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RENEWABLE RESOURCES DEVELOPMENT REPORT

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EXECUTIVE SUMMARY

California's long history of support for renewable energy has positioned the state as a recognized leader. California is home to three of the largest developed wind resource areas in the world and has the largest developed wind industry of any state in the nation. The state produces the world's largest amount of electricity from concentrating solar power facilities and is the third largest market for photovoltaic energy (after Germany and Japan). Biomass and geothermal are also important renewable resources for electricity generation and account for nearly 70 percent of renewable resource generation in the state. Today, about 11 percent of the electricity Californian's use in their homes and businesses each year is generated from renewable sources.

California's renewable resources are far from fully developed. The Energy Commission estimates that the state has the potential to generate 10 times the electricity generated today from renewable sources. The other states in the Western Electricity Coordinating Council also have abundant renewable resources, particularly wind and solar. These resources are relevant because California imports 25 percent of its electricity, and out-of-state renewable generation could supply some of California's future renewable supply portfolio.

How and when these remaining renewable resources may be developed is the topic of this report. California is driving further development of the state's renewable resources through a Renewables Portfolio Standard, established in 2002 by Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002). In addition, California provides financial incentives for increased renewable development and sustained renewable operation through the Renewable Energy Program, established in 1997 and continued in 2002 by Senate Bill 1038 (SB 1038, Sher, Chapter 515, Statutes of 2002).

The Renewables Portfolio Standard requires that retail sellers of electricity increase their sales of electricity produced by renewable energy sources by at least 1 percent per year, achieving 20 percent by 2017, at the latest. Since passage of the Renewables Portfolio Standard bill, the ***Energy Action Plan*** was adopted by the California Energy Commission, the California Public Utilities Commission, and the California Power Authority. The ***Energy Action Plan*** establishes a more aggressive goal for renewable energy development with a target of 20 percent by 2010.[1]

Estimates of the costs of electricity from renewable resources suggest that the Renewables Portfolio Standard goals established in California are economically feasible. Renewable resource costs have been declining over time, and are projected to decline further as technological improvements are employed. With zero fuel costs in most cases, renewable generation can avoid the cost volatility recently experienced with natural gas prices.

BENEFITS OF RENEWABLE DEVELOPMENT

California continues to drive development of its renewable resources because of the benefits these resources bring to the state. Generating electricity from renewable resources provides environmental and economic benefits compared to conventional electricity generation, contributing to energy diversity and security.

Electricity from renewable resources reduces the amount of carbon dioxide released into the air from conventional electricity generation. Global climate change, which is related to carbon dioxide levels in our air, is one of the most significant environmental issues the world faces today. Global climate change is linked to higher ambient temperatures, increases in extreme weather events, rising sea levels, and other global problems. Effects on California may include reduced Sierra snow pack, greater flooding, sea water intrusion in bays and deltas, and increased susceptibility of pests and diseases impacting human health and our biological resources. The Energy Commission estimates that meeting the Renewables Portfolio Standard requirements could reduce annual carbon dioxide emissions by 38 million tons in the Western Electricity Coordinating Council by 2013, with annual reductions of 62 million tons by 2013 if the Renewables Portfolio Standard is accelerated.

Further development of California's renewable resources will also reduce emissions of pollutants that cause poor air quality in the state. California's current electricity generation system produces fewer harmful air emissions such as nitrogen oxides and sulfur dioxide than the rest of the nation, because natural gas and renewable energy are the primary resources for electricity generation. Our natural gas power plants produce relatively few emissions of these pollutants compared to coal or oil fired facilities, and new facilities being built are relatively clean and efficient. Renewable resources, however, release even fewer pollutants into the air, and, in many cases, emit no pollution at all.

The Energy Commission estimates that meeting the Renewables Portfolio Standard could reduce annual emissions of oxides of nitrogen in the Western Electricity Coordinating Council by 20,000 tons by 2013. Accelerating the Renewables Portfolio Standard to 2010 could reduce annual emissions of oxides of nitrogen in the region by 31,500 tons by 2013.

Generating electricity from renewable resources also contributes to California's energy security by reducing our reliance on natural gas. During the height of the electricity crisis in late-2000 through mid-2001, natural gas prices in the state were extremely high. In addition, investor-owned-utilities had difficulty paying for the energy being procured from generators. Many natural gas power plants had difficulty generating electricity with expensive fuel costs and uncertain payments for power.

Most of the state's renewable generators continued operating during the crisis, even without payments for their power.

The Energy Commission estimates that about 2.5 percent of annual natural gas demand for electricity generation in the Western Electricity Coordinating Council can be offset by meeting the California's Renewables Portfolio Standard. Accelerating the Renewables Portfolio Standard can displace about 5 percent of this annual natural gas demand.

POLICIES DRIVING RENEWABLE DEVELOPMENT

California developed most of its existing 7,000 megawatts of renewable energy because of the mandate to purchase power from renewable and co-generating power sources as embodied in the federal Public Utilities Regulatory Policy Act. Most of the 28,900 gigawatt-hours per year (GWh/yr) of electricity generated in 2002 from renewable resources is sold to California's three large investor-owned utilities under long term standard offer contracts established in the 1980s and 1990s as the California Public Utilities Commission implemented the Public Utilities Regulatory Policy Act requirements. These contracts most often included fixed prices tied to an estimate of escalating fossil fuel costs that led to significant premiums in price over actual market prices for electricity.

More recently, development of renewable resources has been driven by the Renewable Energy Program's production incentives for generation of renewable power from new, existing, and emerging renewable projects. The annual budget for the Renewable Energy Program, from 1998 through 2011, is $135 million. Funds for this program are collected from ratepayers of the three large investor-owned utilities in the state.

In 2002, the Legislature passed the Renewables Portfolio Standard, which requires that certain retail sellers of electricity increase their sales of electricity from renewable energy sources by at least 1 percent per year, achieving 20 percent by 2017, at the latest. Since passage of the Renewables Portfolio Standard bill, the ***Energy Action Plan*** was adopted and establishes a more aggressive goal for renewable energy development with a target of 20 percent by 2010. The Renewable Energy Program will provide funds to generators to cover the above-market costs for electricity, and design a tracking and verification system to ensure that retail sellers are meeting their procurement targets.

RENEWABLE DEVELOPMENT POTENTIAL AND COSTS

The available data and studies on technical potential of electricity generation from renewable resources vary, sometimes significantly, depending on time-frames, methods of collection, and criteria used to filter the data. The estimated combined technical potential for wind, geothermal, biomass, biogas, small hydroelectric, and solar (photovoltaic and concentrated solar power) in California is more than 262,000 GWh/year.[2,3]

In terms of technical potential in the Western Electricity Coordinating Council region, California ranks fourth behind Montana, Colorado, and Wyoming. The total technical potential for development of wind, geothermal, biomass, and solar (photovoltaic and concentrating solar power) resources in Western Electricity Coordinating Council (excluding California) is estimated to be more than 3.7 million GWh/year. Wind accounts for almost 2.8 million GWh/year or 75 percent of the total.

Electricity from renewable resources can be produced at a reasonable cost and, in some cases, can compete with the expected cost of a new natural gas power plant. Renewable resources that are most cost competitive today include wind, geothermal, and limited biomass applications. Additional renewable technologies will become competitive with advances that increase efficiency and lower costs.

The cost of generating electricity from wind has dropped significantly in the last 20 years, making wind the fastest growing (on a percentage basis) central station renewable source for power generation. In many regions of the country, the production tax credit has contributed to making wind power among the lowest cost options for new capacity. Further cost reductions are expected to result from efficiency improvements, higher hub heights, larger rotors, advances in electronics, and additional experience operating large wind projects.

A recent estimate of cost trends for development of renewable energy suggests that by 2005 a 75 megawatt wind plant (Class 4 wind site[4]) may deliver power at a levelized cost of electricity at about 4.9 cents per kilowatt-hour (cents/kWh) without the production tax credit, and 3.4 cents/kWh with the production tax credit (2003 dollars). The estimate suggests that the same size plant in a Class 6 wind site[5] may have a levelized cost of electricity of 4.1 cents/kWh without the production tax credit, and 2.7 cents/kWh with the tax credit.[6]

The estimate suggests that the levelized cost of electricity from a 100 megawatt concentrated solar power parabolic trough system without storage will be about 12 cents/kWh in 2005. By 2010, the estimate suggests that the levelized cost of energy from an installed system with storage could drop to as low as 6.4 cents/kWh.

By 2005, a 50 megawatt geothermal system is expected to have a levelized cost of energy of 5.3 to 5.5 cents/kWh. The levelized cost of energy from a 2 megawatt landfill gas facility is estimated to be 4.4 cents/kWh in 2005, dipping to 3.7 cents/kWh by 2017. Electricity from landfill gas is an economically competitive and mature technology with a high capacity factor. By 2005, the levelized cost of energy for anaerobic digester gas from animal waste is estimated to be 4.3 cents/kWh, dropping to 3.6 cents/kWh by 2017. A 20 megawatt solid biomass direct combustion facility is estimated to have a levelized cost of 6.4 cents/kWh in 2005, dropping to 5.6 cents/kWh by 2017.

The estimate suggests that the levelized cost of energy for photovoltaic systems will be nearly cost competitive (without rebates) by 2017. By 2005, a residential customer in a high insolation region should be able to install a 3 kW photovoltaic system that generates electricity at about 23 cents/kWh (without incentives). By 2017, it is estimated that these costs will drop to approximately 12.6 cents/kWh.

Much of California's installed renewable energy capacity is relatively old, raising the potential for refurbishing or repowering this existing equipment. Technological advances in wind generation, in particular, imply that most of California's existing capacity, which was installed before 1990, could be repowered and use the wind resources at those sites more efficiently and cost-effectively. Repowering of these sites is currently uncertain however, due to issues surrounding the federal production tax credits, one of the primary incentives for wind development in the country.

Currently, the production tax credit is set to expire at the end 2003, which is driving wind development this year. The current production tax credit includes a clause that affects facilities that sell output to investor-owned utilities under contracts entered into before January 1, 1987. A repowered facility is eligible for the production tax credit if the existing standard offer contract is "amended" such that any wind generation in excess of historical norms is either sold to the utility at its current avoided costs, or else sold to a third party.[7] To date, such amendments have been difficult to negotiate and implement, limiting repowering of these facilities.

Pending federal legislation extends the production tax credit beyond the end of this year, and potentially expands the credit to generation from other renewable resources (beyond wind). This may provide an incentive to repower some of California's older renewable facilities, especially if facilities are also eligible to receive supplemental energy payments as part of the Renewables Portfolio Standard. Approximately 450 – 900 megawatts of existing capacity are good candidates for repowering. Repowering geothermal facilities can potentially add several hundred megawatts with 100 megawatts possible from repowering landfill gas projects.

ESTIMATED ENERGY REQUIREMENTS FOR THE RENEWABLES PORTFOLIO STANDARD AND ACCELERATED RENEWABLES PORTFOLIO STANDARD

The Energy Commission estimated the amount of electricity from renewable resources required to meet the state's Renewables Portfolio Standard and the amount needed to meet the accelerated Renewables Portfolio Standard goal in the ***Energy Action Plan***. **Table 1** presents the estimated amount of additional renewable electricity required to meet the California's statewide Renewables Portfolio Standard.

Table 1. Estimated Amount of Renewable Electricity (Gigawatt-hours/year) needed to reach California's RPS by 2017[8]

2001 baseline and interim procurement*		Total Added by 2017	20% of 2017 sales
Retail seller	**GWh/yr**	**GWh/yr**	**GWh/yr**
Pacific Gas and Electric Company	8,358	9,522	17,880
Southern California Edison	11,908	5,123	17,031
San Diego Gas and Electric	1,062	2,721	3,783
All Electric Service Providers and Community Choice Aggregators	1,865	3,837	5,702
Sub-total	23,193	21,203	44,396
Rest of State**	7,177	9,407	16,584
Total (rounded)	**30,370**	**30,610**	**60,980**

Source: ***Renewable Resources Development Report***

Table 2 presents the estimated amount of additional electricity from renewable resources that obligated parties would need to acquire to address the accelerated Renewables Portfolio Standard goal outlined in the ***Energy Action Plan***.

Table 2. Estimated Amount of Renewable Electricity (Gigawatt-hours/year) needed to Accelerate California's RPS to 2010 (20 percent of Retail Sales in 2010)[9]

2001 baseline and interim procurement*		Total Added by 2010	20% of 2010 sales
Retail seller	GWh/yr	GWh/yr	GWh/yr
Pacific Gas and Electric Company	8,358	7,792	16,150
Southern California Edison	11,908	3,339	15,247
San Diego Gas and Electric	1,062	2,304	3,365
All Electric Service Providers and Community Choice Aggregators	1,865	3,237	5,102
Sub-total	23,193	16,672	39,865
Rest of State**	7,177	8,124	15,301
Total (rounded)	30,370	**24,800**	**55,170**

Source: ***Renewable Resources Development Report***

Although the actual mix of renewable energy resources to meet the Renewables Portfolio Standard and their eventual location will be determined by the bids in response to solicitations, the Energy Commission has developed scenarios for meeting the Renewables Portfolio Standard. These scenarios are based on known proposed renewable energy projects in the state.

The Kern County wind resource area may be capable of satisfying much, if not all, of the renewable energy demand through 2008. Least-cost-best-fit considerations will likely encourage geographic and resource diversity.[10] Geothermal and biomass resources are expected to be valued for their ability to provide base load power that matches the generation profile of conventional sources. Smaller scale resources such as landfill gas and anaerobic digester gas are likely to play a more limited role.

Concentrating solar power becomes a factor in scenarios in the 2008-2017 timeframe. Central station solar photovoltaic systems are not expected to play a significant role in meeting the Renewables Portfolio Standard. Distributed generation solar photovoltaic technology, however, has seen an enormous growth in recent years, and is expected to continue to be an important distributed generation resource. Distributed generation reduces retail sales of electricity, thereby reducing the amount of renewable energy required to meet 20 percent of retail sales.

CHALLENGES OF RENEWABLE RESOURCE DEVELOPMENT

Implementation of the Renewables Portfolio Standard will require attention to several important policy issues. Expansion of the transmission system to accommodate renewable resource development will likely be costly. Transmission limitations will be affected by capacity constraints, the portion of the Renewables Portfolio Standard that is met by out-of-state resources, and whether renewable energy certificates can be used to meet the requirement. A balance must be made between renewable resource development and the operational compatibility of the existing electricity system and “least-cost-best-fit” considerations. There is too much uncertainty to know if there are sufficient public goods charge funds to meet the Renewables Portfolio Standard, or an accelerated Renewables Portfolio Standard. The state should assess the adequacy of public goods charge funds at the conclusion of the first Renewables Portfolio Standard solicitation.

Electricity generation from renewable resources does not come without impacts to the environment. Turbines and transmission lines associated with wind energy are especially problematic for migratory birds, in particular raptors. Negative environmental issues with geothermal resource development include the potential for groundwater and surface water contamination and impacts to cultural resources. The manufacturing and disposal process for photovoltaic panels can pose risks of exposure to toxic materials to workers and the environment. Small hydroelectric generation can negatively impact water quality, fish migration, river flows, and cultural resources. Environmental problems associated with biomass include emissions from power generation facilities and possible damage to forests and wildlife.

CHAPTER 1: INTRODUCTION AND BACKGROUND

INTRODUCTION

Senate Bill 1038 (SB 1038) requires the California Energy Commission (Energy Commission) to submit a comprehensive renewable electricity generation resource plan to the Legislature, which describes the potential renewable resources available in California, along with a plan to increase the annual amount of electricity generated from renewable sources.

This report is organized to provide an indication of changes in development of renewable energy resources over time, moving from past to present to future. Accordingly, this report provides a historical context for renewable electricity generation in California and the other states in the Western Electricity Coordinating Council (WECC). The renewable resources included in this report are wind, geothermal, biomass, biogas, solar photovoltaic, concentrating solar power, small hydroelectric, and ocean energy.

California led the nation in the amount of retail electricity sales coming from renewable energy sources in 1999 and 2000, the latest years for which comparative data are available.[11] This report provides data on installed capacity of renewable energy in California and the remaining WECC, along with technical potential estimates of renewable energy resources for the region.

Renewable energy costs have declined over time, and this trend is expected to continue in the future with advances in technology. This report presents levelized cost of energy economics for renewable energy technologies for the years 2005, 2008, 2010, and 2017, which correspond with key dates for the Renewables Portfolio Standard (RPS). The status of the RPS program is provided along with a discussion of outstanding policy issues and program requirements.

This report also provides an update to the ***Preliminary Renewable Resource Assessment*** (PRRA) provided to the California Public Utilities Commission (CPUC) on July 1, 2003.[12] Whereas the PRRA focused on the energy needs of the investor-owned utilities (IOUs) and Electric Service Providers (ESPs) for transmission planning purposes, this report expands its scope to include the energy needs of the rest of the state (publicly-owned electric utilities and other IOUs). Adjustments have been made to the estimates of renewable energy resources needed to meet RPS obligations, the amount of proposed renewable projects, and the installed renewable capacity within California and the WECC. An RPS compliance scenario for the entire state, using data from existing and proposed projects, is included.

The ***Energy Action Plan*** includes a goal of meeting the requirements for the RPS by 2010 (20 percent renewable energy by 2010). The additional renewable energy needed to meet this goal has been estimated along with the requirements for each obligated entity throughout the state. A scenario for meeting this statewide goal is outlined along with a discussion of the issues and opportunities with accelerating implementation of the RPS.

The benefits, challenges, and barriers to renewable energy development are discussed, including fuel diversity, environmental and public health benefits, and expansion of distributed generation. The driving policy issues associated with achieving the RPS in California are outlined and include transmission constraints, sufficiency of public goods funds, least-cost-best-fit issues, creditworthiness of investor-owned utilities, and financial risk of renewable energy investments. The report also summarizes issues related to activities of publicly-owned electric utilities and other retailers of electricity to meet statewide goals of the RPS.

This report includes a brief summary of current and future research to improve the efficiency and reliability of renewable energy as well as reduce technology costs. Key research projects by the Energy Commission's Public Interest Energy Research Program (PIER) on renewable energy are highlighted.

LEGISLATIVE REQUIREMENTS

Legislative Requirements in SB 1038

As required in SB 1038, this report includes a renewable resource electricity generation plan describing the renewable resource potential for California. Specifically, the statute requires the following:

Sec. 383.5 (j) of the Public Utilities Code:

> The Energy Commission shall, by December 1, 2003, prepare and submit to the Legislature a comprehensive renewable electricity generation resource plan that describes the renewable resource potential available in California, and recommendations for a plan for development to achieve the target of increasing the amount of electricity generated from renewable sources per year, so that it equals 17 percent of the total electricity generated for consumption in California by 2006. The Energy Commission shall consult with the [California Public Utilities] commission, electrical corporations, and the Independent System Operator, in the development and preparation of the plan.

Chaptered subsequently, Senate Bill 1078 (SB 1078) supercedes the requirement of 17 percent by 2006 with the requirement that renewable energy provide 20 percent of retail electricity sales by 2017.

SB 1038 also requires the CPUC to develop a renewable energy transmission plan. Specifically the statute requires the following:

Sec. 383.6 of the Public Utilities Code:

> The Public Utilities Commission shall, by December 1, 2003, prepare and submit to the Legislature, a comprehensive transmission plan for renewable electricity generation facilities, to provide for the rational, orderly, cost-effective expansion of transmission facilities that may be necessary to facilitate the development of renewable energy generation facilities identified in the renewable electricity generation resource plan prepared pursuant to subdivision (j) of Section 383.5. The Public Utilities Commission shall consult with the State Energy Resources Conservation and Development Commission, the Independent System Operator, the electrical corporations in the development and preparation of the plan.

SB 1038 requires the CPUC to use the renewable resource plan developed by the Energy Commission in preparing the transmission plan. Both reports must be submitted to the Legislature by December 1, 2003.

Related Legislative Requirements

Senate Bill 1389 (SB 1389, Bowen, Chapter 568, Statutes of 2002) requires the Energy Commission to adopt an Integrated Energy Policy Report every two years. The first policy report was due to the Governor and the Legislature in November 2003. The policy report is supported by three subordinate reports:

- ***Electricity and Natural Gas Assessment***
- ***Transportation, Fuels, Technologies and Infrastructure Assessment***
- ***Public Interest Energy Strategies Report***

The ***Renewable Resources Development Report*** (RRDR) is prepared in support of the ***Public Interest Energy Strategies Report.***

Also in 2002, the Legislature passed SB 1078, which created the RPS. This program requires IOUs, ESPs, and other regulated entities to ensure that 20 percent of retail sales come from renewable electricity resources by 2017, within certain cost constraints. SB 1078 also contains requirements for publicly-owned electric utilities, specifically,

387. (a) Each governing body of a local publicly-owned electric utility, as defined in Section 9604, shall be responsible for implementing and enforcing a RPS that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.

Definition of Renewable Energy

This report contains information regarding the existing, proposed, and technical potential renewable energy, consistent with definitions of eligible renewable energy in SB 1038 and SB 1078, as applicable.

Consistent with SB 1038, the energy resources that are included in this report are biomass, waste tire, solar thermal, wind, geothermal, small hydroelectric power less than 30 megawatts (MW), digester gas, landfill gas, and municipal solid waste.

The report also contains information regarding existing grid-connected photovoltaic (PV) systems eligible for support under the Emerging Renewables Program, the CPUC Self-Generation Incentive Program, or publicly-owned electric utility public goods charge (PGC)-funded incentive programs.

Energy resources that are most likely to be eligible under the SB 1078 RPS program are included in the estimates of proposed and technical potential. Provided that additional criteria are met, facilities using the following resources are likely to be eligible for the RPS:

- Biomass
- Solar thermal electric
- Photovoltaic
- Wind
- Geothermal
- Fuel cells using renewable fuels
- Small hydroelectric generation of 30 MW or less
- Digester gas
- Municipal solid waste conversion
- Landfill gas
- Ocean wave, ocean thermal, and tidal current.

For some resource types, RPS eligibility is contingent upon information (e.g., appropriation of water) that is beyond the level of detail included in this report. Where this is the case, only a portion of the technical potential estimated here is likely to be eligible for the RPS. Further detail regarding eligibility criteria for the RPS program is provided in Chapter 5.

REPORT DEVELOPMENT PROCESS

To facilitate coordination of the Energy Commission SB 1038 renewable resource plan with the CPUC SB 1038 transmission plan, the Energy Commission agreed to prepare and deliver a PRRA for 2005 and 2008 on July 1, 2003 to the CPUC.

The Energy Commission's Ad Hoc Integrated Energy Policy Report Committee and the Renewables Committee held a Joint Committee Workshop in June 2003 to solicit public input from the CPUC, utilities, California Independent System Operator (CA ISO), renewable developers, and other interested parties on the draft preliminary resource assessment. The Energy Commission used information from this workshop, along with input from staff and technical consultants to revise the draft PRRA.

On July 1, 2003, the PRRA was delivered to the CPUC. The assessment allowed the CPUC to conduct an analysis of current and potential transmission constraints, primarily for the IOUs. New information gathered since the July 1, 2003 PRRA is included in this report. In addition, this report expands the scope to include the energy requirements of the rest of the state.

During summer of 2003, Energy Commission staff worked with technical consultants in collecting, developing, and analyzing data for inclusion in the RRDR. The goal is to develop a comprehensive report on the status, trends, and future of renewable energy development for California. On October 1, 2003, the Staff Draft of this report was released for public comment. Twelve parties provided written comments on the staff draft. Following receipt of comments on the staff draft, the report was revised and the Committee Final was released on November 7, 2003. The Energy Commission adopted the report with minor revisions at the Business Meeting on November 19, 2003.

HISTORY

Renewable Development in California

The availability of renewable resources in California has contributed to the state's historical commitment to support renewable energy. The oil embargos in the 1970s — along with rising energy prices, reliance on fossil fuels, and concerns about air pollution — all contributed to the interest in renewable energy. In 1978, President Carter signed the National Energy Act into law, which aimed to reduce the nation's dependence on imported oil, increase energy efficiency, and conservation, and promote renewable energy resources. President Carter also signed the Public Utilities Regulatory Policies Act (PURPA) into law, the most significant bill of the

National Energy Act, which aimed to foster the development of renewable sources for electricity generation.

PURPA required utilities to purchase power from non-utility generators, including renewable generators, at the utilities' full avoided cost. In California, the utilities were required to sign Standard Offer contracts that provided escalating fixed energy payments for 10 years. Based on high oil price projections and expensive nuclear power, these contracts, in retrospect, turned out to be quite expensive. In California, prices for Standard Offer contracts often exceeded 10 cents per kilowatt-hour (kWh).[13] As Standard Offer contracts expired and avoided costs declined to 3 cents per kWh, renewable electricity projects were not able to compete with new natural gas turbines, leading to 300 MW of renewable energy being shut down between 1993 and 1997.

In 1996, California passed Assembly Bill 1890 (AB 1890, Brulte, Chapter 854, Statutes of 1996), which placed a surcharge on electricity sold by IOUs to be used to fund public interest programs, including energy efficiency, energy research and development, and renewable energy. AB 1890 directed that a total of $540 million be collected from 1998 to 2002, to be used to build a market for renewable energy, with financial incentives to support existing, new, and emerging renewable electricity generation technologies. The Energy Commission serves as program administrator for the Renewable Energy Program. Senate Bill 1194 (SB 1194, Sher, Chapter 1050, Statutes of 2000) and SB 1038 extended the collection of $135 million per year in public goods funds for an additional 10 years.

In 2000-2001, California faced disruption and turmoil in the energy market which had an impact on renewable energy development in the state. Significant electricity price increases along with periods of short supply provided uncertainty and confusion in the market. Electric utilities, faced with financial crisis, were not able to purchase electricity on behalf of their customers, and consumers were no longer able to choose renewable energy as their electricity source, as direct access had been suspended. This combination of events left little or no market for new central-station electricity generated by renewable resources.

Responding to the impact the energy crisis had on renewable development and to further the expansion of renewable energy in the state, the Legislature passed SB 1078 creating the RPS. The RPS requires that certain retail sellers of electricity increase their sales of electricity from renewable energy by at least 1 percent per year achieving 20 percent by 2017 at the latest. Since passage of the bill, the ***Energy Action Plan*** establishes a target of 20 percent renewable energy by 2010.[14]

Renewable Development in Other Western Electricity Coordinating Council States

The WECC is a voluntary organization that focuses on bulk power generation and transmission. The WECC covers nearly 1.8 million square miles and includes the following:

- Canadian provinces of Alberta and British Columbia
- Northern portion of Baja California, Mexico
- Washington
- Oregon
- California
- Idaho
- Utah
- Nevada
- Arizona
- New Mexico
- Colorado
- Wyoming
- Montana

As with California, many of the member states in WECC have abundant renewable resources. The development of these resources has varied by region, but has primarily been the result of the PURPA and, more recently, the adoption of funding for public benefits programs and RPS programs as well as the improving economics of wind power.

Arizona is not as advanced as other western states in developing its renewable resources, especially the tremendous solar insolation that reaches the state. This is expected to change as the Arizona Corporation Commission approved an RPS that will require utilities and other electricity providers to obtain as much as 1.1 percent of their energy from renewable sources by 2007. Sixty percent of that must come from solar energy. Funds from the PGC may be used to cover RPS compliance costs.[15] Numerous large-scale solar projects have now been completed and additional projects are under development as a result of the RPS.

Colorado has plentiful wind, solar, and biomass resources that have yet to be developed. The geothermal resource is modest and not likely to be developed with current technology. Colorado has not adopted an RPS; however, green pricing programs to support wind farms have proven successful, and some development is occurring merely due to the low costs of wind power.[16]

Idaho has developed their biomass resource (120 MW) successfully, compared to other western states. The wind, geothermal, and solar resources are also superb, but have yet to be tapped for electricity production. Idaho has not adopted an RPS.

Most of the non-hydroelectric renewable energy in Montana comes from biomass generated from the state's farming and logging industry. Montana has an outstanding wind resource — the best of the western states. The wind resource potential alone could provide more than 70 times the power needed for the state.[17] Montana does not have an RPS; however, approximately $15 million annually is allocated to support renewable energy, research and development, energy efficiency, and low income energy assistance from a systems benefit charge, approximately $2 million of which is dedicated to renewable energy specifically.

The geothermal resource in Nevada is among the largest of any western state, with 4 percent of current electricity generation from geothermal facilities.[18] The state has significant untapped potential for electricity generation from its solar and wind resources. In 2001, the Nevada legislature passed an RPS bill. Beginning with a 5 percent renewable energy requirement in 2003, the amount of renewable energy will increase by 2 percent every 2 years achieving a 15 percent requirement by 2013. At least 5 percent of the RPS standard must come from solar. No specific funding support is identified; however, the Nevada Public Utilities Commission (NPUC) approves contracts for renewable energy; and if they determine the renewable energy prices are acceptable, then the provider is allowed to recover all associated costs.

New Mexico's arid climate results in less potential for biomass, but the state has favorable wind, solar, and geothermal resources. Currently, the state produces less than 1 percent of its energy from renewable resources; however, this will likely change with implementation of an RPS. On December 17, 2002, the New Mexico Public Regulation Commission unanimously approved an expansive new renewable energy rule requiring utilities to produce 5 percent of all energy they generate for New Mexico customers from solar, wind, hydroelectric, biomass, or geothermal sources by 2006. Generation from renewable energy must increase by at least 1 percent per year until the portfolio standard of 10 percent is attained by 2011. Utilities are required to file a portfolio plan with the state's Public Regulation Commission. No specific funding is available to support the RPS requirement; however, if the portfolio plan filing is approved, the utility can recover all costs that result from achieving the RPS.

Oregon possesses significant potential for geothermal energy development, and in recent years, the state has moved forward in developing its wind and biomass resources. Oregon does not have an RPS; however, in 1999, the legislation for utility restructuring included a public benefits charge with total annual funding for renewable energy expected to be $8.7 million.[19] The Energy Trust of Oregon, a non-profit organization, provides program administration.

Most of the electricity generation from renewable energy in Utah comes from geothermal. The state also has good wind resources, and the southern half of Utah has excellent solar resources. Utah has not passed an RPS, nor does it have a public benefits charge to support renewable energy.

Washington ranks second to California in the development of renewable resources among WECC states, with biomass and wind making up the majority of installed capacity in the state. Solar and geothermal resources can be found to a lesser extent. Washington does not have an RPS, but is implementing green power pricing programs.

The wind resource in Wyoming is one of the best in the country, with the electricity generated from Wyoming wind farms exported to Oregon, Colorado, and Utah.[20] Other available renewable resources include solar, biomass, and geothermal, although the geothermal resource is found in environmentally sensitive areas around Yellowstone National Park. Wyoming has not adopted an RPS.

Other than existing small hydroelectric projects in Alberta and British Columbia, current information was not analyzed on renewable development for the international portion of WECC (including the Canadian provinces of Alberta and British Columbia and the northern portion of Baja California, Mexico) and is not included in this report.[21]

CHAPTER 2: RENEWABLE ENERGY TECHNOLOGIES

WIND

According to American Wind Energy Association (AWEA), the growth in wind power generation capacity worldwide has quadrupled over the last 5 years.[22] The United States has seen a 10 percent growth in wind energy generating capacity in 2002. The AWEA is projecting an even stronger year for 2003, as developers work to install wind systems before the Production Tax Credit (PTC) is set to expire.[23]

The historical growth in the wind industry can be attributed to several developments. The cost of electricity production has dropped significantly in the last 20 years — from 80 cents per kilowatt hour (/kWh) in 1980 to about 4 cents/kWh today.[24] An increased demand driven by both consumer choice for green power and adoption of regulations such as the Renewables Portfolio Standard (RPS) contributed to the growth, as did federal and state incentives designed to stimulate the market for wind power.

In addition to the technical advances that have reduced the cost of electricity production, wind turbines have increased in physical size and power output. The average capacity of large wind turbines 20 years ago was 150 kW. Today, the typical capacity is 750 kW, with 1 or 2 megawatt (MW) machines becoming more common, and turbines as large as 6 MW under development.[25]

Most of the wind farms in the United States are developed by private companies on their own land or land leased from farmers, ranchers, or the government. California is home to three of the largest wind energy development areas in the world and has the largest developed wind industry of any state in the nation.[26]

The Altamont Pass Wind Resource Area averages 18-27 miles per hour (mph) wind speed in the summer and drops to 9-15 mph in the winter. For the most part, Pacific Gas and Electric Company (PG&E) purchases the electricity generated from the wind turbines installed at Altamont Pass. The Tehachapi Wind Resource Area (Tehachapi) in Kern County covers a 40 square mile area with the best winds (15-20 mph) occurring from March to September. For the most part, the wind turbines installed at Tehachapi produce electricity for Southern California Edison (SCE). San Gorgonio Pass, just north of Palm Springs, has over 4,000 wind turbines at the 70 square mile site. The average wind speed in this area is 15-20 mph.[27] For the most part, SCE purchases the electricity from the wind turbines installed at San Gorgonio.

Two additional developed wind resource areas are also located in California. In Solano County the electricity is purchased by PG&E, PPM Energy, and the Sacramento Municipal Utility District (SMUD). Finally, the energy generated from wind at Pacheco Pass is purchased by PG&E.[28]

A significant portion of California's existing wind capacity is old and less efficient than today's turbines, presenting an opportunity for repowering. The wind resource in California is concentrated in specific areas and electricity generation plants at these sites will most likely be repowered over time. Many issues factor into repowering decisions, including the availability of the federal PTC and a restrictive clause that limits a wind project with an existing qualifying facility (QF) contract from repowering under that same contract.

Senate Bill 1038 (SB 1038) states that repowered facilities will be eligible for supplemental energy payments (SEPs) if the capital investment to repower is at least 80 percent of the value of the repowered facility. The California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) are currently developing the implementation rules for SEPs, and these rules will be a factor in repowering decisions. The California Wind Energy Association (CalWEA) estimates that, with removal of the restrictive clause in the federal tax code, up to 450 MW of wind capacity might be repowered within three years, with additional repowering occurring over a longer time scale.[29]

The lack of a reliable federal policy regarding wind power had created a significant challenge for the industry. In 1992, the PTC was enacted, which provides a credit of 1.5 cents/kWh for electricity production from wind resources. Over the last 5 years, this tax credit has been extended twice and is set to expire again on December 31, 2003. These short-term extensions create uncertainty for the industry, which can delay projects and investments and lead to the loss of jobs. A multi-year extension of the tax credit could provide the stability for growth to continue.

The small wind turbine industry offers a variety of products with capacities ranging from a few hundred watts up to 100 kW, producing electricity to supply homes, farms, and small businesses. Recently, the market for small wind turbines has been growing at about 40 percent a year.[30] The AWEA's long-term vision for small wind systems is that they become a new category of home energy appliance.[31]

Customers of California's investor-owned utilities (IOUs) can receive rebates on grid-connected small wind systems through the Emerging Renewables Program administered by the Energy Commission and the Self-Generation Incentive Program administered by the PG&E, SCE, San Diego Gas and Electric (SDG&E), and Southern California Gas Company. Two hundred and thirteen small wind systems have been installed through the Emerging Renewables Program since 1999.[32] No wind systems have yet been installed through the Self-Generation Incentive Program.

Despite the improvements in small wind technology in recent years, there is general agreement that more work is needed to improve operating reliability, reduce or eliminate noise issues, and lower manufacturing and installation costs.

GEOTHERMAL

The growth in the geothermal industry was slow in the 1990s. One of the problems facing the industry was the need to lower the cost of generation to be more competitive with natural-gas fired electric generation.[33] Recent indications suggest increased growth in the development of geothermal electric energy over the next 10 years. Renewable energy solicitations in California have drawn proposals for development of almost 7,000 gigawatt-hours per year (GWh/year). Proposals in other Western Electricity Coordinating Council (WECC) states reviewed for this study total more than 3,000 GWh/year.

The technologies most often used to produce electricity from geothermal resources in California are flash steam power and binary cycle power plants. The flash steam power technology is typically used at sites that have high temperature fluids (usually above 400 degrees Fahrenheit. Fluids at these sites boil into steam as they rise to the surface. The steam is used to power a turbine, which turns a generator to produce electricity.[34]

Binary cycle power plants can be used with lower temperature geothermal resources where the water does not become steam before rising to the surface. It can also be used in conjunction with flash steam power systems. In binary cycle power plants, hot brine from the geothermal well is used to transfer heat to a hydrocarbon "working fluid" with a lower boiling point than the geothermal brine. The two fluids do not come into direct contact with one another. Once the working fluid is converted to steam, the steam is used to power a turbine and the brine from the geothermal resource is returned to the well.[35]

The research funded by the Energy Commission’s Geothermal Resources Development Account is aimed at addressing the following issues as they relate to geothermal electric generation: 1) life-cycle costs, 2) technology to enhance or replenish geothermal reservoir systems, 3) mitigation of adverse impacts, and 4) improved environmental protection.[36] In addition, research funded by the Public Interest Energy Research (PIER)-renewable energy program is studying ways to make geothermal exploration more cost competitive.[37]

Most of California's developed geothermal resources are located in Sonoma, Lake, Imperial, and Inyo Counties. Other geothermal resource areas in the state are found in Lassen, Mono, Siskiyou, and Modoc Counties. Some of the sites for new geothermal development are located in areas characterized by sensitive cultural and environmental concerns. Other issues that could delay development include permitting and access to transmission.

CONCENTRATING SOLAR POWER

Concentrating Solar Power (CSP), also known as solar thermal electric, uses reflective materials to concentrate sunlight onto a thermal receiver, which absorbs and converts it into heat. The heat is then used in a steam generator or engine to produce electricity. The three primary types of CSP systems currently being developed by US industry are parabolic trough technology, dish/engine technology, and power tower technology.

According to the ***Renewable Energy Atlas of the West***, the southwest portion of the United States has the greatest potential for CSP in the world. California is home to Solar Electric Generating Systems (SEGS), the world's largest CSP facility. The SEGS plants have a combined capacity of 354 MW and sell their electricity to SCE. The SEGS facility participates in the Existing Renewable Facilities Program, which provides funding to support existing in-state renewable energy.

The SEGS facility uses parabolic trough technology, in which solar energy is reflected from mirrored troughs onto a receiving tube. The oil in the tube is heated to create steam, which powers a conventional turbine generator to produce electricity. These systems can use up to 25 percent natural gas to supplement the solar output during cloudy days or at night and still qualify as a renewable resource under federal guidelines. This technology can also incorporate thermal storage by setting aside the heated oil in its hot state for electrical generation at a later time. Parabolic trough technology is the most mature CSP technology available today and will likely continue to be so in the near future.

Dish/engine technology is best suited for small applications — in the 7-25 kW range. The technology consists of glass mirrors that focus solar energy onto a receiver in the center of the dish. The receiver contains fluid that is heated and used in an engine, which is attached to the receiver, to generate electricity. The most common dish/engine technology uses a Stirling engine, which takes the heat from the receiver to move pistons driving a generator to product electricity.[38]

Power tower technology uses a large field of sun-tracking (heliostats) mirrors to concentrate solar energy onto a receiver on top of a tall tower. The receiver collects the heat to generate electricity through a conventional steam generator. Earlier power towers used steam as the heat transfer fluid while current systems use molten salt because of its efficiency and storage capabilities.

There are many benefits of power tower technology including thermal storage capability, which allows energy to be dispatched to the electricity grid when power is needed. The technology can achieve load factors of up to 65 percent.[39] In one case, a 10 MW plant delivered power to the grid 24 hours per day for almost 7 straight days before clouds interrupted operation.[40]

Significant improvements have been made in CSP technology and cost; however, additional research and development is needed to make CSP cost-competitive with conventional fossil fuel plants. Cost reductions can come from expanding the market for the technology and with improvements in systems and components.

Researchers are developing lower cost solar concentrators, high-efficiency engine/generators, and high-performance receivers. Advances in low-cost thermal storage will provide future CSP plants the ability to operate as dispatchable power.

BIOMASS

In California today, operating biomass and biogas electricity generation facilities use a range of organic waste material as fuel. Solid biomass fuels include woody agricultural wastes (e.g., orchard prunings, fruit pits, nut shells, and rice hulls); urban wood wastes (e.g., broken pallets, wood-product manufacturing wastes, and landscape trimmings); forest thinnings; and forest slash. Biogas fuel sources include landfill gas, dairy and swine manure, and sewage wastewater facilities.

Municipal solid waste (MSW) and biodiesel facilities have limited eligibility in California's RPS. According to the Energy Commission's RPS Phase 1 decision, existing MSW combustion facilities in Stanislaus County that began operating before September 26, 1996 can be used to adjust RPS baseline requirements, but otherwise, MSW combustion facilities are not eligible for California's RPS. MSW facilities that use "an eligible solid waste conversion technology" to gasify or convert MSW into a clean-burning fuel before combustion are eligible for the RPS. In addition, the Phase 1 decision states that electricity produced from biodiesel is eligible for the RPS if it is derived from either 1) a biomass feedstock or residue and consists of no more than 25 percent fossil fuel or 2) an eligible "solid waste conversion" process of MSW. Currently, biodiesel is made from recycled cooking oil and soybean oil and is used as a fuel blend with petroleum diesel fuel in some transit fleets and tourist boats.[41] Other applications of biodiesel in the transportation sector are discussed in ***The Transportation Fuels, Technologies and Infrastructure Assessment Report*** (publication no. 02-IEP-01).[42]

SB 1038 contains a lengthy section containing a general definition and a list of 8 criteria that must be met for a solid waste conversion technology to be eligible for the RPS. The general definition is "a technology that uses a non-combustion thermal process to convert solid waste to a clean burning fuel for the purpose of generating electricity." One of the 8 criteria that must be met is "the technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control." For the complete list of criteria, see Public Utilities Code (PUC) Section 383.5.

Producing electricity from solid organic waste materials greatly reduces emissions of particulate matter and other air pollutants relative to open field burning, controlled burns, or uncontrolled forest fires. Generating electricity from organic solid waste also reduces the amount of waste that is sent to landfills. Generating electricity from animal manure helps to control odor, pathogens, and wastewater discharges associated with animal waste.

The National Renewable Energy Laboratory (NREL) reports that researchers are studying the use of pyrolysis to convert biomass to a substance called "pyrolysis oil" through anaerobic heating. It may be possible for this process to be developed as a solid waste conversion technology that is eligible for RPS under PUC Section 383.5; however, the NREL suggests that the greater economic rewards for the technology may be found outside of the electricity sector:

> Because pyrolysis oil can also be refined in ways similar to crude oil, it may also be more valuable as a source of biofuels and biobased products than for biopower generation. Unlike direct combustion, cofiring, and gasification, this technology is not yet in the marketplace.[43]

The Energy Commission estimates that there are more than 800 MW of active biomass plants (including woody agricultural wastes, urban wood wastes, forest thinnings and slash, and MSW) in California. Beyond existing biomass facilities, the PIER program estimates that there is an additional 1,300 MW of technical potential available in California. Approximately 100 MW of biomass plants returned to service in 2001.[44] Regarding biogas facilities in California, the Energy Commission estimates that there are more than 400 MW of existing facilities and that an additional 200 MW of technical potential is available. Based on publicly available data reviewed for this report, 135 MW of undeveloped biogas and 210 MW of undeveloped biomass energy are included in the scenarios for meeting California's RPS by 2017 and the accelerated RPS with renewable energy providing 20 percent of retail sales by 2010. It is also possible that out-of-state biomass facilities may contribute to California's RPS.

Biomass and biogas electric generation facilities are subject to some seasonal variation in fuel availability (especially woody agricultural wastes). These facilities tend to operate as base load plants, but can also be designed for dispatchable generation. The latter configuration may be of particular importance in meeting the state's goal of "least cost best fit" in the RPS program. Because their relatively small size and geographically dispersed locations, these facilities usually do not impact transmission planning, although preliminary results from the PIER strategic value analysis project suggest that this varies according to location within the state.

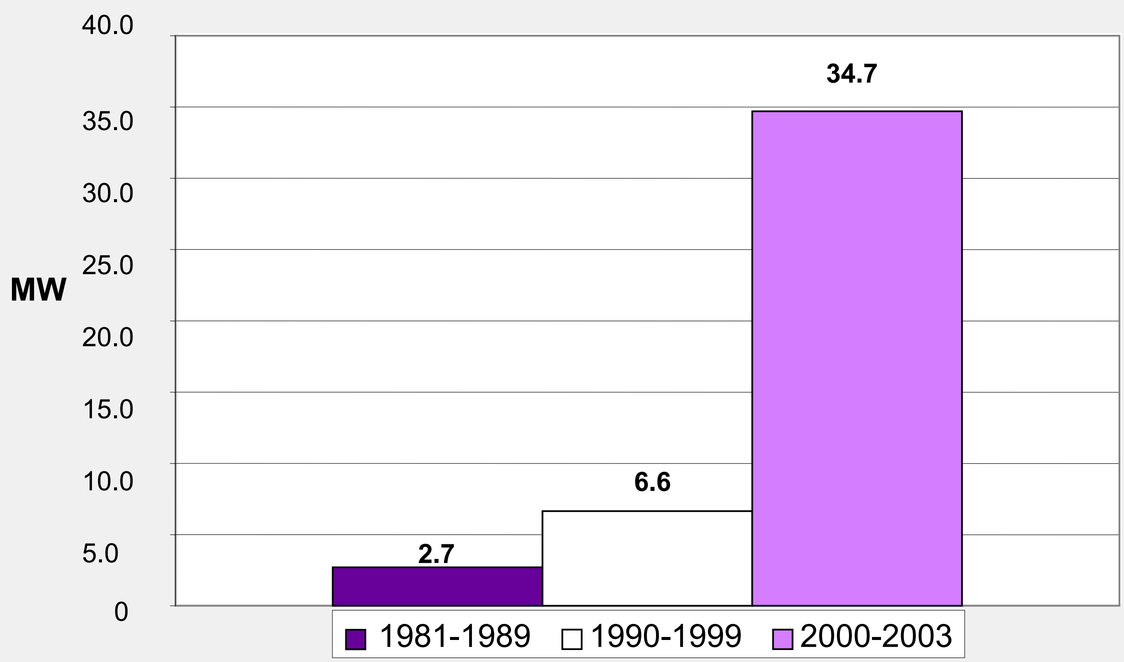
SOLAR PHOTOVOLTAIC

Since the late 1990s, the solar photovoltaic (PV) market has been growing at a substantial rate. In 2002, world production of PV panels grew by 43.8 percent.[45]

Several events contributed to this rapid market growth, including the success of the PV programs in Japan and Germany. Japan alone produced almost 50 percent of the PV panels manufactured during 2002. PV manufacturing costs have come down as a result of increasing the scale of PV production and improved automation. Incentive programs, adoption of RPS programs, and federal and state tax credits have also contributed to brisk growth in the market.

The PV market in the United States has made respectable progress with industry growth rates of 15 to 20 percent.[46] In 2002, the domestic PV market in the United States grew to 57 MW,[47] with over 30 MW installed in California. By mid-2003, over 44 MW of PV were installed in California. **Figure 1** shows the trend of installed PV in California over the last 20 years.

Figure 1. Grid-Connected PV Capacity Installed in California by Date



Source: California Energy Commission, “Amount (MW) of Grid-Connected Solar Photovoltaics (PV) in California,1981 to Present,” July 2003

The PV market is thought to have great potential for continued growth. The U.S. Department of Energy states that “it is easy to foresee PV’s 21st century preeminence.”[48] PV allows residential and business consumers to make a choice about their energy source based on personal values and concerns. Increasingly, factors beyond price affect the value of energy. Other factors include power quality and reliability, price volatility, meeting power needs during power outages and shortages, and concerns about the environment and global climate change.

Solar PV systems are also an important distributed energy generation technology. Distributed PV can reduce the need to build new transmission lines or upgrade existing lines, can be sited close to the user, and can be installed in increments to match the customers load requirements. Solar PV systems also fit with utilities' generation requirements by generating electricity during daily load peaks.

Solar PV technology has continued to improve with increasing conversion efficiencies and declining costs. Crystalline silicon cells connected together to form modules constituted about 90 percent of the solar cell market in 2001. Technology costs are subject to the relatively high cost of semiconductor material.

The remaining market share is primarily thin film technology. Thin film solar cells use much less semiconductor material and can be made translucent as shingles for roofs, incorporated into glass, or attached to plastic and stainless steel. Thin film can be made in large runs using mass-production techniques, which lower the manufacturing costs. Integrating PV into a commercial building can reduce the overall cost of the system because the solar feature provides two functions — it replaces the traditional building materials such as tile, brick, or glass, and it generates electricity.[49]

The next generation solar technology, now at the basic research phase, is expected to lower the costs of electricity generation to below 20 cents/kWh. These technologies are expected to show very high conversion efficiencies (three or four times that of current silicon-wafer cells) at lower costs.[50]

Without rebate incentives, solar PV systems are not currently cost competitive with grid power, but the technology has been experiencing cost reductions of about 5 percent per year in real terms over the past 10 years. Unlike most other renewable energy technologies, PV can be customer-sited and therefore competes against average retail rates. According to the July 2003 Staff Report, *California Investor-Owned Utilities Retail Electricity Price Outlook,* 2003-2013, 2003 retail rates in California, including IOUs and publicly-owned electric utilities, average about 15 cents/kWh for commercial buildings and 12 cents/kWh for residential buildings. When comparing PV to these retail rates, the technology is expected to be nearly cost competitive, without financial incentives, by 2017, assuming electricity rates remain somewhat stable and PV cost reduction trends continue.

Two statewide programs provide financial incentives for PV systems installed in PG&E, SCE, and SDG&E service territories. The Emerging Renewables Program, administered by the Energy Commission, provides rebates for systems 30 kW or smaller. Since the program began in 1998, over 5,000 PV systems have been installed totaling over 21 MW of PV capacity. PG&E, SCE, SDG&E, and Southern California Gas Company administer the Self-Generation Incentive Program, which supports distributed generation systems larger than 30 kW. To date, PV systems with more than 4.5 MW of capacity have been installed through the Self-Generation Incentive Program.

