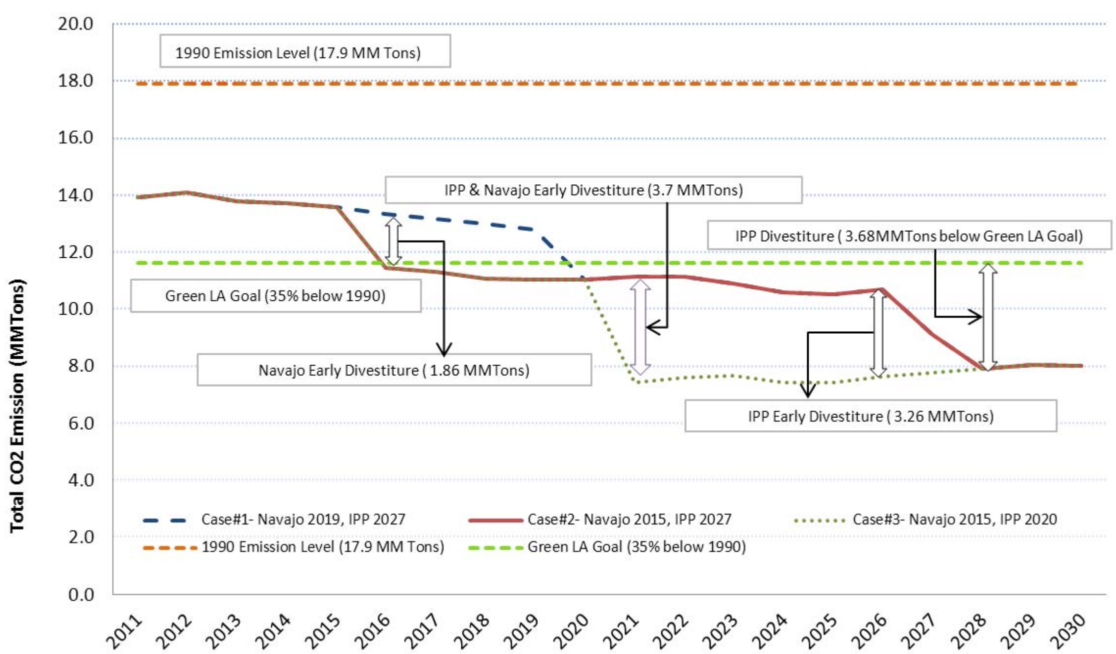


Figure ES-2. CO_2 emissions comparison by calendar year.

Current CO_2 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. Early divestiture of Navajo shown in Cases 2 and 3 results in approximately 7.5 MMT less CO_2 emissions between 2016 and 2019 and early divestiture of IPP shown in Case 3 results in a reduction of CO_2 emissions of 21.1 MMT between 2020 and 2027.

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. These costs assume full funding of the Power System programs including the Power Reliability Program and Energy Efficiency programs, among others. The Power System costs shown below in Figure ES-3 reflect short-term spending reductions through 2011-12 fiscal year with subsequent years reflecting a restoration of funding levels to insure that the IRP recommendations can be realized. The illustrated costs and rates presented below 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 3 cases analyzed.

Figure ES-3 summarizes the total annual power system costs.

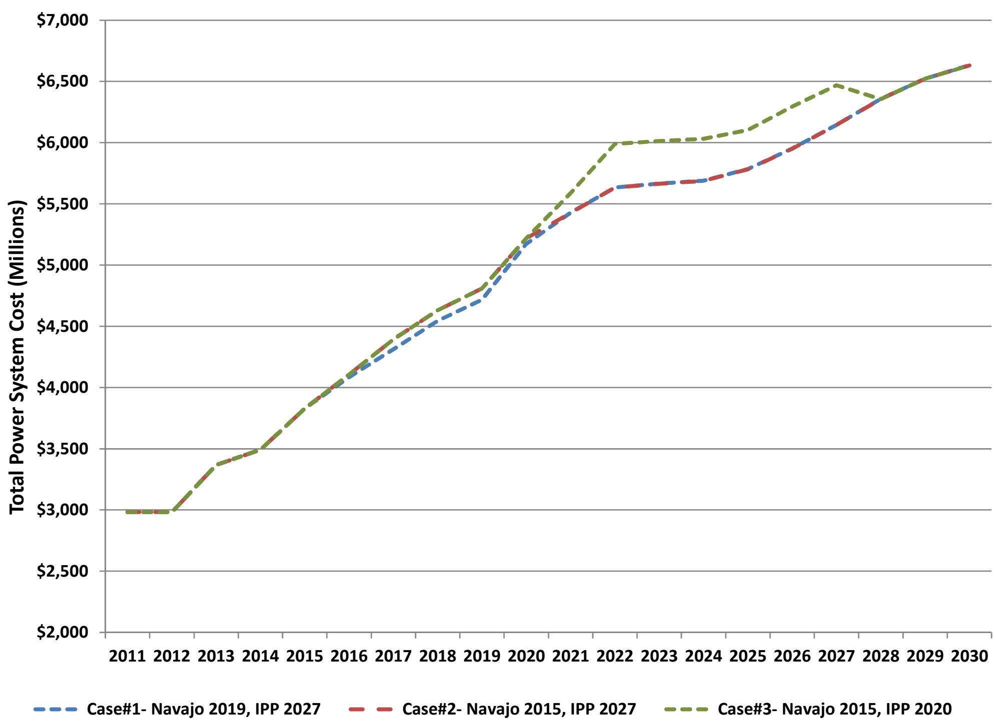


Figure ES-3. Comparison of annual power system costs over next 20 fiscal years.

Sensitivity Analyses on the Recommended Cases

With the early divestiture of Navajo in 2015 and the IPP coal contract ending in June 2027, increased bulk power costs are expected to rise with the divestiture of each of these resources as shown on Figure ES-4. It is important to note that bulk power costs shown in Figure ES-4 include fuel, renewable and other purchase power costs in addition to coal divestiture related costs which are shown in Table 4-4. Applying high and low fuel prices to these bulk power costs, the divestiture 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.

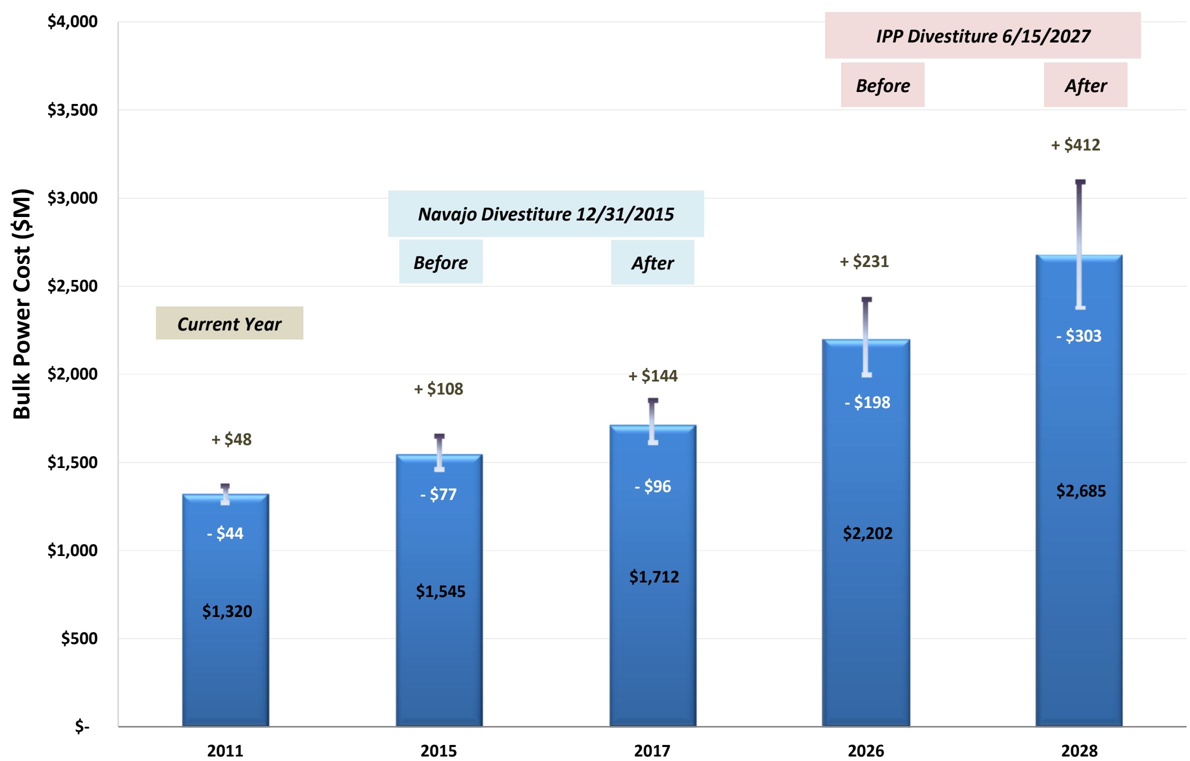


Figure ES-4. Recommended case - bulk power cost before and after coal divestitures with potential cost impacts from high and low fuel prices.

Rate Contributions from Environmental and Reliability Programs

Summarized in Figure ES-5 is the cost contribution from various environmental and reliability programs towards the retail rates. One can draw the conclusion that there is a significant cost to comply with various reliability and regulatory requirements while divesting of Navajo in 2015 and IPP in 2027.

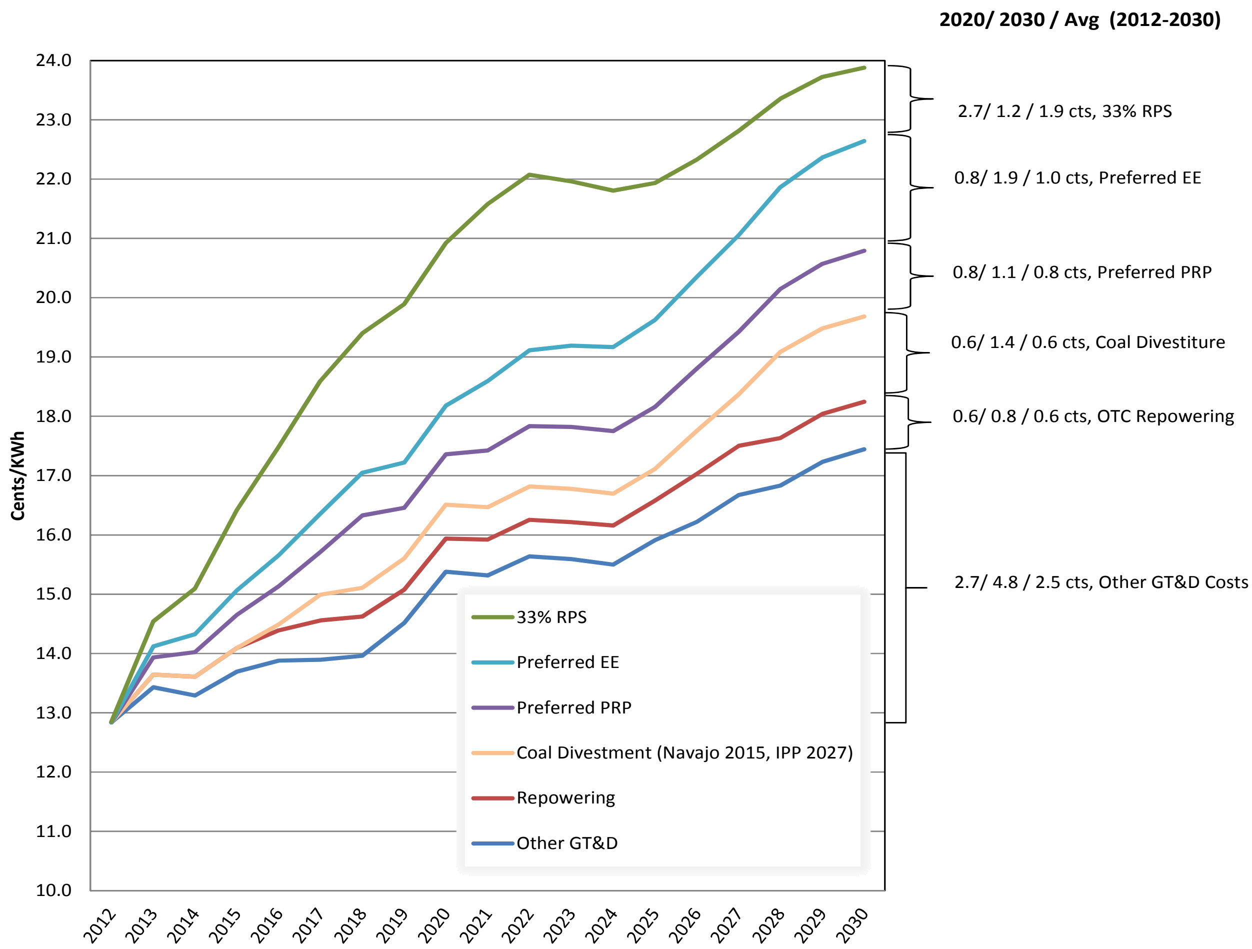


Figure ES-5. Electric rate contributions of environmental and reliability programs by fiscal year based on the 2011-12 budget forecast (preferred case).

A few observations from Figure ES-5 can be made regarding the RPS and EE program. Firstly, the influence of the RPS program on rates increases substantially through 2020 when the RPS percentage of sales reaches 33%. Beyond 2020, the RPS component of rates begins to decline as fuel savings increases over time with escalating fuel prices. Secondly, the EE program component of rates increases over time as power system fixed costs are distributed over the reduced energy sales attributable to the EE program.

Figures ES-6 and ES-7 further illustrate the effect that costs related to environmental and reliability programs will have on average residential and commercial/industrial customer monthly bills from these environmental and reliability programs.

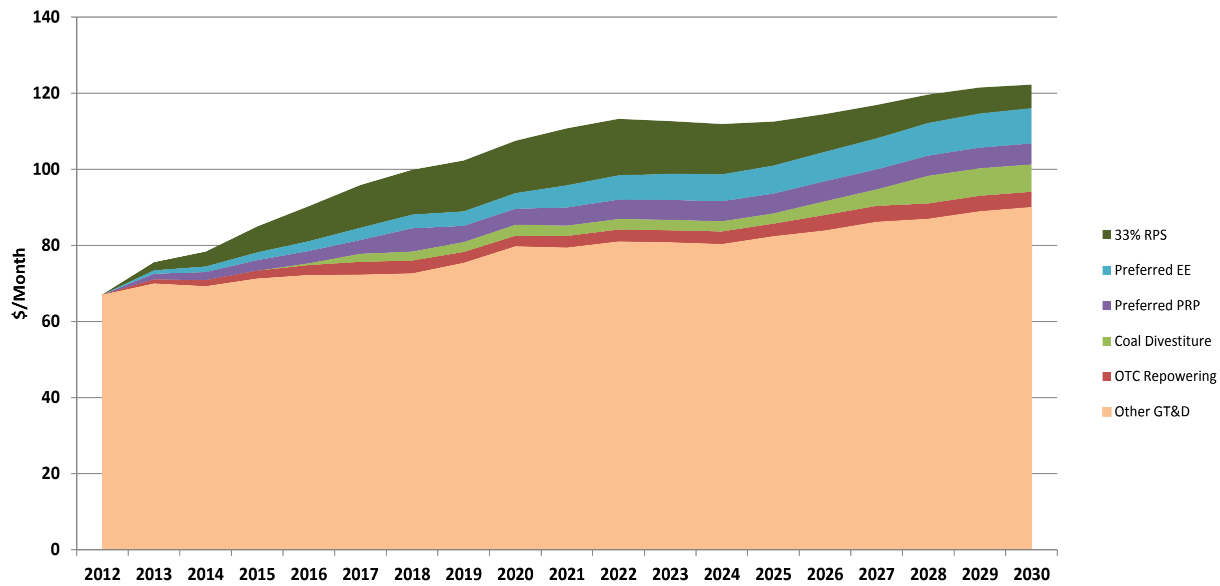


Figure ES-6. Average residential customer bill (500 kWh/month) with environmental and reliability programs by fiscal year based on the 2011-12 budget forecast (preferred case).

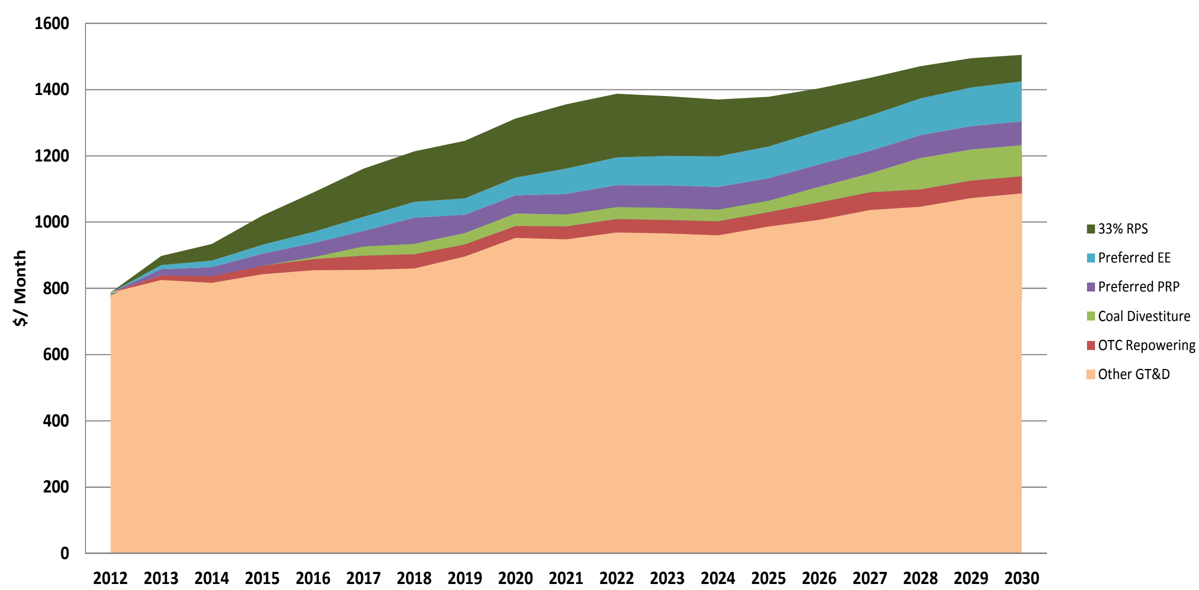


Figure ES-7. Average commercial/industrial customer bill (6,500 kWh/month) with environmental and reliability programs by fiscal year based on the 2011-12 budget forecast (preferred case).

Recommended Strategic Case

Decisions to fund coal divestiture strategies cannot take place independent of other power system programs. Maintaining reliability and meeting regulatory requirements are primary considerations before any coal divestiture cases can be considered. However, this IRP presupposes funding of these programs so that the recommended coal divestiture 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 2 (see Table ES-3 below) with early Navajo coal divestiture in 2015 becomes the recommended case for the 2011 IRP. Although Case 2 represents additional cost as compared to Case 1, the additional costs to rate payers appears to be reasonable in light of the environmental benefit of reducing CO_2 emissions by 7.5 MMT. Early divestiture of Navajo also provides additional time to insure a smooth transition in acquiring and implementing replacement resources. The 2010 IRP included the same recommendation to accelerate divestiture of Navajo and this IRP further clarifies and supports this prior recommendation. This recommended case presents a reasonable approach to achieving environmental goals without excessive costs to our ratepayers while limiting potential exposure to possible fuel price volatility to within manageable limits.

Table ES-3. 2011 IRP RECOMMENDED CASE

	2020	SB 1368 Compliance Date		New Renewables Installed (MW) 2011-2020			New Renewables Installed (MW) 2011-2030			
Case ID	RPS Target	Navajo Replacement	IPP Replacement	Geo/ Biomass	Wind	Solar	Geo/ Biomass	Wind	Solar	Generic
Case 2	33%	12/31/2015	6/15/2027	243	492	726	308	492	917	162

The changing generation energy mix for 2010, 2020, and 2030 based on the Recommended Case is illustrated in Table ES-4.

Table ES-4. ENERGY MIX FOR RECOMMENDED CASE

Year	2010	2020	2030
Coal	39%	26%	0%
Natural Gas	22%	21%	45%
Nuclear	11%	9%	8%
Hydro	3%	4%	4%
Renewable	20%	33%	33%
Energy Efficiency [1]	0%	7%	10%
Generic Purchase/ Other	5%	0%	0%

[1] Forward-looking, does not include 3% existing as of 2010.

VIII CONCLUSIONS/RECOMMENDATION

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.

The analysis performed in Section 4 to identify the 2011 IRP recommended case closely mirrors the same recommended strategy put forth in the 2010 IRP which incorporated feedback from LADWP's 2010 community outreach efforts (See Section 5.2 and Appendix N for details). The 2011 IRP recommended strategy differs slightly from the 2010 IRP in the timing of the Navajo coal divestiture which is now planned for 2015 instead of 2013. Another difference is in the renewable installed capacity by technology type (e.g. geothermal, wind, and solar). The reasons for these changes are further explained in Section 3.2.1.

Regulatory and Reliability Initiatives

- SB 2 (1X) - RPS Percentage

  LADWP must increase its percentage of renewable energy per recently enacted state law, from the current 20 percent at the end of 2010, to 33 percent by the end of 2020. SB 2 1(X) also establishes interim targets to ensure progress towards the 33 percent goal. Addressing this mandate requires the continued diligence LADWP has demonstrated in raising its renewable portfolio from 3 percent in 2003 to 20 percent in 2010.

- Power Reliability Program and System Infrastructure Investment

  LADWP must re-establish sustained funding to invest in replacing aging transmission and distribution infrastructure to ensure system reliability, especially during significant weather events. Recent funding shortfalls have resulted in an increase in system outages. Section 1.6.2 of this IRP discusses the negative consequences that continued underfunding poses to the city.

- Repowering for Reliability and to Address OTC

  LADWP will continue to repower older, gas-fired generating units at its coastal generating station for the reasons discussed previously. The repowering program is a long term series of projects that will increase reliability and eliminate the need for once-through ocean cooling.

- AB 32 – CO_2 Cap and Trade

  LADWP will participate in the mandated green house cap-and-trade system which is scheduled to start January 1, 2013. During the next year, LADWP will participate in the regulatory process that will clarify some outstanding details of the proposed program.

- SB 1368 Compliance

  Navajo and 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 with a combination of renewable energy, demand response, EE, short term market purchases, and conventional gas-fired generation.

- Energy Efficiency

  LADWP will continue to pursue and implement energy efficiency programs per AB 2021 standards, including recommendations contained in its latest Market Potential Study.

- 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. In 2016, LADWP expects to file a notice-of-intent (NOI) and initiate the formal studies and applications for re-license. Based on reviews of re-licensing activity for similar projects, LADWP could expect cumulative expenditures of approximately $10 million prior to filing the NOI and approximately $80 million before the license expires.

- Transmission

  LADWP should implement those recommendations of the latest Ten-Year Transmission Assessment Plan in order to maintain reliability in accordance with regulatory guidelines.

Strategic Initiatives

- Early Compliance with SB 1368

  Comments from the public workshops indicated the desire to comply with SB 1368 as early as possible. Navajo must be compliant with SB 1368 by 2019. LADWP recommends divestiture from Navajo by 2015. This will reduce LADWP's CO_2 emissions by 7.5 million metric tons and required additional revenue of about $343 million.

  In this 2011 IRP, LADWP recommends no change in IPP until 2027 at which time the site would be reconfigured, providing LADWP with firm transmission capacity for potential renewable projects. However, LADWP is actively investigating potential options in coordination with the Intermountain Power Agency (IPA) Board and the other participants, and will further address this issue in next year's 2012 IRP.

- Local Solar

  Comments received at the public workshops indicate local solar development should be a priority in LADWP's renewables procurement strategy. LADWP is recommending a policy action to allow approximately 40-50 percent of its solar resources be sited locally through initiatives including the Solar Incentive Program, feed-in tariffs, and installation of solar on City-owned properties. Local solar costs an estimated additional $50/MWh over utility-scale solar located outside the Los Angeles Basin, estimated to cost $120/MWh, primarily due to economies of scale and about 30% better solar insolation, even when considering transmission and distribution costs.

- Public Benefits

  LADWP should continue to pursue public benefit initiatives, including low-income and lifeline programs, refrigerator exchange, conservation, public outreach and education.

- Advanced Reliability Improvements

  LADWP is looking ahead to technologies that will enhance the reliability of its system, including smart grid technologies, enhanced information systems, automation of system functions, and advanced methods of outage management. These enhancements will also better integrate local generation such as solar into the distribution network, enable smart charging of electric vehicles, and advance demand-side management technologies.

- System Losses

  To reduce system losses, LADWP should implement the recommendations of the recently completed Reactive Power Management Study, including the installation of shunt capacitors and shunt inductors at appropriate locations within the system grid.

- Demand Response

  LADWP should begin the development of a formal Demand Response program that will initially provide 5 MW of 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.

Revenue Requirements

The reliability, regulatory, and strategic initiatives discussed above require revenue funding as shown in Table ES-5. In addition to funding for basic generation, transmission, and distribution, revenue is required to fund the Power Reliability Program, increase renewable energy, address OTC, energy efficiency and demand reduction, fund local solar programs, and transition away from coal.

Table ES-5. RECOMMENDED REVENUE REQUIRED TO FUND PROGRAM INITIATIVES, 2011-2020

PROGRAM INITIATIVE	Revenue Requirement ($ Billion)
Power Reliability	$6.8
OTC Repowering of Power Plants	$1.2
Transition from Coal (Navajo GS)	$0.4
Increasing Renewable Energy	$6.0
Expand Renewable Transmission	$0.5
Expand Local Solar	$0.7
Increasing Energy Efficiency	$0.7
Smart Grid Investments	$0.3
SUBTOTAL	$16.6
Basic Generation, Transmission and Distribution	$23.4
TOTAL	$39.9

Some elements of the plan will take five to ten years to implement. It is important to commit to a direction so that critical time and resources are not lost. Subsequent IRPs will refine the direction as additional information becomes available. The recommended plan allows for flexibility to incorporate necessary adjustments over time. It is also important to set a steady course and pace to allow for reasoned and deliberate action by LADWP staff, Board, or City Council to avoid situations leading to unfavorable pricing or adverse rate impacts. The IRP implementation must be viable from a technical and financial perspective to best balance all the priorities of reliability, environmental stewardship, and cost.

1.0 INTRODUCTION

1.1 Overview of the 2011 Integrated Resource Plan

This document represents the Los Angeles Department of Water and Power (LADWP) Integrated Resource Plan (IRP) for 2011. The goal of this IRP is to identify a portfolio of generation resources 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 IRP considers a 20 year planning horizon to guide LADWP as it executes major new 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:

- High reliability of electric service
- Competitive electric rates consistent with sound business principles
- Responsible environmental stewardship meeting 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, allow for volatility in fuel and other cost factors, comply with federal, state, and local regulations, and guarantee fiscal responsibility.

The 2011 integrated resource planning process developed alternative strategic cases that assess different options of divestiture from coal-fired generation. These 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.

1.2 Organization of the IRP

This document begins with a brief discussion of the objectives of this IRP (Section 1.3).

Section 1.4 provides a brief overview of the current Power System—LADWP's electricity generation, transmission and distribution infrastructure. Power System upgrades are also addressed.

Section 1.5 summarizes LADWP's major recent accomplishments, underscoring LADWP's commitment to environmental leadership, maintaining a high level of electric service reliability, and competitive energy rates.

Section 1.6 summarizes the key issues and challenges facing LADWP. As the largest municipal utility in the U.S., LADWP faces unique challenges that are expected to become more complex and demanding over the timeframe considered in this IRP.

Section 1.7 summarizes the Public Outreach effort conducted in as part of the 2010 IRP process. The 2010 public outreach conclusions are considered applicable to this 2010 IRP. Next year's 2012 IRP process will include a new public outreach program.

Section 1.8 discusses the 2011 IRP development process that resulted in this document.

The remainder of this IRP is organized as follows:

- 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.
- Section 3, "Strategic Case Development," establishes potential alternatives available to LADWP to meet its projected electricity demand.
- Section 4, "Strategic Case Analysis," addresses the operational modeling used to assess the impact of each alternative on cost, energy rates, and levels of greenhouse gas emissions.
- Section 5, "Recommendations," provides an overview of recommendations, including near-term actions and long-term goals.

1.3 Objectives of the IRP

This 2011 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.

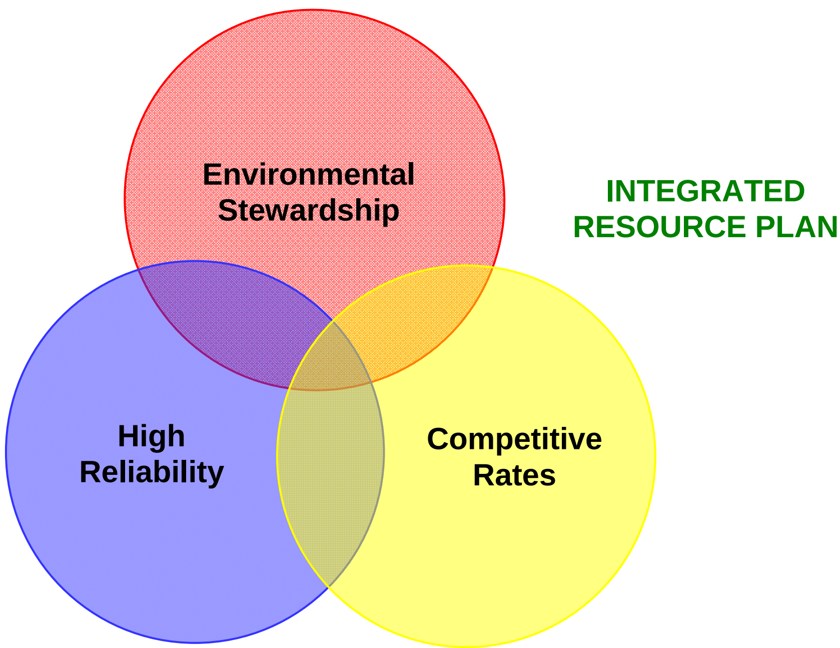


Figure 1-1. Objectives of this IRP.

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 will comply with all Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) standards regarding system reliability. NERC and WECC are electric utility organizations that enforce reliability standards on owners, operators and users of the bulk power system.

- CAISO/RTO

  The California Independent System Operator or CAISO was established in 1998 as part of California's electric utility restructuring effort. CAISO was established as a non-profit corporation to provide an impartial link between power plants and utilities. LADWP is not a member of the CAISO but has recently been certified by the CAISO to be a scheduling coordinator which will authorize LADWP to buy and sell energy and/or ancillary services in the CAISO market. The ability to interface with CAISO increases the reliable operation of the bulk power system.

- Balancing Authority

  LADWP is a registered Balancing Authority with NERC and is responsible for coordinating and balancing the 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. This policy serves the City of Los Angeles well. However, in consideration of economic and environmental factors involved with the coal divestiture options (discussed in Section 3 and 4), a limited amount of generation capacity is proposed to come from 3rd quarter purchases acquired in the wholesale electricity market. These purchases will be temporary in the 2015 to 2030 timeframe, will be called upon only in the third quarter of a given year, and will amount to less than 4% of the total system capacity needs.

- 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 that is 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 1.6.5 and Appendix C for more details.

- Power Reliability Program

  In response to an increasing frequency of 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 avert prevent problems before they occur, and (3) establishing replacement cycles for facilities that are in alignment with the equipment's life cycle. See Section 1.6.2 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 disturbances, and 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.

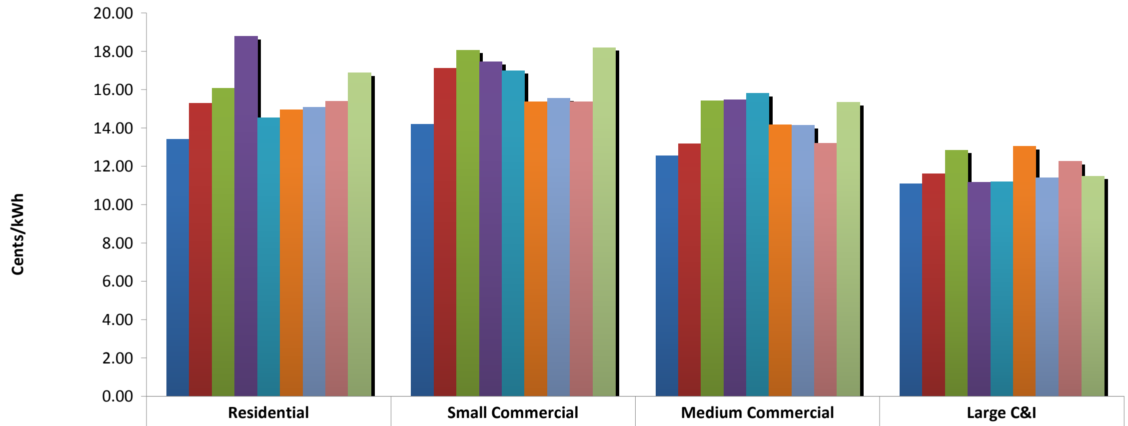
1.3.2 Competitive Rates Consistent With Sound Business Principles

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

As shown in Figure 1-2, LADWP's rates for Fiscal Year 2010/2011 were lower than other utilities in Southern California.

Annualized Rates Comparison for the Fiscal Year 2010/2011



	Residential	Small Commercial	Medium Commercial	Large C&I
LADWP (July 2011)	13.41	14.21	12.56	11.10
SCE	15.30	17.12	13.17	11.63
PG&E	16.08	18.06	15.44	12.86
SDG&E	18.78	17.46	15.49	11.18
Anaheim	14.54	17.00	15.81	11.21
Burbank	14.95	15.38	14.18	13.05
Glendale	15.08	15.58	14.15	11.40
Pasadena	15.39	15.37	13.22	12.27
Riverside	16.87	18.21	15.35	11.50

Rate Class

Figure 1-2. LADWP rate comparison among other electric utilities.

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

Financial Metrics

Since LADWP sells substantial amounts of bonds to sustain 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:

- Bond rating

  Maintain LADWP's current "AA" bond credit rating to keep financing costs as low as possible.

- Debt service coverage

  Maintain a debt service coverage ratio of at least 2.25

- Adjusted debt service coverage

  Maintain an adjusted debt service coverage ratio of at least 1.75

- Full obligation coverage

  Maintain a full obligation coverage ratio of 1.5

- City transfer

  Maintain a level of net income sufficient to ensure stable transfer of funds to the City.

- Cash on hand

  110 days of operating cash or $300 million, whichever is greater.

- Capitalization ratio

  Maintain a capitalization ratio of 65% percent or less.

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 efforts to increase its use of renewable energy resources to provide electricity to Los Angeles. 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. For more information, see Sections 1.5, 1.6.4, 2.4, 3.4.2, and Appendix D.

- Carbon dioxide (CO_2) emissions

  LADWP will continue its efforts to reduce CO_2 emissions. The potential early divestiture from coal-fired generation, a key strategic focal point of this 2011 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 1.6.3 and Appendix C.

- Once-Through Cooling

  LADWP has embarked on a series of repowering projects that are reducing the use of ocean water for cooling at its coastal generating stations. Completed projects to date have already reduced ocean water use by 17% from 1990 levels. The Haynes 5 & 6 repowering project, currently in construction and scheduled for completion in 2013, will further reduce ocean water use by another 25%. Within the 20-year planning horizon of this IRP, five additional repowering projects will totally eliminate the use of ocean water. More information on OTC can be found in Sections 1.6.5.

- Energy efficiency

  Since 2000, LADWP has spent approximately $282 million on its energy efficiency programs, and these programs have reduced long-term peak period demand and consumption by approximately 303 MW and 1,256 GWh, respectively. 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

  To date, LADWP has encouraged the installation of more than 41 MW of solar installations at over 4,500 customer locations through its ratepayer-funded Solar Incentive Program. Additionally, LADWP is developing a feed-in tariff program that will further promote solar development across the city. Solar energy will help LADWP achieve its environmental goals of increased energy generated from renewable resources and the reduction of greenhouse gas emissions.

- Demand Response Program

  This IRP recommends the development 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. Details regarding the proposed DR program are included in Section 2.3.2.

1.4 LADWP's Power System

"Capacity" is an electric utility term referring to how much power a system can generate at a given instant in time, while "energy" refers to how much power the system generates over a given period of time. Capacity is expressed in megawatts (MW) or gigawatts (GW), while energy is expressed in megawatt-hours (MWh) or gigawatt-hours (GWh).

LADWP's Power System serves approximately 4.1 million people and is the nation's largest municipal electric utility. LADWP experienced an all-time 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. The current economic recession has reduced energy demand slightly over the preceding three years.

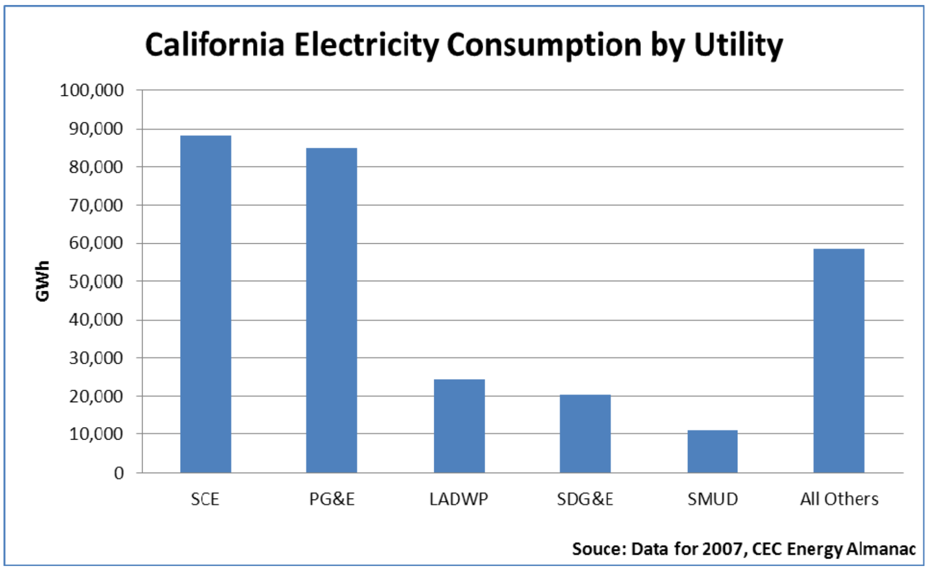


Figure 1-3. Comparison of California utilities by consumption.

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, and enables the transport of power from a diversified set of generation resources from across the Western United States.

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.

- 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 reduced long-term peak period demand by approximately 303 MWs, resulting in 1,256 GWh of energy savings.

- Emissions reduction

  As of 2010, CO_2 emissions from power generation are 23% lower than 1990 levels. The lower emissions are attributed to the respective sales of 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 level,

- 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 can facilitate the integration of intermittent renewable energy. This project is also one of many 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. See Section 1.6.2 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. Over 17,100 LADWP customers participated in the program during 2010. These participants receive approximately 104,000 MWh of renewable energy annually. Since program inception, in 1999, to the end of 2010, 818,768 MWh of renewable energy was procured, making it one of the largest voluntary green pricing programs in the nation.

- Solar Incentive Program

  To date, LADWP has encouraged the installation of 41 MW of solar at approximately 4,500 customer locations through its ratepayer-funded Solar Incentive Program.

- Upgraded capacity on the Southern Transmission System (STS)

  In May 2011, 480 MW of additional capacity was added to the existing transmission line from Utah, of which LADWP's share is 288 MW. The increased capacity allows LADWP to increase procurement of renewable energy.

- Navajo Generating Station retrofitted with low NO_X burners

  In March 2011, Navajo 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, 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 next step for the project is to upgrade and build a new transmission line from the new substation to a new Haskell Canyon Station near Santa Clarita.

- 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 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.

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.

However, the inability to fund the programs designed to address these issues warrants some discussion. Current budget constraints are deferring a number of initiatives and programs. 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.

1.6.1 Adequate Multi-year Funding to Support Programs

Based on last year's 2010 IRP, a multi-year rate increase was recommended beginning fiscal year 2011-12. The rate increase would have supported elements of last year's 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.

A multi-year funding plan is necessary to provide consistent and sustainable project and program development. Funding that is based on annual budgets are subject 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.
- 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.

A rate process that began earlier this year is addressing the revenue needs for LADWP. A proposed 3-year rate adjustment that would support the programs listed above is being considered. The expectation is that the rate process will conclude sometime in 2012. 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.

Aging Facilities and Infrastructure

LADWP's generating units sited within the Los Angeles Basin were primarily built in the late 1950s and early 1960s. While these units have undergone extensive upgrades, they are approaching the end of their service lives. Repowering of these units began in 1994, and refurbishment is approximately one-third complete. Repowered units will be substantially cleaner, more efficient, and more reliable 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.

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 on-line. No other means of voltage control, such as static capacitors and reactors, have been installed. As a result, LADWP's ability to control voltage has decreased. As more renewables become available, even fewer local generating units are likely to be on-line, and the ability to control nighttime voltage may become unmanageable.

Grid Reliability

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. LADWP has also investigated the system's reactive power needs, and recommends further improvements to reduce system losses and optimize performance. More information can be found in Section 2.4.4.

Integration of Intermittent Renewable Energy

The integration of renewable energy into the grid poses major challenges. Integrating renewables may, paradoxically, require additional gas–fired generation. 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 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. This stabilization is known as “regulation.” A preferred solution would use energy storage to regulate delivery of energy and reduce the severity of integration problems. LADWP currently uses, among other resources, pumped water storage and hydro resources for regulation. Batteries and compressed air offer alternative storage solutions, but those technologies are still in development and have not yet been proven as commercially viable.

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

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.[1] In response, 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.

The PRP has clearly defined annual targets for various distribution, substation, and transmission assets. While cable replacements consistently reached ideal replacement rates, the overall number of underground related outages has been falling. However, the overhead distribution replacements did not reached their ideal replacement rates, and the number of overhead outages has continued to rise. This has also contributed to the overall aging of the overhead system. Overhead outages have increased and are expected to continue to degrade with less replacements moving forward. Since 72% of the distribution system is overhead, we can expect the overall distribution outage rate to continue to increase unless replacements are increased dramatically.

[1] To illustrate the age of the City’s distribution system, over 50 percent of the 308,000 distribution poles are at least 50 years old.

In the years since the program was implemented, a clear correlation has been established between the amount of funding for PRP and the successful reduction of outages. As shown on Figure 1-4, during the initial 3 years of the PRP, when the program was fully funded, total outages declined by 28%. Budget constraints since then, however, have resulted in program underfunding. As a consequence, outage frequency has flattened out and is on the up rise. The projected outage levels shown in Figure 1-4 reflect current budget shortfalls. Adequate funding is necessary to get the PRP back on track towards its goal of reducing outage levels.

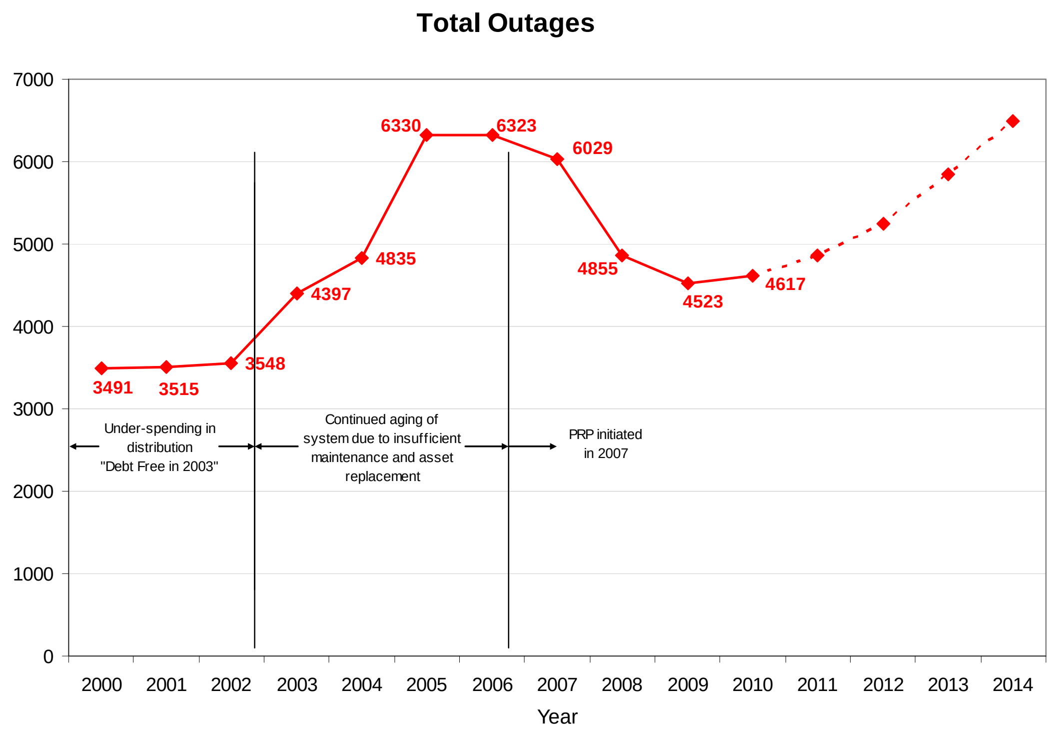


Figure 1-4. Total outages between 2000-2010, and projected to 2014.

Additional information on LADWP's PRP can be found in Appendix E.

1.6.3 GHG Emissions Reduction

LADWP's GHG emissions reduction strategy must comply with state and federal regulations. At the time of this writing, key legislation and regulations either promulgated or proposed include:

- Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006, calls for reducing the state's GHG emissions to 1990 levels by 2020. The regulations for implementing a greenhouse gas emissions trading 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. Electric distribution utilities, including LADWP, will receive an administrative allocation of emission allowances that reflects their respective annual emissions as they implement aggressive energy efficiency measures and the 33 percent Renewable Portfolio Standard. The ARB will continue to work with stakeholders to monitor the impacts of the regulation on all sectors, including the electricity sector.

- SB 1368, the California Greenhouse Gas Emissions Performance Standard Act, also 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.

In the absence of comprehensive federal climate legislation, the U.S. Environmental Protection Agency (EPA) has taken steps toward regulating GHG emissions from electric power plants under authority of the federal Clean Air Act, and will be issuing a new revised schedule for regulations in the coming months.

LADWP has historically relied upon coal for base load generation. Currently, 39 percent of the energy delivered to LADWP customers is 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 land lease expires in 2019 but has a stipulation for a 25-year extension. IPP's contract is in effect until 2027. These stations provide dependable, low cost base load generation to Los Angeles. Coal-fired generation, however, emits about twice as much CO_2 as energy generated with natural gas. Accordingly, this 2011 IRP focuses on early coal divestiture options as a means to comply with AB 32 and lower LADWP's GHG emission levels. Sections 3 and 4 discuss the alternative strategic case options in detail.

1.6.4 Increasing Renewable Resources

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

- 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.

- State legislation – SB 2 (1X) – which was passed in April 2011 and became effective December 10, 2011, will subject 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
- Achieve 33 percent renewables by 2020 and maintain this level in all subsequent years.

In addition, SB 2 (1X) sets certain conditions regarding renewable energy contracts entered into on or after 6/1/2010, as shown in Table 1-1.

Table 1-1. SB 2 (1X) CATEGORY REQUIREMENTS FOR RPS ENERGY CONTRACTS

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)
A	Minimum 50%	Minimum 65%	Minimum 75%
B	See footnote 2	See footnote 2	See footnote 2
C	Maximum 25%	Maximum 15%	Maximum 10%

[1]Categories are defined as follows:

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

Category C = Energy or RECs from eligible resources that do not meet the requirements of category A or B, including unbundled RECs.

[2]Remainder % of resources which are neither in Category A nor Category C.

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 farms into the LADWP power grid 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.

1.6.5 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 major 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 total generation capacity affected by OTC is significant – approximately 2,162 MW, or roughly 35 percent of LADWP's annual peak demand in 2010. The total expenditures required are also significant, on the order of $2.4 billion. Because of the size and scope of the work required, and for various reasons discussed below, the work to comply with OTC 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 been replaced even without the OTC requirement. However, the OTC mandate requires some units to be replaced sooner than what may have been otherwise.

Discussions between LADWP and the SWRCB have resulted in the following timeline for OTC compliance (Figure 1-5).

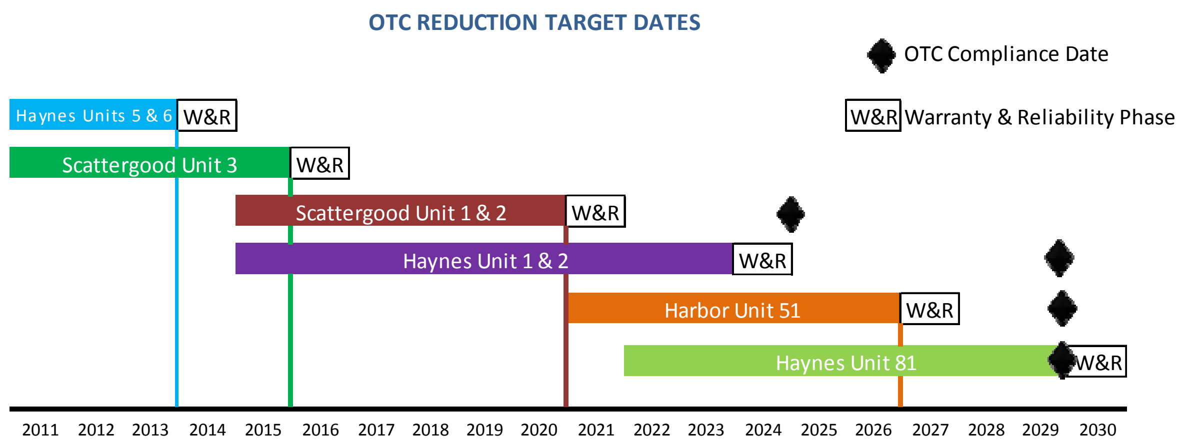


Figure 1-5. Timeline for OTC compliance.

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 the peak summer demand. An older existing unit 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 1-5.

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 1-5 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 1-6. 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.

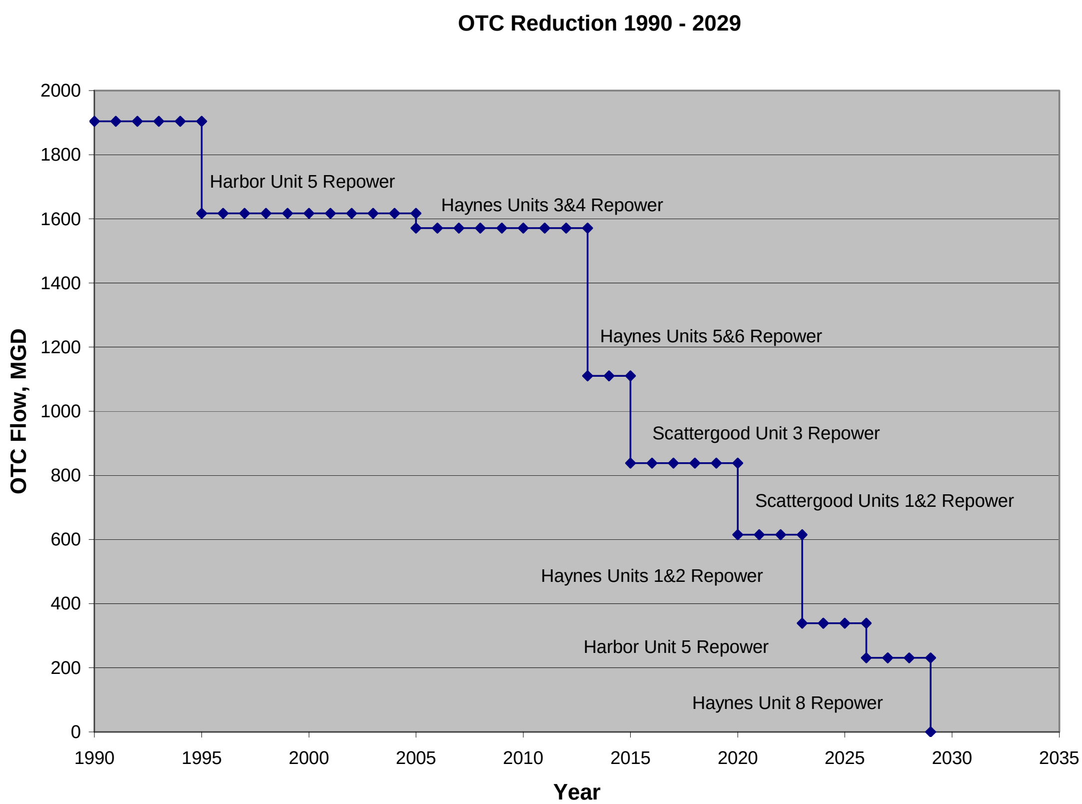


Figure 1-6. LADWP's reduction in once-through cooling from 1990 to 2029.

1.6.6 Additional Challenges

Additional challenges that LADWP must address include an increased risk from natural gas price volatility, cyber security legislation, hydro-plant re-licensing, 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. The energy profiles of all strategic cases analyzed in this IRP are composed of approximately 45 percent gas-fired generation by 2030. 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.

- Cyber Security Legislation

  Cyber security legislation which provides additional authority to the federal government, has been pending for several years. The Grid Reliability and Infrastructure Defense Act (GRID Act) of 2011 would grant new authority to the Federal Energy Regulatory Commission (FERC) to determine power system vulnerabilities and required actions by the power industry, and additional authority related to physical security and other threats. 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.

- 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. Based on reviews of re-licensing activity for similar projects, LADWP could expect cumulative expenditures of approximately $10 million prior to filing the NOI and approximately $80 million before the license expires. From DWR's recent experience at re-licensing of Oroville Dam, they have informed LADWP that future mitigation cost could exceed $1 billion dollars for a new 50-year license period.

- 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 off peak as on peak, 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 sales when compared to peak. 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. It is imperative that LADWP implement tools to shift load from peak hours to off peak hours to reverse this trend and improve system performance.

1.7 Public Process

LADWP conducts a public review process on their IRP every other year. A public review process was held in the fall of last year in support of the 2010 IRP. The review process included a series of public workshops and stakeholder meetings with representatives from neighborhood councils, environmental groups, and local business associations. The 2010 public review process is relatively recent, and the input gathered and the conclusions that emerged from that process remain mainly intact. A full scale public outreach program, similar to the one held in 2010, is planned for next year's 2012 IRP.

Therefore, this 2011 IRP relies on the findings from last year's public outreach effort (for details see Appendix N). In summary, following are the themes that emerged.

LADWP should:

- Emphasize a variety of energy resources
- Maximize energy efficiency and conservation
- Eliminate coal from its generation portfolio
- Emphasize local solar generation
- Avoid adverse impacts to vulnerable communities
- Clarify costs of IRP implementation and potential impacts to ratepayers
- Reduce environmental impacts
- Provide proactive leadership and transparency

Section 5 includes a discussion on how LADWP incorporated these ideas into its recommended strategy.

1.8 2011 IRP Development Process

Note: The 2011 IRP process did not include public review. Next year's 2012 IRP process will include a public outreach program similar to the one conducted as part of the 2010 IRP.

The IRP is prepared by a group of engineers dedicated to LADWP resource planning and preparation of the IRP. This group is managed by a Supervising Engineer, with a direct reporting staff of four. While this group performs the production model and report preparation for the IRP, the bulk of the work is collaborative across the different work groups and functional areas of the Power System.

The IRP is developed in multiple stages, including:

1. <u>Identifying and approving key assumptions</u>

   The assumptions form the basis for subsequent analysis, and include such factors as load and fuel price forecasts, renewable resource percentages 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.

2. <u>Establishing clear goals and objectives</u>

   The overarching goal of LADWP's IRP planning efforts is to produce a long term plan that ensures the 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. <u>Establishing strategic case alternatives</u>

   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 area for LADWP is coal divestiture; therefore, this IRP considers three alternative options for reducing coal-fired energy (whereas last year a decision area was the amount of renewable energy to adopt, it is no longer discretionary due to regulatory mandates, and is not a distinguishing feature among the current alternatives). Each case is vetted through LADWP management and working meetings are held to agree on final cases to be assessed.

4. Completing 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, including a third party consultant review. 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.

5. Recommending and approving a preferred case

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

Each of these stages includes coordination between multiple LADWP organizations responsible for different aspects of power system operations, preparing recommended positions for each stage, presenting recommendations to LADWP's leadership team, including Division and Section Heads, and ultimately presenting recommendations to the General Manager. At each of these presentations, modifications to recommendations are noted. The approval process for recommendations is based on consensus from the managers of each area of responsibility.

1.9 Conclusions

Addressing all of these challenges requires considerable amounts of labor and capital resources, which applies upward pressure on LADWP's electric rates. It is important to note that LADWP cannot compromise on its responsibility to ensure adequate reliability of its power system. As facilities age, they must be repaired and eventually replaced.

LADWP is focusing on both near-term and long-term solutions. Attainment of the objectives and goals documented in this 2011 IRP will require the continued implementation of existing programs and projects, as well as the introduction and expansion of 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 2011-2016

Program Areas in Progress

- **Haynes 5&6 Repowering** (Sections 1.6.5, 2.4, 3.2.1, and 3.3; Tables 4-5, 5-3, and 5-4; Appendix F)
- **Scattergood Repowering** (same as Haynes 5&6 references)
- **Coal Divestiture Planning and Implementation** (Sections 1.6.3, 2.4, 3.2.1, 3.3, 3.5, 4, and 5)
- **Replacing aging distribution infrastructure** (Sections 1.6.2; Appendix E)
- **RPS procurement** (Sections 2.4, 3,4, and 5; Appendices D and M)
- **Solar Program Development** (Sections 2.4, 3.2, and 5; Appendices D, G, and M)
- **Existing EE program elements** (Section 2.3; Appendix B)

New Program Areas

- **Demand Response Program** (Sections 2.3.2, 3.2.1, 5.3, and 5.6; Table 4-3)
- **New EE program elements** (Section 2.3; Appendix B)
- **Smart Grid Implementation** (Section 2.3.4; Appendix L)
- **Transmission Line Improvements** (Sections 2.4.4 and 5; Appendix I; Tables 4-5 and 5-3)
- **Grid Reliability Improvements** (Sections 2.4.4 and 5)
- **Haynes 1&2 Repowering** (Sections 1.6.5 and 3.3)

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
- Supply-side Resources
- Transmission/Distribution
- 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 like the California Energy Commission (CEC), California Public Utilities Commission (CPUC), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), 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

For this IRP, LADWP developed a forecast of customer demand for energy over the next 20 years (the complete 2011 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 2011 Retail Electrical Sales and Demand Forecast

The effect of the recent recession and slower than normal recovery combined with cooler than normal weather depressed electricity sales by approximately 6 percent off their fiscal year 2007-08 peak. Losses 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 remain flat over the next three years. The load forecast predicts an increase of 1.6 percent in 2014-15 due to the expected completion of large mixed-use projects. The growth in annual peak demand over the next twenty years is predicted to be about 1.1 percent—approximately 65 MW per year—with less growth over the next few years due to the current recession. After 2016, some of the growth will not be realized at the meter depending on the adoption of energy efficiency and distributed generation technologies.

The 2011 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 September 2010 are reconciled to the General Accountings Consumption and Earnings Report.	*Historical Sales, Net Energy for Load and weather data is updated through September 2010.*
2. Historical NEL, peak demand and losses through September 2010 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 March 2010.*
4. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2009 benchmark.	*Employment data is updated through September 2010 using the March 2009 benchmark.*
5. Historical population and forecasts is provided by the State of California Department of Finance.	Population data is updated through January 2010.
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 September 2010.*
8. The plug-in electric vehicle (PEV) forecast is based on the CEC 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 through 2016 represents sales that will be realized at the meter. 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.

Energy efficiency and customer solar installations cause about a two percent drop in retail electricity sales. The remaining decreases in the next two years are attributed to economic conditions. Personal consumption should decrease as personal income flattens and savings and tax rates increase. Vacancy rates in the commercial sector are expected to increase short term. Manufacturing jobs are forecast to continue to decline. Retail electricity growth will lag growth in the economy somewhat. Businesses will become more efficient and begin to increase their operating margins as the economy improves. As shown in Figure 2-1, once the operating margins increase, new hiring will begin again and then retail electricity sales will begin to grow.

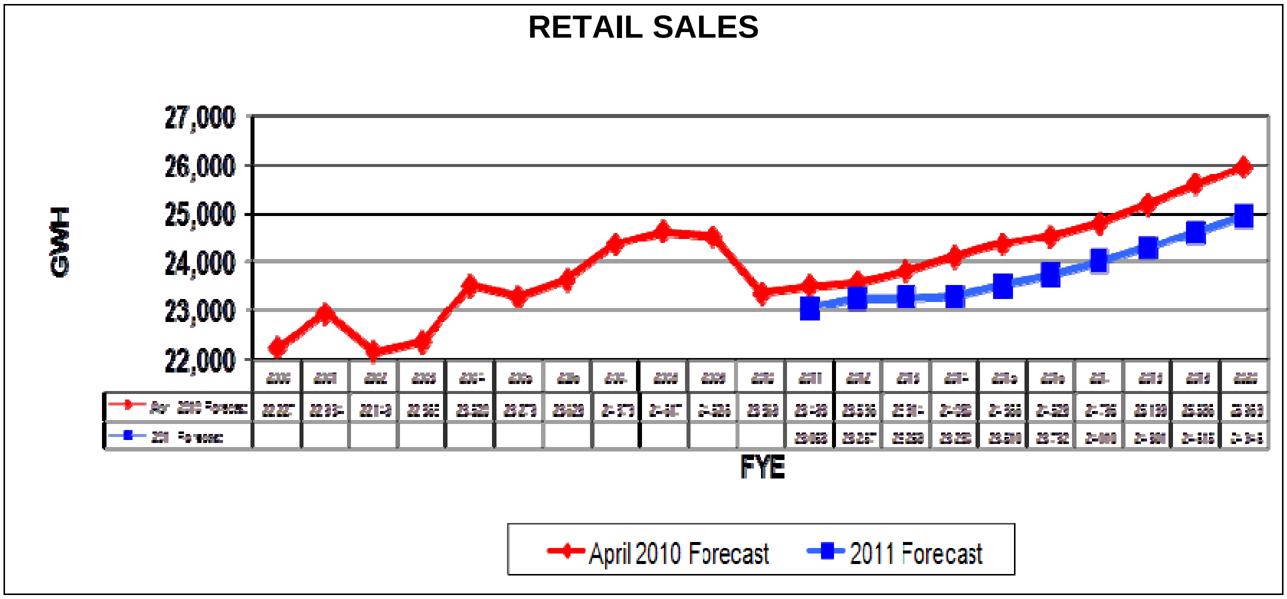


Figure 2-1. Retail sales net of energy efficiency and distributed generation.

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)**	**YOY Growth Rate**	**(GWH)**
2009-10	23,491	-4.2%	10
2010-11	23,051	-1.40%	176
2011-12	23,221	0.7%	383
2012-13	23,175	-0.2%	676
2013-14	23,258	0.4%	928

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.

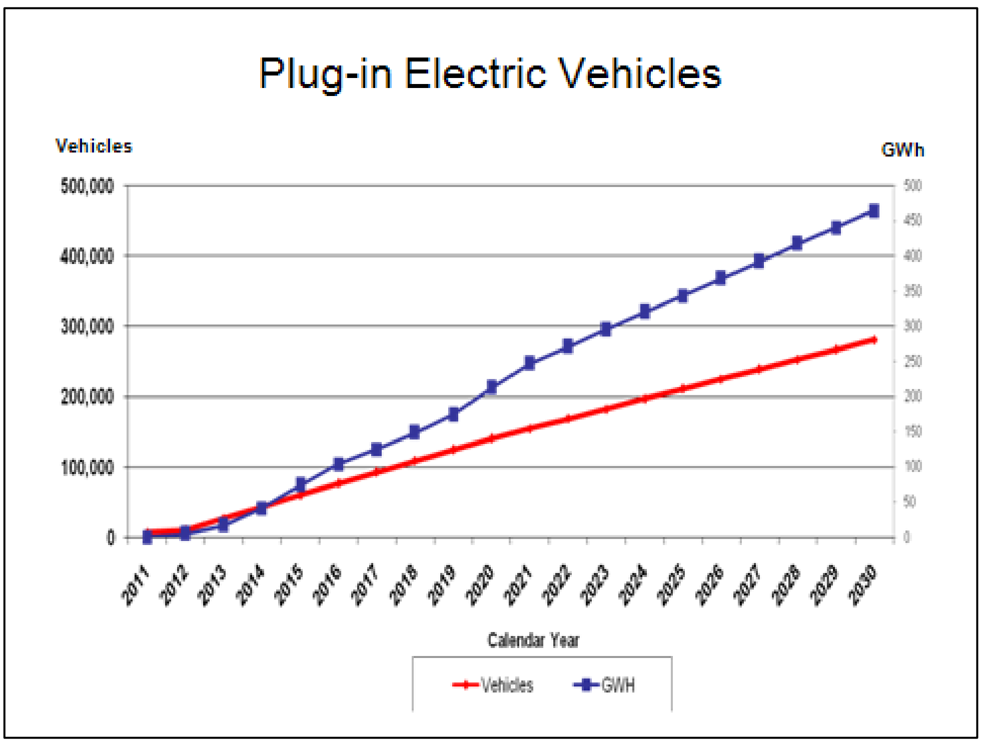


Figure 2-2. Forecasted number of plug-in electric vehicles.

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)
2010-11	5589[1]		6042
Forecast			
2015-16	5809	0.8%	6277
2020-21	6211	1.0%	6710
2030-31	7000	1.1%	7560
2040-41	7780	1.1%	8403

[1] Weather-normalized. Actual peak was 6142 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 2009 is 5589 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.

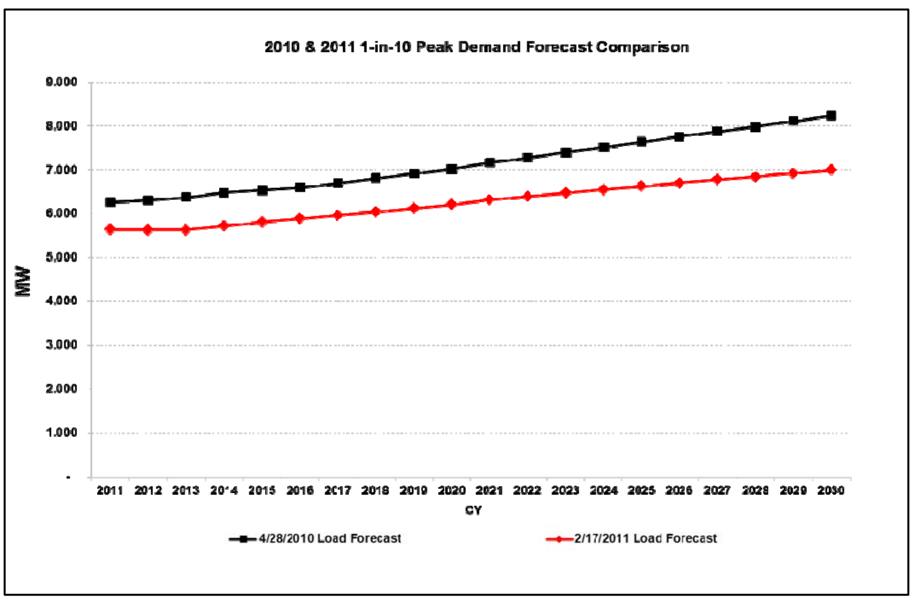


Figure 2-3. One-in-ten peak demand forecast comparison.

2.3 Demand-Side Resources

Demand Side Resources (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 and related support areas:

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

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.
- Information regarding the impact of "Smart Grid" technology on customer load profile and resource requirement.

2.3.1 Energy Efficiency

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

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.
- A recent program, which distributed two free CFLs to LADWP's 1.2 million residential customers through direct-to-door distribution. The intent of the one-time direct-to-door distribution was to achieve cost effective energy savings and increase customer awareness of this inexpensive, yet effective, EE measure. CFLs were also distributed at events and in connection with other energy efficiency programs.

Since 2000, LADWP has spent approximately $282 million on its energy efficiency programs, and these programs have reduced long-term peak period demand and consumption by approximately 303 MW and 1,256 GWh, respectively. LADWP is committed to developing comprehensive programs with measurable, verifiable goals as well as implementing robust, cost-effective energy efficiency programs.

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 "Market 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.

The study evaluated a multitude of measures for potential inclusion into LADWP's EE program; including:

- LADWP's existing program elements
- High-efficiency air conditioners (higher efficiency levels, variable refrigerant flow systems)
- High-efficiency lighting (CFLs, LED lamps)
- Upgraded insulation in buildings
- Retro-commissioning and routine maintenance
- Programmable communicating thermostats and energy management systems

The following recommendations resulted from the 2011 potential study:

Residential Sector

- LADWP should keep its existing programs, with the exception of CFL Distribution, which should be replaced with a broader Energy Efficient Lighting Program.
- Two new programs should be adopted: (1) Low-Income Energy Efficiency and (2) Whole House Performance.
- Continue public outreach to maintain and broaden public awareness of available EE benefits, and to promote participation.

Commercial and Industrial Sector

- LADWP should keep its existing program elements, but should modify its lighting program to educate customers on expanded choices that will comply with new lighting standards.

The ten-year EE plan, incorporating budget, capitalization, and driver considerations is shown in Table 2-4. These projections have been incorporated into the IRP production model and are factored into the case analysis described in Section 3 of this IRP.

Table 2-4. RECOMMENDED EE PROGRAM PLAN

FY Ending	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Program Cost ($Million)	50	50	67	87	100	100	100	100	100	100
Annual Net Savings (GWh)	118	224	164	182	217	183	96	98	99	63
Cumulative Net Savings (GWh)	118	362	526	708	925	1,108	1,204	1,302	1,400	1,463
Savings as a % of Baseline	0.5%	1.6%	2.3%	3.0%	3.9%	4.6%	5.0%	5.3%	5.6%	5.8%

Further information regarding LADWP's EE program is included in Appendix B.

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 mechanism. The objective of DR is to lower energy usage at critical peak demand periods, which will lower overall system costs. DR programs are voluntary; customers that choose to participate are compensated through lower rates, rebates, or other financial incentive.

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 reduces wholesale energy costs by reducing the amount of energy that would otherwise be purchased to meet load. 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 2011 IRP is to provide funds to develop and implement DR. The analysis of all strategic cases considered in this 2011 IRP (discussed in more detail in Section 4) calls for a small 5 MW DR program beginning in 2013 that gradually builds to 200 MW by 2020 and 300 MW by 2030. This will provide adequate learning 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 currently common in the industry. Depending on the circumstances of how energy is used, certain programs will be more suitable to particular customer segments than others.

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

<u>Critical Peak Pricing</u> – Retail electric rates are temporarily adjusted up, typically as a response to events or conditions such as extreme high peak loads. 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 is a lower base rate throughout the year.

<u>Peak Rebate Pricing</u> – Similar to Critical Peak Pricing, but instead of raising the customer’s rate during an event (which creates a disincentive), a positive incentive is created where the customer receives a rebate for reducing or shifting their load during the peak load event.

<u>Real Time Pricing</u> – 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 aware of the changing market prices on a continual 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.

<u>Demand Bidding</u> – 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.

<u>Curtailable/Interruptible</u> – 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.

<u>Aggregation Programs</u> – 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 2011 IRP recommends funding to initiate a formal DR program with the capacity targets as shown in Table 2-5:

Table 2-5. DEMAND RESPONSE TARGET SCHEDULE (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 divestiture. Section 4 discusses the strategic cases in detail. As shown in the case analysis, DR is a key part 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 that have provided considerable experience and data. LADWP is closely monitoring fuel cell development.

More details regarding DG can be found in Appendix G.

2.3.4 Smart Grid

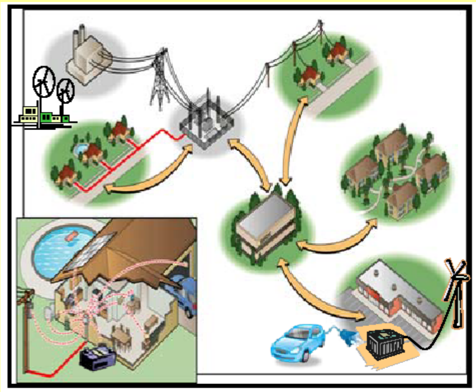
"Smart Grid" is a term used to describe a variety of advanced information-based utility improvements. Smart Grid refers to intelligent data gathering and advanced two-way digital communication capabilities overlaid on electric distribution networks to provide real-time data that enhances the utility's 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.

LADWP is implementing eleven Smart Grid initiatives:

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*



1. Renewable Integration
2. Transmission Automation
3. Substation Automation
4. Distribution Automation
5. Advanced Metering Infrastructure
6. Demand Response
7. Advance Telecommunications
8. System and Data Integration
9. Cyber Security
10. Feed-in Tariff
11. Solar Incentives

Through a US Department of Energy grant in 2009, LADWP 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 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
- Spot Sales

The major issues affecting generation are then 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/Grid Reliability
- Reserve Requirements

The LADWP Power System has a diverse mix of generating resources. Figure 2-4 shows LADWP's Power System capacity and energy breakdown as of December 31, 2010 as well as what the capacity and energy mix was at the end of 2006.[1] The largest change between these two periods is the decrease in coal-fired energy from 47 percent in 2006 to 39 percent in 2010, and the corresponding increase in energy from renewable resources, from 7 percent in 2006 to 20 percent in 2010.

[1] "Capacity" and "Energy" are electric utility terms that distinguish between how much power the system is capable of generating at a given instant in time (capacity; in megawatts) and how much power the system generates over a given period of time (energy; in megawatt-hours). Capacity numbers are expressed in MW, and energy numbers are expressed in MWh.

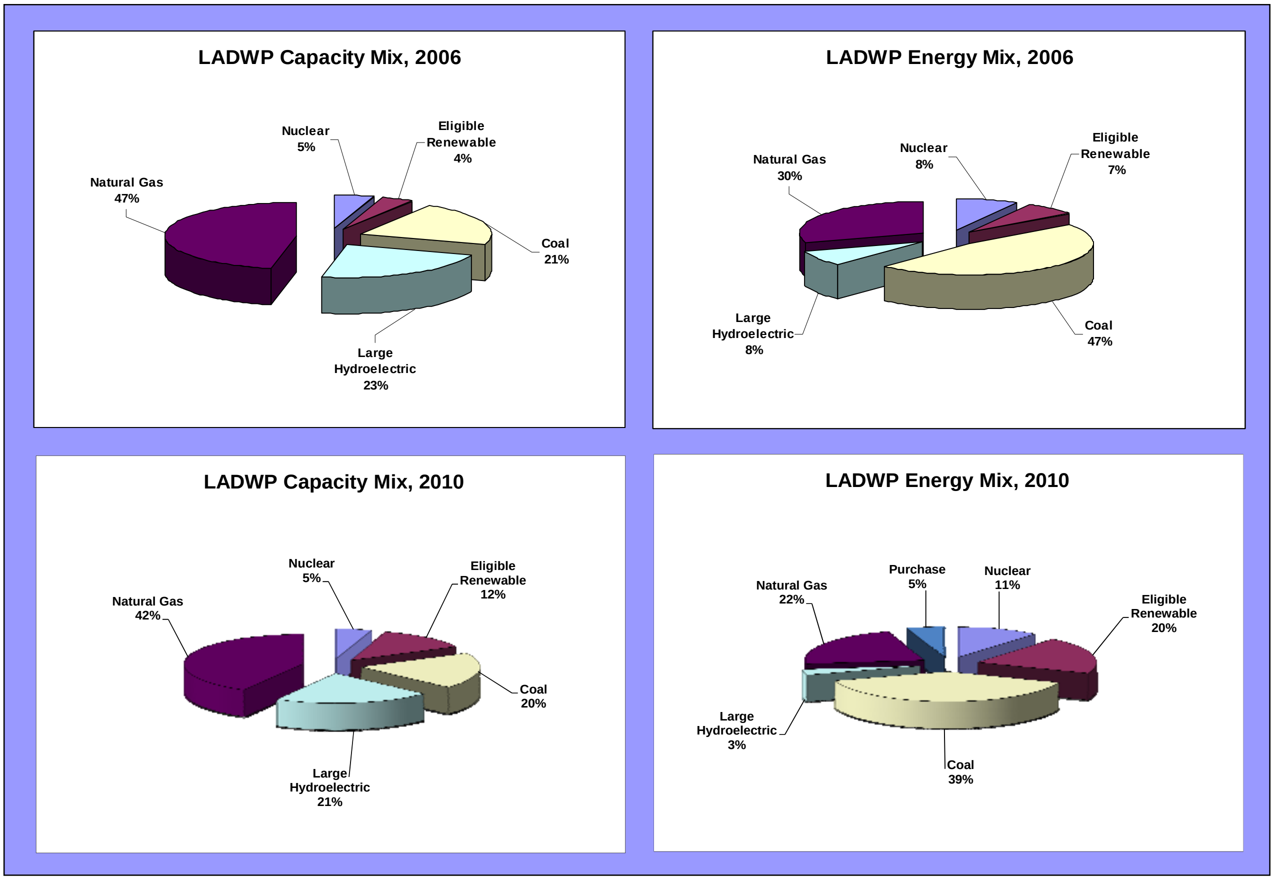


Figure 2-4: LADWP capacity and energy mix for 2006 and 2010.

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 2-6 lists existing LADWP generation resources.

Table 2-6: Capability of existing LADWP generating resources (as of September 2011)

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	16	82	466	461	Units 1, 2 and 5 operate as a combined cycle unit. Once-through cooling (OTC)
		2	1995	16	82			
		5	1995	16	65			
		10	2002	9	47.4			
		11	2002	9	47.4			
		12	2002	9	47.4			
		13	2002	9	47.4			
		14	2002	9	47.4			
Haynes Generating Station	Natural Gas	1	1962	49	222	1555.6	1525	Units 8, 9 and 10 operate as a combined cycle unit. Unit 7 is used for auxiliary power only. OTC
		2	1963	48	222			
		5	1966	44	292			
		6	1967	44	243			
		7	1970	41	1.6			
		8	2005	6	250			
		9	2005	6	162.5			
		10	2005	6	162.5			
Scattergood Generating Station	Natural Gas	1	1958	53	183	817	796	Includes 16 MW for Hyperion digester gas OTC
		2	1959	52	184			
		3	1974	37	450			
Valley Generating Station	Natural Gas	5	2001	10	43	576	556	Units 6, 7 and 8 operate as a combined cycle unit.
		6	2003	8	159			
		7	2003	8	159			
		8	2003	8	215			
Total Net Capability of Natural Gas Stations						**3415**	**3338**	
Intermountain Generating Station	Coal	1	1986	25	900	1100	1100	Reduced by current recall
		2	1987	24	900			
Navajo Generating Station	Coal	1	1974	37	750	477	477	
		2	1974	37	750			
		3	1975	36	750			
Mohave Generating Station	Coal	1	1971	40	0	0	0	Decommissioned on 12/31/05
		2	1971	40	0			
Total Net Capability of Coal Stations						**1577**	**1577**	
Palo Verde Generating Station	Nuclear	1	1986	26	1333	387	380	
		2	1986	26	1336			
		3	1988	24	1334			
Total Net Capability of Nuclear Stations						**387**	**380**	
Castaic Power Plant	Hydro	Various	1972-1978	33-39	1620	1247	1175	Pumped Storage
Hoover Power Plant	Hydro	Various	1936	75	491	491	436	
Total Net Capability of "Large" Hydro Stations						**1738**	**1611**	
Aqueduct System	Hydro	Various	1917-1987	24-94	126.7	83.1	24.2	11 Units total
Owens Valley System	Hydro	Various	1908-1958	53-103	16	12.5	1.2	7 Units total
Owens Gorge System	Hydro	Various	1952-1953	58-59	112.5	112.5	109.4	3 Units total
Owned & Contracted Renewables	Renewable/DG	Various	2002-2011	1-9	1141	1141	343	Note [5]
Total Net Capability of Small Hydro and Renewable / Distributed Generation						**1349**	**478**	
Total Net Capability of LADWP Resources						**8464**	**7384**	
State's Capacity Entitlement (See Note[6])						-120	-55	
Total Net Capability of LADWP System						**8346**	**7329**	Note [7]

Notes:

1. Power source data are based on Power System Engineering Division's January 2011 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 September 2011.
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 stations is shown in Figure 2-5.

