2008

Power Supply

Integrated Resource Plan

City of Riverside
Public Utilities Department
Resources Division

City of Riverside
Public Utilities Department

Our Mission

Riverside Public Utilities is committed to the highest quality water and electric services at the lowest possible rates to benefit the community.

Our Vision

Riverside Public Utilities will be recognized as a community treasure with a national reputation for excellence.

Our Core Values

The City of Riverside Public Utilities Department values...

Safety
Honesty and Integrity
Teamwork
Professionalism
Quality Service
Creativity and Innovation
Inclusiveness and Mutual Respect
Community Involvement
Environmental Stewardship

Three-Year Goals[1]

Improve system reliability, increase capacity, and obtain optimal power and water resources
Attract, develop, and retain quality employees
Enhance organizational effectiveness, efficiency and financial health
Increase public awareness and support for Riverside Public Utilities
Provide environmental leadership in renewable energy, conservation and sustainability

[1] Not in priority order

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City of Riverside
Public Utilities Department - Resources Division

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EXECUTIVE SUMMARY

Increasing fossil fuel prices, worldwide concerns about global warming and the beginning of a new California wholesale electricity marketplace combine to present a significant challenge to future resource planning efforts by the Riverside Public Utilities Department ("RPU").

This *2008 Power Supply Integrated Resource Plan* ("IRP") provides an analysis of, as well as the types and timing related to, Riverside's acquisition of new power resources, including Demand Side Management ("DSM") and conservation-based "resources." The goal of Riverside's resource additions and DSM measures is to reliably meet the electricity needs of Riverside's ratepayers at the lowest possible cost consistent with sound business practices.

This IRP proposes more emphasis on renewable resources and DSM than in the past, recognizing that California and the Federal government are working on various means to reduce greenhouse gases and will likely implement some form of emission tax and, in the next few years, a cap and trade policy for greenhouse gas emissions.

RPU has less natural gas generation than most other California utilities but more coal-fired generation. As a result, RPU will be more adversely affected financially by greenhouse gas legislation than other California utilities.

To attempt to minimize the financial impacts of greenhouse gas reduction legislation, RPU proposes to devote almost all of its future resource acquisition efforts to renewable resources, especially geothermal generation, and DSM technologies.

Renewable resources may be more expensive in the short-run than traditional fossil fuel fired generation, but their price is not affected by geo-political events and, given the expected increase in prices for fossil fuel resources, can be melded into RPU's existing resource mix with little long-term impact on customer rates in comparison to those resources.

DSM technologies attempt to shift energy use to the less expensive periods of the day without adversely impacting how people and businesses use energy. Implementing thermal energy storage programs and encouraging more efficient use of residential appliances, especially refrigerators, freezers and air conditioning, form the basis of new or expanded DSM programs.

As RPU continues its transition to a greener, more efficient utility, it must also deal with a new wholesale marketplace in California. The California Independent System Operator ("CAISO") will implement their Market Redesign and Technology Upgrade ("MRTU"), scheduled to occur on April 1, 2009. The MRTU is primarily intended to increase the reliability of California's electric system while potentially reducing the cost of supplying energy to all of California's ratepayers.

However, the MRTU wholesale market is incredibly complex and assumes that each participant thoroughly understands how the market operates. This is especially true in how the MRTU market allocates the use and cost of California's transmission system.

An entity that participates in the market but does not understand how to offer its resources or use its existing transmission could suffer significant additional costs. RPU has spent millions of dollars over the past few years preparing for the new market, including personnel training, extensive participation in the CAISO stakeholder process used to develop the MRTU market rules, and implementing new software programs necessary to participate efficiently in this market.

Participating successfully in the MRTU market will require that RPU adopt new scheduling procedures and bidding strategies to make best use of its generation resources. RPU is currently participating extensively in the market simulations conducted by the CAISO in anticipation of the new market and has found that this participation has significantly helped to develop the new market in a manner that protects RPU's interests.

RPU will meet the new challenges of providing reliable and affordable electricity to Riverside's ratepayers. This IRP will change as the industry and the world economies evolve. RPU's planning efforts now attempt to take into account its lack of insulation from world geo-political events.

Although this and future Integrated Resource Plans are intended to form the basis for formulating and executing supply-side and demand-side strategies, it should be recognized that wholesale power markets in the Western United States, and particularly in California, are continuing to see unprecedented change. Therefore, staffs' in the Resources Division's Power Planning/Marketing, Power Projects/Contracts, and Power Scheduling/Operations areas must retain the flexibility to quickly alter the assumptions underlying this IRP and adjust their resource procurement and management activities as circumstances develop. In all cases, however, resource procurement and management by RPU personnel will comply with the requirements of the Energy Risk Management Policy, unless expressly exempted from those requirements by RPU's governing bodies on a case-by-case basis.

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CHAPTER 1 – INTEGRATED RESOURCE PLAN OVERVIEW

Introduction

Since the electricity crisis of 2000-2001, RPU has focused on increasing the reliability of service to its retail customers while keeping costs as low as reasonably possible.

RPU faces new challenges over the next few years as it attempts to adjust to a new wholesale electric marketplace while replacing several lower cost expiring supply contracts. At the same time, RPU will significantly reduce greenhouse gas[2] emissions to meet its goal of at least 33% renewable resources by 2020 and to meet new state and federal regulations. This effort will restrict the types of resources that are available to meet future energy demands.

Integrating Supply and Demand-Side Resources

This 2008 Integrated Resource Plan ("IRP") emphasizes the integration of supply-side and DSM programs, including aggressive conservation measures. While the rising cost and complexity of acquiring and operating new resources is one of the primary reasons, it is important to recognize the benefits that conservation and DSM technologies can represent to RPU's ratepayers. Appropriately designed conservation and DSM programs can lower customer costs while increasing economic development activity within Riverside.

DSM programs that reduce RPU's summer peak demand reduce the need for costly peaking energy and capacity, allowing RPU's customers to benefit from the reduced cost of power supply. Customers that adopt DSM programs benefit from lower costs while non-participating customers benefit from RPU's lower revenue requirements, hence lower rates.

Additionally, conservation and DSM programs reduce greenhouse gas emission levels and help RPU meet its own aggressive environmental goals[3], as well as California's emissions limitations.

[2] Defined in the Kyoto Protocol "basket" of emissions as carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[3] RPU's renewable energy portfolio goals are 20 percent of retail energy requirements in 2010, 25 percent by 2015 and 33 percent by 2020.

Programs that are most beneficial to RPU, in terms of cost reduction, include thermal energy storage, air conditioner replacement, refrigeration/freezer replacement and pool pump management programs. Each of these different programs reduces summer on-peak demand requirements and reduces the amount of future peaking capacity required by RPU to meet customer demand.

Another effective DSM program is Time-of-Use Rates. During on-peak hours, when RPU customer demands for electricity are highest, the cost of providing electricity is greater than at mid- and off-peak periods, when demand is lower. With Time-of-Use Rates, the cost varies according to the period in which RPU customers use the electricity. This cost incentive tends to flatten RPU's on-peak demand by shifting that demand to mid-peak and off-peak periods and reducing the amount of peaking capacity required by RPU.

Market Redesign and Technology Upgrade

One of the crucial issues facing RPU is developing strategies for participating in the CAISO's new Market Redesign and Technology Upgrade ("MRTU"). The MRTU will replace the existing energy-based wholesale market that evolved in the aftermath of the 2000/01 western energy crisis. In terms of staff time and computer systems, RPU continues to invest significant resources in preparation for the implementation of MRTU.

Two of the key components of MRTU are Resource Adequacy and Locational Marginal Pricing ("LMP").

Resource Adequacy

Resource Adequacy is the requirement that each Load Serving Entity ("LSE"), such as RPU, have sufficient unit-specific generation resources to meet its forecasted peak loads, plus CAISO-mandated reserves. By insuring that each LSE has sufficient resources to meet peak loads, plus a 15 percent planning margin, the CAISO is attempting to prevent the possibility of energy shortages that were partially responsible for the 2000/01 energy crisis.

The CAISO has also added a second type of capacity requirement, Local Capacity Requirement ("LCR"). LCR is supplied from generation resources located within the same transmission zone, or "load pocket," as the LSE. RPU's Local Capacity zone roughly includes the Los Angeles basin area. For example, RPU receives Resource Adequacy credit from the CAISO in connection with its Intermountain Power Project entitlement, but does not receive LC credit due to its location outside of the transmission zone in which RPU physically resides. Riverside's ownership interest in the San Onofre Nuclear Generating Station ("SONGS"), however, provides RPU with CAISO credit for both Resource Adequacy and LCR requirements.

Locational Marginal Pricing

LMP was introduced in an attempt to encourage the future construction of generation at appropriate points on the existing transmission system through locational price signals. This is

accomplished by the calculation of discrete prices for each of approximately 3,000 locations on the CAISO grid where energy can be injected or withdrawn, as opposed to the CAISO's existing 1998 methodology which separates the CAISO's transmission system into only three such pricing locations or "zones." In a LMP market, the marginal energy cost at each of the 3,000 locations mentioned above is comprised of three components – energy costs, the marginal cost of transmission losses and transmission congestion costs.

Energy Costs

Utilities, such as RPU, currently dispatch energy from their own generation to meet their native customer load requirements and any wholesale sales. Even if less expensive generation is available in the market, a utility may still operate higher priced generation because of a lack of certainty surrounding the terms and conditions of acquiring market energy, or due to contractual or operating restrictions on the resource (such as must-run limitations).

Under the MRTU regime, the CAISO assumes dispatch control over most generation in the State and operates that generation to minimize total statewide energy costs, subject to local reliability requirements and generator operating constraints. Generation owned or controlled by California utilities will largely be dispatched in economic order.

Energy costs are determined by the supply and demand of energy in the CAISO marketplace on a five-minute basis. Each supplier provides an energy bid showing how much energy they are willing to provide from each generation source at different prices. This is matched with demand bids from LSEs showing how much energy they are willing to purchase at different prices. Theoretically, no entity should pay more for energy under this proposal than it would by dispatching its own resources, although transmission costs could be significantly greater due to congestion.

Transmission Congestion Costs

The advantage of the MRTU bidding scheme is that all of the generation resources controlled by California utilities or power marketers would be used to meet hourly energy requirements in a least-cost fashion. Utilities should see their power supply costs decline (or at worst remain constant) assuming that resource bids are managed correctly. Generation cannot be withheld from the market as was the case in the so-called energy crisis of 2000/01, which resulted in artificial shortages that drove up wholesale power supply prices. The primary disadvantage of this new transmission market (in addition to its extreme complexity) is the manner in which transmission usage is priced and the risk of congestion pricing as described in more detail below.

The CAISO will implement a transmission congestion pricing mechanism that charges users of the transmission grid a volumetrically-based congestion cost when the sum of market participant requests for transmission service exceed the capability of the relevant transmission facilities. To partially protect themselves from these transmission congestion costs for their resources, LSE's

are permitted to request *Congestion Revenue Rights* ("CRR") from the CAISO.[4] Upon MRTU implementation, LSEs will attempt to match their energy bids with theirs CRRs over the relevant transmission path in order to receive the intended congestion price hedge[5].

Transmission Losses

As part of delivering energy using transmission lines, a portion of the energy will be consumed by those lines in the form of heat. Energy consumed by a transmission line itself is referred to as transmission losses. Market participants, such as RPU, cannot accurately plan for or bypass the CAISO's allocation of marginal transmission losses related to the market participant's accepted energy bids. All market participants will be allocated the same percentage of losses on those energy bids for each five-minute ISO market interval.

Summary of MRTU Impacts

Implementation of the CAISO's MRTU market does not affect the amount of capacity resources that RPU must purchase. Instead, MRTU will affect the type and potential location of future capacity additions. Generation resources subject to the MRTU market should only be acquired if long-term transmission cost hedges, in the form of CRRs, can be secured, otherwise RPU would be accepting the unhedged risk of higher transmission costs through congestion rents.

The MRTU market places a premium on resource flexibility. Resources that can be bid into the MRTU market to cap costs are much preferred over higher cost units that must be dispatched.

As a result of the MRTU market design, RPU can only estimate monthly or annual costs based upon the assumption that specific resources will be dispatched to meet load. Based upon CAISO-predicted MRTU market clearing prices, it is probable that RPU's internal generation will not be required to operate for economic reasons. If this is the case, actual power supply costs will be lower than RPU's forecast. It is more likely, however, that RPU's internal generation resources will operate for CAISO or RPU grid reliability reasons in the near term.

A more detailed description of the CAISO's MRTU market is presented in Appendix A.

Riverside's Future Resource Requirements

Starting in 2007, certain low-cost, long-term power supply contracts entered into by RPU in the 1980's and 1990's began expiring. Additional power supply contracts are set to expire in the next two years[6], presenting RPU with the challenge of replacing these resources.

[4] An entity can largely protect itself against congestion costs by the acquisition of CRR, financial instruments made available by the CAISO and intended to allow a market participant to hedge against the risk of congestion costs. In effect, CRRs act as a form of insurance that pays the CRR holder when congestion costs are incurred.

[5] At this time, RPU believes that its transmission congestion exposure for existing resources is relatively small but will increase after 2010 when its pre-existing transmission rights expire and new resources are added to its resource mix.

Prior to the restructuring of California's electricity markets in 1998, sellers in wholesale power markets were willing to enter into long-term, fixed price contracts. Today, due to the volatility of the primary fuels market, regulatory uncertainty and an overall shortage of regional generation capacity, sellers are largely no longer willing to enter into such contracts. If a willing seller is identified, purchases are nevertheless difficult to negotiate unless the purchaser (i.e., RPU) assumes much of the financial risk associated with non-performance of the contracted resource, whether due to forced outages, counterparty credit concerns, or failure of the CAISO's market mechanisms.

Structural change, such as FERC Orders 888 and 890, affecting transmission use in the wholesale power industry has helped to eliminate some of the past regional price differences. These changes have largely prevented transmission owners from inappropriately reserving unused transmission capacity for their own future use, opening new markets for generators and helping to equalize regional prices.

As a result of these changes, power supply contracts that RPU entered into many years ago are unlikely to be renewed under their current favorable terms. For example, RPU's current power supply contract with Deseret Generation and Transmission Cooperative (Deseret) carries an average price of $24.50/MWh ($0.0254/KWh). The Deseret contract will expire at the end of 2009 and will be replaced with a larger baseload renewable resource having a melded cost of approximately $77/MWh ($0.077/KWh), adding approximately $12 million to RPU's annual wholesale power costs in 2010. Energy provided by the coal-based Deseret resource amounted to approximately 18 percent of RPU's total annual retail energy requirements, while energy from its replacement will provide approximately 8% of those requirements in 2010 and 17% of those requirements in 2011.

Risk Management

A common risk management measure of the need for new energy resources is the Value-at-Risk ("VAR") metric. VAR is the expected cost of future energy needs if those needs were met at current forward market prices.

Table 1.1 on the next page shows RPU's projected annual VAR for the period CY 2008 through 2015.

[6] In 2007 power purchase agreements with the California Department of Water Resources for summer capacity and energy expired. By 2009, the power purchase agreements related to the Milliken, Mid Valley and Badlands resources will have expired, totaling 6 MW of landfill gas-fired baseload generation. At the end of 2009, the 52 MW Deseret Generation and Transmission Cooperative power purchase agreement expires, followed in early 2011 by one of RPU's two Bonneville Power Administration capacity-energy exchange agreements (23 MW). Together these resources represented 75 MW of summer capacity and approximately 26 percent of RPU's total annual energy requirements.

Table 1.1: RPU's Future Unmet Energy Requirements								
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Unmet Energy GWh (VAR)	262	248	328	70	6	65	72	93
Exposure at $90/MWh ($million)	$23.6	$22.3	$29.5	$6.3	$.54	$5.8	$6.5	$8.4
Unmet Energy (percent VAR)	11	10	14	3	0.3	3	3	4

As Table 1.1 shows, RPU's VAR increases over the next few years due to the expiration of purchase agreements with the California Department of Water Resources ("CDWR"), Deseret Generation & Transmission Co-operative, NM Milliken LLC, NM Mid Valley LLC and the County of Riverside (i.e., the Badlands resource). Additionally, RPU is examining the potential impact from expiration of one of RPU's two capacity-energy exchange agreements with the Bonneville Power Administration in early 2011.

The CDWR contracts for non-specific power expired in 2007. Together they provided 53 MW of summer on-peak (May through October) capacity and approximately 30 GWh of monthly energy during the summer months. RPU's peak summer load is approximately 600 MW. Deseret provides 52 MW of coal-based energy for all hours of the day, or approximately 420 GWh per year. The coal-based Deseret power supply contract will expire on December 31, 2009.

On January 31, 2011, the first of RPU's Bonneville Power Administration ("BPA") contracts for non-specific power is scheduled to expire. RPU has two capacity-energy exchange contracts with BPA. The capacity-energy exchange agreements allow RPU to deliver inexpensive excess baseload energy to BPA during low load periods in exchange for capacity and energy from BPA during high load periods. The primary advantage of the BPA contracts is that they allow RPU to use its excess (in terms of RPU's low load energy requirements) inexpensive baseload energy and leverage that excess energy as payment for capacity and energy provided by BPA during high load periods.

The expired CDWR contracts, in addition to the existing Deseret contract, provided almost 20 percent of RPU's summer peaking requirements and 25 percent of RPU's total annual energy requirements at relatively inexpensive prices in comparison to today's markets. With the anticipated expiration of the first BPA contract in 2011, RPU will require more summer peaking capacity and energy.

Capacity Requirements

The CAISO requires RPU to have sufficient resources to meet its forecasted monthly peak demands, plus reserves of 15 percent. With the expiration of the CDWR contracts in 2007 and a small increase in forecasted 2008 monthly peak demand, RPU required additional generation capacity for the summer period.

This deficiency will continue throughout the planning horizon, absent short-term or long-term resource additions. However, approximately 100 MW of the deficit is due to CAISO-imposed reserve requirements that can be acquired fairly inexpensively in the short-term market. For 2008, the capacity requirement shown was met with capacity purchases using the commonly-accepted Western Systems Power Pool master agreement.

Environmental Constraints

In 2006, California Governor Schwarzenegger signed Assembly Bill 32: *The California Global Warming Solutions Act* and Senate Bill 1368: *The Greenhouse Gas Emissions Performance Standard* into law. Together, these two bills require that California's statewide greenhouse gas emissions be reduced to 1990 levels by 2020 and restrict greenhouse gas emissions from future baseload generation.

These two bills effectively prohibit RPU from investing in coal-fired generation and require that future investment be applied to state-of-the-art combined-cycle generation or renewable resources in order to offset the greenhouse gas emissions associated with Riverside's existing coal-fired generation, the Intermountain Power Project ("IPP").

RPU is investigating a number of long-term renewable resources, primarily geothermal projects. While solar photovoltaic and wind generation are potentially attractive alternatives, neither can provide the reliable level of capacity and energy required by RPU over the next few years. Solar photovoltaic generation is still being pursued primarily as a small distributed generation alternative and the intermittent nature of wind generation resources currently precludes their use as a major component of RPU's resource mix.

Table 1.2: Resource CO2 Emissions per MWh

Resource	Fuel	CO2 lbs/MWh
Deseret – Bonanza	Coal	2,312
Deseret – Hunter	Coal	2,133
IPP	Coal	2,225
Palo Verde	Nuclear	0
Songs	Nuclear	0
Badlands	Biogas	0
Hoover	Hydroelectric	0
Salton Sea Unit 5	Geothermal	100
Wintec	Wind	0
Springs	Natural Gas	1,435
RERC	Natural Gas	1,277
Non-Specific Source		
BPA	Hydroelectric	921

Senate Bill 1368 ("SB1368") restricts the ability of California's LSE's to make significant investments in long-term, baseload resources having average CO_2 emissions that exceed 1,100

lbs/MWh. As shown in Table 1.2 above, RPU's existing coal and natural gas generation facilities exceed this level, although none of RPU's natural gas resources are operated as baseload generation and would therefore be exempted from the requirements of SB1368.

Natural Gas Purchases

Assembly Bill 32 ("AB32") and SB1368 essentially require California utilities to make the majority of new non-renewable investment in high efficiency natural gas-fired projects, primarily combined cycle generation. Natural gas-fired combined cycle generation is generally very efficient and clean compared to other types of fossil-fuel generation alternatives. As will be discussed in more detail, RPU is cognizant of the primary fuel price risks that flow from an over-dependence on natural gas generation. Any disruptions in natural gas supplies could have a severe impact on RPU's cost structure, unless natural gas purchases are managed strategically.

RPU is investigating a number of long-term options to manage natural gas costs, including new purchase and gas transportation agreements to hedge long-term natural gas price and supply risks.

Regulatory Requirements

Regulatory risk has increased as municipal utilities become increasingly subject to rules and requirements promulgated by state and federal regulatory entities that once had little or no influence over their operations. In addition to requirements imposed by the CAISO, the North American Electric Reliability Corporation ("NERC"), the Western Electricity Coordination Council ("WECC") and the Federal Energy Regulatory Commission ("FERC") have additional regulatory powers to promote regional reliability and, where allowed, to impose significant monetary penalties for failure to comply with mandated reliability standards. The need for this new authority largely stems from the widespread (multi-state) blackouts which have occurred over the last decade. Over the last few years, California regulators have obtained an ever-increasing level of authority over municipal utility operations as a result of new legislative mandates.

The CAISO

The CAISO is consistently moving forward with a number of Resource Adequacy and integrated capacity market proposals that it intends to incorporate into its tariffs. Many of RPU's concerns have centered on Resource Adequacy requirements, including Local Capacity obligations. To ensure that RPU is fully informed about initiatives proposed to be undertaken by the CAISO, RPU actively participates in the CAISO's stakeholder processes and influences, to the extent possible, the ultimate form of any requirements that may apply to RPU's resource acquisitions.

The NERC

The Energy Policy Act of 2005 imbued the NERC with new and far reaching regulatory powers related to system reliability policies, standards and practices. Along with the ability to mandate compliance with its detailed reliability standards, the NERC has been vested with audit rights

and the ability to impose significant monetary penalties for non-compliance. Although many of the NERC's new reliability standards do not directly apply to Riverside's circumstances, RPU is obligated to comply with a significant number of those standards. Compliance is assured through RPU's designation of a full-time employee responsible for compliance with regulatory and legislative mandates.

The WECC

The WECC acts as the Regional Reliability Council, under NERC direction, responsible for promulgating its own regional reliability standards for all or part of fourteen western states and portions of Canada and Mexico. In addition, the WECC bears responsibility for enforcing both its own reliability standards and those of the NERC. The WECC has begun auditing utilities to insure compliance with those reliability standards. Compliance audits are scheduled over a five-year period with the possibility of unannounced audits during this time period. As described above with respect to the NERC, RPU has designated a full-time employee to be responsible for RPU's compliance with regulatory and legislative mandates, including those imposed by the WECC.

The FERC

In addition to exercising regulatory authority over the reliability standards issued by the NERC and the WECC, as described above, the Federal Energy Regulatory Commission has issued new transmission rules in its Order 890 proceeding that require LSEs to meet Resource Adequacy requirements.

In that order, the FERC ruled that only firm resources[7] transmitted over a firm transmission path may be considered as contributing to the satisfaction of Resource Adequacy requirements. In the past, firm resources could be transmitted over interruptible, or "non-firm," transmission paths and still be considered as Resource Adequacy contributors. With this change, the FERC now requires the seller of firm resources to acquire specific, identified transmission paths between the generator and the purchaser's point of receipt. This effectively prevents bilateral sales of unspecified system capacity[8] from being considered a firm resource because the capacity cannot be tracked back to a specific generation source. More importantly, Order 890 prohibits the reservation of firm transmission service for transactions without a specifically identified generation source.

[7] Resources are considered "firm" when the entity selling the resource has agreed not to interrupt or curtail energy deliveries except under very specific circumstances. Those circumstances are typically related to a force majeure event or an event that otherwise threatens the reliability of the supplier's service to its own customers.

[8] "Unspecified system capacity" refers to capacity derived from all or a portion of a supplier's resource portfolio, as opposed to a specific resource or combination of resources. Referred to as "unit contingent," the designation of specific resource(s) underlying a power sale is considered inferior to unspecified system capacity, which implicitly includes the supplier's obligation to provide capacity reserves in connection with the supply.

The California Air Resources Board

The California Air Resources Board ("CARB") is a part of the California Environmental Protection Agency, an organization which reports directly to the Governor's Office. Their mission is to promote and protect public health, welfare and ecological resources through the effective and efficient reduction of air pollutants while recognizing and considering the effects on the economy of the state. The Federal Clean Air Act passed in 1970, and last amended in 1990, forms the basis for the national air pollution control effort. Basic elements of the clean air act which the CARB has oversight, include stationary source emissions standards and permit requirements. The CARB does not have authority to issue permits directly to stationary sources of air pollution. Primary responsibility for permitting all sources rests with the local and regional air pollution control authorities known as Air Pollution Control Districts ("APCD") or Air Quality Management Districts ("AQMD").

The California Energy Commission

The California Energy Commission ("CEC") is the state's primary energy policy and planning agency. Created in 1974 the CEC responsibilities include:

i) Forecasting future energy needs and keeping historical energy data,
ii) Licensing thermal power plants 50 megawatts or larger,
iii) Promoting energy efficiency by setting the state's appliance and building efficiency standards,
iv) Supporting public interest energy research that advances energy science and technology through research, development, and demonstration programs,
v) Supporting renewable energy by providing market support to existing, new, and emerging renewable technologies; providing incentives for small wind and fuel cell electricity systems; and providing incentives for solar electricity systems in new home construction,
vi) Implementing the state's Alternative and Renewable Fuel and Vehicle Technology Program, and
vii) Planning for and directing the state response to energy emergencies.

The most important development in the California energy policy in the past two years is the arrival at consensus that California must act to mitigate its greenhouse gas emissions, in order to reduce the impact of climate change. In 2006, the Legislature passed and the Governor signed two landmark pieces of legislation, AB32 and Assembly Bill 118, with far-reaching implications for energy policy. The CEC has roles in implementing both successfully.

The most comprehensive is AB32, the California Global Warming Solutions Act of 2006, which sets an economy-wide cap on California greenhouse gas emissions at 1990 levels by no later than 2020. This is an aggressive goal that represents approximately an 11 percent reduction from current emissions levels and nearly a 30 percent reduction from projected business-as-usual levels in 2020. Twenty-five percent of the state's greenhouse gas emissions are attributable to electricity generation while 38 percent is attributed to the transportation sector.