A number of public utilities in California also administer programs that provide subsidies for PV systems. The SMUD, for example, has installed more than 11 MW of PV and the Los Angeles Department of Water and Power (LADWP) has installed over 5.8 MW of PV.

Another effective method to garner support for PV systems has been ballot initiatives. In November 2001, the City of San Francisco passed a $100 million bond initiative to support the installation of 10 to 12 MW of PV panels on city facilities. The first project to use these funds is a 675 kW PV system on the roof of the Moscone Convention Center. The City of San Diego is currently investigating issuing a solar bond similar to San Francisco.

OCEAN ENERGY

Ocean energy is one of the resources identified as “renewable” in SB 1038. Tapping the ocean for power generation is relatively new, with the technologies consisting of tidal power, wave power, and ocean thermal energy conversion.

Tidal power takes advantage of the gravitational pull of the moon and harnesses energy from the difference between high and low tides of 5 meters (16 feet) or more. A dam or barrage across a bay or estuary forces water through turbines that turn a generator and produce electricity. The largest tidal power project in the world is a 240 MW plant near Saint Malo, France. Currently, there are no tidal plants in the United States and none are planned; however, good tidal conditions exist in both the Pacific Northwest and Atlantic Northeast regions.[51]

Wave power extracts energy directly from surface waves or pressure fluctuations below the surface. All of the current technologies use mechanical power to activate a generator directly, to transfer energy to a working fluid, or air to drive a turbine/generator. Wave power densities in California coast waters are sufficient to produce between 7 and 17 MW per mile of coastline.[52] Europe is the world leader in research and development of wave energy technology.

Many uncertainties still remain, despite the fact that wave power is nearing the end of the research and development phase. Cost and performance uncertainties must be overcome before large-scale investments will be attracted to the technologies. Most wave energy technologies have not yet developed a proven track record. Historically, generating costs of wave energy have been high but are predicted to be economic in niche markets such as near the end of a distribution grid or isolated areas not connected to the grid.[53]

Ocean thermal energy conversion (OTEC) uses the temperature difference between the warmer top layer of the ocean and the colder deep ocean water. All OTEC facilities require that a costly large diameter intake pipe be submerged a mile or more into the ocean, bringing the colder water up to the surface. OTEC facilities require substantial upfront capital investment and will probably not attract private sector investors until the price of fossil fuel rises dramatically or significant government incentives are provided.

Ocean energy technologies are quite expensive and cannot economically compete with traditional power sources. Permitting an ocean energy facility is also problematic. Some of the issues may include disturbance or destruction of marine life, possible threat to navigation from collisions, and degradation of scenic ocean views from energy devices and transmission lines located near or on the shore.[54]

SMALL HYDROELECTRIC

SB 1038 lists small hydroelectric generation of 30 MW or less as meeting the criteria for an "in-state renewable electricity generation technology," but it must meet certain additional requirements to be eligible for support from the Energy Commission's Renewable Energy Program. This technology is not eligible to receive payments if it is a "hydroelectric generation project that will require a new or increased appropriation of water under part 2 (commencing with Section 1200) of Division 2 of the Water Code."[55]

Senate Bill 1078 (SB 1078) states that the output of a small hydroelectric facility procured or owned by an electric utility, as of September 12, 2002, is only eligible for establishing the RPS baseline for the utility. The bill also states that a new hydroelectric facility is not an eligible renewable energy resource if it requires new or increased appropriation or diversion of water.[56]

California depends on large and small hydroelectric power to meet a portion of its electricity needs, with about 15 percent of the electricity used in the state coming from this source. In 2002, the staff estimates that small hydroelectric power provided about 1.6 percent of electricity generation used in California.

In California, hydroelectric power falls into three categories: storage, pumped storage, and run-of-the-river. Because of peaking and dispatch capability, storage and pumped storage provide the most benefits. These resources can be used for peak demand and system reliability. Run-of-river hydroelectric plants produce electricity at levels that vary with the amount of annual rainfall and snowfall.

Small hydroelectric facilities divert the natural flow of water through a channel or conduit to spin the turbine of an electrical generator and return the water downstream of the turbine. Hydroelectric power provides clean, renewable electricity and frequently other benefits such as habitat for fish and wildlife and opportunities for recreation. Despite this, generating electricity from the natural flow of water comes with negative environmental impacts. Changing water level, water temperature, and water quality can affect fish, plant, and animal life. Diversion structures and changes in water levels have an effect on fish movement.

PIER is working to better understand the interactions between hydroelectric power generation and aquatic ecosystems. The areas of research include assessing the environmental effects of fluctuations in water flows, developing indices to assess the biological integrity of streams and rivers, and developing methods to forecast runoff to improve reservoir management.[57]

The Federal Energy Regulatory Commission (FERC) licenses hydroelectric power facilities for a 30 to 50 year period. The lengthy process is governed by laws and regulations that require extensive planning, environmental studies, and public input. The FERC licensing process ensures that communication occurs between relevant agencies and organizations and that the necessary studies are conducted. It also aims to minimize damage to the environment from hydroelectric projects. The FERC has recently revised its regulations for licensing hydroelectric facilities with the Final Rule published in the Federal Register on August 25, 2003.[58] With the new process, an applicant's pre-filing consultation and National Environmental Policy Act scoping is conducted concurrently (and not sequentially), which increases the need for coordination, identification of issues, and early public participation.

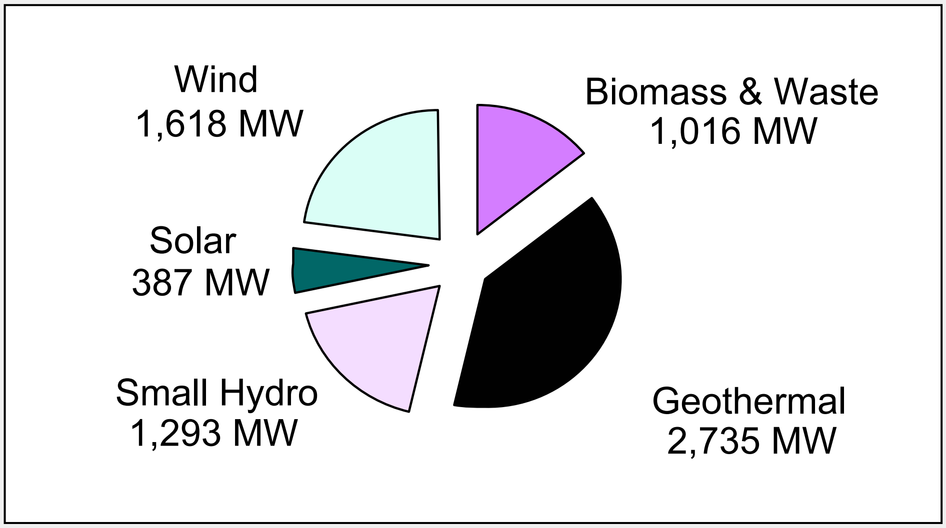
CHAPTER 3: SITUATION ANALYSIS

INSTALLED RENEWABLE CAPACITY IN CALIFORNIA

Over the past two decades, California has developed one of the largest and most diverse renewable generation industries in the world. In the year 2002, California had over 7,000 megawatts (MW) of renewable energy capacity, including solid-fuel biomass, geothermal, wind, small hydroelectric (30 MW or less), concentrating solar power (CSP), photovoltaic systems (PV), landfill gas, digester gas, and municipal solid waste (MSW) facilities. The staff estimates that these facilities produced about 28,900 gigawatt-hours (GWh) in 2002, representing about 11 percent of the electricity used in California. **Figures 2** and **3** show the relative capacity (MW)[59] and generation (GWh)[60] by technology for electricity generated by renewable sources in 2002.

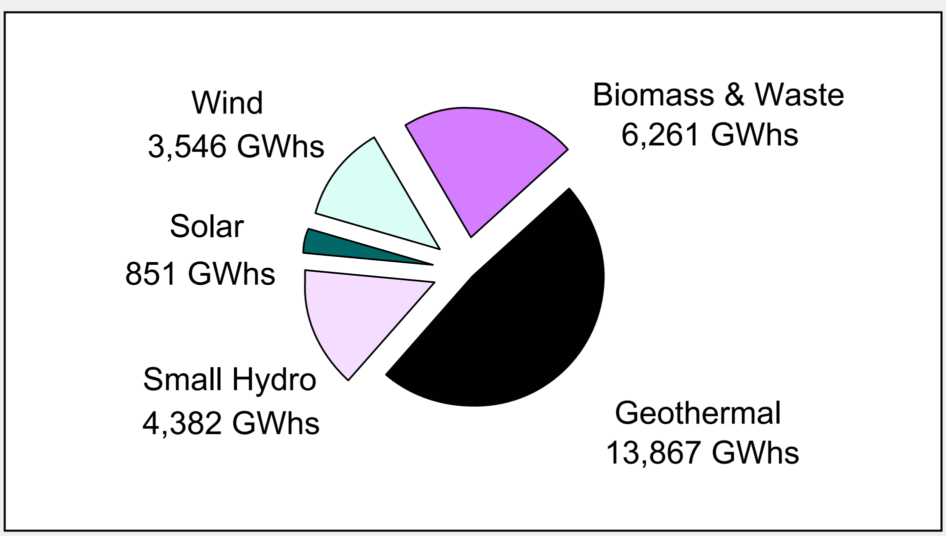
Much of California's renewable development arose from the federal Public Utilities Regulatory Policies Act (PURPA) of 1978, which required utilities to purchase power from non-utility generators, including renewable generators, at the utilities' full avoided cost. PURPA was implemented in California through the use of "standard offer" contracts between utilities and non-utility generators. There are four types of these contracts, with most non-utility renewable energy in California under the Interim Standard Offer 4 (ISO4) contracts.[61] The ISO4 contracts, which covered a period of up to 30 years, provided fixed per kilowatt hour (kWh) energy payments for up to 10 years based on forecasted avoided costs, with payments converting to short-run avoided costs in year 11 of the contracts. The contracts also provided fixed capacity payments for up to 30 years. These guaranteed energy and capacity payments helped to attract financing for independent energy projects. As a result of the availability of these contracts, about 5,000 MW of renewable capacity were added to California's electricity system between 1985 and 1990.

Figure 2. California's In-State Renewable Capacity (2002) in MW



Source: California Energy Commission Cartography Unit, August 2003

Figure 3. California's In-State Renewable Generation (2002) in GWh/year



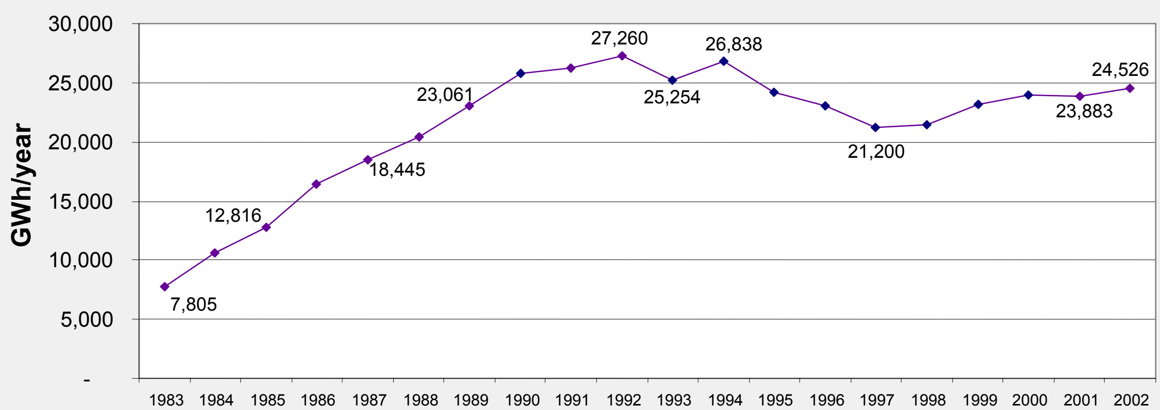
Source: California Energy Commission, "1983-2002 California Electricity Generation."
Small hydroelectric generation data are from the "2002 Total Electricity Production"

Between 1994 and 1998, renewable energy generation in California declined; as a result partly of low energy prices combined with the end of the high fixed-energy price period for many ISO4 contracts. When these contracts were originally signed, avoided costs were expected to increase over time. Instead, they decreased significantly in the late 1980s and continued to be low during the 1990s. This situation created what was known as the “price cliff” for facilities with ISO4 contracts, since at that time, short-run energy prices were as much as 85 percent lower than the energy prices these facilities received toward the end of the fixed price period.

Beginning in 1998 and continuing through to today, renewable energy generation in California has increased, due, in part, to the success of the California Energy Commission (Energy Commission) Renewable Energy Program.

Figure 4 illustrates the statewide pattern of renewable energy generation (excluding small hydroelectric power) over the period 1983-2002.

Figure 4. Non-Hydro Renewable Electricity Generation in California



Source: California Energy Commission, “1983-2002 California Electricity Generation”

California’s renewable resources are widespread, but are generally found in specific geographic regions relative to the technology.

Most of the wind capacity installed in California can be found in three general areas: the Altamont Pass Wind Resource Area (represented by Alameda, Contra Costa and San Joaquin Counties), the Tehachapi Wind Resource Area (Kern County), and Riverside County (San Gorgonio Pass and Palm Springs). Other wind resource areas that had a limited amount of installed capacity at the end of 2002 include San Diego, San Benito, and Solano counties.

Like wind, most of the geothermal capacity currently installed in California is limited to three general areas: The Geysers (Sonoma and Lake Counties), Imperial County

(Salton Sea, Heber, and East Mesa), and Coso Hot Springs (Inyo County). Lassen and Mono Counties have geothermal plants as well.

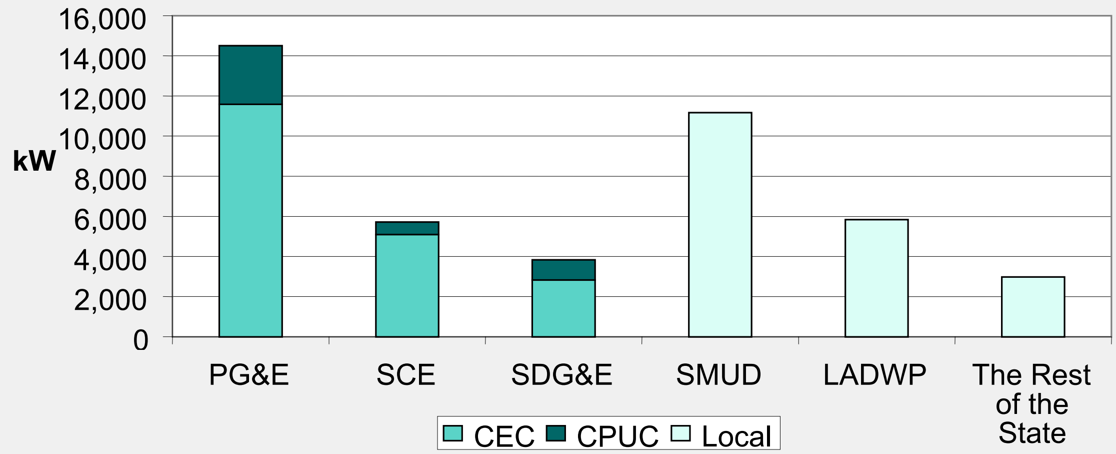
The CSP plants currently installed in California are located in one general area — the Southeast desert. Kern and San Bernardino Counties account for all of the CSP facilities in California. The proposed concentrating solar power projects are also located in San Bernardino County.

Biomass is more widely distributed throughout the state than is wind, geothermal, or CSP. No single county has a majority of the installed biomass capacity. Rather, a biomass facility is likely to be located closer to its fuel-source, a lumber mill, wastewater treatment plant, or a landfill.

Like biomass facilities, small hydroelectric plants are scattered across the state. They are located on canals, rivers, and creeks. No single county has a majority of the installed small hydroelectric capacity.

The installed capacity of solar PV is less concentrated than wind or geothermal, but more concentrated than biomass or small hydroelectric facilities. A large amount of the 44 MW (33 MW at the end of 2002) of PV installed in California can be found in Sacramento and Los Angeles Counties. The remainder of the capacity is fairly well distributed throughout the state, though it is largely found in the service territories of Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). **Figure 5** shows the location, by service territory, of grid-connected PV systems within California. **Figure 5** also distinguishes between which incentive programs assisted in the installation of the system.

Figure 5. Grid-Connected Photovoltaic Capacity Installed in California by Service Territory



Source: California Energy Commission, "Amount (MW) of Grid-Connected Solar Photovoltaics (PV) in California,1981 to Present," July 2003

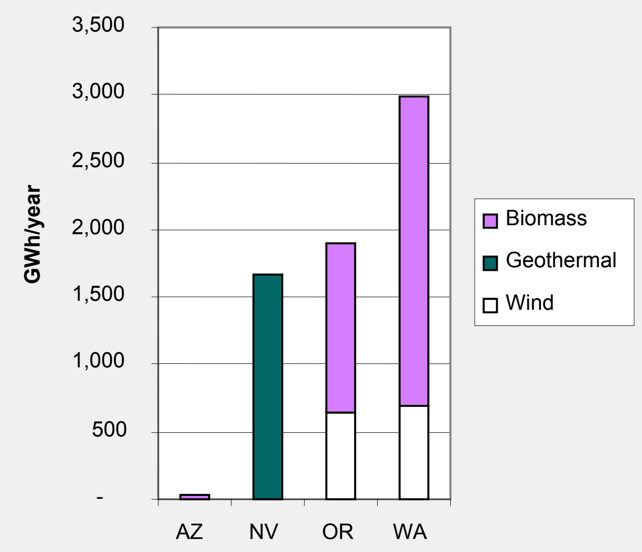
INSTALLED RENEWABLE CAPACITY IN OTHER WESTERN ELECTRICITY COORDINATING COUNCIL STATES

The Western Electricity Coordinating Council (WECC) consists of 11 western states, portions of western Canada and a section of Baja California, Mexico that is adjacent to California. Beyond California, the staff divided the other members of the WECC into the following categories: 1) adjacent states (Oregon, Nevada, Arizona), and Washington; 2) outer tier states (i.e., Montana, Idaho, Wyoming, Utah, Colorado, New Mexico; and 3) international WECC members. This division of WECC members is intended to match the transmission and the Renewables Portfolio Standard (RPS) rule-making issues associated with transporting electricity from adjacent, non-adjacent, and international WECC members.

Figure 6 shows existing wind, biomass, and geothermal energy facilities in Washington and WECC states that are adjacent to California (i.e., Oregon, Nevada, and Arizona). The data for biomass and geothermal are from 2001, while the wind data is from 2002. On-line biomass, geothermal, and wind facilities in WECC (excluding California) generate about 8,600 GWh/year. **Figure 6** shows that about

6,600 GWh/year was generated in Washington and WECC states adjacent to California from wind, biomass, and geothermal energy facilities.

Figure 6. Existing Renewable Energy Resources in Washington and WECC States adjacent to California (Wind, Geothermal, and Biomass)



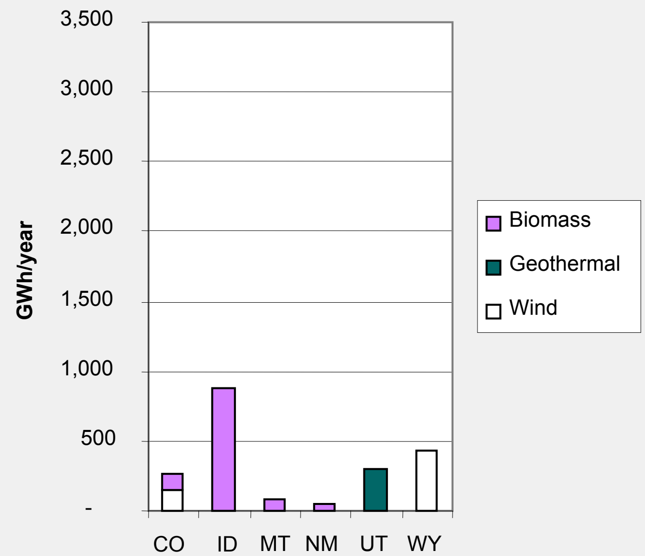
Source: ***Renewable Energy Atlas of the West***

Figure 7 shows existing wind, geothermal, and biomass energy facilities in outer tier WECC states (i.e., Montana, Idaho, Wyoming, Utah, Colorado, and New Mexico). **Figure 7** shows that about 2,000 GWh/year is generated in these states from geothermal, biomass, and wind energy resources.

There are close to 1,900 MW of existing small hydroelectric facilities in the WECC states outside of California. Using a capacity factor of 35 percent, average energy production from these facilities is estimated to be almost 5,800 GWh/year.

About 380 MW of operating small hydroelectric resources are installed in the provinces of Canada that are members of WECC. Using a capacity factor of 35 percent, average energy production from these facilities is estimated to be about 1,170 GWh/year.

Figure 7. Existing Renewable Energy Resources in WECC Outer Tier States (Wind, Geothermal, and Biomass)



Source: ***Renewable Energy Atlas of the West***

LEVELIZED COST OF ENERGY ECONOMICS FOR RENEWABLE ENERGY

The ***Final Staff Draft Report Comparative Cost of California Central Station Electricity Generation Technologies*** (Cost of Generation Report) contains estimates of the cost of central station generation technologies for a number of fossil fuel and renewable energy generation technologies.[62] For renewable energy, the Cost of Generation Report includes the following central station generation technologies: 1) geothermal binary (35 MW with 2005 as in-service year), 2) geothermal flash (50 MW with 2005 as in-service year), 3) PV (50 MW with 2003 as in-service year, 4) solar parabolic trough without thermally enhanced storage or gas (110 MW with 2003 as in-service year), 5) solar parabolic trough with gas only (110 MW with 2003 as in-service year), 6) solar thermal – Stirling dish engine (31.5 MW with 2003 as in-service year), 7) solar parabolic trough with thermally enhanced storage only (110 MW with 2003 as in-service year), and 8) wind power (100 MW with 2004 as in-service year).

To provide an indication of renewable energy cost trends over time, including biomass and distributed generation PV systems, together with wind, geothermal, and CSP, the staff relied on a levelized cost of energy model prepared by Navigant Consulting, Inc. (Navigant Consulting), subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036). The assumptions used by Navigant Consulting to develop these cost trend estimates are included in Appendix D. All levelized cost figures below are presented in real, 2003 dollars

According to the estimates prepared by Navigant Consulting, a number of renewable energy technologies are expected to be competitive with conventional electricity generation technologies on a levelized cost of energy basis (see **Table 3)** by 2005, even without the federal production tax credit (PTC). Renewable technologies that are currently the most cost competitive include wind, select biomass applications, and geothermal. When configured as a firm peaking resource, CSP can compare favorably with recent estimates of conventional sources of peaking power. The estimates below will be suggestive only, as actual prices will vary because of circumstances associated with individual plants. As technological advancement continues, a broader array of renewable technologies may become competitive, depending, in part, on the extent of technological advances and the extent to which conventional generation technologies increase or decrease in cost over time (**Table 4**). Finally, if the federal PTC for wind is extended indefinitely, and expanded to include certain geothermal and biomass applications, the levelized cost of energy is expected to be even more attractive (**Table 5**).

It is important to note that different renewable energy resources provide different products. The general characteristics (e.g., dispatchability, intermittency) and timing (e.g., base load, peaking) differ from resource to resource. Furthermore, specific projects may incorporate designs (e.g., biomass fuel types) that cause products to differ within renewable resource types.

Table 3. Projected Cost of Renewable Energy in 2005 (Without the Production Tax Credit, 2003 Dollars)

Technology	**Size (MW)**	**Levelized Cost of Energy (cents/KWh)**
Wind Class 6	75	4.1
Wind Class 4	75	4.9
Landfill Gas	2	4.4
Animal Digester Gas (ADG) – Animal Waste – farmer/coop financed	0.1	4.3
Geothermal Flash	50	5.3
Geothermal Binary	50	5.5

Source: Navigant Consulting, subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036).

Table 4. Projected Cost of Renewable Energy in 2005, 2008, 2010, and 2017 (Without the Production Tax Credit, 2003 Dollars)

		Levelized Cost of Energy (cents/kWh)			
Technology	**Size (MW)**	**2005**	**2008**	**2010**	**2017**
Wind Class 6	75	4.1	3.4	3.3	2.7
Wind Class 4	75	4.9	3.9	3.6	3
Concentrating Solar Power	100	12.1	6.7	6.4	6
PV High Insolation 250 kW	0.25	27.5	22.9	21.1	15.6
PV Low Insolation 250 kW	0.25	34	28.4	26	19.3
PV High Insolation 3 kW	0.003	23.3	21.8	18.8	12.6
PV Low Insolation 3 kW	0.003	28.7	26.9	23.2	15.6
Landfill Gas	2	4.4	4.1	4.1	3.7
ADG – Animal Waste – developer financed	0.1	6.9	6.2	6.2	5.6
Solid Biomass-Direct Combustion	20	6.6	6.2	6.2	5.7
ADG – Animal Waste – farmer/coop financed	0.1	4.3	3.8	3.8	3.6
Geothermal Flash	50	5.3	5	4.9	4.5
Geothermal Binary	50	5.5	5.1	4.9	4.2

Source: Navigant Consulting, subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036).

Table 5. Projected Cost of Renewable Energy in 2005, 2008, 2010, and 2017 (With the Production Tax Credit, 2003 Dollars)

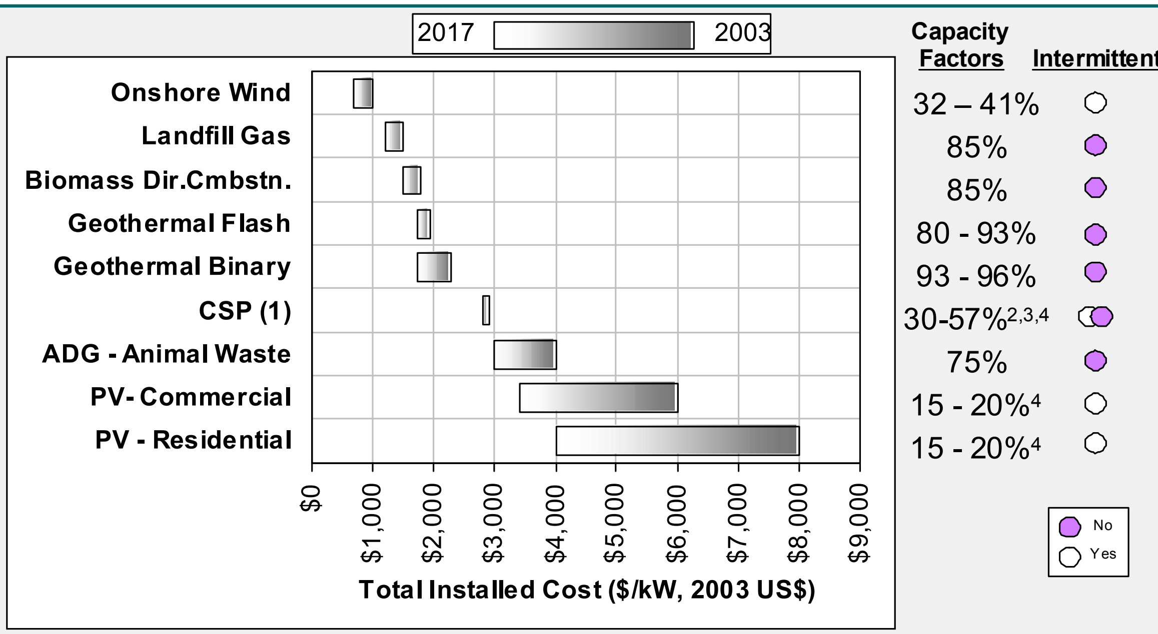
Technology	Size (MW)	Levelized Cost of Energy (cents/kWh)			
		2005	2008	2010	2017
Wind Class 6	75	2.7	2	1.8	1.3
Wind Class 4	75	3.4	2.5	2.2	1.6
ADG – Animal Waste – developer financed	0.1	5.7	4.9	4.9	4.3
Solid Biomass-Direct Combustion	20	5.4	5	5	4.4
ADG – Animal Waste – farmer/coop financed	0.1	3.2	2.8	2.8	2.5
Geothermal Flash	50	4.3	4.1	4	3.7
Geothermal Binary	50	4.5	4.2	4	3.4

Source: Navigant Consulting, subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036).

Methodology for Cost Estimation

For consistency of comparison, the levelized costs presented here are from the project-owner perspective, except for PV systems. The data for PV systems are presented from the building owner perspective. Anaerobic digester gas from animal wastes is evaluated from both the developer and farmer perspectives. The cost comparisons include state and federal tax incentives, but do not include any state financial incentives resulting from public goods charge (PGC) funds. It is important to note that developer economics alone do not determine the actual price at which resources are sold in the market through power purchase agreements or other contractual vehicles. The price of any specific resource is based upon a myriad of factors, including dispatchability, ability to follow loads, and availability and prices of competing supplies. Some of these considerations are addressed later in this section. The projected installed cost of renewable technologies in California can be found in **Figure 8** below. The figure illustrates the expected reduction in cost over time along with information on intermittency and capacity factors. See Appendix D for more detailed assumptions used in this analysis.

Figure 8. Total Installed Cost of CA Renewable Technologies



1. Parabolic trough technology. 2. Low end is without thermal storage, high end is with 12 hours molten salt thermal storage. 3. Thermal storage provide some dispatchibility and control of output. 4. These are effective capacity factors, including effects of temperature degradation and dust losses. Note: Assumptions of system size are provided in Appendix D. Source: Navigant Consulting, subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036).

Wind

By 2005, a 75 MW wind power plant is expected to deliver power at a real levelized cost of electricity (in 2003 dollars) of about 4.9 cents/kWh in Class 4 wind sites,[63] and about 4.1 cents/kWh in Class 6 wind sites,[64] without the Federal PTC of 1.8 cents/kWh. With the PTC, wind energy economics improve to 3.4 cents/kWh and 2.7 cents/kWh by 2005 from a developer perspective, for Class 4 and Class 6, respectively.

These cost estimates are significantly lower than some wind bids by developers in California over the past several years,[65] as well as recent Energy Commission technology cost estimates. Were it not for corroborating empirical evidence from other states, the estimates shown above might be viewed as overly optimistic; however, recent bidding experience in a number of states shows wind repeatedly falling into the 2.5 to 3.5 cents/kWh range. There are several reasons wind development can be more expensive in California than in other states. Land lease rates in California's highly developed wind resource areas such as Palm Springs and Tehachapi are above the national average, due largely to a dwindling supply of developable sites. Also, California's generally more strict permitting requirements will typically increase the cost and risk associated with the permitting process. Sales tax and property taxes also make projects more expensive in California compared with other states.[66] These factors notwithstanding, it can be expected that wind development in California will experience continuing downward price pressure; particularly as new, less crowded resource areas are developed.

Current wind energy technology is considered mature, but technological advances are likely to make wind economics even more attractive over time. Capacity factors are expected to increase in equivalent wind regimes due to larger rotor sizes resulting from advances in composite materials, as well as from taller turbine towers. Tower heights of 80 meters or higher may be commercially available in the United States by 2004. Rapid advances in power electronics are also increasing turbine efficiency by cutting electrical losses while improving power quality and grid integration. With continued technological improvements, wind energy is becoming more economically competitive with conventional sources in California and the WECC.

Wind Power's Success Story

Wind-generated electricity today is 1/10 the cost that it was in the early 1980s, when it was first introduced in California. The technology has also improved dramatically in terms of reliability. Rapid technological and cost improvements have moved wind technology from fledgling status to the world's fastest growing generation resource on a percentage growth basis. In 2002, the global cumulative installed capacity was approximately 32,000 MW, 15 percent of which was in the United States. Similar levels of growth are expected in 2003 and beyond. General Electric's recent purchase of a major wind turbine manufacturing business and commitment to becoming the global leader in wind technology demonstrates that wind is moving into the mainstream and that its rapid progress is likely to continue.

Wind power, with the Federal PTC, is now among the lowest cost power options for new capacity in many regions of the United States. Renewable energy solicitations from several states have recently resulted in power purchase agreement costs as low as 2.5 cents/kWh. The largest wind farms in strong wind resource areas, such as the 300 MW Stateline project on the Oregon–Washington border, produce power for as low as 2.5 cents/kWh. In fact, wind has out-priced conventional generation resources, including natural gas and coal-fired plants, to win recent all-source solicitations in both Colorado and Minnesota. Continued cost reductions are expected through economies of scale, efficiency improvements, higher hub heights, larger rotor diameters, economies of production, and advancements in power electronics, as well as through rapidly accumulating operating experience with utility-scale wind projects.

While it is true that the intermittency of wind power does impose costs on the grid system, several recent studies in the U.S. Midwest, Northwest, and in Europe have shown that the cost impact of substantial penetrations of wind power (e.g., 20 percent of peak load) is quite muted, at less than $5/MWh (and even lower for lower penetrations). Furthermore, in the future, storage technology such as pumped hydro and compressed air storage may reduce these costs further. Wind technology has seen double-digit growth rates over the past decade, and as technology cost reductions continue, wind energy is expected to play an even greater role in California's energy future.

Concentrating Solar Power

By 2005, the real levelized cost of electricity from a 100 MW parabolic trough system without thermal energy storage is expected to be about 12 cents/kWh. Where this resource is configured as a firm peaking resource, it can compare favorably with recent estimates of conventional sources of peaking power. Today, hybrid systems can combine solar thermal electric technology with conventional gas-fired generation to improve both the economics and system output. Beyond 2007, it may be possible to couple energy storage technologies with parabolic trough systems cost-effectively. Molten salts are being successfully investigated as a thermal energy storage medium for use with parabolic trough solar power stations. With significant technological advance, the levelized cost of energy for parabolic trough solar stations with storage could drop to as low as 6.4 cents/kWh by 2010.

Installed system costs without storage in 2005 are expected to be about $2,900/kW for a 100 MW plant. By 2010, the installed cost should be about the same, but will have incorporated 12 hours/day of storage using molten salts. This should increase the capacity factor from about 30 percent in 2005 to 56 percent by 2010.

Photovoltaics

By 2005, a commercial building owner should be able to install a 250 kW PV system on a flat roof building with about a 5 degree tilt that generates power at about 27.5 cents/kWh in a high insolation region, excluding rebate incentives. A residential customer in a similar region should be able to install a 3 kW PV system that generates power at a slightly lower levelized cost of about 23.3 cents/kWh, excluding rebate incentives. By 2017, it is expected that these costs may drop to approximately 15.6 cents/kWh and 12.6 cents/kWh, respectively.

Without rebate incentives, solar PV systems are not currently cost competitive with grid power, but the technology has been experiencing cost reductions of about 5 percent per year in real terms over the past 10 years. Unlike most other renewable energy technologies, PV can be customer-sited and therefore competes against average retail rates. According to the July 2003 Staff Report, *California Investor-Owned Utilities Retail Electricity Price Outlook,* 2003-2013, 2003 retail rates in California, including IOUs and publicly-owned electric utilities, average about 15 cents/kWh for commercial buildings and 12 cents/kWh for residential buildings. When comparing PV to these retail rates, the technology is expected to be nearly cost competitive, without financial incentives, by 2017, assuming electricity rates remain somewhat stable and PV cost reduction trends continue.

These estimates refer to retrofit PV installations on existing buildings. The staff believes that, in general, installing PV equipment during the construction of new buildings or homes should cost less than installing the same equipment on an existing building. Cost savings for PV installations on new construction could include the following: 1) full access to electric wiring, 2) bulk purchase of equipment, 3) placement of mounting hardware prior to installation of roofing materials, 4) reduced transaction costs for contract execution, and 5) efficiencies of scale in installation labor. On the other hand, owners of newly constructed buildings and homes may choose to install building-integrated PV systems, which are often more expensive than other PV systems.

Landfill Gas

The analysis projects the real levelized cost of electricity for a landfill gas facility in California to be 4.4 cents/kWh in 2005, dropping to 3.7 cents/kWh by 2017. These estimates assume no Section 29 tax incentives, which have been a major driver for development in the past. Also assumed is that the costs associated with the gas collection system need not be recovered through electricity sales revenue. Landfill gas operates with high capacity factors (approximately 85 percent) and does not have the intermittency issues associated with some renewable energy technologies. Landfill gas is competitive today and is a mature application of conventional technology, with cost and performance typically driven by the characteristics of internal combustion engines and small gas turbines. Because of the relatively small scale of the projects, development costs (i.e., project costs exclusive of equipment and installation) can be high on a per kW basis. Project economics are not expected to change significantly in the future.

Anaerobic Digester Gas with Animal Waste

The real levelized cost of power from anaerobic digester gas (ADG) (if cogeneration revenue is netted out) is expected to approach competitiveness in 2005 at 4.3 cents/kWh, assuming farmer/coop financing. The inclusion of a PTC, which is being considered at the Federal level for open and closed loop biomass systems, would result in a levelized cost of energy of 3.2 cents/kWh. This price is expected to reach 3.6 cents/kWh by 2017 or 2.5 cents/kWh with a PTC. The estimate suggests that developer financing results in a higher expected levelized cost of energy at about 6.9 cents/kWh in 2005, dropping to 5.6 cents/kWh by 2017. The addition of the PTC reduces the levelized cost of energy to about 5.7 cents/kWh in 2005 and 4.3 cents/kWh in 2017.

ADG with animal waste occurs at scales around 25 to 200 kW. Because of the small scale and need to install the digester and gas handling equipment, anaerobic digestion of animal waste has a high capital cost. In addition to the potential energy cost savings, farmers are considering installations of ADG systems to meet tightening environmental regulations (e.g., odor, pathogen control, wastewater discharges, and limits on land application of animal waste). As with landfill gas, ADG does not have the intermittency issues associated with some renewable energy technologies.

Solid Biomass – Direct Combustion

The direct combustion of biomass is expected to achieve a levelized cost of energy of 6.6 cents/kWh in 2005 and 5.7 cents/kWh in 2017.[67] The direct combustion of biomass fuel is a mature technology with limited potential for cost reduction and efficiency improvement over time. The technology achieves high capacity factors of about 85 percent and does not have the intermittency issues associated with some renewable energy technologies. The key to the technology's cost effectiveness is the availability of a long-term supply of low-cost fuel.

While the combustion of biomass does produce air pollutant emissions, solid biomass is generally considered to be a carbon dioxide (CO_2)-neutral fuel. Moreover, the use of modern circulating fluidized bed technology in conjunction with other controls helps minimize power plant emissions. The beneficial use of biomass residues for power generation can also offset other environmental consequences, such as landfilling and open field burning. This resource is also unique in providing economic benefits to biomass-based industries, namely agriculture and forest products.

Not evaluated here was the potential for solid-fuel biomass cogeneration, which could potentially lead to more attractive economics or biomass gasification technology that may become attractive in the future either in standalone systems or for co-firing with fossil fuels.

Geothermal

By 2005, 50 MW flash and binary geothermal systems are expected to have a real levelized cost of energy of 5.3 cents/kWh and 5.5 cents/kWh, respectively.[68] Flash systems typically operate with fluids greater than 400 degrees Fahrenheit (F) and binary systems operate with fluids less than 400 degree F (representing a less desirable, but often a more plentiful resource). If a Federal PTC is passed for geothermal energy, the levelized cost of energy of flash and binary systems could drop to 4.4 or 4.5 cents/kWh. Unlike the wind energy PTC, the 1.8 cents/kWh geothermal PTC is likely to apply only to 90 percent of the output over five years because geothermal already receives a 10 percent Investment Tax Credit.

For comparison on the economics, in late 2002, Nevada Power announced that its renewable solicitation had attracted geothermal bids in the range of 4.2 to 5.2 cents/kWh, with 1 percent annual escalation over 20 years[69]. Also, Calpine and the U.S. Bonneville Power Administration (BPA) signed contracts in 2001 for about 50 MW of flash systems at approximately 5.5 cents/kWh, and the California Power Authority signed letters of intent two years ago for 315 MW of geothermal at 6 cents/kWh. The Calpine project that has the BPA contract is also the recipient of a New Renewable Resources Account auction award that could total more than $20 million.

Geothermal energy is nearly competitive with conventional power options and installed system cost reductions are expected to continue. Installed costs for binary systems — likely to be the most prevalent system type going forward — are expected to decline from $2,275/kW in 2005 to $1,750/kW in 2017 (in 2003 dollars), resulting in a levelized cost of energy in 2017 without the PTC of 4.2 cents/kWh.

Geothermal also has the added benefits of providing very high capacity factors of greater than 90 percent and presenting no intermittency issues. Barriers to geothermal development include permitting challenges, the high cost of resource exploration (often 30 percent of the overall project costs), and a 1 to 10 percent annual reduction in well productivity, which requires the construction of new wells or the recharge of existing wells. Well field maintenance can vary and can add significantly to the cost. Transmission access has also been a barrier, given the geographic constraints to the geothermal resource.

INDIRECT COSTS NOT CAPTURED IN LEVELIZED COST OF ENERGY ECONOMICS

Although the levelized cost of energy economics suggests that a number of renewable energy technologies are nearing cost competitiveness with new natural gas power plants on a direct cost basis, other factors must be considered. Several of these factors are discussed below.

Integration Costs

Unless some form of energy storage is utilized,[70] intermittent weather-dependent resources like wind and solar may impose certain costs on the grid, in terms of voltage regulation and load-following services, imbalance energy payments,[71] and reserve requirements. Electricity production from intermittent resources may fluctuate significantly on a real-time basis. Weather-dependent resources are also difficult to predict, making it difficult for wind generators to commit to the day-ahead scheduling practiced in many conventional wholesale electricity markets.

Several recent studies have found that the cost of integrating large amounts of new wind capacity (e.g., up to 20 percent of peak load) into specific utility grid systems in the Pacific Northwest, upper Midwest, and parts of Europe are quite manageable, at less than $5/MWh. The cost is even less at lower penetration levels. Wind integration costs in California are being studied through a project supported by the Public Interest Research (PIER) program. The final report on integration costs for California is expected by June 2004.[72]

In support of California's commitment to increase the development of its wind resources, the California ISO (CA ISO) Board of Governors approved a proposal in September 2001 to develop new rules for scheduling intermittent resources. This proposal contemplated use of state-of-the-art wind forecasting methodologies to substantially improve the quality of day-ahead and hour-ahead wind production forecasts, thereby reducing costly real-time imbalances. Under this program, known as the "Participating Intermittent Resource Program," the CA ISO's wind forecasting contractor, True Wind Solutions, will produce refined forecasts on a day-ahead and hour-ahead basis. Participating wind generators must pay a forecast fee of

10 cents/MWh of delivered energy, must install anemometers and real-time metering equipment, and must submit “preferred” energy schedules to the CA ISO that match the CA ISO’s forecast of energy deliveries. In exchange, participants in this program will be able to net any imbalance in energy charges on a monthly basis. The program, which was approved by the Federal Energy Regulatory Commission (FERC) in April 2003, is underway, with the first participating project being High Winds Energy Center in Solano County. Several projects representing about 260 MW are enrolled in the program.[73]

Product Type and Capacity Value

These issues include (1) whether the renewable generator offers base load, peaking, or as-available output; (2) the degree of dispatchability or curtailability involved; and (3) the “capacity value” of the resultant product. Because of their intermittency, wind and solar power offer “as-available” power. In contrast, technologies such as landfill gas, biomass direct combustion, geothermal, and ADG are base load technologies with high annual capacity factors. For these technologies, the fuel can either be stored (as in solid biomass) or produced on a continuous and relatively constant basis (as in landfill gas, digester gas, or geothermal energy). The use of thermal storage or natural gas hybridization with concentrating solar power can produce a firm peaking power energy product.

Based on limited dispatchability, renewable generators are typically not considered peaking plants, though in some cases even production from intermittent renewable resources may closely match load profiles (e.g., CSP and PV). The resource provides capacity to the system and contributes to average system reliability. The degree of capacity value is typically based on the historic contribution of a particular plant or resource to system capacity and reliability.

Capacity value will typically be higher for non-intermittent renewable generators (e.g., biomass and geothermal), which respond more like conventional generation technologies and have limited dispatchability. The value of the ability to load follow and to make relatively greater contributions to capacity is not captured in levelized cost of energy calculations, but could narrow the economic gap between higher levelized cost of energy resources such as biomass and low levelized cost of energy resources such as wind.

THE DYNAMICS OF REPOWERING DECISIONS IN CALIFORNIA

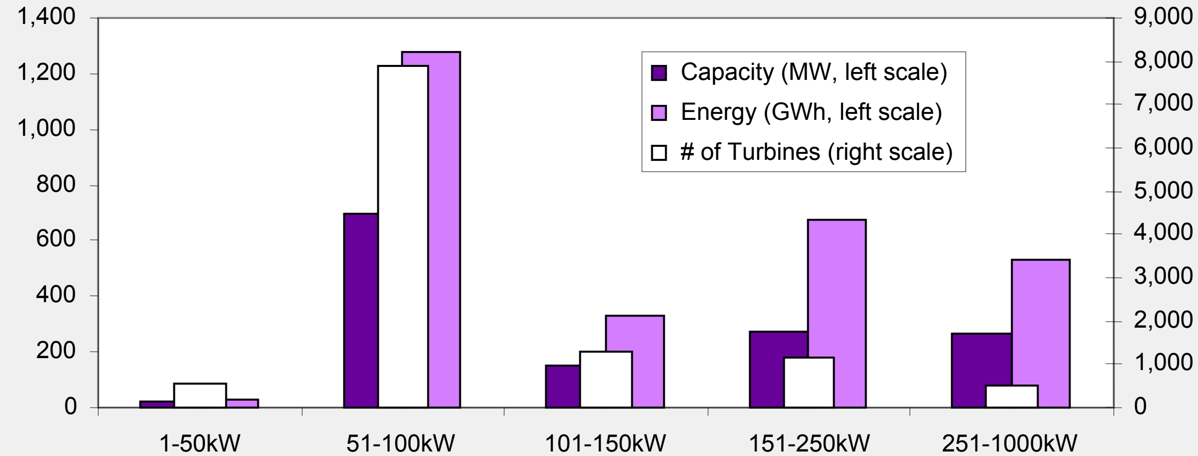
Given the aging condition of much of California's installed renewable energy capacity and the substantial value that existing renewable sites hold, it is quite likely that in addition to new site development, significant repowering of existing sites will eventually occur.[74] This is also reflected in the analysis of RPS needs in Appendix A, which presumes that the renewable baseline will remain constant through 2017 – i.e., that at least some repowering will occur.

Much of California's existing renewable capacity is old and inefficient, especially wind. **Figure 9** groups existing California wind capacity, production, and number of turbines as of 1999 into various turbine size ranges. The greatest concentration of capacity, energy, and turbines is within the 51 to 100 kW range, which is a full order of magnitude below the megawatt-class turbines that, since 2002, have become the industry standard. Most of California's existing wind capacity was installed prior to 1990, and by the end of 1995, the average nameplate capacity of wind turbines installed in California was only 118 kW.[75]

Similarly, a sizable portion of California's geothermal capacity was installed in the 1970s or early 1980s, making most of these plants at least 20 years old. Geothermal repowering may be limited by the life of the steam and hot water field.

At some point in the future, many of the aging wind and geothermal plants will most likely be repowered. Economic, legislative, regulatory, institutional, and financial considerations all have a direct bearing on when this will take place. Following are five issues that could factor into a renewable generator's decision to repower an existing California facility.

Figure 9. Existing California Wind Power Capacity, Production and number of Turbines (1999)



Source: ***California Energy Commission Wind Performance Report Summary, 1996-1999***

Federal Production Tax Credit Legislation

Section 45 of the U.S. tax code deals with the PTC and contains a clause that places restrictions on repowered facilities that sell output to investor-owned utilities (IOUs) under contracts entered into before January 1, 1987. Specifically, a repowered facility will be eligible for the PTC if the existing standard offer contract is "amended" such that any wind generation in excess of historical norms is either sold to the utility at its current avoided costs or else sold to a third party.[76] As long as the utility need only honor the standard offer contract price for generation amounts that are "normal" by historical standards, then the entire repowered facility can still qualify for the PTC. It may, therefore, be feasible for a repowered wind project to earn the PTC, by selling the "normal" amount of power to the utility at the standard offer contract price, and selling any incremental output to meet the RPS at market rates. Nonetheless, this clause has reportedly had a chilling effect on wind repowering decisions so far.

Expansion of the Federal Production Tax Credit to Other Forms of Renewable Generation

Both the House and Senate 2003 energy proposals call for a 3-year extension of the PTC. The House proposal also expands the credit to geothermal, solar, and biomass facilities. An expansion of the PTC could provide a major incentive to repower non-wind renewable facilities, particularly if such repowered facilities would also be eligible for supplemental energy payments (SEPs).

Eligibility for Supplemental Energy Payments under California's RPS

Senate Bill 1038 (SB 1038) states that "Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility." The Energy Commission is currently developing rules to implement the legislative intent with respect to SEP eligibility. The stringency of these rules, and the likelihood of a generator meeting the 80 percent threshold, will be a factor in repowering decisions.[77]

Uncertainties over Future Short Run Avoided Costs and Natural Gas Prices

Most California renewable energy Qualifying Facilities (QFs) are now earning a temporary, negotiated short-run avoided cost (SRAC) fixed price at 5.37 cents/kWh (plus capacity payments) through 2006-2007, at which time the standard offer contract price will revert to traditional SRAC, unless the California Public Utilities Commission (CPUC) either extends the current price or sets a new price. Traditionally, SRAC calculations have been heavily influenced by natural gas prices, rising when gas prices are high, and falling when gas prices are low.
Senate Bill 1078 (SB 1078) allows existing renewable facilities to negotiate an additional five-year fixed-price contract upon expiration of the initial five-year term.

> 390.1. Any non-utility power generator using renewable fuels that has entered into a contract with an electrical corporation prior to December 31, 2001, specifying fixed energy prices for five years of output may negotiate a contract for an additional five years of fixed energy payments upon expiration of the initial five-year term, at a price to be determined by the commission.

