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Abstract

This report presents a detailed overview of electricity supply trends in California and the Western Electricity Coordinating Council region through the year 2016. California's electricity system is physically interconnected with many local entities and embedded within a very large western interconnection. The report also provides the Energy Commission staff's review of electricity resource plans filed by California's load serving entities detailing how they expect to meet retail load obligations through the forecast period. The report identifies issues and concerns that could develop in the near future. The electricity resource assessments are the foundation for the biennial *Energy Report* for policy recommendations to the Governor, Legislature, and other state agencies.

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CHAPTER 1: INTRODUCTION

This report provides a detailed overview of California's electricity supply trends through the year 2016. The importance of ensuring adequate energy supplies to California cannot be overstated. California is the sixth largest economy in the world, and its life's blood is energy. Even relatively short power interruptions are big news in the state's increasingly energy-dependent economy. Without energy, many activities of our modern lives come to a halt.

The Energy Commission plays a key role in ensuring that Californians have the energy they need, when they need it. The Energy Commission is required to make extensive regular assessments of all aspects of statewide energy demand and supply (Public Resources Code (PRC) section 25301). These assessments are the basis for the Energy Commission's biennial *Energy Report*, which in turn becomes the foundation for policy recommendations to the Governor, the Legislature, and other agencies   Distilling these critical recommendations from complex data from numerous sources requires that the Energy Commission fully grasp the intricacies of the load trends and resource development that, together, affect the strength and reliability of the state's electric system.

California's electric system is one of the largest in the country. But despite its size, it is highly dependent upon both many local entities and the vast Western Interconnection of which it is a part. A problem in one area can quickly escalate to a problem for all, as has been graphically illustrated in several major transmission disruptions over the past few years.

This staff report summarizes four separate staff assessments into a single document:

- An electricity supply-demand five-year outlook to determine whether California's electricity system can maintain its required 7 percent operating reserve margin.

- A review of the electricity supply-demand outlooks prepared by numerous planning and power marketing organizations in the Western Interconnection region to determine whether electricity surpluses outside California will continue to be available for import.

- A summary of electricity "resource plans" submitted by 13 publicly-owned utilities and five energy service providers in California with peak loads of at least 200 megawatts (MW) in 2003 or 2004.

- An assessment of retail electricity prices from 2006 to 2016 for California customers served by investor-owned utilities, publicly-owned utilities, and energy service providers, collectively called Load-Serving Entities (LSEs).

Given the policy preferences established in the *Energy Action Plan* (*EAP*), commonly called the “loading order,” it is crucial to understand how LSEs plan to meet their future customer loads. The California Public Utilities Commission (CPUC) has direct regulatory oversight of investor-owned utilities (IOUs). The *Investor-Owned Utility Resource Plan Summary Report,* therefore, provides lots of detail on IOU Resource Plans, which were also publicly presented at an Energy Commission *Energy Report* hearing on June 29, 2005.

Publicly owned utilities (POUs) are not without oversight. Their local governing boards have both the authority and the obligation to make sure that resources are available to serve their growing customer demand. Yet they are required to publicly disclose far less information than their more regulated IOU counterparts. Energy service providers (ESPs) have great autonomy in securing electricity for their retail customers. This report strives to present a transparent understanding of POU and ESP procurement and energy delivery capability by providing a summary of their resource plans. Though today’s less regulated market provides confidentiality for some POU/ESP data, there is still much available to guide statewide reliability planning efforts.

This report also provides a short background on California’s electricity generation and transmission systems, operations, the fundamentals of LSE supply-adequacy and procurement activities, and customer choice and direct access. This primer is helpful in providing a context in an industry that has undergone monumental change after nearly a century of vertically-integrated stability.

Appendices provide additional details about California power plant additions and retirements between 2006 and 2008, summaries of the Resource Plans submitted by 13 POUs and five ESPs, and tables that examine California retail price outlook.

The major findings from these assessments were the following:

- Beyond 2006, if aging power plants retire and are not replaced, California’s electricity system will not be able to maintain the required 7 percent operating reserve margin during high-demand periods of very hot weather. Beyond 2005, if aging power plants retire and are not replaced, most of Southern California will be unable to maintain this margin even under normal temperature conditions.

- California will continue to rely heavily upon imported electricity from the Southwest and Northwest. Surplus electricity from the Southwest has been California’s main source of imported power, but that region’s explosive growth will likely absorb future surpluses. The Northwest will continue to have a large surplus of electricity capacity available for export to California and the Southwest in the summer, but a portion of this capacity will be stranded in the Northwest due to transmission constraints to the south.

- In 2006, the 21 reporting LSEs collectively expect their non-coincident peak demand to total approximately 55,800 MW. By 2016, this peak is expected to rise 7.7 percent to 60,091 MW with annual energy consumption to increase from 260,200 GWh in 2006 to 282,000 GWh in 2016.

- California investor-owned utilities expect to lose approximately one percent of their retail customer loads to publicly owned utilities by 2016, while energy service providers expect to maintain the same 5.9 percent share of the electricity market throughout the 2006-to-2016 outlook period.

- By 2016, approximately 24,000 MW of new supply resources will be needed to serve total peak requirements. These requirements would serve retail loads, maintain a 15 percent planning reserve margin, and satisfy firm sales requirements. This 24,000 MW of capacity includes power to replace both expiring supply contracts and retiring power plants.

- Retail customers of the state's investor-owned utilities can expect electricity rates to remain constant from 2006 through 2016, though their rates will remain substantially higher than rates in other western states. They will also continue to be higher than those paid by customers of the state's publicly owned utilities. If current price trends continue, however, the differences in rates between California's investor-owned and publicly owned utilities will diminish.

- Each of these trends must be recognized, explored, and planned for as California's energy appetite grows each year. Managing that growth in a way that balances the interests of consumers, energy providers, the environment, and others is the goal of this and other Energy Commission Reports.

CHAPTER 2: CALIFORNIA'S SUPPLY INFRASTRUCTURE

This chapter provides an overview of the California electricity generation and transmission system. The purpose of this chapter is to provide background information on the electricity system, recent resource development trends, relationship to the western electricity market and an outlook through 2010. This information should put the need for new electricity resources and procurement activities into perspective.

Overview of California's Electricity System

California's electricity system is a unified grid of component parts: generators, transmission lines, distribution lines and control operators. The generation component includes various generation technology types from small-scale rooftop photovoltaic systems designed to meet the needs of a household to large centralized generation stations that can meet the needs of cities. Power moves to where it is needed by a network of high- and medium- voltage transmission lines. At the distribution level, the voltage is stepped down so it can be used by consumers. Control operators are responsible for system reliability. They schedule and dispatch generation when needed and ensure that the power quality is maintained to prevent damage to electrical devices.

California's electric system was developed over the past century by investor-owned utilities (IOUs), publicly-owned utilities (POUs), irrigation districts, and independent power producers. These electricity providers have built power plants and transmission lines, and own distribution systems that cover the state, linking sources of electric energy to customers.

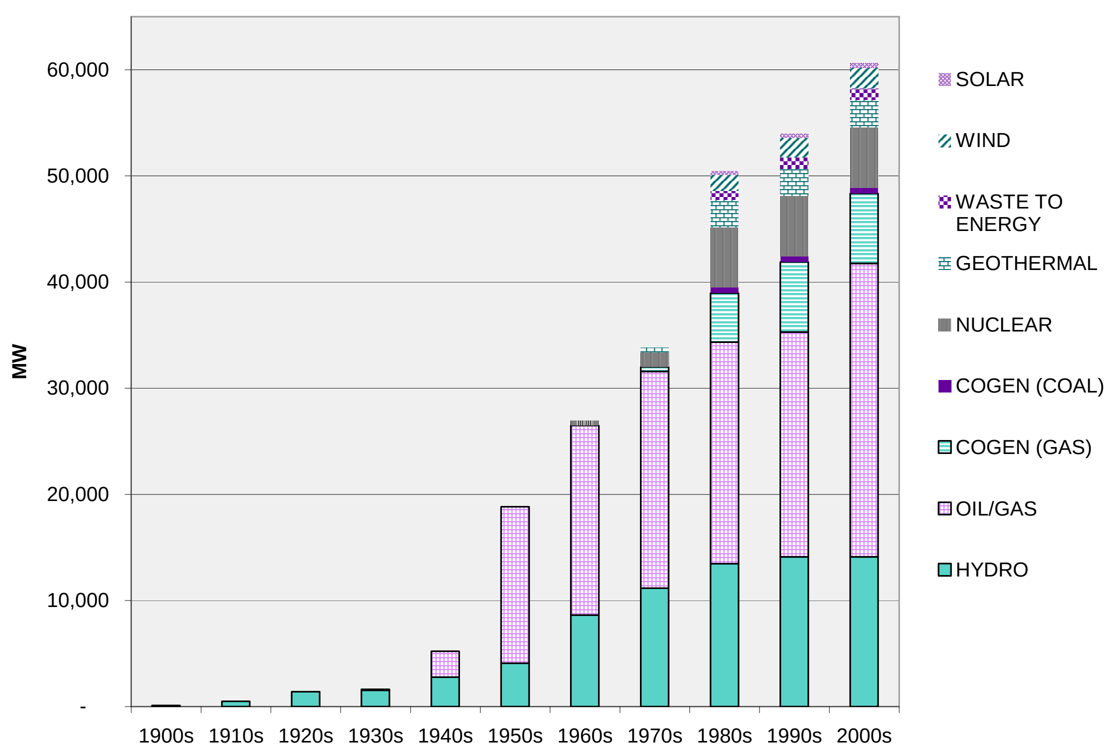
Hydro-electric and coal-fired steam turbines were the earliest generation sources in California. Hydroelectric turbines, less expensive than coal, became the dominant technology beginning at the turn of the 20th Century and peaking in the 1960s. Substantial hydroelectric pumped storage capacity was added from the late 1960s to the early 1980s. Today, most of the cost-effective sites for large hydropower projects in California have already been developed. Oil-fired power plant development began in the late 1930s and peaked in the 1950s. Since the 1970s, because of air quality concerns, fossil-fueled generation in California shifted from oil to natural gas. Most new fossil-fueled plants built in California since the 1970s use natural gas because of its lower air emissions and favorable performance attributes (economy, reliability and ease of dispatch).

From the late 1960s to the mid 1980s, four nuclear power plants (Diablo Canyon, San Onofre, Humboldt and Rancho Seco) were added to California's utility system, though two (Humboldt and Rancho Seco) have since been decommissioned.

The United States Congress passed the Public Utilities Regulatory Policies Act (PURPA) in 1978 to encourage fuel-technology diversity and reduce dependence on fossil fuels. One of the outcomes of this law was the creation of a class of generators known as qualifying facilities (QFs). QFs are independent power producers that utilize renewable technologies and/or co-generation to generate electricity. The California Public Utilities Commission (CPUC) required major investor-owned utilities, Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric (respectively PG&E, SCE, SDG&E) to sign power purchase contracts with QFs. Subsequently, during the 1980s and early 1990s, the majority of new generation was built as the result of QF contracts with cogeneration systems fueled mostly by natural gas, and renewable resources such as small hydro, geothermal, wind, biomass/landfill gas, and solar energy.

Figure 2-1 shows the cumulative capacity for different types of power plants available at the end of each decade in California since the beginning of the 20th Century.

Figure 2-1
Cumulative Generating Capacity in California by Decade and by Fuel/Technology Type (excludes retirements)



Source: US Department of Energy, Energy Information Agency EIA 860 database (2003) with updates from the Energy Commission's Electricity Analysis Office

Table 2-1 shows the online dates of power plants built in California since 2001. While 22,066 MW of capacity have been certified and approved for construction by the Energy Commission, only 13,091 MW have actually been completed since 2001. A total of 225 MW in wind capacity has been added since 2003. In addition, needed transmission upgrades have lagged and congestion has increased in certain areas of the CA ISO control area.

Table 2-1
Power Plants Built in California Since 2001

Plant Name	Name Plate Capacity (MW)	Inservice Year
Additions		
Metcalf	600	2005
Haynes	575	2005
Pastoria Phase 1	250	2005
Pastoria Phase 2	480	2005
Pico Power	147	2005
Clearwater Cogen	31	2005
Fresno Cogen Expansion	25	2005
Miscellaneous	12	2005
2005 Additions	**2,120**	
Windridge Phase 2	40	2004
Windland	20	2004
Miscellaneous	1	2004
2004 Additions	**61**	
La Paloma Generating LLC	1,200	2003
High Desert Power Plant	849	2003
Elk Hills Power LLC	623	2003
Blythe Energy LLC	591	2003
AES Huntington Beach LLC	452	2003
Sunrise Power LLC	270	2003
Los Esteros Critical Energy Center	180	2003
Tracy Peaker	169	2003
High Winds LLC	162	2003
Woodland	98	2003
THUMS	57	2003
Agua Mansa Power Plant	48	2003
Creed Energy Center	47	2003
Feather River Energy Center	47	2003
Goose Haven Energy Center	47	2003
Lambie Energy Center	47	2003
Riverview Energy Center	47	2003
Wolfskill Energy Center	47	2003
Mountain View III	22	2003
Miscellaneous	26	2003
2003 Additions	**5,030**	

Plant Name	Name Plate Capacity (MW)	Inservice Year
Additions		
Moss Landing Power Plant	1,398	2002
Delta Energy Center	944	2002
Harbor	235	2002
Henrietta Peaker	98	2002
Lake	70	2002
Whitewater Hill Wind Partners	62	2002
Valero Refinery Cogeneration Unit 1	51	2002
CalPeak Power Vaca Dixon No 1	50	2002
CalPeak Power El Cajon No 6	49	2002
King City Peaking	47	2002
Yuba City Energy Center	47	2002
Valley	47	2002
Gilroy Peaking Energy Center	45	2002
Cabazon Wind Partners	41	2002
Springs Generating Station	40	2002
Ethan Taft	25	2002
Miscellaneous	26	2002
2002 Additions	**3,276**	
Los Medanos Energy Center	678	2001
Sutter Energy Center	636	2001
Sunrise Power LLC	335	2001
Indigo Energy Facility	150	2001
Larkspur Energy Facility	100	2001
Hanford Energy Park Peaker	92	2001
Gilroy Peaking Energy Center	90	2001
Mountain View	67	2001
CalPeak Power Border	50	2001
CalPeak Power Panoche No 2	50	2001
CalPeak Power Enterprise No 7	49	2001
Chula Vista I	49	2001
Escondido Power Plant	49	2001
Gates Peaker	47	2001
Century Generating Facility	45	2001
Drews Generating Facility	45	2001
Harbor Cogen	25	2001
Fresno Cogen Partners	22	2001
Miscellaneous	27	2003
2001 Additions	**2,604**	
TOTAL ADDITIONS	**13,091**	

Source: US Department of Energy, Energy Information Agency EIA 860 database (2003) with updates from the Energy Commission's Facility Siting Office

As new capacity is added, other capacity may be retired or mothballed. Once a plant is retired, it is not expected back online. To mothball capacity means to shut down operations and physically prepare the plant for long-term storage. In 2004, several plants were mothballed. However, some recently mothballed capacity has been brought back online due to concerns about resource adequacy. For a listing of plants that have been mothballed or retired since 2001, see Table 2-2 below.

Table 2-2
Retired and Mothballed Power Plants in California Since 2001

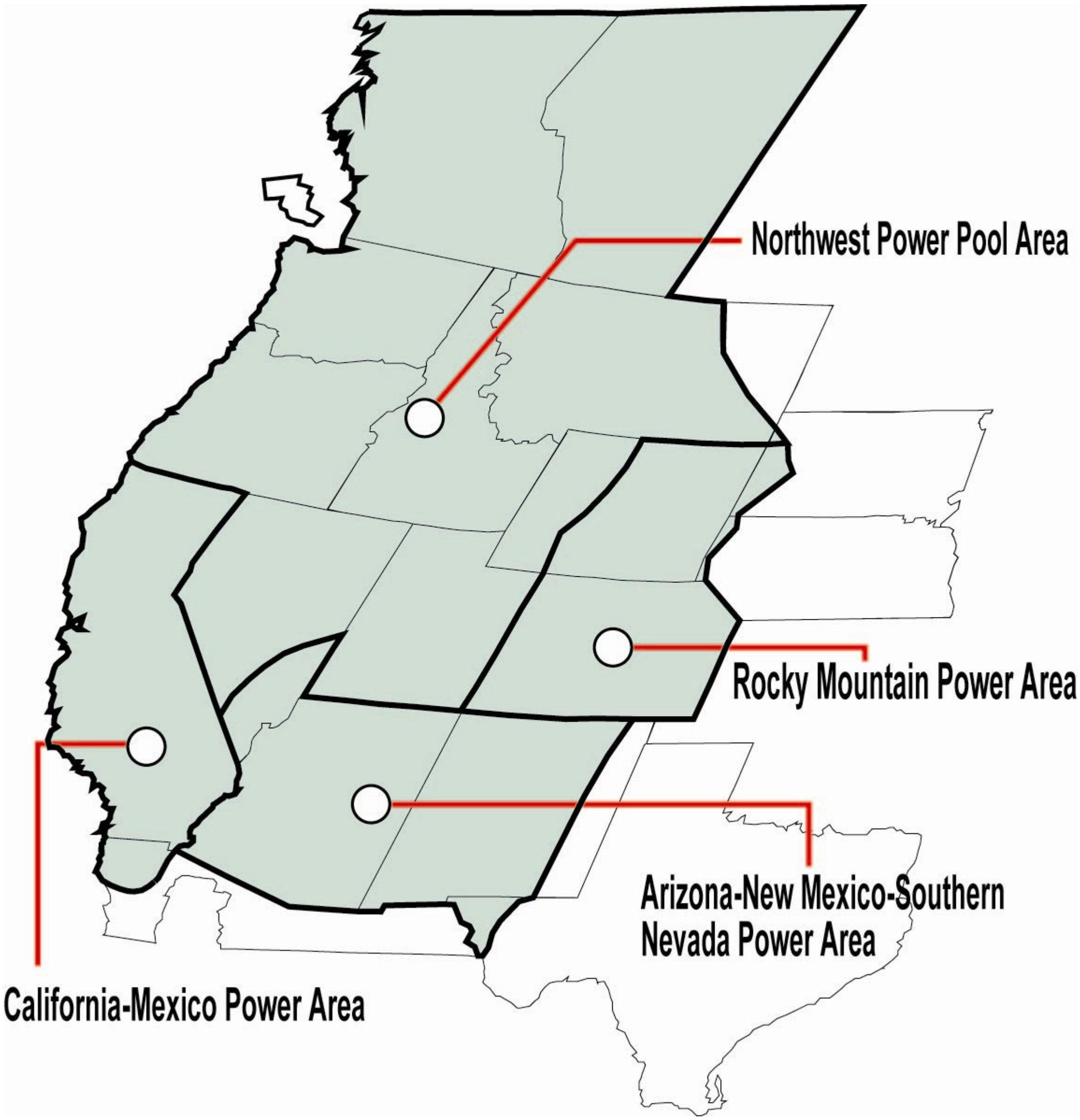
Plant Name	Name Plate Capacity (MW)	Inservice Year	Retirement Year
Retirements			
Long Beach Generation LLC	521	1976	2004
Haynes	328	1964	2004
2004 Retirements	**849**		
Pittsburg Power	680	1954	2003
Valley	346	1956	2003
Etiwanda Generating Station	246	1953	2003
Haynes	230	1965	2003
Etiwanda Generating Station	138	1969	2003
AES Alamitos LLC	133	1969	2003
Riverside Canal Power	100	1953	2003
Olive	62	1978	2003
Chula Vista I	49	2001	2003
Escondido Power Plant	49	2001	2003
Riverside Canal Power	40	1955	2003
Magnolia	23	1969	2003
Miscellaneous	26	Various	2003
2003 Retirements	**2,122**		

Plant Name	Name Plate Capacity (MW)	Inservice Year	Retirement Year
Retirements			
El Segundo Power	312	1956	2002
Mountainview Power LLC	131	1958	2002
Magnolia	55	1953	2002
Broadway	46	1957	2002
Broadway	46	1955	2002
North Island	37	1972	2002
Coidgen	33	1986	2002
Growgen	33	1986	2002
Grayson	31	1974	2002
Naval Station	26	1976	2002
Miscellaneous	58	Various	2002
2002 Retirements	**807**		
Patio Test Cell Solar Turbi	4	2000	2001
Patio Test Cell Solar Turbi	6	1995	2001
Humboldt Pulp Mill	28	1966	2001
2001 Retirements	**39**		
Mothballed Plants			
Morro Bay Power Plant	169	1956	
Morro Bay Power Plant	169	1955	
Total Mothballed	**338**		
Total Retirements	**3,817**		

Source: U.S. Department of Energy, Energy Information Agency EIA 860 database (2003) with updates from the Energy Commission's Facility Siting Office

California's grid is interconnected with a larger grid that serves 11 western states, and parts of two countries: British Columbia and Alberta, in Canada, and northern Baja California Norte, in Mexico. This interconnection is mutually beneficial by allowing greater dispatch flexibility and sharing of surplus capacity. California's demand peaks during the summer, while the Pacific Northwest's demand peaks during the winter months. Because the seasonal peaks do not coincide, each system does not need to build the full capacity to meet its annual peak demand but can instead share excess seasonal capacity. By sharing seasonal surpluses of generation capacity, the Pacific Northwest gets cheaper natural gas- and coal-fired electricity from California and the Southwest when it needs it during the winter. Likewise, in the summer, inexpensive hydroelectric capacity from the Pacific Northwest is sent south to California over a system of transmission lines that interconnect control areas from British Columbia to Baja California. Figure 2-2 shows the sub-areas of the Western system as defined by the Western Electricity Coordinating Council (WECC).

Figure 2-2
Map Showing Western Electricity Coordinating Council



Source: California Energy Commission

Transmission Links Generation to Load

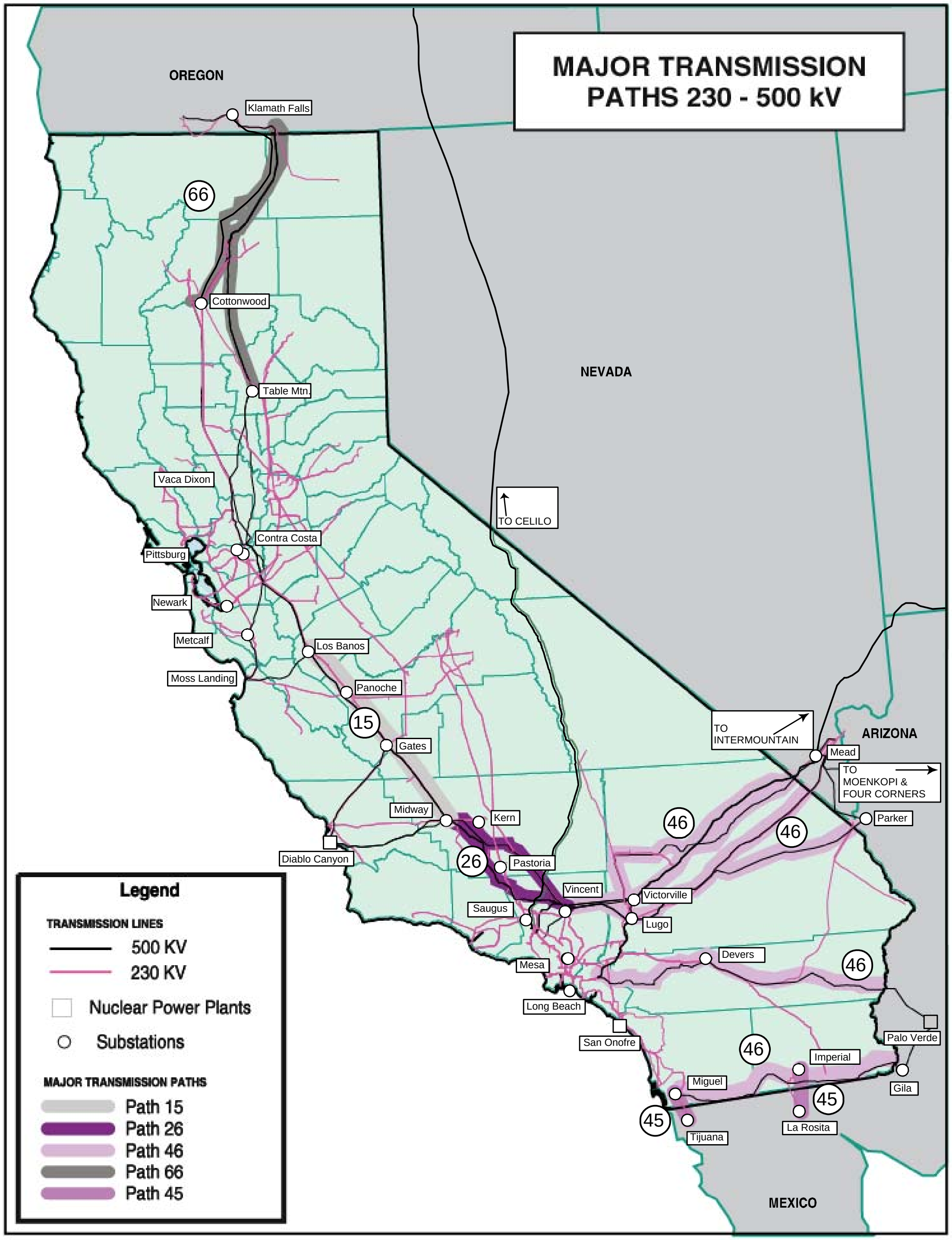
California is criss-crossed by 31,270 miles of bulk electric transmission lines, along with their supporting towers and substations. The transmission system links generation to load in a complex electrical network that balances supply and demand on a moment-to-moment basis. An efficient transmission system not only helps deliver the lowest-cost generation to consumers, but stimulates competitive market behavior, pools resources for ancillary services, and provides emergency support in the event of unit outages or natural disasters.

Most of California's electric transmission system was originally built to connect generating facilities to major load centers in the Los Angeles, San Francisco, and Sacramento areas. Thermal generating facilities, like large gas-fired and nuclear plants, were built near the coast or in nearby valleys close to load centers, requiring relatively short transmission lines. Hydroelectric facilities in the Sierra Nevada are some of the most remote sources of generation in the state. Through the late 20th Century, the state's investor-owned utilities (PG&E, SCE, and SDG&E) designed, built, and operated their own systems to meet the needs of their customers.

Until the mid-1960s, the three IOUs operated their transmission systems independently, with only a few small ties between utilities. As California's dependence on oil and gas generation increased and licensing of large generating stations became increasingly difficult, the IOUs planned and built higher-voltage, long lines to neighboring states. The 500 kV transmission lines were built primarily for importing hydroelectric power from the Pacific Northwest and thermal generation from the Southwest. While these transmission lines provided access to less costly out-of-state power, they also provided the additional benefit of emergency interconnection support among the state's utilities to avoid potential wide-scale power disruptions. Between 1968 and 1974, California utilities either built or participated in building about 3,700 miles of 500 kV lines to access remote generation. Since the 1980s only two additional 500 kV projects have been built to access out-of-state resources, and both were initiated by California municipal utilities. While IOUs have not recently built inter-state connections, they have invested in intra-state transmission upgrades to serve new load, reduce local congestion, and improve overall efficiency.

California's current bulk inter- and intra-state transmission system is shown in Figure 2-3. The map highlights the most heavily utilized paths whose expansion could provide significant benefits. The map also shows major substations and the three nuclear power plants owned by California's IOUs.

Figure 2-3
Major Transmission Paths
230 – 500 kV



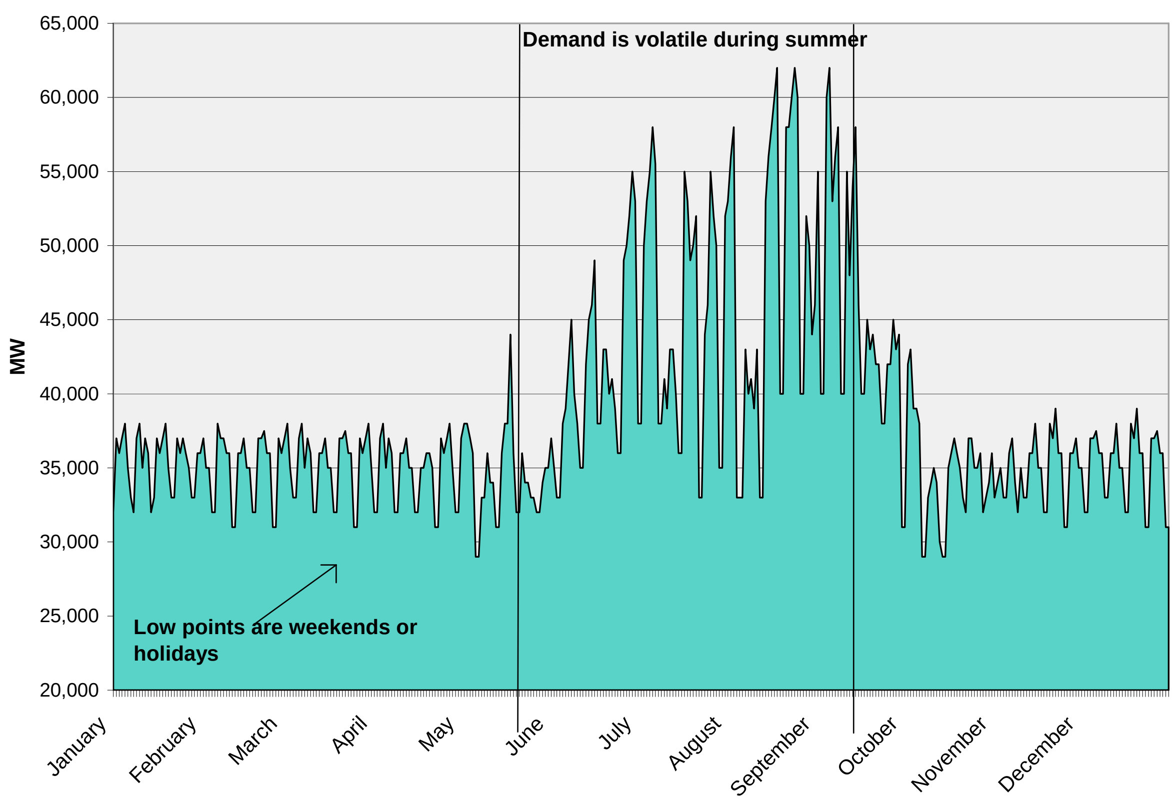
Source: California Energy Commission

Electricity Generation System Operation

California and the western states have surplus capacity available for most hours in the year. For a small number of hours, capacity that sits idle for most of the year is needed to meet peak demand.

Electricity use varies widely over the time of day and time of year. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. Because air conditioning loads drive peak demand, California sees its greatest demand spikes during the summer months (June, July, August, and September). On a hot summer day, this swing can be 85 - 90 percent. Figure 2-4 shows how peak demand changes over the course of the year. This variable load requires a generation system that is extremely flexible. The full available capacity of the system needs to be dispatched only to meet a few hours of peak demand.

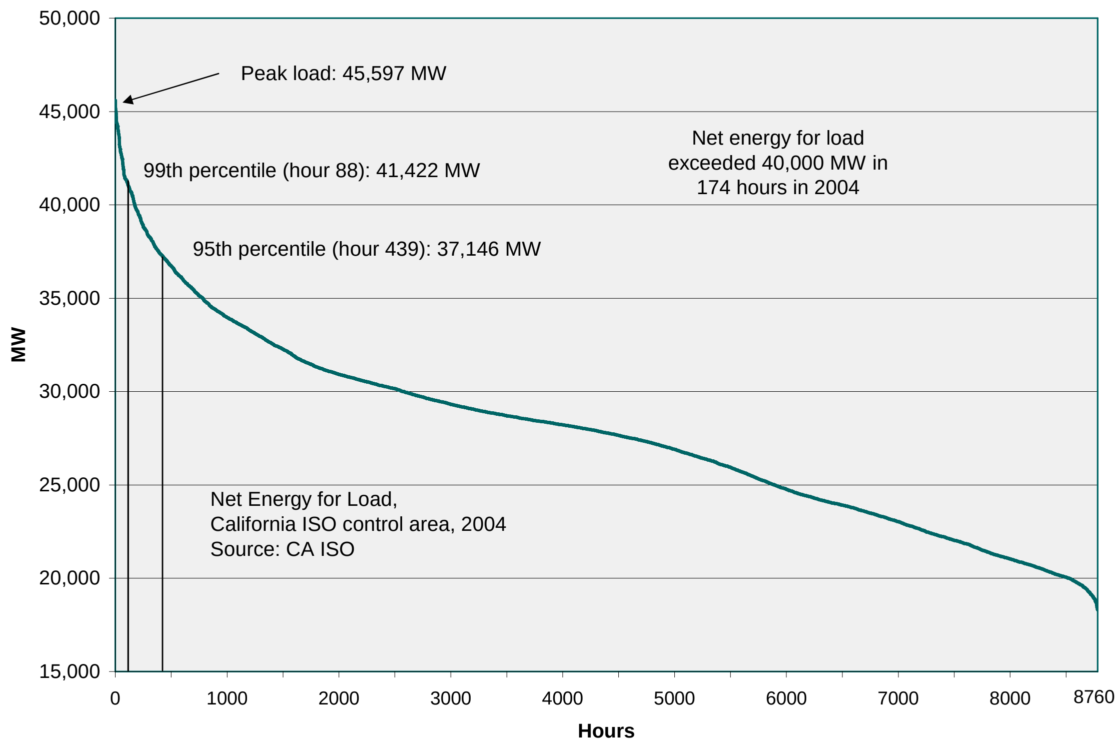
Figure 2-4
Annual Pattern of Daily Peak Demand



Source: California Energy Commission

Figure 2-5 shows the 2004 California Independent System Operator hourly demand, sorted from high to low levels; this chart is referred to as a "load duration curve." This figure is useful in determining the number of hours when loads will be high and the types of generation needed to meet hourly demand.

Figure 2-5
CA ISO 2004 Load Duration Curve



Source: California Energy Commission and CA ISO

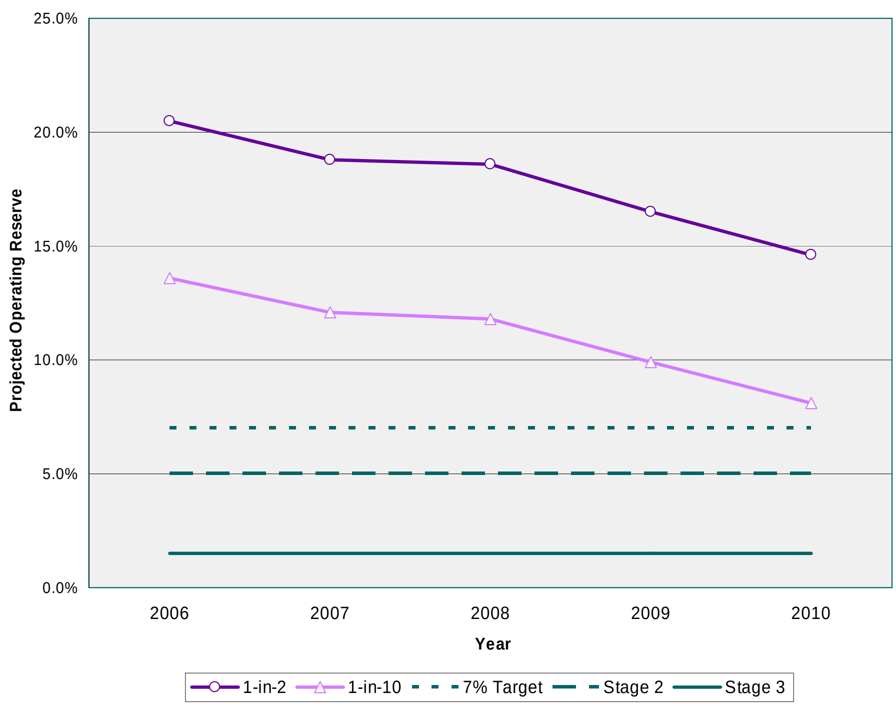
Peak electricity demand increases dramatically in the summer due to air conditioning loads. The difference in demand between an average summer day and a very hot peak day is 6 percent. This difference is equivalent to three years' average growth in statewide electricity demand. The generation system must be capable of adding or dropping generation from some facilities to accommodate the wide daily swings in demand, the high summer peaks, weather variability, and economic growth cycles.

Along with adapting to these shifts in demand and changes in consumer habits, the system must accommodate the varying availability of generation, pipelines, transmission lines, storage facilities, and fuel sources. Figure 2-4 and Figure 2-5 demonstrate the importance of demand responsiveness programs, photovoltaic technology and load management programs. Peaking power plants can provide capacity for a short amount of time during high demand periods. There is generally sufficient generation capacity available during the shoulder and off-peak periods on a hot day.

California Supply and Demand Trends: 2006–2010 Outlook

California's ability to maintain minimum required operating reserve margins over the next five years will be largely determined by its ability to reduce demand and secure the necessary resources to meet increased load due to population growth and economic expansion and to offset the possible retirements of aging power plants, particularly in Southern California. Energy Commission staff report, *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements* identified several power plants with a high risk of retirement if they do not secure contracts providing financial incentives for their continued operation.[1] Figure 2-6 and Figure 2-7 demonstrate the potential impact that high-risk retirements could have on the statewide load and resource balance if prudent actions are not taken.

Figure 2-6
Statewide Base Case Scenario

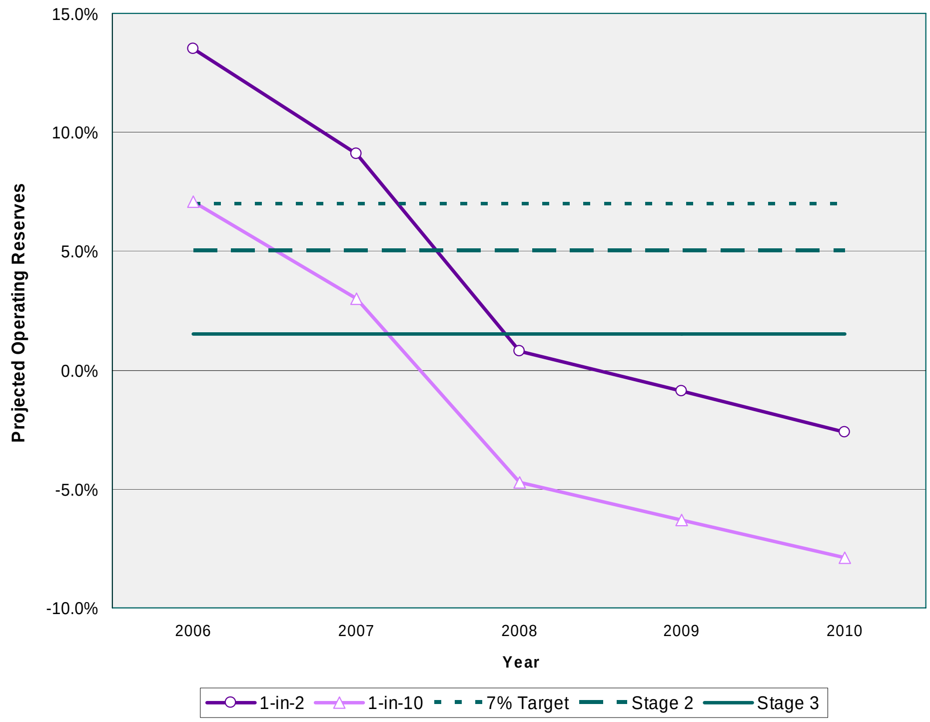


Source: California Energy Commission

The starting point for all resource assumptions used in both scenarios is the *Summer 2005 Electricity Supply and Demand Outlook – Staff Draft Report*. *California Energy Demand 2006-2016 – Staff Energy Demand Forecast (CED 2006)* provides the demand assumptions used to calculate operating reserve margins in the scenarios. The CED 2006 is currently in the *2005 Integrated*

Energy Policy Report workshop process and may change before adoption by the Energy Commission.