Addressing the impacts of the transportation sector on climate change, Assembly Bill 118 created the Alternative and Renewable Fuel and Vehicle Technology Program. The program is intended to increase the use of alternative and renewable fuels and innovative technologies that will transform California's fuel and vehicle types to help attain the state's climate change policies. Assembly Bill 118 authorizes the Energy Commission to provide, upon appropriation by the Legislature, approximately $120 million in annual incentives to public agencies, vehicle and technology consortia, businesses, public-private partnerships, workforce training partnerships and collaboratives, fleet owners, consumers, recreational boaters, and academic institutions.

The South Coast Air Quality Management District

Local air district permitting activity in the Los Angeles is the responsibility of the South Coast Air Quality Management District ("SCAQMD"). Permitting activity in the Los Angeles basin falls into two broad categories:

i) Authority to Construct – any entity proposing to construct, modify, or operate a facility or equipment that may emit pollutants from a stationary source (i.e. power plant) into the atmosphere must first obtain an Authority to Construct from the SCAQMD and
ii) Operating Permits – any entity operating a facility that emits air pollution must obtain an operating permit from the SCAQMD.

Other Regulatory Risks

Regulatory risk includes the potential for increased costs to ratepayers if regulatory requirements are reversed or dramatically changed. The current confusion surrounding MRTU implementation is an example of how regulatory changes can increase market participant costs. RPU invested significant staff time and funds in an effort to meet the CAISO's announced goal of MRTU implementation by April 2008. Yet, in late February 2008, the CAISO announced a delay in MRTU implementation to an unspecified future date. Later, a new implementation date of October 1, 2008 was established. Currently, the CAISO is suggesting that MRTU implementation will occur April 1, 2009. Had the CAISO provided market participants, such as RPU, more advance notice that MRTU would not be implemented beginning in April 2008, RPU's 2008 capacity procurement strategy would have been modified to minimize costs.

Although unlikely, it is also possible that a new California governor could reverse the State's timetable in moving toward dramatically increased renewable energy procurement, which results in higher costs for RPU's ratepayers. RPU has positioned itself well in comparison to surrounding utilities that have not invested in renewable resources and benefitted from early purchases of lower-than-market-cost renewable supplies. More importantly, RPU has secured significant renewable resources well into the future (e.g., 2020 to 2040).

RPU can minimize regulatory risk by continuing to participate actively in the various legislative and regulatory processes, ensuring that future resource acquisitions comport with current and

anticipated regulatory requirements, and engaging in sound resource planning practices with a comprehensive understanding of the State's current and anticipated political environment.

Renewable Energy Alternatives

Currently, RPU generates or purchases approximately 11 percent of its annual retail energy requirements from renewable energy sources. By far, the most important current renewable resource is the Salton Sea Unit 5 geothermal project in Imperial County. This generation resource currently provides 20 MW of energy during all hours of the year and in 2009 will increase to 46 MW hourly. RPU is committed to having a minimum of 20 percent of its annual energy requirements met by renewable energy sources by 2010, with that minimum increasing to 25 percent in 2015 and 33 percent in 2020.[9]

Renewable resources, including solar, geothermal, small hydroelectric, biomass and biogas generation, initially tend to cost approximately $20 - $35 per MWh more than traditional fossil fuel generation. However, because renewable resource prices are not subject to the same politico-economic forces as fossil fuels, renewable resource costs tend to become less expensive over time than a comparable fossil fuel resource. RPU will achieve long-term price stability, and lower rates to its customers, by concentrating on the addition of renewable resources to its resource mix.

California's environmental laws essentially preclude RPU from entering into any future supply arrangements with coal-fired generation resources. Even gas-fired generation resources, other than combined cycle and cogeneration resources, often do not meet the 1,100 lbs/MWh emissions restriction contained in SB 1368.

Table 1.3 on the next page summarizes 2008 RPU's renewable resources.

[9] These goals were adopted by the Board of Public Utilities in May 4, 2007 and the Riverside City Council on December 9, 2008.

Table 1.3: Summary of RPU's Existing Renewable Resources.		
Resource Name	**Fuel Type**	**Capacity**
Salton Sea Unit 5	Geothermal	20 MW (46 MW in 2009)
Wintec	Wind	1.32 MW
Badlands	Bio-gas	1.3 MW
Milliken/Mid Valley Landfill **(expired June 2008)**	Bio-gas	4.6 MW
Utility Operations Center	Photovoltaic	150 KW
Janet Goeske Senior Center	Photovoltaic	69.6 KW
City Hall Ceremonial Patio	Photovoltaic	17.4 KW
Hunt Park	Photovoltaic	9.92 KW
Shamel Park	Photovoltaic	9.92 KW
Islander Park	Photovoltaic	9.92 KW
Orange Terrace	Photovoltaic	89.72 KW

RPU will expand its portfolio of renewable resources over the next few years in an economic and planned manner that minimizes the effect of higher initial prices to the ratepayer. Among the local renewable resources RPU is pursuing is approximately 3 MW of existing grease-to-gas powered baseload generation and a 1 MW fuel cell using local digester gas as a fuel source. These additional resources are in or near commercial operation at Riverside's own Regional Water Quality Control Plant and will be included in Riverside's renewable portfolio in 2008, provided that certification of those resources by the CEC is possible and the renewable attributes can be retained by Riverside. Annual energy from these small resources is expected to total approximately 31.5 GWh with minimal cost to RPU's customers.

Conservation and Demand-Side Management

RPU intends to continue expanding its conservation and DSM programs to reduce the need for additional on-peak capacity purchases.

Many of the current RPU customer programs emphasize conservation, although future programs will emphasize DSM measures that shift on-peak demand to the off-peak period, such as thermal energy storage units.

RPU recognizes the value to the utility and ratepayers of expanding cost-effective conservation and DSM programs. As importantly, well designed energy efficiency programs can promote economic activity within the City of Riverside, as opposed to exporting revenue and jobs to other communities.

Results and Recommendations

Based upon the analysis performed in this IRP, the following recommendations are presented:

1. In 2009, RPU requires additional capacity and energy resources. RPU should enter into a long-term power purchase agreement or asset purchase, if economic, with the City of Corona for 28 MW of capacity and energy from the Clearwater Power Plant, a natural gas-fired cogeneration facility. This purchase will partially replace the energy from the expired CDWR power purchase agreements;

2. Recognizing the increasing risk of natural gas prices on RPU's cost structure, natural gas management and hedging efforts should be increased. This may include becoming part of the "Muni-Gas" purchasing group or other hedging alternatives and could result in RPU assuming balancing obligations for natural gas supplies. Also, prior to June 2008 RPU should determine the type of transportation customer role it will assume under Southern California Gas Company's new "FAR OFF" program;[10]

3. RPU should carefully monitor the progress of the Renaissance Geothermal Project to ensure that at least one of the two planned 32 MW generators begin operation in 2010. This will replace the expiring coal-based Deseret power purchase agreement and provide a long-term source of renewable energy with a low escalation rate;

4. Beginning in 2013, RPU should enter into 10-15 MW baseload renewable resource purchases every other year to meet future load growth and replace expiring power supply contracts. By choosing only renewable energy sources in the future, RPU can protect

[10] The Firm Access Receipt and Off-System Delivery (FAR OFF) program is the system of firm access rights and off-system delivery on the SoCalGas transmission system. FAR OFF will be implemented on October 1, 2008, and will provide customers, gas suppliers and California producers with new options and opportunities related to transmission pricing and character of service.

itself against rapidly escalating natural gas costs and actually reduce long-term costs as natural gas prices escalate more quickly than renewable energy costs;

5. RPU should attempt to extend the 23 MW BPA Capacity Sale/Exchange Agreement set to expire in 2011. This contract provides significant summer capacity and peaking energy benefits to RPU that would be difficult to replace with other types of power purchase agreements;

6. Several types of DSM programs are cost effective from a utility, participating and non-participating customer viewpoint. These programs include thermal energy storage, central heating and cooling districts and distributed solar generation programs. RPU's Power Planning/Marketing group and Public Benefits group should work together closely to implement these programs and reduce the need for additional generation to meet summer peaking requirements;

7. RPU should include the likelihood of carbon taxes or GHG taxes in all resource planning and conservation/DSM efforts beyond 2010. Proposals under AB 32 include carbon taxes ranging between $30 and $50/MWh;

8. MRTU could significantly change the way that RPU's resources are dispatched. While RPU has the option to "self-schedule"[11] all its existing resources to meet load, MRTU could result in lower energy costs if an appropriate bidding strategy is utilized. RPU should also investigate the possibility of bidding its internal resources as both spin and non-spinning reserve to increase revenues; and

9. One of RPU's greatest risks under MRTU is the effect of transmission congestion pricing. RPU should anticipate actively managing the acquisition and use of Congestion Revenue Rights to hedge these considerable cost risks.

[11] The term "Self-Schedule" refers to a MRTU market participant's option to purchase transmission service from the CAISO as a price taker; i.e., resource schedules are submitted to the CAISO without associated congestion management bids that might otherwise limit the market participant's exposure to congestion costs. Without such bids, the market participant is declaring to the CAISO's business systems that it wishes to use CAISO transmission regardless of potential congestion costs.

CHAPTER 2 – DEMAND AND ENERGY FORECAST

Introduction

The load forecast is an integral part of RPU's power resource planning process, with forecasted peak demands and energy requirements vital for determining future resource acquisitions and MRTU strategies. It is also an effective process for predicting future retail sales revenue and establishing strategic planning requirements for the electric distribution system.

Methodology

The objective of the load forecast model is to produce reliable estimates of RPU's monthly system energy requirements and monthly peak demands. This is achieved by analyzing customer class data components and examining trends in customer growth and energy use. Forecasts of customer growth are then developed using population and/or employment projections. This method applies to Residential and Commercial classes. The Miscellaneous class, which makes up 2 percent of RPU's energy requirements, is modeled as a simple function of Riverside's population. Monthly peak demands are then derived by applying monthly load factors to the monthly energy requirements.

Customer Classes

To analyze historical energy usage, customers are divided into three classes:

- Residential: Includes all rate subclasses;
- Commercial: Includes all commercial, industrial and large time-of-use customers; and
- Miscellaneous: Includes outdoor lighting, street lights and traffic signals.

Independent Variables

A variety of independent variables and combinations of variables were evaluated in the customer energy use sub-models to identify which ones were most significant for each customer class. The historical data selected for independent variables, in order of significance, were: city population, heating and cooling degree-days, county employment, retail price of electricity and city per-capita income.

Statistical Analysis

Linear regressions of energy sales were performed for Residential and Commercial classes using monthly historical data from January 2002 through December 2007. The linear equations developed from these regressions were then used to project monthly energy sales by customer class for 2008 through 2026. Linear regressions performed for the Miscellaneous class were not viable due to significant migration of accounts to the Commercial class over the past few years.

Residential

The residential rate class makes up 90 percent of the City's electric customers and accounts for 35 percent of total energy sales. Over the past ten years (1998-2007), energy sales grew at an average annual rate of 2.6 percent. During the same period, Riverside's population—the primary driver for this class—grew at an average annual rate of 1.9 percent. This would infer that energy use per customer is increasing.

Population, electricity price, and cooling and heating degree-days were the independent variables used in the historical energy sales regression analysis, where *Monthly Residential Energy Sales equal* :

$$(Population * 0.7590) + (CDD * 92) + (HDD * 36) – (Price * 1,353,977)$$

Applying this equation to the forecast model, residential energy sales are expected to grow at an average annual rate of 1.8 percent between 2008 and 2017. Over the same period, City population is projected to grow at an average annual rate of 1.6 percent.

Commercial

The commercial rate classes make up 10 percent of the City's electric customers, but account for 63 percent of total energy sales. Over the past ten years (1998-2007), energy sales grew at an average annual rate of 3.0 percent. During the same period, Riverside County employment—the primary driver for this class—grew at an average annual rate of 3.8 percent.

Employment and cooling/heating degree-days were the independent variables used in the historical energy sales regression analysis, where *Monthly Commercial Energy Sales equal*:

$$(Employ * 0.1248) + (CDD * 48) – (HDD * 20)$$

Applying this equation to the forecast model, commercial energy sales are expected to grow at an average annual rate of 2.2 percent between 2008 and 2017. Over the same period, County employment is projected to grow at an average annual rate of 2.3 percent.

Miscellaneous

The miscellaneous rate class accounts for only 2 percent of total energy sales. Due to a significant migration of meters into the commercial class during the past few years, it was impossible to perform regression analysis on this data. Therefore the miscellaneous class was forecasted as a simple function of City population, starting with 2007 data, where the *Monthly Miscellaneous Energy Growth Rate equals*:

$$(0.0082) * City\ Population\ Growth\ Rate$$

Applying this equation to the forecast model, miscellaneous energy sales are expected to grow at an average annual rate of 1.6 percent between 2008 and 2017.

System Energy Requirements

Once the monthly energy sales forecast model for the three customer classes is completed, individual class forecasts are summed to obtain total annual energy sales. Then, electric distribution system losses of 5 percent are added to the total energy sales, where *Monthly System Energy Requirements equal*:

*Monthly Energy Sales * 1.05*

System energy requirements are forecasted to grow at an average annual rate of 2.1 percent between 2008 and 2017. For comparison, the annual growth rate averaged 2.7 percent from 1998 to 2007.

Monthly Peak Demands

Average monthly load factors were developed from historical energy and peak demands (1991-2007), where *Monthly Load Factor equals*:

$$\frac{\textit{Monthly Energy (MWh)}}{\textit{Monthly Peak Load (MW) x Hours in Month}}$$

Forecasted monthly peak demands were then calculated by multiplying the respective month's load factor by the forecasted monthly energy requirement, where *Monthly Peak Load equals*:

$$\frac{\textit{Monthly Energy Requirement}}{\textit{Monthly Load Factor * 730}}$$

Scenario Analysis

In the forecast model, "normalized" monthly cooling degree- and heating degree-days were used as independent variables. Therefore, the energy and peak demand projections in the forecast expect "normal" weather throughout the years. However, weather conditions play a significant role in how the City's customers use energy. Summer heat waves especially have a significant impact due to increased air conditioning load. For this reason, two modeling scenarios were run to reflect adverse hot and adverse cool weather conditions.

Hot Weather Scenario

For the effects of adverse warm weather, cooling degree- and heating degree-days from the warmest year in the past twenty were used in the forecast model. The outcome demonstrated that adverse warm weather can increase annual energy requirements by 4.4 percent and annual peak loads by 7.4 percent.

Cool Weather Scenario

For the effects of adverse cool weather, cooling degree-days and heating degree-days from the coolest year in the past twenty were used in the forecast model. The outcome demonstrated that adverse cool weather can reduce annual energy requirements by 2.3 percent and annual peak loads by 6.8 percent.

Forecast Results

Figure 2.1 presents the forecast of monthly energy requirements from 2008 through 2017 for the hot and cool scenarios. Annual energy growth is 1.9 percent between 2008 and 2017, although hot weather can increase annual requirements by as much as 100 GWh. At the other extreme, cool weather can reduce annual forecasted amounts by approximately 50 GWh. The primary reason for the smaller impact of cool weather is that cooler weather does not significantly reduce winter energy use in comparison to baseline assumptions.

Peak demand growth is projected to be 1.5 percent annually with temperature impacts on annual peak demand adding or subtracting 43 MW. That is, a cool or hot summer can increase or decrease annual peak demand by 43 MW from the baseline scenario. Figure 2.2 presents the long-term peak demand forecast.

Figure 2.1: System Energy Requirements

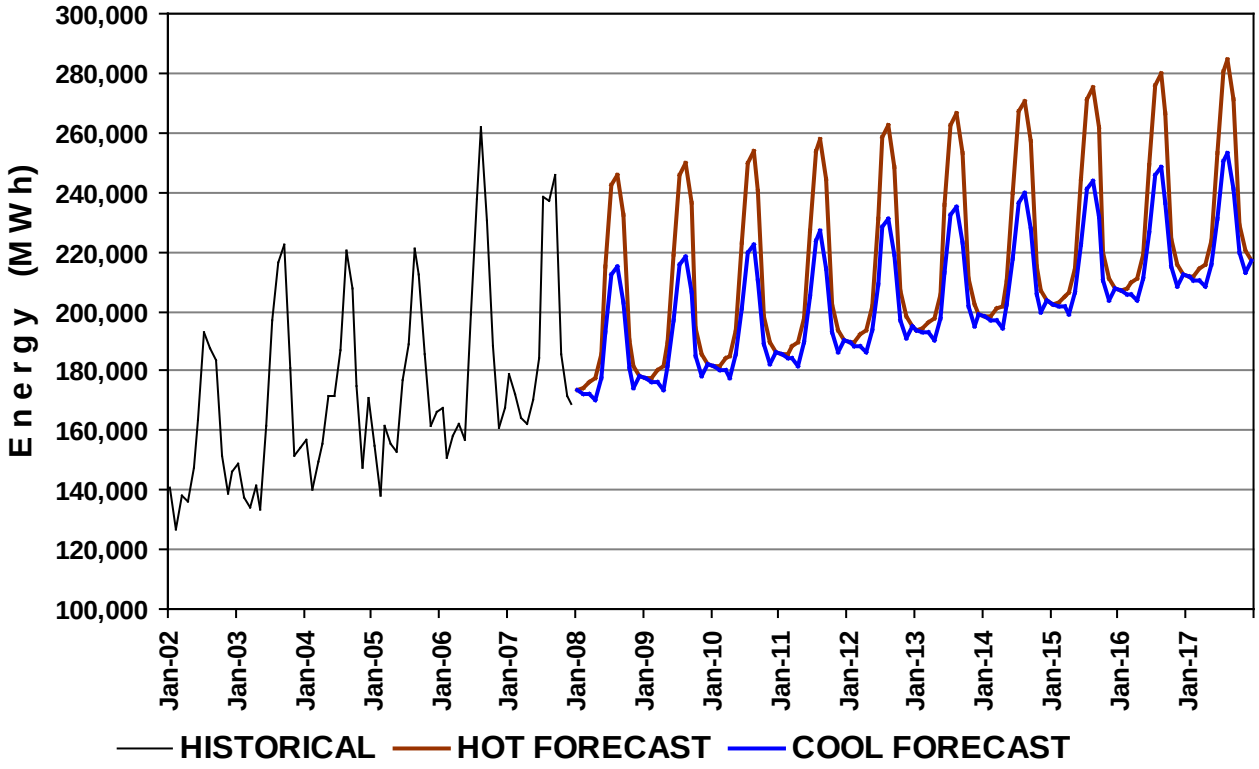
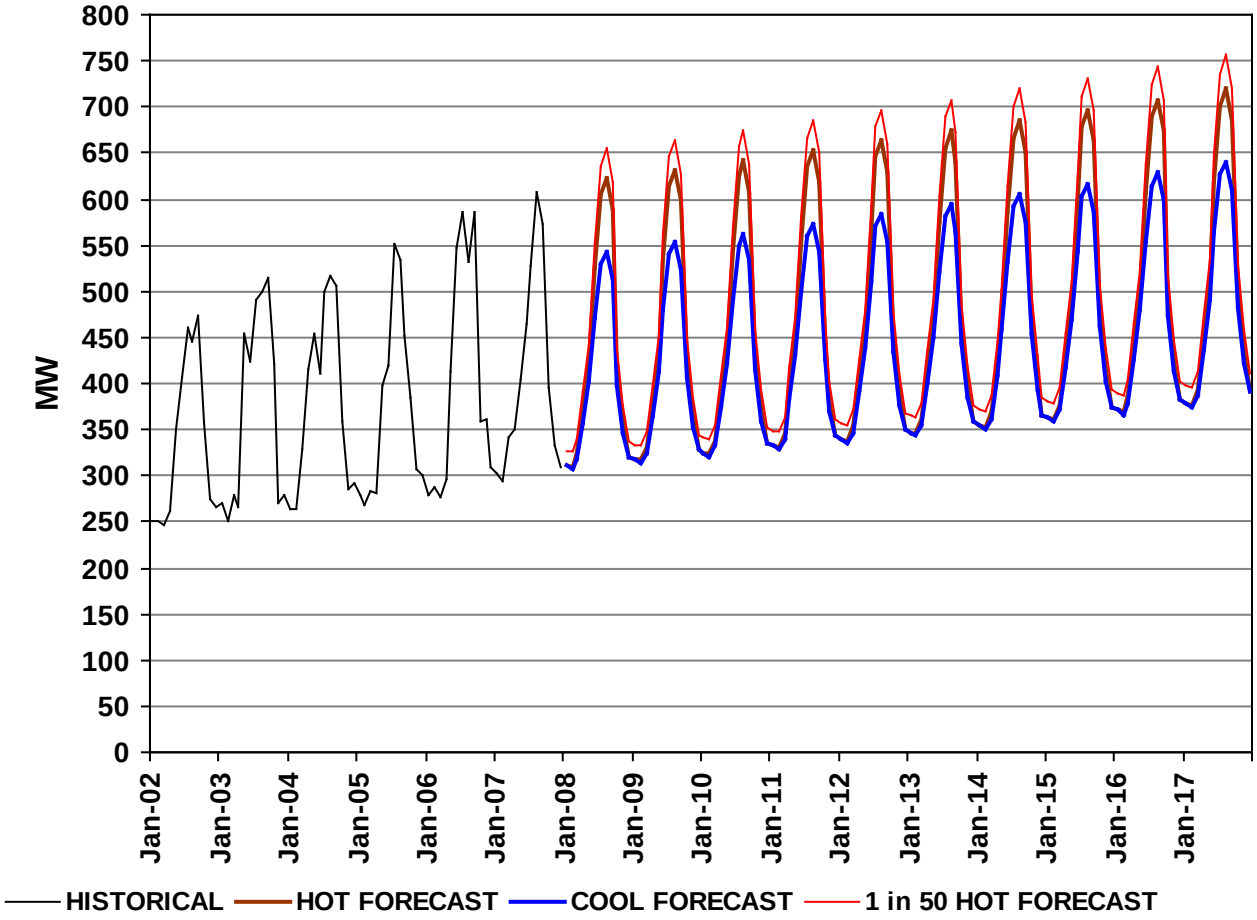


Figure 2.2: System Peak Demands



Summary

Appendix B presents the forecasts of monthly energy requirements and peak demand under the different temperature assumptions.

Both annual peak demand and energy requirements continue to grow but at a slower rate than has been seen over the past five years, primarily due to the current weak economic conditions in California that are expected to continue into late 2009 or mid 2010.

CHAPTER 3 – EXISTING GENERATION RESOURCES

Introduction

RPU's resource portfolio has evolved to address key issues such as market price volatility, risk tolerances, internal generation needs, increasing load demands and a commitment to renewable resources. In particular, RPU is well positioned to respond favorably to regulatory risk and California's legislative mandates by delaying long-term, non-renewable resource commitments during the pendency of the CAISO's MRTU market implementation.

This mix of resources was sufficient to meet RPU's all-time summer peak demand of 610 MW set in August 2007.

Table 3.1: 2008 Long-term Resource Portfolio

EXISTING RESOURCES	TYPE	CAPACITY (MW)	EXPIRATION	ASSET TYPE
San Onofre	Baseload, Nuclear	40	2022	Ownership
Intermountain	Baseload, Coal	137	2027	Bilateral Contract
Palo Verde	Baseload, Nuclear	12	2027	Bilateral Contract
Hoover	Annual Peaking, Hydro	26	2017	Bilateral Contract
Springs	Internal Gen, Gas	40	None	Ownership
RERC 1 & 2	Internal Gen, Gas	98	None	Ownership
Deseret	Baseload, Coal	52	2009	Bilateral Contract
BPA I	Annual Peaking	23 Summer 16 Winter	2011	Bilateral Contract
BPA II	Annual Peaking	60 Summer 15 Winter	2016	Bilateral Contract
Wintec	Renewable, Wind	1	2017	Bilateral Contract
Badlands	Renewable, Biomass	1	2008	Bilateral Contract
Neo	Renewable, Biomass	5	2008	Bilateral Contract
Salton Sea	Renewable, Geothermal	20/46 (6/2009)	2020	Bilateral Contract
POTENTIAL RESOURCES	**TYPE**	**CAPACITY (MW)**	**EXPIRATION**	**ASSET TYPE**
Clearwater	Baseload, Combined-cycle	28	None	Ownership
Geothermal	Renewable, Geothermal	50	➢ 2025	Bilateral Contract
FUTURE, UNDER CONTRACT	**TYPE**	**CAPACITY (MW)**	**EXPIRATION**	**ASSET TYPE**
Renaissance	Renewable, Geothermal	32 (2010) 64 (2011)	30 Years	Bilateral Contract
RERC 3 & 4	Internal Gen, Gas	98 (2010)	None	Ownership

However, several contracts are expiring. Note that in addition to the CDWR contracts that expired in 2007 (totaling 53 MW), RPU must also replace the 52 MW Deseret contract in 2009 and the 23/16 MW BPA Capacity Sale/Exchange Agreement (i.e., BPA 1) in 2011. If approved

by its governing bodies, RPU's planned economic acquisition of the City of Corona's Clearwater Generating Station will partially replace the expired CDWR contracts, and RPU's recent execution of a long-term power purchase for the Renaissance geothermal power project will replace the expiring Desert contract.

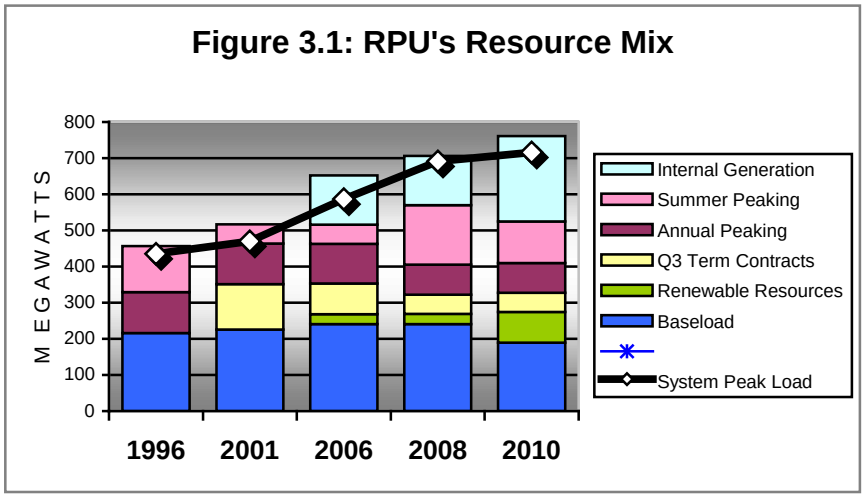
Table 3.2 presents RPU's loads and resources showing annual capacity requirements and existing generation capacity.