Gas prices also impact the "market price referent" against which renewable energy contracts will be benchmarked under the RPS. With low gas prices, the market price referent will be low, meaning that winning renewable bidders will require relatively high SEPs. Under such a scenario, the total amount of SEP funding available may be prematurely depleted, and California may not meet its RPS targets, resulting in a reduction of demand for renewable energy, and a corresponding reduction in demand for repowered renewables.

If, on the other hand, the temporary SRAC is extended or gas prices remain high, then a generator may be able to amortize the capital costs of repowering a facility over a longer term. There may also be more RPS-related demand for repowered renewable energy, as the market price referent will be high, resulting in low SEPs and a high likelihood of reaching the RPS targets.

Air Quality Permits

The increasing stringency of air quality permits can either discourage or encourage repowering among biomass or landfill gas plants. Any repowering will likely "re-open" a facility's air quality permit, a situation that most generators prefer to avoid. On the other hand, existing biomass or landfill gas generators may find that gradual erosion in the amount of allowable or "grandfathered" emissions from their plants may necessitate at least an upgrade of pollution control technology, and perhaps even a repowering.

Estimates of Repowering Potential in California

Based on the factors listed above and discussions with various industry groups and developers, the following is a rough estimate of repowering potential in California by major technology.

- **Wind:** The California Wind Energy Association (CalWEA) believes that there is little prospect for wind repowering until the Section 45 restriction on repowered facilities is removed from the federal tax code. If this occurs, CalWEA estimates that up to 450 MW of nameplate wind capacity might repower within three years.[78] This estimate presumes no net increase in nameplate capacity, but given the greater efficiency of today's technology, this repowering would result in roughly 470 GWh/year of incremental wind energy. Transmission constraints in select wind resource areas (e.g., Tehachapi) could discourage incremental repowering, just as they do new development.

- **Biomass:** The California Biomass Energy Alliance does not foresee repowering of biomass facilities in the near future. The RPS does not provide adequate incentive relative to existing QF contracts, and there are many impediments to repowering (e.g., obtaining a new air quality permit, arranging financing, meeting the SB 1038 80-percent threshold to qualify for SEPs). The Biomass Collaboration, on the other hand, believes that with appropriate incentives to repower, biomass facilities can increase energy production by roughly 10-30% or more.[79]

- **Geothermal:** Repowering potential for geothermal facilities exists mainly at The Geysers, which is majority-operated by Calpine. Most other geothermal facilities are relatively new, use fairly efficient technology, and have more than 10 years remaining on their standard offer contracts.[80] Calpine estimates that several hundred MW of geothermal capacity could be repowered at The Geysers. The uncertainties include the stringency of Energy Commission rules governing SEP payments to repowered facilities as well as whether the federal PTC is expanded to geothermal facilities.

- **Concentrating Solar Power:** The potential for significant repowering of concentrating solar power appears to be minimal, even if the technology becomes eligible for the federal PTC.

- **Landfill gas:** Because they are relatively cost-competitive, landfill gas facilities have a fairly strong incentive to repower for RPS purposes. Landfill gas generators in the state may try to sever their standard offer contracts and repower if they qualify for SEPs.[81] Two landfill gas projects that participated in the New Renewable Resources Account's first auction have repowered and have been receiving incentive payments since 1999.

Assuming many of the factors discussed fall into place, the bulk of any repowering would come from wind (about 450 MW initially, but potentially rising to about 900 MW), geothermal (several hundred MW), and landfill gas facilities (about 100 MW). Of these three resource types, the greatest repowering-related gains in efficiency and output would likely come from wind, which has experienced dramatic technological improvements since the 1980s. The bulk of California's existing wind projects were installed in the 1980s. While the capacity of repowered projects may increase, the real benefit would come from the increased amount of energy the repowered projects provide.

CHAPTER 4: RENEWABLE RESOURCE TECHNICAL POTENTIAL

The California Energy Commission's Public Interest Energy Research (PIER) program has a series of research projects underway to update the estimates of technical potential for renewable energy in California. Results available as of August 1, 2003 are reported here to update the information included in the ***Preliminary Renewable Resource Assessment*** (PRRA).

For wind energy resources, the PIER estimates of technical potential are higher than the Regional Economic Research, Inc. (RER) estimates published in 2002. For geothermal and biomass/biogas, the PIER estimates are lower than the RER estimates. For concentrating solar power (CSP), the PIER data show more than ten times the technical potential shown in the RER data. PIER data for photovoltaic (PV) technical potential are also much higher than the RER data. Both PIER and RER solar data sets are reported in Appendix C. The PIER data for technical potential were used in all cases but solar. The RER data were for solar to provide an estimate of solar technical potential that is more conservative.

Ocean energy is also a qualifying renewable energy resource for meeting the Renewables Portfolio Standard (RPS) goals. California has an extensive coastline, which may provide an opportunity to develop ocean energy resources. The California Energy Commission (Energy Commission), through the PIER program, will be assessing the technical potential for ocean energy development, cost of generation, and environmental impacts. Those results are not yet complete; however, so ocean energy resources are not addressed further in this section.

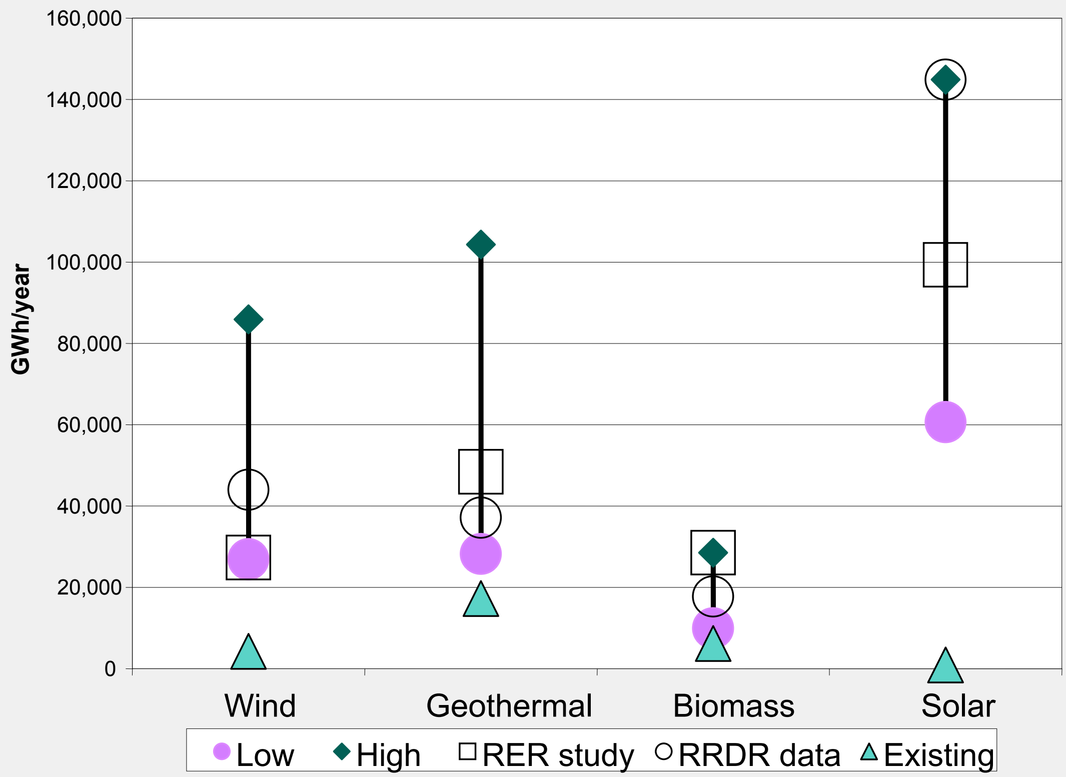
TECHNICAL POTENTIAL FOR CALIFORNIA

The gross technical potential for wind, geothermal, biomass, biogas, small hydroelectricity, and solar power is estimated to be more than 262,000 gigawatt-hours per year (GWh/year).[82] By way of comparison, total electricity generated in California in 2002 was 272,509 GWh.[83]

The estimates for California's gross renewable technical potential vary, sometimes greatly, among studies (**Figure 10**). The reasons for these variations include the different time frames in which the studies were conducted and the filtering of data using differing criteria. **Figure 10** includes total technical potential in relation to existing renewable energy facilities. This figure also shows the difference among technical potential estimates across studies.[84] For example, the lowest estimate of technical potential for California geothermal in the studies reviewed for this assessment was 28,200 GWh/year. The highest estimate for geothermal in

California was 104,300 GWh/year. In general, existing renewable energy facilities only utilize a small proportion of the gross technical potential for renewable energy in California reported in **Figure 10**.

Figure 10. Technical Potential in California, by Technology (GWh/year)



Source: ***Renewable Resources Development Report***

The PRRA reported remaining technical potential for renewable energy in California that was calculated using estimates of technical potential from the 2002 study by RER, ***Technical Potential of Renewable Resource Technologies***. This report uses new estimates of technical potential for wind, biomass, biogas and geothermal electric generation in California. The new estimates were provided by the PIER program.

The technical potential data for wind were filtered for areas with wind power densities greater than 500 Watts per square meter at a hub height of 70 meters. This is roughly equivalent to Class 4+ wind resource areas. The PIER data also contain estimates for low-speed wind resources and data for a range of hub heights, though these data were not used in this report.

The following fuel sources are included in the data for biomass: chaparral, lumber mill residue, forest slash, forest thinnings, woody agricultural, urban wood, urban yard, waste paper, waste plastic, field crops, shells, pits, and hulls. The data for biogas include landfill gas, dairy and swine manure, and sewage wastewater facilities.

The data for geothermal electric technical potential in California were supplied by Geothermex, a technical contractor to the PIER program.

The technical potential for small hydroelectric generation in California was derived from the Hydropower Evaluation Software that was developed by the Idaho National Engineering and Environmental Laboratory for the U.S. Department of Energy. The Hydropower Evaluation Software is based on data from the Southwestern Power Administration (SWPA).[85] These data do not filter out sites that have existing large hydroelectric facilities or sites where adding capacity to sites with existing facilities, regardless of size, would exceed the 30 MW limit. Only a portion of the small hydroelectric potential reported here is likely to meet the RPS program requirements, given SB 1038's stringent requirements for eligible incremental hydroelectric generation.

The data from the PIER program for solar PV and CSP are included in Appendix C to provide an indication of the total amount of energy that could be generated from each resource type. Work is underway to apply additional filters to the PIER data to constrain the estimates to locations with the greatest opportunities for solar installations (e.g., roof top applications for PV, maximum solar insolation for CSP). As results from this effort were not available for inclusion in this report, the more conservative RER estimates from 2002 were used to estimate technical potential for PV and CSP technologies, although the capacity factor for the latter was changed from 15 percent to 25 percent.

Table 6 shows an estimate of the gross total technical potential, on-line renewable energy projects, and proposed projects for the counties and renewable resources in California. The data are shown here in GWh/year. Capacity factors used to convert information from megawatts to GWh/year are shown in Appendix C.

In a number of counties in California, renewable energy resources that are on-line plus proposed renewable energy projects yield a total greater than the estimated technical potential. In some cases, this technical potential may be a result of double counting of proposed projects, or proposals based on a different methodology for estimating technical potential. For wind, this potential may be caused by a conservative interpretation of the data provided by PIER. The technical potential for wind energy used in this study includes the PIER data for wind above a certain power density (500 Watts per square meter) at a single hub height (70 meters). On-line wind turbines, however, capture wind resources at a range of power densities and hub heights.

Table 6. Potential Electricity (GWh/year) from Renewables in California[86]

Resource Location [a]	County/Technology	Total Potential GWh/year	Est On-line GWh/year	Potential minus On-line (GWh/yr)	Proposed GWh/year
PG&E and smaller utilities in northern California					
	Siskiyou geothermal	3,564	-	3,564	1,481
	Solano wind	823	41	783	1,232
	Modoc geothermal	331	-	331	828
	Alameda wind	394	363	31	646
	Other wind	1,434	985	449	-
	Other geothermal	11,787	14,513	[b]	-
	Other solid biomass	9,856	3,770	5,816	233
	Other LFG/digester	947	333	614	307
	Other CSP	2,788	0	2,788	-
	Other PV	5,357	-	5,357	
	Other small hydro	5,568	3,084	2,483	7
	Subtotal	**42,849**	**23,089**	**22,486**	**4,805**
SCE and smaller utilities in southern California					
	Imperial geothermal	16,888	4,353	12,535	1,892
	Imperial solid biomass	90	102	[c]	561
	Imperial LFG/digester	2	-	2	-
	Imperial wind	1,433	-	1,433	-
	Imperial CSP	24,265	-	24,265	-
	Imperial PV	53	-	53	-
	Imperial small hydro	22	199	[c]	-
	Kern wind	13,903	1,453	12,450	11,620
	Mono geothermal	686	315	371	2,759
	Riverside wind	4,633	691	3,941	1,619
	San Bernardino wind	5,812	-	5,812	279
	San Bernardino CSP	52,871	482	52,389	263
	Los Angeles solid biomass	1,404	343	1,061	350
	Los Angeles LFG/digester	1,338	366	971	208
	Los Angeles wind	5,909	-	5,909	307
	Other wind	7,379	-	7,379	92
	Other geothermal	4,079	2,382	1,698	-
	Other solid biomass	2,175	593	1,582	11
	Other LFG/digester	876	450	426	268
	Other CSP	62,003	355	61,649	-
	Other PV	5,980	-	5,980	-
	Other small hydro	546	638	[c]	4
	Subtotal	**212,347**	**12,722**	**199,906**	**20,232**
SDG&E and Escondido utilities*					
	San Diego wind	2,266	9	2,257	1,226
	San Diego solid biomass	487	-	487	-
	San Diego LFG/digester	185	179	6	208
	San Diego CSP	2,965	-	2,965	-
	San Diego solar PV	1,029	-	1,029	-
	San Diego small hydro	20	44	[c]	-
	Subtotal	**6,952**	**232**	**6,744**	**1,435**
TOTAL		**262,150**	**36,045**	**229,135**	**26,470**
Total excluding PV, small hydro		**243,575**	**32,080**	**214,235**	**26,390**

Source: ***Renewable Resources Development Report***

Appendix B contains a map showing the service territories of the utilities in California. Some counties are served by one or more publicly-owned electric utilities and an investor-owned utility (IOU). Some publicly-owned electric utilities and smaller IOUs serve portions of more than one county. In **Table 6**, the renewable energy resources located in the area served by publicly-owned electric utilities were grouped to indicate general physical location in relation to the IOU responsible for much of the resource development and/or transmission planning for the county. Imperial County is an exception. The renewable energy resources located in Imperial County were listed under the affiliation of Imperial Irrigation District. For the purposes of transmission planning at the California Public Utilities Commission (CPUC), Imperial County was included in Southern California Edison (SCE)'s conceptual transmission study.

Whether renewable energy resources will be developed and contracted to serve local electricity load or not depends on a number of factors, such as whether the utility serving the local area has met its RPS requirements, whether the local supply of electricity exceeds demand, the location of the renewable energy resources in relation to the dynamics of the transmission grid (e.g., will local use of the electricity ease transmission congestion?), and whether the renewable energy resource has won an RPS bid solicitation and received a power purchase agreement in the local area.

Proposed Projects

Multiple sources are utilized to identify proposed renewable projects in California, including the Energy Commission's New Renewables Program, the Southern California Public Power Authority (SCPPA) Request for Proposals (RFP), California Power Authority (CPA) Letters of Intent (LOIs), the recent Northern California Power Agency (NCPA) RFP, and SCE Transmission Reports. Some data sources do not use uniform identification information. Every effort was made to compare the databases and to prevent double counting; however, if multiple entries exist, it should not be significant.[87]

There are significant increases in the number of proposed projects and amount of energy from proposed projects in this report, compared to the PRRA delivered to the CPUC July 1, 2003. This difference resulted from three changes in data sources. First, this report uses primary data from CPA for its LOIs as opposed to relying on the Lawrence Berkeley National Laboratory (LBNL) summary that was used in the PRRA. After distribution of the PRRA, it was discovered that the LBNL summary does not include the most recent information regarding proposed projects. Second, the NCPA solicitation was included in this report. It was not available in time to be included in the PRRA. Third, this report includes data for small hydroelectric and PV. The data for these resources were not included in the PRRA.

Energy Commission's New Renewables Program

The Energy Commission's New Renewables Program database, updated to end of March 2003, was utilized to identify California new on-line and proposed projects. Projects currently receiving payments from the Energy Commission's New Renewable Resources Account are assumed to be on-line, as opposed to proposed.

Southern California Public Power Authority Request for Proposals

SCPPA provided information on technology, megawatts of capacity, location (county and state), potential on-line date, and point of delivery for all project proposals under SCPPA's recent renewable energy solicitation.

California Power Authority Letters of Intent

In the period from fall 2001 through spring 2002, the CPA entered into 73 LOIs with individual renewable projects in California. The LOIs contain developer name and sometimes project name. The LOIs contain no specific information on location other than interconnect zone (north of transmission Path 15, south of transmission Path 15). Using the project name and developer information, locations were extrapolated and projects were cross-referenced with the Energy Commission's New Renewables Program and SCPPA RFP projects. Of the 73 original entries, 20 were eliminated from consideration because they duplicated proposals found in the other sources consulted for this report.

Northern California Power Agency Request for Proposals

NCPA conducted an RFP in spring 2003 and provided limited information on the responses it received. Information includes technology, capacity, and interconnect zone. As such, these data are insufficient to locate the projects by county. These data were extensively cross-referenced with other data sets to check for duplicate projects. Of 65 original entries, 36 were eliminated. The location of those maintained is typically listed as "unknown" by interconnect zone (north of Path 15, south of Path 15). Additionally, the totals by technology provided by NCPA do not match the sums of the project capacities, indicating that NCPA apparently discounted the viability of a significant number of the bids.

The proposed projects reviewed for this study could total more than 26,000 GWh/yr of renewable energy generation in California. A county-by-county list of proposed projects and selection criteria is included in Appendix C.

TECHNICAL POTENTIAL FOR OTHER WESTERN ELECTRICITY COORDINATING COUNCIL STATES

The estimates of renewable energy resource technical potential are approximations of the total amount of energy that could be generated from each resource type. Theoretically, the renewable resources of the Western Electricity Coordinating Council (WECC) considered in this section have the potential to supply many times over the WECC region's electricity needs. It is important to note, however, that estimates of technical potential ignore the obstacles associated with getting that generation to market. In addition, technology improvements could significantly alter the estimates of technical potential.

The total technical potential for renewable energy resource development in other WECC states (not including California) for wind, geothermal, biomass, and solar (CSP and PV) is estimated to be more than 3,700,000 GWh/year (**Table 7**). With on-line facilities generating about 8,600 GWh/year and over 33,000 GWh/year in proposed projects, these resources remain relatively untapped.

Wind energy accounts for almost 90 percent of the proposed renewable energy resources reviewed for this study. Proposed wind projects in Oregon and Washington account for almost 70 percent of all of the proposed projects in WECC states outside of California (**Table 8**).

The data used for this report show proposed renewable energy projects in Nevada totaling more than 4,000 GWh/year with almost 2,000 GWh/year from wind, 1,850 GWh/year from geothermal, less than 200 GWh/year from biomass, and about 100 GWh/year from solar.

Table 7. Technical Potential (GWh/year) in Other WECC states (Wind, Geothermal, Biomass, and Solar)

State	Wind	Geothermal	Biomass	Solar	Total
AZ	5,000	5,000	1,000	101,000	112,000
CO	601,000	-	4,000	83,000	688,000
ID	49,000	5,000	9,000	60,000	123,000
MT	1,020,000	-	6,000	101,000	1,127,000
NM	56,000	3,000	500	104,000	163,500
NV	55,000	20,000	1,000	93,000	169,000
OR	70,000	17,000	10,000	68,000	165,000
UT	23,000	9,000	1,000	69,000	102,000
WA	62,000	-	11,000	42,000	115,000
WY	883,000	-	-	72,000	955,000
Total	**2,824,000**	**59,000**	**43,500**	**793,000**	**3,719,500**

Source: ***Renewable Energy Atlas of the West***

Table 8. Indication of Proposed Projects (GWh/year) in Other WECC states (Wind, Geothermal, Biomass, and Solar)

State	**PROPOSED (GWh/year)**				
	Wind	**Geothermal**	**Biomass**	**Solar**	**Total**
Capacity Factor	**35%**	**90%**	**80%**	**25%**	
AZ	123	-	-	-	123
CO	803	-	-	-	803
ID	613	79	-	-	692
MT	822	-	-	-	822
NM	2,020	-	-	-	2,020
NV	1,978	1,854	175	109.5	4,117
OR	11,728	394	-	-	12,122
UT	460	788	-	-	1,248
WA	11,065	-	-	-	11,065
WY	552	-	-	-	552
TOTAL	**30,164**	**3,116**	**175**	**110**	**33,564**

Sources: Due to limited access to data at the time this study was prepared, information provided for proposed projects in other WECC states is not comprehensive. For Washington and Oregon the data were collected from Bonneville Power Authority (BPA) Open Access Same Time Information System (OASIS). For Nevada, data were collected from their recent (as of August 2003) solicitation for renewable energy. The Data do not include the Montana wind solicitation, nor do data include the Colorado all-source solicitation from several years ago. Data do not include OASIS sites outside of BPA.

CHAPTER 5: CALIFORNIA'S RENEWABLES PORTFOLIO STANDARD

In 2002, the California Renewables Portfolio Standard (RPS) was established with the passage of Senate Bill 1078 (SB 1078). The RPS requires certain retail sellers of electricity to increase their sales of electricity from renewable energy by at least 1 percent per year achieving 20 percent by 2017 at the latest. While allowing each publicly-owned electric utility the flexibility to define its own RPS, SB 1078 also establishes a statewide goal for publicly-owned utilities of 20 percent of retail electricity sales provided by renewable energy by 2017. Senate Bill 1038 (SB 1038) extends funding for the California Energy Commission (Energy Commission) Renewable Energy Program and revises its structure, including the provision of Supplemental Energy Payments (SEPs) in support of California's RPS program.

In addition, the ***Energy Action Plan*** encourages acceleration of the RPS so that 20 percent of retail sales of electricity come from renewable resources by 2010. The state's energy agencies recognize the ***Energy Action Plan*** goal and are working to achieve it.

This chapter summarizes the efforts taken to date to implement the RPS and address transmission issues related to the policy.

STATUS OF PROGRAM IMPLEMENTATION

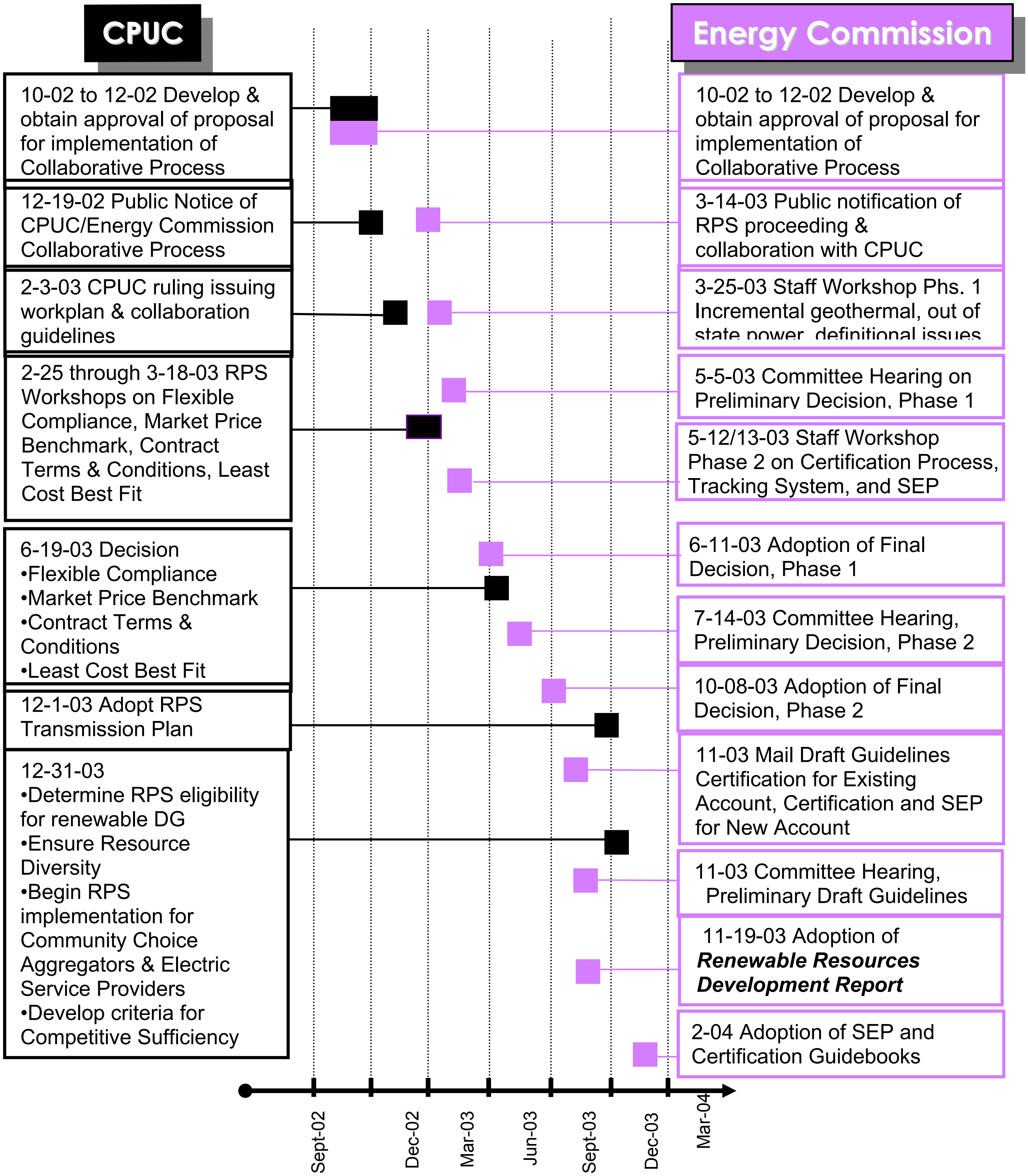
The California Public Utilities Commission (CPUC) and the Energy Commission have established a collaborative process to develop rules to implement California's RPS. The two agencies have developed a work plan and designated collaborative staff from both agencies to work on RPS proceedings. A number of well-attended public workshops have been held at the Energy Commission and the CPUC to discuss RPS implementation issues. The lead decision-making authority is divided between the two agencies as follows:

> Energy Commission: Eligibility of out-of-state power, eligible renewable technologies, incremental geothermal generation, certification of renewable electricity generation facilities, guidelines for supplemental energy payments, developing an accounting system for the RPS.
>
> CPUC: Renewable generation baseline and annual procurement targets, flexible compliance and penalty mechanisms, standard contract terms and conditions, market price referents, as well as least-cost and best-fit bid ranking criteria.

Both Agencies Under Respective Authority: Eligibility of renewable distributed generation, ensuring resource diversity, commencement of RPS implementation for Electric Service Providers (ESP) and Community Choice Aggregators (CCA), criteria to determine competitive sufficiency, and a finalized RPS tracking and verification system, including the role of renewable energy certificates, if applicable.

The RPS implementation issues have been divided into three phases. **Figure 11** indicates the phase, timing, and agency with decision making authority for the RPS implementation issues. The RPS implementation issues that have been addressed to date are summarized below. The allocation of issues between the two agencies and decisions related to implementation of California's RPS have been based on applicable language and direction in SB 1078 and SB 1038.

Figure 11. Timeline for Implementation of California's RPS



Source: California Energy Commission, Renewable Energy Program

Eligibility of Out-of-State Power

After considering public comments filed at prior workshops and discussion with the RPS collaborative staff at the Energy Commission and the CPUC, the Energy Commission adopted a decision on June 11, 2003 that defines the eligibility requirements for renewable resources that investor-owned utilities (IOUs) can purchase to meet the RPS. The Energy Commission decided that eligible renewable generators located out-of-state can deliver electricity to California to satisfy RPS purchase requirements and receive SEPs, provided that one of the following conditions is met:

1. It is located near the border of the state with the first point of interconnection to the Western Electricity Coordinating Council (WECC) transmission system located within California; or

2. It meets the eligibility criteria for supplemental energy payments in that the facility is located so that it is or will be connected to the WECC transmission system, and is developed with guaranteed contracts to sell its generation to end-use customers located in California IOU service territories while it receives SEPs.[88]

Since the June adoption of the decision, two bills were signed into law that provide additional specifications regarding the RPS eligibility of out of state power. Senate Bill 67 (SB 67, Bowen, Chapter 731, Statutes of 2003) was signed by the Governor on October 8, 2003. SB 67 clarifies the eligibility of out-of-state renewable resources for California's RPS and adds the following language to the Public Utilities Code:

> 399.16. The [California Public Utilities] commission may consider an electric generating facility that is located outside the state to be an eligible renewable energy resource if it meets the criteria described in Section 399.12 and all of the following requirements:
>
> (a) It is located so that it is, or will be, connected to the Western Electricity Coordinating Council (WECC) transmission system.
> (b) It is developed with guaranteed contracts to sell its generation, and demonstrates delivery of energy, to a retail seller or the Independent System Operator.
> (c) It participates in the accounting system to verify compliance with the renewables portfolio standard by retail sellers, once established by the State Energy Resources Conservation and Development Commission pursuant to subdivision (b) of Section 399.13.

Senate Bill 183 (SB 183, Sher, Chapter 666, Statutes of 2003) was signed by the Governor on October 2, 3003. SB 183 amends the Public Resources Code and clarifies the eligibility of out-of-state renewable resources participating in California's RPS program to receive supplemental energy payments:

> 25743. (b) (2) The commission may determine as part of a solicitation, that a facility that does not meet the definition of an ''in-state renewable electricity generation technology'' facility solely because it is located outside the state, is eligible for funding under this subdivision if it meets all of the following requirements:
>
> (A) It is located so that it is or will be connected to the Western Electricity Coordinating Council (WECC) transmission system.
>
> (B) It is developed with guaranteed contracts to sell its generation to end-use customers subject to the funding requirements of Section 381, or to marketers that provide this guarantee for resale of the generation, for a period of time at least equal to the amount of time it receives incentive payments under this subdivision.

Eligible Renewable Technologies

As cited in the Energy Commission's RPS Phase 1 decision, California Public Utilities Code Section 383.5(b)(1) defines an "in-state renewable electricity generation technology" as follows:

> The facility uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.[89]

To implement the RPS, clarification related to small hydroelectric generation, biomass, municipal solid waste, and hybrid technologies was needed. On these topics, the RPS Phase 1 and Phase 2 decisions determined the following:[90]

1. Criteria for determining whether a small hydroelectric project involves a new or increased appropriation or diversion of water should address what data will be used to establish the starting point for water flows, ... the time intervals used to calculate the starting point, ... [and] whether projects that change the timing, but not the quantity, of water released during a given time period are eligible. A self-certification process will be used to administer this aspect of RPS eligibility.

2. A self-certification process will be used to administer the requirement that new biomass applicants for RPS eligibility ... certify annually, under penalty of perjury, that the fuel use for their facility meets the criteria in SB 1038.

3. In general, municipal solid waste (MSW) combustion facilities do not meet the requirements for the RPS, with the following exception: MSW combustion facilities are eligible for the purpose of adjusting a retail seller's baseline, provided that the facility's combustion, control, and generation equipment are located wholly within the boundaries of Stanislaus County, and the facility began operating before September 26, 1996.

4. Facilities using an eligible solid waste conversion technology to gasify or convert MSW into a clean-burning fuel before combustion are eligible for meeting a retail seller's required additional procurement.

5. The electricity produced from the combustion of biodiesel is eligible for the RPS to the extent that the biodiesel is derived from either 1) a biomass feedstock such as “agricultural crops and agricultural wastes and residues” and consists of no more than 25 percent fossil fuel, or 2) an eligible “solid waste conversion” process of MSW.

6. A renewable facility may be eligible for the RPS if it uses up to, but not more than, 25 percent fossil fuel, which is consistent with eligibility requirements in the Energy Commission's Renewable Energy Program. Under this program, the percentage of fossil fuel used may not exceed 25 percent of the total energy input of the facility during a given calendar year. This requirement stems from the federal law applicable to qualifying small power production facilities.

Incremental Geothermal Generation

The Energy Commission’s Phase 1 and Phase 2 decisions determined the type of incremental geothermal generation that would be eligible for California's RPS and additional requirements that must be met for such generation to be eligible for SEPs. According to the Phase 1 decision, incremental geothermal generation is eligible for the RPS if it is a product of eligible capital expenditures, which must meet the following criteria:

1. A substantial capital project, resulting in replacement of generating equipment or increase in steam converted to generation at a facility;
2. A sustainable impact on the underlying reservoir use; that is, a project does not cause an increase in the decline rate of the reservoir; and
3. A capital project completion date after September 26, 1996.[91]

The decision refers to repowering or refurbishing generating equipment, adding a binary bottoming cycle, and increased water injection as examples of eligible capital expenditures that are likely to meet the criteria for eligible incremental geothermal electricity generation.

According to the Phase 2 decision, repowered geothermal facilities may be eligible to receive SEPs if they meet the following requirements:

1. The entire steam generator, including the turbine rotors, shaft, stationary blades, and any gear assemblies ("prime generating equipment") have been replaced with new prime generating equipment, that is, equipment that has not been used before.
2. The capital investment made to replace the prime generating equipment with new prime generating equipment equals at least 80 percent of the value of the repowered facility." See the Phase 2 decision (pp. 12-16) for information regarding methods used to determine and document compliance with this requirement.
3. All prime generating equipment at the facility must be replaced with new equipment for the facility to qualify as a repowered facility.[92]

Flexible Compliance and Penalty Mechanisms

The CPUC June 19, 2003 decision adopted flexible rules for compliance with the RPS that allow the IOUs to receive credit in future years for procuring more than their RPS annual procurement target (APT). In addition, the decision allows an IOU to defer up to 25 percent of its APT from one year without explanation, provided that it is made up within three years. In the first year, 100 percent of the APT may be deferred, provided that it is procured within three years. In the year in which a deferred portion of an APT is due, the procurement made in that year applies first to the current year's APT, with excess applied to the deferred amount. A penalty in the amount of five cents per kilowatt hour, up to $25 million per utility, will be owed for deferred amounts that are past due.

More than 25 percent of an APT may be deferred, provided that one of four conditions is demonstrated by the utility:

> a) Insufficient response to [request for offers] RFO, b) Contracts already executed will provide future deliveries sufficient to satisfy current year deficits, c) Inadequate public goods funds to cover above-market renewable contract costs, d) Seller non-performance (... beyond the control of the utility).[93]

IOUs must submit a filing on February 1 of each year documenting whether the previous year's APT was met. The filing must also provide an "accounting of past, current and anticipated future deficits and any additional information deemed necessary based on utility consultation with the [Public Utilities] Commission's Energy Division." If more than 25 percent of the APT was not met, the filing must provide documentation for any of the four conditions noted above, if applicable, or documentation to "convince the [Public Utilities] Commission that a deferral would promote ratepayer interests and the overall procurement objectives of the RPS program.” [94]

Standard Contract Terms and Conditions

The June 19, 2003 CPUC decision adopted the following standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators, as required by SB 1078:

1. The decision directs the parties to negotiate more detailed standard terms and conditions, with the Edison Electric Institute Master Agreement as the basis for the negotiations. The decision also recommends that the following standard terms be incorporated: product definitions, contract term, [California Public Utilities] Commission approval language, supplemental energy payment awards and contingencies, ownership of renewable energy certificates, confidentiality, performance standards, non-performance or termination penalties, scheduling coordination and responsibility for imbalances.[95]
2. The decision endorsed the goal of "prompt negotiation to resolve ... a stalemate around repowering of existing wind facilities ... as the repowering of existing wind facilities in prime locations is a common-sense approach to increasing procurement of renewable energy, with costs that should be lower than for new greenfield projects." (p. 57)
3. The decision stated that the utilities should seek bids for 10, 15, and 20-year products.
4. The decision allows bilateral contracts only when such contracts do not require any public goods charge (PGC) funds.

On October 22, 2003 Administrative Law Judge Peter V. Allen issued a ruling acknowledging that the negotiations and workshops held to date had failed to lead to agreement among the parties regarding standard terms and conditions. As SB 1078 requires the CPUC to adopt standard terms and conditions, the ruling specifies a process and schedule for this task, including deadlines for parties to submit briefs and reply briefs stating their positions. The ruling also indicates a process for litigation of this issue, should further negotiation prove unsuccessful.[96]

Market Price Referents

The June 19, 2003 CPUC decision also adopts a process for determining market price referents for base load and peaking renewable electricity products. The market price referents can be thought of as estimates of the amount that the IOUs would pay for each energy type if they were not purchasing renewable power. Obligated electricity suppliers under the RPS are not required to purchase renewable energy at a price over the relevant market price referent. Instead, the Energy Commission will fund any costs, up to any price cap that may yet be determined, above the market price referent through SEPs. The CPUC decision states that a combined cycle plant will be used to establish the market price referent for base load renewable energy products and that a combustion turbine will be used as the proxy for establishing the market price referent of peaking products.

The actual market price referent for the first solicitation will not be known until after the bids have been received, as stated in SB 1078. This requirement is intended to increase the incentives for developers to submit competitive bids in the procurement process. As a result of this practice, the portion of each winning bid that is above the market price referent and eligible for SEPs will not be known in advance.

Least-Cost and Best-Fit Bid Ranking Criteria

The CPUC June 19, 2003 decision establishes criteria for the ranking and selecting of renewable bids, based on two goals: minimizing the cost to the ratepayer and obtaining resources that fit with IOU resource needs. The decision defines "best fit" as "the renewable resources that best meet the utility's energy, capacity, ancillary service and local reliability needs," with the added condition that "for the short-term, renewable generation that can operate as dispatchable or peaker power may possibly fall slightly higher on the 'procurement hierarchy.'"[97]

According to the June 19, 2003 decision, the RPS procurement for each IOU will be based on its publicly available annual RPS plan. Each IOU will prepare an RPS procurement plan, which is subject to CPUC approval. The plan should contain information that will allow bidders to develop products to fit each IOU's needs. Costs and benefits to the transmission system, local and system reliability, low income and minority communities, environmental stewardship, and resource diversity will also be considered in selecting winning bids.

Distributing Supplemental Energy Payments

Details regarding the procedures that will be used to distribute SEPs were determined in Phase 2 of the Energy Commission's RPS proceeding. Two key elements related to distribution of SEPs are highlighted below:

> To be considered eligible for SEPs, resources must begin commercial operation or be "repowered" (as defined on pp, 10-16 of the Phase 2 decision) on or after January 1, 2002 and meet the other eligibility requirements of SB 1038. The on-line date will be periodically updated as needed.
>
> The Energy Commission will determine whether public goods charge (PGC) funds are adequate to meet SEP requirements after each competitive bid solicitation. Regarding the steps for this evaluation, the Phase 2 decision states the following:

> If PGC funds are inadequate, then the Energy Commission will identify which bidders could be fully funded under the utilities' least-cost-best-fit ranking required under SB 1078, so that projects with the best ranking would be awarded SEPs first. … The Energy Commission will notify the CPUC, IOU, and bidders of the availability of PGC funds within 30 days of receiving all data needed to conduct this evaluation. The Energy Commission will also notify the CPUC, IOU and winning bidders of the potential PGC award per winning bidder. The Energy Commission will approve the final PGC awards after the winning bidders have met all of their environmental review requirements. (p. 22)

Certification of Renewable Electricity Generation Facilities

Decisions regarding the certification of renewable electricity generation facilities are included in the Energy Commission's October 2003, ***Renewable Portfolio Standard: Decision on Phase 2 Implementation Issues, Commission Report***. Among the decisions related to this topic, the report describes a process to pre-certify projects under development or in construction, subject to further verification once projects are completed. The report also states that the Energy Commission will institute an audit procedure to conduct spot checks. Audit results will be posted on the Energy Commission website to support industry self-policing. The report also states that penalties for non-compliance will be included in the power purchase agreement between the retail seller and the renewable energy generator.

In addition, the report states that certification must be renewed every year to capture facility changes and confirm that all resources remain eligible for the RPS. If a certified or pre-certified entity does not respond to the Energy Commission's request for an information update in a timely manner, it will risk losing its certification status.[98]

Developing the Accounting System for the Renewables Portfolio Standard

To meet the purposes described in SB 1078 and SB 1038 regarding an accounting system for the RPS, the Energy Commission's October 2003 Commission Report ***Renewables Portfolio Standard: Decision on Phase 2 Implementation Issues*** stated the following:

> The Energy Commission will (1) use an interim contract-path accounting system to verify RPS compliance for 2003 and 2004; and (2) develop a long-term electronic-path accounting system in coordination with the Western Governors'

Association (WGA) that can record renewable generation and transactions through the system starting in 2005 and meet the needs specified in SB 1078:

1. Verify compliance with the RPS by retail sellers,
2. Ensure that renewable energy output is counted only once to meet the RPS of California or any other state, and
3. Verify retail product claims in California or any other state.

For both the interim and long-term systems, in-state and out-of-state renewable energy generators that are eligible for the RPS must first be certified by the Energy Commission.[99]

Interim Solicitations for Renewable Energy

The CPUC issued an Assigned Commissioner's Ruling in Docket R. 01-10-024 on August 13, 2003 to indicate the procedures under which IOUs may voluntarily conduct interim solicitations for renewable energy prior to resolution of the remaining RPS implementation issues. This ruling clarified the conditions that must be met for such interim solicitations to qualify for RPS goals. Subsequent to this decision, SCE released a Request for Offers for renewable energy resources,[100] and PG&E has requested approval of additional renewable energy contracts.

TRANSMISSION PLANNING FOR RENEWABLES

SB 1038 requires the Energy Commission to complete a renewable resource plan and the CPUC to complete a renewable transmission plan. Both reports must be submitted to the Legislature by December 1, 2003, but the CPUC is directed to use the renewable resource plan in preparing its transmission plan. To facilitate coordination of these tasks, the Energy Commission agreed to prepare a ***Preliminary Renewable Resource Assessment*** (PRRA). The PRRA was delivered to the CPUC on July 1, 2003. The PRRA focused on the renewable energy needs of the IOUs and ESPs. This report expands the focus to address the energy needs of the entire state, including publicly-owned electric utilities.

Using the draft assessment as a basis for developing bounding cases for renewable resource development, preparation of the CPUC transmission planning report is moving forward through CPUC Investigation 00-11-001. To date, the following milestones have been achieved:

The CPUC, Energy Commission, California Independent System Operator (CA ISO), IOUs, renewable energy developers, and interested stakeholders meet frequently to discuss developments in the CPUC transmission planning report.

SCE, PG&E, and SDG&E have complied with the CPUC's order to prepare conceptual studies of transmission needs associated with the RPS. Starting with the renewable energy resource scenario in the PRRA and addressing possible impacts of accelerating the RPS to 20 percent by 2010, the studies identify possible transmission infrastructure additions or upgrades needed to interconnect RPS resources to the transmission grid, identify cost estimates, and address other related issues. Key findings from each of the reports are summarized below.

SCE believes that 75 percent of the renewable resources identified in the PRRA are located in their service territory, and that these resources exceed what is required to meet the RPS. Development of transmission for these resources will allow export of renewable energy from SCE to other utilities in support of statewide RPS goals. SCE also notes that much of the energy generation is located in four locations with large quantities of existing renewable energy capacity. Cost for the transmission upgrades are estimated at $1.2 billion (net present value 2003 dollars) for the 2017 build-out system with accelerated development for 2005-2010.[101]

PG&E estimates cumulative costs to meet its requirements under SB 1078 to be $180 to $240 million. Accelerating RPS to 20 percent by 2010 is estimated to add another $295 to $420 million. All estimates are in 2003 dollars, without accounting for inflation.[102]

SDG&E identifies a total cost of $51 million for its preferred interconnection plan.[103]

On September 24, 2003, Solargenix Energy, LLC filed a conceptual transmission study in CPUC Investigation 00-11-001. The study was prepared by SCE after completion of SCE's conceptual study of transmission needs for RPS. The study describes the transmission requirements for interconnecting 1,000 MW of CSP located at Harper Lake in San Bernardino County. The project would be phased over time with 100 MW on-line by 2005, an additional 400 MW by 2008, and 500 MW by 2017. SCE reported that the net present value of the costs related to transmission needed for the Solargenix project is $86.79 million. Accelerating construction from 2017 to 2010 would result in transmission-related upgrade and construction costs with a net present value of $104.61 million.

CHAPTER 6: RENEWABLE RESOURCE ASSESSMENT

AMOUNT OF ELECTRICITY REQUIRED TO MEET THE STATEWIDE RENEWABLES PORTFOLIO STANDARD

Table 9 identifies the estimated additional procurement of renewable energy needed to achieve the statewide Renewables Portfolio Standard (RPS) goals set out in Senate Bill 1078 (SB 1078) (RPS demand). To reach the statewide goal of 20 percent of retail sales by 2017, the amounts shown in **Table 9** must be added to the staff's estimation of the 2001 baseline and publicly available information regarding the 2003 Interim Procurement.[104]

Table 9. Estimated Statewide RPS Cumulative Additional Procurement beyond Baseline and 2003 Interim Procurement to meet SB 1078 goals

	2005	2008	2017
Energy: gigawatt-hours/year (GWh/year) cumulative additions	4,230	13,120	30,610

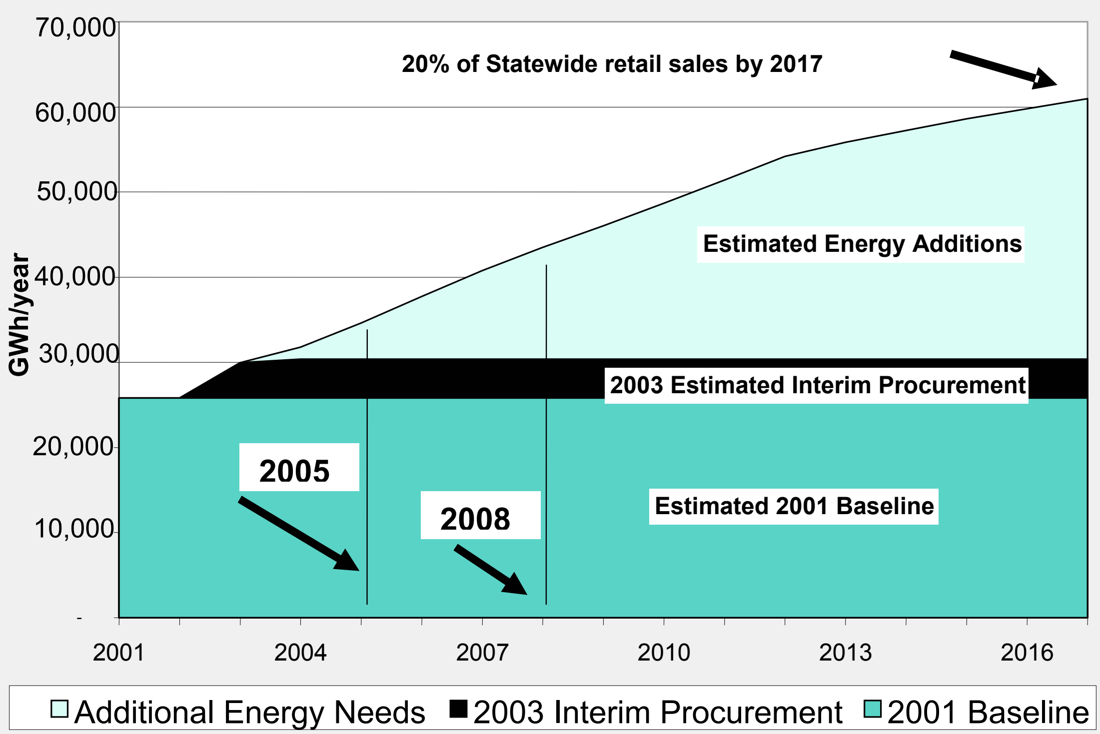
Source: ***Renewable Resources Development Report***

For the years 2004 to 2017, the staff estimated how much renewable energy would be required per year to meet the RPS. Beginning in 2003 for the Electric Service Providers and Community Choice Aggregators (ESP/CCAs) and the rest of the state and 2004 for the investor-owned utilities (IOUs), the staff calculated growth of 1 percentage point each year until the 20 percent target is met (10 percent to 11 percent to 12 percent, and so on). After the 20 percent target is met, the staff assumes that the percent of renewable energy is maintained. If any of the obligated entities do not reach the 20 percent target by 2017 with an annual 1 percentage point growth rate, they must grow at a rate proportionately higher to reach the 20 percent target. The trajectory created by these calculations establishes an estimate of the Annual Procurement Target (APT).

This analysis is designed to estimate the amount of additional renewable energy required to meet the RPS goals in each year, with an emphasis on the years 2005, 2008, and 2017. The analysis does not attempt to model flexible compliance with the RPS requirements, where the required energy could be procured prior to or after the actual year to meet the APT. Flexible compliance does not change the total amount of additional energy required to meet the RPS, but it is likely to affect the timing of actual purchases. This analysis also assumes that the amount of energy identified in the estimated 2001 renewable energy baseline continues to be procured each year by the same retail seller and at the same amount as in 2001. In fact, the amount of baseline energy procured each year could decline, or increase, or could shift among retail sellers. These effects are not included here. A decline in baseline energy procured would require additional energy to meet the RPS goals; a shift in baseline resources among retail sellers could shift the nature or location of procurement for the RPS.

Figure 12 illustrates the staff's estimated baseline, 2003 Interim Procurement, and the additional renewable energy that will be required to meet the statewide RPS goal.