Figure 2-7
Statewide High Risk Retirement Scenario



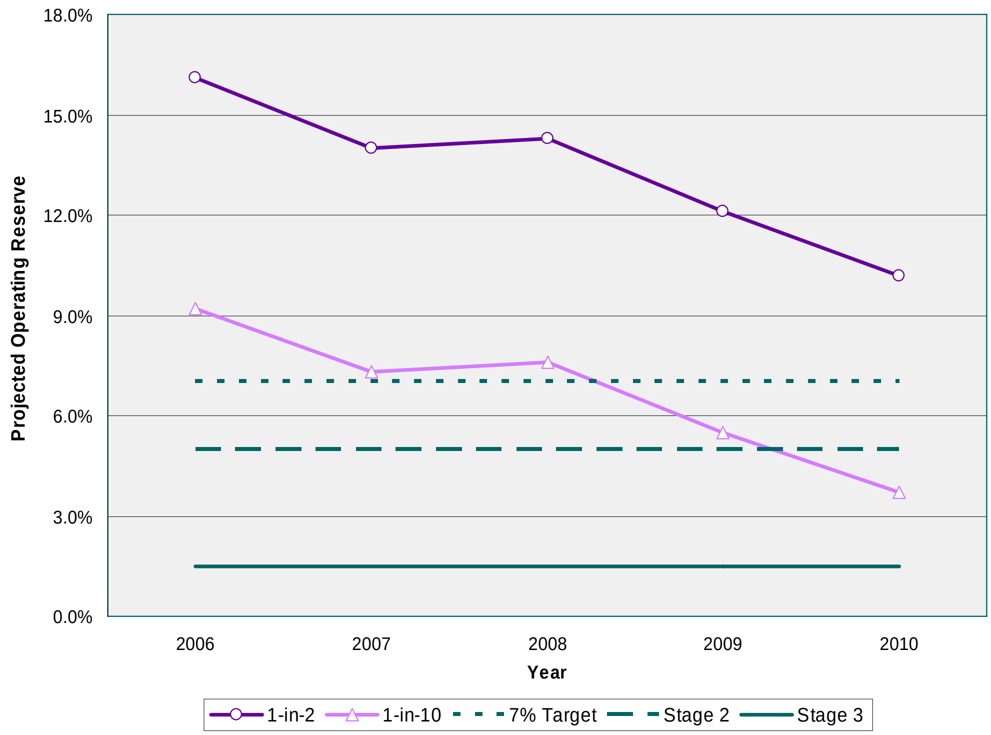
Source: California Energy Commission

The Base Case scenario did not include retirement of any high-risk plants. Using this base case, all four forecasted regions, California Statewide, CA ISO, CA ISO Southern Region (SP26) and CA ISO Northern Region (NP26) exceed the WECC Minimum Operating Reserve Criteria (MORC) of 7 percent under 1-in-2 temperature conditions through 2010. Under the adverse conditions of 1-in-10, high temperatures and above-average outages, all forecasted regions except SP26 can sustain the MORC for the entire forecast period. By comparison, under the High Risk Retirement Scenario, statewide reserve margins do meet the 7 percent requirement under the adverse conditions beyond 2006, but by 2008 the MORC cannot be sustained under average temperature conditions.

Nearly two-thirds of the plants identified as high risk are located in Southern California. Figure 2-8 and Figure 2-9 illustrate the impact of high-risk retirements on the region that currently has the smallest percentage of reserve capacity.

If high-risk retirements are not considered, projected operating reserves in SP26 exceed 7 percent until summer 2009 under hot temperature and high forced and planned outage conditions.

Figure 2-8
CA ISO SP26 Base Case Scenario

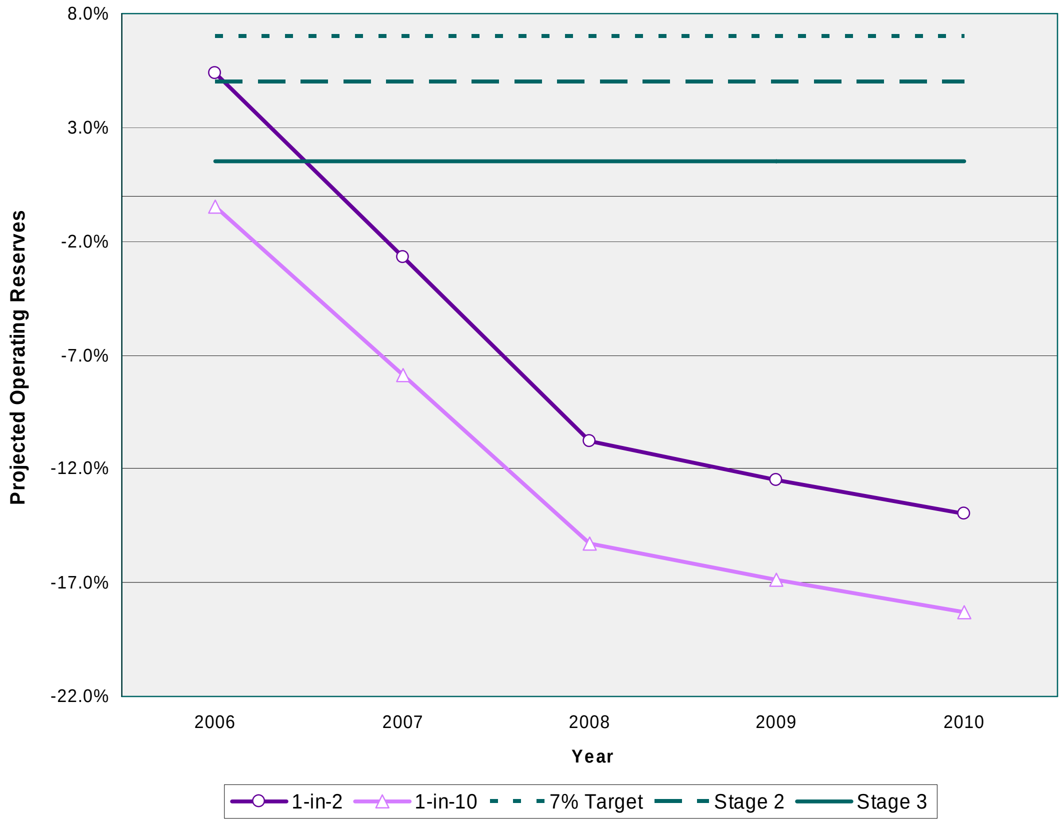


Source: California Energy Commission

Under the High-Risk Retirement Scenario, projected operating reserves could fall below 7 percent during average temperature conditions in 2006 and in the event of adverse temperature conditions; a CA ISO Stage 3 declaration and rotating outages could occur.

The Energy Action Plan Loading Order[2] has been established as the preferred method of securing resources to meet the long-term deficits created by the retirement of these aging power plants. However, in the near-term, new demand reduction programs and/or short-term contracts delaying the retirement of key high-risk facilities may be the most expedient options for maintaining the WECC minimum operating reserve margins, particularly in the Southern California Region served by the CA ISO. Table 2-3 provides a summary of the amount of capacity considered under the high-risk retirement scenario and the first year in which it is at risk to retire.

Figure 2-9
CA ISO SP26 High Risk Retirement Scenario



Source: California Energy Commission staff assessment.

Table 2-3
Summary of High Risk Retirements

	SP 26	NP 26	CA ISO	Non-CA ISO	Statewide Total
2006*	-2,240	-1,006	-3,246	0	**-3,246**
2007	-1,310	0	-1,310	0	**-1,310**
2008	-1,900	-1,983	-3,883	0	**-3,883**
Total	**-5,450**	**-2,989**	**-8,439**	**0**	**-8,439**

* Includes some high risk retirements occurring in late 2005.

Source: California Energy Commission

In determining projected operating reserves under both scenarios, several high-probability generation additions were included through 2008. A summary of these additions is included in Table 2-4. Complete listings for both tables are included in Appendix A.

The California Public Utilities Commission (CPUC) Resource Adequacy proceedings may identify additional resources to replace the capacity shortage created as the aging fleet retires. These proceedings may also identify new generation resources expected beyond 2008 that could be included in scenarios as high-probability additions.

Table 2-4
Summary of High Probability Generation Additions

	SP 26	NP 26	CA ISO	Non-CA ISO	Statewide Total
2006	1,706	366	2,072	480	**2,552**
2007	0	0	0	153	**153**
2008	550	0	550	851	**1,401**
Total	**2,256**	**366**	**2,622**	**1,484**	**4,106**

Source: California Energy Commission

In addition to the capacity listed in Table 2-4, there are nearly 8,000 MW of potential new power plants that have been sited by the Energy Commission. Development conditions for these plants have been approved, but construction is on hold for various reasons. An additional 1,100 MW of new capacity are under review, with decisions expected by early 2006. If particular facilities are contracted by utilities and construction is not delayed, they could be operational by summer 2008.

Table 2-5 lists the Net Import assumptions used in the base case and high-risk retirement scenarios. These imports are derated from the WECC Path Rating Catalog to reflect actual operating characteristics of the line. For example, the California Oregon Intertie (COI) is rated at 4,800 MW flowing north to south. However, because of operational limitations, a more realistic rating is 4,000 MW.

Table 2-5
Net Interchange Assumptions

Import Area	MW
Northwest Imports (COI)	4,000
Northwest Imports (CA ISO)	2,000
Southwest Imports	2,900
Southwest Imports (Dynamic)	1,003
LADWP Control Area Imports	2,834
IID Imports	184
Statewide Total	12,921

Source: CA ISO 2004 and Energy Commission Staff Estimate of Improvements

Several new transmission projects have been identified to increase California's future import potential; however, this forecast does not include any transmission improvements beyond those already in place by summer 2005. Improvements completed in 2005 are identified in Table 2-6 below.

Table 2-6
2005 Transmission Improvements

2005 Projects	MW
Mission-Miguel #2	~400
South of Lugo	~500
Path 26 Upgrade	~900

Source: CA ISO and California Energy Commission

Resource adequacy in California through 2010 will be influenced to a large extent by the continued operation of power plants at risk of retiring due to lack of financial incentives. If these plants are retired and their capacity is not replaced by alternative resources, California will not be able to maintain minimum required operating reserve margins beyond 2006 during periods of very hot temperatures, and the CA ISO Southern Region will fall below minimum required operating reserve margins in 2006 during normal temperature conditions.

California will continue to rely heavily upon imports from the Northwest and Southwest throughout the forecast period. Both scenarios include a robust level of imported capacity from these regions throughout the forecast period. Chapter 3 provides a more in-depth outlook of resource adequacy in these regions to better determine their ability to export surplus capacity into the California market.

CHAPTER 3: ELECTRICITY SUPPLIES IN THE WESTERN INTERCONNECTION

The Western Interconnection is an independent transmission network within the U.S. bulk power system. More than 71 million people are served by this network. Its summer peak (140,000 MW in 2003) represents approximately 5 percent of worldwide electricity demand.[3]

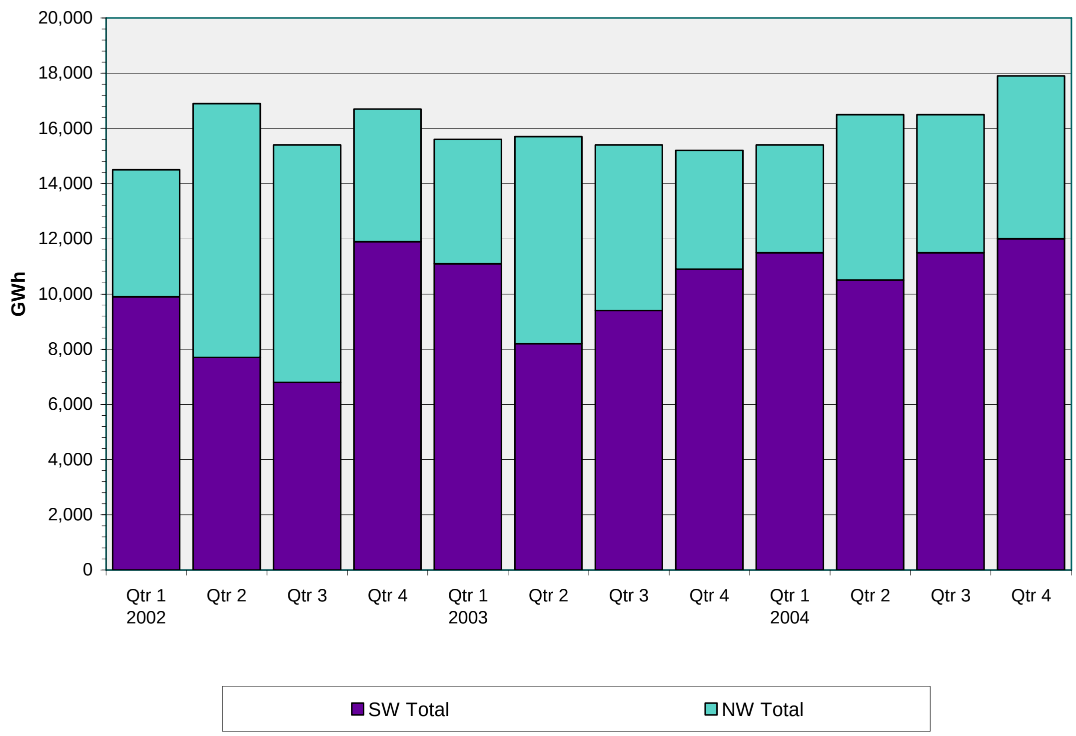
In addition to electricity generation and transmission facilities, the Western Interconnection is a network of public and private organizations interacting to ensure a reliable electricity system. There are 169 member organizations in the Western Electricity Coordinating Council (WECC)[4], including two federal power marketing agencies, state and provincial regulatory and planning agencies, and public and investor-owned electric utilities. Members of the WECC share timely information about electric loads and generation and transmission facilities.

California's only source of imported power is the WECC region because North America does not have a fully integrated transmission grid. Two sub-regions within the WECC are particularly important to California: the Pacific Northwest (including Western Canada), and the Desert Southwest. Although California utilities and independent power producers export power to the Pacific Northwest and Southwest sub-regions, this chapter focuses on California's net wholesale electricity imports. Figure 3-1 below depicts recent historical trends in net wholesale electricity imports into California from each sub-region quarterly during the past three years. Electricity imports do not include generation from out-of-state facilities that are owned by California utilities or secured under long-term contracts. The Southwest has been the largest supplier to California, except in the second and third quarters of 2002, when Pacific Northwest hydroelectricity was abundant.

Droughts in the Pacific Northwest can reduce seasonal and annual energy exports (measured in MWh) to California, but they do not prevent the Pacific Northwest from shipping short-duration peaking capacity. "Capacity" shipments are available, because the sub-region can store water behind hydroelectric dams.

The chapter is divided into three sections. The first section summarizes a power supply assessment for the WECC region and provides a table of the region's new and proposed capacity additions. The second section provides information about the Pacific Northwest, including load-growth trends, recent capacity additions, and proposed additions. The section emphasizes the role of the Bonneville Power Administration as a source of low-cost, surplus power to California. The Northwest Power and Conservation Council's power plan for the Pacific Northwest and resource plans by the region's largest LSEs are summarized. The section presents export obligations to California from U.S. Pacific Northwest suppliers, and recent historical records of exports to Western states from Western Canada. The third section presents information about the Southwest and Rocky Mountain sub-regions, including their peak demand and energy consumption load growth, recent capacity additions and proposed additions. Utility resources plans to add coal-fired generation are presented but not analyzed. Lastly, the Southwest chapter highlights the imports of low-cost power into California from the Western Area Power Administration.

Figure 3-1
Net Electricity Imports into California



Source: California Energy Commission

WECC 2005 Power Supply Assessment

WECC staff uses load and electricity infrastructure information to assess regional needs. The most recent power supply assessment, entitled *WECC 2005 Power Supply Assessment*, was published for review and comment on May 31, 2005.[5] The following is a summary of the draft report's key findings.

The Western Electricity Coordinating Council (WECC) used a deterministic load-resource model[6] to forecast if the region could be unable to meet load and maintain reserve margins during the area's peak-demand season. Although the model divides the region into 25 demand areas and transmission zones, the results of the *2005 Power Supply Assessment* were aggregated into six larger sub-regions. This summary presents the assessment's results by sub-region, but acknowledges that the "map" of the study used smaller demand areas and transmission zones. Four summer-peaking sub-regions were studied: the Rockies, Desert Southwest, Northern California, and Southern California/Mexico. The peak-demand month in all four sub-regions was assumed to be July. The winter-peaking sub-regions were Western Canada and the Northwest; their peak-demand month was assumed to be December. The analysis covered 2005 through 2014. The load-resource model simulates zones within each sub-region so that load requirements are met with both that sub-region's own generation resources and imports. Generation surpluses can be exported through a zone or series of zones to a downstream zone with a supply deficit, but the model "prefers" to give a zone's surpluses to an adjacent zone, if that zone has a deficit.

The resource adequacy of each zone was studied under six scenarios, summarized in Table 3-1 by sub-region. Two scenarios tested each zone's ability to meet forecasted load and reserve requirements[7] during the peak-demand month (Scenarios 1 and 3). Two other scenarios tested resource and reserve sufficiency under extreme temperature conditions in those same months (Scenarios 2 and 4). In Scenarios 1 through 4, Power System Design Criteria[8] (PSDC) are used as "guideline" reserve requirements. Another scenario was used to determine if each zone could meet load requirements and maintain a 15 percent planning reserve margin (Scenario 5). Finally, Scenario 6 tested whether each zone could maintain the 15 percent planning reserve margin throughout the forecast period if power plants currently in the late stages of permitting with definitive commercial operation dates were available to serve the zone's forecasted load. The 15 percent planning reserve margin used in Scenarios 5 and 6 is not related to the PSDC used in Scenarios 1 through 4.

The study included a number of conservative assumptions. Except for the final scenario, generation additions included in the analysis were limited to facilities already under "active" construction. Only new or expanded transmission projects deemed "highly likely" to be completed were included in the analysis, such as the Palo Verde-Southern California upgrades in 2007 and 2009. Peak demands for the two winter-peaking sub-regions were assumed to occur at the same time; peak demands for the four summer-peaking sub-regions were also assumed to coincide.

WECC 2005 Power Supply Assessment Results

The results were used to predict the first year in which each zone could experience a resource deficit. The results were also used to quantify the power surpluses or deficits in each sub-region under each scenario. Table 3-2 excerpts the first-year deficit results from the *2005 Power Supply Assessment* for each sub-region.

Table 3-1
WECC Scenario Descriptions

Scenario	Description
1 — Summer Peak	Evaluates if there are sufficient resources (local generation and imported capacity) in each zone to meet the forecasted July load requirements, with the load requirements increased by the applicable PSDC reserve requirements.
2 — Summer Peak	Same as Scenario 1, except that an elevated temperature condition is modeled by adding the reported load increases to the load requirements.
3 — Winter Peak	Same as Scenario 1, except that December resource capacities and load requirements are applied.
4 — Winter Peak	Same as Scenario 3, except that a temperature reduction is modeled by adding the reported load increases to the load requirements.
5 — Summer Peak	For comparison purposes, this scenario (unrelated to the PSDC reserve requirements in Scenarios 1 through 4) simulates a planning reserve margin analysis by escalating the forecasted loads by 15 percent. “Uncommitted” generation is not counted as available to meet the planning reserve margin.
6 — Summer Peak	Same as Scenario 5, except that the uncommitted generation additions are included as available capacity.

Source: WECC

Table 3-2
Year Zone Could Experience Resource Deficit.
WECC Scenario Results

Sub-Region	Scenario					
	1	2	3	4	5	6
Western Canada			2012	2008		
Northwest					2013	
Rockies	2009	2009			2009	2009
Desert Southwest	2010	2008			2008	2009
Northern California	2013	2012			2010	2011
Southern California/ Mexico	2009	2008			2008	2009

Source: WECC

A brief summary of results from the *2005 Power Supply Assessment*s for each sub-region follows:

- Western Canada (British Columbia and Alberta) might have a resource deficit starting in winter 2008 under extreme temperature conditions (a 10-degree Fahrenheit dip below normal) or in winter 2012 under the current load forecast. Throughout the forecast period, Canada will likely meet a 15 percent planning reserve margin, although its surpluses under that scenario (Scenario 5) drop from approximately 2,600 MW in 2005 to only 227 MW by 2014.

- The Northwest (Washington, Oregon, Idaho, Utah, portions of Montana and Wyoming, and northern and central portions of Nevada) can meet its forecasted loads under both current and extreme weather conditions but may not meet the 15 percent planning reserve margin, beginning in 2013. If generation currently in the permitting process is included, however, the Northwest would likely maintain surpluses exceeding 8,100 MW, above the 15 percent reserve margin through 2014.

- The Rockies (Colorado and portions of Wyoming) could have supply deficits beginning in summer 2009, under four scenarios. The first two scenarios involve load requirements under normal and extreme temperature conditions (an increase of 5 degrees Fahrenheit above normal). The other two scenarios maintain the 15 percent planning reserve margin with and without additional generation resources.

- The Desert Southwest (Southern Nevada, Arizona, and New Mexico) might experience a supply deficiency beginning in summer 2008 due to extreme hot temperatures. Under normal temperature conditions, existing supplies may be adequate to serve forecasted loads until 2010. Also in 2008, the Desert Southwest might not meet the 15 percent planning reserve margin under normal load conditions. With additional generation resources (those in the late stages of permitting), however, the Desert Southwest could meet the 15 percent planning reserve margin through 2008.

- Northern California's (North of Path 15) first supply deficit is projected to occur in 2010 due to insufficient resources to maintain a 15 percent planning reserve margin. Additional generation resources would delay that problem for one year. Other than a reserve margin shortage, Northern California's first supply deficit could occur in 2012, under extreme summer temperatures, or in 2013, with normal temperatures.

- Southern California/Mexico's (South of Path 15 and Northern Baja California) forecasted first-year supply deficits were nearly identical to those forecasted for the Desert Southwest. In 2008, the sub-region may not be able to either maintain a 15 percent reserve margin or meet load under extreme summer temperature conditions. Resource additions would delay reserve-margin shortages by one year. In 2009, the sub-region could have supply shortages in summer under the current load forecast.

- Under the two winter scenarios, none of the four summer-peaking sub-regions are projected to have supply-adequacy problems.

Under the two summer scenarios, both the Western Canada and Northwest sub-regions had resource surpluses throughout the 2005-2014 forecast period. Northwestern surpluses, however, fell below available Canadian surpluses in the last two years under extreme temperature conditions and in the last year under normal load conditions. According to the WECC report, “In all of the summer studies, a large capacity surplus in the Northwest led to the formation of transmission constraints to the south…Any remaining capacity surplus is stranded in the north by the transmission constraints.” Previous WECC assessments[9] identified this “North-South Split” caused by transmission constraints.

Under the two winter scenarios, the Desert Southwest and Southern California/Mexico sub-regions are expected to have supply surpluses throughout the forecast period. Surplus capacity in the Desert Southwest, however, was projected to be much larger than surpluses in Southern California/Mexico. Northern California has surpluses in winter for only the first two years of the forecast period. The absence of surpluses could be the result of exports (into the Northwest) of all available resources not needed to serve Northern California loads.

The results of the Energy Commission staff’s *Summer 2005 Electricity Supply and Demand Outlook*[10] differ from WECC assessment results for Southern California, because the Energy Commission used September as its peak month (instead of July) and did not include the load and resources of Northern Baja California, Mexico or the Los Angeles Department of Water and Power (LADWP). LADWP and Baja California were not included in the staff’s assessment because it is outside the California Independent System Operator Control Area.

WECC Recent and Proposed Capacity Additions

Recent and proposed generation additions for the four WECC sub-regions are shown in Table 3-3.

Capacity additions characterized as “operational” had on-line dates from spring of 2000 through May 2005. More than 40,000 megawatts (MW) of new generating (nameplate) capacity became operational during that period. Another 9,354 MW of new capacity additions have either begun site preparations or are further along in their construction. Once completed and on-line, the WECC region will have more than 49,000 MW of new capacity, most of which was installed in the California-Mexico and Southwest sub-regions.

Table 3-3
Proposed Generation Additions in WECC Sub-regions

Capacity Additions	Operational or Under Construction (MW)			Proposed (MW)				
Region	**Operational**	**Under Construction**	**Subtotal**	**Approval Received**	**Application Under Review**	**Starting Approval Process**	**Press Release**	**Subtotal**
CA-Mex	13,826	4,297	18,123	3,178	1,030	2,305	1,165	7,678
Northwest	9,540	1,769	11,309	6,456	6,373	6,020	4,743	23,592
Rocky Mountain	3,837	282	4,119	90	750	129	2,750	3,719
Southwest	12,939	3,006	15,945	2,580	1,950	2,425	1,095	8,050
WECC Total	40,142	9,354	49,496	12,304	10,103	10,879	9,753	43,039

Source: California Energy Commission[11]

Proposed capacity additions include power plants in one of four stages of development. They have: 1) received the necessary permits to build and operate, but have not yet started construction; or 2) are in the regulatory approval and permitting process; or 3) have recently begun the approval process; or 4) have been announced by the project developers in a press release that provides project details (capacity, developer, location). While it is not possible to forecast which of these proposed projects will be approved and built, those with necessary permits are the most likely to be built. Those projects that have not advanced far in the development process are less likely to be completed.

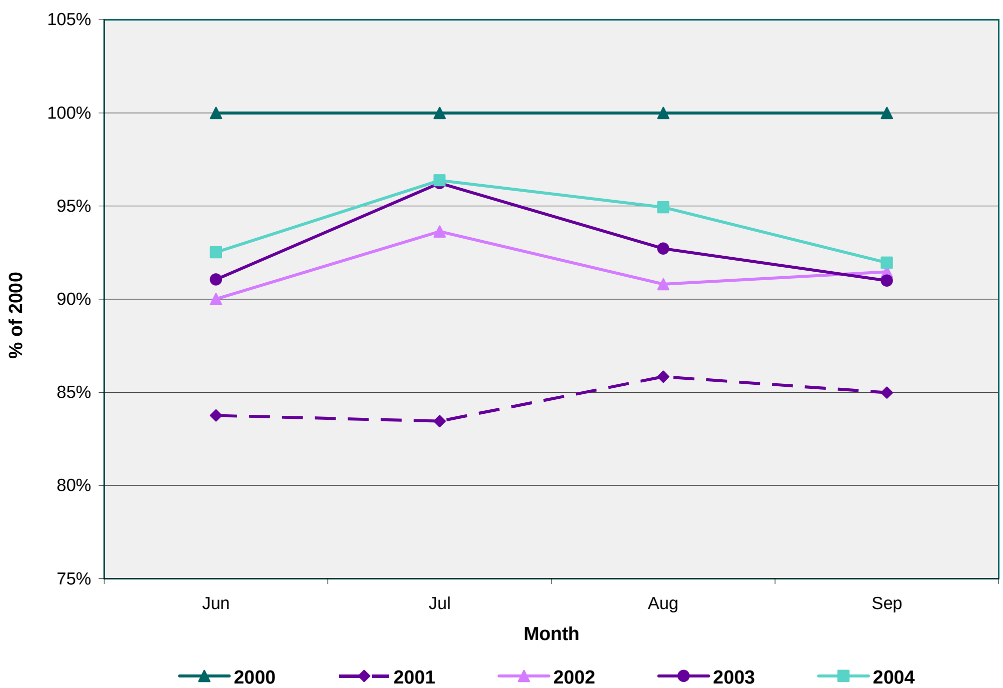
Table 3-3 does not include proposed power plants that have since been cancelled, denied permits by the lead regulatory agency, or been delayed indefinitely by the developer. For the entire WECC, the amount of proposed generation capacity that was cancelled, denied approval, or delayed indefinitely between the spring of 2000 to May 2005 is approximately 65,000 MW. Nearly 16,000 MW of this cancelled or indefinitely-postponed capacity had received the necessary approvals, and approximately 2,400 MW were under construction.

The Pacific Northwest Region

The Pacific Northwest currently has large reserve margins, particularly in the off-peak summer months. Electric loads are beginning to rebound from the Western Electricity Crisis of 2000-2001, as illustrated in Figure 3-2. Closures of large aluminum smelters[12] and energy conservation efforts were major contributors to declines in both electric energy consumption and peak demand. Figure 3-2 plots electric consumption in summer 2000 as a baseline, then compares the baseline with the monthly consumption values set in 2001 through 2004.

Capacity additions by fuel type in the Northwest Region for years 2000-2004 are listed in Table 3-4. Major capacity additions include the Hermiston and Coyote Springs plants in Oregon, the Chehalis and Goldendale plants in Washington, and large cogeneration facilities in Canada. Wind capacity additions in Washington and Oregon include the Stateline Wind Farm.

Figure 3-2
Northwest Energy Load-Percent of Year 2000
Temperature Adjusted-U.S. Portion Only



Source: Northwest Power Pool

Table 3-4
Northwest Capacity Additions/Expansion (MW)

Year	Natural Gas	Coal	Wind/Other	Total Capacity
2000	871	0	105	976
2001	2,222	42	373	2,637
2002	2,055	25	302	2,382
2003	1,904	0	266	2,170
2004	662	125	113	900
Thru 5/2005	0	450	25	475
Total	7,714	642	1,184	9,540

Source: California Energy Commission

Bonneville Power Administration

The Bonneville Power Administration (BPA) is a federal agency based in the Pacific Northwest that markets wholesale electrical power from 31 federal dams and several other non-federal power plants. The dams and their transmission lines are called the Federal Columbia River Power System (FCRPS). BPA provides approximately 40 percent of the region's power. It also operates and maintains approximately three-fourths of the region's high-voltage transmission. This high-voltage system transmits power from both federal and non-federal electricity generating units and connects the Pacific Northwest to Canada, California, Utah, and other states to the south and east.

BPA earns its primary revenues from selling "firm" (delivery-guaranteed) power from the FCRPS. According to federal law, publicly owned utilities and other entities in the U.S. Pacific Northwest have priority rights to electricity produced at federal dams. BPA's priority customers are the publicly owned, cooperative, and tribal utilities; residential and small-farm customers of investor-owned utilities (IOUs); and "direct service industries." This last category includes companies operating large industrial facilities, such as aluminum manufacturing plants. BPA also sells power to federal agencies in the Northwest.

Most of the precipitation in the Columbia River Basin falls as snow in winter. In the spring and early summer, about 60 percent of the natural runoff comes from melting snow. Some of this water passes through "run-of-river" hydroelectric dams at nearly the same rate it enters the reservoirs behind the dams. Other portions of the flow are captured in reservoirs and stored until the late summer, fall, and winter. Water is released from storage reservoirs for power generation throughout the year, but electricity demand in the region reaches a peak in winter due to widespread use of electric space heating. Water releases in winter not only generate needed electricity, they free up space in reservoirs for flood control of next spring's snowmelt.

In addition to flood control and power generation, an important factor governing reservoir operations is the need to help restore stocks of salmon and sturgeon in the Columbia River. A “biological opinion” issued periodically by the National Marine Fisheries Service ensures that maximum amounts of stored water are available for fish flows every season. This has the effect of reducing the amount of water that can be emptied from a storage reservoir to generate power, or passed through the “run-of-river” turbines. Many Columbia River dams have bypass facilities that “spill” water in order to carry juvenile salmonids (“smolts”) safely around power plants. Providing more water for fish, however, reduces the amount of hydropower that can be generated and sold as “firm power” to BPA customers.

Table 3-5 below provides a summary of BPA’s most recent 10-year forecast of annual energy load obligations and resources in average MW.[13] The FCRPS expects to be in deficit starting in 2009 because of load growth by BPA’s public customers and the expiration of inter-regional purchases and import contracts. These projections are considered to be conservative, since they assume very low output by the federal hydroelectric system (using the worst water-supply conditions on record, 1937) and deliveries at maximum contract levels.

Table 3-5
BPA Forecast Energy Load Obligations and Resources in Average MW

Operating Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Obligations	8,911	8,839	8,460	8,413	8,373	8,523	8,532	8,437	8,661	8,494
Resources	9,320	9,307	8,527	8,433	8,315	8,454	8,347	8,310	8,187	8,316
Surplus/ Deficit	409	468	67	20	-58	-69	-185	-127	-252	-178

Source: Bonneville Power Administration

According to BPA, these forecasted load deficits could be met by any combination of the following:

- Better-than-critical water conditions due to increased water flow and water storage,
- Power purchases from new merchant plants operating in the Pacific Northwest,
- Power purchases from merchant plants operating outside the Pacific Northwest region (imports), and
- Purchases of off-system storage and exchange agreements allowing for seasonal shaping of federal hydropower with other Pacific Northwest entities or regions.

Resource Plans for the Pacific Northwest

In 1980, Congress authorized Idaho, Montana, Oregon, and Washington to form the Northwest Power and Conservation Council (NWPCC) and required the NWPCC to develop a 20-year power plan for the region every five years. Each power plan addresses the region's power system and actions to mitigate its impacts upon fish and wildlife. In May 2005, the NWPCC published *The Fifth Power Plan: A Guide for the Northwest's Energy Future*.[14] Following is a synopsis of that plan's executive summary.

The "environment" has changed since *The Fourth Northwest Conservation and Electric Power Plan* was published in 1998. Then, the "world" was composed of the BPA and regulated public and investor-owned utilities. Today, it is a mix of regulated and unregulated elements, including independent power producers (IPPs).

The Northwest continues to face "familiar" uncertainties about electric demand, hydro conditions, and forced outages of major power plants. It also faces new uncertainties, including:

- An increased role of natural gas-fired generation and volatile natural gas prices,
- An increased concern about the impact of global climate change on electricity resource choices, and
- The volatility of the wholesale electricity power market.

Key policy issues affecting the region's ability to assure an adequate, efficient, economic, and reliable power system include the following:

- Standards for resource adequacy
- Planning, funding, and operating transmission
- Interaction between power, fish, and wildlife, and
- The future role of the Bonneville Power Administration in power supply and who could replace BPA in acquiring resources for the region's many small public utilities.

The plan sets "ambitious but achievable" energy conservation targets: 700 MW between 2005 and 2009, and 2,500 MW during the 20-year planning period. It also recommends that utilities secure agreements with customers to reduce power demand by 500 MW during periods of high prices and limited supply between 2005 and 2009, and by larger amounts thereafter.

The plan incorporates both state programs and utility plans adding more than 1,100 MW of new wind generation capacity between 2005 and 2014. Up to 5,000 MW of new wind capacity would be developed through the end of the 20-year planning period. During the next five years, however, information will be gathered about the performance and cost of wind resources within the regional power system to address questions of both the ability to integrate intermittent wind into the existing power system at reasonable costs and the availability of wind resource areas that are large enough, geographically diverse, and close to transmission lines.

The plan also calls for "being prepared" to develop new fossil-fueled generation, including natural-gas and coal-fired power plants. Coal gasification generation projects could begin in 2012. If coal gasification technology fails to materialize, however, the plan indicates that 400 MW of conventional coal-fired capacity could be needed by 2013.

The plan defines an "adequate" power system as having "a high probability of being able to maintain service when the region experiences a poor water year, unexpected load growth, or the failure of some new resources to perform as planned." The NWPCC region currently has a "modest" generation surplus under critical-water conditions, due in part to a significant amount of new generation, most built by IPPs. The region's individual utilities, however, are currently in a deficit. IPP generation is available, but the region's utilities have not committed to purchase power through long-term contracts. Unless "purchased for the long term," the plan cautions that IPP generation will be sold at "market prices." In the near term, however, utilities can buy power from the wholesale electricity market, including from in-region IPPs, for less cost and lower risk than building their own power plants.

Adequate transmission is "key" for ensuring that new generating resources can deliver outputs to prospective customers. According to the plan, time is running short for resolving questions of how to plan for, build, pay for, and effectively manage the region's transmission system. It suggests that if the Grid West, Regional Representatives Group process does not succeed by the end of 2005, the region should seek "alternative means" of resolving its transmission issues.

In May 2004, the NWPPC recommended revising the Bonneville Power Administration's role in power supply. If its recommendations are adopted, many smaller public utilities could be making resource decisions in addition to BPA, investor-owned utilities and larger public utilities.

Northwest Resource Plans

A review of resource plans filed at regulatory agencies throughout the Northwest reveals that while the region as a whole is fully resourced, individual LSEs will need to acquire some resources during the next decade to meet their demands, especially during winter peak seasons. This is primarily due to load growth and contract expirations during the forecast period. Some LSEs are considering renewing contracts or entering into new purchase power agreements.

Independent power producers own approximately 3,000 MW of generation in the region. Much of this installed capacity is not committed to serving loads under long-term contracts and the IPPs lack access to transmission capacity outside the region. Many other LSEs are contemplating developing thermal generation and renewable projects in order to meet their future demand. These supply options can all be used to avoid or reduce the risks posed by drought conditions and fluctuating natural gas prices which can significantly affect the cost of short-term or spot market purchases. Northwest LSEs such as Idaho Power, Sierra Pacific Power (Nevada), and the Energy Northwest Consortium (Washington), have company-owned generation proposals in their resource plans.