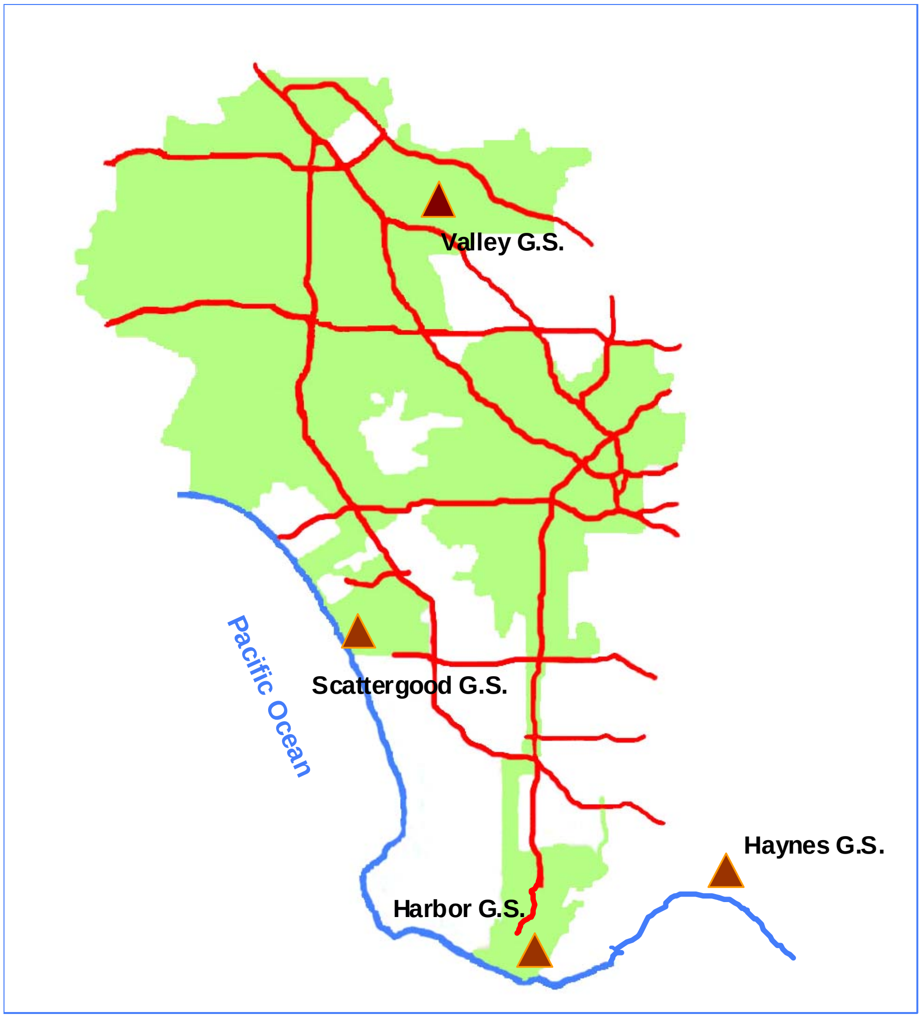


Figure 2-5. LADWP in-basin generating stations.

Each station consists of multiple generating units, with each unit ranging is size between 43 MW and 450 MW. A summary of each station's capabilities is shown in Table 2-5. 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.

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's from these stations is 477 MW from NGS and approximately 1,200 from IPP. A summary of each station is included in Table 2-5. Further details and discussion is provided in Appendix F.

Contractual arrangements for power from IPP will expire on June 15, 2027 while NGS operates under a co-tenancy agreement that shall remain effective throughout the initial term of its land lease until December 31, 2019 and throughout the lease extension thereafter.

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". Small hydro consists of generating units with less than 40 MW of capacity generally located along the Los Angeles Aqueduct. They also qualify as a renewable resource for electricity generation. For discussion purposes they are grouped within renewable resources.

Current Renewable Energy Projects

Existing secured renewable resources total over 1200 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

- Small Hydro
  - Aqueduct and Owens Valley projects
  - Hydro PowerEx
  - North Hollywood
  - Sepulveda
  - Castaic Upgrade

- Solar
  - LADWP In-Basin
  - Customer Net Metered

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

Additional renewable energy (including geothermal) comes from market purchases.

Figure 2-6 presents the current energy profile for renewable resources in LADWP's portfolio.

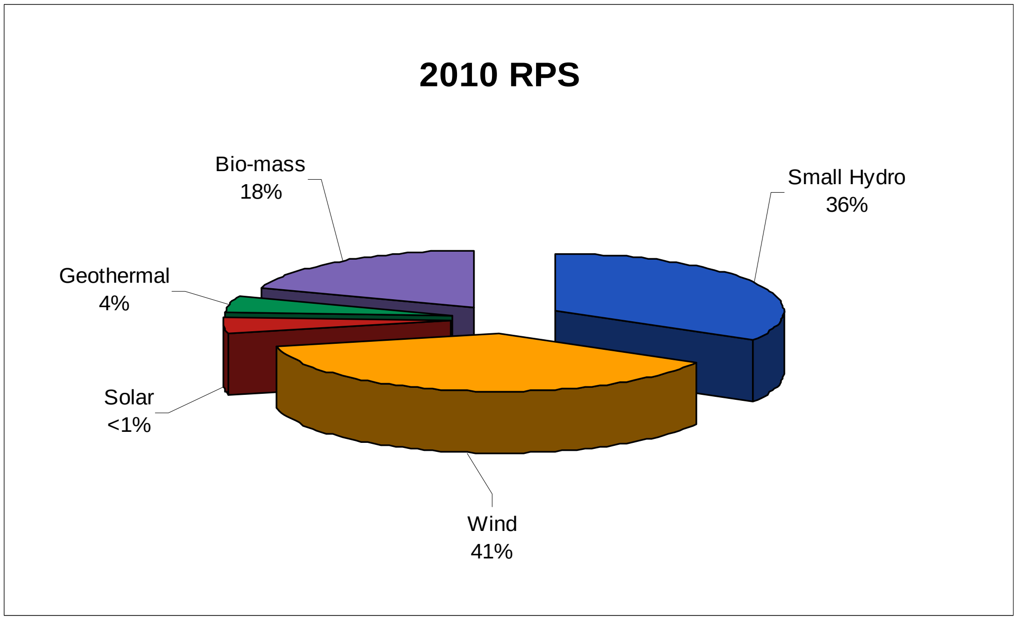


Figure 2-6: 2010 IRP renewable energy mix.

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 early divestiture from coal-fired energy to accelerate GHG reductions.

2.4.2.1 Repowering Program to Replace Aging Infrastructure

There is an urgent 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 problems and outages. The units to be replaced at the Scattergood and Haynes generating stations are between 44 and 53 years old, and are among the oldest remaining units in LADWP's generation fleet. Minimizing outages at these locations close to the system load center is especially important for the reliable operation of the in-basin electrical network, including the transmission and distribution systems. Variable resources, such as solar or wind power, can augment existing in-basin gas-fired generation, but do not serve as adequate replacements for purposes of voltage support. LADWP's local transmission system cannot be reliably operated without generation from local 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.

- 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 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 local regulations related to once through cooling and NO_X emissions.

- 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 1.6.5. Table 3-3 contains a listing of specific repowering projects.

  In addition to repowering, OTC interim mitigation measures will be required until a facility is fully compliant. These measures include the funding into projects to alleviate impacts, such as the installation of alternative technologies to reduce impingement and/or entrainment. These issues are discussed in more detail in Appendix C.

- NO_X compliance
  In mid-2000, during the statewide energy crisis, LADWP predicted that NO_X emissions from the in-basin generating units would exceed the available supply of NO_X RECLAIM Trading Credits issued by the South Coast Air Quality Management District (SCAQMD). Although LADWP's NO_X emissions ultimately did not exceed its allocation in 2000,on August 29, 2000 the SCAQMD Hearing Board issued a "Stipulated Order for Abatement" to the LADWP. Under the terms of the Order, LADWP was required to perform a series of repowering projects at its in-basin generating stations. The Stipulated Order was later superseded by a Settlement Agreement to accommodate scheduling and other issues. This agreement was revised in September 2011 and addresses the current repowering projects at the Haynes and Scattergood Generating Stations.

2.4.2.3 Coal-Fired Generation

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

- SB 1368 Compliant Coal-Fired Generation

  As presented in Section 3, the analysis of future potential resource portfolios includes a set of strategic cases that accelerate compliance with SB 1368 for coal-fired generation by year 2020. 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) regulatory factors that today are uncertain.

  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 baseload 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 baseload 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 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 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. 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" IPP contract obligations extending to 2027, LADWP has committed to continue to fulfill all contractual obligations. At the same time, LADWP is investigating ways to maintain compliance with SB 1368. LADWP is reviewing several options.

LADWP has called for a strategic business plan to be developed for IPP. This effort, which is currently underway, involves IPA as owners of the IPP assets and the 36 participants that have power sales contracts. This effort is seen as a way to focus on the current and future needs of the project owners and those with power contracts and seek ways to find mutually beneficial solutions. Many of the participants, including LADWP, would like to settle on solutions that can be implemented in the next few years thereby reducing uncertainty with regard to the future use of IPP.

The work product that was approved in 2010 directed the subcommittee to continue work in 5 strategic areas:

- An energy trading hub at the site
- Generation development (A plan for future generation)
- Asset optimization
- Transmission
- Communications (Preparing advocacy efforts to assure future success)

The Energy Trading Hub Subcommittee has completed the majority of its work and is launching a 1 year trial of the program starting February 1, 2012. The Generation Subcommittee has considered a number of alternatives using natural gas and has determined that several of these are possible. Currently, this subcommittee is directing its efforts at the various contracts and governances that oversee the project and is drafting language that will facilitate options for future generation. The other three committees are meeting on as needed basis.

- Navajo Generating Station

The Navajo Generating Station (NGS) is a coal-fired generation station located near Page, Arizona. It consists of three units with a combined capacity of 2,250 MW. Salt River Project 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.

Replacement options for NGS are discussed in Section 3.5.

2.4.3 Future Renewables for LADWP

The increase of renewables, as a percentage of electricity sales, from the current 20% 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 rooftop 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. All strategic case alternatives include the following targets for new renewable acquisitions between 2011 and 2020:

New Renewable Installed Capacity (MW) 2011-2020			
Geothermal & Biomass	Wind	Non-DG Solar	Distributed Solar
243	492	401	325

Furthermore, maintaining at least 33% of renewables beyond 2020 requires additional renewables to account for load growth, project turnover, and output degradation as projects age. All strategic case alternatives include the following additional targets for new renewable acquisitions between 2021 and 2030:

New Renewable Installed Capacity (MW) 2021-2030			
Geothermal & Biomass	Generic	Non-DG Solar	Distributed Solar
65	162	50	141

Details regarding future renewables can be found in Appendices F and M.

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 the near future, LADWP anticipates that revenue from excess energy sales may be less due to aging facilities, anticipated load growth, and GHG emission regulations.

Transmission for Renewable Energy

Transmission infrastructure improvements to access renewable energy are in various phases of development or construction:

- Barren Ridge Renewable Transmission Project. Up-to-date information is available for this project at http://www.ladwp.com/ladwp/cms/ladwp009508.jsp. This project, scheduled to be completed in 2016, will increase the capacity of the existing 230kV Barren Ridge—Rinaldi transmission segment. As of August 2011, approximately 2800MW from a combination of wind and solar projects are being investigated for potential interconnection. Castaic Power Plant, with its flexibility as a pump storage facility, stores surplus variable energy for optimal dispatch.

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

  - New Haskell Canyon Switching Station
  - New double-circuit 230kV transmission line from Barren Ridge Switching Station to new Haskell Canyon Switching Station
  - New 230kV circuit on existing structures from Haskell Canyon to the Castaic Power Plant
  - Reconductor the existing 230kV transmission line from Barren Ridge Switching Station to existing Rinaldi Substation, through Haskell Canyon Switching Station
  - Expand existing Barren Ridge Switching Station

- Pacific Direct Current Intertie (PDCI) Upgrade. LADWP and its PDCI partners are considering increasing the capacity of the PDCI from 3100MW to as much as 3650MW. 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 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 recently commissioned and completed Light Detection and Ranging study indicate the transmission portion 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.

Regional transmission plans have shown that in order for LADWP and its Western counterparts to meet their renewable energy goals at the lowest cost, additional transmission improvements will be needed. While the projects listed here 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 2011 plan has 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.
- An upgrade of the existing Northridge-Tarzana 230 kV Line 1.
- Transmission upgrades between the Haskell, Olive, and Sylmar Switching Station.
- Construction of a new Cottonwood 230 kV substation with a new 100 MVAR capacitor bank.

These infrastructure improvements are critical to avoid potential overloads on key segments of the Basin transmission system. Certain of these overload conditions would require load shedding events (intentional power outages) to minimize the impact on the power system as a whole.

System Losses

LADWP Power System transmission and distribution losses are approximately 11.5 percent, and are higher than the industry average of 6-8 percent partly due to its long transmission reach to external generation from Utah, the Desert Southwest, and the Pacific Northwest. However, there may be opportunities to reduce some losses by addressing the system's reactive power needs. To optimize performance and reduce these system losses, LADWP commissioned a 2011 Reactive Power Management Study, which arrived at the following recommendations:

- Retire 9 synchronous condensers which are beyond their useful lives and in subpar operating condition.
- Install shunt compensation to replace the retired synchronous condensers and to enhance system security:
    - Shunt capacitors totaling 1565MVAR, with consideration given to dynamic devices at Rinaldi and Hollywood Stations. The capacitors would be located at receiving and distributing stations and distribution feeders.
    - Shunt inductors totaling 930MVAR, with consideration given to dynamic devices at Rinaldi and Hollywood Stations. The inductors would be located at receiving and distributing stations and distribution feeders.
- Implement a customer power factor improvement program as the current aggregate customer power factor is less than 0.75, lagging.
- Install and implement a real-time MVAR reserve margin monitoring and alarm system to alert power system operators of decaying operating margins so outages might be averted.

FERC Order 1000 - The California Transmission Planning Group

With the release of Federal Energy Regulatory Commission (FERC) Order 1000 in July 2011, which directs 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.

With Order 1000, CTPG must now consider reorganizing CTPG as an interregional planning organization with local and regional planning members or continue as a regional planning organization with WECC, or a yet unknown entity, serving as its interregional planner. CTPG and its members have up to eighteen months to formalize their positions with FERC. As the 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 signed into law on October 11, 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 2-7 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 2-7: Major out-of-basin generating stations and major transmission lines.

2.4.5 Reserve Requirements

Reliability of the electric power system is dependent upon two elements: "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). These standards define the system reserve margin requirements and other criteria for which LADWP must 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. Under the 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 stable 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 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 was assumed that the dependable capacity of wind would be 10 percent of its nameplate capacity and the dependable capacity of solar photovoltaic would be 27 percent of its nameplate capacity.

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.

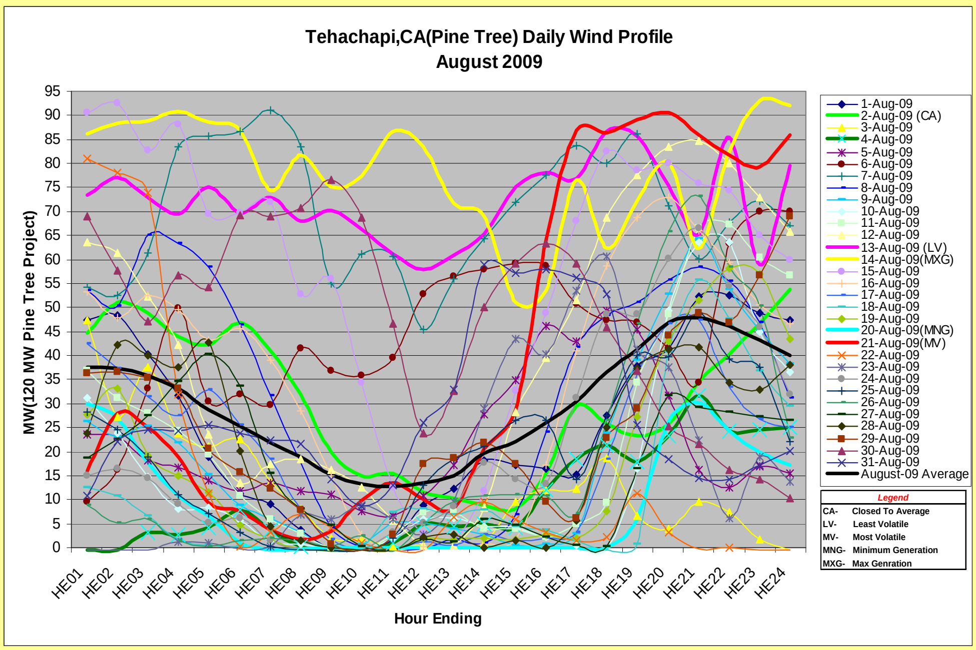
This local requirement is particularly important in the context of deciding how to schedule the repowering of units that use once through cooling. It is for this reason that no unit will be taken out of service before an equivalently-sized, locationally-equivalent replacement unit is constructed, tested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

3.0 STRATEGIC CASE DEVELOPMENT

3.1 Overview

IRP planning is an on-going process and as such, the development of the 2011 IRP strategic cases incorporates the latest changes that have occurred in the regulatory landscape, and tactical plans developed by the power system. This 2011 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.

Last year’s 2010 IRP analyzed 6 strategic cases representing different potential renewable resource portfolio mixes, with and without the early divestiture of IPP, and recommended a comprehensive strategy that adopted elements of a number of the cases analyzed. The 2011-12 fiscal-year financial planning process included many of the assumptions and recommendations set forth in the 2010 IRP.

The regulatory state of affairs was far from certain at the time the 2010 IRP was prepared, and many of the state laws and major regulations affecting generation resources such as AB32, SB1368, SB 2 (1X), and US EPA 316(b), were in process, and even today are still being finalized. This 2011 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 key parameters 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 2011 IRP Model Assumptions

At the heart of the IRP analysis effort is the computer-based production cost modeling of the LADWP Power System. In order 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 M. In this section, the major changes in the assumptions since last year's IRP are summarized, followed by a discussion of the general price inputs that were applied to this 2011 IRP.

3.2.1 Major Changes to 2010 IRP Assumptions

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

Load Forecast

As shown in Table 3-1, the new load forecast is lower than the previous forecast used in the 2010 IRP. Compared to the prior forecast, electricity sales in the calendar year 2020 decreased by 7.3 percent. The new forecast reduces the overall need for renewable energy (assuming 33% RPS) by approximately 631 GWh in 2020 and 1,309 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 is shown in Appendix M.

Table 3-1. TOTAL ELECTRICITY SALES IN GWH

	2020	2030
Old Forecast – 2010 IRP	26,150	30,632
New Forecast – 2011 IRP	24,239	26,665
Difference	-1,911	-3,967

Demand Response

In the 2010 IRP, demand response (DR) started with a 50 MW program in 2011 and increased incrementally to a total of 500 MW installed by 2023. The lower load forecast used in the 2011 IRP delays the need to implement DR programs to provide added system capacity as can seen by the revised implementation schedule shown in Figure 3-1.

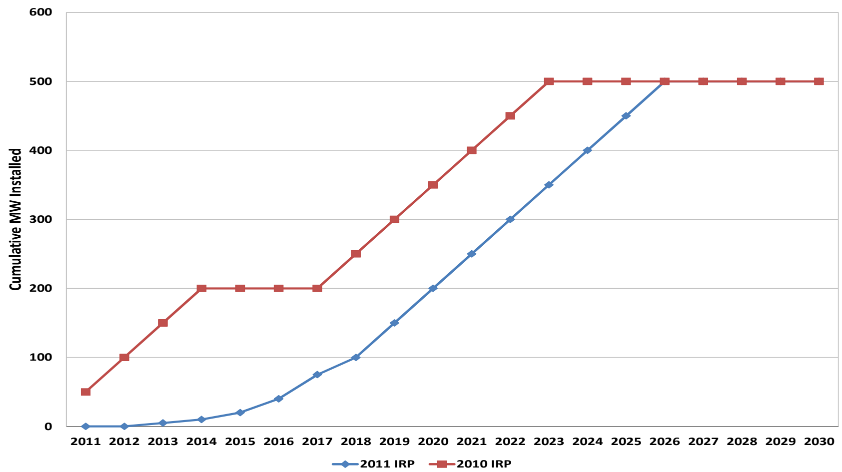


Figure 3-1. Comparison of 2010 and 2011 IRP demand response program implementation by calendar year.

Energy Efficiency

The Energy Efficiency (EE) forecast used in the 2011 IRP includes lower DSM funding levels for the 2011/12 through 2013/14 fiscal years due to short term budgetary constraints. Compared to last year, EE energy savings decrease after the 2015-16 fiscal year, even after funding levels return to normal. The main reason for this is that efficiency opportunities in lighting (which is the largest EE program component) will dissipate due to the implementation of new Federal and State lighting standards that raises the minimum efficiency level for a variety of electric products. These Federal and State efficiency standards create fewer opportunities to give financial incentives to customers to install products that exceed the higher efficiency standards and the resulting energy savings will be incrementally less. Although these standards result in fewer opportunities to provide incentives from the utility, the energy efficiency savings from these standards are nevertheless accounted for in the sales load forecast and do contribute to reducing overall sales and load growth. The cumulative EE savings incorporated in the 2011 IRP will reach 2,699 GWh in 2020 and 3,439 GWh in 2030 as shown in Figure 3-2. Efficiency savings prior to 2011 of 1,256 GWh and 303 MW from 2000 to 2010, equivalent to 5.5 percent of customer sales, are already reflected in the load forecast. The table below shows the projected cumulative savings from 2006 through 2030.

As of December 6th, 2011, the Board of Water and Power Commissioners approved an advanced EE program with a goal of 8.5 percent of sales by the end of fiscal year 2019-20 and beginning fiscal year 2010-11. The adoption of the advanced program results in approximately 920 GWh of additional gross EE savings by 2020. Due to the timing of this approval, this change could not be incorporated in the 2011 IRP, however, the advanced program will be considered in the 2012 IRP modeling results.

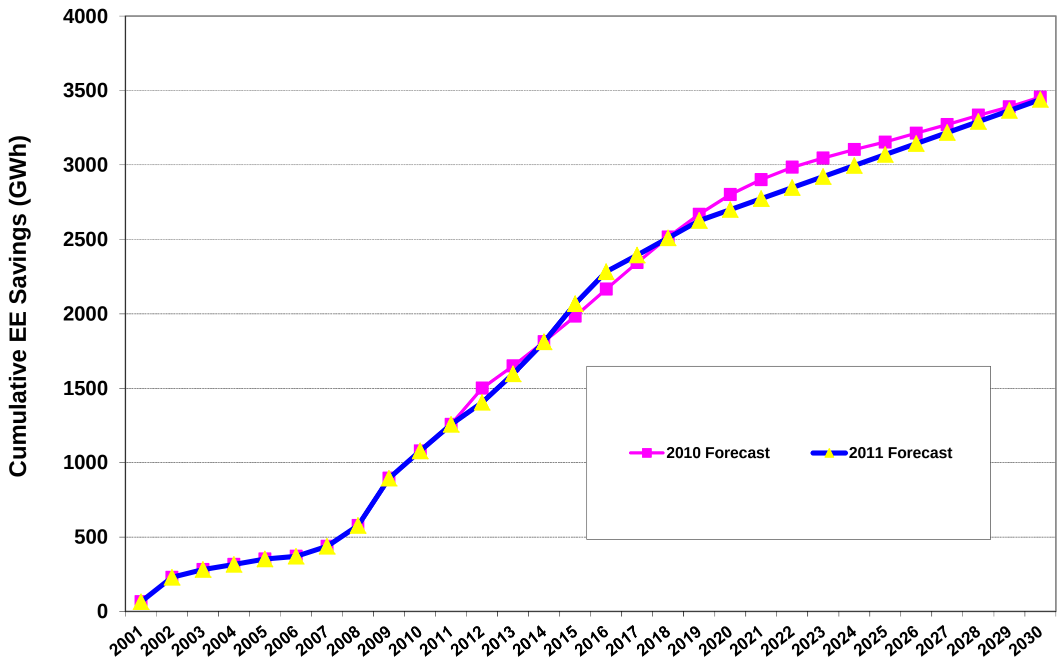


Figure 3-2. Comparison of 2010 and 2011 IRP gross energy efficiency forecasts by fiscal year.

<u>Solar C-N-M and FIT</u>

The solar Customer-Net-Metered (CNM) program (a.k.a. Solar Incentive Program) and Feed-In-Tariff (FIT) programs used in the 2011 IRP are based on projections dated October 2011. Figure 3-3 shows the comparison of CNM and FIT program projections used in the 2011 IRP vs. the 2010 IRP. The CNM solar is higher in years 2012-2016 primarily because of a dramatic increase in participation levels of the SIP program in 2010, and expected continued strong interest in the program given the tax benefits available and currently lower solar prices. FIT is lower in 2013-2015 due to a delay in implementation of the program due to budget constraints, but higher in 2017-2023 due to the plan to accelerate the program to take advantage of tax benefits available through 2016.

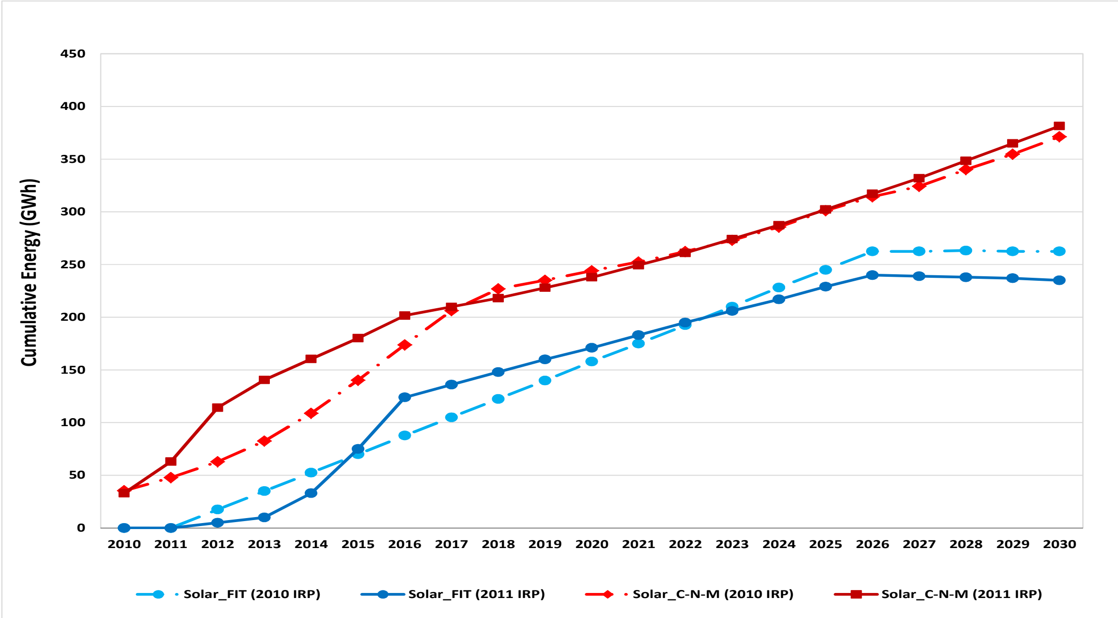


Figure 3-3. Comparison of solar projections, 2011 vs. 2010.

Renewables

Table 3-2 is a comparison of the overall renewable mix planned for the 2011 IRP vs. the 2010 IRP:

Table 3-2. RENEWABLE MIX, 2010 VS. 2011

		2020	New Renewable Installed Capacity (MW) 2011 – 2020					New Renewable Installed Capacity (MW) 2011 – 2030				
Case ID	Resource Strategy	RPS Target	Geothermal	Biomass	Wind	Non-DG Solar	Dist. Solar	Geothermal/ Biogas	Wind	Non-DG Solar	Dist. Solar	Generic
Recommended Case 2010 IRP	33% RPS Balanced	33%	320	0	580	315	315	320	680	485	485	160
All Cases in 2011 IRP	33% RPS SB 2 (1X) Compliant	33%	183	60	492	401	325	308	492	451	466	162

One major RPS change from the 2010 IRP was a large reduction in geothermal projects, especially in the short term. Suitable geothermal sites in accessible locations near existing transmission lines have been difficult to locate. The 2011 IRP lowers the amount of geothermal expected in 2020 by 43 percent. In the short term, increased use of low cost biogas will largely replace the energy that would have been generated by geothermal projects until more viable geothermal sites can be identified. Another change was the deferral of the Owens Valley Solar Project from 2013 to 2018 due to recent budget reductions and tax benefits for third party developed solar projects that are scheduled to end after 2016, making development of LADWP facilities that are not eligible for direct tax benefits more viable. As previously discussed, the revised load forecast decreases the need for renewables. This results in the lower overall capacity requirements in both the short term 2010 - 2020 and longer term 2020-2030 time periods as shown above.

Navajo Early Divestiture
Divestiture of the Navajo Generating Station (NGS) on December 31, 2013, as described in the 2010 IRP recommended case, will be extended to December 31, 2015. Member utilities of NGS have "first rights of refusal" involving the sale of other member shares. After 6-months notification of their intent to exercise "first right of refusal" rights member utilities have 3 years to complete the purchase. Although NGS participants could potentially complete the purchase sooner, the most realistic estimate of a sale being completed has been extended to December 31, 2015.

GHG Costs
Projected GHG cost impacts resulting from AB32, and as incorporated in the 2010 IRP, have been significantly reduced as a direct result of recent changes in the final regulations approved by the California Air Resources Board (CARB). Although some uncertainty still remains regarding the final regulations, the expectation of allowance prices being applied to all GHG produced, as previously assumed in the 2010 IRP, have been replaced with allowance prices being applied only to the amount exceeding the CARB allowance allocation within a compliance period. Additionally, GHG regulations are expected to begin on January 1, 2013, one year later than the assumed start date in the 2010 IRP. The net effect of the allocation changes between the 2010 and 2011 IRP was a $1.25 billion reduction in anticipated allowance costs between 2010 and 2020.

Gas Prices
Natural gas costs continue to remain stable for the near term and spot market price forecasts for gas have changed little since the 2010 IRP. The Pinedale gas reserves owned by LADWP continue to provide a low cost source of gas and estimates of gas volumes to be produced from Pinedale have risen since the 2010 IRP. These production increases have lowered the overall system gas costs. Opal and SoCal expected gas prices used in the 2011 IRP were 7 and 10 percent lower on average, respectively, in the short term (2011-2020), but were 11 and 14 percent higher on average, respectively, in the long term (2021-2030) as compared to the 2010 IRP.

Coal Prices
IPP forecasted coal prices are 22 percent lower in the short term (2011-2020) and 34 percent lower in the longer term (2021-2027) as compared to the 2010 IRP. Navajo coal prices are 10 percent lower in the short term (2011-2019) as compared to the 2010 IRP.

IPP Recall
IPP capacity is a function of the capacity recalled by Utah participants. Estimates for this recall amount, or the capacity entitlement transferred from the Utah participants to LADWP, has risen by 112 MW in the short term (2011-2020) and 44 MW in the long term (2021-2027) as compared to the 2010 IRP thereby increasing our share of IPP capacity entitlement. This raised the energy and capacity expected from IPP generation in the 2011 IRP as compared to the 2010 IRP.

Once-Through Cooling

Recent OTC decisions by the State Water Resources Board have accelerated the compliance date for repowering the LA-basin coastal generation stations. Whereas December 31, 2040 was the date used in the 2010 IRP, the new "no later than" compliance date is December 31, 2029. The new repowering dates (see Table 3-3 below) and resulting efficiency improvements resulting from the more efficient replacement units have been incorporated into the 2011 IRP production model.

Table 3-3. BASIN PLANTS REPOWERING – TARGET SCHEDULE[1]

Unit	Nameplate Capability [1] (MW)	Action and Resulting Nameplate Capacity	Compliance Date (No Later Than)	LADWP Draft Target Date[3]
Haynes 1	230	Replace with 444 MW CC	12/31/2029	12/31/2023
Haynes 2	230			
Haynes 5	343	Replace with 600 MW CT	12/31/2013	6/1/2013
Haynes 6	343			
Scattergood 1	163	Replace with 367 MM CC	12/31/2024	12/31/2020
Scattergood 2	163			
Scattergood 3	497	Replace with 509 or 574 MW CC[2]	12/31/2015	12/31/2015
Harbor 1, 2 & 5	240	Repower with same MW	12/31/2029	12/31/2026
Haynes 8, 9 & 10	650	Repower with same MW	12/31/2029	12/31/2029

Notes: 1. Maximum or dependable capacity of the unit will be different based on permitting requirements as well as other constraints.
2. For Scattergood Generating Station, Unit 1 and 2 will be replaced with 300 MW (if unit 3 replaced with a 508 MW unit) or 233 MW (if unit 3 replaced with a 575 MW unit).
3. The LADWP target dates are very ambitious and based on many physical and budgetary assumptions, and are subject to change. They represent LADWP's best effort to comply with the regulations as fast as possible and assumes no unexpected complications or delays. Subject to further evaluations and studies.

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 M.

Supply-side Resources
Table 3-4 presents a summary of the major price assumptions for supply-side resources.

Table 3-4. SUMMARY OF SUPPLY-SIDE RESOURCE ASSUMPTIONS

Resource	Levelized Cost[1] ($/MWh)	Capacity Factors	Dependable Capacity
Solar Photovoltaic – PPA	$144	23% - 31%	27%
Solar Photovoltaic - LA Solar – Public/Private Partnership In-Basin	$177	21%	27%
Solar Photovoltaic – LA Solar – Public/Private Partnership Owens	$153	24%	27%
Solar Customer-Net-Metered	$136	18%	27%
Solar Feed-In-Tariff	$179	18%	27%
Wind	$106	24% - 42%	10%
Geothermal	$138	90%	90%
New Combined Cycle Gas (310 MW)	$63	58%	100%
New Simple Cycle Gas (50/100 MW)	$302	4%	100%

[1]Net Present Value (annual costs, 2011-2030) / 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 3-4, are fundamental forecasts obtained from Wood Mackenzie that consider a range of future assumptions including economic growth, supply and demand, and environmental regulations.

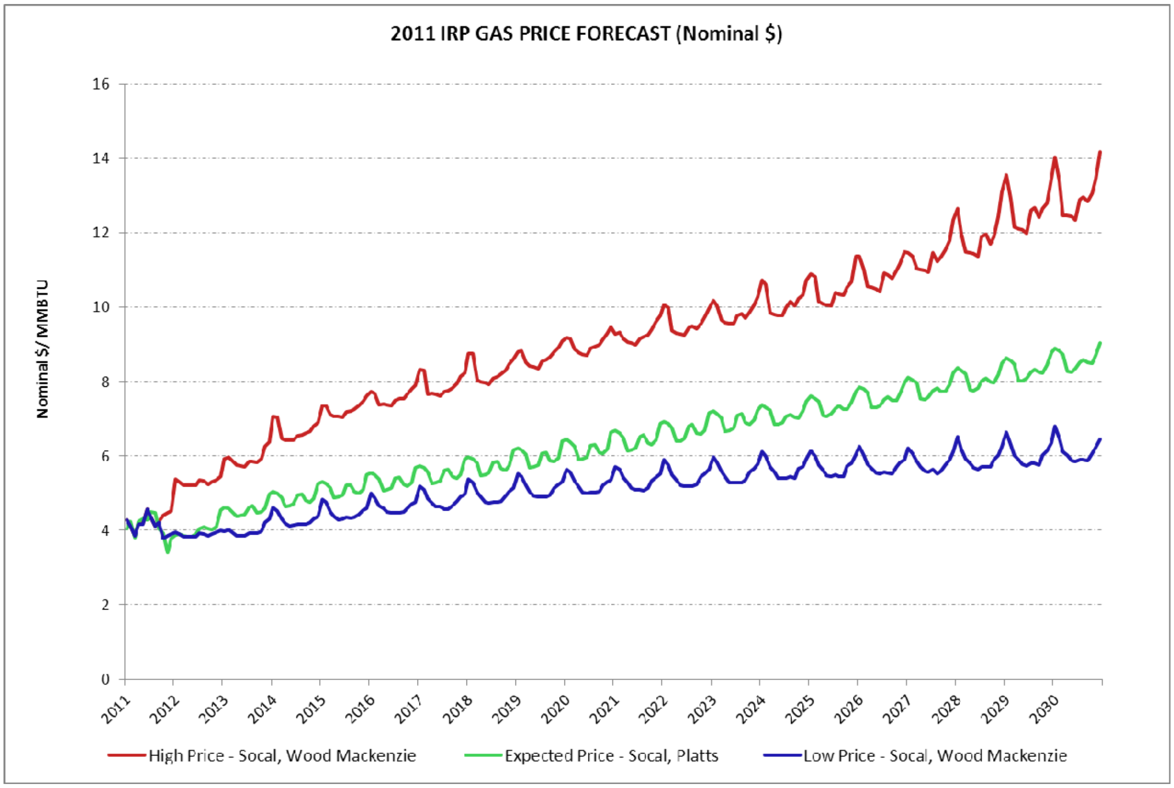


Figure 3-4. Natural gas price forecast (SoCal).

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 from experience, and agency models as a template. This template assumed GHG pricing starting at $24/metric ton in 2013 escalating to $45/metric ton in 2020. Beyond the year 2020, the AB32 Cap and Trade program ends and may be replaced by another State or Federal program. Assuming that there will be another program, allowance prices beyond 2020 were assumed to remain at $45/metric ton through 2030 and the allowance allocated by CARB was assumed to remain constant. Future IRP's will consider changing this assumption as new information about future programs becomes available. Unlike the 2010 IRP where a sensitivity analysis was done using high and low GHG prices, the 2011 IRP does not include high and low GHG prices because the expected costs are not as significant as other cost drivers. Figure 3-5 depicts the GHG allowance prices used to evaluate the portfolios.

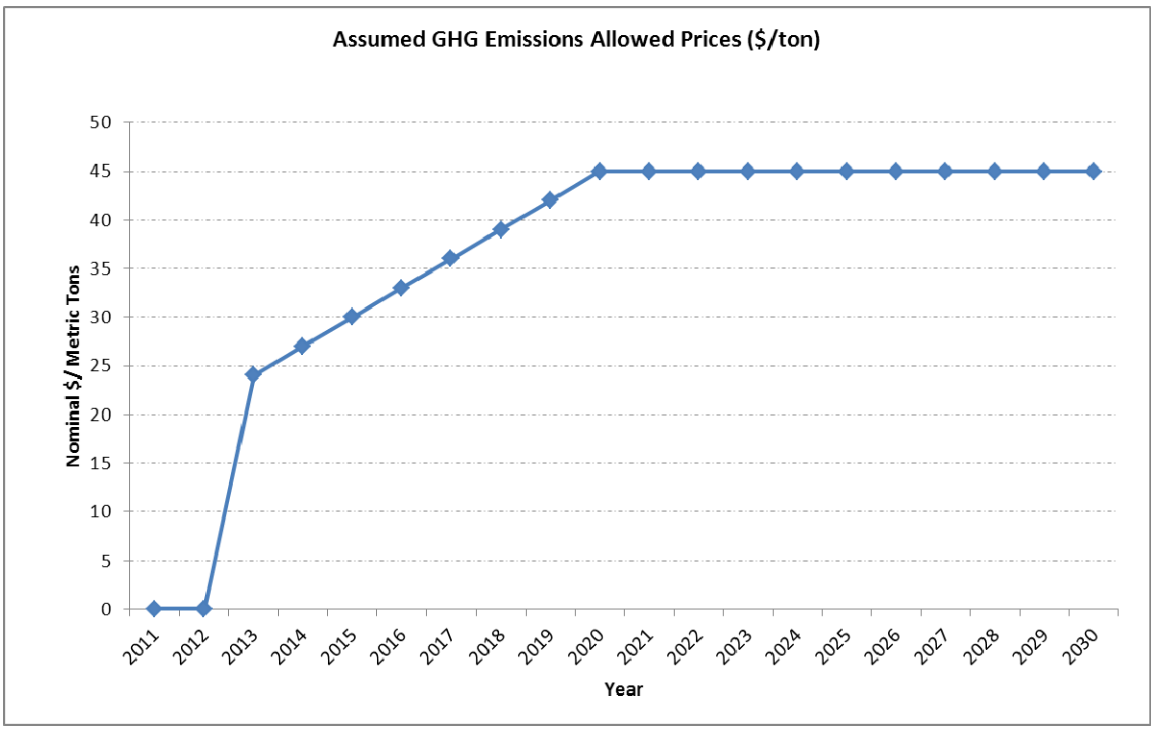


Figure 3-5. Assumed GHG emissions allowance prices.

3.3 Strategic Case Key Parameters

The 2011 IRP strategic cases must reflect 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.

SB1368

SB1368 requires that imported energy from outside California meet a GHG emissions standard of 1,100 lbs per MWh. To comply with this requirement, all future 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, three Coal divestiture cases have been considered in this 2011 IRP. The three divestiture cases will further define the costs and operational impacts that divestiture 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 virtually all in-basin generation 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 3-6 below:

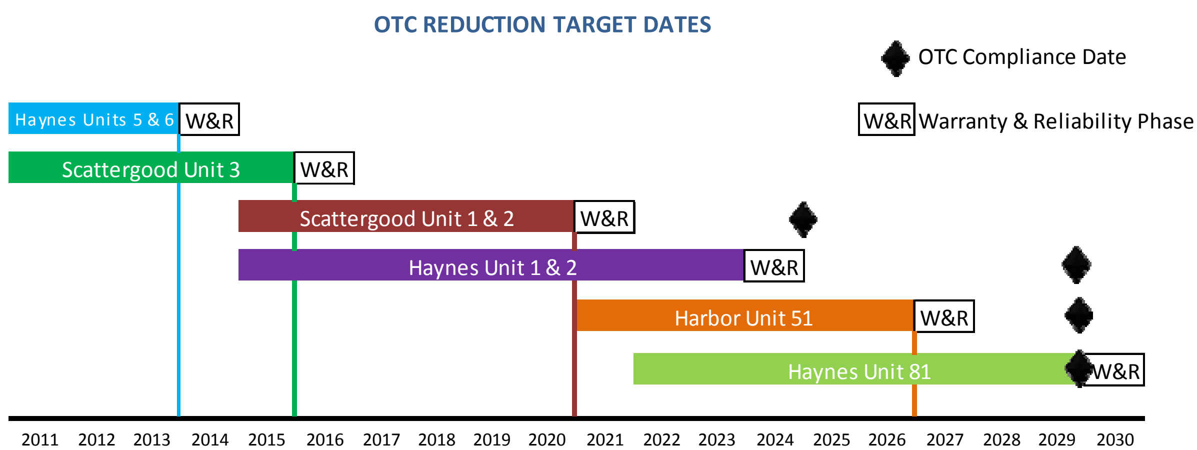


Figure 3-6. Timeline for OTC repowering projects.

While developing the timeline for the repowering program, LADWP had to consider a number of reliability, financial, and other contingent requirements. Because the power system relies on the in-basin units to produce energy, and provide voltage support and stability, it is important to keep all of the units continuously available during summer months. This means that during summer months the total capacity available from the in-basin units remain constant. This requires a strict sequencing of the separate repowering projects. Further studies will be required to determine the impact on system reliability from the accelerated repowering schedule.

Another consideration is the cost of the program. Repowering just one unit requires a significant amount of money—on the order of $500 million or more. Spreading the program over time minimizes the need for sudden and significant infusions of capital, and helps LADWP to preserve proper cash flow and capitalization ratios to maintain its credit rating.

Other issues include the long lead times required for environmental permitting, engineering design, and equipment procurement. The limited space available within some of the generating station property boundaries also presents planning difficulties. The timeline represents LADWP's best effort to comply with the mandated compliance deadlines while also meeting its reliability and fiscal responsibilities.

SB 2 (1X)

As discussed at the end of Section 1.6.4, 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 portfolio as shown in Figure 2-6. 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 2010 IRP established a diversified resource mix for the next 20 years including goals for estimated MW's installed for each renewable technology. The 2011 IRP retains the same diversified renewable mix goals set forth in the 2010 IRP recommended case while including the latest updates based on available resources. As shown in Table 3-2, all strategic case scenarios being considered in the 2011 IRP use the same renewable resource plan. Future IRP's will likely address different renewable resource mixes as the CEC further develops specific regulations to enforce SB 2 (1X).

Accelerated Coal Divestiture

To achieve a high level of Power System reliability, minimize the impact on ratepayer energy prices, and exercise environmental stewardship while complying with federal, state, and local regulations, the 2011 IRP Strategic Cases were developed to assist policymakers and ratepayers to make informed decisions regarding the accelerated divestiture of Coal resources to promote GHG reduction prior to SB1368 compliance which occurs in 2019 for Navajo and 2027 for IPP. Accelerated Coal divestiture is discretionary, unlike other mandated regulatory requirements described previously. It is important that the environmental benefits and resulting electricity rate and resource impacts be fully understood by ratepayers and policy makers.

3.4 Candidate Portfolios Development Process

A candidate portfolio is a set of renewable and non-renewable generation resources, DSR resources, regulatory constraints, policy goals, and assumptions that 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 Net Short and Resource Adequacy

The first step in developing the 2011 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, and the contribution of its renewable energy component towards resource adequacy was determined. Combined-cycle gas generation, energy efficiency, short term purchases, and demand response 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 M.

3.4.2 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.

Assumptions were made for the cost and performance of each technology used to convert the renewable resources to electricity. A summary of the main assumptions made for biomass, geothermal, solar, and wind is presented in Appendix M.

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. Specifics for the resource valuation methods are also covered in Appendix M.

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.

3.5 2011 IRP Strategic Cases

The 2011 IRP analyses a focused set of strategic cases, expanding on the results from the 2010 IRP process. Cases from last year that included a variety of renewable percentage targets were eliminated. A streamlined set of 3 coal divestiture cases where then included for the 2011 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 is discretionary and thus appropriate for analysis. The 2011 IRP strategic cases are designed to assist policymakers and ratepayers to make informed decisions regarding accelerated coal divestiture, particularly with regard to the environmental benefits and resulting resource and electricity rate impacts.

- Case #1 provides a baseline without any early coal divestiture. Navajo Generating Station continues until 12/1/2019 and the Intermountain Power Project (IPP) until 6/15/2027.

- Case #2 considers an early divestiture of NGS, by 12/31/2015.

- Case #3 considers early divestiture of both coal plants – NGS by 12/31/2015 and IPP by 12/31/2020.

Table 3-5 provides a more detailed description of each strategic case.

As mentioned earlier, the same renewable resource plan applies to all cases. Table 3-6 summarizes each candidate renewable portfolio. For comparison purposes, the recommended case from last year's IRP is also included.

The different cases require distinct resource strategies to replace the divested 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 Qtr 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 to quantify the risk associated with fuel price volatility on each case. Section 4 discusses the modeling results, and presents the 2011 IRP Recommended Case that emerged from the analysis process. Section 5 discusses in greater detail the recommended case and the resulting impact on rates as well as the actions required to implement the recommended case.

Table 3-5. DESCRIPTION OF STRATEGIC CASES

Case ID	Description
Case 1 (Base Case)	No Early Coal Divestiture – 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 SB1368. Maintains the 33 percent standard renewables mix recommended to comply with SB 2 (1X).
Case 2	Navajo Early Replacement Strategy – This case considers early replacement 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).
Case 3	Navajo and IPP Early Replacement Strategy – This case considers early replacement 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).
Recommended Case 2010 IRP	33% RPS Balanced Strategy – Primarily used to compare the other strategic cases to the recommended long term strategy described in the 2010 IRP with 33 percent renewable compliance by 2020. Considers early divestiture of Navajo on 1/1/2014 or five years prior to contract expiration and assumes replacement of IPP in 2027.

Table 3-6. CANDIDATE RESOURCE PORTFOLIOS FOR 2011 IRP

		2020	GHG or SB 1368 Compliance Date		New Renewables Installed Capacity (MW) 2011 – 2020					New Renewables Installed Capacity (MW) 2011 – 2030				
Case ID	Resource Strategy	RPS Target	Navajo Replacement	IPP Replacement	Geo-thermal	Bio-mass	Wind	Non-DG Solar	Dist. Solar	Geothermal/ Biomass	Wind	Non-DG Solar	Dist. Solar	Generic
1 (Base Case)	**No Early Coal Divestiture**	**33%**	**12/1/2019**	**6/15/2027**	**183**	**60**	**492**	**401**	**325**	**308**	**492**	**451**	**466**	**162**
2	**Navajo Early Replacement**	**33%**	**12/31/2015**	**6/15/2027**	**183**	**60**	**492**	**401**	**325**	**308**	**492**	**451**	**466**	**162**
3	**Navajo and IPP Early Replacement**	**33%**	**12/31/2015**	**12/31/2020**	**183**	**60**	**492**	**401**	**325**	**308**	**492**	**451**	**466**	**162**
Rec. Case 2010 IRP	**33% RPS Balanced**	**33%**	**1/1/2014**	**6/15/2027**	**320**	**0**	**580**	**315**	**315**	**320**	**680**	**485**	**485**	**160**

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4.0 STRATEGIC CASE ANALYSIS

4.1 Overview

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 and generic types of future generating resources. The resource mix of renewable generating resources and thermal generating resources must satisfy: (1) resource adequacy requirements for reliability, and (2) specific increasing targets of renewable resources as a percentage of total energy sales.

For this 2011 IRP, the key strategic consideration is the accelerated reduction of GHG emissions by way of early divestiture of coal generation. The model runs analyzed different coal divestiture scenarios for LADWP's two coal projects, the Intermountain Power Project (IPP) and Navajo Generating Station (NGS). The results for each model run 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 NERC and FERC regulations, which dictated either replacing or re-powering aged infrastructure or end-of-life generating power plants.

The selection of the best case for LADWP ratepayers hinges mainly upon the load forecast, price of natural gas and coal, GHG emission levels, capital, and O&M costs. These factors are the major cost drivers for bulk power in the cases analyzed. All cases meet the mandated RPS percentage targets and renewable resources are included in the analysis and are the same for all cases analyzed.

Section 4.2 reviews 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 revenues requirements and electricity rate schedule needed to support it, and the consequences of funding short falls.

4.2 Strategic Case Runs

The cases analyzed in this 2011 IRP were introduced in Section 3.5 and are briefly reviewed here. The timing of coal divestiture (and the associated resource replacement) is the key parameter that differentiates the three strategic cases. Table 4-1 summarizes the portfolios for each case. For comparison purposes, the recommended case from last year's IRP is also included.

The following inter-related resource parameters were assumed to occur in each of the three strategies:

- OTC Repowering Schedule per Table 3-3
- Energy efficiency penetration of approximately 3071 GWh by 2030
- RPS Resource Mix, schedule per Table M-2 and M-3 of Appendix M
- GHG allowance methodology and prices on page M-17 of Appendix M
- Gas and Coal Fuel prices, as shown on Tables 4-6 and 4-7
- IPP capacity and recall schedule on Page M-16 of Appendix M

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

4.2.1 Modeling Methodology

4.2.1.1 Planning & Risk (PROSYM)

Simulations were performed using Planning & Risk (PAR), a third-party software program sold and distributed by Ventyx Corporation based in Atlanta, GA. PAR is an hourly chronological production cost model that commits and dispatches resources 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 M.

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 divestiture strategies, and operational inputs regarding future gas-fired units. Details regarding the model assumptions are provided in Section 3 and Appendix M

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 1.6.3 for details). 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 3.3.2.

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 fulfillment of 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 4-2 lists the net dependable capacities of the different resource technologies assumed for this IRP analysis.

Table 4-2: 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 three 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 4.3.3 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

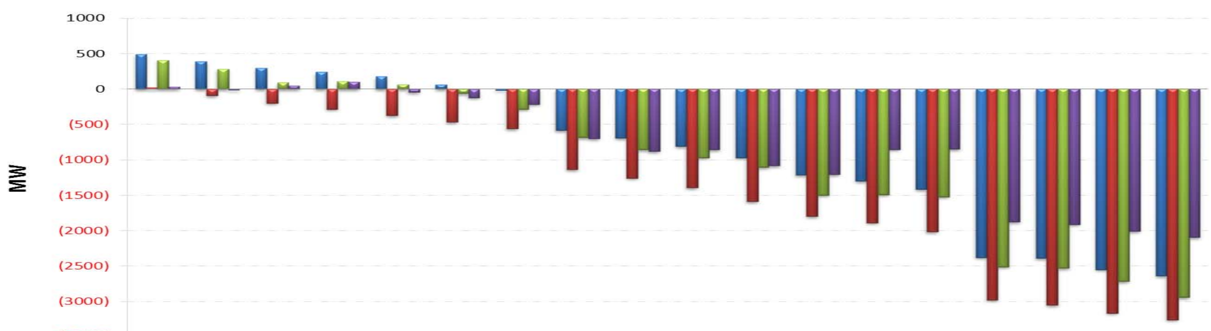
Resource strategies are not designed to totally avoid the chance of a power outage due to inadequate supply resources. Such a strategy would be very expensive and would mean that some resources would be built with a small chance of ever operating, or would have an unacceptably low capacity factor. Most 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 NERC/WECC reliability criteria 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 criteria 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

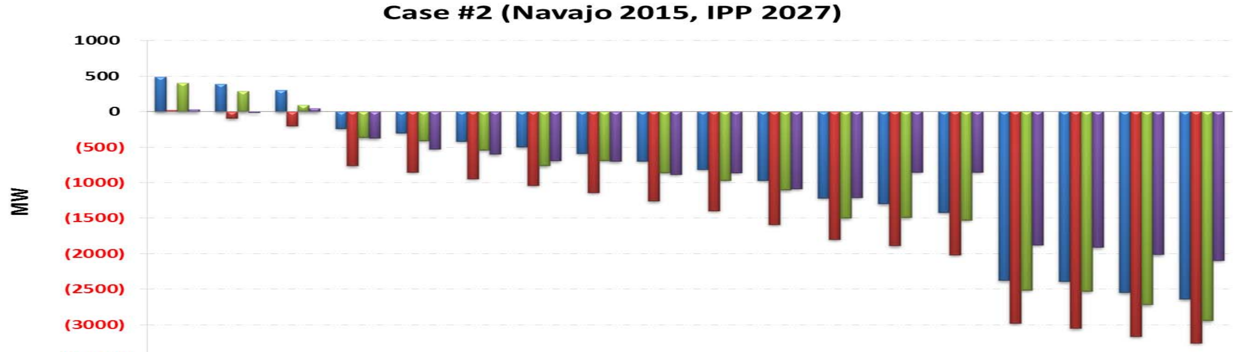
The process of ensuring resource adequacy for each strategic case is iterative. Initially, a model run is made for each case without any resource additions. The results indicate the amount of resource surplus or shortfall into the future. Without any resource additions, a deficit is eventually reached as a result of coal divestitures, generation unit retirements and the expiration of power purchase contracts on the supply side, as well as load growth on the demand side. Figure 4-1 present the resource shortfalls for the three strategic cases prior to any resource additions. For planning purposes, the figures focus on the most critical months of each year – July through October.

Case #1 (Navajo 2019, IPP 2027)



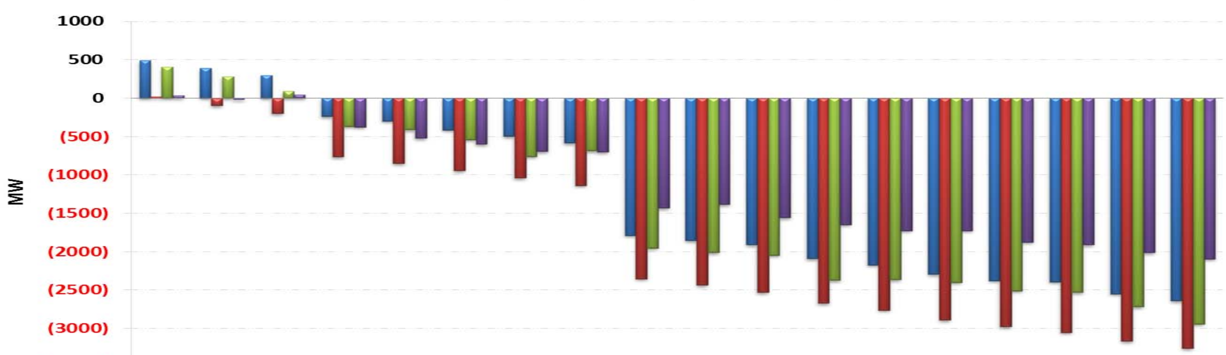
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
July	493	389	301	241	180	63	(19)	(585)	(695)	(810)	(968)	(1215)	(1299)	(1419)	(2378)	(2391)	(2549)	(2640)
August	23	(95)	(198)	(285)	(373)	(467)	(560)	(1137)	(1259)	(1393)	(1588)	(1798)	(1887)	(2015)	(2977)	(3051)	(3164)	(3258)
September	408	286	92	110	68	(64)	(283)	(686)	(858)	(968)	(1104)	(1499)	(1490)	(1524)	(2511)	(2531)	(2717)	(2942)
October	35	(17)	49	104	(45)	(121)	(215)	(700)	(880)	(857)	(1082)	(1208)	(852)	(851)	(1875)	(1911)	(2011)	(2094)

Case #2 (Navajo 2015, IPP 2027)



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
July	493	389	301	(236)	(297)	(414)	(496)	(585)	(695)	(810)	(968)	(1215)	(1299)	(1419)	(2378)	(2391)	(2549)	(2640)
August	23	(95)	(198)	(762)	(850)	(944)	(1037)	(1137)	(1259)	(1393)	(1588)	(1798)	(1887)	(2015)	(2977)	(3051)	(3164)	(3258)
September	408	286	92	(367)	(409)	(541)	(760)	(686)	(858)	(968)	(1104)	(1499)	(1490)	(1524)	(2511)	(2531)	(2717)	(2942)
October	35	(17)	49	(373)	(522)	(598)	(692)	(700)	(880)	(857)	(1082)	(1208)	(852)	(851)	(1875)	(1911)	(2011)	(2094)

Case #3 (Navajo 2015, IPP 2020)



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
July	493	389	301	(236)	(297)	(414)	(496)	(585)	(1788)	(1853)	(1911)	(2090)	(2174)	(2294)	(2378)	(2391)	(2549)	(2640)
August	23	(95)	(198)	(762)	(850)	(944)	(1037)	(1137)	(2352)	(2436)	(2531)	(2673)	(2762)	(2890)	(2977)	(3051)	(3164)	(3258)
September	408	286	92	(367)	(409)	(541)	(760)	(686)	(1951)	(2011)	(2047)	(2374)	(2365)	(2399)	(2511)	(2531)	(2717)	(2942)
October	35	(17)	49	(373)	(522)	(598)	(692)	(700)	(1431)	(1383)	(1558)	(1646)	(1727)	(1726)	(1875)	(1911)	(2011)	(2094)

Year/Month

Figure 4-1. Summer months resource adequacy shortage with coal divestiture by calendar year (1 in 10)

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:

- Because the analysis already includes renewable resources expected to be in place by the end of 2011, any additional renewables added will increase LADWP's overall resource portfolio and help achieve compliance with SB 2 (1X).
- Energy efficiency, demand response, short-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 recommended resource replacement strategy for each case and briefed the General Manager and Financial Services Organization. The recommended solution employs a mix of new renewable generation, energy efficiency, demand response, new gas-fired combined cycle units, and short-term 3rd quarter energy purchases to replace Navajo and IPP Coal and to supplement load growth. Table 4-3 shows the breakdown of the replacement resources recommended for the three cases.

Table 4-3. RESOURCES RECOMMENDED FOR RESOURCE ADEQUACY BY CALENDAR YEAR

Base Case (Navajo 2019, IPP 2027)

Capacity (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	61	88	111	132	145	156	167	175	183	191	199	207	215	223	231	239	247	255
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500
New Renewable	30	47	120	166	251	310	356	403	446	500	528	575	605	623	637	646	656	662
Navajo Replacement CC	0	0	0	0	0	0	0	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
Short Term Q3 Purchase								75	100	125	225	325	325	375	175	225	325	400
Total Replacement	**96**	**145**	**251**	**338**	**471**	**565**	**674**	**1153**	**1279**	**1415**	**1602**	**1807**	**1894**	**2021**	**2992**	**3060**	**3177**	**3266**

Case 2 (Navajo 2015, IPP 2027)

Capacity (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	61	88	111	132	145	156	167	175	183	191	199	207	215	223	231	239	247	255
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500
New Renewable	30	47	120	166	251	310	356	403	446	500	528	575	605	623	637	646	656	662
Navajo Replacement CC				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	1150	1150	1150	1150
Short Term Q3 Purchase				125	100	75	75	75	100	125	225	325	325	375	175	225	325	400
Total Replacement	**96**	**145**	**251**	**763**	**871**	**940**	**1049**	**1153**	**1279**	**1415**	**1602**	**1807**	**1894**	**2021**	**2992**	**3060**	**3177**	**3266**

Case 3 (Navajo 2015, IPP 2020)

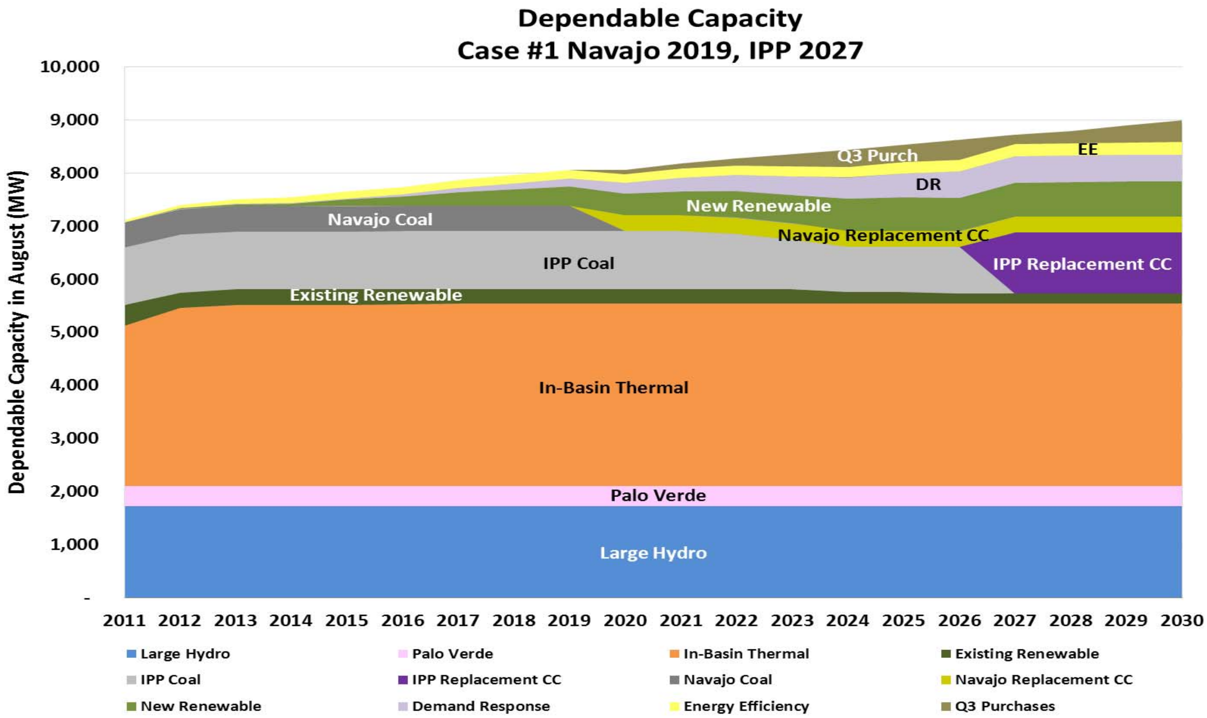
Capacity (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	61	88	111	132	145	156	167	175	183	191	199	207	215	223	231	239	247	255
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500
New Renewable	30	47	120	166	251	310	356	403	446	500	528	575	605	623	637	646	656	662
Navajo Replacement CC				300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC					0	0	0	0	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Short Term Q3 Purchase				125	100	75	75	75	25		25	50	50	100	175	225	325	400
Total Replacement	**96**	**145**	**251**	**763**	**871**	**940**	**1049**	**1153**	**2354**	**2440**	**2552**	**2682**	**2769**	**2896**	**2992**	**3060**	**3177**	**3266**

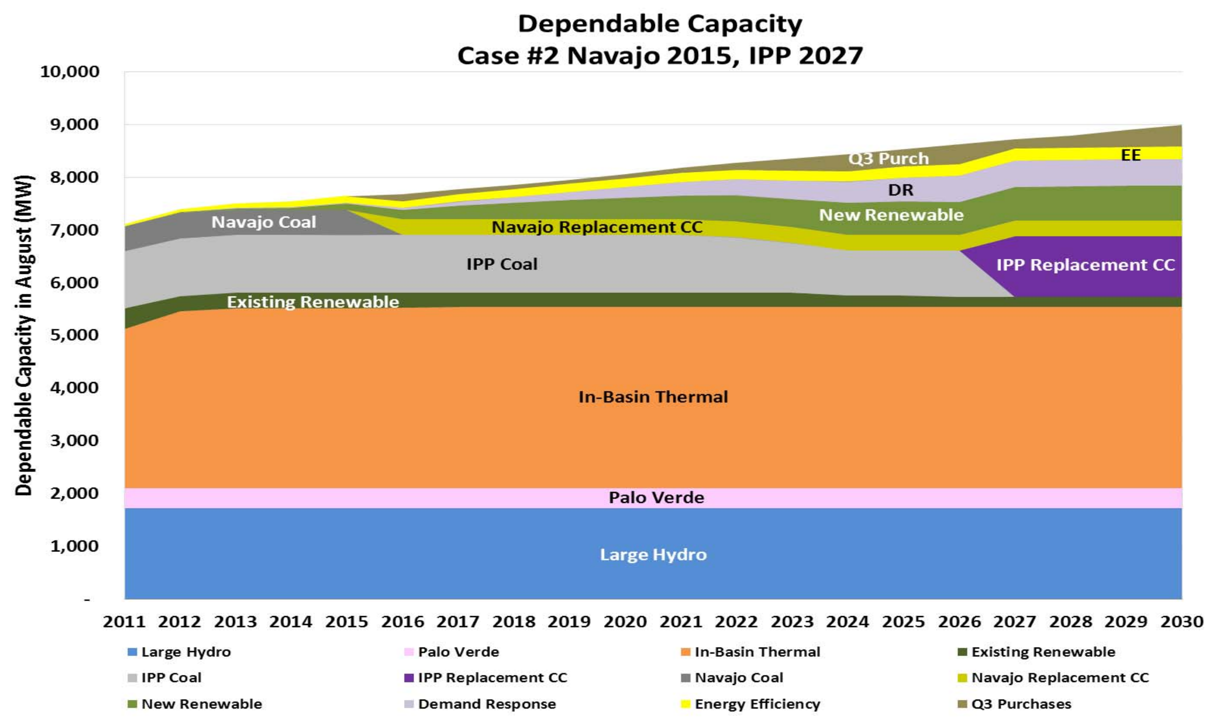
Figure 4-2 shows the net dependable capacity profiles for the 3 cases after including the recommended resources to satisfy resource adequacy requirements. In each case, Navajo is replaced with new renewable generation and a 300 MW replacement combined cycle gas-fired unit upon divestiture. Energy efficiency,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

When IPP energy ceases in 2027 for Cases 1 and 2 and 2020 for Case 3, that production is replaced entirely with a 1,150 MW combined cycle natural gas unit. The larger combined cycle unit will be necessary to reduce short-term purchases and to provide 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, short-term purchases, and a portion of the 1,150 MW combined cycled gas-fired unit.

Short-term purchases are meant to satisfy peak load growth in the summer months where capacity is needed only over a short period of time. The planned addition of short-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 insure that the market possesses adequate depth and reasonable pricing so that these purchases can be relied upon to fill system capacity needs.

In Cases 2 and 3 with Navajo 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.





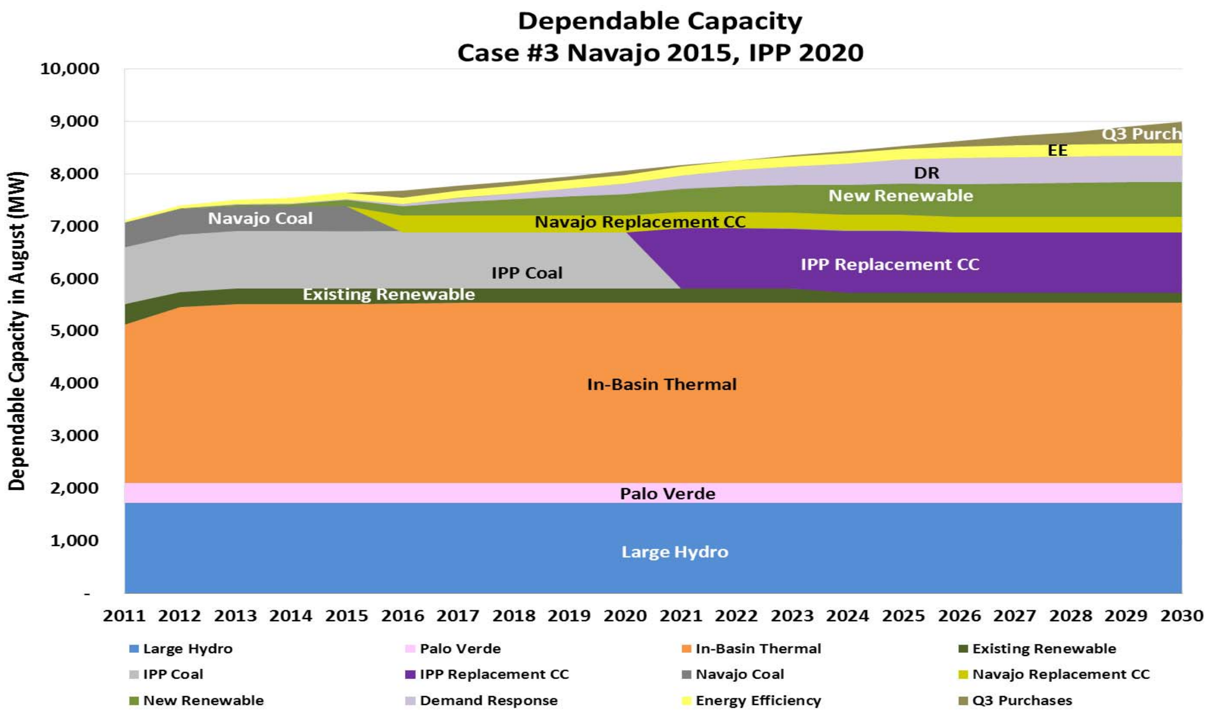


Figure 4-2. Dependable capacity mix by calendar year.

4.3.2 GHG Emissions Considerations

The primary objective of coal divestiture is to reduce overall GHG emissions. Energy produced from coal emits approximately twice the amount of GHG emissions on a lbs/mmbtu basis, when compared to energy produced from natural gas. The reductions of GHG emissions are reflected in the production cost model simulations. Figure 4-3 illustrates a comparison of the resulting GHG emission levels of the three cases. Divestiture of Navajo results in an average 1.86 Million Metric Tons (MMT) reduction in GHG each year while IPP results in an average 3.26 MMT reduction each year. GHG reductions are accelerated in Cases 2 and 3 with the divestiture 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 divestiture. 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 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. Early divestiture of Navajo shown in Cases 2 and 3 results in approximately 7.5 MMT less GHG emissions between 2016 and 2019 and early divestiture of IPP shown in Case 3 results in a reduction of GHG emissions of 21.1 MMT between 2020 and 2027.

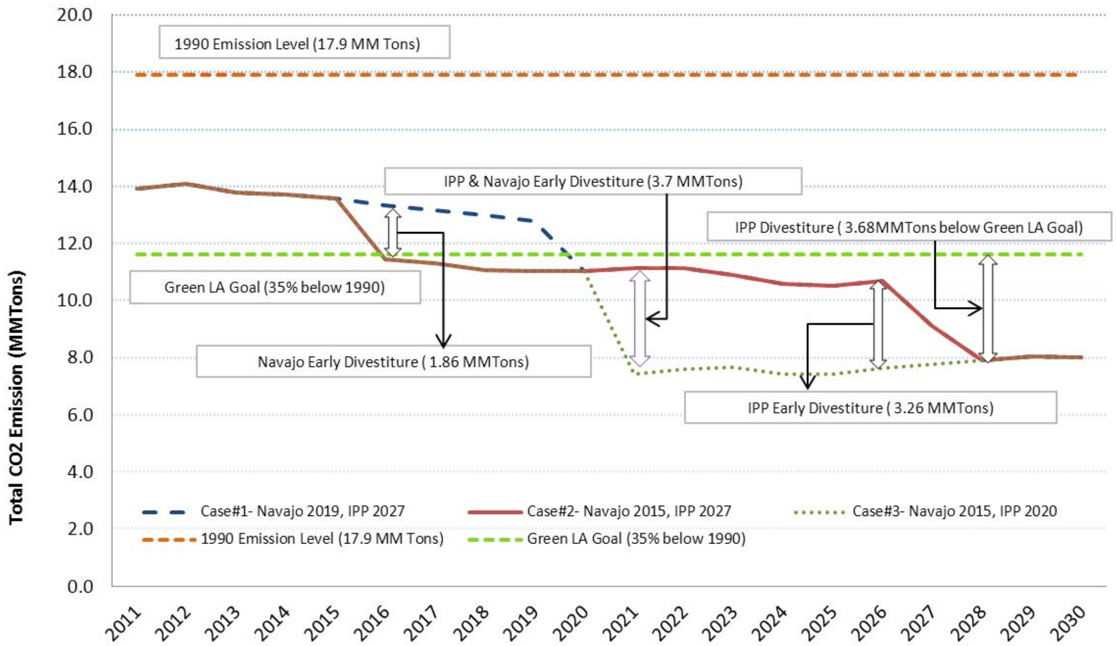


Figure 4-3. GHG emissions comparison by calendar year.

In addition to GHG, Oxides of Nitrogen (NO_X) were also measured within the production model. Figure 4-4 summarizes NO_X emissions for each of the three cases. With the installation of SCR equipment since 1989, NO_X emissions of in-basin generation has been reduced by 90 percent and represents approximately 0.5 percent of all LADWP NO_X emissions with the other 99.5 percent coming from out-of-basin coal-fired generation.

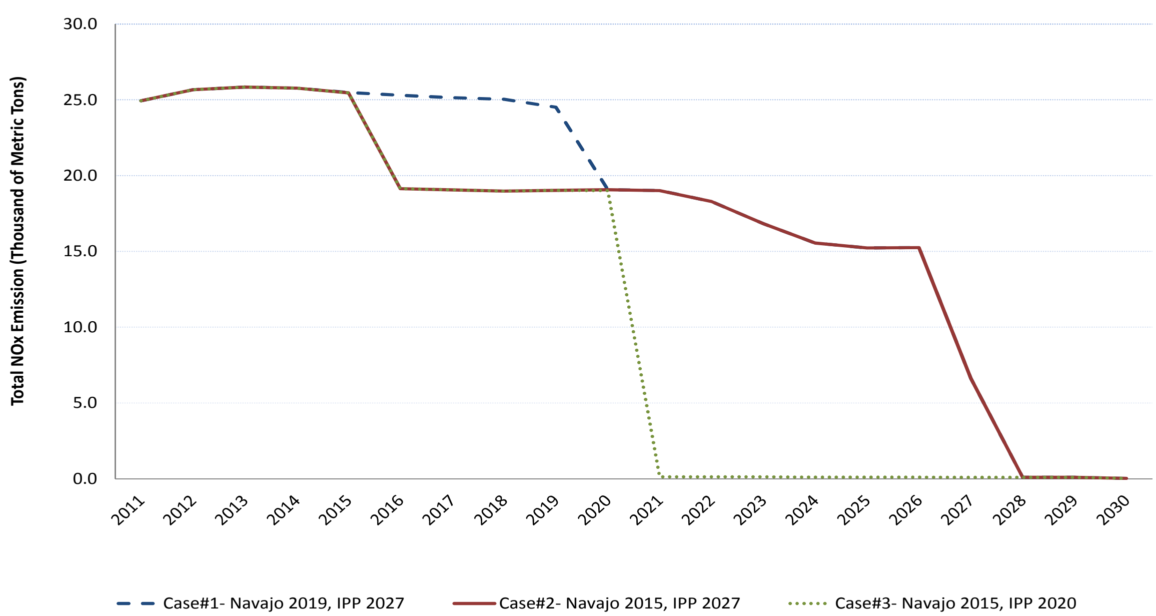


Figure 4-4. NO_X emissions comparison by calendar year

4.3.3 Economic Considerations

The economic considerations for the three cases included a comparison of fuel and variable costs, and a fuel price stress test to account for potential future price volatility which affects possible ranges of bulk power costs. 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 Cases

The total fuel and variable costs for the 3 coal divestiture cases are shown in Figure 4-5 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 4.3.3.2.