Figure 12. Statewide Estimated Renewable Energy Baseline, 2003 Interim Procurement, and Statewide Renewable Additions to meet California's RPS Requirements



Source: ***Renewable Resources Development Report***

The estimated 2001 baseline is the starting point towards meeting RPS compliance. The estimated amount of additional renewable energy procured during the 2003 Interim Procurement by the IOUs represents a portion of the amount of additional energy that is needed to meet the statewide RPS goal by 2017. This analysis also assumes that the ESP/CCAs and the rest of the state procured a net increase of

1 percent of their retail sales in 2003, and these renewable energy additions are included in the 2003 Estimated Incremental Procurement. With these assumptions, the IOUs and ESP/CCAs will need to procure an additional 21,200 gigawatt-hours per year (GWh/year) of renewable energy to reach the RPS mandated goal of 20 percent, by 2017, and the rest of the state will need to procure 9,410 GWh/year by 2017.

Table 10 shows the estimated additional GWh/year of electricity needed to meet the estimated energy obligations under the RPS. These values are in addition to the estimated 2001 baseline energy and the annual generation from the Interim Procurement.

Table 10. Estimated Statewide RPS Additional Procurement beyond Baseline and 2003 Interim Procurement (GWh/year)

	2005	2008	2017
PG&E			
Utility	1,253	4,169	9,521
ESP/CCA	188	489	1,314
SCE			
Utility	756	2,965	5,123
ESP/CCA	259	677	1,873
SDG&E			
Utility	0	319	2,721
ESP/CCA	84	223	650
Rest of the State	1,693	4,277	9,407
Total NEW			
Utility	2,009	7,453	17,365
ESP/CCA	531	1,389	3,837
Rest of State	**1,693**	**4,277**	**9,407**
	4,230	**13,120**	**30,610**

*Because of rounding, the data do not add to total.

Source: ***Renewable Resources Development Report***

Details regarding this estimate of RPS requirements are provided in Appendix A.

Alternate Statewide Sales Forecasts

In addition to the baseline sales forecast used to estimate energy requirements for the RPS and the accelerated RPS, the staff developed a high and low statewide sales forecast (see Appendix A). Under the high sales forecast, the estimated statewide sales in 2017 is projected to be 315,313 GWh, compared to the 304,896 GWh baseline sales forecast for 2017. This results in an extra 2,083 GWh/year required to meet the RPS under the high sales forecast versus the baseline sales forecast. Under the low sales forecast, the estimated statewide amount of energy sales in 2017 is projected to be 293,799 GWh. This results in 2,219 fewer GWh/year being procured by 2017 versus the baseline sales forecast. The renewable technical potential in California (262,000 GWh/year) is abundant enough to meet the 20 percent requirement under the high, baseline, or low sales forecast.

Renewables Portfolio Standard Investor-Owned Utility Requirements for 2005, 2008, 2017

Pacific Gas & Electric Company

The staff forecasted the amount of energy that Pacific Gas and Electric Company (PG&E) would sell from 2003 through 2013, at an annual, average growth rate for this time period of 1.7 percent. This same growth rate was applied by the staff to estimate sales for 2014 to 2017.

The estimated sales data for PG&E for 2001 are slightly different than data that PG&E provided to the California Public Utilities Commission (CPUC) in a January 6, 2003 (R.01-10-024) filing. For 2001, the staff estimated that PG&E sold 75,681 GWh.

In a January 6, 2003 (R. 01-10-024) filing, PG&E calculated their 2001 percentage of power provided by eligible renewable power sources to be 10 percent of their total energy portfolio. Energy Commission staff converted this total into energy, and used it for the energy number. For 2001, staff estimated that PG&E sold 7,532 GWh of eligible renewable energy.

In their Advice letter dated January 2, 2003 (2334-E), PG&E indicated they would procure approximately 826 GWh/year beginning in 2003 for their Interim Procurement requirement.

In addition to their estimated 2001 baseline and estimated 2003 Interim Procurement, California Energy Commission (Energy Commission) staff calculated that PG&E will need to procure an additional 1,253 GWh/year by 2005, 4,169 GWh/year by 2008 and 9,521 GWh/year by 2017 to meet their RPS obligations (See Appendix A). The staff estimates that PG&E will meet its 20 percent target by 2013. Subsequent procurement is not at 1 percent a year, but maintains 20 percent of retail sales.

Southern California Edison

The staff forecasted the amount of electricity that Southern California Edison (SCE) would sell from 2003 through 2013, at an annual, average growth rate of 1.8 percent. This same rate was used to calculate sales estimates for 2014 to 2017.

The staff's 2001 sales data for SCE are slightly different than data SCE provided to the CPUC in a January 2, 2003 (R.01-10-024) filing. For 2001, the staff estimated that SCE sold 74,286 GWh.

In a U-338 E filing on January 6, 2003 (R. 01-10-024), SCE indicates that their renewable qualifying facilities (QFs) in 2001 provided 10,610 GWh. Based on an analysis of SCE's Federal Energy Regulatory Commission (FERC) Form No. 1, the staff added an additional 550 GWh of small hydroelectric generation that potentially was not counted by SCE, but may qualify as part of SCE's 2001 renewable baseline. For 2001, staff estimated that SCE sold 11,160 GWh of eligible renewable energy.

SCE's January 2, 2003 filing indicated that they would procure at least 748 GWh/year for their Interim Procurement requirement.

In addition to SCE's estimated 2001 baseline and 2003 Interim Procurements, Energy Commission staff calculated that SCE will need to procure an additional 756 GWh/year by 2005, 2,965 GWh/year by 2008, and 5,123 GWh/year by 2017 (See Appendix A). The staff estimates that SCE reaches 20 percent by 2007. Subsequent procurement is not at 1 percent a year, but maintains 20 percent of retail sales.

Subsequent to preparation of the estimates of renewable energy that SCE would need to procure to meet the RPS, SCE announced that over 20 percent of their sales came from renewable resources for the months of May and June, 2003.[105] In addition, SCE indicates that they will be at nearly 20 percent for the 2003 period, and is planning to have more than 20 percent of its sales come from renewable resources in the future.[106] SCE released a new solicitation for renewable energy on August 29, 2003.[107]

San Diego Gas & Electric

The staff forecasted the amount of energy that San Diego Gas and Electric (SDG&E) would sell from 2003 through 2013, at an annual, average growth rate of 1.9 percent. This same rate was applied by the staff to estimate sales for 2014 to 2017.

The staff estimated SDG&E's sales data for 2001 to be 15,000 GWh/year. Per a January 2, 2003 filing (R.01-10-024), SDG&E considers their 2001 sales to be confidential.

In a January 6, 2003 filing (R. 01-10-024), SDG&E indicates that their renewable energy sales will be 4.5 percent in 2003 and 7.1 percent in 2004. For 2003, 3.76 percent of the 4.5 percent will be additional renewable energy, per the Interim Procurement requirement. Energy Commission staff estimates that in 2001, 0.74 percent of SDG&E's total sales came from renewable resources, accounting for 112 GWh of eligible renewable energy.[108]

Energy Commission staff estimates that SDG&E will not need to procure any additional renewable energy in 2005 beyond what is already in its estimated 2001 baseline and that delivered under contracts signed during the Interim Procurement process. SDG&E will need to procure 319 GWh/year by 2008 and 2,721 GWh/year by 2017 (See Appendix A). SDG&E will reach 20 percent by 2017 with an average annual procurement of 245 GWh/year between 2003 and 2017.

Renewables Portfolio Standard Electricity Service Provider/Community Choice Aggregator Requirements for 2005, 2008, 2017

SB 1078 requires that IOUs and ESP/CCA providers ensure that 20 percent of their electricity sales come from eligible renewable resources by 2017. Rather than look at the amount that each individual direct access company sells, this analysis looks at the service territories where these providers sell electricity.

The staff forecasted the amount of electricity that the ESPs/CCAs would sell between 2003 and 2013 by service territory. The retail sales forecast shows an average growth rate of 1.3 percent (PG&E), 1.6 percent (SCE), and 2.2 percent (SDG&E) between 2003 and 2013. These percentages were used to extrapolate estimated retail sales for 2014-2017. It is important to note that while the amount of energy sold by ESPs/CCAs increases over time, the percentage in relation to IOU sales remains roughly constant.

The staff estimated ESPs/CCA sales for 2001 to be 10,392 GWh. This number includes energy from renewable and non-renewable energy resources. To calculate the portion of 2001 ESP/CCA sales that came from renewable resources, the staff used information from the Energy Commission's Customer Credit program. This program provided "Customer Credits" to consumers who purchased eligible renewable electricity from ESPs that were registered with the Energy Commission. Through this program, consumers choosing renewable or "green power" could receive payment of up to 1.0 cent per kilowatt-hour (cent/kWh) for renewable electricity purchased in 2001.

For 2001, Energy Commission staff estimates that there were 745 GWh of eligible renewable sales for the ESP/CCAs (direct access providers). This is the amount of renewable energy sales eligible for Customer Credits and that received payment from the Energy Commission in 2001. Determining the IOU service territory where the recipients of the eligible renewable energy resided is not possible with the current publicly available data. Therefore, the staff assumed that ESP/CCAs had the same percentage of eligible renewable sales. This value was derived by taking the total estimated ESP/CCA renewable sales, 745 GWh, and dividing that by the total amount of Direct Access sales in 2001, 10,392 GWh. Therefore, for this analysis, the estimated 2001 ESP/CCA renewable baseline is 7.17 percent for all ESP/CCAs. In terms of total load in 2001, the 10,392 GWh of aggregate ESP/CCA load is split among utility service territories as follows: 3,761 GWh for PG&E; 4,168 GWh for SCE; and 2,463 GWh for SDG&E. These ESP/CCA estimates differ slightly from data reported by the IOUs in some of their CPUC filings. It is likely that some of this load has reverted back to the IOUs.

In addition to their 2001 estimated baseline and the assumed 2003 procurement of an additional 1 percent of renewable energy under SB 1078, the staff estimates that ESP/CCA providers will need to procure an additional 531 GWh/year by 2005, 1,389 GWh/year by 2008 and 3,837 GWh/year by 2017 to meet RPS requirements. ESP/CCAs should reach their requirements by 2015, with subsequent procurement maintained at 20 percent of retail sales.

Renewables Portfolio Standard Rest of State Requirements for 2005, 2008, 2017

The focus of SB 1078 is largely directed at PG&E, SCE, and SDG&E, although it includes references to ESP/CCAs and publicly-owned electric utilities as well. The Energy Commission and the CPUC have not yet begun developing rules for the application of California's RPS to ESP/CCAs. Publicly-owned electric utilities will develop and implement their own programs, and the Energy Commission intends to provide assistance as needed.

SB 1078 leaves adoption of an RPS standard up to each publicly-owned electric utility, but it also requires that each publicly-owned electric utility RPS standard "recognizes the intent of the Legislature to encourage renewable resources." At the same time, SB 1078 establishes the same goal for all of California that it adopted for SCE, SDG&E, PG&E, and ESP/CCAs: 20 percent of retail sales by 2017.

The Energy Commission staff estimates that smaller IOUs (those not explicitly covered by the mandatory RPS) and publicly-owned electric utilities would need to procure about 9,400 GWh of additional renewable energy by 2017. This amount is beyond the estimated 2001 baseline (6,270 GWh) and the estimated the 2003 RPS procurement (910 GWh).

SB 1078 allows publicly-owned electric utilities the flexibility to define their own RPS programs. A number of publicly-owned electric utilities are planning to define large hydroelectric generation as an eligible renewable technology. If large hydroelectric power is used by publicly-owned electric utilities to meet their RPS goals, the amount of additional renewable energy procured beyond existing resources may be smaller, as some of these utilities receive a substantial portion of their electricity from large hydroelectric generation. It is important to note that the RPS program excludes large hydroelectric generation from the definition of eligible renewable energy that applies to investor-owned utilities. The use of different definitions of "eligible renewable" for different RPS programs within California may cause some confusion and may not adequately meet the intent of the legislation.

Smaller IOUs may have difficulty meeting the statewide RPS requirement as they may face high transmission "wheeling" costs, difficulty accessing renewable energy due to their small size (e.g., a 20 percent RPS represents less than 5 megawatts (MW) of renewable energy), limited ability to accommodate intermittent resources in their energy supply, and existing long-term contracts for more than 80 percent of energy supply needs. Many smaller publicly-owned electric utilities have joined regional associations to benefit from aggregated resource solicitation and supply arrangements. It is not clear whether this option is available for smaller IOUs. In its Decision number 03-06-071, the CPUC stated its intention to open a new rulemaking to address RPS implementation issues for ESPs and CCAs. This rulemaking will also address issues for small IOUs.

AMOUNT OF ELECTRICITY REQUIRED TO MEET THE ACCELERATED RENEWABLES PORTFOLIO STANDARD

Table 11 identifies the estimated additional procurement of renewable energy needed to achieve the accelerated RPS goals set out in ***Energy Action Plan*** (20 percent by 2010). The amounts shown in **Table 11** must be added to staff's estimation of the 2001 baseline and publicly available information regarding the 2003 Interim Procurement.

Table 11. Estimated Statewide RPS Cumulative Additional Procurement beyond Baseline and 2003 Interim Procurement for Accelerated RPS

	2005	2008	2010	2017
Energy: GWh/year cumulative additions	6,120	17,850	24,800	30,610

Source: ***Renewable Resources Development Report***

The staff interprets SB 1078 literally in determining how much energy the obligated entities would be required to procure each year. In calculating the 1 percent increase per year, staff used an estimation of 2001 baseline level of renewable energy. Beginning in 2003 for the ESP/CCAs and the rest of the state and in 2004 for the IOUs, staff calculated growth of 1 percentage point each year until the 20 percent target is met (10 percent to 11 percent to 12 percent, and so on) by 2010. After the

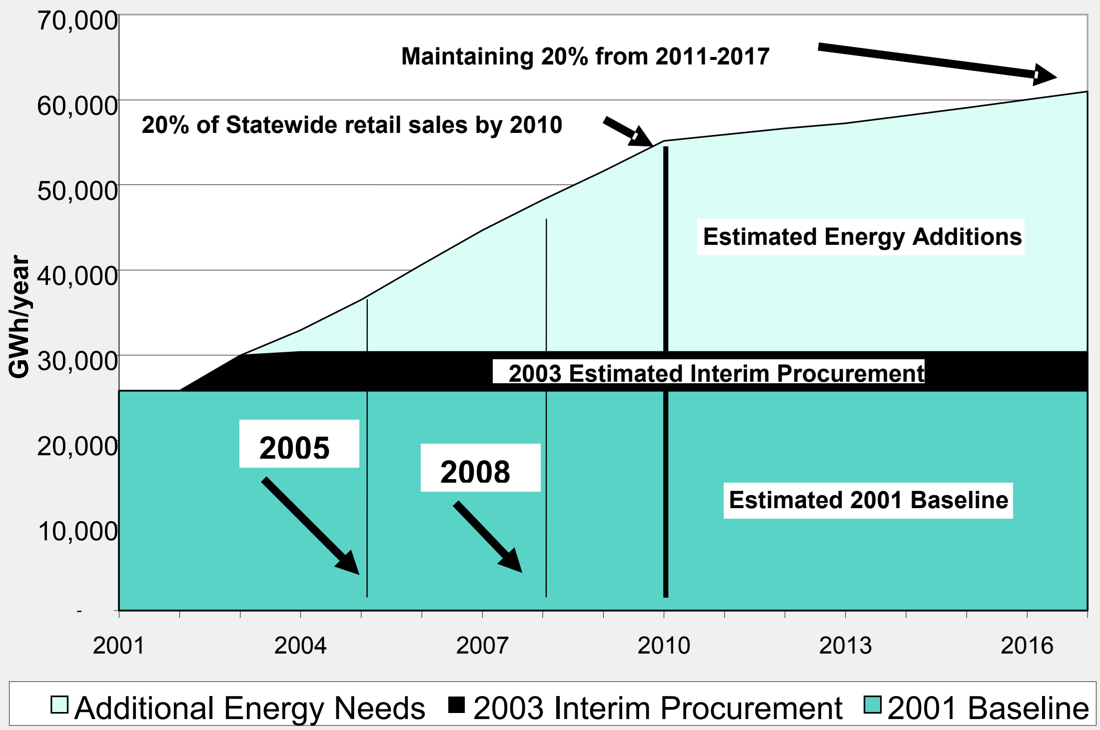
20 percent target is met, the staff assumes that it is maintained at 20 percent until 2017. If any of the obligated entities do not reach the 20 percent target by 2010 with an annual 1 percentage point growth rate, they must grow at a rate proportionately higher to reach the 20 percent target.

This analysis is designed to estimate the amounts of additional renewable energy required to meet the ***Energy Action Plan*** statewide RPS goals in each year, with an emphasis on the years 2005, 2008, 2010, and 2017. The analysis includes no attempt to model flexible compliance with the RPS requirements, where the required energy could be procured prior to or after the actual year it is required to meet the APT. Flexible compliance does not change the total amount of additional energy required to meet the RPS, but it is likely to affect the timing of actual purchases. This analysis also assumes that the amount of renewable energy identified in the estimated 2001 baseline continues to be procured each year by the same retail seller and at the same amount as in 2001. In fact, the amount of baseline energy procured each year could decline, increase, or could shift among retail sellers. These effects are not included here. A decline in baseline energy procured would require additional energy to meet the RPS goals; a shift in baseline resources among retail sellers could shift the nature or location of procurement for the RPS.

Figure 13 illustrates the staff's estimated 2001 statewide baseline, 2003 Interim Procurement, and the additional renewable energy needed statewide to meet the statewide accelerated RPS. A comparison to **Figure 12** demonstrates the accelerated nature of the ***Energy Action Plan*'s** RPS goals.

The estimated 2001 renewable energy baseline is the starting point towards RPS compliance. The additional renewable energy estimated to have been procured by IOUs in 2003 represents a portion of the amount of additional energy that the obligated entities need to procure to meet the ***Energy Action Plan*** RPS goal by 2010. This analysis also assumes that the ESP/CCAs and the rest of the state procured renewable energy representing a net increase of 1 percent of their retail sales in 2003 and these renewable energy additions are included in the 2003 Estimated Incremental Procurement. With this assumption, the IOUs, ESP/CCAs, and the rest of the state will need to procure an additional 24,800 GWh/year of renewable energy to reach the statewide ***Energy Action Plan*** RPS goal of 20 percent by 2010. Between 2011 and 2017, an additional 5,800 GWh/year of renewable energy will need to be procured, for statewide total additions of 30,610 GWh/year beyond the 2003 Estimated Incremental Procurement.

Figure 13. Estimated Renewable Energy Baseline, 2003 Interim Procurement and Statewide Additions needed to meet the Accelerated RPS Requirements



Source: ***Renewable Resources Development Report***

Table 12 shows the estimated additional electricity from renewable resources needed to meet the statewide accelerated RPS goals under the ***Energy Action Plan***. These values are in addition to the estimated 2001 baseline energy and the annual generation from the Interim Procurement.

Table 12. Estimated Statewide Accelerated RPS Additional Procurement Beyond Baseline and 2003 Interim Procurement (GWh/year)

	2005	2008	2010	2017
PG&E				
Utility	1,823	5,375	7,792	9,521
ESP/CCA	343	810	1,142	1,314
SCE				
Utility	756	2,965	3,339	5,123
ESP/CCA	466	1,113	1,578	1,873
SDG&E				
Utility	157	1,421	2,304	2,721
ESP/CCA	149	361	518	650
Rest of State	2,429	5,803	8,124	9,407
Total NEW				
Utility	2,736	9,761	13,434	17,365
ESP/CCA	958	2,285	3,237	3,837
Rest of State	2,429	5,803	8,124	9,407
	6,120	17,850	24,800	30,610

*Because of rounding, the data do not add to total.

Source: ***Renewable Resources Development Report***

Details regarding this estimate of accelerated RPS goals are provided in Appendix A.

Alternate Statewide Sales Forecasts

In addition to the baseline sales forecast used to estimate energy requirements for the RPS and the accelerated RPS, Energy Commission staff developed a high and low statewide sales forecast (see Appendix A). Under the high sales forecast, the estimated statewide sales in 2010 is projected to be 282,892 GWh, compared to the 275,829 GWh baseline sales forecast, resulting in an extra 1,413 GWh/year required to meet the accelerated RPS. Under the low sales forecast, the estimated statewide sales in 2010 is projected to be 268,037 GWh, resulting in 1,558 fewer GWh/year required to meet the accelerated RPS. The renewable technical potential in California (262,000 GWh/year) far exceeds what is required to meet the accelerated RPS under the high, baseline, or low sales forecasts.

Accelerated Renewables Portfolio Standard Requirements for Investor-Owned Utilities

Pacific Gas & Electric Company

The staff forecasted the amount of energy that PG&E would sell from 2003 through 2013, at an annual average growth rate of 1.7 percent. This same growth rate was applied by the staff to calculate sales for 2014 to 2017.

The estimated sales data for PG&E for 2001 are slightly different than the data that PG&E provided to the CPUC in a January 6, 2003 (R.01-10-024) filing. For 2001, staff estimated that PG&E sold 75,681 GWh.

In a January 6, 2003 (R. 01-10-024) filing, PG&E calculated their 2001 percentage of power provided by eligible renewable power sources to be 10 percent of their total energy portfolio. Energy Commission staff converted this total into energy, and used it for the energy estimate. For 2001, the staff estimated that PG&E sold 7,532 GWh of eligible renewable energy.

In their Advice letter dated January 2, 2003 (2334-E), PG&E indicated they would procure approximately 826 GWh/year beginning in 2003 for their Interim Procurement requirement.

In addition to their estimated 2001 baseline and estimated 2003 Interim Procurement, Energy Commission staff calculated that PG&E will need to procure an additional 1,823 GWh/year by 2005, 5,375 GWh/year by 2008 and 7,792 GWh/year by 2010 to meet their ***Energy Action Plan*** RPS obligations (See Appendix A). The staff estimates that PG&E will meet its 20 percent target by 2010. Subsequent procurement is not at 1 percent per year, but maintained at 20 percent of retail sales.

Southern California Edison

The staff forecasted the amount of electricity that SCE would sell from 2003 through 2013, at an annual, average growth rate of 1.8 percent. This same rate was used to calculate sales for 2014 to 2017.

The staff's 2001 sales data for SCE are slightly different than data SCE provided to the CPUC in a January 2, 2003 (R.01-10-024) filing. For 2001, staff estimated that SCE sold 74,286 GWh.

In a U-338 E filing on January 6, 2003 (R. 01-10-024), SCE indicates that their renewable QFs in 2001 provided 10,610 GWh. Based on an analysis of SCE's FERC Form No. 1, the staff added an additional 550 GWh of small hydroelectric generation that potentially was not counted by SCE, but may qualify as part of SCE's

2001 renewable baseline. For 2001, the staff estimated that SCE sold 11,160 GWh of eligible renewable energy.

SCE's January 2, 2003 filing indicated they would procure at least 748 GWh/year beginning in 2003 for their Interim Procurement requirement.

In addition to SCE's estimated 2001 baseline and 2003 Interim Procurements, the staff calculated that SCE will need to procure an additional 756 GWh/year by 2005, 2,965 GWh/year by 2008 and 3,339 GWh/year by 2010 (See Appendix A). The staff estimates that SCE reaches 20 percent by 2007. Subsequent procurement is not at 1 percent a year, but maintains 20 percent of retail sales.

Subsequent to preparation of the estimates of renewable energy that SCE would need to procure to meet the RPS, SCE announced that over 20 percent of their sales came from renewable resources for the months of May and June, 2003.[109] In addition, SCE indicates that they will be at nearly 20 percent for the 2003 period, and is planning to have more than 20 percent of its sales come from renewable resources in the future.[110] SCE released a new solicitation for renewable energy on August 29, 2003.[111]

San Diego Gas & Electric

The staff forecasted the amount of energy SDG&E would sell from 2003 through 2013, at an annual, average growth rate of 1.9 percent. This same growth rate was applied by the staff to calculate sales for 2014 to 2017.

The staff estimated SDG&E's sales data for 2001 to be 15,000 GWh/year. Per a January 2, 2003 filing (R.01-10-024), SDG&E considers their 2001 sales to be confidential.

In a January 6, 2003 filing (R. 01-10-024), SDG&E indicates that their renewable energy sales will be 4.5 percent in 2003 and 7.1 percent in 2004. For 2003, 3.76 percent of the 4.5 percent will be additional renewable energy, per the Interim Procurement requirement. Energy Commission staff estimates that in 2001, 0.74 percent of SDG&E's total sales came from renewable resources, accounting for 112 GWh of eligible renewable energy.[112]

In addition to their estimated 2001 baseline and their estimated 2003 Interim Procurements, Energy Commission staff estimates that SDG&E will need to procure an additional 157 GWh/year in 2005, 1,421 GWh/year by 2008 and 2,304 GWh/year by 2010 (See Appendix A). SDG&E will reach 20 percent by 2010, with an average, annual procurement of 407 GWh/year between 2003 and 2010.

Accelerated Renewables Portfolio Standard Requirements for Electricity Service Providers/Community Choice Aggregators

SB 1078 requires that IOUs and ESP/CCAs ensure that 20 percent of their electricity sales come from eligible renewable resources by 2017. The ***Energy Action Plan*** moves this goal up to 2010. Rather than look at the amount that each individual direct access company sells, this analysis looks at the service territories into which those providers sell electricity.

The staff forecasted the amount of electricity that the ESPs/CCAs would sell between 2003 and 2013 by service territory. The retail sales forecast shows an average growth rate of 1.3 percent (PG&E), 1.6 percent (SCE), and 2.2 percent (SDG&E) between 2003 and 2013. These percentages were used to extrapolate estimated retail sales for 2014-2017. It is important to note that while the amount of energy sold by ESPs/CCAs increases over time, the percentage in relation to IOU sales remains roughly constant.

The staff estimated ESPs/CCA sales for 2001 to be 10,392 GWh. This number includes supply from renewable and non-renewable energy resources. To calculate the portion of 2001 ESP/CCA sales that came from renewable energy resources, the staff used information from the Energy Commission's Customer Credit program. This program provided "Customer Credits" to consumers who purchased eligible renewable electricity from ESPs that were registered with the Energy Commission. Through this program, consumers choosing renewable or "green power" could receive payment of up to 1.0 cents per kilowatt-hour for renewable electricity purchased in 2001.

For 2001, the Energy Commission staff estimates that there were 745 GWh of eligible renewable sales for the ESP/CCAs (direct access providers). This is the amount of renewable energy sales eligible for Customer Credits and that received payment from the Energy Commission in 2001. Determining the IOU service territory where the recipients of the eligible renewable energy resided is not possible with the current publicly available data. Therefore, the staff assumed that ESP/CCAs had the same percentage of eligible renewable sales. This value was derived by taking the total estimated ESP/CCA renewable sales, 745 GWh, and dividing that by the total amount of Direct Access sales in 2001, 10,392 GWh. Therefore, for this analysis, the estimated 2001 ESP/CCA renewable baseline is 7.17 percent for all ESP/CCAs. In terms of total load in 2001, the 10,392 GWh of aggregate ESP/CCA load is split among utility service territories as follows: 3,761 GWh for PG&E; 4,168 GWh for SCE; and 2,463 GWh for SDG&E. These ESP/CCA estimates differ slightly from data reported by the IOUs in some of their CPUC filings. It is likely that some of this load has reverted back to the IOUs.

In addition to their 2001 estimated baseline and the assumed 2003 procurement of an additional 1 percent of renewable energy, the Energy Commission staff estimates that ESP/CCA providers will need to procure an additional 958 GWh/year by 2005, 2,285 GWh/year by 2008 and 3,237 GWh/year by 2010 to meet the accelerated RPS goals of the ***Energy Action Plan***. ESP/CCAs should reach their requirements by 2010, with subsequent procurement maintained at 20 percent of retail sales.

Accelerated Renewables Portfolio Standard Rest of State Requirements for 2005, 2008, 2017

The focus of SB 1078 is largely directed at PG&E, SCE and SDG&E, although it includes references to ESP/CCAs and publicly-owned electric utilities as well. The ***Energy Action Plan***'s statewide goal of 20 percent renewable energy by 2010 applies to the publicly-owned electric utilities as well as the IOUs.

Senate Bill 1078 leaves adoption of an RPS standard up to each publicly-owned electric utility, but it also requires that each publicly-owned electric utility RPS standard "recognizes the intent of the Legislature to encourage renewable resources." At the same time, SB 1078 establishes the same goal for all of California that it adopted for SCE, SDG&E, PG&E, and ESP/CCAs. Meeting the RPS requirement on an accelerated schedule is the goal outlined in the ***Energy Action Plan***.

The Energy Commission staff estimates that smaller IOU and publicly-owned electric utilities would need to procure an additional 8,124 GWh by 2010, and ultimately 9,407 GWh by 2017. This amount of renewable energy is beyond the estimated 2001 baseline (6,270 GWh) and estimated interim procurement (910 GWh).

RESOURCE SCENARIO FOR THE RENEWABLES PORTFOLIO STANDARD AND ACCELERATED RENEWABLES PORTFOLIO STANDARD

This section provides an assessment of the possible mix of technologies and geographic locations that could provide the needed renewable energy, in two scenarios: a baseline scenario of 20 percent by 2017, and an accelerated renewable development scenario of 20 percent by 2010, meeting the goal in the ***Energy Action Plan***.[113] Unlike the earlier ***Preliminary Renewable Resource Assessment*** (PRRA), this analysis includes both the renewable energy purchase obligations of IOUs and ESPs/CCAs under the state's RPS, as well as the renewable energy needs of publicly-owned electric utilities and other obligated entities, assuming that those entities pursue renewable energy in a way consistent with the RPS obligations of IOUs and ESPs/CCAs, as specified in SB 1078.

Assumptions and Approach

The scenarios here are merely examples of the renewable resources and locations that ***might*** be developed to meet the state's renewable energy objectives. To reach a higher level of certainty would require detailed information regarding the status of each individual proposed project; however, this information is not publicly available. In planning for renewable resource development, predicting the amount of renewable energy needed by electricity suppliers to meet RPS goals is possible; however, it is problematic to predict with accuracy the exact resources and locations that will provide this energy.

This assessment assumes that all renewable energy purchases will be met with renewable resources located in California or near the border with the first point of interconnection to the Western Electricity Coordinating Council (WECC) transmission system located within California. The Energy Commission is well-aware that out-of-state renewable resources are eligible to meet the renewable energy needs of electricity suppliers in California, but assumes in-state development for this assessment to show that the state's renewable resources are sufficiently plentiful to meet the state's RPS-derived renewable energy demand. This assessment also includes a narrative discussion of the possible role of out-of-state (including Mexican and Canadian) renewable generation in helping to meet California's renewable energy development objectives. The use of out-of-state resources may be especially important in the accelerated renewable energy development scenario.

The approach used to create the scenarios consisted of comparing statewide renewable energy demand with empirical data on proposed renewable energy projects in the state and technical potential data for in-state renewable resources. Also considered were the levelized cost of energy economics of different renewable resources over time, and the timeline required to bring certain renewable resource areas into electricity production. More weight is placed on the empirical data collected on proposed renewable energy projects in the state, as these projects represent real development activity, and show the locations and energy resource types that appear most attractive to current renewable energy developers.[114]

For the purpose of the scenarios, geographic areas with the greatest level of proposed projects are assumed to be those most likely to supply RPS demand. Similarly, the mix of technologies used in the scenarios was developed based on the mix of technologies represented in the proposed project data. Previous renewable energy solicitations and interconnection requests were used to develop a renewable energy mix of wind (66 percent), geothermal (25 percent), biomass (8 percent, 4 percent of which is landfill gas/digester gas, and 4 percent of which is solid-waste biomass), and concentrating solar power (CSP) (1 percent).[115] This mix was assumed in both of the scenarios.

Solar photovoltaics (PV) and small hydroelectric facilities are not included in the two scenarios that follow.[116] Though these resources are unlikely to play a significant role in meeting RPS obligations in the time period considered for this study, the important role of distributed, customer-sited renewable energy (especially PV) in meeting California's renewable energy objectives is discussed in the pages that follow.

In converting between energy values (GWh/year) and capacity values (MW), the following capacity factor assumptions have been used: 35 percent for wind, 90 percent for geothermal, 85 percent for landfill gas and digester gas, 80 percent for "other" biomass, which includes solid-waste biomass, municipal solid waste (MSW), and biofuel, and 25 percent for concentrating solar power (CSP).

Comparing Scenarios: Preliminary Renewable Resources Assessment versus Renewable Resources Development Report

The focus of the PRRA was transmission planning for the IOUs and ESP/CCAs. To aid in preparation of the CPUC transmission plan, the PRRA included a scenario for IOUs and ESP/CCAs (see **Figures 14** and **15**). The ***Renewable Resource Development Report*** (RRDR) addresses statewide RPS goals. **Table 13** provides a scenario to meet the statewide RPS goals. **Table 15** provides a scenario to meet the statewide accelerated RPS goals. **Tables 13** and **15** include IOUs, ESP/CCAs and load serving entities in the rest of the state (including publicly-owned electric utilities).

Figure 14. Scenario from PRRA (GWh/year)

Table 4. California RPS Supply Scenario by Physical Location - in GWh/year (Resources Located in California)

Gwh		Additional Supply to meet RPS demand					
		Proposed	**2005**	**2008**	**2017**	**Total**	**Remaining Potential**
Physical location (IOU)/IID	**Additional RPS Demand**		2,540	6,300	12,360	21,200	
	County/Resource						
PG&E	Siskiyou/geothermal	1,480		800	680	1,480	6,280
	Solano/wind	1,230	400	200	630	1,230	380
	Modoc/geothermal	830			830	830	3,130
	Alameda/wind	640		200	440	640	1,930
	Other wind	0				0	8,970
	Other geothermal	0				0	930
	Other biomass	1,925	125	55	345	525	13,380
	Other solar						6,020
(IID)	Imperial/geothermal	1,890	800	580	510	1,890	13,450
	Imperial/biomass	560			560	560	0
	Imperial/wind	0				0	230
	Imperial/solar						14,600
SCE	Kern/wind	11,620	1,000	2,600	5,200	8,960	0[a]
	Mono/geothermal	2,760			1,222	1,222	0[a]
	Riverside/wind	1,085	140	245	700	1,085	3,760
	San Bernardino/wind	160			160	160	740
	San Bernardino/ solar thermal	158			158	158	31,710[b]
	LosAngeles/biomass	550		550		550	2,020
	Los Angeles/wind	310		310		310	160
	Other wind	90			90	90	360
	Other geothermal	0				0	7,440
	Other biomass	210			210	210	4,270
	Other solar						42,760
SDG&E	San Diego/wind	1,225		600	625	1,225	150
	San Diego/biomass	75	75			75	950
	San Diego/solar						2,800
	Total Resources	26,800 [c]	**2,540**	**6,300**	**12,360**	**21,200**	166,420 [d]

[a] Existing and proposed wind energy development in Kern County exceeds the RER estimate of total potential used for this report. Clarification of this contradiction is part of ongoing work to be summarized in the Renewable Resources Development Report before the end of 2003.

[b] Includes photovoltaics.

[c] The total proposed shown here (26,800 GWh/year) excludes 1,452 GWh/year of proposed renewable energy identified as "North of Path 15" or "South of Path 15."

[d] Excludes SMUD remaining potential: 10 GWh wind, 630 GWh geothermal, and 450 GWh solar.

Source: ***Preliminary Renewable Resource Assessment***

Figure 15. Scenario from PRRA (MW)

Table 5. California RPS Supply Scenario by Physical Location – in MW (Resources Located in California)

Physical location (IOU)/IID	County/Resource	Capacity Factor	Proposed	2005	2008	2017	Total	Remaining Potential
PG&E	Siskiyou/geothermal	90%	185		100	85	185	805
	Solano/wind	35%	400	130	65	205	400	125
	Modoc/geothermal	90%	105			105	105	400
	Alameda/wind	35%	210		65	145	210	630
	Other wind	35%						2,925
	Other geothermal	90%						120
	Other biomass	80%	75	20	5	50	75	1,910
	Other solar	15%						4,580
(IID)	Imperial/geothermal	90%	240	100	75	65	240	1,710
	Imperial/biomass	80%	80			80	80	0
	Imperial/wind	35%						75
	Imperial/solar	15%						11,110
SCE	Kern/wind	35%	3,790	325	850	1,755	2,925	0
	Mono/geothermal	90%	350			155	155	0
	Riverside/wind	35%	355	45	80	230	355	1,225
	San Bernardino/wind	35%	50		50	0	50	240
	San Bernardino/solar	15%	120			120	120	24,500
	LosAngeles/biomass	80%	80		80	0	80	290
	Los Angeles/wind	35%	100		100	0	100	50
	Other wind	35%	30			30	30	120
	Other geothermal	90%						945
	Other biomass	80%	30			30	30	610
	Other solar	15%						32,540
SDG&E	San Diego/wind	35%	400		195	205	400	50
	San Diego/biomass	80%	10	10			10	135
	San Diego/solar	15%						2130
	Total Resources		**6,610**	**630**	**1,665**	**3,255**	5,550	**87,225**

Source: ***Preliminary Renewable Resource Assessment***

Prior to developing a statewide scenario for the RPS and a statewide scenario for an accelerated RPS, the available data on proposed renewable energy projects in the state were assessed to incorporate any new information since the issuing of the PRRA. Changes to the PRRA data were reviewed in an earlier section of this report. One of the most significant changes is in the amount shown for proposed wind project development in Riverside County. The net change in proposed projects went from 355 MW to 530 MW. Other minor changes were the result of rounding data to the nearest 5 MW.

Proposed projects in California were sufficient to meet the statewide RPS needs in the PRRA; however, that is not the case with this report. To meet the statewide RPS needs, and the accelerated RPS needs, the scenarios draw from the remaining technical potential of the various resource types.

Another significant change from the PRRA was the inclusion of 270 MW of additional wind resource potential in Kern County, identified in the PRRA workshop. This 270 MW was used in conjunction with the 810 MW of remaining proposed wind projects (from the PRRA) in Kern County to meet the statewide RPS need in the scenarios.

To further cover the gap between RPS-derived renewable energy demand and the aggregate amount of proposed renewable energy projects, the RRDR includes an additional 60 MW of CSP from the amount of the remaining potential, 700 MW of additional wind generation (310 MW in San Bernardino County, and 315 MW in Los Angeles County), some additional biomass generation (45 MW, in PG&E service territory), and 130 MW of geothermal in Imperial County.

Scenario to Meet SB 1078 Goals

The scenarios that follow assume a mix of renewable energy sources and geographic locations that are consistent with empirical data on proposed renewable energy projects in the state. The actual mix of technologies used to meet renewable energy purchase obligations will be determined through bid solicitations. In all cases, these solicitations will likely select resources not solely based on the cost of electricity as delivered to the busbar, but also based on indirect costs and the attributes of the specific projects in question. For IOUs and ESPs/CCAs, these solicitations will be undertaken in accordance with the rules established by the CPUC and Energy Commission. Because these rules have not yet been fully formulated, and the implementation of the rules may change over time, the scenarios that follow should be viewed as merely one set of possible futures.

The first scenario assumes that the RPS obligations of IOUs and ESP/CCAs are achieved on the defined SB 1078 schedule: 20 percent by 2017 in 1 percent or greater annual increments. Publicly-owned utilities are assumed to also meet these objectives, on a similar schedule.

With these assumptions, 2005 statewide cumulative renewable energy demand beyond the resources identified as baseline generation or included in the 2003 Interim Procurement is estimated to be 4,230 GWh/year.[117] In 2008, an additional 8,890 GWh/year beyond the amount required in 2005 must be added,[118] for a cumulative total of 13,120 GWh/year.[119] By 2017, 17,490 GWh/year must be added to the cumulative number for 2008,[120] to reach a total additional procurement of 30,610 GWh/year.[121]

Table 13 identifies a scenario for meeting this renewable energy demand with renewable energy projects located in California. Geographic locations and resource types are consistent with the proposed project database discussed earlier. Because of assumed differences in resource timing, the technology mix for *each* of the years highlighted in the table varies somewhat from that presented in the PRRA.

All proposed projects are used to meet statewide aggregate renewable energy demand in this scenario.[122] Because the aggregate incremental demand for renewable energy (30,610 GWh by 2017) exceeds the amount of renewable generation in the proposed project database (26,390 GWh), staff assumes that additional projects (that are not in the proposed project database) will be identified and developed to fill the shortfall. These additional projects are assumed to come on line by 2017 and to have a somewhat similar resource type breakdown as those in the proposed project database. The projects are assumed to be located in areas with the most remaining renewable resource potential.[123]

The Kern County wind resource area, if developed in a concerted manner, could satisfy much, if not all, of the cumulative renewable energy demand through 2008. Based on the transmission proceeding dealing with Tehachapi transmission investments and the proposed SCE Long-Term Resource Plan, SCE may be willing to make these transmission investments.[124] Moreover, earlier analysis showed that wind power is likely to be relatively cost effective on a $/MWh basis at the busbar. This scenario, therefore, identifies the Kern County wind resource area as a major contributor to renewable energy supply and presumes that additional Kern County wind begins to be developed by 2005 with a deeper penetration by 2008 and 2017. This scenario also includes wind projects proposed in other resource areas: Riverside, Solano, and San Diego, and to a lesser extent Alameda, Los Angeles, and San Bernardino. Additional wind projects in Los Angeles and San Bernardino Counties not in the proposed project database are assumed to come on-line by 2017, given the sizable remaining resource potential in both of these locations.

At the same time, given least-cost-best-fit considerations, it is anticipated that electricity suppliers will seek some geographic and resource diversity in their procurement plans. In particular, geothermal and biomass resources can provide base load power that matches the generation profile of some conventional resources, and may therefore be viewed favorably relative to wind, even if the electricity is delivered at a somewhat higher busbar cost.

For these reasons, the scenarios presented in the following tables include significant amounts of geothermal energy as part of the renewable energy supply. The scenario presumes that Southern California geothermal resources make it to market more quickly than Northern California geothermal resources, given permitting difficulties. Northern California resources located in Mono, Imperial, Siskiyou, and Modoc counties are assumed to be on-line by 2008.

Landfill gas, anaerobic digester gas (ADG), and solid fuel biomass are also likely to play a role in renewable energy supply, but at a smaller scale and located closer to load than other renewable resources. Proposed landfill gas and ADG projects are assumed to come on-line more rapidly than proposed solid biomass-direct combustion projects because of more attractive economics and lower risk.

The CSP resource is likely to have characteristics that make it relatively more valuable than other renewable resource options; however, the higher cost of this generation source, relative to wind, geothermal, and biomass, may constrain its development. (An earlier section of this report shows that the cost of electricity generation from CSP may decrease rapidly over the coming years, however.) As such, this scenario assumes some development of CSP in the 2008-2017 time period.

The scenarios shown in **Table 13** and **Table 15** were based on a review of publicly available proposals at the time. Subsequently, SCE completed a conceptual study of the staged development of 1,000 MW of CSP at Harper Lake in San Bernardino County. It is likely that this project will be submitted as part of near-term competitive bid solicitation for RPS evaluated according to least-cost-best-fit criteria. Costs and benefits to the transmission system, local and system reliability, low income and minority communities, environmental stewardship, and resource diversity will also be considered in selecting winning bids. Depending on the result of the solicitations, CSP may play a greater role in meeting California's RPS and the ***Energy Action Plan*** goals than suggested by the scenarios included here.

Table 13 shows a scenario for the physical location of additional renewable energy facilities utilized to meet California's renewable energy demands in 2005, 2008, and 2017. The aggregate additional renewable energy demand is listed at the top of the table with proposed projects allocated across technologies, geographic locations, and years. The total additional supply for each year shown at the bottom of the table matches the estimated RPS demand at the top of the table. Projects assumed to come on line through 2017 are sorted by the utility service territory in which they would be located.

Table 14 converts the information in **Table 13** from electricity to capacity (MW) using the following assumed capacity factors: 35 percent for wind, 90 percent for geothermal, 85 percent for landfill gas/ADG, 80 percent for other biomass, and 25 percent for CSP.

Table 13. Renewable Energy Supply Scenario to meet Estimated Statewide RPS Demand with Resources Located in California (GWh/year)[125]

Physical location	Additional RPS Demand	Additional Supply to Meet Estimated Statewide RPS Renewable Energy Demand: Proposed Projects	2005	2008	2017
	Additional RPS Demand		4,230	8,890	17,490
	County/Resource				
PG&E and smaller utilities in northern California*					
	Siskiyou/geothermal	1,480	-	780	700
	Solano/wind	1,230	660	310	260
	Modoc/geothermal	830	-	-	830
	Alameda/wind	645	150	340	155
	Other/wind	-	-	-	-
	Other/geothermal	-	-	-	-
	Other/solid biomass	230	-	175	380
	Other/landfill-digester gas	310	150	160	-
	Other/CSP	-	-	-	-
	Subtotal	**4,725**	**960**	**1,765**	**2,325**
SCE and smaller utilities in southern California*					
	Imperial/geothermal	1,890	945	475	1,500
	Imperial/solid biomass	560	-	-	560
	Imperial/ landfill-digester gas	-	-	-	-
	Imperial/wind	-	-	-	-
	Imperial/CSP	-	-	-	-
	Kern/wind	11,620	875	4,320	7,250
	Mono/geothermal	2,760	-	395	2,365
	Riverside/wind	1,620	615	580	425
	San Bernardino/wind	280	150	120	950
	San Bernardino/ CSP	265	-	-	395
	Los Angeles/solid biomass	350	-	350	-
	Los Angeles/ landfill-digester gas	210	110	100	-
	Los Angeles/wind	305	310	-	965
	Other/wind	90	-	-	90
	Other/geothermal	-	-	-	-
	Other/solid biomass	10	-	10	-
	Other/landfill-digester gas	270	110	110	50
	Other/CSP	-	-	-	-
	Subtotal	**20,230**	**3,115**	**6,460**	**14,550**
SDG&E and Escondido utilities*					
	San Diego/wind	1,225	-	610	615
	San Diego/solid biomass	-	-	-	-
	San Diego/ landfill-digester gas	210	155	55	-
	San Diego/CSP	-	-	-	-
	Subtotal	**1,435**	**155**	**665**	**615**
	Total Resources	**26,390**	**4,230**	**8,890**	**17,490**

*This table is meant to provide a scenario of renewable energy development to meet the RPS. The mix of technologies shown in the table is based on the mix of proposals submitted in recent solicitations. The actual mix of technologies used to meet renewable energy purchase obligations will be determined through bid solicitations held by IOUs, ESP/CCAs, and publicly-owned electric utilities. Source: ***Renewable Resources Development Report***.

Table 14. Renewable Energy Supply Scenario to meet Estimated Statewide RPS Demand with Resources Located in California (MW)

Physical location	County/Resource	Capacity Factor	Proposed	2005	2008	2017	Total
PG&E and smaller utilities in northern California*							
	Siskiyou/geothermal	90%	190	-	100	90	190
	Solano/wind	35%	400	215	100	85	400
	Modoc/geothermal	90%	105	-	-	105	105
	Alameda/wind	35%	210	50	110	50	210
	Other/wind	35%	-	-	-	-	-
	Other/geothermal	90%	-	-	-	-	-
	Other/solid biomass	80%	35	-	25	55	80
	Other/ landfill-digester gas	85%	40	20	20	-	40
	Other/CSP	25%	-	-	-	-	-
	Subtotal		980	285	355	385	1,025
SCE and smaller utilities in southern California*							
	Imperial/geothermal	90%	240	120	60	190	370
	Imperial/solid biomass	80%	80	-	-	80	80
	Imperial/ landfill-digester gas	85%	-	-	-	-	-
	Imperial/wind	35%	-	-	-	-	-
	Imperial/ CSP	25%	-	-	-	-	-
	Kern/wind	35%	3,790	285	1,410	2,365	4,060
	Mono/geothermal	90%	350	-	50	300	350
	Riverside/wind	35%	530	200	190	140	530
	San Bernardino/wind	35%	90	50	40	310	400
	San Bernardino/ CSP	25%	120	-	-	180	180
	Los Angeles/solid biomass	80%	50	-	50	-	50
	Los Angeles/ landfill-digester gas	85%	30	15	15	-	30
	Los Angeles/wind	35%	100	100	-	315	415
	Other/wind	35%	30	-	-	30	30
	Other/geothermal	90%	-	-	-	-	-
	Other/solid biomass	80%	2	-	2	-	2
	Other/LFG-digester	85%	35	15	15	5	35
	Other/ CSP	25%	-	-	-	-	-
	Subtotal		5,447	785	1,832	3,915	6,532
SDG&E and Escondido utilities*							
	San Diego/wind	35%	400	-	200	200	400
	San Diego/solid biomass	80%	-	-	-	-	-
	San Diego/LFG-digester	85%	30	20	10	-	30
	San Diego/ CSP	25%	-	-	-	-	-
	Subtotal		**430**	**20**	**210**	**200**	**430**
	Total Resources		**6,857**	**1,090**	**2,397**	**4,500**	**7,987**

* This table is meant to provide a scenario of renewable energy development to meet the RPS. The mix of technologies shown in the table is based on the mix of proposals submitted in recent solicitations. The actual mix of technologies used to meet renewable energy purchase obligations will be determined through bid solicitations held by IOUs, ESP/CCAs, and publicly-owned electric utilities.
Source: ***Renewable Resources Development Report***

Scenario to Meet Accelerated SB 1078 Goals

The second scenario assumes that the RPS obligations of IOUs and ESP/CCAs are achieved on an accelerated schedule, consistent with the ***Energy Action Plan***: 20 percent by 2010, then remaining constant at 20 percent until 2017. Publicly-owned electric utilities are also assumed to meet these accelerated objectives.