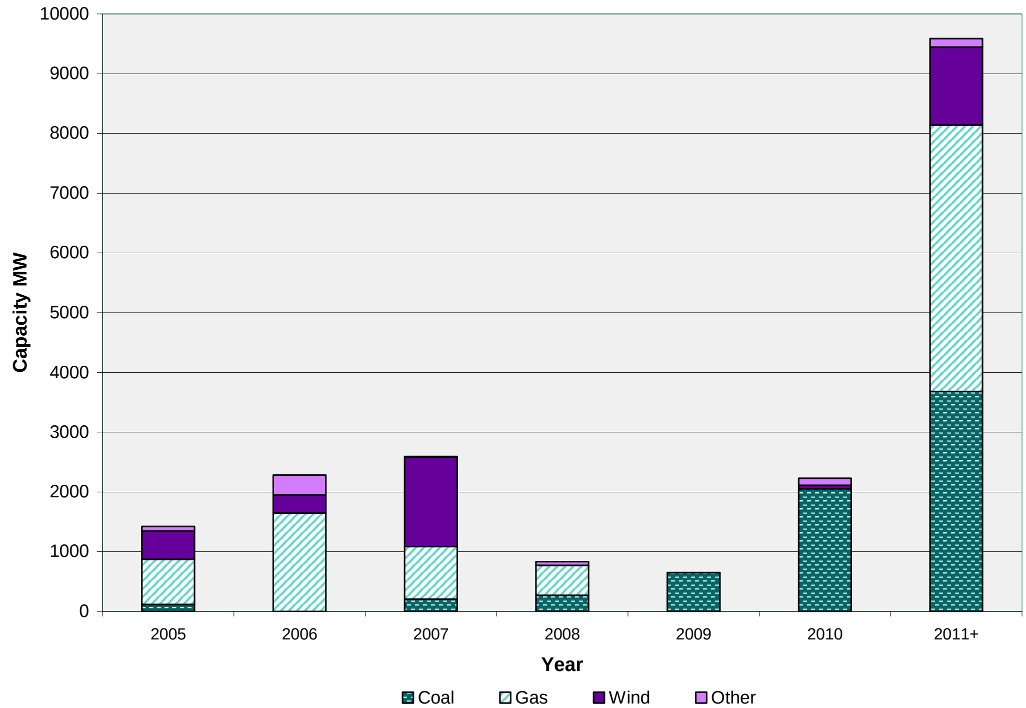
Figure 3-3 illustrates potential future capacity additions in the region. Projects included in this figure are in various stages of development, but all have applied for required permits. Many of these projects may not be developed, but the least likely to be developed are in the 2011 to 2014 category.

Natural gas-fired power plants and wind generators make up the largest share of recent additions, while coal-fired generation could represent the majority of additions in 2008 and thereafter. A detailed list of proposed projects is on the Energy Commission website at:

www.energy.ca.gov/electricity/wscc_proposed_generation.html

In addition to adding generation capacity, most LSE's are continuing with plans to implement demand-side and energy efficiency programs. Plans like these that help LSEs meet their winter peak load obligations will also help reduce summer loads, increasing the region's ability to export excess energy to California during summer months.

Figure 3-3
Proposed Future Capacity Additions-Northwest Region



Source: California Energy Commission

Northwest Energy Exports

California and the Southwest benefit from their proximity to the Pacific Northwest and their interconnection to the BPA transmission system. During high spring and summer river flows, demand for electricity in the Pacific Northwest is at its lowest and BPA likely has surplus power to sell from its run-of-river dams.

Table 3-6 below presents a breakout of BPA's and other suppliers' export-contract obligations with LSEs in the Pacific Southwest in average MW per year.[15] Other Northwest supply contractors include PPL, Portland General Electric, Puget Sound Energy, and Seattle City Light. The majority of LSEs identified by name are California public utilities (e.g., Anaheim, Burbank, Glendale, Pasadena, Riverside, Colton, SMUD), but also include the Bay Area Regional Transit District and the California Department of Water Resources. The volume of electricity committed for export to these California utilities and others decreases with time, due to contract expirations. These "surplus firm" contracts require BPA (and others) to commit a small portion of the region's surplus generation to entities outside the Pacific Northwest Region.

Table 3-6
Northwest Supplier Export-Contract Obligations in Average MW

Exports	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Pacific Southwest	660	586	399	270	186	185	180	178	160	152

Source: Bonneville Power Administration

The types of export contracts include capacity and energy sales and power exchanges. Exchange agreements establish an exchange of energy instead of a direct sale of energy or capacity. They enable utilities in California to take advantage of seasonal differences in peak loads with BPA or other Northwest suppliers. A Northwest supplier provides the California entity with capacity or energy service in summer, and in return the supplier receives energy from the California entity in winter. Such seasonal exchanges have economic benefits, including lower energy costs, and sometimes have environmental advantages including reducing the use of air-polluting thermal plants.

“Surplus firm” exports to the Pacific Southwest vary monthly. Although annual exports for the 2006 operating year were projected to be 586 average MW, monthly quantities ranged from 850 to 496 average MW, reflecting the Pacific Southwest’s higher summer demand.

During a critical-water-condition (dry) year, the FCRPS system can only generate approximately 7,000 average MW,[16] despite 22,500 MW of nameplate capacity for hydroelectric dams in the Columbia River Basin.[17] BPA limits the amount of power it will commit to deliver under power sales contracts based on this potential minimum output. When the region receives average or above-average snow and rainfall, however, hydroelectricity is available in excess of BPA’s firm-load obligations and can be sold as surplus firm and “non-firm” energy.

BPA uses the 50 water-year record to produce a long-term forecast of “secondary” energy sales. BPA fine-tunes this forecast annually with current hydrological data when it enters a new water year. Under average water conditions, approximately 2,500 average MW of surplus electricity can be generated by FCRPS. In 1997, BPA had a “great” water year. The FCRPS produced approximately 13,000 average MW and BPA marketed more than 4,600 average MW [18] of surplus power.

When water conditions are “dry,” BPA has little surplus power to sell and revenues decline. When natural gas prices are low, BPA must lower its prices to compete against gas-fired generators. During abundant water conditions, potential buyers offer to pay less for BPA power because they understand that BPA is marketing large volumes of hydroelectric supply produced by “must run” (run-of-river) resources in response to spring flood control or other non-power requirements (e.g., flows for fish outmigration). Another factor that limits BPA's surplus sales to California and other states is its limited transmission capacity.

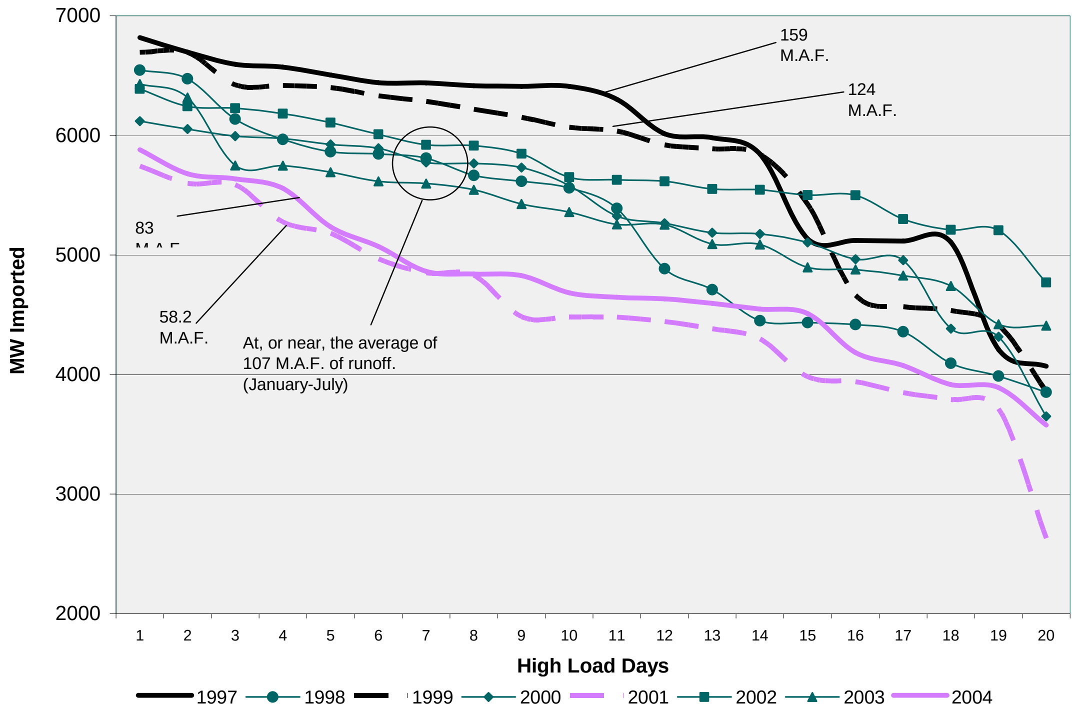
BPA offers to sell surplus power each workday, according to the following priority list of potential buyers: 1) Pacific Northwest public utilities, 2) Pacific Northwest IOUs and direct service industrial customers, 3) "Southwest" public utilities (including California), and 4) all others (e.g., California IOUs and energy service providers with direct access customers).[19] The market price for power is determined at the time of the request.

Figure 3-4 plots California electricity imports from the Northwest from 1997 through 2004 on the 20 highest peak-load days of each year. Import quantities are the highest, one-hour average on each peak day. The chart also provides labels showing hydrological run-off conditions in million acre feet (MAF) for each year. The data show imports increase during wet years.

On February, 2005, BPA published its *Policy for Power Supply Role for Fiscal Years 2007-2011.*[20] Under this new policy, BPA intends to reduce its "power acquisition role" and expects its "customers and the market to respond with the necessary electric industry infrastructure investments." Many BPA customers have power sales contracts that expire in 2011. The firm power rates for these contracts, however, expire at the end of August 2006. BPA customers sought formal assurances from BPA that they would continue to receive power at the low rate through 2011. BPA wanted to plan what it would offer under new 20-year contracts that would replace those expiring in 2011.

In particular, BPA wanted to apply "lessons learned" from the Western Electricity Crisis. The crisis taught BPA to "avoid the need to acquire large amounts of power on short notice to meet [contractual] load obligations." Under the new policy, sales of firm power would be limited to "an amount approximately equal to the firm capacity of the existing Federal system. BPA expects that firm power load service in excess of the Federal system will be provided at a higher, tiered rate that reflects the incremental cost of power purchased or acquired to meet those additional loads." BPA customers will thus be faced with choosing to pay BPA to acquire new resources or to acquire new resources themselves.

Figure 3-4
North to South Flows on Northwest Interties



Source: BPA Transmission Business Line at:
http://www.transmission.bpa.gov/orgs/opi/intertie/monthly/index.shtm

As part of the effort to implement this policy, BPA and the Northwest Power and Conservation Council initiated a "Resource Adequacy Framework for the Pacific Northwest"[21] to develop a resource adequacy "standard" and common approach to evaluate whether the region's load-serving entities have adequate generation and transmission capacity to meet their load obligations.

If the new policy and "resource adequacy" framework increase generation and transmission capacity in the Pacific Northwest, California would benefit because additions to meet winter peak demand will likely become available as surplus power for export to California and others in the Pacific Southwest in meeting their high demand summer months.

Western Canada Exports

Western Canada and the western U.S. have traded electricity since the first major international transmission line between British Columbia (B.C.) and the state of Washington was energized in the 1960s. Among all provinces, B.C. continues to be the largest electricity exporter to the western United States.

Alberta also exports relatively small amounts of electricity to Washington, Oregon, and Montana.

Table 3-7 shows recent trends in electricity exports from these two provinces to individual western states. Washington and California are the biggest importers of Canadian power. Since 2002, Oregon has also imported greater amounts of Canadian electricity. Recent imports by Oregon may be due to better hydroelectric conditions in Western Canada than in the Pacific Northwest.

California's imports declined sharply in 2003 and 2004. A number of factors could explain why California's imports fell in 2003 (e.g., access to lower-cost electricity from western U.S. sources). In 2004, California imports from Canada declined sharply because the Pacific Direct Current Intertie, which connects California to the Pacific Northwest and is the conduit for California's Canadian imports, was derated through that summer and removed from service during the fall and early winter of 2004 to allow equipment upgrades.

In the early years of data shown in Table 3-7, small quantities of power imported into Arizona, New Mexico, Utah, and Idaho were combined and reported as "Other" imports. Imports to these states, as well as to Nevada and Wyoming, have since increased and the National Energy Board (NEB) now reports them individually.

According to the NEB, firm exports have declined gradually since 1998, reflecting the shorter-term basis upon which electricity sales are now transacted while interruptible (nonfirm) sales have increased.[22] This trend is a consequence of electric industry restructuring in both the U.S. and Canada. Specifically, the reciprocity provisions of the Federal Energy Regulatory Commission (FERC) Order No. 888 opened access to transmission systems in B.C. and adjacent markets in the U.S. Pacific Northwest, California, and Alberta, significantly supporting increased trade.[23] Another contributor to this trend may be the power marketing and trading activities of Powerex Corporation.

Powerex Corporation is a wholly-owned subsidiary of BC Hydro, and is the largest exporter of electricity in the Pacific Northwest. British Columbia generates power mainly from hydro-based resources. Water levels influence the availability of hydroelectric generation and its export to the Western U.S. BC Hydro is able to store water in reservoirs during off-peak periods for generation, then export power during peak hours and peak seasons when prices are higher, a practice called "energy banking."

The majority of B.C. has been served by BC Hydro, a traditional vertically integrated utility. As part of the plan to restructure B.C.'s electric industry, however, IPPs will develop all new generation. BC Hydro will be generally restricted to improving its existing portfolio of plants, with 11,000 MW of nameplate capacity.

Table 3-7
Annual Electricity Imports from Canada
in Gigawatt-hours

Importing State	1998	1999	2000	2001	2002	2003	2004
Arizona		-		55	64	37	152
California	1,341	1,149	1,699	3,322	1,923	296	187
Colorado	1	2	11	36	7	10	37
Idaho		86		47	<1	2	33
Montana	27	18	70	-	52	11	40
Nevada	-	-	-	-	85	250	203
New Mexico		-	-	-	15	29	79
Oregon	704	473	180	151	1,477	3,121	2,523
Utah		-	-	-	9	8	-
Washington	6,869	9,081	7,933	3153	4,384	3,446	6,711
Wyoming	-	-	-	-	21	29	75
Other[24]	154	-	163	-	-	-	-
TOTAL	9,096	10,809	10,056	6,764	8,037	7,239	10,040

Source: National Energy Board[25]

The British Columbia Transmission Corporation (BCTC) now manages BC Hydro's transmission system as an independent transmission operator. BCTC operates with non-discriminatory access to the transmission system for all market participants. By creating the BCTC, IPPs are promised improved access to the B.C. grid and participation in the U.S. wholesale markets.

The extent to which exports from B.C. could increase depends upon both the growth in IPP generation relative to domestic demand and access to export markets through transmission system operations.

Electricity Exports from Alberta

Currently, the largest market for Alberta's electricity exports is B.C. Through the B.C. Intertie, Alberta and B.C. exchange electricity on a daily basis. Alberta imports power from B.C. hydroelectric power plants during peak periods, especially the late afternoon and early evening, then returns off-peak power. This power exchange enables Alberta's predominately thermal-based generation system (coal and natural gas-fired generation) to run relatively constantly and efficiently throughout the day, while B.C.'s predominately hydro-based system can operate to accommodate Alberta's peak loads and store water behind its dams at night.

Alberta's access to the U.S. electricity market is primarily through the same intertie to the B.C. transmission grid. Alberta has no direct link with the U.S. for wholesale power transfers. (There is also indirect access to the U.S. via an intertie with Saskatchewan.) In August 2004, the government of Alberta passed the Transmission Regulation (Regulation) to remove transmission constraints in Alberta and ensure that transmission is developed in a timely manner. Under the new Regulation, the Alberta Electricity System Operator was directed to "proactively plan for transmission system upgrades." Among other actions, the Regulation created a "framework…to allow for the development of merchant [transmission] lines capable of importing and exporting electricity between Alberta and neighboring jurisdictions."

In 2003, the NEB suggested that "An important development that could significantly increase Alberta exports is the surplus of electricity that could come about from cogeneration in the Fort McMurray area, which is the center of oil sands development in Alberta."[26] A recent survey of the oil sands industry revealed plans to build 30 cogeneration plants at oil sands project sites by 2014.[27] These plants will have an installed capacity of approximately 3,151 MW. Of this capacity, however, 2,375 MW would be used on-site and only 749 MW would be surplus and available for export to electricity markets. Earlier surveys of the oil sands industry by the same working group reported that 1,024 MW of this cogeneration capacity would be developed for export.

The authors of the survey gave two reasons why oil sands companies were building cogeneration capacity close to their site needs, with minimum electricity export capacity: high natural gas prices, and low prices for wholesale electricity. "Oil sands developers are focused on production of oil and are less willing to take on an additional risk of spending capital for additional cogeneration capacity…" Additional "barriers" to developing surplus electricity for export from Fort McMurray included:

- Lack of transmission access to larger export markets outside of Alberta, and

- Lack of confidence that additional [transmission] lines into and out of Fort McMurray will be constructed.

A transmission line project, called NorthernLights Transmission, has already been proposed to carry surplus electricity from the Fort McMurray oil sands-cogeneration projects into the Western U.S.[28] The project proponents' website states, "Oil sands cogeneration potential could exceed 3,500 MW by 2010. This [capacity] far exceeds expected Alberta demand - allowing more than 2,000 MW for export. NorthernLights will complement construction of the planned generation by providing the key link between the generation supply source and energy markets."

The NorthernLights project illustrates Alberta's interest in directly accessing Western U.S. markets for electricity sales. In addition, Alberta has identified the need to bring its interconnection with British Columbia up to its rated capacity, thereby providing increased access to markets outside Alberta through that route.

The Southwest and Rocky Mountain Sub-Regions

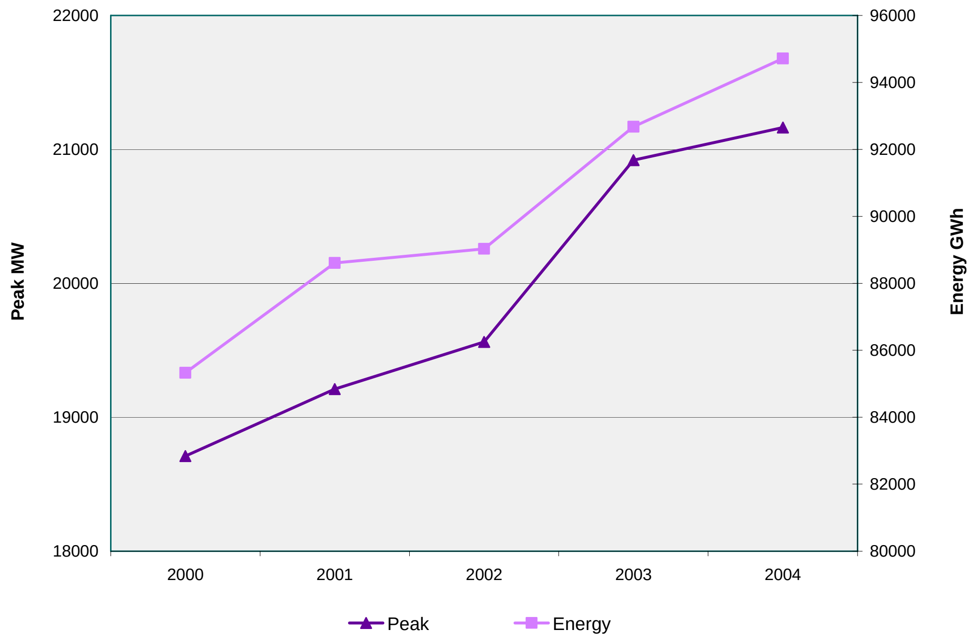
The Southwest sub-region experienced moderate-to-high load growth during the 2000-2004 time period. While the Phoenix and Las Vegas areas have had sustained levels of high population growth during the last decade, the regional outlook is not as robust.

Figure 3-5 shows summer peak and energy trends for five major LSEs in the Southwest sub-region from 2000-2004.[29] Year-to-year growth of peak loads varies from a low of 1.2 percent (2003-2004) to a high of 6.9 percent (2002-2003).

Figure 3-6 plots summer peak and energy trends in the Rocky Mountain sub-region from 2000-2004 for major LSEs.[30] Air conditioning use in the Denver area has climbed in recent years, contributing to an increase in summer peak loads.

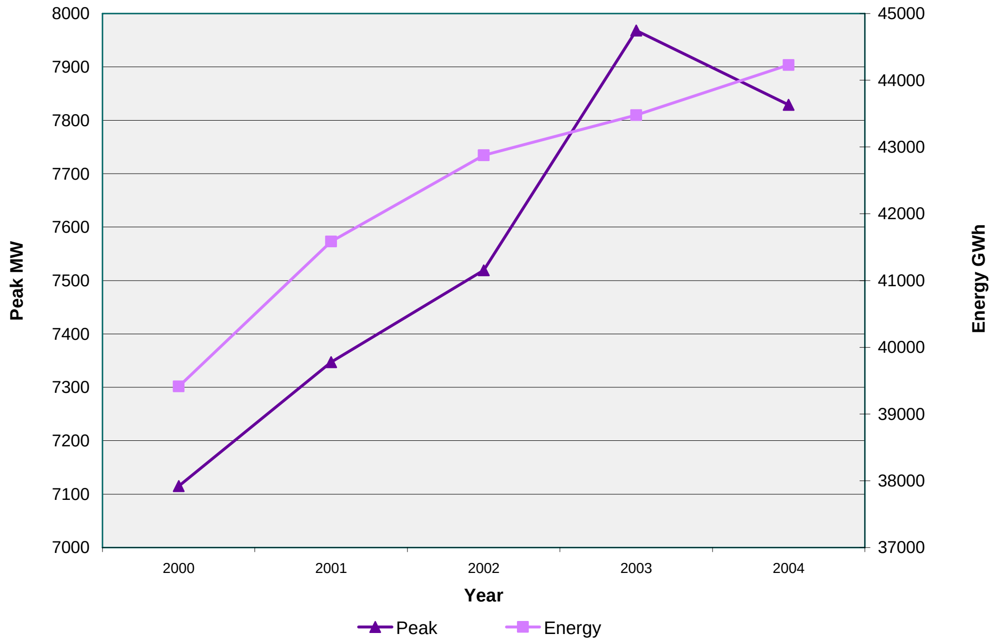
Capacity additions in the Southwest and Rocky Mountain sub-regions for years 2000-2004 are listed in Table 3-8 and Table 3-9, respectively. Nearly all the capacity additions were natural gas-fired combined-cycle units. While these units are reliable, efficient, clean-burning generators, they have become more expensive to operate since fuel costs have increased substantially since 2002.

Figure 3-5
Southwest Summer Peak & Energy
Historical Trends for Five Major LSEs



Source: California Energy Commission

Figure 3-6
Rocky Mountain Sub-Region Summer Peak & Energy Historical Trends for Major LSE's



Source: California Energy Commission

Table 3-8
Southwest Capacity Additions (MW)

Year	Natural Gas	Coal	Wind/Other	Total Capacity
2000	624	0	0	624
2001	1,481	0	0	1,481
2002	3,325	0	0	3,325
2003	5,015	0	204	5,219
2004	2,230	0	60	2,290
Total	12,675	0	264	12,939

Source: California Energy Commission

Table 3-9
Rocky Mountain Capacity Additions (MW)

Year	Natural Gas	Coal	Wind/Other	Total Capacity
2000	376	0	52	428
2001	673	0	50	723
2002	804	0	0	804
2003	780	90	306	1,176
2004	706	0	0	706
Total	3,339	90	408	3,837

Source: California Energy Commission

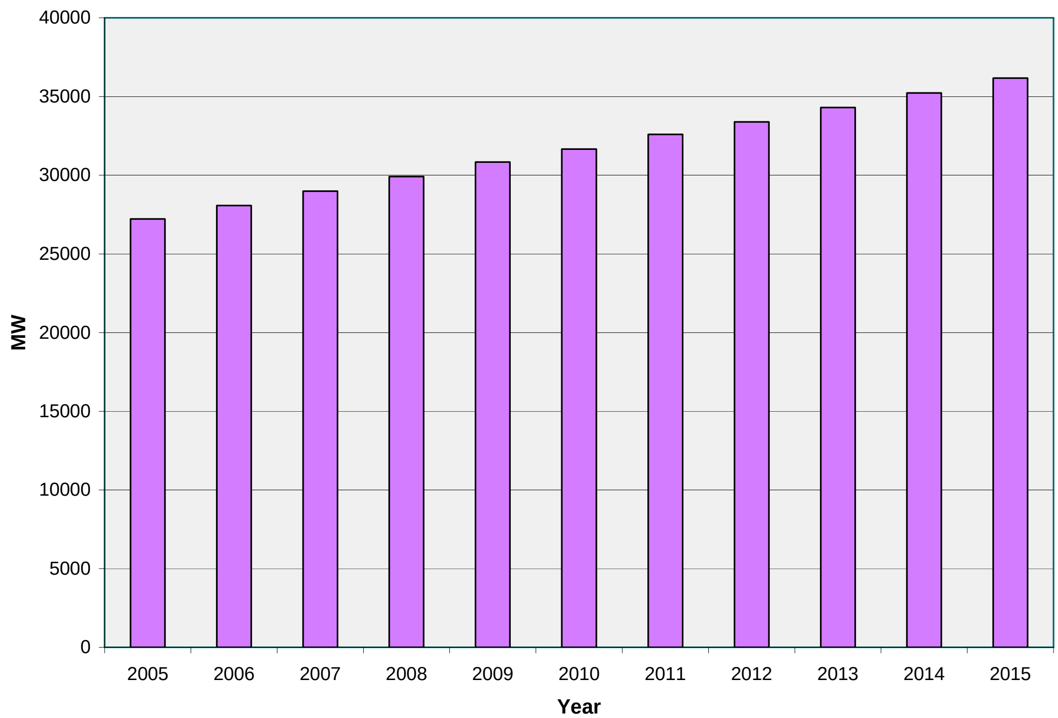
According to the Western Electricity Coordinating Council's 10-Year Coordinated Plan Summary (September 2004), regional peak load growth in the Southwest will grow at a 3.2 percent rate through 2009, at which time growth rates are expected drop below 3 percent. Summer peak demand levels are shown in Figure 3-7. For this report, load levels for 2014 and 2015 were estimated using a summer peak growth level of 2.7 percent for 2013.

Major utilities in the Southwest plan to meet load growth through a combination of generation additions and power contracts. Nevada Power Company and Public Service Company of New Mexico (and others) recently purchased partially-built power plants, Charles Lenzie and Luna, to complete and serve their loads. Nevada Power Company previously applied to the Nevada Public Utilities Commission to build a 520 MW baseload power plant and an 80 MW peaking power plant before its Lenzie acquisition. Nevada Power Company recently announced it would purchase a 75 percent share of the Silverhawk Facility (570 MW) near Las Vegas.

The Arizona Corporation Commission has restricted Arizona Public Service (APS) from building its own power plants until 2015.[31] As a result, APS is relying on contracted power to meet soaring peak demand. APS recently issued a request for proposals to provide 1,000 MW to meet peak and energy needs for a minimum of five years, beginning in 2007. Tucson Electric Power is developing the Springerville Unit 3 Power Plant (400 MW) which is expected to be online in 2006. The Salt River Project (SRP) holds all necessary permits to build Unit 4 at this facility but is waiting until market conditions are more favorable before starting construction. SRP also owns the Santan Power Plant (750 MW), which is under construction.

Proposed capacity additions for the Southwest and Rocky Mountain sub-regions are shown in Figure 3-8. The majority of these projects are proposed for the Southwest sub-region. Only the following three projects are near-term Rocky Mountain additions: two wind projects (129 MW combined) for 2005 and one coal-fired power plant (750 MW) for 2009. For the years 2005 through 2007, most additions are natural gas-fired generation or wind generation. Most proposed projects in 2008 or later are coal-fired power plants. Projects proposed for 2011+ are less likely to be completed. A detailed list of proposed projects is on the Energy Commission website at: www.energy.ca.gov/electricity/wscc_proposed_generation.html.

Figure 3-7
Southwest Summer Peak Load



Source: WECC 10 Year Report (9/04)

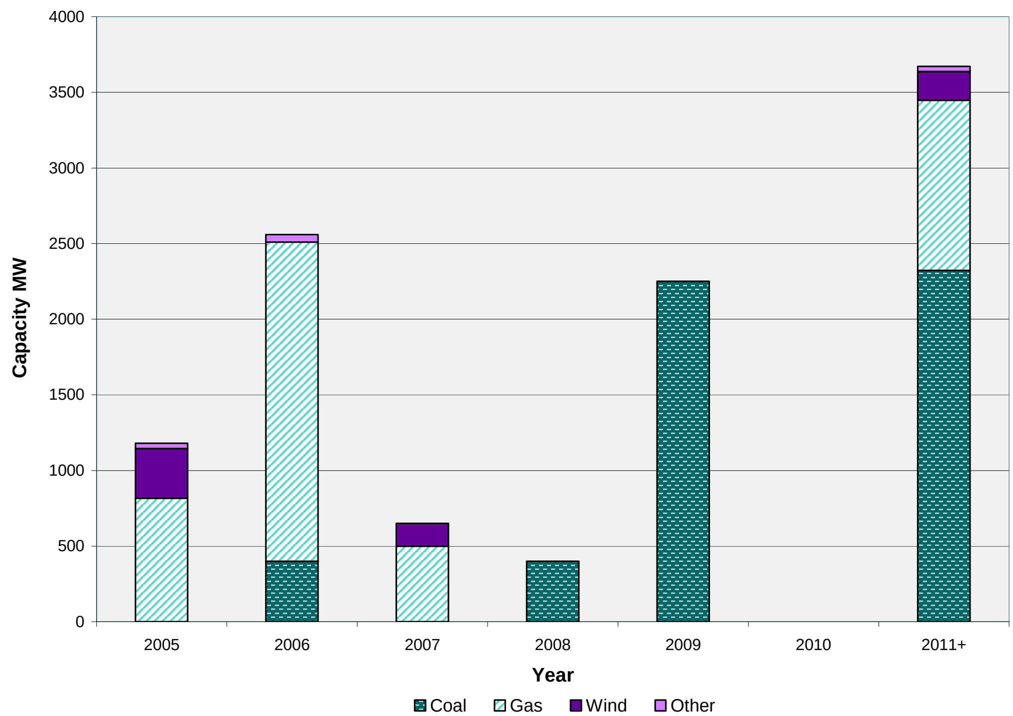
The WECC estimates that the Rocky Mountain sub-region should experience annual summer peak load growth rates at around 2.5 percent through the forecast period. Summer peak demand levels are shown in Figure 3-9. For this report, load levels for 2014 and 2015 were estimated using summer peak growth level of 2.6 percent for 2013.

The single largest LSE in Colorado, Xcel Energy, issued a least-cost resource plan. The plan identifies the need to secure approximately 3,600 MW of resources by 2013. Approximately 1,600 MW of these resources can be obtained through contract renewals, but the remaining capacity must come from new generation. Solicitations for renewable energy resources and “all source” resources have already been issued. Xcel Energy is also planning to build a 750

MW addition to the Comanche coal-fired facility to meet 20 percent of its forecasted resource need.

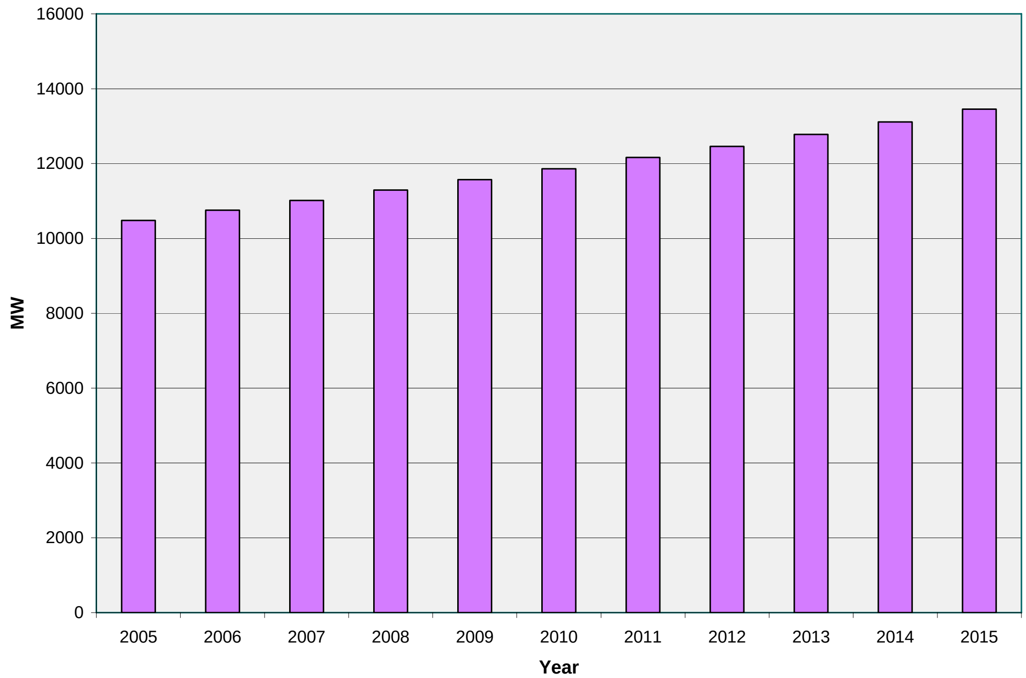
In the Southwest, capacity reserve margins are diminishing due to record levels of load growth (largely driven by population growth in the Phoenix and Las Vegas), combined with a recent slow-down in generation additions.

Figure 3-8
Proposed Future Capacity Additions-Southwest & Rocky Mountain Regions



Source: California Energy Commission

Figure 3-9
Rocky Mountain Summer Load



Source: WECC 10 Year Report (9/04)

Western Area Power Administration

The Western Area Power Administration (WAPA) is a federal power marketing agency serving 15 western states, including Arizona, California, Colorado, Montana, Nevada, New Mexico, Utah and Wyoming. Its service area excludes the Pacific Northwest, since that region is served by its sister power marketing agency, the BPA. WAPA's service area also extends outside the boundaries of the Western Interconnection.

Southern California is served by two different WAPA projects: Boulder Canyon and Parker-Davis. The Boulder Canyon Project includes the Hoover Power Plant (2,079 MW of installed capacity), Lake Mead reservoir, and associated transmission facilities. Power from this project is sold in three states: Arizona, California (57 percent), and Nevada. Five customers accounted for 91 percent of power sales in Fiscal Year (FY) 2004: Metropolitan Water District of Southern California, Colorado River Commission, Arizona Power Authority, Los Angeles Department of Water and Power, and Southern California Edison. Nine other California municipal utilities also receive allocations of Boulder Canyon power. Power deliveries are "firm" as long as there is sufficient water in Lake Mead reservoir. Otherwise, customer entitlements are temporarily reduced. Existing power contracts expire in 2017. In FYs 2002 through 2004, WAPA did not sell any nonfirm power because of "extremely dry hydrological conditions."

The Parker-Davis Project is comprised of the Parker and Davis dams, both of which are below Hoover Dam. The project's operations are integrated with the Hoover Power Plant. If Parker-Davis generation is insufficient to meet firm contract obligations, Hoover generation may be used or WAPA may buy power from other resources. In FY 2004, the top five customers included the Imperial Irrigation District (13.5 percent of total firm sales) and Edwards Air Force Base in the California Mojave Desert (7.6 percent). No nonfirm power was sold in FY 2004, due to poor hydro conditions and the requirement to release water for fish. More than 57 GWh of nonfirm power, however, were sold to California municipalities in FY 2003.

Conclusions

California's electricity system is part of the larger Western Interconnection, enabling California entities to purchase and exchange electricity with entities in other western states, British Columbia, and Northern Baja California, Mexico. California's biggest electricity trading regions are the Pacific Northwest and the Desert Southwest.

Many generation and transmission-owning organizations within this region are members of the WECC. The WECC staff recently published results from an analysis of when and where electricity-supply shortages could occur. The results suggested that the West as a whole has sufficient supplies, but that transmission constraints inhibit the flow of surpluses from the Pacific Northwest into California and the Desert Southwest. Based on very conservative assumptions, "shortages" caused by insufficient generation and transmission constraints could reduce margins in Southern California below the 15 percent planning reserve margin as early as 2008, and in Northern California as early as 2010.

Electricity supply in the Pacific Northwest is generated primarily by federal hydroelectric dams on the Columbia River. Poor water conditions reduce the amount of hydroelectricity available for regional use and export, though enough water is stored behind dams to provide short-term capacity shipments to California when these supplies are needed. The BPA markets this low-cost power to the region's utilities through long-term contracts and delivers it over its transmission system. Surpluses are determined annually and marketed daily. Very little is sold to California entities under "surplus firm" power contracts. Under a new BPA policy, independent power producers and the region's electric utilities must build most of the new generation, not BPA.

As long as the Pacific Northwest remains a winter-peaking region, California and other summer-peaking regions in the Western Interconnection can generally expect to purchase and exchange power with BPA and other power marketers to meet summertime demand. British Columbia also operates a hydroelectric system and markets surplus power to California. This power is delivered through the Pacific Northwest's transmission network, so transmission constraints between California and the Pacific Northwest can limit Canadian imports as well.

The Desert Southwest added more than 12,000 MW of new electric generating capacity within the last five years, most of it natural gas-fired. California has relied on imports from the Desert Southwest for decades, but this neighboring region is currently the fastest growing area in the nation. Surplus capacity and electricity may not be indefinitely available for export to California at current levels.

Utilities in the Desert Southwest and Pacific Northwest regions follow integrated resource plans similar to those used by California's investor-owned utilities. These plans include aggressive energy conservation programs, renewable energy purchase targets, and competitive solicitations for new electric generation from independent power producers. These utilities, however, are attempting to reduce their reliance upon outside sources of power (including imports) by building their own generation. A review of their resource plans suggests that more coal- than natural gas-fired generation will be built in the future, because of concern about natural gas supplies and prices.

CHAPTER 4: FUNDAMENTALS OF SUPPLY ADEQUACY AND PROCUREMENT ACTIVITIES

Supply adequacy means different things in different time periods. For long-term planning it might mean ensuring that one year from now, or maybe five years from now, a Load Serving Entity (LSE) expects to have enough committed resources to serve its electric load. These committed resources should be sufficient to allow for a reasonable level of contingencies that develop from time to time, but which cannot be specifically forecast.

Typical contingencies include the forced maintenance outage of a generating plant because of mechanical failure, or a spike in electric load due to unusually hot weather. If supplies are adequate for these contingencies, LSEs will still be able to serve their electric demand.

For short-term planning – next week, next month, or next summer – supply adequacy has a very different meaning. It still means ensuring there are enough resources. However, the short-term supply adequacy assessment is determined by more specific information on current events such as the actual maintenance status of existing resources, scheduled outages of nuclear plants for refueling, scheduled online dates for plants under construction, and more timely knowledge of what load levels will be. Short-term planning may use new and more accurate performance factors for recently completed wind turbines and gas-fired plants.

For an LSE that needs to procure additional short-term supplies, short-term power must come from existing resources already available in energy markets. This could be power that is not already committed or needed by others. Such short-term procurement (defined here as less than three months ahead) does not, in general, lead to new construction of generation or transmission because there is typically no time for such construction, or because the procurement need is based on unique or short-term situations that might not recur continuously in the future for any particular load-serving entity. Mid-term procurement is defined here as three months to five years ahead.