Table 3.2: Loads and Resources

	2008	2009 Q1/Q2	2009 Q3/Q4	2010	2011	2012	2013	2014	2015
Forecasted Peak Demand (MW)	580	590	590	600	611	621	632	643	655
Required Reserves (15 percent)	87	89	89	90	92	93	95	96	98
Total Capacity Requirement (MW)	667	679	679	690	703	714	727	739	753
Resource Capacity (MW)									
Internal Generation (MW)									
Springs 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Springs 2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Springs 3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Springs 4	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
RERC 1	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
RERC 2	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
RERC 3	0	0	0	49.0	49.0	49.0	49.0	49.0	49.0
RERC 4	0	0	0	49.0	49.0	49.0	49.0	49.0	49.0
Within CAISO									
SONGS 2	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
SONGS 3	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Badlands	1.2	0	0	0	0	0	0	0	0
Wintec	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Neo	4.6	0	0	0	0	0	0	0	0
Cogeneration Unit	14.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
External to CAISO									
PVNGS 1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
PVNGS 2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
PVNGS 3	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
IPP1	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5
IPP2	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5
Salton Sea Unit 5	20.0	20.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Hoover	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
Deseret	52.0	52.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA	83.0	83.0	83.0	83.0	83.0	60.0	60.0	60.0	60.0
Baseload Renewable/Renaissance	0	0	0	32.0	64.0	64.0	64.0	64.0	64.0
Resource Adequacy Capacity Purchase	165.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Resources	694.3	537.5	563.5	641.5	673.5	650.5	650.5	650.5	650.5
Surplus (Deficit)	27.30	(141.50)	(115.50)	(48.50)	(29.50)	(63.50)	(76.50)	(88.50)	(102.50)

Resource Capacity

As illustrated in Figure 3.1, Riverside's resource portfolio has evolved over the past decade to address regulatory changes, market volatility and environmental concerns, while preserving the



flexibility necessary to react to regulatory risk, RPU has delayed non-renewable long-term resource procurement to guard against entering into any power purchase agreement that was inconsistent with the CAISO's evolving market redesign.

Summer Resources

From a wholesale power supply perspective, there are presently adequate resources to meet short-term summer peak loads, plus reserves, under both normal and adversely hot summer weather conditions.[12] Internal generation (Springs and RERC) would be dispatched last (as the most expensive generation) to meet high temperature related demand. Conversely, in a cooler-than-normal summer scenario, internal generation units would only be needed to cover the forced outage of another resource or to respond to a RPU distribution system reliability concern.

[12] This IRP speaks only to the fulfillment of RPU's wholesale power supply needs, and does not address internal transmission system planning and operating criteria. Although RPU has "adequate resources to meet short-term summer peak loads under both normal and adversely hot summer weather conditions" from a power supply standpoint, RPU's ability to import power through its interconnection to the CAISO grid is limited and must be supplemented by the use of RPU's internal generating capability to maintain system reliability, typically during summer periods. RPU is constructing the Riverside Transmission Reliability Project, a second interconnection with CAISO grid, and when energized in 2014 the dependence on running out of merit internal generation will be lessened.

Spring/Fall Resources

Summer-level capacity associated with the BPA contracts and internal generation help to provide sufficient coverage for the transitional months in spring and fall. June and October loads are particularly unpredictable due to a historically wide range of weather events, such as a cool "June Gloom" or "Indian Summer" heat wave in October.

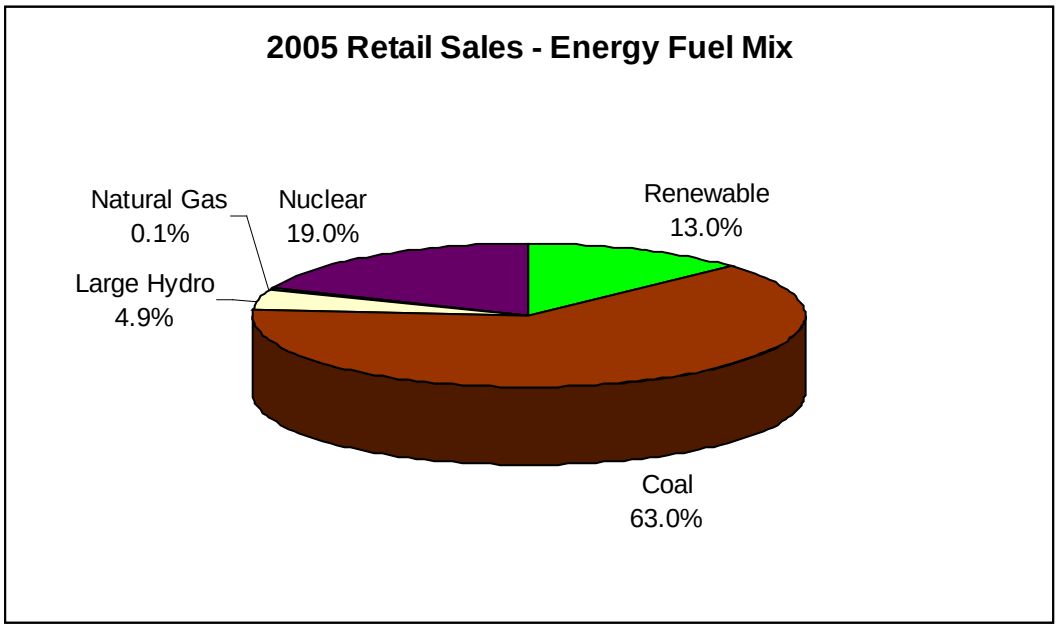
Winter Resources

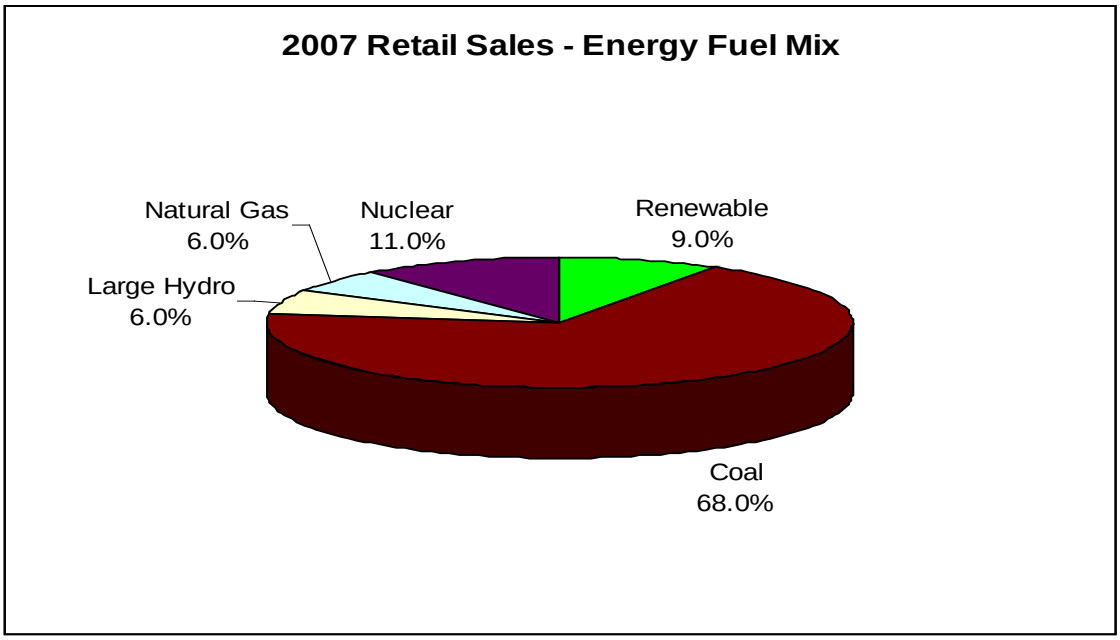
Baseload and winter peaking resources provide adequate capacity to meet docile loads during this 6-month period. Surplus baseload energy during the off-peak hours is used to return energy to BPA in payment for peaking capacity and energy previously provided by BPA under the exchange agreements.

Summary of Resources

The following charts illustrate the fuel diversity mix of energy sold to retail customers in 2005 and 2007. Note that the California Energy Commission's revision of its guidebook entitled *Renewables Portfolio Standard Eligibility* (Third Edition, 2007) precluded RPU's use of Renewable Energy Credits (RECs) beginning in 2007. Thus, Riverside was prevented from continuing its practice of at least levelizing its renewable energy percentage through the procurement of small hydro and wind energy Renewable Energy Credits (a.k.a., "Green Tags") from the Bonneville Power Administration.

Figure 3.3: Energy Fuel Mix Comparison




2007 Retail Sales - Energy Fuel Mix
Natural Gas
6.0%
Nuclear
11.0%
Renewable
9.0%
Large Hydro
6.0%
Coal
68.0%

CHAPTER 4 - CONSERVATION AND DEMAND-SIDE MANAGEMENT

Introduction

An important portion of RPU's resource strategy is expanded conservation and DSM programs.

Conservation programs are intended to reduce the total amount of energy used by customers. Examples of conservation programs include replacement of incandescent light bulbs with compact fluorescent bulbs, as well as replacement of air conditioner and refrigerator units with more energy efficient models. In this case, the customer uses less energy at all times of the day. Another conservation example is encouraging industrial customers to use more efficient motors to reduce total energy use.

DSM programs, in contrast to strict conservation measures, do not necessarily reduce the total amount of energy used by customers but instead change the timing of energy usage, moving energy use from high production cost periods to low production cost periods. Examples of DSM programs include pool pump programs that encourage customers to operate their pool pumps during off-peak periods or thermal energy storage systems that shift air conditioning loads to off-peak periods.

Conservation programs tend to save customers money by reducing the total amount of energy purchase, while DSM programs tend to reduce overall utility costs, hence allowing rate stability or reduction, by reducing the amount of capacity required to meet customer needs.

Evaluating Conservation and DSM Programs

Three high level perspectives can be used to evaluate the cost-effectiveness of a conservation or DSM program. These are:

- Effect on the customer
- Effect on the utility
- Effect on society

By examining the financial impacts on each of these groups, RPU can identify the mix of conservation/DSM programs that maximizes the benefits to each customer class and minimizes the financial impacts on RPU and non-participating customers.

Each type of conservation/DSM program affects the participating customer, non-participating customers and the utility. Generally, a customer that participates in one or more of these programs reduces their costs and their payments to the utility. At the same time, the utility can reduce power supply costs. However, if the utility's reduction in power supply costs is less than the customer's reduction in costs, the utility must raise rates to other, non-participating customers. That is, even though the utility's costs decline as a result of a conservation/DSM program, the utility's revenues decline more and the utility must raise rates to non-participating customers.

Many conservation programs raise costs to non-participating customers. DSM programs generally do not have the same negative impact on non-participating customers, instead reducing utility costs more than the decline in utility revenue, allowing the utility to reduce costs for all customers.

RPU Avoided Costs

The underlying premise of DSM programs is that they encourage customers to switch energy use from a higher cost period (1 pm to 8 pm) to a lower cost period (11 pm to 7 am, or weekends). As a result, RPU's total cost of meeting customer requirements will decline.

The cost of producing energy to meet customer requirements varies during the day. During the low load hours, energy from RPU's inexpensive generation resources is used to meet customer demands. But as load increases, more expensive generation resources are used to meet the increase in customer demand.

To the extent customers can reduce their energy consumption during the high cost periods and use as much or more energy during the low cost periods, the utility's total costs (and rates) decline.

Measuring the Effect of a Conservation/DSM Program on a Participating Customer

If a customer chooses to participate in a conservation/DSM program, their financial savings in each year are equal to:

*Savings = ((kWh saved) * (retail rate)) + ((Demand Reduction) * (Demand Rate)) + ((Utility Incentives) – (Program Costs))*

If the energy savings, plus any utility incentives, are greater than program participation costs, the customer should participate in the DSM/conservation program.

For most non-demand metered customers, primarily those in the residential and small commercial classes, the financial success of a program is primarily due to reducing total energy use. Hence, programs that are most attractive to residential customers are those that are targeted at high energy use applications, such as lighting, refrigeration and air conditioning (and electric heating).

For demand metered customers, the program benefits are often dominated by demand charge savings.

Measuring the Effect of a Conservation/DSM Program on the Utility

The impact of a new DSM/conservation program on the utility is the utility's reduction in power supply costs, less its costs that include any rebates or incentives paid to participating customers and the future reduction in retail revenues.

For most programs, the greatest cost to the utility is the future reduction in revenues from the retail customer, although the size of any program rebates will affect the overall program benefits.

The reduction in power supply costs is more difficult to measure. If a program reduces on-peak costs, then the savings could be substantial. But, a program that reduces energy costs (and thus customer energy use) during low load periods might have detrimental cost impacts if the utility must sell the newly-created surplus energy at a loss.

The utility generally maximizes power supply cost savings by reducing its purchase of high cost, on-peak energy during the highest load periods of the day.

One of the more important parts of the analysis is recognizing that if the financial impact on the utility is negative, non-participating customers will be required to subsidize the participating customers through increased rates.

Measuring the Effect of a Conservation/DSM Program on Society

The impact of a program on society is actually very difficult to quantify due to the large number of externalities that can be considered. How can the reduction in greenhouse gas emissions be quantified and included in the analysis? What other externalities should be included in the analysis and how should they be priced?

From a societal viewpoint, if any externalities are included in the analysis, the benefits of conservation/DSM programs are almost always positive. The biggest issue is then determining how the program costs and benefits will be divided between the utility, participating and non-participating customers.

Existing RPU Programs

RPU currently has a wide mix of conservation/DSM programs aimed at all segments of its customer base, as shown in Table 4.1 below. These programs result in annual energy savings to RPU of 7,311 MWh (0.3 percent of 2007 customer energy requirements) and demand savings of 1.71 MW (0.3 percent of customer 2007 peak demand). Additionally, GHG emissions are reduced by 76,541 tons annually, equating to 0.01 percent of Riverside's total 2005 GHG emissions.[13]

Future Conservation/DSM Programs

As energy prices continue to rise, the value of new conservation/DSM programs will continue to increase. RPU is evaluating the cost-effectiveness of a variety of new programs with the intent of expanding as many programs as financially viable.

[13] 2005 GHG emissions were quantified and audited through RPU's membership and participation in the California Climate Action Registry.

Table 4.1: RPU's Current Conservation and DSM Programs and Results

[redacted]

Programs that reduce summer peak demand requirements tend to have the greatest value to RPU, although not necessarily to participating customers without time-of-use billing. From RPU's viewpoint, the most economic programs would include expansion of thermal energy storage and air conditioner replacement programs. These programs tend to shift energy use to low cost periods with no significant impact on the total energy requirement. Residential and non-demand metered commercial customers prefer programs that reduce the total amount of energy they use, such as lighting upgrades and refrigerator/freezer replacement programs.

RPU can identify the avoided capacity costs due to installation of DSM programs by its customers. To encourage DSM programs, RPU can offer incentives based upon its avoided capacity costs. DSM programs should be developed to reduce on-peak energy use, especially during the summer months, and to increase the use of RPU's current and forecasted surplus of off-peak generation.

CHAPTER 5 – FUTURE RESOURCE REQUIREMENTS

Introduction

When choosing the types of resources that RPU should acquire, either through long-term power supply purchases or ownership interests, a number of different factors are taken into consideration. These evaluation factors include traditional measures such as the resource's operating characteristics, transmission availability, cost, availability of fuel, compatibility with the existing resource mix, and a variety of new regulatory requirements.

In the past, resource planning was performed by identifying the unmet future requirements for both capacity and energy and then adding resources exhibiting the appropriate costs and operating characteristics. A variety of new resource options would be added to the existing resource mix and the net present value of power supply costs over some period would be calculated. The operating characteristics of the resources were varied to identify different resource options. The resource option that resulted in the lowest net present value would be selected, assuming transmission access was available.

This type of analysis often results in choosing the least-cost resource without regard to other considerations such as environmental impacts or system reliability, each of which affect costs in the future. As an example, adding a new coal-fired facility to replace the expired CDWR contracts might result in the lowest overall power supply cost, but it does not account for the regulatory and non-price restrictions on the use of coal.

Another example would be to select a resource that has inappropriate operating characteristics. A gas-fired, combined-cycle plant will have lower energy costs than a gas-fired, simple-cycle turbine if operated for sixteen hours each day, but may not be economic when restricted to operating for only a few hours per day to meet peaking requirements. Conversely, utilizing relatively high cost simple-cycle generating units for baseload or quasi-baseload operation is typically not viewed as an economic alternative.

Choosing the appropriate resources can significantly reduce long-term power supply costs. In addition, other resource planning objectives, such as meeting renewable resource procurement goals, are included in RPU's resource analysis.

Resource Acquisition Goals

RPU has several resource planning goals intended to provide reliability and price certainty for retail customers. These goals include, but are not limited to, acquiring sufficient resources to meet load, including Resource Adequacy plus Local Capacity Requirements, minimizing power supply costs and procuring renewable resources to meet the Renewable Portfolio Standard goals set by the Board of Public Utilities and City Council.

Renewable resources may have an initial cost that is greater than traditional natural gas-fired generation. However, the escalation rate of energy costs for renewable resources is significantly

less than the cost forecasted for natural gas-fired resources. As a result, after a few years many renewable resources are less expensive than comparable natural gas-fired resources.

By adding 10 to 15 MW of new long-term baseload renewable resources to RPU's renewable resource portfolio each year beginning in 2013, the rate impact of renewable resources can be mitigated and RPU would have almost 200 MW of renewable resources by 2015, providing over half of RPU's energy requirements with no significant rate impact.

Resource Requirements 2008 – 2010

The first period examined was CY 2008 through CY 2010. This period was chosen to determine RPU's immediate capacity and energy needs, including through the first year of MRTU operation.

2008 Resource Requirements

The following table presents RPU's loads and capacity resources for CY 2008:

Table 5.1: 2008 Monthly Loads and Resources

Month	Forecasted Peak Demand (MW)	Reserve Obligation (MW)	Total Requirement (MW)	Existing Resources (MW)	Surplus or Deficit (-) (MW)
Jan	311	47	358	473	115
Feb	307	46	353	475	122
Mar	317	48	365	440	75
Apr	357	54	411	417	6
May	409	61	470	496	26
Jun	490	74	564	589	25
July	564	85	649	651	2
Aug	580	87	667	676	9
Sep	539	81	620	626	6
Oct	405	61	466	493	27
Nov	345	52	397	486	89
Dec	321	48	369	509	140

From a Resource Adequacy, or capacity-only perspective, RPU will meet its capacity obligations in FY 2008 by purchasing 20 MW of local capacity from Shell Trading, Inc. and summer capacity amounts ranging from 30 to 115 MW. RPU's procurement of Resource Adequacy capacity guarantees the availability of energy to the CAISO, but does not include the availability of energy to RPU, therefore RPU must still ensure that it has sufficient energy resources to meet retail energy requirements.

Replacing the now-expired CDWR summer capacity purchases has been an essential goal of the planning process. CDWR provided 53 MW of on-peak capacity and energy that RPU utilized at almost 100 percent of its capability, or slightly less than 10 percent of RPU's total monthly requirements during the May through October period.

RPU has partially replaced the CDWR purchases for 2008 with purchases of capacity and energy from the City of Corona's 28 MW Clearwater Cogeneration Plant, and a 10 MW baseload renewable energy purchase. However, even with these two resource additions, RPU remains 15 to 35 GWh (0.6% to 1.4% of projected customer energy requirements) short of meeting its summer energy needs, even when operating its internal generation at its maximum level.

2009 Resource Requirements

RPU's Salton Sea Unit 5 geothermal contract increases from 20 MW to 46 MW starting June 1, 2009. To meet summer 2009 capacity requirements, RPU has procured sufficient Resource Adequacy capacity from Reliant Energy.

The greatest challenge in 2009 will be operating under the CAISO's new MRTU market structure, where high resource availability and dispatch flexibility have more value than in today's market.

2010 Resource Requirements

On December 31, 2009, the 52 MW coal-fired baseload Deseret power purchase agreement expires. Deseret provides approximately 35 GWh per month of energy to meet Riverside's retail customer requirements. With the expiration of the Deseret contract, RPU would be significantly short of energy, absent the contracted increase in its Salton Sea Unit 5 baseload geothermal resource from 20 to 46 MW, described above.

Even with the 26 MW increase in capacity and energy available from Salton Sea Unit 5 beginning June 1, 2009, expiration of the Deseret power purchase results in a net loss of 26 MW of generating capacity. With RPU's recent finalization of the Shoshone Renaissance geothermal project power purchase agreement, the 26 MW deficit left by the expiration of the Deseret resource will be seamlessly replaced before the summer of 2010 with a 32 MW baseload renewable resource. A second 32 MW unit will be placed in service by Renaissance in 2011 for a total project capability of 64 MW.

RPU also anticipates completing construction of the two additional gas-fired turbines within the City of Riverside in 2010. These two 49 MW gas-fired generators are intended to provide summer reliability rather than generate significant amounts of peaking energy. To meet energy requirements, RPU is investigating several renewable resource projects in the west as well as large, efficient gas-fired combined-cycle facilities near Riverside.

Summary of 2008 – 2010 Resource Requirements

Even though load growth is anticipated to be relatively low for the next two years as a result of the ongoing economic slowdown, the expiration of two important power supply contracts would have resulted in a significant shortage of energy without corrective actions having been taken by Power Resources staff. From a capacity viewpoint, RPU is slightly short during the summer 2010 months, but has sufficient capacity during the winter, spring and fall.

RPU has purchased sufficient Resource Adequacy capacity for 2008 and 2009 in order to meet the CAISO's tariff requirements, and the commercial operation of the first 32 MW Renaissance geothermal resource in 2010 will contribute significantly to meeting that year's summer capacity requirements.

Resource Requirements 2010 – 2015

The only expiring contract during this period is the 23 MW Bonneville Power Administration ("BPA") Capacity Sale/Exchange Agreement ("BPA 1 Agreement").

The BPA 1 Agreement began in 1991 and provides an inexpensive source of summer and winter peaking capacity and energy. RPU schedules up to 23 MW of energy from the Pacific Northwest during limited on-peak hours in the summer period (May through October) and up to 16 MW per hour during limited on-peak hours in the winter period (November through April). RPU returns this energy during the evenings. RPU pays for a portion of the capacity with energy deliveries during the winter and early spring, with payment for the remaining portion settled monetarily. The BPA 1 Agreement's value depends upon the historic diversity between the Desert Southwest region, that experiences its peak demands during the summer afternoons due to air conditioning, and the Pacific Northwest region that sees its greatest demands during the winter period as a result of electric heating requirements. Extending this agreement will be beneficial to RPU. However, due to the long-term growth of electric demand in the Pacific Northwest and concerns over the future availability of water and hydroelectric generation, it is unknown whether BPA will be willing to extend the agreement for more than a few years, if at all.

Riverside's recently executed agreement for geothermal energy from the proposed Renaissance project is expected to provide at least 32 MW of baseload renewable energy beginning in 2010, with that amount increasing to 64 MW in 2010 or 2011. With the addition of this resource, Riverside anticipates achieving its goal of 33 percent renewable energy in 2011, fully nine years before the goal established by its Renewables Portfolio Standard.

As previously discussed, new baseload renewable resource additions in 10 to 15 MW increments beginning in 2013 can be expected to increase Riverside's renewable energy mix to approximately 50 percent of its retail customer requirements as early as 2013.

Other Issues

Other issues include the ultimate disposition of RPU's entitlement in the Intermountain Power Project. Currently, RPU has a long-term power purchase agreement with the Intermountain

Power Agency ("IPA") for generation from this project[14]. The State of California recently enacted very restrictive greenhouse gas requirements that will impact existing and potential resources, such as the Intermountain Power Project.

At this time, the State's discussions on greenhouse gas taxes are preliminary and it is not known what level, if any, of emission taxes will be imposed. RPU continues to dedicate significant resources, in terms of staff time and consulting costs, to monitoring and influencing legislation and the design and implementation rules and regulations affecting RPU's provision of reliable, cost-effective power to its customers.

2015 – 2020 Resource Requirements

Beyond 2015, RPU's resource requirements will depend upon a variety of issues such as the success of MRTU, development of new transmission resources by the CAISO and others in the Western States, as well as new regulatory and emissions requirements.

At this time, there are no specific resources that RPU is investigating that would come on-line after 2015, although RPU's resource requirements will increase at around 1.9 percent per year with the need for summer peaking resources growing faster than loads in the remainder of the year.

Consistent with the expressed desire of Riverside's governing bodies to promote renewable resources, reduce greenhouse gas emissions and foster a sustainable community, it is expected that resource additions during and beyond the referenced period will primarily focus on the procurement of renewable resources.

Summary of Resource Requirements

2008

- Economically procured Clearwater gas-fired combined cycle plant (28 MW) for on-peak energy and capacity needs.

- Secured Calpine geothermal renewable contract (10 MW) for baseload energy needs.

2009

- June 1st: Existing Salton Sea Unit 5 geothermal contract increases from 20 MW to 46 MW.

- Sufficient Resource Adequacy capacity for 2009 acquired from Reliant Energy during 2008.

- December 31st: 1999 Deseret baseload contract (52 MW) expires.

[14] The power purchase agreement with IPA extends through 2027.

2010

- April 1st: Renaissance Geothermal Project Unit 1 (32 MW) anticipated to begin initial baseload operations.

- June 1st: RPU's proposed gas-fired units RERC 3 and 4 (98 MW) expected on-line for summer on-peak energy and capacity needs.

- October 1st: Renaissance Geothermal Project Unit 2 (32 MW) anticipated to begin initial baseload operations.

2011

- January 1st: Renew BPA 1 (23 MW) if possible, or replace with comparable annual on-peak energy agreement with another party.

- April 1st: Renaissance Geothermal Project Unit 3 (32 MW) anticipated to begin initial baseload operations.

2013-15

- Procure 10-15 MW of renewable resources by 2015.

2016

- Renew BPA 2 (60 MW), or replace with comparable annual on-peak capacity/energy agreement with another party.

CHAPTER 6 – RESOURCE EVALUATION

Introduction

Given the uncertainty of regulatory and legislative actions related to greenhouse gas concerns, as well as implementation of the CAISO's MRTU markets, identifying which resources should be added to RPU's existing resource mix is a particularly difficult process. Using Global Energy Decisions, Inc. ("GED") production cost model, *PaR*™, a number of different resource scenarios are analyzed in an attempt to identify the resources (or the resource characteristics) that should be added to RPU's future resource mix.