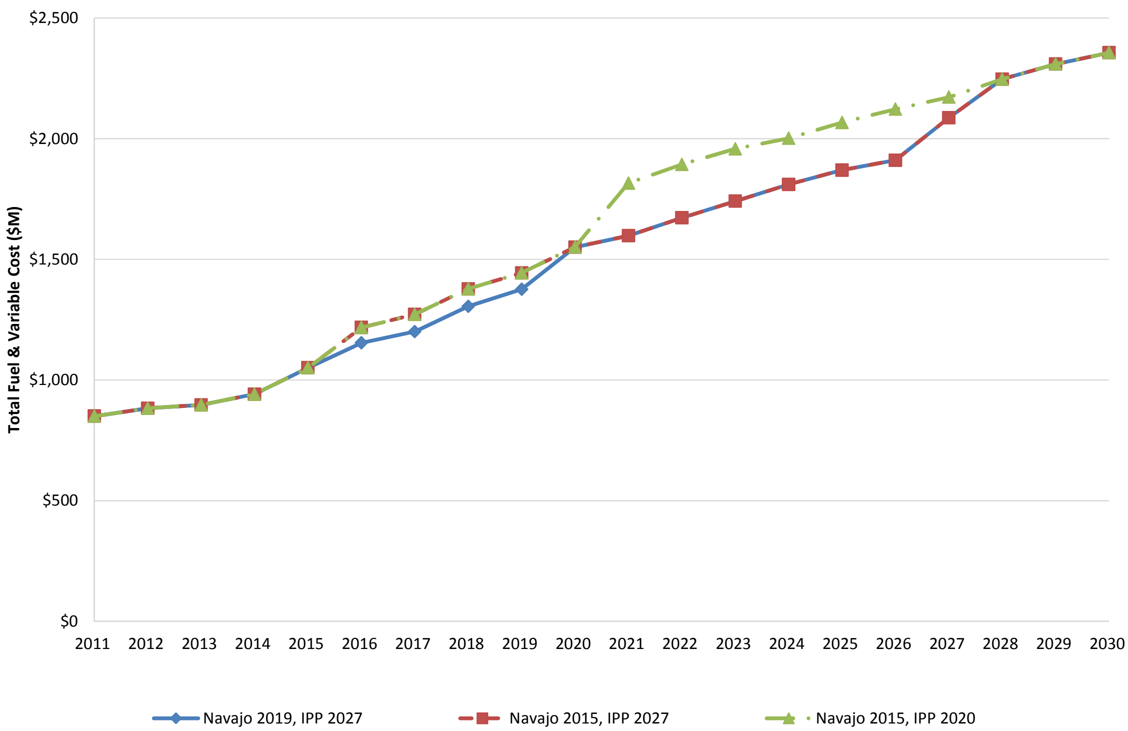


Figure 4-5. Total fuel and variable cost comparison by calendar year (Includes renewable project costs).

Divestiture 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 replacement gas-fired combined cycle units and new renewable energy. The gas-fired replacement resources for Navajo can be better seen in Table 4-4. Because all 3 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 4-4 do not include any costs associated with new renewable resources.

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

Delta -Navajo Early Divestiture Study (Case 2 - Case 1) [FYE]	2016	2017	2018	2019	2020	Total
Capital & Fixed OM Cost						
300 MW Navajo Replacement Cost	$9 M	$18 M	$18 M	$18 M	$6 M	$68 M
SubTotal	$9 M	$18 M	$18 M	$18 M	$6 M	$68 M
Additional Fuel Cost	$25 M	$65 M	$66 M	$74 M	$33 M	$264 M
Additional VOM Cost	$0 M	$4 M	$3 M	$3 M	$2 M	$12 M
Total Cost Delta	$ 34	$ 87	$ 87	$ 94	$ 41	$343 M
Billed Energy Sale (GWh)	23,390	23,567	23,755	23,977	24,239	Average
Est. Rate Increase (cents/kWh) *	0.15	0.37	0.36	0.39	0.17	0.36

Note: * Noncumulative rate increase.

Delta - IPP Early Divestiture Study (Case 3 - Case 2) [FYE]	2021	2022	2023	2024	2025	2026	2027	Total
Capital & Fixed OM Cost								
1,150 MW IPP Replacement CC	$66 M	$133 M	$133 M	$133 M	$133 M	$133 M	$126 M	$856 M
Natural Gas Pipe line	$2 M	$4 M	$4 M	$4 M	$4 M	$4 M	$4 M	$28 M
SubTotal	$68 M	$137 M	$137 M	$137 M	$137 M	$137 M	$131 M	$884 M
Additional Fuel Cost	$88 M	$198 M	$190 M	$188 M	$170 M	$190 M	$180 M	$1,203 M
Additional VOM Cost	$ 9	$ 26	$ 26	$ 23	$ 18	$ 19	$ 18	$139 M
Total Cost Delta	165	361	353	348	325	346	328	$2,226 M
Billed Energy Sale (GWh)	24,601	24,820	25,046	25,283	25,519	25,750	25,983	Average
Est. Rate Increase (cents/kWh) *	0.67	1.45	1.41	1.38	1.27	1.34	1.26	1.35

Note: * Noncumulative rate increase.

4.3.3.2 Fuel Price Stress Test

The importance of stress testing the model results of the 3 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 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 4-6. 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.

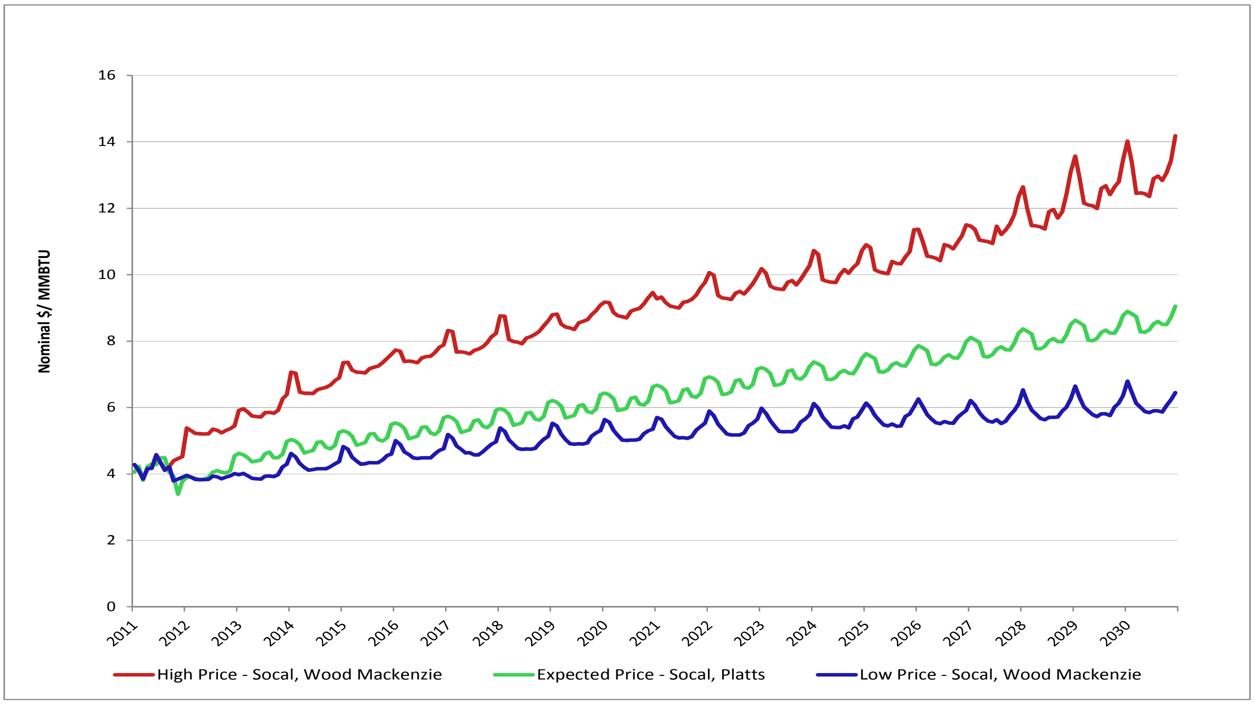


Figure 4-6. High, low, and expected natural gas price forecasts (So Cal Gas).

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 lower than expected prices. This is wholly consistent with past historical gas prices which are shown in Figure 4-7 – the relative shape of the curve is asymmetrical with the forward tail (higher prices) extending further away from the mean of the curve.

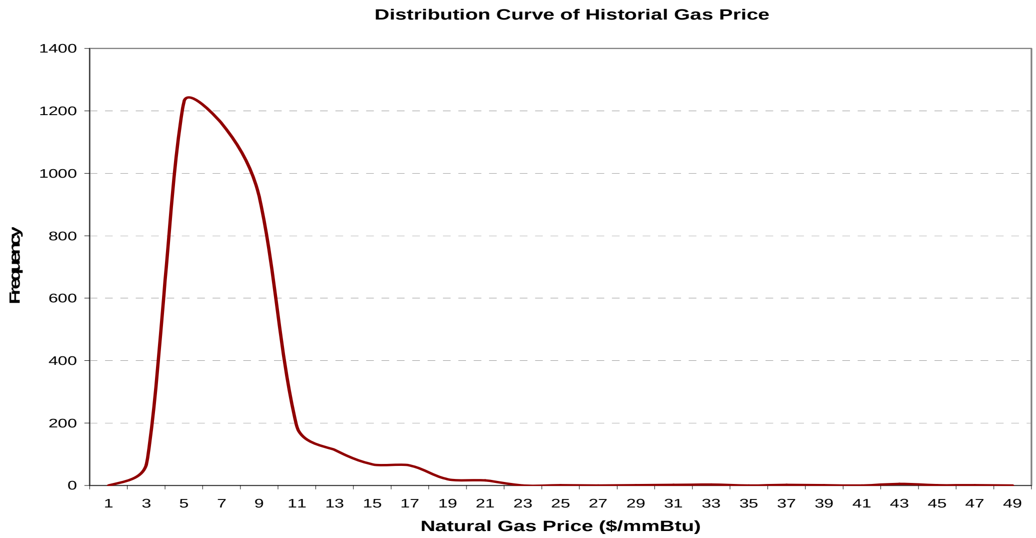
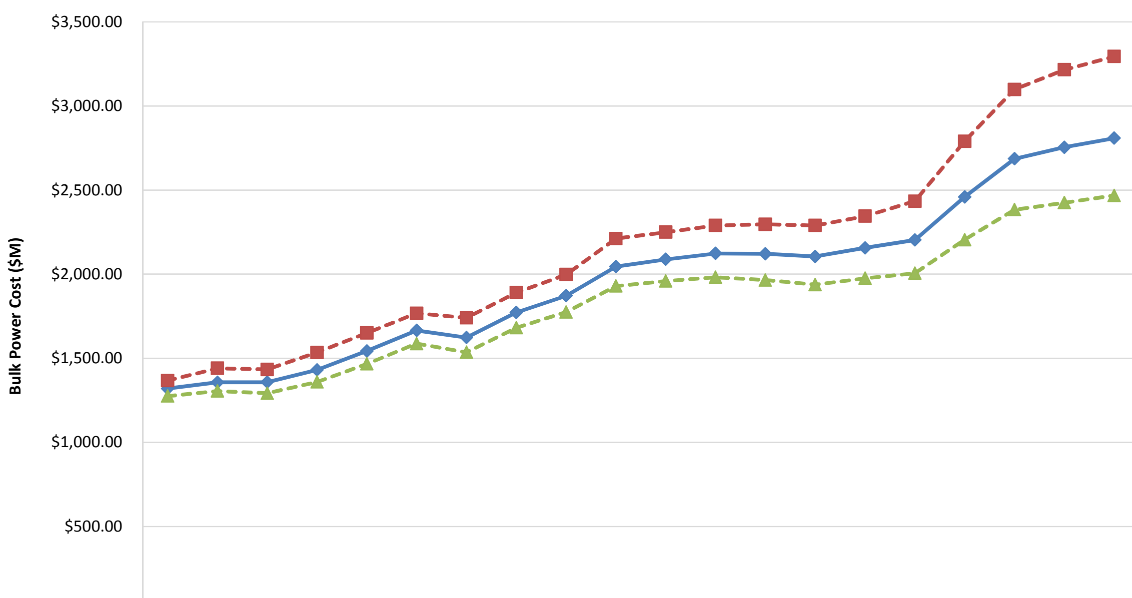


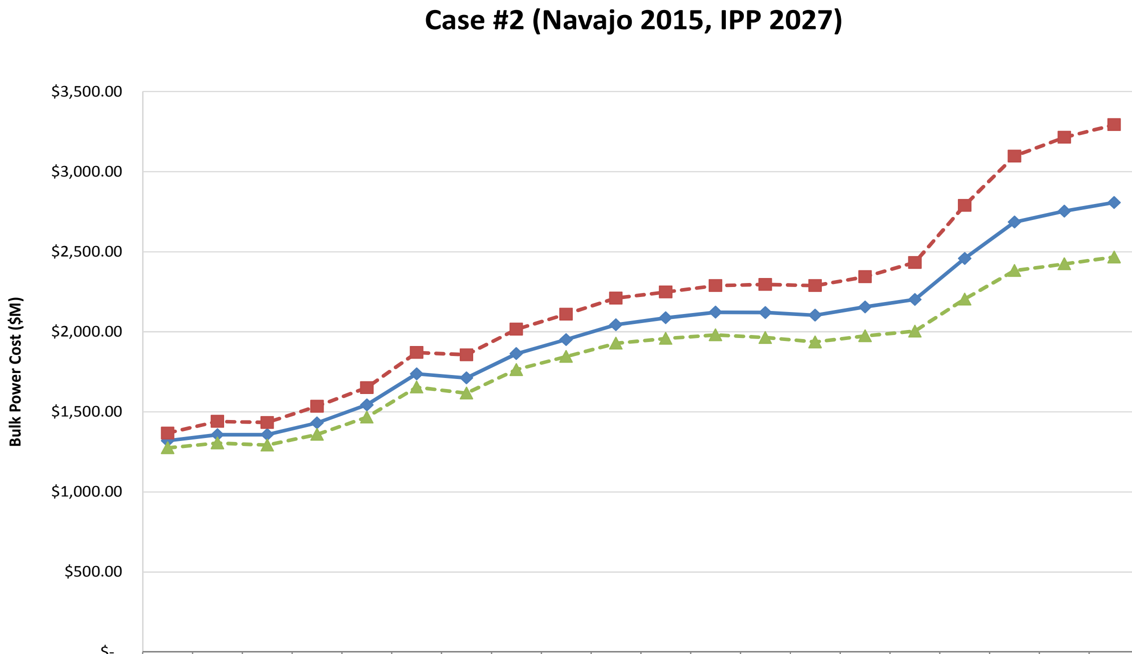
Figure 4-7. Historical distribution of natural gas prices (SoCal, 2005 through 2010).

The high and low fuel price ranges were then incorporated into the three strategic case model runs. The three charts shown in Figure 4-8 display the results of bulk power costs for each of the 3 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.

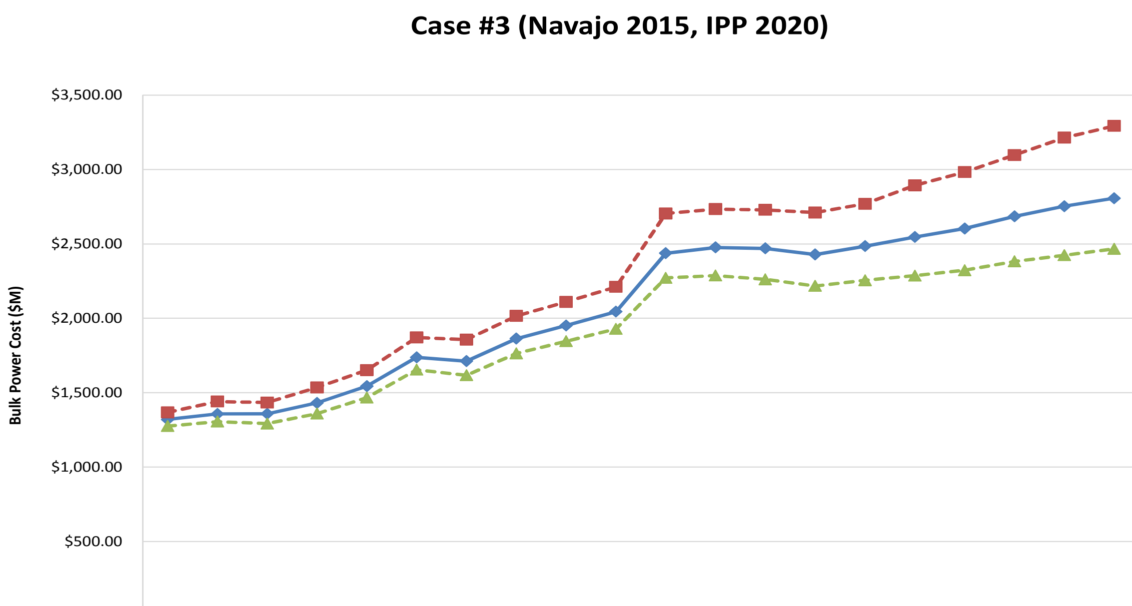
Case #1 (Navajo 2019, IPP 2027)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Case #1	$1,319	$1,357	$1,357	$1,431	$1,543	$1,665	$1,623	$1,772	$1,872	$2,045	$2,088	$2,123	$2,121	$2,105	$2,156	$2,203	$2,459	$2,686	$2,754	$2,808
Case #1_H	$1,367	$1,440	$1,433	$1,535	$1,650	$1,767	$1,740	$1,891	$1,998	$2,211	$2,249	$2,289	$2,296	$2,289	$2,345	$2,434	$2,790	$3,098	$3,215	$3,294
Case #1_L	$1,275	$1,305	$1,292	$1,359	$1,466	$1,587	$1,535	$1,682	$1,775	$1,929	$1,959	$1,981	$1,965	$1,938	$1,975	$2,005	$2,205	$2,383	$2,424	$2,468



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Case #2	$1,319	$1,357	$1,357	$1,431	$1,543	$1,737	$1,712	$1,863	$1,951	$2,043	$2,087	$2,122	$2,120	$2,103	$2,155	$2,201	$2,457	$2,685	$2,753	$2,807
Case #2_H	$1,367	$1,440	$1,433	$1,535	$1,651	$1,870	$1,856	$2,015	$2,110	$2,210	$2,248	$2,288	$2,295	$2,288	$2,343	$2,433	$2,789	$3,097	$3,213	$3,293
Case #2_L	$1,275	$1,305	$1,292	$1,359	$1,466	$1,654	$1,616	$1,763	$1,845	$1,928	$1,958	$1,980	$1,964	$1,936	$1,974	$2,004	$2,204	$2,382	$2,423	$2,466



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Case #3	$1,319	$1,357	$1,357	$1,431	$1,543	$1,737	$1,712	$1,863	$1,951	$2,044	$2,437	$2,476	$2,469	$2,428	$2,484	$2,546	$2,603	$2,685	$2,753	$2,807
Case #3_H	$1,367	$1,440	$1,433	$1,535	$1,651	$1,870	$1,856	$2,015	$2,110	$2,211	$2,704	$2,734	$2,728	$2,710	$2,769	$2,893	$2,982	$3,097	$3,213	$3,293
Case #3_L	$1,275	$1,305	$1,292	$1,359	$1,466	$1,654	$1,616	$1,763	$1,845	$1,929	$2,271	$2,287	$2,261	$2,217	$2,255	$2,286	$2,322	$2,382	$2,423	$2,466

Figure 4-8. Bulk power cost comparison - high, low, and expected fuel prices.

To better compare the risk associated with higher natural gas prices between the 3 strategic cases, three years - 2016, 2019, and 2021 - are used for comparison as shown in Figure 4-9 below.

In the year 2016, both Cases 2 and 3 show divestiture of NGS with 300 MW of gas-fired CC replacement generation. These cases are facing higher fuel and variable spending risk exposure to natural gas price fluctuations.

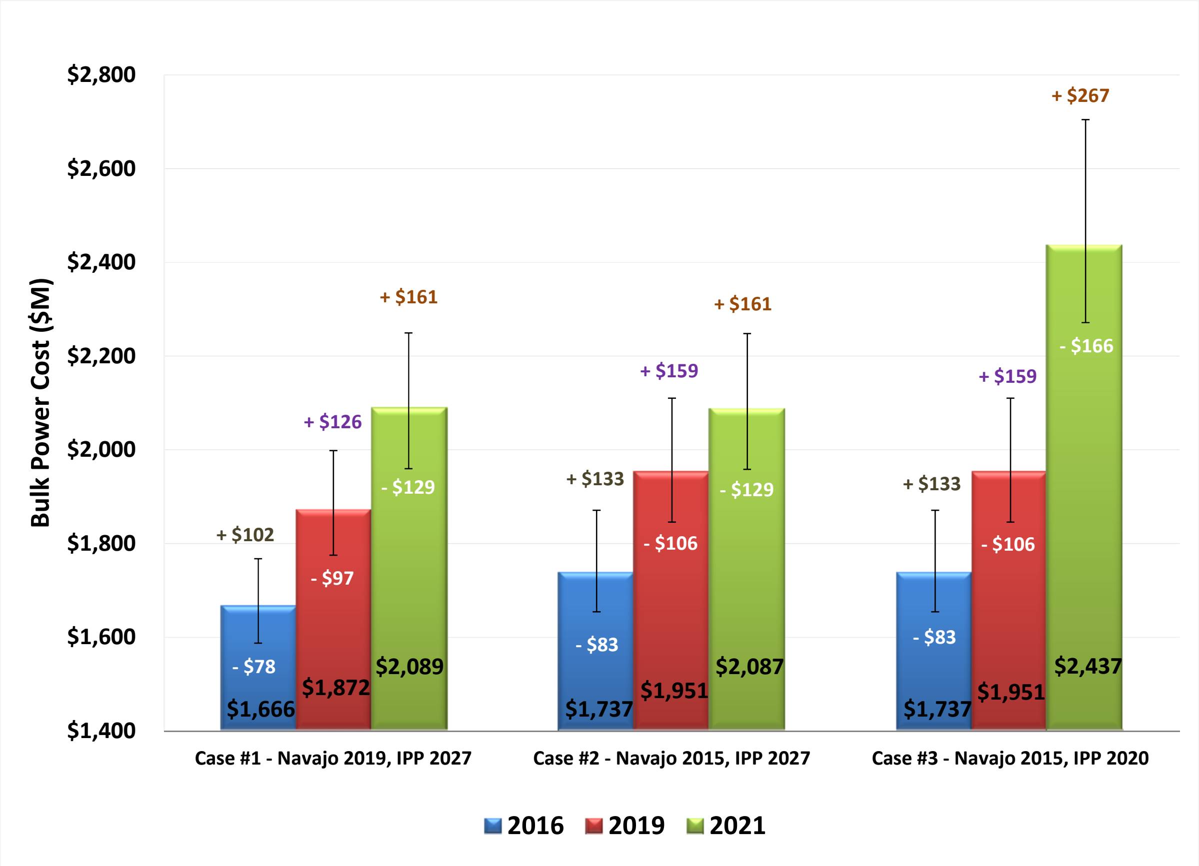


Figure 4-9. Bulk power cost with high and low comparison by calendar year.

By the year 2020 NGS will retire in all three cases, with Case 3 showing IPP also being replaced in 2020 with two 575 MW combined cycle units. With all coal generation being eliminated in 2021 for Case 3, 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 4-10 shows the potential rates that could be experienced under the 3 cases given high, expected, and low fuel ranges.

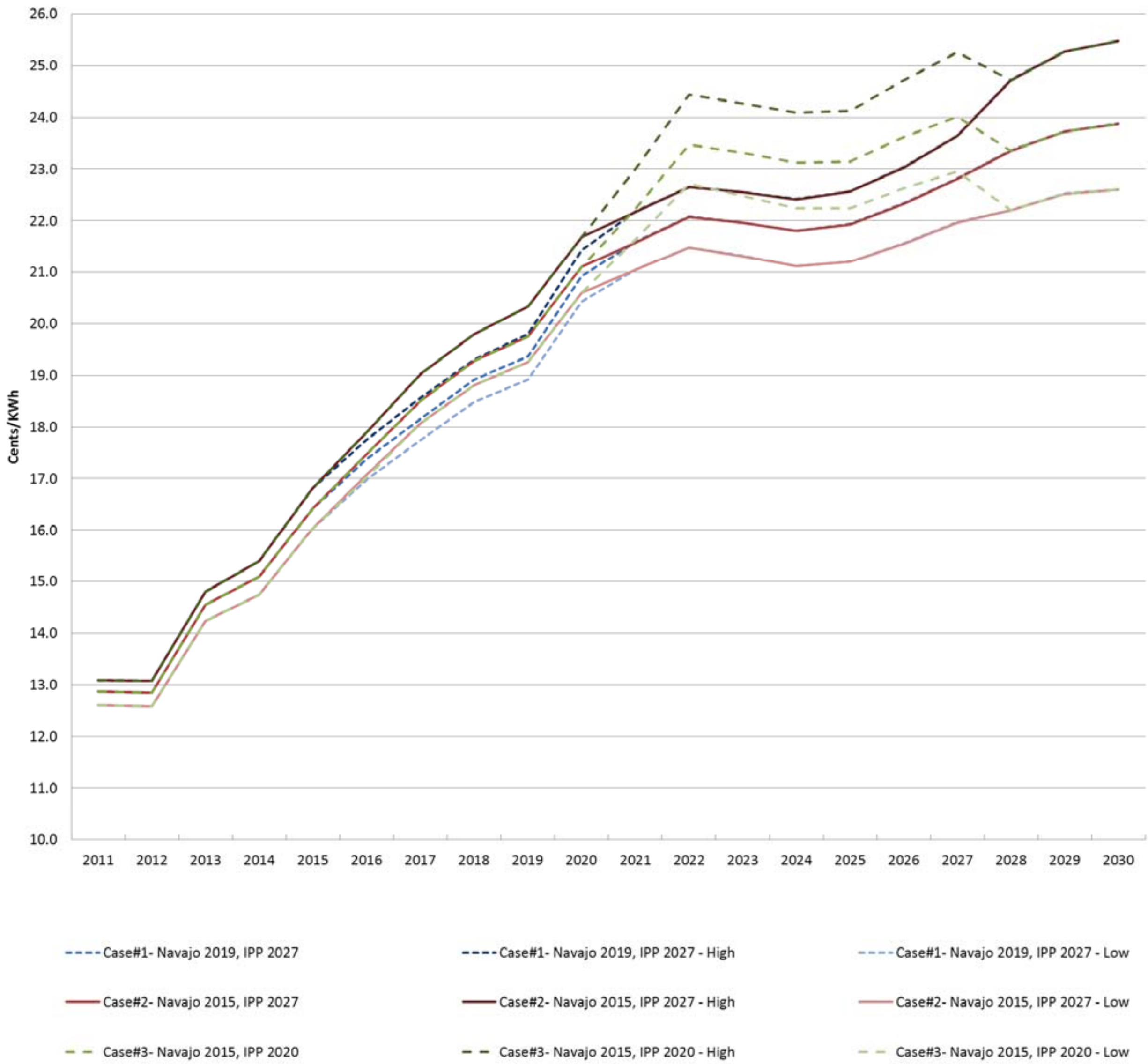


Figure 4-10. Estimated electric rate comparison over 20 years by fiscal year-ending.

4.3.3.3 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 4-11 and Table 4-5. Today, these reliability and regulatory programs comprise 32% of all power system costs and in 2020 these same programs will grow to approximately 47%.

Table 4-5 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.

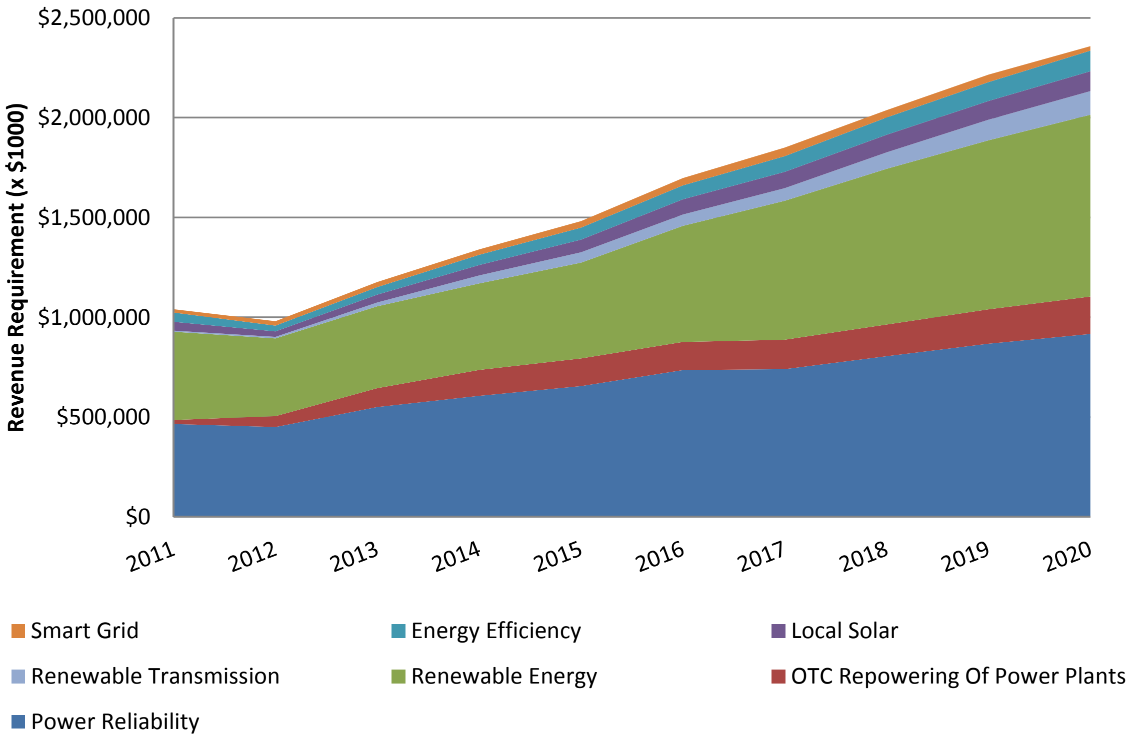


Figure 4-11. Annual revenue requirement for reliability and regulatory program for fiscal year ending 2011 through 2020.

Table 4-5. Annual revenue requirements of power system programs, fiscal year ending 2011 through 2020 (x$1000)

(FYE)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Reliability										
Debt Serv. & Depr. (Less Smart Grid)	$72,749	$107,093	$141,683	$179,437	$211,446	$249,334	$290,677	$342,043	$386,167	$431,411
O&M	$392,788	$343,324	$409,122	$427,436	$443,833	$486,513	$449,644	$463,154	$481,992	$485,644
	$465,537	$450,417	$550,805	$606,873	$655,279	$735,847	$740,322	$805,197	$868,159	$917,055
Sum Total 2011-2020	**$6,795,489**									
OTC Repowering Of Power Plants										
Debt Serv. & Depr.	$19,828	$54,639	$94,439	$129,403	$138,530	$141,053	$147,519	$158,728	$171,669	$186,906
	$19,828	$54,639	$94,439	$129,403	$138,530	$141,053	$147,519	$158,728	$171,669	$186,906
Sum Total 2011-2020	**$1,242,713**									
Transition from Coal Early (NGS)										
Debt Serv. & Depr.	$0	$0	$0	$0	$0	$9,000	$18,000	$18,000	$18,000	$6,000
Fuel & VOM	$0	$0	$0	$0	$0	$25,000	$69,000	$69,000	$77,000	$35,000
	$0	$0	$0	$0	$0	$81,000	$88,000	$89,000	$82,000	$41,000
Sum Total 2011-2020	**$381,000**									
Renewable Energy										
Debt Serv. & Depr.	$48,556	$47,980	$48,673	$50,950	$53,528	$75,064	$126,605	$173,126	$205,001	$226,948
O&M	$93,524	$26,681	$25,812	$28,214	$29,041	$29,689	$28,272	$30,052	$31,272	$32,078
Purchased Power (PPA's)	$300,446	$314,249	$335,712	$354,527	$397,795	$476,395	$540,998	$576,960	$610,856	$652,051
	$442,525	$388,910	$410,198	$433,691	$480,364	$581,148	$695,875	$780,138	$847,129	$911,077
Sum Total 2011-2020	**$5,971,054**									
Renewable Transmission										
Debt Serv. & Depr.	$5,600	$8,298	$19,327	$39,676	$51,470	$56,878	$63,762	$82,743	$103,245	$118,611
	$5,600	$8,298	$19,327	$39,676	$51,470	$56,878	$63,762	$82,743	$103,245	$118,611
Sum Total 2011-2020	**$549,609**									
Local Solar										
SB1 Debt Serv. & Depr.	$5,047	$13,903	$22,825	$29,164	$31,972	$32,936	$33,509	$33,891	$34,146	$34,251
SB1 O&M	$33,937	$0	$0	$0	$0	$0	$0	$0	$0	$0
UBS Debt Serv. & Depr.	$5,349	$11,484	$13,245	$15,064	$16,959	$19,603	$23,281	$27,067	$30,919	$33,916
FIT (PPA)	$0	$1,699	$3,201	$7,922	$14,999	$23,558	$24,480	$26,639	$28,798	$30,781
	$44,333	$27,086	$39,270	$52,149	$63,930	$76,097	$81,270	$87,597	$93,863	$98,947
Sum Total 2011-2020	**$664,544**									
Energy Efficiency										
Debt Serv. & Depr.	$1,081	$5,959	$13,651	$22,282	$30,944	$39,378	$47,827	$56,276	$64,839	$73,288
O&M	$45,166	$22,906	$23,783	$29,054	$28,810	$30,682	$30,553	$30,556	$29,624	$30,552
	$46,247	$28,866	$37,434	$51,336	$59,754	$70,059	$78,380	$86,832	$94,462	$103,840
Sum Total 2011-2020	**$657,210**									
Smart Grid										
Debt Serv. & Depr. (Oper. Sup.)	$9,869	$15,022	$15,863	$18,849	$17,871	$20,317	$25,443	$27,998	$28,457	$13,411
Debt Serv. & Depr. (PRP)	$6,821	$7,878	$9,681	$8,701	$15,143	$16,643	$17,776	$8,979	$8,979	$8,979
	$16,690	$22,899	$25,543	$27,549	$33,014	$36,960	$43,219	$36,977	$37,436	$22,390
Sum Total 2011-2020	**$302,678**									
Basic Gen, Trans, Dist										
	$1,947,841	$2,010,184	$2,209,311	$2,190,998	$2,397,128	$2,456,837	$2,540,415	$2,616,531	$2,650,283	$2,890,785
Sum Total 2011-2020	**$23,910,313**									
Total Power System Revenue Requirement										
	$2,983,000	$2,983,000	$3,367,000	$3,492,000	$3,828,000	$4,179,000	$4,415,000	$4,661,000	$4,845,000	$5,172,000
Sum Total 2011-2020	**$39,925,000**									

4.3.3.4 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. These costs assume full funding of the Power System programs including the Power Reliability Program and Energy Efficiency programs among others. Total annual Power

System costs are shown in Figure 4-12 and reflect short-term spending reductions through 2011-12 fiscal year with subsequent years reflecting a restoration of funding levels to insure that the longer term IRP recommendations can be realized. The costs shown 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 3 cases analyzed.

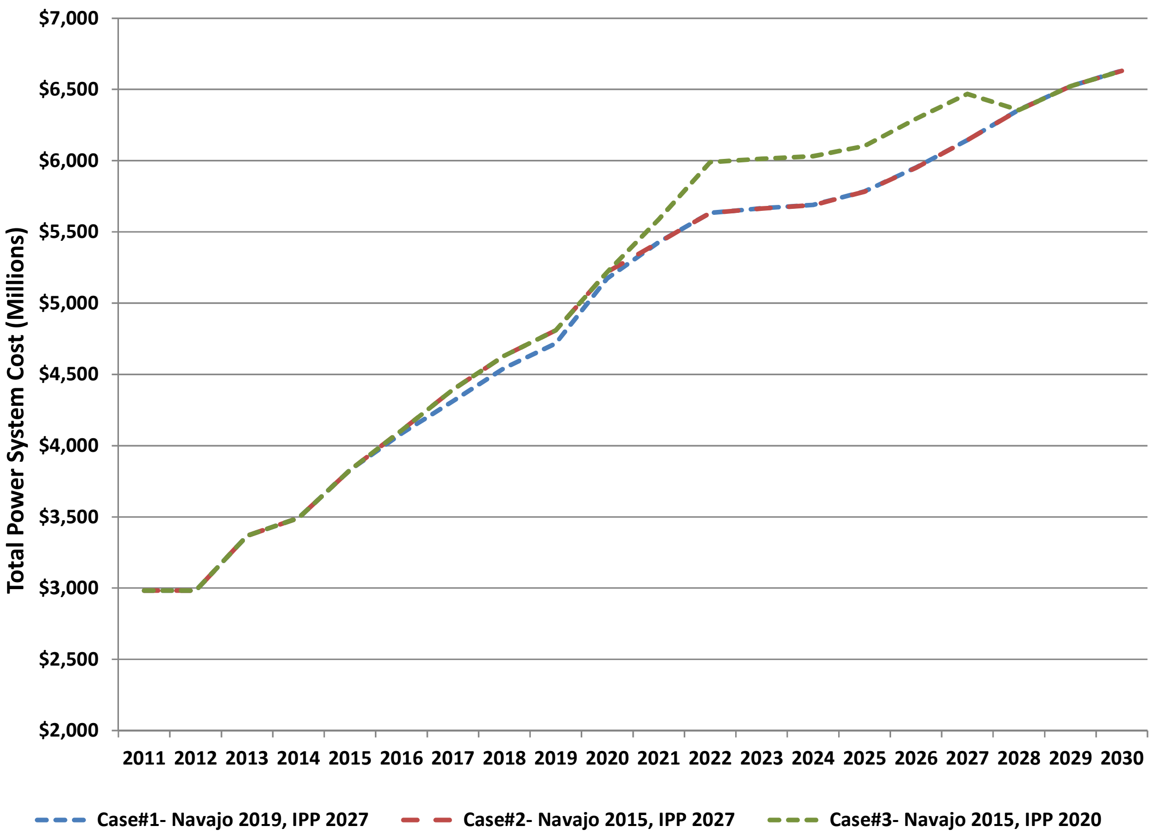


Figure 4-12. Comparison of annual power system costs over the next 20 fiscal years.

Figure 4-13 illustrates the net present value of the total power system costs for each of the strategic cases.

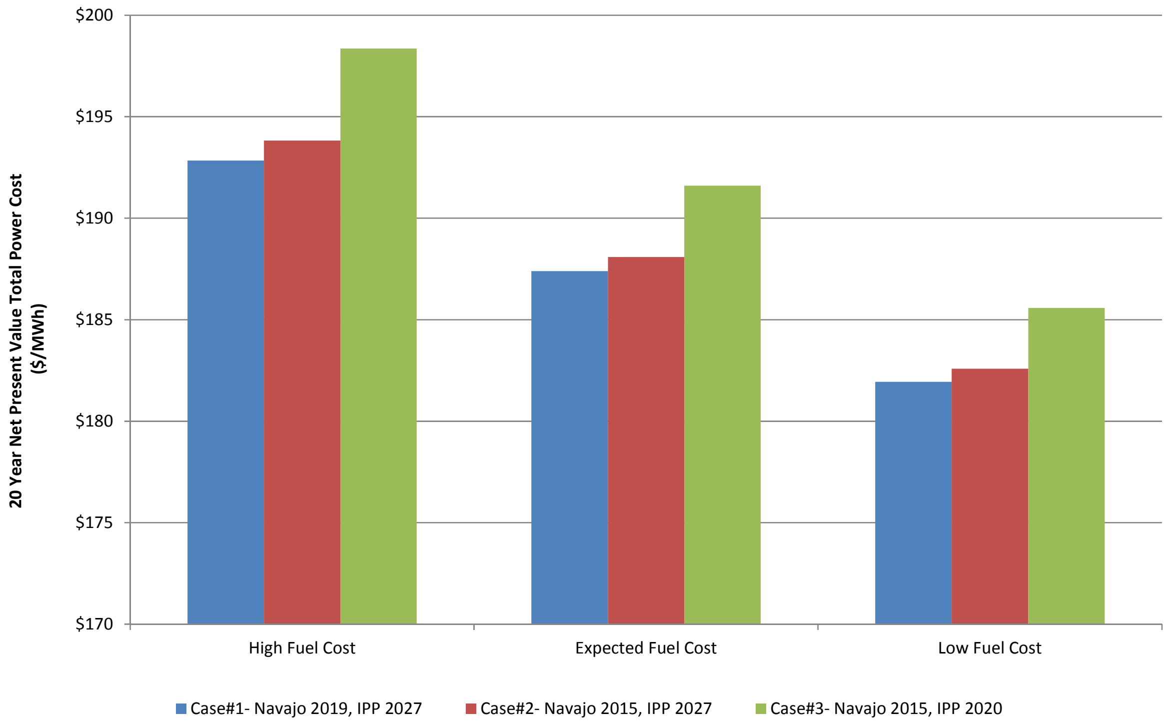


Figure 4-13. Total net present value comparison of power system costs.

4.4 Strategic Case Conclusions and Recommendations

4.4.1 Reliability

All three 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 three cases are considered equal in terms of meeting reliability. To insure that reliability is maintained during the divestiture 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 7.5 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 21.1 million metric tons over the 20-year period.

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 divestiture options of either Case 2 and 3 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 Demand Response and Energy Efficiency programs, and providing additional external generation to supplement the lost generation resulting from coal divestiture.

With early divestiture of Navajo, additional rate increases of 0.36 cents per kwh or a one time 2.0% increase in the average customer bill would be necessary to achieve GHG reductions of 7.5 million metric tons between years 2016 and 2019. However, as previously discussed in Section 4.3.3.2, the early divestiture of Navajo will expose ratepayers to potentially higher natural gas fuel prices that may result in rate increases up to 1 cent per kwh or a one time increase of 5.7% in the average customer bill if gas prices were to remain at these higher levels.

Considering Case 3 with early divestiture of IPP and Navajo, rate increases of approximately 1.35 cents per kwh or a one time 6.1% average increase in the typical customer bill would be necessary to achieve additional GHG reductions of 21.2 million metric tons between the years 2021 and 2027 due to the divestiture of IPP. With potentially higher natural gas fuel prices, resulting rate increases could be as high as 2.4 cents per kwh or a one time increase of 11% in the average customer bill if gas prices were to remain at these higher levels.

4.4.4 Recommended Case

Decisions to fund coal divestiture strategies cannot take place independent of other power system programs. Maintaining reliability and meeting regulatory requirements are primary considerations before any coal divestiture cases can be considered. However, this IRP presupposes funding of these programs so that the recommended coal divestiture 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 2 with early Navajo coal divestiture in 2015 becomes the recommended case for the 2011 IRP. Although Case 2 represents additional cost as compared to Case 1, the additional costs to rate payers appears to be reasonable in light of the environmental benefit of reducing GHG emissions by 7.5 MMT. Early divestiture of Navajo also provides additional time to insure a smooth transition in acquiring and implementing replacement resources. The 2010 IRP included the same recommendation to accelerate divestiture of Navajo and this IRP further clarifies and supports this prior recommendation. This recommended case presents a reasonable approach to achieving environmental goals 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 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 mandates include, for example, establishment of LADWP's RPS, early compliance with SB 1368, and investing in local solar.

The analysis performed in Section 4 to identify the 2011 IRP recommended case closely mirrors the same recommended strategy put forth in the 2010 IRP which incorporated feedback from LADWP's community outreach efforts which were conducted in 2010. The 2011 IRP recommended strategy differs slightly from the 2010 IRP in the timing of the Navajo coal divestiture which is now planned for 2015 instead of 2013. Another difference is in the renewable installed capacity by technology type (e.g. geothermal, wind, and solar). The reasons for these changes are further explained in Section 3.1.1.

Regulatory and Reliability Initiatives

- SB 2 (1X) - RPS Percentage

  LADWP must increase its percentage of renewable energy per recently enacted state law, from the current 20 percent at the end of 2010, to 33 percent by the end of 2020. SB 2 (1X) also establishes interim targets to ensure progress towards the 33 percent goal. Addressing this mandate requires the continued diligence LADWP has demonstrated in raising its renewable portfolio from 3 percent in 2003 to 20 percent in 2010.

- Power Reliability Program (PRP) and system infrastructure investment

  LADWP must re-establish sustained funding to invest in replacing aging transmission and distribution infrastructure to ensure system reliability, especially during significant weather events. Recent funding shortfalls have resulted in an increase in system outages. Section 1.6.4 of this IRP discusses the negative consequences that continued underfunding poses to the city.

- 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 previously. The repowering program is a long term series of projects that will increase reliability and eliminate the need for once-through ocean cooling.

- AB 32 – GHG Cap and Trade

  LADWP will participate in the mandated green house cap-and-trade system which is scheduled to start January 1, 2013. During the next year, LADWP will participate in the regulatory process that will clarify some outstanding details of the proposed program.

- SB 1368 Compliance

  Navajo and 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 with a combination of renewable energy, demand response, EE, short term market purchases, and conventional gas-fired generation.

- Energy Efficiency

  LADWP must procure sufficient resources to meet load growth and maintain system reliability and will continue to pursue and implement energy efficiency programs per AB 2021 standards and as recommended in its latest Market Potential Study. Along with augmenting its generation portfolio, LADWP will implement EE to reduce energy demand. EE programs are not only crucial for meeting customer load growth, they also represent a cost-effective strategy for reducing GHG emissions, since the cleanest kilowatt-hour any utility can produce is one that is never generated.

- 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. Based on reviews of re-licensing activity for similar projects, LADWP could expect cumulative expenditures of approximately $10 million prior to filing the NOI and approximately $80 million before the license expires.

- Transmission

  LADWP should implement those recommendations of the latest Ten-Year Transmission Assessment Plan, in order to maintain reliability in accordance with regulatory guidelines.

Strategic Initiatives

- Early Compliance with SB 1368

  Comments from the public workshops indicated the desire to comply with SB 1368 as early as possible. Navajo must be compliant with SB 1368 by 2019. LADWP recommends divestiture from Navajo by 2015. This will reduce LADWP's GHG emissions by 7.5 million metric tons and required additional revenue of about $343 million.

  LADWP recommends modeling and planning for IPP to be compliant with SB 1368 by 2027. However, LADWP will continue to evaluate options in future IRPs. LADWP will continue to work with the Intermountain Power Agency (IPA) Board and the other participants to secure IPP as a renewable energy hub and provide replacement generation compliant with SB 1368. LADWP recommends no change in IPP until 2027 at which time the site would be reconfigured, providing LADWP with firm transmission capacity for potential renewable projects.

- Local Solar

  Comments received at the public workshops indicate local solar development should be a priority in LADWP's renewables procurement strategy. LADWP is recommending a policy action to allow approximately 40-50 percent of its solar resources be sited locally through initiatives including the Solar Incentive Program, feed-in tariffs, and installation of solar on City-owned properties. Local solar costs an estimated additional $50/MWh over utility-scale solar located outside the Los Angeles Basin, estimated to cost $120/MWh, primarily due to economies of scale and about 30% better solar insolation, even when considering transmission and distribution costs.

- Public Benefits

  LADWP should continue to pursue public benefit initiatives, including low-income and lifeline programs, refrigerator exchange, conservation, public outreach and education.

- Advanced Reliability Improvements

  LADWP is looking ahead to technologies that will enhance the reliability of its system, including smart grid technologies, enhanced information systems, automation of system functions, and advanced methods of outage management. These advanced system enhancements are recommended from a planning perspective to not only increase reliability, but also to better integrate local generation such as solar into the distribution network, enable smart charging of electric vehicles, and advance demand-side management technologies.

- System Losses

  To reduce system losses, LADWP should implement the recommendations of the recently completed Reactive Power Management Study, including the installation of shunt capacitors and shunt inductors at appropriate locations within the system grid.

- Demand Response

  LADWP should begin the development of a formal Demand Response program that will initially provide 5 MW of 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.

5.2 Incorporating Public Input

Through its public outreach efforts in 2010, 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 increasing transparency. This input played a key role in shaping the recommendations set forth in this IRP. A discussion of these themes is presented below.

- Theme: Emphasize a variety of energy resources

  Related IRP Recommendations

  - LADWP will procure 160 MW of generic renewable resources, potentially including biomass, ocean tidal power, and other emerging technologies.
  - LADWP will also continue to seek a diversified energy portfolio as well as continue to diversify its portfolio regionally to enhance system reliability.

  Discussion

  As LADWP continues to work towards attaining its state-mandated RPS requirement, it is also imperative that the renewable energy technologies support LADWP's objectives of providing reliable service at competitive rates while maintaining environmental stewardship. Of the aforementioned renewable technologies, those believed to be available in large quantities in the western US at competitive prices are geothermal, wind, biogas, and solar, which make up a bulk of LADWP's renewable portfolio. Recent advancements in these technologies have resulted in an increase in their capacity factors, therefore providing more energy at lower cost as well as benefiting from large economies of scale. Consumption of natural gas, which is already a major component of LADWP's generation resource portfolio, will increase to support increasing amounts of intermittent renewable resources and to help supply baseload power as LADWP transitions away from coal. Nuclear power, which makes up about nine percent of LADWP's energy mix, would likely remain at current levels in the next decade. In addition to "traditional" renewable resources such as wind and solar, LADWP will certainly consider up and coming technologies such as algae and wave power as these technologies become more mature and economically competitive.

- Theme: Maximize Energy Efficiency and Conservation to Meet Future Energy Needs

  Related IRP Recommendations

  - LADWP is recommending to increase energy efficiency to reduce at least seven percent of the total load by 2020 (three percent was achieved prior to

2010). LADWP will pursue the recommended programs contained in the recently completed market potential study.

- LADWP is recommending 500 MW of demand-side management/response programs to shift load away from peak hours or to control load during peak hours. Tactical plans will be developed that may utilize smart grid technology, incentives, and rate designs to meet this objective.

Discussion

LADWP's Demand Side Management program, which includes the Energy Efficiency, Demand Response, and Combined Heat and Power programs, plays an integral role in shaping power system planning. With the goals of lowering overall energy consumption and shifting peak demand loads to off peak periods, the need to build additional generation is reduced, resulting in capital and fuel cost savings as well as emissions reduction.

LADWP is exploring ways which would educate and empower ratepayers to reduce energy consumption, whether that is in the form of technology, incentives, and programs, or a combination of these. Future installation of two-way smart meters will facilitate real time pricing based on current supply and demand, and customers will be able to make smarter choices on energy use based on market driven Time of Use rates. LADWP is formulating strategies that will include new incentives and Time of Use tiered rate structures allowing ratepayers to fully participate on the demand side of the equation. To increase efficient buildings, LADWP offers an incentive program to building owners and developers for construction of new buildings to conform to high efficiency LEED standards, which are 25 percent to 35 percent more energy efficient than regular buildings.

As discussed in this 2011 IRP, LADWP has completed its Energy Efficiency Market Potential Study and is preparing its implementation plans that will support program execution. Like many other areas, however, adequate funding is essential if the city is to realize the benefits that efficiency provides.

- Theme: Eliminate Coal from LADWP’s Energy Portfolio

Related IRP Recommendations:

- LADWP is recommending a policy action 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 open to a mutually agreeable early compliance plan between the project participants that preserves the site and transmission for compliant fossil and renewable generation.
- LADWP is currently 21 percent below 1990 levels of GHG emissions and is planning further emissions reductions.

Discussion

Recommendations set forth in this 2011 IRP include making the transition away from coal to other forms of generation earlier than the contract termination date, such as terminating the Navajo contract in 2015 instead of 2019. Depending on the outcome of legislation which may impose GHG emission taxes and cap and trade requirements, it may be prudent for LADWP to divest away from coal resources early and replace it with a combination of renewable technologies and combined cycle units. Securing renewable resources early may also substantially save LADWP and its ratepayers money, before demand for renewables increase as mandated levels of renewable energy increases over the next several years.

Since coal generation is a baseload resource, the optimal solution is to replace the coal generation with geothermal, a renewable baseload resource. However given the disparity between the amount of available geothermal resources and the amount of coal generation that needs to be replaced, the remainder would need to be made up of other renewable sources such as wind and solar with natural gas powered combined cycle plants to act as backup maintaining a constant level of generation when the wind is not blowing and when the sun is not shining. Combined cycle plants have operating characteristics which allow for a higher penetration of intermittent renewable resources than coal-fired generation. The characteristics assist in maintaining grid reliability with high levels of intermittent resources. Natural gas plants are also much more environmentally friendly than coal plants, emitting only half as much CO_2.

- Theme: Emphasize Local Solar Generation

Related IRP Recommendations:

  - LADWP is recommending a policy action to allow approximately 40-50 percent of its solar resources be sited locally through initiatives including the Solar Incentive Program, feed-in tariffs, and installation of solar on City-owned properties. LADWP recommends this as a balanced approach between the benefits of local solar and the benefits of large, controllable solar projects connected to LADWP's transmission lines. The actual percentage will vary based on the success of the local programs.

Discussion

As outlined in this 2011 IRP, LADWP has designated 40 percent of solar development to be in-basin, or approximately 325 MW, enough to power almost ninety thousand homes. In-basin solar eliminates transmission issues and losses, and improves local grid reliability. LADWP realizes that developing in-basin solar fosters local economic growth, and will utilize incentive programs, Feed-in-Tariff schemes, and other stimulus in order to promote development. In August 2011, LADWP resumed its solar incentive program which was redesigned to better accommodate customer demand. LADWP also hopes to implement a feed-in tariff over the next year.

- Theme: Avoid Adverse Impacts to Vulnerable Communities

Related IRP Recommendations:

  - LADWP will continue to implement a low-income electric rate program.
  - LADWP will develop plans that address energy efficiency deployment and other incentive programs that effectively reach out to low income communities and may help mitigate impacts of future rate increases.
  - Local geographic diversity is critical to maintain high reliability of the electric grid, and LADWP will continue this policy so that no single community will experience an inequitable share of impacts from energy facilities.

Discussion

Even though acquiring more renewable resources may result in potential future rate increases, this may not necessarily translate into higher bills for all customers. Increased adoption of Demand Side Management techniques could offset a rate increase, and may even result in lower bills. LADWP strives to provide low-income ratepayers as much assistance as possible, and will continue to offer a lower rate to those that are economically disadvantaged. LADWP also proposes to conduct free residential energy audits to low income customers first, so that additional savings achieved by increased energy efficiency could be realized immediately. An example of this is that such audits may provide low income ratepayers free energy efficient refrigerators, funded by the LADWP Energy Efficiency Program.

Having geographical diversity in generation is important at both the regional and local levels. At the regional level, having resources that are geographically dispersed provides LADWP additional reliability, and results in efficient resource utilization and lower cost. For example, LADWP's system interconnects to BPA's network in the Pacific Northwest, fostering a symbiotic relationship that allows abundant inexpensive hydroelectric power to be delivered to LADWP in the spring and summer, when BPA's demand is low and LADWP's demand is high, at the same time enabling LADWP to sell excess power to BPA in the winter when BPA's demand is high and LADWP's is low. At the local level, it would be technically advantageous to distribute solar installations evenly throughout the LA basin, so that circuits will not be overloaded. This would ensure that there will be no unequal impact to any one community, since an equal distribution of distributed generation sources is necessary to maintain reliability.

- Theme: Clarify Costs of IRP Implementation and Potential Impacts to Ratepayers

  Related IRP Recommendations

  - LADWP will incorporate a detailed financial analysis into the IRP development process to identify the costs of various planning alternatives and recommendations using computer modeling software.

  Discussion

  Impacts of the Strategic Case Alternatives, including the recommended case, on electricity rates, as well as the strategic, regulatory and reliability investments recommended in this IRP are included in Sections 4.2. Included in the rate analysis is a sensitivity analysis that considers high and low forecasts for natural gas and coal fuel costs. Also presented is the annual revenue requirements of power system programs through 2020.

  While there are secondary costs associated with environmental and health impacts of fossil fuel plants, LADWP is not in a position to quantify these costs since there are governing bodies at the federal and state levels responsible for setting standards and legislation that would address these concerns. However, LADWP is working to make the transition from coal to renewables and clean natural gas earlier than originally scheduled so that GHG emissions can be curtailed sooner.

  As discussed previously, potential future increases may not necessarily translate into higher bills nor impact low-income communities. As for improved transparency and accountability, the Board of Water and Power Commissioners recently approved the establishment of an independent ratepayer advocate whose responsibility is to review, analyze, and provide expert independent advice to policy makers regarding utility rates and proposed rate changes, and to provide ongoing review and analysis regarding rate-related and budgetary issues.

- Theme: Reduce Environmental Impacts

  Related IRP Recommendations

  - To minimize environmental impacts, LADWP will maximize the use of existing transmission and facility infrastructure to generate and deliver energy. All projects will have the proper environmental review and impacts on the environment will be mitigated as necessary.

Discussion

Being a good environmental steward is one of LADWP's main objectives, and we strive to meet that standard with the construction and maintenance of each and every project. As we look to making the transition away from coal, one strategy that we have adopted is to procure and develop renewable resources in close proximity to the coal plant, so that we can take advantage of the existing transmission infrastructure. For solar, we would maximize the use of rooftops as installation sites. This principal of siting new generation facilities on existing brownfield sites and reusing existing structures not only minimizes environmental impact but is also very cost effective.

- Theme: Provide Proactive Leadership and Transparency

Related IRP Recommendations

  - LADWP will develop plans to better educate ratepayers on progress related to this IRP (e.g. energy efficiency) and will continue the IRP process of biannual updates to provide transparency on its long-term goals.
  - LADWP will improve its system operations and run its power grid as effectively as possible. LADWP has recently completed a study on how it can increase the efficiency of the power delivery grid through advanced reliability improvements.
  - This 2011 IRP sets forth LADWP's long-term plans and objectives, clarifying implementation of various initiatives and their potential impacts on ratepayers. A discussion of rate impact is included in Section 4 of this IRP.

Discussion

LADWP will take steps to expand public outreach programs to better educate the public about the critical roles that energy efficiency and conservation have on the power system. LADWP is also instituting programs to improve operations and system reliability, performing system wide technical studies, as well as identifying ways to incorporate smart meters. As discussed previously, a ratepayers' advocate would help facilitate transparency and accountability in any new actions undertaken by LADWP. An IRP public outreach effort, similar to the one held in 2010, is scheduled for next year's 2012 IRP process.

5.3 Recommended Strategic Case

Based on the results of LADWP's stakeholder meetings and public outreach effort, and rigorous cost-benefit analysis, LADWP has developed a Recommended Case for this 2011 IRP that includes the following:

- At least seven 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 2030. 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 162 MWs of generic renewable resources by 2030. 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.
- Replace the Navajo Generating Station by 2015, 4 years ahead of the legally mandated date. IPP is recommended to be replaced in 2027 at the end of its contract, however LADWP is open to a mutually agreeable early compliance for GHG reduction between project participants that preserves the site and transmission for compliant fossil and renewable generation.
- Implement advanced reliability improvements.
- Emphasize local solar by proposing approximately 40 to 50 percent of solar capacity being proposed to be locally sited in Los Angeles. This will be accomplished through programs such as the Customer Solar Incentive Program, Feed-in tariffs, and Solar on Los Angeles properties under public/private partnership.

This recommended case is summarized in Table 5-1.

Table 5-1. 2011 IRP Recommended Case

	2020	SB 1368 Compliance Date		New Renewables Installed (MW) 2011-2020			New Renewables Installed (MW) 2011-2030			
Case ID	RPS Target	Navajo Replacement	IPP Replacement	Geo/ Biomass	Wind	Solar	Geo/ Biomass	Wind	Solar	Generic
Case 2	33%	12/31/2015	6/15/2027	243	492	726	308	492	917	162

Figure 5-1 illustrates the changing generation resource percentages for 2010, 2020, and 2030 based on the Recommended Case. Energy efficiency savings of 1,256 GWh or 5.5 percent of sales that was implemented between 2000 and 2010 is already factored into the load and is not included as part of the generation resource mix shown below.

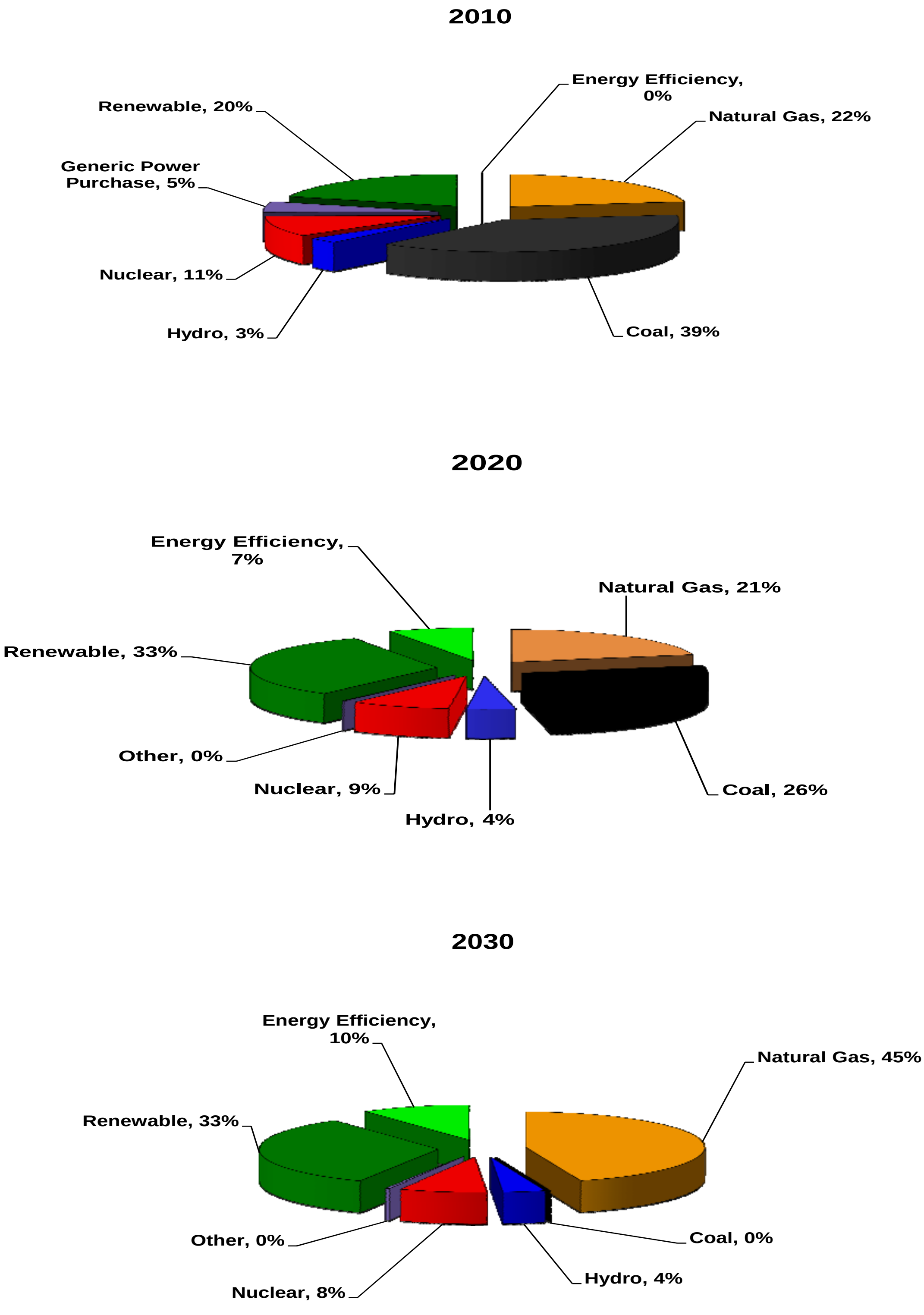

Figure 5-1. Generation resource percentages for 2010, 2020, and 2030.

Figure 5-2 shows the renewable energy resource mix of the Recommended Case. The major change from the 2010 IRP is that biogas fills a critical gap in meeting RPS targets by replacing primarily geothermal generation in the short term.

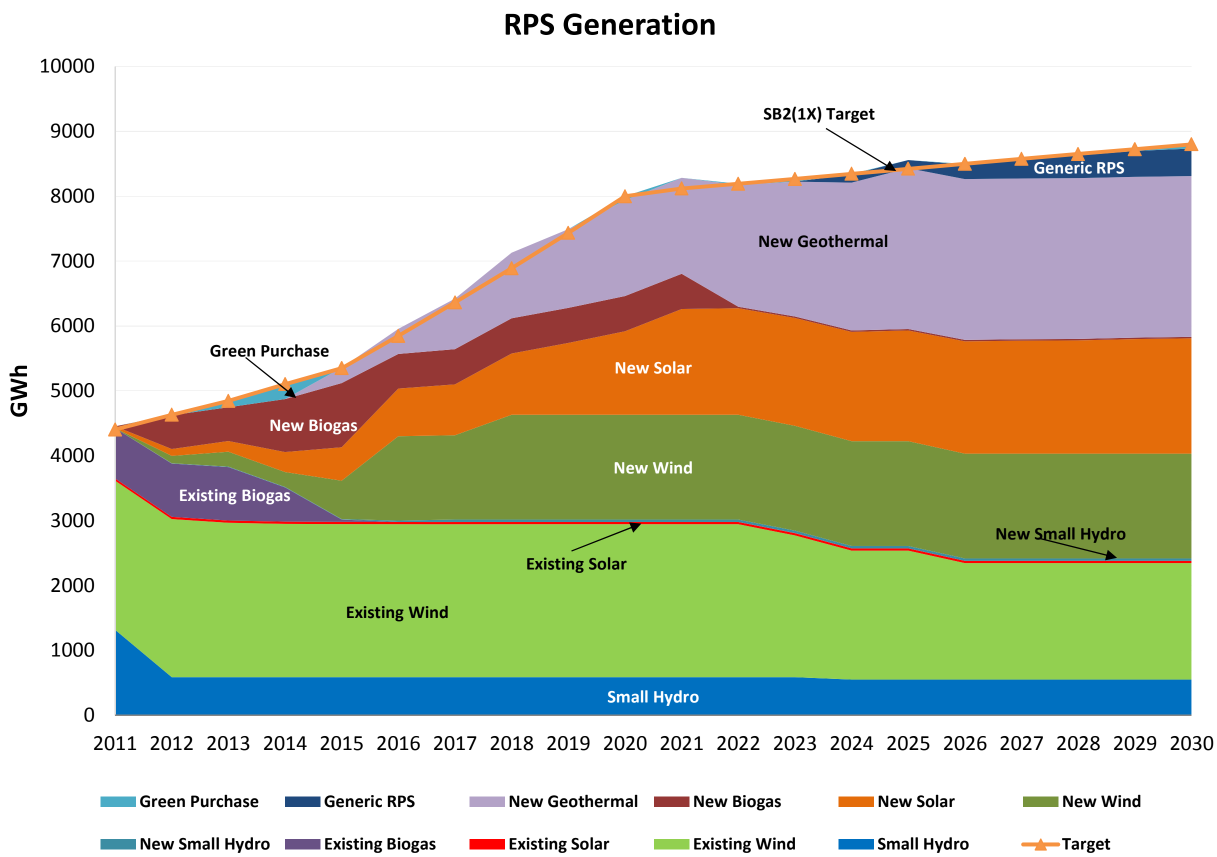

Figure 5-2. Recommended case renewable generation by technology.

With the early divestiture of Navajo in 2015 and the IPP coal contract ending in June, 2027, increased bulk power costs are expected to rise with the divestiture of each of these resources as shown on Figure 5-3. It is important to note that bulk power costs shown in Figure 5-3 include fuel, renewable and other purchase power costs in addition to coal divestiture related costs which are displayed in Table 4-4. Applying high and low fuel prices to these bulk power costs as discussed in Section 4.2.3.2, the divestiture 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.

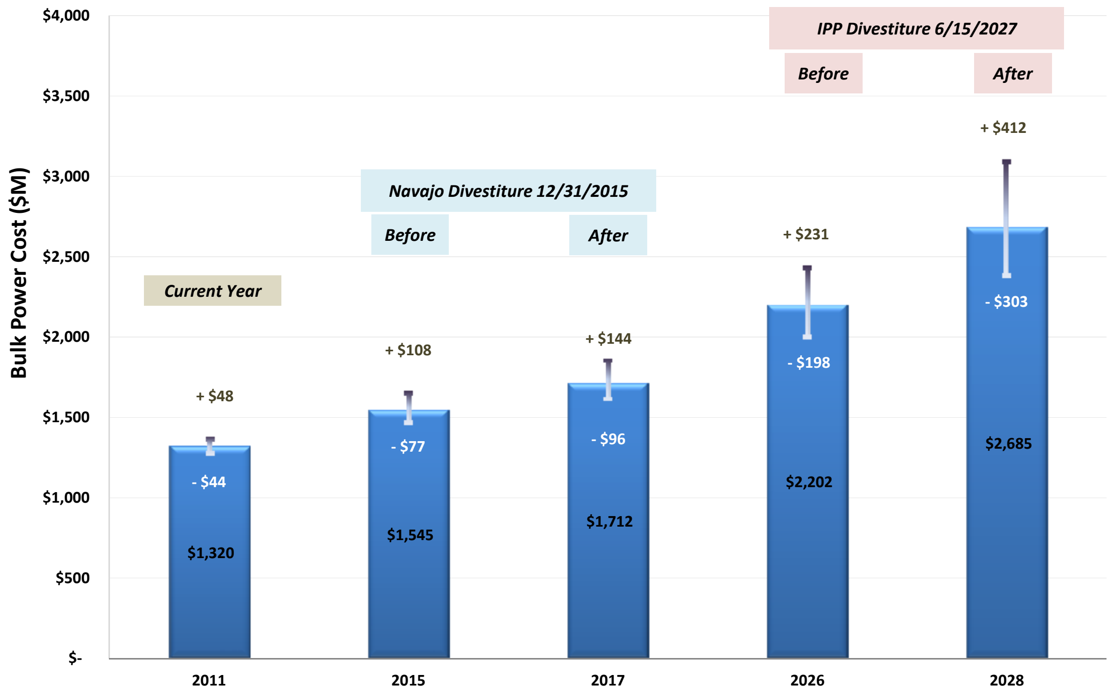

Figure 5-3. Recommended case - bulk power cost before and after coal divestitures with potential cost impacts from high and low fuel prices.

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

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

(FY)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy & Capacity Cost																				
Energy Efficiency	$ 46	$ 29	$ 37	$ 51	$ 60	$ 70	$ 78	$ 87	$ 94	$ 104	$ 112	$ 120	$ 129	$ 137	$ 146	$ 154	$ 163	$ 171	$ 180	$ 188
Demand Response	$ -	$ -	$ 0	$ 0	$ 1	$ 1	$ 3	$ 4	$ 6	$ 8	$ 10	$ 10	$ 11	$ 12	$ 12	$ 13	$ 14	$ 14	$ 14	$ 14
New Renewable																				
Solar	$ 3	$ 12	$ 25	$ 39	$ 67	$ 98	$ 115	$ 132	$ 158	$ 184	$ 225	$ 249	$ 250	$ 253	$ 256	$ 259	$ 261	$ 261	$ 261	$ 264
Wind	$ -	$ 2	$ 27	$ 27	$ 37	$ 127	$ 147	$ 177	$ 198	$ 201	$ 202	$ 203	$ 205	$ 208	$ 209	$ 211	$ 213	$ 216	$ 217	$ 219
Geo	$ -	$ -	$ -	$ -	$ 13	$ 28	$ 79	$ 113	$ 143	$ 176	$ 197	$ 224	$ 271	$ 302	$ 335	$ 353	$ 361	$ 361	$ 368	$ 373
Small Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Generic RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ 18	$ 24	$ 38	$ 45	$ 53	$ 59
Green Purchase	$ -	$ 0	$ 4	$ 12	$ 9	$ -	$ -	$ -	$ -	$ 3	$ 3	$ 1	$ 3	$ 2	$ 0	$ 0	$ 1	$ 1	$ 2	$ 5
New Renewable Subtotal	**$ 3**	**$ 14**	**$ 55**	**$ 78**	**$ 126**	**$ 253**	**$ 343**	**$ 424**	**$ 501**	**$ 565**	**$ 628**	**$ 679**	**$ 731**	**$ 776**	**$ 820**	**$ 850**	**$ 874**	**$ 886**	**$ 904**	**$ 922**
Short Term Q3 Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ 14	$ 11	$ 9	$ 9	$ 10	$ 14	$ 18	$ 34	$ 52	$ 55	$ 67	$ 33	$ 44	$ 67
Replacement CC Capital Cost																				
Navajo Replacement CC	$ -	$ -	$ -	$ -	$ -	$ 9	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18
IPP Replacement CC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 133	$ 133	$ 133
Total	**$ 50**	**$ 43**	**$ 93**	**$ 130**	**$ 186**	**$ 333**	**$ 442**	**$ 533**	**$ 619**	**$ 695**	**$ 767**	**$ 828**	**$ 889**	**$ 942**	**$ 996**	**$1,035**	**$1,075**	**$1,222**	**$1,247**	**$1,274**

These projected costs are in addition to the total annual power operating revenue requirement today of about 2.95 billion. In addition to the revenue required to replace coal and meet future peak load growth, additional revenue is required to fund the Power Reliability Program, modernize gas-fired in-basin generation to eliminate once-through cooling, support investments in smart grid to support energy efficiency and demand response programs, and maintain the basic funding of the existing generation, transmission, and distribution infrastructure as shown in Table 5-3.

Table 5-3. Recommended revenue to fund program initiatives, 2011-2020

PROGRAM INITIATIVE	**Revenue Requirement ($ Billion)**
Power Reliability	$6.8
OTC Repowering of Power Plants	$1.2
Transition from Coal (Navajo GS)	$0.4
Increasing Renewable Energy	$6.0
Expand Renewable Transmission	$0.5
Expand Local Solar	$0.7
Increasing Energy Efficiency	$0.7
Smart Grid Investments	$0.3
SUBTOTAL	$16.6
Basic Generation, Transmission and Distribution	$23.4
TOTAL	$39.9

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.

5.4 Revenue Requirements

A brief discussion, repeated from Section 1, 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 last year's 2010 IRP, a multi-year rate increase was recommended beginning fiscal year 2011-12. The rate increase would have supported elements of last year's 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.

A multi-year funding plan is necessary to provide consistent and sustainable project and program development. Funding that is based on annual budgets are subject 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.
- 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.

A rate process that began earlier this year is addressing the revenue needs for LADWP. A proposed 3-year rate adjustment that would support the programs listed above is being considered. The expectation is that the rate process will conclude sometime in 2012. 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.

5.5 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 during the similar period.

The model is modified to analyze the three cases with their respective 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 nine strategic cases are overlaid on existing capital and O&M expenses for the approved FY11-12 budget data, which contains forward-looking budget data up until FY20-21. For years beyond FY20-21, general capital and O&M expenses are escalated at 3 percent per annum.

LADWP retail revenue comes from three billing factors: (1) base rate (2) energy cost adjustment (ECA) and reliability cost adjustment (RCA) factors. The interplay of these three factors is described briefly below.

The ECA is used to cover fuel, purchased power, RPS and energy efficiency-related expenses. The ECA is adjusted quarterly and currently has an adjustment cap of 0.1 cts/kWh (i.e., increasing by no more than 0.1 cts per kWh).

The RCA is used to cover power reliability related expenses. The RCA is adjusted annually and has a maximum factor of 0.3 cts/kWh. This maximum has been reached in FY10-11 and cannot be adjusted any higher. Since reliability related expenses are not projected to go lower than FY10-11 spending levels, significant RCA under-collection may exist.

The base rate is used to cover non-fuel, non-purchased power, and non-RPS related expenses. Base rate 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.

Since LADWP needs to sell substantial amounts of bonds in the near future to sustain its capital expenditures, maintaining an "AA" credit rating is essential to minimize financing costs. To maintain such a rating and mitigate potential rate increases, it is recommended the Board of Water and Power Commissioners approve the following policies: (1) maintain debt service coverage of 2.25, (2) maintain a minimum of $300 million of operating cash-on-hand, and (3) maintain a capitalization ratio not exceeding 65 percent, (4) maintain adjusted debt service coverage of 1.75, and (2) maintain full obligation coverage of 1.5.

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. Adjusted debt service coverage has the debt service amount containing regular debt and off-balance sheet debt. Full obligation coverage deducted the city transfer from the cash available from operation and then divides the amount over the total of regular and off-balance sheet debt. Off-balance sheet debt is the debt owned by a third party, but LADWP will be responsible for the debt payment; for example, debt raised by Intermountain Power Agency and Southern California Public Power Authority. 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 3 strategies are shown on Figure 5-3 below. Factors driving the increases over the twenty-year period are: 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 payment for emission allowances due to anticipated CO_2 cap-and-trade program requirements.

The capital cost and the associated O&M expense of any new generation resource is priced at 2011 dollars with 1.5 percent escalation except for certain solar projects, which are priced at levelized 2011 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.

Under the Recommended Case, 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 (see Figure 5-3).

The CO_2 emission allowance price is estimated to range from $24 per Metric Ton in 2013 to $45 per Metric Ton in 2030. 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 2011 IRP recommended case bounded by a high and low range fuel price with a comparison to the 2010 IRP recommended case. The high range assumes higher natural gas and coal costs while the low range assumes minimal natural gas and coal costs. The current recommended case retail price rate forecast is much lower than the 2010 IRP rate impact forecast for two major reasons. As described in Section 3.2, the fuel price forecast is significantly lower for 2011, and the assumption for GHG emissions cost was significantly lowered for 2011 after AB 32 regulations were finalized in October 2011.

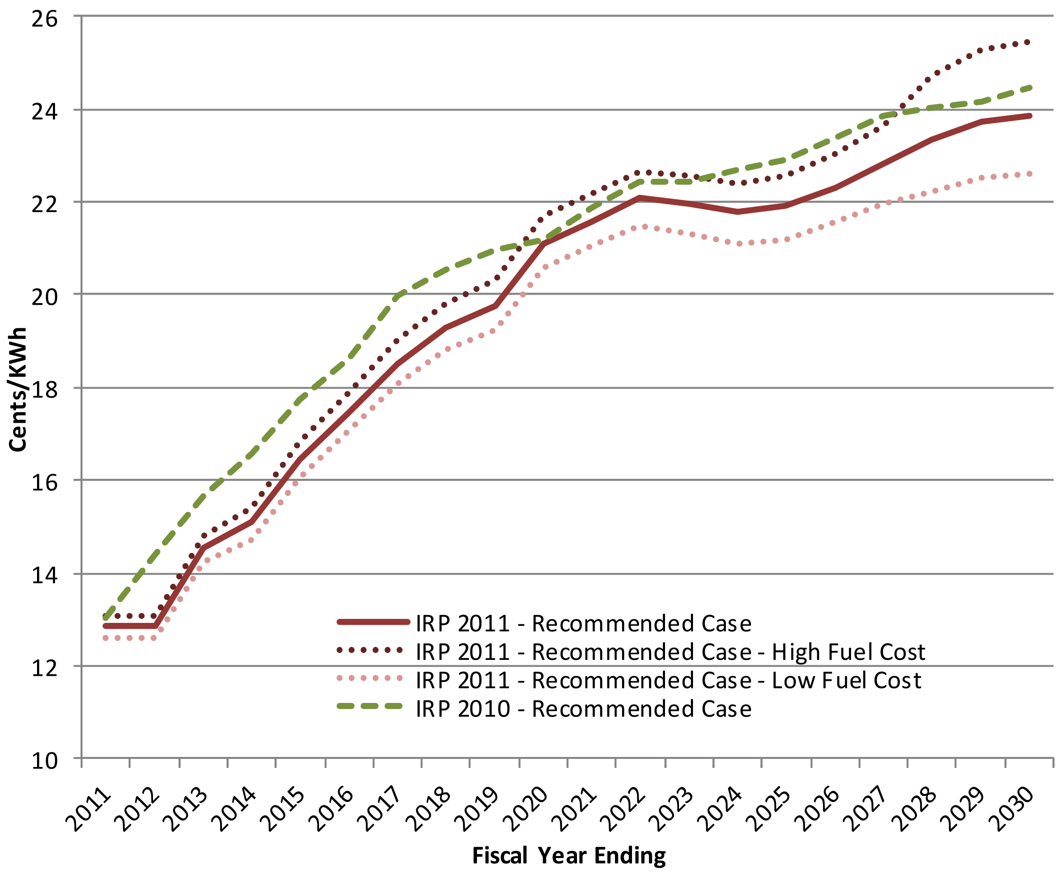

Figure 5-3. Recommended Case - retail price impact bounded by high and low range fuel with the 2010 IRP recommended case included for comparison.