Procurement to meet resource adequacy standards and reporting requirements will not fully determine what resources are ultimately used to serve an LSE's load. Even a resource-adequate LSE may not schedule its already-procured and already-paid-for capacity should economic resources from the spot market become available. For example, a municipal utility may continue to maintain an older fossil plant with a high heat rate, and consider this plant as dependable capacity in short-term and long-term resource adequacy assessments. However, during most operating days, and perhaps even a peak demand day, this older plant may stay in reserve shutdown if the utility has secured cheaper resources from elsewhere to serve its load. What counts as dependable capacity to the owner, may not be available on short notice as dependable capacity to other LSEs or the control area operator. While this older plant may be inefficient in fuel usage and have high maintenance costs relative to output, the utility may find these operating expenses to be a prudent means to ensure physical resource adequacy. It may also reduce the financial risks of relying on markets for needed capacity.

Getting from Resource Adequacy to New Power Plants

It is the long-term planning application usage of resource adequacy requirements that ultimately drives construction of new generating facilities – or "new steel in the ground." Peak loads are gradually increasing throughout the West because of economic expansion and population growth. As loads increase over time, the existing installed base of "steel in the ground" electric generation is gradually becoming inadequate for reliably meeting future loads, on a planning basis.

No one LSE, however, can accurately predict whether there is enough capacity, say, five years from now to serve loads throughout in the West, or in any one specific sub-region of the West. Each LSE can look only at its own expected requirements and assess the extent to which existing, committed, pending, and planned capacity will adequately serve its contractual and retail obligations.

Additional procurement of capacity committed to an LSE's load may or may not lead to actual construction of new generation. It may, for example, simply lead to increased obligations of a merchant supplier planning to either source the electricity from an existing power plant that otherwise would have been selling into the future spot markets (i.e., it had no commitments), or source that electricity from the future spot markets themselves. Alternatively, additional procurement may include direct contractual obligations to build a new power plant.

In either event it is the aggregate of many independent LSE actions (or, in some cases, anticipated actions) throughout California and the West that ultimately leads to construction of new generating resources. Even increased merchant obligations can eventually lead to new construction as their risk exposure of sourcing these obligations from the spot markets makes new construction an increasingly economic alternative to mitigate financial exposure.

In the absence of a regulatory planning and procurement mandate, LSE have much discretion in ensuring resource adequacy. How an LSE selects options often depends upon the LSE's tolerance for risk, combined assessments of market conditions, cost, regulatory requirements, and environmental performance. In addition, LSEs often dynamically manage their resource adequacy requirements through a non-standard portfolio of resource commitments of varying terms and advance procurement horizons.

Here is an example of a common portfolio approach: An LSE has, under existing long-term commitments or ownership, firm resources for meeting 90 percent of its current load requirements, with short-term supply commitments to cover an additional 20 percent of load. The LSE intends to rely on the spot market for up to 5 percent of load. Together, these resource commitments provide 115 percent of the LSE's forecast peak load. This 15 percent planning reserve margin is deemed adequate for that forecast period. In this case, the LSE's current resource requirements are a mix of short and long-term commitments, with a minor reliance on the spot market. It may also have contracted to build a new power plant that will be on-line in five years, at which time its resource portfolio will consist entirely of long-term commitments adding up to 120 percent of forecast peak load (i.e., the LSE will then have excess capacity equal to 5 percent of its forecast peak). This future excess capacity is projected to evaporate eight years hence, but the LSE makes no commitment today for meeting its requirements eight years in the future and beyond. At some point, after its excess capacity is gone, the LSE may once again be making short-term commitments to meet its increased resource needs. That could prompt the LSE to make another long-term supply resource commitment. In reality, California has many investor-owned and publicly owned utilities in various stages of this procurement cycle.

Different LSEs have different tolerances for electricity and fuel price risks. LSEs also have different business plans and financial resources, regulatory requirements, and obligations to serve retail customers. Even in the same class of LSEs, a publicly owned utility will differ from other POUs in its unique load shape, supply resources, ownership of transmission resources, commitments to implementing renewable energy goals, flexibility to dispatch energy-limited resources due to air quality or water supply limitations, and a host of other unique considerations.

This example helps illustrate several discretionary factors that control the extent to which resource adequacy requirements advance to new generation:

- The amount of resources (often expressed as a planning reserve margin) deemed adequate.

    – Clearly, an LSE will procure more capacity if a 20 percent (rather than 15 percent) planning reserve margin is required by the LSE's governing board, its regulators, or its control area.

- Horizon for advance procurement.

  - That is, will an LSE make commitments today to ensure resource adequacy for its load requirements one year out? For five years out? For ten years out? Will such commitments today be for the full resource adequacy amount or for some partial amount, leaving the rest to be procured in a shorter time frame?

- Term of the commitment.

  - An LSE could meet its resource adequacy requirements through a rolling series of one-year commitments. Alternatively, and possibly as a technique to get pricing concessions or to reduce exposure to market price risk, an LSE might contract for a five-year term, or even ten-year term.

Power plant construction basically requires a financial commitment by some credit-worthy party willing to pay the full capital outlay cost of construction. Essentially, this requires that:

- An LSE (or a group of LSEs) commits to pay for the plant in some way, such as with a long-term power purchase agreement, or
- An LSE (or a group of LSEs) contracts for part of the plant output, and a merchant entity (or power pool, or another LSE) contracts for other parts (perhaps looking to remarket this share to other LSEs at a later date), or
- A merchant commits to the full plant, looking to market plant output to LSEs in aggregate at a later date.

The more that LSEs rely on long-term horizons and long commitment terms, the more directly their individual resource adequacy needs will be translated into new capacity. The more LSEs rely on short-term horizons and short commitment terms, the more indirect the link between individual resource adequacy and power plant construction, since it must be processed through the merchant sector in aggregate.

As groups, the major investor-owned utilities, the publicly-owned utilities, and the energy service providers have different approaches to procurement for meeting their resource adequacy. Some of the considerations unique to each of these groups are summarized below.

Investor-Owned Utilities – Considerations and Overview

IOU resource procurement, in general, is currently guided by legislation contained within Assembly Bill 57 (Wright), Chapter 835, Statutes of 2002, which also gives the Public Utilities Commission oversight over that procurement. The

CPUC's formal procurement guidelines are set forth currently in its Decision 04-12-048 issued December 16, 2004.

Essentially, the CPUC has ruled that IOUs may procure to long-term planning reserve margins of 15 percent to 17 percent (resource adequacy targets), and utilize short-term, mid-term, or long-term contracts. The CPUC uses Procurement Review Groups (identified separately for each IOU), made up of non-market participant and state agency representatives, to monitor certain technical aspects of each IOU's procurement practices and advise the CPUC.

For short-term procurement, up to three months, IOUs may enter into negotiated bilateral agreements without seeking CPUC approval. For mid-term procurements that exceed three months but are less than five years in term, the IOU must consult with its respective Procurement Review Group. For bilateral contract terms exceeding five years (long-term procurement), and for procurement obligations resulting in rate-based treatment of asset acquisitions, the IOU must seek approval from the CPUC.

AB 57 also provides that, "until a 20 percent eligible renewable resources portfolio is achieved," each IOU must procure renewable energy resources with the goal of adding at least an additional 1 percent per year.[32] This annual procurement requirement is conditionally limited by sufficient public goods charge funds available to cover the above-market costs for renewable energy. Reaching annual renewable energy portfolio targets may, therefore, be contingent upon adequate amounts of available cost-competitive renewable options in the market place.

The CPUC's procurement guidelines have adopted the "loading order" recommended in the state's Energy Action Plan. Essentially, this "loading order" requires that all cost-effective energy efficiency and demand-side resources be procured before any generation resources. Next, generation resources are to be procured through open, all-source solicitations, in which renewable resources enjoy a rebuttable presumption. Renewable and non-renewable bids are ranked by each IOU's least-cost best-fit criteria. The RPS annual procurement targets must first be met, within the identified RPS flexible compliance rules. But, as required by the CPUC's long-term procurement plan decision, the "IOUs should not curtail their procurement of renewables once the target is met, but should consider investments in all cost-effective renewable resources beyond 20 percent."[33] That is, even after the RPS annual procurement target is met, additional renewable generation bids must still be accepted before accepting non-renewable bids, if their least-cost best-fit criteria scores are better.

The CPUC has lifted its ban on affiliate transactions in resource procurement, and now allows utilities to self-build (utility owned) options to compete in an all-source solicitation. For self-build options, cost recovery is allowed only up to the bid cost, and any capital cost savings are shared 50/50 between ratepayers and utility owners.

Existing IOU procurement plans, guided by CPUC requirements, are a mix of short-, medium-, and long-term bilateral contracts in addition to some new generation that will be utility-owned and placed in the rate base.

Publicly Owned Utilities – Considerations and Overview

The history of publicly owned utilities is very different from that of investor-owned utilities. Part of that history, shared nationwide among publicly owned utilities, includes statutory and regulatory battles with IOUs over access to bulk power supplies.

Resource adequacy objectives, strategies, and requirements are generally set individually by each POU serving load in California. POU procurement tends to have long-term focus, based on goals of achieving self-sufficiency. POUs tend to own and finance their own generation assets, or have sufficient long-term contractual commitments to meet full resource adequacy requirements over both the short- and medium-term. This POU tendency toward asset ownership and long-term firm contractual rights is also true for transmission, especially if POU supply resources are distant from load.

Short-term needs are often met through negotiated bilateral agreements, most often with other public agencies. Typically, city councils and public utility boards allow their utilities to enter into agreements for power purchases for up to one year, but require council or board approval for longer term agreements. No additional approvals beyond the local level are usually required. Unlike IOUs, the POUs do not have revenue requirements that include paying dividends to shareholders, or the obligation to provide capital to parent companies or subsidiaries. However, POUs may be obligated to provide revenues to municipal public purpose programs or even the general fund. And, like IOUs, POUs may have financial and reporting obligations to bondholders, the SEC, and credit-rating firms when they have borrowed funds to construct infrastructure.

Operating reserve margins for POUs are generally determined by individual interconnection agreements or regional requirements including those imposed upon interconnected utilities by the WECC (for those POUs that are control area), or by other control area operators (for those POUs not in the CA ISO control area and not a control area operator). Few, if any, POUs within the state still rely totally on IOUs to provide their bulk power needs through long-term, full-requirements contracts. The vast bulk of POU load requirements are procured separately from the IOUs. Within the CA ISO, POUs may have metered sub-system agreements or other arrangements with their interconnected IOU. These agreements are largely used to accommodate small daily imbalances in real-time supply and demand due to minor forecasting errors and dispatch deviations from generation schedules.

In California, the development and ownership of transmission and generation have been just as strong among POUs, often through joint action, as among IOUs. Under the leadership of the Los Angeles Department of Water and Power, about a dozen Southern California POUs have participated in joint action generation, transmission, and fuel acquisition projects, totaling billions of dollars, through their membership in the Southern California Public Power Authority (SCPPA), a joint powers agency that operates on behalf of, and at the direction of, their member systems. Joint action projects have also been established by POUs in the northern part of the state through the Northern California Power Agency (NCPA). This municipal "power pool" is headquartered in Roseville. NCPA members have jointly participated in geothermal, hydroelectric, and gas-fired power projects.

AB 1890 (Brulte), Chapter 854, Statutes of 1996, ordering the restructuring of the electric utility industry, was passed by the California Legislature in 1996. AB 1890 imposed two requirements on the POUs: that at least once a year the electric bills of city-owned utilities show how much money is transferred to that city's general fund, and that the utilities collect a non-bypassable charge to be used for "public benefit" programs similar to those imposed upon IOUs.

POUs in California are not subject to the Renewables Portfolio Standard Program legislation SB 1078 (Sher), Chapter 516, Statutes of 2002 requiring IOUs to increase annually their eligible renewable energy resources by at least 1 percent of retail energy sales, such that they reach 20 percent by 2017. However, most POUs have approved goals or policies which adopt annual procurement targets—and eligible renewable resource definitions—similar to those required of IOUs under SB 1078. None of the POUs, however, have committed to using the non-bypassable public benefit charge under the same terms and conditions followed by the state-regulated IOUs.

Energy Service Providers – Considerations and Overview

Energy Service Providers (ESPs) in California today operate in a business environment drastically different from either IOUs or POUs. ESPs do not have a geographic franchise as the monopoly provider of electricity. Nor do they have the obligation to be a power provider of last resort. Without this franchise, ESPs provide only what their customer base seeks—which is typically according to terms of short-term to mid-term contracts (of one-month to five-year duration). These retail contracts provide ESP customers with competitively priced capacity and energy products. These contracts may also provide a hedge against alternative energy pricing from a franchise utility or a competitor ESP. Procurement practices of the ESPs reflect their retail sales contracts.

Since an ESP can never reliably anticipate loads, changes in regulatory policy, or future resource costs much beyond what is under contract, its supply portfolio typically consists of a mix of short-term or medium-term (one three-month to five-year) supply contracts for a mix of 6x16 (6 days a week; 16 hours a day) peaking products and 7x24 (7 days a week; 24 hours a day) baseload products. The ESP then often shapes its supply to hourly load requirements, using spot and imbalance markets. Although load uncertainty may preclude long-term contracting for some ESPs, there are other ESPs (which may be subsidiaries of investment banks) that may have strong balance sheets and a larger risk tolerance for long-term deals. In aggregate, the medium-term contracting by ESPs can facilitate and indirectly lead to development of new generation by merchant developers.

Unlike IOUs and most POUs with supply portfolios of real assets and bilateral system power purchases, ESP portfolios usually consist of system bilateral purchases. These contracts for firm power implicitly carry an obligation on the part of the power seller to provide adequate reserves and manage resource adequacy obligations. The power provider normally owns a generating asset that supplies the ESP with capacity and energy. However, the power supply contract often specifies only points of delivery on the grid, without naming the generating facility. In the case of a forced or unscheduled outage to the likely generating resource, the power supplier will be strongly obligated to find replacement resources since there will be contractual penalties for non-supply, often called "liquidated damages." In practice, the power supplier will also seek out cheaper sources of capacity and energy in wholesale and bilateral short-term and spot markets. Thus, the use of liquidated damages (LD) contracts can lower supply costs to the power supplier, the ESP, and the ESP customer.

A regulatory mandate for ESPs themselves to maintain their own additional capacity reserves above such LD contracts would significantly alter ESP procurement practices. A change in operations by a single industrial ESP customer can significantly affect the ESP's load requirements. This can happen because ESPs have a relatively small load base compared with IOUs and most POUs. This would also change the ESPs operating reserve requirements and mandated resource adequacy requirements. For example, with year-ahead resource adequacy requirements, if an industrial customer decides in the spring to drop a production shift during the upcoming summer months, the ESP with adequate mid-term resources would suddenly find itself with excess capacity in the short term. The ESP could be forced to sell that excess capacity in the spot market at a significant loss. Although IOUs and POUs can face similar risks, the impact is much less substantial since it is often a relatively small adjustment to forecast load.

Other regulatory mandates would significantly alter ESP procurement practices. For example, the CPUC will implement the SB 1078 renewable energy portfolio standards for ESPs in the near future. IOUs are required to offer in RPS solicitations long-term contracts of at least 10-year terms for renewable energy procurement. This long-term commitment is considered essential for renewable resource developers and those that finance these projects. But a 10-year procurement contract for any kind of energy would be very risky for an ESP lacking a captive customer base for that time period. For this reason alone, a liquid and viable market that trades unbundled “renewable energy credits” (RECs) may be essential for ESPs to attain renewable energy expectations set forth in AB 57 and the state’s Energy Action Plan.

The creation of formal, transparent markets for both capacity and unbundled RECs is likely to add cost and complexity to the LSE’s obligation to serve. However, capacity and REC markets may prove necessary and beneficial to ESPs in meeting resource adequacy and renewable portfolio standard requirements in the face of load uncertainty.

Customer Choice and Direct Access

In the mid 1990s, advocates of competitive electric policies in California promised cheaper, long-term contracts for larger customers (mostly industrial) and reduced prices through regulation and price caps for small customers (mostly residential). This emphasis on lower cost through competition has been called “misguided advocacy… Electricity competition was sold on the basis that it would lower prices for all customers during all time periods for all uses.”[34]

Competition was expected to lower the cost of electricity to all consumers. “In a competitive market, [consumers] will pay less for their electricity, because they will have the right to choose their electric service provider”.[35]

Traditionally, local electric companies provided their customers a complete package of services, from generation to delivery, at prices regulated by the CPUC.[36] This approach changed through implementation of California’s electric industry restructuring law (AB 1890) and a series of landmark implementation decisions by the CPUC in 1997. AB 1890 was primarily driven by large industrial customers. To make “customer choice” possible, investor-owned electric utilities were required to separate, or "unbundle," their electric service bills into two components and charge separately for power supply and power delivery. Transmission charges were also broken out in post-AB 1890 legislation.

Once services were unbundled, customers could shop around and compare prices offered by other electric power suppliers, a process called “direct access.”[37] Electricity consumers were given the option to purchase their electricity competitively at prices determined solely between them and an alternative electric supplier.[38] They could also continue buying electricity from the local utility under constraints and conditions and at prices regulated by the

CPUC. In either case, distribution of the electricity continued to be provided by the local utility at prices set by the CPUC, and the local utility continued to maintain its power lines.

History of Direct Access in California

Direct access programs began shortly after passage of AB 1890, the Electric Utility Industry Restructuring Act in 1996. Alternative electricity suppliers targeted different markets, including residential customers[39], government entities, commercial businesses with multiple facilities, and large industrial customers. Two kinds of customer choice emerged: business-targeted direct access offering low-cost power, and higher-priced electricity generated exclusively from renewable energy generating facilities. Residential customers comprise most of the participants in this “green” power market.

Before the 2000-2001 electricity crisis, alternative electricity suppliers provided service to 200,000 California customers. During the 2000-2001 electricity crisis, however, wholesale electricity prices spiked. For direct-access customers, prices were more than double what the local utility would have charged.[40] Droves of direct-access customers returned to their local utility for retail electric service. (Investor-owned utilities had lower and more stable rates because their rates had been reduced and frozen for a transition period mandated by AB 1890.)

Enron, a major alternative electricity supplier at the time, returned its direct-access customers to local utility service without customer permission or knowledge. Local utilities accumulated significant debt buying high-priced power for existing customers as well as accommodating the large influx of returning former direct-access customers.

Some direct-access customers fared much better than others during the electricity crisis. For example, customers of Strategic Energy, L.L.C. of Carlsbad, California had low and stable rates because this alternative electricity supplier had secured long-term contracts with 126 separate generators and was not at the mercy of the wholesale spot market.[41]

During the special legislative session to resolve the electricity crisis, the California Legislature passed AB 1X (Keeley), Chapter 4, Statutes of 2001, which assigned the California Department of Water Resources (DWR) responsibility for buying electricity on behalf of local utilities and their retail customers. Once DWR took over and negotiated new long-term contracts, electricity prices dropped and stabilized.

AB 1X also directed the CPUC to suspend direct access until DWR “no longer procures power for retail end-users.” Although AB 1X became law on February 1, 2001, the CPUC did not implement a decision to suspend direct access until

September 20, 2001.[42] During that seven-month delay, businesses were aware that a suspension of direct-access programs was imminent. Before the CPUC finally suspended direct access, alternative electricity suppliers were allowed to sign up new customers and many businesses rushed to lock in lower-priced electricity. Once direct access was suspended, alternative electricity suppliers could not sign up new customers, but they could honor all existing contracts.

DWR committed more than $51 billion in contracts with merchant power generators in the short- and long-term. The state had to repay an $8 billion loan from the General Fund and finance $43 billion worth of long-term contracts through the largest revenue bond sale in U.S. history. Direct access was perceived as a “loophole” that needed to be closed so that potential investors would not question California’s ability to repay the bonds. In its September 20 decision to suspend direct access, the CPUC stated, "Suspending the right to acquire direct access service will assist in issuing these bonds at investment grade, by providing DWR with a stable customer base from which to recover its costs…”[43]

Figure 4-1 shows total statewide electricity sales to direct access customers from January 2001 (during the electricity crisis) to present day. Electric service providers lost all but 2 percent of statewide electricity sales between March and June, 2001. They quickly recovered market share, however, and peaked at 14 percent in June 2002. Today, industrial customers (more than 500 kW per month) represent 21 percent of all direct access customers.[44]

Current Status of Direct Access in California

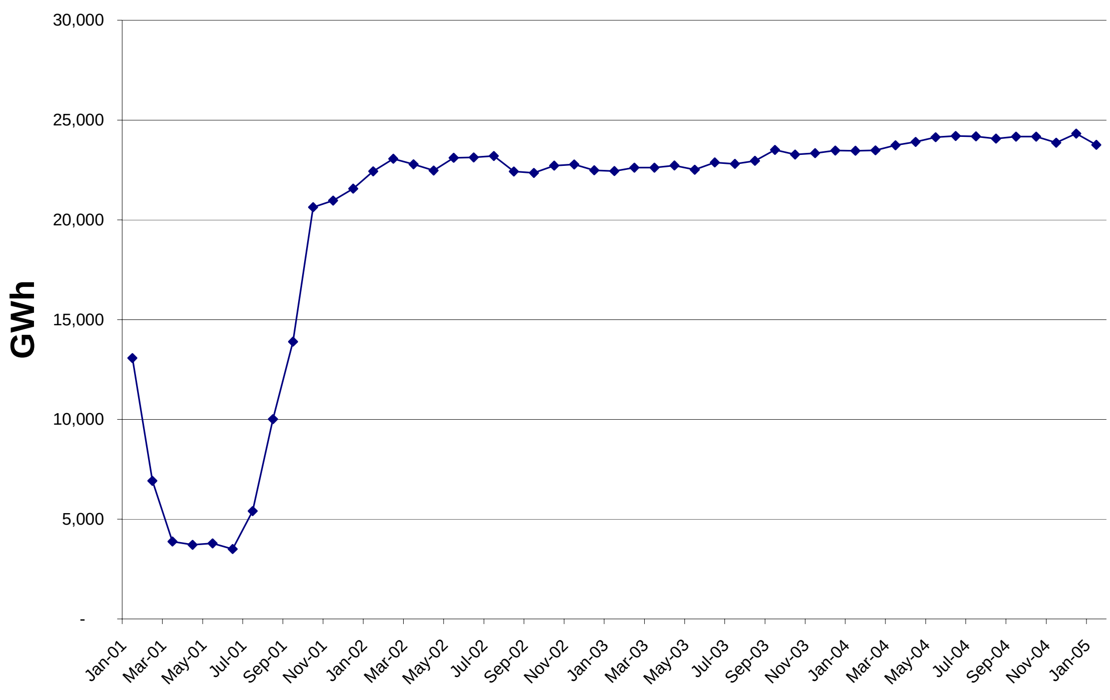
The CPUC’s suspension of direct access is still in effect, although customers with direct access contracts can continue to purchase electricity from alternative electricity suppliers. Customers may even change suppliers, but their choice of electric service providers (ESPs) is slim. More than 200 companies participated in California’s electricity market as ESPs, but the energy crisis caused a big shake out. Today, only 18 companies are registered with the CPUC.[45] Half of these do business only with “large customers.” More than 2,000 MW of load and approximately 13 percent of total monthly sales are still served by direct access contracts.[46] Figure 4-1 shows total monthly energy sales to direct access customers from January 2001 through January 2005.

Direct access customers who returned to local utility service during the electricity crisis and then left utility service again for direct access service now pay an “exit fee” (now called a “cost responsibility surcharge, CRS”) of $0.027 per kilowatt-hour to cover their portion of DWR’s costs.[47] Direct access customers that remained direct-access customers throughout the electricity crisis do not have to pay the CRS. Recently, the California Legislature passed a law[48] allowing the CPUC to waive or defer a portion of the exit fee for direct-access companies that returned to local utility service without their permission or knowledge, but quickly returned to direct access service.

If a direct access customer decides today to return to local utility service, that customer must provide six months' advance notice to the local utility. The purpose of this requirement is to enable the utility to adjust its procurement activities to accommodate the additional load. Furthermore, direct-access customers cannot increase their electrical consumption beyond the amounts set forth in their supply contracts.

A CPUC ALJ comment decision proposes extending the CPUC's administration of the SB 1078 Renewables Portfolio Standard Program to all ESPs. Pending legislation also would require all LSEs to meet RPS obligations and other public purpose program goals (e.g., resource diversity). These added regulatory requirements could reduce the price competitiveness of ESPs relative to other retail electricity suppliers already complying with these obligations to meet statewide policy goals.

Figure 4-1
Total Statewide Electricity Sales to Direct Access Customers



Source: California Public Utilities Commission

Community Choice Aggregation

The Legislature has also passed new laws providing exemptions to the direct access suspension. The cities of Cerritos and San Marcos were authorized to act as “community aggregators” for their residents in Southern California Edison’s service territory. The reason for the exemption is that these cities are participating in the municipally owned Magnolia power plant project, expected on-line in August 2005.

In addition, the Legislature passed AB 117 (Migden), Chapter 838, Statutes of 2002, allowing cities and counties to aggregate consumers’ electrical loads on an “opt-in basis.” Community aggregation is a form of direct access where a municipality acts as a purchasing agent on behalf of its residents. “Community choice” aggregators will be required to file an implementation plan with the CPUC and pay exit fees. Customers of community choice aggregators must also continue to contribute to the local utility’s public goods accounts for renewables, energy efficiency, research and development, and low-income programs.[49]

A CPUC ALJ comment decision proposes extending the CPUC’s administration of the SB 1078 Renewables Portfolio Standard program to all CCAs. These added regulatory requirements could reduce the price competitiveness of CCAs relative to other retail electricity suppliers already complying with these obligations to meet statewide policy goals.

Impacts on Utility Resource Planning

Community-choice aggregation (CCA) and the potential for lifting the current ban on new direct access contracts create considerable uncertainty for the amount of load existing utilities must serve in the future. If customers depart from the local utility to buy electricity from a different provider, then utilities could end up “over-procuring” power resources and incurring “stranded costs” associated with these resources. The utilities are concerned that the CPUC may not allow them to recover these “stranded costs” from ratepayers.

The CPUC’s response to these concerns has been to suggest that investor-owned utilities procure “a mix of resources, fuel types, contract terms and types, with some baseload, peaking, shaping and intermediate capacity, and with a healthy margin of built-in flexibility and sufficient resource adequacy.”[50]

The CPUC encouraged cities and counties seriously considering CCA to approach their local investor-owned utility and discuss procurement strategies, such as allocating some of its supply contracts to the CCA once it is formed.

The utilities’ potential loss of large industrial and commercial customers to independent merchant generators through direct access is also a problem, since the pattern of use by these customers (their daily “load profile”) is typically flat, while the utility’s focus under the long-term procurement plan will be to buy electricity to meet peak demand. The utility will not buy much baseload capacity until long-term contracts negotiated by DWR expire.

CHAPTER 5: SUMMARY OF LSE ELECTRICITY RESOURCE PLANS

The Energy Commission adopted a set of electricity data requests necessary to conduct supply adequacy assessments for the *2005 Energy Report*. The data requests include a resource assessment on the progress towards energy efficiency, demand response, and renewable energy goals. This chapter provides a summary of the electricity Resource Plans submitted by the three investor-owned utilities, 13 publicly owned utilities, and 5 energy service providers in California whose peak load was at least 200 MW in 2003 or 2004. The *Investor-Owned Utility Resource Plan Summary Assessment Report* (Publication Number CEC-700-2005-014) provides a more detailed review of the Resource Plans by investor-owned utilities.

Design and Purpose of Energy Commission Data Collection

Resources Plans and Purposes

The submittals from each LSE are not resource “plans” in the sense that they identify specific acquisitions. They are plans that identify what will likely be procured through solicitations, construction, contracting, or other processes.

The LSE submittals compare expected electricity demand against expected supply from existing and planned (or committed) resources and identifies either a supply surplus or a gap. Where demand was higher than existing and planned resources, the LSE was asked to quantify the gap. This gap is indicative of the LSE’s long-term “net open position” and reflects the amount of resources the LSE needs to procure.

The capacity Supply Forms were designed to generically identify the amount, timing, and type of resource additions the LSE would need to meet a 15 percent planning reserve margin under the assumed conditions of each scenario.[51] The energy Supply Forms were similarly designed and assume expected conditions for key assumptions such as energy demand and hydroelectric generation, but without a planning reserve margin.

The combination of renewable and non-renewable generic resource additions identified in the forms is effectively the amount of future resources needed by each LSE, assuming other existing and planned resources in the resource plan come to fruition, including the assumed level of loading order resources.

The Forms and Instructions required the LSE to identify how much of its net open position would be procured from the following “generic” resource categories:

- Short-term or spot market purchases (up to three consecutive months in duration),

- RPS-eligible renewables (to meet its minimum RPS annual energy procurement targets), and

- Non-renewable procurement, including construction, power purchase agreements, and generic contractual supplies. LSEs were asked to identify specific amounts of capacity and energy in this category as baseload, load-following and peaking, load following (year-round), and peaking (seasonal).

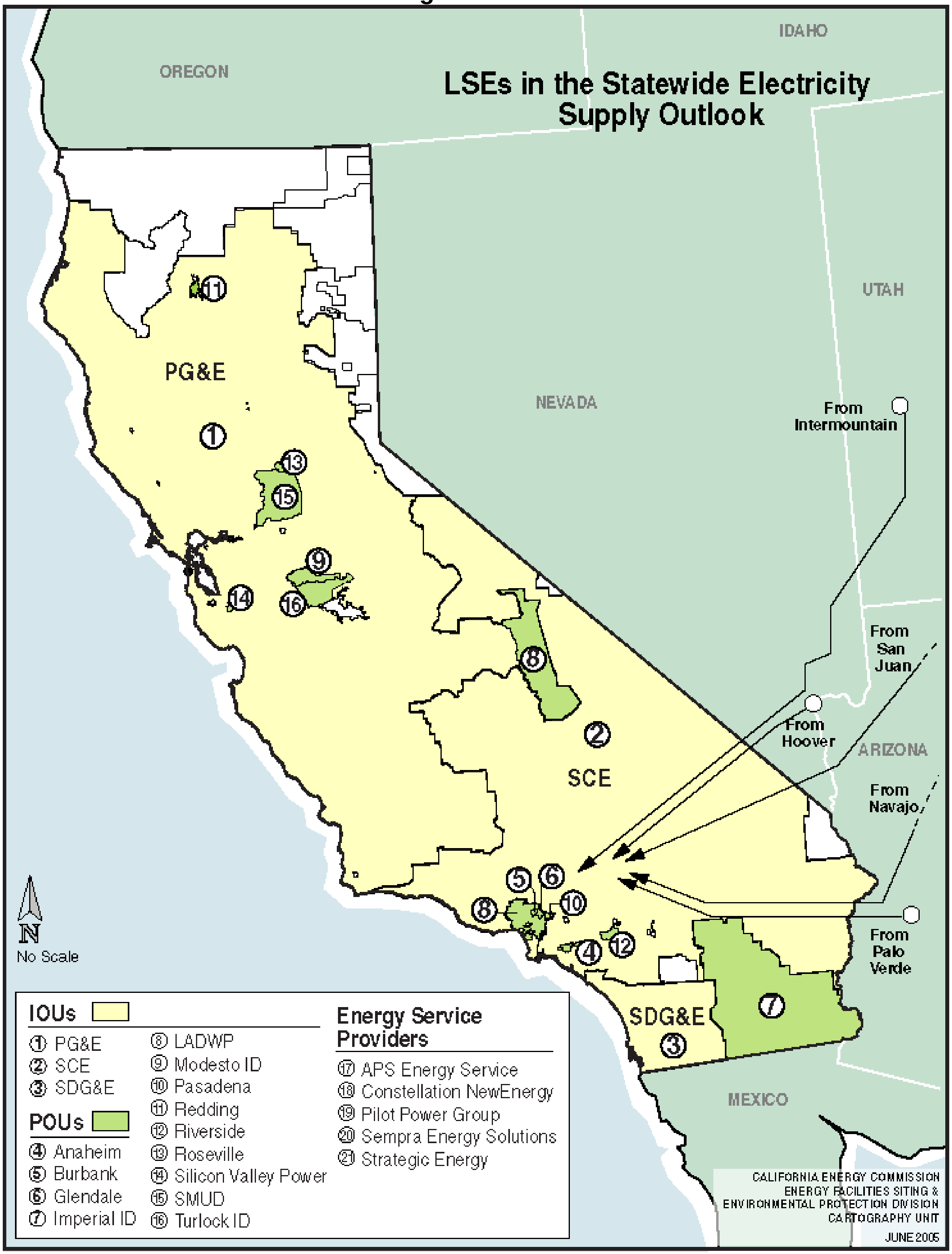
The narratives supplementing the Supply Forms were to include assessments of the major uncertainties which influence resource planning decisions, along with some discussion of their actual influence on the resource plan.

Focus on Medium and Large Electric Retailers

A total of 21 LSEs provided the requested resource plan data. This forecast data came from three investor-owned utilities (IOUs), 13 publicly owned utilities (POUs), and five Energy Service Providers (ESPs). The geographic service territories of these IOUs and POUs are shown in Figure 5-1. All 21 LSEs submitted data using Excel forms developed by the Energy Commission, which greatly facilitated the aggregation of data and initial assessments in this report. Individual LSE resource plan data was completed as early as February 14 and as late as May 4. Appendix B has a summary of these supply resource plans for each POU, and one summary that more generally describes the plans of the ESPs.

A total of 35 small LSEs in California were exempt from filing resource plans because their retail peak loads in 2003 and 2004 were less than 200 MW. This included four IOUs, 20 POUs, four ESPs, four Rural Electrical Cooperatives, and three water agencies. The geographic service territories of these small utilities are shown on Figure 5-2. Altogether, these 35 LSEs had non-coincident peak retail loads of about 1,450 MW in 2004, as shown in Table 5-1. Two of these IOUs and two of these Cooperatives also serve retail loads in neighboring states. Three public water agencies with generation were exempt from filing: the Metropolitan Water District of Southern California, the California Department of Water Resources, and the U.S. Bureau of Reclamation (and its power marketing sister agency, the Western Area Power Administration).

Figure 5-1



Source: California Energy Commission

Figure 5-2

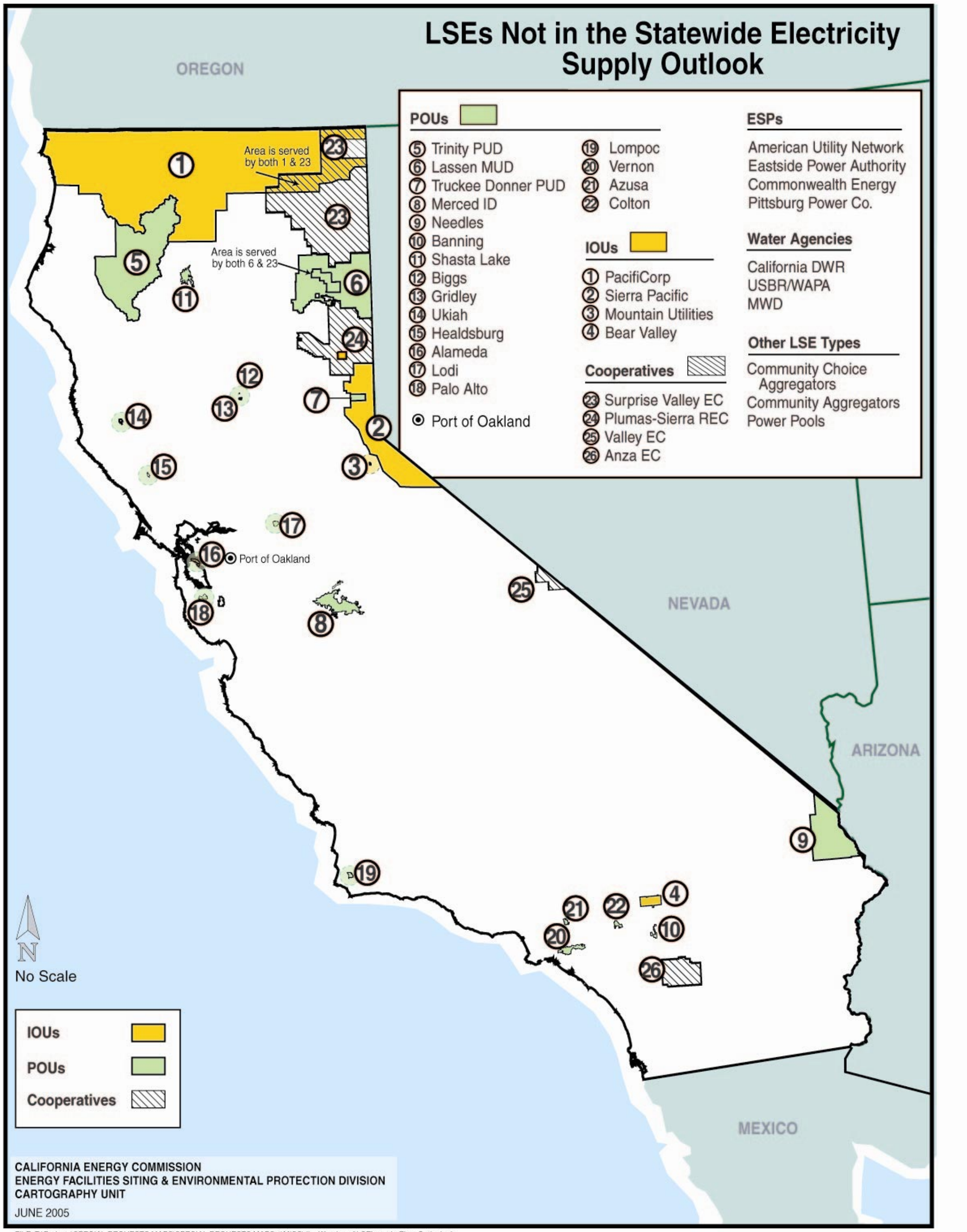

LSEs Not in the Statewide Electricity Supply Outlook
OREGON
NEVADA
ARIZONA
MEXICO
POUs
5 Trinity PUD
6 Lassen MUD
7 Truckee Donner PUD
8 Merced ID
9 Needles
10 Banning
11 Shasta Lake
12 Biggs
13 Gridley
14 Ukiah
15 Healdsburg
16 Alameda
17 Lodi
18 Palo Alto
19 Lompoc
20 Vernon
21 Azusa
22 Colton
Port of Oakland
IOUs
1 PacifiCorp
2 Sierra Pacific
3 Mountain Utilities
4 Bear Valley
Cooperatives
23 Surprise Valley EC
24 Plumas-Sierra REC
25 Valley EC
26 Anza EC
ESPs
American Utility Network
Eastside Power Authority
Commonwealth Energy
Pittsburg Power Co.
Water Agencies
California DWR
USBR/WAPA
MWD
Other LSE Types
Community Choice Aggregators
Community Aggregators
Power Pools
Area is served by both 1 & 23
Area is served by both 6 & 23
N
No Scale
IOUs
POUs
Cooperatives
CALIFORNIA ENERGY COMMISSION
ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION
CARTOGRAPHY UNIT
JUNE 2005
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Table 5-1
LSEs Not in the Statewide Electricity Supply Outlook

Exempt LSEs < 200 MW Retail Load in 2004	LSE Class	Peak Retail MW
Alameda Power & Telecom	POU	68.1
American Utility Network	ESP	5.0
Anza Electric Cooperative, Inc.	Co-op	10.0
Azusa Light & Water Department, City of	POU	59.0
Banning Electric Department, City of	POU	46.8
Bear Valley Electric Service (BVES)	IOU	34.0
Biggs Electrical Department	POU	3.8
California Department of Water Resources (CDWR)	Water	0.0
Colton Electric Utility Department	POU	75.7
Electric America / Commonwealth Energy	ESP	160.0
Gridley Municipal Utilities	POU	8.3
Healdsburg Municipal Electric Department	POU	19.0
Lassen Municipal Utility District	POU	26.7
Lodi Electric Utility	POU	117.5
Lompoc Utility Service	POU	25.2
Merced Irrigation District	POU	69.1
Metropolitan Water District of Southern California (MWD)	Water	0.0
Mountain Utilities	IOU	3.2
Needles, City of	POU	17.9
PacifiCorp	IOU	20.0
Palo Alto Utilities Department	POU	177.9
Plumas-Sierra Rural Electric Cooperative (PSREC)	Co-op	28.7
Port of Oakland	POU	7.2
Shasta Lake, City of	POU	31.6
Sierra Pacific	IOU	131.4
Surprise Valley Electrification Corporation (SVEC)	Co-op	25.6
Trinity Public Utilities District (TPUD)	POU	6.4
Truckee Donner PUD	POU	31.3
Ukiah Power Authority	POU	29.7
Valley Electric Cooperative	Co-op	15.0
Vernon Municipal Light Department, City of	POU	196.0
Western Area Power Administration (WAPA)	Water	0.0
Total of Non-Coincident Peak Retail Loads in 2004		1,450.1

Source: California Energy Commission

Forms and Instructions to LSEs

On January 19, 2005, the Energy Commission adopted forms and instructions for completing electricity supply resource plans. The Energy Commission directed load-serving entities to submit resource plans covering the years 2006 through 2016, using common terms and conventions. Each LSE with a peak retail load of at least 200 MW in 2003 or 2004 was required to provide the requested data. On March 2, 2005, the Energy Commission adopted supplemental instructions to these same LSEs, requiring narrative statements on risks and uncertainties. The resource plans were due March 1, and the narrative submittals on risk management were due April 1.