Statewide cumulative renewable energy demand for 2005, beyond the resources identified as baseline generation or included in the 2003 Interim Procurement, is estimated to be 6,120 GWh/year.[126] In 2008, an additional 11,730 GWh/year beyond the amount required in 2005 must be added,[127] for a cumulative total of 17,850 GWh/year.[128] By 2010, an additional 6,950 GWh/year beyond the amount required in 2008 must be added,[129] for a cumulative total of 24,800 GWh/year.[130] Growth in renewable energy demand after 2010 is more modest, increasing only with overall electric sales growth. Nonetheless, by 2017, 5,810 GWh/year must be added to the cumulative number for 2010,[131] to reach a total additional procurement of 30,610 GWh/year (the same as in the first scenario).[132]

Table 15 identifies a scenario for meeting this renewable energy demand largely with renewable energy projects located in California that have been proposed for construction or repowering. Geographic locations and resource types are again consistent with the proposed project database. All proposed projects are used to meet aggregate renewable energy demand in this scenario. Because the aggregate incremental demand for renewable energy again exceeds the amount of renewable generation in the proposed project database, we assume that additional projects are built to fill the shortfall. These projects are the same as those assumed in the previous scenario. This scenario will require an aggressive development schedule for in-state renewable energy resources. Though not considered here, it is likely that an accelerated RPS scenario may lead to significant additions of renewable energy located outside of the state but delivered into the state.

Transmission upgrades to the Kern County wind resource area and the Solano Wind area are assumed to occur on an accelerated schedule, allowing these resource areas to be developed more quickly. PG&E has indicated that advancing the need for transmission upgrades on an "accelerated basis (from 2008 to 2005) could pose significant challenges to upgrading the transmission system to support the generation."[133] Geothermal resources are also added at a more rapid pace, though not as quickly as wind, given assumed development and permitting time. Biomass resources are added rapidly, with landfill gas and ADG development accelerated more quickly than solid-fuel biomass. CSP is assumed to break into the market by 2010.

Table 15 shows a scenario for the physical location of additional renewable energy facilities utilized to meet California's accelerated statewide RPS demand in 2005, 2008, 2010, and 2017. **Table 16** converts the information in **Table 15** to capacity (MW) using the same capacity factors that were used earlier.

Table 15. Accelerated RPS Supply Scenario in GWh/year (in-state resources)[134]

Physical location		Proposed Projects	2005	2008	2010	2017
		Additional Supply to Meet Estimated Statewide Accelerated RPS Renewable Energy Demand				
	Additional Accelerated RPS Demand		6,120	11,730	6,950	5,810
	County/Resource					
PG&E and smaller utilities in northern California*						
	Siskiyou/geothermal	1,480	-	780	235	465
	Solano/wind	1,230	965	265	-	-
	Modoc/geothermal	830	-	120	120	590
	Alameda/wind	645	155	415	15	60
	Other/wind	-	-	-	-	-
	Other/geothermal	-	-	-	-	-
	Other/solid biomass	230	175	70	-	310
	Other/landfill-digester gas	310	225	85	-	-
	Other/ CSP	-	-	-	-	-
	Subtotal	**4,725**	**1,520**	**1,735**	**370**	**1,425**
SCE and smaller utilities in southern California*						
	Imperial/geothermal	1,890	945	710	945	315
	Imperial/solid biomass	560	-	350	210	-
	Imperial/landfill-digester gas	-	-	-	-	-
	Imperial/wind	-	-	-	-	-
	Imperial/ CSP	-	-	-	-	-
	Kern/wind	11,620	1,210	5,855	4,370	1,010
	Mono/geothermal	2,760	-	790	790	1,180
	Riverside/wind	1,620	765	855	-	-
	San Bernardino/wind	280	150	185	-	890
	San Bernardino/ CSP	265	-	-	265	130
	Los Angeles/solid biomass	350	-	350	-	-
	Los Angeles/landfill-digester gas	210	180	30	-	-
	Los Angeles/wind	305	305	110	-	860
	Other/wind	90	90	-	-	-
	Other/geothermal	-	-	-	-	-
	Other/solid biomass	10	-	10	-	-
	Other/landfill-digester gas	270	185	85	-	-
	Other/ CSP	-	-	-	-	-
	Subtotal	**20,230**	**3,830**	**9,330**	**6,580**	**4,385**
SDG&E and Escondido utilities*						
	San Diego/wind	1,225	610	615	-	-
	San Diego/solid biomass	-	-	-	-	-
	San Diego/landfill-digester gas	210	160	50	-	-
	San Diego/ CSP	-	-	-	-	-
	Subtotal	**1,435**	**770**	**665**	**-**	**-**
	Total Resources	**26,390**	**6,120**	**11,730**	**6,950**	**5,810**

*This table provides a scenario of renewable energy development to meet the RPS. The mix of technologies shown in the table is based on the mix of proposals submitted in recent solicitations. The actual mix of technologies used to meet renewable energy purchase obligations will be determined through bid solicitations held by IOUs, ESP/CCAs, and publicly-owned electric utilities. Source: ***Renewable Resources Development Report***.

Table 16. Renewable Energy Supply Scenario to meet Estimated Statewide Accelerated RPS Demand with Resources in California (MW)

Physical location	County/Resource	Capacity Factor	Proposed	2005	2008	2010	2017	Total
PG&E and smaller utilities in northern California*								
	Siskiyou/geothermal	90%	190	-	100	30	60	190
	Solano/wind	35%	400	315	85	-	-	400
	Modoc/geothermal	90%	105	-	15	15	75	105
	Alameda/wind	35%	210	50	135	5	20	210
	Other/wind	35%	-	-	-	-	-	-
	Other/geothermal	90%	-	-	-	-	-	-
	Other/solid biomass	80%	35	25	10	-	45	80
	Other/Landfill-digester gas	85%	40	30	10	-	-	40
	Other/ CSP	25%	-	-	-	-	-	-
	Subtotal		**980**	**420**	**355**	**50**	**200**	**1,025**
SCE and smaller utilities in southern California*								
	Imperial/geothermal	90%	240	120	90	120	40	370
	Imperial/solid biomass	80%	80	-	50	30	-	80
	Imperial/landfill-digester gas	85%	-	-	-	-	-	-
	Imperial/wind	35%	-	-	-	-	-	-
	Imperial/ CSP	25%	-	-	-	-	-	-
	Kern/wind	35%	3,790	395	1,910	1,425	330	4,060
	Mono/geothermal	90%	350	-	100	100	150	350
	Riverside/wind	35%	530	250	280	-	-	530
	San Bernardino/wind	35%	90	50	60	-	290	400
	San Bernardino/ CSP	25%	120	-	-	120	60	180
	Los Angeles/solid biomass	80%	50	-	50	-	-	50
	Los Angeles/landfill-digester gas	85%	30	25	5	-	-	30
	Los Angeles/wind	35%	100	100	35	-	280	415
	Other/wind	35%	30	30	-	-	-	30
	Other/geothermal	90%	-	-	-	-	-	-
	Other/solid biomass	80%	2	-	2	-	-	2
	Other/landfill-digester gas	85%	35	25	10	-	-	35
	Other/ CSP	25%	-	-	-	-	-	-
	Subtotal		**5,447**	**995**	**2,592**	**1,795**	**1,150**	**6,532**
SDG&E and Escondido utilities*								
	San Diego/wind	35%	400	200	200	-	-	400
	San Diego/solid biomass	80%	-	-	-	-	-	-
	San Diego/landfill-digester gas	85%	30	20	10	-	-	30
	San Diego/ CSP	25%	-	-	-	-	-	-
	Subtotal		**430**	**220**	**210**	**-**	**-**	**430**
	Total Resources		**6,857**	**1,635**	**3,157**	**1,845**	**1,350**	**7,987**

* This table provides a scenario of renewable energy development to meet the RPS. The mix of technologies shown in the table is based on the mix of proposals submitted in recent solicitations. The actual mix of technologies used to meet renewable energy purchase obligations will be determined through bid solicitations held by IOUs, ESP/CCAs, and publicly-owned electric utilities.
Source: ***Renewable Resources Development Report***.

The Role of Non-California WECC Renewable Generation

The two scenarios presented in this report assume that only renewable resources located within California (or with a first point of interconnection in California) are utilized to meet the state's renewable energy requirements. The report establishes that adequate renewable resources exist in California to meet expected renewable energy demand at a reasonable cost, even in the accelerated RPS scenario of 20 percent renewable energy by 2010.

Many questions remain regarding what role non-California WECC resources might play in fulfilling California's renewable energy demands. In the report entitled ***Renewables Portfolio Standard: Decision on Phase I Implementation Issues***, the Energy Commission ruled that resources located within the WECC would be eligible under the state's RPS as long as such a project is "developed with guaranteed contracts to sell its power to end-users subject to the funding requirements of Public Utilities Code (PUC) section 381 (i.e., end use customers of California IOUs)." Not addressed in that ruling or subsequent rulings to date is the precise standards for the "delivery" of such power to California or the eligibility of out-of-state renewable generation for supplemental energy payments (SEPs). These issues are to be determined in a later phase of the proceeding.

How these eligibility issues play out has important implications for the way in which California's renewable energy demands might be met, because the non-California WECC renewable resource potential is vast and these resources could potentially displace some development of higher-priced California-based resources. As shown earlier in this report, the total technical potential for renewable energy in the non-California WECC states is more than fourteen times greater than renewable technical potential in California. In addition to these vast resources in the U.S. West, there is also significant renewable potential in the non-California WECC parts of Canada and Mexico, though this is not addressed in this report.

The demand for these renewable resources in other states (and Canada and Mexico) is quite small compared to the potential renewable supply. Currently Nevada, Arizona, and New Mexico have their own state-level RPS policies. The estimates for the combined demand for new renewable energy under these state policies is unlikely to exceed 1,420 GWh/year in 2005, rising to 3,220 GWh/year by 2008 and 6,990 GWh/year by 2017. Provided their policies remain unchanged, by 2017, non-California RPS driven demand will capture less than 2 percent of the remaining technical potential in the three states with RPS programs. Non-RPS related demand for renewable energy in non-California WECC states includes integrated resource planning processes, green power marketing programs, and the economics of wind power. Also, in the last few years, state legislatures in Utah, Washington, and Colorado have considered implementing state-level RPS policies, though they have not yet done so. The vast renewable energy potential in the West greatly exceeds any growth in demand for renewable resources.

Non-California WECC renewable resource potential is not only significant, but may also be available at a reasonable cost, making it attractive to California renewable purchasers. Publicly disclosed pricing information for projects bid into regional wind power solicitations in the last few years has shown wind bids of under 4.0 cents/kWh, and on occasion, below 3.0 cents/kWh, on a real (i.e., constant dollar value) levelized basis. For geothermal, recent costs are 4.2-5.2 cents/kWh, with 1 percent annual escalation over 20 years.[135] A new generation of even more efficient wind turbines has been released and costs have continued to be pushed down in the two years since disclosure of bid information.

The degree that non-California WECC projects contribute to California's renewable energy needs depends primarily on three issues: (1) SEP eligibility, (2) transmission availability, and (3) deliverability rules.

- **SEP Eligibility:** If non-California WECC renewable projects are eligible for California SEPs, these projects could be priced more competitively and be in position to win a larger share of renewable solicitations in California. While the Energy Commission has ruled that non-California WECC renewable generation will be eligible for the state's RPS, and has the authority (under SB 1038) to offer SEPs to such projects, the Energy Commission has not yet ruled whether such projects will receive SEPs. The final decisions on SEP eligibility may play a role in defining the degree to which out-of-state resources participate in California's RPS. Nonetheless, out-of-state renewable energy projects may be able to contract at prices below the market price referents, as determined by the CPUC, and therefore may not require SEPs to compete successfully in the California RPS.

- **Transmission Availability:** Transmission availability will also have an impact on whether out-of state resources meet California's renewable energy demands. Much of the technical renewable potential in the WECC is located far from population centers and existing transmission lines. Integrating more remote resources into the existing transmission system may require costly investment in new transmission infrastructure.

  Even if renewable energy can be cost-effectively interconnected into the existing grid, the question remains whether the existing transmission system has the capability to transmit the power from the facility to loads in California. Wheeling power into California may be costly and difficult, limited by physical transmission constraints and additive transmission access charges.

- **Rules for Power Delivery:** Related to transmission access are the rules established to ensure that non-California WECC resources are "delivered" to California. The detailed design of these rules will play a significant role in defining the cost of delivery to the state, and therefore the extent to which out-of-state resources participate in California's RPS. SB 1038, and the Energy Commission's Phase I ruling, indicate that such projects must be "developed with guaranteed contracts to sell power to end-users subject to the funding requirements of PUC section 381 (i.e., end use customers of California IOUs)." Flexible rules on deliverability might enable market participants to structure delivery of non-California WECC renewable energy into California despite constrained transmission access. For example, if Renewable Energy Certificates can be unbundled and sold to California purchasers separately from commodity electricity, then transmission constraints are unlikely to be a major barrier. If, on the other hand, out-of-state renewable projects must schedule on a minute-to-minute basis into the CA ISO market (securing transmission from source to end user), then existing transmission constraints may act as a barrier to non-California WECC renewable energy.

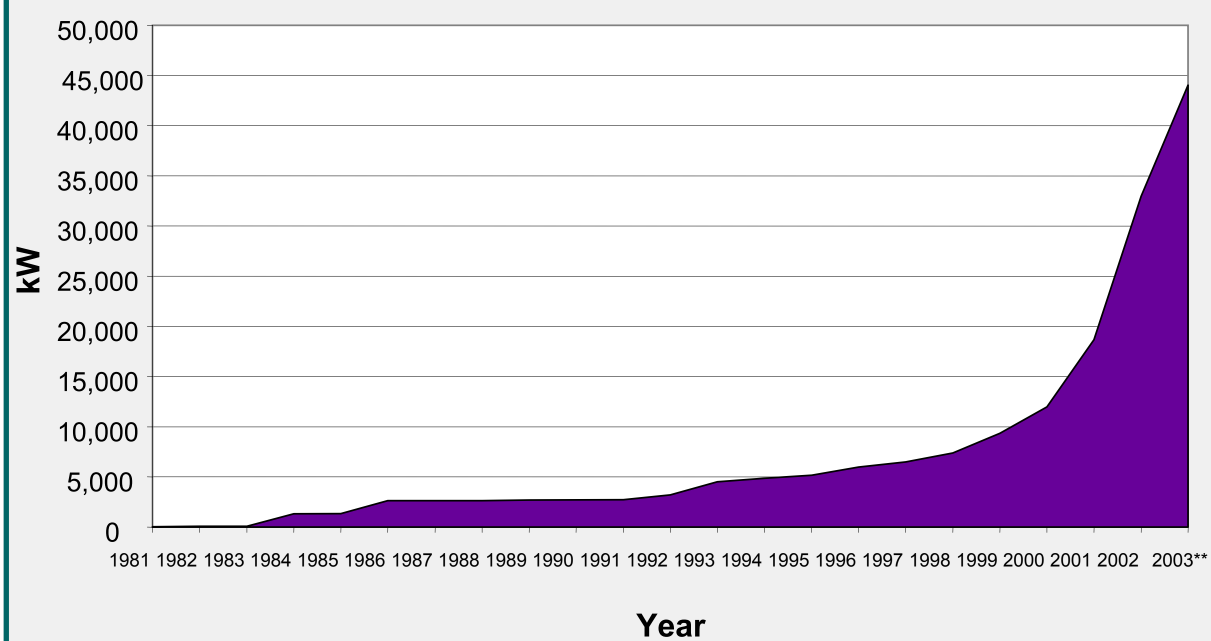
The Role of Distributed, Customer-Sited Renewable Generation

Distributed, customer-sited renewable energy projects are not likely to play a significant role in meeting aggregate RPS obligations in the near term. In spite of this, customer-sited, grid-connected PV applications and customer-sited wind and biomass applications have undergone significant growth.

Distributed renewable energy generation reduces the demand for electricity from central station resources in the state. This will reduce the retail sales of electricity in California and require less central-station renewable energy to achieve the RPS.

Solar PV energy has witnessed explosive growth in recent years. Through mid-2003 44 MW of grid-connected PV has been installed in California. Over 75 percent of this capacity has been added since the beginning of 2000, with over 14 MW installed in 2002 and 11 MW through mid-2003, making California the third largest market for PV energy internationally, after Japan and Germany. **Figure 16** shows the rapid growth in cumulative in-state PV capacity in recent years. Customer-sited small wind installations and biomass sources have seen more modest growth in aggregate capacity terms, but have also seen substantial incremental sales compared to historic growth rates.

Figure 16. Grid-Connected Photovoltaic Capacity Installed in California Cumulative



Source: California Energy Commission, “Amount (MW) of Grid-Connected Solar Photovoltaics (PV) in California,1981 to Present,” July 2003

The majority of PV installations prior to 1998 can be attributed to the Sacramento Municipal Utility District, which has installed over 11 MW of PV through mid-2003. Since 1998, the Energy Commission’s Emerging Renewables Program has offered incentives to grid-connected, customer-sited renewable energy installations (including PV) located in the service territories of the state’s IOUs. From 1998 through mid 2003, this program has provided support for the installation of nearly 20 MW of PV capacity. The CPUC Self-Generation Incentive program also offers rebates for larger customer-sited renewable energy installations (over 30 kW), and has provided support for the installation of more than 4 MW of PV through mid-2003. The Los Angeles Department of Water and Power (nearly 6 MW) and other municipal utilities (about 1 MW) have similarly developed customer rebate programs in their service territories.

Financial incentives, federal and state tax credits, accelerated depreciation, and volatile and high electricity rates have contributed to the growth of the PV market in California. The PV industry’s capacity to meet this market growth has also been strengthened. Rebates will decline over time, and in the longer term, will be eliminated, as the cost of PV and other distributed renewable energy options decline to a point where markets are able to sustain themselves.

Decisions of whether and how customer-sited renewable energy generation will be able to participate in the state's RPS will be made jointly by the CPUC and Energy Commission in a latter phase of the RPS proceedings. In all cases, development of customer-sited renewable installations will reduce the remaining load on which RPS obligations apply.

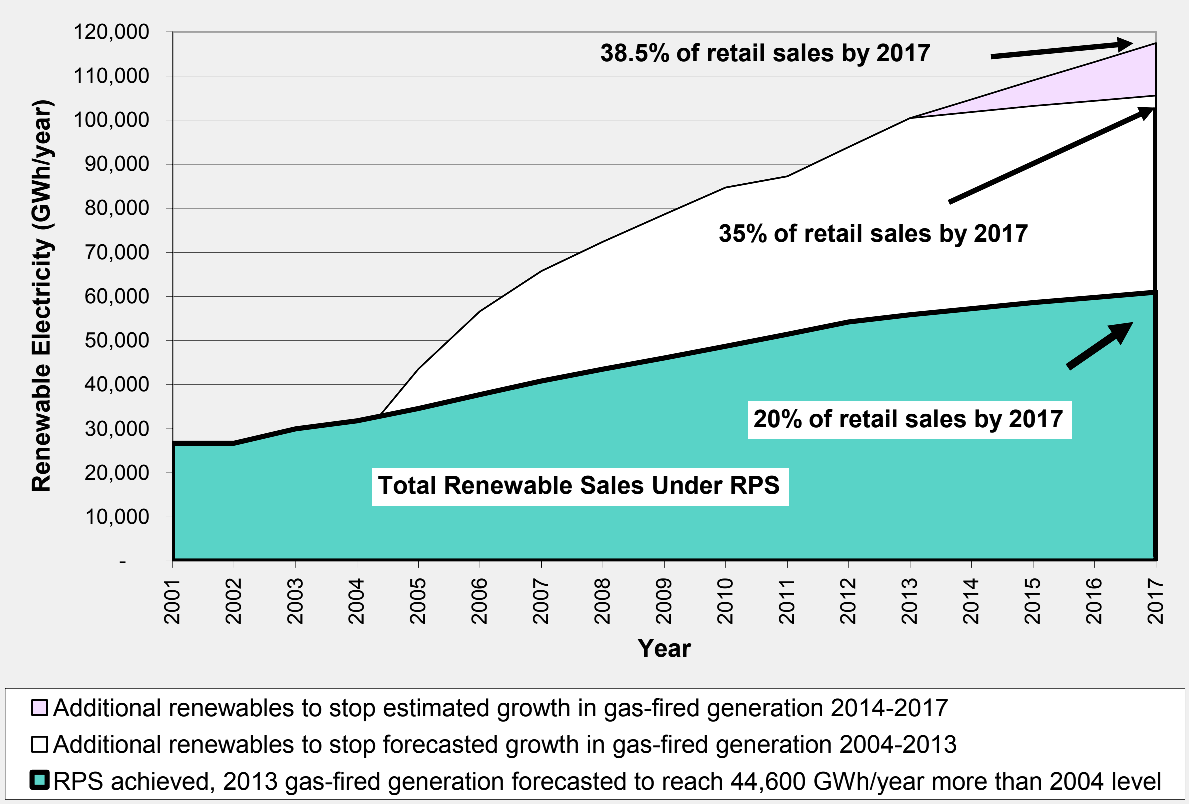
MEETING GROWTH IN ELECTRICITY DEMAND WITH RENEWABLE ENERGY

The baseline electricity growth scenario described in the ***Electricity Infrastructure Assessment*** includes RPS achievement by 2017 and assumes that current funding levels for energy efficiency and demand side management measures continue. Results from the scenario show an increase in gas-fired generation in California from about 90,700 GWh in 2004 to about 135,300 GWh in 2013, a growth of about 44,600 GWh.[136] This amount is equivalent to about 16 percent of estimated retail sales for California in 2013 (286,100 GWh). Data collected for this report indicate that there is enough technical potential in California, Washington, and adjacent WECC states to meet this need with renewable energy. If electric generation from renewable energy resources could be used to replace the estimated growth in gas-fired generation from 2004-2017, the total amount of renewable energy by 2017 would reach about 38 percent (See **Figure 17**). This would position renewable energy as the largest source of electricity generation in California.

On July 3, 2003, CPUC Commissioner Susan P. Kennedy provided direction and scope for further rulemaking regarding energy efficiency (R.01-08-028), including a proposal that California meet 100 percent of demand growth with energy efficiency, demand response, and renewable resources. **Figure 17** shows an upper bound on the potential role of renewable energy should this proposal be implemented.

While there are sufficient potential renewable resources to furnish such a large fraction of the annual kilowatt-hours used by California consumers, other essential features of the electricity system need to be taken into account. Electricity must be available when and where it is wanted. These load-following and local delivery characteristics require that the system have electricity when it needs it, while minimizing over generation. It also requires that an integrated transmission system be able to get supply to load. Of course, the design and operation of an electric generating system must incorporate multiple considerations, including the various needs for base load versus peaking power, local voltage support, spinning reserve, and the load-following flexibility that natural gas fueled electric generation facilities traditionally provide. Before advocating an aggressive goal of 38 percent renewable energy, the state's oversight agencies and renewable industry must evaluate the cost, reliability, and operational implications of developing such a system.

Figure 17. Hypothetical Replacement of Forecasted Growth in Gas-fired Generation with Renewable Energy (2004-2017)



Source: ***Public Interest Energy Strategies Report***, October 2003

CHAPTER 7: BENEFITS AND CHALLENGES OF RENEWABLE RESOURCE DEVELOPMENT

Renewable energy resources have the potential to contribute to employment, energy diversity and security, public health, and environmental quality, including efforts to address climate change. The efforts to lay the groundwork for distributed generation also raise important benefits and challenges for California's electricity system.

The benefits and challenges to California's electricity system vary by resource type, because renewable energy resources provide different products. The general characteristics (e.g., dispatchability, intermittency) and timing (e.g., base load, peaking) differ from resource to resource. Furthermore, specific projects may incorporate designs (e.g., innovative wind turbine design, energy storage) that cause products to differ within renewable resource types.

EMPLOYMENT

Increasing California's reliance on renewable energy resources can create employment opportunities in California, other Western Electricity Coordinating Council (WECC) states, and overseas. An overview of the scale, location, and type of employment opportunities that are likely to result from California's Renewables Portfolio Standard (RPS) is described below.

Provided the barriers and issues to achieving the RPS are addressed, the RPS is expected to stimulate an increase in economic activity in California's renewable industry. While an estimate of the net effect of this increase is not attempted here, the following data provide some indication of job growth associated with the RPS.

In a 2001 report entitled ***California Renewable Technology Market and Benefits Assessment***, the Electric Power Research Institute estimated the employment rates in terms of jobs/megawatt (MW) for the construction and operation and maintenance jobs for a range of renewable energy resource types. For construction-related jobs, the estimates were as follows: wind was 2.57 jobs/MW, geothermal was 4.00 jobs/MW, solar photovoltaic (PV) energy was 7.14 jobs/MW, and biomass was 3.71 jobs/MW. For operation and maintenance, the estimates were as follows: wind 0.29 jobs/MW, geothermal 1.67 jobs/MW, solar PV 0.12 jobs/MW, and biomass 2.28 jobs/MW. Assuming these employment rates decrease over time due to gains in expertise and efficiency, ***Renewable Energy and Jobs: Employment Impacts of Developing Markets for Renewables in California*** from Environment California Research and Policy Center (Environment California), which is affiliated with

California Public Interest Research Group (CalPIRG), estimated in-state construction person-years to be about 4,800 and in-state operation and maintenance person-years to be about 118,000 over the life of the plants built to meet the RPS. In addition, Environment California estimated that the RPS would lead to about 78,000 person-years of employment for manufacturing/construction of renewable energy facilities and components overseas.[137]

Employment opportunities in California related to renewable energy require a range of scientific, technical, and marketing expertise. The following provides an overview of the job opportunities related to renewable energy development in California:

- Analysis of available wind, geothermal, biomass, solar, ocean wave, and small hydroelectric resources;
- Design of utility scale and distributed generation renewable energy facilities;
- Development, marketing, financing, permitting, environmental assessment, and siting of facilities;
- Construction and installation of renewable energy electric generation facilities; and
- Operation and maintenance.

California's RPS is designed to encourage a steady stream of renewable development. New construction would occur at a faster rate with the accelerated RPS, especially for renewable resources intended to meet San Diego Gas & Electric's (SDG&E) RPS requirements. Following the construction phase, employment opportunities are likely to shift to operation and maintenance, along with some continued development and repowering of renewable resources.

The physical location of the plants will be decided through the RPS procurement solicitations. The scenarios for renewable resource development included earlier (see **Tables 13** and **15**) are based on resources located in California, but resources used to meet the RPS may be located out of state. Within California, many of the possible opportunities for plant construction and operation and maintenance employment are likely to be located in relatively rural areas. Biomass projects linked to forest thinning efforts are likely to create jobs in rural communities in the northern portion of the state. Such jobs are likely to be located in communities that were built around the lumber industry, but may now be facing difficult economic conditions. Geothermal projects are likely to be located in a number of northern counties and arid inland counties. Solar projects are likely to be located in the southeastern arid portions of the state. Kern County holds the largest potential for wind resource development, although four other southern California counties (Los Angeles, Riverside, San Bernardino, and Santa Barbara) also show technical potential greater than 1,000 MW each. Many of the out-of-state project proposals submitted in response to recent publicly available bid solicitations are located in Washington, Oregon, and Nevada.

Opportunities for employment in business development, marketing, and financing related to renewable energy are likely to be located in urban centers near customers, clients, and regulatory agencies.

FUEL DIVERSITY

Increasing California's reliance on renewable energy resources can contribute to energy diversity and economic security by reducing reliance on natural gas. The Energy Commission staff utilized a market simulation model (MarketSym TM) to evaluate the uncertainties that may affect natural gas and coal demand and stress the WECC electricity and natural gas infrastructure. To evaluate the impact of renewable energy in isolation from other changes in the WECC electricity system (including areas of Canada and Mexico), an accelerated RPS scenario, RPS by 2017 scenario, and a pre-RPS trends scenario for investor-owned utilities (IOUs) were simulated holding the load adjustments attributed to energy efficiency and other demand-side management efforts constant. These scenarios were simulated in addition to the scenarios summarized in the "Electricity Infrastructure Assessment," which is part of the ***Electricity and Natural Gas Assessment Report***. This analysis compared only energy outputs; it did not examine the system benefits and costs of varying quantities and/or types of resources. The results from these scenarios are suggestive only.[138]

The renewable energy simulations suggest that meeting the RPS for the IOUs may displace 2.5 percent of annual demand for natural gas in electricity generation that would otherwise occur in the WECC in 2013 and each year thereafter. Accelerating the RPS to 20 percent of retail sales by 2010 (as modeled) practically doubles this effect, raising it to a reduction of about 4.5 percent (**Table 17**).

Table 17. Simulation Results for Reduction in Annual Natural Gas use (GBtu)* in WECC's Electricity Sector due to a scenario of IOU procurement to meet the RPS and Acceleration of RPS

	Pre-RPS trend	RPS (as modeled)	Accelerated RPS (as modeled)
GBtu use in 2013	21,257,324	20,728,818	20,281,466
% reduction from Pre-RPS trend		2.55%	4.59%
% reduction from RPS			2.16%

*GBtu = Giga (Billion) British Thermal Units. Source: California Energy Commission, Systems Analysis Office

As noted in the "Electricity Infrastructure Assessment," natural gas prices have fluctuated widely over the past 3 years. Natural gas-fired generators sometimes use financial hedges to limit price risk at some cost. Many renewable energy resources have zero or small fuel costs, in comparison to most conventional generation resources. Renewable energy resources are able to sign fixed-price contracts that do not vary based on the price of natural gas. An increasing proportion of these fixed-price contracts, as envisioned through the RPS, should require less financial hedging to mitigate price risk. The degree to which this occurs depends on the specific contract arrangements established through the RPS. Reducing the system exposure to price risk through fixed price renewable contracts may cost more or less than addressing the same risk with financial hedging of natural gas prices, depending on the costs and other benefits of these contracts.

Ratepayer prices for renewable energy will be affected by the expectations for natural gas at the time of procurement, since pricing for RPS energy generation is a combination of a "market price referent" (e.g., natural gas combined cycle plant) and a supplemental energy payment from public goods charge (PGC) funds. Funds from the PGC will be used to bridge the gap between the market price referent and the bid price for the winning RPS bids, if necessary.

Natural gas prices may rise or fall; however, under an RPS, customers would be somewhat insulated from price volatility. The details regarding contract terms for the RPS are expected to be decided by the California Public Utilities Commission (CPUC) as part of the RPS proceeding before the end of 2003.

A 2003 study from Lawrence Berkeley National Laboratory, ***Accounting for Fuel Price Risk***, recommends the use of forward natural gas prices rather than gas price forecasts to compare renewable energy generation to natural gas-fired electricity generation.[139] The report notes that gas price forecasts provide no assurance that actual prices will reflect forecasted prices. In contrast, contracts for the forward prices for natural gas are designed to ensure delivery of natural gas for 2 to 10 years at prices determined today, with a value for uncertainty built into the contracted price. The report argues that the price stability by the forward prices is a better approximation of the price stability offered by renewable energy than natural gas forecasts and should be the preferred natural gas comparison to renewable energy.

Based on data from 2000-2003, the report finds that 2-10 year gas forward prices were higher than Energy Information Administration reference case forecasts by 0.4 cents per kilowatt hour (cents/kWh) on average. The report cautions against extrapolating from this number, as the data used may not indicate general trends. Instead, the report argues for the use and extension of forward price curves in gas-price forecasts and for the collection of fixed-price long-term gas-fired electricity bids from generators. The report also notes that forward prices for natural gas may not capture the reduced credit risk associated with the fixed-price renewable contracts relative to natural gas contracts of similar duration, nor does it capture the value of the potential for increased renewable energy to reduce demand for gas-fired electricity generation in the future, which could reduce the price of natural gas.

Beyond market-related price fluctuations, electricity deliveries could also be disrupted due to major earthquakes, wildfires, severe weather, or man-made disasters. Any central station form of electricity generation is subject to transmission outages, such as those caused by man-made or natural disasters. Distributed generation located on-site for critical service centers can be of assistance during an interruption of electric transmission grid service. Because they can be installed quickly in a wide range of locations and operate without interconnection to the transmission grid, small on-site PV systems (e.g., 2 kW) have been used during the day in disaster response to power such essential services as street lighting, communications, medical services, traffic signals, and gasoline pumps at service stations. An important attribute of PV systems is that, unlike many emergency generators, they do not require gasoline or other liquid fuels to operate. Such fuels may be difficult to locate during a disaster or its aftermath.

ENVIRONMENTAL AND PUBLIC HEALTH BENEFITS

Californians prize their environment, and public agencies have worked hard to protect the air, water, and land resources in the state, but environmental problems associated with energy use in California remain of concern. One remaining significant issue is emissions of greenhouse gases, which are contributors to global climate change, from fossil fuel combustion for electricity generation. As reported in ***Climate Change in California*** (publication no. 100-03-017D), climate change represents a significant risk to California as a result of a warming and increasingly variable climate. The signs of a global warming trend continue to become more evident, and much of the scientific debate is now focused on expected rates at which future changes will occur. Rising temperatures and sea levels and changes in hydrological systems are threats to California's economy, public health, and environment.

Climate change is expected to impact the state's energy infrastructure in two ways. Climate change could lead to more frequent severe weather events. It is also expected to change the timing and quantity of snow-melt used by hydroelectric generation resources in California and imported to California from the Pacific Northwest. These changes could necessitate a shift in the nature of energy-related emergency response planning. It could also lead to shifts in the quantity and timing of hydroelectric generation available to California. Renewable energy could play a role in providing on-site emergency power. On a larger scale, renewable energy can also reduce the need to build new natural gas plants to guard against potential reductions in hydroelectric generation due to climate change.

The generation of electricity from renewable energy rather than fossil fuels can reduce carbon dioxide (CO_2) and other greenhouse gas emissions associated with climate change. Relative to a projection of pre-RPS trends in CO_2 emissions, the

MarketSym™ simulations suggest that achieving the IOU RPS requirements could reduce annual CO_2 emissions by about 38 million tons from gas-fired and coal-fired electricity generation in the WECC by 2013 and each year thereafter. The model suggests that achieving the RPS by 2010 could reduce annual CO_2 emissions by about 62 million tons in 2013 and each year thereafter.

The accelerated RPS/high demand side management (DSM) scenario reported in the "Electricity Infrastructure Assessment," which assumes that IOU RPS requirements are achieved in 2010 and DSM funding is doubled, suggests that annual CO_2 emissions from natural gas and coal in California may be reduced by about 60 million tons CO_2 in 2012 and each year thereafter.

Beyond the RPS, further steps could be undertaken to reduce emissions of greenhouse gases through the transportation sector, energy efficiency and demand-side management, and renewable energy resources in the electricity sector. The following is a list of possible renewable energy actions toward this end:

1. Reduce fuel costs at biomass power plants by accounting for the environmental costs of alternative disposal of the fuels (e.g., open-field burning).

   An interagency task force of relevant agencies — such as the California Integrated Waste Management Board, California Department of Forestry, California Air Resources Board and Air Quality Management Districts, and others— should be created to reexamine methods of reducing fuel costs and volatility of costs at biomass facilities. Potential measures to consider include:

   - Establish air-quality credits for avoiding open-field burning in central valley farms.
   - Enact "feebates" or tax-credits for construction and logging industries to foster delivery of waste product to biomass facilities.
   - Identify a range of measures to be included in forestry management plans to increased delivery of waste products to biomass facilities.

2. Increase purchases of renewable energy by state and local governments.

   State and local governments, as consumers, can increase their demand for renewable energy through their electricity purchases and other policies. They can also encourage other institutions to develop and implement market-based strategies and programs. Specific actions include:

   - Expand green pricing programs run by municipal utilities.
   - Promote new customer aggregations and community wind development.
   - Identify measures that will increase government purchases of renewable energy.
   - Incorporate renewable technologies into state and local security plans and structures.

3. Increase opportunities for renewable distributed generation and agricultural use of renewable energy.

   Beyond state and local programs that provide financial incentives for installing renewable energy and distributed generation, additional actions are needed to continue to grow this vital industry in California. These actions include:

   - Provide technical and financial assistance to agricultural producers and processors to shift their energy sources to renewable sources such as biofuels, PV, concentrating solar power (CSP), and wind.
   - Develop incentives for food processors and other industries with significant organic wastes to use digester gas self-generation.
   - Continue to remove barriers to renewable self-generation embedded in local codes and interconnection requirements.
   - Incorporate, as appropriate per Public Resources Code Section 25402, renewable distributed generation technologies in energy standards for new building construction.
   - Expand net metering to include broader biogas generation opportunities.

In addition to CO_2, the staff also simulated the reduction in nitrogen oxides (NO_x) emissions that may result from IOU procurement of additional renewable energy under the RPS and accelerated RPS. In California, NO_x emissions from the generation of electricity from natural gas are well controlled. As stated in the ***Electricity and Natural Gas Assessment Report***, combustion-fired electric generation contributes a relatively small portion of the emissions of NO_x (3 percent) in California. Further additions of new efficient combined-cycle power plants, new renewable power plants, and energy efficiency and load management programs in the coming years will continue this trend.

Notwithstanding the above considerations, to estimate the public health benefits associated with IOU RPS requirements, the Energy Commission staff focused on reduced emissions of NOx and reduced utilization of coal-fired electric generation plants. For 2002, approximately 10 percent of California's electricity was generated from coal-fired electricity generation plants. The plants providing this electricity to California are located in Nevada and Utah.[140]

NOx emissions affect the environment as well as public health and are a factor in ground-level ozone formation, acid rain, eutrophication of terrestrial and aqueous ecosystems, depletion of stratospheric ozone, and climate change.[141] NOx is associated with a wide range of public health problems, including breathing problems, asthma, and reduced resistance to colds and other infections.[142] Achieving and/or accelerating California's RPS is expected to reduce emissions of NOx in the WECC.

The simulations suggest that achieving the RPS could reduce annual NOx emissions from natural gas and coal in the WECC by 20,000 tons in 2013 and each year thereafter. Achieving the RPS by 2010 could reduce annual NOx emissions in the WECC by 31,500 tons in 2013 and each year thereafter (**Table 18**). This NO_x reduction builds upon the gains made in recent years to reduce NO_x emissions in the electricity sector. Additional information regarding the public health effects of California's electricity generation system are reported in the ***Electricity and Natural Gas Assessment Report***.

Table 18. Simulated Reduction in annual NOx Emissions from a Scenario of IOU Renewables for RPS and Acceleration of RPS

	Pre-RPS trend	RPS (as modeled)	Accelerated RPS (as modeled)
NOx Emissions (tons) In 2013	5,742,000	5,722,000	5,711,000
Annual reduction in NOx emissions from pre-RPS trend (tons) in 2013		20,000	31,000
Percent NOx reduction from Pre-RPS trend		0.3%	0.5%
Percent NOx reduction from RPS			0.2%

Source: California Energy Commission, Systems Analysis Office

The replacement of coal-based electricity by renewable energy would also reduce emissions of mercury and sulfur oxides (SOx).[143] Public health problems associated with high concentrations of these pollutants include asthma, chronic bronchitis, and even death. (Additional information regarding public health effects of California's electricity generation system are reported in the ***Electricity and Natural Gas Assessment Report***.)

Renewable energy can also contribute to sustainable forestry management, reduced volume of organic municipal solid waste (MSW), and reduced emissions of landfill gases. Regarding forestry management, the presence of dry grasses and brush can greatly increase the heat intensity of a forest fire, causing more damage than would be caused if the material has been removed. On the other hand, decaying matter is an important part of nutrients for soils and flora. It provides shelter for forest fauna as well. Careful collection of dry grasses and brush for biomass electricity generation according to sustainable forestry management practices can help reduce the likelihood of high heat fires, while leaving some material for forest soil regeneration and other ecological functions.

As California's population grows, the need to reduce the amount of material sent to landfills becomes more pressing. Diverting the organic MSW stream from the state's landfills to generate electricity changes a part of the waste stream into a productive fuel source. Another issue related to MSW is the methane that is produced through the decay of material that is deposited in landfills. Methane produced by closed

MSW landfills that is not collected and used for electricity production is often flared. As methane is a potent greenhouse gas, this runs counter to statewide efforts to address climate change. Using landfill gas to generate electricity reduces the release of methane into the atmosphere.

ENVIRONMENTAL ISSUES ASSOCIATED WITH RENEWABLE ENERGY

The ***2003 Environmental Performance Report*** indicates that environmental challenges of gas-fired generation in California include the need to reduce emissions of greenhouse gases such as CO_2, make further reductions in NOx and particulate matter of 10 microns or less (PM_{10}) in air basins with air quality problems, reduce NOx emissions from boiler and combustion turbine facilities used to meet peak energy demand, reduce the use of once-through water cooling, and reduce nitrogen deposition in sensitive ecological areas. Appendix D of the ***2003 Environmental Performance Report*** also describes environmental challenges associated with large hydroelectric generation. Renewable energy resources can reduce the use of gas-fired generation in California and replace energy from decommissioned hydroelectric projects, thereby reducing the environmental impacts associated with those energy resources. It is important to note that increasing the use of renewable energy requires attention to address a different set of environmental impacts. Many of the environmental impacts of renewable energy can be handled with existing mitigation technologies.

The full implementation and acceleration of California's statewide RPS goals would result in benefits including lowered greenhouse gas emissions, increased fuel diversity, and reduced criteria air emissions. On the other hand, like any new resource or infrastructure development, other environmental issues are raised. For example, the ***2003 Environmental Performance Report*** notes that there is a potential need for new transmission connections for renewable energy located in rural areas, which may impact land use.

Repowering existing renewable resources with newer, more efficient energy generation equipment offers the opportunity to utilize existing transmission infrastructures. The Energy Commission's Public Interest Energy Research program (PIER) is currently studying the impact of new generation on transmission congestion. Preliminary results indicate that added generation reduces the need to add or upgrade transmission infrastructure in some cases, but in other cases it aggravates congestion.

The key environmental issue associated with **wind energy** is the impact of the turbines and associated transmission infrastructure on resident and migratory bird populations, especially raptors, and their habitat. The wind turbines in the Altamont Pass Wind Resource Area are especially problematic, due to prey density, terrain features, and wind turbine placement.[144] Research efforts are underway to identify optimal placement of wind facilities and equipment design changes to minimize interaction with birds.[145] Wind energy procurement solicitations can also create incentives to reduce wind energy-related avian deaths and address other environmental concerns, such as noise and visual impacts. For example, the Bonneville Power Administration's 2001 *Request for Wind Project Proposals* requires the use of "state-of-the-art measures to minimize potential avian mortality, noise, and visual impacts of the facility."[146]

For **geothermal**, the key environmental and public health issues are 1) land use, 2) potential groundwater and/or surface water contamination, and 3) emissions of hydrogen sulfide at a rate of 0.0145 kilograms per megawatt hour (kg/MWh), dissolved solids, and CO_2 (45 kg/MWh).[147] Many geothermal resources in California are located in areas valued as wilderness, sacred areas, or recreation areas. The constraints on building an electricity generation facility in such areas (and bringing transmission to the facility) make some geothermal resources infeasible for development. Land subsidence may also be a concern, depending on the structure of the geothermal resource.[148]

Development of geothermal resources may pose a risk of groundwater and/or surface water contamination, depending on the technology utilized to harness the geothermal energy (e.g., open-loop or closed-loop system) and the care with which geothermal fluids are managed. To avoid groundwater contamination, best practices must be used in geothermal well construction and disposal of water and wastewater used in geothermal energy generation. In many cases, water and wastewater is re-injected into the geothermal resource to avoid depleting the resource. At The Geysers geothermal energy facility in Lake County, treated municipal wastewater is being injected into geothermal wells.[149]

The main environmental problems associated with **biomass** are emissions associated with the transportation of biomass material to the electricity generation facility, potential damage to forests, wildlife, and watersheds from harvesting of forest products, and emissions of NO_x, SO_x, carbon monoxide, and particulate matter. A number of efforts are underway to address these concerns. For example, distributed generators are being developed to use biomass in cogeneration applications, which could reduce the distance that biomass is transported to produce electricity.[150] Rulemaking proceeding R.03-03-015 at the CPUC is considering whether to create an incentive for IOUs to promote sustainable management of watersheds surrounding their hydroelectric facilities. To be eligible for the RPS, the following are requirements for wood and wood wastes used for biomass electricity generation: the wood and wood wastes have been harvested according to an approved timber harvest plan, they have been harvested for the purpose of forest fire fuel reduction or forest stand improvement, and they do not transport insect or disease nests outside zones of infestation.[151] As discussed in the previous section, where harvesting practices are sustainable, biomass generation can function as a waste disposal process that provides electricity as a marketable product.[152]

Control technologies are available to reduce criteria air pollutant emissions from electricity generation fueled by biomass; however, emissions from biomass combustion cannot reasonably be reduced below emissions from natural gas electricity generation. CO_2 emissions from biomass electricity generation are generally considered to be zero, as the plant matter used to generate electricity releases the same amount of CO_2 that it consumed in photosynthesis.[153]

Concentrating Solar Power that operates without a fossil fuel component has few environmental issues beyond the amount of land that is required (5-10 acres /MW) and, in the case of trough and power tower technology, water requirements (2-4 cubic meters of water per MWh generated). Dish/Stirling engines do not require water for operation, other than a small amount for mirror cleaning. In solar trough systems, the oil used for heat transfer (Monsanto Therminol VP-1) is a hazardous material according to California standards. On-site bio-remediation technology is available to decontaminate soil affected by a spill of this material.[154]

The greatest environmental and health risk associated with **PV panels** is accidental occupational exposure to potentially toxic substances (e.g., cadmium, lead solder). Cadmium is a carcinogen (lung and prostate) and can cause damage to kidneys and bone if exposure continues over a long period of time.[155] Lead can damage the nervous system, kidneys, and reproductive system. In children, lead can cause problems in mental and physical development, anemia, or brain damage.[156] Drawing on techniques used in the manufacture of semiconductors, the U.S. industry follows exacting procedures to guard against worker exposure. Worker health is further monitored through medical tests of exposure to known hazards in the work place. Final disposal of PV panels could pose a risk as well, although PV panels are designed to encapsulate toxic materials. To further minimize this risk and maintain a low-cost supply of materials, the U.S. industry plans to recycle PV panels for the manufacture of new panels.[157]

Although **ocean wave** energy conversion is not widely commercialized, it is included as one of the renewable energy generation technologies eligible for support through the Energy Commission's Renewable Energy Program, provided that related requirements in Senate Bill 1038 (SB 1038) and Senate Bill 1078 (SB 1078) are met.[158] The potential environmental impacts identified to date [(e.g., potential impacts to salmon, herring, and large mammal migration routes, potential impacts on coastline, build up of sediments, seabed disturbance due to moorings and sub-sea devices)] suggest the need for careful environmental review and site selection when this technology becomes commercialized.[159]

New **small hydroelectric** generation (30 MW or smaller) that does not require new or increased appropriation or diversion of water may be eligible for the RPS if certain criteria are met.[160] More generally, small hydroelectric generation can produce negative environmental impacts in the following areas: river flows, water quality, fish passage, watershed protection, threatened and endangered species, and cultural resources.[161] Some small hydroelectric projects require Federal Energy Regulatory Commission (FERC) licenses, including a review of environmental impacts. According to the ***Environmental Performance Report***, opportunities to minimize the impact of small hydroelectric facilities include the use of the following small hydroelectric resource sites: canals, water supply facilities and pipelines, incremental hydro,[162] and existing dams lacking hydroelectric generation.

Clearly, renewable energy resources provide some environmental and public health benefits relative to fossil fuel generation, but they also pose some risks. Attentive efforts are currently in use or under development to address many of these concerns. Continued recognition, awareness, and monitoring of environmental performance are needed to maintain and improve the net environmental benefits of the technologies listed here.

LAYING THE GROUNDWORK FOR EXPANSION OF DISTRIBUTED GENERATION

The U.S. Department of Energy's ***Strategic Plan for Distributed Energy Resources*** (September 2000) set a goal of expanding distributed generation (i.e., electricity that is generated on-site or near the place of use, typically ranging in capacity from 3 to 10,000 kW) in the United States to reach 20 percent of new electric capacity additions by 2010.[163] Recent trends in the installation of PV systems suggest that renewable distributed generation could play an important part of the growth in distributed generation.[164]

One of the possible benefits of distributed generation is its potential for reducing transmission constraints. The Strategic Value Assessment funded by the PIER program is currently studying the impact of new generation on transmission congestion. Preliminary results indicate that added distributed generation reduces the need to add or upgrade transmission infrastructure in some cases, but in other cases it aggravates congestion.

Further expansion of renewable distributed generation in California faces several barriers and uncertainties, including high capital costs, siting and permitting issues, grid interconnection issues, and utility tariffs (e.g., back-up tariffs, stranded costs).

A number of activities and proceedings are underway at the Energy Commission and the CPUC to address issues related to distributed generation in California.[165] For further information on these activities see the Energy Commission's *Distributed Energy Resource Guide*, available on-line at [www.energy.ca.gov/distgen/.]

CHAPTER 8: DRIVING POLICY ISSUES REGARDING CALIFORNIA'S STATEWIDE RENEWABLES PORTFOLIO STANDARD

Increasing the amount of electricity in California that is generated by renewable resources will face a number of challenges, ranging from transmission to operational compatibility. This report highlights issues related to the following challenges:

- Expanding the transmission system to accommodate development of renewable energy resources. Transmission lines linking renewable energy sites (often in rural locations) with load centers can be costly. Renewable distributed generation, resources located in populated areas, and repowering of existing renewable resources can help reduce the need to develop new lines to rural areas. Research is underway to analyze the value of placing new generation resources in strategic junctures of the transmission grid to minimize the need for new transmission infrastructure.

- Improving the economic viability of new renewable electricity generation facilities. In accordance with SB 1038 and SB 1078, the New Renewables Program will provide supplemental energy payments (SEPs) to renewable electricity generators for any above-market costs of renewable energy. Without such payments for the above-market costs, the utilities may not be obligated to purchase renewable power to fulfill their Renewables Portfolio Standard (RPS) obligations. Thus, the state's success in achieving the RPS target may depend to a large extent on the availability of the funds in the New Renewables Program. At this point, there is too much uncertainty regarding market price referents, winning bid prices, maintenance of baseline, and interest rates to determine whether public goods charge (PGC) funds will be adequate to meet the RPS, and acceleration of the RPS.

- Addressing the operational compatibility of renewable resources with the existing electricity system. Not all forms of renewable energy provide the type of power-on-demand that the system counts on for reliably serving California's customers. Approaches to address this issue include 1) identifying integration costs in relation to the type and timing of energy provided by a generation facility and developing fair ways for allocating these costs and 2) funding research on electricity firming options (e.g., storage).