Production costing models are used in the electric power industry to simulate the expected amount of electricity produced by different generation units and the expected cost of producing electricity for a given power generation system. Production cost models account for the uncertainty in the availability and use of the generating units due to scheduled and forced outages and expected avoided costs. Usually, the major component of the operating cost for each unit is its cost of fuel.

Generally, the results are dependent upon the underlying assumptions used in the modeling process. The most critical assumptions used in RPU's modeling approach include demand and energy growth and the escalation of natural gas prices.

The forecasts of demand and energy growth were discussed earlier (Chapter 2). This chapter discusses the various assumptions used in modeling long-term resource costs, options for meeting the electricity needs of RPU's customers, and recommends a long-term resource acquisition strategy.

Impacts of Existing Resources on Future Costs

RPU has invested in ownership or long-term power purchase agreements of generation resources as a way of stabilizing energy prices and insuring reliability. RPU's long term resources[15] essentially provide a cushion from market price shocks.

RPU's capacity resources meet almost 80 percent of RPU's capacity needs over the forecast period, while its energy resources meet almost 70 percent of long-term needs.

By far, the greatest risks to RPU's future power supply costs are the CAISO's market redesign efforts and environmental and regulatory risks that affect the Intermountain Power Project, especially GHG taxes or penalties.

[15] These resources include BPA1, BPA2, IPP, SONGS, PVNGS, Hoover, Wintec, Salton Sea Unit 5 geothermal, Renaissance geothermal, RERC and the Springs units.

Natural Gas Price Forecasts

Beginning in 2008, RPU began relying more heavily on natural gas-fired generation sources than in the past. In 2007, RPU only generated 6 percent of its energy using natural gas-fired generation facilities. The addition of a natural gas-fired resource in 2008 increased the percentage of gas-fired generation to 11.4 percent. Each new resource that is considered will be evaluated in relation to purchases from natural gas-fired resources. Even if RPU chooses not to acquire additional gas-fired generation in the future, the price of short-term energy and spot energy purchases in California will be set by prevailing natural gas costs.

It is important to analyze natural gas price forecasts for use in comparing resource options and costs associated with the resource. Three different sources were used for natural gas forecasts – the federal government's Energy Information Administration ("EIA"), Global Energy Decisions, Inc. ("GED") and the California Public Utility Commission ("CPUC"). A summary of their annual price forecasts is shown in Table 6.1.

Table 6.1: Forecasts of Natural Gas Prices ($/MMBTU)

	EIA	GED	CPUC
2005	$ 7.62	-	-
2006	$ 6.24	-	-
2007	$ 6.00	-	-
2008	$ 6.99	$ 7.65	$ 9.10
2009	$ 6.81	$ 8.19	$ 8.97
2010	$ 6.56	$ 7.72	$ 8.66
2011	$ 6.45	$ 6.95	$ 8.36
2012	$ 6.55	$ 7.13	$ 8.15
2013	$ 6.79	$ 7.70	$ 8.07
2014	$ 6.87	$ 7.95	$ 7.99
2015	$ 6.94	$ 8.60	$ 7.91
2016	$ 7.17	$ 9.17	$ 7.82
2017	$ 7.41	$ 9.72	$ 8.13
2018	$ 7.69	$ 9.87	$ 8.23
2019	$ 8.05	$ 9.94	$ 8.47
2020	$ 8.24	$ 10.09	$ 8.78

Source: EIA – Energy Information Administration, February 2008
GED, "Fall 2007 Electricity and Fuel Price Outlook."
CPUC, "Energy Division Resolution E – 4118 October 4 2007."

All three of these forecasting groups anticipate that natural gas prices will decline over the next few years before increasing in real terms.

Generation from natural gas-fired resources accounts for more than 45 percent of all California electricity needs.[16] RPU currently utilizes only a small amount of gas-fired generation; i.e., the RERC and Springs units, which combined account for 138 MW of capacity, but are used only for summer peaking requirements. These units typically generate 80 GWh annually, or approximately 3 percent of RPU's annual energy requirements.

With the inclusion of a new natural gas-fired generator into RPU's energy mix in 2008 (i.e., the City of Corona's Clearwater Cogeneration Plant), natural gas-fired generation increased to 11.4 percent of RPU's annual retail energy requirements. If the Deseret purchase were replaced by a gas-fired generator instead of the Renaissance geothermal project, RPU would be directly dependent upon natural gas for almost 30 percent of its annual energy needs in 2010.

Effect of Rising Natural Gas Prices on RPU's Resource Mix

The forecasted rise in natural gas costs over the next decade impacts RPU's willingness to enter into renewable resource contracts that have either fixed prices or low escalation rates relative to natural gas. A renewable resource that has a higher initial price will, at some point in time, become less expensive than gas-fired generation, depending upon the forecasted escalation rate for natural gas. For example, RPU was attempting to decide between two long-term resource additions beginning in 2009, the first choice was a new power purchase agreement tied to natural gas costs and having an assumed 11,000 BTU/kWh heat rate.[17] The second was a renewable energy resource that escalated at 2 percent annually. Using GED's forecasted natural gas costs shown in Table 6.1 above, the price for energy under the natural gas scenario, in comparison to a renewable resource initially priced higher would be:

Table 6.2: Example of Prices of Renewable and Non-Renewable Energy

Year	Natural Gas Price ($/MMBTU)	Energy Price ($/MWh)	Renewable Energy Price ($/MWh)
2009	$ 8.19	$82.23	$90.56
2010	$ 7.72	$84.92	$92.37
2011	$ 6.95	$76.45	$94.22
2012	$ 7.13	$78.43	$96.10
2013	$ 7.70	$84.70	$98.03
2014	$ 7.95	$87.45	$99.99
2015	$ 8.60	$94.60	$101.99
2016	$ 9.17	$100.87	$104.02
2017	$ 9.72	$106.92	$106.11
2018	$ 9.87	$108.57	$108.23
2019	$ 9.94	$109.34	$110.39

[16] California Energy Commission, California Electricity Statistics & Data

[17] Heat rate is a measure of efficiency equating heat input, in terms of British Thermal Units, to electric energy output. A lower heat rate would suggest that less natural gas is necessary to produce one kilowatt-hour of energy (i.e., increased efficiency), while a higher heat rate indicates less efficiency.

In the first few years, the renewable energy resource would increase RPU's total power supply costs in comparison to a long-term purchase from a natural gas-fired resource. However the power purchase from a natural gas resource would expose RPU's customer to future price volatility and significant escalation risk as more natural gas generation replaces coal generation in utility resource portfolios. By 2017, the escalation of natural gas prices results in the natural gas-fired resource rising to cost parity with the renewable resource. RPU's customers are still left exposed to future increases in natural gas price volatility and price escalation that can result in the long term cost of the natural gas resource exceeding the cost of the renewable resource which raises the total power supply costs.

If RPU began layering a small amount of baseload renewable resources into its resource mix each year, lower overall costs would likely result within a few years. Acquiring renewable resources without initially adversely impacting RPU's retail rates will present a challenge to Power Resources staff. That is, it is not RPU's intent to penalize existing customers by acquiring renewable resources at above market prices in order to benefit future customers with below market rates.

Under the City of Riverside's Renewables Portfolio Standard, RPU can acquire renewable resources so long as they do not increase retail rates by more than 5 percent. At current rate levels, this translates into an annual investment of approximately $9,500,000 for the above-market component of renewable energy resources.

Another important point is that renewable energy sources are much less volatile than natural gas-fired resources over long time periods. Natural gas is the most volatile commodity traded in commodity markets. Natural gas supplies can be hedged for two or three years into the future but they cannot be hedged (without physical ownership or significant credit risk) for longer periods. Renewable resources provide a hedge against natural gas volatility, protecting RPU from rapidly escalating fossil fuel costs.

Natural Gas Management

When RPU's current resource mix is examined, the most important determinate of future energy costs will be the price of natural gas. RPU continues to devote significant efforts toward mitigating the forecasted increase in natural gas costs.

Managing natural gas costs includes investigating the feasibility of long-term, fixed price gas contracts and pre-payment options offered through the Southern California Public Power Authority, as well as directly through "Muni-gas," a firm that provides pre-paid gas supplies to municipal entities.

RPU will also need to become heavily involved in the daily scheduling of spot market gas supplies and monthly balancing of those supplies against actual needs. Currently, RPU purchases these services from BP Energy, Inc., although the recent adoption by RPU's governing bodies of the North American Energy Standards Board's standard contract terms and conditions will significantly expand the number of potential gas-supplier counterparties.

Historic Relationship Between Gas and Electricity Prices

Over the past few years, there has been a strong relationship between natural gas price levels and energy prices. Summer on-peak energy prices have been priced at the conversion rate of natural gas into electricity using a 12,000 BTU/kWh heat rate, while summer off-peak prices have been trading at a heat rate of around 8,500 – 9,000 BTU/kWh. Annual purchases have been trading at approximately a 10,000 BTU/kWh average heat rate.

For comparison, the two Riverside Energy Resource Center (RERC) units have estimated heat rates of 10,600 BTU/kWh and the four Springs units have an estimated heat rate of 14,400 BTU/kWh.

Resource Planning Scenarios

The resource planning process was initially performed based on four scenarios. These include:

1) Do nothing;
2) Add a 28 MW cogeneration facility in 2008 and 32 MW renewable resources in 2010 and 2011;
3) Meet all requirements after 2010 with natural gas-fired combined cycle facilities;
4) Meet all requirements after 2010 with renewable resources;

The first scenario is intended to identify RPU's future resource requirements, including monthly VAR. This scenario can also be used to evaluate the potential costs of using financial instruments in a MRTU marketplace to hedge energy costs rather than using physical generation sources to meet future needs.

The second scenario relies primarily on green resources to meet Riverside's future electricity needs with a combined cycle generator satisfying a portion of those needs. The primary reason for this resource recommendation is that it will be difficult to satisfy future capacity and energy needs solely with renewable resources having the necessary operating characteristics.

The third scenario, meeting future requirements with combined cycle facilities, essentially looks at high efficiency, central generation gas-fired facilities to meet future needs.

The final scenario, meeting almost all future resource needs with renewable resources, attempts to determine the cost to RPU of becoming essentially a "green" utility by entering into 10 to 15 MW of baseload renewable resource contracts in alternating years beginning in 2015.

Risks Associated With Resource Acquisitions

Choosing how to acquire resources in the future implies a willingness to accept risk. Choosing the wrong resource could significantly increase long-term power supply costs. At the same time, relying on the short-term or spot markets for any future energy requirements could also increase costs.

The primary risks that RPU faces when making a resource decision include:

Market Price Risk: The financial penalty for acquiring resources at above market prices. This occurs when energy prices are fixed and then decline, or prices are not fixed and then rise.

There is no easy way to guard against price risk other than to use financial instruments. For example, in a period of rapidly rising prices RPU can purchase energy at a fixed price (protecting itself against future price increases) and then purchase a Put Option.[18] If energy prices increase, the value of the Put Option is lost, although RPU would not pay additional energy costs. If energy prices fall, however, the Put Option increases in value, reducing energy costs as the market price declines.

Regulatory Risk: Regulatory risk refers to the financial penalty that could be incurred when regulatory bodies change or amend regulations in a manner that adds costs to the use of existing resource assets. RPU faces significant regulatory risk due to its long-term ownership interest in the Intermountain Power Project. When RPU committed to a long-term entitlement in the Intermountain Power Project, the threat of carbon taxes and GHG emission penalties was unknown. Over time, changing regulatory requirements have added costs to the facility with the possibility of additional costs in the future to meet GHG emission limits.

It is difficult to mitigate the possibility of regulatory risk. Power purchase agreements can be written to allow regulatory "outs" if the counter-party agrees (or is willing to accept all the regulatory risk themselves) but this comes with additional costs.[19]

The most effective way to attempt to mitigate regulatory risk is to participate in various legislative and regulatory forums to identify and influence potential initiatives and incorporate them into the planning process.

Non-performance Risk: Non-performance risk refers to the risk that high replacement costs, as well as deficiency penalties may be incurred by RPU if a resource provider fails to provide the contracted commodity. Even if the purchase agreement specifies the supplier's payment of liquidated damages for non-performance, it is likely that RPU would still recognize some monetary loss.

Non-performance risks have increased recently as RPU works with smaller renewable energy resource developers. Protecting against non-performance risk from these entities is difficult because these suppliers typically form limited-liability corporations with no significant assets, other than the power sales agreement with RPU.

[18] The seller of a Put Option collects an up-front cash premium in exchange for agreeing to accept a specified amount of energy from the Put Option purchaser at a pre-determined price. Put Option purchasers typically anticipate declining prices in the relevant power markets, thus allowing the option purchaser to "lock-in" a minimum price at which its energy may be sold. Put Option sellers rely on increasing prices that ideally will prevent the purchaser's exercise of the Put Option.

[19] An example includes RPU's Deseret power purchase agreement, executed in 1992, which included an option for Riverside to unilaterally terminate the agreement in the event that emissions reductions were required.

Even larger renewable energy developers are willing to declare bankruptcy and abrogate their contractual obligations if the cost of complying becomes too high.

One of the most effective ways to protect against non-performance is for RPU to develop smaller renewable projects on its own. This option may not be feasible for larger projects but for small projects is a viable alternative.

Summary of Risk

Besides price risk, regulatory risk and non-performance risk, RPU faces considerable uncertainty in the marketplace and cannot protect itself against all forms of financial risk. RPU's strategy is to recognize that risk exists and attempt to minimize it through appropriate hedging activities that diversify risks and active participation in legislative and regulatory arenas.

With the implementation of the CAISO's MRTU market in California, the nature of risk may change depending upon how the market develops. It is possible that financial instruments will become much more important in the market as opposed to physical resources that act as a hedge. In the MRTU market, identifying and purchasing price caps for energy will likely become more important than in the current bi-lateral physical market.

Scenario 1: Do Nothing

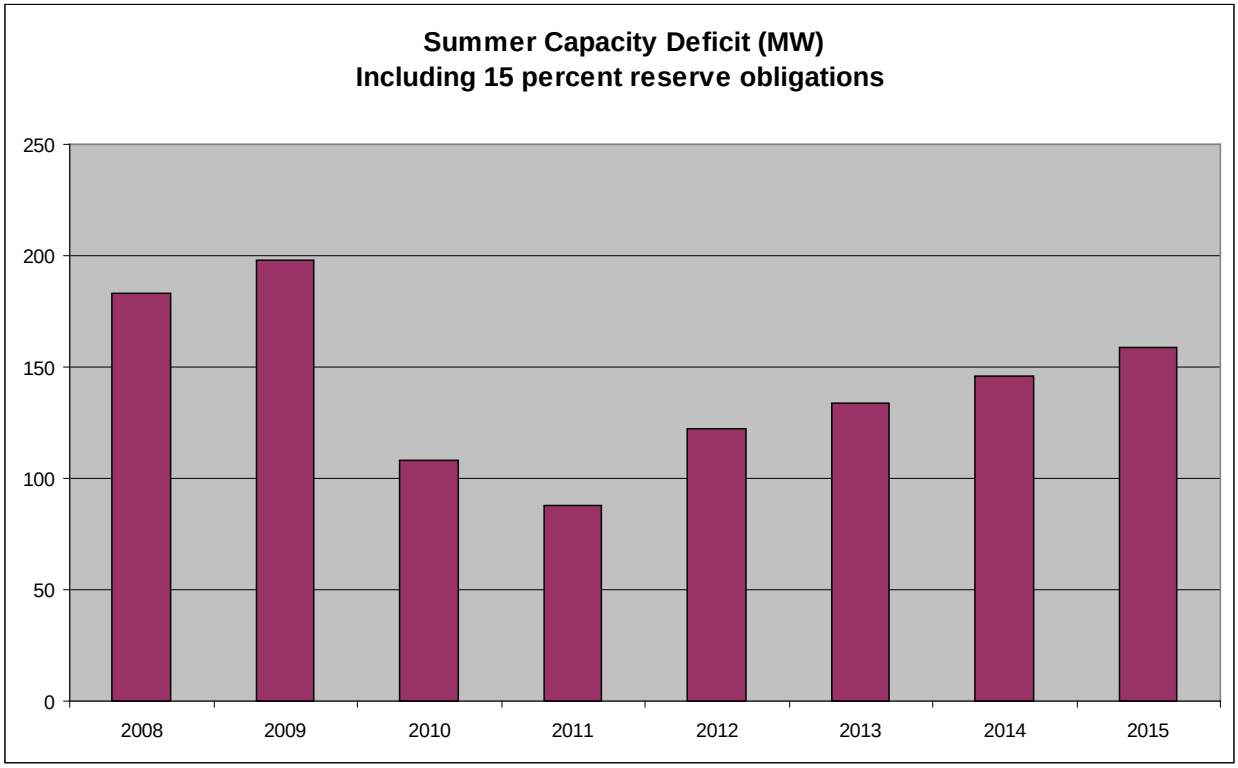
The first scenario assumes that RPU's resource mix is set between 2008 and 2020, and that as existing power purchase agreements terminate (such as the Deseret contract in 2009 and the BPA 1 Agreement on December 31, 2010), RPU purchases all of its remaining energy requirements from the MRTU spot market.

Only the third and fourth RERC units were added into the generation base case because they have already been approved by the City Council and permitting has commenced. Also, the Salton Sea Unit 5 geothermal project begins providing an additional 26 MW of capacity and energy starting in June 2009 under an existing contract.

The primary reason for this scenario was to specifically identify RPU's future resource needs on a monthly basis for the next 13 years.

The analysis shows that RPU requires increasing amounts of capacity over the next 13 years as illustrated in Figure 6.1 for the period 2008 – 2015.

Figure 6.1



The capacity deficit is partially due to the CAISO's 15 percent reserve requirement. Although RPU is capacity short during the summer months by approximately 100 MW, reserve requirements increase capacity requirements by an additional 90 to 105 MW.

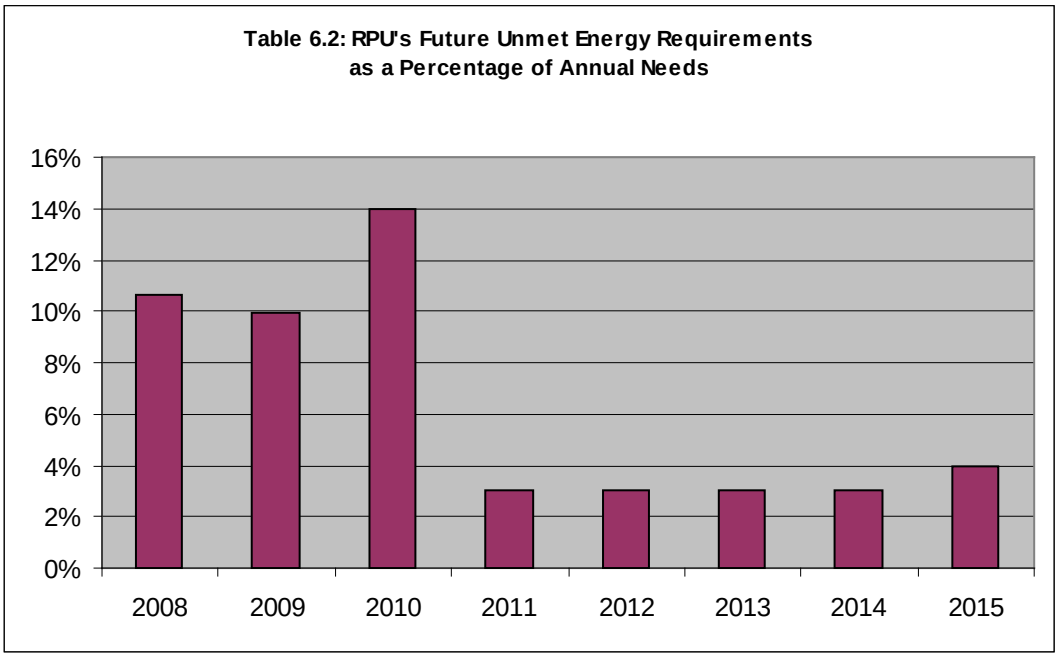
In one sense, annual summer capacity deficits may be misleading. RPU has sufficient capacity to meet forecasted loads for the months of October through March of 2012 and is deficit capacity in May and June by only minimal amounts. RPU is actually only deficient in capacity when air conditioning loads increase the heavy load hour system peak demand.

Currently, the capacity deficit is met through short-term purchases of Resource Adequacy capacity. Resource Adequacy capacity is a capacity purchase made from a qualified generation resource that guarantees the delivery of energy to the CAISO markets if called upon by the CAISO.

Capacity purchases during the summer on-peak period can be partially offset by DSM programs, although these programs are unlikely to significantly reduce summer capacity requirements (5 to 7 MW) during this planning period.

While capacity is obviously important, RPU suffers from a much larger shortage of energy.

RPU's energy shortages, as measured by its VAR (value at risk) show that within the next two years 20 percent of RPU's forecasted energy requirements need to be purchased or constructed.



Even when RPU adds RERC 3 and RERC 4 with a total capacity of 98 MW, there limited energy associated with these units due to operating restrictions imposed by the South Coast Air Quality Management District.

Financial Model

The financial results of the "Do Nothing" scenario show that RPU's power supply costs would rise by 18.6 percent over the next five years, as shown in the following table:

Table 6.3: Results of "Do Nothing" Scenario

Summary $000	2009	2010	2011	2012	2013
Gross Cost	$173,502	$185,999	$197,385	$193,664	$197,746
Net Cost	$151,835	$164,727	$176,790	$173,027	$177,125
Spot Energy Buy Percent	11.3%	14.3%	21.3%	18.5%	19.3%
Spot Energy Sell Percent	3.2%	2.2%	0.7%	1.0%	0.9%
Average Cost/MWh	$61.14	$65.19	$69.30	$67.41	$68.01

Total power supply costs show a slight dip in 2012 due to the forecasted decline in natural gas costs and reduced off-peak requirements with the expiration of the BPA 1 Agreement.

The increase in power supply costs is attributable to the expiration of the CDWR summer peaking energy contract in FY 2007/2008 and the Deseret contract in FY 2009/2010. Both of these contracts provided lower cost energy to RPU and their expiration results in RPU having to make significant purchases from the short-term markets to meet load requirements.

A risk to RPU of this scenario is that as much as 20 percent of future energy purchases are unhedged or subject to both market price and supply risks. A rapid increase in energy costs due to supply disruptions or other problems could result in significant increases in overall power supply costs.

By not acquiring future capacity and energy to meet anticipated load requirements, RPU would be accepting significant market price and delivery risks. RPU would essentially be gambling that future spot prices will remain low relative to the cost of new generation facilities.

However, in a world with significant regulatory/legislative risk, chronic capacity shortages and volatile primary fuel prices, relying on spot market prices to remain below long-term market prices for any significant period is not the recommended alternative.

Scenario 2: Cogeneration And Renewable Resource Alternative

The next scenario examined replacement of the CDWR contracts with an in-basin, gas-fired cogeneration facility, the Clearwater Power Plant, and then a baseload renewable resource replacement for the expiring Deseret contract in 2010. The Renaissance Geothermal Project in northern Utah was chosen as the most desirable resource addition based upon its renewable aspect, costs, on-line date and transmission availability. The first 32 MW generating unit from this project is expected on-line in early 2010, with the second 32 MW unit expected in operation later in 2010 or early 2011. Riverside's agreement for the purchase of power from this project extends for thirty years.

<u>Clearwater Power Plant</u>

With the expiration of the coal-based Deseret power purchase agreement in 2009, RPU is challenged with replacing an economic baseload resource that provided almost 20 percent[20] of RPU's annual energy requirements and 52 MW of capacity. In addition, RPU must meet local capacity requirements as part of the CAISO's Resource Adequacy program.

RPU began looking for a local, high efficiency power plant and began discussions with the City of Corona for a long-term power purchase agreement or (preferably) ownership of the Clearwater Power Plant.

[20] Deseret provides approximately 455 GWh of energy annually to RPU.

The Clearwater Power Plant is a 22 MW gas-fired turbine with an associated 6 MW steam turbine and generator. The hot exhaust from the gas turbine is recycled by a heat recovery steam generator ("HRSG") to generate steam which in turn drives the steam turbine/generator. This combination produces electricity overall more efficiently than either the gas turbine or steam turbine alone.

The Clearwater Power Plant gas turbine exhaust also provides heat for a system used to dry wastewater sludge from the City of Corona's wastewater treatment facility, reducing the City of Corona's cost of transporting the solid waste. Preliminary discussions with Corona indicate that it is willing to purchase this heat from RPU at prevailing market prices if Riverside purchases the asset itself, partially offsetting RPU's cost of Clearwater Plant operations.

The Clearwater Power Plant has a nominal minimum operating level of 14 MW and a nominal maximum operating level of approximately 28 MW, and can operate within this range with little efficiency loss.

In combined-cycle mode, the Clearwater Power Plant has an estimated heat rate of approximately 8,520 BTU/kWh. In contrast, RPU's existing RERC and Springs simple-cycle generators have heat rates of 10,600 and 14,400 BTU/kWh, respectively. Based upon the efficiency of its operation, the Clearwater Plant is expected to economically generate during all on-peak hours of the year and most hours during the summer months, the RERC units are expected to be utilized during summer on-peak periods and the Springs units during super on-peak and emergency periods.

Renaissance Geothermal Project

The Renaissance Geothermal Project ("Renaissance") is planned to be located in northern Utah on Shoshone tribal land and is being developed jointly between the Northwestern Band of the Shoshone Nation and IdaTherm, Inc., a company created to develop the local geothermal fields.

As previously described, the first 32 MW Renaissance unit is scheduled to go on-line in 2010, just as RPU's Deseret power supply agreement terminates. The power from Renaissance would use the same transmission path as the Deseret purchase, easing the transition between the two purchases.

RPU indicated an interest in initially purchasing up to 50 MW of hourly capacity and energy from the project. However, given the price of energy from the unit and the project developers' unwillingness to sell "partial units," RPU agreed to purchase the project's full 64 MW of capability. The term of RPU's purchase extends thirty years, coinciding with the anticipated life of the project.