The LSEs were asked to provide specific information, detailed in the following five Supply Forms:

- S-1 Capacity Resource Accounting Table: This capacity supply and demand balance table includes monthly dependable (not nameplate) capacity for the years 2006 through 2016.

- S-2 Energy Resource Accounting Table: This energy supply and demand balance table includes monthly expected energy for the years 2006 through 2016.

- S-3 Generic Renewable Capacity and Energy Locations: These annual dependable capacity and expected energy tables provide an estimated geographic and technology breakout of new generic renewable resources that would be procured (over and above generation from existing and planned renewable generation) to meet the IOU's Renewables Portfolio Standard annual procurement targets. These tables should be consistent with the S-1 and S-2 tables.

- S-4 QF Energy and Cost Projections: Provided for each qualifying facility (QF) contract included in the resource plan, these forms describe the contract and contract pricing mechanism, dependable capacity, expected annual energy generation, annual energy cost, and annual fixed costs. These tables should be consistent with the S-1 and S-2 tables.

- S-5 Bilateral Contracts: These forms provide information about existing bilateral contracts with suppliers of capacity or energy, excluding QF and California Department of Water Resources (CDWR) contracts (which are treated separately) and contracts with public utilities that integrate hydroelectric generation facilities.

Peak Demand Calculations

All LSEs were asked to forecast their peak demand for each month of the forecast period. This number, in megawatts (MW), includes both power needed to serve retail loads and the power needed to deliver supplies to loads. These peak demand estimates, therefore, include allowances for transmission and distribution line losses, station loads of utility-controlled resources, and unaccounted for energy. LSEs serving as a Utility Distribution Company were asked to distinguish demand from direct access customers and demand from their own "bundled service" customers.

Energy Efficiency, Demand Response, and Distributed Generation

The IOUs were also directed to separately report adjustments to load attributed to energy efficiency programs, price sensitive demand response programs, and distributed generation. The Los Angeles Department of Water and Power (LADWP) also reported energy efficiency and distributed generation numbers. The Sacramento Municipal Utility District (SMUD) reported distributed generation estimates as adjustments to its future monthly load forecasts.

Reference Cases and Preferred Cases

In the "Reference Case," the IOUs were directed to make certain assumptions about the amounts and timing of customer load that could depart bundled service for either Community Choice Aggregation or municipal utility service. IOUs were also directed to assume that price-sensitive demand response targets adopted by the CPUC in D.03-06-032 would be met. Also in the Reference Case, IOUs were directed to assume that by calendar year 2010 energy from state-defined eligible renewable resources will equal at least 20 percent of retail energy sales.

In what was labeled the "Preferred Case" by PG&E and the "Alternate Case" by SCE and SDG&E, IOUs were asked to submit a full set of electricity supply forms incorporating their own preferences, assessments, strategies, and judgments. This included a request to the IOUs to use their own assumptions about departing load, energy efficiency, and renewable energy procurement. The IOUs were also asked to provide additional information on an accelerated renewables scenario, local reliability area assessments, resource plan costs, natural gas price sensitivity, and other topics of special concern. The data and information submitted by the IOUs has been reported by staff in the "Revised Investor-Owned Utility Resource Plan Summary Assessment." http://www.energy.ca.gov/2005publications/CEC-700-2005-014/CEC-700-2005-014.PDF

Results of LSE Resource Plan Submittals

Aggregating Data for Public Release

Aggregated IOU data presented in this report is limited to information submitted by PG&E in its Preferred Case, and by SCE and SDG&E in their respective Alternate Cases. This data was aggregated with filings submitted by POUs and ESPs in their Reference Cases. Each LSE used its independent judgment, assumptions, and internal assessment protocols to arrive at its own forecast and estimate of demand, and its own estimate of supplies considered deliverable to load.

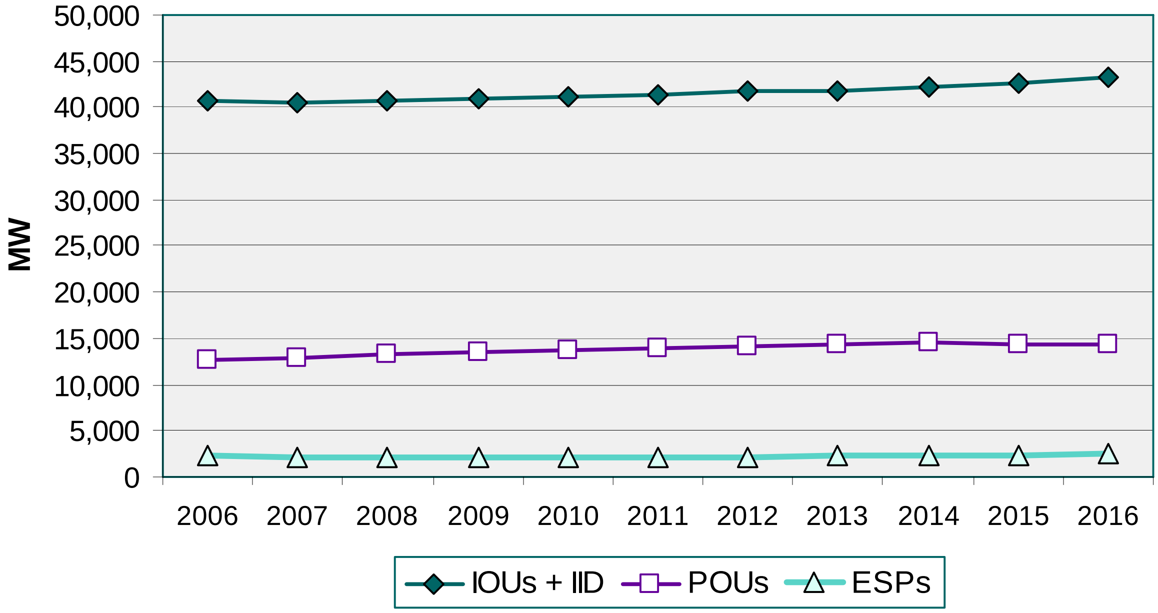
Using the resource plan filing data from all 21 LSEs, the Energy Commission has made public annual numbers on forecasted LSE loads, annual energy production, and dependable capacity of supply resources related to the peak demand for each LSE. No assessments of this data were performed. The annual numbers made public cover only years 2009 through 2016. Individual supply resources were aggregated to general supply categories. These data tables were published in the "Resource Plan Aggregated Data Plan Results" (# CEC-150-2005-1, 73 pages) This Energy Commission staff report was posted June 28, 2005 at: http://www.energy.ca.gov/2005publications/CEC-150-2005-001/CEC-150-2005-001.PDF.

These data tables present LSE annual capacity and energy supply numbers aggregated to four control areas: LADWP, SMUD, Imperial ID, and CA ISO. For the CA ISO control area, the data tables were further disaggregated to the three IOU planning areas. Statewide ESP resource plan data was disaggregated to these CA ISO planning areas, using information available from demand filings.

Summarizing Load and Resource Forecasts

Figure 5-3 provides "30,000-foot" reconnaissance-level snapshot of expected peak loads in California's retail markets through 2016. This is a multi-faceted aggregation of many different assumptions, forecasts, and estimates. These data were provided by the 21 LSEs serving peak loads over 200 MW in 2004 and indicate the single annual net peak customer demand an individual LSE expects to serve during the next 11 years. This net peak demand includes a 15 percent reserve margin for each LSE (except that SMUD and Burbank did not show this reserve margin in their filings), with LADWP showing a reserve margin of nearly 20 percent. Roseville did not forecast capacity or energy numbers for 2015 or 2016, which explains the slight dip for POUs in those years. This is an aggregation of non-coincident peak loads. It does not include smaller LSEs, community choice aggregators, or major water agencies such as USBR and CDWR. It is not, therefore, either a statewide or a coincident peak forecast.

Figure 5-3
Forecast Annual Peak Loads 2006-2016 by LSE Class



Source: California Energy Commission, aggregated LSE Resource Plan data

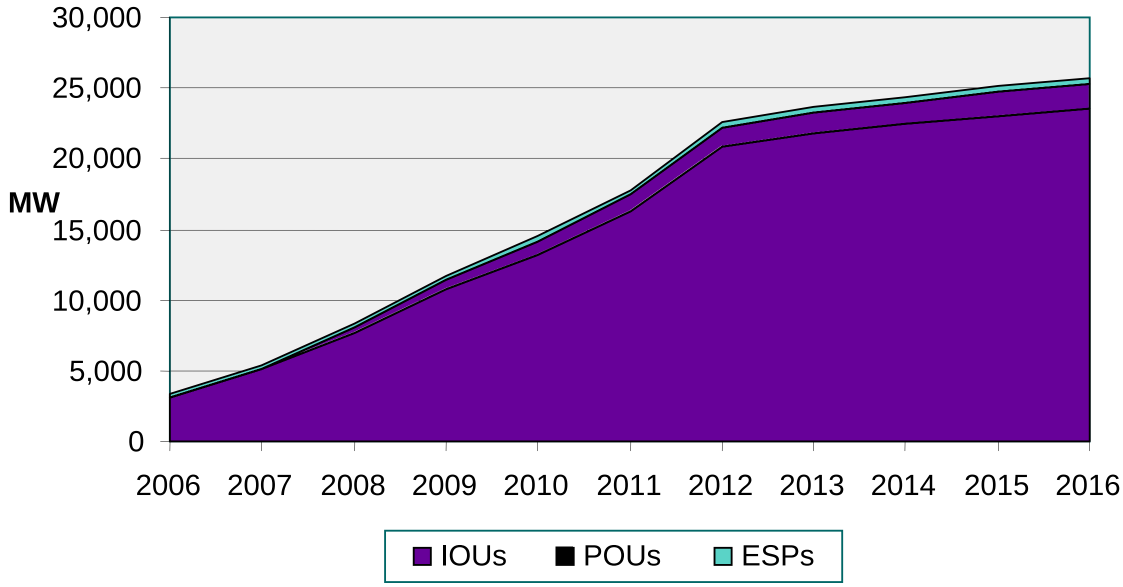
Those qualifications aside, Figure 5-3 shows some remarkable aggregate stability in the collective assumptions about loads and market shares that each class of LSE could be called upon to serve. Peak load forecasts for Imperial ID and the three large IOUs have been granted confidentiality for the years 2006, 2007, and 2008. These four LSEs, therefore, have been grouped together to avoid disclosing business-sensitive data. For the other 12 POUs, peak demand forecasts for bundled customers are not confidential and are presented in Appendix Table B-1. Forecasted peak demand for the five filing ESPs has been determined to be confidential and is presented only in Figure 5-3 above, aggregated on a statewide basis.

The 21 reporting LSEs collectively expect their peak demand in 2006 to total 55,794 MW. This collective non-coincident sum is forecast to be 60,091 MW in 2016, an increase of 7.7 percent. The three IOUs and IID together (for purposes of this figure), expect to meet 73.1 percent of these peak loads in 2006, and 71.9 percent in 2016. The 12 other POUs are preparing to serve 22.8 percent of these peak loads in 2006, and expect their obligations to grow to 24 percent of these peak loads in 2016. In 2006, ESPs expect to serve 4.1 percent of the retail market. In 2016, ESPs as a group estimate their most likely market share will still amount to 4.1 percent of total peak retail demand. What may be most remarkable about these numbers is the shared expectation among portfolio managers of gradual, modest peak load growth and continuation of current market shares among classes of LSEs.

Summarizing Generic Resource Capacity Needs

By 2016, about 24,000 MW of generic new supply resources will be needed to serve total peak requirements, including retail loads, a 15 percent planning reserve margin, and firm sales requirements. This includes power to replace expiring supply contracts and capacity to replace retiring plants. The three IOUs and IID will have the most need for new capacity, as shown in Figure 5-4.

Figure 5-4
Forecast Generic Resource Capacity Additions by LSE Class

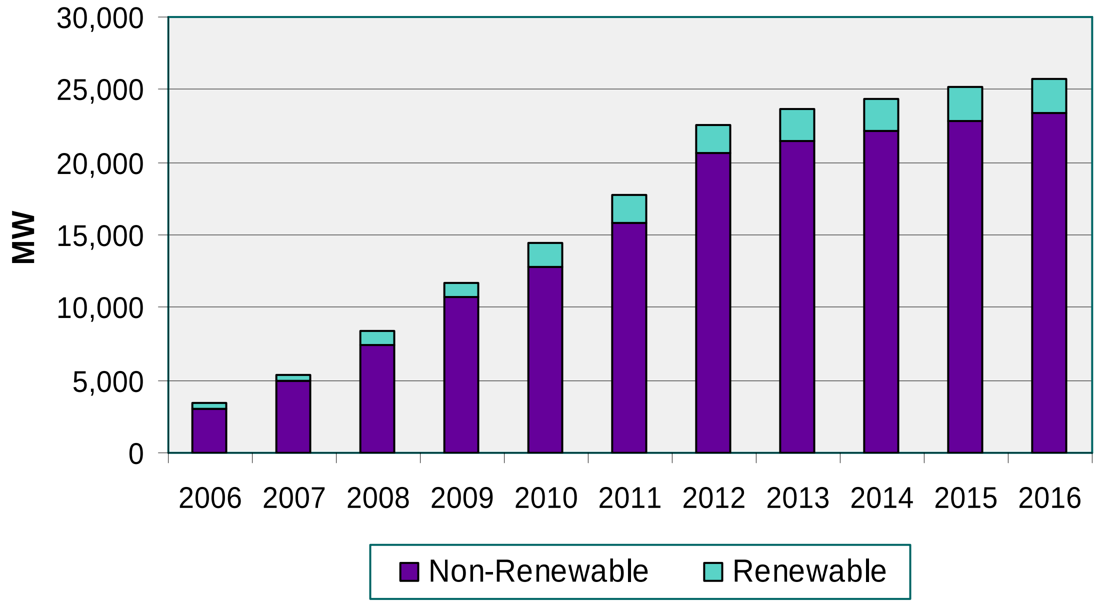


Source: California Energy Commission, aggregated LSE Resource Plan data

These numbers include generic renewable and non-renewable capacity needs of all types. Most of the need for generic capacity additions pertains to the IOUs. CPUC procurement proceedings have already authorized IOUs to fill much of this generic capacity need, especially for the early years in the forecast period.

Figure 5-5 shows the aggregate estimates of renewable and non-renewable generic resources that LSEs will show collectively in their plans. These are dependable capacity estimates, which may be significantly less than installed or nameplate ratings. For example, LADWP has plans to bring the 120 MW nameplate Pine Tree Wind project online in 2006, but rates this resource as 0 MW dependable capacity.

Figure 5-5
Generic Capacity Additions by Generic Resource Type



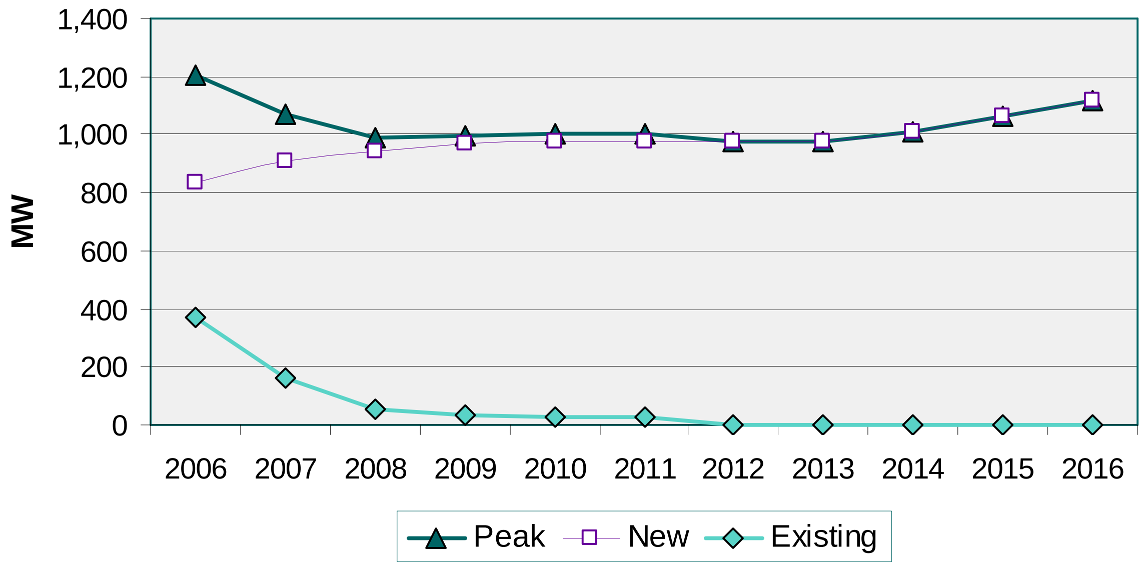
Source: California Energy Commission, aggregated LSE Resource Plan data

Collectively, POUs have enough surplus capacity to serve their non-coincident peak loads for another three years. These collective surplus amounts (990 MW in 2006, declining to 231 MW in 2009) have not been subtracted to offset generic capacity needs for other POUs, shown in Figure 5-4. The principle reason for not offsetting one LSE's surplus capacity with another's need for generic capacity need is that individual LSEs do not have an obligation to sell their surplus capacity to other California LSEs, or to make this surplus capacity available to California wholesale markets. The obligation to plan, procure, firm up and schedule adequate resources to serve load belongs to each LSE, not the class of LSEs, or the transmission planning area, or the control area. Each LSE is expected to forecast its end use loads and export requirements, establish a 15 percent planning reserve margin (assumed with these instructions), implement resource adequacy procurement and reporting requirements (by June 2006 for IOUs), schedule resources with control area operators, and dispatch resources according to what each control area requires to maintain WECC-established operating reserve margins during real-time operations.

Summarizing ESP Demand Forecasts

The obligations between ESPs and customers are limited to their current contract, most of which are short-term, as shown in Figure 5-6**.** Five ESPs provided load and resource forecast data to the Energy Commission. Most of these companies filed data on or about April 1, 2005. Figure 5-6 shows that by the peak demand month in 2006 (which is July, August, or September, depending upon the company), 70 percent of forecast demand will be for customers under new retail demand contracts, including renewals with existing customers. By summer 2008, only 5 percent of ESP peak demand will come from existing contractual obligations (as of April 2005).

Figure 5-6
Forecast ESP Peak Demand



Source: California Energy Commission, aggregated ESP Resource Plan data

The ESPs collectively will need generic capacity additions to replace (or renew) existing retail demand contracts in effect in April 2005.

This load uncertainty is a constant concern for ESPs and frequently limits their long-term procurement options. ESPs have tended to adopt a “conservative” business plan that avoids over-procurement of capacity and energy resources beyond the known retail demand requirements of their customers and their required reserve margins. A six-month supply contract to an industrial manufacturer or grocery retail chain is therefore likely to be backed by a supply contract for nearly the same amount of capacity and energy for the same duration. Each ESP may have hundreds of individual wholesale electricity supply contracts matched to its retail customer load-serving contracts. ESPs can contract with any supplier and the actual generating resource need not be named or specified. ESPs tend to use the same wholesale suppliers over and over, which could be a merchant generator (such as Coral Power and Calpine) or a power marketer (such as Morgan Stanley).

Unlike IOUs and POUs, the ESPs do not have the obligation to serve customers beyond the contractual terms of their retail demand contracts. These are highly competitive electricity suppliers delivering energy to cost-conscious and demanding corporate customers who are under no obligation for continued loyalty. Future revenue streams are not guaranteed. Another major difference is that financial solvency for ESPs is not assured by regulatory oversight agencies or governing boards.

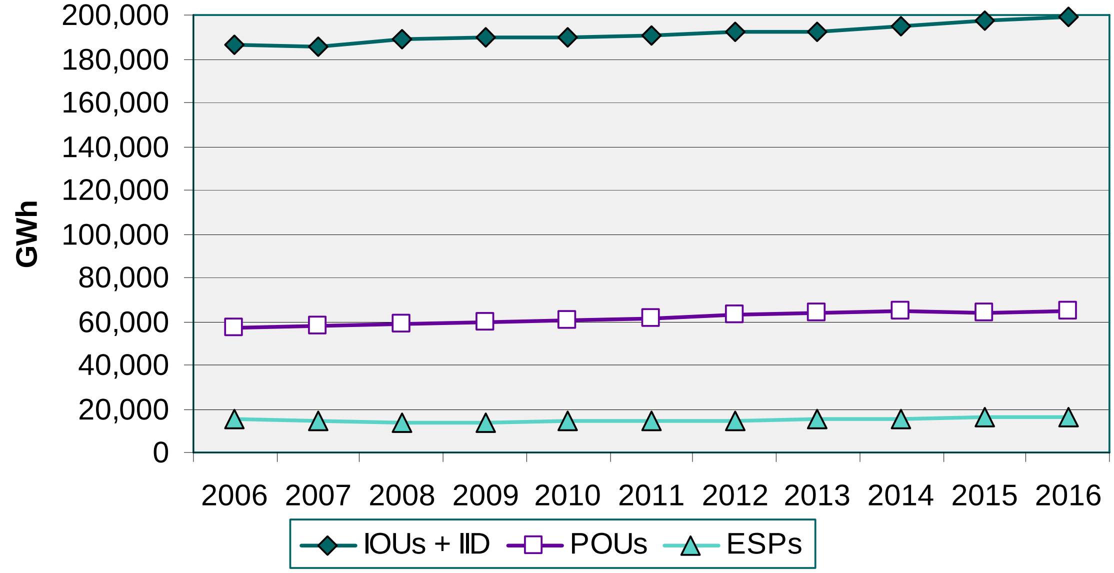
According to the limited information requested and received by the Energy Commission, all ESP customers are in the distribution territories of the three large IOUs. A retail customer of an ESP could return voluntarily to IOU service at the expiration of its retail demand contract served by the ESP, but this seems unlikely since IOU energy costs are significantly higher. Once an ESP customer returns to IOU service, it cannot depart bundled service without incurring substantial exit fees. However, there are no exit fees imposed on an ESP customer switching to another ESP. This leads to a somewhat fixed share of the retail market for all ESPs. This fixed share of the retail market leads to intense competitive pressures between ESPs for a very limited number of customers. The companies that have survived and prospered into 2005 are survivors of a harsh competitive business environment born of deregulation in California in 1996.

Summarizing LSE Energy Forecasts

As shown in Figure 5-7, LSE forecasts of steady annual customer energy demand growth show a similar pattern to the peak load growth shown in Figure 5-3. Aggregate annual amounts of energy supplies needed to serve load grow from 260,207 GWh in 2006 to 282,033 GWh in 2016. This includes transmission losses, distribution losses, and UFE (unaccounted for energy), so is somewhat higher than expected retail sales. These numbers do not include firm sales obligations or expected spot market sales; they include only energy delivery to bundled customers (for IOUs and POUs) and direct access customers (for ESPs). The three IOUs and IID together will provide 72.2 percent of this energy supply in 2006, and 71.1 percent in 2016. The other 12 POUs will collectively supply and deliver 22 percent of this energy total in 2006, and 23 percent in 2016. The collective ESP share of these needed energy supplies is 5.9 percent in 2006, and about 5.8 percent in 2016.

Considering the capacity and energy numbers together provides insight about a competitive advantage of ESP retailers. The relative share of ESP energy deliveries (5.9 percent) is higher than its relative share of meeting peak demand (4.1 percent). This is largely because a predominance of industrial and large commercial ESP customers allows ESP companies to supply their customers with more efficient, economical baseload resources with higher capacity factors. In relative terms, ESPs have less need for procurement of peaking and load-following resources than do their IOU and POU counterparts.

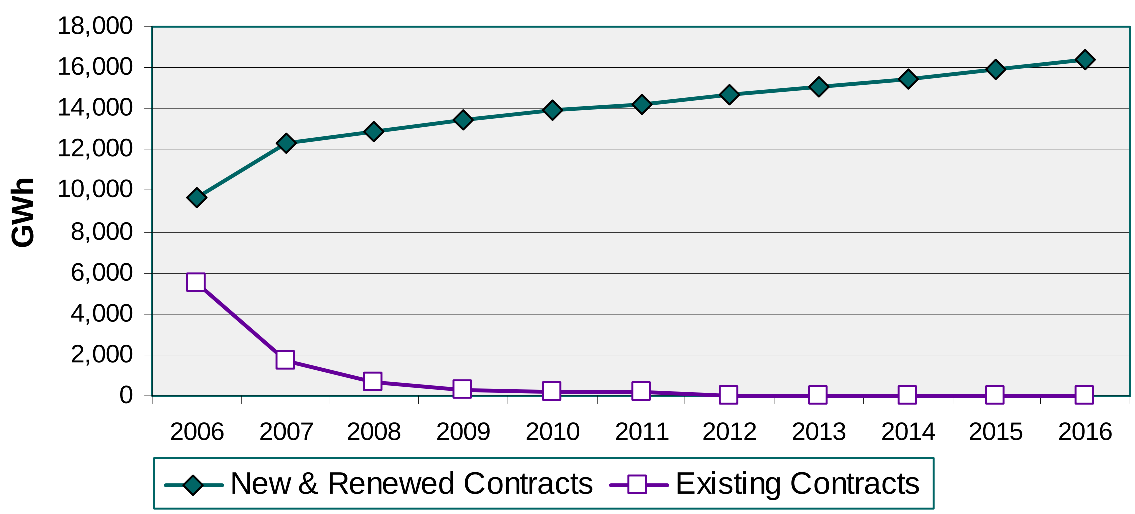
Figure 5-7
Forecast Annual Energy Demand



Source: California Energy Commission, aggregated LSE Resource Plan data

Figure 5-8 shows a pattern for collective ESP estimates of annual energy, similar to the collective forecast for ESP capacity needs shown in Figure 5-4. As of April 1, 2005, about 64 percent of forecast energy demand in 2006 could be attributed to existing customer contracts. For 2008, less than 5 percent of total estimated energy demand will satisfy contractual obligations known in spring 2005. For ESPs, the obligation to serve each customer is short-lived and contractually limited.

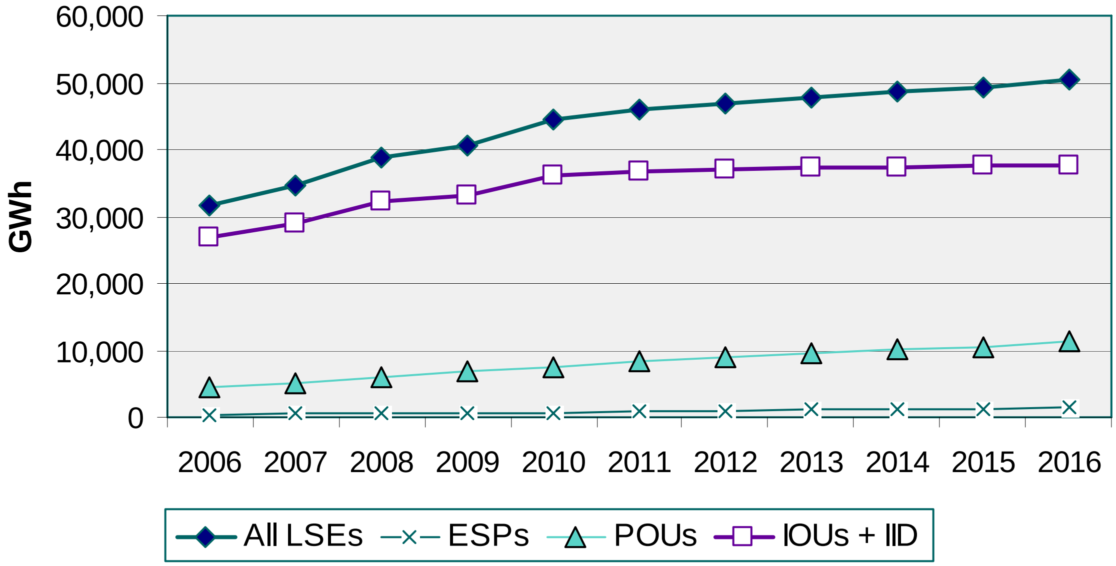
Figure 5-8
Estimated ESP Annual Energy Demand



Source: California Energy Commission, aggregated ESP Resource Plan data

Figure 5-9 shows the amounts of annual energy that LSEs expect from state-defined eligible renewable energy resources. The forecasts of IOUs and IID have been aggregated to avoid disclosing confidential data.

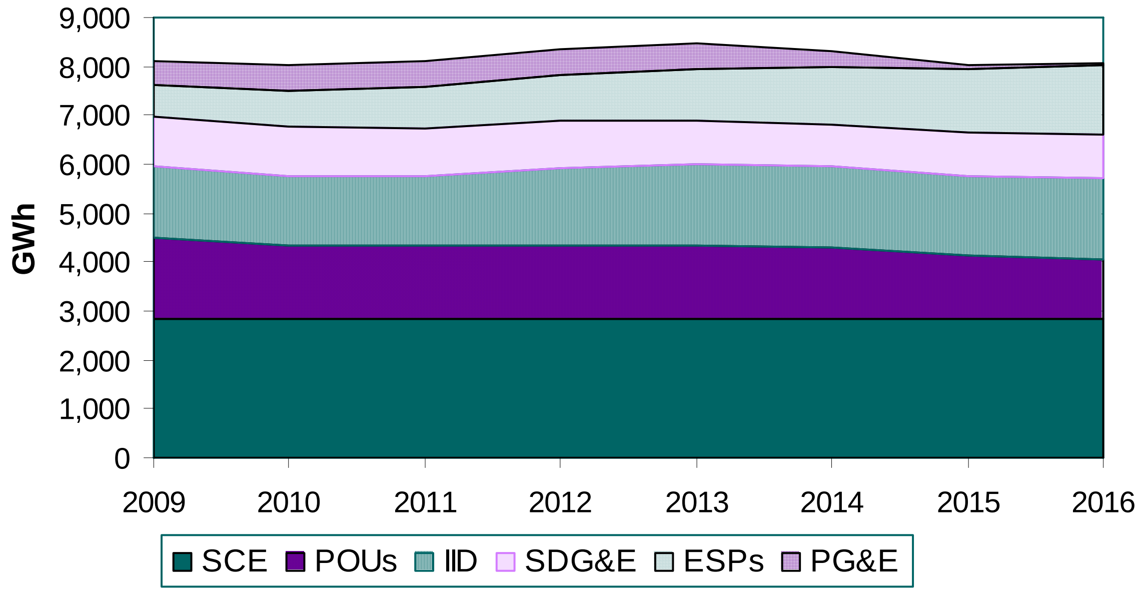
Figure 5-9
Forecast Eligible Renewable Energy Supplies



Source: California Energy Commission, aggregated LSE Resource Plan data

Figure 5-10 shows one primary procurement source of renewable energy that is not owned by utilities: bilateral contracts. These do not include renewable energy that some utilities expect to purchase on a short-term or spot market basis, or include renewable energy credits (RECs) that might be purchased by an LSE. Annual data for the first three years in the forecast period are not included to avoid disclosing confidential data. For the IOUs, renewable contract supplies are based on their preferred case (PG&E) or their Alternative Cases (SCE and SDG&E respectively). These cases assume an obligation that 20 percent of their retail energy sales will be supplied by eligible renewable energy resources by 2017. For SCE, this target will be achieved by 2009, which is reflected in a nearly constant forecast level to maintain this percentage through 2016.

Figure 5-10
Renewable Energy Bilateral Contract Supplies



Source: California Energy Commission, aggregated LSE Resource Plan data

Summarizing Hydroelectric Capacity and Energy Forecasts

Most LSEs expect to add some amount of new supply resources by 2016. Many utilities expect to build additional utility-owned thermal resources. No one expects to add nuclear resources during the forecast period. Only SMUD and SDG&E anticipate adding additional utility-controlled hydro resources. For SMUD, Iowa Hill has the potential to add 400 MW of pumped-storage capacity to their Upper South Fork American River Project. This may be especially helpful for integrating wind energy from FPL-built turbines in the Delta, since the Delta Breeze on a hot summer day usually begins to blow a few hours after the daily load peak driven by air conditioning use. For SDG&E, about 40 MW of new hydro are expected, starting in 2008 from San Diego County Water Authority projects.

Table 5-2 shows total dependable capacity from hydroelectric resources for the peak summer month as forecasted by 12 municipal utilities and irrigation districts. Capacity data for PG&E, SCE, and IID are aggregated together to avoid disclosing confidential data. None of the ESPs reported hydroelectric resources in their supply portfolios. As an aggregate number, this includes all utility-owned or controlled resources whether large or small, pumped storage capacity, and Hoover entitlements. It does not include QF hydro, or resources owned by CDWR and MWD used to partially serve their own non-retail loads. Table 5-2 does not include hydroelectric components of contractual supplies such as firm power contract deliveries from Western, BPA, PacifiCorp, or other entities that own hydro assets.

Table 5-2
Forecast Dependable Hydro Capacity to meet Peak LSE Demands

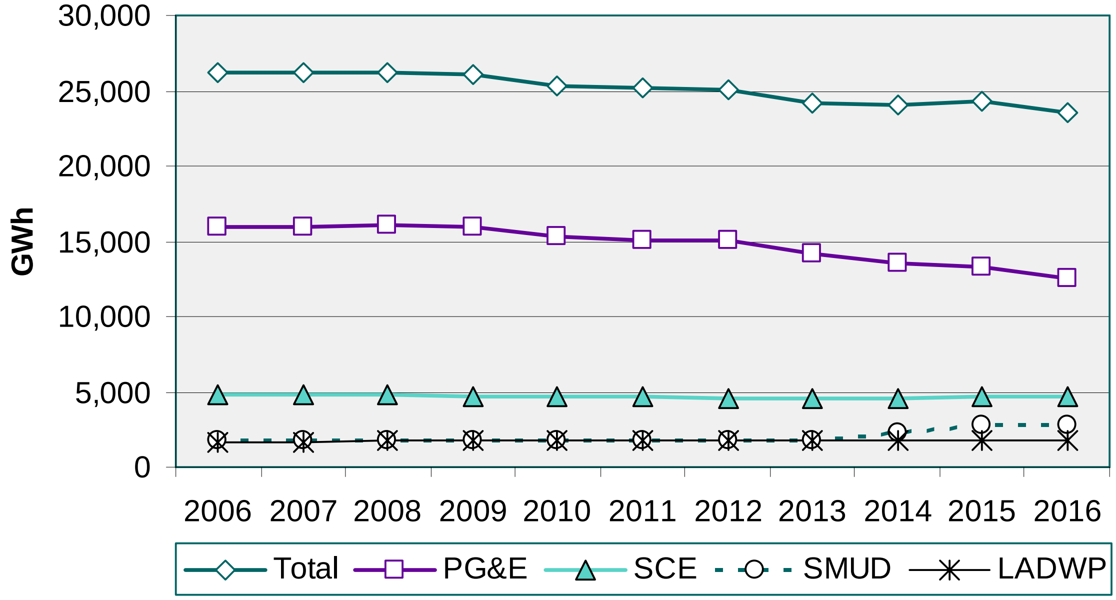
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
LADWP	1,804	1,804	1,804	1,804	1,804	1,804	1,804	1,804	1,804	1,804	1,804
SMUD	688	688	688	688	688	688	688	688	1,088	1,088	1,088
Silicon Valley	178	178	178	178	178	178	178	178	178	178	178
Turlock	135	135	135	135	135	135	135	135	135	135	135
Roseville	74	74	74	74	74	74	74	74	74	74	74
Modesto	62	62	62	62	62	62	62	62	62	62	62
Anaheim	40	40	40	40	40	40	40	40	40	40	40
Pasadena	35	35	35	35	35	35	35	35	35	35	35
Riverside	30	30	30	30	30	30	30	30	30	30	30
Burbank	20	20	20	20	20	20	20	20	20	20	20
Glendale	20	20	20	20	20	20	20	20	20	20	20
Redding	1	1	1	1	1	1	1	1	1	1	1
IOUs + IID	7,873	7,874	7,915	7,916	7,917	7,918	7,919	7,920	7,854	7,855	7,856
Total MW	10,960	10,961	11,002	11,003	11,004	11,005	11,006	11,007	11,341	11,342	11,343

Source: California Energy Commission, LSE Resource Plan data

Instructions to LSEs requested their estimates of dependable capacity under median hydrological conditions, and that they define how they use that term, or that they follow the definition endorsed by the CPUC that includes the ability to operate during four super-peak hours for three consecutive days. LADWP affirmed, for example, that dependable capacity for its Castaic pumped storage resource is 1,175 MW for one hour on any given day (subject to modest derates during facility upgrades), but is otherwise consistent throughout the forecast period. LSEs were instructed to identify reductions in capacity and energy they consider most probable as a result of new FERC license conditions, water quality certification constraints, climate change, and contract expiration. Remarkably, only one utility indicated a year-to-year reduction in hydro dependable capacity from any and all causes, and this was only for 67 MW in 2014.