Summarized in Figure 5-4 is the cost contribution from various environmental and reliability programs towards the retail rates. One can draw the conclusion that there is a significant cost to comply with various reliability and regulatory requirements while divesting of Navajo in 2015 and IPP in 2027.

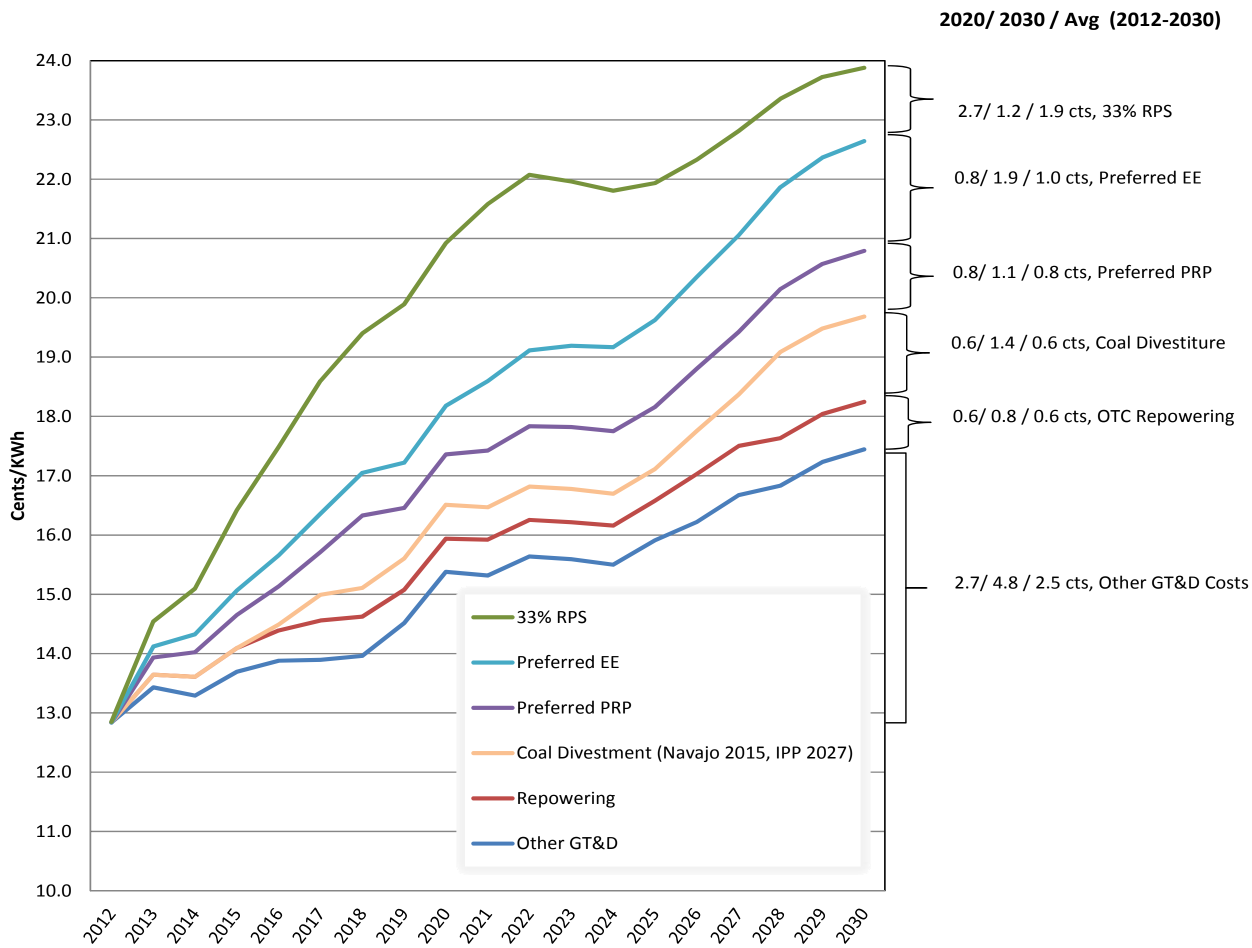

Figure 5-4. Electric rate contributions of environmental and reliability programs by fiscal year based on the 2011-12 budget forecast (preferred case).

A few observations from Figure 5-4 can be made regarding the RPS and EE program. Firstly, the influence of the RPS program on rates increases substantially through 2020 when the RPS percentage of sales reaches 33%. Beyond 2020, the RPS component of rates begins to decline as fuel savings increases over time with escalating fuel prices. Secondly, the EE program component of rates increases over time as power system fixed costs are distributed over the reduced energy sales attributable to the EE program.

The cost contributions from various environmental and reliability programs towards the retail rates are summarized in Table 5-4.

Table 5-4. Cost contributions from various environmental and reliability programs

Program	Retail Rate Impact at FY2020 (cents/kWh)	Retail Rate Impact at FY2030 (cents/kWh)	Average Retail Rate Impact 2011-2030 (cents/KWh)
33% RPS from 20% RPS	2.7	1.2	1.9
Preferred EE	0.8	1.9	1.0
Basic Power Reliability Program	0.5	0.4	0.3
Preferred Power Reliability Program	0.3	0.7	0.5
Coal Divestiture	0.6	1.4	0.6
OTC Repowering	0.6	0.8	0.6
Total - Recommended Case	**5.5**	**6.4**	**4.9**

Figures 5-5 and 5-6 further illustrate the impact to average residential and commercial/industrial customer monthly bills from these environmental and reliability programs.

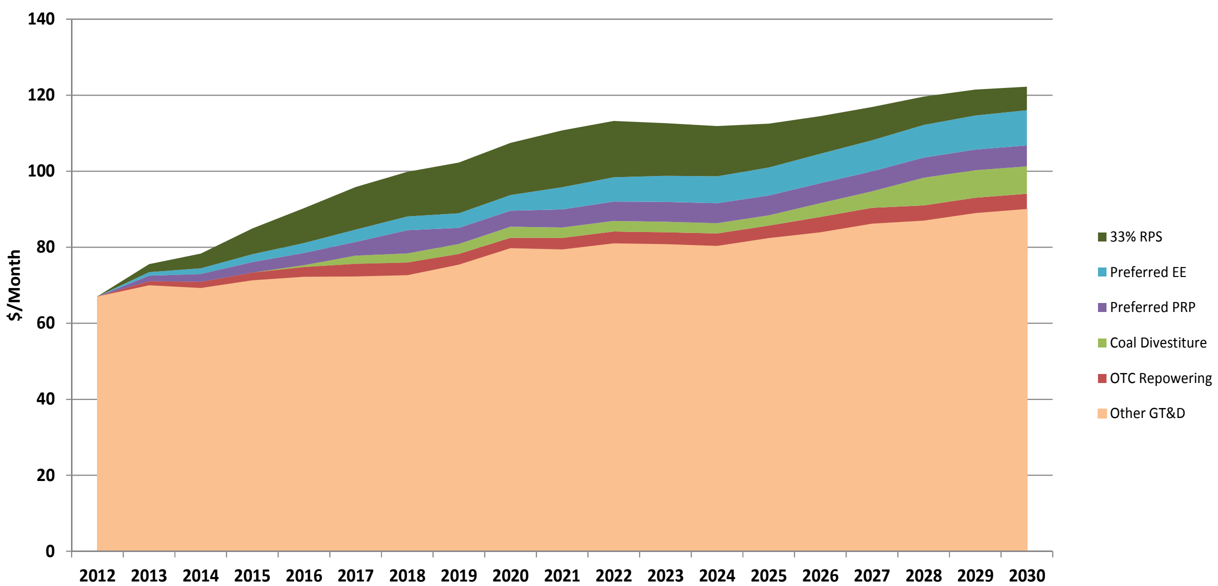

Figure 5-5. Average residential customer bill (500 kWh/month) with environmental and reliability programs by fiscal year based on the 2011-12 budget forecast (preferred case).

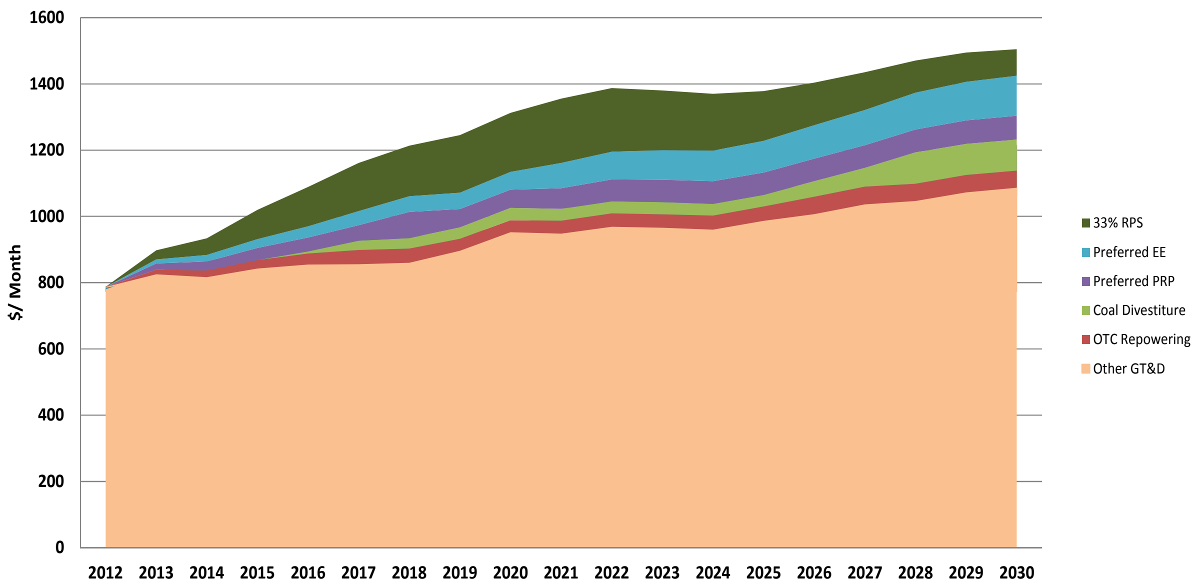

Figure 5-6. Average commercial/industrial customer bill (6,500 kWh/month) with environmental and reliability programs by fiscal year based on the 2011-12 budget forecast (preferred case).

Aside from the environmental and reliability improvement programs, increased fossil fuel expenses also drive the rate increase, for example: (1) coal that feeds IPP is projected to climb from 2011's $1.88/mmbtu to 2027's $3.72/mmbtu, and (2) natural gas at SoCal border is projected to climb from 2011's $4.10/MMBtu to 2030's $8.6/MMBtu. If these fuel increases do not materialize, then the average rate and cost curves shown in Figures 5-3 thru 5-6 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 watch to see if these unfold as assumed. If expectations change (e.g., because of unanticipated technology changes, commodity price fluctuations, and policy changes), then the long-term plan will need to be revisited. Under all cases, it is assumed that the following items will occur, and that each will be central to LADWP regardless of the resource portfolio selected:

- Ensure that the power generation, transmission and distribution infrastructure operates in a reliable and efficient manner. Continue the Power Reliability Program initiated in 2007 which improves maintenance practices, addresses aging power system infrastructure, increases capital construction programs necessary to support load growth, and maintains staffing levels to support reliability related work.
- Support and advocate incremental requirements in Title 24 and other Green Building and appliance standards to reduce energy usage.

- Re-power Scattergood, Haynes, and Harbor end of life in-basin generation consistent with power system needs and environmental requirements.
- Continue to be self-sufficient, by maintaining system generation resources equal to or greater than customer's electrical needs.
- Provide sufficient generation, demand response, and limited short term purchases in Q3 to cover operating and replacement reserves in accordance to applicable federal and regional reliability requirements.
- Maintain full control of transmission assets and continue to augment those assets commensurate with load growth and renewable energy opportunities.
- Work with the Water System to develop programs that reduce the usage of electricity and conserve water, as well as optimizing hydroelectric energy production.
- Maintain a "AA" credit rating, a debt service of at least 2.25 times, operating cash of $300 million, capitalization ratio not greater than 65 percent, and electric rates lower than neighboring investor owned utilities. In addition, LADWP will maintain net income sufficient to ensure stable City Transfers.

Each of the targets listed above will be tested in the future to meet requirements for system reliability, fiscal responsibility and environmental stewardship. Modifications will be made as necessary to assure that these core principles are met.

5.6 Near-term Actions

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. From the development assumptions listed above 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 Generation Stations.
2. Continue to investigate the technical and contractual options for coal-fired generation to be compliant with SB 1368.
3. Replace the Navajo Coal Plant by 2015.
4. Implement recommendations contained in the recently completed Energy Efficiency Market Potential Study.
5. Implement recommendations contained in the Ten-Year Transmission Assessment Plan and the Reactive Power Management Study.
6. Develop a Demand Response Program to initially provide 5 MW of peak load reduction capability by 2013 which will ramp up incrementally to 200 MW by 2020 and 500 MW by 2026.
7. Develop renewable strategies for geothermal, biogas, solar, and wind resources to ensure increasing levels of renewable procurement in accordance with SB 2 (1X).
8. 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.
9. Procure and develop advanced technologies in the areas of: weather forecasting energy scheduling, customer kWh metering, high speed communications and information systems, and large scale energy storage systems.
10. 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 to maximize operational efficiencies;
    e. Assess and develop necessary transmission facilities to deliver electricity generated from new facilities.
11. Develop a renewable energy feed-in tariff program to encourage 30 MW of renewable generation resources to be developed by July, 2015.
12. Sign Power Purchase Agreements for an additional 200-300 MW of cost effective renewable energy projects by 2014.
13. Encourage the development of an additional 50 MW of customer owned solar projects before 2015.
14. Develop up to 30 MW of Solar on Los Angeles properties under public/private partnership projects before 2015.

15. Investigate the potential 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. Include the flexibility for closing these contracts as well.

5.7 Long-term Goals

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 will be issued in 2012, and every two years thereafter.

Appendix A. Load Forecasting

A.1 Overview

The 2011 Retail Sales and Demand Forecast (2011 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.

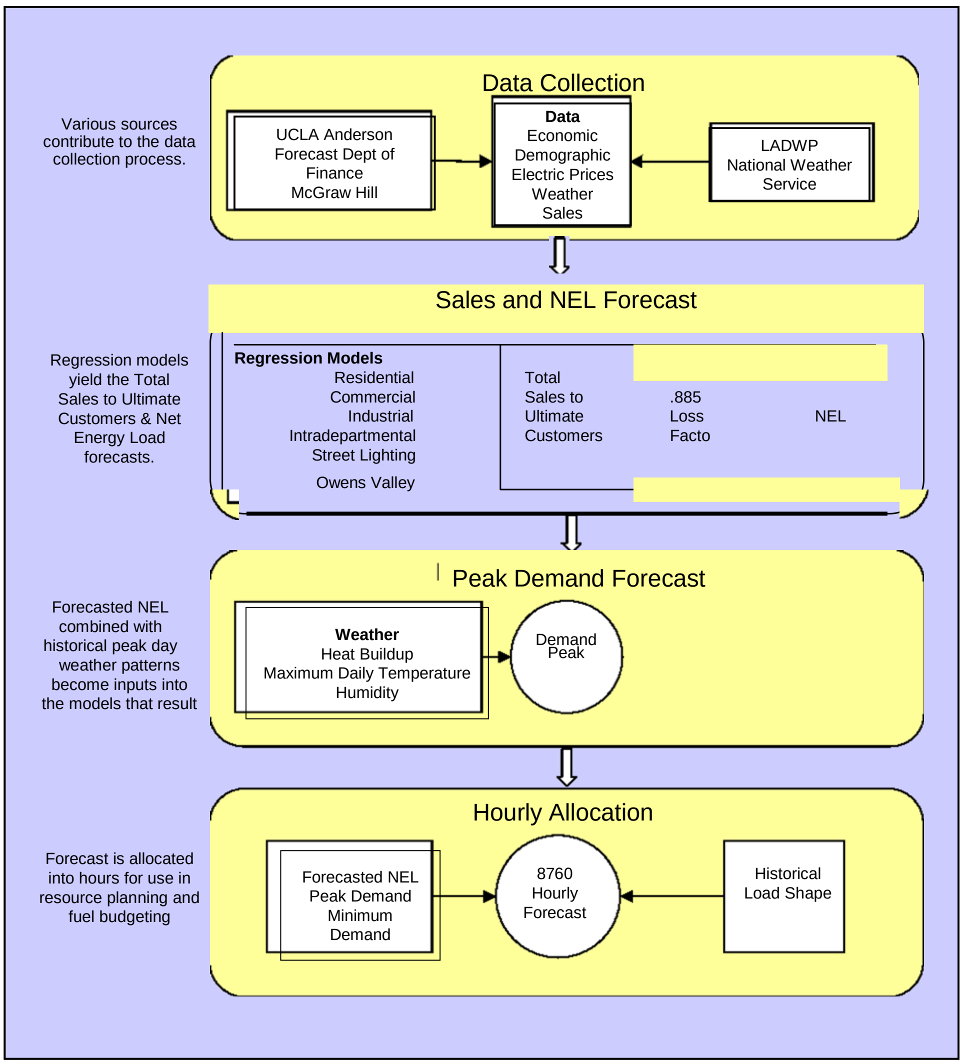

Figure A-1. Overview of the load forecasting process

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 2011 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 2011 Forecast is created early in the planning process, budgeted utility energy efficiency programs are subject to change. Planners using the 2011 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 2011 Forecast.

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

Fiscal Year	SECTOR SALES Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	PHEV (GWh)	Total Sales to Ultimate Customers (GWh)	Net Energy for Load (GWh)	Peak Demand (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	8,181	12,270	2,116	485	1	23,053	25,972	6,142
2011-12	8,398	12,280	2,074	499	6	23,257	26,301	5,642
2012-13	8,382	12,308	2,063	491	14	23,258	26,235	5,650
2013-14	8,320	12,395	2,053	484	31	23,283	26,329	5,652
2014-15	8,383	12,531	2,057	477	62	23,510	26,537	5,713
2015-16	8,479	12,623	2,058	478	94	23,732	26,850	5,762
2016-17	8,588	12,765	2,058	479	120	24,010	27,093	5,840
2017-18	8,718	12,905	2,058	481	139	24,301	27,420	5,911
2018-19	8,860	13,048	2,059	483	166	24,615	27,772	5,990
2019-20	9,016	13,192	2,059	484	194	24,946	28,215	6,072
2020-21	9,172	13,385	2,060	486	236	25,339	28,582	6,160
2021-22	9,329	13,564	2,060	488	263	25,704	28,998	6,271
2022-23	9,476	13,683	2,060	490	287	25,996	29,334	6,345
2023-24	9,640	13,801	2,061	491	312	26,304	29,750	6,420
2024-25	9,807	13,919	2,061	493	336	26,616	30,030	6,498
2025-26	9,970	14,035	2,061	495	360	26,920	30,375	6,574
2026-27	10,132	14,151	2,062	497	384	27,226	30,720	6,650
2027-28	10,295	14,265	2,062	498	409	27,530	31,100	6,726
2028-29	10,454	14,378	2,063	500	432	27,826	31,362	6,786
2029-30	10,609	14,489	2,063	502	456	28,120	31,732	6,875
2030-31	10,771	14,604	2,064	504	481	28,423	32,075	6,948
2031-32	10,935	14,734	2,064	505	506	28,744	32,471	7,026
2032-33	11,096	14,864	2,064	507	529	29,061	32,757	7,106
2033-34	11,258	14,994	2,065	509	553	29,379	33,153	7,184
2034-35	11,421	15,123	2,065	510	577	29,697	33,512	7,263
2035-36	11,583	15,252	2,066	512	603	30,016	33,907	7,342
2036-37	11,743	15,380	2,066	514	626	30,328	34,189	7,420
2037-38	11,899	15,508	2,066	516	650	30,640	34,577	7,498
2038-39	12,054	15,636	2,067	517	674	30,949	34,927	7,574
2039-40	12,211	15,764	2,067	519	700	31,262	35,316	7,651

Table updated through December 2010

Annual Percent Change	Residential	Commercial	Industrial	Miscellaneous*	PHEV	Total Sales to Ultimate Customers	Net Energy for Load	Peak Demand
1991-2001	1.03%	0.55%	-1.02%	0.53%		0.50%	0.48%	-0.02%
2001-10	1.07%	0.32%	-3.11%	0.04%		0.21%	0.36%	0.83%
2010-16	0.36%	0.21%	-0.13%	-1.79%		0.26%	0.20%	0.16%
2010-20	0.83%	0.57%	-0.07%	-0.94%		0.66%	0.62%	0.62%
2009-30	1.24%	0.76%	-0.02%	-0.29%		0.93%	0.90%	0.93%
2009-40	1.30%	0.79%	-0.01%	-0.08%		0.97%	0.96%	0.98%

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

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CITY OF LOS ANGELES

DEPARTMENT

OF

WATER AND POWER

2011 RETAIL ELECTRIC SALES AND DEMAND FORECAST

JD mw

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February 18, 2011
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2011 Retail Electric Sales and Demand Forecast

Overview

The 2011 Forecast (Forecast) supersedes the April 2010 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 located at the Energy Control center.
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 2009 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 plug-in hybrid electric vehicle (PHEV) forecast is based on the California Energy Commission (CEC) statewide PHEV 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.
11. The energy efficiency forecast is based on approved LADWP-based programs through fiscal year 2013 and the forecasted impacts of the Energy Independence Security Act (EISA) and the Huffman Bill on residential lighting. Historical installation rates are provided by the Energy Efficiency group.
12. Historical solar rooftop installations and objectives are provided by the Solar Energy Development group.
13. Electric Price Forecast is developed by Financial Services organization.

Historical data is current through December 2010.

Five-Year Sales Forecast

The Retail Sales Forecast represents sales that will be realized at the meter through Fiscal Year End 2013. After FYE 2013, some of the forecasted sales will not be realized at the meter due to the incremental impacts of LADWP-sponsored energy efficiency programs. Available in-house is a Gross Forecast which forecasts sales before the impacts of energy efficiency and solar rooftop. The purpose of the Gross Forecast is to allow modeling of different energy efficiency and distributed generation scenarios.

The historical accumulated Energy Efficiency and Solar Saving are from 1999 forward and only include LADWP installed savings. Since July 1, 2006, 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 1.4 percent in Fiscal Year 2010-11 is partially attributed to a cooler than normal summer which has already occurred. Likewise, the 0.7 percent increase in Fiscal Year 2011-12 includes the cooler summer in 2010 compared against normal summer weather.

Forecasted Energy Efficiency is based on the California Energy commission definition of "committed " energy efficiency which is LADWP budget through FYE 2013 and forecasted Huffman bill savings. The long-run LADWP energy efficiency goal is to reach the AB 2021 objective of 10 percent savings during the time period 2007 through 2016. The targeted goal for rooftop solar installations is 148 MW by 2020.

Short-Run Growth

Fiscal Year	Retail Sales		Accumulated EE & Solar Savings	Gross Sales
Ending June 30	(GWH)	YOY Growth Rate	(GWH)	(GWH)
2009-10	23369		1289	24658
Forecast				
2010-11	23051	-1.4%	1465	24516
2011-12	23221	0.7%	1672	24893
2012-13	23175	-0.2%	1965	25140
2013-14	23258	0.4%	2217	25475
2014-15	23641	1.6%	2334	25975

[1] Actual sales through December 2010

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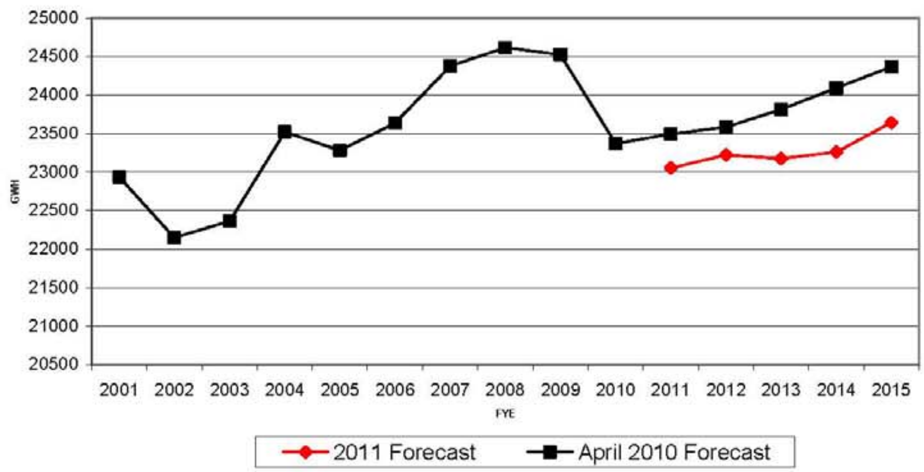
Retail Sales Net of Energy Efficiency and Distributed Generation



Peak Demand Forecast

Growth in annual peak demand over the next ten years is 0.8 percent.

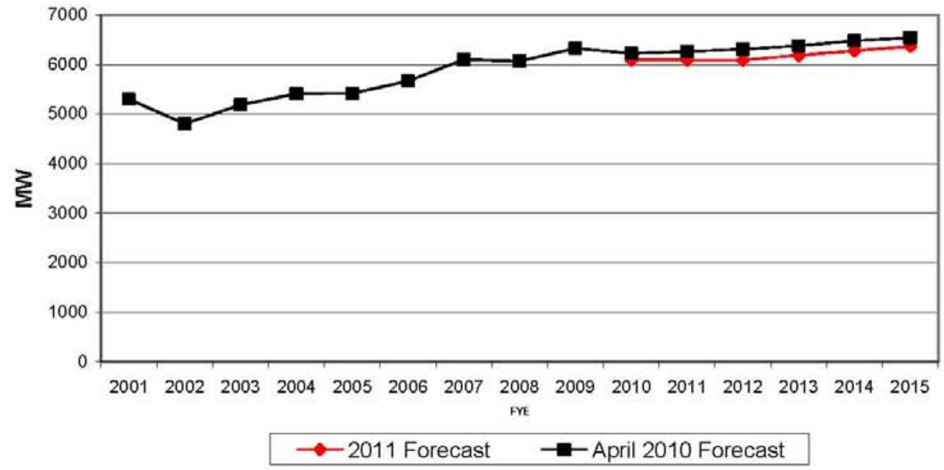
Long-Run Growth

Fiscal Year End June 30	Base Case Peak Demand (MW)	Growth Rate Base Year 2010-11	One-in-Ten Peak Demand (MW)
2010-11	5589[1]		6042
Forecast			
2015-16	5809	0.8%	6277
2020-21	6211	1.0%	6710
2030-31	7000	1.1%	7560
2040-41	7780	1.1%	8403

[1]Weather-normalized. Actual peak was 6142 MW.

In 2010, the System set its calendar annual peak at 6142 MW on September 27, 2010 on a day that was a one-in-thirty-seven weather event. The weather-adjusted one-in-two peak for 2010 is 5589 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. 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.

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.

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.

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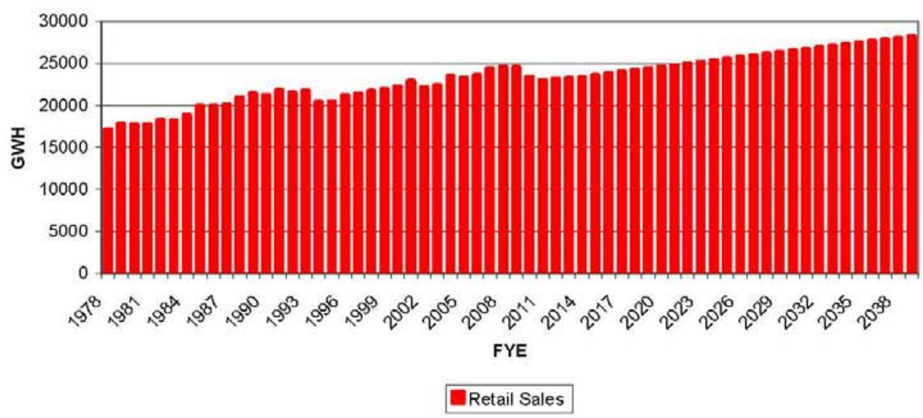
The decline in forecasted sales 2008 through 2010 is most directly compared to the decline in sales between 1992 and 1994. The 1992 through 1994 time period was difficult for Los Angeles in many aspects. An economic slump occurred mostly created by the downsizing of the aerospace industry but it also 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%

Retail Sales before Regulatory Impacts



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. Most economic models based on history would have predicted a faster economic recovery given the amount of publicly-announced fiscal and monetary stimulus. The actual fiscal stimulus was below the announced target. According to www.recovery.gov , only 40% of the funds made available by Recovery Act have been spent as September 2010. Monetary policy has worked for large firms that can reach international markets as the S&P 500 in 2010 neared historical peak earnings. S&P 500 companies have created over one million jobs in the USA according to Economy Policy

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Institute. Small firms continue to struggle as loan requirements are stringent and there is a reluctance to invest given the economic uncertainty. UCLA Anderson is forecasting the Los Angeles County to remain in the recovery phase until 2012. Historically, it will be the longest combined recession and recovery since World War II.

Variables in the Forecast

Population: A new United States Census was taken in April 2010. Local data is expected by June 2011. Historical population data is likely to be recast as interim data between forecasts is based on statistical studies. Los Angeles is a particularly difficult place to estimate population due to the highly transient nature of the citizenry. Los Angeles experiences high levels of foreign immigration and domestic out-migration. It was thought that the majority of out-migration was to Riverside and San Bernardino counties. Los Angeles renters moved to these counties to become homeowners. The housing crisis changed the migration pattern and there is uncertainty whether or not this long-time historical pattern will resume.

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 forecasted to be historically slow during the recovery so it will take some time to see the ultimate outcome of SB 375 and the "Housing that Works" plan.

Emission Allowances: AB 32 seeks to reduce emissions to 1990 levels using a cap-and – trade scheme to begin in 2012. Program is designed to protect utilities and consumers but experience informs us that unintended consequences could arise as occurred during energy deregulation in the late 1990s.

Plug-in Hybrid Electric Vehicles (PHEV): The Forecast adopted the CEC forecast for PHEV adoption rate. LADWP is making PHEVs a key strategic initiative so adoption rates could be faster. On the other hand, there are competing technologies to PHEVs that the public may choose. Other credible forecasts including the United States Energy Information Administration have significantly lower forecasts for PHEV adoption citing problems with battery technology. The Forecast adapted an EPRI charging load profile for PHEVs. LADWP in-house strategies could significantly alter that charging profile.

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 PHEV 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.

2011 RETAIL ENERGY AND DEMAND FORECAST

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

	SECTOR SALES					Total Sales	LOSSES		Net					
	Residential	Commercial	Industrial	Miscellaneous*	PHEV	to Ultimate Customers	Total	DC Line	Energy for Load	Cogen	Service Area Load	Peak Demand	Cogen	Service Area Peak
Fiscal Year	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)[1]	(MW)	(MW)
2000-01	7,542	12,107	2,754	531	0	22,934	2,753	319	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	365	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	437	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	287	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	294	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	411	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	426	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	412	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	418	27,447	1,084	28,531	6,006	196	6,202
2009-10	8,300	12,463	2,073	532	0	23,369	3,157	416	26,526	1,092	27,617	5,709	203	5,912
2010-11	8,181	12,268	2,116	485	1	23,051	2,913	416	25,965	1,105	27,070	6,142	212	6,354
2011-12	8,389	12,253	2,074	499	6	23,221	3,039	416	26,260	1,117	27,377	5,639	224	5,862
2012-13	8,359	12,248	2,063	491	14	23,175	2,982	416	26,157	1,139	27,295	5,635	239	5,873
2013-14	8,313	12,378	2,053	484	31	23,258	3,053	416	26,311	1,172	27,483	5,633	258	5,891
2014-15	8,419	12,627	2,057	477	62	23,641	3,031	416	26,672	1,209	27,881	5,725	277	6,002
2015-16	8,538	12,775	2,058	478	94	23,942	3,136	416	27,078	1,258	28,336	5,809	293	6,101
2016-17	8,647	12,916	2,058	479	120	24,221	3,110	416	27,331	1,287	28,618	5,891	306	6,196
2017-18	8,777	13,056	2,058	481	139	24,512	3,146	416	27,658	1,287	28,945	5,962	314	6,276
2018-19	8,920	13,199	2,059	483	166	24,826	3,185	416	28,010	1,287	29,297	6,041	319	6,359
2019-20	9,075	13,344	2,059	484	194	25,157	3,296	416	28,453	1,287	29,740	6,123	316	6,439
2020-21	9,231	13,536	2,060	486	236	25,549	3,270	416	28,820	1,287	30,107	6,211	319	6,530
2021-22	9,388	13,716	2,060	488	263	25,915	3,322	416	29,236	1,287	30,523	6,323	330	6,653
2022-23	9,536	13,834	2,060	490	287	26,207	3,365	416	29,572	1,287	30,859	6,396	337	6,732
2023-24	9,699	13,952	2,061	491	312	26,515	3,472	416	29,987	1,287	31,274	6,471	344	6,814
2024-25	9,867	14,070	2,061	493	336	26,826	3,442	416	30,268	1,287	31,555	6,549	354	6,902
2025-26	10,029	14,186	2,061	495	360	27,131	3,482	416	30,613	1,287	31,900	6,625	362	6,987
2026-27	10,192	14,302	2,062	497	384	27,436	3,521	416	30,957	1,287	32,244	6,701	368	7,069
2027-28	10,354	14,417	2,062	498	409	27,741	3,597	416	31,337	1,287	32,624	6,778	377	7,154
2028-29	10,513	14,529	2,063	500	432	28,037	3,563	416	31,600	1,287	32,887	6,838	386	7,224
2029-30	10,669	14,640	2,063	502	456	28,330	3,639	416	31,969	1,287	33,256	6,926	396	7,322
2030-31	10,830	14,756	2,064	504	481	28,634	3,680	416	32,313	1,287	33,600	7,000	401	7,401
2031-32	10,994	14,885	2,064	505	506	28,955	3,753	416	32,709	1,287	33,996	7,078	401	7,479
2032-33	11,156	15,016	2,064	507	529	29,272	3,724	416	32,995	1,287	34,282	7,157	401	7,558
2033-34	11,317	15,146	2,065	509	553	29,590	3,801	416	33,391	1,287	34,678	7,236	401	7,637
2034-35	11,480	15,275	2,065	510	577	29,908	3,842	416	33,750	1,287	35,037	7,314	401	7,715
2035-36	11,642	15,403	2,066	512	603	30,226	3,919	416	34,145	1,287	35,432	7,393	401	7,794
2036-37	11,802	15,531	2,066	514	626	30,539	3,888	416	34,427	1,287	35,714	7,472	401	7,873
2037-38	11,959	15,660	2,066	516	650	30,850	3,964	416	34,814	1,287	36,101	7,549	401	7,950
2038-39	12,113	15,788	2,067	517	674	31,159	4,005	416	35,165	1,287	36,452	7,626	401	8,027
2039-40	12,271	15,916	2,067	519	700	31,473	4,081	416	35,554	1,287	36,841	7,703	401	8,104
	Table updated through December 2010													
Annual Percent Change														
1991-2001	1.03%	0.55%	-1.02%	0.53%		0.50%			0.48%		0.57%	-0.02%		0.10%
2001-10	1.07%	0.32%	-3.11%	0.04%		0.21%			0.36%		0.26%	0.83%		0.84%
2010-16	0.47%	0.41%	-0.13%	-1.79%		0.40%			0.34%		0.43%	0.29%		0.53%
2010-20	0.90%	0.68%	-0.07%	-0.94%		0.74%			0.70%		0.74%	0.70%		0.86%
2009-30	1.26%	0.81%	-0.02%	-0.29%		0.97%			0.94%		0.93%	0.97%		1.08%
2009-40	1.31%	0.82%	-0.01%	-0.08%		1.00%			0.98%		0.97%	1.00%		1.06%

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

PEAK DEMAND - MW
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2001-02	4799	4805	4681	4604	3694	3626	3632	3576	3421	3599	4177	4493	4805
2002-03	4910	4874	5185	4463	4039	3735	3878	3724	3932	3860	4782	4522	5185
2003-04	5337	5410	5273	4159	3825	3887	3632	3606	4080	5161	5316	4448	5410
2004-05	5402	5123	5418	4087	3701	3956	3848	3698	3583	3815	4629	4524	5418
2005-06	5667	5405	5093	4692	4040	3732	3709	3702	3677	3592	4587	5498	5667
2006-07	6102	5305	5656	4529	4406	3965	4023	3694	4214	4059	4840	4729	6102
2007-08	5341	6071	5917	4557	4052	3908	3908	3778	3868	4769	5303	6006	6071
2008-09	5128	5384	5472	5647	3997	4176	3707	3672	3706	5064	4761	4304	5647
2009-10	5569	5553	5709	4510	3794	3918	3925	3756	3597	3523	3818	4322	5709

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2010-11	5511	5592	6142	4900	4457	3786	3813	3787	3787	4091	4409	4670	6142 [1]
2011-12	5252	5639	5254	4477	3947	3917	3810	3788	3784	4088	4407	4668	5639
2012-13	5249	5635	5251	4474	3945	3915	3803	3777	3777	4090	4408	4668	5635
2013-14	5238	5633	5250	4475	3937	3907	3859	3832	3832	4159	4482	4746	5633
2014-15	5315	5725	5336	4550	3995	3964	3908	3881	3881	4223	4549	4817	5725
2015-16	5383	5809	5415	4619	4046	4015	3956	3928	3929	4285	4615	4886	5809
2016-17	5449	5891	5492	4686	4096	4064	4002	3975	3974	4338	4672	4946	5891
2017-18	5512	5962	5559	4744	4143	4111	4052	4024	4024	4397	4735	5012	5962
2018-19	5581	6041	5632	4807	4194	4162	4104	4077	4076	4458	4800	5081	6041
2019-20	5653	6123	5710	4873	4249	4217	4160	4124	4132	4523	4870	5155	6123
2020-21	5731	6211	5792	4944	4307	4274	4232	4204	4203	4605	4958	5248	6211
2021-22	5829	6323	5896	5033	4381	4348	4280	4252	4251	4659	5016	5309	6323
2022-23	5896	6396	5964	5092	4431	4398	4330	4301	4300	4713	5075	5371	6396
2023-24	5964	6471	6034	5152	4482	4448	4381	4336	4351	4771	5136	5436	6471
2024-25	6035	6549	6107	5214	4536	4501	4432	4402	4401	4827	5197	5500	6549
2025-26	6104	6625	6179	5275	4588	4553	4482	4451	4451	4882	5256	5563	6625
2026-27	6173	6701	6249	5336	4640	4604	4532	4501	4501	4938	5317	5627	6701
2027-28	6243	6778	6321	5397	4692	4656	4571	4518	4540	4982	5364	5677	6778
2028-29	6297	6838	6377	5445	4733	4696	4630	4599	4598	5047	5433	5750	6838
2029-30	6377	6926	6459	5516	4793	4756	4678	4647	4646	5101	5492	5812	6926
2030-31	6444	7000	6528	5575	4843	4806	4730	4698	4698	5158	5553	5877	7000
2031-32	6515	7078	6601	5637	4897	4859	4773	4711	4740	5205	5603	5930	7078
3032-33	6574	7157	6661	5688	4941	4903	4835	4802	4802	5273	5677	6008	7157
2033-34	6660	7236	6748	5763	5005	4967	4887	4854	4854	5331	5739	6074	7236
2034-35	6732	7314	6822	5826	5060	5021	4939	4906	4906	5388	5801	6139	7314
2035-36	6804	7393	6895	5889	5114	5075	4981	4911	4947	5435	5851	6192	7393
2036-37	6861	7472	6954	5939	5157	5118	5043	5009	5008	5502	5923	6269	7472
2037-38	6946	7549	7040	6013	5221	5181	5094	5059	5059	5558	5984	6332	7549
2038-39	7016	7626	7112	6074	5273	5233	5145	5110	5110	5615	6044	6396	7626
2039-40	7087	7703	7184	6136	5326	5286	5186	5107	5151	5660	6093	6448	7703

[1] Weather Normalized for Fiscal Year 2010-11 is 5589 MW.

MINIMUM DEMAND - MW
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2001-02	1933	1944	1985	1927	1879	1988	2010	1936	1881	1932	1879	1942	1936
2002-03	2009	1986	2015	1940	1917	1984	1996	1996	1913	1858	1892	1996	1959
2003-04	2140	2187	2163	1808	1982	2030	2107	2103	1931	1926	1912	2095	2032
2004-05	2071	2171	2161	2061	2057	2108	1984	2083	1982	1944	1925	2035	2049
2005-06	2100	2187	2043	2083	2085	2128	2109	2074	2114	2041	2068	2122	2096
2006-07	2406	2246	2196	2093	2088	2242	2276	2170	2080	2036	2050	2152	2170
2007-08	2287	2289	2173	2146	2106	2114	2229	2190	2121	2125	2078	2192	2171
2008-09	2262	2347	2229	2182	2091	2155	2131	2135	2117	2022	2062	1997	2144
2009-10	2041	2172	2155	2049	2050	2170	2142	2107	2047	2015	2000	2066	2085

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2010-11	2084	1925	1981	2029	2045	2091	2101	2146	2130	2167	2190	2088	2081
2011-12	2280	2311	2182	2190	2126	2075	2100	2223	2128	2165	2188	2087	2171
2012-13	2279	2310	2180	2189	2125	2074	2096	2140	2124	2161	2184	2083	2162
2013-14	2274	2305	2176	2185	2121	2070	2127	2171	2155	2193	2216	2113	2176
2014-15	2308	2339	2208	2217	2152	2100	2154	2199	2183	2221	2244	2140	2205
2015-16	2337	2369	2236	2245	2179	2127	2180	2305	2210	2248	2272	2167	2240
2016-17	2366	2398	2264	2273	2206	2153	2205	2252	2235	2274	2298	2192	2260
2017-18	2393	2426	2290	2299	2232	2178	2233	2280	2263	2303	2327	2219	2287
2018-19	2423	2456	2318	2328	2260	2205	2262	2310	2293	2332	2357	2248	2316
2019-20	2455	2488	2349	2358	2289	2234	2293	2420	2324	2364	2389	2279	2353
2020-21	2488	2522	2381	2390	2320	2264	2332	2382	2364	2405	2431	2318	2383
2021-22	2531	2566	2422	2431	2360	2303	2359	2409	2391	2433	2458	2344	2417
2022-23	2560	2595	2449	2459	2387	2329	2386	2437	2419	2461	2487	2371	2445
2023-24	2589	2625	2478	2487	2415	2356	2415	2544	2447	2490	2516	2400	2480
2024-25	2620	2656	2507	2517	2443	2384	2442	2494	2476	2519	2545	2427	2503
2025-26	2650	2687	2536	2546	2472	2412	2470	2522	2503	2547	2574	2455	2531
2026-27	2680	2717	2564	2575	2499	2439	2498	2550	2532	2576	2603	2482	2560
2027-28	2710	2747	2593	2604	2527	2466	2519	2651	2553	2598	2625	2504	2592
2028-29	2734	2771	2616	2626	2549	2488	2552	2605	2586	2631	2659	2536	2613
2029-30	2769	2807	2649	2660	2582	2520	2578	2633	2613	2659	2687	2562	2643
2030-31	2798	2836	2677	2688	2609	2546	2607	2662	2642	2688	2716	2591	2672
2031-32	2829	2867	2707	2717	2638	2574	2630	2764	2666	2712	2741	2614	2705
3032-33	2854	2893	2731	2742	2662	2597	2665	2721	2701	2748	2777	2648	2728
2033-34	2891	2931	2767	2778	2696	2631	2693	2750	2730	2777	2807	2677	2761
2034-35	2923	2963	2797	2808	2726	2660	2722	2780	2759	2807	2837	2705	2790
2035-36	2954	2994	2826	2838	2755	2688	2745	2882	2783	2831	2861	2728	2824
2036-37	2979	3020	2850	2862	2778	2711	2779	2838	2817	2866	2896	2762	2846
2037-38	3016	3057	2886	2897	2812	2744	2807	2866	2845	2895	2925	2790	2878
2038-39	3046	3088	2915	2926	2841	2772	2835	2895	2874	2924	2955	2818	2907
2039-40	3077	3119	2944	2956	2869	2800	2858	2997	2897	2947	2978	2840	2940

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NET ENERGY FOR LOAD- GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2206	2338	2138	2109	1965	2044	2100	1830	1972	1966	2068	2168	24903
2002-03	2391	2324	2306	2096	2005	2076	2077	1854	2069	1957	2104	2111	25370
2003-04	2581	2621	2352	2262	1983	2139	2119	1964	2136	2069	2253	2221	26701
2004-05	2460	2444	2440	2175	2051	2187	2166	1912	2101	2020	2209	2172	26338
2005-06	2582	2572	2232	2221	2076	2154	2141	1927	2143	2015	2238	2527	26828
2006-07	2935	2589	2398	2187	2142	2227	2178	1972	2200	2091	2267	2318	27502
2007-08	2664	2760	2420	2267	2119	2222	2251	2079	2144	2132	2288	2580	27928
2008-09	2701	2703	2528	2406	2115	2240	2187	1962	2131	2069	2253	2152	27447
2009-10	2597	2523	2542	2176	2030	2201	2151	1917	2087	1985	2078	2239	26526

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	2373	2424	2311	2171	2069	2165	2121	1910	2086	2017	2149	2169	25965
2011-12	2484	2539	2327	2210	2046	2141	2119	1978	2084	2016	2148	2168	26260
2012-13	2482	2537	2325	2208	2045	2140	2115	1905	2080	2012	2144	2164	26157
2013-14	2478	2532	2321	2204	2041	2136	2146	1932	2110	2041	2175	2195	26311
2014-15	2514	2569	2354	2236	2071	2167	2173	1957	2137	2067	2203	2223	26672
2015-16	2546	2602	2384	2265	2097	2195	2200	2051	2164	2093	2230	2251	27078
2016-17	2577	2634	2414	2293	2123	2222	2226	2004	2189	2117	2256	2277	27331
2017-18	2607	2665	2442	2319	2148	2247	2253	2029	2216	2143	2284	2305	27658
2018-19	2640	2698	2472	2348	2174	2275	2283	2056	2245	2171	2313	2335	28010
2019-20	2674	2733	2504	2379	2203	2305	2314	2154	2275	2201	2345	2367	28453
2020-21	2710	2770	2538	2411	2233	2336	2354	2120	2315	2239	2385	2408	28820
2021-22	2757	2818	2582	2453	2271	2377	2381	2144	2341	2264	2413	2435	29236
2022-23	2789	2850	2612	2481	2297	2404	2408	2168	2368	2290	2440	2464	29572
2023-24	2821	2883	2642	2510	2324	2432	2437	2264	2396	2318	2469	2493	29987
2024-25	2854	2917	2673	2539	2351	2460	2465	2220	2424	2344	2498	2522	30268
2025-26	2887	2951	2704	2569	2378	2489	2492	2245	2451	2371	2526	2550	30613
2026-27	2920	2984	2735	2598	2405	2517	2520	2270	2479	2397	2554	2579	30957
2027-28	2953	3018	2765	2627	2432	2545	2542	2359	2500	2418	2577	2601	31337
2028-29	2978	3044	2789	2650	2453	2567	2575	2319	2532	2449	2610	2634	31600
2029-30	3016	3083	2825	2683	2485	2600	2602	2343	2559	2475	2637	2662	31969
2030-31	3048	3115	2855	2712	2511	2627	2631	2369	2587	2502	2666	2691	32313
2031-32	3082	3150	2886	2742	2538	2656	2654	2460	2610	2525	2690	2715	32709
3032-33	3109	3178	2912	2766	2561	2680	2689	2421	2644	2557	2725	2751	32995
2033-34	3150	3220	2950	2802	2595	2715	2718	2448	2673	2585	2755	2781	33391
2034-35	3184	3254	2982	2833	2623	2745	2747	2474	2702	2613	2784	2810	33750
2035-36	3218	3289	3014	2863	2651	2774	2770	2565	2725	2635	2808	2834	34145
2036-37	3245	3317	3039	2887	2673	2797	2805	2526	2758	2667	2842	2869	34427
2037-38	3285	3358	3077	2923	2706	2832	2833	2551	2786	2694	2871	2898	34814
2038-39	3318	3392	3108	2952	2734	2860	2861	2577	2814	2721	2900	2927	35165
2039-40	3352	3426	3139	2982	2761	2889	2884	2667	2836	2743	2923	2951	35554

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TOTAL SALES TO ULTIMATE CUSTOMERS- GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1971	1948	2055	1903	1845	1794	1827	1798	1738	1724	1657	1888	22149
2002-03	1977	1932	1977	2037	1819	1918	1849	1872	1678	1755	1691	1860	22363
2003-04	1948	2164	2200	2110	2027	1891	2006	1810	1735	1852	1843	1933	23520
2004-05	1991	2120	2116	2070	1895	1977	1969	1852	1778	1798	1756	1956	23279
2005-06	1998	2176	2151	2055	1874	2038	1985	1863	1831	1828	1781	2053	23634
2006-07	2234	2390	2304	2137	1953	1959	1983	1932	1852	1853	1850	1932	24378
2007-08	2147	2253	2365	2187	1986	1979	2005	2015	1896	1899	1855	2031	24617
2008-09	2383	2143	2300	2270	2079	1964	2007	2002	1799	1819	1836	1926	24526
2009-10	1982	2127	2253	2289	1867	1881	1947	1925	1759	1745	1711	1883	23369

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	1943	1987	2068	2110	1891	1960	1969	1879	1799	1770	1786	1888	23051
2011-12	2026	2114	2153	2043	1900	1890	1971	1884	1801	1770	1784	1885	23221
2012-13	2022	2111	2152	2040	1896	1886	1969	1882	1798	1764	1777	1878	23175
2013-14	2017	2109	2150	2039	1893	1884	1981	1897	1813	1780	1796	1900	23258
2014-15	2055	2150	2192	2079	1931	1921	2007	1924	1838	1803	1818	1923	23641
2015-16	2081	2178	2219	2105	1954	1945	2033	1950	1863	1826	1841	1947	23942
2016-17	2106	2205	2246	2130	1976	1966	2057	1973	1885	1847	1861	1969	24221
2017-18	2129	2231	2272	2154	1998	1989	2082	1999	1910	1870	1884	1993	24512
2018-19	2155	2259	2300	2181	2023	2014	2109	2026	1936	1895	1909	2018	24826
2019-20	2182	2289	2329	2209	2048	2040	2138	2056	1964	1922	1935	2045	25157
2020-21	2211	2320	2360	2238	2074	2067	2176	2094	2001	1957	1970	2080	25549
2021-22	2248	2359	2398	2274	2108	2101	2203	2120	2027	1981	1993	2104	25915
2022-23	2273	2385	2424	2299	2130	2124	2228	2146	2051	2004	2016	2127	26207
2023-24	2298	2412	2451	2325	2154	2148	2255	2173	2077	2029	2040	2152	26515
2024-25	2324	2440	2480	2351	2179	2174	2282	2200	2103	2053	2064	2176	26826
2025-26	2350	2468	2507	2377	2202	2198	2308	2226	2129	2077	2088	2200	27131
2026-27	2375	2495	2534	2403	2226	2222	2335	2253	2155	2101	2111	2224	27436
2027-28	2401	2523	2562	2429	2250	2247	2362	2281	2180	2125	2134	2248	27741
2028-29	2426	2550	2589	2454	2273	2271	2388	2306	2205	2148	2157	2271	28037
2029-30	2450	2576	2615	2479	2296	2295	2414	2331	2229	2171	2179	2294	28330
2030-31	2475	2603	2642	2505	2319	2319	2441	2358	2255	2196	2204	2319	28634
2031-32	2501	2631	2670	2532	2344	2344	2468	2388	2282	2222	2229	2344	28955
3032-33	2528	2660	2699	2558	2368	2369	2496	2414	2309	2247	2253	2369	29272
2033-34	2555	2689	2727	2585	2393	2395	2523	2442	2336	2272	2278	2395	29590
2034-35	2582	2718	2756	2612	2417	2420	2551	2469	2363	2298	2303	2420	29908
2035-36	2609	2746	2784	2639	2442	2445	2578	2499	2390	2323	2328	2445	30226
2036-37	2635	2775	2813	2666	2466	2469	2606	2524	2416	2348	2352	2469	30539
2037-38	2662	2803	2841	2692	2490	2494	2632	2551	2442	2373	2376	2494	30850
2038-39	2688	2831	2868	2718	2513	2518	2659	2578	2468	2398	2400	2518	31159
2039-40	2714	2860	2897	2744	2537	2543	2686	2608	2495	2423	2424	2543	31473

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RESIDENTIAL SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	608	659	640	661	582	622	653	654	568	559	520	557	7282
2002-03	600	673	670	678	595	618	652	647	560	560	530	576	7358
2003-04	639	773	787	746	641	682	701	688	596	595	578	635	8061
2004-05	630	726	745	731	620	680	724	687	600	606	552	606	7907
2005-06	640	772	771	712	610	659	701	685	625	649	583	644	8051
2006-07	774	919	838	750	629	669	724	733	631	624	576	628	8495
2007-08	694	812	838	799	646	694	734	761	664	634	593	670	8540
2008-09	758	859	815	816	692	706	731	735	636	616	581	634	8578
2009-10	665	793	820	819	675	696	712	725	629	598	560	607	8300

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	635	710	720	765	659	697	752	734	667	624	599	619	8181
2011-12	694	776	799	754	675	683	754	739	671	626	600	619	8389
2012-13	693	776	799	752	672	680	753	738	668	621	594	613	8359
2013-14	688	773	795	747	665	671	748	736	666	618	592	613	8313
2014-15	696	782	805	756	672	679	758	747	676	627	600	621	8419
2015-16	705	794	816	767	680	687	770	760	687	636	608	629	8538
2016-17	714	806	827	776	687	695	779	770	696	644	615	637	8647
2017-18	723	817	839	787	696	705	792	784	708	655	625	646	8777
2018-19	734	829	852	799	707	716	806	798	721	666	636	657	8920
2019-20	746	843	866	812	718	728	820	813	736	679	647	668	9075
2020-21	758	857	880	825	729	740	835	828	750	691	659	679	9231
2021-22	771	872	895	839	741	752	849	843	763	703	670	690	9388
2022-23	782	885	908	851	751	763	863	858	777	716	681	701	9536
2023-24	794	899	923	864	763	776	879	874	792	729	693	713	9699
2024-25	807	914	938	878	776	790	894	890	807	742	706	725	9867
2025-26	820	929	952	892	788	802	909	906	821	756	718	736	10029
2026-27	832	943	967	905	800	815	925	922	836	769	730	748	10192
2027-28	845	958	982	919	812	828	940	937	851	782	742	759	10354
2028-29	857	972	996	932	824	841	955	953	865	795	753	771	10513
2029-30	869	985	1010	945	835	853	970	968	879	807	765	782	10669
2030-31	881	999	1025	958	847	866	985	984	894	821	777	793	10830
2031-32	893	1014	1040	972	859	879	1001	1000	909	834	789	805	10994
3032-33	906	1028	1054	985	871	892	1016	1016	923	847	801	816	11156
2033-34	918	1043	1069	999	883	905	1031	1032	938	860	813	828	11317
2034-35	931	1057	1084	1012	894	917	1046	1048	953	873	825	839	11480
2035-36	943	1072	1098	1026	906	930	1062	1063	968	887	837	851	11642
2036-37	956	1086	1113	1039	918	943	1077	1079	982	900	848	862	11802
2037-38	968	1100	1127	1052	929	955	1091	1094	996	912	860	873	11959
2038-39	980	1114	1141	1065	940	967	1106	1110	1011	925	871	884	12113
2039-40	992	1128	1155	1078	952	979	1121	1125	1025	938	883	895	12271

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COMMERCIAL SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1086	1025	1147	975	1020	952	916	887	936	931	902	1067	11843
2002-03	1141	983	1050	1091	989	1065	951	969	885	959	958	1036	12077
2003-04	1023	1140	1154	1101	1084	969	1073	862	943	979	1017	1064	12408
2004-05	1084	1124	1129	1099	989	1046	1013	934	956	954	964	1082	12374
2005-06	1097	1151	1121	1115	1019	1081	1027	958	959	952	984	1116	12580
2006-07	1201	1216	1181	1134	1093	1085	1009	968	999	997	1039	1063	12984
2007-08	1169	1171	1254	1130	1090	1062	1051	1022	1002	1023	1048	1111	13134
2008-09	1369	1035	1225	1200	1144	1055	1031	1033	950	958	1025	1061	13084
2009-10	1097	1066	1190	1240	980	1007	1016	983	924	957	964	1039	12463

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FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	1083	1061	1125	1118	1024	1010	1002	940	932	944	978	1051	12268
2011-12	1105	1107	1124	1067	1012	994	1003	940	931	943	977	1049	12253
2012-13	1103	1105	1123	1067	1012	995	1004	940	931	943	976	1049	12248
2013-14	1103	1106	1125	1071	1017	1001	1020	957	949	961	996	1070	12378
2014-15	1133	1136	1155	1100	1045	1028	1034	970	961	973	1008	1083	12627
2015-16	1147	1150	1168	1113	1057	1041	1046	982	972	985	1020	1096	12775
2016-17	1160	1163	1181	1125	1069	1052	1057	992	983	995	1031	1108	12916
2017-18	1172	1176	1194	1137	1081	1063	1068	1003	994	1006	1042	1120	13056
2018-19	1185	1189	1207	1150	1092	1075	1079	1014	1004	1017	1054	1133	13199
2019-20	1199	1202	1219	1162	1104	1086	1091	1025	1016	1028	1066	1146	13344
2020-21	1212	1215	1232	1174	1116	1097	1110	1045	1035	1048	1086	1166	13536
2021-22	1233	1236	1253	1194	1135	1117	1120	1054	1044	1057	1095	1177	13716
2022-23	1244	1247	1264	1205	1145	1126	1129	1063	1053	1066	1105	1187	13834
2023-24	1255	1258	1274	1215	1154	1135	1139	1072	1062	1075	1114	1198	13952
2024-25	1266	1269	1285	1225	1164	1145	1148	1081	1071	1084	1124	1208	14070
2025-26	1277	1280	1296	1235	1174	1154	1157	1090	1080	1093	1133	1218	14186
2026-27	1288	1291	1306	1246	1183	1164	1166	1099	1088	1101	1142	1229	14302
2027-28	1298	1302	1317	1256	1193	1173	1175	1107	1097	1110	1151	1239	14417
2028-29	1309	1312	1327	1265	1202	1182	1184	1116	1105	1118	1160	1248	14529
2029-30	1319	1323	1337	1275	1211	1191	1193	1124	1114	1126	1169	1258	14640
2030-31	1329	1333	1347	1285	1220	1200	1202	1133	1122	1135	1178	1269	14756
2031-32	1341	1345	1359	1296	1231	1211	1212	1143	1132	1146	1189	1281	14885
3032-33	1353	1357	1371	1307	1242	1221	1222	1153	1142	1156	1200	1292	15016
2033-34	1365	1369	1382	1319	1252	1231	1232	1163	1152	1166	1210	1304	15146
2034-35	1377	1381	1394	1330	1262	1241	1242	1173	1162	1176	1221	1315	15275
2035-36	1389	1393	1406	1341	1273	1251	1252	1182	1172	1186	1231	1327	15403
2036-37	1401	1405	1417	1352	1283	1261	1262	1192	1182	1196	1242	1338	15531
2037-38	1413	1417	1429	1363	1293	1271	1272	1202	1191	1206	1252	1349	15660
2038-39	1425	1429	1440	1374	1304	1281	1282	1212	1201	1216	1263	1361	15788
2039-40	1437	1441	1452	1385	1314	1291	1292	1221	1211	1226	1273	1372	15916

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HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	232	217	219	217	199	182	217	213	195	194	194	218	2496
2002-03	187	225	205	219	189	199	192	212	195	195	163	203	2383
2003-04	237	202	210	229	242	197	186	213	152	231	199	187	2485
2004-05	229	218	192	190	245	208	190	188	182	195	193	218	2447
2005-06	209	198	216	180	206	251	207	175	204	187	173	245	2451
2006-07	209	205	233	203	187	166	204	188	175	186	187	190	2332
2007-08	232	214	220	209	206	176	175	184	185	195	167	202	2366
2008-09	206	201	210	202	194	158	201	188	171	203	185	184	2303
2009-10	171	218	196	180	163	134	177	174	167	148	147	199	2073

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	181	175	184	183	171	214	172	166	165	164	167	174	2116
2011-12	184	186	186	177	170	169	171	165	164	163	167	173	2074
2012-13	183	185	185	177	169	168	170	164	163	162	166	172	2063
2013-14	182	184	184	176	168	167	169	163	162	161	165	171	2053
2014-15	182	184	185	176	169	167	170	164	162	161	165	171	2057
2015-16	182	184	185	176	169	168	170	164	162	162	165	171	2058
2016-17	182	184	185	177	169	168	170	164	162	162	165	171	2058
2017-18	182	184	185	177	169	168	170	164	162	162	165	171	2058
2018-19	182	184	185	177	169	168	170	164	162	162	165	171	2059
2019-20	182	184	185	177	169	168	170	164	162	162	165	171	2059
2020-21	182	184	185	177	169	168	170	164	162	162	165	171	2060
2021-22	182	184	185	177	169	168	170	164	163	162	165	171	2060
2022-23	182	184	185	177	169	168	170	164	163	162	165	171	2060
2023-24	182	185	185	177	169	168	170	164	163	162	165	171	2061
2024-25	182	185	185	177	169	168	170	164	163	162	165	171	2061
2025-26	182	185	185	177	169	168	170	164	163	162	165	171	2061
2026-27	182	185	185	177	169	168	170	164	163	162	165	172	2062
2027-28	182	185	185	177	169	168	170	164	163	162	165	172	2062
2028-29	182	185	186	177	169	168	170	164	163	162	165	172	2063
2029-30	182	185	186	177	169	168	170	164	163	162	165	172	2063
2030-31	182	185	186	177	169	168	170	164	163	162	165	172	2064
2031-32	182	185	186	177	169	168	170	164	163	162	166	172	2064
3032-33	182	185	186	177	169	168	170	164	163	162	166	172	2064
2033-34	182	185	186	177	169	168	171	164	163	162	166	172	2065
2034-35	182	185	186	177	169	168	171	164	163	162	166	172	2065
2035-36	183	185	186	177	169	168	171	164	163	162	166	172	2066
2036-37	183	185	186	177	169	168	171	165	163	162	166	172	2066
2037-38	183	185	186	177	170	168	171	165	163	162	166	172	2066
2038-39	183	185	186	177	170	168	171	165	163	162	166	172	2067
2039-40	183	185	186	177	170	168	171	165	163	162	166	172	2067

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HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	442	492	470	490	423	454	470	482	407	406	370	403	5310
2002-03	432	503	492	505	427	449	469	472	432	435	406	447	5469
2003-04	499	616	627	596	498	531	542	539	460	462	453	501	6324
2004-05	500	583	599	589	487	534	570	545	467	476	431	477	6258
2005-06	507	624	625	574	482	520	557	551	496	520	461	515	6431
2006-07	630	759	687	610	503	536	577	589	501	492	458	510	6852
2007-08	558	663	685	649	512	551	584	610	527	500	468	534	6841
2008-09	609	702	660	660	547	553	567	574	490	475	445	487	6769
2009-10	513	621	640	640	514	530	535	549	472	449	414	450	6327

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FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	470	535	537	578	486	519	568	555	504	472	453	468	6144
2011-12	525	586	604	570	510	516	570	559	507	473	453	468	6341
2012-13	524	586	604	569	508	514	569	558	505	470	449	463	6318
2013-14	520	584	601	565	502	507	566	556	504	467	448	463	6283
2014-15	526	591	608	572	508	513	573	565	511	474	453	469	6363
2015-16	533	600	617	580	514	519	582	574	519	481	460	476	6454
2016-17	540	609	625	587	519	525	589	582	526	487	465	481	6536
2017-18	547	617	634	595	526	533	599	592	536	495	473	488	6634
2018-19	555	627	644	604	534	541	609	603	545	503	480	496	6742
2019-20	564	637	654	614	542	550	620	615	556	513	489	505	6859
2020-21	573	648	665	623	551	559	631	626	567	522	498	513	6977
2021-22	583	659	677	634	560	568	642	638	577	532	506	521	7096
2022-23	591	669	686	643	568	577	652	648	587	541	515	530	7207
2023-24	600	680	697	653	577	587	664	661	599	551	524	539	7331
2024-25	610	691	709	664	586	597	676	673	610	561	533	548	7458
2025-26	620	702	720	674	595	607	687	685	621	571	542	557	7580
2026-27	629	713	731	684	604	616	699	697	632	581	552	565	7703
2027-28	638	724	742	694	614	626	711	709	643	591	561	574	7826
2028-29	648	734	753	705	623	636	722	720	654	601	569	582	7946
2029-30	657	745	764	714	631	645	733	732	665	610	578	591	8064
2030-31	666	755	774	724	640	655	745	744	676	620	587	600	8186
2031-32	675	766	786	735	649	664	756	756	687	630	596	608	8310
3032-33	685	777	797	745	658	674	768	768	698	640	605	617	8432
2033-34	694	788	808	755	667	684	779	780	709	650	614	626	8554
2034-35	704	799	819	765	676	693	791	792	720	660	623	635	8677
2035-36	713	810	830	775	685	703	802	804	731	670	632	643	8800
2036-37	722	821	841	785	694	712	814	816	742	680	641	652	8920
2037-38	732	832	852	795	702	722	825	827	753	690	650	660	9039
2038-39	740	842	862	805	711	731	836	839	764	699	659	668	9156
2039-40	750	853	873	815	719	740	847	850	775	709	667	676	9275

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HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	30	36	32	36	29	34	33	37	28	31	26	30	382
2002-03	29	36	33	36	29	33	32	35	27	30	26	31	376
2003-04	31	40	38	38	30	36	34	37	29	32	27	33	406
2004-05	30	38	36	37	30	36	36	37	29	32	26	31	398
2005-06	30	39	36	36	28	34	33	36	30	34	28	32	398
2006-07	35	46	38	36	28	34	34	38	30	31	26	31	408
2007-08	32	41	39	40	30	35	35	40	32	32	28	34	419
2008-09	36	44	39	41	33	37	37	41	33	34	30	35	439
2009-10	34	43	43	46	38	41	41	44	37	36	32	36	473

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	37	43	42	46	39	43	44	43	39	36	35	36	481
2011-12	40	45	46	44	39	40	44	43	39	36	35	36	488
2012-13	40	45	46	44	39	40	44	43	39	36	35	36	486
2013-14	40	45	46	43	39	39	44	43	39	36	34	36	483
2014-15	40	45	47	44	39	39	44	43	39	36	35	36	489
2015-16	41	46	47	45	40	40	45	44	40	37	35	37	496
2016-17	42	47	48	45	40	40	45	45	40	37	36	37	503
2017-18	42	47	49	46	40	41	46	46	41	38	36	38	510
2018-19	43	48	50	46	41	42	47	46	42	39	37	38	519
2019-20	43	49	50	47	42	42	48	47	43	39	38	39	528
2020-21	44	50	51	48	42	43	49	48	44	40	38	39	537
2021-22	45	51	52	49	43	44	49	49	44	41	39	40	546
2022-23	45	51	53	49	44	44	50	50	45	42	40	41	554
2023-24	46	52	54	50	44	45	51	51	46	42	40	41	564
2024-25	47	53	55	51	45	46	52	52	47	43	41	42	574
2025-26	48	54	55	52	46	47	53	53	48	44	42	43	583
2026-27	48	55	56	53	46	47	54	54	49	45	42	43	593
2027-28	49	56	57	53	47	48	55	55	49	45	43	44	602
2028-29	50	56	58	54	48	49	56	55	50	46	44	45	611
2029-30	51	57	59	55	49	50	56	56	51	47	44	45	620
2030-31	51	58	60	56	49	50	57	57	52	48	45	46	630
2031-32	52	59	60	57	50	51	58	58	53	48	46	47	639
3032-33	53	60	61	57	51	52	59	59	54	49	47	47	649
2033-34	53	61	62	58	51	53	60	60	55	50	47	48	658
2034-35	54	61	63	59	52	53	61	61	55	51	48	49	667
2035-36	55	62	64	60	53	54	62	62	56	52	49	49	677
2036-37	56	63	65	60	53	55	63	63	57	52	49	50	686
2037-38	56	64	66	61	54	56	63	64	58	53	50	51	695
2038-39	57	65	66	62	55	56	64	65	59	54	51	51	704
2039-40	58	66	67	63	55	57	65	65	60	55	51	52	713

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HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	66	62	69	62	66	62	75	67	66	56	60	56	767
2002-03	69	66	76	68	71	64	78	68	34	30	34	31	688
2003-04	40	43	50	41	42	40	47	41	39	33	32	30	477
2004-05	31	34	39	34	34	34	41	34	34	30	29	28	402
2005-06	33	35	38	30	30	29	32	27	27	25	26	25	358
2006-07	34	37	37	29	27	24	33	32	29	27	27	26	362
2007-08	31	33	37	33	30	30	34	34	32	27	28	29	379
2008-09	36	37	39	35	35	37	47	43	41	37	40	40	466
2009-10	48	52	61	55	51	49	57	52	51	43	47	48	613

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	58	58	68	63	62	59	61	59	54	50	48	50	689
2011-12	56	62	64	61	54	55	61	60	54	50	48	50	675
2012-13	56	62	64	61	54	55	61	59	54	50	48	49	673
2013-14	55	62	64	60	53	54	60	59	54	50	48	49	669
2014-15	56	63	65	61	54	55	61	60	54	50	48	50	678
2015-16	57	64	66	62	55	55	62	61	55	51	49	51	687
2016-17	58	65	67	63	55	56	63	62	56	52	50	51	696
2017-18	58	66	68	63	56	57	64	63	57	53	50	52	707
2018-19	59	67	69	64	57	58	65	64	58	54	51	53	718
2019-20	60	68	70	65	58	59	66	65	59	55	52	54	731
2020-21	61	69	71	66	59	60	67	67	60	56	53	55	743
2021-22	62	70	72	68	60	61	68	68	61	57	54	56	756
2022-23	63	71	73	68	60	61	69	69	63	58	55	56	768
2023-24	64	72	74	70	61	62	71	70	64	59	56	57	781
2024-25	65	74	75	71	62	64	72	72	65	60	57	58	794
2025-26	66	75	77	72	63	65	73	73	66	61	58	59	807
2026-27	67	76	78	73	64	66	74	74	67	62	59	60	820
2027-28	68	77	79	74	65	67	76	75	68	63	60	61	834
2028-29	69	78	80	75	66	68	77	77	70	64	61	62	846
2029-30	70	79	81	76	67	69	78	78	71	65	62	63	859
2030-31	71	80	82	77	68	70	79	79	72	66	63	64	872
2031-32	72	82	84	78	69	71	81	81	73	67	64	65	885
3032-33	73	83	85	79	70	72	82	82	74	68	64	66	898
2033-34	74	84	86	80	71	73	83	83	76	69	65	67	911
2034-35	75	85	87	81	72	74	84	84	77	70	66	68	924
2035-36	76	86	88	83	73	75	85	86	78	71	67	68	937
2036-37	77	87	90	84	74	76	87	87	79	72	68	69	950
2037-38	78	89	91	85	75	77	88	88	80	73	69	70	963
2038-39	79	90	92	86	76	78	89	89	81	74	70	71	975
2039-40	80	91	93	87	77	79	90	91	83	75	71	72	988

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HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	256	253	256	253	236	227	233	224	222	218	218	234	2829
2002-03	250	258	249	245	231	300	170	235	211	254	179	238	2820
2003-04	252	271	269	251	243	233	244	218	225	226	233	241	2906
2004-05	246	260	258	244	221	239	238	215	218	218	219	239	2816
2005-06	249	268	254	246	226	240	240	221	225	219	221	251	2861
2006-07	268	276	262	244	233	236	239	222	222	225	230	213	2871
2007-08	253	264	274	243	237	232	232	227	223	229	215	238	2866
2008-09	260	264	250	250	234	232	227	225	210	209	214	226	2802
2009-10	238	252	256	348	123	224	227	224	205	214	206	226	2743

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	237	238	248	244	221	227	235	222	216	215	219	233	2755
2011-12	249	255	259	246	231	228	235	223	216	215	219	233	2807
2012-13	248	254	259	246	230	228	235	222	216	214	218	232	2804
2013-14	248	254	259	246	231	228	237	225	219	217	222	236	2821
2014-15	253	260	265	251	236	233	240	228	221	220	224	239	2871
2015-16	256	263	268	254	238	236	243	231	224	222	227	241	2904
2016-17	259	266	271	257	241	238	245	233	226	225	229	244	2935
2017-18	262	269	274	260	243	241	248	236	229	227	232	247	2968
2018-19	265	272	277	263	246	244	251	239	232	230	234	250	3002
2019-20	268	275	280	266	249	247	254	242	235	233	237	252	3037
2020-21	271	279	283	269	252	249	258	246	239	237	241	257	3080
2021-22	275	283	288	273	256	253	261	249	241	239	244	259	3121
2022-23	278	286	290	276	258	256	263	251	244	242	246	262	3152
2023-24	280	289	293	278	261	258	266	254	246	244	248	264	3183
2024-25	283	292	296	281	263	261	269	257	249	247	251	267	3215
2025-26	286	294	299	284	266	263	271	259	251	249	253	270	3246
2026-27	289	297	302	286	268	266	274	262	254	251	256	272	3277
2027-28	291	300	304	289	270	268	277	265	256	254	258	275	3307
2028-29	294	303	307	292	273	271	279	267	259	256	260	277	3337
2029-30	297	306	310	294	275	273	282	270	261	258	263	279	3367
2030-31	299	308	313	297	278	275	284	272	264	261	265	282	3398
2031-32	302	311	316	300	280	278	287	275	267	263	268	285	3431
3032-33	305	314	319	302	283	281	290	278	269	266	270	288	3464
2033-34	308	317	322	305	285	283	293	281	272	269	273	290	3498
2034-35	311	320	325	308	288	286	295	283	275	271	276	293	3531
2035-36	314	324	328	311	290	288	298	286	277	274	278	296	3564
2036-37	316	327	331	314	293	291	301	289	280	276	281	298	3597
2037-38	319	330	334	316	296	294	304	291	283	279	283	301	3629
2038-39	322	333	336	319	298	296	306	294	285	282	286	304	3662
2039-40	325	336	339	322	301	299	309	297	288	284	289	306	3694

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FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	327	321	383	266	302	298	264	253	285	257	303	289	3549
2002-03	314	330	328	323	289	299	292	286	262	271	274	306	3574
2003-04	342	342	345	332	312	296	291	276	270	293	307	325	3732
2004-05	325	346	345	329	293	306	296	274	282	283	288	319	3686
2005-06	327	351	340	327	300	310	302	276	283	274	288	335	3713
2006-07	357	375	349	334	310	301	309	271	289	287	297	312	3792
2007-08	344	346	365	336	314	291	294	294	281	288	302	320	3775
2008-09	356	345	361	346	326	299	289	291	270	269	294	300	3745
2009-10	301	274	317	319	291	272	267	265	246	256	259	283	3349

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	287	288	303	305	279	327	294	277	273	275	283	303	3495
2011-12	320	323	328	311	295	290	294	277	273	275	283	303	3571
2012-13	319	322	327	311	294	290	294	277	272	274	283	302	3567
2013-14	319	322	328	312	295	291	298	281	277	279	287	308	3597
2014-15	327	330	336	319	303	298	302	285	280	282	291	311	3662
2015-16	330	334	339	323	306	302	305	288	283	285	294	315	3703
2016-17	334	337	343	326	309	305	308	291	286	288	297	318	3741
2017-18	337	341	346	330	312	308	311	294	289	291	300	321	3779
2018-19	341	344	350	333	315	311	314	297	292	294	303	324	3818
2019-20	344	348	353	336	318	314	318	300	295	297	306	328	3858
2020-21	348	352	357	340	322	317	323	305	300	302	312	333	3911
2021-22	354	357	362	345	327	322	326	308	303	305	314	336	3959
2022-23	357	360	365	348	329	325	328	311	306	307	317	339	3993
2023-24	360	364	368	351	332	328	331	313	308	310	320	342	4026
2024-25	363	367	372	354	335	330	334	316	311	312	322	345	4060
2025-26	366	370	375	357	338	333	336	318	313	315	325	348	4093
2026-27	369	373	378	360	340	336	339	321	316	317	327	351	4126
2027-28	372	376	381	362	343	338	342	324	318	320	330	353	4159
2028-29	375	379	384	365	346	341	344	326	321	322	333	356	4191
2029-30	378	382	386	368	348	343	347	329	323	325	335	359	4223
2030-31	380	385	389	371	351	346	350	331	326	327	338	362	4256
2031-32	384	388	393	374	354	349	353	334	329	330	341	365	4293
3032-33	387	392	396	377	357	352	355	337	332	333	344	368	4329
2033-34	390	395	399	380	360	355	358	340	334	336	347	372	4366
2034-35	394	398	402	383	363	357	361	343	337	339	350	375	4402
2035-36	397	402	406	386	365	360	364	346	340	342	352	378	4438
2036-37	400	405	409	390	368	363	367	348	343	344	355	381	4474
2037-38	404	408	412	393	371	366	370	351	346	347	358	384	4510
2038-39	407	412	416	396	374	369	373	354	348	350	361	387	4546
2039-40	410	415	419	399	377	372	376	357	351	353	364	390	4582

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A-3 SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	731	660	724	676	677	615	615	618	622	647	565	754	7905
2002-03	785	606	680	727	669	671	677	638	596	613	683	678	8023
2003-04	641	746	748	731	736	640	733	556	627	642	660	686	8146
2004-05	705	726	720	711	669	695	662	610	626	630	641	706	8101
2005-06	715	733	720	730	680	719	668	633	623	630	649	735	8236
2006-07	776	770	780	743	737	727	656	653	663	659	683	703	8552
2007-08	790	763	821	754	725	727	699	682	680	700	699	732	8774
2008-09	952	624	814	803	769	705	684	697	633	669	691	708	8749
2009-10	750	721	806	779	744	677	716	689	650	659	670	721	8582