- Incorporating renewable resources into the electricity system through long-term commitments considering the shape and amount of future demand. Of critical importance in deciding which renewable resources will be most successful in investor-owned utility (IOU) and Electric Service Provider and Community Choice Aggregator (ESP/CCA) solicitations are “least-cost-best-fit” considerations, as well as issues related to the creation of market price referents to which renewable bids will be compared. Least-cost-best-fit considerations include product type and capacity value, transmission costs, integration costs, and remarketing costs. Publicly-owned electric utilities will have their own unique considerations in determining which renewables to incorporate into their electricity system.

- Obtaining financing for new, renewable generation. Financing for new renewable generation is affected by IOU creditworthiness and by uncertainty regarding federal and state incentives for renewable energy, but conditions are improving. The strong participation in solicitations for the interim procurement of renewable energy held by Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) in 2002 and other recent solicitations is an encouraging indication of the interest of the financial community to participate in the development of renewable energy. Several institutional and regulatory developments in the last year will further assist in developing and financing of renewable energy generation.

- Identifying activities by publicly-owned electric utilities and ESP/CCAs to develop renewable resources. SB 1078 states that publicly-owned electric utilities shall define their own RPS programs, consistent with the intent of the Legislature. A number of publicly-owned electric utilities are planning to define large hydroelectric generation as an eligible renewable technology. If large hydroelectric power is used by publicly-owned electric utilities to meet their RPS goals, the amount of additional renewable energy procured beyond existing resources may be smaller, as some of these utilities receive a substantial portion of their electricity from large hydroelectric generation. The RPS program excludes large hydroelectric from the definition of eligible renewable energy that applies to IOUs and ESP/CCAs. The use of different definitions of “eligible renewable” for different RPS programs within California may cause confusion to the end user and may not adequately meet the intent of the legislation.

TRANSMISSION CONSTRAINTS

The impact of transmission constraints on meeting California’s statewide RPS will be greatly affected by the following issues: 1) the proportion of the RPS met by out-of-state renewable energy facilities, 2) capacity constraints on transmission paths connecting renewable resources in the Western Electricity Coordinating Council (WECC) to load centers, and 3) whether “renewable attribute” can be separated from the underlying energy and traded in the form of a "renewable energy certificate" to meet the RPS, thereby somewhat reducing the impact of transmission constraints.

Although publicly available information suggests that proposed renewable energy projects in the inner tier WECC states total more than 27,000 gigawatt-hours per year (GWh/year), the proportion of the RPS that will be met by out-of-state resources is not known. Technical potential in the outer tier states is estimated to be more than 30,000 GWh/year for geothermal and biomass and more than 2 million GWh/year for wind; however, transmission constraints may limit the ability to deliver electricity from outer tier WECC states into California to meet the state's RPS.

As reported in the ***Electricity Infrastructure Assessment*****,** the construction of new transmission lines has been stalled in California in recent years due to three issues: challenges in justifying project benefits and need, difficulties with project financing, and local opposition to environmental and property value impacts. Accelerating the RPS raises another issue: it may create pressure on utilities to develop transmission lines to export energy from areas that, under the SB 1078 RPS timeline (20 percent by 2017), may be expected to use the energy to meet local electricity load growth.[166]

Meeting a portion of the RPS requirements through distributed generation and/or re-powering of existing renewable energy resources may reduce the need to install new transmission lines or build transmission ahead of load growth. The California Energy Commission (Energy Commission) Public Interest Energy Research (PIER) program is currently studying the impact of new generation on transmission congestion. Preliminary results indicate that added generation reduces the need to add or upgrade transmission infrastructure in some cases, but in other cases it aggravates congestion. In addition, Federal Energy Regulatory Commission (FERC) rules and pending decisions regarding the allocation of the cost of transmission upgrades is an important issue for the development of renewable energy.

The California Public Utilities Commission (CPUC), in consultation with the Energy Commission, will decide whether tradable renewable energy certificates will be eligible for California's RPS. In addition, the CPUC will submit a transmission plan for renewable electricity generating facilities to the Legislature by December 1, 2003. Allowing the use of tradable renewable energy certificates as a mechanism for meeting RPS obligations may help to avoid congested areas in the transmission lines carrying electricity from other WECC states to California.

Given the remaining uncertainties regarding the scale and type of participation of out-of-state renewable energy resources in California's RPS, and the pending completion of the CPUC SB 1038 transmission study, this issue should be revisited early in 2004. If tradable renewable energy certificates are not allowed and physical delivery of electricity from renewable resources is required, then California-based renewable generation facilities are likely to play the predominant role in meeting California's RPS. If this is the case, transmission constraints in the Tehachapi and Salton Sea area may delay renewable energy procurement. The efforts to build new transmission lines and/or develop and utilize advances in transmission technology allowing greater throughput of electricity through existing lines is likely to reduce such constraints in later years.

Further information regarding proposed transmission projects, including an inter-utility project proposed to address RPS needs, is available in the Transmission White Paper released with the August 8 ***Electricity and Natural Gas Assessment Report***.

SUFFICIENCY OF PUBLIC GOODS CHARGE FUNDS

The methodology for calculating market price referents was decided by the CPUC on June 19, 2003, but the actual market price referent for the first renewable energy solicitation will not be known until after the bids have been received. As stated in SB 1078, the market price referents will not be known in advance of the solicitation to which they apply. This requirement is intended to increase the likelihood that developers will submit competitive bids in the procurement process. As a result of this practice, the portion of each winning bid that is above the market price referent and eligible for supplemental energy payments will not be known in advance.

If SEPs are inadequate, the renewable energy procurement goals of SB 1078 may not be fully achieved. On this point, Public Utilities Code Section 399.15 (b)(4) states the following:

> (4) If supplemental energy payments from the Energy Commission, in combination with the market prices approved by the commission, are insufficient to cover the above-market costs of eligible renewable energy resources, the commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available supplemental energy payments.

The sufficiency of PGC funding will depend on the costs of winning bids, retail sales trends, the proportion of existing energy production that requires replacement, interest rates available for unexpended Renewable Resource Trust Fund (RRTF) moneys, and the market price referents above which RRTF incentives will be paid.[167]

Availability of PGC funds may be placed at risk to the extent that the state borrows money that is currently idle from the fund and does not pay it back in a timely manner. For example, in fiscal year 2002-2003, the RRTF loaned $150 million to the general fund, transferred $7 million of accrued interest to the general fund to help address the budget crisis, and loaned $8.9 million to the California Power Authority. As a result, the amount available for SEPs may be reduced by the amount of interest lost over the duration of the loans and the $7 million transferred to the general fund.[168]

The rate at which the RRTF earns interest also has a financial impact on the state's ability to meet the RPS. Assuming 10-year contracts procured according to the estimated energy requirements for meeting the RPS by 2017, staff estimates that the state could earn up to $150 million in interest on the RRTF at a 2 percent annual interest rate over the period 2002-2027. If used to augment PGC funds collected from ratepayers, this interest could increase the amount of funding available for SEP payments. To the extent that the interest is lower than 2 percent, the estimated amount of interest that could be used for SEPs would be less.

Also, if the retail electricity sales forecast used in this analysis is low or the baseline amount of renewable energy decreases, the amount of incremental renewable energy needed to meet the 20 percent target will increase. Depending on the gap between the market price referents and the winning bids, an increase in the amount of incremental energy needed to meet the RPS could stretch the need for SEPs beyond the available funds.

Out-of-state participation in the RPS is likely to increase the number of bidders in competitive solicitations. With greater competition, it is possible that the winning bid prices will be lower than may be the case without out-of-state participation, depending upon the type and location of the renewable resources. This may result in lower SEPs per GWh/year, potentially extending the amount of total energy that can be supported with existing funds.

At this point in time, there is too much uncertainty regarding market price referents, winning bid prices, maintenance of baseline, and interest rates to determine whether PGC funds will be adequate to meet the RPS, or an acceleration of the RPS. At the conclusion of the first solicitation under the RPS, the state should re-evaluate the adequacy of PGC funds. If funds are not expected to be adequate, the state should evaluate whether the funds should be increased.

LEAST-COST-BEST-FIT-ISSUES

Another key issue related to expanding the role of renewable energy in California is the need to address the operational compatibility of renewable resources with the existing electricity system. Matching RPS procurement to the shape and amount of demand already covered by long term commitments poses a challenge.

Of critical importance in deciding which renewable resources will be most successful in IOU and ESP/CCA solicitations are "least-cost-best-fit" considerations, as well as issues related to the creation of market price referents to which renewable bids will be compared.

SB 1078 requires that bids submitted in response to IOU RPS solicitations be selected according to a rank ordering of:

> …least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources. (Public Utilities Code Section 399.15(a)(2)(B)).

Further, in determining the appropriate market price referent to which renewable bids are compared, SB 1078 requires a consideration of:

> The value of different products including base load, peaking, and as-available output." (§399.15(c)).

The CPUC's Order Initiating Implementation of the SB 1078 RPS program (Decision 03-06-071, June 19, 2003) provides further clarification on the implementation of these requirements.

In particular, the CPUC's order defines "best fit" as:

> …the renewable resources that best meet the utility's energy, capacity, ancillary service and local reliability needs," with the added condition that "for the short-term, renewable generation that can operate as dispatchable or peaker power may possibly fall slightly higher on the 'procurement hierarchy' (Decision 03-06-071, page 28-29).

The CPUC's order also decided that the market price referent for base load renewable electricity will be a natural gas, combined-cycle plant and the referent for peaking energy will be a combustion turbine plant. The market price referent for as-available (intermittent) energy will be either the base load or peaking referent, depending on which product that resource bids. The order also addressed issues related to the establishment of capacity value benchmarks, especially for as-available (intermittent) renewable generation.

SB 1078 and the CPUC's subsequent order make clear that, at a minimum, the following specific considerations will influence bid selection:

- Product type and capacity value – whether the renewable generator offers base load, peaking or as-available output, the degree of dispatchability or curtailability involved, and the "capacity value" of the resultant product.

- Transmission costs – generation plant interconnection costs, and the costs of upgrades or expansions of the transmission system required by the addition of specific generators.

- Integration costs – the cost of integrating renewable resources into the electricity system, as determined (in part) by an ongoing Integration Study, being conducted by the PIER program.

- Remarketing costs – the cost of selling existing utility generation at a loss due to a mismatch in the timing of renewable generation and utility resource needs.

Although the general methodology is known, the actual market price referents will not be known until after bids have been received. Similarly, the effect of "least-cost" considerations will not be known until detailed implementation rules are established, and solicitations are conducted. "Best-fit" considerations, meanwhile, will be inextricably linked to the needs of a particular utility in each individual solicitation. Prospective bidders would benefit from additional information regarding utilities' least-cost-best-fit needs to help create a better match between the utility needs and bids offered to meet those needs.[169]

These uncertainties make it impossible to forecast the contributions of specific renewable energy technologies and resource areas for the future RPS needs of IOUs and ESPs/CCAs. Moreover, the resource comparison process by the state's publicly-owned utilities will vary with utility and over time and is not currently known. Nonetheless, it is clear that based on least-cost-best-fit considerations and the determination of market price referents, those technologies with the lowest delivered busbar cost, measured as dollars per megawatt hour ($/MWh), will not necessarily dominate renewable solicitation results.

- **Wind:** As shown in an earlier section of this report, wind power is expected to be among the least expensive renewable resources at the busbar. Despite this, the Energy Commission does not expect wind power to meet the entirety of the incremental renewable energy needs of the state. Wind power plants have an intermittent generation profile and provide less capacity value than most other renewable resource options. In some cases, the transmission investments needed to bring increased wind production to market will be significant, as wind power resources are more constrained geographically than some other renewable resource options. Though the absolute magnitude of integration costs is not yet known, the costs of integrating wind power are likely to exceed those for other renewable energy options. Finally, depending on the seasonal and diurnal profile of specific wind resource areas, wind power may create higher or lower remarketing costs than base load renewable generation options.

- **Geothermal:** Geothermal power plants are typically highly reliable and operate as base load power. Relative to wind power, geothermal power plants offer a firmer source of electricity supply, higher capacity value, and lower integration costs. Like wind power, however, geothermal resources are geographically constrained. As such, transmission interconnection costs, as well as the cost of transmission upgrades and expansions, may be significant as new resource areas are developed and existing areas are expanded.

- **Biomass:** Biomass power plants are fueled by a wide range of biomass sources but, like geothermal, typically operate as base load capacity and therefore have higher capacity value than wind generation. The costs of integrating biomass and remarketing utility power are likely to be similar to that for geothermal energy. Landfill gas and digester systems are typically small enough individually as to not require significant transmission investments. Solid-waste fuelled biomass plants, meanwhile, have some locational flexibility, allowing projects to be sited in areas that do not require as sizable transmission investments as might be required for some wind and geothermal plants.

- **Solar:** Though solar photovoltaics (PV) and concentrating solar power (CSP) generation can be intermittent in nature (unless tied to storage, or operated in hybrid mode with natural gas), diurnal and seasonal production profiles for solar technologies more closely track California's electric load than other renewable options. The use of storage or hybridization with natural gas, common with CSP generation, can make this source even more attractive. The value of solar energy may, therefore, exceed that of the other renewable energy options, at least in some cases. Integration and remarketing costs will depend on whether storage or hybrid operation are used, but, in any case, are likely to be lower than for wind power even without storage or hybrid operation. Indirect transmission costs are also likely to be low, because some geographic flexibility exists; in fact, these resources may sometimes support the transmission and distribution system if sited appropriately.

Least-cost-best-fit considerations and the determination of market price referents will have a substantial influence of the types and locations of the renewable resources used to meet California's renewable energy needs. These considerations, all else being equal, may make solar electricity relatively more attractive, and wind power relatively less attractive compared to base load renewable generation options: geothermal and biomass.

Operational Compatibility

Although historically most renewable generation has been operated in a non-dispatchable, must-run fashion, some renewable resources can be constructed and operated with some level of dispatchability. Geothermal, CSP, biomass, landfill gas, and digester gas resources can all be designed with "fuel" storage and dispatchable generation. Wind and solar PV technologies must generate when their "fuel" is available, and generally require electricity storage options (e.g., pumped hydroelectric facilities, compressed air, or batteries) to achieve dispatchability.[170]

The overall average operating profile of solar energy tracks summer peak hours in California more closely than other renewable energy resources.[171] The operating profile of wind energy varies by geographic location, but where wind energy is a function of on-shore and off-shore wind patterns, wind energy is likely to be available during the morning and evening peaks of winter energy demand, but less so on the hottest summer afternoons. In California, where temperature differences between the inland valleys and the coast have a significant effect on wind patterns, wind projects are more likely to be generating in the late afternoon and evening time periods during the summer.

The operation of renewable energy in conjunction with energy storage systems has not been economically attractive in the past.[172] To help address this issue, the Energy Commission is currently funding research in the area of cost-effective energy storage for wind and PV renewable energy sources.[173] Storage technologies under evaluation include the following: existing hydroelectric resources, batteries, superconducting magnetic energy storage, and regenerative fuel cells.[174] In addition, the Energy Commission is working with the California Independent System Operator (CA ISO) to investigate the best use of energy storage to support expanded use of wind electricity generation.

Long-Term Commitments

In response to the 2000-2001 energy crises, the Department of Water Resources (DWR) signed long-term energy contracts, most of which are set to expire in 2010 and 2011.[175] The CA ISO estimates that these contracts will provide 30 percent of the summer peak demand (about 12,900 of 42,900 MW). These contracts provide such a large portion of California's non-peak electricity that they may pose a challenge to the integration of non-peak renewable electricity generation. As the state's aging electricity generation stock is phased out, the proportion of retail sales served by non-renewable base load may decline, thereby creating a better niche for renewable base load electricity generation than currently available. Contract terms and flexible compliance mechanisms for the RPS are under development at the CPUC. These mechanisms may allow IOUs and ESP/CCAs to bank or delay acquisition, helping to address the need to fit renewable energy to utility load shapes. This will be especially important in the accelerated RPS case of 20 percent by 2010, which is estimated to entail an additional 17,880 GWh/year of electricity for the entire state from renewable energy resources by 2008, before most of the DWR contracts are set to expire.

The CPUC Decision 03-06-071 (June 19, 2003) states that least cost and best fit must be treated as linked concepts in California's RPS program: "In that context the utilities should be considering the best fit that is available, which may or may not be a perfect (or even good) fit with their needs." [176] The efforts to improve the cost effectiveness of dispatchable/peaker renewable energy may help to increase the likelihood that the least-cost-best-fit renewable energy projects complement current and future load shapes for the state's electricity demand.

CREDITWORTHINESS OF INVESTOR-OWNED UTILITIES

The large increases in wholesale electricity costs during the energy crisis of 2000-2001 undermined the creditworthiness of PG&E and SCE. In January 2001, DWR began acting as the creditworthy backer for these utilities. SDG&E remained creditworthy through the crisis, but ratepayers suffered large increases in retail prices.

Although credit issues for PG&E and SCE are not fully resolved, the IOUs are slowly returning to financial stability. In September 2002, the CPUC allocated the long-term contracts negotiated by DWR to the three IOUs. These entities are now responsible for the day-to-day functioning of the contracts, integrating these resources into their long-term procurement plans, and purchasing sufficient resources for their remaining need.

PG&E is currently in Chapter 11 bankruptcy protection. In June 2003, PG&E submitted a proposed settlement agreement to the CPUC (Investigation 02-04-026). According to the proposed settlement, PG&E would emerge from bankruptcy in early 2004. The CPUC plans to make a decision on the proposed bankruptcy settlement in December 2003.

As of late August 2003, Moody's Investors Service was conducting a rating review to determine whether to raise SCE's credit rating. Recent developments are expected to affect Moody's rating of SCE positively. For example, SCE has paid costs and debt related to provision of electricity during the 2000-2001 energy crisis. Also, federal (September 2002) and state court rulings (August 2003) have ruled that the settlement agreement between SCE and the CPUC is consistent with federal and state law.[177] Following the August 2003 state court ruling, the issue is expected to return to federal court for a decision on the entire agreement.[178]

The relationship between IOU creditworthiness and RPS requirements were addressed by the CPUC. The June 19, 2003 CPUC decision on implementation of the RPS finds that while an IOU cannot be ordered to purchase renewable energy until it is creditworthy, annual RPS purchase obligations will accumulate. The CPUC decision also states that no penalties will be assessed for delays in procurement during the period in which an IOU is not creditworthy.

FINANCING

Financing for new renewable generation is affected by IOU creditworthiness and uncertainty regarding federal and state incentives for renewable energy, but conditions are improving. Strong participation in solicitations for the Interim Procurement of renewable energy held by PG&E, SCE, and SDG&E in 2002 and other recent solicitations is an encouraging indication of the interest by the financial community in participating in the development of renewable energy. Several institutional and regulatory developments in the last year will further assist in the development and financing of renewable energy generation.

One such regulatory development is Senate Bill 67 (SB 67). SB 67 clarifies the linkages between creditworthiness, availability of financing, and availability of reasonable terms of procurement for RPS. Specifically, SB 67 amends Sec. 399.14(a) of the Public Utilities Code to read as follows:

> (1)(A) The [CPUC] commission shall not require an electrical corporation to conduct procurement to fulfill the renewables portfolio standard until the commission determines either of the following:
>
> > (i) The electrical corporation has attained an investment grade credit rating as determined by at least two major rating agencies.
> >
> > (ii) The electrical corporation is able to procure eligible renewable energy resources on reasonable terms, those resources can be financed if necessary, and the procurement will not impair the restoration of an electrical corporation's creditworthiness. This provision shall not apply before April 1, 2004, for any electrical corporation that on June 30, 2003, is in federal court under Chapter 11 of the federal bankruptcy law.

At the federal level, the Production Tax Credit (PTC) provides a tax credit for new wind projects for the first 10 years of energy production in the amount of 1.8 cents/kWh, adjusted for inflation. Repowered wind projects can benefit from this tax credit under certain conditions, such as renegotiating or amending their existing long-term contracts. Renegotiation of such contracts has not occurred significantly since this provision was added to the PTC law, which has limited repowering in California. Unless extended by Congress, this tax credit is scheduled to expire December 31, 2003.

Another federal incentive, the Renewable Energy Production Incentive, provides annual payments of 1.5 cents/kWh to qualifying renewable energy facilities beginning operations between October 1, 1993 and September 30, 2003 that are owned by state, local government entities, or not-for-profit cooperatives. Absent reauthorization, Renewable Energy Production Incentive payments will not be available for development of new renewable energy resources owned by state or local government or not-for-profit cooperatives. This may have a negative impact on the availability of financing for some new renewable generation projects.

In addition, steps are being taken to improve the creditworthiness of PG&E and SCE. This is expected to reduce the cost of financing renewable energy projects in California. In addition, progress has been made to establish the rules that are required to launch California's RPS, including a procedure for procuring renewable resources before all of the rules for the RPS are set in place. There is continuing uncertainty regarding the allocation of costs related to transmission congestion and integration. This may still be affecting the cost of financing new renewable energy projects.[179]

The RPS will provide power purchase agreements, and provided that funding is adequate, the RPS will provide SEPs for those qualifying winners of RPS bid solicitations whose bid price exceeds the applicable market price referent(s). Availability of SEPs will be a significant factor in the ability to finance a new renewable energy project whose bid exceeds the market price referent.

Should the private sector investment community not provide the capital for new generation, it may be necessary for a public entity, such as the California Power Authority (CPA) to help finance key projects. The CPA may issue bonds for up to $5 billion to help finance the development and installation of renewable energy, efficiency and targeted gas technologies. As reported in the ***Power Authority 2003 Investment Plan*****,** the CPA anticipates providing financing for renewable energy resources through the following:

- Finance renewable energy projects that have long-term power purchase agreements with an IOU, obtained through a competitive solicitation,
- Develop, finance and own renewable energy resources at-cost for the benefit of IOU customers, possibly using tax-exempt debt,
- Facilitate the aggregation of small renewable energy resources (under 5 MW) to respond to the competitive solicitations offered by the IOUs, and
- Provide financing or turn-key renewable energy for municipal utilities.

The ***Energy Action Plan*** adopted by the Energy Commission, CPUC, and CPA specifies that "agency actions will attract private investment into California's energy infrastructure to stretch and leverage public funds and consumer dollars." An analysis of whether the RPS is advancing this goal should be conducted at the conclusion of the first RPS solicitation.

ISSUES RELATED TO THE RENEWABLES PORTFOLIO STANDARD IN THE REST OF THE STATE

SB 1078 also contains requirements for publicly-owned electric utilities, specifically,

> 387. (a) Each governing body of a local publicly-owned electric utility, as defined in Section 9604, shall be responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.

Available information indicates that publicly-owned electric utilities are planning the following activities in support of renewable energy development in California:

- Los Angeles Department of Water and Power (LADWP) currently has about 2 percent renewable energy. LADWP recently announced that it will increase its use of renewable energy with such projects as the Pine Trees wind project near Mojave.[180]

- The Sacramento Municipal Utility District (SMUD) hopes to achieve 10 percent renewable energy by 2006 and 20 percent renewable energy by 2011.[181]

- Roseville Electric has adopted an RPS goal of 20 percent renewable energy; however, unlike the renewable definition used in SB 1078, Roseville counts large hydroelectric generation as part of its renewable portfolio.[182]

- Anaheim Public Utilities recently began two new programs — Green Power for the Grid and Sun Power for the Schools. Both programs allow Anaheim customers to pay a nominal monthly fee to support renewable energy.[183]

- Silicon Valley Power, serving the City of Santa Clara, already exceeds the amount required by the RPS. For 2002, Silicon Valley Power estimates that 26 percent of its energy is supplied by eligible renewable resources.[184]

- Modesto Irrigation District has committed to develop 30 MW of new renewable energy resources.[185]

SB 1078 states that publicly-owned electric utilities shall define their own RPS programs consistent with the intent of the Legislature for the statewide RPS goals. A number of publicly-owned electric utilities are planning to define large hydroelectric generation as an eligible renewable technology. If large hydroelectric power is used by publicly-owned electric utilities to meet their RPS goals, the amount of additional renewable energy procured beyond existing resources may be smaller, as some of these utilities receive a substantial portion of their electricity from large hydroelectric. SB 1078 excludes large hydroelectric power from the definition of “eligible renewable energy” that applies to IOUs. The use of different definitions of “eligible renewable” for different RPS programs within California may cause some confusion and may not adequately meet the intent of the legislation.

The staff conducted a brief survey of publicly-owned electric utilities’ activities in support of California’s statewide RPS goal. As of September 5, 2003, completed surveys had been received from 14 of the 34 publicly-owned electric utilities surveyed. In addition, two publicly-owned electric utilities did not complete the survey, but responded with general information about their efforts to promote renewable energy.

The survey asked whether the publicly-owned electric utility was taking steps to support California’s statewide goal. It also asked respondents to comment on key issues, barriers, or opportunities facing publicly-owned electric utilities with regard to the procurement/sale of renewable energy. Finally, respondents were asked what steps, if any, the Legislature should consider to support publicly-owned electric utilities in achieving 20 percent renewable electricity by 2017 and by 2010. The results of the survey are summarized below.

- All but one of the respondents indicated that they would do “something” to support a local RPS. Responses ranged from having already met the 20 percent goal (Silicon Valley Power – City of Santa Clara) to the view that the goal is not realistically achievable, but that an effort will be made to comply with the spirit of the legislation (City of Shasta Lake).

- All respondents cited the costs of renewable energy as a key barrier to meeting the statewide RPS goal of 20 percent by 2017.

- Four of the respondents indicated that their RPS will likely be met using large hydroelectric power (Alameda, Redding, Roseville and Shasta Lake).

- More than half of the respondents stated that the Legislature should let publicly-owned electric utilities retain local control. Other suggestions included creating a “renewable bank” that the smaller publicly-owned electric utilities could buy from making publicly-owned electric utilities eligible for the production tax credit and defining all hydroelectric generation as renewable.

- The most common technologies (other than large hydroelectric) cited as helping meet the RPS are wind, small hydroelectric, and PV.

- Results suggest that the two issues with the most negative effect on publicly-owned electric utility RPS efforts are 1) competition between the IOUs and publicly-owned electric utilities for renewable energy resources and 2) difficulty in financing the construction of new renewable energy facilities.

- The issues that have the most positive effect on publicly-owned electric utility RPS activities are the availability of PGC funds for renewable energy, the belief that the transmission needed to bring the renewable energy into their service territories will be built, and the match between operating characteristics of renewable energy and load needs.

- There was a concern among some publicly-owned electric utilities (Glendale, Merced, Modesto, and Santa Clara) that increasing support for renewable energy would diminish their ability to fund other PGC programs, specifically efficiency, where they feel money would be better spent.

In addition, the California Municipal Utilities Association has identified a number of RPS-related issues addressing the participation of publicly-owned electric utilities in a statewide renewable development plan. The Energy Commission plans to work with the publicly-owned electric utilities to address these issues in the context of local efforts to implement the statewide RPS goal.[186]

Smaller investor-owned utilities may have difficulty meeting the statewide RPS requirement. The circumstances facing Bear Valley Electric Service provide an example. First, existing long-term commitments meet Bear Valley Electric's long-term energy needs. Second, 20 percent of retail sales for Bear Valley Electric is 3.5 MW. The utility believes that procuring an amount this small may be difficult. Third, Bear Valley Electric pays wheeling access charges for transmission. These charges have increased by more than 50 percent since 2002. Bear Valley believes that transmission projects associated with the RPS will further increase the wheeling access charges and argues that such projects should be weighed against cost-effective alternatives to projects requiring upgrades to transmission.[187]

Many smaller publicly-owned electric utilities have joined regional associations to benefit from aggregated resource solicitation and supply arrangements. It is not clear whether this option is available for smaller IOUs. In decision number 03-06-071 of the Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development (R01-10-024), the CPUC stated its intention to open a new rulemaking to address RPS implementation issues for ESPs and CCAs. This rulemaking will also address issues for small IOUs.[188]

CHAPTER 9: RESEARCH ON RENEWABLE ENERGY

Many entities conduct research, development and demonstration of renewable resources and technologies including the U.S. Department of Energy, the eleven offices under the purview of the Office of Energy Efficiency and Renewable Energy, and the national laboratories funded by the U.S. Department of Energy, including the National Renewable Energy Laboratory. Internationally, even more aggressive renewable energy research and development activities are underway.

While many different institutions are conducting research on renewable energy, the Public Interest Energy Research (PIER) program is the largest source of funding for electricity-related ‘public interest’ research, development and demonstrations in the state. For this reason, this chapter will only discuss the renewable energy research being conducted by the PIER program.

PUBLIC INTEREST ENERGY RESEARCH PROGRAM

The PIER program, administered by the California Energy Commission (Energy Commission), was established in 1996 with the passage of Assembly Bill 1890 (AB 1890). The PIER program conducts energy-related research in a number of areas, including research on renewable energy.

The mission of PIER renewable energy research is to help develop renewable energy that will provide significant public benefits to California's electricity system. Four primary objectives to achieving that mission are to: 1) maximize value provided by renewable energy, 2) lower the cost of energy supplied by renewable resources, 3) expand applications of renewable resources in California's electricity system, and 4) pursue breakthrough renewable technologies.

The passage of Senate Bill 1078 (SB 1078) creating California's Renewables Portfolio Standard (RPS) program has influenced all on-going and proposed work in the PIER renewable energy area. PIER is undertaking research activities that support the goals outlined in the ***Energy Action Plan***. To support the state’s goal of achieving 20 percent of electricity coming from renewable energy resources by 2010, the PIER program is conducting research that can be grouped into the following types:

- Activities that help build a roadmap for meeting the RPS goals,
- Demonstrations for near and medium term deployment of renewable energy, and
- Research work, focused by renewable technology areas, that addresses unique California needs and opportunities and is highly leveraged.

Activities that Help Build a Renewables Portfolio Standard Roadmap

Effective development and deployment of renewable energy that meets both the RPS goals and provides high public benefits will require a well-conceived road map. The PIER renewable energy area has initiated several different activities to help create a roadmap for renewable energy development and deployment in California. Among the products being developed are the following:

- Up-to-date and higher resolution resource assessments to better identify the quality and locations of California's remaining renewable resources,[189]
- Technology characterizations including the status and trends of renewable energy technology costs and performance,
- Web-based tools that enable consumers to assess the feasibility of different renewable energy technologies, and
- A strategic value analysis that identifies potential electricity system "hot spots," the types and magnitude of renewable resources that could possibly be used to address the "hot spots," and comparisons between conventional versus renewable energy solutions.

Demonstrations for Near and Medium-Term Deployment of Renewable Energy

The PIER renewable energy area has pursued development of renewable technologies for deployment in the near and medium-term on two fronts. One focuses on developing groups of renewable projects that address affordability and diversity issues facing California's electricity suppliers. These projects are intended to act as templates that can be widely adopted by other California electricity suppliers. The second area for renewable development focuses on improvements in specific renewable resources to increase their near-term value to California's electricity system.

Over $31 million has been provided under the PIER renewable energy area for three efforts: $13.6 million to the Sacramento Municipal Utility District (SMUD), $11.7 million to Commonwealth Energy, and $5.8 million to Hetch Hetchy Water and Power (originally awarded to Northern California Power Agency). The SMUD effort represents a template for using renewable resources in a hot inland area to help meet summer peak demand. The Commonwealth Energy effort represents a template for using biomass and solar resources in combination to help convert a possible environmental liability issue into a clean and renewable distributed generation option. The Hetch Hetchy effort represents a template for using mixes of renewable energy resources in various sizes and deployment strategies to help meet electricity needs in an urban area facing capacity and congestion constraints. The Hetch Hetchy program is also a cooperative effort of over twenty municipal and investor-owned utilities (IOUs) spearheaded by the Center for Resource Solutions as their Public Renewables Partnership program. As such, the Hetch Hetchy effort also represents an important template for the coordinated development of renewable technologies among California investor and municipal utilities.

Research Work Focusing on California's Unique Needs and Opportunities

In addition to addressing RPS goals and demonstrating technologies for near term deployment, PIER renewable research activities focus on meeting unique needs and opportunities in the state. Research activities within in each technology area include:

Wind research activities:

- Resolving intermittency issues:
  - Lower cost methods for firming wind with storage or hybrid (e.g., fossil or other renewable) generation technologies
  - Developing wind forecasting methods that help better integrate wind generation into the California Independent System Operator (CA ISO) day-to-day scheduling operations
- Harnessing California's untapped wind resources:
  - Identifying optimal locations and methods for new wind energy sites in California
  - Developing low wind speed turbines with lower costs and improved capacity factors
  - Investigating ways to lower the cost and increase the reliability of integrating wind energy into California's electricity system
  - Exploring lower cost approaches for transmission interties to wind energy projects
- Addressing environmental impacts:
  - Development of bird flight paths to avoid mortality of at risk endangered avian species

Biomass research activities:

- Lowering costs of biomass power:
  - Expanding the capability to use lower cost biomass residues
  - Demonstrating the use of bioreactors thereby extending landfill life and improving landfill gas to electricity economics

- Improving performance:
  - Increasing co-firing and peaking capabilities of biomass power plants
- Making biomass power cleaner:
  - Developing low nitrogen oxides technologies that meet and exceed California Air Resources Board's 2007 distributed generation goals
  - Demonstrating ways to reduce groundwater and air quality impacts at landfills, dairies and wastewater treatment facilities through the use of advanced anaerobic digester gas systems
- Increasing responsiveness of biomass to local needs:
  - Developing small modular biomass technologies that help solve local electricity capacity and congestion problems
  - Expanding biomass technologies that can help address wild fire risks, urban landfill capacity problems and air quality issues tied to open field burning of agricultural residues

Geothermal research activities:

- Reducing risks and costs associated with geothermal exploration:
  - Expanding development of lower cost imaging exploration tools
- Resolving transmission constraints:
  - Exploring lower cost approaches for transmission interties to geothermal energy projects
- Improving resource management:
  - Developing methods for predicting decline of geothermal resources within targeted reservoirs and ways to slow or reverse the decline
  - Investigate strategic wastewater injection methods to reservoirs facing decline of the resource

Solar research activities:[190]

- Lowering costs and improving value:
  - Decreasing balance of system costs
  - Developing solar technologies that have multiple benefits
- Improving integration to meet California transmission grid needs:
  - Establishing grid connected systems with enhanced customer reliability and backup
  - Integrating energy efficiency and solar technologies to help develop affordable zero energy homes
- Addressing intermittency issue:
  - Optimizing methods and storage technologies that employ solar to help meet peak demand

PIER's Renewable Energy Strategic Value Analysis

The Strategic Value Analysis Project will help identify the impacts, benefits, technologies, and locations for developing and deploying renewable energy to meet California's electricity needs and the RPS. The study has four major components.

First, power flow simulations of California's electricity system will be conducted over the next twenty years to identify possible capacity, congestion, or reliability problems. The simulations are based on information obtained from IOUs, the Western Electricity Coordinating Council and California municipal utilities. The simulations take into account different load growths, climate variations, hydroelectric supplies, and contingency occurrences to provide a bracketed set of electricity scenarios. Areas of the state that have significant capacity, reliability, or congestion problems are identified as potential "hot spots."

Second, information on the locations and characteristics of the "hot spots" are transferred into a geographical information system (GIS) database. Renewable resource information, climate zones, environmental information, and certain types of demographic information are also transferred into the GIS database. Overlays are developed that examine the quantities and types of renewable energy resources contained in the identified "hot spot" areas. The power flow simulations are then run again using various penetration levels of renewable energy resources to determine their ability to help resolve the "hot spot" conditions. The preliminary results indicate both the upper and lower limits at which renewable resources could possibly help address the "hot spots." While the preliminary results indicate the possible impact of renewable energy resources, they do not compare how renewable energy resources compete against other solutions to the "hot spots," such as transmission and distribution upgrades or fossil generation options.

The third component of the study is to conduct comparisons between renewable and other solutions based on performance and cost. The results from the penetration analyses and the performance/cost comparisons will give an indication of the feasibility of deploying renewable energy to help address the "hot spots." The performance and cost comparisons also can be used to back into a set of technical and cost targets for renewable energy development. In particular, where commercially available renewable technologies cannot compete on a cost or performance basis against existing conventional solutions, the derived targets can act as research and development targets for future renewable technologies.

The fourth component of the study is to evaluate the ability of distributed generation renewable resources to help address localized electricity system problems as well as examine how localized solutions can affect regional electricity issues. Case studies will be conducted in at least three locations of the state to examine the renewable distributed generation options.

The Energy Commission will deliver a report on the results of the strategic value analysis to the Legislature by December 2003. To date, analyses have been conducted for 2003, 2005, 2007, and 2009. The preliminary results indicate that while the state has significant renewable resources, tradeoffs will be likely among the resources developed, the costs of building new transmission, and the possibility of importing renewable energy from nearby states.

CHAPTER 10: CONCLUSIONS

California has aggressively pursued electricity generation from renewable resources. In 2002, the state had over 7,000 megawatts (MW) of renewable capacity from biomass (solid-fuel, digester and landfill gas, and municipal solid waste), geothermal, small hydroelectric (30 MW or less), concentrated solar power (CSP), photovoltaics (PV), and wind. These facilities produced an estimated 28,900 gigawatt-hours per year (GWh/year) of electricity from renewable sources, accounting for about 11 percent of the electricity used in California.

Senate Bill 1038 (SB1038) directs the Energy Commission to develop a comprehensive renewable generation resource plan which describes the renewable energy potential along with a plan to increase electricity generation from renewable resources. SB 1038 also directs the California Public Utilities Commission (CPUC) to use the Energy Commission's renewable resource plan in preparing a transmission plan for electricity generated by renewable sources; both plans must be submitted to the Legislature by December 1, 2003.

To facilitate coordination of these tasks, the Energy Commission delivered a ***Preliminary Renewable Resource Assessment*** (PRRA) to the CPUC on July 1, 2003. The PRRA covered requirements for renewable resources for the investor-owned utilities (IOUs) and Electric Service Providers/Community Choice Aggregators. This report not only covers those entities, but also covers requirements for the entire state.

Additional data have been collected and analyzed since the PRRA was delivered to the CPUC. For example, this report includes updated information on proposed wind development in Riverside County as well as additional wind potential in Kern County.

As concluded in the PRRA and also illustrated in this report, California and the remaining states in the Western Electricity Coordinating Council (WECC) have considerable renewable resources, well in excess of the existing Renewables Portfolio Standard (RPS) requirements for all WECC states. The estimated total technical potential for wind, geothermal, biomass, biogas, CSP, small hydroelectric, and PV in California is over 262,000 GWh/year. The total technical potential in the non-California WECC for non-hydroelectric renewable resources is 3.7 million GWh/year, with wind accounting for 2.8 million GWh/year of the total.

The analysis in this report demonstrates that not only do the WECC states have a vast supply of untapped potential renewable resources, but development of these resources can come at a reasonable cost in many market niches. Moreover, the decline in installed costs for renewable energy projects is expected to continue with technology advances.

Wind, geothermal, and limited biomass applications are the most cost competitive renewable resources today. When configured as a firm peaking resource, CSP can compare favorably with recent estimates of conventional sources of peaking power. By 2005, a 75 MW wind plant (Class 4 wind site) is expected to deliver power at a real levelized cost of electricity (with the production tax credit) of 3.4 cents per kilowatt hour (cents/kWh), in 2003 dollars. During this same time-frame, a 50 MW geothermal system should have a levelized cost of electricity of approximately 5.3 cents/kWh to 5.5 cents/kWh. Also by 2005, the levelized cost of electricity for anaerobic digester gas (ADG) from animal waste is estimated to be as low as 4.3 cents/kWh.

Wind in particular has witnessed rapid technological and cost improvements. Today electricity from wind is one-tenth the cost it was 20 years ago when first introduced in California, and with continued improvements, wind power is expected to be economically competitive with conventional electricity generation sources in the near-term.

Electricity from customer-sited PV can be compared with retail electricity rates and, if technological advance continues at a rapid pace, is expected to be nearly cost competitive with retail rates by 2017. The PV market has seen substantial growth in the last several years. As of mid-2003, over 44 MW of PV systems have been installed in California.

The staff estimates that the additional procurement of renewable energy needed to achieve the statewide RPS goals is 4,230 GWh/year in 2005, 13,120 GWh/year for 2008, and 30,610 GWh/year in 2017. This report concludes that there are enough proposed renewable energy projects and undeveloped technical potential for renewable energy resources in California to meet the statewide RPS requirements. Out-of-state renewable energy resources are also eligible to participate in RPS bid solicitations, provided that certain criteria are met.

The staff estimates that the additional procurement of renewable energy needed statewide to achieve the accelerated RPS goal as confirmed in the ***Energy Action Plan*** is 6,120 GWh/year by 2005, 17,850 GWh/year by 2008, 24,800 GWh/year by 2010, and 30,610 GWh/year by 2017.

The mix of renewable resources and locations used to meet the RPS will be determined by the bids received in response to renewable energy solicitations. The staff has developed scenarios for how the RPS and an accelerated RPS could possibly be met. The scenarios are primarily based on renewable energy projects that have already been proposed in the state.

The Kern County wind resource area may be capable of satisfying much, if not all, of the renewable energy demand through 2008; however, least-cost-best-fit considerations will likely encourage geographic and resource diversity. Geothermal and biomass resources are expected to be valued for their ability to provide base load power that matches the generation profile of conventional sources. Smaller scale resources such as landfill gas and ADG are likely to play a more limited role. CSP becomes a factor in scenarios in the 2008-2017 timeframe.

The CPUC and the Energy Commission will continue collaborating to develop the rules for California's RPS. The implementation of the standard will require consideration of several important policy issues. The impact of renewable energy development on the transmission system will be affected by existing transmission capacity constraints, the portion of the RPS met by out-of-state resources, and whether renewable energy certificates can be used to meet the RPS requirement. Renewable resource development must be balanced with the operational compatibility of the existing electricity system and "least-cost-best-fit" considerations. At this time, it is not known whether there are sufficient public goods charge (PGC) funds to meet the RPS or an accelerated RPS. The adequacy of PGC funds should be assessed at the conclusion of the first RPS solicitation.

Generating electricity from renewable sources does not come without environmental impacts. Wind turbines and associated transmission lines are problematic for migratory and resident birds. Developing geothermal resources can result in groundwater and surface water contamination while small hydroelectric development can negatively impact water flows, water quality, and fish migration.

The research that supports electricity from renewable resources is being conducted by many entities; however, the Public Interest Energy Research (PIER) program is the largest source of energy-related research in California. To support the RPS, the PIER program is developing renewable resource assessments, technology characterizations, web-based tools, and a strategic value analysis that identifies potential electricity system "hot spots." The PIER program is also working on projects that address the environmental impacts associated with wind, biomass, and biogas projects.

LIST OF ACRONYMS

ADG	animal digester gas
APT	Annual Procurement Target
AWEA	American Wind Energy Association
BPA	Bonneville Power Administration
CA ISO	California Independent System Operator
CalPIRG	California Public Interest Research Group
CalWEA	California Wind Energy Association
CCA	community choice aggregator
Cents/kWh	cents per kilowatt hour
CO_2	carbon dioxide
CCA	Community Choice Aggregator
CPA	California Power Authority
CPUC	California Public Utilities Commission
CSP	concentrating solar power
DSM	Demand side management
DWR	Department of Water Resources
ESP	electric service provider
FERC	Federal Energy Regulatory Commission
GBtu	Giga (Billion) British Thermal Units
GIS	geographic information system
GWh	Gigawatt-hours
ISO4	Interim standard offer 4
IOUs	investor-owned utilities
Jobs/MW	jobs per megawatt
Kg/MWh	kilogram per megawatt hour
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LOIs	Letters of intent
mph	miles per hour
MSW	municipal solid waste
MW	megawatts
NPUC	Nevada Public Utilities Commission
NREL	National Renewable Energy Laboratory
NOx	nitrogen oxides
NCPA	Northern California Power Agency
OASIS	Open Access Same Time Information System
OTEC	ocean thermal energy conversion
PGC	Public goods charge
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research
PM_{10}	particulate matter (10 microns or less)

List of Acronyms (continued)

PRRA	***Preliminary Renewable Resource Assessment***
PTC	Production tax credit
PUC	Public Utilities Code
PURPA	Public Utilities Regulatory Policies Act
PV	photovoltaic
QF	qualifying facility
RER	Regional Economic Research
RFP	Request for Proposals
RPS	Renewables Portfolio Standard
RRDR	***Renewable Resources Development Report***
RRTF	Renewable Resources Trust Fund
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority
SDG&E	San Diego Gas and Electric
SEGS	Solar Electric Generating Systems
SEPs	Supplemental energy payments
SMUD	Sacramento Municipal Utility District
SOx	sulfur oxides
SRAC	Short-run avoided cost
SWPA	Southwestern Power Administration
WECC	Western Electricity Coordinating Council
WGA	Western Governor's Association

ENDNOTES

[1] The ***Energy Action Plan*** is available on-line at http://www.energy.ca.gov/2003_energy_action_plan/index.html. Accessed September 1, 2003.
[2] Technical Potential was provided by the Commission's PIER program, except for solar where the RER data was used.
[3] The estimate of technical potential for small hydroelectric does not include energy from existing hydroelectric facilities. Also, it does not filter out sites that have existing large hydroelectric facilities or sites where adding to existing facilities would exceed the 30 MW limit.
[4] Class 4 wind defined as ~ 7 – 7.5 m/s or 15.7 mph at 50 meter hub height.
[5] Class 6 wind defined at ~ 8 – 8.8 m/s or 17.9 mph at 50 meter hub height.
[6] The June 5, 2003, California Energy Commission ***Final Staff Draft Report Comparative Cost of California Central Station Electricity Generation Technologies*** (100-03-001F) contains estimates of central station generation technologies for a number of fossil fuel and renewable energy generation technologies. In order to provide an indication of renewable energy cost trends over time, including biomass and distributed generation PV systems together with wind, geothermal, and CSP, staff needed to look for an additional source of data. For this purpose, staff relied on a levelized cost of energy model prepared by Navigant Consulting, Inc. (Navigant Consulting), subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036). The assumptions used by Navigant Consulting to develop these cost trend estimates are included in
Appendix D.
[7] Note, however, that seeking the necessary "amendment" entails renegotiating the contract, which could prove to be difficult if the utility is uncooperative.
[8] *Based on estimated 2001 baseline and publicly available information on the Interim Procurement. This analysis assumes that all of the "obligated entities" identified in the table above procured an additional one- percentage point increase in their renewable baseline between 2001 and 2003. **Rest of state includes Rural Cooperatives, IOUs other than PG&E, SDG&E, and SCE, and publicly-owned electric utilities. These entities are not specifically required to achieve 20 percent renewable generation.
[9] *Based on estimated 2001 baseline and publicly available information on the Interim Procurement. This analysis assumes that all of the "obligated entities" identified in the table above procured an additional one-percentage point increase in their renewable baseline between 2001 and 2003. **Rest of state includes Rural Cooperatives, IOUs other than PG&E, SDG&E, and SCE, and publicly-owned electric utilities. These entities are not specifically required to achieve 20 percent renewable generation.
[10] Consideration of least cost best fit is included in SB 1078.

[11] Renewable Electric Power Sector Net Generation by Source and State, 1999. "Appendix C: Table C1." Energy Information Administration. http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/appendixc.html Viewed September 11, 2003. Hydroelectric was subtracted from this assessment since much of the hydroelectric is large hydroelectric (>30 MW), which is not an eligible renewable source for the purposes of California's RPS.
[12] This report was prepared with the assistance of XENERGY, Inc. Contracting Team, Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036).
[13] U.S. Department of Energy, Energy Information Administration, 1998, ***Renewable Energy Annual 1998***, p. 9.
[14] The ***Energy Action Plan*** can be downloaded at: http://www.energy.ca.gov/2003_energy_action_plan/index.html.Viewed September 11, 2003
[15] Arizona Corporation Commission, ***Final Rulemaking for the Environmental Portfolio Standard***. Available online at http://www.cc.state.az.us/utility/electric/R14-2-1618.htm. Accessed November 4, 2003.
[16] Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, GreenInfo Network, July 2002, ***Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential.*** A project of the Hewlett Foundation and the Energy Foundation. Available on-line at www.EnergyAtlas.org.
[17] Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, GreenInfo Network, July 2002, ***Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential.*** A project of the Hewlett Foundation and the Energy Foundation. Available on-line at www.EnergyAtlas.org.
[18] Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, GreenInfo Network, July 2002, ***Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential.*** A project of the Hewlett Foundation and the Energy Foundation. Available on-line at www.EnergyAtlas.org.
[19] U.S. Department of Energy, "Status of State Electric Industry Restructuring Activity as of February 2003," Available on-line at http://www.eia.doe.gov/cneaf/electricity/chg_str/oregon.html, Accessed September 16, 2003.
[20] Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, GreenInfo Network, July 2002, ***Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential.*** A project of the Hewlett Foundation and the Energy Foundation. Available on-line at www.EnergyAtlas.org.
[21] Powerex submitted written comments that the Canadian provinces of British Columbia and Alberta have substantial renewable resources yet to be developed. Powerex states that the total renewable resource potential in British Columbia is estimated to be 21,500 GWh/year. An additional 400 MW of predominantly wind will be on-line in Alberta by 2006. Powerex Corporation, November 17, 2003, "Comments of Powerex on The Committee Final Renewable Resource Development Report." Filed with the California Energy Commission, Docket No. 02-REN-1038.

[22] AWEA, 2003, Global Wind Energy Market Report, available on-line at http://www.awea.org/pubs/documents/globalmarket2003.pdf. Accessed September 12, 2003.

[23] American Wind Energy Association, 2003, Global Wind Energy Market Report, available on-line at http://www.awea.org/pubs/documents/globalmarket2003.pdf. Accessed September 12, 2003.

[24] U.S. Department of Energy – Energy Efficiency and Renewable Energy, Wind Power Today, May 2003, pg. 4.