As shown in Figure 5-11, PG&E forecasts a slight reduction over time in the amount of energy produced from its diverse, well-developed portfolio of utility-owned and controlled resources. Other LSEs may anticipate a similar reduction in energy output as a result of FERC licenses, including increases in in-stream flows, but their filings did not quantify and document them.

Figure 5-11
Forecast Annual Hydroelectric Energy Supplies



Source: California Energy Commission, aggregated LSE Resource Plan data

Figure 5-11 includes both forecasted and proxy data from different LSEs. However, the total annual amounts of energy from California hydro shown in Figure 5-11 do not include generation from plants owned by the CDWR or MWD. The totals include all reporting LSEs who own or control hydroelectric resources—which is about 2,000 GWh more than generated by the four largest utility portfolios: PG&E, SCE, SMUD, and LADWP. Despite their very different hydroelectric resources, SMUD and LADWP expect to generate nearly the same amounts of energy from their hydro portfolios under median hydrological conditions, at least until SMUD's 400 MW Iowa Hill Pumped Storage Project comes online in 2014.

CHAPTER 6: CALIFORNIA RETAIL ELECTRICITY PRICE OUTLOOK 2006-2016

This chapter presents an outlook on electricity retail rates for customers of California Load Serving Entities (LSEs) with peak loads more than 200 MW in 2004. The outlook covers 11 years, from 2006 through 2016.

The rate outlook in this chapter was prepared to serve as a useful baseline for electricity consumers, market participants, regulatory decision-makers, and government agencies. For example, the Energy Commission Demand Office uses this outlook as one input to the electricity demand forecast. Potential investors use this outlook to evaluate cogeneration and energy efficiency projects. Some agencies determine their future energy budgets with these rate projections. This outlook is not an absolute prediction of what future electricity rates will be since future regulatory actions, technology developments, and market changes can alter key fundamental assumptions. The projection uses the best available information and set of assumptions the staff believes probable and realistic. Many factors influence prices. The purpose of this report is to provide consumers, market participants, and policy makers with a reasonable price scenario.

The LSEs covered in this chapter include 3 investor-owned utilities (IOUs), 13 municipal and irrigation districts, and 5 Energy Service Providers (ESPs). Within each type, they are named by size, in descending order. The IOUs are: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). The publicly owned utilities (POUs) are Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utilities District (SMUD), Imperial Irrigation District, Modesto Irrigation District, Anaheim, Riverside, Turlock Irrigation District, Silicon Valley Power, Roseville Electric, Pasadena, Glendale, Burbank, and Redding Electric Utility. The ESPs are Sempra Energy Solutions, APS Energy Services, Strategic Energy LLC, Pilot Power Group, and Constellation NewEnergy.

In this outlook, the staff provides estimates of typical retail electricity rates, given projected energy prices, utility plans and programs, and regulatory decisions. There is a fundamental difference between the current price outlook and past staff retail electricity projections. In the past, staff has collected and used data and information from publicly available sources to make its projections. In the current outlook, staff solicited public and confidential information from the LSEs listed above to compile electricity rate projections. Based on LSE submittals, the staff concludes that:

- Consumers in California pay substantially higher electricity rates than consumers in other western states.

- Retail electricity rate projections for IOU consumers in California indicate a constant trend though 2016.

- The generation portion of the retail electricity price amounts to at least 50 percent for most retail customers. Larger customers pay a higher percentage. This trend will continue through the end of the outlook period.

- If current trends continue, retail electricity price differences between IOUs and POUs will diminish over the outlook period. However, IOU rates will continue to be higher than municipal/irrigation district rates.

Electricity Rates: California vs. Western States

Residential, commercial, and industrial electricity customers in California continue to pay higher retail rates than customers in other western states. Retail electricity rates for all California consumers are at least fifty percent higher than for consumers in other western states. The details are presented in Table 6-1 and Appendix C.

Table 6-1
Electricity Rates
California (CA) and Western United States (WUS)
Nominal Cents/kWh

Customer Classes	2004		2005	
	CA	WUS	CA	WUS
Residential	11.8	8.0	11.8	7.8
Commercial	11.9	7.0	11.1	6.9
Industrial	8.5	5.0	8.0	4.8

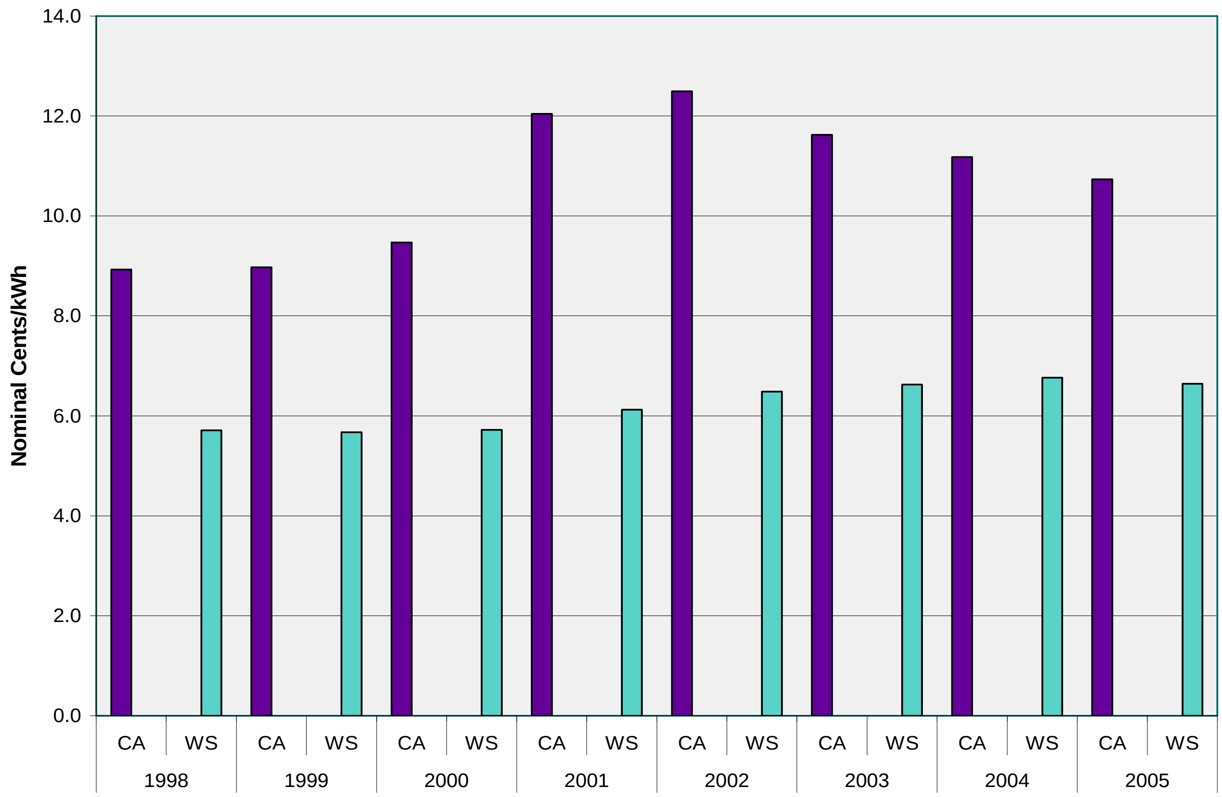
Source: EIA and Energy Commission staff

Notes: "California" retail electricity prices include investor and publicly owned utility customers. "Western United States" retail prices include Arizona, Colorado Idaho, Montana, Nevada, New Mexico Utah, Wyoming, Oregon, and Washington utility customers.

California electricity customers have historically paid higher electricity prices than customers in other western states. One of the main drivers for the electricity industry restructuring in 1998 (after passage of AB 1890 in 1996) was to lower electricity rates for consumers. From 1998 to the middle of 1999, rates were frozen for all IOU customers. On July 1, 1999, San Diego Gas and Electric (SDG&E) customers initially saw their rates slightly decline from previous levels. Rates continued at the same level for customers of the other two large IOUs. Then in the summer of 2000, electricity prices for retail consumers of SDG&E climbed as much as 100 percent due to the high cost of energy SDG&E

purchased on the open market. This price spike had serious impacts not only on California consumers, but also on consumers in other states. Overall, California consumers suffered the brunt of the crisis. Average retail electricity prices increased from approximately 9.0 cents/kWh in 1998 to 13.0 cents/kWh by the end of 2001, as indicated in Figure 6-1 and Appendix C.

Figure 6-1
Historical Average Retail Electricity Prices CA/Western States
1998-2005



Source: U. S. Energy Information Administration

The difference between commercial and industrial electricity rates in California and other western states, can be as low as 1.2 cents/kWh in Nevada and as high as 6.0 cents/kWh in Idaho, as indicated in Appendix C.

Rate Outlook 2006-2016

Retail rates are the prices consumers pay to electric utilities for the electricity they use. IOUs list some of these components in their bills to customers. Rates for IOU customers include the cost of generation, transmission, distribution, public purpose programs, competition transition charge (CTC), nuclear decommissioning, Department of Water Resources (DWR) contract costs and bond financing, and other miscellaneous charges. Although not generally listed in the bills, rates for municipal utility customers include similar costs, except that municipal utilities do not have DWR contracts, DWR bond financing, or CTC costs. Some municipal utilities collect a "rate stabilization fund" charge in their rates to cover inevitable fluctuations in energy prices like those that occurred during the 2000-2001 energy crisis.

PG&E, SCE, SDG&E and most of the municipal utilities project stable electricity prices through the outlook period. Table 6-2 indicates weighted average electricity prices for residential, commercial, and industrial customers of IOU and municipal customers through 2016.

Residential, commercial, and industrial IOU customers currently pay higher rates than their municipal utility counterparts. Although the gap for IOU and municipal residential customers narrows through the outlook period, the difference can be as high as 4.0 cents/kWh for commercial customers. For industrial customers the difference is in the 3.0 cents/kWh range. Consolidated retail prices for IOU and municipal utilities are listed in Appendix D.

Table 6-2
Average Retail Electricity Price Outlook
2005-2016
(Nominal cents/kWh)

Investor-Owned Utilities	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Residential	12.9	12.4	12.1	12.0	12.2	12.1	12.0	12.2	12.0	12.2	12.2	12.2
Commercial	14.2	14.0	13.9	14.3	14.3	14.1	13.8	14.0	13.8	14.1	14.1	14.1
Industrial	10.7	10.7	10.6	11.0	11.1	10.8	10.5	10.6	10.4	10.6	10.6	10.6
Municipal Utilities												
Residential	10.9	11.1	11.3	11.2	11.2	11.4	11.6	11.8	11.9	12.1	12.3	11.6
Commercial	9.6	9.8	9.9	9.9	10.0	10.1	10.2	10.3	10.5	10.6	10.7	10.3
Industrial	7.8	8.1	8.1	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	7.9

Source: Energy Commission staff
Note: IOU rates include Edison, PG&E, and SDG&E. POU rates include LADWP, SMUD, Imperial ID, Modesto ID, Anaheim, Riverside, Turlock, Silicon Valley Power, Roseville, Pasadena, Glendale, Burbank, and Redding.

Generation/Non-Generation Charge

As indicated in Table 6-3, most IOU electricity customers are currently paying at least 50 percent more for generation, and will continue to pay that much through

2016, if the current CPUC method of allocation does not change. Generation charges include the cost of IOU retained generation, DWR contract power cost, renewable generation, qualifying facility (QF) contracts, spot purchases, and ancillary services.

Appendix D shows current and projected IOU generation and non-generation charges by customer class. “T&D” charges include all non-generation charges including transmission, distribution, nuclear decommissioning, trust transfer amount charges, DWR bond charges, and other surcharges.

As indicated in Appendix E, larger consumers pay a higher percentage of generation costs in their rates. Although most residential customers of the three IOUs currently pay approximately 50 percent of their electricity rate on generation, commercial and industrial customers pay as much as 70 percent. This trend appears to continue through the outlook period.

Table 6-3
IOU and ESPs Average Generation, Transmission and Distribution Charge Projections
2005 - 2016

	PG&E			SCE			SDG&E			ESPs
Year	**Generation**	**T&D**	**Total**	**Generation**	**T&D**	**Total**	**Generation**	**T&D**	**Total**	**Generation**
2005	5.4	6.8	12.2	7.8	5.0	12.8	6.1	7.7	13.8	5.6
2006	6.1	5.7	11.8	8.4	5.1	13.6	6.1	7.4	13.5	5.5
2007	6.1	5.5	11.5	8.5	5.5	13.9	6.1	7.4	13.5	5.9
2008	6.2	5.3	11.4	8.3	5.2	13.5	6.1	7.0	13.1	5.4
2009	6.2	5.5	11.7	8.2	5.4	13.5	6.1	7.0	13.1	5.5
2010	6.0	5.6	11.6	8.2	5.5	13.7	6.1	7.0	13.1	5.5
2011	5.7	5.8	11.5	8.1	5.6	13.7	6.1	7.0	13.1	5.6
2012	5.8	5.9	11.8	7.9	5.7	13.6	6.1	7.0	13.1	5.7
2013	5.9	5.7	11.7	7.9	5.8	13.7	6.1	7.0	13.1	5.8
2014	6.1	5.9	12.0	7.9	5.9	13.8	6.1	7.0	13.1	5.8
2015	NA	NA	NA	7.9	6.1	13.9	6.1	7.0	13.1	5.8
2016	NA	NA	NA	7.9	6.2	14.1	6.1	7.0	13.1	5.8

Source: IOU Retail Electricity Price Projection filing for the Energy Commission’s 2005 Energy Report

Notes: ESPs used to derive an average generation charge were Sempra Energy Solutions, APS Energy Services, Pilot Power Group, Strategic Energy, and Constellation NewEnergy. ESP generation costs do not include surcharges such as exit fees and DWR contract costs.

ENDNOTES

[1] California Energy Commission, 'Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements,' 100-04-005D identified power plants at risk of retirement.
[2] California's Energy Action Plan: Preferred Loading Order of Resources
[3] "Overview of the Electric System Today," Michehl R. Gent, North American Electric Reliability Council, April 2003, http://www.energetics.com/meetings/electric/pdfs/presentations/mgent.pdf.
[4] <http://www.wecc.biz/documents/library/staff/membership/WECCMembers.pdf>
[5] <http://www.wecc.biz/documents/meetings/Joint/2005/June/PCC/Power_Supply_Report_06-01-05.pdf>
[6] The model is called the Supply Adequacy Model.
[7] The reserve requirements were defined as WSCC Power Supply Design Criteria and as the WECC Planning Coordination Committee's guidelines.
[8] The power supply design criteria are described in Attachment 7 of http://www.wecc.biz/documents/meetings/board/2005/April/PCC_Report_Complete_Background Material.pdf.
[9] See all other WECC *Power Supply Assessments* at http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=56.
[10] http://www.energy.ca.gov/2005publications/CEC-700-2005-006/CEC-700-2005-006-SD.PDF
[11] http://www.energy.ca.gov/electricity/wscc_proposed_generation.html
[12] The BPA decided to discount electrical rates for 577 MW of power delivered to three aluminum companies and a paper mill over the next five years. According to BPA administrator Steve Wright, the decision was difficult, but warranted to keep important jobs in the region and to support the economy of many Northwest communities. See: "Manufacturers get a deal from BPA," Associated Press article printed in *The Register-Guard,* July 5, 2005.
[13] *2003 Pacific Northwest Loads and Resources Study (White Book),* Bonneville Power Administration, December 16, 2004, http://www.bpa.gov/power/pgp/whitebook/2003/.
[14] http://www.nwcouncil.org/energy/powerplan/plan/Default.htm
[15] "Table A-2: Regional Exports 2005-2014 Operating Years 2003 White Book," Technical Appendix 1, *Pacific Northwest Loads and Resources Study 2003*, Bonneville Power Administration, http://www.bpa.gov/power/pgp/whitebook/2003/. Go to Technical Appendix - Volume 1, Energy Analysis (DOE/BP-3560).
[16] Meeting Notes from Power Net Revenue Improvement Sounding Board, Bonneville Power Administration, January 16, 2004, http://www.bpa.gov/Power/PL/pnrisb/01-16-2004_Mtg_Notes.pdf.
[17] The Columbia River System Inside Story, Federal Columbia River Power System, second edition, April 2001, page 7, http://www.bpa.gov/power/pg/columbia_river_inside_story.pdf. Additional nameplate capacity is provided by the hydroelectric dams on the Snake River, which is also part of the FCRPS.
[18] Meeting Notes from Power Net Revenue Improvement Sounding Board, Bonneville Power Administration, January 16, 2004, http://www.bpa.gov/Power/PL/pnrisb/01-16-2004_Mtg_Notes.pdf.
[19] See *BPA's Daily Notice* webpage at http://www.bpa.gov/power/psb/dailyoffer/daily.shtml.
[20] http://www.bpa.gov/power/pl/regionaldialogue/02-04-2005_policy.pdf
[21] http://www.bpa.gov/corporate/business/restructuring/Docs/2005/RA_Letter_060805.pdf
[22] Canadian Electricity Exports and Imports An Energy Market Assessment, National Energy Board, January 2003, Page 14, http://www.neb-one.gc.ca/energy/EnergyReports/EMAElectricityExportsImportsCanada2003_e.pdf.
[23] The reciprocity provisions allow Canadian entities access to U.S. electricity markets if Canada allows U.S. entities access to Canadian markets.

[24] In 1998, "Other" included imports to Arizona, Idaho, and Utah and, in 2000, it included imports to Arizona, Idaho, and New Mexico.
[25] This table was prepared with data compiled from National Energy Board Annual Reports from 1998 through 2004, Table E8, Electricity Trade Between the United States and Canada, See http://www.neb-one.gc.ca/Publications/index_e.htm#AnnualReports. Data on imports by Alaska and Nebraska were omitted.
[26] Canadian Electricity Exports and Imports An Energy Market Assessment, National Energy Board, January 2003, Page 14, http://www.neb-one.gc.ca/energy/EnergyReports/EMAElectricityExportsImportsCanada2003_e.pdf.
[27] *Oil Sands Co-generation Potential: Survey Results,* Co-generation/Transmission Sub-Committee of the Athabasca Regional Issues Working Group, March 29, 2005, http://www.oilsands.cc/pdfs/RIWG%20Co-gen-Transmission%20Report%202005.pdf.
[28] See: http://www.northernlightstransmission.com/
[29] The data is not temperature adjusted which could explain the "spike" from years 2002 to 2003 in peak demand, and to a lesser extent, energy use.
[30] This data is not adjusted for differences in temperature which could explain the substantial increase in peak from 2002 to 2003, and the decrease in peak load from 2003-2004.
[31] Exceptions to this restriction include small generators and facilities installed to address reliability concerns.
[32] Assembly Bill No. 57, Statutes of 2002, Section 454.5(b)(9)(A).
[33] Decision 04-12-048, December 16, 2004, pages 77-78.
[34] Ken Malloy, Center for Advancement of Energy Markets, CAEM Morning Report, March 29, 2005.
[35] "Bringing Consumer Choice to Electricity" by The Honorable Thomas DeLay, Heritage Lecture #582. April 8, 1997, http://www.heritage.org/Research/EnergyandEnvironment/HL582.cfm
[36] Electricity service provided by publicly owned utilities, such as the City of Palo Alto and Modesto Irrigation District, is not regulated by the CPUC.
[37] "Direct access" implies that electricity is purchased wholesale, directly from generators. Instead, direct-access providers are purchasing the electricity wholesale, not their customers.
[38] Every alternative energy supplier must be registered with the CPUC. The following types of alternative electricity suppliers operate within the local utility's service territory, breaking the utility's previously held exclusive right to sell power: unregulated affiliates of other electric companies located in California, unregulated affiliates of other electric companies located in other states; and electric power marketers or brokers who purchase electricity from many electricity generating companies and then sold it to California customers.
[39] In some cases, alternative electricity suppliers sold higher-priced "green power" from renewable energy sources.
[40] The Legislature enacted a reduction and freeze on residential rates (10 percent less than the cost of electricity in 1994) as part of AB 1890. At the beginning of electric industry restructuring, wholesale electricity prices were less than the frozen residential rates which made it possible for alternative electricity suppliers to attract new customers.
41 "North County Businesses Rush to Get 'Direct Access'," Denis Devine, *North County Times,* http://www.commerceenergygroup.com/media_center/media_coverage/07_02_01.htm.
[42] The Legislature asked the CPUC to delay its suspension decision so that the Legislature would have more time for finding a way to preserve direct access, as requested by alternative electricity suppliers and their customers.
[43] CPUC Decision 01-09-060 September 20, 2001 http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION%5C/9812.doc
[44] California Public Utilities Commission, Supplemental Direct Access Implementation Activities Report, Statewide Summary, March 15, 2005, http://www.cpuc.ca.gov/static/industry/electric/electric+markets/direct+access/todatefebruary2005_web.xls.
[45] See http://www.cpuc.ca.gov/published/ESP_Lists/esp_udc.htm

[46] Statement of Commissioner Susan P. Kennedy, Western Energy Institute Annual Meeting, San Francisco, California, September 20, 2004, http://www.cpuc.ca.gov/static/aboutcpuc/commissioners/03kennedy/statements/040920_speech_wei_annual_meeting.pdf

[47] There is controversy about the amount of this exit fee, because it is not high enough to truly cover the direct access customers' share of DWR costs in a timely manner. The shortfall in collections is being "loaned" to direct-access customers by the local utilities' retail customers. The CPUC majority reasoned that a cap on the exit fee was necessary to "maintain the viability of existing direct access contracts."

[48] Former AB 1284 (Leslie)

[49] Public goods funds are collected as part of the local utility's distribution costs, not its power supply costs.

[50] CPUC Ruling under proceeding 04-04-003, page 181.

[51] If a reserve margin different from 15 percent is used by the LSE, the LSE's resource gap will differ.

CALIFORNIA AND WESTERN ELECTRICITY SUPPLY OUTLOOK REPORT APPENDICES A-E

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APPENDIX A: 2006 – 2008 CALIFORNIA ADDITIONS AND RETIREMENTS

CA ISO Control Area

SP26

Additions

Name	MW	Expected By Summer
Malburg	129	2006
Riverside ERC	85	2006
Mountainview	1012	2006
Palomar Escondido	480	2006
	1706	
Otay Mesa	550	2008
	550	

Retirements (High Risk)

Name	MW	Date
Coolwater 1/2	-146	2005
Mandalay 1/2	-433	2006
Ormond	-1491	2006
South Bay 4	-170	2006
	-2240	
El Segundo	-670	2007
Etiwanda 3/4	-640	2007
	-1310	
Coolwater 3/4	-482	2008
South Bay 1-3	-471	2008
Encina 1-5	-947	2008
	-1900	

NP26

Additions

Name	MW	Expected By Summer
Ripon	86	2006
Walnut Energy Center	240	2006
San Francisco Peaker	40	2006
	366	

Retirements (High Risk)

Name	MW	Date
Morro Bay 1/2 (Mothballed)	-326	2005
Pittsburg 7	-680	2006
	-1006	
Contra Costa 6	-336	2008
Contra Costa 7	-336	2008
Morro Bay 3/4	-679	2008
Pittsburg 5/6	-632	2008
	-1983	

Non-CA ISO Control Areas

LADWP & IID Control Areas

Additions

Name	MW	Expected By Summer
Salton Sea #6 with Amendment	215	2008
El Centro 3 upgrades	37	2008
Haynes 5 & 6 Repower	599	2008
	851	

SMUD Control Area

Additions

Name	MW	Expected By Summer
Cosumnes	480	2006
	480	
Roseville Combined Cycle	153	2007
	153	

APPENDIX B: SUMMARIES OF LSE SUPPLY RESOURCE PLANS

Table B-1
Forecast Annual Peak Loads (MW) of Publicly Owned Utilities (POUs)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
LADWP	5,585	5,667	5,750	5,817	5,892	5,957	6,014	6,064	6,114	6,165	6,219
SMUD	3,005	3,064	3,125	3,184	3,246	3,308	3,371	3,431	3,492	3,550	3,598
Modesto	679	703	726	753	779	807	833	864	889	917	946
Anaheim	557	570	580	591	601	614	622	633	642	651	662
Riverside	539	544	550	555	561	572	584	595	606	618	630
Turlock	482	489	496	504	511	518	525	533	541	548	556
Silicon Valley	435	449	456	462	469	476	484	491	491	506	513
Roseville	337	353	372	390	405	418	423	426	430		
Pasadena	299	302	305	308	311	314	317	320	323	327	330
Glendale	286	290	294	298	303	308	312	316	320	324	328
Burbank	283	287	292	296	300	305	309	314	319	324	328
Redding	247	254	261	269	277	285	293	302	312	322	332
Totals	12,734	12,972	13,207	13,427	13,654	13,882	14,089	14,289	14,479	14,252	14,441

Source: California Energy Commission, LSE Resource Plan data

Publicly Owned Utilities

Los Angeles Department of Water & Power (LADWP)

Existing Resources

For each and every month beginning in January 2006 through May 2008, the Los Angeles Department of Water and Power (LADWP) has 5,425 MW of dependable capacity from fossil and nuclear resources. This total could decline slightly to 5,381 MW when repowering of Haynes begins and is then forecast to be 5,439 MW for the last four years of the forecast period through 2016.

About 63 percent of this capacity comes from four in-basin gas-fired plants: 803 MW Scattergood, 580 MW Valley, 463 MW Harbor, and 1,548 MW Haynes (using 2006 figures). LADWP also has dependable capacity and firm transmission from hydroelectric, nuclear, and coal-fired resources that are physically located in other states, but not designated as “imports.” These distant resources include Hoover

Dam (463 MW), Palo Verde (368 MW), Intermountain (1,186 MW), and Navajo (477 MW). LADWP has 10 percent ownership in Mojave, which will go offline by January 2006 and is it is assumed to stay off-line during the forecast period. Actual operation of Mojave may change as owners resolve pending issues or provide for alternative options.

The Castaic hydroelectric plant, on the West Branch of the California Aqueduct, provides 1,175 MW of valuable pumped-storage capacity. Modernization activities and storm damage may temporarily reduce this capacity to 872 MW while 10 MW of increased capacity is added to each of the six turbines. This modernization will add flexibility and energy efficiency to operations but is not expected to increase total plant generating capacity. LADWP delivers energy to CDWR in tandem with water deliveries through the system, equal to an average 45 MW.

During most years, LADWP can count on 166 MW from its series of large and small hydro plants located in the Owens Gorge, Owens Valley, and along the two aqueducts that deliver drinking water to the City of Los Angeles.

Because of its strong record on reliability first and low retail rates second, LADWP does not expect to lose customers to direct access retailers or community choice organizations.

LADWP was the only publicly owned utility to voluntarily provide numbers for three prominent if modest types of supply preferred resources. LADWP predicts slight adjustments to load from distributed generation (about 2 MW per year), and modest adjustments from future energy efficiency programs (from 9 to 18 MW per year). Dispatchable demand response counts for 30 MW throughout the forecast period.

LADWP does not have QF contracts or bilateral supply contracts, as defined by EIA. Also, although LADWP does have power purchase agreements with a few owners of cogeneration plants, it does not count on these facilities for any dependable capacity. Emerging technologies such as fuel cells and microturbines provide a modest amount of energy, but are not counted on for capacity during the forecast period.

Economy purchases represent an optional supply source for LADWP but are not counted as dependable capacity to serve forecast load. These purchases are often negotiated in the short-term or spot markets when it is economical for LADWP to do so. Many of these economy purchases can be delivered from out-of-state generating resources using LADWP’s extensive transmission network, especially when output from its in-basin less efficient gas plants can be reduced to RMR levels. These economy purchases are limited mainly by the need to run in-basin plants certain minimum amounts in order to: provide local voltage support, maintain grid stability, and meet operating reserve requirements. For LADWP, these requirements are related to the largest single contingency (outage) in the supply portfolio. This single-largest contingency would be a forced outage or loss of transmission from the Intermountain coal plant (1,186 MW) near Delta, Utah.

Based on WECC reserve requirements and this contingency, LADWP is required to maintain around 1,100 MW of planning reserve margin, which is nearly a 20 percent planning reserve margin, significantly higher than the 15 percent to 17 percent margin that the CPUC has mandated for the IOUs.

Peak Demand

August is the peak demand month for LADWP. The net demand for retail customers is expected to rise from 5,585 MW in August 2006, to 6,219 MW in August 2016. For years 2010 through 2016, LADWP used proxy numbers for resources and loads. LADWP staff emphasize these proxy numbers have not yet been approved by LADWP governing authorities, but were provided to the Energy Commission using staff's best engineering judgement. The firm peak resource requirement includes a planning reserve margin of 1,100 MW, pursuant to WECC operating criteria and the average 45 MW obligation to CDWR.

Incremental Resource Needs

LADWP anticipates adding 60 MW of dependable capacity from generic (unnamed) renewable resources in 2010, plus another 60 MW in 2012, 2014 and 2016. Using existing and planned (named) resources, plus 240+ MW generic renewable resources and additional purchases of generic renewable resources, LADWP will have adequate electricity supplies to meet forecast load through 2016. This expectation of resource adequacy includes the 1,100 MW planning reserve margin and scheduled re-powering of Haynes and Scattergood.

Energy Requirements

August is the peak month for total energy demand. In 2006, the utility's total energy requirement, including economy sales, is pegged at 28,441 GWh. This amount increases to 31,727 GWh in 2016, representing an annual increase of about 1.1 percent.

Renewable Resources

LADWP has a strong preference for utility-owned and controlled resources, but may use contracted renewable energy supplies if they are necessary to achieve its RPS goals. LADWP expects to purchase about 250 GWh of renewable energy annually as part of its economy purchases. In the Tehachapi wind resource area, LADWP is developing Pine Tree Wind (120 MW nameplate), expected to be online in 2006 and producing 364 GWh annually. Significant biomass production is expected starting in 2008 (368 GWh per year). The Bradley landfill should contribute another 38 GWh each year.

Using the state-definition of eligible renewable resources, total amounts of renewable energy from both existing and planned resources and renewable energy purchases are forecast to grow from 1,075 GWh in 2006, to 4,639 GWh in 2016. These figures include generic renewable resource additions, which may grow from 278 GWh in 2006 to 3,420 GWh in 2016. Counting generic additions, renewable energy from utility-controlled resources and purchases will grow from 4 percent of total bundled customer load in 2006 to 15.2 percent in 2016.

For local reporting, energy from Hoover Dam (624 GWh) and Castaic Pumped Storage Facility (914 GWh) will not be counted towards meeting LADWP's renewable goals. However, LADWP will count as renewable all annual generation from Owens Gorge (228 GWh), Owens Valley (46 GWh), and aqueduct hydro plants (345 GWh). This is in accordance with recent Los Angeles City Council decisions which set ambitious RPS goals, and would not use the 30 MW nameplate distinction between state-defined eligible renewable resources and large hydro. By its own accounting, renewable energy will reach 13 percent in year 2010, and 19 percent by year 2016. These figures include generic renewable resource additions. LADWP will also count renewable energy from digester gas from the Hyperion sewage treatment plant, a fuel delivered for combustion with natural gas at nearby Scattergood.

Resource Planning Strategy and Goals

LADWP's approved "2000 Integrated Resource Plan" was designed to repower LADWP's 10 aging in-basin units while maintaining its paramount objectives: reliable service to customers, competitive price, and environmental leadership. At that time, LADWP set a goal meeting 50 percent of load growth (about 40 MW per year) with energy efficiency, renewable resources, and decentralized small-scale power sources. LADWP intends to remain a self-sufficient electricity supplier.

Uncertainties of Concern to LADWP

LADWP staff is currently preparing a new 10-year integrated resource plan. LADWP is the largest municipal electric utility in the nation, and serves about 10 percent of the load in California, while owning about 28 percent of high voltage transmission import capacity into California. Its electric service area is the City of Los Angeles, plus a small area in the Owens Valley. LADWP shares many of the concerns affecting a major LSE, an active market participant, an owner-operator of gas-fired and hydro generation, a responsible control area operator, and an owner of an extensive interstate transmission system. As a Department of city government, LADWP is ultimately responsible to publicly elected leadership, as well as to its rate-paying customers. LADWP is expected to provide funds for public benefit programs, such as low income energy assistance, and to transfer to the City's General Fund a certain percentage of the previous year's gross revenues. If net revenues from energy sales are less than expected, DWP is vulnerable to reductions in its long-term capital outlays and other controllable expenses. Proposed funding for the RPS goals will be made through a surcharge to customer rates, which is subject to Los Angeles City Council approval.

In its demand data filing with the Energy Commission, LADWP stated, "Population is probably the most significant variable in the forecast for the years 2010 and beyond" ("Retail Electric Sales and Demand Forecast" by City of Los Angeles Department of Water and Power, October 2004, page 5). While that demand driver is known, its weight is unknown. "The bottom line for LADWP is that there is no consensus on the population forecast, which adds uncertainty to the [demand] forecast." LADWP does not expect a large growth in peak summer demand. "A key assumption in the [demand] Forecast is that Peak Demand will grow at the same rate as NEL. This assumption implies a constant load factor over time. Over the past 10 years, the System Load Factor has been increasing. We attribute the increase in load factor to energy efficiency improvements, load shifting and the initial development of distributed generation."

Given the importance of its in-basin gas-fired generation, LADWP is concerned about current and forecasted prices of natural gas supplies. LADWP projects gas costs, has a natural gas financial hedging program, and now has a natural gas field in Southwestern Wyoming. LADWP regards the data as trade secrets, and the Energy Commission has granted confidentiality to this data about gas costs and hedging for three years.

Spot Market Supplies

DWP makes good use of short-term spot markets to save money, compared with the cost of DWP in-basin production. In August 2000, DWP saw routine reliance on short-term or wholesale markets as "an unacceptably risky situation for DWP and its customers" because this "wholesale market is one where energy is rationed by price and where the energy shortages can be created by market gaming rather than actual shortages."

Sacramento Municipal Utility District (SMUD)

Existing Resources

Sacramento Municipal Utility District (SMUD) is the second largest publicly owned utility in California. In 2006, SMUD expects to have 3,055 MW of dependable capacity to serve load obligations, 50 MW from interruptible and emergency programs, and another 150 MW from dispatchable demand response. SMUD forecasts 1,001 MW of utility-controlled fossil resources throughout the forecast period. This includes: McClellan 72 MW, Campbell's Soup 172 MW, Proctor & Gamble 163 MW, Carson Ice 94 MW, and 500 MW at Cosumnes Phase 1. SMUD's Upper South Fork American River Project supplies 647 MW large hydro and 41 MW of small hydro. By July of 2014, an additional 400 MW of renewable pumped storage at Iowa Hill may be online. Capacity from renewable contracts comes from Camp Far West 8 MW (small hydro), PPM Wind 19 MW, Keifer Landfill 8 MW, Calpine Geothermal 50 MW, and Snohomish PUD 36 MW. Other bilateral contracts total 1,132 MW in July 2006. This bilateral contract supply amount decreases each year to 315 MW in July 2016.

Peak Demand

SMUD's forecasts net peak demand for its bundled customers to be 2,938 MW in 2006, increasing to 3,535 MW in 2016. Demand is forecasted to peak in July of each year. For this peak resource requirement, the average annual increase over the forecast period is 1.9 percent. Near-term annual increases are highest: 2006-7 is 2.1 percent, and 2007-8 is 2.0 percent.

SMUD reports modest amounts of distributed generation as an adjustment to the load forecast. In July 2006, there will be 13.6 MW of distributed generation in place, an amount expected to grow steadily to 15.1 MW by July 2016.

Incremental Resource Needs

SMUD counts Cosumnes 1 as available by Jan 2006, though the plant's construction is delayed by a legal dispute with the project developer. Looking at line 48 "total capacity" and comparing with line 12 "firm peak resource requirement" shows that SMUD has surplus capacity until summer 2008, when small capacity deficits begin (4 MW in June, 5 MW in July, 21 MW in August, 20 MW in September). Surpluses remain throughout the non-summer months but re-appear each summer from 2009 through 2016.

Energy Requirements

SMUD's "Net Energy for Bundled Customers" have the same values as "Total Energy Requirement," with exceptions in 2005 and 2006 that account for firm energy sales (exchange). The Total Energy Requirements average annual increase over the period is 1.6 percent.

Renewable Resources

SMUD's Solano Wind Farm is located near Montezuma Hills Road in Solano County. The Wind Farm Project's 182 MW of capacity will be developed in phases between 2003 and 2011. Transmission service to SMUD is provided by PG&E through the CA ISO.

Solano Wind Farm Phase 1 is currently in commercial operation and generates about 46 GWh a year. The wind farm consists of 23 Vestas V47 wind turbines with a combined nameplate capacity of 15 MW.

SMUD estimates that the marginal wind resource needed to help reach a 28 percent eligible "renewables" target would cost SMUD an extra $15/MWh over what it would otherwise procure. This $15/MWh premium for eligible renewable resources is up from the current estimate of $5/MWWh. SMUD plans to add more wind to its Montezuma Hills land resource, using new 2 MW to 3 MW large turbines, but at a slower pace of development due to higher capital costs.

Resource Planning Strategy and Goals

The Sacramento Municipal Utility District has these resource planning principles:

- Reduce costs to customers and provide greater price stability.
- Improve reliability of its electrical system.
- Retain flexibility in evolving energy markets.

Uncertainties of Concern to SMUD

SMUD's Upper American River Project is subject to large year-to-year variations in hydro generation due to above or below average precipitation. Because of this variation and its impact on SMUD's supply budget, SMUD has weather hedge agreements to mitigate the financial impact.

Another uncertainty facing SMUD is the proposed annexation of the cities of Davis, West Sacramento, and Woodland in eastern Yolo County. The potential impact of this annexation was being studied by SMUD staff in April 2005, so this potential was not included or assumed in the supply Resource Plan submitted to the Energy

Commission. A feasibility study commissioned by SMUD and the cities of Davis, West Sacramento and Woodland is currently available on the Internet at http://www.smud.org/annexation/beck_study.html

Spot Market Supplies

SMUD expects to rely on spot market purchases (beginning in July 2006) for about 100 MW, about 3.4 percent of its forecast peak demand. This use of short-term and spot-market purchases increases to 575 MW in 2013 but assumes that Cosumnes Phase 2 with 500 MW will not built.