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	753	718	770	763	700	696	652	612	603	611	634	681	8193
2011-12	715	718	730	693	658	647	652	612	603	610	633	680	7950
2012-13	714	717	729	692	658	647	652	611	602	609	632	679	7943
2013-14	713	717	730	694	660	650	661	621	612	620	643	691	8013
2014-15	730	734	747	711	677	666	669	628	619	627	651	698	8157
2015-16	738	742	755	718	684	673	676	635	626	633	657	706	8243
2016-17	746	750	762	726	690	680	683	641	632	639	664	713	8325
2017-18	753	757	770	733	697	686	689	648	638	645	670	720	8406
2018-19	760	765	777	740	704	693	696	654	644	652	677	727	8489
2019-20	768	772	785	747	711	699	702	660	651	659	684	735	8573
2020-21	776	780	792	754	717	706	714	672	662	670	695	747	8684
2021-22	788	792	804	766	729	717	719	677	668	675	701	753	8788
2022-23	794	799	810	772	734	723	725	682	673	680	707	759	8857
2023-24	801	805	816	778	740	728	730	688	678	686	712	765	8926
2024-25	807	811	823	784	746	734	735	693	683	691	717	771	8995
2025-26	813	818	829	790	751	739	741	698	688	696	723	777	9063
2026-27	820	824	835	796	757	744	746	703	693	701	728	783	9131
2027-28	826	830	841	801	762	750	752	709	698	706	734	789	9198
2028-29	832	837	847	807	768	755	757	714	703	711	739	794	9263
2029-30	838	843	853	813	773	761	762	719	708	716	744	800	9328
2030-31	844	849	859	819	778	766	767	724	713	721	750	806	9396
2031-32	851	855	866	825	785	772	773	730	719	727	756	813	9472
3032-33	858	863	873	832	791	778	779	735	725	733	762	820	9548
2033-34	865	870	879	838	797	784	785	741	731	739	768	826	9623
2034-35	872	877	886	845	803	790	791	747	737	745	774	833	9698
2035-36	879	884	893	851	809	796	797	753	742	750	780	840	9773
2036-37	886	891	900	858	815	801	803	758	748	756	786	846	9848
2037-38	893	898	907	864	821	807	808	764	754	762	793	853	9923
2038-39	900	905	913	870	827	813	814	770	760	768	799	859	9998
2039-40	907	912	920	877	833	819	820	775	765	774	805	866	10072

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EXPERIMENTAL RATES - ELECTRICITY SALES - GWH
(Includes Real Time Pricing, Contract Demand, and Guarantee Load Factor)
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	85	89	89	87	80	72	105	83	76	77	83	87	1014
2002-03	64	99	86	100	71	80	89	105	84	89	56	94	1017
2003-04	110	72	89	100	120	85	79	107	51	126	90	79	1109
2004-05	118	94	83	88	129	97	89	101	88	94	87	118	1184
2005-06	98	84	105	75	96	148	111	83	111	92	73	122	1199
2006-07	96	90	113	103	83	73	98	92	83	97	91	99	1119
2007-08	100	100	105	97	103	77	90	89	85	87	80	108	1121
2008-09	96	91	101	94	98	65	120	95	88	91	87	93	1119
2009-10	60	124	93	65	65	54	72	68	68	55	50	88	863

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	67	73	70	76	73	58	84	81	80	80	82	86	910
2011-12	90	91	92	87	83	83	84	81	80	80	82	85	1018
2012-13	90	91	91	87	83	82	84	80	80	79	81	85	1013
2013-14	90	91	91	87	83	82	83	80	79	79	81	85	1011
2014-15	90	91	92	87	83	83	84	80	80	79	81	85	1016
2015-16	90	91	92	88	84	83	84	81	80	80	82	85	1018
2016-17	90	91	92	88	84	83	84	81	80	80	82	85	1020
2017-18	91	92	92	88	84	83	84	81	80	80	82	85	1022
2018-19	91	92	92	88	84	83	84	81	80	80	82	86	1024
2019-20	91	92	93	88	84	84	85	81	80	80	82	86	1026
2020-21	91	92	93	88	84	84	85	81	81	81	82	86	1029
2021-22	91	92	93	89	85	84	85	82	81	81	83	86	1031
2022-23	92	93	93	89	85	84	85	82	81	81	83	86	1033
2023-24	92	93	93	89	85	84	85	82	81	81	83	87	1034
2024-25	92	93	93	89	85	84	85	82	81	81	83	87	1036
2025-26	92	93	94	89	85	84	86	82	81	81	83	87	1038
2026-27	92	93	94	89	85	85	86	82	81	81	83	87	1040
2027-28	92	93	94	90	86	85	86	82	82	81	83	87	1041
2028-29	92	94	94	90	86	85	86	83	82	82	84	87	1043
2029-30	93	94	94	90	86	85	86	83	82	82	84	87	1045
2030-31	93	94	94	90	86	85	86	83	82	82	84	88	1046
2031-32	93	94	95	90	86	85	86	83	82	82	84	88	1048
3032-33	93	94	95	90	86	85	86	83	82	82	84	88	1050
2033-34	93	94	95	90	86	86	87	83	82	82	84	88	1052
2034-35	93	95	95	91	87	86	87	83	83	82	84	88	1054
2035-36	94	95	95	91	87	86	87	83	83	83	85	88	1055
2036-37	94	95	95	91	87	86	87	84	83	83	85	89	1057
2037-38	94	95	96	91	87	86	87	84	83	83	85	89	1059
2038-39	94	95	96	91	87	86	87	84	83	83	85	89	1061
2039-40	94	95	96	91	87	86	87	84	83	83	85	89	1063

RESIDENTIAL ACCUMULATED ENERGY EFFIENCY SAVINGS - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2	2	2	3	3	3	3	3	3	3	3	3	34
2002-03	3	4	4	4	4	4	3	4	4	4	4	4	45
2003-04	4	5	4	4	4	4	4	4	4	4	5	5	53
2004-05	5	5	5	5	5	5	5	5	5	5	6	6	62
2005-06	6	6	6	6	6	6	5	6	6	6	6	7	71
2006-07	7	7	7	7	7	7	7	7	7	7	8	8	86
2007-08	9	9	9	9	9	9	9	9	10	10	11	12	115
2008-09	13	13	13	13	12	12	14	16	21	22	23	25	195
2009-10	25	26	24	24	23	22	22	22	23	23	24	26	283

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	27	27	25	25	24	24	24	24	25	26	27	30	309
2011-12	31	31	30	29	28	28	27	28	29	30	32	34	357
2012-13	36	36	34	33	32	32	31	32	33	34	36	39	407
2013-14	40	40	37	36	34	33	33	33	34	34	36	39	430
2014-15	40	40	37	36	34	33	33	33	34	34	36	39	430
2015-16	40	40	37	36	34	33	33	33	34	34	36	39	430
2016-17	40	40	37	36	34	33	33	33	34	34	36	39	430
2017-18	40	40	37	36	34	33	33	33	34	34	36	39	430
2018-19	40	40	37	36	34	33	33	33	34	34	36	39	430
2019-20	40	40	37	36	34	33	33	33	34	34	36	39	430
2020-21	40	40	37	36	34	33	33	33	34	34	36	39	430
2021-22	40	40	37	36	34	33	33	33	34	34	36	39	430
2022-23	40	40	37	36	34	33	33	33	34	34	36	39	430
2023-24	40	40	37	36	34	33	33	33	34	34	36	39	430
2024-25	40	40	37	36	34	33	33	33	34	34	36	39	430
2025-26	40	40	37	36	34	33	33	33	34	34	36	39	430
2026-27	40	40	37	36	34	33	33	33	34	34	36	39	430
2027-28	40	40	37	36	34	33	33	33	34	34	36	39	430
2028-29	40	40	37	36	34	33	33	33	34	34	36	39	430
2029-30	40	40	37	36	34	33	33	33	34	34	36	39	430
2030-31	40	40	37	36	34	33	33	33	34	34	36	39	430
2031-32	40	40	37	36	34	33	33	33	34	34	36	39	430
3032-33	40	40	37	36	34	33	33	33	34	34	36	39	430
2033-34	40	40	37	36	34	33	33	33	34	34	36	39	430
2034-35	40	40	37	36	34	33	33	33	34	34	36	39	430
2035-36	40	40	37	36	34	33	33	33	34	34	36	39	430
2036-37	40	40	37	36	34	33	33	33	34	34	36	39	430
2037-38	40	40	37	36	34	33	33	33	34	34	36	39	430
2038-39	40	40	37	36	34	33	33	33	34	34	36	39	430
2039-40	40	40	37	36	34	33	33	33	34	34	36	39	430

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COMMERCIAL ACCUMULATED ENERGY EFFIENCY SAVINGS - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	26	27	26	26	26	26	27	28	30	31	33	37	343
2002-03	38	39	36	36	34	34	33	34	35	36	38	41	436
2003-04	43	43	40	39	37	37	36	37	38	38	40	44	472
2004-05	45	45	42	41	40	39	38	39	40	40	43	46	498
2005-06	47	48	45	44	42	41	40	41	42	43	45	49	525
2006-07	50	50	47	46	44	43	42	44	45	46	48	53	559
2007-08	54	55	51	51	48	47	46	48	49	51	55	62	618
2008-09	65	67	64	64	62	61	61	64	66	68	72	78	790
2009-10	82	83	78	77	74	73	72	74	77	78	85	93	946

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	96	97	92	91	87	85	83	86	87	89	94	102	1089
2011-12	105	106	100	98	94	93	91	94	97	99	105	114	1196
2012-13	117	118	111	109	105	103	101	105	107	109	116	125	1326
2013-14	128	128	120	117	111	108	105	108	109	111	117	125	1387
2014-15	128	128	120	117	111	108	105	108	109	111	117	125	1387
2015-16	128	128	120	117	111	108	105	108	109	111	117	125	1387
2016-17	128	128	120	117	111	108	105	108	109	111	117	125	1387
2017-18	128	128	120	117	111	108	105	108	109	111	117	125	1387
2018-19	128	128	120	117	111	108	105	108	109	111	117	125	1387
2019-20	128	128	120	117	111	108	105	108	109	111	117	125	1387
2020-21	128	128	120	117	111	108	105	108	109	111	117	125	1387
2021-22	128	128	120	117	111	108	105	108	109	111	117	125	1387
2022-23	128	128	120	117	111	108	105	108	109	111	117	125	1387
2023-24	128	128	120	117	111	108	105	108	109	111	117	125	1387
2024-25	128	128	120	117	111	108	105	108	109	111	117	125	1387
2025-26	128	128	120	117	111	108	105	108	109	111	117	125	1387
2026-27	128	128	120	117	111	108	105	108	109	111	117	125	1387
2027-28	128	128	120	117	111	108	105	108	109	111	117	125	1387
2028-29	128	128	120	117	111	108	105	108	109	111	117	125	1387
2029-30	128	128	120	117	111	108	105	108	109	111	117	125	1387
2030-31	128	128	120	117	111	108	105	108	109	111	117	125	1387
2031-32	128	128	120	117	111	108	105	108	109	111	117	125	1387
3032-33	128	128	120	117	111	108	105	108	109	111	117	125	1387
2033-34	128	128	120	117	111	108	105	108	109	111	117	125	1387
2034-35	128	128	120	117	111	108	105	108	109	111	117	125	1387
2035-36	128	128	120	117	111	108	105	108	109	111	117	125	1387
2036-37	128	128	120	117	111	108	105	108	109	111	117	125	1387
2037-38	128	128	120	117	111	108	105	108	109	111	117	125	1387
2038-39	128	128	120	117	111	108	105	108	109	111	117	125	1387
2039-40	128	128	120	117	111	108	105	108	109	111	117	125	1387

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HUFFMAN BILL ACCUMULATED ENERGY EFFIENCY SAVINGS - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	0
2002-03	0	0	0	0	0	0	0	0	0	0	0	0	0
2003-04	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-05	0	0	0	0	0	0	0	0	0	0	0	0	0
2005-06	0	0	0	0	0	0	0	0	0	0	0	0	0
2006-07	0	0	0	0	0	0	0	0	0	0	0	0	0
2007-08	0	0	0	0	0	0	0	0	0	0	0	0	0
2008-09	0	0	0	0	0	0	0	0	0	0	0	0	0
2009-10	0	0	0	0	0	0	0	0	0	0	0	0	0

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	0	0	0	0	0	0	0	0	0	0	0	0	0
2011-12	0	0	0	0	0	0	1	1	1	2	2	2	9
2012-13	3	3	4	4	5	6	7	8	9	10	10	9	77
2013-14	10	11	13	14	17	20	20	19	20	20	19	17	201
2014-15	18	18	21	22	25	29	29	26	27	27	25	22	287
2015-16	23	23	27	27	31	35	35	32	32	33	30	27	354
2016-17	27	27	32	32	36	41	40	36	37	37	34	29	408
2017-18	30	30	34	34	38	43	42	38	38	38	35	31	431
2018-19	31	31	35	36	39	45	44	40	40	40	36	32	448
2019-20	32	32	37	37	41	46	46	41	41	42	38	33	466
2020-21	34	34	39	39	43	49	49	44	44	44	40	35	494
2021-22	36	36	41	41	45	52	51	46	46	46	42	37	518
2022-23	37	37	43	43	47	54	53	47	47	48	43	38	536
2023-24	38	38	44	44	48	55	54	48	48	49	44	39	549
2024-25	39	39	44	44	49	56	55	49	49	49	45	39	556
2025-26	39	39	45	45	50	57	56	50	50	50	46	40	566
2026-27	40	40	46	46	50	57	56	51	51	51	46	41	575
2027-28	41	41	46	47	51	58	57	51	51	52	47	41	583
2028-29	41	41	47	47	52	59	58	52	52	52	48	42	592
2029-30	42	42	48	48	53	60	59	53	53	53	48	42	600
2030-31	42	42	48	49	53	61	60	54	54	54	49	43	609
2031-32	43	43	49	49	54	62	60	54	54	54	50	43	617
3032-33	43	44	50	50	55	62	61	55	55	55	50	44	625
2033-34	44	44	50	51	56	63	62	56	56	56	51	45	634
2034-35	45	45	51	51	56	64	63	57	57	57	52	45	642
2035-36	45	45	52	52	57	65	64	57	57	57	52	46	651
2036-37	46	46	53	53	58	66	65	58	58	58	53	46	659
2037-38	46	46	53	53	59	67	65	59	59	59	54	47	667
2038-39	47	47	54	54	59	68	66	60	60	60	54	48	676
2039-40	48	48	55	55	60	68	67	60	60	60	55	48	684

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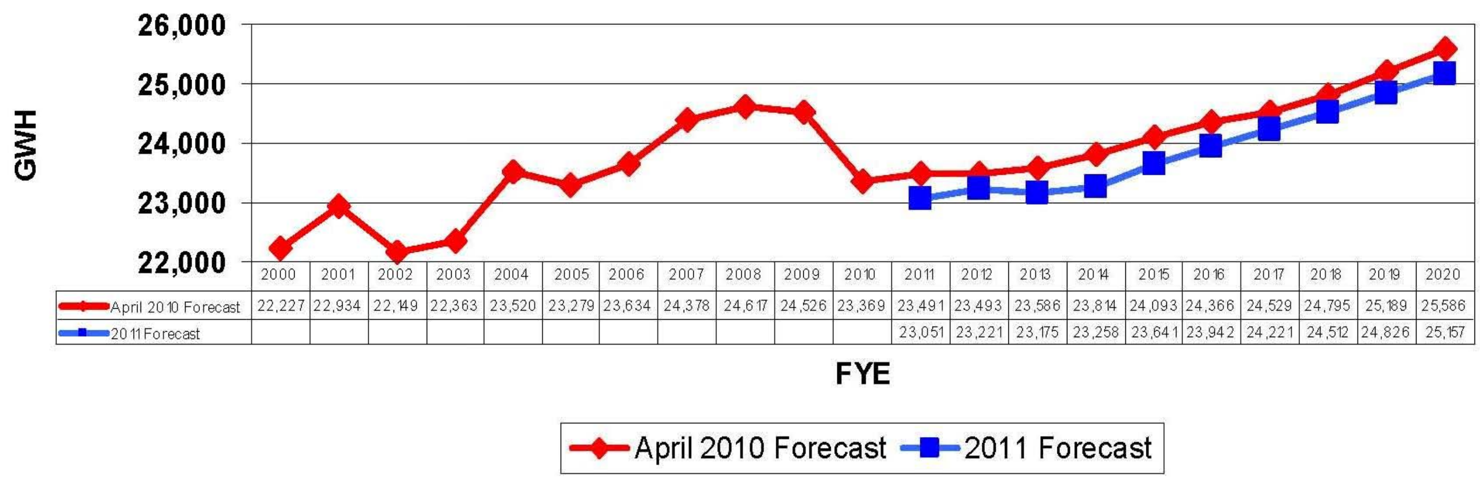
Load Forecasting | | Page 27

Retail Sales

- Key Change Factors from April 2010 to 2011
  - Balance Sheet Recession means lengthy recovery period.
  - Commercial vacancy rates remain high.
  - Construction activity remains at low level for extended period.
  - Higher electric prices to meet 33% renewable goal.
  - Includes Huffman Bill energy efficiency savings as a committed resource.

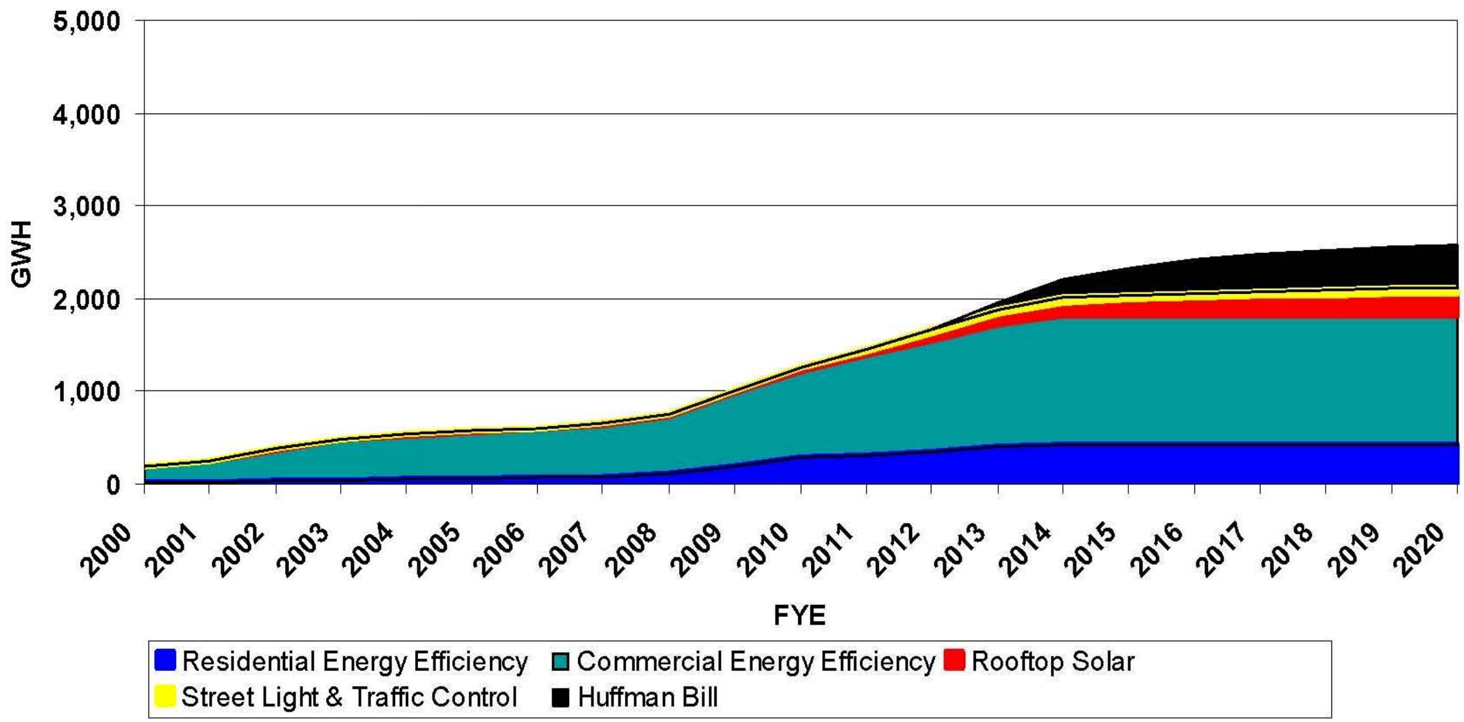


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
April 2010 Forecast	22,227	22,934	22,149	22,363	23,520	23,279	23,634	24,378	24,617	24,526	23,369	23,491	23,493	23,586	23,814	24,093	24,366	24,529	24,795	25,189	25,586
2011 Forecast												23,051	23,221	23,175	23,258	23,641	23,942	24,221	24,512	24,826	25,157

2011 Forecast Chartbook

Forecasted Accumulated Savings
Energy Efficiency and Solar Rooftops

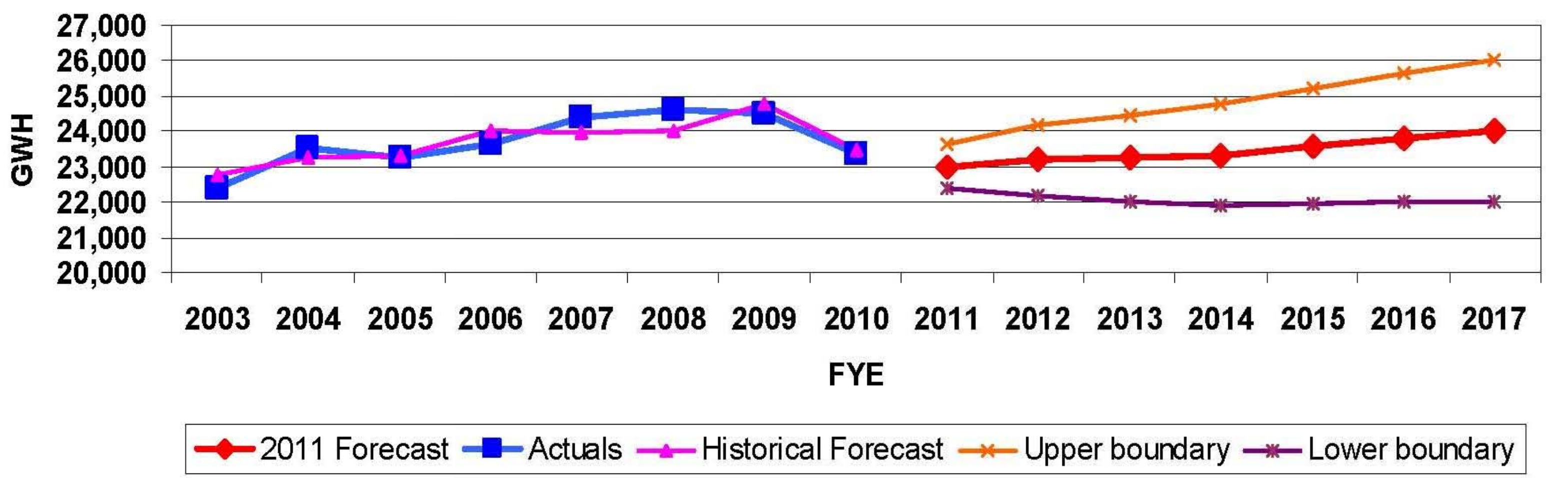
- Components of Change
  - "Committed" LADWP EE programs through FYE 2013.
  - Huffman Bill savings.
  - "Uncommitted" EE will be accounted for as a resource.
  - Solar Rooftop Goal – 148 MW installed by 2020



2011 Forecast Chartbook 29

Retail Sales

- Accuracy
  - EE and Solar were not modeled explicitly in Historical Forecasts.
  - Historical accuracy is -0.1% with a 1.6% deviation. However expect larger variation in accuracy due to uncertainty of new programs.
  - Forecast variation is a function of weather, economic forecasts, meeting program goals and model specification.



2011 Forecast Chartbook

30

Peak Demand

- Cases
  - The variance around the 1-in-2 forecasted peak has widened.
  - Climate change research expects more frequent heat storms to occur of longer duration.
  - 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	5,639	5,635	5,633	5,725	5,809	5,891	5,962	6,041	6,123	6,211
1-in-10												6,096	6,092	6,089	6,188	6,277	6,365	6,442	6,527	6,615	6,710
1-in-40												6,338	6,334	6,331	6,433	6,525	6,616	6,696	6,784	6,876	6,974

FYE

1-in-2 1-in-10 1-in-40

2011 Forecast Chartbook 31

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.

Fiscal Year	Base Case	1 in 5	1 in 10	1 in 20	1 in 40
2011-12	5,589	5,887	6,042	6,171	6,282
2012-13	5,639	5,939	6,096	6,226	6,338
2013-14	5,635	5,935	6,092	6,222	6,334
2014-15	5,633	5,933	6,089	6,219	6,331
2015-16	5,725	6,030	6,188	6,320	6,433
2016-17	5,809	6,117	6,277	6,411	6,525
2017-18	5,891	6,203	6,365	6,500	6,616
2018-19	5,962	6,278	6,442	6,579	6,696
2019-00	6,041	6,360	6,527	6,665	6,784
2020-21	6,123	6,447	6,615	6,755	6,876
2021-22	6,211	6,539	6,710	6,852	6,974
2022-23	6,323	6,656	6,830	6,974	7,098
2023-24	6,396	6,733	6,909	7,055	7,181
2024-25	6,471	6,812	6,990	7,137	7,265
2025-26	6,549	6,894	7,074	7,223	7,352
2026-27	6,625	6,975	7,157	7,308	7,438
2027-28	6,701	7,054	7,238	7,391	7,523
2028-29	6,778	7,135	7,321	7,475	7,608
2029-30	6,838	7,198	7,385	7,541	7,676
2030-31	6,926	7,291	7,481	7,639	7,775
2031-32	7,000	7,369	7,560	7,720	7,857
2032-33	7,078	7,450	7,644	7,806	7,945
2033-34	7,157	7,534	7,730	7,894	8,034
2034-35	7,236	7,617	7,815	7,980	8,122
2035-36	7,314	7,700	7,900	8,067	8,210
2036-37	7,393	7,783	7,985	8,154	8,299
2037-38	7,472	7,865	8,070	8,240	8,387
2038-39	7,549	7,946	8,153	8,325	8,473
2039-40	7,626	8,027	8,236	8,410	8,559
2040-41	7,703	8,108	8,319	8,495	8,646

2011 Forecast Chartbook

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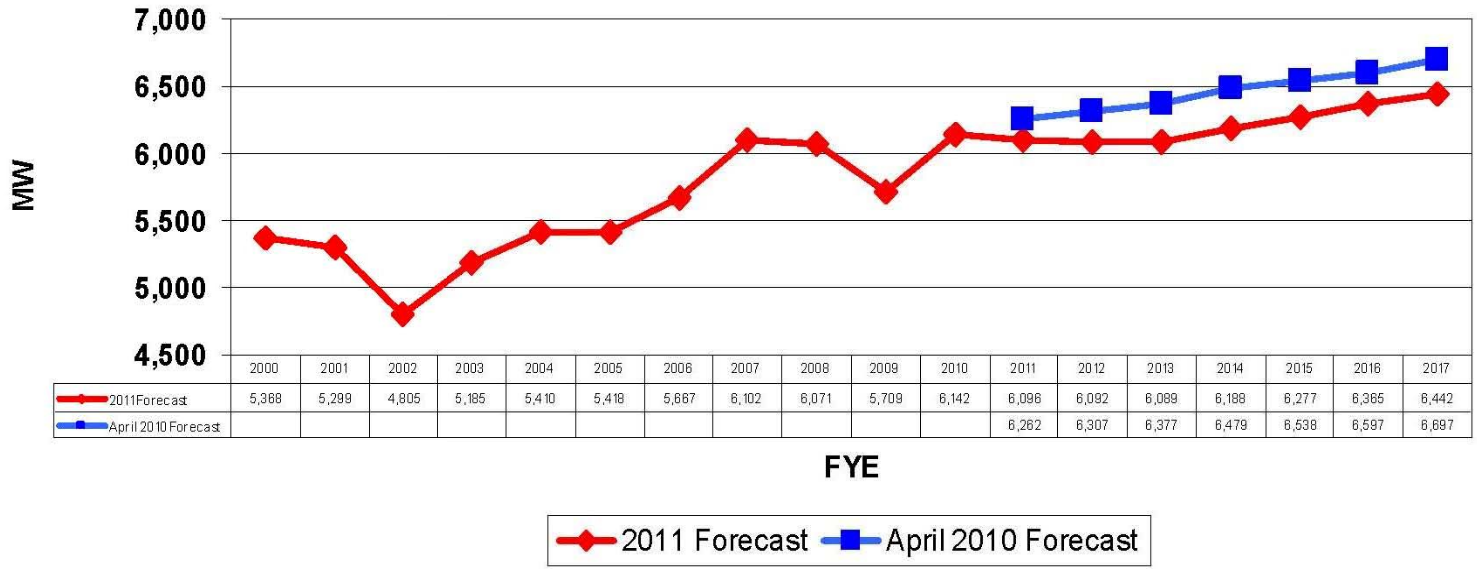
1-in-10 Peak Demand

- Resource Planning.
  - Weather-normalized peak in Summer 2010 was 5589 MW compared to the April 2010 forecast of 5797 MW.
  - The 1-in-10 Peak Demand Forecast is used in the Integrated Resource Plan.



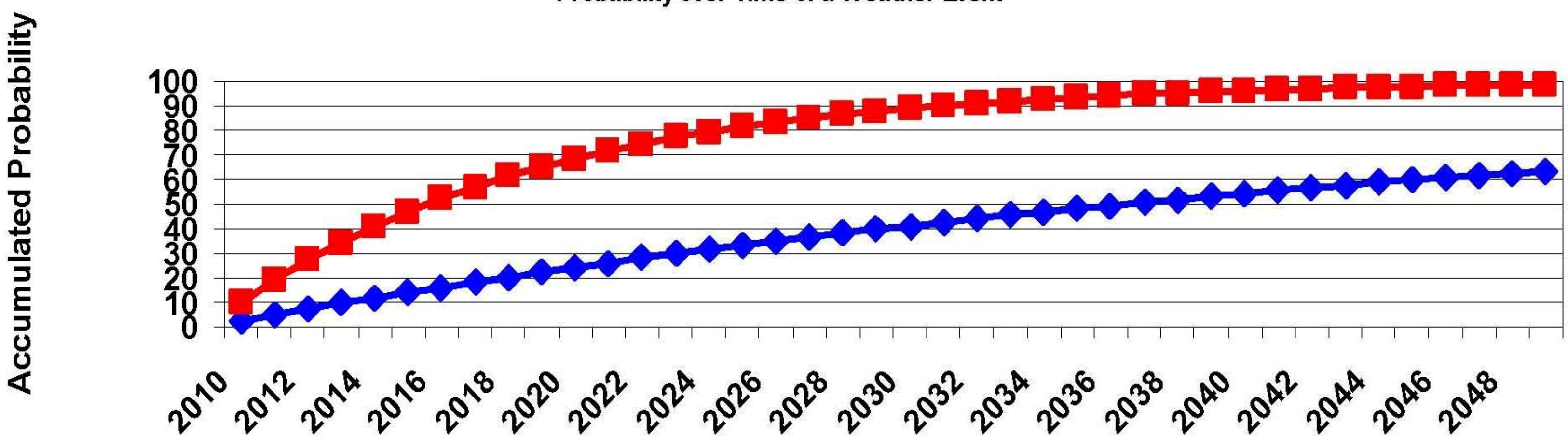
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011Forecast	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	6,096	6,092	6,089	6,188	6,277	6,365	6,442
April 2010 Forecast												6,262	6,307	6,377	6,479	6,538	6,597	6,697

2011 Forecast Chartbook 33

1-in-10 Peak Demand

- Probability accumulates over time.
  - There is a 69% chance of having a 1-in-10 weather event by 2020.
  - There is a 24% chance of having a 1-in-40 weather event by 2020.
  - $P_t=1-(1-P_e)^t$

Probability over Time of a Weather Event



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
1-in-40	2.5	4.9	7.3	9.6	11.9	14.1	16.2	18.3	20.4	22.4	24.3	26.2	28.0	29.8	31.6	33.3	35.0	36.6	38.2	39.7
1-in-10	10.0	19.0	27.1	34.4	41.0	46.9	52.2	57.0	61.3	65.1	68.6	71.8	74.6	77.1	79.4	81.5	83.3	85.0	86.5	87.8

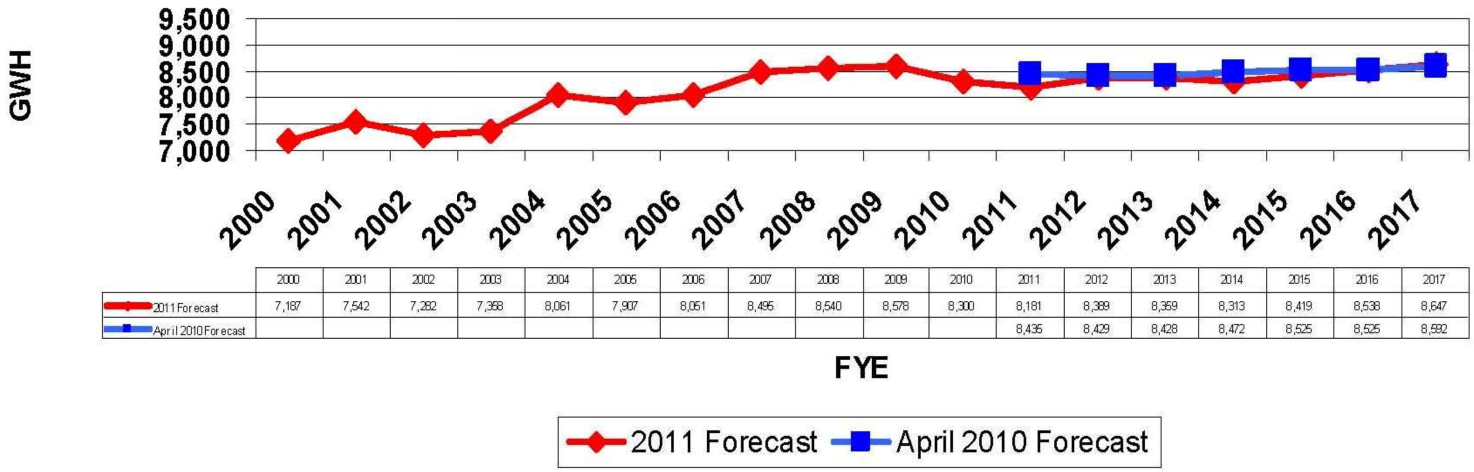
	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
1-in-40	41.2	42.7	44.1	45.5	46.9	48.2	49.5	50.8	52.0	53.2	54.4	55.5	56.6	57.7	58.8	59.8	60.8	61.8	62.7	63.7
1-in-10	89.1	90.2	91.1	92.0	92.8	93.5	94.2	94.8	95.3	95.8	96.2	96.6	96.9	97.2	97.5	97.7	98.0	98.2	98.4	98.5

Year

2011 Forecast Chartbook 34

Residential Energy Sales

- Components of Change
  - Higher weather response. All new units have air conditioning.
  - Fewer units built and higher vacancy factor.
  - Huffman Bill lighting impacts.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011 Forecast	7,187	7,542	7,282	7,358	8,061	7,907	8,051	8,495	8,540	8,578	8,300	8,181	8,389	8,359	8,313	8,419	8,538	8,647
April 2010 Forecast												8,435	8,429	8,428	8,472	8,525	8,525	8,592

2011 Forecast Chartbook

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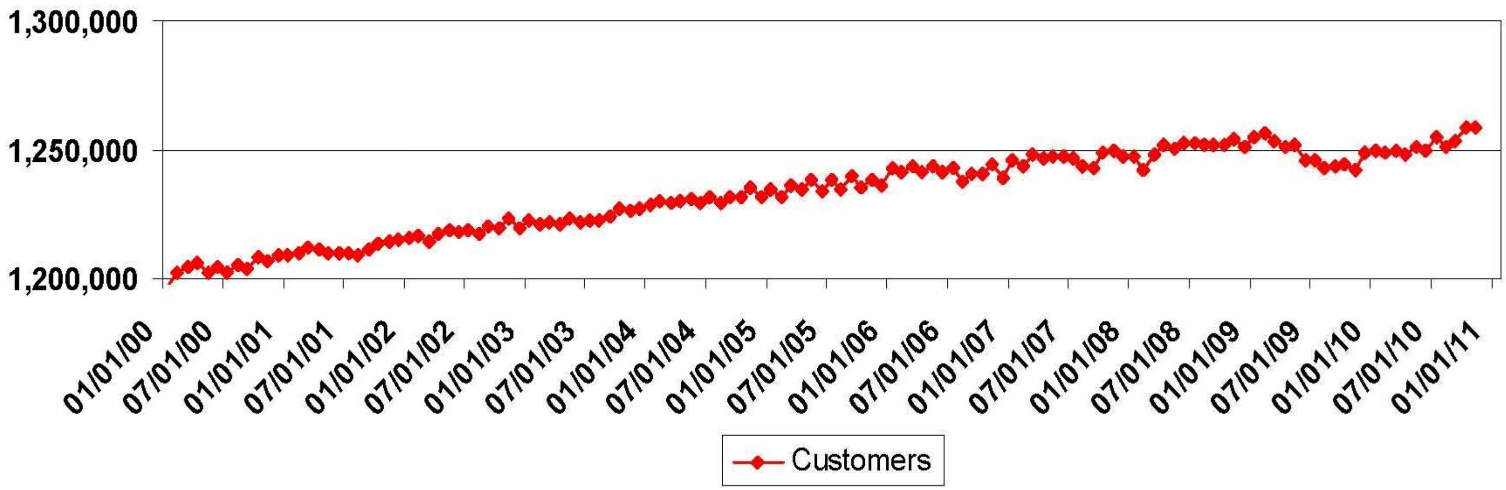
Residential Energy Sales

Number of Residential Customers

- Recent Evidence
  - Vacancy rising outstripping the growth in new units.
  - The majority of residential customers live in multi-family units.

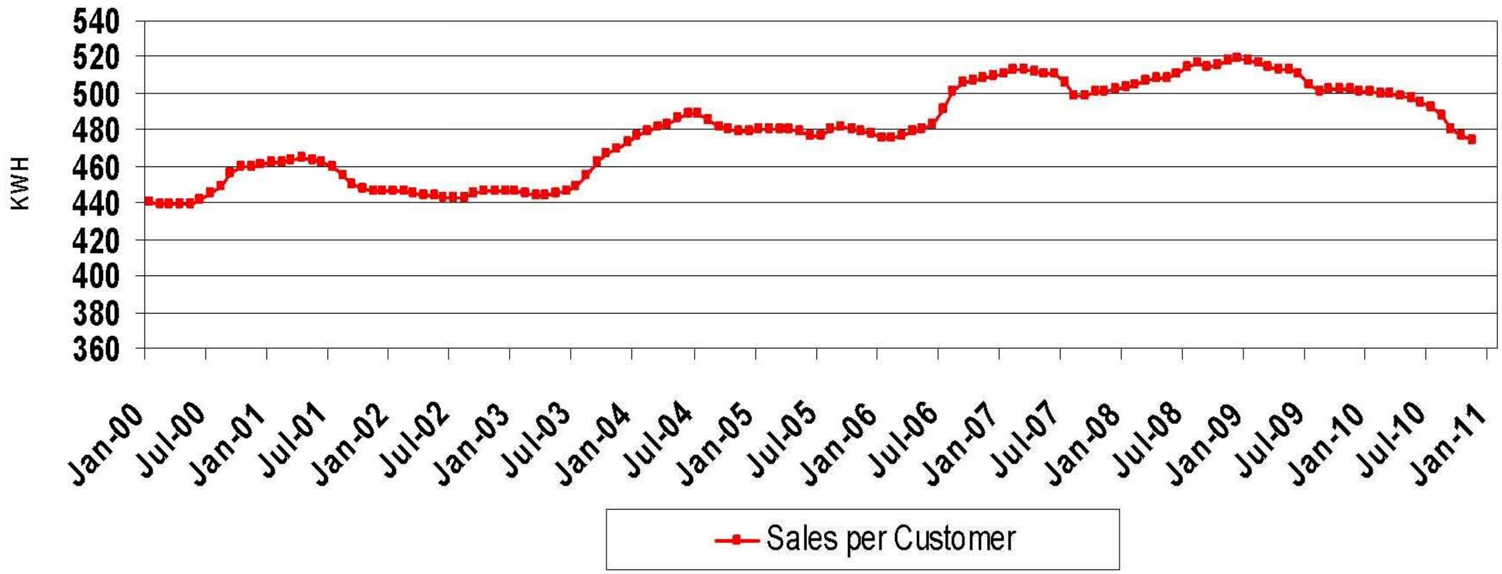


2011 Forecast Chartbook 36

Residential Sales

12-month Moving Average Sales per Customer

- Recent Evidence
  - Sales per residential customer reached an all-time high of 519 KWH per month in December 2008.
  - The November 2010 rate is 475 KWH per Month.
  - Replacing 2010 summer weather with normal adds 11 KWH to the November 2010 monthly rate.



2011 Forecast Chartbook 37

Residential Energy Sales

New Residential Building Units

- Housing Forecast fundamentally unchanged.
- New units are 20% Single-Family and 80% Multi-family which lowers future average consumption per household.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011 Forecast	6,567	7,062	5,673	7,361	12,340	10,666	14,448	10,554	6,080	2,607	3,129	3,820	6,239	8,961	8,814	8,512	10,000	10,000
April 2010 Forecast											2,534	3,839	6,549	8,758	8,640	10,000	10,000	10,000

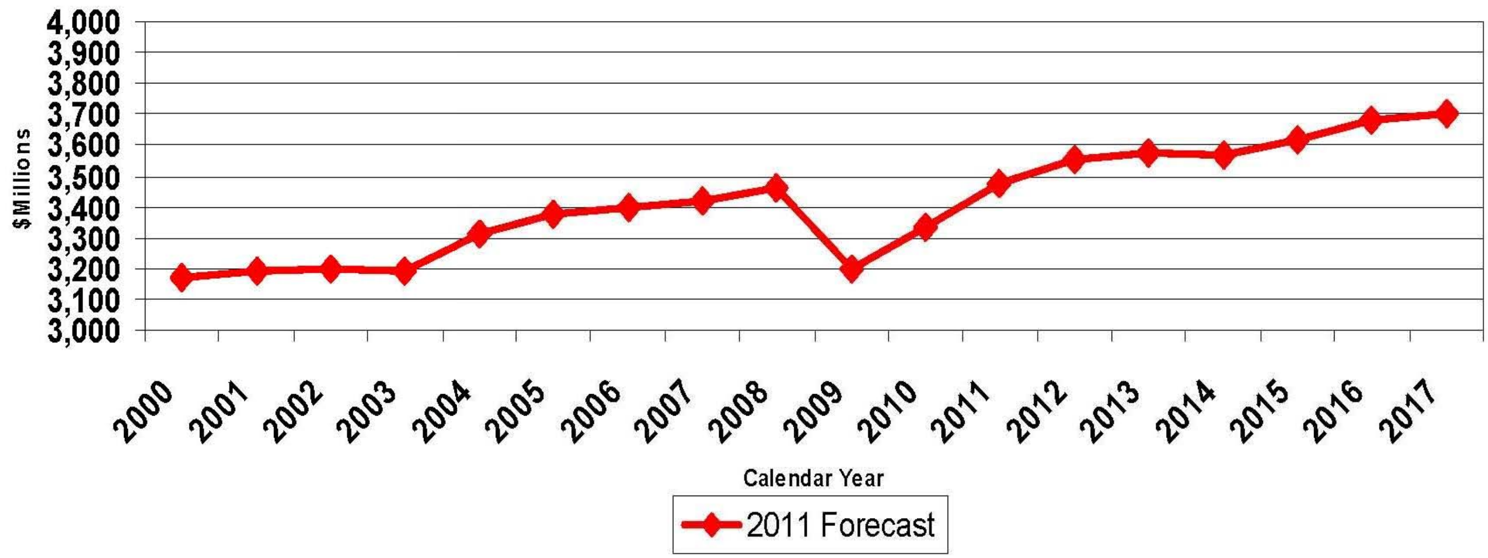
Calendar Year

2011 Forecast — April 2010 Forecast

2011 Forecast Chartbook 38

Residential Energy Sales
Recent Economic Impact

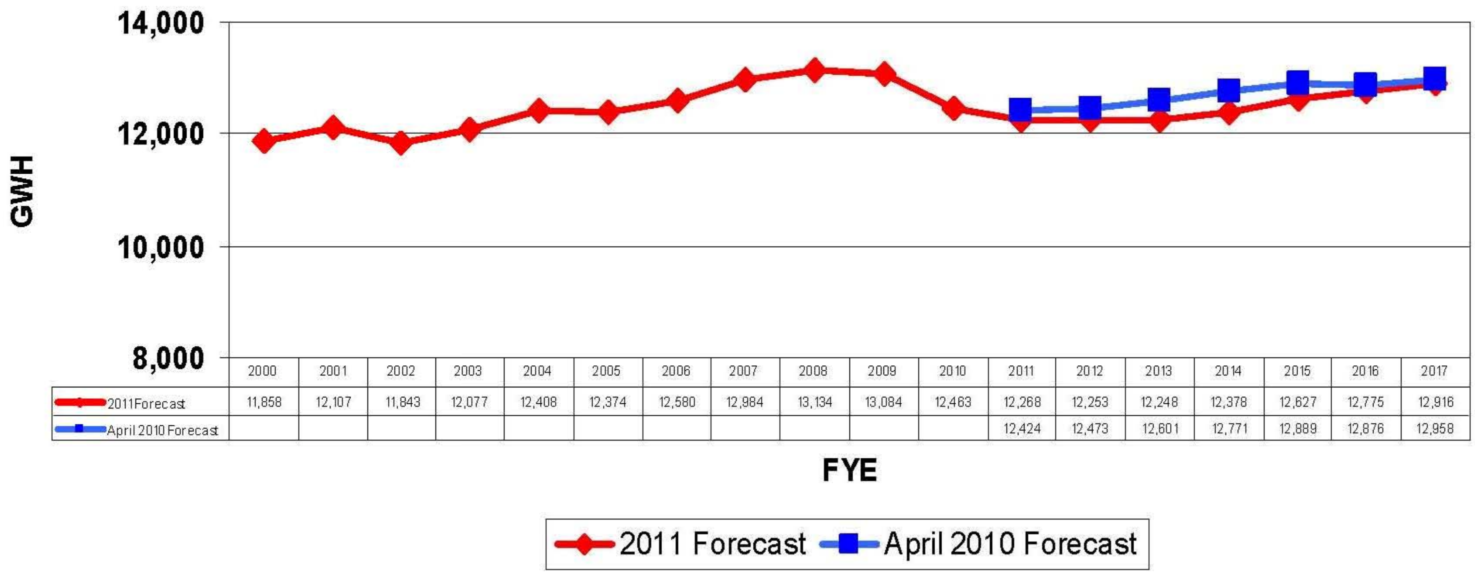
- Real Personal Consumption.
  - Recovery ends and expansion begins in 2012.



2011 Forecast Chartbook 39

Commercial Energy Sales

- Components of Change
  - Commercial construction activity down.
  - Service employment forecast down slightly.
  - Higher real electric prices.
  - Committed energy efficiency included only through 2013. Some forecasted sales beyond 2013 will not be realized at the meter.

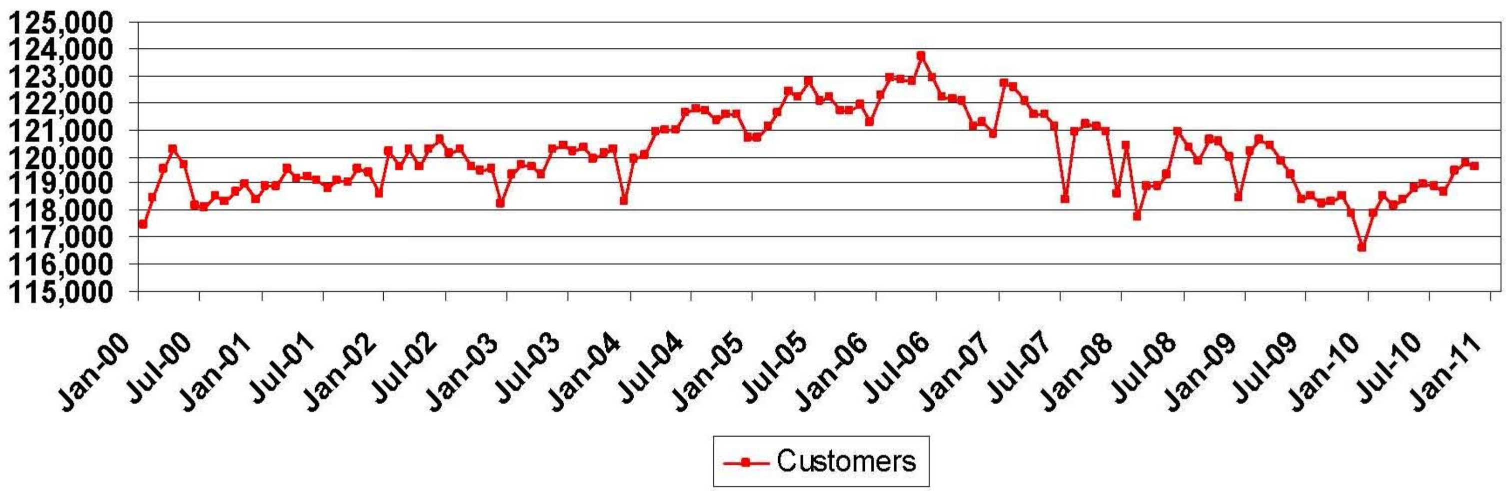


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011Forecast	11,858	12,107	11,843	12,077	12,408	12,374	12,580	12,984	13,134	13,084	12,463	12,268	12,253	12,248	12,378	12,627	12,775	12,916
April 2010 Forecast												12,424	12,473	12,601	12,771	12,889	12,876	12,958

2011 Forecast Chartbook 40

Commercial Energy Sales
Number of Commercial Customers

- Recent Evidence
  - The number of commercial customers peaked in June 2006.

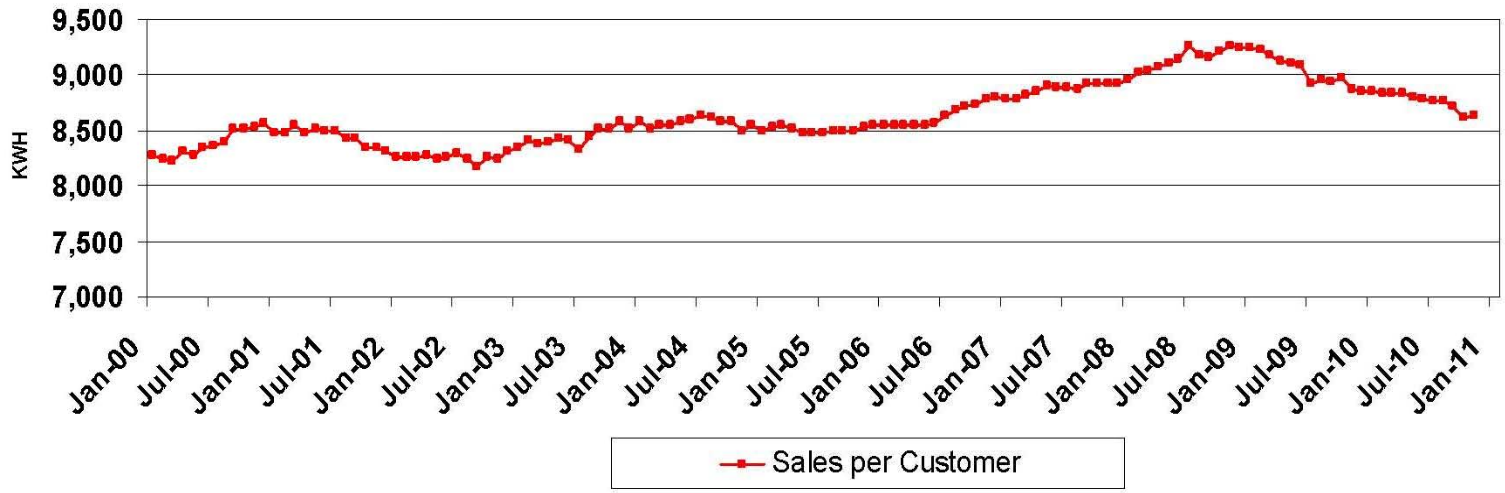


2011 Forecast Chartbook 41

Commercial Energy Sales

Twelve-Month Moving 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 8639 KWH.
  - Adjusting to normal summer weather for 2010 adds 262 KWH to current sales per customer.



2011 Forecast Chartbook

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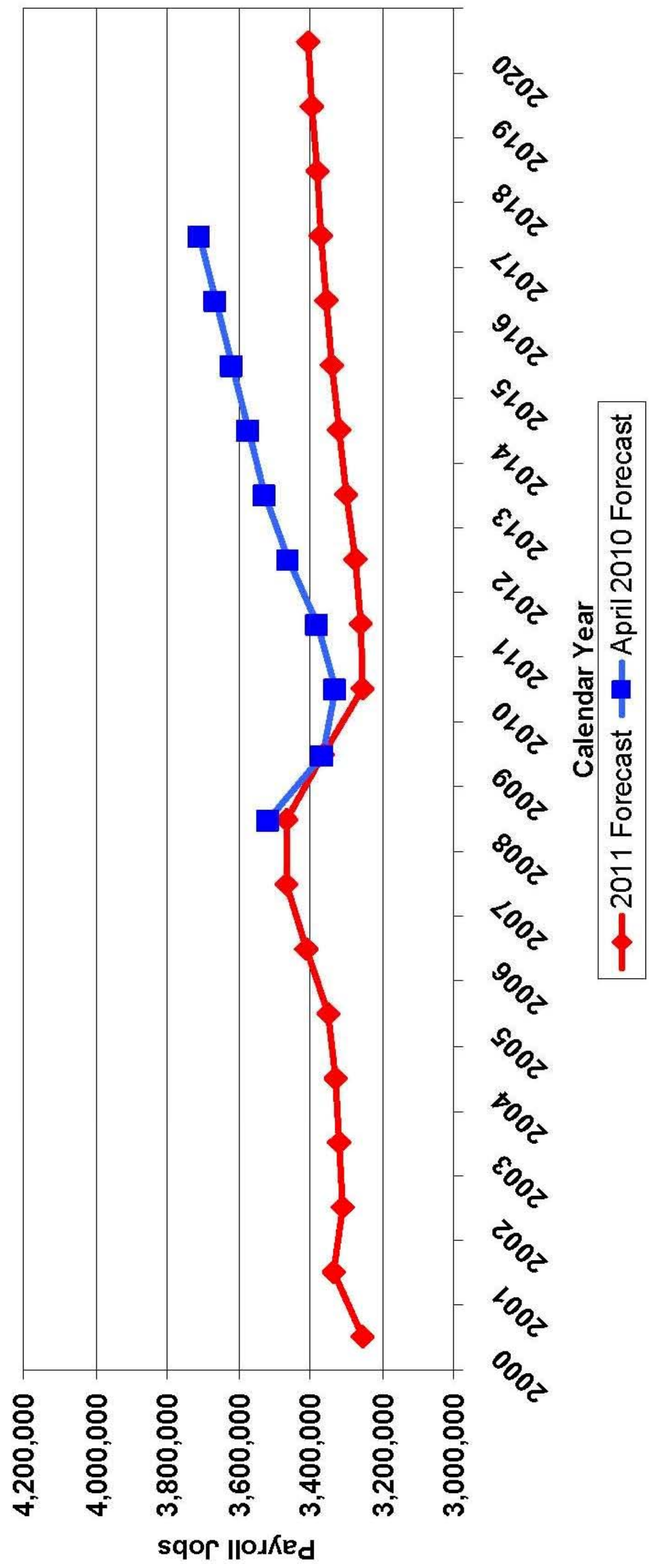
Commercial Energy Sales

Local Employment in Service Sector

- LA County Commercial Services Employment
  - Balance Sheet Recession
  - Employment does not return to former level by 2020.



2011 Forecast Chartbook

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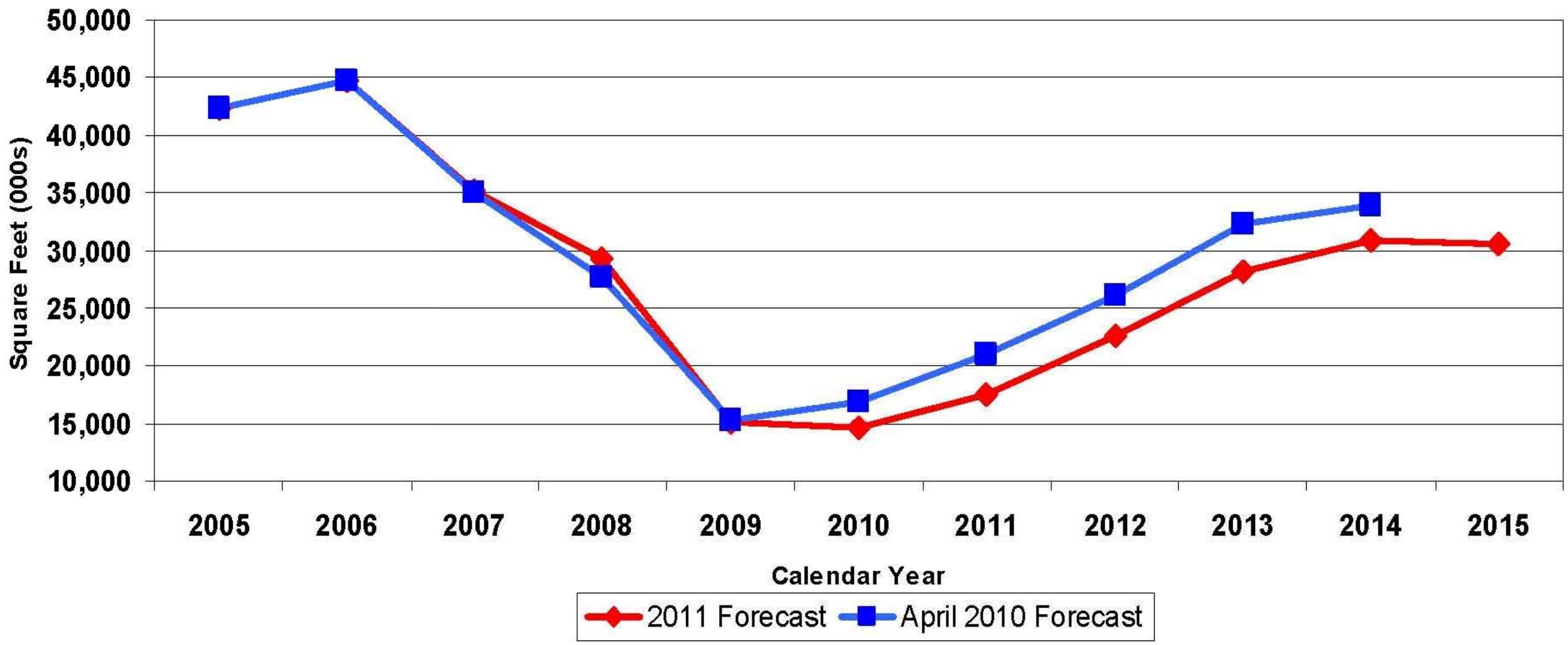
Commercial Energy Sales

McGraw-Hill Construction Forecast

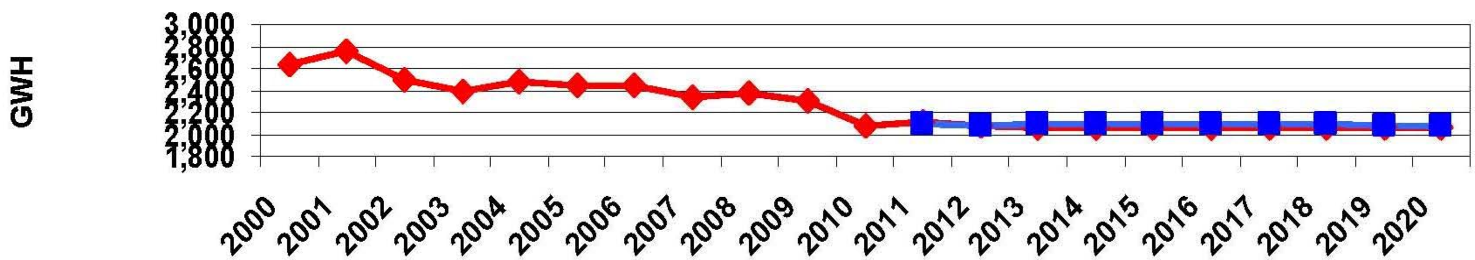
- Commercial Floorspace Additions
  - Construction activity at historically low levels.
  - Office vacancy rates in San Fernando Valley at 18 percent.
  - New models for delivering commercial services require smaller physical presence.
    - Big Box retailers
    - Internet



2011 Forecast Chartbook 44

Industrial Energy Sales

- Components of Change
  - Land use issue: Once industrial land is vacated, residential and commercial building tend to replace it. 3 percent vacancy rates in the industrial sector.
  - Manufacturing continues to move offshore.
  - Higher real electric prices.
  - No EE or rooftop solar in the Industrial Forecast. All EE and solar assigned to Residential, Commercial and Streetlight sectors.

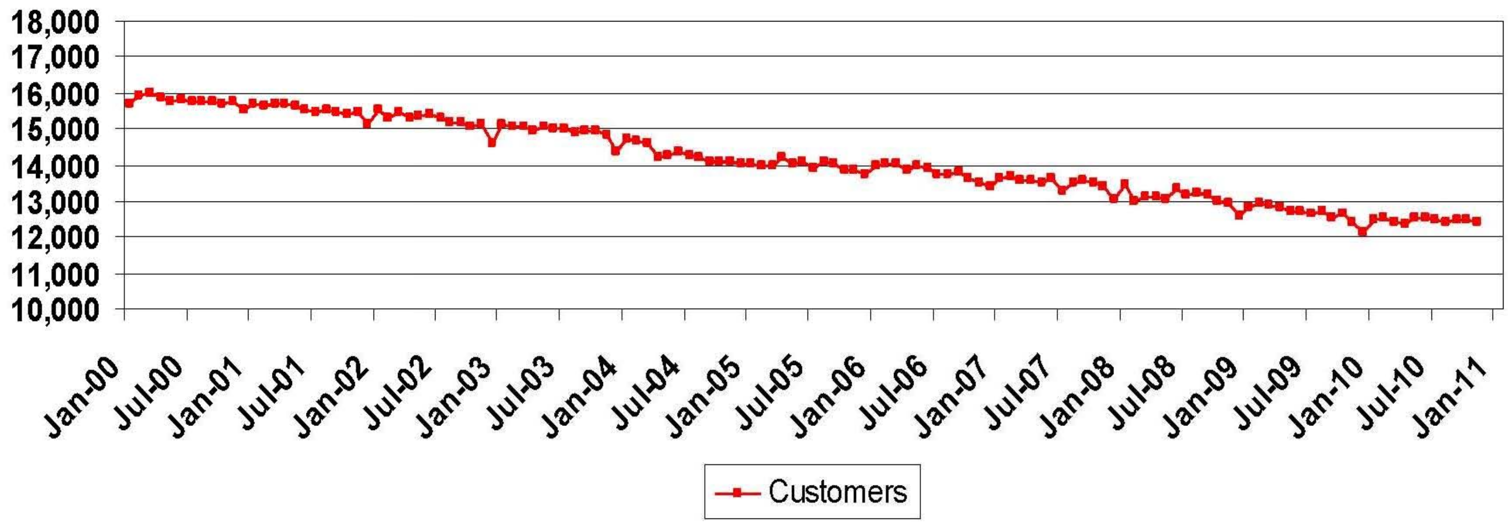


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011 Forecast	2,637	2,754	2,496	2,383	2,485	2,447	2,451	2,332	2,366	2,303	2,073	2,116	2,074	2,063	2,053	2,057	2,058	2,058	2,058	2,059	2,059
April 2010 Forecast												2,087	2,081	2,097	2,099	2,098	2,098	2,094	2,087	2,084	2,084

FYE

Industrial Energy Sales
Number of 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 industries to remain although no new heavy industry will be built. It is the light industry and assembly jobs that are disappearing.



2011 Forecast Chartbook

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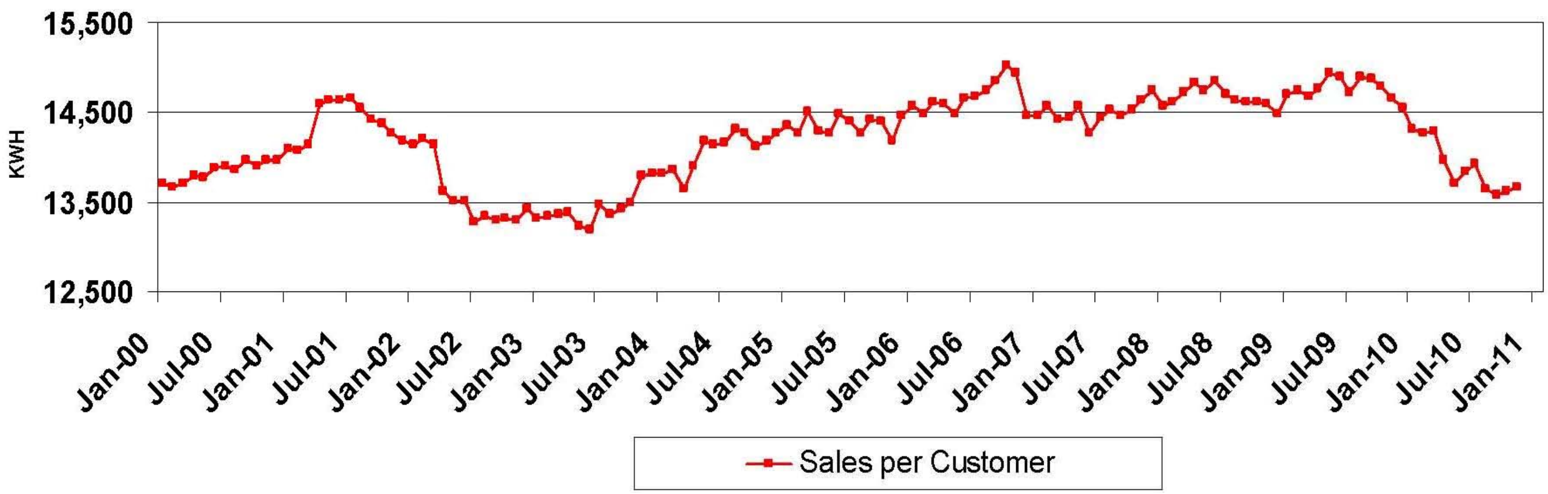
Industrial Sales

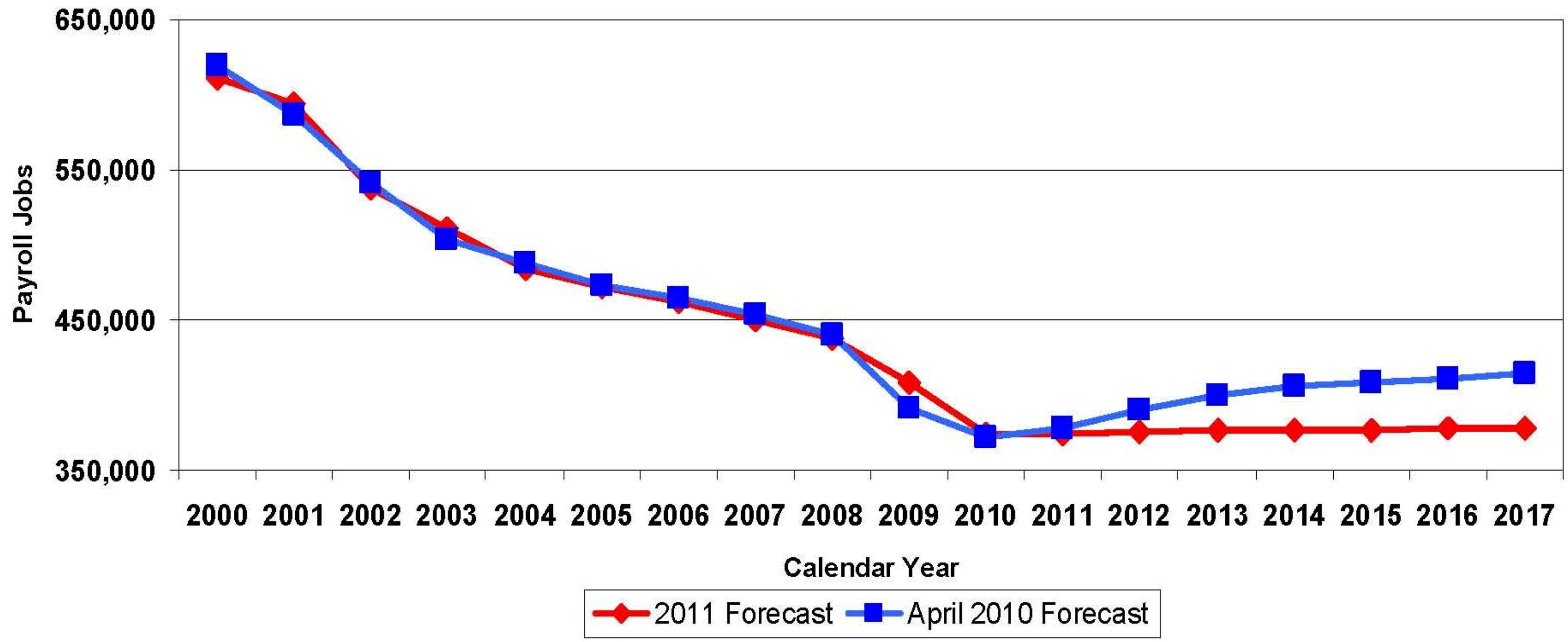
Twelve-Month Moving Average Sales per Customer

- Recent Evidence
  - Sales per customer per month peaked in October 2006 at 15018 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 13666 KWH.



Industrial Sales
Employment Outlook

- LA County Manufacturing Employment
  - Future employment forecast is slightly positive. 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.

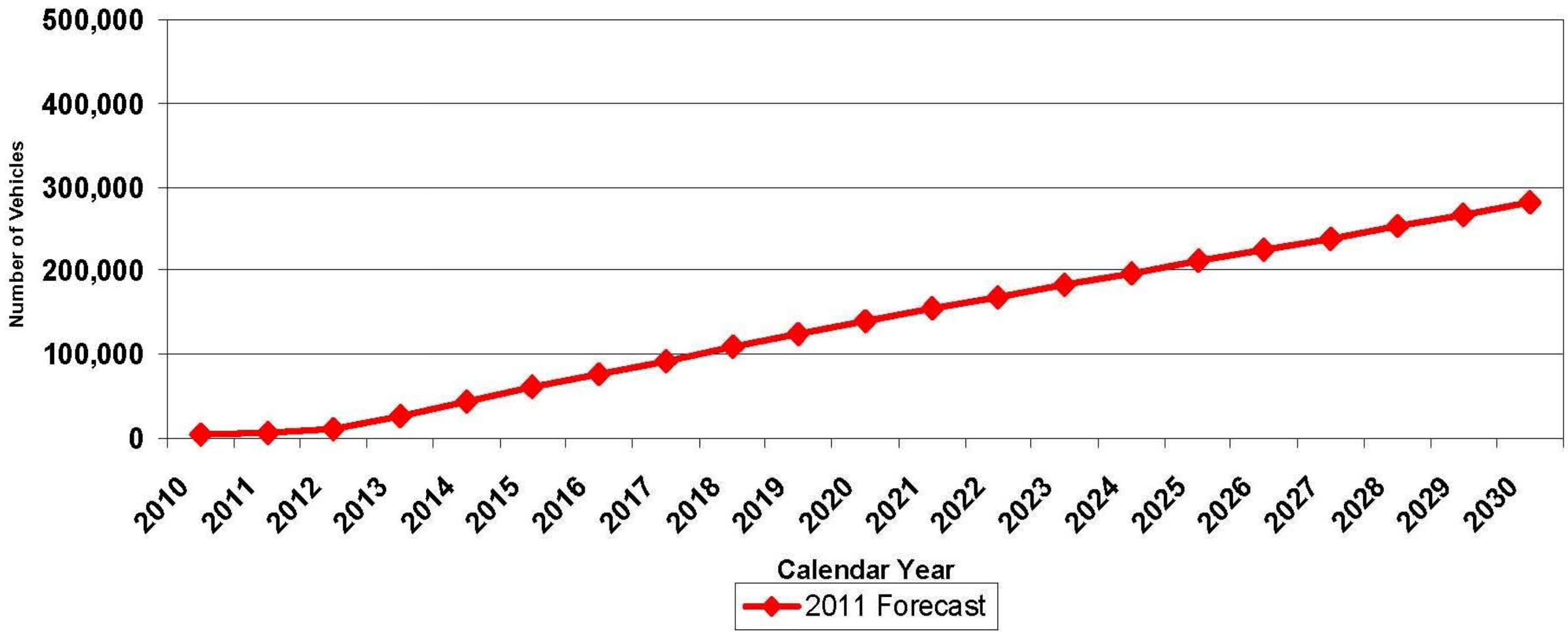


2011 Forecast Chartbook 48

Plug-in Hybrid Electric Vehicles

Potential New Load Growth

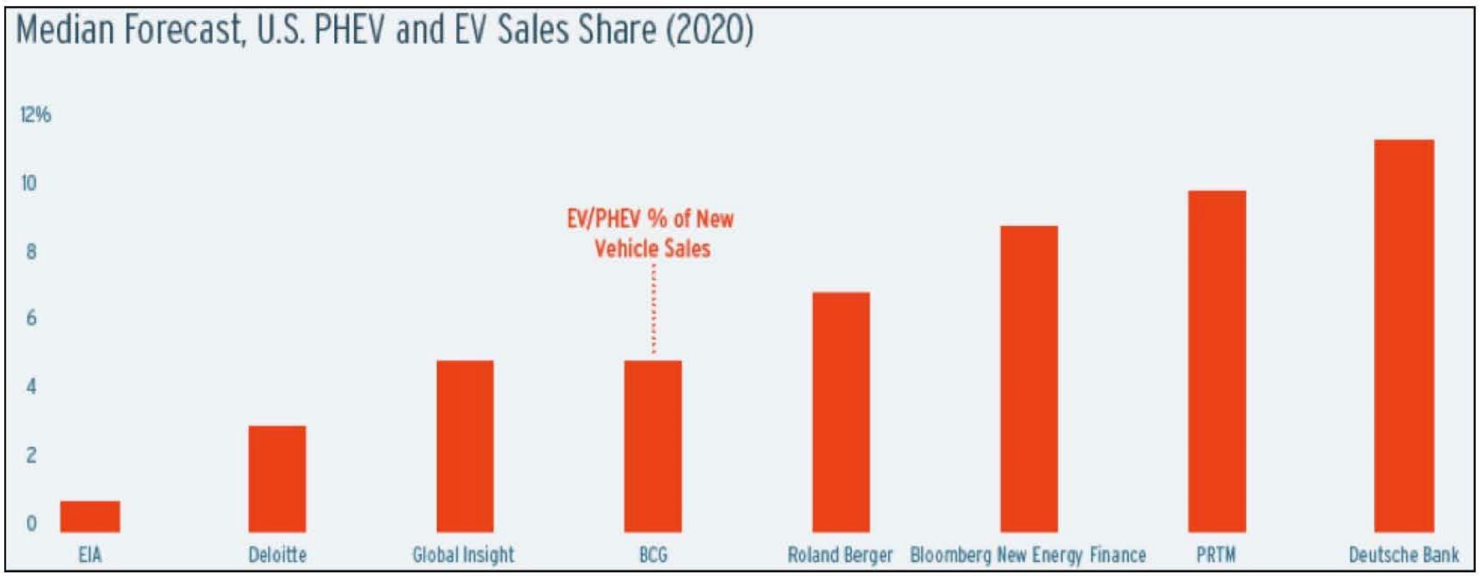
- Adopted the California Energy Commission Forecast.
- Forecast dependent on:
  - Improved battery technology.
  - Implementation of Smart Grid.
  - Implementation of Charging stations



Plug-in Hybrid Electric Vehicles

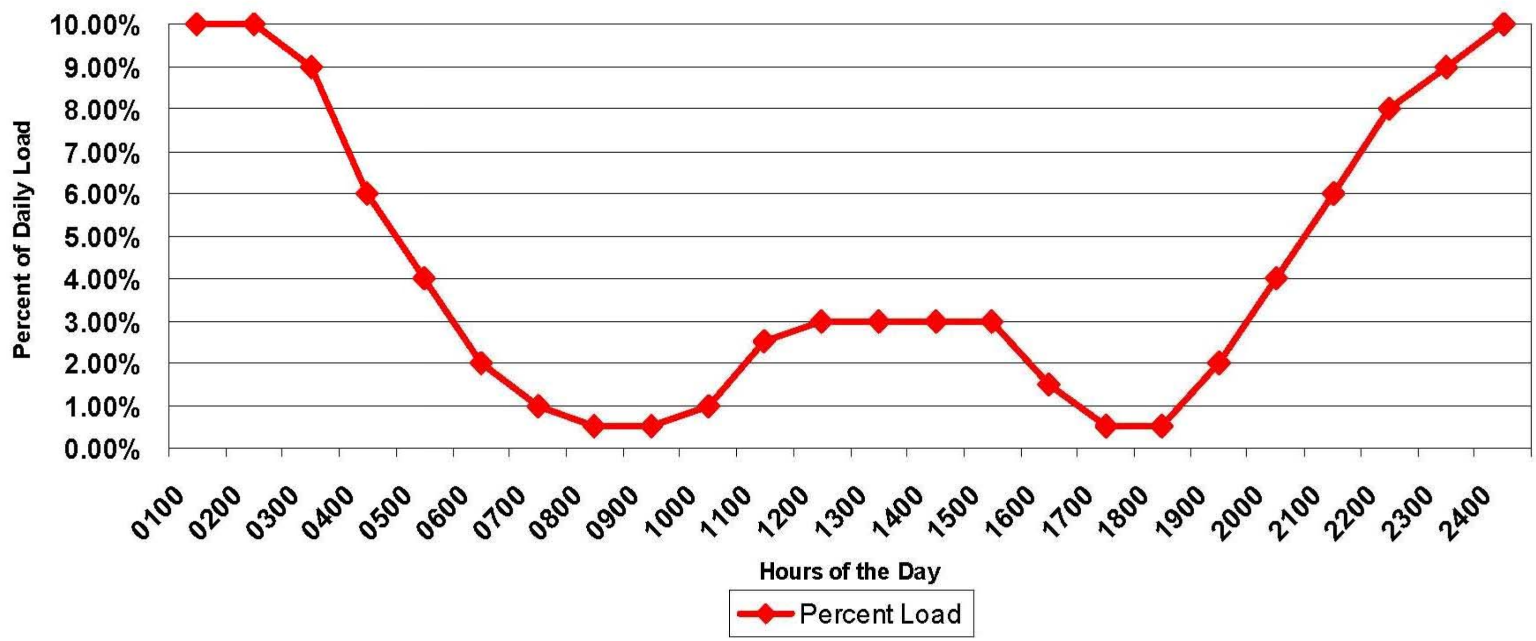
Uncertainty in Forecast

- California Energy Commission Forecast is approximately 10% of new car sales in 2020 which is at the higher end of independent forecasts.
- Chart courtesy of John Petersen on Seeking Alpha Website.



Plug-in Hybrid Electric Vehicles Charging Profile Assumption

- Based on EPRI research.
- Load Shape potentially could be engineered to optimize LADWP production function.