Modeling Process

Two new generation facilities were added to RPU's resource mix, Clearwater Power Plant in April 2008 and a 32 MW Renaissance unit in January 2010[21]. Clearwater Power Plant provided an additional 28 MW of local and system capacity reducing RPU's spot energy purchases and annual Resource Adequacy capacity purchases, while Renaissance provided Resource Adequacy capacity, but did not provide any additional LCR.[22]

Table 6.4: Results of Clearwater Power Plant and Renaissance Simulation

Summary $000	2009	2010	2011	2012	2013
Gross Cost	$180,425	$199,781	$210,842	$211,036	$215,537
Net Cost	$144,606	$157,315	$172,371	$169,707	$175,786
Spot Energy Buy Percent	5.3%	3.7%	3.5%	2.7%	3.4%
Spot Energy Sell Percent	7.1%	9.9%	8.5%	10.3%	9.7%
Average Cost/MWh	$58.42	$62.45	$67.74	$66.12	$67.43

Adding these two resources will reduce RPU's future power supply costs while simultaneously providing a degree of future price stability. As previously discussed, limiting RPU's exposure to the volatile natural gas market is highly recommended. The addition of the Clearwater Power Plant to RPU's resource portfolio is not inconsistent with this approach.

The rate for energy related to Renaissance is initially set at $77/MWh, with an annual escalation rate tied to the implicit price deflator. This is below the forecasted price of energy (renewable and non-renewable) in the California marketplace.

The Clearwater Power Plant has an 8,520 BTU/kWh heat rate, significantly below the heat rate typically assumed by spot market sellers to establish energy prices for on-peak spot market purchases, while approximately equal to the off-peak heat rate. The high efficiency of the unit means that energy costs will be approximately $34/MWh less expensive than on-peak purchases when gas is priced at $9.00/MMBTU, reducing annual energy costs by $4.5 million in

[21] A delay from January 2010 to April 2010 for the in-service date of this resource, if such a delay should occur, would have no significant impact on the model results.

[22] To be considered a Local Capacity resource for RPU, the resource must be located in the same CAISO-defined region as the load it serves. In RPU's case, the Los Angeles Basin Area.

comparison to spot market purchases. The savings is reduced by the estimated capital and operating and maintenance (O&M) costs of $4.2 million per year. As gas prices increase and drive heavy load hour electricity prices higher, the benefits of the Clearwater Power Plant increase.

The Clearwater Power Plant actually shows better financial results as natural gas costs rise and the energy cost savings increase. With low natural gas costs, the energy savings alone cannot offset the capital and O&M costs associated with the unit. Off-setting the CAISO's LCR while reducing the transmission congestion risks of power imported from outside the CAISO system, however, is expected to materially outweigh the risk of lower than forecasted natural gas prices and adds significantly to the value of the Clearwater Power Plant.

Including these two resources in RPU's resource mix reduces total power supply costs by approximately $2.0 million in 2009, increasing the savings to $7.0 million by 2013 in comparison to the "Do Nothing" scenario. In addition, RPU's VAR exposure declines significantly as spot market electricity purchases decline to less than 5 percent annually, compared to approximately 20 percent in the "Do Nothing" scenario.

Another factor not expressly considered in the annual cost of power is the immediate reduction in greenhouse gas emissions due to the power purchase from Renaissance.

AB32 and SB1368 require the State's utilities and industries to reduce their emissions of greenhouse gases under threat of significant administrative costs and potential fines. Renewable resources in California generally have an environmental premium attached to their price and cost between $22 and $35 more per MWh than non-renewable resources.

In the first, "Do Nothing" scenario, renewable energy as a percentage of total purchases is approximately 16 percent after 2009, primarily due to the Salton Sea Unit 5 geothermal project increase[23].

In the second case, the addition of the Renaissance Project increases RPU's renewable generation to approximately 33 percent of its projected customer requirements in 2011.

This increase in renewable energy adds approximately $4.0 million to RPU's annual energy costs in 2010 while reducing RPU's emissions of greenhouse gases by 12.5 percent in comparison to natural gas-fired generation.

Finally, RPU's VAR is significantly reduced in the second scenario with less than 4 percent of future forecasted energy requirements unhedged after 2010.

[23] The Salton Sea Unit 5 geothermal project is expected to generate approximately 193 GWh in FY 2008/09, increasing to 400 GWh thereafter.

Scenario 3: Meet All Future Needs with Natural Gas-Fired Resources

The third scenario studied the possibility of meeting future energy requirements with high efficiency natural gas-fired generation facilities located within the Los Angeles Basin. Combined-cycle units would be acquired once the Clearwater Power Plant and Renaissance resources came online to meet future energy needs.

Power marketers, such as Reliant and AES, have proposed a number of new or re-powered large combined-cycle facilities between 2012 and 2015. These proposed units would meet the current SB1368 Emissions Performance Standard and would be located within the Los Angeles Basin area. Any capacity or energy purchased from these proposed facilities would be accomplished through power purchase agreements.

The proposed units would be very efficient, with heat rates of approximately 8,000 BTU/kWh (or better). Capacity prices range from $6 to $10 per kW-month, reflecting the capital-intensive nature of the units with estimated construction costs ranging from $2,000 to $2,500 per kW of installed capacity.

Using the CPUC's forecast of natural gas prices, energy from the proposed units would cost between $70 and $75 in 2012, well below the forecasted "spot" market price.

The simulation of power supply costs after adding one 15 MW combined-cycle unit in 2012 and a second in 2015 are shown in Table 6.5 below:

Table 6.5: Results of Additional Natural Gas Generation Additions

Summary $000	2009	2010	2011	2012	2013
Gross Cost	$180,425	$199,781	$210,842	$215,980	$224,777
Net Cost	$144,606	$157,315	$172,371	$169,024	$175,275
Spot Energy Buy percent	5.3%	3.7%	3.5%	2.0%	2.2%
Spot Energy Sell percent	7.1%	9.9%	8.5%	13.2%	15.6%
Average Cost	$58.4	$62.5	$67.7	$65.9	$67.3

In comparison to the Clearwater/Renaissance scenario, power supply costs are reduced by approximately $500,000 to $700,000 annually. This savings is primarily due to the high efficiency of the gas-fired combined cycle generators in comparison to spot market purchases, but does not include savings expected to result from RPU's avoidance of CAISO Local Capacity and other Resource Adequacy requirements. Absent these new resources, RPU would likely be required to pay a monthly demand charge, estimated at $10/kW-month or $1,800,000 annually, for capacity from the proposed combined-cycle units.

It may be possible for RPU to enter into a gas hedging agreement with the unit's owners to fix gas prices. This would provide additional price certainty for RPU, at least on a year-to-year basis.

Scenario 4: Renewable Alternative

The final alternative studied was acquiring the Clearwater Power Plant and Renaissance in addition to the third and fourth RERC units, and then purchasing 10-15 MW of baseload renewable resources by 2015. Thereafter, 10-15 MW of baseload renewable energy would be purchased roughly every other year. This alternative has the price certainty benefit of long-term contracts with relatively low escalation rates. RPU would meet over 50 percent of its retail load requirements with renewable resources, primarily geothermal, with only the Clearwater Power Plant and RPU's internal generation resources powered by natural gas. The difficulty with becoming a predominantly renewable utility is overcoming the generally high initial cost of renewable resources relative to less expensive gas-fired generation.

Renewable resources are currently priced at a premium compared to traditional resources. This is partly due to the State of California's legislated desire to reduce greenhouse gas emissions by requiring CPUC regulated utilities to have at least 20 percent of their resource needs met by renewable resources by 2010, with the possibility of this percentage increasing to at least 33 percent by 2020.

Renewable resources would also be exempt from some of the potential effects of carbon taxes or other emission penalties should the State legislature decide to impose them in the future.

RPU began investing in renewable power resources during the 2000-2001 energy crisis with the installation of a 150 kW photovoltaic generation carport structure at the Utility Operations Center. In 2002, California adopted legislation directed to support the procurement of "Eligible" renewable power resources, thereby reducing the states reliance on conventional sources of power considered harmful to the environment. Responding to the State's mandate, the Public Utilities Board and the City Council adopted a Renewables Portfolio Standard ("RPS") and renewable energy procurement goals to further define Riverside's role and commitment to environmental stewardship through the procurement of renewable power resources. Goals adopted included 25 MW of renewable resources from long term contracts and 1 MW from local generation.

<u>Renewables Portfolio Standard (RPS)</u>

Senate Bill 1078 (2002) required that each governing body of a local publicly owned electric utility implement and enforce a RPS that recognizes the intent of the legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement. The expressed goal of SB1078 was for CPUC-jurisdictional entities to reach a 20 percent reliance on renewable power resources by year 2020. These entities were further required to increase renewable energy procurement at a minimum of 1 percent each year in order to reach the goal by 2020.

The Board of Public Utilities and City Council initially approved a Renewables Portfolio Standard in 2003 with stated goals and targets. The expressed goal required that RPU increase its supply of electricity from "eligible" renewable resources. "Eligible" renewable resources for purposes of this RPS include: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, hydroelectric generation, digester gas, municipal solid waste, landfill gas, ocean wave, ocean thermal, and tidal current. The initial RPS further specified that at least 15 percent of Riverside's retail energy requirements be met by renewable resources no later than 2010, with that requirement increasing to 20 percent by the year 2017. In 2007, RPU's Board of Public Utilities adopted more aggressive renewable energy procurement targets by establishing 20, 25 and 33 percent thresholds by the years 2010, 2015 and 2020, respectively.

Emissions Regulations

In 2006, Governor Schwarzenegger signed into law AB32: The California Global Warming Solutions Act, and SB1368: The Greenhouse Gas Emissions Performance Standard. AB32 requires that California's statewide greenhouse gas emissions be reduced to 1990 levels by 2020. SB1368 restricts greenhouse gas emissions for new baseload generation and states that carbon dioxide emissions not exceed 1,100/lbs per MWh, an amount equal to the emissions of a state-of-the-art combined-cycle generating facility, for a long-term (greater than five years) baseload generation resource.

Significant financial commitments related to non-compliant resources are prohibited under SB1368. Thus, these resources cannot be considered by RPU in evaluating future procurement options. As a result, future resource options are limited to technologies such as renewables, high efficiency natural gas, hydroelectric and nuclear power generation. While natural gas resources may comply with the SB1368 limitations, potential carbon impacts and regulations from AB32 legislation currently under development could affect the price of the resource by the adoption of a carbon adder fee. Therefore, any evaluation of a natural gas resource should include an estimate of the potential financial impact on the utility's carbon footprint.

AB32 directs the California Air Resources Board ("CARB") to quantify California's 1990 emission levels and establish reduction targets and methods required to reduce California's greenhouse gas emissions to that level (estimated to be 25 percent, or 174 million tons of CO_2) by 2020. CARB is tasked with developing the point of regulation and market mechanisms required to reach this target.

A Proposed Interim Decision, released in March 2008 by the California Public Utilities Commission ("CPUC") and the California Energy Commission ("CEC"), recommends a number of policies and requirements that CARB adopt in its scoping plan for electricity sector greenhouse gas reductions. These recommendations include:

1. Mandatory reductions through programmatic measures: All retail providers should be required to meet the same energy efficiency requirements, Renewables Portfolio Standard and Emissions Performance Standard.

2. Establishment of a cap-and-trade program to reduce costs by permitting the trading of carbon allowances.

3. Designating the Point of Regulation in a cap-and-trade program as the first "deliverer" of electricity imported into California or the first entity that generates power in California (in-state generators). The energy deliverer will carry the emissions compliance obligation, buying carbon allowances through auction and reporting compliance efforts to the CARB.

4. Establishment of an allowances auction (partial or full) with proceeds allocated to greenhouse gas reduction measures or electricity rate mitigation.

Mandatory greenhouse gas caps will begin in 2012 for significant sources and decrease in a linear fashion to meet the 2020 goal.

The addition of emission regulations accelerates and supports RPU's need to procure clean renewable resources.

Future Resource Options

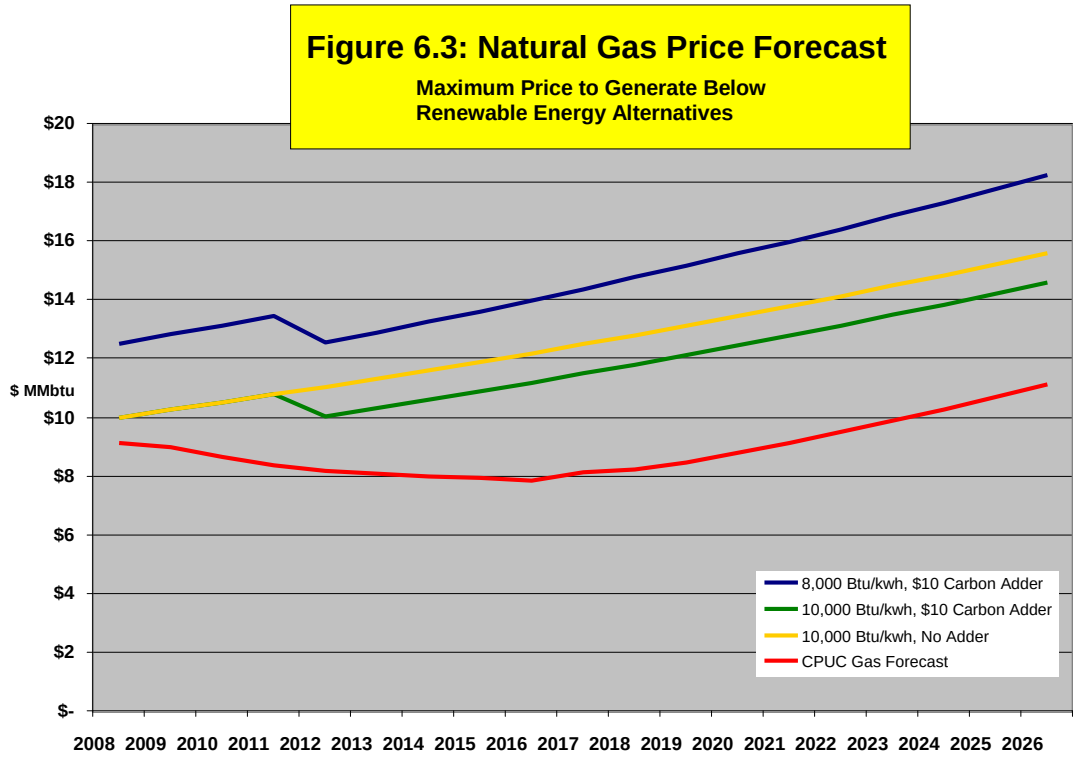
In 2005, RPU's CO_2 footprint from owned generation resources was 1,023,225 metric tons and was forecasted to increase to 1,062,810 tons in 2006[24]. The possibility of an emissions allowance auction could result in an increase in wholesale power costs of $8 -$25 per ton, or $4 - $13 per MWh for a fossil fuel resource as suggested by CPUC Commissioner Peevey. For purposes of financial analysis of resource options, a $10 per MWh carbon fee will be added to the evaluation of all fossil fuel-based resource options.

Renewable resources have long been considered desirable for their environmental benefits, but also a more expensive resource that is difficult to justify to the ratepayer. Attempts to comply with the spirit of the RPS legislation, SB1078, have centered on incorporating small amounts of renewable resources into RPU's overall portfolio mix, thus minimizing the incremental financial impacts to the ratepayers. RPU's overall resource mix remains largely based on fossil fuel resources, although RPU has already procured a significant amount of long-term renewable energy and is continuing to pursue all renewable resource options that are consistent with the goals established by its governing bodies.

The following graph illustrates the price of natural gas required to remain more economical than a $100/MWh renewable resource. Natural gas prices for 2008 have exceeded $9/MMBTU, while various forecasts predict that natural gas prices will dip below $8/MMBtu for several years before climbing above $9/MMBtu. The comparison reflects a $1 to $2/MMBtu increase from current gas prices depending on the efficiency of the gas-fired resource. AB32 imposed regulations could increase wholesale natural gas prices with the addition of a carbon adder fee. The graph also includes an assumed $10/MWh carbon fee beginning in 2012. The addition of the

[24] These values have been audited by the California Climate Action Registry as part of RPU's membership in that organization.

carbon fee more realistically brings the renewable "clean" resource into price competition with the natural gas resource, and thus a viable resource option for significant long-term energy supply.



Note: Assumes $10 Carbon Adder in 2012
Renewable Resource $100 w/2.5 esc.

Results of Simulation

A power supply cost simulation was performed using RPU's existing resources, plus the Clearwater Power Plant and Renaissance facilities. Then, additional purchases of baseload renewable resources in 10 MW blocks were added in alternative years beginning in 2013.

The simulation shows that adding renewable resources on a staggered basis has a small impact on total resource costs in comparison to natural gas-fired facilities.

Table 6.6: Total Power Supply Costs with Renewable Energy Resources					
Summary $000	**2009**	**2010**	**2011**	**2012**	**2013**
Gross Cost	$180,425	$199,781	$210,841	$211,035	$224,433
Net Cost	$144,605	$157,315	$172,370	$169,707	$179,978
Spot Energy Buy percent	4.7%	3.2%	3.4%	2.4%	2.5%
Spot Energy Sell percent	7.0%	9.8%	8.5%	10.2%	12.0%
Average Cost	$58.42	$62.45	$67.75	$66.12	$69.0

Under the renewable scenario, total power supply costs rise by $4.7 million in comparison to the natural gas alternative. However, the renewable energy prices now begin escalating at a slower rate and with less volatility so that by 2017, the natural gas scenario actually leads to higher total costs.

High Natural Gas Prices

The analyses of future generation costs are based upon natural gas price forecasts provided by the CPUC. No entity has a proven record of correctly forecasting long-term energy prices, primarily due to non-economic factors that affect oil and natural gas costs. That is, it is difficult to forecast the political and socio-economic factors that impact world energy prices.

The forecasts of natural gas prices presented above were prepared under the assumption that there would be no significant political disruptions that impacted world energy markets. Nevertheless, world oil markets are being impacted by a variety of minor events – political unrest in Nigeria, increasing tensions between Venezuela, Columbia and Ecuador, and Turkish military incursions against Kurds in western Iraq that threaten major oil pipelines.

While none of the above circumstances by themselves would significantly impact world markets, the combination of these political activities, plus continued uncertainty in the US economy, is driving natural gas prices upward. When compared to the natural gas forecasts prepared by the CPUC, GED and EIA, energy prices are currently well above the GED and EIA forecasts and slightly greater than the CPUC forecast for 2008. However, the CPUC forecast shows that energy prices will decline in the future. If instead natural gas prices rise, then a utility plan that is based upon low natural gas prices is at risk.

The evaluations of alterative resource acquisitions used the CPUC natural gas price forecast. Using this forecast, the least cost alternative for RPU is to acquire 25 MW of additional natural gas-fired generation in 2012 and 2015. If, however, natural gas prices do not decline in the future, the least cost generation expansion plan would no longer include natural gas generation.

An analysis of power costs was performed where natural gas prices were allowed to increase at a 4 percent annual rate beginning with 2007 average costs.

In this scenario, the increasing cost of natural gas, occurring just as RPU begins investing in natural gas resources, causes total power supply costs to rise by $5 million in FY 2008/09 and as much as $16 million by 2013.

By choosing to invest in natural gas resources to meet future needs, RPU would be accepting the likelihood that natural gas prices will rise and force retail rates upwards in the future.

Table 6.7: Effects of Rapidly Escalating Natural Gas Prices

Summary $000	2009	2010	2011	2012	2013
Gross Cost	$180,425	$199,781	$210,842	$218,237	$230,501
Net Cost	$144,606	$166,959	$179,735	$181,760	$191,520
Spot Energy Buy percent	5.3%	3.7%	3.5%	2.0%	2.2%
Spot Energy Sell percent	7.1%	9.9%	8.5%	13.2%	15.6%
Average Cost	$58.4	$64.0	$69.3	$69.3	$71.6

Effects of Emission Tax

As discussed above, California regulators are discussing the imposition of an emission tax of $8 per ton of CO_2 beginning in 2012 and increasing to $20-$25 per ton by 2025. With RPU's current resource mix, this proposal would add as much as $30,000,000 annually to power supply costs.

This estimate is based upon RPU's 2012 coal-fired resources (the Intermountain Power Project, with approximately 1,140 GWh of annual generation) and natural gas-fired resources (Clearwater Power Plant , RERC and Springs) at an average "tax" of $4 per MWh.

Since it is not known exactly how the CARB will apply the tax, only wide estimates are currently possible. Regardless, the potential cost to RPU of an emissions tax would significantly impact retail rates.

Comparison of Scenarios

A comparison of the various scenarios studied provides a somewhat surprising result. If RPU adopts the renewable resource acquisition strategy, total power supply costs would not be significantly greater than acquiring efficient natural gas resources, even if natural gas prices followed the CPUC's natural gas price forecast and declined for the next several years.

If natural gas prices increase from 2007 levels rather than decline, the renewable alternative becomes significantly more valuable.

Table 6.8: Net Present Value (NPV) Summary						
FY	**2009**	**2010**	**2011**	**2012**	**2013**	**NPV**
Do Nothing Scenario	$151,835	$164,727	$176,790	$173,027	$177,125	**$843,504**
NPV	$144,605	$149,412	$152,718	$142,350	$138,782	**$727,867**
Plus Clearwater and Renaissance	$144,606	$157,315	$172,371	$169,707	$175,786	**$819,785**
NPV	$137,720	$142,689	$148,901	$139,618	$137,733	**$706,661**
Plus Natural Gas Generation	$144,606	$157,315	$172,371	$169,024	$175,275	**$818,591**
NPV	$137,720	$142,689	$148,901	$139,056	$137,333	**$705,699**
High Natural Gas Prices	$144,606	$157,896	$174,144	$171,275	$180,418	**$828,339**
NPV	$137,720	$143,216	$150,432	$140,908	$141,362	**$713,639**
Plus Renewable	$144,332	$157,108	$173,241	$170,823	$179,978	**$825,482**
NPV	$137,459	$142,502	$149,652	$140,537	$141,017	**$711,167**

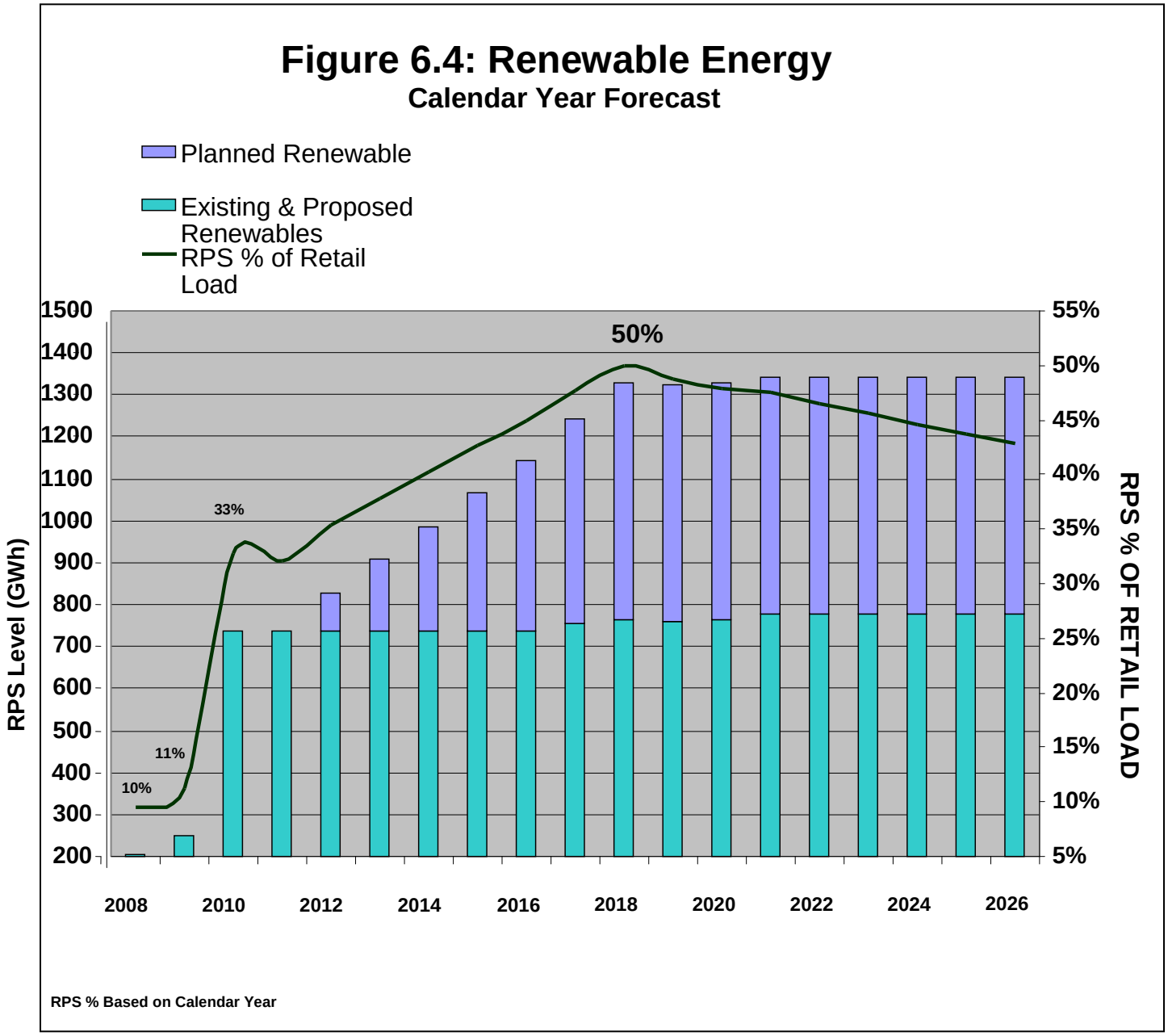
Summary and Conclusion

The scenarios presented above show that adding the Clearwater Power Plant to RPU's resource mix in 2008, the Renaissance Project in 2010/2011 and another 10 to 15 MW of baseload renewable generation in 2013 leads to the lowest total power supply costs over the planning horizon. If natural gas prices decline, a combined-cycle facility results in the lowest total costs, assuming that there are no carbon taxes or other environmental penalties.

If natural gas prices rise in the future, adding 10 to 15 MW of baseload renewable resources every two years beginning in 2013 results in the lowest long-term power supply costs, along with the added benefits of greater price certainty and less risk of penalties. Even with the declining forecast of natural gas costs used by regulatory bodies at the state and federal level, a renewable resource portfolio has a slight impact on rates over the next five years.

There is no reason to believe that fossil fuel prices in the foreseeable future will begin a long-term price decline. As such, entering into long-term renewable resource contracts will result in the lowest risked-balanced rates for RPU ratepayers.