Imperial Irrigation District (IID)

Introduction

Imperial Irrigation District (IID) is the sixth largest load-serving electric utility in the state, and operates one of four control areas located entirely within California. In response to the Energy Commission request for supply data, IID provided new information forms S-1, S-2, and S-3. Since this new information is in draft form and needs to be approved by the Board before it is made public, IID requested confidentiality for their submission for two years. Confidentiality was granted for the entire forecast horizon for the next two years, with the understanding that the information would be made public well before two years. IID also provided information on bilateral contract supplies using form S-5, but this information is not considered confidential. Along with other LSEs requesting Resource Plan confidentiality, the Executive Director requested that IID consent to a proposal that would allow aggregated summary tables to be published. IID granted this request, and energy and capacity tables were published in Energy Commission Staff paper CEC-150-2005-001 on June 29, 2005.

Much of the information presented below was compiled from IID's 2003-2004 Annual Report and press releases posted on the utility's website.

Existing Resources

IID-owned resources include: 24 MW of low-head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, 162 MW of peaking gas turbines, and shares of other plants including 104 MW at San Juan and 14 MW at Palo Verde.

IID has a contract for 25 MW of firm capacity with Coral Power, LLC. This contract began on May 1, 2003 and expires December 31, 2007. The agreement is not unit contingent, is not dispatchable, and has no associated dependable capacity. This appears to be a 7X24 contract though it is not explicitly stated..

In September 2000, IID signed contract with Calpine Power Services Company for a 150 MW share of South Point Energy Center. This contract provides both capacity and energy through April 30, 2007.

Although IID's rates are not regulated by the FERC, as IID is non-jurisdictional, in a May 25, 2005 decision (Docket No. ER01-2887-003) on an updated market power analysis governing other purchasers, FERC concluded that South Point Energy Center satisfies FERC's standards for market-based rates, so that the next updated market power analysis is not due for three years.

IID recommissioned the Double Weir Mini Hydro Project, capable of generating 360 kW. It was scheduled to begin generating on April 19, 2005. The project was first commissioned in 1961, and taken out of service in 1986 due to mechanical problems. The $2.5 million project was funded by the Public Benefits Charge; it came in on schedule and $500,000 under budget.

IID can count on 14 MW of dependable capacity and 100 GWh of monthly energy from nearby Palo Verde Nuclear Station in Western Arizona.

Peak Demand

In 2004, IID served a peak load of 870 MW, with 1,050 MW (nameplate) of generating resources. The IID service area includes all of Imperial County, the Coachella Valley in Riverside County, and parts of Eastern San Diego County.

In 2003, the peak load at 4 p.m. on July 15 was 792 MW, a 7 percent increase over the previous peak in 2002. IID's projection for 2003 was 3 percent load growth. To cover the increase, the utility needed 100 MW of additional capacity, which was met with short-term contracts instead of its combustion turbines. In 2009, this net peak demand (not including a 15 percent planning reserve margin) is expected to be 1,064 MW. By 2016, net peak demand is expected to be about 1,334 MW.

For its uncommitted dispatchable demand response, IID plans to join other large energy users, offering financial incentives to help balance load during high-demand hours in the summer.

Incremental Resource Needs

In April 2005, IID announced expansion of its contract with Inland Energy Consulting to assist with RFPs and contract development for renewable and source supplies. Both RFPs are expected to be released in 2005.

In May 2005, IID announced that a one-month open season would be held in June 2005 for suppliers holding existing, valid contracts to provide energy and capacity from units not yet in commercial operation, allowing them to extend their existing agreements by one year. The open season could apply to a 20-year contract with Guepard Energy, Inc. for firm, unit contingent must-take energy from an as-yet-unconstructed 18 MW generation facility. The contract began in December 2003 and expires July 1, 2005.

In May 2005, the Board authorized IID Energy to begin construction of two generation facilities that will add 350 MW of capacity to the system. The projects were identified through a competitive solicitation. One project, scheduled to begin operation in 2008, is the Niland Combustion Turbine Project (100 MW), which can be expanded to a 140 MW combined-cycle unit. The second project is the repowering of El Centro Unit 3, converting it to a combined-cycle gas-fired unit and upgrading its capacity to 120 MW. Power deliveries are scheduled to begin in 2009. Total projected cost is $200 million.

Additional contracts are in negotiation, including a 10-year contract for 50 MW, with energy delivery beginning as early as 2006. IID is seeking four five-year contracts for 25 MW from a variety of producers. Of the four contracts, IID will seek three contracts with call options.

In general, IID expects that as peak demand grows, a new 50 MW gas-fired LM6000 unit could be added to the utility-owned generation portfolio roughly every two years.

Energy Requirements

Mid-range projections for load growth in the Imperial Valley and the Coachella Valley are 5.5 percent and 8.85 percent, respectively. The annual average increase was previously estimated at 5 percent, but actually exceeded 8 percent in 2004. A press release in June 2005 states that IID serves 122,000 customers.

Forecast energy demand for all of 2009 is estimated at 4,207 GWh. By 2016, annual energy demand is expected to grow to 5,271 GWh.

Renewable Resources

IID provided contract information for a geothermal facility. In 2001, IID announced a unit-contingent contract with CalEnergy for 170 MW Salton Sea Geothermal for 20 years from its commercial operation date. The project was delayed but is now expected to be online in 2006. The ramp-up was supposed to begin at 40 MW in 2005, reaching 170 MW in 2007. Delivery is must-take and year-round.

In January 2004, IID announced an interconnection agreement with CalEnergy Obsidian Energy LLC for access to generation from the Salton Sea Unit 6 Geothermal Plant (185 MW). Later press releases cite 200 MW of geothermal under contract. Although not required to comply with the state's renewable energy targets, IID's purchase of 200 MW of geothermal energy from Salton Sea 6 coupled with its existing geothermal and hydro generation, exceeds the state's principle renewable energy goal. That goal is for each LSE to supply 20 percent of its retail sales energy from renewable resources by 2017.

For the forecast period 2009-2016, energy demand is estimated to total 37,760 GWh. This number includes transmission losses, distribution losses, and "UFE" (unaccounted for energy), so it is slightly higher than ultimate retail sales numbers. In this same time period, IID expects to receive 12,416 GWh of geothermal energy from Salton Sea 6, plus 1,881 GWh from small hydro plants (less than 30 MW nameplate). Thus, these two sources of eligible renewable energy are forecast to provide 37.8 percent of the GWh needed to serve retail loads during this time. IID also expects to have 1,254 GWh from large hydroelectric resources.

Resource Planning Strategy and Goals

While IID provided the data requested on the electricity supply forms, the utility did not provide the requested statements about uncertainties, risk factors, or strategies it considers useful for addressing those concerns. IID was always cordial, professional, and responsive to information requests originating in Sacramento, and has been careful to provide information voluntarily, stating "Imperial Irrigation District does not acknowledge the jurisdictional authority of the agencies collecting this data to require municipally owned utilities and/or irrigation districts' compliance with this request …" Staff gratefully acknowledges the data and information provided by IID.

Uncertainties of Concern

None stated.

Spot Market Supplies

To address its ongoing need for access to spot market energy, IID joined Public Power Initiative of the West (PPIW) and jointly developed the http://www.westtrans.net website. The website sponsors celebrated their first year of operation on March 31, 2005. The website provides a single internet site where information is posted on available transmission capacity, and resources are posted for bidding and offline negotiations. The information is updated every hour.. The website organizes 20 public and private transmission providers in 13 western states seeking available transmission capacity to serve 5.5 million energy customers on 24 networks through 27,000 miles of power lines.

For the years 2009 through 2016, IID does not indicate an intention to use the spot market or short-term markets for dependable capacity.

Modesto Irrigation District (MID)

Existing Resources

Modesto Irrigation District (MID) has three utility-controlled fossil-fueled plants: McClure (two combustion turbines), Ripon (two combustion turbines), and Woodland (two combined-cycle units). Dependable capacity from these three plants varies only slightly throughout the forecast horizon: 330 MW during most months, and 327 MW for a summer derate.

MID’s share of hydro capacity from Don Pedro is constant at 62 MW for all months except October and November, when it drops to 15 MW. New Hogan reservoir provides a constant 3 MW of small hydro supply. Modesto’s total capacity from existing and planned resources is forecast to increase from 739 MW in August 2006 to 795 MW in August 2016.

For non-traditional “supply” resources, Modesto expects interruptible and emergency programs to help reduce loads by 22 MW from May through September in all years of the forecast period. Dispatchable demand response increases from 11 to 18 MW for this period.

Peak Demand

Modesto’s firm peak resource requirement increases from 772 MW in August 2006 to 1,085 MW in August 2016. These figures include a 3 MW per month allocation for firm sales commitments, and a 15 percent planning reserve margin. A 62 MW purchase from Hetch Hetchy (City and County of San Francisco) is supplied with its own reserves. Like all other POUs, Modesto does not expect customer load to depart to direct access retailers or community choice organizations.

Incremental Resource Needs

Modesto plans to purchase small amounts of capacity from the spot market in two of the summer months in 2006. Spot market purchases may increase to 185 MW in Aug 2009. Modesto plans to add 150 MW of generic base load capacity in January

2010 after which spot market purchases will drop sharply. Another 50 MW of generic baseload may be added in Jan 2013 and Jan 2016.

Energy Requirements

The average annual energy increase for MID is 3 percent per year, going from 2,659 GWh in 2006 to 3,609 GWh in 2016. Wholesale energy sales are projected to remain at 10 GWh per year throughout the forecast horizon.

Renewable Resources

Modesto has two existing renewable supply contracts. Future Winds capacity maximizes in September in all years, and increases from 15 MW in 2006 to 29 MW in 2016. The High Winds contract (4 to 15 MW) expires in spring 2014. Modesto does not list any capacity from generic renewable resource additions. However, MID shows generic renewable energy supply beginning in 2011 with 74 GWh, increasing to 1,040 GWh in 2016.

Resource Planning Strategy and Goals

Modesto ID's portfolio is dominated by natural gas- fired generation, so MID hedges its gas portfolio to minimize the impact of gas price swings.

Uncertainties of Concern to Modesto ID

No statements about risk assessments were provided.

Spot Market Supplies

In the adverse hydro scenario, MID elects to add spot purchases to cover shortfalls in capacity as long-term contracts expire.

City of Anaheim, Public Utilities Department

Existing Resources

The City of Anaheim, Public Utilities Department owns only one thermal generating resource outright, Anaheim CTG, with 44 to 46 MW of dependable capacity. Anaheim has entitlements to power from out-of-state coal resources: Intermountain

(IPP) Units 1 and 2 (236 MW), and San Juan 4 (47 MW). Anaheim takes 70 MW of baseload nuclear power from San Onofre Units 2 and 3 through most of 2009, but does not expect to continue its ownership share of that resource after the steam generator replacement project begins.

August is always the peak demand month for Anaheim. September peak demands are consistently 3 MW or 4 MW less than in August. For August 2006, dependable capacity of existing and planned resources are estimated at 586 MW, declining to 549 MW in August 2016. Anaheim does not show capacity for uncommitted dispatchable demand response, interruptible programs, or emergency programs.

Peak Demand

The firm peak resource requirement in August 2006, including a 15 percent planning reserve margin, is 641 MW. This total increases to 761 MW in 2016. These amounts are equal to Anaheim's net peak demand for its retail customers since Anaheim does not have firm long-term wholesale obligations.

Incremental Resource Needs

Anaheim shows a need for 171 MW of load-following and peaking capacity, starting in January 2008. Though listed as a generic need, this is a planned resource. With the inclusion of a 171 MW gas-fired resource addition, Anaheim's Resource Plan is able to cover it's August 2016 peak plus 58 MW of reserve. The expected energy from this planned resource varies by the month, starting with 29 GWh in June 2008 and growing progressively to 66 GWh by August 2016. Anaheim's Resource Plan includes energy from spot market and short-term purchases.

Energy Requirements

Total Energy Requirement for the year 2006 is 2,873 GWh. Total Energy Requirement for the year 2016 is 3,616 GWh. The Total Energy Requirement's average annual increase over the period is 2.6 percent.

Renewable Resources

Anaheim begins the 2006 forecast period with 21 MW of renewable resources under contract. This amount increases progressively to 64 MW by 2016. Monthly energy from these contract renewable supplies (wind, landfill, geothermal, and biomass) starts at 15 GWh in January 2006 and reaches 47 GWh in August 2016. This does not include 40 MW from Hoover, an important load-shaping resource for Anaheim that reliably supplies 2 to 6 GWh of energy every month. For the entire forecast period, Anaheim expects state-defined eligible renewable resources to supply 4,277 GWh, equal to 12 percent of its total energy requirement. Adding 487 GWh from Hoover would bring total renewable energy to 13.3 percent of total energy requirements.

Resource Planning Strategy and Goals

The bulk of Anaheim's Resource Plan consists of nearly 500 MW of utility-controlled fossil and nuclear resources. Over half of these resources consist of coal-fired imports from IPP Unit 1 and Unit 2 in Delta, Utah, and San Juan Unit 4 in Farmington, New Mexico. The IPP units and the importing transmission facilities such as the Southern Transmission System comprise Anaheim's largest single contingency. The Magnolia Power Project in Burbank will provide 118 MW (92 MW base and 26 MW peaking) of natural gas-fired generation. This plant is expected to come online in July 2005. The Anaheim CTG provides 46 MW of peaking capacity and is located within Anaheim's service territory. Anaheim's ownership in the San Onofre Nuclear Generation Station (SONGS) provides 70 MW of baseload capacity, but will be reduced to zero in 2009 when Anaheim elects to not participate in the proposed steam generator replacement project.

In its statements on risk and uncertainty, Anaheim describes its strategy for maintaining local reliability at reasonable cost, and adding locally-sited resources . Anaheim's portfolio is now heavily weighted to baseload coal and nuclear resources, with a reliance on imported power from Hoover for load-shaping. The potential value of locally-owned resources is magnified by Anaheim's lack of direct ownership in transmission. Following is an excerpt from Anaheim's narrative on managing risk and uncertainty:

> A small, but important component to Anaheim's Resource Plan is our 40 MW entitlement in the Boulder Canyon Project (Hoover Dam) as shown on line 17 of Form S-1. As the majority of Anaheim's portfolio consists of base load resources, the flexibility afforded by a large hydro unit provides Anaheim with much needed load shaping capacity. However, the ongoing drought in the western United States has highlighted the risk associated with poor hydrological conditions and the need for a diversified portfolio.
>
> Finally, 171 MW of capacity for load-following and peaking energy is included in Anaheim's Resource Plan on line 54 of Form S-1. This facility is expected to be a natural gas fired generation station located within Anaheim's service territory and is envisioned to begin operation in early 2008. The risks associated with powering a plant with natural gas appear outweighed by a reduction in transmission losses, lack of

> transmission constraints, local voltage support, self-provision of ancillary services, quick start technology, and load following capacity.

In summary, Anaheim's reference case is a fully resourced portfolio of diverse fuel types and generating technologies. It is designed to provide Anaheim's ratepayers with reliable service at the lowest possible cost, while meeting environmental obligations and contributing to the reliability of California's electric grid. footnote: (Charles Gus, Integrated Resource Planner, City of Anaheim, Electricity Resource and Bulk Transmission Data Submittal to the California Energy Commission, April 1, 2005)

Uncertainties of Concern to City of Anaheim, Public Utilities Department

Charles Guss, Integrated Resource Planner I for the City of Anaheim, Public Utilities Department provided the following comments.

> As Anaheim is a mature community with little undeveloped open space, load growth due to new industrial, commercial, and residential development is small. Energy consumption over the study period (2006 to 2016) is forecasted to grow by about 2.6 percent annually while peak demand is forecasted to grow by 2.3 percent annually. The increase in capacity factor as a result of differing growth rates is explained by expectations that consumer products, technological developments, and manufacturing techniques will become more energy-dependent in the future.

Major Uncertainties and Risk Analysis

Loss of large industrial or commercial customers due to an economic downturn would result in a loss of retail revenue proportional to the amount of exiting load. Anaheim expects to be able to offset some of this lost retail revenue through either a decrease in wholesale purchases or an increase in wholesale sales. Changes to our Resource Plan would be dependent upon the amount of lost load and planning reserve requirements.

The addition of large industrial or commercial customers due to economic growth would result in additional retail revenue proportional to the amount of additional load. In the short term, Anaheim would be able to serve this load through a reduction in wholesale sales and the inclusion of term purchases into its Resource Plan. In the long term, Anaheim might need to acquire additional renewable and non-renewable resources. Since Anaheim's service territory is largely built out, a substantial increase in demand due to new development is unlikely. However, a modest increase in demand due to advances in energy-dependent technologies is more plausible. The net financial affect of load growth beyond our load forecast is generally positive.

Wholesale Energy Prices

An increase in natural gas prices could potentially to increase Anaheim’s total generation cost. Anaheim’s long-term resource plans include 335 MW of natural gas fired generation as intermediate and peaking resources. Since Anaheim’s resource portfolio includes a diverse fuel mix, the financial impacts from natural gas price fluctuations could be mitigated through reliance on more economic resources. The increase in wholesale electricity prices due to higher natural gas prices could also further mitigate the increase in generation costs through increasing wholesale sales revenue. However, the overall impact of higher natural gas prices would be higher generation costs. In terms of Anaheim’s resource plans, a sustained increase in natural gas prices might cause Anaheim to shift away from natural gas peaking resources.

An increase in wholesale electricity prices without a corresponding increase in natural gas prices would increase Anaheim’s net wholesale revenue. Anaheim’s Resource Plan is increasingly self-sufficient and does not rely heavily on wholesale purchases to cover capacity and energy deficits. An increase in wholesale electricity prices would therefore increase Anaheim’s wholesale sales revenue more than it would increase wholesale purchase costs. The net result would be an increase in wholesale revenue. However, higher ancillary service costs, higher transmission congestion costs, higher fees from the CA ISO, and higher fuel costs due to resource scarcity would offset some, if not all, this increase in net wholesale revenue. Higher wholesale electricity prices, therefore, may or may not necessitate a change to Anaheim’s Resource Plan.

LSE Resource Portfolios

Anaheim has adopted a Renewable Portfolio Standard of 15 percent renewable by 2017. The renewable resources considered by Anaheim are generally base load or intermittent. Although these resources have comparable average costs to non-renewable resources, their operating characteristics make them difficult to incorporate into an already heavily base-loaded portfolio. Anaheim therefore has the tendency to “squeeze out” other base load resources with comparable costs. For example, Anaheim has chosen not to participate in the Steam Generator Replacement Program at the San Onofre Nuclear Generating Station and relinquish its ownership percentage, in order to pursue its RPS. A mandate to increase Anaheim’s RPS percentage or speed up the timing would further exacerbate this problem.

In order to minimize risk to ratepayers, Anaheim generally maintains enough capacity to fully cover its monthly peak load forecast. During the summer months, when peak loads are volatile, Anaheim generally maintains more than enough capacity to meet forecasted peak load in order to mitigate the risk of unplanned outages and wholesale price spikes. A resource adequacy requirement of 15-17 percent above forecasted peak load would require Anaheim to acquire additional peaking and intermediate resources over its 10-year plan. In addition, a requirement to make unused capacity available to the CA ISO markets could lead to higher power supply costs for load serving entities that may not be fully recovered in the CA ISO markets.

Core/Non-Core – Departing Load

Loss of load from direct access, load aggregation or the application of the core/non-core customer service paradigm could result in a loss of retail revenue proportional to the amount of exiting load. Anaheim expects to be able to offset some of this lost retail revenue through a decrease in wholesale purchase volume or an increase in wholesale sales volume. Anaheim's current Resource Plan is designed to serve all customers within its service territory, and changes to its Resource Plan would be dependent upon the amount of lost load and planning reserve requirements.

Riverside Public Utilities

Existing Resources

Throughout the forecast period, The City of Riverside (Riverside Public Utilities) can depend upon 136 MW of power from the Intermountain coal units in Utah. Riverside has 52 MW of nuclear power in its portfolio, including 12 MW from Palo Verde, and 20 MW from each of the two San Onofre units. Riverside expects to continue using San Onofre after its steam generator replacement project is complete; it is scheduled to begin in 2009. Among other fossil fuel resources, Riverside owns the 40 MW capacity Springs Units 1-4, and expects to have 96 MW of new simple cycle generation for peaking from RERC Units 1-2. Riverside can take 52 MW from coal-fired Deseret, under contract through 2009. Riverside has an ongoing 30 MW share of hydropower from Hoover Dam. Riverside also has diversity and firm energy exchange agreements with BPA that can provide 83 MW from May to October, and 31 MW in other months through 2010.

Peak Demand

August is normally the peak demand month. Riverside forecasts its peak customer demand in 2006 will be 539 MW (620 MW including a 15 percent planning reserve margin). This amount may steadily increase to 630 MW in 2016 (724 MW with a 15 percent planning reserve margin).

Incremental Resource Needs

Riverside anticipates that 55 MW of generic non-renewable peaking capacity will be needed by summer 2009, growing to 120 MW by 2012. About 45 MW of baseload capacity may be needed by mid-2010, plus 40 MW of load-following in 2011, growing to 60 MW of generic load-following need by 2013.

Energy Requirements

Riverside's total annual energy requirement, including up to 214 GWh of firm sales or exchanges, is forecast at 2,480 GWh in 2006, rising to 2,747 in 2016. August is the peak month for energy use, closely followed by September and July. Riverside expects to make modest purchases of short-term and spot market energy, especially in 2010, for 431 GWh.

Renewable Resources

Riverside begins 2006 with 27 MW of state-defined eligible renewable resources, including 20 MW from Salton Sea Geothermal Unit 5, through 2013, plus 7 MW from three local landfills, and 1 MW (dependable) of wind. These renewable resources are expected to produce 215 GWh in 2006, equal to 9.5 percent of its retail demand. The Resource Plan calls for 43 GWh of renewable energy in 2007 from generic resources. This amount increases to 431 GWh in 2014, and remains at 431 GWh in 2015 and 2016.

Resource Planning Strategy and Goals

Riverside utilizes a chronological production cost model to evaluate its potential resource mix solutions to meet certain planning criteria and targets. Among the targets are a 15 percent monthly planning reserve above the expected monthly peak, annual spot market purchases and sales projections of less than or equal to 10 percent of system requirements, Q3 heavy load spot purchase and sales volumes of less than or equal to 10 percent of system requirements, and renewable generation targets of 15 percent and 20 percent of retail load by 2010 and 2015,respectively. System requirements are defined as native load + transmission losses + third party obligations (primarily return obligations).

Uncertainties of Concern to Riverside Public Utilities

The following are the uncertainties of concern to Riverside Public Utilities:

- Load growth
- Renewable Portfolio Standard targets
- Spot market prices
- Regulation

Spot Market Supplies

Through 2008, Riverside includes only small short-term and spot market purchases for needed capacity, keeping this reliance under 1.5 percent. In 2009, this supply category grows in importance to 4.6 percent, and is in low double digits most years after that, peaking at 14.7 percent of the firm peak resource requirement in 2014. As stated in the supply filing:

> While Riverside plans to procure sufficient capacity to meet its expected monthly peak obligation plus a 15 percent reserve margin on a forward basis, spot market energy is a viable component of Riverside's supply portfolio. To minimize the price risk associated with potentially volatile spot energy prices, a 10 percent threshold is defined in Riverside's Energy Risk Management Policy. It is desirable to balance both spot energy purchases and sales within the 10 percent limit to effectively hedge uncertainty in power costs. Due to the expected addition of 96 MW of new simple cycle generation, spot energy purchases are forecasted to be minimal, with potentially sizable volumes available for surplus sales on average summer days when economic.

Turlock Irrigation District (TID)

Existing Resources

By the beginning of the forecast period in 2006, Turlock Irrigation District (TID) will have three utility-controlled fossil-fueled resources: Walnut (52 MW), Almond (49 MW), and the new Walnut Energy Center which is rated 250 MW nameplate, 265 MW dependable in winter, 240 MW dependable in summer, and 252 MW dependable in shoulder months. Turlock has three hydro power plants in its portfolio: Don Pedro (134 MW, not including the 31.66 percent share owned by Modesto ID), La Grange (12 MW), and Turlock Lake (3 MW). Turlock has bilateral supply contracts with Calpine for 50 MW through May 2008, which generally include 35 MW of baseload from the Sutter Plant. Turlock can count on 58 MW from Power Resources Cooperative through 2018. WAPA supplies another 4 to 6 MW. During the summer months, Turlock receives 10 to 28 MW from Hetch Hetchy (City and

County of San Francisco), as scheduled by PG&E. Turlock ID also has 6 MW to 8 MW of geothermal capacity from NCPA.

For July 2006, Turlock expects to have 661 MW available from existing and planned resources. This amount of dependable capacity declines to 611 MW in July 2016 due mainly to expiration of existing bilateral contracts.

Peak Demand

Turlock expects net peak demand for its bundled customers will be 482 MW in August 2006, increasing to 556 MW in August 2016 (not including a 15 percent planning reserve margin). Turlock did not report having capacity available from interruptible/emergency programs, or from dispatchable demand response programs.

Incremental Resource Needs

The filing by Turlock shows 6 MW of generic renewable capacity starting in January 2006 and remaining at 6 MW through 2016. However, forecast amounts of generic renewable energy rises from 3.9 GWh to 25.4 GWh during this same period. A need for generic non-renewable peaking capacity first appears in August 2013, estimated at 14 MW. This generic capacity need grows to 23 MW in 2014, 33 MW in 2015, and 42 MW in 2016.

Energy Requirements

For 2006, Turlock's estimated total energy requirement is 1,920 GWh. Turlock's total annual energy requirement is predicted to have an average annual increase of 1.68 percent over the forecast period. For 2016, Turlock's total energy requirement is estimated to be 2,242 GWh.

Uncertainties of Concern to Turlock Irrigation District

These comments about uncertainties and risk were provided Nancy Folly, Utility Analyst, with Turlock Irrigation District.

> The amount of capacity of the Walnut Energy Center (currently under construction) will likely vary once construction is completed and the unit is running. Another line item with uncertainty is our load. Our load forecast was updated in 2004. However, severe weather conditions and other factors are cause for uncertainty within the forecast.

The last point of uncertainty lies within the capacity number provided for our “Generic Renewable Resources”. The Turlock Irrigation District Board has set a target of 20 percent of Retail Sales by 2017 come from renewable sources. The amount of capacity to be acquired is unknown at this time. Turlock Irrigation District is currently evaluating several different [renewable energy] scenarios.

Uncertainty about the actual monthly resource mix is inevitable. Market power and gas prices along with hydro availability could cause our dispatch of resources to change.

There are several other factors that will affect Turlock Irrigation District resource planning. Locational Marginal Pricing will affect the District’s operations. Turlock Irrigation District is expected to be operating our own Control Area in the near future. The dispatch of our resources may change in order to meet our control area requirements.

Silicon Valley Power (SVP)

Existing Resources

The City of Santa Clara’s electric utility is now known as Silicon Valley Power (SVP). Silicon Valley Power has 281 MW of thermal resources, including Pico (148 MW), Gianera combustion turbines (50 MW), plus shares of NCPA geothermal, and San Juan (coal). Hydro resources vary from 178 to 252 MW, depending upon month. This level of hydro resources would be lowered by 74 MW under 1-in-10 adverse (critically dry) conditions. In August 2006, SVP’s existing and planned resources will total 541 MW, including 57 MW of geothermal capacity, and a 25 MW wind contract is under negotiation. This total of existing and planned resources declines by August 2016 to 526 MW. Geothermal resources diminish by 13 MW over this forecast period. SVP also reports an 8 MW interruptible program. Beyond the first few years, SVP includes no spot purchases in its Resource Plan.

Peak Demand

For 2006, Silicon Valley Power forecasts its net peak demand for its bundled customers will be 435 MW (500 MW including a 15 percent planning reserve margin). By 2016, this amount increases to 513 MW (590 MW with reserves). No uncommitted demand-side resources are expected. Nor does SVP anticipate making firm sales obligations, or departures of existing retail customer loads.

Incremental Resource Needs

Planning reserve margins under 1-in-2 hydro are 43.2 percent in 2006 (26.2 percent under 1-in-10 hydro). In the absence of additional procurement, this planning reserve margin declines to 18.9 percent in 2016 under 1-in-2 hydro conditions. Under 1-in-10 hydro and no additional procurement, SVP would still have a 15.8 percent planning reserve margin in 2010, and 4.5 percent in 2016.

SVP indicates a baseload need beginning in 2009, but the indicated capacity is primarily for shoulder month needs (July, August needs do not exceed 50 MW under 1-in-10 hydro until 2014), and is less than 100 MW through 2016.

Annual energy needs begin in 2009 at 275 GWH, increasing steadily to 556 GWh by 2016, or 10 percent to 17 percent of the total energy requirement, respectively. SVP identified the capacity they need as baseload capacity (i.e., non-peaking). Energy purchases would likely be contractual purchases of shoulder month energy from baseload sources.

Energy Requirements

Because SVP has neither expected uncommitted demand-side resources nor expected loss of load to ESPs, CCAs, or firm sales obligations, SVP's “Forecast Total Energy Demand,” “Net Energy Demand for Bundled Customers,” and “Total Energy Requirement” are all the same. Total Energy Requirements average annual increase over the period is 1.7 percent. Near-term annual increases are highest: 2006-7 is 3.3 percent, and 2007-8 is 1.8 percent. Afterwards, annual average growth in energy use is 1.5 percent per year.

Renewable Resources

SVP has 29 MW of small hydro, 57 MW of NCPA geothermal, and a pending 25 MW wind purchase. State-defined eligible renewable energy supplies equal 27.1 percent of total demand in 2006, gradually decreasing to 19.7 percent in 2016. If Silicon Valley’s 165 MW of large hydro is included in the renewable total, supplies would total 48.9 percent of load in 2006, declining to 38.1 percent in 2016.

Resource Planning Strategy and Goals

The City of Santa Clara does business as Silicon Valley Power (SVP) and has these internal goals and commitments:

- Provide its customer-owners with reliable, cost-effective electric service through local acquisition and local control of electric resources.

- Minimize its dependence on fossil and nuclear generation in favor of renewable energy sources.

- Support legislative and regulatory policies that will lead to overall market stability and predictability.

- Attain self-sufficiency in response to the uncertainty and volatility of energy supply and prices arising from a restructured electric market in California.

  – The primary reason for this approach is that there is no strong evidence that [shows], over the forecast period, electric energy or capacity will be readily available when and where needed, or that the price of such energy and capacity will be stable.

    ▪ Nevertheless, Santa Clara must depend on others for a significant portion of its generation and transmission needs.

    ▪ In response, Santa Clara carefully considers the stability and commitment of its suppliers in providing what Santa Clara cannot provide or build itself.

Uncertainties of Concern to Silicon Valley Power

The major short-term variables confronting Santa Clara include:

- Annual and monthly variations in energy and capacity availability from Santa Clara's hydro-based resources.

  – SVP estimates that it must prepare to replace up to 300 GWh over the course of a dry hydro year, and may be subject to unavailability of up to 136 MW of its WAPA contract capacity under certain conditions.

  – Consequently, SVP has necessarily planned for capacity reserves and energy availability that at first glance appear to be "high" compared with systems consisting primarily of thermal generation.

- Capacity unavailability due to scheduled and unscheduled outages.

  – SVP's resource planning and operations are designed to be consistent with WECC standards.

  – SVP's resource planning and operations are designed to be consistent with obligations under its Metered Sub-System (MSS) agreement with the California Independent System Operator (CA ISO).

- Changes in energy demand due to weather variations, specifically hot temperatures.
  - SVP's loads are moderately sensitive, increasing by about 2-3 MW for each degree of temperature.
  - A 100 degree day is likely to increase SVP's 400 MW peak load forecast to about 407 MW. This is well within SVP's capacity availability.
- The relationship between short-term wholesale electric energy prices and Santa Clara's variable cost of energy, particularly gas-fired energy, from its own resources.
  - In real time, SVP seeks to minimize its cost of production but retains a preference to purchase from the wholesale market when the net effect is to reduce SVP's total variable cost of energy production and purchases.
  - However, for planning and financial reasons, SVP's primary objective is to maintain a generation and transmission portfolio that provides both physical and financial stability.

Roseville Electric

Existing Resources

The only two utility-controlled fossil-fuel thermal resources currently in the portfolio of Roseville Electric's are shares of plants managed by the Northern California Power Agency (NCPA). Roseville can count on 21 MW from NCPA's STIG Unit, plus 16 MW from the NCPA CT Unit. The Roseville Energy Park is scheduled to begin operation in April 2007 with 162 MW.

Roseville has a 78 MW share in NCPA's large hydro plant, Collierville, on the upper Stanislaus River, plus a 10 MW share in NCPA's geothermal resources.

Roseville takes energy and firm capacity from two contract suppliers: up to 43 MW from Morgan Stanley through 2010, and up to 7 MW exchange with SCL.

Roseville Electric's total existing and planned capacity in July 2006 is 348 MW, including bilateral contract supplies. This amount of total capacity increases to 441 MW in July 2014, the last peak month shown on Roseville's data submittal.

Peak Demand

Roseville forecasts its net peak demand for its bundled customers will be 134 MW in July 2006, increasing to 170 MW in 2014. The peak month is always July in the forecast.

Incremental Resource Needs

Roseville expects to be adequately resourced through 2014, mostly using utility-owned thermal generation, power pool resources (from the Northern California Power Agency), and bilateral contract supplies.

Roseville did not submit a “balanced” resource plan that includes a 15 percent planning reserve margin. The total peak requirement includes all the forecast peak demand for its bundled customers, and a modest 4 MW to 15 MW for firm sales obligations, but does not include a single megawatt for a planning reserve margin. What also makes the load-resource tables “unbalanced” is that a matching supply resources to account for this planning reserve margin has not been added to the categories on the form for this purpose: generic renewable capacity, generic non-renewable capacity, or short-term and spot market purchases. The resource tables provided by Roseville do include short-term and spot market purchases of capacity and energy, and do not, unfortunately, list any generic resource additions needed to serve firm load and maintain the 15 percent planning reserve margin. Fortunately, these minor omissions (which are not unique to Roseville) are not large numbers. The “net short” in 2006 would be 15 MW in 2006, 36 MW in 2007, and 17 MW in 2008. For 2009 through 2014, the calculated net short amount of needed generic capacity is either 9 MW or 11 MW.

Energy Requirements

For 2006, Roseville’s total energy requirement is 1,319 GWh. The average annual increase in energy during the forecast period is 2.5 percent. In 2014, Roseville expects to need 1,660 GWh to meet its load and delivery obligations.

Renewable Resources

In 2006, Roseville expects 96 GWh from its geothermal, landfill gas, and wind resources under contract, equal to 7.5 percent of its net annual demand for retail load. Roseville also forecasts taking 236 GWh from the Collierville hydro plant, which would equal 18.4 percent of total retail demand. Roseville does not have plans to add generic renewable resources during the forecast period.

Uncertainties of Concern to Roseville Electric

As the new Roseville Energy Park moves towards construction, Roseville is concerned with natural gas fuel supply, pipeline delivery and storage costs, and the potential failure of counterparties to fulfill their gas delivery arrangements. These uncertainties pose a financial risk to the City of Roseville. Roseville does not yet have in place firm gas supply and transmission arrangements to meet all the Roseville Energy Park fuel supply needs, and is therefore exposed to some price volatility for such commodities and services. To mitigate such risks, the City of Roseville has developed a fuel supply management strategy focused on reliability and price risk management.

The new Roseville Energy Park will allow the city to reduce its dependence on the forward purchase market. Roseville expects to reduce forward purchases so that such purchases will be eliminated by 2012. This will reduce Roseville's price risks related to these forward markets. Roseville Energy Park will help reduce short-term market purchases from 493 GWh in 2006, to 212 GWh in 2007, and 65 GWh in 2008.

Pasadena Water and Power

Existing Resources

Pasadena Water and Power (Pasadena) controls two fossil-fueled plants with 199 MW available for local dispatch: 65 MW from Broadway 3 (through 2013), 47 MW from Glenarm Units 1 and 2 (through 2014), and 87 MW from Glenarm Units 3 and 4 (through at least 2016). Pasadena has a 19 MW share of the Magnolia plant in Burbank, expected to go online in July 2005. Pasadena can call upon a 20 MW share of Hoover hydropower, and counts another 15 MW from small hydro units. Contracts for energy from landfill gas, Ormat Geothermal, and PPM Wind add about 7 MW to the supply portfolio.

Pasadena has several long-term bilateral contracts including a dependable 107 MW from Intermountain in Utah, 10 MW from Palo Verde in Arizona. Pasadena has contracts with BPA that include must-take energy in May and June, and energy exchange options (daily and seasonal exchanges) in other months. Up to 27 MW is normally available from BPA during peak hours of summer months. Bilateral Contract capacity totals 144 MW in 2006 MW, and declines to 117 MW in 2016 due to contract expirations.

In August 2006, Pasadena's total dependable capacity from existing and planned resources totals 403 MW. This total will hold at 393 MW in the summer months of 2013, but declines in subsequent years as the Broadway 3 and Glenarm Units 1 and 2 retire.

Peak Demand

Pasadena estimates net peak demand for its bundled customers will be 299 MW in 2006, increasing to 330 MW in 2016. August is modeled as the peak demand month, though estimated demand for both July and September are within 4 MW of the August peak.

Incremental Resource Needs

Total existing and planned resources in August 2006 are 403 MW (equal to a 34 percent planning reserve margin). With these same resources, and modest load growth, Pasadena expects to maintain a 24 percent planning reserve margin through August 2012. In 2014, Pasadena predicts that 60 MW of generic non-renewable load-following or peaking capacity will be needed, with another 60 MW needed in 2015.

Energy Requirements

The outlook for average annual average energy use in Pasadena is 0.2 percent growth per year, from 1,338 GWh in 2006 to 1,373 GWh in 2016. Pasadena has no expected uncommitted demand side resources or expected loss of load to ESPs or Community Choice Aggregators over the forecast period.

Renewable Resources

Pasadena has 15 MW from small hydro plants, and a 20 MW share of Hoover, but does not own or control other renewable generation. Despite having a capacity resource surplus through 2013, Pasadena anticipates adding 3 MW per year of generic renewable capacity starting in 2009. Over the entire forecast period, Pasadena expects that state-defined eligible renewable resources will provide 11 percent of the total energy requirement. This figure rises to 15 percent when energy from Hoover dam is included.

Resource Planning Strategy and Goals

Not provided.

Uncertainties of Concern to Pasadena

- Actual load growth may be greater than the growth rate projection.
- Uncertainty due to Pasadena's recent membership in the CA ISO as a participating transmission owner.
- Availability of natural gas.

- Stability and availability of renewable resources.
- Drought conditions in the Southwest.
- California NO_x, CO_2, SO_x, and ROG emissions restrictions.
- Reinstatement of deregulation.