2011 Forecast Chartbook

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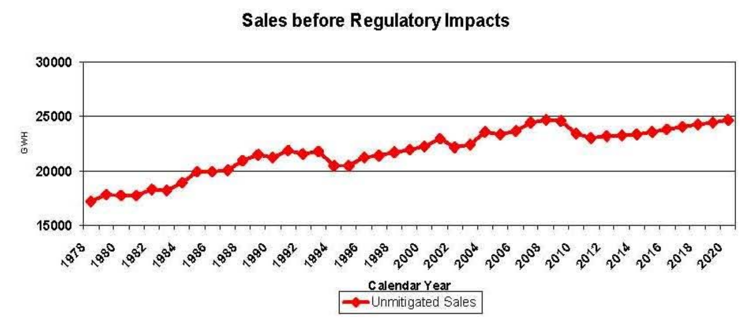
Plausibility

- Comparing unmitigated 2011 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.
  - Next decade similar to what occurred in the 1990s before additional regulation.

Peak-to-Through Analysis		
Years	GWH Decline	Percent Decline
2008-2011	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%



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 present the recently completed EE market potential study. Based on the study results, a plan is recommended with identified savings and costs targets. For more specific details regarding the potential study, see the reference at the end of this appendix.

B.1 Background

LADWP has active EE programs that have been in place for several years. Since 2000, LADWP has spent approximately $282 million on its EE programs, which have reduced long-term peak demand and consumption by approximately 303 MW and 1,256 GWh, respectively. 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.
- A recent program, which distributed two free CFLs to LADWP's 1.2 million residential customers through direct-to-door distribution. The intent of the one-time direct-to-door distribution was to achieve cost effective energy savings and increase customer awareness of this inexpensive, yet effective, EE measure. CFLs are also distributed at events and in connection with other energy efficiency programs.

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	Cumulative FY 06-11
LADWP Adopted Targets (2006) - Net GWh	58	275	315	300	280	1,228
Actual Energy Savings Achieved - Net GWh	58	118	270	156	154	756
Actual % of Adopted Target	100%	43%	86%	52%	55%	62%
Actual Energy Savings - Gross GWh	68	139	318	184	181	890
Approved EE Budget ($million)	28	79	77	93	69	346
Revised EE Budget ($million)	n/a	n/a	n/a	>50	50	
Actual EE Funds Spent ($million)	14	38	68	44	50	214
Actual % of Budget	51%	48%	88%	48%	72%	62%
Effective Cost - $/kWh	$0.018	$0.023	$0.018	$0.020	$0.023	

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 a Market Potential Study, includes an updated plan for moving forward.

B.2 Market 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 "Market 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 Market 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.

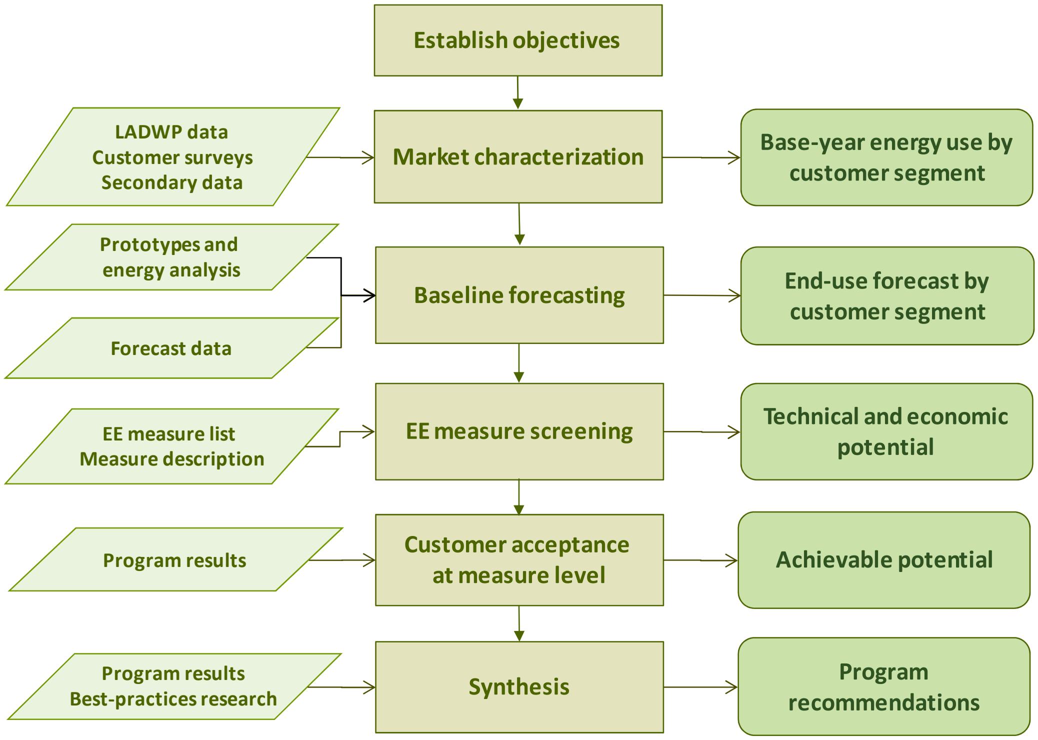


Figure B-1. 2010 Market Potential Study analysis approach.

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.

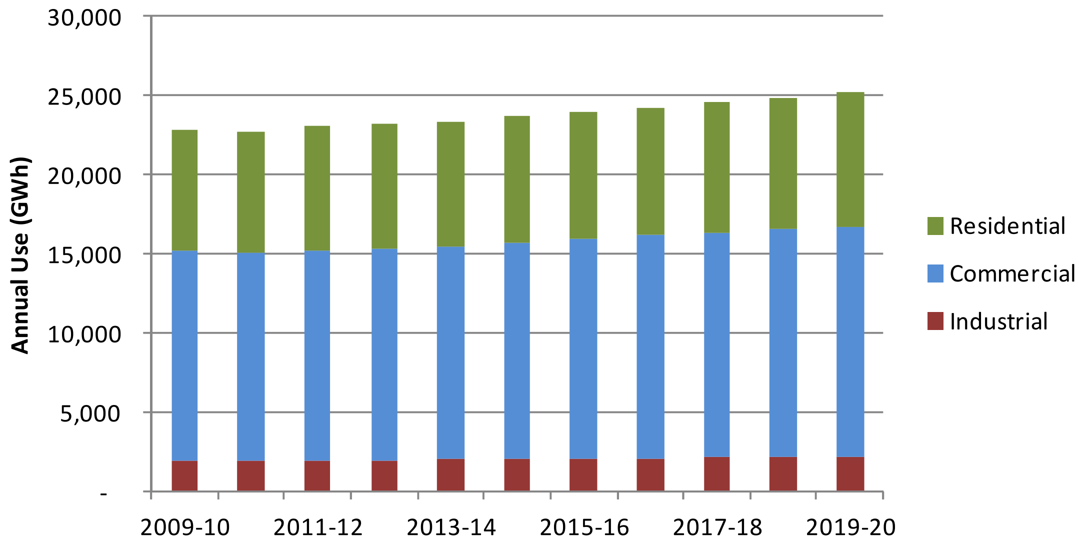


Figure B-2. Baseline forecast results through 2019-20.

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

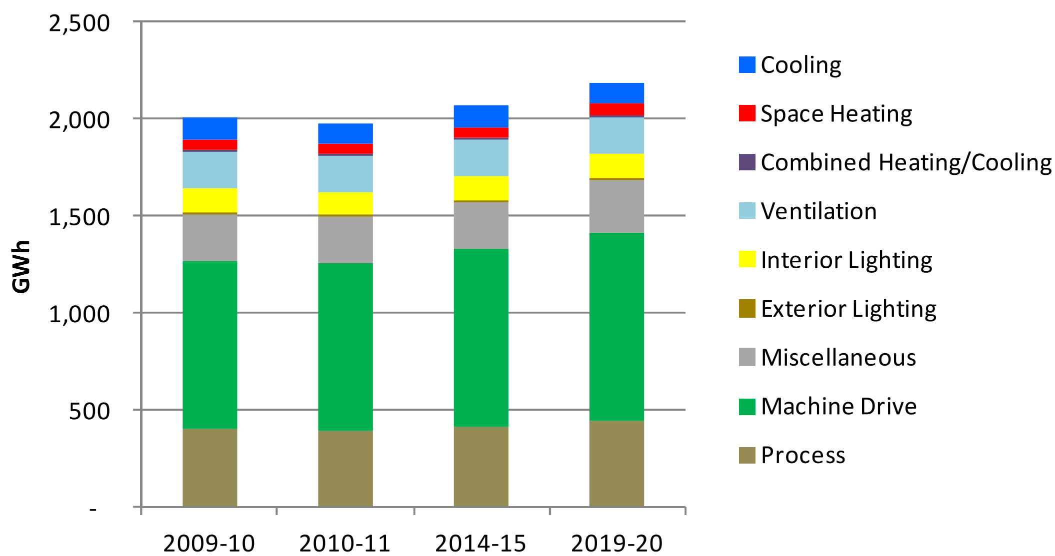


Figure B-3. Industrial sector baseline forecast results.

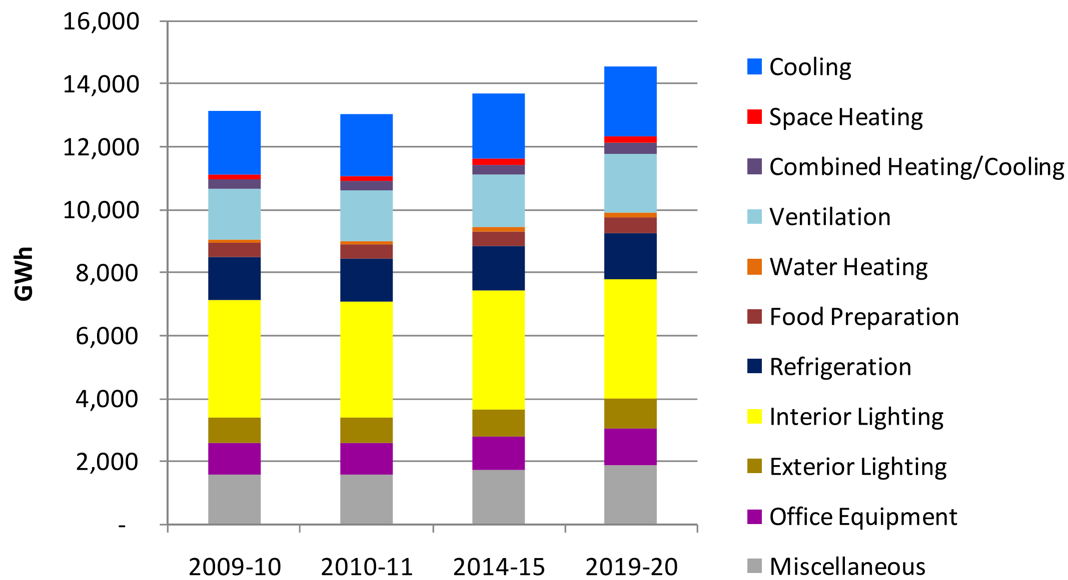


Figure B-4. Commercial sector baseline forecast results.

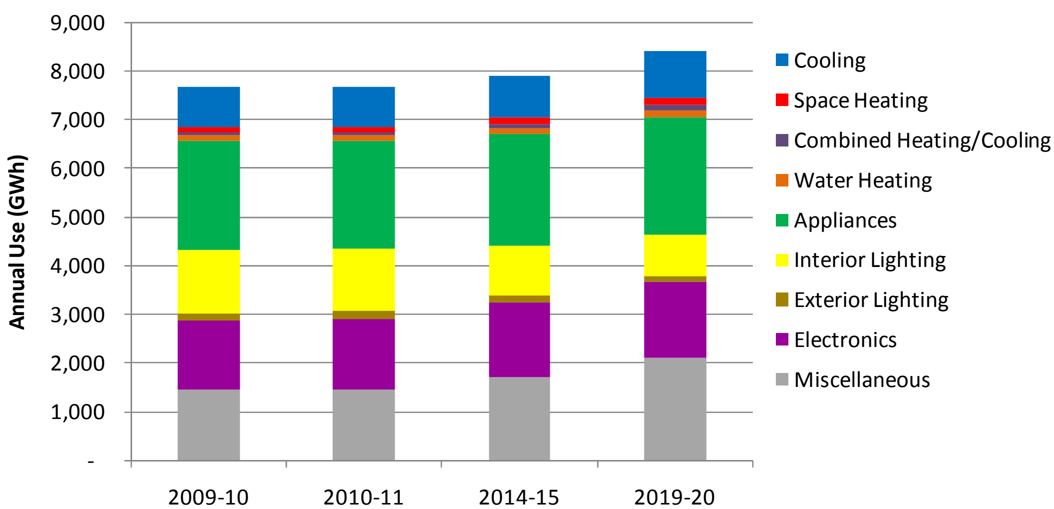


Figure B-5. Residential sector baseline forecast results.

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 assumes 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.

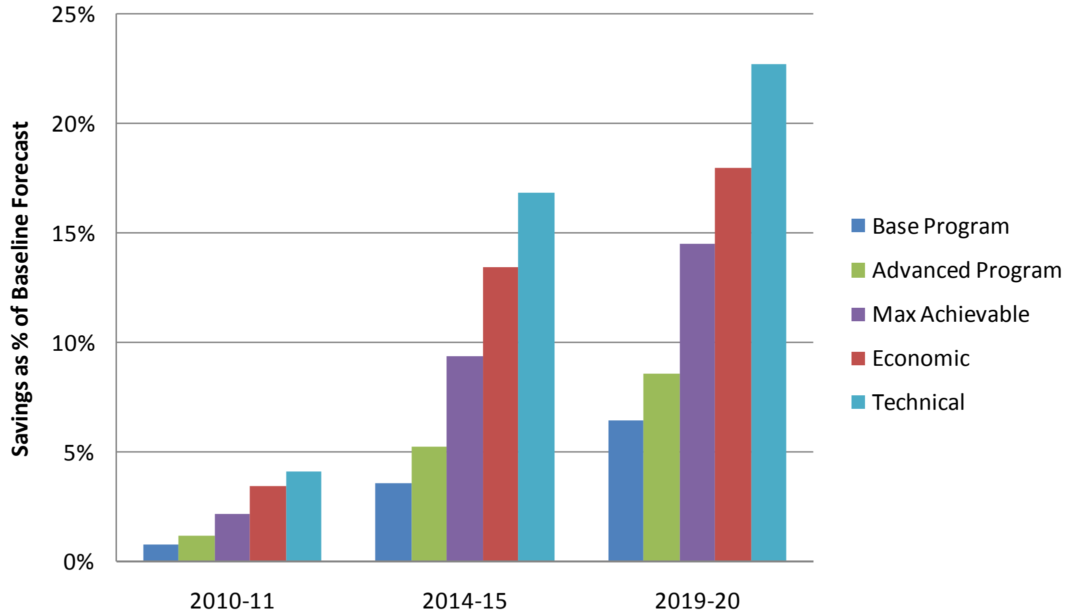


Figure B-6. Cumulative energy savings as a percentage of the baseline forecast.

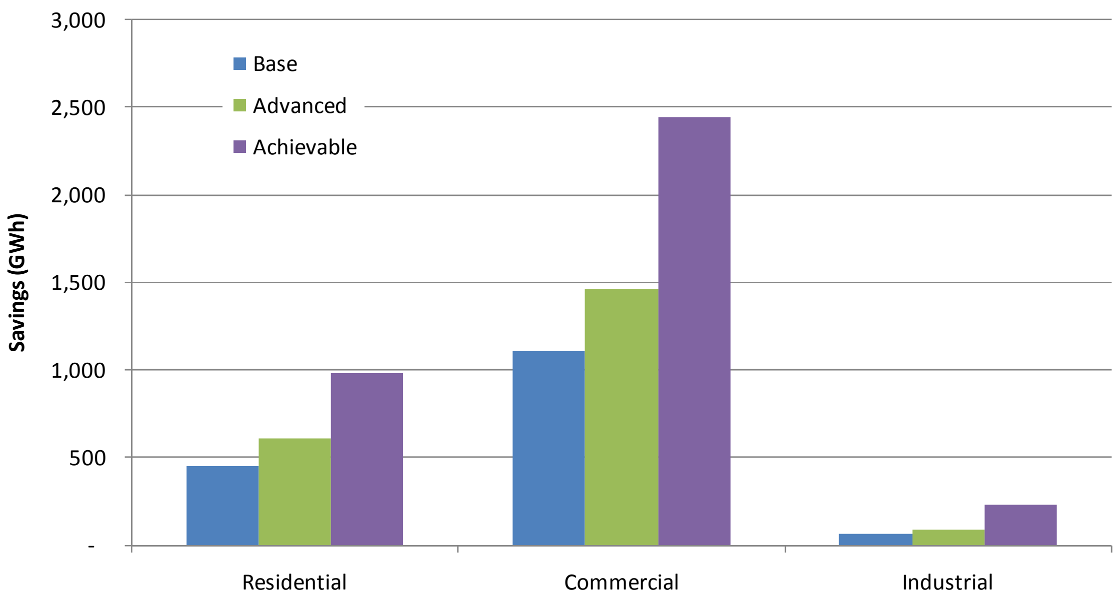


Figure B-7. Cumulative energy savings in GWh.

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

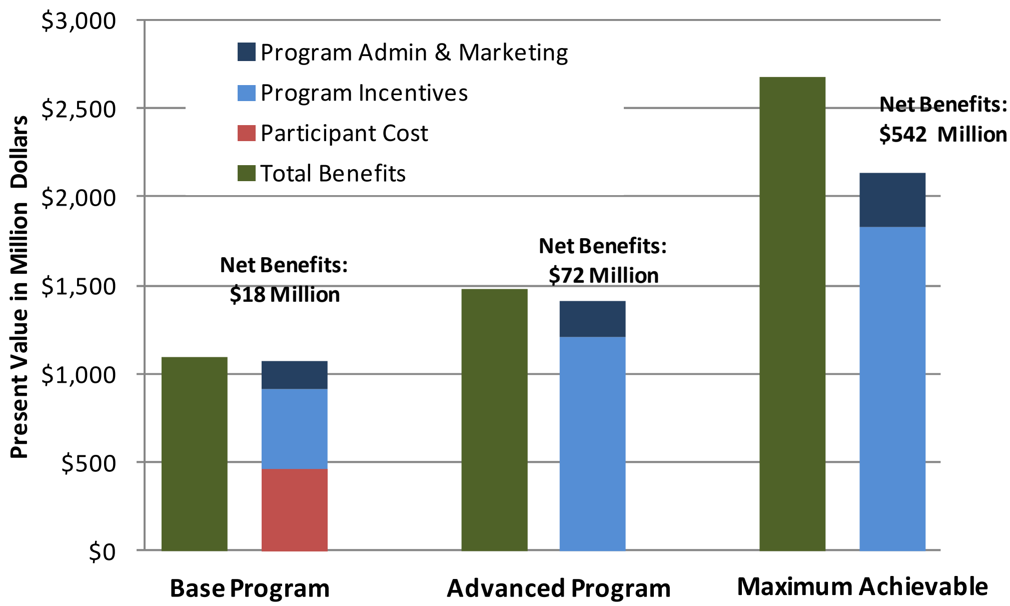


Figure B-8. Cost and benefits for base and advanced programs.

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

Residential Programs

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 form 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-10 illustrates potential residential EE program savings for fiscal year 2019-20.

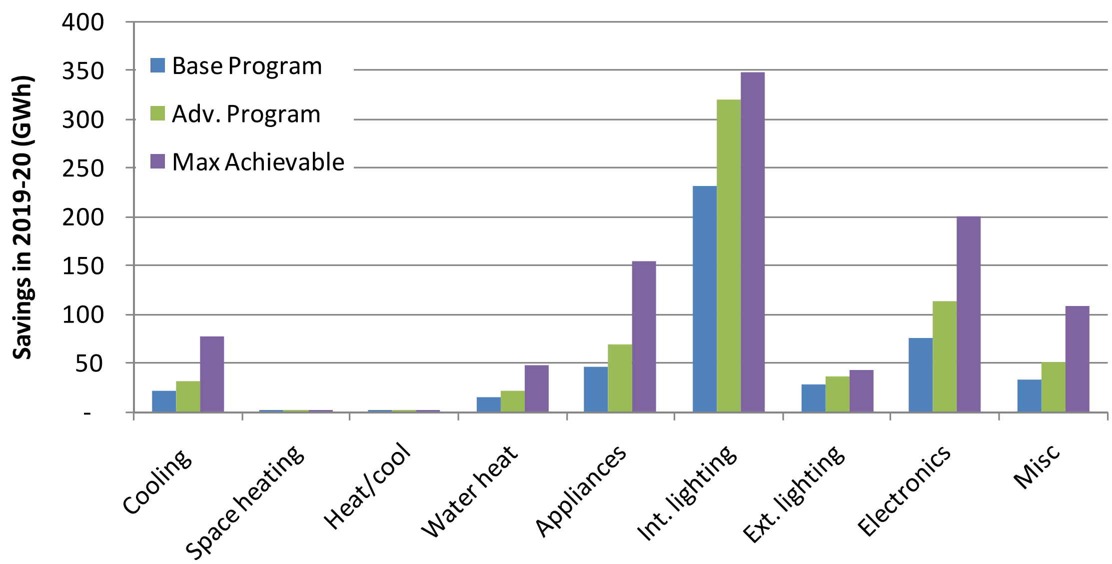


Figure B-10. Potential residential EE program savings in 2019-20.

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 form 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-11 and B-12 illustrate potential commercial and industrial savings for year 2019-20.

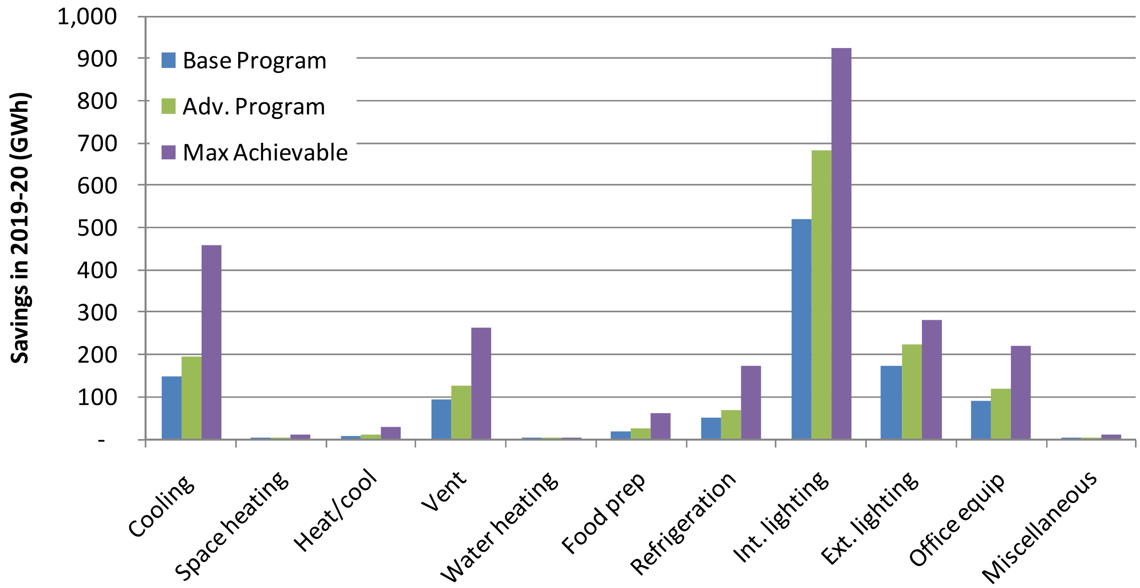


Figure B-11. Projected commercial EE savings in 2019-20.

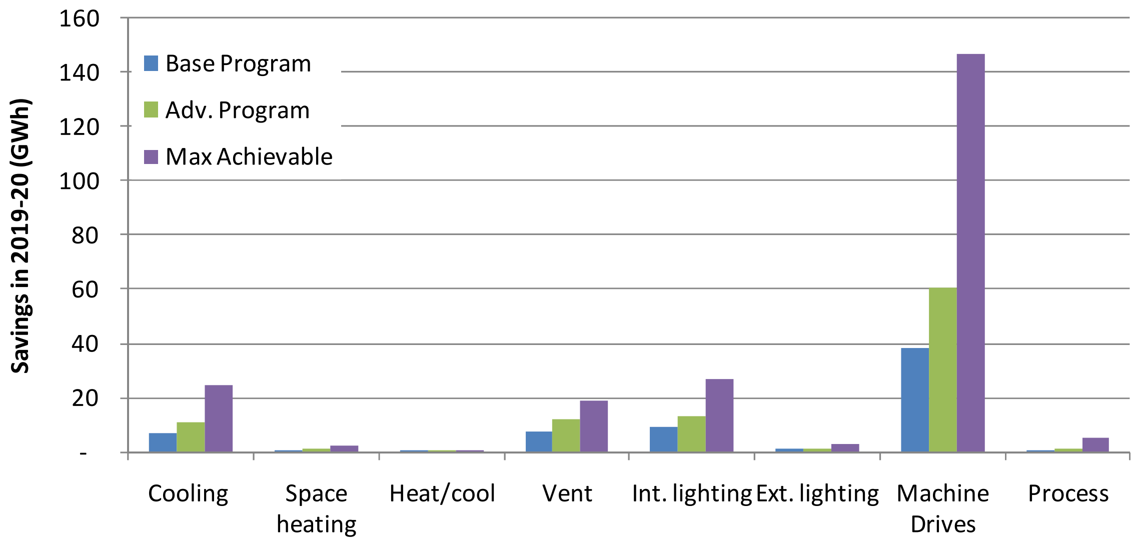


Figure B-12. Projected industrial EE savings in 2019-20.

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:

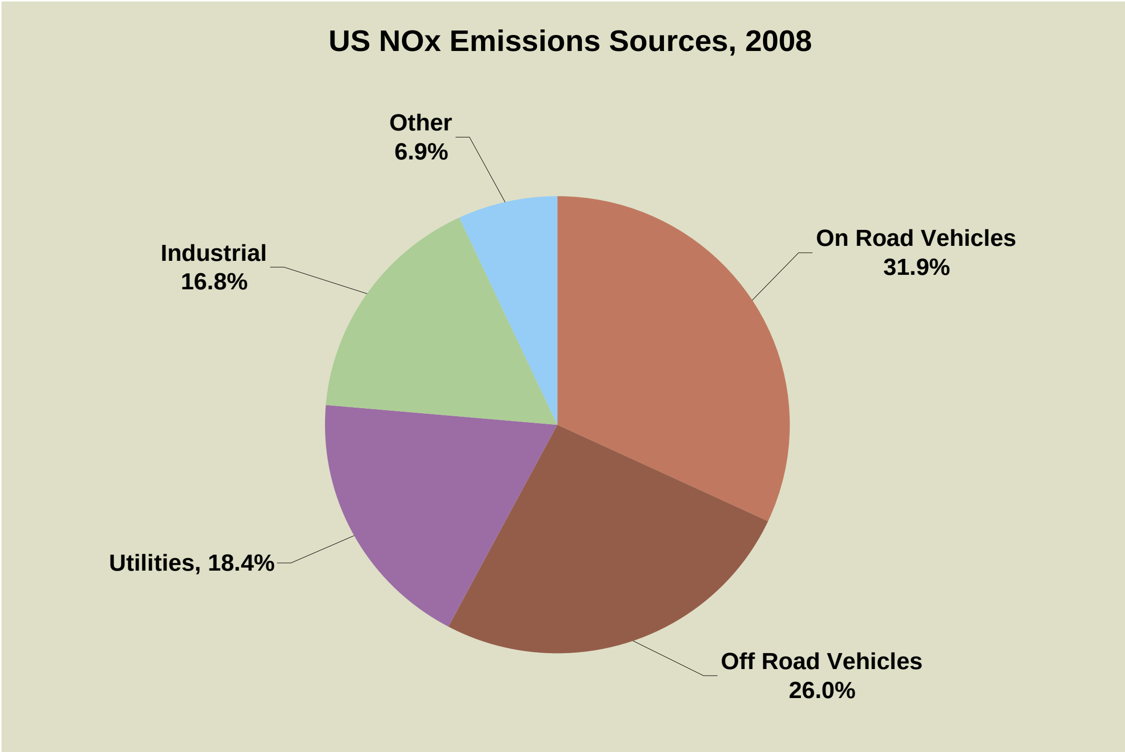
- Increasing the use of renewable energy to meet the needs of LADWP's customers (20 percent by December 31, 2010 and 35 percent by December 2020 through the development of wind, solar, geothermal, and biomass energy sources and acquiring the associated transmission required to transmit such energy to 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.

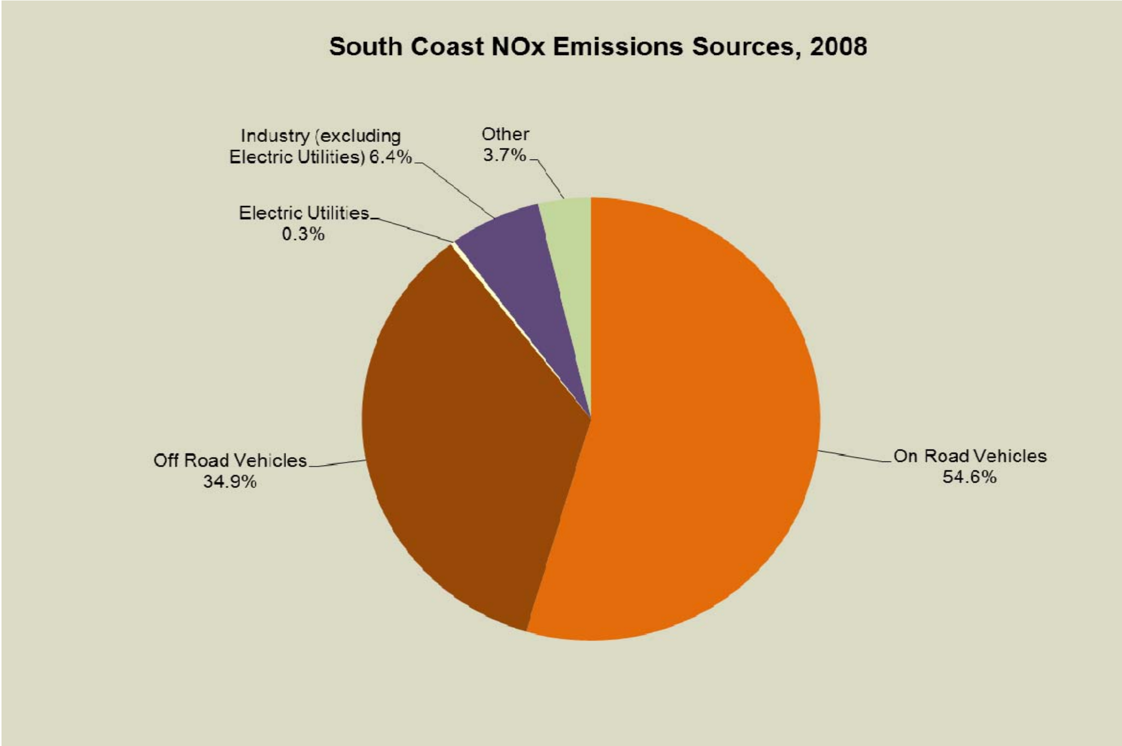
NO_X forms when fuel is burned at high temperatures, as in a combustion process. Figure C-1 shows the primary man-made sources of NO_X as reported by the United States Environmental Protection Agency (U.S. EPA) in 2008.



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 will be 742 tons of NO_X per day. This is down from 820 tons per day in 2008 due to greater regulation of stationary sources and more efficient vehicles. Roughly 90 percent of these emissions are from vehicles, as shown in Figure C-2.



Source: California Air Resources Board, 2008 Estimate

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 June 2009, the U.S. House of Representatives took historic action with the passage of H.R. 2454: The American Clean Energy and Security Act of 2009, introduced by Representatives Waxman (D-CA) and Markey (D-MA), which set a goal of 17 percent below 2005 levels by 2020, 83 percent by 2050. The U.S. Senate considered a similar cap-and-trade bill, S. 1733: The Clean Energy Jobs and American Power Act, introduced by Senators Kerry (D-MA) and Boxer (D-CA), which set a goal of 20 percent below 2005 levels by 2020, 83 percent by 2050. Other legislative proposals have offered different approaches, such as the Carbon Limits and Energy for America's Renewal Act, introduced by Senators Cantwell (D-WA) and Collins (R-ME) that focused on a cap-and-dividend that would return a portion of auction revenues to consumers directly or the American Power Act, introduced by Senators Kerry and Lieberman (I-CT). 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). Subsequently, four bills were introduced in 2011 that would limit U.S. EPA's authority to regulate GHG emissions in varying degrees, but none were successful.

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:

- <u>Endangerment Finding</u>: 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 insofar as the permit will be completed in the 2011 timeframe.

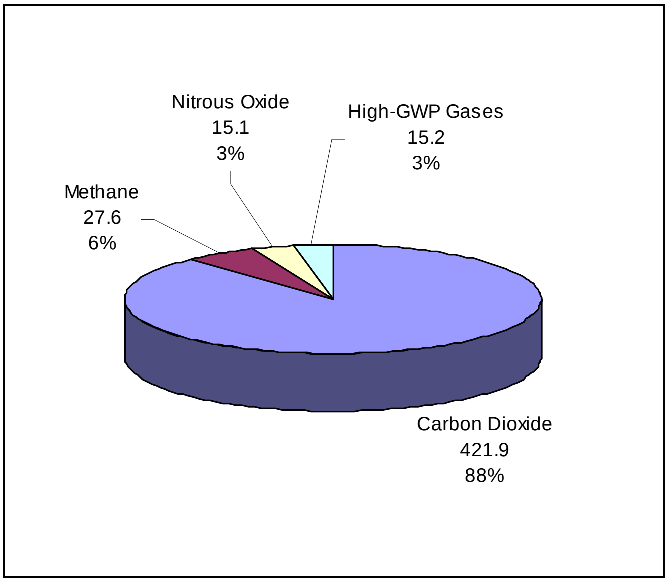
C.3.2 Western Climate Initiative (WCI)

Originally established by the Western Governor's Association in February 2007, the WCI is currently a collaboration of California and four Canadian provinces (British Columbia, Manitoba, Quebec, and Ontario) to reduce GHG emissions 15 percent below 2005 levels by 2020 from their power generation, industrial, petrochemical, and transportation sectors. The primary mechanism for achieving this reduction would be through a regional cap-and-trade program.

The WCI finalized its design for a regional cap-and-trade program in July 2010. Under this plan, entities and facilities annually emitting 10,000 metric tons or more of the regulated GHGs, measured in CO_{2e}, will have to begin reporting their 2010 emissions in early 2011. Although the program is scheduled to begin in 2012, the jurisdictions that are expected to move forward have all indicated they will not be ready for compliance to begin until January 1, 2013. The first phase of the cap-and-trade program will cover power generation, including electricity imported into the WCI region, industrial fuel combustion, industrial processes, and petrochemical companies emitting 25,000 metric tons or more of CO_{2e} each year. The second phase will begin in 2015 and will cover emissions from transportation fuel use as well as residential and commercial fuel use. Before WCI jurisdictions will be able to trade allowances between each other, separate linkage agreements will be required that establish the conditions for interfacing between trading systems.

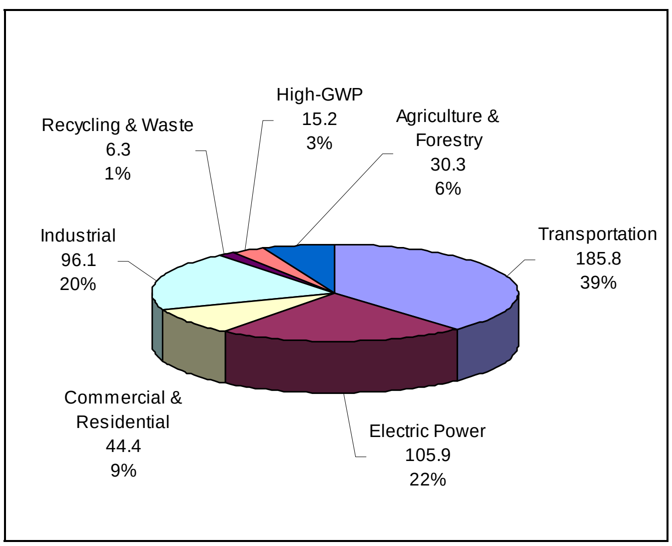
C.3.3 California Efforts to Address Climate Change

This section describes California's GHG emissions inventory and policies and actions to reduce GHG emissions. Figures C-3 and C-4 show California's 2006 statewide GHG emissions by pollutant and by sector.



Source: California Air Resources Board

Figure C-3. California GHG emissions by GHG (2006)



Source: California Air Resources Board

Figure C-4. California GHG emissions by sector (2006)

Based on the ARB's Update to the Scoping Plan (2011), the 2020 emissions baseline used in the 2008 Scoping Plan is 596 $MMTCO_{2e}$. This estimate of statewide 2020 emissions was developed using pre-recession 2007 IEPR data and reflects GHG emissions expected to occur in the absence of any reduction measures in 2010. 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.[1]

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.

[1] ARB Status of Scoping Plan Recommended Measures.
http://www.arb.ca.gov/cc/scopingplan/status_of_scoping_plan_measures.pdf

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.

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[2]. In 2007, the ARB established a 1990 statewide greenhouse gas emissions baseline of 427 MMT of carbon dioxide equivalent (CO_{2e})[3] 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.
- 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.

[2] GHGs covered by AB 32 include the following: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.
[3] 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.

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 similar trading programs in the four Canadian provinces of British Columbia, Manitoba, Quebec and Ontario on or after 2013. Starting in 2013, the cap starts at about 2 percent below the emissions level forecast for 2012 and declines about 2 percent in 2014. From 2015 to 2020, the cap trajectory declines about 3 percent annually from 2015 to 2020.

Although the program commences on January 1, 2012, compliance and enforcement with the program is delayed until January 1, 2013, with the first auctions scheduled for August and November 2012. At the time the ARB Board adopted the cap-and-trade regulation, the Board directed staff to address several key outstanding issues as part of a new rulemaking scheduled to take place in 2012 that will ultimately make further refinements to the program before compliance begins. Two of those issues that LADWP will focus on in 2012 include the provisions surrounding resource shuffling and point of regulation for electricity imports. The resource shuffling provision has potential implications for LADWP's coal transition as it relates to Navajo Generating Station if divestiture is not recognized by ARB as an emission reduction. The point of regulation for electricity imports was changed by ARB staff from the entity that owns the power being imported to California to the entity that schedules the power into California. LADWP will continue to work with other utilities and the ARB to better understand the potential implications this may have on reporting of specified electricity imports (high-emitting as zero-emitting electricity) by parties that do not retain ownership of that power.

C.3.4 The City of Los Angeles GREEN LA Plan

On May 15, 2007, Los Angeles Mayor Antonio Villaragosa released the "GREEN LA – An Action Plan to Lead the Nation in Fighting Global Warming" (GREEN LA Plan) that has an overall goal of reducing the GHG emissions by 35 percent below 1990 levels by 2030. This goal exceeds the targets set by both California and the Kyoto Protocol and is the greatest reduction target of any large U.S. city. Key strategies listed in the GREEN LA Plan related to energy and water include the following:

Energy

Green the Power from the Largest Municipal Utility in the United States

- Meet the goal to increase renewable energy from solar, wind, biomass, and geothermal sources to 20 percent by 2010.
- Increase the efficiency of natural gas-fired power plants.
- Increase biogas co-firing of natural gas-fired power plants.

Make Los Angeles a Worldwide Leader In Green Buildings

- Establish a comprehensive set of green building policies to guide and support private sector development designed to reduce carbon dioxide emissions by 80,000 tons by 2012. Approved on April 22, 2008, the Private Sector Green Building Plan makes Los Angeles the largest city in the nation to adopt such a plan.
- Implement other related Green Buildings efforts. For example, (e.g., all City-owned buildings over 7,500 square feet will be required to meet LEED Silver Standards). Other efforts, including the adoption of respective ordinances and updating of applicable building codes, will enable the City of Los Angeles to transform its building stock in both the public and private sector thereby facilitating all buildings to operate in a more energy efficient manner consistent with technological innovations and economic incentives whenever possible.

Transform Los Angeles Into the Model of an Energy Efficient City

- Reduce energy use by all City departments to the maximum extent feasible.
- Complete energy efficiency retrofits of all City-owned buildings to meet a 20 percent or more reduction in energy consumption.
- Install the equivalent of 50 “cool roofs” per year by 2010 on new or remodeled City buildings.
- Install solar heating for all City-owned swimming pools.
- Improve energy efficiency at drinking water treatment and distribution facilities. Maximize energy efficiency of wastewater treatment equipment.
- Replace 140,000 conventional street lights with light emitting diode (LED) green street lights, reducing carbon emissions by 40,500 tons per year and saving the city $10 million annually.

Help Angelenos Be “Energy Misers”

- Distribute two compact fluorescent light (CFL) bulbs to each of the 1.2 million households in the City.
- Increase the level and types of customer rebates for energy efficient appliances, windows, lighting, and heating and cooling systems.
- Increase the distribution of energy efficient refrigerators to qualified customers.
- Create a fund to “acquire” energy savings as a resource from LADWP customers.

Water

- Decrease Per Capita Water Use.
- Meet all additional demand for water resulting from growth through water conservation and recycling.
- Reduce per capita water consumption by 20 percent.
- Implement the City’s innovative water and wastewater integrated resources plan that will increase conservation and maximize use of recycled water, including capture and reuse of storm water.
- Meet city directives and ordinances with respect to water conservation. Monitor technological improvements with respect to equipment, appliances, and engineered systems that would reduce the water consumption of various buildings and related need to adopt relevant ordinances and update municipal codes consistent with cost-effective technology available in the marketplace.

C.3.5 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 2008.

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	14,651,016	13,834,001	28,041,998	1,152
2010	13,771,166	12,623,181	27,490,842	1,104
Difference between 1990 and 2010	-4,154,245	-5,141,693	2,009,310	-446
% Change from 1990	-23%	-29%	8%	-29%

Notes:

1. Calculated CO_2 emissions using fuel data and fuel-specific emission factors from the California Registry's reporting protocols.
2. Used source specific data where available, and 1100 lbs CO_2/MWh for unspecified power purchased.

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, which is scheduled to take effect starting Jan 1, 2011, 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. As a result, LADWP's 2008 SF6 emissions rate was slightly under 1 percent. 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.

LADWP's Historical Accomplishments in Reducing GHG Emissions

In 1995, LADWP signed a Climate Challenge Participation Accord with the U.S. Department of Energy (DOE), voluntarily committing to reduce GHG emissions from power generation to keep LADWP's average CO_2 emissions from 1991 - 2000 below its 1990 baseline. LADWP achieved this goal. In addition, LADWP voluntarily participated in DOE's EIA-1605b "Voluntary Reporting of Greenhouse Gases" program from 1995 – 2005, annually reporting CO_2 emissions from power generation as well as programs to reduce emissions.

In 2000, LADWP set a new goal in its Integrated Resource Plan to reduce GHG emissions five percent below 1990 levels by 2008. LADWP exceeded this goal (actual 2008 power generation portfolio CO_2 emissions were 9.3 percent lower than our 1990 baseline).

In 2002, LADWP became a charter member of the California Climate Action Registry, and has since reported and certified eight annual entity-wide GHG emissions inventories with the Registry.

C.3.6 LADWP Programs and Projects to Reduce CO_2 Emissions

Since 1990, LADWP has undertaken numerous programs to reduce CO_2 emissions. Tables C-2 and C-3 below show the variety of LADWP's emission reduction programs and reductions achieved.

Table C-2. EMISSION REDUCTION PROGRAMS

Years	Program	Description	Cumulative CO_2 Emissions Avoided or Sequestered (short tons)
Renewable Energy			
2004-2008	Renewable Energy	LADWP's goals are to achieve 20% RPS by 2010 and 35% RPS by 2020.	3,521,102
Water Conservation			**3,129,099**
1991-2008	Water Conservation Program	Encourage customers to conserve water with rebates for installing hardware such as ultra-low-flush toilets and low-flow shower heads, a rate structure that rewards conservation, and public education.	Hardware: 1,771,814 Behavior: 1,311,324 3,083,139
1999-2008	High efficiency clothes washers	Rebates for purchase of energy efficient residential & commercial clothes washers.	45,960
Energy Efficiency			**1,738,544**
1999-2008	Refrigerator Replacement	Sale of high efficiency refrigerators at discount prices to multi-family residential units and non-profit organizations that are DWP customers, and removal & recycling of old refrigerators.	27,606
1999-2008	Commercial Lighting	Incentives for small commercial customers to install lighting equipment that exceeds Title 24 standards.	935,781
1999-2008	HVAC Replacement	Incentives for small commercial customers to install HVAC equipment that exceeds Title 24 standards. Expanded to include residential HVAC units from 2000-2002.	236,440
2000-2008	Chiller Replacement	Incentives for businesses and hospitals to install new high-efficiency water or air-cooled chillers that exceed Title 24 standards.	285,894
2002-2008	Consumer Rebate	Rebates to residential customers for purchase & installation of Energy Star appliances, lighting, windows, and HVAC.	105,737
2004-2008	Refrigerator Retirement	Free pick-up and recycling of old spare refrigerators for residential customers.	54,164
2004-2008	CFL Distribution	Free compact florescent light bulbs to residential customers.	42,818
2006-2008	Non-Residential Refrigeration	Rebates for non-residential customers to improve the energy efficiency of refrigeration equipment, reduce energy consumption in cold storage facilities, and install high efficiency refrigerated cases and equipment.	4,142

Table C-2. EMISSION REDUCTION PROGRAMS

Years	Program	Description	Cumulative CO_2 Emissions Avoided or Sequestered (short tons)
(Continued from page C-15)			
2006-2008	Small Business Direct Install	Provide free energy assessments, recommend lighting improvements, and install lighting upgrades to assist small business customers become more energy efficient.	30,001
2007-2008	New Construction	Incentives for building to LEED or CHPS 2006 standards, or for installing equipment from an approved list of energy efficient products.	133
2007-2008	Custom Performance	Incentives for non-residential customers to install energy saving measures, equipment or systems that exceed Title 24 or minimum industry standards such as equipment controls, industrial processes and other innovative energy saving strategies.	15,826
Digester and Landfill gas-to-energy			**1,152,479**
1995-2008	Scattergood	Burn digester gas from Hyperion Wastewater Treatment Plant at Scattergood Generating Station to generate electricity.	1,139,881
2002-2007	Lopez Canyon	Burn landfill gas in micro turbines at Lopez Canyon Landfill to generate electricity.	12,599
Recycling			**159,034**
1998-2008	Recycling Program	Recycling of paper, cardboard, metals and other materials from LADWP facilities.	440,136
Electricity Generation & Distribution System			**61,497**
1999-2008	Solar Power	LADWP's Solar Power Program includes: • Customer systems (net metered) • LADWP and City facilities (grid connected).	61,497
Tree Planting (Urban Forestry)			**195,545**
1998-2008	Cool Schools	Planted 9274 trees (cumulative) at LA Unified School District campuses.	48,187
2001-2008	Trees for a Green LA	Distributed 114,427 trees (cumulative) for planting around customer homes and in community areas.	138,793
2007-2008	Million Trees LA	Distributed 23,958 trees (cumulative) for planting around the City of Los Angeles.	8,565
Miscellaneous			**3,638**
2000-2008	Energy Star Office Equipment	Use of Energy Star office equipment (computers & monitors, printers, copiers and FAX machines).	3,638
Total CO_2 Emissions Avoided / Sequestered (Current Programs)			**6,436,197**

Table C-3. COMPLETED / DISCONTINUED PROGRAMS FOR EMISSION REDUCTION

Years	Program	Description	Cumulative CO_2 Emissions Avoided or Sequestered (short tons)
Energy Efficiency			**175,526**
1999-2001	Neighborhood Bill Reduction Service	Provide free CFLs, clean refrigerator condenser coils, distribute low-flow shower heads & aerators, and check for toilet leaks for residential low income customers.	154,108
1999-2001	Commercial Refrigeration Tune-up	Free audits and tune-ups of refrigeration equipment for small commercial customers.	3,856
2000-2002	HVAC Tune-up	Low cost tune-ups of A/C equipment for commercial and residential customers.	17,510
2005	Efficient Motors	Incentives for commercial & industrial customers to install premium efficiency electric motors.	52
Building Energy Efficiency Retrofits			**101,056**
1999-2004	John Ferraro Building Lighting Retrofit	Eliminated 50% of the light fixtures, replaced the remaining fixtures with energy efficient equipment, and installed automatic lighting controls in LADWP's corporate office building.	89,220
2001-2002	Cool Roofs	Incentives to install Energy Star roofing product on commercial or multi-family residential buildings (state funded).	4,164
2001-2004	Reflective Window Film	Incentives to install reflective film on windows to reduce building solar heat gain and reduce A/C load.	3,848
2004-2005	City Building Retrofit	Retrofit 37 City of LA facilities with energy efficient lighting.	2,604
2006	City Energy Efficiency Loan	Loans to other city departments to implement energy efficiency measures.	1,220
Electricity Generation & Distribution System			**9,266**
1996-2005	Energy Efficient Transformers	1592 Energy Star transformers were purchased in 1995 & installed in LADWP's distribution system.	9,266
Total CO_2 Emissions Avoided (Completed Projects / Discontinued Programs)			**297,610**

Additional actions and changes in LADWP's generation resource mix from 1990 to 2009 include:

- Replacement of two steam generators in each of Palo Verde Nuclear Generating Station's (PVNGS) three generating units, to provide for the continued use of the units to the end of their projected 40-year life and possibly through their 20-year extended life. The project began in 2003 and was completed in 2007. The replacement of the steam generators and the turbine rotors resulted in an increase in power output of approximately 210 MWs for PVNGS.
- The seven units of the Castaic Pump Storage Power Plant (Castaic Plant) are currently being rotated out of service for modernization. This multi-phase process, began in 2004 and is expected to continue through 2013. To date, modernization to five units have been completed. The refurbishment is projected to increase the efficiency of the units and add up to 80 MWs of capacity to the Castaic Plant.
- Certain IPP participants have a right under the IPP Excess Power Sales Agreement to recall from LADWP up to 18.2 percent of the capacity of IPP (currently equal to approximately 327 MWs) for defined future summer or winter seasons or both, following no less than 45 days notice and up to 43 MWs of such capacity on a seasonal basis following no less than 90 days notice. Such participants are currently recalling 48 MWs of winter season capacity from LADWP. Future capacity of IPP subject to recall from LADWP under the Excess Power Sales Agreement can vary.
- Recent drought conditions and low lake levels have reduced the LADWP's capacity entitlement at the Hoover Plant from 491 MWs of capacity (calculated based on 25.16 percent of 1,951 MWs of total contingent capacity) to an annual average of approximately 411 MWs (calculated based on 25.16 percent of 1,634 MWs annual average output capability). Future available capacity from Hoover Plant will depend on future drought condition.
- The LADWP Power RPS Policy was established to increase the amount of energy LADWP generates from renewable power sources to 20 percent of its energy sales to retail customers by 2010 and 33 percent renewable energy by 2020. Acquisitions of the renewable energy are based on a competitive bidding process through the issuance of Requests for Proposals. To date, renewable projects in-service or under construction, provide a total of 5,300 gigawatt per hour (GWh) of renewable energy annually.
- The Power Reliability Program (PRP) is a comprehensive, long-term power reliability program developed by LADWP to replace aging infrastructure or make permanent repairs to generation, transmission and distribution infrastructure that has failed during recent outages. Through the program, LADWP plans to accelerate the management and replacement of transformers, poles, underground cables, underground vaults, station transformers, new distribution and receiving stations, and modifications to existing stations. LADWP also plans to install new control, integrated central monitoring and dispatch systems needed to facilitate reliable and secure system operations and modify its staff training programs and increase staffing.

- The LADWP continued its commitment to energy efficiency through numerous programs and services for customers to encourage the installation and use of energy efficient measures and equipment LADWP establish annual efficiency targets reducing total forecasted electricity consumption by 10 percent over the next 10 years. LADWP is on track to meet the requirements established under AB 2021. Since 2000, the LADWP energy efficiency programs have reduced long-term peak period demand and consumption by approximately 271.1 MWs and 894.1 GWh of energy savings. LADWP has budgeted funding for fiscal year 2009-10 to renew and expand its commitment to energy efficiency.
- 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. Over 17,100 LADWP customers participated in the program during 2010. These participants receive approximately 104,000 MWh of renewable energy annually. Since program inception, in 1999, to the end of 2010, 818,768 MWh of renewable energy was procured, making it one of the largest voluntary green pricing programs in the nation.
- Completion of the Pine Tree Wind Project which is a 135 megawatt wind generating facility north of Mohave, California, consisting of 90 wind turbines The project began commercial operation on June 16, 2009.
- Numerous environmental laws and regulations, specifically those relating to air and water quality, affect the LADWP Power System’s facilities and operations. LADWP monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis.

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 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:

- As a result of the Haynes 5&6 repowering project, reduce the number of OTC units to 7 by 2013. This will decrease ocean water use from 1571 MGD to 1110.2 MGD, an overall reduction of 42% from 1990 ocean water usage levels.

- As a result of the Scattergood 3 repowering project, further reduce the number of OTC units to 6 by 2015, decreasing ocean water use from 1110.2 MGD to 839.8MGD, an overall reduction of 56% from the original ocean water usage level.

- As a result of the Scattergood 1&2 repowering project, further reduce the number of OTC units to 4 by 2020, decreasing ocean water use from 839.8 MGD to 563.3MGD; an overall reduction of 70% from the original ocean water usage level.

- As a result of the Haynes 1&2 repowering project, further reduce the number of OTC units to 2 by 2024, decreasing ocean water use from 563.3 MGD to 338.7 MGD, an overall reduction of 82% from the original ocean water usage level.

- By 2026, further reduce of the number of OTC units to 1, decreasing ocean water use from 338.7 MGD to 231 MGD, an overall reduction of 87% from the original ocean water usage level.

- By 2029, final reduction of OTC units to 0, 100% elimination of OTC.

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

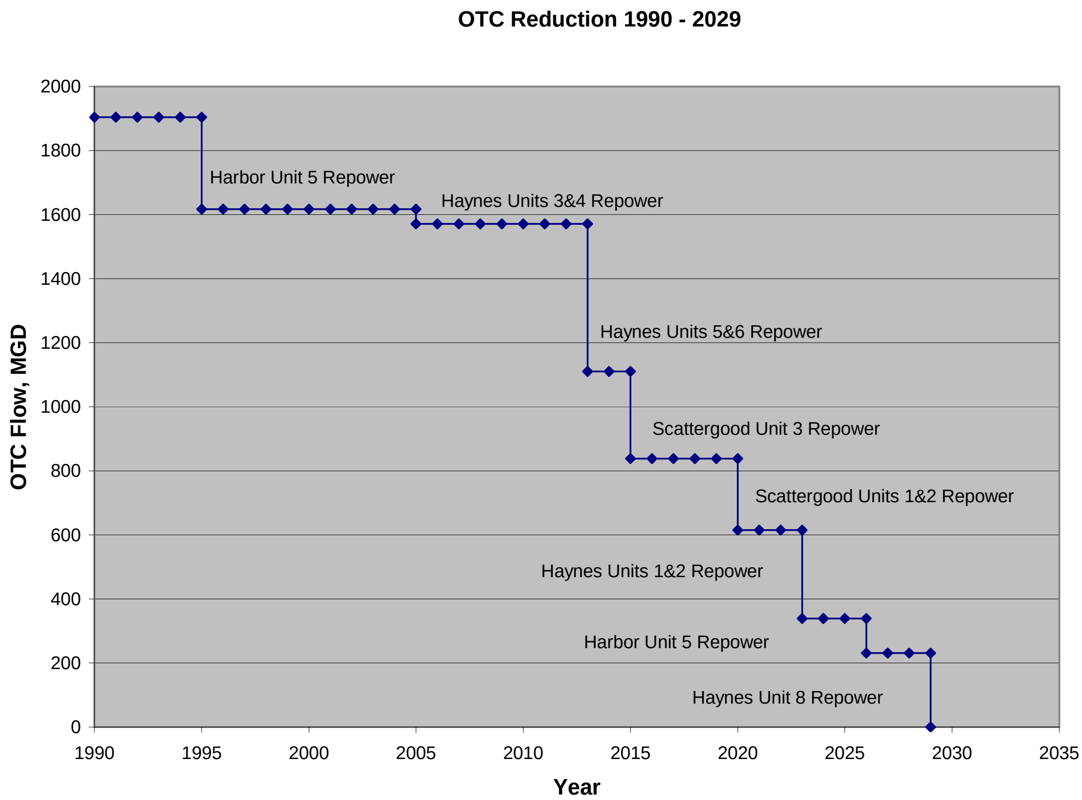


Figure C-5: LADWP OTC reduction from 1990 to 2029.

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 placed remanded Rule and 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 UP EPA is targeting the end of 2012 to finalize its Rule. The use of BPJ by permitting authorities is still in effect.

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 know as the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) will assist the SWRCB in reviewing the required utility implementation plans and in monitoring the 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 conduct a study or studies, singularly or jointly with other facilities, to evaluate new technologies or improve existing technologies to reduce impingement and entrainment. LADWP must 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 commencing these studies and has begun the Haynes Units 5&6 repowering project in order to meet the 2013 deadline. Also, the conceptual planning and design for the Scattergood Unit 3 has commenced in order to meet the 2015 deadline.

C.5 Mercury Emissions

Mercury 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 mercury emissions to the air in the United States, accounting for over 40 percent of all domestic human-caused mercury emissions. The EPA estimates that about 1/4 of U.S. emissions from coal-burning power plants are deposited within the contiguous U.S., and the remainder enters the global cycle.

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 was scheduled to finalize its rule by 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.

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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 2011 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 response 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 2010 is shown on Figure D-1

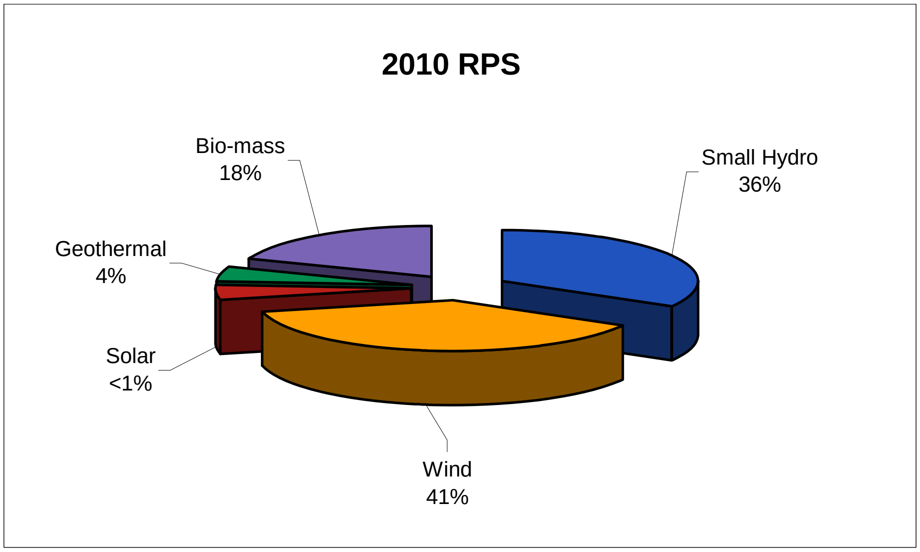


Figure D-1: 2010 Renewable Energy Mix

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) becomes 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 are 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 have not yet been finalized.

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 and could be completed by the end of 2011. The total renewable potential for the California ISO/IID Path 42 upgrades is approximately 1,400 MW.

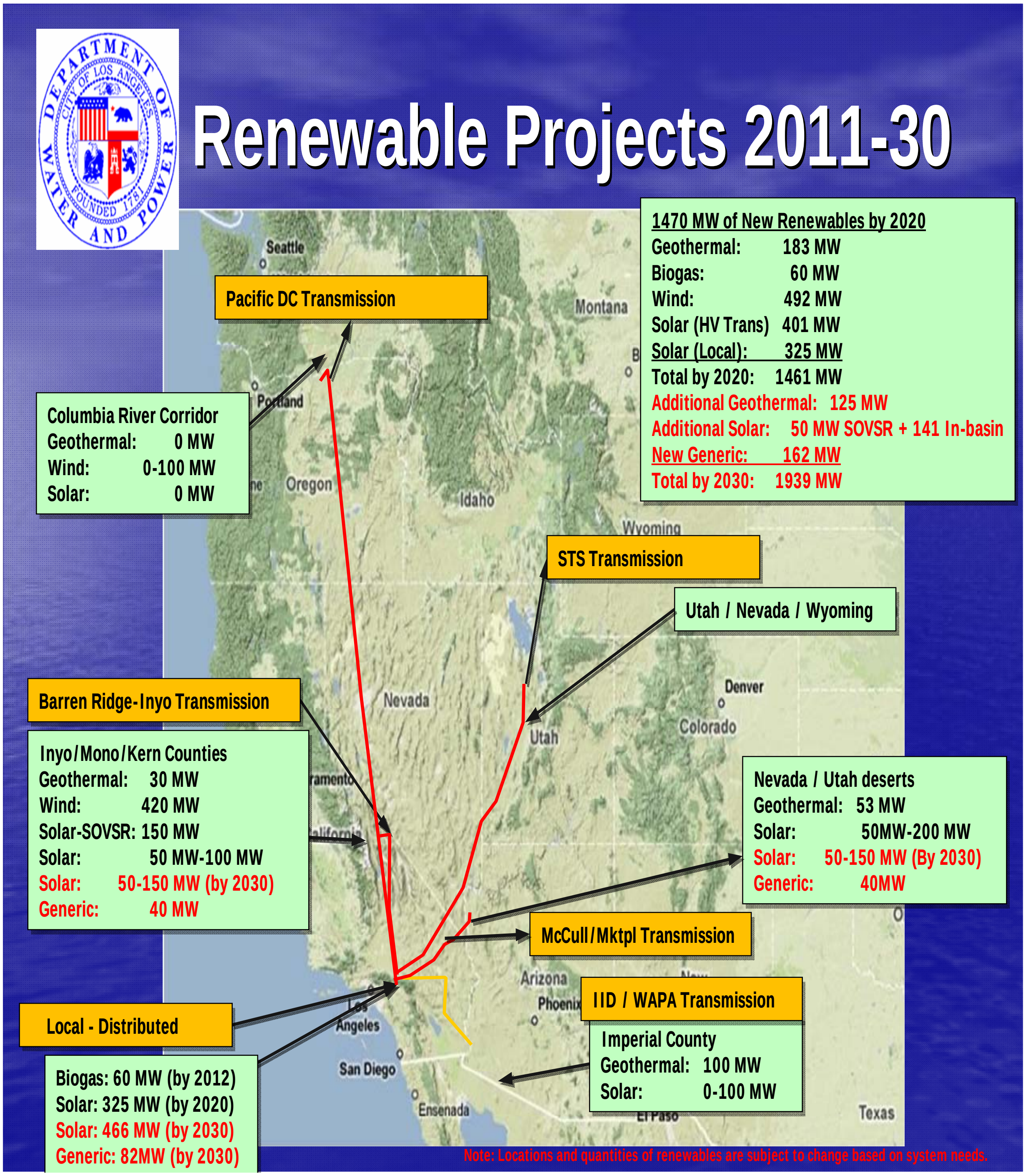


Figure D-2: Renewable Transmission Paths and Potential Resources, 2010 - 2030

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 400 million to 950 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 wind, solar, and geothermal 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 1,250 GWh or 28 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.

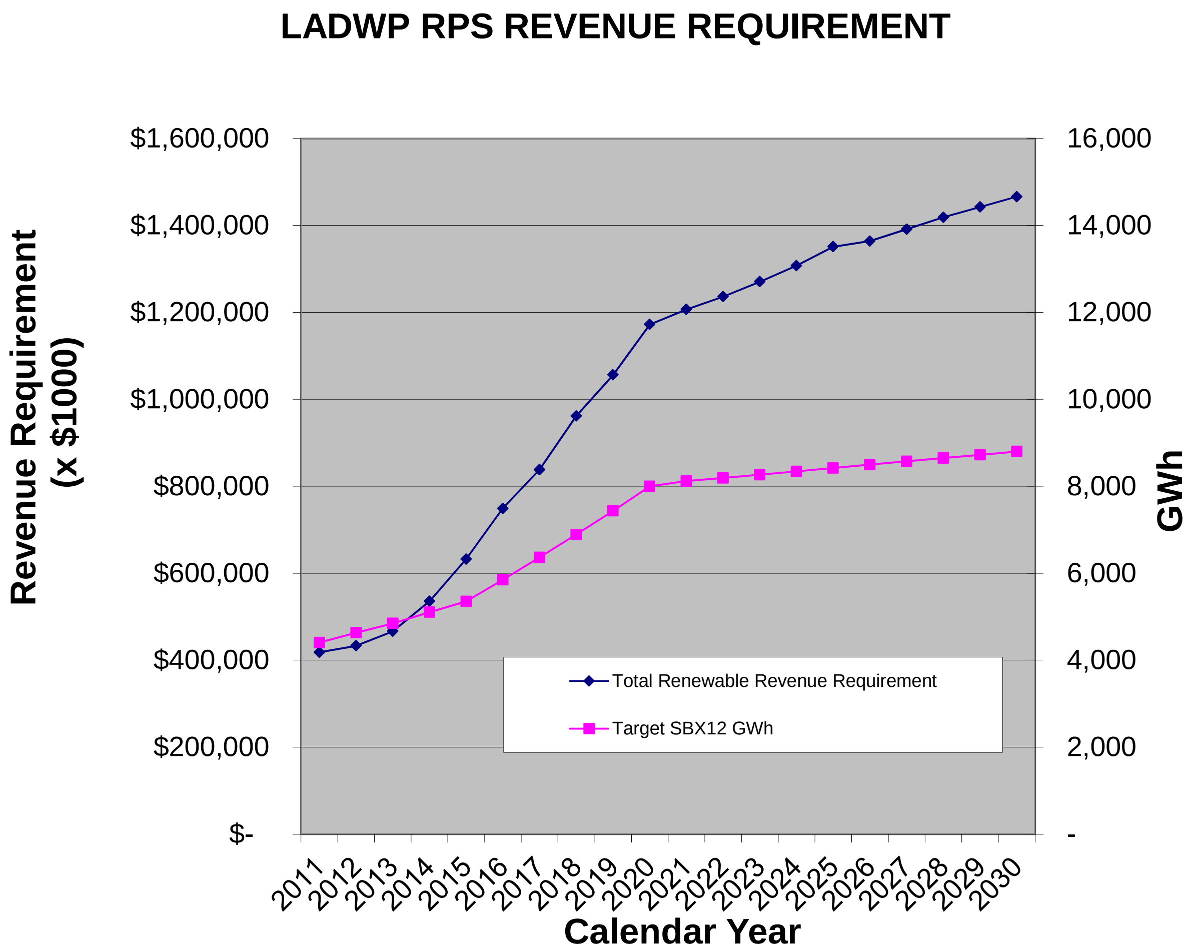
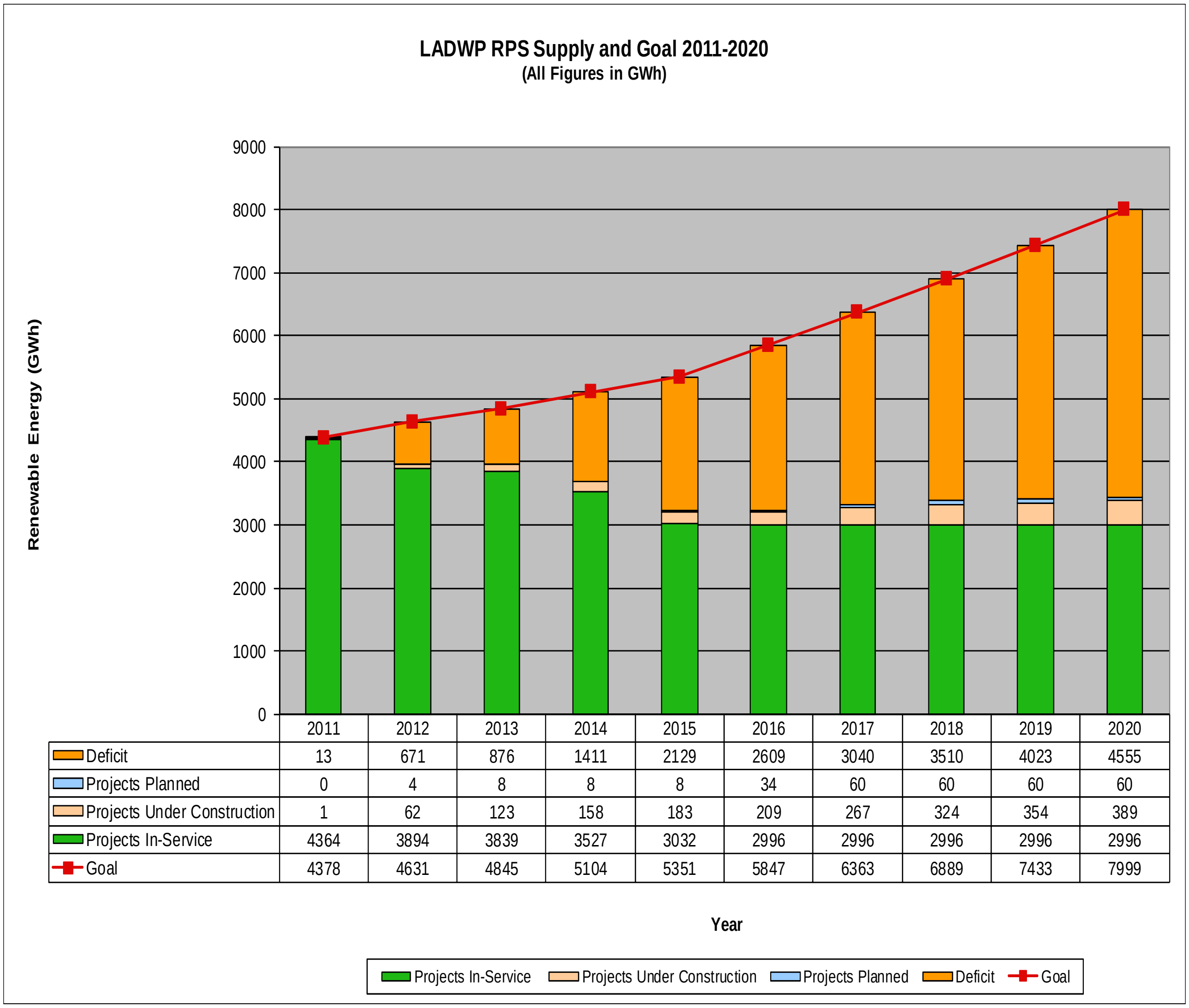


Figure D-3 – LADWP RPS Revenue Requirement 2011-2030.



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Deficit	13	671	876	1411	2129	2609	3040	3510	4023	4555
Projects Planned	0	4	8	8	8	34	60	60	60	60
Projects Under Construction	1	62	123	158	183	209	267	324	354	389
Projects In-Service	4364	3894	3839	3527	3032	2996	2996	2996	2996	2996
Goal	4378	4631	4845	5104	5351	5847	6363	6889	7433	7999

Figur 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

The current California Energy Commission (CEC) Overall Program Guidebook of January, 2011 defines biogas as "a gas derived from RPS-eligible fuel including biomass, digester gas, and/or landfill gas". CEC is currently working on a new Guidebook to comply with the SB 2 (1X) RPS requirements to further define eligible sources of Biogas.

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

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 CEC Guidebook states, "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 CEC also considers landfill gas (LFG) - gas produced by the breakdown of organic matter in a landfill - a renewable fuel.

The LADWP's gas-fired generating units capable of burning a mixture of biogas and conventional natural gas fall under the CEC multi-fuel designation. The CEC Guidebook states, "…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 short-term contracts with developers to purchase LFG. 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.

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 is located in-state or satisfies certain out-of-state requirements.
- 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.
- As much as possible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process.

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 2010 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 2010 Power Content Label

POWER CONTENT LABEL			
Annual Report of Actual Electricity Purchases for LADWP Calendar Year 2010			
ENERGY RESOURCES	LADWP Power ACTUAL MIX	LADWP Green Power ACTUAL MIX	2010 CA POWER MIX** (for comparison)
Eligible Renewable ***	20%	100%	14%
-- Biomass & waste	4%	59%	2%
-- Geothermal	1%	0%	5%
-- Small hydroelectric	7%	41%	2%
-- Solar	0%	0%	0%
-- Wind	8%	0%	5%
Coal	39%	0%	7%
Large Hydroelectric	3%	0%	11%
Natural Gas	22%	0%	42%
Nuclear	11%	0%	14%
Other	0%	0%	0%
Unspecified sources of power*	5%	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
Linden Wind
PPM Pebble Springs Wind
Willow Creek Wind
Pine Tree Wind Power Project
Milford Wind Phase I
Milford Wind Phase II
Windy Point Phase II
Powerex - BC Hydro
MWD Sepulveda
Lopez Canyon Landfill
WM Bradley Landfill
Penrose Landfill
Toyon Landfill
Valley Generating Station (GS) – Multi-fuel
Scattergood GS – Multi-fuel
Haynes GS – Multi-fuel
Harbor GS – Multi-fuel
Shell Energy Landfill Gas
Atmos Energy Landfill Gas
Hyperion Digester Gas – Scattergood GS
LADWP Small Hydro Power Plants (PP)

San Francisquito Power Plant 1
San Francisquito Power Plant 2
San Fernando Power Plant 2
Foothill Power Plant
Franklin Power Plant
Sawtelle Power Plant
Haiwee Power Plant
Cottonwood Power Plant
Division Creek P. P.
Big Pine Power Plant
Pleasant Valley P. P.
Upper Gorge P. P.
Middle Gorge P. P.
Control Gorge P. P.
North Hollywood Pump Station PP
Castaic Hydro Plant – Efficiency Upgrades
SB-1 Customer Net Metered Solar PV
DWP Built Solar
Silverlake Library
LA Convention Center Canopy
Sun Valley Library
Lake View Terrace Library
Canoga Park Library
North Central Animal Shelter
Ascot Library
Hyde Park Library
Ducommon Fitness Center
Truesdale Warehouse
Van Nuys Truck Shed
Distribution Station 3 (Vincent Thomas Bridge)
Main Street Yard
Exposition Park Library
Granada Hills Yard
LADWP JFB Parking Lot
LA Convention Center Cherry St Parking Lot
Council District 6 Field Office

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Appendix E Power Reliability Program

E.1 Overview

This Appendix describes LADWP's existing power reliability programs, which has provided high quality service to customers for more than 90 years. Recommendations are then presented for programs and actions to ensure high reliability in the future. Finally, statistical information is provided on the progress of the Power Reliability Program (PRP).

E.2 Historic Reliability of LADWP System

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, and it is LADWP's goal to continue this into the foreseeable future. However, as a result of aging electrical distribution infrastructure, there are significant challenges for LADWP to continue to maintain these reliability goals.

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. Historically, 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 and specifically the City. 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 demonstrates that the installation of these poles (and the related electrical distribution infrastructure) was directly related to the historical population growth.

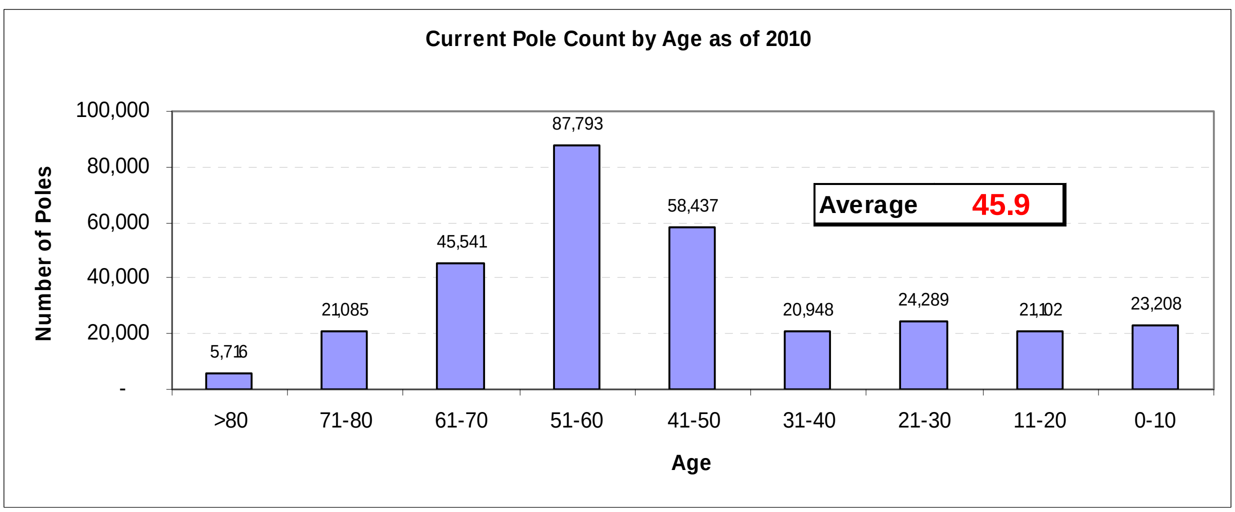


Figure E-1. Pole count by year range installed.

As a testimony to the initial design and installation of this electrical infrastructure, it has reliably served the residents of the City over the last 40 to 70 years. However, data now shows that reliability is beginning to deteriorate. In the past few years, outage rates have increased, including several high profile outages, demonstrating that this equipment is at the end of its service life. As more of the infrastructure ages and there is related performance deterioration, it will create a significant backlog of deferred maintenance and require increased levels of reliability-enhancing capital work. Existing staffing and funding levels will not be sufficient to replace the infrastructure that is needed to maintain the reliability that LADWP customers have come to expect.

E.3 Recommendations to Improve System Reliability

System reliability can be measured in terms of the key SAIDI and SAIFI performance indicators, defined below:

- SAIFI – System Average Interruption Frequency Index -Total number of sustained customer interruptions divided by the total number of customers, expressed in interruptions per customer per year.
- SAIDI – System Average Interruption Duration Index -Total minutes of sustained customer interruption divided by the total number of customers, expressed in minutes per customer per year.

Power System staff and independent industry experts have reviewed the overall system and have developed the following set of initial recommendations to improve reliability. These are summarized in the following subsections.

E.3.1 Operations and Maintenance (O&M) Programs

- Abnormal Circuits and Open Circuits: Abnormal Circuits and Open Circuits are cables that have been temporarily repaired and not in an as designed condition. These temporary repairs were made in the interest of restoring service in a timely manner rather than making permanent repairs, which were planned later. However, because temporary repairs are increasing, more staff is needed to make permanent repairs. Expanding Distribution Construction and Maintenance (DC&M) crews and proceeding with the Cable Replacement program will facilitate timely permanent restoration.
- Station Equipment Maintenance: The current maintenance practice is generally reactive to failures, not proactive and/or preventative. There is a large backlog of maintenance jobs. Maintenance practices should be modified, increasing maintenance frequency and adjusting staffing as appropriate.
- Overhead Transmission Maintenance: There is substantial deferred maintenance and a large volume of new capital work. Maintenance frequency should be increased and staffing adjusted as required.