Figure 6.4 shows the effects on RPU's total resource portfolio of the recommended supply plan.



City of Riverside
Public Utilities Department - Resources Division

2008 Power Supply
Integrated Resource Plan

Appendix A

California Independent System Operator
Market Redesign and Technology Upgrade

Introduction

Soon after the CAISO's initial operations in 1998, the FERC directed the CAISO to redesign its transmission market methodology, particularly its zonal approach to transmission congestion management. This redesign effort was given the moniker *Market Design 2002* (MD02) and was intended to correct numerous identified flaws in the CAISO's market mechanisms. The CAISO's MD02 effort was not implemented in a timely fashion and, ultimately, these flaws were exploited by a number of market participants - leading to what has been termed the 2000-2001 Energy Crisis. The CAISO has continued attempting to redesign the California wholesale energy markets in order to prevent a repeat of the 2000-2001 Energy Crisis. The CAISO's latest attempt at redesigning its markets has been designated *Market Redesign and Technology Upgrade* ("MRTU"). The MRTU wholesale market redesign requires significant changes to the way RPU plans for, acquires and operates its generation resources and wholesale power supply transactions.

The current pre-MRTU market relies primarily on traditional bilateral transactions between market participants, where LSE's meet their loads through generation resources and power purchase agreements. The CAISO's current Imbalance Energy market is used to supply or absorb, as appropriate, any energy deviations between forecasted loads and LSE-supplied bilateral energy transactions. Because the CAISO's Imbalance Energy market is only intended to accommodate small deviations between LSE supply and demand, its expected energy volumes should be small compared to the amount of load represented by the CAISO system. During the 2000-2001 Energy Crisis, the CAISO's Imbalance Energy market was inappropriately used as an optional real-time market mechanism, resulting in abnormally large LSE deviations and extraordinarily high energy prices. The CAISO does not currently operate any forward energy markets, leaving this obligation to the LSEs and their bilateral transactions.

Although the CAISO also operates an Ancillary Services (i.e., capacity-based) market, LSEs today are primarily concerned with the supply of energy to meet their load. Nevertheless, the CAISO has implemented new capacity procurement requirements for LSEs as MRTU implementation approaches. These new obligations for LSEs to procure capacity reflects the

CAISO's increasing concern that sufficient generating capacity may not be available at all times to meet CAISO system load.

The MRTU market represents a significant shift away from the CAISO's original thinking. The CAISO's original design was expected to promote a prolific new electricity commodity market, with system reliability a by-product of that activity. This original philosophy was embodied in the CAISO's corporate mantra "*Reliability Through Markets*," which was discontinued soon after the 2000-2001 Energy Crisis. With the implementation of the MRTU market, CAISO electric system reliability is the primary consideration and cost is considered secondarily.

The Current CAISO Market

The CAISO currently operates as a single control area, now referred to as a "Balancing Authority," originally derived from the combined transmission grids of California's three major investor-owned utilities; Southern California Edison ("SCE"), Pacific Gas & Electric ("PG&E") and San Diego Gas & Electric ("SDG&E"). Since its initial operation in 1998, the CAISO's operational control of transmission facilities has been extended by the inclusion of several of the State's governmental utilities' transmission entitlements (excluding those of the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District, among others). Using the transmission entitlements under its operational control, the CAISO provides non-discriminatory access to the transmission grid for wholesale buyers and sellers of electricity.

Much of the CAISO's pre-MRTU efforts have been aimed at ensuring feasible schedules[25] and the maintenance of reliable system operating conditions. This requires the CAISO to manage congestion between the three major transmission zones comprising the CAISO grid, while ensuring that sufficient generation is available for reliability. Flaws associated with this zonal approach to management of the transmission grid include generators ignoring intra-zonal transmission constraints (assuming generator awareness of the constraints) and a potential lack of adequate generating capacity to ensure reliable system operation. That is, the CAISO cannot be assured that sufficient capacity, strategically located within the CAISO transmission grid and responsive to CAISO operating instructions, is available to reasonably assure reliable grid operations.

Finally, from an economic standpoint, there is no ability to ensure that the lowest cost resources will be used to satisfy load and system reliability requirements. In many instances, high cost generation is operated to address locational reliability concerns, while low cost generation remains idle.

In addition to those identified above, a number of additional problems should be addressed to increase reliability and help keep wholesale energy prices low. These identified problems include:

[25] The feasibility of schedules refers to the CAISO transmission grid's ability to accommodate the requested use of certain CAISO grid components. The use of the CAISO grid is requested by market participants through their submission of resource "schedules," which represent hourly amounts of energy to flow over those components. For example, market participant schedules totaling 1000 MW and requested to flow from Point A to Point B would be considered infeasible if the facilities between those points could only accommodate 900 MW.

- Inadequate incentives for market investment in new capacity;
- The absence of a state-wide resource planning process;
- Elimination of the traditional utility's "obligation to serve;"[26]
- The absence of incentives to enhance demand price responsiveness;
- Increased reliance on spot market purchases.

MRTU Goals

The new MRTU marketplace is intended to address many of the identified problems plaguing the current CAISO wholesale market.

MRTU focuses on the CAISO's core functions. It is designed to provide reliable operation of the State's transmission system, while providing non-discriminatory, bid-based access to the grid. Just as importantly, the new market is designed to increase the amount of generation capacity available to meet California's needs through the imposition of Resource Adequacy requirements on LSEs.

The MRTU Market

The MRTU market uses a full network model[27] to identify transmission grid constraints before the scheduling of resources that use the grid actually occurs. The full network model establishes over 3,000 points, or "nodes," on the CAISO transmission system to identify constraints and to assign costs at each of the nodes. Each nodal price is referred to as the Locational Marginal Price ("LMP") at that node. The LMP is made up of three separate components: system energy costs, the marginal cost of transmission system losses, and transmission congestion costs.

- Energy Cost Component: System energy cost is the incremental cost to produce the next MWh of energy from resources available to the CAISO. System energy costs are the same for all entities at all nodes on the CAISO grid.

- Transmission Loss Component: The cost of transmission losses is based on the marginal quantity of transmission losses on the CAISO grid, and is the same for all entities using the CAISO grid.

- Congestion Cost Component: Transmission congestion costs are the most difficult to manage. Congestion costs are the additional costs that may be imposed at any of the 1,200 nodes due to transmission constraints. For example, assume there are two

[26] Much has been said about utilities' traditional "obligation to serve," and the failure of California's investor-owned utilities to retain that obligation after CAISO implementation in 1998. In essence, the obligation to serve is demonstrated by a utility's willingness to pay whatever market price is required to procure needed power and maintain reliable service to its customers. A refusal to pay prevailing prices for available power, with rolling blackouts resulting, is an example of abrogating one's obligation to serve.

[27] In contrast to the CAISO's current zonal transmission system model under which transmission paths into and out of the three major areas of the CAISO grid are analyzed, a full network model will analyze probable transmission conditions on all of the major transmission network facilities comprising the CAISO grid.

generators at different locations on the CAISO transmission grid; one can generate at $50/MWh and the other at $100/MWh. If the grid cannot accommodate all of the generation from the lower cost unit and the CAISO must use energy from the higher cost unit, the congestion cost would be the difference between the two generator costs, or $50/MWh.

Identifying and measuring congestion costs in a LMP environment is exceptionally difficult and largely dependant on a variety of factors, such as load levels and the location of individual generators on the grid. In addition to LMP, the CAISO intends to operate day-ahead and real-time energy markets in conjunction with its Ancillary Services market. These energy markets are created by the removal of the CAISO's "Market Separation Rule." The Market Separation Rule required that all LSEs submit resource schedules exactly equal to, or in "balance" with, their load schedules. With MRTU's elimination of this rule, LSEs will be free to submit load schedules that exceed their resource schedules, thus making an implicit offer to purchase energy from the CAISO's markets for the difference. Likewise, LSEs may submit resource schedules that exceed their load schedules, thus making an implicit offer to sell energy to the CAISO's markets for the difference.

Scheduling and Bidding

As described above, today's pre-MRTU marketplace requires each LSE to schedule its energy resources to exactly meet its load. In MRTU, entities can purchase energy from the CAISO's day-ahead market in addition to meeting load with their own contracts or generation.

Under MRTU, each generation resource will bid its energy supplies into the CAISO's markets at a specific transmission node. The CAISO will then choose which of the available resources to be dispatched based upon costs, transmission availability, the need for local capacity and other factors (LSE's can choose to dispatch their own resources in non-economic order by Self-Scheduling[28] if they so choose).

By requiring each resource to show its cost of generation, the CAISO can theoretically minimize the overall cost of energy for the State and ensure that no LSE pays more for energy than if it dispatched it's own resources.

MRTU Impact on RPU

Any discussion of the CAISO's MRTU effort must recognize the dynamic nature of its ongoing development. New and revised aspects of the proposed MRTU market are discovered at a breakneck pace. Therefore, it is impossible at this time to accurately predict how MRTU implementation will affect RPU's power supply costs. RPU can choose to Self-Schedule its resources and, ideally, be no worse off than if MRTU did not exist; provided, that transmission system congestion does not occur. If the CAISO's prediction of MRTU operations is accurate,

[28] Self-Scheduling refers to an entity's ability to force the dispatch of a specific resource to meet the entity's requirements, regardless of potential congestion costs. Thus, an entity that elects to Self-Schedule the output of a specified resource assumes the full risk of congestion costs and adopts the role of a price-taker with respect to these costs.

RPU's future power supply costs should be lower than if RPU operated its own resources to meet its customer loads.

RPU has expended approximately $4.5 million to date in preparation for MRTU implementation. This money is being used to upgrade RPU's computer hardware and scheduling/accounting applications to conform with MRTU requirements, training of personnel and development of the necessary software and communications equipment and services necessary to efficiently leverage MRTU implementation. Through its provision of certain wholesale power supply services to the cities of Azusa, Banning and Corona, a portion of these RPU costs are shared by other similarly situated utilities, thus significantly helping to mitigate the cost of RPU's infrastructure investments, while leveraging RPU's staff expertise.

If the CAISO's predictions related to MRTU operations is accurate, RPU's future power supply costs should be lower than if RPU operated its own resources to meet its customer loads, and RPU should see a return on this investment. If the CAISO is unable to implement the MRTU marketplace, or implementation delays continue, some of these expenditures will have been unnecessary.

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Appendix B

Summary of Transmission Rights and Costs

Introduction

RPU began acquiring transmission rights in the late 1970's as a necessary means of accessing inexpensive energy from regions outside of Southern California. Most of RPU's transmission resources were originally acquired to allow power purchases from a specific resource.

At its inception, the CAISO's transmission system was comprised of the combined transmission systems of California's major investor-owned utilities ("IOU's"). The IOU's were SCE, PG&E and SDG&E, which became the CAISO's first Participating Transmission Owners ("PTO's") under the CAISO's tariff by transferring operational control of their transmission facilities and entitlements to the CAISO. In return for this transfer, the IOU's, as PTO's, began receiving monthly payments from the CAISO for recovery of their annual transmission revenue requirements. The funds for these payments originate from the fees charged by the CAISO to all users of the CAISO grid.

Not having initially transferred its transmission entitlements to the CAISO, Riverside was required to continue paying the cost of those entitlements (debt service, O&M, capital improvements), as well as the CAISO's transmission wheeling cost,[29] in order to obtain contiguous transmission services from its various resources to its load. On January 1, 2003, RPU itself became a PTO by transferring operational control of its transmission entitlements to the CAISO. Like the IOU's, RPU then began receiving monthly payments from the CAISO for recovery of RPU's annual transmission revenue requirement. RPU continues to receive those monthly payments.

As a further incentive to encourage entities to become a PTO, RPU also receives Firm Transmission Rights ("FTR's") equal to its entitlements transferred to the CAISO. RPU will continue to receive these FTR's until the earlier of (i) MRTU implementation, when FTR's will be converted to CRR's, or (ii) December 31, 2010. Upon MRTU implementation, all LSE's will be allocated CRR's based on their load requirements. If MRTU implementation is delayed until

[29] The CAISO's transmission wheeling cost is derived from the aggregate transmission revenue requirements of all PTOs; i.e., entities that have transferred operational control of their transmission entitlements to the CAISO.

after December 31, 2010, RPU would be required to purchase in the CAISO's auction any FTR's it desired to hedge congestion costs during the intervening period.

Becoming a PTO reduced RPU's net annual transmission costs by approximately $17,500,000. This net reduction results from the CAISO's reimbursement of RPU's annual transmission revenue requirement, while assessing RPU for transmission service at a rate reflecting the average cost of all PTO transmission revenue requirements. In 2008 this represented a reduction in RPU's transmission service costs from $7.54 per MWh to $3.30 per MWh.

A brief description of RPU's different transmission entitlements is provided below. It is important to recognize, though, that as of 2010 RPU will lose any priority rights on these lines and would need to purchase CRR's on these transmission paths in order to continue bringing unit specific power into Riverside and avoid the risk of transmission congestion charges.

Mead-Phoenix Project

The Mead-Phoenix Project consists of 500 kV alternating current transmission lines between Westwing and Perkins Substations, between Perkins and Mead Substations, and between Mead and Marketplace Substations. Westwing and Perkins Substations are located near Phoenix, Arizona, while Mead and Marketplace Substations are located near Boulder City, Nevada. RPU's entitlement in this 1,300 MW transmission path is 12 MW. RPU's participation in this path was prompted by the need to procure long-term transmission related to its 12 MW entitlement in the Palo Verde Nuclear Generating Station.

Mead-Adelanto Project

The Mead-Adelanto Project consists of a 500 kV alternating current transmission line between Marketplace and Adelanto Substations. Marketplace Substation is located near Boulder City, Nevada, while Adelanto Substation is located near the City of Adelanto, California. RPU's entitlement in this 1,800 MW transmission path is 118 MW. RPU's participation in this path was prompted by the need to procure long-term transmission related to its 12 MW entitlement in the Palo Verde Nuclear Generating Station, and to allow for future resources expected to use the now-defunct Utah-Nevada Transmission Project, a high voltage transmission line originally planned to connect the Pacific Northwest and the Desert Southwest.

Southern Transmission System ("STS")

The STS is a 1000 kV direct current transmission line between the Intermountain Power Project and the Adelanto Substation. The Intermountain Power Project is located near Delta, Utah, while the Adelanto Substation is located near the City of Adelanto, California. RPU's entitlement in this 1,920 MW transmission path is 195 MW. At present, the STS is a transmission component required for delivery of power related to RPU's Intermountain Power Project entitlement, as well as power under RPU's power purchase agreement with the Deseret Generation & Transmission Cooperative.

The STS will be used to convey RPU's energy entitlements from the Renaissance Geothermal Project beginning in 2010.

Northern Transmission System ("NTS")

The NTS consists of two transmission paths: two 345 kV alternating current transmission lines between the Intermountain Power Project and the Mona Substation, and one 230 kV alternating current transmission line between the Intermountain Power Project and the Gonder Substation. The Intermountain Power Project is located near Delta, Utah, while the Mona Substation is located near the City of Mona, Utah, and the Gonder Substation is located near Ely, Nevada. RPU's NTS entitlements are currently reduced by 20 MW by virtue of its sale of firm bidirectional service to Deseret between Mona and Gonder, leaving 51 MW available on the Intermountain-Mona path and zero on the IPP-Gonder path.

The IPP-Mona portion of the NTS will be used to convey RPU's Renaissance Geothermal Project energy entitlements beginning in 2010.

Celilo – Sylmar 1000 kV DC Line

Also known as the Pacific DC Intertie, the Celilo-Sylmar 1000 kV DC line is a direct current transmission line between Sylmar, California and The Dalles, Oregon. Riverside's 23 MW bi-directional firm transmission service entitlement was purchased from the cities of Burbank and Pasadena in 1990 to convey energy associated with the BPA-Riverside Capacity Sale/Exchange Agreement and will terminate concurrent with termination of that agreement in 2010.

Adelanto – Lugo Transmission Service

Under three separate agreements with the Los Angeles Department of Water and Power ("LADWP"), RPU currently has firm transmission service entitlements totaling (i) 313 MW from LADWP's Adelanto Switching Station to the midpoint of the Lugo-Victorville 500 KV line, and (ii) 118 MW from the midpoint of the Lugo-Victorville 500 KV line to LADWP's Adelanto Switching Station. These transmission service entitlements provide a path between the ISO Controlled Grid and Riverside's entitlements in the STS and the Mead-Adelanto Project.

Mead – Vista

Under contract with SCE, RPU holds a 30 MW entitlement to firm transmission service from the Western Area Power Administration's Mead 230 KV Substation located in Boulder City, Nevada to Riverside's point of interconnection on the CAISO Controlled Grid at SCE's Vista Substation. This transmission right was initially procured in order to transmit energy and capacity associated with Riverside's Hoover Power Station entitlement.

Lugo-Vista Transmission Service

Under two contracts with SCE, RPU holds a total of 168 MW in firm transmission service entitlements from the midpoint of the Lugo-Victorville 500 KV line to Riverside's point of interconnection on the CAISO Controlled Grid at SCE's Vista Substation. These rights were originally procured to accommodate RPU's entitlements in IPP and the Palo Verde Nuclear Generating Station.

San Onofre-Vista Transmission Service

Under a contract with SCE RPU holds a 42 MW entitlement to firm transmission service from the San Onofre Nuclear Generating Station ("SONGS") to Riverside's point of interconnection on the ISO Controlled Grid at SCE's Vista Substation. This entitlement was procured to accommodate RPU's ownership entitlement in SONGS.

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Appendix C

Long-Term Demand Forecast

Regression Statistics

Following are the regression statistics for historical energy sales in the Residential and Commercial rate classes.

RESIDENTIAL

Multiple R	0.9917
R Square	0.9834
Adj R Square	0.9680
Standard Error	7,884
Observations	72

	df	SS	MS	F
Regression	4	2.505E+11	6.262E+10	1,007
Residual	68	4.226E+9	62,157,014	
Total	72	2.547E+11		

	Coefficients	Std Error	t Stat	P-value
Population	0.759027	0.294638	2.57613	0.012167
CDD	91.9939	8.16665	11.2645	3.36E-17
HDD	36.0868	11.3473	3.18021	0.002217
Price	-1,353,977	642,387	-2.10772	0.038743

COMMERCIAL

Multiple R	0.9984
R Square	0.9968
Adj R Square	0.9823
Standard Error	6,023
Observations	72

	df	SS	MS	F
Regression	3	7.911E+11	2.637E+10	7,268
Residual	69	2.503E+9	36,282,195	
Total	72	7.936E+11		

	Coefficients	Std Error	t Stat	P-value
CDD	48.5936	6.20794	7.82765	4.13E-11
HDD	-19.5283	8.61698	-2.26626	0.026575
Employment	0.124789	0.002395	52.0962	3.9E-57

Data Sources

The following data sources were used in this forecast model:

Customer Energy Sales:	RPU-Finance
Retail Electricity Prices:	RPU-Finance
City Population:	City Planning Dept.
Cooling/Heating Degree-Days:	Nat'l Weather Bureau (UCR Station)
County Employment—historical:	State Finance Dept.
County Employment—projections:	City Planning Dept / Webb & Assoc.
Historical Energy/Peak Loads:	RPU-Power Resources

MONTHLY ENERGY (MWh)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
2008	173,635	172,490	172,440	170,016	180,288	200,682	225,784	229,187	213,055	184,289	174,489	178,466	**2,274,821**
2009	177,532	176,390	176,350	173,928	184,209	204,612	229,722	233,138	217,014	188,255	178,464	182,463	**2,322,077**
2010	181,515	180,377	180,348	177,928	188,217	208,629	233,748	237,178	221,060	192,310	182,526	186,548	**2,370,383**
2011	185,586	184,452	184,434	182,016	192,315	212,735	237,862	241,307	225,197	196,454	186,679	190,725	**2,419,762**
2012	189,748	188,619	188,610	186,195	196,503	216,933	242,069	245,528	229,425	200,690	190,924	194,993	**2,470,237**
2013	194,003	192,877	192,880	190,467	200,784	221,223	246,368	249,842	233,747	205,021	195,263	199,357	**2,521,832**
2014	198,351	197,230	197,244	194,833	205,161	225,609	250,763	254,252	238,165	209,447	199,699	203,816	**2,574,571**
2015	202,797	201,680	201,705	199,297	209,634	230,092	255,255	258,760	242,680	213,971	204,232	208,375	**2,628,480**
2016	207,340	206,228	206,265	203,859	214,207	234,675	259,847	263,368	247,296	218,596	208,867	213,035	**2,683,584**
2017	211,985	210,877	210,926	208,523	218,881	239,359	264,541	268,078	252,014	223,323	213,603	217,797	**2,739,909**
2018	216,732	215,630	215,691	213,290	223,659	244,147	269,339	272,892	256,837	228,155	218,445	222,665	**2,797,482**
2019	221,585	220,487	220,561	218,163	228,542	249,041	274,243	277,813	261,766	233,094	223,394	227,641	**2,856,331**
2020	226,545	225,452	225,538	223,144	233,534	254,044	279,256	282,843	266,804	238,142	228,453	232,727	**2,916,482**
2021	231,615	230,527	230,626	228,235	238,636	259,157	284,380	287,984	271,954	243,302	233,623	237,925	**2,977,965**
2022	236,797	235,715	235,827	233,438	243,852	264,384	289,617	293,239	277,218	248,576	238,908	243,238	**3,040,808**
2023	242,094	241,017	241,143	238,757	249,182	269,726	294,970	298,610	282,599	253,967	244,309	248,669	**3,105,041**
2024	247,508	246,437	246,576	244,194	254,631	275,186	300,441	304,099	288,098	259,476	249,830	254,219	**3,170,696**
2025	253,042	251,976	252,129	249,751	260,200	280,767	306,034	309,711	293,719	265,108	255,474	259,892	**3,237,802**
2026	258,698	257,638	257,806	255,430	265,892	286,472	311,750	315,446	299,464	270,864	261,241	265,690	**3,306,391**

MONTHLY PEAKS (MW)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
	0.001791	0.001780	0.001840	0.002100	0.002271	0.002440	0.002500	0.002530	0.002530	0.002200	0.001976	0.001800
2008	311	307	317	357	409	490	564	**580**	539	405	345	321
2009	318	314	324	365	418	499	574	**590**	549	414	353	328
2010	325	321	332	374	427	509	584	**600**	559	423	361	336
2011	332	328	339	382	437	519	595	**611**	570	432	369	343
2012	340	336	347	391	446	529	605	**621**	580	442	377	351
2013	347	343	355	400	456	540	616	**632**	591	451	386	359
2014	355	351	363	409	466	550	627	**643**	603	461	395	367
2015	363	359	371	419	476	561	638	**655**	614	471	404	375
2016	371	367	380	428	486	573	650	**666**	626	481	413	383
2017	380	375	388	438	497	584	661	**678**	638	491	422	392
2018	388	384	397	448	508	596	673	**690**	650	502	432	401
2019	397	392	406	458	519	608	686	**703**	662	513	441	410
2020	406	401	415	469	530	620	698	**716**	675	524	451	419
2021	415	410	424	479	542	632	711	**729**	688	535	462	428
2022	424	420	434	490	554	645	724	**742**	701	547	472	438
2023	434	429	444	501	566	658	737	**755**	715	559	483	448
2024	443	439	454	513	578	671	751	**769**	729	571	494	458
2025	453	449	464	524	591	685	765	**784**	743	583	505	468
2026	463	459	474	536	604	699	779	**798**	758	596	516	478

SCENARIO: MONTHLY ENERGY (MWh) in Adverse Hot Weather

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
2008	173,635	173,970	176,141	177,417	185,469	215,189	242,216	246,063	232,596	190,507	181,891	178,466	**2,373,560**
2009	177,489	177,831	180,009	181,293	189,351	219,079	246,113	249,967	236,508	194,426	185,817	182,401	**2,420,283**
2010	181,429	181,778	183,964	185,254	193,320	223,055	250,097	253,959	240,507	198,432	189,831	186,423	**2,468,047**
2011	185,457	185,813	188,006	189,304	197,377	227,120	254,169	258,039	244,594	202,527	193,934	190,535	**2,516,875**
2012	189,575	189,938	192,139	193,443	201,525	231,275	258,332	262,210	248,773	206,714	198,128	194,738	**2,566,788**
2013	193,784	194,154	196,363	197,675	205,764	235,523	262,587	266,474	253,045	210,993	202,415	199,034	**2,617,812**
2014	198,086	198,465	200,682	202,001	210,098	239,865	266,938	270,833	257,411	215,368	206,798	203,427	**2,669,971**
2015	202,485	202,871	205,096	206,423	214,529	244,303	271,384	275,288	261,875	219,840	211,278	207,916	**2,723,289**
2016	206,981	207,375	209,609	210,944	219,058	248,841	275,930	279,843	266,438	224,411	215,858	212,506	**2,777,792**
2017	211,577	211,979	214,222	215,565	223,687	253,479	280,577	284,499	271,102	229,084	220,540	217,197	**2,833,506**
2018	216,275	216,686	218,937	220,288	228,420	258,220	285,327	289,258	275,870	233,861	225,325	221,993	**2,890,458**
2019	221,078	221,497	223,757	225,117	233,257	263,066	290,182	294,123	280,744	238,743	230,217	226,894	**2,948,674**
2020	225,987	226,414	228,684	230,052	238,202	268,020	295,145	299,095	285,726	243,734	235,217	231,905	**3,008,182**
2021	231,005	231,441	233,721	235,097	243,256	273,084	300,218	304,178	290,818	248,836	240,328	237,027	**3,069,010**
2022	236,134	236,580	238,869	240,254	248,423	278,261	305,404	309,374	296,023	254,051	245,553	242,262	**3,131,188**
2023	241,377	241,832	244,131	245,526	253,704	283,552	310,705	314,685	301,344	259,381	250,893	247,614	**3,194,745**
2024	246,737	247,201	249,510	250,914	259,103	288,960	316,124	320,114	306,783	264,830	256,352	253,084	**3,259,711**
2025	252,215	252,689	255,008	256,422	264,621	294,488	321,662	325,663	312,342	270,400	261,932	258,675	**3,326,117**
2026	257,814	258,299	260,628	262,052	270,261	300,139	327,323	331,336	318,025	276,092	267,635	264,390	**3,393,994**