Spot Market Supplies

Pasadena does not expect to purchase capacity from the short-term or spot markets until the second half of 2015. However, Pasadena does expect to use these markets for energy purchases throughout the forecast period, probably for economic reasons, for about 4 percent of its total energy needs.

Glendale Water & Power

Existing Resources

Glendale's' dependable fossil capacity varies slightly over the forecast period. Glendale's gas-fired Grayson units generate 249 MW as needed. Glendale has a 40 MW share of Magnolia, expected online in July 2005. Coal-fired power imports from Intermountain and San Juan provide 38 MW and 20 MW, respectively. Glendale also takes 11 MW of baseload nuclear power from Palo Verde, and up to 20 MW of hydropower from Hoover.

Contractual resources include 50 MW in summer months from Portland General Electric, through September 2012, and 10 MW from BPA through April 2008. In these exchange contracts, capacity and energy are returned north during off-peak winter months.

Existing and planned resources in September 2006 total 458 MW, including 4 MW of landfill, 3 MW of geothermal, and 3 MW from a wind contract. Glendale includes no spot market or short-term purchases in its forecast.

Peak Demand

In 2006, Glendale's projected net peak demand for bundled customers is 286 MW (338 MW including reserves). By 2016, this increases to 334 MW (384 MW with reserves). No firm sales obligations are expected. Peak demand is forecast to occur in September, with August peak demand close behind.

Incremental Resource Needs

For 2006, Glendale will apparently have a planning reserve margin equal to (155.8) [this number must be wrong] percent of forecast peak load requirements. Glendale's total capacity from existing and planned resources declines to 388 MW after September 2012 and remains static through 2016 but is still sufficient to maintain a 15 percent planning reserve margin (which would be 384 MW in September 2016). Glendale therefore has no need to add generic resources during the forecast period.

Energy Requirements

Glendale's average annual average growth is 1.1 percent per year. Total deliveries are forecast to increase from 1,297 GWh in 2006 to 1,443 in 2016. Glendale has no expected uncommitted demand side resources, or expected loss of load to ESPs or CCAs over the forecast period. Monthly energy demand is forecast to peak in August and ebb in March.

Renewable Resources

Glendale forecasts it will annually take 71 GWh or 72 GWh from its 20 MW share of Hoover, along with 65 to 78 GWh from other renewable resources (Chiquita Canyon Landfill, Ormat Geothermal, and PPM Wind). Glendale does not have a plan to add additional renewable resources to its portfolio. Averaged over the entire forecast period, renewable energy supplies amount to 11.4 percent of Glendale's net energy demand for bundled customers when Hoover is included. Without Hoover, the state-defined eligible renewable resources will supply about 6 percent of retail load requirements over the forecast period.

Resource Planning Strategy and Goals

Glendale Water & Power (GWP) supplies power to the City of Glendale, using the utility-owned Grayson Power Plant generating units, long-term power supply purchase contracts, and spot energy purchases. Recent history indicates that Grayson Power Plant generates approximately 15 percent of Glendale's energy requirements. The remaining 85 percent of the energy requirements are mostly purchased from power generating projects outside the Los Angeles Basin.

Glendale also has significant long-term power purchase resources. The Department has a total of 209 MW net capacity entitlements in seven power projects and three firm power arrangements. GWP also has firm transmission from the Southwest U.S. through its participation in SCPPA projects, and a firm transmission ownership entitlement in the Pacific Northwest DC.

Natural gas and landfill gas are the primary fuels for local generation.

Glendale has no planned transmission facilities for the next 10 years.

Uncertainties of Concern to Glendale

Glendale Water & Power (GWP) realizes there are many uncertainties which could significantly affect its forecasts for future load and energy requirements. Among the unpredictable events acknowledged by GWP:

- A war or major armed conflict.
- An oil or natural gas embargo.
- A major earthquake or natural disaster.
- Severe weather conditions: prolonged drought or El Niño conditions.
- Hyper inflation or collapse of the national economy.
- A major technological breakthrough altering the methods or economics of energy delivery or production.

All these events are unpredictable in timing and effect. GWP operates in a prudent, fiscally sound manner and updates its forecasts regularly to take account of developing changes. GWP feels it is not cost effective for its small staff to develop scenarios for these events.

Spot Market Supplies

Glendale reported no spot market capacity purchases on form S-1, but did report forecast spot energy purchases on form S-2 in all years, in amounts that gradually increase to 33 GWh in August 2016.

City of Burbank, Department of Water and Power

Existing Resources

Burbank reports 350 MW of dependable supply capacity for every July in the forecast period. Major thermal resources include Burbank's share of Intermountain Power Project (Coal) 75 MW, Burbank's share of Palo Verde (Nuclear), 10 MW, Magnolia Power Project (Gas), 96 MW (expected online July 2005), Olive 1 (Gas) 44 MW, Olive 2 (Gas), 55 MW, and Lake 1 (Gas), 47 MW. Burbank does not anticipate adding any other thermal resources during the forecast period.

Peak Demand

Demand is forecasted to peak in July of each year. Net peak demand for bundled customers is 283 MW in July 2006, increasing to 336 MW in July 2016. Burbank's peak resource requirement shows a consistent increase of 1.5 percent per year over the forecast period.

Incremental Resource Needs

Burbank expects to add incremental Q3 resources as the need arises. However, Burbank's filing data does not reflect any resource additions during the forecast period (2006-2016). Existing and planned capacity are less than 115 percent of forecast demand in each July starting in 2008, and in each August starting in 2010, and in each September starting in Sept 2012. The planning reserve values for July, August and September, 2016 are, respectfully, 3.9 percent, 6.2 percent, and 8.6 percent. It is clear from the submitted data and subsequent communication with that Burbank will add additional resources on a timely basis to maintain adequate planning reserve margins.

Energy Requirements

Burbank expects energy demand will continue to grow at about 1.5 percent per year for the next several years. Burbank's "Forecast Total Energy Demand" (S-2, line 1) shares the same values as "Net Energy Demand for Bundled Customers" (S-2, line 8) for all values in the forecasted period. These values grow by 1 percent per year over the forecasted period. The only exceptions occur in calendar years 2007 (0.9 percent) and 2008 (0.6 percent). Burbank's S-2 line 9 shows its firm sales obligations from January 2006 through April 2008. When firm sales obligations are added to "Net Energy Demand for Bundled Customers," the total exactly matches the "Total Energy Requirement" (S-2, line 10).

Renewable Resources

No data listed on Form S-2, lines 18, 26, 42 or 52. No small (less than 30 MW) hydro energy is listed.

Burbank asserts it has a commitment to achieve state RPS goals that currently apply only to IOUs.

> "Burbank has adopted a Renewable Portfolio Standard which commits the utility to procure 20 percent of its energy needs via renewable resources by the year 2017. The end goal is clear. However, we do not have a firm plan on when to bring on additional renewable resources. With the addition of the Magnolia Plant in its portfolio Burbank has sufficient resources to meet the expected load growth over the next few years. We expect to incorporate additional renewable energy as supported by demand growth."

The resource planning data on Burbank's Form S-2 does not match the expectation that renewable resources will be added as demand grows. It appears from form S-2 that the total renewable energy component (ignoring large hydro) does not rise above 2.0 percent in any month of the forecast. (This calculation adds line 40 "total renewable resources" to line 23 "total renewable contracts" on Burbank's Form S-2, and divides that sum by line 8 "net energy demand for bundled customers). If large hydro (greater than 30 MW nameplate) resources are counted as renewable, then the percentage grows a bit to a high of 4.2 percent (This second calculation adds the quantities on line 40 "total renewable resources" + line 23 "total renewable contracts" + line 15 "total for all hydro plants over 30 MW" from Burbank's Form S-2, and divides that quantity by line 8 "net energy demand for bundled customers).

Resource Planning Strategy and Goals

The narrative does not specify any goals or planning strategies. Burbank typically uses a 50 MW planning reserve margin target. "For 2006, 50 MW would have us at a 17.7 percent [planning] reserve margin."[1]

Uncertainties of Concern to Burbank

How Burbank might add renewable resources to its supply portfolio is recognized as a major planning uncertainty. Two others are considered significant: fuel costs and future load growth.

> "Burbank will self-generate a sizable portion of its energy needs via gas-fired resources. As such, the utility faces uncertainties in both the future cost and availability of the commodity. Should current fuel prices continue to rise and become sustained at high levels our dispatch of our generating units may change if we could secure cheaper power from the market."
>
> "Burbank has witnessed erratic fluctuation in annual peak demand over the past few years. Burbank's historic peak demand was 284 MW in 1998. Subsequently, annual peak loads have remained high in the 260 MW level range."[2]

Spot Market Supplies

According to Form S-1, Burbank does not rely on "Short-term and Spot Market Purchases" for any dependable capacity. On Form S-2, line 45, Burbank indicates

[1] Email from Himanshu Pandey to Jim Woodward, July 11, 2005.
[2] Personal communication from Himanshu Pandey, Burbank, to Jim Woodward, California Energy Commission, July 11, 2005.

an unusual use of monthly short-term and spot market energy purchases. The largest purchases are forecast for the months of May, which has the cheapest wholesale prices from abundant hydro supplies in wet years. The months of August are second highest in volume purchases, and are more likely to relate directly to monthly energy demands, which also peak in August.

Redding Electric Utility (REU)

Existing Resources

The Redding Power Plant is rated 132 MW of dependable capacity in the summer months (139 MW in other months) with 135 MW nameplate. Five units of varying sizes and types allow for delivery of baseload, load-following, and peaking energy. In conjunction with the Modesto Irrigation District and Silicon Valley Power, Redding has a 22 MW ownership share in San Juan Generating Station in New Mexico. This coal-fueled resource provides year-round baseload energy to PacifiCorp that is subsequently delivered to Redding during the high-peak summer months.

Redding's website reports that a significant portion of the utility's energy supplies come from hydroelectric plants, especially Shasta Dam and points north. WAPA provides 104 MW in July and at least 70 MW in October. In its bilateral contracts, Redding reports three other supplies: 50 MW from PacifiCorp (through 2015), 25 MW from American Electric Power (through 2014), and 13 MW from the City of Shasta Lake (in 2006 only).

Peak Demand

Redding Electric Utility is the smallest LSE in California required to file electricity supply forms. In 2006, Redding's firm peak retail demand is expected to exceed 200 MW only during June, July, and August. Redding's peak demand month is July, by a wide margin. Peak power demands in July, including a 15 percent planning reserve margin and firm sales obligations, are forecast to rise from 304 MW in 2006 to 369 MW in 2015.

Incremental Resource Needs

Redding's existing resources will be adequate to serve forecasted load through 2010. This includes a 15 percent planning reserve margin, plus firm exchange obligations. 10 MW of wind resources have been added for delivery in 2007. By 2010, Redding expects to need 25 MW of generic non-renewable capacity in order to maintain the 15 percent planning reserve margin.

Energy Requirements

Redding's annual energy requirements (including firm sales obligations and exchanges) fluctuate between 1,130 GWh in 2006 to 1,064 GWh in 2016, with a low of 971 GWh in 2008 and a high of 1,109 in 2015. July is modeled as the peak month for energy demand, but August is close behind.

Renewable Resources

For the entire forecast period, Redding expects to supply 51 percent of its total retail customer needs with renewable energy. However, only 1.0 percent of its retail sales will be served by energy from Redding's 3 MW Whiskeytown Hydro Plant (100 GWh). Most of Redding's renewable energy (2,827 GWh in 11 years) will come from WAPA, with a portfolio of 97 percent large hydro and 3 percent small hydro. Redding has purchased 10 MW of renewable wind resources for delivery in 2007 to produce approximately 86 GWh annually through 2016.

Resource Planning Strategy and Goals

Redding Electric Utility (REU) holds several long-term contractual agreements for the delivery of power over high voltage transmission lines. All contracted deliveries are firm, fixed, and hold firm physical or owner-ship-like rights for delivery over the California-Oregon Transmission Project, the Pacific AC Intertie, or the Western Area Power Administration's (Western) Central Valley Project Transmission System.

Uncertainties of Concern to Redding Electric Utility (REU)

REU incorporates several uncertainties into its energy forecasting process. The greatest uncertainties relating to energy deliverables include fuel price volatility, hydrologic conditions, and future transmission availability. Energy values have been assessed using conservative estimates for fuel prices derived from the latest market trends, forward price curves, and staff estimates. REU has also sought solutions to hydrologic volatility by constructing local generation and signing long-term fixed contracts from alternative generation sources.

REU actively engages in portfolio diversification and risk mitigation strategies in order to minimize risks and optimize price - keeping costs low and reliability high. Redding evaluates other risks including regulatory, environmental, and electric market structure changes. Redding is also adapting to its resource planning and risk mitigation protocols in its new position in the SMUD/Western Control Area.

Spot Market Purchases

REU's system is energy sufficient while capacity resources are in line with the accepted planning reserve standard of 15-18 percent of peak load plus firm sales obligations. Wholesale spot-market purchases are kept to a minimum. Redding does not consider reliance upon California's short-term energy markets to be a prudent choice. REU forecasts the use of wholesale market purchases only for asset optimization.

Energy Service Providers

APS Energy Services
Constellation NewEnergy
Pilot Power Group, Inc.
Sempra Energy Solutions
Strategic Energy, LLC

The monthly, resource-specific data collectively comprising the Resource Plans has been granted confidentiality for four of these ESPs. This includes specific forecast data and company assessments about uncertainties and strategies to manage business risks. One company did not seek confidentiality for its information. Therefore, the attributes of these Resource Plans are summarized in only general terms or using aggregate numbers. Specific assessments are included without company attribution.

Existing Resources

Energy service providers do not, as part of their normal business plans, use company-owned generation to supply retail customer load. These companies carefully match wholesale power supply contracts to align with retail demand obligations, end-use load forecasts, and their strategic business plan. These supply contracts can be complex, short-term, mid-term, or long-term, and can involve more than one supplier of generation. Power suppliers may include merchants, power pools, power marketers, and utilities (publicly and investor-owned) who may be active in these private, bilateral markets. For four of these companies, details about these bilateral contract supplies have been granted confidential status until 2016 or the contract end of term, whichever is later.

APS Energy Services is affiliated with Arizona Public Service Company which does own generation in Arizona.

Sempra Energy Solutions (SES) is an energy service provider that is a separate company but affiliated with Sempra Energy. Sempra Energy also happens to be the corporate parent of San Diego Gas and Electric (SDG&E) and the Southern California Gas Company.

Peak Demand

For 2006, these five companies estimate their collective peak retail demand (not including a 15 percent planning reserve margin) will be 1,207 MW (see Figure 5-6). This is an estimate of the “most likely” case, including the peak demand for likely new customers, plus the expected demand of current customers who renew or extend their direct access contracts. This collective estimate of “most likely” non-coincident peak demand is 1,115 MW in 2016.

The peak demand month for these five companies may be in July, August, or September. For some companies, demand in June, July, August, September and October is only slightly less than their peak demand month.

At least one company was reluctant to forecast future retail demand beyond current contractual obligations. This reluctance to estimate precise monthly numbers out 11 years was attributed to substantial uncertainties about legislation, regulatory requirements, and competitive electricity market conditions. The filing from at least one company simply left blank cells on the spreadsheet for the last eight years in the forecast period. At least one ESP, however, has subsequently updated their demand forecast, providing the Energy Commission with more complete data.

Incremental Resource Needs

In the Resource Plans filed by all ESPs, there appear to be substantial variation in the specificity of plans to serve existing and planned customer loads. Several ESPs explicitly indicated a commitment to maintain a 15 percent planning reserve margin for their firm obligations, while some others did not report having secured enough resources to cover existing loads.

For most months in the forecast period, ESPs plan to meet projected resource requirements using mid-term bilateral contracts, or short-term and spot market purchases, or generic resources. These generic resources could be entirely baseload or load-following non-renewable supplies, acquired from bilateral contract suppliers. One company forecast a constant 50 percent of its energy and capacity needs would be supplied by short-term bilateral contracts or spot market purchases. Another company disclaimed any intent to rely upon short-term or spot market purchases for needed capacity, stating, “We purchase to the peak of our requirement, we do not anticipate needing to buy to cover our peak load."

One company asserted a lack of reliance on short-term and spot market purchases for needed monthly energy, stating, “We have met all our future obligations and will not purchase bi-lateral contracts unless we sign more customers.” Collectively, ESP filings show a need for generic capacity resources that totals 259 MW in 2006, 300 MW in 2009, and 423 MW in 2016. These amounts are shown in Figure 5-4.

One company submitted load-resource tables that are "unbalanced" in that a matching supply resource is not listed in the categories on the form for bilateral contracts, generic renewable capacity, generic non-renewable capacity, or short-term/spot market purchases. While that company provided confidential data on its bilateral contracts, using form S-5, this company did not include capacity values on form S-1, or energy value totals on form S-2. It became apparent that future demand by potential new customers, and future demand of existing customers with new contracts, will have to be met by using some combination of bilateral contracts and spot market purchases.

One company submitted plans to secure sufficient resources to meet its projected firm resource requirements using renewable contracts, other bilateral contracts, and modest use of short-term and spot market purchases. This last category will likely provide about 11 percent of its estimated capacity needs, and about 4 percent of its estimated energy needs.

At least one company plans to secure sufficient resources to meet its projected firm resource requirements entirely using bilateral contracts, short-term and spot market purchases, but without using short term or spot market purchases for needed capacity.

ESPs have conservatively not procured resources to serve this very uncertain load. However, what makes the load-resource tables "unbalanced" for at least one company is that a matching supply resource was not listed in the categories on the form for bilateral contracts, generic renewable capacity, generic non-renewable capacity, or short-term/spot market purchases. It becomes apparent that future bilateral contracts and spot market purchases will likely provide most of the capacity (and energy) needed to projected demand.

At least one ESP gave no indication regarding plans for adding to its portfolio of supply resources.

This fall, the CPUC is expected to adopt resource adequacy requirements covering the period June 2006 onwards. If these requirements match D.04-10-035 and the Phase II workshop Report discussion, then at least some ESPs will be required to modify their strategies and to acquire qualifying resources that cover both expected monthly peak loads and the minimum 15 percent planning reserve margin.

Energy Requirements

For 2006, these five companies estimate their collective annual retail energy demand will be 15,134 GWh. This is an estimate of the "most likely" case, including the peak demand for likely new customers, plus the expected demand of current customers who renew or extend their direct access contracts. Collectively, energy requirements are estimated to be 14,068 GWh in 2010 and 16,353 GWh in 2016. The trend is shown on Figure 5-7.

For most ESPs, the month with largest amount of energy use is consistently July or August. Total amounts of energy delivered to at least one company to its retail customers are fairly consistent from month to month. For this ESP, energy demand peaks in August, but this amount is typically just 16 percent larger than energy use in February when monthly energy consumption ebbs.

Two companies forecast growth in customer energy requirements. At least one company forecast a general downward trend in monthly energy demand, no doubt reflecting the contract expiration dates of its existing customer base. One company forecast flat-line energy use by its retail customers for the entire forecast period, meaning that each August had the same high figures, and each December had the same low figures, etc.

Renewable Resources

The amounts of energy supplied under contracts from renewable energy sources are estimated to grow from 293 GWh in 2006, to 649 GWh in 2009, to 738 GWh in 2010, and 1,446 GWh in 2016. These amounts are shown on Figure 5-9 and Figure 5-10.

Only one company submitted a Resource Plan indicating that it was on a path to deliver 20 percent of its retail energy requirements from state-defined eligible renewable resources by 2017. For this company, renewable energy supplies will comprise 12 percent of retail sales requirements in 2009, and 19 percent in 2016.

At least two companies do not anticipate signing any contracts for renewable energy delivery during the forecast period. Nor do these companies anticipate adding generic renewable resources to the portfolio of supply contracts. On the capacity and energy tables, no data was provided on the rows related to renewable supplies. They may anticipate purchasing renewable energy on spot markets, or meeting their renewable energy obligations by purchasing renewable energy credits (RECs). However, the supply forms and instructions did not specifically ask for this type of data, and the companies did not identify these options as part of their compliance strategy.

Uncertainties of Concern to ESPs

One company warns that because its customers are free to leave, it is difficult to make long term projections of demand. From its narrative:

> “Unlike the IOUs, energy service providers … do not have captive customers. Direct Access (DA) qualified customers can choose service

> from any ESP or can choose to return to bundled utility service. Accordingly, the largest uncertainties for ___ are whether its current customers remain ___, whether its current customers choose another ESP, whether it's current customers choose to return to bundled service from the IOU's, and whether ___ can entice customers of other ESPs to switch from their current provider(s) to ___."

One ESP warns of other uncertainties related to serving Direct Access (DA) customers:

> "The wholesale cost of power is another significant uncertainty over which ___ has no control and no ability to influence. As wholesale power costs increase, the costs that DA customers must pay also increase. When the DA CRS of $27 per MWh is added to the wholesale power costs, some customers may choose to return to bundled service by the applicable IOU."

> "Another major uncertainty for … all ESPs is regulatory uncertainty. California has proven itself an extremely unstable market with constant change. Anti-free market forces continue to try to regulate or legislate DA out of existence. In addition to frontal assaults on DA, opponents of a free market are constantly trying to undermine DA by adding economic, regulatory or administrative burdens on DA customers and providers."

> "As a result of regulatory uncertainty in the past, many customers have been unwilling to enter into long-term power purchase transactions, even when wholesale power prices were extremely favorable. This may continue to be an issue in the future as well."

One company is mostly concerned with uncertainty regarding the wholesale market. From its narrative:

> "The number one driver of uncertainty for ___ is the wholesale power market; specifically the forward curve for energy delivered into SP-15 and NP-15. This uncertainty far-and-away surpasses the regulatory environment…. Unfortunately, ___ has no ability to control the cost of energy as we procure from the wholesale markets. At some point, if the wholesale market prices continue to rise, as they have over the past two years, the economics of Direct Access will reverse and most, if not all of ___ load, will migrate to a lower cost supplier."

Regulatory uncertainty is one of the top concerns for most ESPs. From one company's narrative:

> “The second greatest uncertainty for ___ is the regulatory and political environment. This ESP plans and procures energy as demand warrants, we have no assured book of business beyond our contracting window, therefore, ___ has no generating resources under contract beyond that window. Thus, the costs associated with resource adequacy requirements that, through regulation, extend beyond our contracting horizon are costs that ___ incurs with no offsetting counterparty under contract.”

One company is also concerned about stranded costs and exits fees that slow the momentum for moving toward opening direct assess. From its narrative:

> “The third greatest uncertainty is the regulatory lag that exists. The UDC's cost structure and recovery of costs is lagged, in some cases, by years via the 3-year rate case cycle and yearly ERRA proceedings. In addition, the ever-changing DWR revenue requirements and associated “true ups” continues to inject varying degrees of uncertainty over the economics of direct access. The re-payment of the DA-CRS and its eventual withering away is estimated in some scenarios as only a few years out and in other scenarios over a decade out. This kind of uncertainty is but one factor that influences the duration of the term of retail contracts and biases them toward the shorter end of the spectrum.”

One company is mostly concerned with legislative and regulatory uncertainty. From its narrative:

> “The greatest uncertainties an ESP in California faces that can affect its portfolio in near and far range forecasting are varied but predominately come from the legislative and regulatory venues. These are only exceeded by the risk of unintended consequences. The market and competitor behaviors are uncertain but do not have the same level of impact. That is an extremely strong statement given the volatility in the North American energy complex today.”

Near the top of its list are concerns regarding TURN’s so-called “re-regulation ballot initiative”, which would permanently eliminate new direct access. Long-term planning is made more difficult by uncertainties about stranded core/non-core expenses, and potential acceleration of the 20 percent renewable energy goal to 2010.

One company is not optimistic regarding the proposed policy of requiring load serving entities to procure their own reserves. Here is an excerpt:

Resource Adequacy

The final outcome of this regulatory requirement will most likely affect our forecast in three ways. First, if enacted as discussed currently it will effectively destroy the seven-year-old operating reserves market the ISO has run. This will in turn eliminate the transparency of this element of the market. The interface between the capacity and energy markets in the real time from a financial to system operations perspective will become unavailable to market participants as well as policy makers.

The second way our business forecast will be affected is in our inability to manage our portfolio as all western portfolios have been managed for decades with respect to the short term markets. The short term market optimization brought about from physical fundamental knowledge and experience which sets us apart from other market participants will be negated. The only purchasing activity within the operating month will be done by generators due to forced outages. The generators will of course have built this risk premium into every MWh they sell forward thereby significantly increasing the financial expense for no gain to the market. If a specific customer or our portfolio consumption changes dramatically eight months before the summer season we are forced into being in a long position by regulatory compliance in a market that is biased towards lower spot prices.

Or for a more spontaneous example customer ABC decides to pull its third shift for next month which reduces its consumption by thirty percent and now the ESP has power to sell into a falling market. The amount of these types of exposure with no guaranteed rate of return as the UDC enjoys becomes a very real constraint for the business and its future forecast.

The third impact on our business forecast is in the area of product innovation which is the core of bringing value to the customer base beyond the plain vanilla aggregate service the UDC is designed to provide. Our customer's have grown to appreciate and expect their ability to call and co-design their future rates with us incorporating layering of risk and term lengths to suit their specific businesses. The currently discussed capacity showings will take away the customers' flexibility other than on an annual basis. The sensitivity on this issue will be around synthetic products requiring significant risk allocations."

One company is concerned that various proposed legislative bills would significantly impact their business. This company specifically mentioned Assembly Bill 1704 which would lift the direct access suspension, and AB 1585 which would accelerate the state's Renewable Portfolio Standards for ESPs to 2010. Two other examples of uncertainty of concern are potential new regulatory requirements related to resource adequacy for ESPs, and the implementation of exit fees for non-core departing load. All these uncertainties and more affect the ability to forecast and serve customer load in California.

One company is mostly concerned with regulatory uncertainty regarding the potential for full restoration direct access. From its narrative:

> “As an ESP ____ faces a variety of uncertainties that affects its load forecasts. The dominant forms of uncertainty Strategic Energy faces in California are related to Regulatory Uncertainty.”

For this company, regulatory uncertainty includes:

- Implementation of a core/non-core market structure
- Structure of adopted core/non-core market
- Legislative or initiative based re-regulation of the direct access market
- Involvement in Community Choice Aggregation
- Changes to UDC switching rules
- Market Pricing
- DA CRS reassessment
- Current Direct Access Load Growth Opportunities
- Resource Adequacy Requirements
- Renewable Portfolio Standards
- Direct Access Cost Responsibility Surcharge (“DA CRS”)”

Like other ESPs, this company has other concerns regarding legislative and regulatory uncertainty. Among the topics listed from its narrative are:

- Community Choice Aggregation,
- Changing rules that affect the ability of Unbundled Non-Core customers to return to IOUs, ESPs,
- Market Pricing,
- Direct Access exit fees,
- Resource Adequacy Rules imposed on ESPs, and
- Renewable Portfolio Standard rules imposed on ESPs.

APPENDIX C: RECENT RETAIL PRICES IN CALIFORNIA AND WESTERN U.S. STATES

Statewide Prices

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	7.33	7.23	7.25	7.35	7.21	7.34	7.59	7.11
CA	8.93	8.97	9.47	12.04	12.50	11.62	11.18	10.73
CO	5.95	5.95	5.88	5.57	6.00	6.77	7.00	7.29
ID	4.03	4.00	4.17	5.18	5.58	5.22	4.97	4.94
MT	4.79	4.96	5.00	6.26	5.75	6.16	6.09	6.24
NM	6.78	6.58	6.58	7.02	6.73	7.00	7.19	7.13
NV	5.76	5.93	6.17	7.88	8.42	8.29	8.58	8.58
OR	4.90	4.86	4.89	4.97	6.32	6.18	6.09	6.29
UT	5.16	4.86	4.84	6.31	5.39	5.41	5.72	5.40
WY	4.31	4.30	4.34	5.23	4.68	4.76	4.95	4.92

Residential

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	8.68	8.53	8.44	8.30	8.27	8.35	8.47	7.90
CA	10.59	10.68	10.89	12.65	12.90	12.00	11.78	11.75
CO	7.45	7.38	7.31	7.46	7.37	8.14	8.32	8.72
ID	5.28	5.26	5.39	6.03	6.59	6.24	6.08	5.88
MT	6.50	6.78	6.49	6.83	7.23	7.56	7.84	7.43
NM	8.85	8.62	8.36	8.65	8.50	8.69	8.78	8.70
NV	7.00	7.13	7.28	9.07	9.43	9.02	9.70	10.09
OR	5.83	5.75	5.88	6.31	7.12	7.06	7.12	7.17
UT	6.84	6.27	6.29	7.06	6.79	6.90	7.24	7.07
WY	6.28	6.34	6.50	6.96	6.97	7.04	7.10	6.87

Commercial

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	7.76	7.51	7.34	7.36	7.28	7.09	7.50	7.01
CA	9.49	9.79	10.25	12.76	13.22	12.19	11.90	11.11
CO	5.67	5.61	5.55	5.67	5.67	6.60	6.92	7.25
ID	4.34	4.20	4.24	4.94	5.71	5.56	5.34	5.20
MT	5.87	6.35	5.60	6.17	6.53	7.10	7.17	7.08
NM	7.80	7.53	7.06	7.47	7.22	7.36	7.52	7.57
NV	6.50	6.66	6.74	8.44	9.06	8.79	9.10	9.34
OR	5.04	4.94	5.06	5.40	6.59	6.38	6.39	6.64
UT	5.71	5.29	5.23	6.48	5.60	5.59	5.92	5.65
WY	5.25	5.28	5.29	5.49	5.71	5.74	6.00	5.96

Industrial

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	5.12	5.04	5.27	5.30	5.20	5.38	5.50	5.39
CA	6.49	6.57	7.14	9.89	10.83	9.85	8.53	8.00
CO	4.34	4.38	4.25	4.50	4.52	5.10	5.32	5.29
ID	2.92	2.90	3.11	4.56	4.34	4.16	3.83	3.47
MT	3.26	3.14	3.97	4.77	3.70	4.01	4.14	4.31
NM	4.47	4.25	4.69	4.91	4.48	4.95	5.10	5.08
NV	4.57	4.77	4.98	6.57	7.25	7.30	7.25	6.84
OR	3.60	3.58	3.56	3.59	4.72	4.63	4.25	4.24
UT	3.45	3.36	3.35	4.89	3.84	3.79	4.07	3.82
WY	3.38	3.34	3.36	3.88	3.55	3.65	3.90	3.80

Source: DOE-EIA

APPENDIX D: CALIFORNIA RETAIL PRICE OUTLOOK

Consolidated Retail Electricity Price Forecast --- Nominal Cents/kWh

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
PG&E	Residential	12.4	12.7	12.3	12.1	12.0	12.1	12.1	12.0	12.2	12.0	12.3	12.3
	Commercial	13.6	13.9	13.7	13.7	13.9	14.0	13.8	13.6	13.8	13.6	13.7	13.7
	Industrial	9.9	10.1	10.1	10.1	10.3	10.4	10.3	10.0	10.2	10.0	10.2	10.3
	Agricultural	11.2	11.9	11.3	11.3	11.7	11.8	11.8	11.7	11.9	11.7	12.0	12.0
	Other	12.5	12.6	12.6	12.6	13.0	13.2	13.2	13.1	13.3	13.2	13.5	13.6
SCE	Residential	12.5	12.6	13.1	13.5	12.7	12.8	12.9	12.9	12.5	12.6	12.7	12.9
	Commercial	14.2	15.3	15.7	16.2	15.8	15.8	16.0	16.2	16.4	16.5	16.6	16.7
	Industrial	9.8	10.6	11.3	11.5	11.4	11.4	11.5	11.6	11.5	11.6	11.6	11.7
	Agricultural	9.4	9.4	9.9	10.1	10.1	10.1	10.1	9.9	9.4	9.5	9.6	9.6
	Other	14.9	14.3	14.7	15.5	15.6	15.8	16.1	16.0	15.5	15.6	15.9	16.1
SDG&E	Residential	16.2	16.7	16.7	17.0	16.4	16.6	16.9	17.3	17.6	17.9	18.2	18.5
	Commercial	13.3	13.6	13.6	13.8	13.6	13.8	14.0	14.2	14.4	14.6	14.8	15.0
	Industrial	11.2	11.5	11.5	11.8	11.9	12.1	12.4	12.6	12.8	13.0	13.2	13.5
	Agricultural	15.3	15.8	15.8	16.1	16.3	16.6	16.9	17.2	17.5	17.8	18.1	18.4
	Other	15.5	15.4	16.0	16.3	16.6	16.8	17.1	17.5	17.8	18.1	18.4	18.7
BGP	Residential	12.5	12.7	13.0	13.1	13.3	13.2	13.4	13.5	13.6	13.8	13.9	14.1
	Commercial	12.5	12.6	12.9	13.1	13.2	13.1	13.3	13.5	13.6	13.8	14.0	14.1
	Industrial	10.0	10.1	10.4	10.5	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2
	Agricultural	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SMUD	Residential	9.0	10.5	10.8	10.8	10.1	9.9	10.1	10.3	10.4	10.5	10.7	10.9
	Commercial	9.1	10.7	10.9	11.0	10.2	10.1	10.3	10.4	10.5	10.7	10.8	11.0
	Industrial	7.2	8.5	8.7	8.8	8.1	8.0	8.2	8.3	8.4	8.5	8.6	8.8
	Agricultural	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LADWP	Residential	10.4	10.4	10.6	10.8	10.9	11.0	11.2	11.4	11.5	11.7	11.8	12.0
	Commercial	9.6	9.1	9.1	9.3	9.3	9.3	9.4	9.5	9.5	9.6	9.7	9.7
	Industrial	7.4	6.8	6.9	6.9	7.0	6.9	6.9	7.0	7.0	7.0	7.0	7.1
	Agricultural	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other IID	Residential	11.4	11.6	11.8	12.0	12.2	12.5	12.7	12.9	13.1	13.4	13.6	13.8
	Commercial	11.1	11.3	11.5	11.7	11.9	12.1	12.3	12.6	12.8	13.0	13.2	13.5
	Industrial	9.3	9.4	9.6	9.8	10.0	10.2	10.3	10.5	10.7	10.9	11.1	11.3
	Agricultural	9.8	9.9	10.2	10.3	10.5	10.7	10.9	11.1	11.3	11.5	11.7	11.9
	Other	14.2	14.4	14.7	15.0	15.2	15.5	15.8	16.1	16.4	16.6	16.9	17.2

Source : CEC staff

Notes: This outlook of electricity rates consolidates IOU, Municipal and energy service provider (ESP) rates into rates by service territory.

BGP: Burbank, Glendale and Pasadena

APPENDIX E: GENERATION AND T&D COST OUTLOOK BY IOU RATE CLASS

PG&E

	Total			Residential			Small Commercial			Medium Commercial			Industrial		
	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total
2005	5.4	6.7	12.2	4.5	8.4	12.9	6.3	8.8	15.1	8.1	6.3	14.4	7.4	5.5	12.9
2006	6.1	5.7	11.8	5.1	7.3	12.4	7.1	7.7	14.9	9.1	5.1	14.2	8.4	4.5	12.9
2007	6.1	5.5	11.5	5.1	7.0	12.1	7.2	7.4	14.6	9.1	5.0	14.2	8.4	4.4	12.9
2008	6.2	5.3	11.4	5.4	6.7	12.0	7.5	7.1	14.6	9.5	5.1	14.6	8.8	4.5	13.3
2009	6.2	5.5	11.7	5.3	6.8	12.2	7.4	7.3	14.7	9.5	5.2	14.7	8.7	4.6	13.4
2010	6.0	5.6	11.6	5.1	7.0	12.1	7.2	7.4	14.6	9.1	5.3	14.5	8.4	4.7	13.1
2011	5.7	5.8	11.5	4.9	7.1	12.0	6.8	7.6	14.4	8.6	5.5	14.1	8.0	4.8	12.8
2012	5.8	5.9	11.8	4.9	7.3	12.2	6.8	7.8	14.6	8.7	5.6	14.3	8.0	4.9	12.9
2013	5.9	5.7	11.7	4.9	7.0	12.0	6.9	7.5	14.4	8.8	5.3	14.0	8.1	4.6	12.7
2014	6.1	5.9	11.9	5.0	7.2	12.2	7.0	7.7	14.7	9.0	5.4	14.4	8.3	4.7	13.0
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

SCE

	Total			Residential			Small Commercial			Medium Commercial			Industrial		
	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total
2005	7.8	5.0	12.8	6.2	6.4	12.6	8.2	7.6	15.7	10.0	4.4	14.4	8.7	3.3	12.0
2006	8.4	5.1	13.6	6.6	6.5	13.1	8.8	7.7	16.5	10.9	4.6	15.4	9.4	3.4	12.8
2007	8.5	5.5	13.9	6.6	7.0	13.6	8.8	8.2	17.0	10.9	4.9	15.8	9.4	3.7	13.1
2008	8.3	5.2	13.5	6.4	6.3	12.8	8.6	7.6	16.2	10.7	5.0	15.7	9.2	3.8	13.0
2009	8.2	5.4	13.5	6.4	6.5	12.8	8.5	7.7	16.2	10.6	5.1	15.7	9.1	3.8	12.9
2010	8.2	5.5	13.7	6.4	6.6	13.0	8.6	7.9	16.4	10.6	5.2	15.8	9.1	3.9	13.0
2011	8.1	5.6	13.7	6.1	6.8	12.9	8.5	8.1	16.6	10.8	5.4	16.1	9.1	4.0	13.2
2012	7.9	5.7	13.6	5.6	6.9	12.5	8.3	8.3	16.5	10.9	5.5	16.4	9.0	4.1	13.1
2013	7.9	5.8	13.7	5.6	7.0	12.6	8.3	8.4	16.7	10.9	5.6	16.5	9.0	4.2	13.2
2014	7.9	5.9	13.8	5.6	7.2	12.7	8.3	8.6	16.9	10.9	5.7	16.6	9.0	4.2	13.3
2015	7.9	6.1	13.9	5.5	7.3	12.9	8.3	8.8	17.0	10.9	5.8	16.7	9.0	4.3	13.3
2016	7.9	6.2	14.1	5.6	7.5	13.1	8.3	9.0	17.3	10.9	6.0	16.9	9.1	4.4	13.5

SDG&E

	Total			Residential			Small Commercial			Medium and Large Comr		
	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total
2005	6.1	7.7	13.8	7.4	9.0	16.4	7.4	9.5	16.9	4.9	6.4	11.3
2006	6.1	7.4	13.5	7.4	8.7	16.1	7.4	9.1	16.5	4.9	6.2	11.1
2007	6.1	7.4	13.5	7.4	8.7	16.1	7.4	9.1	16.5	4.9	6.2	11.1
2008	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2009	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2010	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2011	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2012	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2013	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2014	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2015	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2016	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1