Figure E-2 shows the SAIDI per Calendar year, both achieved to date and projected, and the impact of the ongoing PRP to reduce the SAIDI to the long term goal of 60 minutes by 2015.

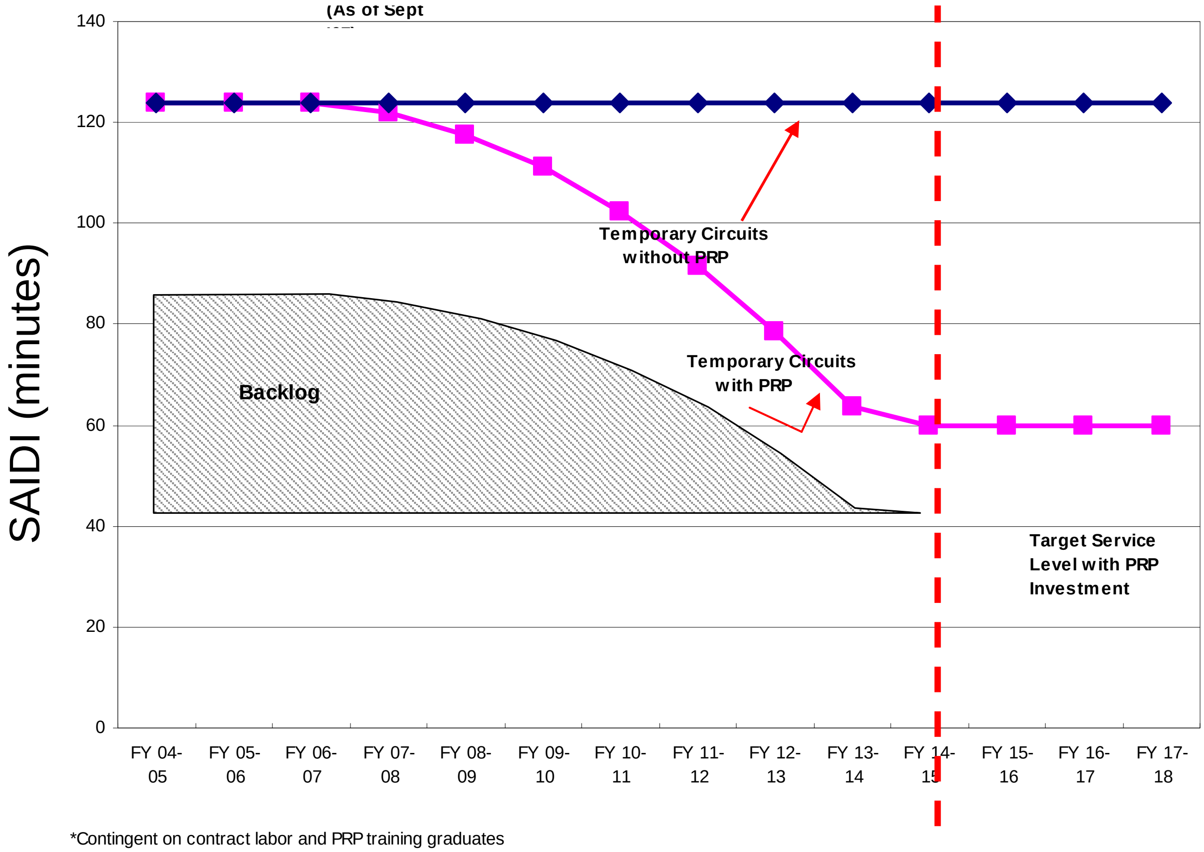


Figure E-2. Temporary circuit restoration and worst performing circuits and stations.

E.3.2 Capital Projects:

- Pole Replacement: The number of poles replaced annually should be increased with the goal of achieving an overall replacement cycle of 60 years.
- Cable Replacement: The amount of underground cable replacements should be increased from 40 miles per year to 60 miles, representing a 75-year replacement cycle. LADWP's Underground Transmission section is also planning to replace one 138-kV underground line per year.
- Distribution Transformers: A transformer management program is required to closely monitor transformer loading. Priority based transformer replacements take into account various factors such as loading, number of customers, age, and neighborhood conditions.
- Load Growth: Construction of new lines and stations to support load growth is a very important infrastructure improvement. Construction resources should be increased to support the timely installation of new facilities. Limited engineering staffing is restricting sufficient numbers of work packages for load growth, maintenance, and construction jobs. A 58,000 labor-hour backlog exists for various records, and approximately 60,000 as-built drawings from the Integrated Resource Plan require processing.

- Deteriorated Vaults & Obsolete Equipment: Over 900 substructures require repair. Much of this work is deferred due to lack of resources. Various obsolete equipment has been identified as needing replacement. Necessary resources and funding should be provided.
- Station Transformers: There are 846 main transformer banks in Distribution, Receiving and Switching stations, some over 60 years old. We are currently changing 2 transformer banks per year. Increased funding is recommended to replace this aging equipment.
- Reliability Engineering Work Group: LADWP should establish this group and develop work processes for structured analysis of failure rates, outage rates, and testing data as input to prioritize the maintenance basis and capital jobs for transmission and delivery (T&D) reliability.
- Generation Reliability Engineering: Staffing should be increased in select generation engineering groups to improve analysis and evaluation of generation unit performance and other reliability related programs and projects.

E.3.3 Distribution Infrastructure Undergrounding Program

- In addition to aesthetic considerations, undergrounding overhead lines has a reliability benefit of reducing the frequency of outages to almost half that of overhead. Currently, LADWP is converting undergrounds at approximately 6 miles per year.

E.3.4 Funding and Resources

The recommendations above are based on the initial observations of the Power System staff and industry experts. As these programs are implemented, prioritizations and/or resources will be directed to the programs that will result in the maximum amount of increased reliability. LADWP’s equipment was installed with significant resources over a long period of time; the program to replace the infrastructure will also require a long-term commitment.

In order to ensure that this program is implemented with the maximum impact on reliability and in the most efficient manner possible, LADWP has established a Power Reliability Oversight Committee. This committee conducts quarterly reviews of all facets of the reliability program and makes changes as needed to improve its effectiveness. This includes a review of percent completion of milestones, cost metrics, and impacts that the program is having on reliability metrics.

E.4 Current Power Reliability Program

As discussed in Section E.1, the PRP provides a blueprint for ensuring continued reliable energy service for future generations of Los Angeles residents. LADWP implemented the PRP through a two-pronged approach—rebuilding infrastructure and providing proactive maintenance—and will invest more than $1 billion in the program over the next 5 to 15 years. The program is funded through a power reliability surcharge. Figure E-3 shows the historic and future planned PRP expenditures.

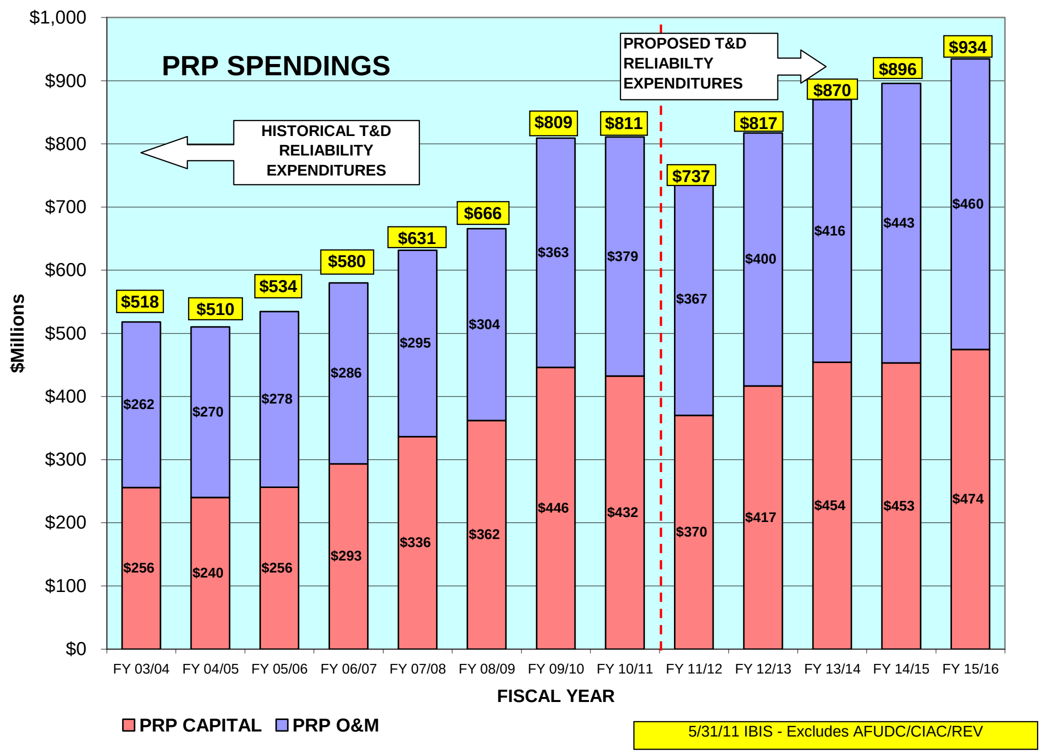
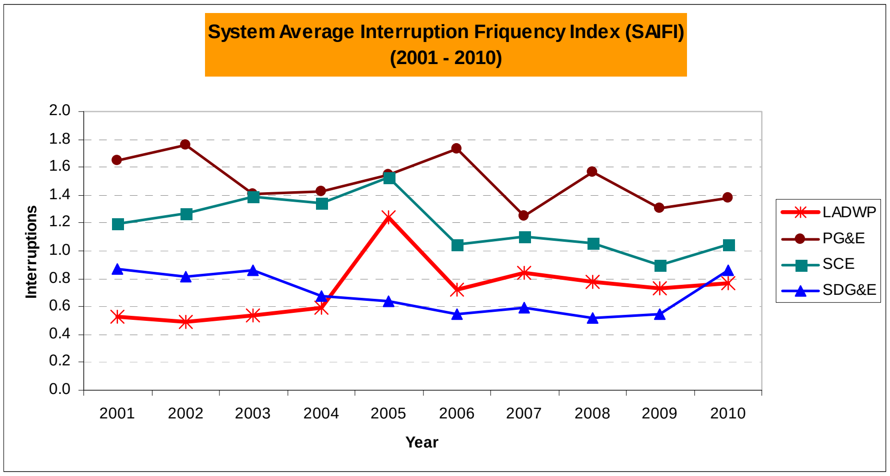


Figure E-3. PRP Expenditures.

The goals of the program include: 1) mitigating problem circuits and stations based on the types of outages specific to the facility, 2) 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, and 3) establishing replacement cycles for facilities that are in alignment with the equipment's life cycle.

***The tables and* figures** below detail the progress of LADWP's Power Reliability Program. Figure E-4 and Tables E-1 and E-2 present the reliability achieved in terms of the SAIDI and SAIFI performance indicators, as compared to California's major investor-owned utilities.



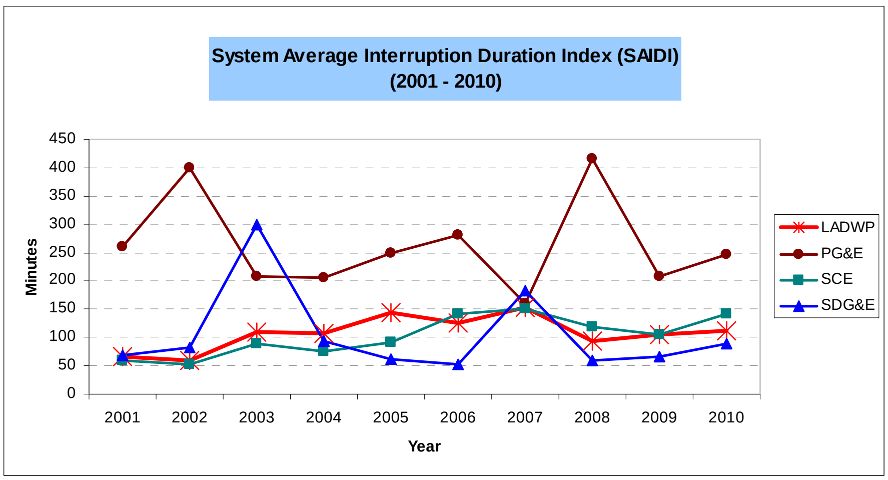


Figure E-4. LADWP PRP reliability comparisons with Investor Owned Utilities (IOUs).

Table E-1. LADWP SAIFI/SAIDI INDICATORS

Key Indicator	Units	2008	2009	2010
SAIFI	Outages / Year	0.78	0.73	0.77
SAIDI	Minutes / Year	93.1	104.5	112.8

Table E-2.1. UTILITY COMPARISON FOR 2009

Key Indicator	Units	LADWP	SCE	PG&E	SD&E
SAIFI	Outages / Year	0.73	0.90	1.31	0.54
SAIDI	Minutes / Year	104.5	105.8	208.2	67.06
Investor Owned Utility data from CPUC					

Table E-2.2. UTILITY COMPARISON FOR 2010

Key Indicator	Units	LADWP	SCE	PG&E	SD&E
SAIFI	Outages / Year	0.77	1.05	1.38	0.86
SAIDI	Minutes / Year	112.8	140.9	246.2	89.77

Table E-3 summarizes the PRP activity as of December 1, 2009 while Figures E-4 to E-9 present actual progress compared to PRP target for key elements of LADWP's PRP program.

Table E-3. LADWP PRP ACTIVITY

Key Performance Indicators (KPI)	Units	*FY 08-09 Target*	FY 08-09 Final	*FY 09-10 Target*	FY 09-10 Final	*FY 10-11 Target*	FY 10-11 Final
System Average Interruption Frequency Index (SAIFI)	Outages per Year	*0.72*	0.69	*0.71*	0.84	*0.70*	0.82
System Average Interruption Frequency Index (SAIDI)	Minutes Out per Year	*125.3*	78.1	*122.7*	120.7	*120.1*	121.7
	System Total						
Abnormal & Temporary 4.8-kV Circuit Backlog Total	1630 Circuits	*118*	139	*110*	153	*102*	164
Priority A Circuits (carrying extra load due to failed components)	Circuits	-	47	-	29	-	47
Priority B Circuits (failed components with no load transfer)	Circuits	-	42	-	37	-	35
Priority C Circuits (extra load due to field work)	Circuits	-	50	-	87	-	82
New Priority	Circuits	-	-	-	-	-	-
Poles Replaced and Reinforced	308,100 Poles	*2975*	2780	*2975*	2815	*2600*	2325
Distribution Transformers Installed	126,000 Transformers	*2400*	2984	*2400*	3184	*2400*	2624
Underground Transmission Cable Replaced	123 Miles						
Length of Underground Cables Replaced	2,242 Miles	*40*	42	*40*	65	*40*	69
Preventive Maintenance for RS, DS and CS							

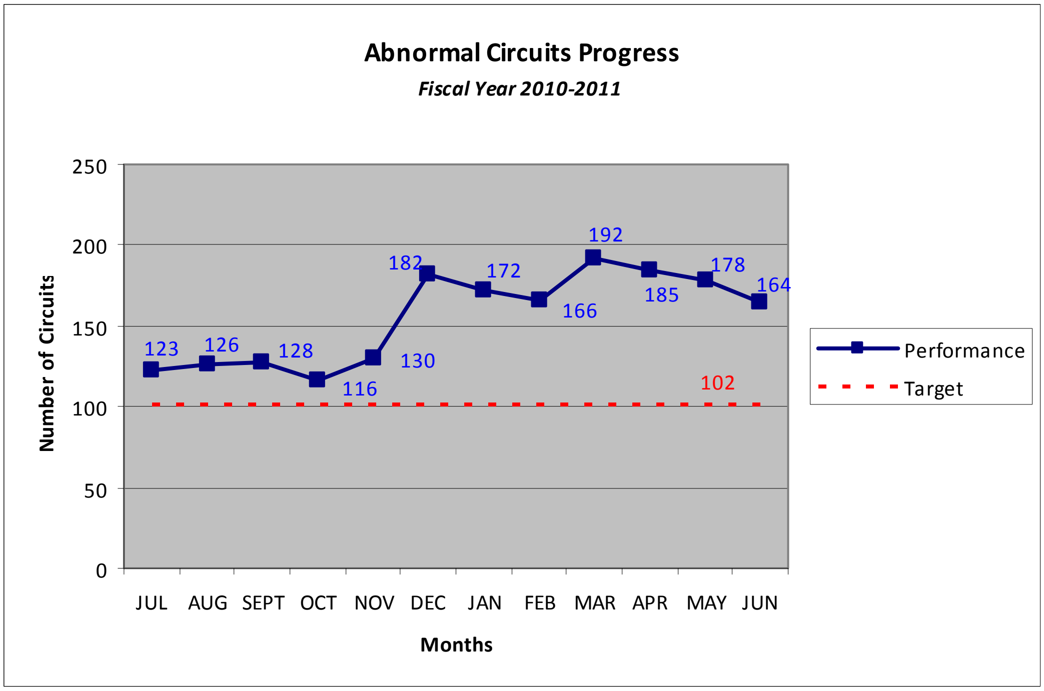


Figure E-5. PRP abnormal and temporary 4.8kV circuit backlog by month.

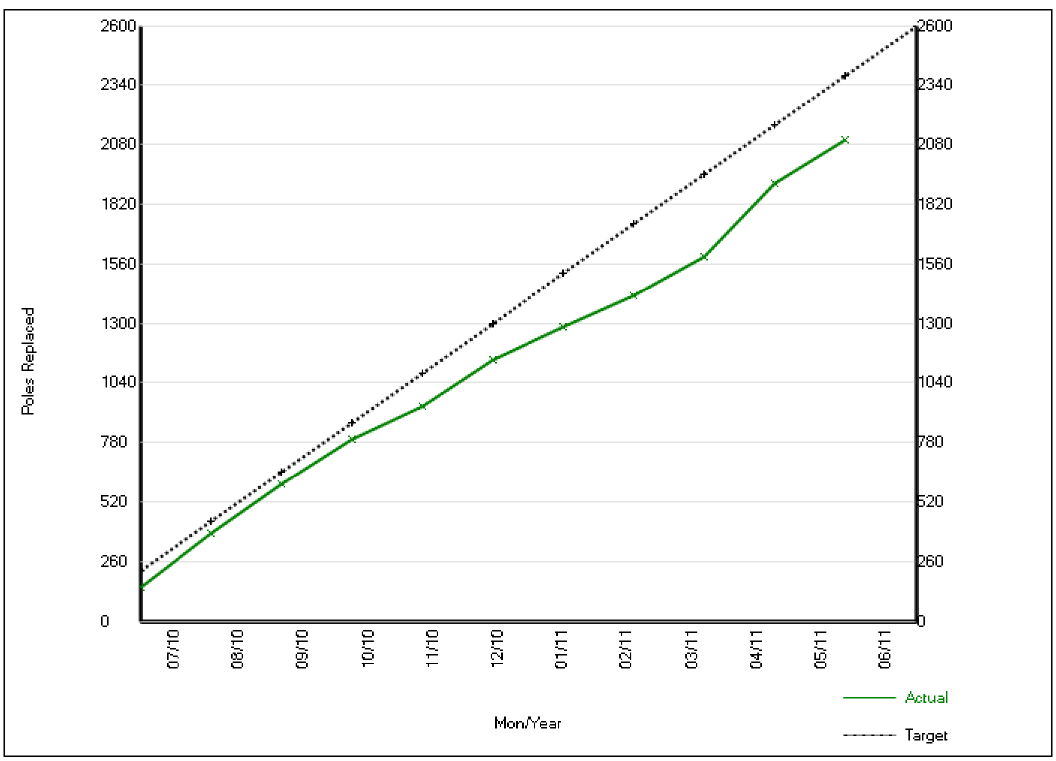


Figure E-6. PRP pole replacement by month, FY 2010-11.

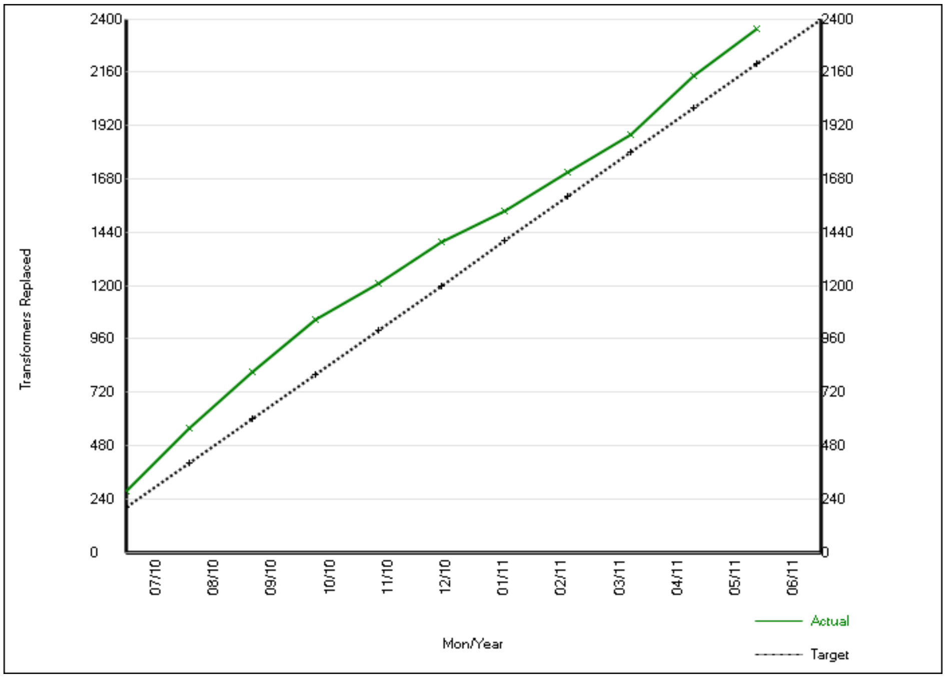


Figure E-7. PRP distribution transformer replacement by month, FY 2010-11.

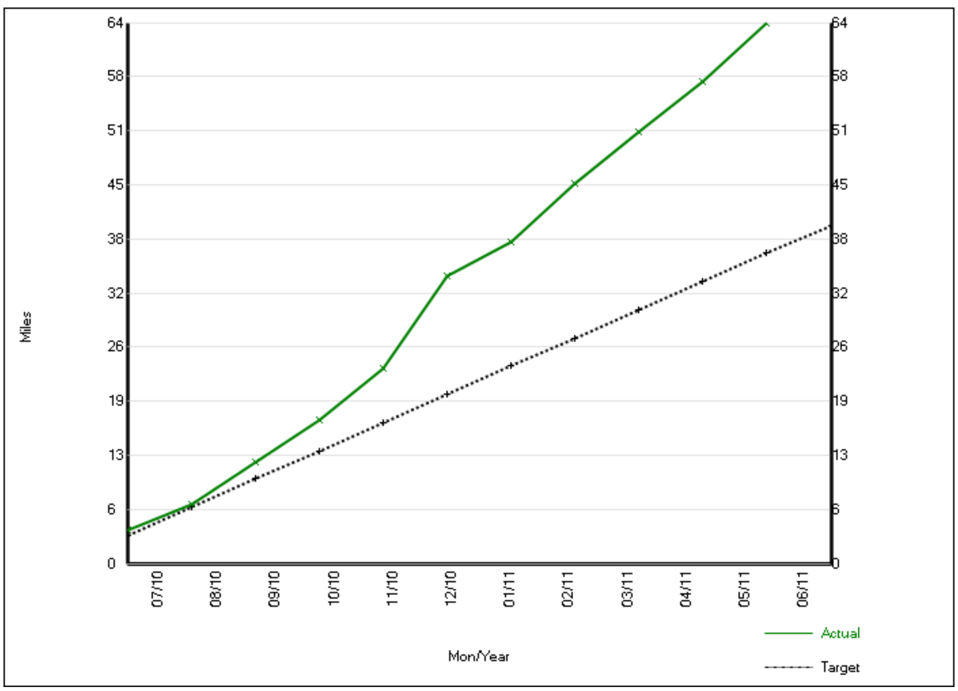


Figure E-8. PRP underground cable replacement by month, FY 2010-11.

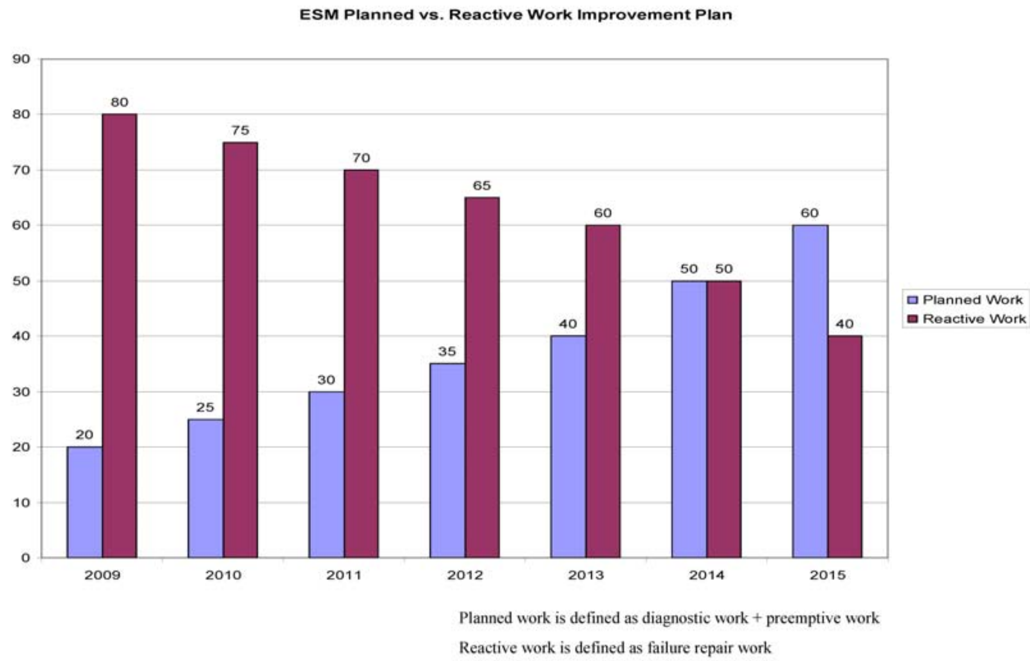


Figure E-9. Circuit load growth and substation maintenance.

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 3,337 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	100,400	82,000	461,000[2]
	2	1995	100,400	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	3,337,000

Notes:

1. COD refers to Commercial Operation Date.
2. Harbor Generating Station Net Dependable Plant Capability is 461 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 simple-cycle gas turbine units by December 2012.

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 576 MWs of maximum capability. 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 461 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 from natural gas and a net dependable capability of 796 MWs from natural gas. Units 1 and 2 also burn digester gas from the adjacent Hyperion Wastewater Treatment Plant.

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]	Nameplate (kW)	Net Max Capability (LADWP kW)	Net Dependable Capability (LADWP kW)	LADWP Expiration	LADWP Share
Intermountain	1 2	1986 1987	820,000 820,000	401,553 401,553	401,553 401,553	15Jun2027	44.617%
Intermountain	1 2	1986 1987	820,000 820,000	36,000 36,000	36,000 36,000	15Jun2027	4% (UP&L)
Intermountain	1 2	1986 1987	820,000 820,000	163,447 163,447	86,000 86,000	15Jun2027	18.161% (Recallable)
Total				1,202,000[2]	1,047,066[2]		
Navajo	1 2 3	1974 1974 1975	803,000 803,000 803,000	159,000 159,000 159,000	477,000[3]	31Dec2019	21.2%
Total				1,679,000	1,524,000		

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. 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 172 MW is the current 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 in excess of 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 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 ranges around 0.06 pounds per million BTU relative to an 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 with the completion of the Unit 1 major overhaul. 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.

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.

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 are estimated at $148.5 million (or $31.5 million for LADWP).

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	Nameplate (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	1,413,000 1,413,000 1,413,000	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	1,413,000 1,413,000 1,413,000	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 design electrical rating of 1,333 MW (Unit 1), 1,336 MW (Unit 2) and 1,334 MW (Unit 3) and a dependable capacity of 1,311 MW (Unit 1), 1,314 MW (Unit 2) and 1,312 MW (Unit 3). PVNGS's combined design capacity is 4,003 MW, and its combined 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 dependable capacity), a joint powers authority in which LADWP participates, so that LADWP has a total interest of approximately 380 MW of 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 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.

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	240,000 265,000 265,000 265,000 265,000 265,000 55,000	1,175,000	Owned Asset	100%
Hoover[3]		1936	2,079,000	491,000	436,000	30Sep2017	15.4229%
Total				1,763,000	1,611,000		

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 causes plant capability to vary constantly. The current Hoover net plant capability as of July 28, 2011 is 1732 MW.

Castaic Pump Storage Power Plant.

The Castaic Pump Storage Power Plant (the "Castaic Plant") is located near Castaic, California. The Castaic Plant is LADWP's largest source of hydroelectric capacity and consists of seven units with a net dependable capacity of 1,175 MWs. The Castaic Plant provides peaking and reserve capacity for LADWP's load requirements.

Hoover Power Plant.

General. The Hoover Power Plant (the "Hoover Plant") is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada and is part of the Hoover Dam facility, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Plant consists of 17 generating units and two service generating units with a total installed capacity of 2,080 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. Due to recent drought conditions and low lake levels, LADWP's capacity entitlement at the Hoover Plant was reduced to an annual average of approximately 436 MWs (calculated based on 25.16 percent of 1,732 MW output capability as of July 28, 2011).

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.
- Wind resources as shown in Table F-8.
- Other resources and distributed generation as shown in Table F-9.

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	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]	1 2 3	1919 1919 1912	14,000 14,000 14,000	0 14,000 18,000	18,000	5,700
San Fernando 1	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 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. WIND GENERATING RESOURCES (In-service or Under Construction)

PLANT name	COD	Nameplate (kW)	NET MAX PLANT CAPABILITY[1] (LADWP kW)	NET DEPENDABLE CAPABILITY[2] [3] (LADWP kW)	LADWP Share
PPM SW Wyoming	2006	144,000	82,200	8,220	57%
Pine Tree	2009	120,000	120,000	12,000	100%
Willow Creek	2009	72,000	72,000	7,200	100%
Pebble Springs	2009	98,700	68,695	6,870	70%
Milford I	2009	200,000	185,000	18,500	93%
Windy Point	2010	202,400	202,400	20,240	100%
Windy Point Expansion	2010	59,800	59,800	5,980	100%
Linden Ranch	2010	50,000	50,000	5,000	100%
Pine Tree Expansion	2010	15,000	15,000	1,500	100%
Milford II	2011	102,000	102,000	10,200	100%
Subtotal			**957,095**	**95,710**	

Table F-9. OTHER RENEWABLE GENERATING RESOURCES (In-service or under Construction)

PLANT name	COD	Nameplate (kW)	NET MAX PLANT CAPABILITY[1] (LADWP kW)	NET DEPENDABLE CAPABILITY[2] [3] (LADWP kW)	LADWP Share
Lopez Microturbine	2002	1,500	1,500	1,350	100%
Penrose Landfill	2006	6,100	6,100	5,490	100%
Bradley Landfill	2006	6,400	6,400	5,760	100%
BC Hydro	2007	50,000	50,000	25,000	100%
MWD Supulveda Hydro	2008	8,540	8,540	4,270	100%
DWP Built PV Solar	2008	1,000	1,000	250	100%
SB1 PV Solar Rooftop Program	1999-2009	17,553	17,553	4,388	100%
Castaic U3&U5 Upgrade	2009	30,000	30,000	30,000	100%
Distributed Generation	1998-2000	303,000	45,000	45,000	15%
LFG 1	2009	0	0	0	0%
LFG 2	2009	0	0	0	0%
Subtotal			**166,093**	**121,508**	

Notes for Tables F-8 and F-9:

Tables include LADWP's renewables and distributed generating sources from LADWP-owned and contracted projects. This table is based on data from the January 2010 RPS Master Project List and contract sources

[1] The full-load continuous rating of a generator unit under specified conditions as designated by the manufacturer.

[2] Maximum Plant Capability reflects water flow limits at hydro plants; or sum of each unit at renewable plants.

[3] 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.

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.

LADWP currently has approximately 350 MW of customer installed DG on its electrical grid, producing approximately 1,700 Gigawatt hours (GWh) annually, most of which is consumed on-site, although some (approximately 40 MWh/h) is exported back to LADWP. Most of the customer installed DG (approximately 300 MW) 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 November 30, 2011, more than 4,500 LADWP customers have installed over 41 MW of solar PV energy systems with the help of LADWP's Solar Incentive Program.

LADWP has installed more than 1 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. Future DG installations for demonstration purposes will showcase new technologies and should add approximately 1 MW in capacity every three years. These projects will be funded with Public Benefits funds, described in Section 2 of the IRP.

Utility installed DG may also play a role in meeting capacity needs in the future that have very low energy production requirements (low capacity factors). It is estimated that approximately 1 MW of DG will be installed annually beginning in 2010. Tables G-1 and G-2 provide projections of DG and Solar PV capacity and energy. The projections are summarized in Table G-3.

Table G-1. PROJECTED DISTRIBUTED GENERATION CAPACITY AND ENERGY - CUMULATIVE

Calendar Year		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Customer generated	MW	290	280	290	300	302	304	306	308	310	312	314	316
	GWh	1650	1600	1650	1700	1720	1730	1740	1760	1770	1780	1790	1800
Utility generated	MW	1	1	1	2	3	4	6	7	8	10	11	12
	GWh	4	4	4	8	9	10	15	16	17	22	23	24

Table G-2. PROJECTED SOLAR PV GENERATION CAPACITY AND ENERGY - CUMULATIVE

Calendar Year		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Customer generated	MW	9	11	13	18	28	54	85	101	113	125	138	143
	GWh	15	18	21	30	33	63	114	141	160	180	202	210
Utility generated	MW	1	1	1	1	1	1	3	6	9	12	21	37
	GWh	2	2	2	2	2	2	5	11	16	22	38	67

NOTE: The LADWP Solar Program is set to encourage the installation of 280 MW of customer-installed PV by 2016 with a budget of $313 million over 10 years.

Table G-3. SUMMARY OF ANNUAL MW OF DISTRIBUTED GENERATION ADDITIONS

Summary of DG, Solar PV and Customer Electrification - Projected Annual Increases (MW)

Row		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1	Excess Customer DG	10	10	10	2	2	2	2	2	2	2	2
2	Utility DG	1	0	1	1	1	2	1	1	2	1	1
3	Customer PV	2	4	5	7	26	31	16	12	12	13	5
4	LADWP PV	0	0	0	0	0	2	3	3	3	9	16
5	Customer Electrification Program	-3	-5	-6	-8	-10	-11	-13	-15	-16	-18	-20
	Total Annual Projections	**10**	**9**	**10**	**2**	**11**	**27**	**8**	**-2**	**-2**	**-3**	**13**
	Total Cumulative Projections	**10**	**19**	**29**	**31**	**42**	**69**	**77**	**75**	**73**	**70**	**83**

Row Notes

1 See Table G-1. The October 2006 Load Forecast incorporates existing Customer DG. Future years are converted to annualized values.

2 See Table G-1. Converted to annualized values

3 See Table G-2. 10 MW of existing Customer PV is deducted. Future years are converted to annualized values.

4 See Table G-2. 1 MW of existing LADWP PV is deducted. Future years are converted to annualized values.

PV funding continues through 2011. This IRP assumes a continuation of the program for future years.

The October 2006 Load Forecast incorporates the existing 10 MW Customer PV and 1 MW LADWP PV

5 The values are negative as they act to add load.

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. Three of the fuel cell plants have accomplished the task and the fuel cells have been removed from service. The fourth plant is being evaluated for viability of continued operation.

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 41 MW on its customers' properties, as of November 30, 2011. 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 125MW. 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.

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.

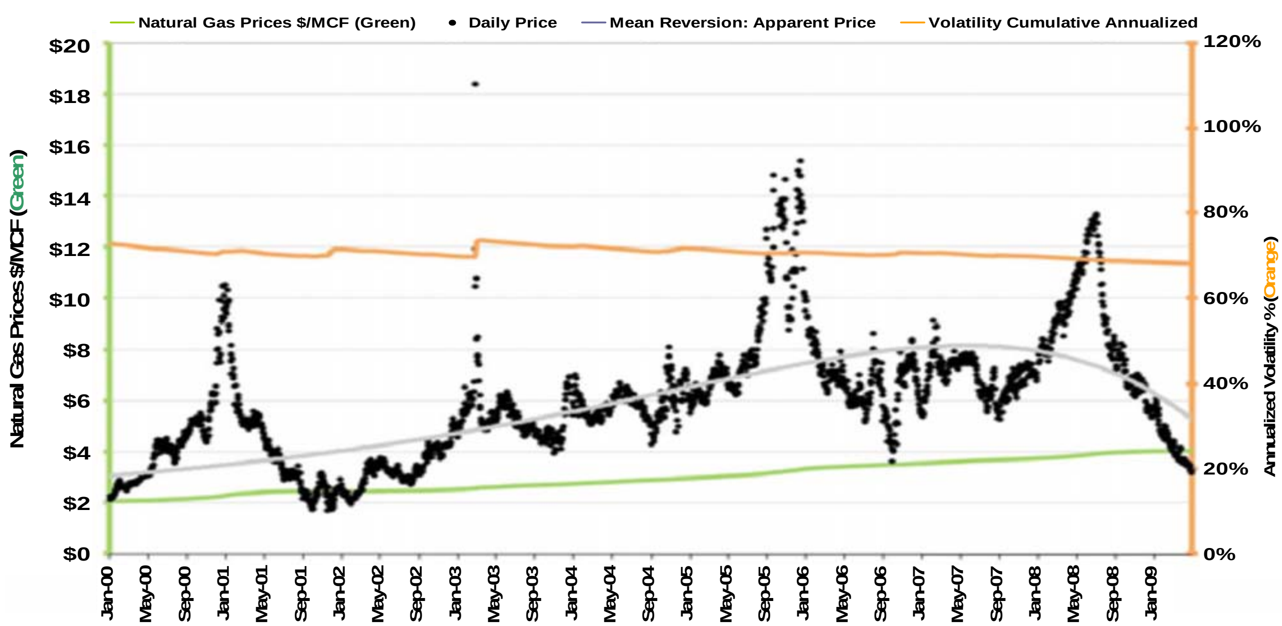


Figure H- 1. Natural gas daily spot prices.

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. 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.
4. LADWP has participated with SCPPA in purchasing an active gas reserve in the Pinedale anticline area of Wyoming. This reserve is currently producing approximately 25,000 million British thermal units (MMBtu)/day, of which LADWP receives approximately 83 percent of the project.
5. 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.
6. 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 contained prices 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.

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 accomodate the delivery of LNG Gas supplies into its system.

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. Implementation of FAR has affected the role of transportation pricing and the distribution of receipt point allocations for deliveries into the California market. The FAR program has been renewed for another three years under the name Basic Transportation Service (BTS). 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 is presently preparing 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. Subsequently, one party that did not settle was able to halt the settlement pending further review by the FERC. The distribution of refunds stands until the FERC resolves the issue.

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.

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.
- 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.

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. 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 $48,000,000 for the four 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 farms 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.

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
- 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 approval of its 2009 BCAP Phase II settlement.
- 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.
- 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.

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 about 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.

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	3,373
East-of-River	9,300	1,109
Pacific DC Intertie @ NOB	2,990	1,196
Owens Valley Transmission	450	450
Intermountain	2,400	1,428

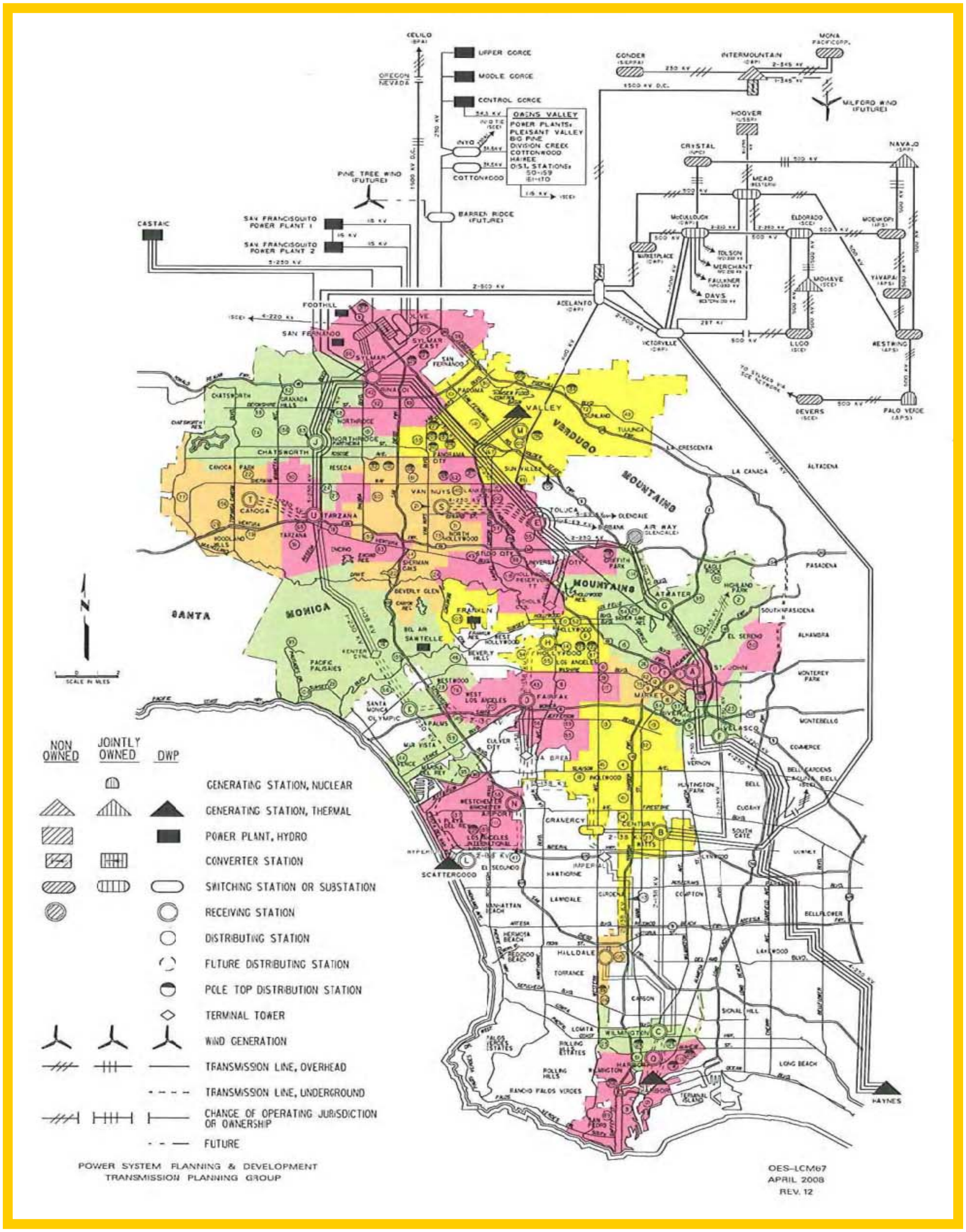


Figure I-1. LADWP Power System diagram.

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 Station receives power from the Intermountain DC corridor. The Victorville 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 McCullough/Marketplace area to the Adelanto/Victorville area along WECC's WOR (Path 46). Path 46 facilitates transportation of electricity from Navajo Generating Station (Page, Arizona) and Palo Verde Generating Station (Wintersburg, Arizona) to Southern Nevada and Southern California. Until the 1580 MW Mohave Generating Station was shut down in 2005, the Mohave-Lugo 500kV line primarily interconnected that station to the WECC power grid. Since 2006, LADWP has been selling available capacity in the wholesale markets via OASIS. The Palo Verde-Devers 500kV line, of which LADWP has contractual rights to 468MW, 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	468
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	0
		WOR Total	10,623	6,278

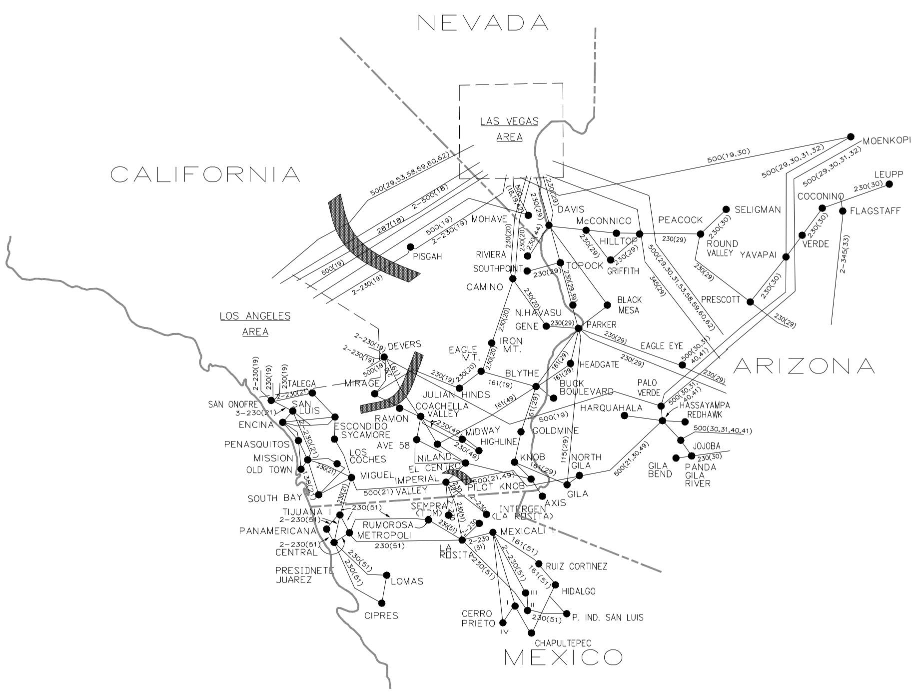


Figure I-2. LADWP West-of-Colorado transmission resources.

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 Southern California. The Palo Verde-Devers 500kV line, of which LADWP currently has contractual rights to 468MW, 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	500	9,300, east to west non-simultaneous	1,109
Moenkopi-Eldorado	500		
Liberty-Peacock-Mead	345		
Palo Verde-Devers	500		
Hassayampa-North Gila	500		
Perkins-Mead	500		

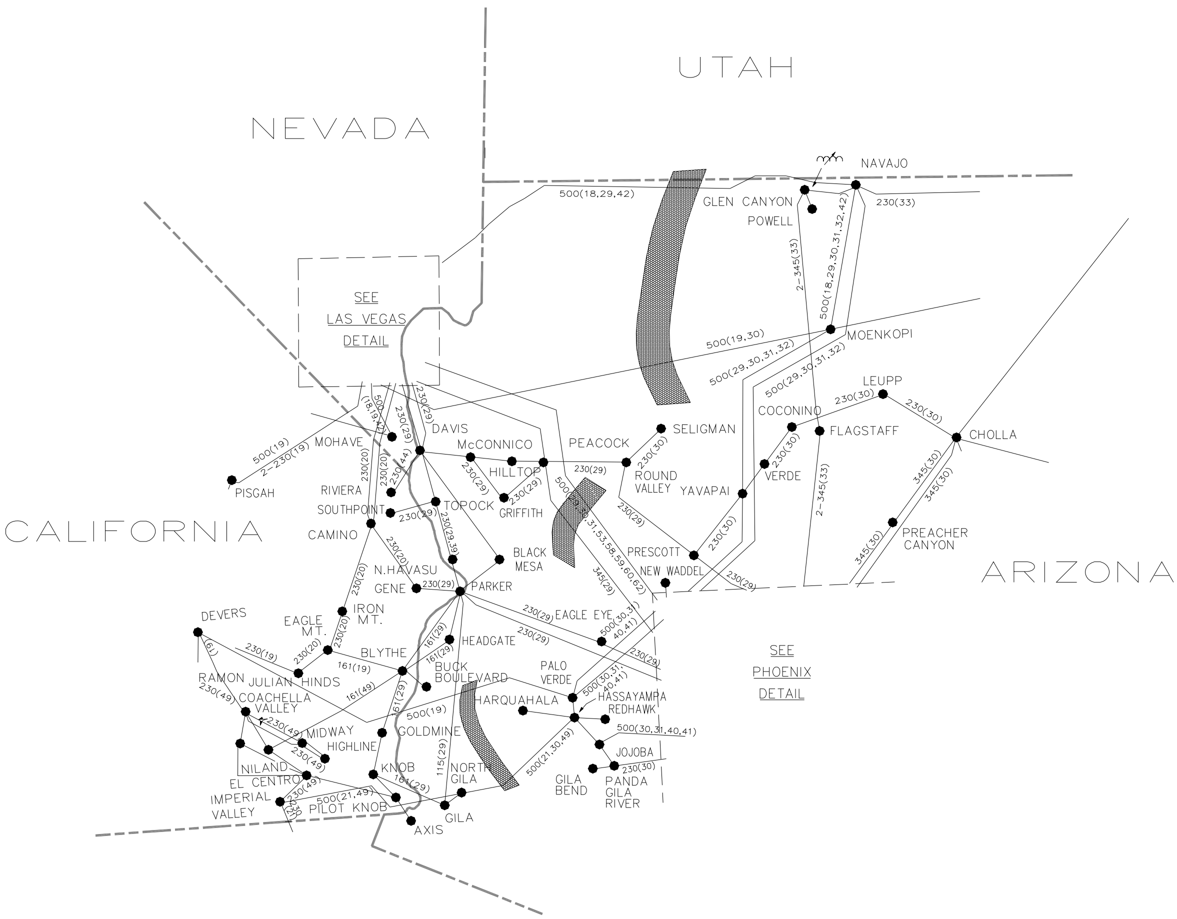


Figure I-3. LADWP East-of-Colorado River transmission resources.

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	300[1]	Owned Asset	300

[1] The normal rating of the line is 459 MVA,

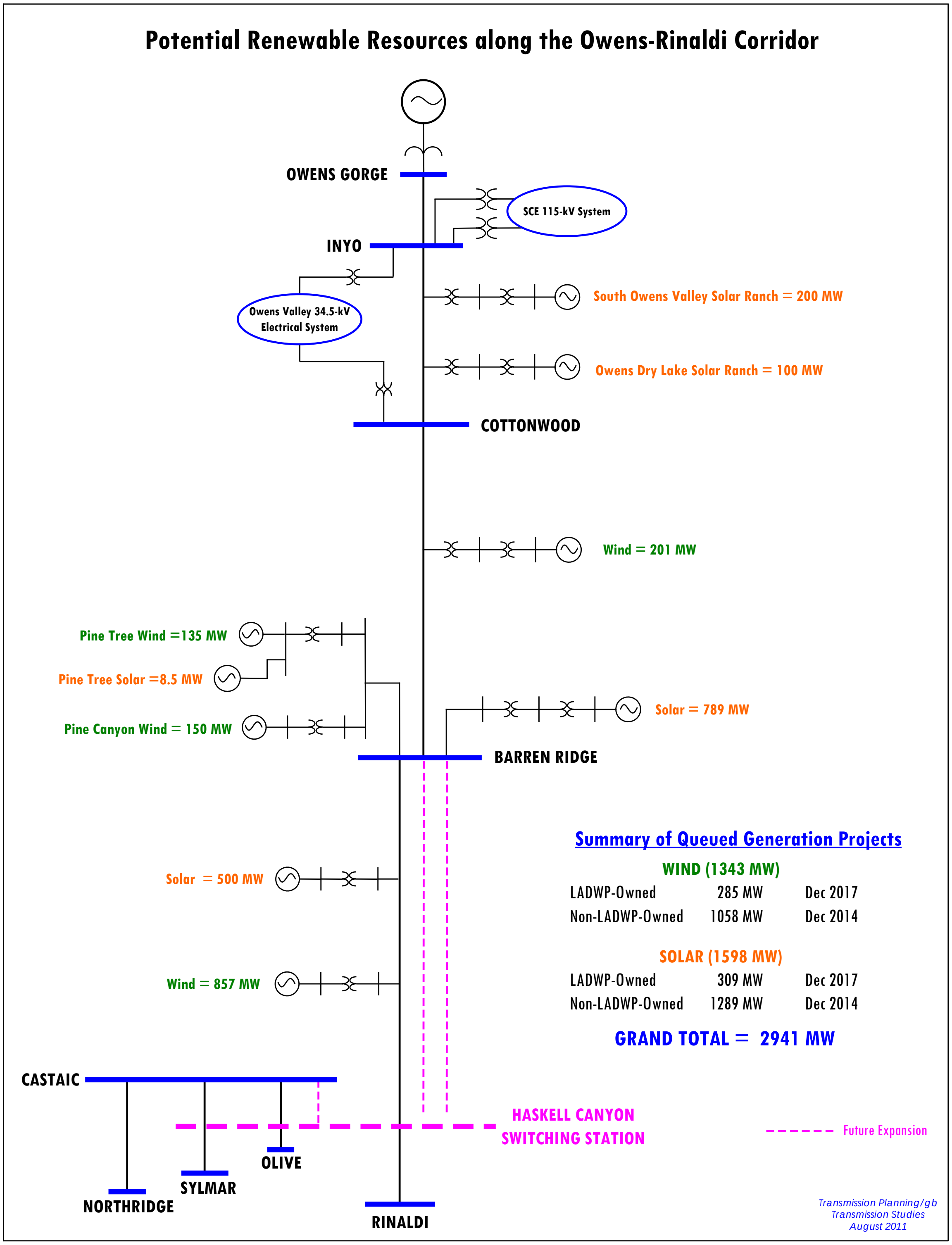


Figure I-4. Owens Valley transmission resources.

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

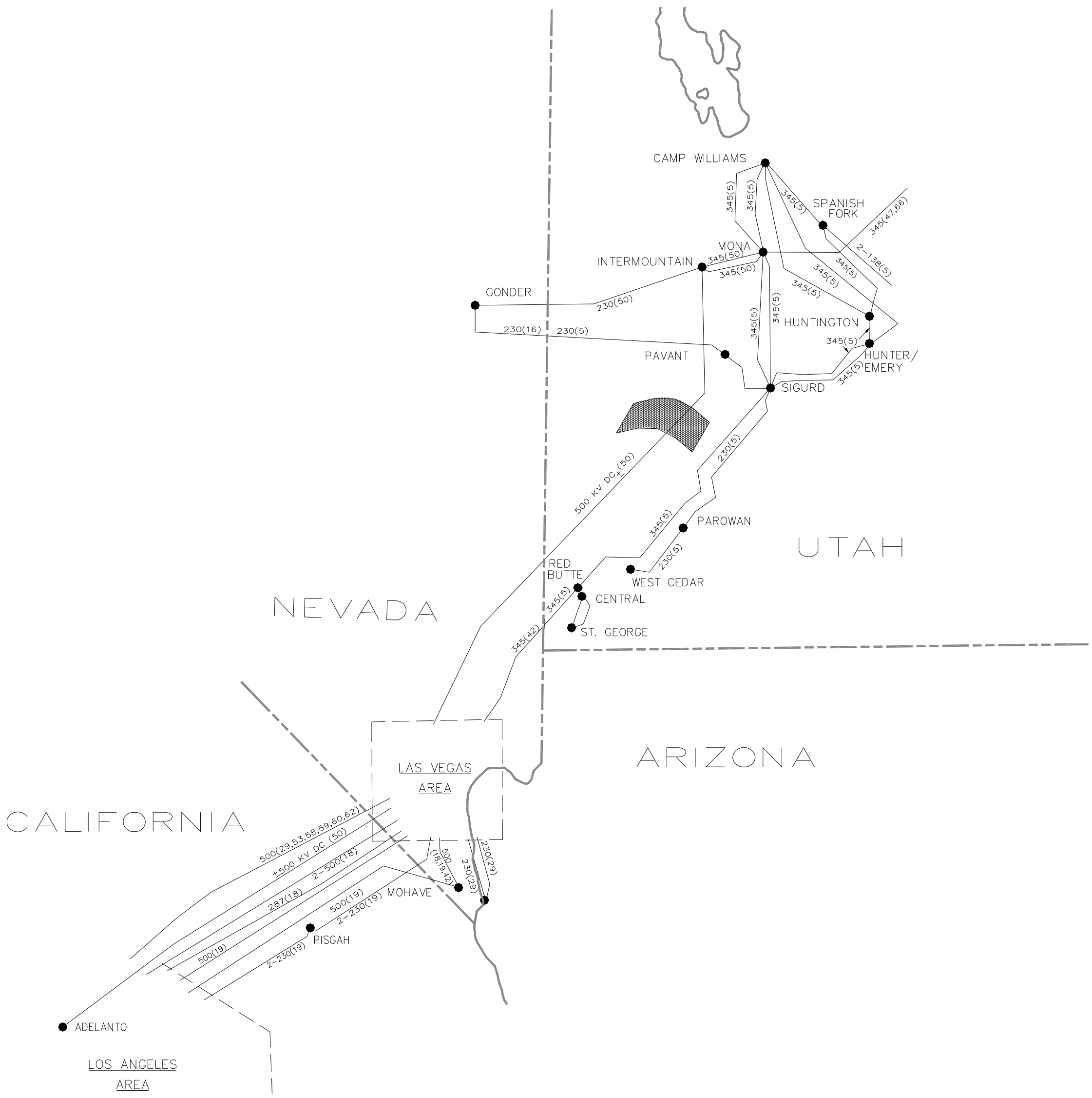


Figure I-5. WECC Path 27.

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

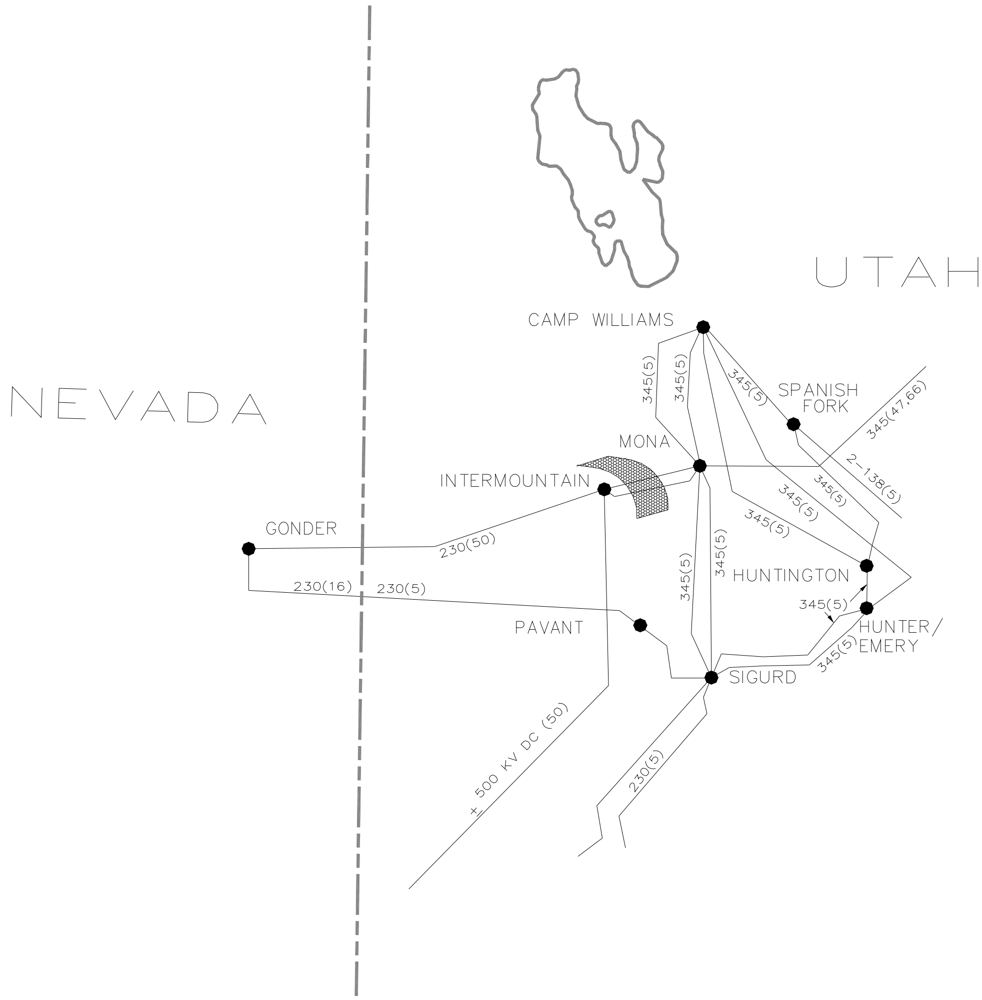


Figure I-6. WECC Path 28.

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

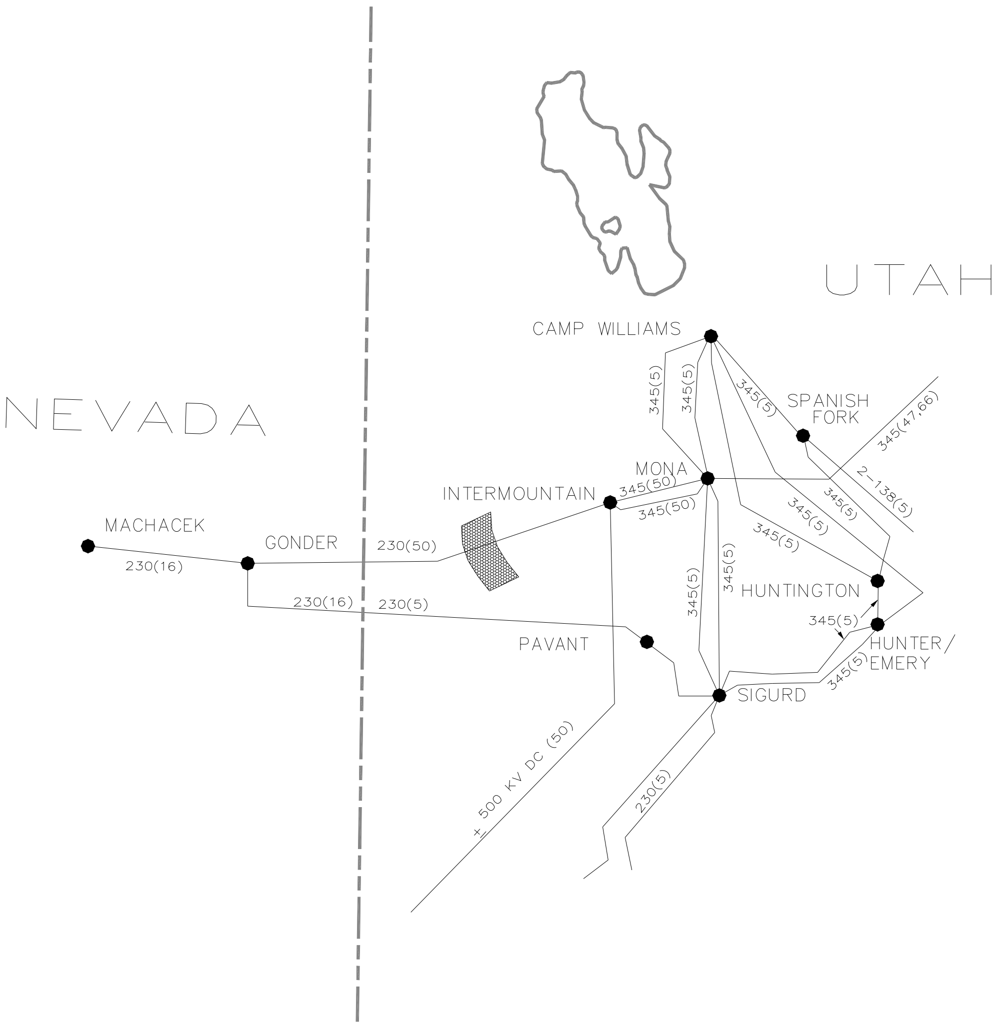


Figure I-7. WECC Path 29.

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 according to nature in a variable and intermittent manner, and the energy from these renewable resources is generally neither controllable nor dispatchable by power system operators. For example, solar resources generally only produce energy when the sun is up, 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. 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 absorb 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 renewable resources, the conventional resources of a power system must become more flexible in their ability to increase and decrease the amount of energy generated 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 2009, 14 percent of energy sold to its customers was generated from renewable energy resources, 20 percent was generated 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 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 have a greater ability to integrate intermittent wind and solar resources.

2) Individual wind farms tend to have a high variability in the amount of energy produced (see Figure J-1).

3) Wind energy production impacts regulation (minute to minute variability), load following (hourly variability), and unit commitment decisions (day ahead flexibility). See Figure J-2.

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 at its minimum.

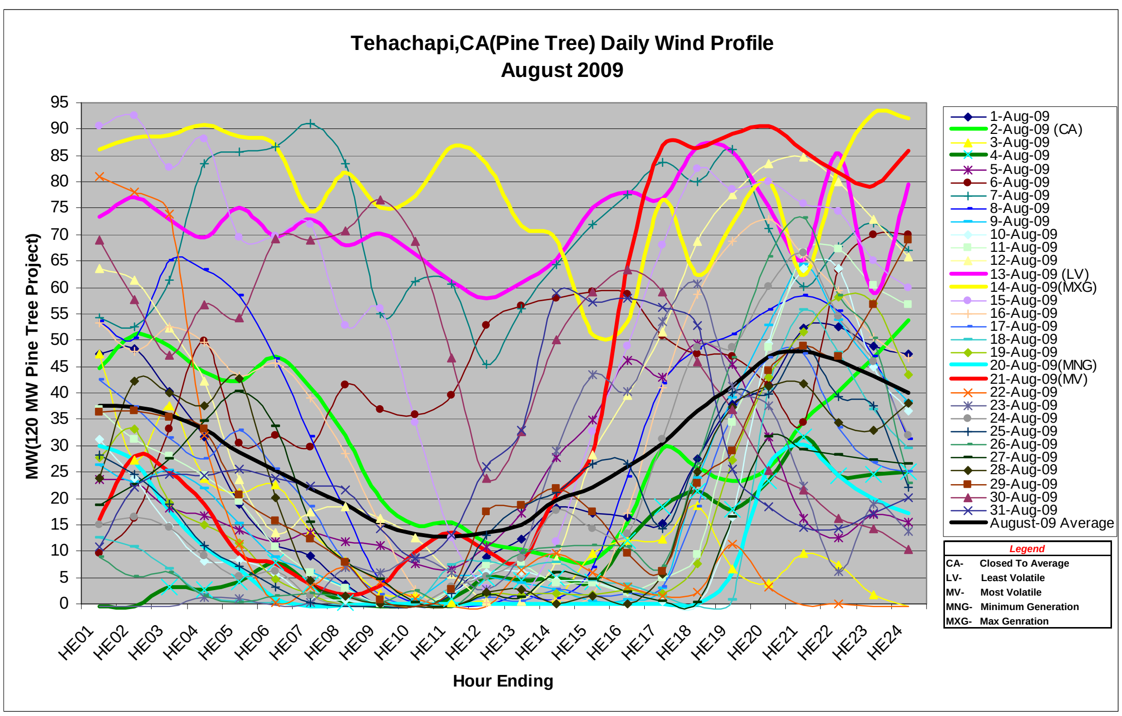
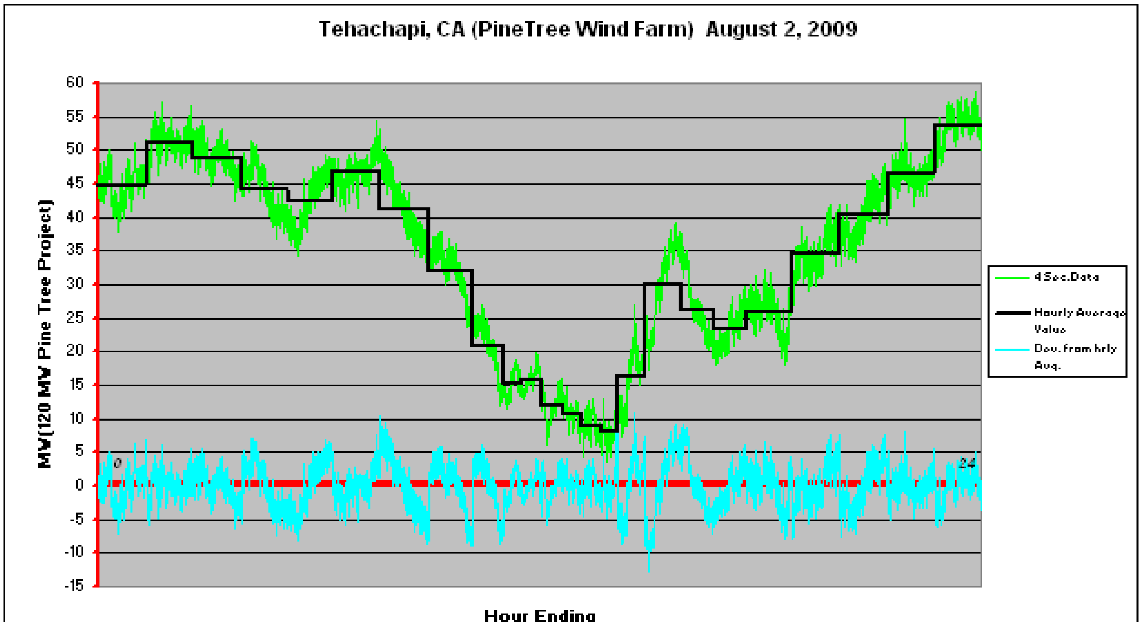


Figure J-1. Wind farm daily wind profiles.



Maximum Hour Deviations (Absolute Values)																							
HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
13.79	11.90	11.92	14.43	14.86	13.38	18.96	14.88	14.84	7.53	8.63	9.92	8.20	8.64	13.04	19.62	21.70	16.39	11.68	14.46	15.53	15.18	13.21	11.35

Note: The 24 hours along the x-axis cannot be accurately displayed because each hour contains different quantities of raw data

Figure J-2. Wind farm impact on load following capability.

7) High wind energy production during low power system energy demand hours in many cases represents the greatest challenges 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 (see Figure J-3).

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 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.

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 be displaced by renewable resources.

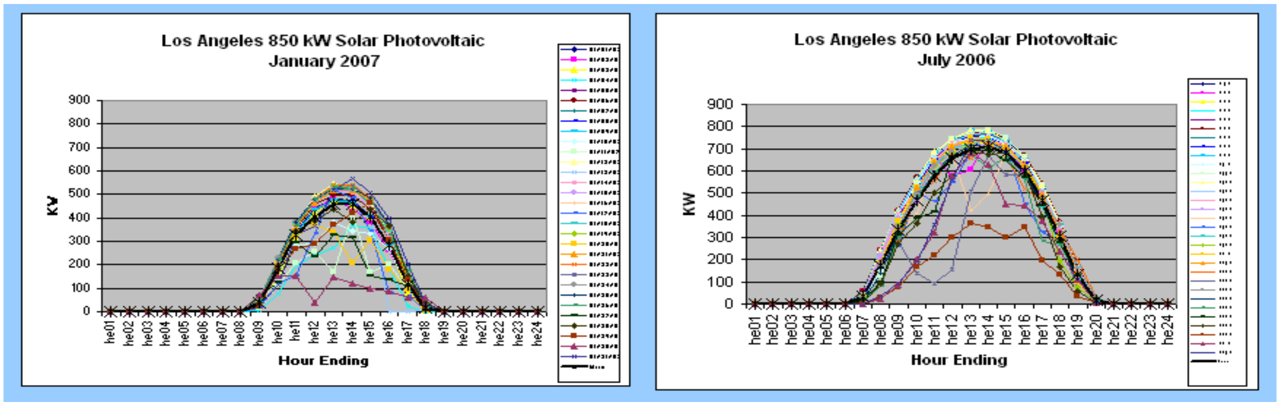


Figure J-3. Solar photovoltaic comparisons.

Some common recommendations from these studies include the following:

1) Successful integration of intermittent renewable resources requires an investment in transmission and generation resources, changes in power system operations and practices, and cooperation among 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) Wind production equipment needs to have “grid friendly” features, including low voltage ride through, voltage control, and reactive power control.

5) Wind energy production must be curtailable by power system operators if wind production negatively affects power system reliability. The power system operators also must have the ability to set power ramp rates for wind projects if needed to ensure power system reliability.

6) Natural gas fired combustion turbines and pump-storage hydro plants are good complements to integrating intermittent renewable resources into existing power systems. Additionally, pump-storage hydro plants with variable speed pumping capability provide even more flexibility to a power system. Other energy storage devices described in Appendix K may also assist in integrating intermittent renewable resources.

7) Customer load shifting programs work well in integrating intermittent renewable resources.

Further studies, planning and system modeling will be needed as additional renewable resources come on-line to assure 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. A proposed ESS demonstration project is described, and a summary of Demonstration Program benefits is provided.

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 plan is to augment this with large-scale battery-based and/or compressed air energy storage when feasible. 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.

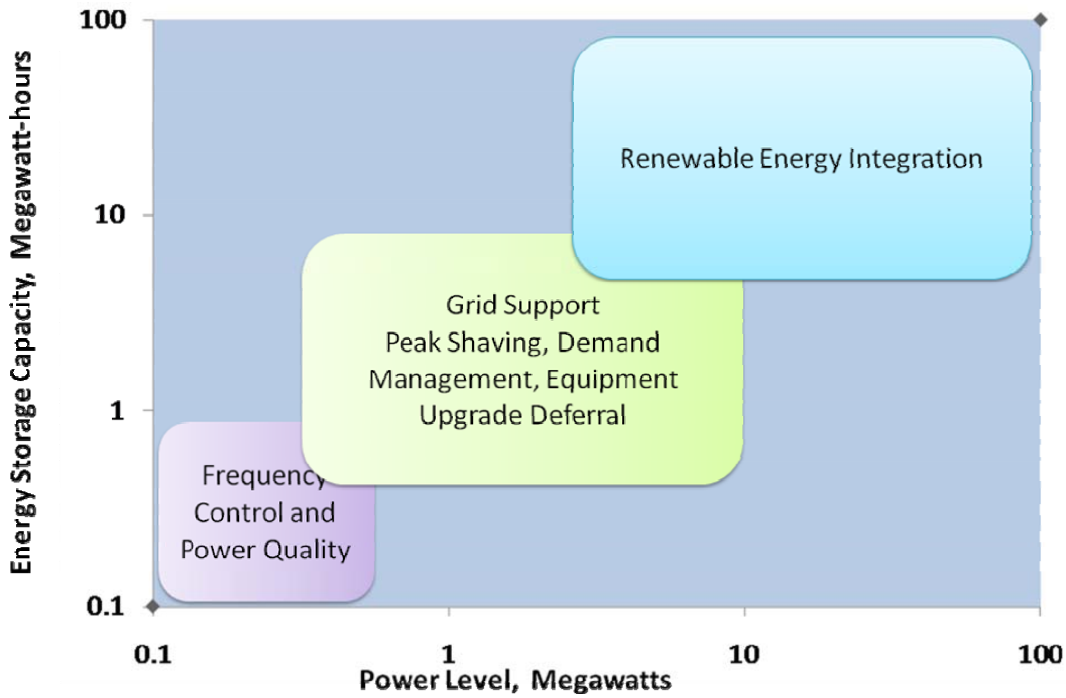


Figure K-1. Requirements of grid-scale ESS.

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.

Lithium-Ion Batteries

Figure 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.

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^{o}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

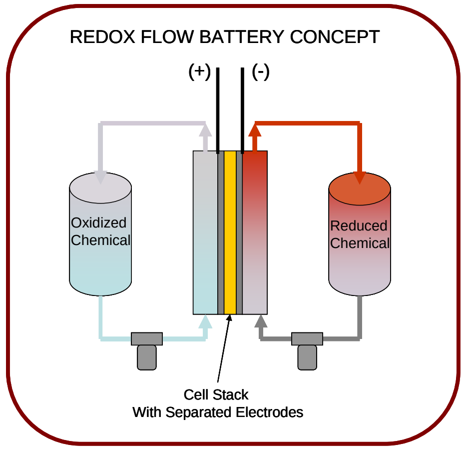


Figure K-4. Redox flow batteries.

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.

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 Potential LADWP Barren Ridge ESS Integration Pilot Project

K.4.1 Background

The proposed Barren Ridge ESS Integration Pilot Project was formulated to demonstrate the benefits of energy systems to effectively utilize the energy generated by wind farms and effectively integrate it with the power grid.

Integrating renewable power systems from wind and solar generated power into the electric grid presents several challenges. These renewable power systems are by nature somewhat unpredictable and intermittent. Thus, the amount of electrical energy they produce varies over time and depends heavily upon a variety of random factors mostly tied to local weather conditions. Small wind power systems can be managed without an ESS, but large wind power systems (at rated capacities somewhere around 10 percent of a grid's capacity) are not grid manageable without an ESS. The is because even moderate fluctuations in wind speed could result in excessive fluctuations in grid-fed wind-generated electricity and hence force grid managers to disconnect wind generated power from the grid just when the potential energy yield is greatest.

Installing large ESSs as part of a wind power system architecture will reduce the power fluctuation problem and will produce frequency-clean, voltage/current controlled, and uninterruptable power into the grid. Several studies have indicated that ESS integration with renewable energy resource power generators will enable clean and controlled delivery of more than 92 percent of the available generated power, while greatly reducing or eliminating the need for back-up fossil fuel power plants.

K.4.2 System Description

The overall system concept for the Barren Ridge ESS Integration Pilot Project is schematically shown on Figure K-5. The energy generated from the Pine Tree Wind Power Project (PTWPP) will be diverted into the ESS at the Barren Ridge Switching Station (BRSS) in California. Additional energy storage will be available at the pumped hydro storage at Castaic Lake. All the power control system equipment will be located at the BRSS.

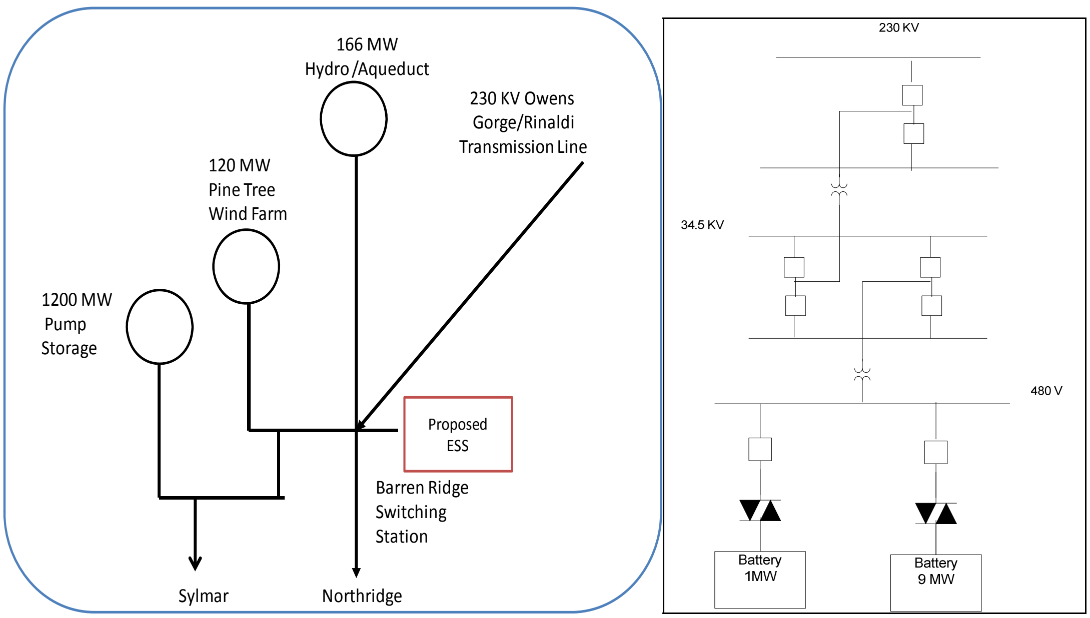


Figure K-5. System concept for Barren Ridge ESS Integration Pilot Project.