SCENARIO: MONTHLY PEAKS (MW) in Adverse Hot Weather

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
	0.001791	0.001780	0.001840	0.002100	0.002271	0.002440	0.002500	0.002530	0.002530	0.002200	0.001976	0.001800
2008	311	310	324	373	421	525	606	**623**	588	419	359	321
2009	318	317	331	381	430	535	615	**632**	598	428	367	328
2010	325	324	338	389	439	544	625	**643**	608	437	375	336
2011	332	331	346	398	448	554	635	**653**	619	446	383	343
2012	340	338	354	406	458	564	646	**663**	629	455	392	351
2013	347	346	361	415	467	575	656	**674**	640	464	400	358
2014	355	353	369	424	477	585	667	**685**	651	474	409	366
2015	363	361	377	433	487	596	678	**696**	663	484	417	374
2016	371	369	386	443	497	607	690	**708**	674	494	427	383
2017	379	377	394	453	508	618	701	**720**	686	504	436	391
2018	387	386	403	463	519	630	713	**732**	698	514	445	400
2019	396	394	412	473	530	642	725	**744**	710	525	455	408
2020	405	403	421	483	541	654	738	**757**	723	536	465	417
2021	414	412	430	494	552	666	751	**770**	736	547	475	427
2022	423	421	440	505	564	679	764	**783**	749	559	485	436
2023	432	430	449	516	576	692	777	**796**	762	571	496	446
2024	442	440	459	527	588	705	790	**810**	776	583	507	456
2025	452	450	469	538	601	719	804	**824**	790	595	518	466
2026	462	460	480	550	614	732	818	**838**	805	607	529	476

SCENARIO: MONTHLY ENERGY (MWh) in Adverse Cool Weather

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
2008	173,635	172,490	172,440	170,016	177,499	193,006	212,061	214,812	202,700	181,103	174,489	178,466	**2,222,716**
2009	177,489	176,351	176,308	173,891	181,382	196,895	215,958	218,716	206,611	185,022	178,415	182,401	**2,269,439**
2010	181,429	180,298	180,263	177,852	185,351	200,871	219,941	222,708	210,610	189,028	182,429	186,423	**2,317,203**
2011	185,457	184,333	184,305	181,902	189,408	204,936	224,014	226,788	214,698	193,123	186,532	190,535	**2,366,030**
2012	189,575	188,457	188,438	186,042	193,555	209,091	228,177	230,959	218,877	197,310	190,726	194,738	**2,415,944**
2013	193,784	192,674	192,662	190,273	197,795	213,339	232,432	235,223	223,148	201,589	195,014	199,034	**2,466,968**
2014	198,086	196,984	196,981	194,599	202,129	217,681	236,782	239,582	227,515	205,964	199,396	203,427	**2,519,127**
2015	202,485	201,390	201,395	199,021	206,559	222,120	241,229	244,037	231,979	210,436	203,877	207,916	**2,572,445**
2016	206,981	205,895	205,908	203,542	211,088	226,657	245,775	248,592	236,541	215,007	208,456	212,506	**2,626,948**
2017	211,577	210,499	210,521	208,163	215,718	231,295	250,422	253,247	241,206	219,680	213,138	217,197	**2,682,662**
2018	216,275	215,205	215,236	212,886	220,450	236,036	255,172	258,007	245,974	224,457	217,923	221,993	**2,739,613**
2019	221,078	220,016	220,056	217,715	225,288	240,883	260,027	262,871	250,847	229,339	222,815	226,894	**2,797,829**
2020	225,987	224,934	224,983	222,650	230,232	245,837	264,990	267,844	255,829	234,330	227,815	231,905	**2,857,337**
2021	231,005	229,961	230,020	227,696	235,287	250,901	270,063	272,927	260,922	239,432	232,926	237,027	**2,918,166**
2022	236,134	235,099	235,168	232,853	240,454	256,077	275,249	278,123	266,127	244,647	238,151	242,262	**2,980,344**
2023	241,377	240,352	240,430	238,124	245,735	261,368	280,550	283,434	271,448	249,978	243,491	247,614	**3,043,901**
2024	246,737	245,721	245,809	243,513	251,133	266,776	285,968	288,863	276,886	255,426	248,950	253,084	**3,108,867**
2025	252,215	251,209	251,307	249,021	256,651	272,305	291,507	294,412	282,446	260,996	254,530	258,675	**3,175,272**
2026	257,814	256,818	256,927	254,650	262,292	277,955	297,168	300,084	288,128	266,689	260,233	264,390	**3,243,150**

SCENARIO: MONTHLY PEAKS (MW) in Adverse Cool Weather

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
	0.001791	0.001780	0.001840	0.002100	0.002271	0.002440	0.002500	0.002530	0.002530	0.002200	0.001976	0.001800
2008	311	307	317	357	403	471	530	**543**	513	398	345	321
2009	318	314	324	365	412	480	540	**553**	523	407	353	328
2010	325	321	332	373	421	490	550	**563**	533	416	360	336
2011	332	328	339	382	430	500	560	**574**	543	425	369	343
2012	340	335	347	391	440	510	570	**584**	554	434	377	351
2013	347	343	354	400	449	521	581	**595**	565	443	385	358
2014	355	351	362	409	459	531	592	**606**	576	453	394	366
2015	363	358	371	418	469	542	603	**617**	587	463	403	374
2016	371	366	379	427	479	553	614	**629**	598	473	412	383
2017	379	375	387	437	490	564	626	**641**	610	483	421	391
2018	387	383	396	447	501	576	638	**653**	622	494	431	400
2019	396	392	405	457	512	588	650	**665**	635	505	440	408
2020	405	400	414	468	523	600	662	**678**	647	516	450	417
2021	414	409	423	478	534	612	675	**691**	660	527	460	427
2022	423	418	433	489	546	625	688	**704**	673	538	471	436
2023	432	428	442	500	558	638	701	**717**	687	550	481	446
2024	442	437	452	511	570	651	715	**731**	701	562	492	456
2025	452	447	462	523	583	664	729	**745**	715	574	503	466
2026	462	457	473	535	596	678	743	**759**	729	587	514	476

City of Riverside
Public Utilities Department - Resources Division

2008 Power Supply
Integrated Resource Plan

Appendix D

Summary of Simulation Results

5 Year Power Supply Cost Projections - EXISTING RESOURCES ONLY					
Resource Capacity Costs $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	3,780	3,780	3,780	3,780	3,780
IPP	47,431	48,617	49,832	51,078	52,355
Hoover	460	460	460	460	460
Deseret	3,432	1,716			
Deseret Amort	3,340	1,670			
RA Capacity	2,963	1,567	1,707	2,206	2,361
Placeholder	-	-	-	-	-
Placeholder					
Placeholder					
ISO OP. Res.	684	684	684	684	684
ISO Regulation	1,086	1,086	1,086	1,086	1,086
BPA 1	842	842	434	-	-
Total	$64,018	$60,422	$57,983	$59,294	$60,726
SONGS	**2009**	**2010**	**2011**	**2012**	**2013**
O&M	7,464	8,210	9,031	9,935	10,928
Insurance	139	133	136	138	141
Decom Expense	3,630	3,351	3,630	3,775	3,926
Taxes and Assessments	872	921	939	958	977
Nuclear Fuel Purchase	1,987	1,019	1,332	1,386	1,172
Total	$14,092	$13,634	$15,069	$16,192	$17,145
Transmission $000	**2009**	**2010**	**2011**	**2012**	**2013**
Mead-Adelanto	2,865	2,865	2,865	2,865	2,865
Mead-Phx	290	290	290	290	290
STS	13,659	13,659	13,659	13,659	13,659
NTS	1,490	1,490	1,490	1,490	1,490
SCE	2,880	2,880	2,880	2,880	2,880
ISO TAC	6,720	6,720	6,720	6,720	6,720
ISO FTR's/CRR's	650	1,440	1,440	1,440	1,440
ISO MLCC	1,200	1,200	1,200	1,200	1,200
ISO RA MLCC	600	600	600	600	600
ISO Intrazonal Cong	600	600	600	600	600
ISO Interzonal Cong	600	600	600	600	600
ISO Wheeling Charge	604	604	604	604	604
ISO GMC	1,877	1,877	1,877	1,877	1,877
ISO Other Gross	600	600	600	600	600
ISO MRTU	2,040	2,040	2,040	2,040	2,040
Burb/Pasa DC	1,080	1,080	1,080	1,080	1,080
LADWP Service	1,075	1,075	1,075	1,075	1,075
SCE WDAT(Non TRR)	1,296	1,296	1,296	1,296	1,296

Total	$40,126	$40,916	$40,916	$40,916	$40,916
Resource Energy $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	536	579	630	675	723
IPP	2,481	3,620	3,733	3,857	3,958
Hoover	331	334	332	331	331
Deseret	7,516	3,789	-	-	-
Cal Energy Geothermal	11,829	24,581	24,581	24,648	24,581
Neo Landfill	646	-	-	-	-
Badlands	340	-	-	-	-
Wintec	533	533	533	534	533
RA Capacity	-	-	-	-	-
CDWR Super	-	-	-	-	-
RERC 1,2 (Fuel)	3,580	2,371	2,313	3,326	3,204
Springs Fuel	-	-	-	-	-
Total	$27,792	$35,806	$32,122	$33,371	$33,330
Planned Additions	**2009**	**2010**	**2011**	**2012**	**2013**
HL DA Options					
Term Market					
RERC 3,4 Fuel					
Wintec Expansion					
Generic Green BL					
Generic Baseload					
Generic Annual HL					
Capacity Reserves					
Spot (Un-Hedged)	27,473	35,221	51,295	43,891	45,630
Total	$27,473	$35,221	$51,295	$43,891	$45,630
Wholesale Revenue $000	**2009**	**2010**	**2011**	**2012**	**2013**
Spot Market	1,180	786	109	151	135
Term Market	-	-	-	-	-
ISO Wheel/Cong	1,200	1,200	1,200	1,200	1,200
ISO TRR	19,286	19,286	19,286	19,286	19,286
Total	$21,666	$21,272	$20,595	$20,637	$20,621
Summary $000	**2009**	**2010**	**2011**	**2012**	**2013**
Gross Cost	$173,502	$185,999	$197,385	$193,664	$197,746
Net Cost	$151,835	$164,727	$176,790	$173,027	$177,125
Annual Reserve Marg.	0.0%	0.0%	0.0%	0.0%	0.0%
Spot Energy Buy %	11.3%	14.3%	21.3%	18.5%	19.3%
Spot Energy Sell %	3.2%	2.2%	0.7%	1.0%	0.9%

Average Cost/kWh	$ 61.14	$ 65.19	$ 69.30	$ 67.41	$ 68.01
Average Cost/kWh	$61.14	$65.19	$69.30	$67.41	$68.01

5 Year Power Supply Cost Projections – Existing Resources Plus Clearwater and Renaissance					
Resource Capacity Costs $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	3780	3780	3780	3780	3780
IPP	47431	48617	49832	51078	52355
Hoover	460	460	460	460	460
Deseret	3432	1716			
Deseret Amort	3340	1670			
RA Capacity	610	1763	1471	270	541
Clearwater O&M	$ 1,226	$ 1,226	$ 1,226	$ 1,230	$ 1,226
Clearwater Renaissance	3122	3122	3122	3122	3122
ISO OP. Res.	684	684	684	684	684
ISO Regulation	1086	1086	1086	1086	1086
BPA 1	842	842	434	0	0
Total	$66,014	$64,966	$62,096	$61,710	$63,255
SONGS	**2009**	**2010**	**2011**	**2012**	**2013**
O&M	7464	8210	9031	9935	10928
Insurance	139	133	136	138	141
Decom Expense	3630	3351	3630	3775	3926
Taxes and Assessments	872	921	939	958	977
Nuclear Fuel Purchase	1987	1019	1332	1386	1172
Total	$14,092	$13,634	$15,069	$16,192	$17,145
Transmission $000	**2009**	**2010**	**2011**	**2012**	**2013**
Mead-Adelanto	2865	2865	2865	2865	2865
Mead-Phx	290	290	290	290	290
STS	13659	13659	13659	13659	13659
NTS	1490	1490	1490	1490	1490
SCE	2880	2880	2880	2880	2880
ISO TAC	6720	6720	6720	6720	6720
ISO FTR's/CRR's	650	650	650	650	650
ISO MLCC	1200	1200	1200	1200	1200
ISO RA MLCC	600	600	600	600	600
ISO Intrazonal Cong	600	600	600	600	600
ISO Interzonal Cong	600	600	600	600	600
ISO Wheeling Charge	604	604	604	604	604
ISO GMC	1877	1877	1877	1877	1877
ISO Other Gross	600	600	600	600	600
ISO MRTU	2040	2040	2040	2040	2040
Burb/Pasa DC	1080	1080	1080	1080	1080
LADWP Service	1075	1075	1075	1075	1075

SCE WDAT(Non TRR)	1296	1296	1296	1296	1296
Total	$40,126	$40,126	$40,126	$40,126	$40,126
Resource Energy $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	536	579	630	675	723
IPP	2481	3620	3733	3857	3958
Hoover	331	334	332	331	331
Deseret	7516	3789	0	0	0
Cal Energy Geothermal	11829	24581	24581	24648	24581
Neo Landfill	646	0	0	0	0
Badlands	340	0	0	0	0
Wintec	533	533	533	534	533
Clearwater	14938	15535	16312	17174	17984
CDWR Super	0	0	0	0	0
RERC 1,2 (Fuel)	2655	1867	1970	3031	3159
Springs Fuel	0	0	0	0	0
Total	$41,804	$50,837	$48,090	$50,251	$51,269
Additions	**2009**	**2010**	**2011**	**2012**	**2013**
HL DA Options					
Term Market					
RERC 3,4 Fuel					
Wintec Expansion					
Renaissance		16724	34569	35530	36319
Generic Baseload					
Generic Annual HL Capacity Reserves					
Spot (Un-Hedged)	10086	7672	7469	6131	8397
Total	$10,086	$24,397	$42,038	$41,661	$44,716
Wholesale Revenue $000	**2009**	**2010**	**2011**	**2012**	**2013**
Spot Market	8577	12336	10620	12827	12235
Term Market	0	0	0	0	0
ISO Wheel/Cong	1200	1200	1200	1200	1200
ISO TRR	19286	19286	19286	19286	19286
Total	$29,063	$32,822	$31,106	$33,313	$32,721
Summary $000	**2009**	**2010**	**2011**	**2012**	**2013**
Gross Cost	$172,122	$193,960	$207,419	$209,940	$216,510
Net Cost	$143,058	$161,138	$176,313	$176,627	$183,789
Annual Reserve Marg.	0.0%	0.0%	0.0%	0.0%	0.0%

Spot Energy Buy %	5.3%	3.7%	3.5%	2.7%	3.4%
Spot Energy Sell %	7.1%	9.9%	8.5%	10.3%	9.7%
Pct Renewable wo/REC's	0%	0%	0%	0%	0%
Average Cost	$57.8	$64.0	$69.3	$68.8	$70.5

5 Year Power Supply Cost Projections - Clearwater/Renaissance and Gas Units					
Resource Capacity Costs $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	3,780	3,780	3,780	3,780	3,780
IPP	47,431	48,617	49,832	51,078	52,355
Hoover	460	460	460	460	460
Deseret	3,432	1,716			
Deseret Amort - Gas 2102	3,340	1,670		1,800	1,800
RA Capacity	610	1,763	1,471	-	-
Clearwater O&M	1,226	1,226	1,226	1,230	1,226
Clearwater Renaissance	3,122	3,122	3,122	3,122	3,122
ISO OP. Res.	684	684	684	684	684
ISO Regulation	1,086	1,086	1,086	1,086	1,086
BPA 1	842	842	434	-	-
Total	$66,014	$64,966	$62,096	$63,240	$64,514
SONGS	**2009**	**2010**	**2011**	**2012**	**2013**
O&M	7,464	8,210	9,031	9,935	10,928
Insurance	139	133	136	138	141
Decom Expense	3,630	3,351	3,630	3,775	3,926
Taxes and Assessments	872	921	939	958	977
Nuclear Fuel Purchase	1,987	1,019	1,332	1,386	1,172
Total	$14,092	$13,634	$15,069	$16,192	$17,145
Transmission $000	**2009**	**2010**	**2011**	**2012**	**2013**
Mead-Adelanto	2,865	2,865	2,865	2,865	2,865
Mead-Phx	290	290	290	290	290
STS	13,659	13,659	13,659	13,659	13,659
NTS	1,490	1,490	1,490	1,490	1,490
SCE	2,880	2,880	2,880	2,880	2,880
ISO TAC	6,720	6,720	6,720	6,720	6,720

ISO FTR's/CRR's	650	650	650	650	650
ISO MLCC	1,200	1,200	1,200	1,200	1,200
ISO RA MLCC	600	600	600	600	600
ISO Intrazonal Cong	600	600	600	600	600
ISO Interzonal Cong	600	600	600	600	600
ISO Wheeling Charge	604	604	604	604	604
ISO GMC	1,877	1,877	1,877	1,877	1,877
ISO Other Gross	600	600	600	600	600
ISO MRTU	2,040	2,040	2,040	2,040	2,040
Burb/Pasa DC	1,080	1,080	1,080	1,080	1,080
LADWP Service	1,075	1,075	1,075	1,075	1,075
SCE WDAT(Non TRR)	1,296	1,296	1,296	1,296	1,296
Total	$40,126	$40,126	$40,126	$40,126	$40,126

Resource Energy $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	536	579	630	675	723
IPP	2,481	3,620	3,733	3,857	3,958
Hoover	331	334	332	331	331
Deseret	7,516	3,789	-	-	-
Cal Energy Geothermal	11,829	24,581	24,581	24,648	24,581
Neo Landfill	646	-	-	-	-
Badlands	340	-	-	-	-
Wintec	533	533	533	534	533
Clearwater	19,419	19,141	18,480	17,889	17,392
	-	-	-	-	-
RERC 1,2,3,4 (Fuel)	3,451	2,300	2,231	3,157	2,634
Springs Fuel	-	-	-	-	-
Total	$47,082	$54,877	$50,520	$51,091	$50,151

Additions	**2009**	**2010**	**2011**	**2012**	**2013**
HL DA Options					
Term Market					
RERC 3,4 Fuel					

Wintec Expansion					
Renaissance		16,724	34,569	35,530	36,319
Gas 2012	-	-	-	6,686	14,082
Generic Annual HL Capacity Reserves					
Spot (Un-Hedged)	13,112	9,453	8,462	3,115	2,440
Total	$13,112	$26,178	$43,031	$45,331	$52,841

Wholesale Revenue $000	**2009**	**2010**	**2011**	**2012**	**2013**
Spot Market	15,334	21,980	17,985	26,470	29,016
Term Market	-	-	-	-	-
ISO Wheel/Cong	1,200	1,200	1,200	1,200	1,200
ISO TRR	19,286	19,286	19,286	19,286	19,286
Total	$35,820	$42,466	$38,471	$46,956	$49,502

Summary $000	**2009**	**2010**	**2011**	**2012**	**2013**
Gross Cost	$180,425	$199,781	$210,842	$215,980	$224,777
Net Cost	$144,606	$157,315	$172,371	$169,024	$175,275
Annual Reserve Marg.	0.0%	0.0%	0.0%	0.0%	0.0%
Spot Energy Buy %	5.3%	3.7%	3.5%	1.4%	1.1%
Spot Energy Sell %	7.1%	9.9%	8.5%	12.9%	14.4%
Average Cost	$58.4	$62.5	$67.7	$65.9	$67.3

5 Year Power Supply Cost Projections - Clearwater/Renaissance/High Gas

Resource Capacity Costs $000	2009	2010	2011	2012	2013
Palo Verde	3,780	3,780	3,780	3,780	3,780
IPP	47,431	48,617	49,832	51,078	52,355
Hoover	460	460	460	460	460
Deseret	3,432	1,716			
Deseret Amort - Gas 2102	3,340	1,670		1,800	1,800
RA Capacity	610	1,763	1,471	270	541
Clearwater O&M	1,226	1,226	1,226	1,230	1,226
Clearwater	3,122	3,122	3,122	3,122	3,122
Renaissance					
ISO OP. Res.	684	684	684	684	684
ISO Regulation	1,086	1,086	1,086	1,086	1,086
BPA 1	842	842	434	-	-
Total	$66,014	$64,966	$62,096	$63,510	$65,055
SONGS	**2009**	**2010**	**2011**	**2012**	**2013**
O&M	7,464	8,210	9,031	9,935	10,928
Insurance	139	133	136	138	141
Decom Expense	3,630	3,351	3,630	3,775	3,926
Taxes and Assessments	872	921	939	958	977
Nuclear Fuel Purchase	1,987	1,019	1,332	1,386	1,172
Total	$14,092	$13,634	$15,069	$16,192	$17,145

Transmission $000	2009	2010	2011	2012	2013
Mead-Adelanto	2,865	2,865	2,865	2,865	2,865
Mead-Phx	290	290	290	290	290
STS	13,659	13,659	13,659	13,659	13,659
NTS	1,490	1,490	1,490	1,490	1,490
SCE	2,880	2,880	2,880	2,880	2,880
ISO TAC	6,720	6,720	6,720	6,720	6,720
ISO FTR's/CRR's	650	650	650	650	650
ISO MLCC	1,200	1,200	1,200	1,200	1,200
ISO RA MLCC	600	600	600	600	600
ISO Intrazonal Cong	600	600	600	600	600
ISO Interzonal Cong	600	600	600	600	600
ISO Wheeling Charge	604	604	604	604	604
ISO GMC	1,877	1,877	1,877	1,877	1,877
ISO Other Gross	600	600	600	600	600
ISO MRTU	2,040	2,040	2,040	2,040	2,040
Burb/Pasa DC	1,080	1,080	1,080	1,080	1,080
LADWP Service	1,075	1,075	1,075	1,075	1,075

SCE WDAT(Non TRR)	1,296	1,296	1,296	1,296	1,296
Total	$40,126	$40,126	$40,126	$40,126	$40,126
Resource Energy $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	536	579	630	675	723
IPP	2,481	3,620	3,733	3,857	3,958
Hoover	331	334	332	331	331
Deseret	7,516	3,789	-	-	-
Cal Energy Geothermal	11,829	24,581	24,581	24,648	24,581
Neo Landfill	646	-	-	-	-
Badlands	340	-	-	-	-
Wintec	533	533	533	534	533
Clearwater	19,419	20,390	21,409	22,541	23,604
	-	-	-	-	-
RERC 1,2,3,4 (Fuel)	3,451	2,450	2,585	3,979	3,575
Springs Fuel	-	-	-	-	-
Total	$47,082	$56,275	$53,803	$56,565	$57,304
Additions	**2009**	**2010**	**2011**	**2012**	**2013**
HL DA Options					
Term Market					
RERC 3,4 Fuel					
Wintec Expansion					
Renaissance		16,724	34,569	35,530	36,319
Gas 2012	-	-	-	9,267	21,023
Generic Annual HL Capacity Reserves					
Spot (Un-Hedged)	13,112	10,070	9,803	3,925	3,312
Total	$13,112	$26,794	$44,372	$48,723	$60,654
Wholesale Revenue $000	**2009**	**2010**	**2011**	**2012**	**2013**
Spot Market	15,334	23,414	20,836	33,355	39,380
Term Market	-	-	-	-	-
ISO Wheel/Cong	1,200	1,200	1,200	1,200	1,200
ISO TRR	19,286	19,286	19,286	19,286	19,286
Total	$35,820	$43,900	$41,322	$53,841	$59,866
Summary $000	**2009**	**2010**	**2011**	**2012**	**2013**
Gross Cost	$180,425	$201,796	$215,466	$225,116	$240,284
Net Cost	$144,606	$157,896	$174,144	$171,275	$180,418
Annual Reserve Marg.	0.0%	0.0%	0.0%	0.0%	0.0%
Spot Energy Buy %	5.3%	3.7%	3.5%	2.0%	2.2%

Spot Energy Sell %	7.1%	9.9%	8.5%	13.2%	15.6%
Average Cost	$58.4	$64.0	$69.3	$69.3	$71.6

5 Year Power Supply Cost Projections - Renewables

Resource Capacity Costs $000	2009	2010	2011	2012	2013
Palo Verde	3,780	3,780	3,780	3,780	3,780
IPP	47,431	48,617	49,832	51,078	52,355
Hoover	460	460	460	460	460
Deseret	3,432	1,716			
Deseret Amort	3,340	1,670			
RA Capacity	610	1,763	1,471	270	541
Clearwater O&M	1,226	1,226	1,226	1,230	1,226
Clearwater	3,122	3,122	3,122	3,122	3,122
Renaissance					
ISO OP. Res.	684	684	684	684	684
ISO Regulation	1,086	1,086	1,086	1,086	1,086
BPA 1	842	842	434	-	-
Total	$66,014	$64,966	$62,096	$61,710	$63,255
SONGS	**2009**	**2010**	**2011**	**2012**	**2013**
O&M	7,464	8,210	9,031	9,935	10,928
Insurance	139	133	136	138	141
Decom Expense	3,630	3,351	3,630	3,775	3,926
Taxes and Assessments	872	921	939	958	977
Nuclear Fuel Purchase	1,987	1,019	1,332	1,386	1,172
Total	$14,092	$13,634	$15,069	$16,192	$17,145

Transmission $000	2009	2010	2011	2012	2013
Mead-Adelanto	2,865	2,865	2,865	2,865	2,865
Mead-Phx	290	290	290	290	290
STS	13,659	13,659	13,659	13,659	13,659
NTS	1,490	1,490	1,490	1,490	1,490
SCE	2,880	2,880	2,880	2,880	2,880
ISO TAC	6,720	6,720	6,720	6,720	6,720
ISO FTR's/CRR's	650	650	650	650	650
ISO MLCC	1,200	1,200	1,200	1,200	1,200
ISO RA MLCC	600	600	600	600	600
ISO Intrazonal Cong	600	600	600	600	600
ISO Interzonal Cong	600	600	600	600	600
ISO Wheeling Charge	604	604	604	604	604
ISO GMC	1,877	1,877	1,877	1,877	1,877
ISO Other Gross	600	600	600	600	600
ISO MRTU	2,040	2,040	2,040	2,040	2,040
Burb/Pasa DC	1,080	1,080	1,080	1,080	1,080
LADWP Service	1,075	1,075	1,075	1,075	1,075
SCE WDAT(Non	1,296	1,296	1,296	1,296	1,296