[25] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. "Wind Farms and Wind Farmers." Consumer Energy Information: EREC Reference Briefs. Available online at http://www.eere.energy.gov/consumerinfo/refbriefs/ad2.html. Accessed October 15, 2003

[26] American Wind Energy Association (AWEA) Wind Project Data Base, available on-line at http://www.awea.org/projects/ Accessed September 11, 2003.

[27] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Wind Farms and Wind Farmers," Consumer Energy Information: EREC Reference Brief, Jan 2003.

[28] American Wind Energy Association, Wind Project Data Base, available on-line at http://www.awea.org/projects/ california.html. Accessed September 11, 2003.

[29] Statement by Nancy Rader, Executive Director, California Wind Energy Association, in response to a question from Commissioner Geesman at the California Energy Commission's Joint Committee workshop on the 2003 ***Integrated Energy Policy Report*** held June 24, 2003 (page 48-49 of hearing transcript). Transcript is available on-line at http://www.energy.ca.gov/energypolicy/documents/2003-06-24_joint_workshop/2003-06-24_TRANSCRIPTS.PDF.

[30] American Wind Energy Association, June 2002, ***The U.S. Small Wind Turbine Industry Roadmap***, page 7. Available on-line at http://www.awea.org/smallwind/documents/31958.pdf. Accessed September 22, 2003.

[31] American Wind Energy Association, June 2002, ***The U.S. Small Wind Turbine Industry Roadmap***. Available on-line at http://www.awea.org/smallwind/documents/31958.pdf. Accessed September 22, 2003.

[32] As of August 26, 2003.

[33] See Charles F. Kutscher, 2000, ***The Status and Future of Geothermal Electric Power***, Conference Paper, Golden, CO: National Renewable Energy Laboratory, U.S. Department of Energy. Available on-line at http://www.nrel.gov/geothermal/pdfs/28204.pdf. Accessed September 18, 2003.

[34] See U.S. Department of Energy, National Renewable Energy Laboratory, "Introduction to geothermal electricity production," Available on-line at http://www.nrel.gov/clean_energy/geoelectricity.html. Accessed September 10, 2003.

[35] U.S. Department of Energy, Office of Geothermal Technologies, "Energy Conversion," DOE/GO-10098-537. Available on-line at http://www.eren.doe.gov/geothermal. Updated March 1998. Accessed September 10, 2003.

[36] California Energy Commission, Geothermal Resources Development Account, "Energy Commission Geothermal Program," available on-line at

http://www.energy.ca.gov/geothermal/index.html. Updated April 18, 2003. Accessed September 10, 2003.

[37] California Energy Commission, "PIER - Renewable Energy Technologies: Overview," Updated October 2001. Available on-line at http://www.energy.ca.gov/pier/renew/. Accessed September 10, 2003.

[38] U.S. Department of Energy, “CSP Technologies Overview” available on-line at http://www.energylan.sandia.gov/sunlab/overview.htm#dish. Accessed October 16, 2003

[39] U.S. Department of Energy, Energy Efficiency and Renewable Energy Network, 2001, “Overview of Solar Thermal Technologies,” available on-line at http://www.energylan.sandia.gov/sunlab/PDFs/solar_overview.pdf. Accessed September 12, 2003.

[40] U.S. Department of Energy, Energy Efficiency and Renewable Energy Network, Concentrating Solar Power and Sun Lab, 2001, “CSP Technologies Overview,” available on-line at http://www.energylan.sandia.gov/sunlab/overview.htm. Accessed September 12, 2003.

[41] U.S. Department of Energy, National Renewable Energy Laboratory, "Bioenergy: An Overview," Consumer Energy Information: EREC Reference Briefs, http://www.eere.energy.gov/consumerinfo/refbriefs/nb2.html. Last updated July 2002. Accessed September 10, 2003.

[42] California Energy Commission, ***Transportation Fuels, Technologies and Infrastructure Assessment Report*** prepared in support of the ***2003 Integrated Energy Policy Report***, 100-03-013D, October 2003. Available on-line at: http://www.energy.ca.gov/energypolicy/documents/2003-10-10_100-03-013D.PDF

[43] U.S. Department of Energy, National Renewable Energy Laboratory, "Bioenergy: An Overview," Consumer Energy Information: EREC Reference Briefs, http://www.eere.energy.gov/consumerinfo/refbriefs/nb2.html. Last updated July 2002. Accessed September 10, 2003.

[44] This figure includes the 30 MW Honey Lake biomass facility that was shut down for a 6-9 month period.

[45] “PV Market Update,” ***Renewable Energy World***, July/August 2003, available on-line at http://www.jxj.com/magsandj/rew/2003_04/pv_market_update.html. Accessed September 12, 2003.

[46] U.S. Department of Energy, Sandia National Laboratory, National Center for Photovoltaics, 2002, ***Solar Electric Power: The U.S. Photovoltaic Industry Roadmap***, http://www.sandia.gov/pv/docs/PDF/PV_Road_Map.pdf. Accessed September 12, 2003.

[47] From Solar Buzz, “Fast Solar Energy Facts: Solar Energy USA,” www.solarbuzz.com/FastFactsUSA.htm Updated July 2003. Accessed September 11, 2003.

[48] Environment California Research and Policy Center, July 2003, ***Renewable Energy and Jobs: Employment Impacts of Developing Renewables in California,*** page 15. Available on-line at http://www.environmentcalifornia.org/reports/renewables_jobs_7_03.pdf. Accessed September 26, 2003. Also, U.S. Department of Energy, Energy Efficiency and

Renewable Energy Network, “Overview of Photovoltaic Technologies.” Available on-line at http://www.eere.energy.gov/power/pdfs/pv_overview.pdf. Accessed September 26, 2003.
[49] U.S. Department of Energy, National Renewable Energy Laboratory, 2002, "Building Integrated Photovoltaics for Commercial Buildings," and "Switching on the Sun," NREL JA-810-31967, June 2002.
[50] U.S. Department of Energy, National Renewable Energy Laboratory, 2002, "Switching on the Sun," NREL/JA-810-3167 July 2002.
[51] See U.S. Department of Energy. Energy Efficiency and Renewable Energy, Consumer Energy Information: EREC Reference Briefs, available on-line at http://www.eere.energy.gov/consumerinfo/refbriefs/nb1.html.
[52] See California Energy Commission, “Ocean Energy," available on-line at www.energy.ca.gov/development/oceanenergy. Last updated June 24, 2002, Accessed September 11, 2003.
[53] See European Commission, Energy Program, Atlas Project, ”Wave Energy – Market Barriers,” available on-line at http://europa.eu.int/comm/energy_transport/atlas/htmlu/wavmark.html. Accessed September 12, 2003.
[54] See California Energy Commission, “Ocean Energy," available on-line at www.energy.ca.gov/development/oceanenergy. Last updated June 24, 2002, Accessed September 11, 2003.
[55] SB 1038, Sher, Chapter 515, Statutes of 2002.
[56] SB 1078, Sher, Chapter 516, Statutes of 2002.
[57] California Energy Commission, August 2003, ***California Hydropower System: Energy and Environment (Staff Draft), Appendix D*** to the ***2003 Environmental Performance Report.***
[58] Federal Energy Regulatory Commission, undated September 12, 2003, Hydroelectric Licensing Rulemaking, Order 2002. Available on line at http://www.ferc.gov/industries/hydropower/indus-act/ht-over.asp.
[59] The installed renewable capacity figures in California were provided by the California Energy Commission’s Cartography Unit. The installed renewable capacity in this report is different than the capacity in the Preliminary Renewable Resources Assessment. As part of the registration process for the RPS, the Commission will attempt to clarify the amount of installed renewable energy facilities in California. Other sources indicate that there are only 900 MW of biomass installed in California, over 1,800 MW of wind installed in California and less than 800 MW of small hydroelectric installed in California.
[60] See California Energy Commission, “1983-2002 California Electricity Generation” report at: http://www.energy.ca.gov/electricity/index.html#generation Updated July 2003. Accessed September 11, 2003. Small Hydroelectric generation data come from the “2002 Total Electricity Production” report at: http://www.energy.ca.gov/electricity/gross_system_power.html. Updated April 22, 2003, Accessed September 11, 2003. For 2001 and 2002, the "average" estimate of how much energy would be produced by installed renewables in California (see Appendix C) is significantly higher than what was actually produced according to the J-11 table.

This is especially true with geothermal. The reason for this discrepancy is that the capacity factor for older and less efficient equipment is lower than the capacity factor for newer and more efficient equipment.

[61] The Standard Offer Number 4 contracts were intended to be interim, pending final regulatory determination of standard terms. However, the ISO4 offers were suspended (no longer available for new contracts) in April 1985 (SO2 offers were suspended in March 1986), after a large amount of capacity was signed

[62] California Energy Commission, August 2003, ***Staff Report: Comparative Cost of California Central Station Electricity Generation Technologies*** (100-03-001). Available on-line at http://www.energy.ca.gov/energypolicy/documents/. Accessed September 18, 2003.

[63] Class 4 wind defined as ~ 7 – 7.5 m/s or 15.7 mph at 50 meter hub height.

[64] Class 6 wind defined at ~ 8 – 8.8 m/s or 17.9 mph at 50 meter hub height.

[65] Though note that many of these wind bids – including those revealed through the contracts signed by the California Department of Water Resources and the Letters of Intent signed by the California Power Authority – were submitted during California's electricity crisis, and therefore may not be truly indicative of actual costs.

[66] Sales tax was not included in the levelized cost of energy for any of the technologies. The California Wind Energy Association submitted written comments that California sales tax adds at least 8.25% to the capital cost of wind compared to other states. Nancy Rader, California Wind Energy Association, November 14, 2003, "Comments of the California Wind Energy Association on the November 7, 2003, Committee Final Renewable Resources Development Report." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.

[67] Assuming a cost of biomass fuel of $30/dry ton.

[68] Calpine submitted written comments on the RRDR calling the 5.3 to 5.5 cents per kWh "aggressive" (too low) given the magnitude of the proposed development. Jack Pigott, Calpine Corporation, October 14, 2003, "Calpine Corporation's comments on the Staff Draft Renewable Resources Development Report." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.

[69] Calpine submitted written comments regarding comparing geothermal projects in California to those in Nevada. Calpine states that "it is important to consider California's higher taxes, labor cost differentials, and the possibility that the project will be subject to the SB 1078 prevailing wage requirement. Jack Pigott, Calpine Corporation, October 14, 2003, "Calpine Corporation's comments on the Staff Draft Renewable Resources Development Report." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.

[70] For bulk power generated from wind and solar energy, storage is typically not used today. Small-scale, off-grid PV systems often include battery storage, but this is not the subject of the analysis presented here.

[71] An "imbalance" occurs when actual deliveries are either more or less than the amount of resource scheduled during any period. Imbalance energy is typically the most expensive type of energy since it is often purchased on a very short-term (hour ahead or real-time) basis.

[72] The PIER renewables program is supporting a wind integration study by the Renewables Portfolio Standards (RPS) Integration Methods Group. The group is led by the California Wind Energy Collaborative (CWEC) and includes staff and researchers from California Independent System Operator (CA ISO), Oak Ridge National Laboratory and National Renewable Energy Laboratory. On September 12, 2003, a staff workshop was held to discuss ***Phase I: Findings and Results of Costs of Integrating Renewables***.
[73] Nancy Rader, California Wind Energy Association, November 14, 2003, "Comments of the California Wind Energy Association on the November 7, 2003, Committee Final Renewable Resources Development Report." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.
[74] Repowering existing sites has other advantages over greenfield development besides access to some of the best renewable resources in the state: a repowered facility will likely be able to take advantage of existing infrastructure (e.g., roads, substations, transmission lines) and will perhaps experience lower permitting hurdles (because of previous use for the same purpose).
[75] BTM Consult ApS, March 2001, ***International Wind Energy Development World Market Update 2000, Forecast 2001-2005***, p. 8.
[76] Note, however, that seeking the necessary "amendment" entails renegotiating the contract, which could prove to be difficult if the utility is uncooperative.
[77] Though this may be the case only for lower-cost technologies (e.g., wind, landfill gas, geothermal), which are more likely to win RPS solicitations. Also note that for a facility with an existing contract originally entered into before September 26, 1996, only the generation above the amount already under contract may compete for SEPs.
[78] The California Wind Energy Association arrived at this number by tallying total capacity from all existing turbines under 200 kW of nameplate capacity, and assuming that roughly half of this capacity would initially repower (on a one-for-one capacity basis) upon removal of the California fix from the PTC legislation. The remaining 450 MW (900 MW total) might also eventually repower, though likely not immediately.
[79] Bryan Jenkins, University of California, Davis, October 7, 2003, "Renewable Resources Development Report: Comments of the California Biomass Collaboration." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.
[80] The Northern California Power Authority (NCPA) owns a portion of the capacity at The Geysers. Note that many of the drivers of repowering mentioned above would not apply to NCPA.
[81] Again, in light of the RPS, it is unclear how willing the utilities would be to break standard offer contracts.
[82] Technical Potential was provided by the California Energy Commission's PIER program, except for solar where the RER data was used. The estimate of technical potential for small hydroelectric does not include energy from existing hydroelectric facilities. Also, it does not filter out sites that have existing large hydroelectric facilities or sites where adding to existing facilities would exceed the 30 MW limit

[83] California Energy Commission, 1983-2002 California Electricity Generation (J-11 table). Available on-line at http://www.energy.ca.gov/electricity/index.html#generation.

[84] Estimates for California's renewable technical potential vary, sometimes greatly, among studies. The reasons for these variations may include the different time frames in which the studies were conducted, the filtering of data using differing criteria, and in the case of solar, how photovoltaic and central station are counted or characterized.

[85] U.S. Department of Energy, Idaho National Engineering and Environmental Laboratory, June 2002, Uniform Criteria for U.S. Hydropower Resource Assessment, ***Hydropower Evaluation Software (HES) User's Manual***, DOE/ID-10338, Rev. 1.

[86] Estimates of on-line energy production were calculated from installed capacity using the following capacity factors: wind 25 percent, geothermal 90 percent, organic biomass 65 percent, MSW/tire 70 percent, biogas 85 percent, solar thermal 27 percent, solar PV 15 percent, small hydro 35 percent. Actual energy production varies year to year and is not shown in this table. Proposals with location designated as only NP15 or SP15 resources are excluded because of insufficient information on location. Superscripted notes to this table are as follows: a) This is the physical location of the renewable energy resource and its need for transmission. The distribution of renewable energy to meet the RPS needs of each IOU and publicly-owned electric utility will be determined through competitive bid solicitations. b) On-line projects exceed technical potential for geothermal in the following counties: Lake, Modoc, and Sonoma. c) Technical potential is less than estimated energy produced from on-line renewable resources.

[87] Generally, in weeding out redundant project entries, the entries were kept from whichever source provided the most useful information. Of 238 original entries for proposed projects from all sources, 77 (32 percent) were eliminated as duplicative or otherwise conflicting.

[88] California Energy Commission, June 2003, ***Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues, Final Commission Report***, Pub. No: 500-03-023F, p. 22.

[89] Solar thermal in this section refers to concentrating solar power electric generation, not solar hot water heating.

[90] California Energy Commission, June 2003, ***Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues, Final Commission Report***, Pub. No: 500-03-023F, p. 6-7. See also California Energy Commission, October 2003, ***Renewable Portfolio Standard: Decision on Phase 2 Implementation Issues, Commission Report***, Pub. No. 500-03-049F, p. 26-28.

[91] California Energy Commission, June 2003, ***Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues, Final Commission Report***, Pub. No: 500-03-023F, p. 17.

[92] California Energy Commission, October 2003, ***Renewable Portfolio Standard: Decision on Phase 2 Implementation Issues, Commission Report***, Pub. No. 500-03-049F.

[93] California Public Utilities Commission, June 19, 2003, Decision 03-06-071, ***Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program***, p. 49.
[94] California Public Utilities Commission, June 19, 2003, Decision 03-06-071, ***Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program***, p. 52.
[95] The Utility Reform Network (TURN) and San Diego Gas and Electric (SDG&E) Joint Principles as cited in California Public Utilities Commission, June 19, 2003, Decision 03-06-071, ***Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program***, p. 55.
[96] California Public Utilities Commission, October 22, 2003, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development, (Rulemaking 01-10-024), ***Administrative Law Judge's Ruling Establishing Procedure For Adoption Of Standard Contract Terms And Conditions*****.**
[97] California Public Utilities Commission, June 19, 2003, Decision 03-06-071, ***Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program***, p. 28.
[98] California Energy Commission, October 2003, ***Renewable Portfolio Standard: Decision on Phase 2 Implementation Issues, Commission Report***, Pub. No. 500-03-049F, p. 25-28.
[99] California Energy Commission, October 2003, ***Renewable Portfolio Standard: Decision on Phase 2 Implementation Issues, Commission Report***, Pub. No. 500-03-049F, p. 29.
[100] For information regarding Southern California Edison's Request for Proposals from Eligible Renewable Resources see "2003 Renewable Resource Solicitation," available on-line at http://www.sce.com/renewablerfo. Accessed September 15, 2003.
[101] Southern California Edison, August 29 2003, ***SCE Renewable Conceptual Transmission Plan***, available on-line at http://www.sce.com/sc3/005_regul_info/default.htm under CPUC Open Proceeding I.00-11-001. Accessed September 12, 2003.
[102] Pacific Gas and Electric Company, August 29, 2003, ***Pacific Gas and Electric Company's Screening Level Study Requires by SB 1038***, filed under CPUC Proceeding I.00-11-001.
[103] R.W. Beck, August 2003, ***Renewables Transmission Study for San Diego Gas and Electric***, filed under CPUC Proceeding I.00.11-001.
[104] The 2017 and 2010 timeframes were used in this report to be consistent with the RPS and the ***Energy Action Plan.***
[105] SCE announced the May and June, 2003 renewable sales numbers in an August 29, 2003 press release. See: http://www.edison.com/media/.
[106] SCE announced their intention to have more than 20 percent of future sales come from renewable energy in a September 9, 2003 letter from Gary L. Schoonyan of SCE to the Commissioners of the California Public Utilities Commission, California

Energy Commission, and the California Power Authority regarding California's ***Energy Action Plan***.

[107] For information regarding Southern California Edison's Request for Proposals from Eligible Renewable Resources see "2003 Renewable Resource Solicitation," available on-line at http://www.sce.com/renewablerfo. Accessed September 15, 2003.

[108] Staff recognizes that this approach is problematic from a mathematical standpoint, but believes that any error introduced by this approach is small.

[109] SCE announced the May and June, 2003 renewable sales numbers in an August 29, 2003 press release. See: http://www.edison.com/media/.

[110] SCE announced their intention to have more than 20 percent of future sales come from renewable energy in a September 9, 2003 letter from Gary L. Schoonyan of SCE to the Commissioners of the California Public Utilities Commission, California Energy Commission and the California Power Authority regarding California's ***Energy Action Plan***.

[111] For information regarding Southern California Edison's Request for Proposals from Eligible Renewable Resources see "2003 Renewable Resource Solicitation," available on-line at http://www.sce.com/renewablerfo. Accessed September 15, 2003.

[112] Staff recognizes that this approach is problematic from a mathematical standpoint, but believes that any error introduced by this approach is small.

[113] Assuming that the standard of 20 percent, once reached in 2010, would remain constant in percentage terms until 2017.

[114] Note again that the proposed project list used in this assessment has been updated somewhat from the one first presented in the ***Preliminary Renewable Resource Assessment***, published July 1, 2003.

[115] In calculating this mix, we excluded proposed projects whose location was not specified, or was only specified as NP15 or SP 15. We excluded these projects because there is significant risk that some of these projects are duplicates of projects already included in the list.

[116] It is possible that some new small hydroelectric facilities will be developed under the California RPS. However, even the small hydroelectric projects identified in the proposed project list may not meet California's stringent requirements for the eligibility of new small hydroelectric facilities under the RPS. As such, this assessment does not discuss small hydroelectric further.

[117] 2,540 GWh/year for IOUs and ESPs/CCAs, and 1,690 GWh/year for the rest of the state.

[118] 6,300 GWh/year for IOUs and ESPs/CCAs, and 2,580 GWh/year for the rest of the state.

[119] 8,840 GWh/year for IOUs and ESPs/CCAs, and 4,280 GWh/year for the rest of the state.

[120] 12,360 GWh/year for IOUs and ESPs/CCAs, and 5,130 GWh/year for the rest of the state.

[121] 21,200 GWh/year for IOUs and ESPs/CCAs, and 9,410 GWh/year for the rest of the state.

[122] Note again that the proposed projects used to construct this scenario exclude those projects whose location is not well specified. Also note that in constructing this scenario, we do not assume that all *individual* projects in the proposed project database are in fact constructed. Instead, we assume that projects consistent in size and renewable resource type to those proposed are built.
[123] Specific projects added include: (1) 45 megawatts of solid-waste biomass facilities in Northern California, (2) 310 megawatts of wind in San Bernardino county, (3) 315 megawatts of wind in Los Angeles county, (4) 130 megawatts of geothermal in Imperial county, (5) 60 megawatts of solar thermal electric power in San Bernardino county, and (6) 270 megawatts of wind in Kern County.
[124] See California Public Utilities Commission R.01-10-024, SCE-L-1, U 338-E filed on April 15, 2003.
[125] The total proposed projects shown here (26,390 GWh/year) excludes proposed renewable energy projects that did not provide sufficient information to assign a county location. The total amount of added renewable energy development exceeds the currently proposed projects in some cases. Where this occurs, additional energy from the remaining technical potential was added to create a scenario meeting the estimated renewable energy demand of the statewide RPS.
[126] 3,690GWh/year for IOUs, ESPs/CCAs. 2,430 GWh/year for the rest of the state.
[127] 8,350 GWh/year for IOUs, ESPs/CCAs. 3,380 GWh/year for the rest of the state.
[128] 12,050 GWh/year for IOUs, ESPs/CCAs. 5,800 GWh/year for the rest of the state.
[129] 4,630 GWh/year for IOUs, ESPs/CCAs. 2,320 GWh/year for the rest of the state.
[130] 16,670 GWh/year for IOUs, ESPs/CCAs. 8,130 GWh/year for the rest of the state.
[131] 4,530 GWh/year for IOUs, ESPs/CCAs. 1,280 GWh/year for the rest of the state.
[132] 21,200 GWh/year for IOUs and ESPs/CCAs, and 9,410 GWh/year for the rest of the state.
[133] Les Guliasi, Pacific Gas and Electric Company, October 7, 2003, "Pacific Gas and Electric Company's Comments -- Renewable Resource Development Report." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.
[134] The total proposed projects shown here (26,390 GWh/year) excludes proposed renewable energy projects that did not provide sufficient information to assign a county location. The total amount of added renewable energy development exceeds the currently proposed projects in some cases. Where this occurs, additional energy from the remaining technical potential was added to create a scenario meeting the estimated renewable energy demand of the statewide RPS.
[135] "Green power gaining clout in price competitiveness," John G. Edwards, March 12, 2003. Las Vegas Review-Journal.
[136] California Energy Commission, 2003, ***Staff Draft Energy Infrastructure Assessment***, (Pub No. 100-03-007F), p. 19.
[137] See Electric Power Research Institute, ***California Renewable Technology Market and Benefits Assessment***, November 2001. Prepared under contract to the Energy Commission. See also, Environment California Research and Policy Center,

Renewable Energy and Jobs: Employment Impacts of Developing Markets for Renewables in California, July 2003. Note: the technology mix assumed by Environment California was 35 percent wind, 50 percent geothermal, and 15 percent biomass. Available online at http://www.environmentcalifornia.org/reports/renewables_jobs_7_03.pdf. Accessed October 17, 2003.
[138] The retail sales estimate and other data used to develop the RPS information have been revised since the scenarios were modeled. For example, the scenario for achieving the RPS by 2010 assumes an average addition of 600 MW/year of renewable electricity from 2004 through 2013 for IOUs only. Because the load forecast has been revised downward, that 600 MW number now appears to be high. Staff's current estimate for the accelerated scenario is the addition of 800 MW from 2004-2010 statewide (5,600 MW).
[139] Mark Bolinger, Ryan Wiser, and William Golove, August 2003, ***Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation***. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division (LBNL-53587).
[140] See California Energy Commission, "California's Major Sources of Energy." Available on-line at http://www.energy.ca.gov/html/energysources.html.
[141] U.S. EPA, "Air Trends: More Details on Nitrogen Dioxide." Available on-line at http://www.epa.gov/airtrends/nitrogen2.html. Updated September 24th, 2002. Accessed June 11, 2003.
[142] See U.S. Environmental Protection Agency, "The Plain English Guide to the Clean Air Act: The Common Air Pollutants (Criteria Air Pollutants)," available on-line at http://www.epa.gov/oar/oaqps/peg_caa/pegcaa11.html. Updated May 13th 2002. Accessed June 10, 2003.
[143] U.S. Environmental Protection Agency, Office of Water, "Air Pollution and Water Quality: Atmospheric Deposition Initiative: Where is the Air Pollution Coming From?" Available on-line at http://www.epa.gov/owowwtr1/oceans/airdep/air5html. Accessed June 10, 2003.
[144] California Energy Commission, 2003, "Developing Methods to Reduce Bird Fatalities in the Altamont Pass Wind Resource Area Project Description (Contract # 500-01-019), ***Public Interest Energy Research Annual Report 2002, Appendix A: PIER program Project Summaries***, p. 135.
[145] K. Sinclair, 2001, ***Status of Avian Research at the National Renewable Energy Laboratory***, NREL: Golden, CO. Available on-line at http://www.nrel.gov/docs/fy01osti/30546.pdf. Accessed June 13, 2003.
[146] Bonneville Power Administration, February 22, 2001, ***Request For Wind Project Proposals***, p. 10. Available on-line at http://www.bpa.gov/power/pgc/wind/Wind_RFP_Final.pdf. Accessed June 11, 2003.
[147] Electric Power Research Institute (EPRI), 2002, ***Renewable Energy Technical Assessment Guide-TAG-RE 2002***, p. 6-24.
[148] Union of Concerned Scientists, "Clean Energy Backgrounder: Environmental Impacts of Renewable Energy Technologies," adapted from material in the UCS book ***Cool Energy: Renewable Solutions to Environmental Problems***, by

Michael Brower (MIT Press, 1992). See http://www.ucsusa.org/clean_energy/renewable_energy/. Last updated 10/26/2002. Accessed June 13, 2003.

[149] Electric Power Research Institute (EPRI), 2002, ***Renewable Energy Technical Assessment Guide-TAG-RE 200***2, p. 6-24.

[150] For example, see California Energy Commission, California Distributed Energy Resource Guide: DER Equipment: Stirling Engines," Available on-line at http://www.energy.ca.gov/distgen/equipment/. Accessed June 14, 2003.

[151] Public Utilities Code, Section 383.5(d)(6)(C), as amended by SB 1038.

[152] U.S. Department of Energy, "Biomass Research and Development Initiative." Available online at http://www.bioproducts-bioenergy.gov. Accessed October 16, 2003

[153] Electric Power Research Institute (EPRI), 2002, ***Renewable Energy Technical Assessment Guide-TAG-RE 200***2, p. 4-75.

[154] Electric Power Research Institute (EPRI), 2002, ***Renewable Energy Technical Assessment Guide-TAG-RE 200***2, p. 7-18

[155] U.S. Department of Labor, Occupational Safety and Health Administration, "Safety and Health Topics: Cadmium." Revised December 20, 2002. Available on-line at http://www.osha.gov/SLTC/cadmium/index.html. Accessed June 14, 2003.

[156] U.S. Agency for Toxic Substances and Disease Registry, June 1999, "ToxFaqs™ for Lead," CAS# 7439-92-1. Available on-line at http://www.atsdr.cdc.gov/tfacts13.html. Accessed June 14, 2003.

[157] Vasilis Fthenakis and Ken Zweibel, 2003, "CdTe PV: Real and Perceived EHS Risks," Prepared for the NCPV and Solar Program Review Meeting 2003. Available on-line at http://www.nrel.gov/cdte/pdfs/ncpv_cdte.pdf. Accessed June 14, 2003. See also EPRI, 2002, ***Renewable Energy Technical Assessment Guide-TAG-RE 2002,*** p. 5-28.

[158] In defining "eligible renewable energy resource" for California's Renewable Portfolio Standard SB 1078 (Section 399.12) refers to the definition of "in-state renewable electricity generation technology" in Section 383.5 of SB 1038, subject to related requirements of SB 1078. SB 1038, Section 383.5(b)(1)(A) contains a list of renewable energy generation technologies that are eligible for support through the Energy Commission's Renewable Energy Program, provided that related requirements in SB 1038 and guidelines for its implementation are met. The list contains the following technologies: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

[159] Electric Power Research Institute (EPRI), 2002, ***Renewable Energy Technical Assessment Guide-TAG-RE 200***2, p. 8-55, 56.

[160] See California Energy Commission, May 2003, ***Renewable Portfolio Standard: Decision on Phase I Implementation Issues, Final Committee Report***. Available at http://www.energy.ca.gov/portfolio/documents/. Accessed June 14, 2003.

[161] See "Hydropower: Filing a Hydropower License Application with the Commission," particularly the environmental reporting requirements described in Title 18, Section 4.41, available on-line at http://www.ferc.gov/hydro/docs/license_application.htm. Accessed June 14, 2003. See U.S. Fish and Wildlife Service, "National Fish Passage Program: Reconnecting Aquatic Species to Historical Habitats," available on-line at http://fisheries.fws.gov/FWSMA/fishpassage. Accessed June 14, 2003. See also, Low Impact Hydropower Institute, Low Impact Hydropower Certification Criteria, Summary of Goals and Standards. Available at http://www.lowimpacthydro.org/. Accessed June 14, 2003.

[162] Incremental hydro is the addition of generation at a hydroelectric generation facility that is already generating power. The incremental power may come from water not already in use for generation purposes (e.g., water in a fish passage system).

[163] California Energy Commission, June 2002, ***Distributed Generation Strategic Plan***, (P700-02-002), p. 31.

[164] U.S. Department of Energy, September 2000, ***Strategic Plan for Distributed Energy Resources***, p. 2. Available on-line at http://www.eere.energy.gov/der/pdfs/derplanfinal.pdf. Accessed June 26, 2003.

[165] These include California Energy Commission, June 2002, ***Distributed Generation Strategic Plan***, P700-02-002; California Energy Commission, Rulemaking Pertaining to Data Collection for Qualified Departing Load CRS Exemptions Docket #03-CRS-01; Rule 21 Working Group (interconnection rules for distributed generation); California Public Utilities Commission, Rulemaking 02-01-011, in which D. 03-04-030 was adopted (April 3, 2003) regarding cost responsibility surcharge mechanisms for customer generation departing load.

[166] Comments provided by Pacific Gas and Electric Company (PG&E), California Energy Commission IEPR Committee hearing held August 28, 2003.

[167] SB 1194 and SB 1038 authorize collection of 51.5 percent of $ 135 million/year for SEP payments from 2002-2011 in support of RPS (about $695 million). The actual amount available for SEP payments may be higher, due to interest earned on the unexpended portion of these funds, rollover funds from the SB 90 programs, and balance transfers from other programs within the Renewable Energy Program.

[168] ***Governor's Budget 2003-2004***, http://www.documents.dgs.ca.gov/osp/GovernorsBudget04/pdf/res.pdf . Accessed June 25, 2003.

[169] Steven Kelly, Independent Energy Producers Association, raised the need for greater information from the utilities for the renewable energy project developers regarding the type of renewable energy development that would best fit each utility's energy needs. Verbal comment at the California Energy Commission's IEPR Committee Hearing held August 28, 2003.

[170] For information on electricity storage technologies see Electric Power Research Institute (EPRI), ***Renewable Energy Technical Assessment Guide-TAG-RE 2002***, chapter 9.

[171] For information regarding peak energy demand in California, see California Independent System Operator (CA ISO), "Today's Outlook," updated every 10 minutes. Available on-line at http://www.caiso.com/outlook.html. Accessed June 17, 2003.

[172] Electric Power Research Institute (EPRI), ***Renewable Energy Technical Assessment Guide-TAG-RE 2002***.

[173] California Energy Commission, 2003, "Project 4.3 Energy Storage for Renewable Generation (Contract # 500-01042)." ***Public Interest Energy Research Annual Report 2002, Appendix A PIER program Project Summaries***.

[174] California Energy Commission, 2003, "Project 4.3 Energy Storage for Renewable Generation (Contract # 500-01042)." ***Public Interest Energy Research Annual Report 2002, Appendix A PIER program Project Summaries***, p. 78. Project Amount: $318,728. Match Funding: $82,837.

[175] California Independent System Operator, April 11, 2003, ***2003 Summer Assessment***. Available on-line at http://www.caiso.com/docs/2003/04/25/2003042514315217744.pdf. Accessed June 20, 2003.

[176] California Public Utilities Commission, June 19, 2003, Decision 03-06-071, ***Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program***, p. 28.

[177] Reuters, August 25, 2003, "Moody's may raise Southern California Edison rtgs," available on-line at Quote.com: Stocks & News: News Center. Available online at http://finance.lycos.com/qc/news/. Accessed September 17, 2003.

[178] Southern California Edison (SCE), 2003, "SCE Response to Supreme Court Decision," available on-line at http://www.sce.com/sc3/005_regul_info/supreme_court.htm, accessed September 17, 2003.

[179] Verbal comments provided by Steven Kelly, Independent Energy Producers Association, at the California Energy Commission's IEPR Committee Hearing held August 28, 2003.

[180] See Los Angeles Department of Water and Power at: http://www.ci.la.ca.us/mayor/oldpresss/ND9468.pdf, accessed October 15, 2003.

[181] See Sacramento Municipal Utility District at: http://www.energy.ca.gov/energypolicy/documents/2003-07-10_workshop/2003-07-02_ATTACHMENT_A.PDF, accessed October 15, 2003

[182] See Roseville Electric at: http://www.rosevilleelectric.org/newsletter/ed1_may03.htm, accessed October 15, 2003

[183] See Anaheim Electric at: http://www.anaheim.net/utilities/news/2002_greenpower.htm, accessed October 15, 2003

[184] See Silicon Valley Power at: http://www.siliconvalleypower.com/Residential/HometownAdvantage/CleanPower.html, accessed October 15, 2003

[185] See Modesto Irrigation District at: http://www.mid.org/board_of_directors/brd_reports_2002/july_2_02.htm, accessed October 15, 2003

[186] Correspondence from Jerry Jordan, Executive Director California Municipal Utilities Association to William J. Keese, Chairman, California Energy Commission, July 15, 2003.

[187] Keith Switzer, Southern California Water Company, October 7, 2003, “Renewable Resources Development Report: Comments of Southern California Water Company.” Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.

[188] California Public Utilities Commission, Decision Number 03-06-071 adopted June 19, 2003. The Decision is titled: ***Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program***, and was part of the Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development, Rulemaking number 01-10-024.

[189] The California Biomass Collaboration, under a grant from the California Energy Commission, is preparing an updated statewide biomass resource assessment. This assessment was not available for inclusion in the Renewable Resource Development Report. Comments from Bryan Jenkins, University of California, Davis, October 7, 2003, "Renewable Resources Development Report: Comments of the California Biomass Collaboration." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.

[190] In comments docketed October 10, 2003 on the staff draft Renewable Resources Development Report, South Coast Air Quality Management District staff suggested the following additional actions in support of concentrating solar power: 1) federal energy policy incentives to increase CSP and wind energy to 10,000 MW; and 2) a road-mapping process for CSP led by the Energy Commission. Staff, South Coast Air Quality Management District, October 10, 2003, "Comments of the South Coast Air Quality Management District staff on the Draft Renewable Resources Development Report of the California Energy Commission." Filed with the California Energy Commission, Docket No. 02-REN-1038 and 02-IEP-1.

APPENDICES

There are four appendices to this report:

- Appendix A. Estimated Energy Requirements to meet the statewide Renewables Portfolio Standard and the Accelerated Renewables Portfolio Standard
- Appendix B. County Maps of California Technical Potential for Wind, Geothermal, and Solar Energy
- Appendix C. Data Tables for Existing, Proposed, and Potential Renewable Energy in California and other Western Electricity Coordinating Council States
- Appendix D. Levelized Cost of Energy by Technology

APPENDIX A. ESTIMATED ENERGY REQUIREMENTS TO MEET THE STATEWIDE RENEWABLES PORTFOLIO STANDARD AND THE ACCELERATED RENEWABLES PORTFOLIO STANDARD

Appendix A summarizes the major assumptions that staff used to estimate the energy requirements needed to meet the statewide Renewables Portfolio Standard and the accelerated Renewables Portfolio Standard, including the retail sales forecast. There are four items in this appendix:

- Estimation of Energy Requirements to meet California's RPS by 2017
- Estimation of Energy Requirements to meet California's RPS by 2010
- Staff's Outlook for California: Baseline Forecasted Retail Sales by Utility (GWh/year)
- Staff's Outlook for California: High Forecasted Retail Sales by Utility (GWh/year)
- Staff's Outlook for California: Low Forecasted Retail Sales by Utility (GWh/year)
- Notes regarding the preparation of staff estimate of California retail sales

Appendix A. Estimation of Energy Requirements to meet California's RPS by 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1			Staff's Outlook for California - Retails Sales by Utility (GWh). Lynn Marshall. Energy Commission's Demand Analysis office through 2013. Staff projected out to 2017 based on (1a)														2014-2017 sales figures assumed at "Annual Growth Rate" of 2003-2013				
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	1a - RATE
3	1	Sales (GWh)	PG&E	75,681	69,950	70,706	72,496	74,205	75,748	76,879	78,530	79,535	80,751	81,814	82,812	83,569	84,989	86,434	87,904	89,398	1.7%
4			SCE	74,286	65,450	66,225	68,146	70,266	72,054	73,126	74,365	75,272	76,234	77,383	78,550	79,289	80,717	82,169	83,649	85,154	1.8%
5			SDG&E	15,000	14,394	14,592	14,947	15,304	15,666	15,938	16,348	16,604	16,826	17,068	17,363	17,541	17,875	18,214	18,560	18,913	1.9%
6			Total	164,967	149,793	151,523	155,589	159,776	163,468	165,943	169,243	171,410	173,811	176,265	178,725	180,399	183,581	186,818	190,112	193,465	
7																					
8			Grand Total Statewide Sales	242,861	241,668	244,139	249,809	255,549	260,671	264,276	268,895	272,165	275,829	279,551	283,252	286,139	290,717	295,368	300,094	304,896	1.6%
9			DA and Rest of State	77,894	91,875	92,616	94,220	95,773	97,203	98,333	99,652	100,755	102,018	103,286	104,526	105,739	107,136	108,550	109,982	111,431	
10			PG&E DA	3,761	8,321	8,320	8,427	8,537	8,647	8,760	8,873	8,989	9,106	9,225	9,345	9,468	9,591	9,715	9,842	9,970	1.3%
11			SCE DA	4,168	11,088	11,087	11,267	11,451	11,638	11,828	12,021	12,218	12,417	12,621	12,827	13,038	13,246	13,458	13,673	13,892	1.6%
12			SDG&E	2,463	3,423	3,423	3,498	3,575	3,654	3,735	3,818	3,902	3,989	4,078	4,168	4,261	4,355	4,451	4,549	4,649	2.2%
13			Total DA	10,392	22,832	22,830	23,193	23,563	23,939	24,322	24,712	25,109	25,512	25,923	26,341	26,767	27,192	27,624	28,064	28,511	
14			Total Rest of State	67,502	69,043	69,787	71,027	72,210	73,264	74,011	74,940	75,646	76,506	77,363	78,185	78,973	79,944	80,926	81,918	82,920	
15			DA % of non IOU	13.34%	24.85%	24.65%	24.62%	24.60%	24.63%	24.73%	24.80%	24.92%	25.01%	25.10%	25.20%	25.31%	25.38%	25.45%	25.52%	25.59%	
16			Rest of State % of n	86.66%	75.15%	75.35%	75.38%	75.40%	75.37%	75.27%	75.20%	75.08%	74.99%	74.90%	74.80%	74.69%	74.62%	74.55%	74.48%	74.41%	
17																					
18			Percent IOU sales	67.93%	61.98%	62.06%	62.28%	62.52%	62.71%	62.79%	62.94%	62.98%	63.01%	63.05%	63.10%	63.05%	63.15%	63.25%	63.35%	63.45%	
19			Percent DA	4.28%	9.45%	9.35%	9.28%	9.22%	9.18%	9.20%	9.19%	9.23%	9.25%	9.27%	9.30%	9.35%	9.35%	9.35%	9.35%	9.35%	
20			Percent Rest	27.79%	28.57%	28.58%	28.43%	28.26%	28.11%	28.01%	27.87%	27.79%	27.74%	27.67%	27.60%	27.60%	27.50%	27.40%	27.30%	27.20%	
21																					
22	2	2001 Base-line	THIS IS CHANGEABLE	2001 GWh	2001%																
23			PG&E	7,532	9.95%		This is for a 14 year total (accounts for 2003 Interim Procurement)														
24			SCE	11,160	15.02%		20% Goal	Minus Baseline	Avg. GWh Yr	MW/Year	MW/Year										
25			SDG&E	112	0.74%		Take 20%	Base and 2003	Divide by 14	50 % CF	55 % CP										
26			Total	18,804	11.40%		5,702.14	5,702.14	407.30	93	85	DA no baseline									
27							5,702.14	3,836.97	274.07	63	57	DA w/ baseline									
28		7.17%	PG&E DA	270	7.17%																
29			SCE DA	299	7.17%		16,583.98	9,406.99	671.93	153	139	Rest of State									
30			SDG&E	177	7.17%		38,693.02	17,770.19	1,269.30	290	263	IOU									
31			Total DA	745	7.17%																
32																					
33			Total DA and IOU Ba	19,549																	
34																					
35			Total Rest of State	6,267	9.28%		This is for a 15 year total (baseline only)														
36							20% Goal	Minus Baseline	Avg. GWh Yr	MW/Year	MW/Year										
37			J-11 Figure	25,816			Take 20%	Base only	Divide by 15	50 % CF	55 % CP										
38							5,702.14	5,702.14	380.14	87	79	DA no baseline									
39							5,702.14	4,957.04	330.47	75	69	DA w/ baseline									
40																					
41							16,583.98	10,316.95	687.80	157	143	Rest of State									
42							38,693.02	19,889.29	1,325.95	303	275	IOU									
43																					
44	3	1% Minimum Percentage Point Growth (capped) as percent		[% shown in (Section 2)] + [1%] up to [20%].																	
45			PG&E			10.95%	11.95%	12.95%	13.95%	14.95%	15.95%	16.95%	17.95%	18.95%	19.95%	20.00%	20.00%	20.00%	20.00%	20.00%	
46			SCE			16.02%	17.02%	18.02%	19.02%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
47			SDG&E			1.74%	2.74%	3.74%	4.74%	5.74%	6.74%	7.74%	8.74%	9.74%	10.74%	11.74%	12.74%	13.74%	14.74%	15.74%	
48			Total			12.28%	13.29%	14.30%	15.30%	16.29%	16.84%	17.40%	17.96%	18.52%	19.08%	19.20%	19.29%	19.39%	19.49%	19.58%	
49																					
50			PG&E DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
51			SCE DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
52			SDG&E			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
53			Total DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
54																					
55			Total Rest of State			10.28%	11.28%	12.28%	13.28%	14.28%	15.28%	16.28%	17.28%	18.28%	19.28%	20.00%	20.00%	20.00%	20.00%	20.00%	
56																					

20% 2017 with % point growth

Gray shading is explanatory.
Green shading is from CPUC filings or press releases regarding future procurements.
Purple shading is from CPUC fillings or press releases regarding the 2001 Baseline.

Appendix A. Estimation of Energy Requirements to meet California's RPS by 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
57	4	1% Minimum Percentage Point Growth (capped) as		(Section 3) * (Section 1).																	
58			PG&E			7,744	8,665	9,611	10,569	11,495	12,527	13,483	14,497	15,506	16,523	16,714	16,998	17,287	17,581	17,880	
59			SCE			10,611	11,601	12,664	13,707	14,625	14,873	15,054	15,247	15,477	15,710	15,858	16,143	16,434	16,730	17,031	
60			SDG&E			255	410	573	743	916	1,103	1,286	1,471	1,663	1,866	2,060	2,278	2,503	2,737	2,978	
61			Total			18,610	20,676	22,848	25,019	27,036	28,503	29,823	31,215	32,645	34,099	34,632	35,419	36,224	37,047	37,888	
62																					
63			PG&E DA			680	773	868	966	1,066	1,169	1,274	1,381	1,492	1,605	1,720	1,839	1,943	1,968	1,994	
64			SCE DA			906	1,033	1,165	1,300	1,439	1,583	1,731	1,884	2,041	2,202	2,369	2,539	2,692	2,735	2,778	
65			SDG&E			280	321	364	408	455	503	553	605	659	716	774	835	890	910	930	
66			Total DA			1,865	2,127	2,396	2,674	2,960	3,255	3,558	3,870	4,192	4,523	4,863	5,213	5,525	5,613	5,702	
67																					
68			Total Rest of State			7,177	8,015	8,870	9,733	10,572	11,454	12,318	13,223	14,145	15,077	15,795	15,989	16,185	16,384	16,584	
69																					
70	5	Additional Energy (GWh) Per Year on top of Baseline			For 2003, (Section 4) - (Section 2). For other years, (Section 4 current year) - (Section 4 prior year)																Total Add'tl Ene
71			PG&E			212	921	946	957	927	1,032	956	1,014	1,009	1,017	191	284	289	294	299	10,347
72			SCE			-	989	1,063	1,043	918	248	181	192	230	233	148	285	291	296	301	6,420
73			SDG&E			143	156	163	170	172	187	183	185	192	202	195	218	225	233	241	2,866
74			Total			355	2,066	2,173	2,170	2,017	1,467	1,320	1,392	1,431	1,453	533	787	805	823	841	19,633
75																					
76			PG&E DA			410	93	95	98	100	103	105	108	110	113	116	118	105	25	26	1,724
77			SCE DA			607	127	131	135	140	144	148	152	157	162	166	170	152	43	44	2,480
78			SDG&E			103	41	43	45	46	48	50	52	54	56	59	61	55	20	20	753
79			Total DA			1,120	262	270	278	286	295	303	312	322	331	341	349	312	88	89	4,957
80																					
81			Total Rest of State			910	838	856	862	839	882	864	905	922	932	717	194	196	198	200	10,317
82																					
83	6	Needed or Known Growth - percent (total) - if NOT at 20% by 2017 with simple 1 % growth		Green highlights represent known Procurements. Otherwise, if not at 20% by (Section 3) method, grow at annual average percent to reach 20% by 2017. If percentage drops over time, this is because the IOU procured more in one year than they were required to, so they are "banking" it forward. The percentage will increase once procurements start again.																	Annual Avg. Growth Rate if not at 20% by 2017 at 1%
84			PG&E			11.82%	11.95%	12.95%	13.95%	14.95%	15.95%	16.95%	17.95%	18.95%	19.95%	20.00%	20.00%	20.00%	20.00%	20.00%	0.00%
85			SCE			17.98%	17.47%	18.02%	19.02%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	0.00%
86			SDG&E			4.50%	7.10%	6.94%	6.78%	7.16%	8.45%	9.73%	11.01%	12.30%	13.58%	14.87%	16.15%	17.43%	18.72%	20.00%	1.28%
87			Total			13.81%	13.91%	14.61%	15.50%	16.43%	17.01%	17.59%	18.18%	18.77%	19.35%	19.50%	19.63%	19.75%	19.87%	20.00%	
88																					
89			PG&E DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
90			SCE DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
91			SDG&E			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
92			Total DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
93																					
94			Total Rest of State			10.28%	11.28%	12.28%	13.28%	14.28%	15.28%	16.28%	17.28%	18.28%	19.28%	20.00%	20.00%	20.00%	20.00%	20.00%	0.00%
95																					
96	7	Needed or Known Growth - GWh (total) - if NOT at 20% by 2017 with simple 1 %		(Section 6) * (Section 1).																	
97			PG&E			8,358	8,665	9,611	10,569	11,495	12,527	13,483	14,497	15,506	16,523	16,714	16,998	17,287	17,581	17,880	
98			SCE			11,908	11,908	12,664	13,707	14,625	14,873	15,054	15,247	15,477	15,710	15,858	16,143	16,434	16,730	17,031	
99			SDG&E			657	1,062	1,062	1,062	1,142	1,381	1,616	1,853	2,099	2,358	2,608	2,887	3,175	3,474	3,783	
100			Total			20,923	21,635	23,337	25,337	27,262	28,781	30,153	31,597	33,081	34,591	35,179	36,028	36,896	37,784	38,693	
101																					
102			PG&E DA			680	773	868	966	1,066	1,169	1,274	1,381	1,492	1,605	1,720	1,839	1,943	1,968	1,994	
103			SCE DA			906	1,033	1,165	1,300	1,439	1,583	1,731	1,884	2,041	2,202	2,369	2,539	2,692	2,735	2,778	
104			SDG&E			280	321	364	408	455	503	553	605	659	716	774	835	890	910	930	
105			Total DA			1,865	2,127	2,396	2,674	2,960	3,255	3,558	3,870	4,192	4,523	4,863	5,213	5,525	5,613	5,702	
106																					
107			Total DA and IOU	19549	19549	22,788	23,762	25,733	28,011	30,222	32,036	33,711	35,467	37,273	39,114	40,043	41,240	42,421	43,397	44,395	
108																					
109			Total Rest of State			7,177	8,015	8,870	9,733	10,572	11,454	12,318	13,223	14,145	15,077	15,795	15,989	16,185	16,384	16,584	
110			Statewide			29,965	31,776	34,604	37,744	40,794	43,490	46,029	48,690	51,418	54,191	55,837	57,229	58,606	59,781	60,979	

20% 2017 with % point growth

Gray shading is explanatory.
Green shading is from CPUC filings or press releases regarding future procurements.
Purple shading is from CPUC fillings or press releases regarding the 2001 Baseline.