K.4.3 Project Site and Assets

The BRSS site was selected because the required assets for this demonstration project, namely, the wind farm generated power and its associated high voltage alternating current transmission lines, are available. Further, the auxiliary PHS facility is linked by other transmission lines to the BRSS.

The LADWP's PTWPP is the largest municipally-owned wind power farm in the U.S. and is located about 12 miles north of Mohave, CA. The PTWPP is sited on 8000 acres of rough terrain and consists of 90, 1.5 MW wind turbines to provide a rated wind power capacity of 135 MW.

A new 8.25-mile transmission line routes power from the PTWPP to the BRSS, where power is tied into the high voltage (230 kV) north-south transmission line that feeds Los Angeles.

The LADWP could conceptually install about 75 miles of new 230 kilovolt (kV) conductors on both existing and new north-south transmission towers to a new Haskell Switching Station (HSS). The conductors would carry the wind and solar generated power between the BRSS and the HSS, which is linked to the Castaic Lake plant at Elderberry Forebay (462 m above sea level).

K.4.4 ESS

Integration of very large-scale wind and solar farms into the grid requires a low-cost, long life ESS capable of storing hundreds of MWh of electrical energy. The hybrid ESS described here combines a moderate amount of battery storage capacity with a large PHS capacity. This hybrid ESS concept is ideally suited for this application and enables the maximum dispatchability (or usability) of all generated renewable power so that the generated renewable power is not wasted.

Further, the battery storage system can be designed with adequate capacity to provide the necessary reserves for serving both frequency response and spinning reserve requirements, while also serving to dampen out the power quality fluctuations inherent in wind and solar power generators. The battery ESS can also provide ramp control as non-spinning reserves ramp up to capacity. The large PHS ESS will satisfy the needed utility load-shifting requirement by pumping water to a higher elevation during off-peak periods and generating power through the hydroelectric generators during peaking periods. Three primary battery ESS candidates being considered for this demonstration are: redox flow batteries, large-capacity lithium ion batteries, and NaS batteries.

Based on the intermittency and variability of wind-generated power, the ESS that will firm up the wind farm output from the PTWPP should be sized to have a power output of at least 80MW and a storage capacity of 560 MWh. This will be in addition to the pumped hydro storage capability at Castaic Lake. Initial design studies and demonstration of the overall design will be conducted at the 10 MW level. LADWP will then use the lessons learned to scale the system up to 80 MW.

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.

Advanced Lithium-Ion Batteries
Many of the safety features provided in small 18650 size cells, such as PRTs and CIDs, are not incorporated into large capacity Li-ion cells. One approach to improve the safety of Li-ion cells is to adopt the use of electrode materials that are inherently safer and still offer the high energy densities provided by lithium-ion technology. To this end, the demonstration project will scale up and implement new electrolytes and cathode materials under development at JPL.

Currently utilized electrolyte formulations, which are composed of organic alkyl carbonates, are highly flammable; there is a strong desire to reduce the inherent flammability of the electrolyte itself. This can be accomplished by the incorporation of flame retardant additives, such as phosphates, phosphites, and phosphonates, and/or the use of non-flammable electrolyte solvents, such as halogenated carbonates and esters. At JPL, development work has been focused upon both approaches, with the intent of developing safer electrolyte solutions for "human rated" aerospace applications.

Advanced Redox Flow Battery
An advanced redox flow battery that operates on iodate/iodide redox coupling has been under development and can potentially offer a superior system for large-scale energy storage compared to the vanadium redox battery. The key improvements achieved by this new concept over the state-of-art vanadium redox battereis are shown in Table K-3. A schematic of an iodide/iodate redox battery with the reactions occuring at either electrode is presented on Figure K-7.

Table K-3: COMPARISON OF SOA AND ADVANCED REDOX BATTERIES

Parameter	Vanadium Redox Battery (State of the Art)	Iodide-Iodate Redox Battery (Advanced Concept)
Environmental Impact	Uses biologically active heavy metal	Uses iodide No heavy metals. Environmentally friendly
Energy Density	25 - 30 Wh/liter	> 50 Wh/liter
Energy losses through membrane	Yes. Cationic reactants diffuse through membrane	No. Anionic reactants cannot diffuse through membrane
Projected Life	10 - 15 years	> 15 years

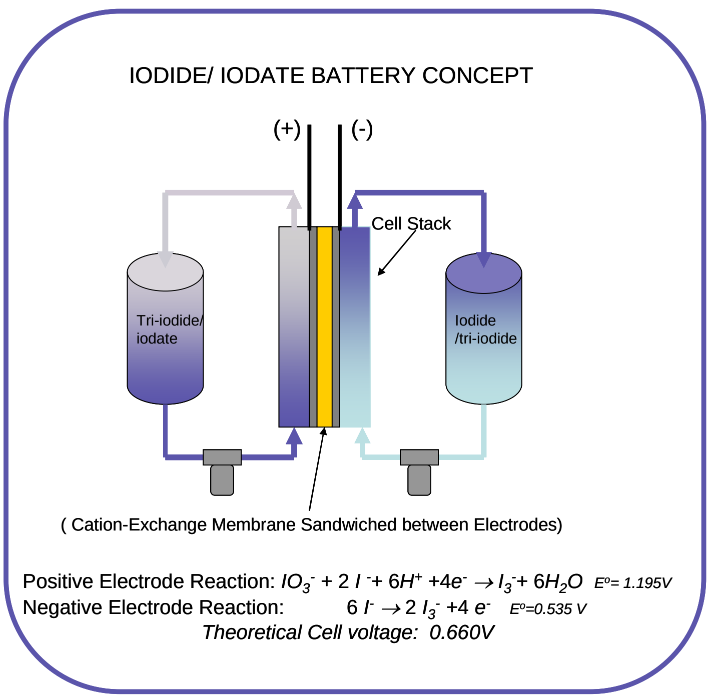


Figure K-7: Schematic of iodide/iodate redox battery.

K-5 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

<table>
<tr><th>LADWP Approach</th><th>Benefits</th><th>Metrics</th></tr>
<tr><td>Use Battery Energy Storage to supply energy when the generation dips from the wind or solar generators during peak demand periods or demand increases</td><td>Lower electricity cost</td><td>Lowering peak demand needed from expensive combustion turbine generators with wind and solar generation</td></tr>
<tr><td>Use Battery Energy Storage to supply energy when the generation dips from the wind or solar generators or during system disturbances</td><td>Reduced power interruptions and increase reliability</td><td>Fewer and Shorter outages</td></tr>
<tr><td rowspan="3">Use Battery Energy Storage to supply energy when the generation dips from the wind or solar generators or during system disturbances</td><td rowspan="3">Reduced costs from better power quality</td><td>Fewer momentary outages</td></tr>
<tr><td>Fewer severe sags and swells</td></tr>
<tr><td>Lower harmonic distortion</td></tr>
<tr><td>Use Battery storage energy from green power reduces CO2 Emissions</td><td rowspan="2">Reduced damages as a result of lower GHG/carbon emissions</td><td>Percentage of green power relative to total power generated.</td></tr>
<tr><td>Increase of battery storage from green power to reduce need for oil or gas</td><td>Percentage of green power relative to total power generated</td></tr>
<tr><td>Reduce reliance on non renewable resources</td><td>Greater energy security from reduced oil consumption</td><td>Percentage of green energy utilized</td></tr>
</table>

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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.

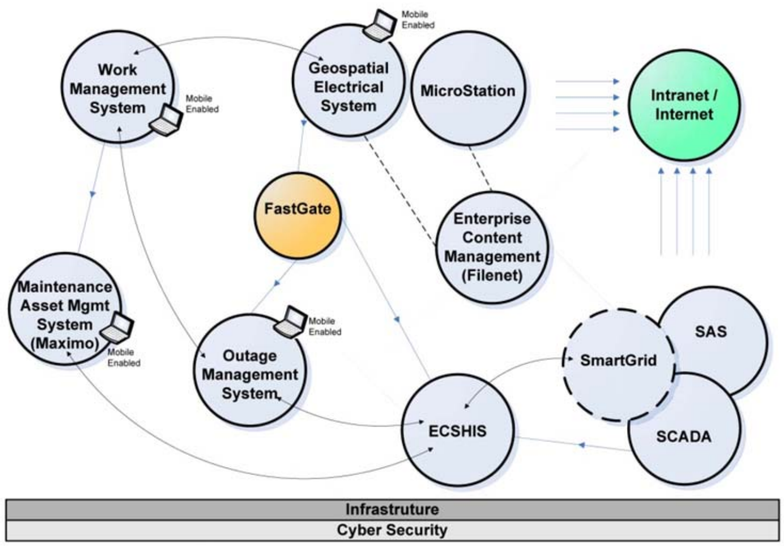

Figure 2.11-1 Power System Technology Architecture

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 19	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.

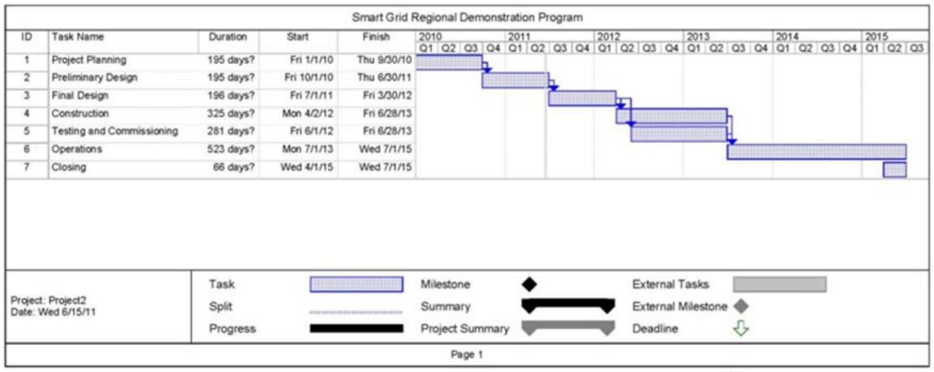

Figure 3.2-1 Smart Grid Regional Demonstration Project Schedule

- 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.

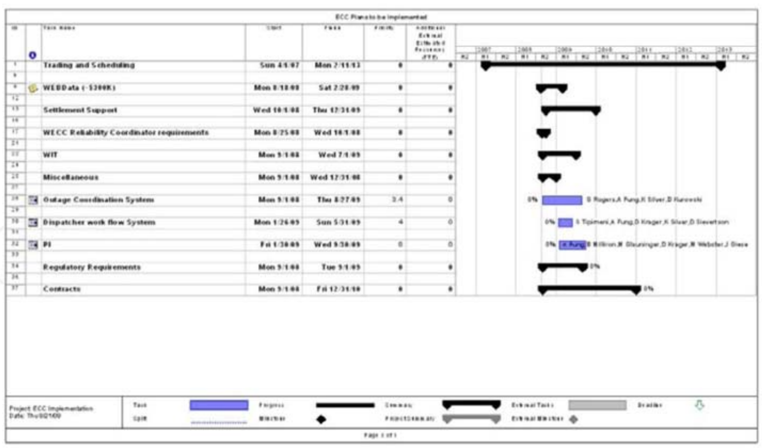

Figure 3.2-2 ECC Plans to be Implemented

- 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.

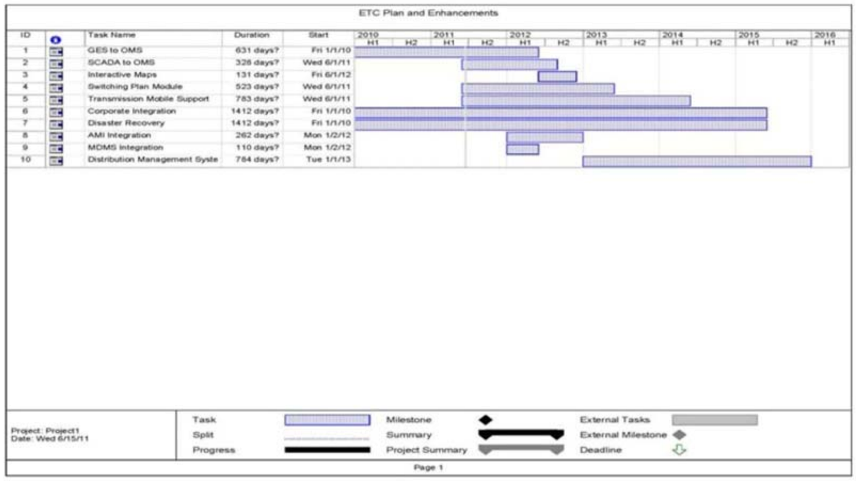

Figure 3.2-3 ETC Plan and Enhancements

- 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.

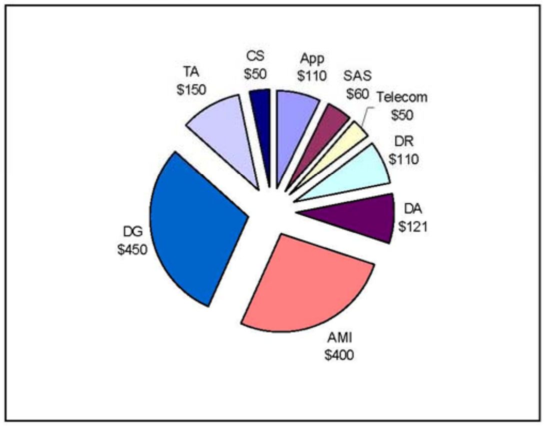

Figure 4.1-1 P2P Cost Graph

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.

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Appendix M Model Description and Assumptions

M.1 Overview

The study horizon for the model analysis is the 20 year period 2011 through 2030. 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 M.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 M.3, Renewable Resources Selection Process/Gap Analysis, describes the method used to assess the amount of future renewables required, and the valuation process used in selecting the future renewable resource portfolio.
- Section M.4, Case Options, reviews the key resource distinctions between the 3 case options under consideration.
- Section M.5, Model Inputs and Assumptions, presents the major input parameters that were used in the production cost model runs.

M.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 M-1 was developed for this IRP.

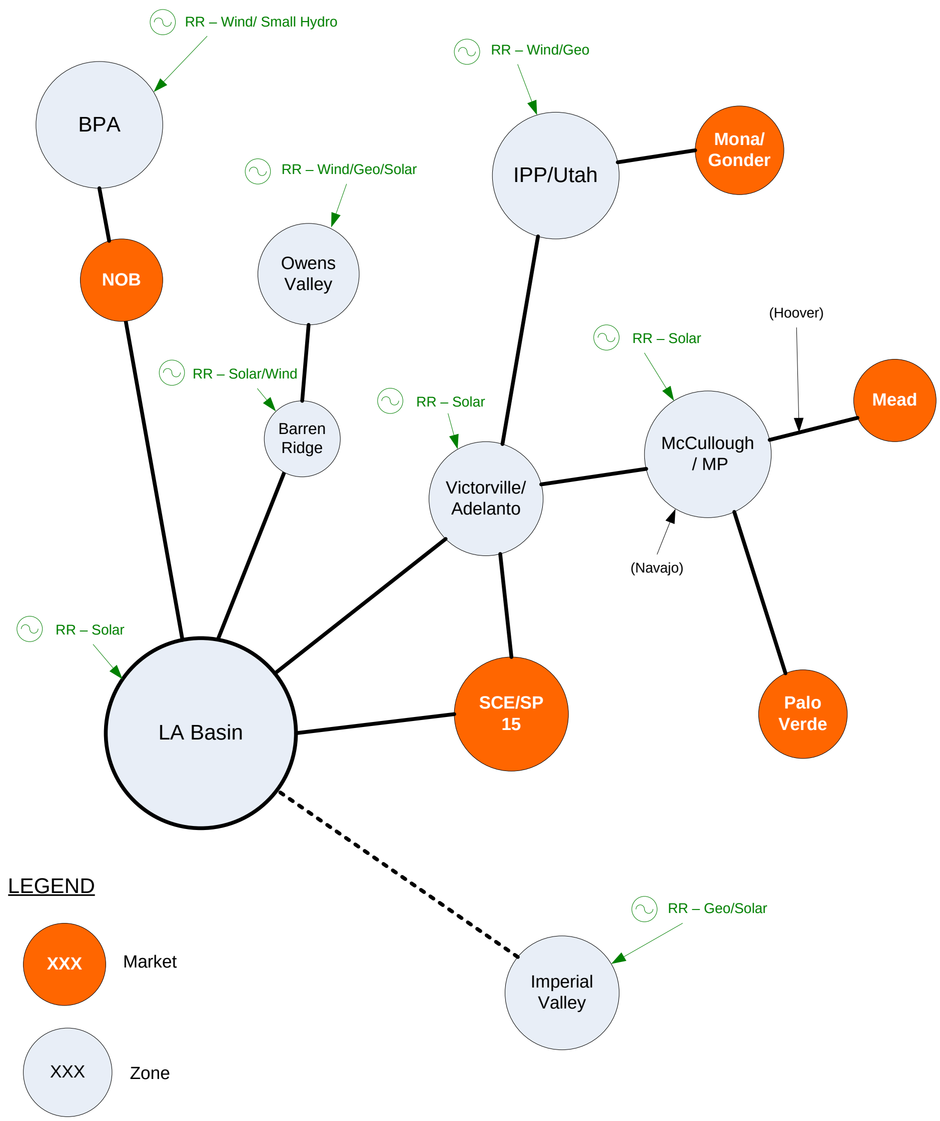


Fig M-1: LADWP Modeling Topology.

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.

M.3 Renewable 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 2.4.5, 3.4.1, 4.2.1.4 and 4.3.1 of this report discuss the LADWP approach to RA.

M.3.1 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.

M.3.2 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.

M.3.3 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

M.3.4 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.

M.3.5 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)*

M.3.6 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

M.3.7 Renewable Energy Portfolio

Utilizing the methodology described in the previous subsections, a best-value portfolio of renewable resources was developed. This portfolio was applied to all case options considered in this IRP. Because regulation mandates the procurement of specific levels of renewables, the quantities are predetermined for compliance periods in accordance with SB 2 (1X). The renewable capacity and energy production schedules shown in Figures M-2 and M-3 were used in all cases including the recommended case (Case 2) and are consistent with the procurement targets established by SB 2 (1X).

RPS Capacity (MW)

Recommended Case 2011 IRP (MW)																							
Station Group	Plant	Item	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Existing Wind	Wind_Linden	Wind_Linden	50	50	50	48	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
	Wind_PebbleSprin	Wind_PebbleSprings	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69					
	Wind_PineTree	Wind_PineTree	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
	Wind_PPMWyoming	Wind_PPMWyoming	82	82	82	82	82	82	82	82	82	82	82	82	82								
	Wind_Willow Crk	Wind_Willow Crk	72	72	72	72	72	72	72	72	72	72	72	72	72	72							
	Wind_WindyPoint	Wind_WindyPoint	262	262	262	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242
	Wind_Milford	Wind_Milford1	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
		Wind_Milford2	0	102	102	102	100	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Existing Small Hydro	AQ & OV& OG	AQ & OV& OG	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
	Hydro_Powerex	Hydro_Powerex	50	50																			
	North Hollywood	North Hollywood	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Hydro_Sepulveda	Sepulveda	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Castaic 3 & 5 Upgrade	Castaic3&5 Upgrade	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	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	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Existing Biogas	Bio_Bradley	Bio_Bradley	6.4	6.4	6.4	6.4	6.4	6.4															
	Bio_Lopez	Bio_Lopez	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	Bio_Toyon	Bio_Toyon	3.6	3.6																			
	Atmos & Shell Gas Credit	Atmos & Shell Gas Credit																					
	Hyperion Digester Gas	Hyperion Digester Gas																					
New Geo	Geothermal	Geo PPA 2014 M						30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
		Geo PPA 2016 T							53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
		Imperial County Joint Geothermal Project -1,2,3,4								25	50	75	100	100	100	100	100	100	100	100	100	100	100
		Generic_Geo													50	75	100	125	125	125	125	125	125
Subtotal			**0**	**0**	**0**	**0**	**0**	**30**	**83**	**108**	**133**	**158**	**183**	**183**	**233**	**258**	**283**	**308**	**308**	**308**	**308**	**308**	**308**
New Solar	Solar_DWP	Solar_DWP_Owens									50	100	150	200	200	200	200	200	200	200	200	200	200
		Solar_DWP_Basin_Planned		1	3	6	9	12	21	37	54	71	88	101	101	100	100	99	99	98	98	97	97
		Adelanto Solar			10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
		Solar_PineTree			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Solar_Feed_In	Solar_FIT			3	6	20	45	75	83	90	98	105	113	120	128	135	143	150	150	150	150	150
	Solar C-N-M	Solar_C-N-M (SB1)	0	26	57	73	85	97	110	115	120	126	132	139	146	154	162	171	180	189	199	209	219
	Solar_PPA	Solar PPA 2014 M					64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
		Solar PPA 2015 R						53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
		Solar PPA 2014 S					35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
		Solar PPA 2020 S											80	80	80	80	80	80	80	80	80	80	80
Subtotal			**0**	**27**	**81**	**103**	**231**	**324**	**376**	**405**	**484**	**565**	**725**	**803**	**817**	**832**	**847**	**863**	**879**	**887**	**897**	**906**	**916**
New Wind	Wind_PineCanyon	Wind_PineCYN									120	120	120	120	120	120	120	120	120	120	120	120	120
	GenericWind	Wind PPA 2012 L			90	90	90	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
		Wind PPA 2015 B						150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
		Wind PPA 2015 W						150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Subtotal			**0**	**0**	**90**	**90**	**90**	**372**	**372**	**372**	**492**	**492**	**492**	**492**	**492**	**492**	**492**	**492**	**492**	**492**	**492**	**492**	**492**
New Bio Gas	Bio GAS	Bio Gas																					
	Biogas Extension	Biogas Extension																					
New Small Hydro	Hydro	WSHydro							4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Castaic U1 update		15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
		Aqueduct PP Improvement							4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Generic_RPS															48	48	86	114	133	152	162
		GreenPurchase																					
Total RPS			**1,151**	**1,295**	**1,386**	**1,385**	**1,508**	**1,911**	**2,017**	**2,071**	**2,295**	**2,401**	**2,586**	**2,664**	**2,728**	**2,686**	**2,702**	**2,742**	**2,728**	**2,765**	**2,794**	**2,822**	**2,841**

Figure M-2. Renewable resource capacity in MW for all cases.

RPS Energy (GWh)

Recommended Case 2011 IRP (GWh)																						
Station Group	**Plant**	**Item**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Existing Wind	Wind_Linden	Wind_Linden	144	145	138	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Wind_PebbleSprin	Wind_PebbleSprings	210	193	193	193	193	193	193	193	193	193	193	193	193	193	193					
	Wind_PineTree	Wind_PineTree	288	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
	Wind_PPMWyoming	Wind_PPMWyoming	215	171	171	171	171	171	171	171	171	171	171	171								
	Wind_Willow Crk	Wind_Willow Crk	199	197	197	197	197	197	197	197	197	197	197	197	197							
	Wind_WindyPoint	Wind_WindyPoint	677	694	645	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641
	Wind_Milford 1	Wind_Milford1	420	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434
	Wind_Milford2	Wind_Milford2	144	217	217	212	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206
Existing Small Hydro	AQ & OV& OG	AQ & OV& OG	838	532	532	532	532	532	532	532	532	532	532	532	532	532	532	532	532	532	532	532
	Hydro_Powerex	Hydro_Powerex	437																			
	North Hollywood	North Hollywood	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Hydro_Sepulveda	Sepulveda	33	38	38	38	38	38	38	38	38	38	38	38	38							
	Castaic 3 & 5 Upgrade	Castaic3&5 Upgrade	6	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Existing Solar	Solar_DWP_Basin	Solar_DWP_Basin_E	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_C-N-M	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Existing Biogas	Bio_Bradley	Bio_Bradley	41	36	36	36	36															
	Bio_Lopez	Bio_Lopez	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Bio_Toyon	Bio_Toyon	9																			
	Atmos & Shell Gas Credit	Atmos & Shell Gas Credit	591	638	638	343																
	Hyperion Digester Gas	Hyperion Digester Gas	131	147	147	147																
		Existing Subtotal	**4,424**	**3,881**	**3,825**	**3,513**	**3,017**	**2,981**	**2,981**	**2,981**	**2,981**	**2,981**	**2,981**	**2,981**	**2,809**	**2,574**	**2,574**	**2,382**	**2,382**	**2,382**	**2,382**	**2,382**
New Geo	Geothermal	Geo PPA 2014 M					237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237
		Geo PPA 2016 T						150	441	441	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
		Generic_Geo												400	600	800	1,000	1,000	1,000	1,000	1,000	1,000
		Subtotal					**237**	**387**	**778**	**1,011**	**1,211**	**1,478**	**1,478**	**1,878**	**2,078**	**2,278**	**2,478**	**2,478**	**2,478**	**2,478**	**2,478**	**2,478**
New Solar	DWP	Solar_DWP_Owens								110	220	330	440	438	436	433	431	429	427	425	423	421
		Solar_DWP_Basin_Planned	1	4	10	15	21	37	66	96	127	157	181	181	179	179	177	177	175	175	174	174
		Adelanto Solar		11	20	20	20	20	20	20	19	19	19	19	19	19	19	19	19	19	18	18
		Solar_PineTree		3.9	17	17	17	17	17	17	16	16	16	16	16	16	16	16	16	16	16	16
	Solar_Feed_In	**Solar_FIT**		5	10	33	75	124	136	148	160	171	193	195	206	217	229	240	239	238	237	235
	Solar C-N-M	Solar_C-N-M (SB1)	30	81	108	127	147	169	177	185	195	205	216	228	241	254	269	284	299	315	332	348
	Solar_PPA	Solar PPA 2014 M				11	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
		Solar PPA 2015 R					12	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
		Solar PPA 2014 S				85	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
		Solar PPA 2020 S										20	196	196	196	196	196	196	196	196	196	196
		Subtotal	**31**	**105**	**165**	**308**	**514**	**735**	**784**	**944**	**1,105**	**1,286**	**1,629**	**1,641**	**1,661**	**1,682**	**1,705**	**1,729**	**1,739**	**1,752**	**1,764**	**1,776**
New Wind	Wind_PineCanyon	Wind_PineCYN								315	315	315	315	315	315	315	315	315	315	315	315	315
	GenericWind	Wind PPA 2012 L		115	230	230	230	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206
		Wind PPA 2015 B					46	552	552	552	552	552	552	552	552	552	552	552	552	552	552	552
		Wind PPA 2015 W					316	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541
		Subtotal PPA's		**115**	**230**	**230**	**592**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**	**1,299**
		Subtotal		**115**	**230**	**230**	**592**	**1,299**	**1,299**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**	**1,614**
New Bio Gas	Bio GAS	Bio Gas		520	520	520	520	520	520	520	520	520	520									
	Biogas Extension	Biogas Extension				295	470															
New Small Hydro	New Small Hydro	WSHydro						11	22	22	22	22	22	22	22	22	22	22	22	22	22	22
		Castaic U1 update		4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
		Aqueduct PP Improvement						15	30	30	30	30	30	30	30	30	30	30	30	30	30	30
		Generic_RPS														125	125	225	300	350	400	425
		GreenPurchase		7	98	230						60		17	43	10		10	2	21	27	65
		Total RPS	**4,455**	**4,631**	**4,845**	**5,104**	**5,358**	**5,955**	**6,421**	**7,130**	**7,491**	**7,999**	**8,282**	**8,191**	**8,266**	**8,343**	**8,556**	**8,498**	**8,574**	**8,657**	**8,724**	**8,800**

Figure M-3. Renewable energy production in GWh for all cases.

M.4 Case Options

Coal divestiture is the key parameter distinguishing the different 2011 IRP strategic cases. Unlike other areas that are constrained by mandated regulatory requirements (such as renewable resources), the decision to divest from coal earlier than legally required is discretionary and thus appropriate for analysis. The 2011 IRP strategic cases are designed to assist policymakers and ratepayers to make informed decisions regarding accelerated coal divestment, particularly with regard to the environmental benefits and resulting resource and electricity rate impacts. Included in Table M-1 is a description of the strategic cases.

Table M-1. Description of strategic cases

Case ID	Description
Case 1 (Base Case)	No Early Coal Divestiture – 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 SB1368. Maintains the 33 percent standard renewables mix recommended to comply with SB 2 (1X).
Case 2	Navajo Early Replacement Strategy – This case considers early replacement 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).
Case 3	Navajo and IPP Early Replacement Strategy – This case considers early replacement 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).
Recommended Case 2010 IRP	33% RPS Balanced Strategy – Primarily used to compare the other strategic cases to the recommended long term strategy described in the 2010 IRP with 33 percent renewable compliance by 2020. Considers early divestiture of Navajo on 1/1/2014 or five years prior to contract expiration and assumes replacement of IPP in 2027.

The displaced energy from early coal divestment 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 M-2 summarizes the different replacement resources for the different cases and Table M-3 summarizes the costs associated with the replacement resources selected for the recommended case (Case 2).

Table M-2. Resources recommended for resource adequacy by calendar year

Base Case (Navajo 2019, IPP 2027)

Capacity (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	61	88	111	132	145	156	167	175	183	191	199	207	215	223	231	239	247	255
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500
New Renewable	30	47	120	166	251	310	356	403	446	500	528	575	605	623	637	646	656	662
Navajo Replacement CC	0	0	0	0	0	0	0	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
Short Term Q3 Purchase								75	100	125	225	325	325	375	175	225	325	400
Total Replacement	**96**	**145**	**251**	**338**	**471**	**565**	**674**	**1153**	**1279**	**1415**	**1602**	**1807**	**1894**	**2021**	**2992**	**3060**	**3177**	**3266**

Case 2 (Navajo 2015, IPP 2027)

Capacity (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	61	88	111	132	145	156	167	175	183	191	199	207	215	223	231	239	247	255
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500
New Renewable	30	47	120	166	251	310	356	403	446	500	528	575	605	623	637	646	656	662
Navajo Replacement CC				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	1150	1150	1150	1150
Short Term Q3 Purchase				125	100	75	75	75	100	125	225	325	325	375	175	225	325	400
Total Replacement	**96**	**145**	**251**	**763**	**871**	**940**	**1049**	**1153**	**1279**	**1415**	**1602**	**1807**	**1894**	**2021**	**2992**	**3060**	**3177**	**3266**

Case 3 (Navajo 2015, IPP 2020)

Capacity (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	61	88	111	132	145	156	167	175	183	191	199	207	215	223	231	239	247	255
Demand Response	5	10	20	40	75	100	150	200	250	300	350	400	450	500	500	500	500	500
New Renewable	30	47	120	166	251	310	356	403	446	500	528	575	605	623	637	646	656	662
Navajo Replacement CC				300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IPP Replacement CC					0	0	0	0	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Short Term Q3 Purchase				125	100	75	75	75	25		25	50	50	100	175	225	325	400
Total Replacement	**96**	**145**	**251**	**763**	**871**	**940**	**1049**	**1153**	**2354**	**2440**	**2552**	**2682**	**2769**	**2896**	**2992**	**3060**	**3177**	**3266**

Table M-3. Resource costs for the recommended case (Case 2) by calendar year

(FY)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy & Capacity Cost																				
Energy Efficiency	$ 46	$ 29	$ 37	$ 51	$ 60	$ 70	$ 78	$ 87	$ 94	$ 104	$ 112	$ 120	$ 129	$ 137	$ 146	$ 154	$ 163	$ 171	$ 180	$ 188
Demand Response	$ -	$ -	$ 0	$ 0	$ 1	$ 1	$ 3	$ 4	$ 6	$ 8	$ 10	$ 10	$ 11	$ 12	$ 12	$ 13	$ 14	$ 14	$ 14	$ 14
New Renewable																				
Solar	$ 3	$ 12	$ 25	$ 39	$ 67	$ 98	$ 115	$ 132	$ 158	$ 184	$ 225	$ 249	$ 250	$ 253	$ 256	$ 259	$ 261	$ 261	$ 261	$ 264
Wind	$ -	$ 2	$ 27	$ 27	$ 37	$ 127	$ 147	$ 177	$ 198	$ 201	$ 202	$ 203	$ 205	$ 208	$ 209	$ 211	$ 213	$ 216	$ 217	$ 219
Geo	$ -	$ -	$ -	$ -	$ 13	$ 28	$ 79	$ 113	$ 143	$ 176	$ 197	$ 224	$ 271	$ 302	$ 335	$ 353	$ 361	$ 361	$ 368	$ 373
Small Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Generic RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ 18	$ 24	$ 38	$ 45	$ 53	$ 59
Green Purchase	$ -	$ 0	$ 4	$ 12	$ 9	$ -	$ -	$ -	$ -	$ 3	$ 3	$ 1	$ 3	$ 2	$ 0	$ 0	$ 1	$ 1	$ 2	$ 5
New Renewable Subtotal	**$ 3**	**$ 14**	**$ 55**	**$ 78**	**$ 126**	**$ 253**	**$ 343**	**$ 424**	**$ 501**	**$ 565**	**$ 628**	**$ 679**	**$ 731**	**$ 776**	**$ 820**	**$ 850**	**$ 874**	**$ 886**	**$ 904**	**$ 922**
Short Term Q3 Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ 14	$ 11	$ 9	$ 9	$ 10	$ 14	$ 18	$ 34	$ 52	$ 55	$ 67	$ 33	$ 44	$ 67
Replacement CC Capital Cost																				
Navajo Replacement CC	$ -	$ -	$ -	$ -	$ -	$ 9	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18
IPP Replacement CC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 133	$ 133	$ 133
Total	**$ 50**	**$ 43**	**$ 93**	**$ 130**	**$ 186**	**$ 333**	**$ 442**	**$ 533**	**$ 619**	**$ 695**	**$ 767**	**$ 828**	**$ 889**	**$ 942**	**$ 996**	**$1,035**	**$1,075**	**$1,222**	**$1,247**	**$1,274**

Each case was modeled using low, medium and high assumptions for gas and coal prices. Results of the model runs were tabulated to compare power costs and GHG emission reduction. See Section 4.3 for a discussion regarding the analysis of the model results for the three cases. The analysis concludes with Case 2 as the recommended case for this 2011 IRP. Additional analysis, including non-generation costs and a rate-impact assessment, are included in Section 5.

M.7 Model Input and Assumptions

The following pages represent the major input parameters and assumptions that were incorporated into the production cost model for this 2011 IRP.

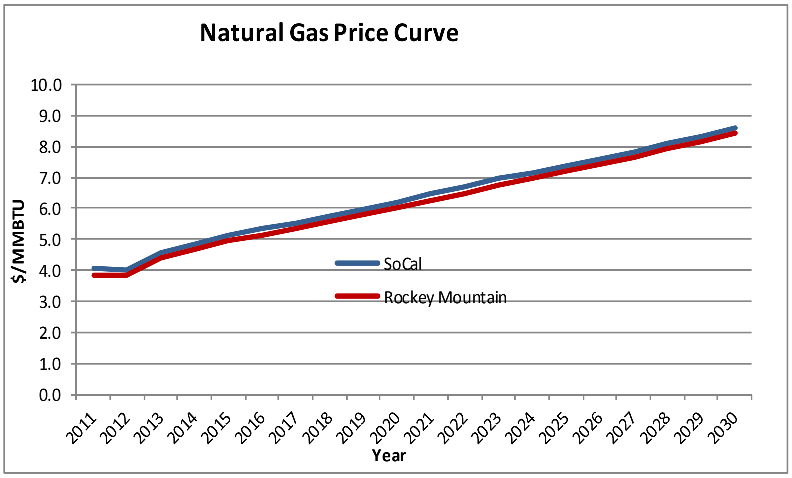
Load Forecast

	October 2010 Forecast (Approved February 2011)						2011 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
2011	26,200	151	19	23,217	1.92%	1.26%	26,391	63	178	23,185	1.89%	1.11%
2012	26,250	327	55	23,202	0.95%	-0.06%	26,681	114	348	23,216	0.86%	0.13%
2013	26,132	481	90	23,160	0.21%	-0.18%	26,778	141	552	23,071	0.25%	-0.62%
2014	26,509	497	121	23,495	1.48%	1.45%	27,208	160	787	23,198	1.53%	0.55%
2015	26,849	497	141	23,795	1.25%	1.28%	27,570	180	1,022	23,263	1.25%	0.28%
2016	27,252	497	159	24,089	1.47%	1.24%	27,993	202	1,186	23,452	1.45%	0.81%
2017	27,496	497	179	24,365	0.88%	1.15%	28,261	210	1,300	23,566	0.93%	0.49%
2018	27,836	497	190	24,670	1.21%	1.25%	28,614	218	1,415	23,756	1.22%	0.80%
2019	28,200	497	195	24,990	1.28%	1.30%	28,983	228	1,510	23,977	1.26%	0.93%
2020	28,654	497	202	25,330	1.57%	1.36%	29,444	238	1,584	24,301	1.56%	1.35%
2021	29,079	497	211	25,766	1.45%	1.72%	29,879	250	1,658	24,601	1.44%	1.23%
2022	29,412	497	222	26,063	1.12%	1.15%	30,224	261	1,732	24,820	1.12%	0.89%
2023	29,751	497	235	26,360	1.13%	1.14%	30,577	274	1,806	25,046	1.13%	0.91%
2024	30,172	497	249	26,674	1.39%	1.19%	31,014	287	1,880	25,345	1.39%	1.20%
2025	30,452	497	264	26,980	0.91%	1.15%	31,311	302	1,954	25,520	0.91%	0.69%
2026	30,795	497	280	27,283	1.10%	1.12%	31,672	317	2,028	25,750	1.11%	0.90%
2027	31,140	497	297	27,591	1.10%	1.13%	32,036	332	2,102	25,983	1.11%	0.90%
2028	31,479	497	316	27,893	1.07%	1.09%	32,396	349	2,176	26,212	1.08%	0.88%
2029	31,812	497	336	28,186	1.04%	1.05%	32,753	365	2,250	26,436	1.05%	0.86%
2030	32,148	497	359	28,481	1.03%	1.05%	33,113	382	2,324	26,665	1.05%	0.86%

Notes:
1. Net Energy for Load for model run (E) = [Net Energy for Load (A) + Energy Efficiency (B) / 0.885 + Solar Rooftop Program (C) / 0.
2. Solar Rooftop Program (F) = Solar Rooftop Program (C) / 0.885
3. Energy Efficiency in 2011 IRP differs from Energy Efficiency in Forecast. IRP treats EE as a variable resource.
4. IRP Calculated Sales (H) = [(E - F - G) + 37]*0.8

Natura Gas Prices

Gas Price used in IRP 2011		
Year	SoCal	Rockey Mountain
2011	4.1	3.8
2012	4.0	3.9
2013	4.6	4.4
2014	4.9	4.7
2015	5.1	4.9
2016	5.3	5.1
2017	5.5	5.4
2018	5.8	5.6
2019	6.0	5.8
2020	6.2	6.0
2021	6.4	6.2
2022	6.7	6.5
2023	7.0	6.7
2024	7.1	7.0
2025	7.4	7.2
2026	7.6	7.4
2027	7.8	7.7
2028	8.1	7.9
2029	8.3	8.2
2030	8.6	8.4



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	1.53
7/1/2023	1.57
7/1/2024	1.62
7/1/2025	1.67
7/1/2026	1.72
7/1/2027	1.77
7/1/2028	1.82
7/1/2029	1.88

Pinedale Gas Volume	
Date	MMBTU/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	9.91
7/1/2023	9.91
7/1/2024	9.91
7/1/2025	9.91
7/1/2026	9.91
7/1/2027	9.91
7/1/2028	9.91
7/1/2029	9.91

LADWP Existing Generation Resources

LADWP Generator Ratings and Capabilities of Power Sources (as of August 2011)[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	240,000		
	2	7/9/1974	287,500	265,000	265,000		
	3	7/13/1976	287,500	265,000	265,000		
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					**1,620,000**	**1,247,000**	**1,175,000**
Hoover Power Plant (Capacity and energy purchase from WAPA through Sep. 2017)					**491,000**	**491,000**	**436,000**
TOTAL HYDRO (Based on average hydro conditions)					**2,366,180**	**1,946,080**	**1,745,930**
	1	1/31/1995	100,400	85,340	82,000	82,000	79,500
	2	1/31/1995	100,400	85,340	82,000	82,000	79,500
	5	1/31/1995	93,750	75,000	65,000	65,000	65,000
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**	**461,000**
	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	157,500
	10	1/25/2005	215,000	182,750	162,500	162,500	157,500
Haynes Generating Station Subtotal					**1,555,599**	**1,555,599**	**1,524,000**
Total Basin Thermal					**3,414,599**	**3,414,599**	**3,337,000**
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	546,200	546,200
Generating Station	2	4/30/1987	991,000	820,000	900,000	546,200	546,200
Intermountain Generating Station Subtotal					**1,800,000**	**1,092,400**	**1,092,400**
Palo Verde Nuclear	1	1/30/1986	1,550,000	1,413,000	1,333,000	128,768	126,643
Generating Station	2	9/19/1986	1,550,000	1,413,000	1,336,000	129,058	126,932
	3	1/19/1988	1,550,000	1,413,000	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**	**1,956,090**	**1,949,714**
TOTAL THERMAL					**11,467,599**	**5,370,689**	**5,286,714**
NET MAXIMUM AND NET DEPENDABLE SYSTEM CAPABILITY w/o CDWR Transfer						**7,316,769**	**7,032,644**
State's Capacity Entitlement						**-120,000**	**-55,000**
NET MAXIMUM AND NET DEPENDABLE SYSTEM CAPABILITY						**7,196,769**	**6,977,644**
Renewables/Distributed Generation as of August 12, 2011 [6]						**1,108,635**	**316,380**
NET MAXIMUM AND NET DEPENDABLE SYSTEM CAPABILITY w/ RE/DG						**8,305,404**	**7,294,024**

Notes:

[1] This table is based on data from Power System Engineering Division January 1, 2011 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 August 12, 2011 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 plants; 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 0.95
Landfill Gas 0.90
Muncipal Solid Waste Conversion 0.90
Small Hydroelectric 0.50
Solar Photovoltaic 0.25
Solar Thermal 0.25
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)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2013	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2014	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2015	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2016	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2017	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2018	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2019	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2020	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2021	Summer	327	(66)	-43	218	72	803	1093
	Winter	327	(58)	-43	226	72	803	1101
2022	Summer	327	(116)	-43	168	72	803	1043
	Winter	327	(108)	-43	176	72	803	1051
2023	Summer	327	(216)	-43	68	72	803	943
	Winter	327	(208)	-43	76	72	803	951
2024	Summer	327	(284)	-43	0	72	803	875
	Winter	327	(284)	-43	0	72	803	875
2025	Summer	327	(284)	-43	0	72	803	875
	Winter	327	(284)	-43	0	72	803	875
2026	Summer	327	(284)	-43	0	72	803	875
	Winter	327	(284)	-43	0	72	803	875
2027	Summer	327	(284)	-43	0	72	803	875
	Winter	327	(284)	-43	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	$484.92	$283.1
2009									$271.2	$156.3	$427.47	$244.4
2010	$104.5	$34.0	$138.5	$57.6	$59.6	$117.2	$138.5	$117.2	$255.7	$167.3	$423.03	$250.5
2011	$128.3	$80.4	$208.7	$51.1	$56.0	$107.1	$208.7	$107.1	$315.9	$170.8	$486.69	$292.7
2012	$95.5	$104.2	$199.7	$45.8	$49.5	$95.3	$199.7	$95.3	$295.0	$167.8	$462.78	$283.8
2013	$104.0	$68.6	$172.6	$42.0	$40.4	$82.4	$172.6	$82.4	$255.0	$171.1	$426.11	$259.7
2014	$137.6	$76.8	$214.4	$38.1	$38.1	$76.2	$214.4	$76.2	$290.6	$174.6	$465.20	$283.5
2015	$130.9	$73.2	$204.1	$34.2	$32.6	$66.8	$204.1	$66.8	$270.9	$178.0	$448.95	$273.6
2016	$154.0	$90.5	$244.5	$30.2	$32.2	$62.4	$244.5	$62.4	$306.9	$181.6	$488.52	$298.5
2017	$98.4	$26.9	$125.3	$25.6	$29.5	$55.1	$125.3	$55.1	$180.3	$185.2	$365.57	$222.8
2018	$152.2	$53.3	$205.5	$19.2	$30.5	$49.7	$205.5	$49.7	$255.2	$188.9	$444.16	$270.7
2019	$113.8	$124.7	$238.5	$12.7	$24.2	$36.9	$238.5	$36.9	$275.4	$192.7	$468.11	$285.3
2020	$61.3	$161.2	$222.5	$9.2	$15.6	$24.9	$222.5	$24.9	$247.4	$196.6	$443.94	$271.3
2021	$66.0	$158.5	$224.5	$7.6	$6.4	$14.0	$224.5	$14.0	$238.4	$200.5	$438.94	$267.5
2022	$102.9	$73.1	$176.0	$4.9	$2.6	$7.5	$176.0	$7.5	$183.5	$204.5	$388.02	$233.6
2023	$53.0	$73.9	$126.9	$1.8	-$2.5	-$0.7	$126.9	-$0.7	$126.2	$208.6	$334.78	$189.7
2024	$7.1	$6.2	$13.3	$0.2	$0.0	$0.2	$13.3	$0.2	$13.5	$212.8	$226.27	$117.1
2025	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$217.0	$217.04	$105.5
2026	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$221.4	$221.38	$107.6
2027	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$225.8	$225.81	$109.8

Demand Response Schedule

CY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MW	0	5	10	20	40	75	100	150	200	250	300	350	400	450	500
Cost ($/KW/yr)	45	45	45	45	45	45	45	45	45	14.6	14.6	14.6	14.6	14.6	14.6

LADWP Solar Program

SB1 Solar Rooftop Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010	28	33	280
2011	54	63	210
2012	85	114	170
2013	101	141	170
2014	113	160	170
2015	125	180	170
2016	138	202	150
2017	143	210	150
2018	148	218	150
2019	154	228	140
2020	160	238	140
2021	167	250	130
2022	174	261	130
2023	182	274	120
2024	190	287	120
2025	199	302	120
2026	208	317	110
2027	217	332	110
2028	227	349	100
2029	237	365	100
2030	247	382	100

DWP Build In Basin Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010	1	1	270
2011	1	2	270
2012	3	5	270
2013	6	11	250
2014	9	16	230
2015	12	22	220
2016	21	38	210
2017	37	67	200
2018	54	97	190
2019	71	128	190
2020	88	158	190
2021	101	182	180
2022	101	182	180
2023	100	180	180
2024	100	180	180
2025	99	178	180
2026	99	178	180
2027	99	176	180
2028	98	176	180
2029	97	175	180
2030	97	175	180

DWP Build Out Basin Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012	19	15	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

Feed-In Tariff Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012	3	5	340
2013	6	10	320
2014	20	33	240
2015	45	75	200
2016	75	124	190
2017	83	136	180
2018	90	148	180
2019	98	160	180
2020	105	171	180
2021	113	193	180
2022	120	195	180
2023	128	206	170
2024	135	217	170
2025	143	229	170
2026	150	240	170
2027	150	239	170
2028	150	238	170
2029	150	237	170
2030	150	235	170

Owens Solar Program

CY	Annual Install Target (MW AC)	Cumulative Effective Install (GWh)	Expenditure ($/MWh)
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018	50	110	153
2019	100	220	153
2020	150	330	153
2021	200	440	153
2022	200	438	153
2023	200	436	153
2024	200	433	153
2025	200	431	153
2026	200	429	153
2027	200	427	153
2028	200	425	153
2029	200	423	153
2030	200	421	153

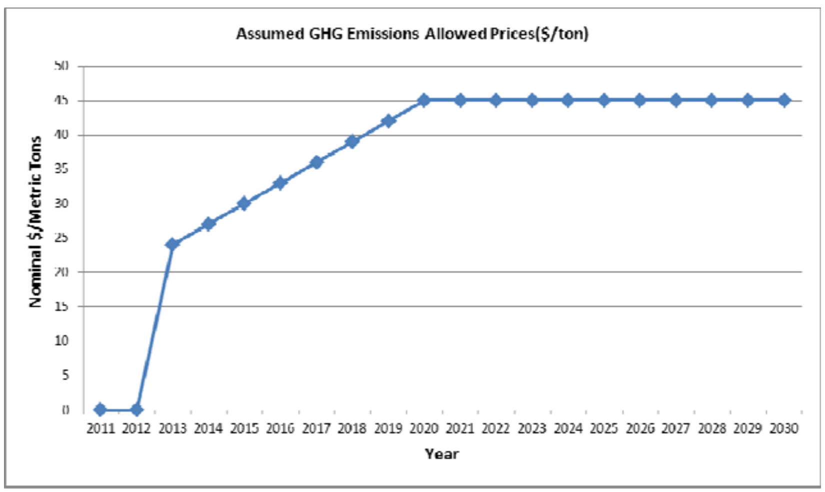
Once-through Cooling Costs

2029 OTC Cost Estimates

2029 Plan - No OTC	FY 10/11	FY 11/12	FY 12/13	FY 13/14	FY 14/15	FY 15/16	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	FY 21/22	FY 22/23	FY 23/24	FY 24/25	FY 25/26	FY 26/27	FY 27/28	FY 28/29	FY 29/30
HnGS Units 5&6 Repowering	175.9	357.3	128.6	10.9																
SGS Unit 3 Repowering	3.7	5.9	265.2	377.4	101.8	23.3														
SGS Units 1&2 Repowering					1.5	4.2	71.0	124.2	143.0	136.5	74.7									
HnGS Units 1&2 Repowering						1.0	2.2	2.7	3.5	36.0	36.0	307.3	260.9	58.0						
HGS Unit 1, 2 & 5 Repowering											1.2	2.6	3.1	5.2	312.1	104.0	57.2			
HnGS Unit 8, 9, &10 Repowering												1.0	2.0	3.0	4.0	34.4	357.7	320.0	165.0	120.0
TOTAL CAPITAL EXPENDITURES	179.6	363.2	393.8	388.3	103.3	28.5	73.2	126.9	146.5	172.5	111.9	310.9	266.0	66.2	316.1	138.4	414.9	320.0	165.0	120.0

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)	$24.0	$27.0	$30.0	$33.0	$36.0	$39.0	$42.0	$45.0	$45.0	$45.0	$45.0	$45.0	$45.0	$45.0	$45.0	$45.0	$45.0	$45.0



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Appendix N Public Outreach

N.1 Overview

This section outlines the public outreach that will be carried out as part of the 2010 IRP process to provide information and increase awareness of LADWP's long-term power resource plans.

N.2 Community workshops

A series of regional public workshops are being scheduled in mid-July 2010 throughout Los Angeles.

Workshops will be publicized through newspaper advertisements, press releases, a dedicated Website and social media.

A dedicated, interactive Website, www.LAPowerPlan.org, will be established and will enable visitors to provide comments directly online.

The workshops will be professionally facilitated.

Following the workshops, LADWP will summarize feedback and post frequently asked questions and responses on the Website.

N.3 Public Comments

This section will address comments received during the Public Outreach effort related to the 2010 Integrated Resource Plan.

N.4 Questions and Answers

This section will address questions received during the Public Outreach effort related to the 2010 Integrated Resource Plan. These will be posted on the Website as well as presented to the Board of Water and Power Commissioners.

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2010 INTEGRATED RESOURCES PLAN
Community Outreach Summary

Prepared for:
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October 12, 2010

Table of Contents

Report Overview

This report provides a summary of input received through the community outreach program conducted for the Los Angeles Department of Water and Power's (LADWP's) 2010 Power Integrated Resource Plan (IRP). The community outreach program consisted of a series of regional public workshops, a website (www.lapowerplan.org), and an online survey, along with stakeholder meetings, which were intended to inform the public about the 2010 IRP and to solicit feedback.

The kickoff public workshop was held on August 12, 2010, at the LADWP headquarters in downtown Los Angeles. Seven regional workshops were held between September 11, 2010, and September 30, 2010. The regional workshops were held throughout Los Angeles to gather input that reflects the City of Los Angeles' geographic and demographic diversity and to maximize participation opportunities. A website was also created for the 2010 IRP; it included an electronic version of the 2010 IRP and associated documents, promoted the public workshops, and provided an interactive online survey consisting of questions similar to the workshop discussion questions. All the presentation materials from the public workshops were also made available on the website. A series of stakeholder meetings were also held in August through October, 2010, with representatives from business and environmental groups with a specific interest in the 2010 IRP.

This summary is arranged into four sections: Report Overview, Community Outreach Program, Discussion Theme Synthesis, and Exhibits. The information contained in each of the remaining sections is described below:

- Community Outreach Program: Provides an overview of all aspects of the outreach related to the 2010 IRP, including the public workshops, website, stakeholder meetings, and elected/appointed official briefings.

- Discussion Theme Synthesis: Contains a summary of the input contributed during the community outreach program. The input has been synthesized to reflect the breadth and depth of the input received and incorporates reoccurring themes that were expressed by participants.

- Exhibits: Includes the project fact sheet, a transcription of the notes from the public workshops, comment cards submitted at the workshops and through the website, and online survey results, as well as other comments collected as part of the community outreach program.

Community Outreach Program

Purpose

The community outreach program was designed to collect broad input on issues, ideas, and concerns related to the 2010 IRP. Input was collected with the intention of providing guidance to LADWP staff in the formulation of a final long-term strategy, and to inform the LADWP Board of Commissioners prior to adoption of a final document. An overview of the 2010 IRP is provided in Exhibit A, Project Fact Sheet.

Specific objectives of the community outreach program were to:

- Prioritize transparency and inclusiveness in the 2010 IRP process.
- Receive feedback and public comments to be incorporated into the Final 2010 IRP document.
- Educate and create awareness about the 2010 IRP among stakeholders and community members.
- Communicate strategies for reducing carbon emissions and integrating renewable resources, while meeting forecasted demand, maintaining reliability, and keeping costs as low as possible.
- Communicate the potential impact on costs and customer rates for various alternative cases analyzed in the 2010 IRP.

To achieve these objects, LADWP developed a multipronged outreach approach to allow community members and stakeholders different opportunities to provide input on the 2010 IRP. Community involvement opportunities were provided through a website, stakeholder meetings, and a series of public workshops. Elected and appointed official briefings were also held to keep local representatives abreast of outreach opportunities and the community's contributions. Input collected through each of these programs is considered of equal importance when considered by LADWP staff.

Public Workshops

The public workshops were held in different locations throughout the city to reflect the geographic and demographic diversity of Los Angeles. Workshops were also held on various days of the week at different times to allow many options for participants to find a convenient workshop schedule.

Workshop Schedule and Location

A kick-off workshop was held in Downtown Los Angeles on August 12, 2010, in the LADWP headquarters. Seven regional workshops were held between September 11, 2010, and September 30, 2010, throughout Los Angeles. Table 1 shows the meeting location and schedule.

Table 1: Location and Time of Community Workshops

Downtown ***Thursday, August 12, 2010*** 7:00 pm – 9:00 pm *LADWP John Ferraro Building* 111 N. Hope Street Los Angeles, CA 90012	**East Valley** ***Saturday, September 11, 2010*** 10:00 am – 12:00 pm *Los Angeles Mission College* 13356 Eldridge Avenue Sylmar, CA 92342	**West LA** ***Monday, September 13, 2010*** 6:00 pm – 8:00 pm *Stephen Wise Temple* 15500 Stephen S Wise Drive Los Angeles, CA 90077
South LA ***Tuesday, September 14, 2010*** 6:00 pm – 8:00pm *California African American Museum—Exposition Park* 600 State Drive Los Angeles, CA 90037	**East LA** ***Wednesday, September 15, 2010*** 6:00 pm – 8:00 pm *California State University* 5151 State University Drive Los Angeles, CA 90032	**Harbor** ***Monday, September 20, 2010*** 6:00 pm – 8:00 pm *Crowne Plaza Los Angeles Harbor* 601 South Palos Verdes Street San Pedro, CA 90731
West Valley ***Wednesday, September 22, 2010*** 6:00 pm – 8:00 pm *Holiday Inn—Warner Center* 21101 Ventura Blvd Woodland Hills, CA 91364	**Northeast LA** ***Thursday, September 30, 2010*** 6:30 pm – 8:30 pm *Glassell Park Senior & Community Center* 3750 Verdugo Road Los Angeles, CA 90055	

Attendance

Attendance varied between each of the public workshops as shown in Table 2. Most attendees identified themselves as customers of LADWP when they signed in, although individuals were not required to be customers to attend the meetings and provide input. Several attendees also identified themselves as being associated with industry groups or environmental organizations, such as solar developers or the Sierra Club. There were also a number of people who attended multiple meetings.

Table 2: Workshop Attendance by Location

Meeting	**Attendees**
Downtown	96
East Valley	41
West LA	34
South LA	38
East LA	17
Harbor	19
West Valley	50
Northeast LA	17

Workshop Publicity

LADWP conducted extensive publicity to maximize inclusiveness and diversity among participants. To publicize the workshops, meeting information was detailed on the project website, advertisements were placed in local and regional newspapers, and press releases and Twitter messages were issued. Targeted outreach was also conducted to inform the Council Districts and engage the Neighborhood Councils.

Web, Email, and Social Networking

LADWP placed electronic advertisements on the City Watch Website, which averages between 220,000 and 500,000 hits daily, beginning August 23 and running through the final workshop September 30. LADWP also used Twitter to send messages ("tweets") about the entire workshop series and to promote each individual workshop; issued Neighborhood Council and stakeholder email blasts; and included the workshop series in customer e-newsletters (*LADWP at Work* and *At Home*), which are emailed to all LADWP residential and commercial customers.

Media

Advertisements that featured the locations and dates of all workshops were placed in community and regional newspapers, including:

- *Daily News*
- *Daily Breeze*
- *L.A. Watts Times*
- *L.A. Sentinel*
- *Korean Daily*
- *Chinese Daily*
- *La Opinion*
- *Philippine Media*
- *Downtown News*
- *Korean Times Daily*
- *Beverly Press/Park La Brea News*
- *Larchmont Chronicle*
- *Tolucan Times*
- *L.A. Business Journal*
- *San Fernando Valley Business Journa*l
- Wave/Independent/Equal Access Media
- Eastern Group Publications

A general news release was issued to announce the first workshop followed by a second release announcing the entire workshop series, emphasizing the desire for public feedback on the 2010 IRP, which included an invitation to the IRP website to take the online survey. Media advisories were also issued the morning of each workshop.

Additional Outreach

To reach additional members of the public, LADWP distributed flyers at public libraries throughout the city. Flyers announcing the workshops, along with fact sheets, were distributed to all Council District field offices, at the Mayor' Office, and at the Council District 2 National Night Out Finale community event at Valley Plaza Park.

LADWP conducted extensive outreach to engage Neighborhood Councils, including announcements at Neighborhood Council meetings, distribution of flyers, and email blasts, which encouraged Neighborhood Councils and community members to attend the regional workshops. LADWP staff also made announcements about the regional workshops to over 30 Neighborhood Council meetings throughout the city in August and September.

Workshop Format

The community workshops consisted of four main components: (1) a presentation on the 2010 IRP by Michael Webster, LADWP Assistant Director of Power System Planning and Development; (2) small group discussions led by facilitators; (3) report back and workshop wrap up; and (4) written comment cards. Please see Exhibit B for the workshop agenda.

Presentation

The workshop presentation established a foundation for the community to get a better understanding of the 2010 IRP. Important contextual information was presented, which provided a historical overview of LADWP's mission, operations, and vertical approach to service; background and objectives of the IRP; and challenges of balancing the objectives. The presentation also outlined specific strategies for reducing carbon emissions and integrating renewable resources, while meeting forecasted demand, maintaining reliability, and keeping costs as low as possible. A video of the presentation was posted on the project website for all community members to view the presentation outside of the workshops.

Small Group Discussions

After the presentation, participants joined smaller breakout sessions ranging from 10 to 15 people, depending on the number of attendees. Through a guided discussion, the small groups provided a forum for participants to provide input and identify issues, share ideas, and voice concerns related to the 2010 IRP. The small groups were also designated to make the complex and technical information in the IRP more accessible by creating an environment where all attendees felt comfortable asking questions and sharing thoughts about the complex technical information in the long-range plan.

Each group was led by a facilitator and an LADWP staff member familiar with the details of the 2010 IRP. Each of the group discussions began by having the group's LADWP staff member lead attendees through the 2010 IRP Executive Summary, which was distributed to each participant as they entered the meeting. The staff member presented the details for each of the six case options, including the mix of resources, estimated costs, estimated reduction in greenhouse gas emissions, and the potential impact on customer rates. This overview was followed by a question and answer period. The LADWP staff member answered technical questions and provided clarification on the 2010 IRP.

Following the LADWP staff presentation and the question and answer period, participants were then given the opportunity to share their perspectives related to the 2010 IRP. Participants were eager to express viewpoints on many issues during the group discussion session.

Discussion Questions

The facilitator assisted the group in communicating priorities, issues, and concerns related to the 2010 IRP by asking the following questions:[1]

1. What priorities does LADWP need to consider when making a recommendation on the IRP long-term strategy?

2. How much more per bill are you willing to pay to implement some of the types of concepts in the IRP?
   - 5%?
   - 15%?
   - 25?
   - 0% (Nothing)?

3. Are there any other comments or ideas you would like LADWP to consider related to the 2010 IRP?

The facilitator maintained a record of the participant responses to each question. After a period of sharing the priorities that were important for consideration in the 2010 IRP as part of the discussion on Question 1, four sticky dots were distributed to each member of the group. Group members were asked to use the dots to identify the priorities, or priority, that were most important to them out of those that were shared among the group. Each dot represented an identification of a priority, and participants were allowed to place multiple dots on a priority to indicate relative importance of a topic over another. The priorities identified by each group were considered in the development of the Discussion Themes.

Exhibit C contains detailed transcriptions of all the notes collected during the discussion group for each public workshop, as well as the results of all the input collected during the dot prioritization exercise.

[1] The following questions were asked at the August 12, 2010, meeting and modified in subsequent workshops: (1) What priorities does LADWP need to consider when making a recommendation on the IRP long-term strategy? (2) What level and mix of renewables should LADWP strive for (solar, wind, geothermal, etc.)—and at what cost? (3) How should LADWP transition away from high carbon emitting resources—and at what cost? (4) Are there any other comments or ideas you would like LADWP to consider related to the 2010 IRP? The questions were modified to eliminate redundancy between Questions 2 and 3, and because of time limitations.

Additional Notes on Question 2

After the group members finished with the prioritization exercise, the facilitator asked Question 2. Participants were asked if they were willing to pay 5%, 15%, 25%, or 0% (nothing) more per bill to implement some of the types of concepts in the IRP. Attendees were asked to raise their hand to indicate support for any amount they felt comfortable supporting. Some group members were uncomfortable answering the question and asked to provide comments instead of, or in conjunction with, raising their hand. This question was intended to understand group members' sentiment about costs. There is no statistical significance associated with the informal poll that was taken during each group discussion. Instead, this question is more appropriately understood as feedback from a focus group that identified larger opinions and attitudes of group members that relate to costs, as well as the priority participants placed on renewable energy development.[2]

Report Back and Wrap Up

To allow participants to get a sense of the discussions that occurred in the other groups, participants reconvened as an audience at the conclusion of the breakout session, where a representative from each group recapped his/her group discussion. To accomplish this, a volunteer from each group reported back on the top three priorities that were collectively identified by the group as the topics with the most dots from the prioritization exercise.

The workshops concluded with an explanation of how workshop input and input collected by other outreach programs would be documented into a summary. It was also explained that the summary would be considered by the project team in formulating the 2010 Final IRP that would be presented to the LADWP Board of Commissioners, and posted on the project website.

Written Comment Cards

At the beginning of the meeting, attendees were also provided a comment card with questions that mirrored the small group discussion questions. The comment card provided a medium for detailed written comments to be submitted. The comment cards were collected at the conclusion of the meeting or could be mailed afterwards to LADWP. In addition, participants were invited to submit additional comments through the website or directly to LADWP. All comment cards, letters, and other input received electronically can be found in Exhibit D.

[2] To provide some context to Question #2, the following statement was made to participants at each of the regional meetings:

As the LADWP staff member explained, one of the goals of this public outreach process is to gauge how much more you would be willing to pay to increase renewable energy and decrease greenhouse gas emissions. The graph on P.12 [of the Executive Summary] indicates that LADWP electric rates will go up a certain percentage over the next 20 years under all six cases. However, let me emphasize that these are hypothetical outcomes based on all the various assumptions used to model the cases. Also it should be noted that energy efficiency/energy conservation can reduce your bill. No matter what happens with the rates, you can choose to use energy more efficiently –buy energy efficient refrigerators and other appliances, or use energy during "off peak" hours. All these strategies can help you reduce electricity costs. The Department is only interested in getting your feedback; your "vote" is NOT an endorsement of a rate increase. Think of yourselves as part of a focus group. Maybe you are willing to pay a little more steadily over 20 years to help the DWP get off of coal power by 2020. Or maybe you prefer not to pay anything now because of financial issues. You can pick 5%, 15%, 25%, or 0% (nothing). Or, you can choose not to vote at all. The main thing is to let LADWP know how you feel regarding this issue.

Website and Online Survey

A project website (www.lapowerplan.org) was created specifically for the 2010 IRP. The website provided access to a complete version of the 2010 IRP and associated technical appendices, as well as a stand-alone version of the Executive Summary, which was formatted to improve readability for the public. A fact sheet about the IRP, which was prepared to convey the complex material in visual and written format, was also made available on the website. The website included a schedule of public workshops, and a section that allowed the public to submit comments and questions about the plan online. Comments submitted through the website can be found in Exhibit D.

In addition, the website contained an online survey that mirrored the questions asked in the public workshops, as well as the comment card distributed during the workshops. Members of the public who were unable to attend a public workshop were given the same opportunity to provide input on the 2010 IRP through the website survey. There were 55 responses to the online survey, all of which can be found in Exhibit E.

Stakeholder Meetings

LADWP conducted meetings targeting specific stakeholders, including business and industry representatives, as well as environmental groups. These meetings were conducted in a similar fashion as the public workshops. Input collected at these meetings is included in the discussion themes found in the next section of this document, and discussion notes can also be found in
Exhibit C.

Business and Industry

LADWP offered presentations for the following business and industry stakeholders:

- Central City Association – meeting on September 21, 2010
- LA Business Council – meeting on September 24, 2010
- Large Commercial Customers – meeting on September 30, 2010
- Valley Industry and Commerce Association – meeting on October 6, 2010

Environmental Groups

Representatives of key environmental groups—including the Sierra Club, National Resources Defense Council, Environment Now and the Green L.A. Coalition—were invited to briefings and contacted directly to attend the kick-off workshop and regional workshops.

Elected/Appointed Officials Briefings

LADWP also met with various elected and appointed officials to provide an overview of the contents of the 2010 IRP and to inform them about the community outreach process. The briefings were intended to inform decision makers about the 2010 IRP and the process, and are not reflected in the discussion themes found in the next section of this document.

- Board of Water and Power Commissioners – Presentation to Board, July 22, 2010.
- Briefings were conducted for staffs of City Council members, Mayor's office, Chief Legislative Analyst (CLA), and Chief Administrative Officer (CAO) on August 12, 2010, and September 16, 2010. A follow-up briefing will be scheduled in October.
- Neighborhood Council Memorandum of Understanding Oversight Committee – briefing August 7, 2010.
- Additional Outreach:
  - A summary of the first workshop was emailed to Council staff.
  - An additional IRP summary after the first week of regional workshops was emailed to Council staff.
  - LADWP requested a special IRP briefing with Councilmembers (Energy & Environment Committee), Mayor, CLA, CAO.
  - LADWP requested to have a special IRP outreach meeting with stakeholders selected by Council members.
  - LADWP requested that the IRP workshop schedule be placed in individual Council community newsletters (it was placed in newsletter of Councilmember Bernard Parks.
  - A final IRP analysis will be provided to Mayor/Council/CAO/CLA staff.

Discussion Theme Synthesis

The public workshops, stakeholder meetings, online survey, and comment cards yielded a significant amount of information from LADWP customers related to the 2010 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.

Methodology for Identifying Discussion Themes

During the community outreach program, attendees provided broad input about issues, ideas, and concerns related to the 2010 IRP. The discussion themes provide a synopsis of this input and represent expansive discussion topics for the community outreach program. For a comprehensive understanding of the richness and range of input, the major discussion themes should be reviewed in conjunction with the transcription of the notes from the small group discussions and stakeholder meetings, the comment cards, and responses to the online survey.

An initial series of broad themes was first identified to categorize all of the statements gathered during the public outreach program. Coding strategies were then used to validate and refine the themes.[3] Using AtlasTI, a computer software program for qualitative data analysis, codes were established for each theme and applied to all of the public input that was collected through the community outreach program. Codes were applied to individual comments and enabled comparison between different comments relating to the same topic. For example, a statement such as "Educate consumers about <u>how</u> to conserve," was ultimately coded as (1) "Energy Efficiency and Conservation" because it was one of many statements provided by workshop participants that related to using less energy or using energy more efficiently, and (2) "Education and Community Outreach" because it relates to efforts by LADWP to inform and engage the community.

After coding all the input, the initial set of themes was refined. A narrative on each theme was also created to provide context and understanding. The narrative is based upon the comments that were tagged with a code relating to specific themes. The comments were reviewed to understand the frequency of certain discussion topics, the breadth of all discussion topics, and the relationships between the topics.

Discussion Themes

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 members of the public who completed the online survey or comment card. 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.

[3] For more information on the methodologies employed to identify themes, please see Ryan, Gery W. and H. Russell Bernard. 2003. "Techniques to Identify Themes." *Field Methods* 15(1):85–109.

Emphasize a *Variety* of Energy Sources

Many participants were supportive of the resource strategies presented in the 2010 IRP. Recognizing that overreliance on a single energy source could lead to instability, attendees advocated for a strategy that integrates a variety of resources. In particular, participants were concerned that natural gas was especially subject to fluctuations in price and relied heavily on delivery pipelines, which could jeopardize reliability. Some attendees expressed a desire to see a wider variety of energy sources beyond wind and solar. Some of the suggested energy sources included:

- Algae
- Biofuels
- Fuel Cells
- Geothermal
- Hydroelectric
- Natural Gas
- Nuclear
- Solid Waste
- Wave

The discussion of these other energy sources varied greatly. Nuclear and geothermal sources were mentioned by various participants. Many attendees indicated that LADWP should stay on the forefront of new advancements, and all viable sources of energy should continually be evaluated as modern technology evolves.

Maximize *Energy Efficiency and Conservation* to Meet Future Energy Needs

Energy efficiency and conservation efforts were strongly supported by participants and were recognized as necessary components in meeting the future energy needs of Los Angeles. Participants expressed that LADWP could use several strategies to encourage customers to use less energy, as well as take steps to make the entire power system (both customer-side and utility-side) more energy efficient.

Many participants recommended that LADWP incorporate additional financial incentives to customers who use less energy. Suggestions included the installation of smart meters to provide information about real-time energy use, enabling customers to make smarter decisions about how they use power. In addition, some attendees believed that an increase in energy rates would also lead to an overall reduction in energy consumption. Participants also suggested that charging higher prices during peak periods than during off-peak periods could encourage conservation when demand is highest, and could potentially shift energy use to periods with a lower demand.

Participants also emphasized the need for education programs for customers on the importance of conservation and ways to conserve energy. Political and cultural challenges in encouraging energy efficiency and conservation were identified as well.

In addition, many participants recommended that LADWP look for ways to improve the efficiency of the power system as a whole. This included suggestions to improve the efficiency of generating and transmitting energy. Several attendees also commented that technical improvements on the customer-side could lead to more efficient energy use, such as using more energy-efficient appliances. There was support for requirements that newly constructed buildings be designed for energy efficiency and it was suggested that older buildings should be retrofitted. Participants also proposed that LADWP provide/expand energy audits to demonstrate to customers what changes or improvements could be made in homes or businesses to use less energy.

***Eliminate* Coal from LADWP's Energy Portfolio**

Many participants expressed concern over the continued use of coal, recommended its removal from LADWP's energy portfolio, and suggested that it be replaced with renewable energy sources as much as possible. These participants noted that the elimination of coal would reduce greenhouse gas emissions and improve air quality, and some said that replacing coal with natural gas would not be a significant improvement. Other participants believed that the secondary costs of coal were not totally being accounted for, and that impacts to the environment and public health have a cost not always reflected in energy prices.

In addition, there was some discussion of the need to insulate the energy portfolio from anticipated cost increases of coal, such as compliance with new regulatory requirements including a cap and trade program. It was recommended by some attendees that this insulation should be created by the development of renewable sources because the cost of natural gas is also predicted to increase. Furthermore, some participants recognized that the proactive development of renewable sources could stabilize cost increases, and avoid potential market-driven/investor-influenced cost spikes.

Finally, some attendees said developing more renewable sources now will allow LADWP to hedge against future uncertain energy market fluctuations and experience lower renewable development prices from early market entry. Other suggestions included increasing the renewable sources in the near-term portfolio while high-yield development sites are still available.

Expand *Local* Solar Generation

There was widespread support for LADWP to expand solar power generation in-basin. However, out-of-basin solar generation was also viewed favorably. Many participants noted that in-basin solar has environmental benefits because of the decreased need for transmission facilities. In addition, some participants felt that distributed, in-basin generation would improve reliability, especially on summer days when both energy demand and solar radiation are typically high. In-basin solar had an additional perceived benefit of creating local jobs and improving the local economy.

Participants suggested that LADWP offer additional incentives to promote small-scale, in-basin photovoltaic systems, which could include subsidized loans to offset construction costs and/or feed-in tariff programs. Some attendees suggested that LADWP advance initiatives to install solar panels on roofs throughout Los Angeles, including on public buildings and parking lots.

Some participants expressed frustration over the current billing system related to individual solar systems, and an owner's inability to sell energy back to LADWP for cash. It was suggested that LADWP consider reevaluating this program and the way in which credits are applied.

Avoid Adverse Impacts to Vulnerable Communities

A number of participants expressed concern over the possibility that some communities in the region may experience unequal impacts from implementing particular components of the IRP. Low-income households, seniors, disabled persons, and others on a fixed income were identified as populations that may be impacted financially by potential costs associated with repowering. There was support for LADWP continuing to provide some protection against overly burdensome costs of electricity to customers who are economically disadvantaged. Many participants believed that costs could also be minimized through incentive programs that encourage energy efficiency. Additionally, some participants voiced opinions that communities with a disadvantaged socioeconomic status have historically received more than their fair share of major infrastructure and suggested that equal distribution of facilities throughout the city should be prioritized.

There was also concern on how facilities would impact communities outside of Los Angeles. Some participants questioned if it is ethical to allow out-of-basin communities to bear the environmental impacts of providing power to Los Angeles and expressed a desire to see out-of-basin generation minimized. However, most understood the benefits of out-of-basin generation, such as greater resource diversity and reliability, and recognized continued collaborative relationships with other out-of-basin utilities.

Clarify Costs of IRP Implementation and *Potential Impacts* to Ratepayers

Nearly all participants felt there was a need to clarify costs of IRP implementation and the potential impacts to ratepayers. Many participants thought that clarifying the different costs associated with generation, transmission, and distribution would provide a more accurate assessment of the overall costs associated with the IRP. Others considered it important to clarify labor and administrative costs of LADWP operations and their relation to the IRP. There was also discussion of the need to demonstrate the relationship between the costs associated with the IRP and LADWP's Strategic Plan.

The relative costs of different energy sources were also of interest to attendees. Many participants were concerned with the externalities associated with the IRP, including the secondary costs of the different case options. Secondary costs of interest to participants include the environmental and public health impacts, which were perceived by many to be costs incurred by the community but not reflected in energy rates. In contrast, other participants suggested that implementing the IRP would create local jobs and provide an economic benefit.

Some participants were adamantly opposed to potential future increases in their energy bills, while others supported an increase with caveats such as the need for improved transparency and accountability, or that additional revenues would be used exclusively for providing more renewable energy and/or getting off coal early. Participants who supported a potential increase often argued that an increase could be offset by reduced energy consumption, which could ultimately lower bills. There was also a desire to avoid any adverse impacts that a potential increase would have on low-income communities and individuals with a fixed income. Many people expressed concern that increasing energy costs would be detrimental to businesses in Los Angeles, especially during the current economic climate.

Reduce Environmental Impacts

Environmental protection was a priority for many participants. Some participants expressed a general concern for the environment, while other participants were interested in specific impacts to wildlife and landscapes, water quality, and aesthetics, as well as the storage of nuclear waste. Many attendees indicated that their concern for the environment extended beyond air quality and global warming/climate change issues.

The environmental impacts of construction, maintenance, and operation of generation, transmission, and/or distribution facilities were all among the activities that participants were concerned about. It was noted that environmental impacts could be reduced by maximizing existing infrastructure and locating new facilities on already disturbed sites, such as rooftops and brownfields, where possible.

Provide Proactive Leadership and Transparency

Participants saw an opportunity for LADWP to take proactive steps to educate the public about existing LADWP programs and incentives, ways to improve energy efficiency and conservation, and the power system in general. Some participants advocated LADWP to make information easily accessible and clearly identify the decision-making process.

Some participants felt that LADWP needed to lead-by-example with their operations and facilities, invest in research and development, and demonstrate the viability of new technologies. Participants supported LADWP continuing outreach to the public by partnering with existing local groups, schools, and other institutions to disseminate important information, especially related to energy efficiency and conservation. Suggestions were also expressed that clear and accessible information about LADWP's power system be made readily available to the public.

Organizational transparency and accountability were important to participants. Participants emphasized that the planning and facility development process continue to involve the public. There was also support for an independent ratepayer advocate to provide transparency and accountability in LADWP's finances and promote the interest of ratepayers in decisions. Some participants felt that billing statements should explicitly separate water and power costs and provide clear information and education on how bills are calculated. There were also suggestions that a program be established to monitor progress in achieving goals outlined in the IRP.

Exhibits

A – Project Fact Sheet

B – Workshop Agenda

C – Discussion Group Notes

D – Comment Cards

E – Online Survey

To view these exhibits, please visit www.lapowerplan.org.

Appendix O Abbreviations and Acronyms

O.1 Overview

This appendix presents acronyms for agencies and other entities, facilities and locations, electric industry terms, miscellany, and units of measure.

O.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

O.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

O.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
CNG	compressed natural gas
CLFR	compact linear frenal reflector
CO_2	carbon dioxide
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
GHG	greenhouse gas
GHGs	greenhouse gases
GREEN	Green Power for Green LA Program
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
SMES	Superconducting Magnetic Energy Storage
SNCR	selective non-catalytic reduction
SOx	sulfur oxide
T&T	transmission and delivery
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

O.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

O.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