TRR)					
Total	$40,126	$40,126	$40,126	$40,126	$40,126
Resource Energy $000	**2009**	**2010**	**2011**	**2012**	**2013**
Palo Verde	536	579	630	675	723
IPP	2,481	3,620	3,733	3,857	3,958
Hoover	331	334	332	331	331
Deseret	7,516	3,789	-	-	-
Cal Energy Geothermal	11,829	24,581	24,581	24,648	24,581
Neo Landfill	646	-	-	-	-
Badlands	340	-	-	-	-
Wintec	533	533	533	534	533
Clearwater	19,419	19,141	18,480	17,889	17,392
CDWR Super	-	-	-	-	-
RERC 1,2 (Fuel)	3,451	2,300	2,231	3,157	4,355
Springs Fuel	-	-	-	-	-
Total	$47,081	$54,877	$50,519	$51,090	$51,873
Additions	**2009**	**2010**	**2011**	**2012**	**2013**
HL DA Options					
Term Market					
RERC 3,4 Fuel					
Wintec Expansion					
Renaissance		16,724	34,569	35,530	36,319
Renewable Baseload	-	-	-	-	9,897
Generic Annual HL Capacity Reserves					
Spot (Un-Hedged)	13,112	9,453	8,462	6,386	5,819
Total	$13,112	$26,177	$43,031	$41,916	$52,035
Wholesale Revenue $000	**2009**	**2010**	**2011**	**2012**	**2013**
Spot Market	15,334	21,980	17,985	20,842	23,970
Term Market	-	-	-	-	-
ISO Wheel/Cong	1,200	1,200	1,200	1,200	1,200
ISO TRR	19,286	19,286	19,286	19,286	19,286
Total	$35,820	$42,466	$38,471	$41,328	$44,456
Summary $000	**2009**	**2010**	**2011**	**2012**	**2013**
Gross Cost	$180,425	$199,781	$210,841	$211,035	$224,433
Net Cost	$144,605	$157,315	$172,370	$169,707	$179,978
Annual Reserve Marg.	0.0%	0.0%	0.0%	0.0%	0.0%
Spot Energy Buy	4.7%	3.2%	3.4%	2.4%	2.5%

%					
Spot Energy Sell %	7.0%	9.8%	8.5%	10.2%	12.0%
Average Cost	$ 58.42	$ 62.45	$ 67.75	$ 66.12	$ 69.05

City of Riverside
Public Utilities Department - Resources Division

2008 Power Supply
Integrated Resource Plan

Appendix E

Existing and Planned Conservation and DSM Programs

Table A: DSM Programs

Demand Side Resource Program	Customer Class Residential – R Commercial – C Industrial – I	Load Change Objective	Program Duration
Off-Peak Swimming Pool Filter Pump Use (Pool Saver Program)	R	Load Shifting	Feb 79 - present
Residential Weatherization for Seniors And Disabled (WeCare Program)	R	Strategic Conservation	Mar 83 – present
Thermal Energy Storage Incentives for Cooling Equipment Replacement (TES Program)	C / I	Load Shifting	Jan 88 – present
Non Residential Air Conditioning Replacement/New Incentive	C	Peak Clipping, Strategic Conservation	Jan 92 – present
Energy Management Technical Assistance Program	C / I	Strategic Conservation	Jul 92 – Jun 93 Dec 98 – present
Energy Management Control System	C	Strategic Conservation	Sep 99 - present
Efficient Refrigerator Incentives (Cool Rewards/ Energy Star)	R / C	Strategic Conservation	Jan 92 – Jun 94 Dec 98 – Jun 02
Residential/Commercial Air Conditioner Replacement Incentive (Cool Cash)	R / C	Peak Clipping	Jan 88 - Jun 96 Dec 98 – present
Low Income Weatherization program For Electrically Heated Dwellings	R	Strategic Conservation	Jul 96 – Jun 02

(Mandated by CA SB 1601)			
Energy Efficient Lighting	C / I	Strategic Conservation	Dec 98 – present
Outdoor Security Lighting	C / I	Strategic Conservation	Dec 98 – 02
Energy Efficiency for Motors Program	C / I	Strategic Conservation	Dec 98 – present
Efficient Cooling Equipment Replacement & Variable Speed / Frequency Motor Drives	C / I	Strategic Conservation	Dec 98 – Jun 04 Feb 00 – Jun 04 Dec 99 – Jun 04
Energy Star Rebate Program	R / C	Strategic Conservation	Aug 00 - present
Refrigerator Recycling Program	R	Strategic Conservation	Apr 00 – present

Table B: Conservation Programs

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	13,126	15,750,028
2000-2001	15,458	16,251,065
2001-2002	19,709	30,323,821
2002-2003	20,774	31,195,162
2003-2004	23,760	33,485,807
2004- 2005	25,662	48,809,205
2005- 2006	26,593	47,075,837
2006- 2007	29,479	53,193,606
2007-2008	31,542	58,512,966
2008-2009	33,750	64,364,262
2009-2010	36,113	70,800,688
2010-2011	38,640	77,880,756
2011-2012	41,345	85,668,831

1. Off-Peak Swimming Pool Filter Pump Use (Pool Saver Program)

This program offers residential customers a $5.00 per month credit on their statement when they shift their swimming pool filter pump usage to the off-peak period. This program has an annual budget of $225, 000.

Through fiscal year 2006 - 2007 there was an average of 3,385 customers enrolled in this program. Useful life of the measures installed as part of this program is more than 30 years. Projected cumulative kilowatt capacity reductions are based on 1.13 kilowatts per participant. Kilowatt-hour reductions can be projected based on kW demand times the number of peak hours. Participant growth in this program is projected at less than 1 percent per year and decreasing.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	3,315	33,150
2000-2001	3,348	33,480
2001-2002	5,018	50,180
2002-2003	3,781	37,810
2003-2004	3,805	38,050
2004-2005	3,573	35,730
2005-2006	3,459	34,590
2006-2007	3,320	33,200
2007-2008	3,207	32,070
2008-2009	3,094	30,940
2009-2010	2,981	29,810
2010-2011	2,868	28,680
2011-2012	2,755	27,550

2. **Residential Weatherization for Seniors and Disabled** - (WECARE Program)

This program is offered as a complementary service to encourage senior and disabled residential customers to be more energy efficient. WeCare is an acronym for Wise Energy use Campaign Aid the Retired and Elderly. Senior part-time utility staff visit the home and perform an energy audit, water audit, and install weather stripping and low flow shower heads. If the water heater is electric then a water heater blanket is installed.

This program began in March 1983. From 1983 through fiscal year 2006-2007 there were 15,682 customers who had participated in this program. Useful life of the measures installed as part of this program is more than 15 years. Projected cumulative kilowatt-hour reductions are based on 561 kWh per participant. There are no associated kilowatt reductions with this strategic conservation program. Participant growth in this program is projected at around 1 percent per year with a program budget of $5,000 annually.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	NA	7,993,128
2000-2001	NA	8,073,059
2001-2002	NA	8,207,138
2002-2003	NA	8,306,435
2003- 2004	NA	8,354,681
2004- 2005	NA	8,450,051
2005-2006	NA	8,525,786
2006-2007	NA	8,609,375
2007-2008	NA	8,695,468
2008-2009	NA	8,782,423
2009-2010	NA	8,870,247
2010-2011	NA	8,958,949
2011-2012	NA	9,048,539

3. **Thermal Energy Storage Incentives for Cooling Equipment ("TES") Program**

This incentive program assists customers with funds when they consider an Off-Peak Cooling system at their existing facilities. These cooling systems can be for space conditioning as well as for process cooling applications. To help with the cost of a feasibility study, the utility will provide a 50 percent match, up to $5,000, toward the cost of a study. If the customer constructs an Off-Peak Cooling system, then the utility has an incentive of $200 per kilowatt of demand shifted from on-peak to off-peak.

Presently, there are seven Off-Peak Cooling systems in the utility service area that were installed to shift existing load from on-peak to off-peak. They are:

- University of California, Riverside campus - 3 systems
- Public Utilities Operations Center - 1 system
- Riverside Unified School District - 1 system
- Riverside City Hall - 1 system
- Riverside County Circle - 1 system

Useful life of the measures installed as part of this program is more than 30 years. Projected cumulative kilowatt reductions are based on 1,000 kW per measure installed. There are no associated kilowatt hour reductions with this load shifting program. There is no participant growth projected in this program due to the associated cost of a TES system. The budget is calculated on per project need.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	1,000	NA
2000-2001	2,000	NA
2001-2002	3,000	NA
2002-2003	3,000	NA
2003-2004	3,000	NA
2004-2005	3,000	NA
2005-2006	3,000	NA
2006-2007	3,000	NA
2007-2008	3,000	NA
2008-2009	3,000	NA
2009-2010	3,000	NA
2010-2011	3,000	NA
2011-2012	3,000	NA

4. **Non-Residential Air Conditioner Replacement Incentive**

This program offers incentives to commercial customers when they replace older, less efficient central air conditioners with new high efficiency units. Rebates ranged from $70 to $120 per ton based on size and efficiency rating of the new units.

Through fiscal year 2006-2007 there were a total of 88 customers who had participated in this program. Useful life of the measures installed as part of this program is more than 15 years. Projected cumulative kilowatt-hour reductions are based on 1,090 kWh per participant. Projected cumulative kilowatt capacity reductions are based on 1.09 kW per participant. Participant growth in this program is projected at around 1.5 percent per year with an annual budget of $50,000.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	1,090	1,090,000
2000-2001	1,101	1,101,000
2001-2002	1,112	1,139,368
2002-2003	1,150	1,261,448
2003-2004	1,163	1,274,528
2004-2005	1,190	1,301,778
2005-2006	1,192	1,332,298
2006-2007	1,195	1,387,888
2007-2008	1,213	1,408,706
2008-2009	1,232	1,429,836

2009-2010	1,250	1,451,284
2010-2011	1,269	1,473,053
2011-2012	1,288	1,495,149

5. **Energy Management Technical Assistance Program**

This program offers all commercial / industrial customers a comprehensive energy audit using a software program designed specifically for businesses. Demand rate and Time of Use customers can receive the services of a technical consultant in addition to the audit.

Through fiscal year 2006-2007 there were 31 customers who had participated in this program. Projected cumulative kilowatt reductions are based on 390 kW per participant. Participant growth in this program is projected around 1 percent per year with an annual budget of $100,000.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	6,240	NA
2000-2001	7,410	NA
2001-2002	8,580	NA
2002-2003	10,530	NA
2003-2004	12,870	NA
2004-2005	14,430	NA
2005-2006	15,210	NA
2006-2007	17,940	NA
2007-2008	20,451	NA
2008-2009	23,314	NA
2009-2010	26,579	NA
2010-2011	30,300	NA
2011-2012	34,542	NA

6. **Energy Management System Assistance**

This program offers all non-residential customers an incentive of 50 percent of the purchase price or $50,000 (whichever is less) for installing an energy management system that will control when the lights, heating and air-conditioning equipment, motors, etc. are turned on and off for optimal energy use.

There were three energy management systems installed during the fiscal year 2001-2002. There was a savings potential of 3,899,668 kWh. There was one additional energy management system

installed in fiscal year 2004-2005. The savings was calculated at 3,900,000 kWh. The annual budget for this program is $50,000.

7. **Efficient Refrigerator Incentives (Cool Rewards Program)**

Riverside Public Utilities offers a rebate for energy efficient refrigerators purchased for residences when such purchases were made to replace an existing refrigerator. The amount of the financial incentives offered, ranging from $75 to $100, was based on the ENERGY STAR`S rating of at least 20 percent more efficient than a standard refrigerator of comparable size. The Refrigerator Rebate program has since merged with the Energy Star Program. Rebates for refrigerators can be obtained through the Energy Star Program.

The program was approved in December 1998, with active participation beginning in December 1999. Target participation is expected to be approximately 1,000 per year. Useful life of the measures installed as part of this program is more than 15 years. Projected cumulative kilowatt-hour reductions are based on 150 kWh per participant. Projected cumulative kilowatt capacity reductions are based on 0.2 kW per participant. Participant growth in the program is projected at around 5 percent a year. The program was stopped at the end of fiscal year 2001-2002 and merged into the Energy Star Rebate program. There is no associated budget with this program.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	200	150,000
2000-2001	210	300,000
2001-2002	220	490,050
2002-2003	NA	NA

8. **Residential Air Conditioner Replacement Incentives** (Cool Cash Program)

This program offers incentives to residential customers when they replace older, less efficient central air conditioners with new high efficiency units. Rebates ranged from $50 to $90 per ton based on size and efficiency rating of the new units. This program was discontinued on June 30, 1996, and started again December 1998. Program guidelines were updated to include financial incentives to participants who installed new high efficient central systems or replaced existing inefficient window units with new high efficiency central systems.

Useful life of the measures installed as part of this program is more than 15 years. Projected cumulative kilowatt-hour reductions are based on 1.090 kWh per participant. Projected cumulative kilowatt capacity reductions are based on 1.09 kW per participant. Participant growth in this program is decreasing, while cumulative growth is increasing. The annual budget of this program is $180,000.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	1,090	1,090,000
2000-2001	1,145	1,145,000
2001-2002	1,569	1,569,010
2002-2003	2,096	2,096,570
2003-2004	2,695	2,696,070
2004-2005	3,231	3,232,350
2005-2006	3,490	3,491,770
2006-2007	3,779	3,780,620
2007-2008	4349	4,347,713
2008-2009	5,001	4,999,869
2009-2010	5,751	5,749,850
2010-2011	6,613	6,612,327
2011-2012	7,604	7,604,176

9. Low Income Weatherization Program for Electrically Heated Dwellings - (Mandated by California State Assembly Bill 1601)

The utility offers a free service to low-income customers who heat their dwellings with electricity. Participants receive up to two free water-saving showerheads and a blanket for an electric water heater. It is estimated that 3,500 customers qualify at any one time for this program. This represents approximately 4 percent of the utilities total residential customers.

This program began in fiscal year 1996-1997. It is projected that 350 low-income customers will participate each fiscal year in this program. Useful life of the measures installed as part of this program is more than 15 years. Projected cumulative kilowatt-hour reductions are based on 175 kWh per participant. There are no associated kilowatt reductions with this strategic conservation program. The program was cancelled at the end of fiscal year 2001-2002 and there is no longer a budget for this program.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	NA	57,750
2000-2001	NA	115,500
2001-2002	NA	173,250
2002-2003	NA	NA

10. **Energy Efficient Lighting Program**

This program offers incentives to commercial / industrial customers when they replace older, less efficient lighting with high efficiency lighting. The incentive is 5 cents per kilowatt-hour of energy savings for one year. This program was approved in December 1998. Through fiscal year 2006-2007 there were a total of 450 customers who had participated in this program.

The energy savings under this program vary because of technology and differences in operating hours. There is a maximum incentive amount of $25,000 per customer account. Cumulative kilowatt-hour reduction in this program is projected at upwards of 17 percent per year with an annual budget of $228,000.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	NA	3,500,000
2000-2001	NA	3,535,000
2001-2002	NA	9,109,758
2002-2003	NA	11,923,336
2003-2004	NA	11,934,550
2004-2005	NA	20,384,769
2005-2006	NA	22,062,365
2006-2007	NA	26,661,555
2007-2008	NA	31,194,019
2008-2009	NA	36,497,002
2009-2010	NA	42,701,492
2010-2011	NA	49,960,745
2011-2012	NA	58,454,071

11. **Outdoor Security Lighting Program**

This program offers incentives to commercial / industrial customers when they replace older less efficient outdoor security lighting with high efficiency lighting. The incentives range from $10 - $35 per fixture. This program was cancelled at the end of fiscal year 2002-2003 and there is no associated budget with this program.

This program was approved in December 1998. The energy savings vary because of technology and differences in operating hours. The program is based on financial incentives with a goal of $50,000 per year. There is a maximum incentive amount of $500 per account. Projected energy savings can be estimated by program budget amount ($50,000) divided by financial incentive ($35 per 175-watt fixture.)

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	1.75	NA
2000-2001	1.87	NA
2001-2002	2.04	NA
2002-2003	NA	NA

12. **Energy Efficiency for Motors Program**

This program is intended to promote market transformation, which means to encourage the widespread use of the most energy efficient motors available. Incentives are offered for replacing older, inefficient motors with equipment that exceeds the federal minimum standards. Rebate amounts range from $35 for a one horsepower motor to $630 for a 200 horsepower motor. The budget is $50,000 annually for this program.

This program was approved in December 1998. The energy savings vary because of technology and differences in operating hours. The program is based on financial incentives with a goal of $75,000 per year. There is a maximum incentive amount of $20,000 per account. Cumulative kilowatt-hour reductions are projected to increase by 10 percent per year.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	NA	
2000-2001	NA	
2001-2002	NA	6,840
2002-2003	NA	13,680
2003- 2004	NA	13,680
2004- 2005	NA	17,100
2005-2006	NA	17,955
2006-2007	NA	21,195
2007-2008	NA	23,314
2008-2009	NA	25,645
2009-2010	NA	28,210
2010-2011	NA	31,031
2011-2012	NA	34,134

13**. Efficient Cooling Equipment Replacement & Variable Speed / Frequency Motor Drives**

This program offers incentives for cooling equipment replacement and variable speed / frequency motor drives. The program is designed to encourage improvements to equipment that

will increase energy efficiency and reduce the energy consumption of existing or new equipment. Cooling equipment incentives are for replacing older, inefficient chillers and refrigeration equipment. This closes the gap in cost between standard equipment and high efficiency equipment. The program target is to issue a minimum of $50,000 in incentives for energy improvements associated with chiller and refrigeration replacements and/or efficiency improvements. Variable speed/frequency motor drive incentives are based on the new unit's electrical energy reduction in relationship to the replaced unit of similar size. This is a downstream incentive program that helps reduce the cost of new equipment. The anticipated program target is to issue a minimum of $50,000 in incentives for energy improvements associated with improvements to variable speed/frequency motor drive efficiency.

This program was approved in December 1998. The energy savings vary because of technology and differences in operating hours. There is a maximum incentive amount of $50,000 per account. Participant growth in this program is projected at 1 percent per year. The program was discontinued at the end of FY 2004-2005 and there is no associated budget.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	NA	
2000-2001	NA	
2001-2002	NA	3,420
2002-2003	NA	10,260
2003- 2004	NA	34,200
2004- 2005	NA	878,954

14. **Energy Star Rebate Program**

This program offers incentives for buying new high efficiency Energy Star rated products that use less electricity than standard units of comparable size. The Energy Star Rebate program has been our most popular program through fiscal year 2006-2007 with 27,917 participants total. The annual budget for this program is $500,000.

There was a total participation of 9,861 customers in 2001-2002 with rebates totaling $3,339,997. The approximate savings based on the program participation was 3,697,875 kWh. Program growth was 197 percent over the estimated participation. There is no way to determine how much of the 3,339,875 kWh is savings as these were not necessarily replacement appliances. Cumulative kilowatt hour reduction is projected to be increased by 18 percent per year starting in Fiscal Year 2007-2008.

TIME PERIOD FY	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	NA	NA
2000-2001	NA	NA
2001-2002	NA	3,697,875
2002-2003	NA	5,559,375
2003- 2004	NA	7,075,500
2004- 2005	NA	8,440,875
2005-2006	NA	9,407,625
2006-2007	NA	10,468,875
2007-2008	NA	12,353,272
2008-2009	NA	14,576,860
2009-2010	NA	17,200,694
2010-2011	NA	20,296,818
2011-2012	NA	23,950,245

15. **Refrigerator / Freezer Recycling Program**

This program offers incentives to residential customers for recycling old operating refrigerators and stand-alone freezers picked up and transported to a recycling facility for dismantling and processing.

This program began in April 2000. Target projections are estimated to be 500 participants annually. The projected kW demand is based on kWh reduction divided by annual operating hours (8,760). Projected cumulative kilowatt-hour reductions are based on 1,656 kWh per participant, based on similar programs. Participant growth in the program is projected at around 3 percent a year with an annual budget of $150,000.

TIME PERIOD (FY)	PROJECTED CUMULATIVE KW REDUCTION	PROJECTED CUMULATIVE KWh REDUCTION
1999-2000	189	1,656,000
2000-2001	198	1,738,800
2001-2002	208	1,977,264
2002-2003	217	1,986,248
2003-2004	227	2,064,548
2004-2005	238	2,167,598
2005-2006	242	2,203,448
2006-2007	245	2,230,898
2007-2008	252	2,297,824
2008-2009	259	2,366,759

2009-2010	266	2,437,762
2010-2011	273	2,510,895
2011-2012	280	2,586,221

City of Riverside
Public Utilities Department - Resources Division
2008 Power Supply
Integrated Resource Plan

Appendix F

Acronyms and Industry Terms

AS	Ancillary Services: Services required as a function of transmitting energy. These services include Operating Reserves (Spinning and Non-Spinning Reserves), Regulation (Up and Down).
BPA	The Bonneville Power Administration: A federal power marketing agency located in the Pacific Northwest and responsible for the marketing and operation of the federal government's Columbia River hydroelectric and transmission system.
BTU	British Thermal Unit: A unit of measure for the quantity of heat required to raise the temperature of one pound of water from 60° to 61°F at a constant pressure of one atmosphere. In the power industry, this term is typically used to express quantities of natural gas. *See* MMBTU.
CEC	The California Energy Commission.
CAISO	The California Independent System Operator.
CARB	The California Air Resources Board.
CDWR	The California Department of Water Resources.
CO_2	Carbon Dioxide: The greenhouse gas of primary concern in California and included in the Kyoto Protocol's "basket" of emissions along with methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
CPUC	The California Public Utilities Commission.
CRR	Congestion Revenue Right: Financial instruments, expressed in 1 MW increments, made available by the CAISO for purchase by market participants and intended to provide a hedge against the risk of congestion costs. In effect, CRRs

act as a form of insurance that pays the CRR holder when congestion costs are incurred.

CY — Calendar Year.

DC — Direct Current.

DSM — Demand-side Management.

EIA — The federal government's Energy Information Administration.

EPS — The Emissions Performance Standard established through the passage of Senate Bill 1368.

FERC — The Federal Energy Regulatory Commission.

FY — Fiscal Year.

GED — Global Energy Decisions, Inc.: The developer of *Planning and Risk* ("PAR"), RPU's production cost model application used for the economic analysis of resources under differing market conditions.

GHG — Greenhouse Gas: Defined in the Kyoto Protocol "basket" of emissions as carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

GWh — Gigawatt-hour: One thousand megawatt-hours of energy.

HRSG — Heat Recovery Steam Generator: A boiler producing steam by using the heated exhaust gasses from a gas turbine. The steam produced by a HRSG is typically used to drive a steam turbine-generator in a combined cycle generating unit configuration.

IPP — The Intermountain Power Project: The two coal-fired generating units nominally rated at 900 MW each and located near Delta, Utah, with associated switchyard facilities. Riverside holds a 7.617% ownership-like interest in this project.

IRP — Integrated Resource Plan: Through the analysis and integration of supply- and demand-side options, a plan developed for the future supply of energy to serve projected customer requirements over a selected time horizon.

kWh — Kilowatt-hour: One thousand watt-hours of energy.

LC — Local Capacity Requirement: The requirement imposed by the CAISO providing that Load Serving Entities supply physical generating capacity in a designation portion of the ISO Controlled Grid to support reliable grid operations. Load

Serving Entities not providing their proportionate amount of Local Capacity are charged by the CAISO for procurement of such capacity on the Load Serving Entity's behalf.

LMP — Locational Marginal Pricing: The real-time calculation of marginal prices at discrete "nodes" within a transmission system.

LSE — Load Serving Entity: An entity operating within the CAISO's markets and responsible for serving end use customer requirements.

MMBTU — One million British Thermal Units. *See* BTU.

MRTU — Market Redesign and Technology Upgrade: The CAISO's redesign of its markets. Originally referred to Market Design 2002, the process of updating the CAISO's systems, processes and procedures to accommodate a drastic revision in market operations.

MW — Megawatt: One thousand kilowatts. One MW is typically estimated to be sufficient for the instantaneous demand of 750 retail customers.

MWh — Megawatt-hour: One thousand kilowatt-hours. One MWh is typically estimated to be sufficient for the supply of energy 750 retail customers for one hour.

NERC — The North American Electric Reliability Corporation: The entity imbued by the FERC with responsibility for promulgating and enforcing electric reliability policies and standards.

NTS — The Northern Transmission System: Together, the two 345 kV transmission lines between the Intermountain Power Project and the Mona Substation and the one 230 kV line extending between the Intermountain Power Project and the Gonder Substation.

PG&E — The Pacific Gas & Electric Company: The largest California investor-owned utility based in San Francisco and providing natural gas and electric services.

PTO — Participating Transmission Owner: A holder of transmission facilities or entitlements that has transferred Operational Control of those facilities and entitlements to the CAISO in return for reimbursement of their annual transmission revenue requirement.

PVNGS — The Palo Verde Nuclear Generating Station: The three-unit nuclear generating station having a combined capacity of approximately 3,660 MW and located 50 miles west of Phoenix, Arizona. RPU's entitlement to power from this facility totals 12 MW.

RA	Resource Adequacy: The requirement imposed by the CAISO and requiring that LSEs procure an amount of capacity equal to the LSE's projected peak demand, plus and reserve amount equal to 15% of such projected peak demand.
RERC	The Riverside Energy Resource Center, where Riverside's two 49 MW simple-cycle generating units are located.
RPS	Renewable Portfolio Standard: A standard for the procurement of renewable energy to serve retail customer requirements. Riverside's currently-adopted RPS goals are 20% of retail customer requirements by 2010, 25% by 2015, and 33% by 2020.
SCAQMD	The South Coast Air Quality Management District.
SCE	The Southern California Edison Company: The second largest California investor-owned utility based in Rosemead and providing electric services.
SDG&E	The San Diego Gas and Electric Company: The third largest California investor-owned utility based in San Diego and providing natural gas and electric services.
SONGS	The San Onofre Nuclear Generating Station: The two-unit nuclear generating station having a combined capacity of approximately 2,200 MW and near San Clemente, California. RPU's entitlement to power from this facility totals 40 MW.
SPRINGS	Riverside's four 10 MW simple-cycle gas turbine driven internal generating units.
STS	The Southern Transmission System: The ± 500 KV DC transmission line extending between the Intermountain Power Project and the Los Angeles Department of Water and Power's Adelanto Switching Station.
VAR	Value-At-Risk: The calculated cost of meeting future energy needs if those needs were met at current forward market prices.
WECC	The Western Electricity Coordinating Council: Under the direction of the NERC, the Regional Reliability Council responsible for promulgating and enforcing its own system reliability policies and standards, and for enforcing those of the NERC.