Appendix A. Estimation of Energy Requirements to meet California's RPS by 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
111	8	Additional Energy (GWh) Per Year on top		For 2003, (Section 7) - (Section 2). For other years, (Section 7 current year) - (Section 7 prior year																	Total Adt'l Ener
112			PG&E			826	307	946	957	927	1,032	956	1,014	1,009	1,017	191	284	289	294	299	10,347
113			SCE			748	-	756	1,043	918	248	181	192	230	233	148	285	291	296	301	5,871
114			SDG&E			545	405	-	-	80	239	235	238	246	259	249	279	289	299	309	3,671
115			Total			2,119	712	1,702	2,000	1,925	1,519	1,372	1,444	1,484	1,510	588	849	868	888	909	19,889
116																					
117			MW/Year with 50% CF			484	163	389	457	439	347	313	330	339	345	134	194	198	203	207	4,541
118																					
119			PG&E DA			410	93	95	98	100	103	105	108	110	113	116	118	105	25	26	1,724
120			SCE DA			607	127	131	135	140	144	148	152	157	162	166	170	152	43	44	2,480
121			SDG&E			103	41	43	45	46	48	50	52	54	56	59	61	55	20	20	753
122			Total DA			1,120	262	270	278	286	295	303	312	322	331	341	349	312	88	89	4,957
123																					
124			MW/Year with 50% CF			256	60	62	63	65	67	69	71	73	76	78	80	71	20	20	1,132
125																					
126			Total Rest of State			910	838	856	862	839	882	864	905	922	932	717	194	196	198	200	10,317
127																					
128			MW/Year with 50% CF			208	191	195	197	192	201	197	207	210	213	164	44	45	45	46	2,355
129																					
130	9	Cumulative Energy (GWh) Per Year on		For 2003, (Section 8). For other years, (Section 8 current year) + (Section 9 prior year																	
131			PG&E			826	1,133	2,079	3,037	3,963	4,995	5,951	6,965	7,974	8,991	9,182	9,466	9,755	10,049	10,347	
132			SCE			748	748	1,504	2,547	3,465	3,713	3,894	4,087	4,317	4,550	4,698	4,983	5,274	5,570	5,871	
133			SDG&E			545	950	950	950	1,030	1,269	1,504	1,742	1,987	2,247	2,496	2,775	3,064	3,362	3,671	
134			Total			2,119	2,831	4,533	6,533	8,458	9,978	11,349	12,793	14,278	15,787	16,375	17,224	18,092	18,980	19,889	
135																					
136			Cumulative MW with	50% CF		484	646	1,035	1,492	1,931	2,278	2,591	2,921	3,260	3,604	3,739	3,932	4,131	4,333	4,541	
137																					
138			PG&E DA			410	503	599	696	796	899	1,004	1,112	1,222	1,335	1,451	1,569	1,673	1,699	1,724	
139			SCE DA			607	734	866	1,001	1,141	1,284	1,432	1,585	1,742	1,904	2,070	2,240	2,393	2,436	2,480	
140			SDG&E			103	144	187	232	278	326	376	429	483	539	598	658	714	733	753	
141			Total DA			1,120	1,382	1,651	1,929	2,215	2,509	2,813	3,125	3,447	3,778	4,118	4,468	4,780	4,868	4,957	
142																					
143			Cumulative MW with	50% CF		256	315	377	440	506	573	642	713	787	862	940	1,020	1,091	1,111	1,132	
144																					
145			Total Rest of State			910	1,748	2,603	3,466	4,305	5,187	6,051	6,956	7,878	8,810	9,528	9,722	9,918	10,117	10,317	
146																					
147			Cumulative MW with	50% CF		208	399	594	791	983	1,184	1,382	1,588	1,799	2,011	2,175	2,220	2,264	2,310	2,355	
148																					
149	10	Cumulative Energy (GWh) Per Year on top of Baseline AFTER 2003 and 2004		For 2003, zero. For 2004, (Section 8). For other years, (Section 8 current year) + (Section 10 prior year)																	
150			PG&E				307	1,253	2,211	3,137	4,169	5,125	6,139	7,148	8,165	8,356	8,640	8,929	9,223	9,521	
151			SCE				-	756	1,799	2,717	2,965	3,146	3,339	3,568	3,802	3,950	4,235	4,526	4,822	5,123	
152			SDG&E				-	-	-	80	319	554	792	1,037	1,297	1,546	1,825	2,114	2,412	2,721	
153			Total				307	2,009	4,009	5,934	7,453	8,825	10,269	11,753	13,263	13,851	14,700	15,568	16,456	17,365	
154																					
155			Cumulative MW with	50% CF			70	459	915	1,355	1,702	2,015	2,345	2,683	3,028	3,162	3,356	3,554	3,757	3,965	
156																					
157			PG&E DA				93	188	286	386	489	594	702	812	925	1,041	1,159	1,263	1,289	1,314	
158			SCE DA				127	259	394	534	677	825	978	1,135	1,297	1,463	1,634	1,786	1,829	1,873	
159			SDG&E				41	84	129	175	223	273	325	380	436	495	555	611	630	650	
160			Total DA				262	531	809	1,095	1,389	1,693	2,005	2,327	2,658	2,998	3,348	3,660	3,748	3,837	
161																					
162			Cumulative MW with	50% CF			60	121	185	250	317	386	458	531	607	685	764	836	856	876	
163																					
164			Total Rest of State				838	1,693	2,556	3,395	4,277	5,141	6,046	6,968	7,900	8,618	8,812	9,008	9,207	9,407	
165																					
166			Cumulative MW with	50% CF			191	387	583	775	976	1,174	1,380	1,591	1,804	1,967	2,012	2,057	2,102	2,148	
167																					
168						DA and IOU	569	2,540	4,818	7,029	8,843	10,518	12,274	14,080	15,921	16,850	18,047	19,228	20,204	21,202	
169						Whole State	1,406	4,234	7,374	10,424	13,120	15,659	18,320	21,048	23,821	25,467	26,859	28,236	29,411	30,609	

20% 2017 with % point growth

Gray shading is explanatory.
Green shading is from CPUC filings or press releases regarding future procurements.
Purple shading is from CPUC fillings or press releases regarding the 2001 Baseline.

Appendix A (2). Estimation of Energy Requirements to meet California's RPS by 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1			Staff's Outlook for California - Retails Sales by Utility (GWh). Lynn Marshall. Energy Commission's Demand Analysis office through 2013. Staff projected out to 2017 based on (1a)																		
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
3																					growth rate
4	1	Sales (GWh)	**PG&E**	75,681	69,950	70,706	72,496	74,205	75,748	76,879	78,530	79,535	80,751	81,814	82,812	83,569	84,989	86,434	87,904	89,398	**1.7%**
5			**SCE**	74,286	65,450	66,225	68,146	70,266	72,054	73,126	74,365	75,272	76,234	77,383	78,550	79,289	80,717	82,169	83,649	85,154	**1.8%**
6			**SDG&E**	15,000	14,394	14,592	14,947	15,304	15,666	15,938	16,348	16,604	16,826	17,068	17,363	17,541	17,875	18,214	18,560	18,913	**1.9%**
7			**Total**	164,967	149,793	151,523	155,589	159,776	163,468	165,943	169,243	171,410	173,811	176,265	178,725	180,399	183,581	186,818	190,112	193,465	
8																					
9		Grand Total Statewide Sales		242,861	241,668	244,139	249,809	255,549	260,671	264,276	268,895	272,165	275,829	279,551	283,252	286,139	290,717	295,368	300,094	304,896	1.6%
10		DA and Rest		77,895	91,875	92,616	94,220	95,773	97,203	98,333	99,652	100,755	102,018	103,286	104,526	105,739	107,136	108,550	109,982	111,431	
11			**PG&E DA**	3,761	8,321	8,320	8,427	8,537	8,647	8,760	8,873	8,989	9,106	9,225	9,345	9,468	9,591	9,715	9,842	9,970	1.3%
12			**SCE DA**	4,168	11,088	11,087	11,267	11,451	11,638	11,828	12,021	12,218	12,417	12,621	12,827	13,038	13,246	13,458	13,673	13,892	1.6%
13			**SDG&E DA**	2,463	3,423	3,423	3,498	3,575	3,654	3,735	3,818	3,902	3,989	4,078	4,168	4,261	4,355	4,451	4,549	4,649	2.2%
14			**Total DA**	10,392	22,832	22,830	23,193	23,563	23,939	24,322	24,712	25,109	25,512	25,923	26,341	26,767	27,192	27,624	28,064	28,511	
15			**Total Rest of State**	67,503	69,043	69,787	71,027	72,210	73,264	74,011	74,940	75,646	76,506	77,363	78,185	78,973	79,944	80,926	81,918	82,920	
16			**DA % of Diff**	13.34%	24.85%	24.65%	24.62%	24.60%	24.63%	24.73%	24.80%	24.92%	25.01%	25.10%	25.20%	25.31%	25.38%	25.45%	25.52%	25.59%	
17			**Rest of State % of Diff**	86.66%	75.15%	75.35%	75.38%	75.40%	75.37%	75.27%	75.20%	75.08%	74.99%	74.90%	74.80%	74.69%	74.62%	74.55%	74.48%	74.41%	
18																					
19		Percent IOU sales		67.93%	61.98%	62.06%	62.28%	62.52%	62.71%	62.79%	62.94%	62.98%	63.01%	63.05%	63.10%	63.05%	63.15%	63.25%	63.35%	63.45%	
20		Percent DA		4.28%	9.45%	9.35%	9.28%	9.22%	9.18%	9.20%	9.19%	9.23%	9.25%	9.27%	9.30%	9.35%	9.35%	9.35%	9.35%	9.35%	
21		Percent Rest		27.79%	28.57%	28.58%	28.43%	28.26%	28.11%	28.01%	27.87%	27.79%	27.74%	27.67%	27.60%	27.60%	27.50%	27.40%	27.30%	27.20%	
22																					
23	2	**2001 Baseline**	THIS IS CHANGEABLE	2001 GWh	2001%																
24			**PG&E**	7,532	9.95%		This is for a 7 year total (accounts for 2003 Interim Procurement)														
25			**SCE**	11,160	15.02%		**20% Goal**	**Minus Baseline**	**Avg. GWh Yr.**	**MW/Year**											
26			**SDG&E**	112	0.74%		Take 20%	Base and 2003	Divide by 7	MW with 50% CF	55% CF										
27			**Total**	18,804	11.40%		5,102	5,102	729	**166**	**151**	**DA no baseline**									
28							5,102	3,237	462	**106**	**96**	**DA w/ baseline**									
29		7.17%	**PG&E DA**	270	7.17%																
30			**SCE DA**	299	7.17%		15,301	8,124	1,161	**265**	**241**	**Rest of State**									
31			**SDG&E**	177	7.17%		34,762	13,434	1,919	**438**	**398**	**IOUs**									
32			**Total DA**	745	7.17%																
33																					
34			**Total DA and IOU Baseline**	19,549																	
35																					
36			**Total Rest of State**	6,267	9.28%		This is for a 8 year total (only baseline)														
37							**20% Goal**	**Minus Baseline**	**Avg. GWh Yr.**	**MW/Year**											
38			**J-11 Figure**	25,816			Take 20%	Base only	Divide by 8	MW with 50% CF	55% CF										
39							5,102	5,102	638	**146**	**132**	**DA no baseline**									
40							5,102	4,357	545	**124**	**113**	**DA w/ baseline**									
41							15,301	9,034	1,129	**258**	**234**	**Rest of State**									
42							34,762	15,958	1,995	**455**	**414**	**IOUs**									
43																					
44	3	**1% Minimum Percentage Point Growth (capped) as percent**		[% shown in (Section 2)] + [1%] up to [20%].																	
45			**PG&E**			10.95%	11.95%	12.95%	13.95%	14.95%	15.95%	16.95%	17.95%								
46			**SCE**			16.02%	17.02%	18.02%	19.02%	20.00%	20.00%	20.00%	20.00%								
47			**SDG&E**			1.74%	2.74%	3.74%	4.74%	5.74%	6.74%	7.74%	8.74%								
48			**Total**																		
49																					
50			**PG&E DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
51			**SCE DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
52			**SDG&E DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
53			**Total DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
54																					
55			**Total Rest of State**			10.28%	11.28%	12.28%	13.28%	14.28%	15.28%	16.28%	17.28%								
56																					

20% by 2010 out to 2017

Gray shading is explanatory.
Green shading is from CPUC filings or press releases regarding future procurements.
Purple shading is from CPUC fillings or press releases regarding the 2001 Baseline.

Appendix A (2). Estimation of Energy Requirements to meet California's RPS by 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
57	4	**1% Minimum Percentage Point Growth (capped) as GWh**		(Section 3) * (Section 1).																	
58			**PG&E**			7,744	8,665	9,611	10,569	11,495	12,528	13,483	14,497								
59			**SCE**			10,611	11,601	12,664	13,707	14,625	14,873	15,054	15,247								
60			**SDG&E**			255	410	573	743	916	1,103	1,286	1,471								
61			**Total**			18,610	20,676	22,849	25,019	27,036	28,503	29,823	31,215								
62																					
63			**PG&E DA**			680	773	868	966	1,066	1,169	1,274	1,381								
64			**SCE DA**			906	1,033	1,165	1,300	1,439	1,583	1,731	1,884								
65			**SDG&E DA**			280	321	364	408	455	503	553	605								
66			**Total DA**			1,865	2,127	2,396	2,674	2,960	3,255	3,558	3,870								
67																					
68			**Total Rest of State**			7,177	8,015	8,870	9,732	10,572	11,454	12,318	13,223								
69																					
70	5	**Additional Energy (GWh) Per Year on top of Baseline**		For 2003, (Section 4) - (Section 2). For other years, (Section 4 current year) - (Section 4 prior year)																	
71			**PG&E**			212	921	946	957	927	1,032	956	1,014								
72			**SCE**			-	989	1,063	1,043	918	248	181	192								
73			**SDG&E**			143	156	163	170	172	187	183	185								
74			**Total**			355	2,066	2,173	2,170	2,017	1,467	1,320	1,392								
75																					
76			**PG&E DA**			410	93	95	98	100	103	105	108								
77			**SCE DA**			607	127	131	135	140	144	148	152								
78			**SDG&E DA**			103	41	43	45	46	48	50	52								
79			**Total DA**			1,120	262	270	278	286	295	303	312								
80																					
81			**Total Rest of State**			910	838	856	862	839	882	864	905								
82																					
83	6	**Needed or Known Growth - percent (total) - if NOT at 20% by 2017 with simple 1 % growth**		Green highlights represent known Procurements. Otherwise, if not at 20% by (Section 3) method, grow at annual average percent to reach 20% by 2017. If percentage drops over time, this is because the IOU procured more in one year than they were required to, so they are "banking" it forward. The percentage will increase once procurements start again.										Annual Avg. Growth Rate if not at 20% by 2010 at 1%							
84			**PG&E**		757	11.82%	12.46%	13.72%	14.98%	16.23%	17.49%	18.74%	20.00%	1.26%							
85			**SCE**		743	17.98%	17.47%	18.02%	19.02%	20.00%	20.00%	20.00%	20.00%	0.00%							
86			**SDG&E**		150	4.50%	7.10%	7.97%	10.37%	12.78%	15.19%	17.59%	20.00%	2.41%							
87			**Total**			13.81%	14.14%	15.06%	16.32%	17.56%	18.37%	19.18%	20.00%								
88																					
89			**PG&E DA**		38	8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
90			**SCE DA**		42	8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
91			**SDG&E DA**		25	8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
92			**Total**			8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%								
93																					
94			**Total Rest of State**		675	10.28%	11.96%	13.30%	14.64%	15.98%	17.32%	18.66%	20.00%	1.34%							
95																					
96	7	**Needed or Known Growth - GWh (total) - if NOT at 20% by 2017 with simple 1 % growth**		(Section 6) * (Section 1).																	
97			**PG&E**	-		8,358	9,036	10,181	11,344	12,479	13,733	14,908	16,150	16,363	16,562	16,714	16,998	17,287	17,581	17,880	
98			**SCE**	-		11,908	11,908	12,664	13,707	14,625	14,873	15,054	15,247	15,477	15,710	15,858	16,143	16,434	16,730	17,031	
99			**SDG&E**	-		657	1,062	1,219	1,625	2,037	2,483	2,921	3,365	3,414	3,473	3,508	3,575	3,643	3,712	3,783	
100			**Total**	-		20,923	22,006	24,064	26,676	29,141	31,089	32,883	34,762	35,253	35,745	36,080	36,716	37,364	38,022	38,693	
101																					
102			**PG&E DA**	-		680	875	1,023	1,175	1,330	1,490	1,654	1,821	1,845	1,869	1,894	1,918	1,943	1,968	1,994	
103			**SCE DA**	-		906	1,169	1,372	1,581	1,797	2,019	2,248	2,483	2,524	2,565	2,608	2,649	2,692	2,735	2,778	
104			**SDG&E DA**	-		280	363	428	496	567	641	718	798	816	834	852	871	890	910	930	
105			**Total DA**	-		1,865	2,407	2,823	3,252	3,694	4,150	4,619	5,102	5,185	5,268	5,353	5,438	5,525	5,613	5,702	
106																					
107			**Total DA and IOU**	19,549	19,549	22,788	24,413	26,887	29,928	32,835	35,239	37,503	39,865	40,438	41,013	41,433	42,155	42,888	43,635	44,395	
108																					
109			**Total Rest of State**	-		7,177	8,497	9,606	10,727	11,828	12,980	14,116	15,301	15,473	15,637	15,795	15,989	16,185	16,384	16,584	
110			**Statewide**			29,965	32,910	36,493	40,655	44,663	48,219	51,619	55,166	55,910	56,650	57,228	58,143	59,074	60,019	60,979	

20% by 2010 out to 2017

Gray shading is explanatory.
Green shading is from CPUC filings or press releases regarding future procurements.
Purple shading is from CPUC fillings or press releases regarding the 2001 Baseline.

Appendix A (2). Estimation of Energy Requirements to meet California's RPS by 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
111	8	Additional Energy (GWh) Per Year on top of Baseline		For 2003, (Section 7) - (Section 2). For other years, (Section 7 current year) - (Section 7 prior year)																	
112			PG&E			826	678	1,145	1,163	1,135	1,254	1,175	1,242	213	200	151	284	289	294	299	
113			SCE			748	-	756	1,043	918	248	181	192	230	233	148	285	291	296	301	
114			SDG&E			545	405	157	406	412	446	438	444	48	59	36	67	68	69	71	
115			Total		-	2,119	1,083	2,058	2,612	2,465	1,948	1,794	1,879	491	492	335	636	647	659	671	
116																					
117			Cumulative MW with 50% CF			484	247	470	596	563	445	410	429	112	112	76	145	148	150	153	3,160
118																					
119			PG&E DA			410	195	148	152	156	160	164	168	24	24	24	25	25	25	26	
120			SCE DA			607	263	203	209	216	222	229	236	41	41	42	42	42	43	44	
121			SDG&E DA			103	83	65	68	71	74	77	80	18	18	19	19	19	20	20	
122			Total DA			1,120	542	416	429	442	456	469	483	82	84	85	85	86	88	89	
123																					
124			Cumulative MW with 50% CF			256	124	95	98	101	104	107	110	19	19	19	19	20	20	20	739
125																					
126			Total Rest of State	-		910	1,320	1,109	1,122	1,101	1,152	1,136	1,185	171	164	158	194	196	198	200	
127																					
128			Cumulative MW with 50% CF			208	301	253	256	251	263	259	271	39	38	36	44	45	45	46	1,855
129																					
130	9	Cumulative Energy (GWh) Per Year on top of Baseline		For 2003, (Section 8). For other years, (Section 8 current year) + (Section 9 prior year)																719.20	5,754
131			PG&E			826	1,504	2,649	3,812	4,947	6,201	7,376	8,618	8,831	9,030	9,182	9,466	9,755	10,049	10,347	
132			SCE			748	748	1,504	2,547	3,465	3,713	3,894	4,087	4,317	4,550	4,698	4,983	5,274	5,570	5,871	
133			SDG&E			545	950	1,107	1,513	1,925	2,371	2,809	3,254	3,302	3,361	3,397	3,463	3,531	3,600	3,671	
134			Total			2,119	3,202	5,261	7,872	10,337	12,285	14,080	15,958	16,449	16,941	17,276	17,912	18,560	19,219	19,889	
135																					
136			Cumulative MW with 50% CF			484	731	1,201	1,797	2,360	2,805	3,215	3,643	3,756	3,868	3,944	4,090	4,237	4,388	4,541	
137																					
138			PG&E DA			410	605	753	905	1,061	1,220	1,384	1,552	1,575	1,599	1,624	1,648	1,673	1,699	1,724	
139			SCE DA			607	870	1,073	1,282	1,498	1,720	1,949	2,185	2,225	2,267	2,309	2,350	2,393	2,436	2,480	
140			SDG&E DA			103	186	252	320	391	464	541	621	639	657	676	694	714	733	753	
141			Total DA			1,120	1,662	2,078	2,507	2,949	3,405	3,874	4,357	4,440	4,523	4,608	4,693	4,780	4,868	4,957	
142																					
143			Cumulative MW with 50% CF			256	379	474	572	673	777	884	995	1,014	1,033	1,052	1,072	1,091	1,111	1,132	
144																					
145			Total Rest of State			910	2,230	3,339	4,460	5,561	6,713	7,849	9,034	9,206	9,370	9,528	9,722	9,918	10,117	10,317	
146																					
147			Cumulative MW with 50% CF			208	509	762	1,018	1,270	1,533	1,792	2,063	2,102	2,139	2,175	2,220	2,264	2,310	2,355	
148																					
149	10	Cumulative Energy (GWh) Per Year on top of Baseline AFTER 2003 and 2004 KNOWN PROCUREMENTS		For 2003, zero. For 2004, (Section 8). For other years, (Section 8 current year) + (Section 10 prior year)																	
150			PG&E				678	1,823	2,986	4,121	5,375	6,550	7,792	8,005	8,204	8,356	8,640	8,929	9,223	9,521	
151			SCE				-	756	1,799	2,717	2,965	3,146	3,339	3,568	3,802	3,950	4,235	4,526	4,822	5,123	
152			SDG&E				-	157	563	975	1,421	1,859	2,304	2,352	2,411	2,447	2,513	2,581	2,650	2,721	
153			Total				678	2,736	5,348	7,813	9,761	11,556	13,434	13,925	14,417	14,752	15,388	16,036	16,695	17,365	
154																					
155			Cumulative MW with 50% CF				155	625	1,221	1,784	2,229	2,638	3,067	3,179	3,292	3,368	3,513	3,661	3,812	3,965	
156																					
157			PG&E DA				195	343	495	651	810	974	1,142	1,165	1,189	1,214	1,238	1,263	1,289	1,314	
158			SCE DA				263	466	675	891	1,113	1,342	1,578	1,618	1,660	1,702	1,743	1,786	1,829	1,873	
159			SDG&E DA				83	149	217	288	361	438	518	536	554	573	591	611	630	650	
160			Total				542	958	1,387	1,829	2,285	2,754	3,237	3,320	3,403	3,488	3,573	3,660	3,748	3,837	
161																					
162			Cumulative MW with 50% CF				124	219	317	418	522	629	739	758	777	796	816	836	856	876	
163																					
164			Total Rest of State				1,320	2,429	3,550	4,651	5,803	6,939	8,124	8,296	8,460	8,618	8,812	9,008	9,207	9,407	
165																					
166			Cumulative MW with 50% CF				301	555	811	1,062	1,325	1,584	1,855	1,894	1,932	1,967	2,012	2,057	2,102	2,148	
167																					
168						DA and IO	1,220	3,695	6,735	9,642	12,046	14,310	16,672	17,245	17,820	18,240	18,962	19,696	20,442	21,202	
169						Whole Stat	2,540	6,123	10,285	14,293	17,849	21,249	24,796	25,540	26,280	26,858	27,773	28,704	29,649	30,609	
170																					

20% by 2010 out to 2017

Gray shading is explanatory.
Green shading is from CPUC filings or press releases regarding future procurements.
Purple shading is from CPUC fillings or press releases regarding the 2001 Baseline.

Appendix A (3). Forecasted Retail Sales in California

Staff's Outlook for California
Forecasted Retail Sales by Utility (GWh)

Year	PG&E: PG&E Customers	PG&E: Municipal Sales in PG&E	PG&E: Direct Access Sales in PG&E	SMUD	SCE: SCE Customers	SCE: Municipal Sales in SCE	SCE: Direct Access Sales in SCE	LADWP	SDG&E: SDG&E Customers	SDG&E: Direct Access Sales in SDG&E	BGP	OTH	DWR	TOTAL
1980	54,908	10,658	0	5,350	53,465	5,870	0	17,669	9,729	0	2,374	2,677	3,354	166,056
1981	56,023	10,993	0	5,693	55,182	6,116	0	18,340	9,875	0	2,452	2,781	5,264	172,719
1982	54,767	10,548	0	5,681	53,313	5,696	0	18,184	9,812	0	2,399	2,660	5,192	168,252
1983	56,757	10,792	0	5,954	55,170	5,922	0	18,492	10,023	0	2,433	2,595	2,497	170,636
1984	60,616	11,851	0	6,360	58,745	6,761	0	19,438	10,616	0	2,644	2,722	3,349	183,102
1985	62,395	12,198	0	6,881	60,034	6,883	0	19,443	10,930	0	2,699	2,770	5,410	189,643
1986	61,071	11,637	0	7,014	61,125	6,943	0	19,671	11,363	0	2,695	2,758	5,031	189,308
1987	63,903	12,317	0	7,419	63,962	7,247	0	20,284	11,920	0	2,754	2,872	4,734	197,412
1988	66,006	12,733	0	7,677	66,251	7,428	0	20,719	12,713	0	2,861	3,055	5,928	205,371
1989	67,642	13,045	0	7,927	67,914	7,305	0	20,642	13,427	0	2,813	3,205	7,413	211,331
1990	69,445	13,369	0	8,358	70,464	7,901	0	20,953	14,331	0	2,951	3,310	8,171	219,254
1991	69,571	13,214	0	8,349	69,072	7,787	0	20,457	14,171	0	2,759	3,323	4,400	213,103
1992	70,671	13,467	0	8,496	71,087	7,545	0	20,945	15,093	0	2,931	3,513	4,088	217,837
1993	70,654	13,382	0	8,435	69,791	7,654	0	21,259	15,036	0	2,996	3,602	4,372	217,180
1994	70,733	13,350	0	8,418	71,117	7,952	0	20,308	15,381	0	2,999	3,758	4,946	218,962
1995	71,797	13,467	0	8,458	71,548	7,577	0	20,939	15,524	0	3,084	3,819	3,562	219,774
1996	73,273	13,746	0	8,805	73,766	8,029	0	21,228	16,046	0	3,152	3,983	5,146	227,174
1997	76,241	14,327	0	9,006	76,057	8,300	0	21,605	16,748	0	3,236	3,972	5,504	234,995
1998	70,121	14,364	5,559	9,123	70,097	8,189	6,161	21,412	13,609	3,641	3,298	3,911	3,421	232,905
1999	71,251	14,564	7,958	9,326	69,388	8,782	8,819	21,434	12,719	5,211	3,240	4,009	5,490	242,192
2000	73,387	15,039	8,396	9,491	74,130	9,108	9,304	22,146	12,926	5,498	3,320	4,227	5,490	252,464
2001	75,681	14,110	3,761	9,334	74,286	8,631	4,168	21,575	15,000	2,463	3,275	4,230	6,349	242,861
2002	69,950	13,925	8,321	9,429	65,450	8,537	11,088	21,724	14,394	3,423	3,343	4,196	7,889	241,668
2003	70,706	14,065	8,320	9,563	66,225	8,649	11,087	21,979	14,592	3,423	3,380	4,262	7,889	244,139
2004	72,496	14,455	8,427	9,729	68,146	8,896	11,267	22,248	14,947	3,498	3,429	4,381	7,889	249,809
2005	74,205	14,756	8,537	9,906	70,266	9,140	11,451	22,582	15,304	3,575	3,471	4,466	7,889	255,549
2006	75,748	15,033	8,647	10,060	72,054	9,352	11,638	22,846	15,666	3,654	3,504	4,580	7,889	260,671
2007	76,879	15,231	8,760	10,214	73,126	9,506	11,828	23,015	15,938	3,735	3,516	4,639	7,889	264,276
2008	78,530	15,509	8,873	10,388	74,365	9,673	12,021	23,211	16,348	3,818	3,530	4,740	7,889	268,895
2009	79,535	15,685	8,989	10,548	75,272	9,816	12,218	23,338	16,604	3,902	3,542	4,828	7,889	272,165
2010	80,751	15,895	9,106	10,710	76,234	9,963	12,417	23,515	16,826	3,989	3,555	4,979	7,889	275,829
2011	81,814	16,086	9,225	10,869	77,383	10,124	12,621	23,724	17,068	4,078	3,570	5,100	7,889	279,551
2012	82,812	16,262	9,345	11,022	78,550	10,287	12,827	23,885	17,363	4,168	3,582	5,257	7,889	283,252
2013	83,569	16,389	9,468	11,172	79,289	10,402	13,038	24,115	17,541	4,261	3,592	5,415	7,889	286,139
Annual Growth Rates (%)														
1980-1990	2.4	2.3		4.6	2.8	3.0		1.7	3.9		2.2	2.1	9.3	2.8
1990-2000	0.6	1.2		1.3	0.5	1.4		0.6	-1.0		1.2	2.5	-3.9	1.4
2000-2013	1.0	0.7		1.3	0.5	1.0		0.7	2.4		0.6	1.9	2.8	1.0
2003-2013	1.7	1.5	1.3	1.6	1.8	1.9	1.6	0.9	1.9	2.2	0.6	2.4	0.0	1.6

Historic Data through 2001

California Energy Demand 2003 - baseline forecast March 21, 2003

CED 2003-2013 Demand Forecast
High Economic Growth Case
Retail Sales by Utility (GWh)

	PG&E			SMUD	SCE			LADWP	SDG&E		BGP	OTH	DWR	TOTAL
Year	PG&E Customers	Municipal Sales in PG&E	Direct Access Sales in PG&E		SCE Customers	Municipal Sales in SCE	Direct Access Sales in SCE		SDG&E Customers	Direct Access Sales in SDG&E				
2003	70,706	14,065	8,320	9,563	66,225	8,649	11,087	21,979	14,592	3,423	3,380	4,262	7,889	244,139
2004	73,406	14,599	8,427	9,804	68,977	8,965	11,267	22,430	15,111	3,498	3,452	4,413	7,889	252,239
2005	75,781	15,011	8,537	10,040	71,690	9,259	11,451	22,908	15,610	3,575	3,515	4,533	7,889	259,799
2006	78,130	15,425	8,647	10,253	74,144	9,529	11,638	23,314	16,101	3,654	3,568	4,651	7,889	266,943
2007	79,900	15,734	8,760	10,458	75,904	9,742	11,828	23,627	16,514	3,735	3,603	4,765	7,889	272,459
2008	81,292	15,982	8,873	10,617	77,010	9,901	12,021	23,804	16,891	3,818	3,615	4,852	7,889	276,566
2009	82,130	16,128	8,989	10,776	77,810	10,033	12,218	23,928	17,139	3,902	3,627	4,929	7,889	279,498
2010	83,278	16,328	9,106	10,933	78,672	10,172	12,417	24,080	17,345	3,989	3,637	5,044	7,889	282,892
2011	84,249	16,500	9,225	11,089	79,672	10,320	12,621	24,258	17,573	4,078	3,650	5,165	7,889	286,287
2012	85,259	16,677	9,345	11,246	80,866	10,486	12,827	24,418	17,873	4,168	3,661	5,322	7,889	290,040
2013	86,080	16,814	9,468	11,402	81,662	10,605	13,038	24,655	18,061	4,261	3,671	5,482	7,889	293,088
2014	87,790	17,117	9,591	11,604	83,391	10,824	13,251	24,940	18,450	4,356	3,702	5,621	7,889	298,493
2015	89,535	17,426	9,715	11,810	85,156	11,047	13,467	25,228	18,848	4,452	3,732	5,765	7,889	303,997
2016	91,314	17,740	9,842	12,019	86,959	11,274	13,687	25,520	19,255	4,551	3,763	5,912	7,889	309,604
2017	93,128	18,059	9,970	12,233	88,801	11,507	13,911	25,815	19,670	4,652	3,794	6,062	7,889	315,313
Annual Growth Rates (%)														
2003-2013	2.0	1.8	1.3	1.8	2.1	2.1	1.6	1.2	2.2	2.2	0.8	2.5	0.0	1.8
	1.99%	1.80%	1.30%	1.77%	2.12%	2.06%	1.63%	1.16%	2.16%	2.21%	0.83%	2.55%	0.00%	1.84%

Historic Data through 2001

CED 2003-2013 Demand Forecast
Low Economic Growth Case
Retail Sales by Utility (GWh)

Year	PG&E PG&E Customers	Municipal Sales in PG&E	Direct Access Sales in PG&E	SMUD	SCE SCE Customers	Municipal Sales in SCE	Direct Access Sales in SCE	LADWP	SDG&E SDG&E Customers	Direct Access Sales in SDG&E	BGP	OTH	DWR	TOTAL
2003	70,706	14,065	8,320	9,563	66,225	8,649	11,087	21,979	14,592	3,423	3,380	4,262	7,889	244,139
2004	72,045	14,377	8,427	9,698	67,612	8,850	11,267	22,120	14,813	3,498	3,409	4,358	7,889	248,365
2005	73,143	14,574	8,537	9,827	69,024	9,032	11,451	22,303	15,051	3,575	3,430	4,428	7,889	252,265
2006	74,147	14,766	8,647	9,926	70,102	9,186	11,638	22,398	15,264	3,654	3,439	4,491	7,889	255,548
2007	74,641	14,862	8,760	10,020	70,549	9,288	11,828	22,422	15,401	3,735	3,431	4,551	7,889	257,375
2008	75,828	15,082	8,873	10,162	71,624	9,447	12,021	22,590	15,738	3,818	3,445	4,643	7,889	261,159
2009	76,740	15,246	8,989	10,319	72,560	9,595	12,218	22,740	15,965	3,902	3,460	4,703	7,889	264,325
2010	78,066	15,479	9,106	10,479	73,528	9,745	12,417	22,907	16,171	3,989	3,471	4,788	7,889	268,037
2011	79,220	15,682	9,225	10,637	74,637	9,903	12,621	23,108	16,402	4,078	3,486	4,874	7,889	271,762
2012	80,213	15,858	9,345	10,787	75,833	10,069	12,827	23,293	16,688	4,168	3,501	4,956	7,889	275,428
2013	81,099	16,010	9,468	10,941	76,752	10,199	13,038	23,575	16,878	4,261	3,516	5,034	7,889	278,661
2014	82,219	16,219	9,591	11,089	77,893	10,369	13,251	23,741	17,126	4,356	3,530	5,118	7,889	282,370
2015	83,355	16,431	9,715	11,239	79,050	10,541	13,467	23,908	17,377	4,452	3,544	5,204	7,889	286,130
2016	84,506	16,645	9,842	11,391	80,225	10,716	13,687	24,076	17,632	4,551	3,558	5,292	7,889	289,939
2017	85,672	16,862	9,970	11,546	81,417	10,894	13,911	24,246	17,890	4,652	3,572	5,381	7,889	293,799
Annual Growth Rates (%)														
2003-2013	1.4	1.3	1.3	1.4	1.5	1.7	1.6	0.7	1.5	2.2	0.4	1.7	0.0	1.3
	1.38%	1.30%	1.30%	1.35%	1.49%	1.66%	1.63%	0.70%	1.47%	2.21%	0.39%	1.68%	0.00%	1.33%

California Energy Demand 2003 - baseline forecast March 19, 2003 14-Nov-02

Appendix A: Notes

Notes regarding the preparation of staff estimate of California retail sales:

The retail sales forecast is derived from the final electricity demand forecast developed for the Integrated Energy Policy Report (IEPR) that is currently under preparation. Staff forecasts electricity demand using models developed at the Energy Commission, with the exception of the industrial and mining sectors, for which the staff uses the INFORM model originally developed by the Electric Power Research Institute (EPRI). Each model develops a forecast using a complex series of calculations that simultaneously consider economic and demographic trends, weather characteristics, changes in energy utilization, regulatory conditions, and recorded consumption. Population and personal income are key drivers for the residential and commercial sectors. Employment and shipments are drivers for the commercial and industrial sectors.

Staff develops a forecast of households using the California Department of Finance population projections. Projections of personal income, shipments and employment are developed from the University of California at Los Angeles (UCLA) Anderson School of Business California forecast of September 2002. This forecast assumes that stronger economic growth will resume in late 2003, followed by steady growth, but at a lower rate than previous post-recession periods. A more detailed presentation of this forecast and assumptions will be published in a Technical Appendix to the IEPR. Descriptions of forecasting methods are also contained in “California Energy Demand: 1995-2015, Volume II Electricity Demand Forecasting Models”, July 1995, Publication Number P300-95-005.

The final demand forecast for the IEPR incorporate several changes as a result of comments received on the draft forecast presented at the February 26, 2003 IEPR workshop. Staff revised the electricity rate forecasts based on comments from utilities. Staff also updated the IOU’s present rates to reflect recent changes. Demand reductions from energy efficiency programs included in the forecast are now consistent with the assumption that the current level of program funding persists through 2011, as authorized by the legislature. In addition, staff modified the residential demand model to better estimate the effect of growth in personal income on residential consumption. The combined effect of these changes is to reduce average annual demand growth by 0.5 percent per year over the next ten years. The average growth rate of the final statewide electricity consumption forecast is 1.6% per year over the next ten years.

The Commission’s energy demand models produce forecasts of electricity consumption for eight utility planning areas. To develop a forecast of utility customer sales for Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E), three adjustments are made to the planning area forecast. First, electricity consumption needs that are privately supplied through self-generation or distributed generation are excluded. To forecast private supply, staff estimated peak load and consumption for 2002 and 2003 using data from PG&E, SCE and SDG&E on new interconnect activity in their territories. After 2003, privately supplied load is assumed to grow at one percent per year.

Second, staff used historic consumption data to allocate the planning area forecast between the utilities’ own customers, and water districts and municipalities (or resale cities) in that planning area.

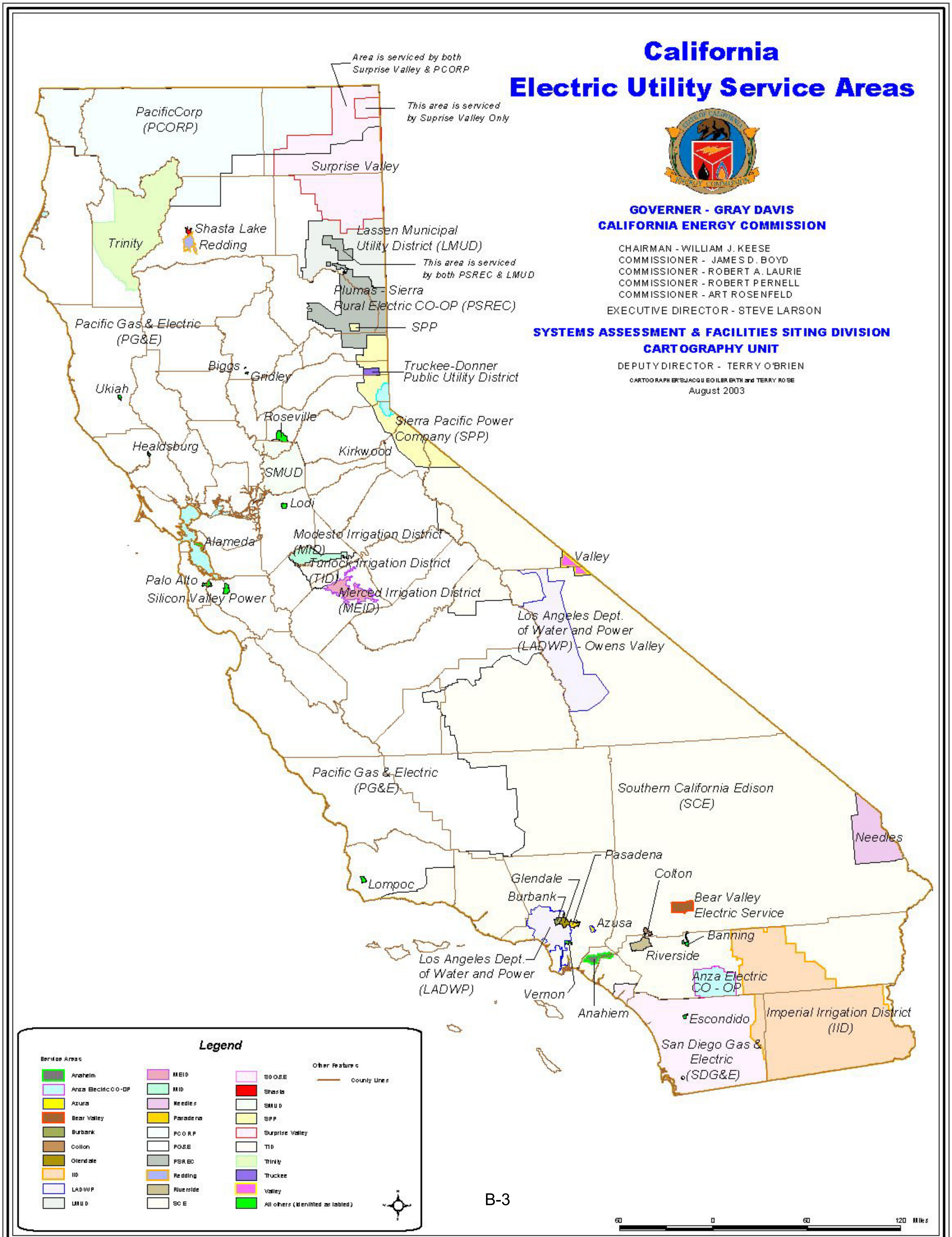
Third, sales to direct access customers are subtracted from the utility customer forecast. To forecast direct access sales, staff used 2002 CPUC reports on actual direct access sales, and assumed that direct access demand grows at the same rate as the overall customer sector for that utility.

APPENDIX B. COUNTY MAPS OF CALIFORNIA TECHNICAL POTENTIAL FOR WIND, GEOTHERMAL, AND SOLAR ENERGY

Appendix B provides a county map of California as will as county maps of technical potential for wind, geothermal, and solar energy. It also contains a county map showing the service areas of all of the utilities in California.

California Counties

T:\Projects\CEC\Counties only filename:Counties only.mxd



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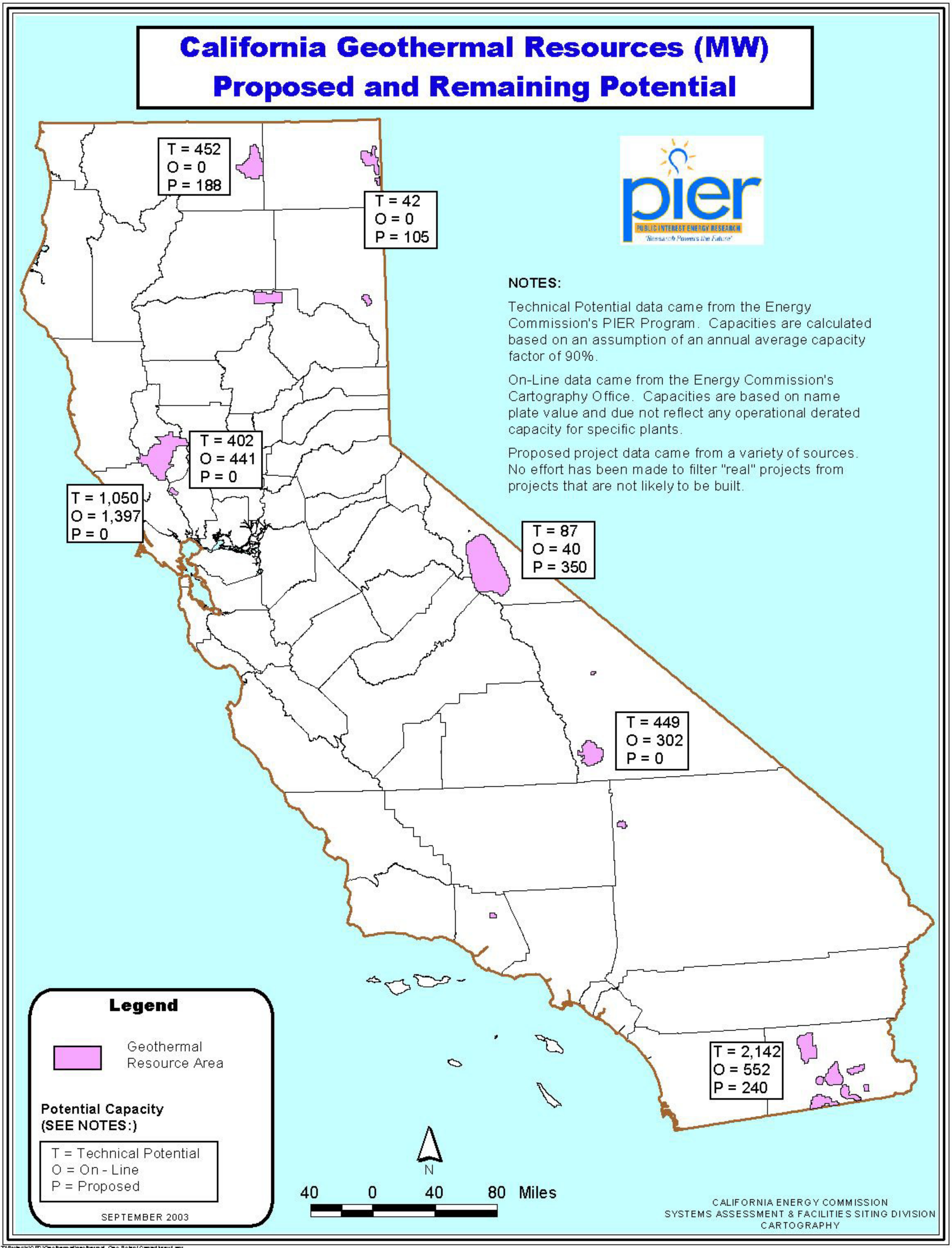
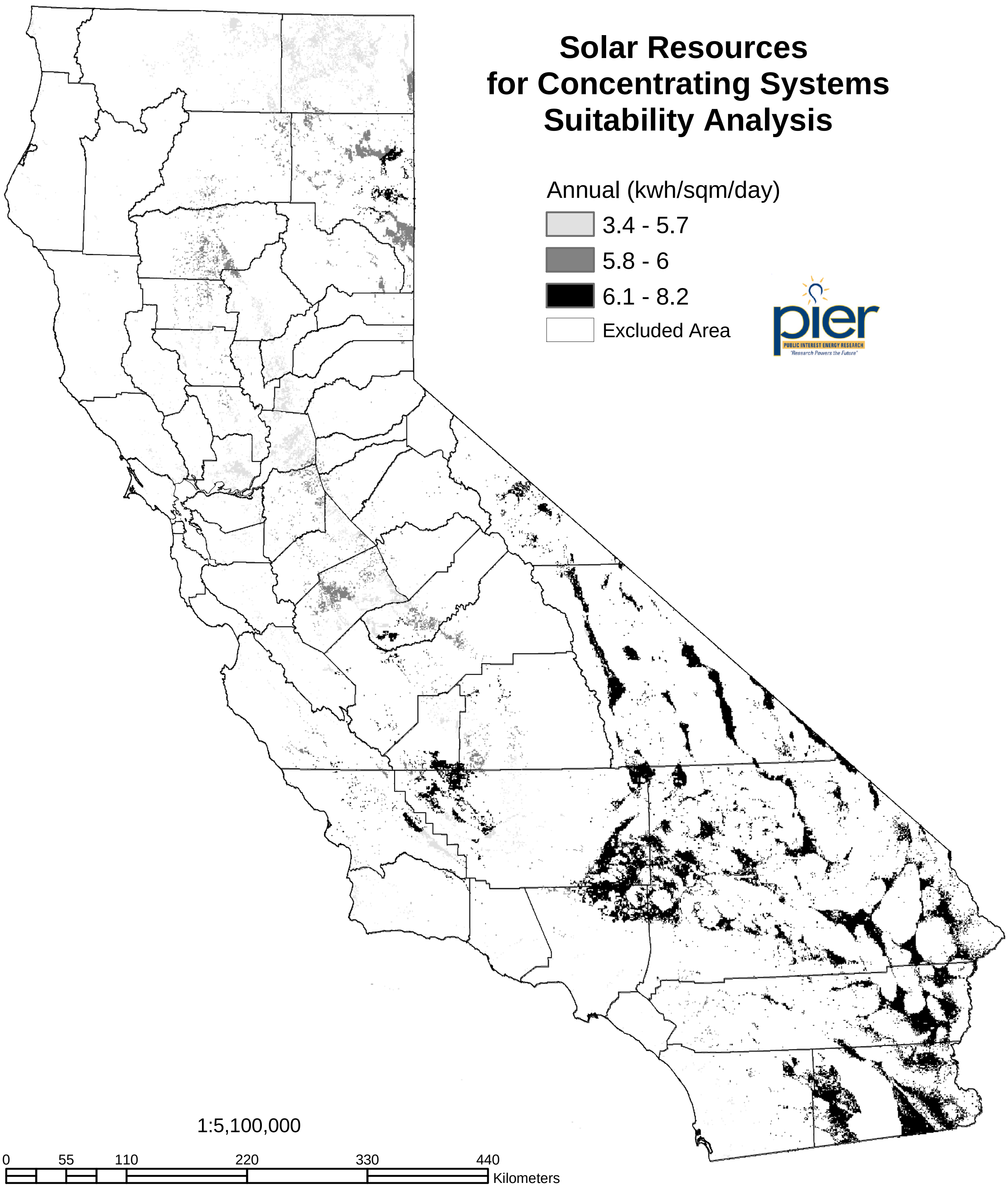
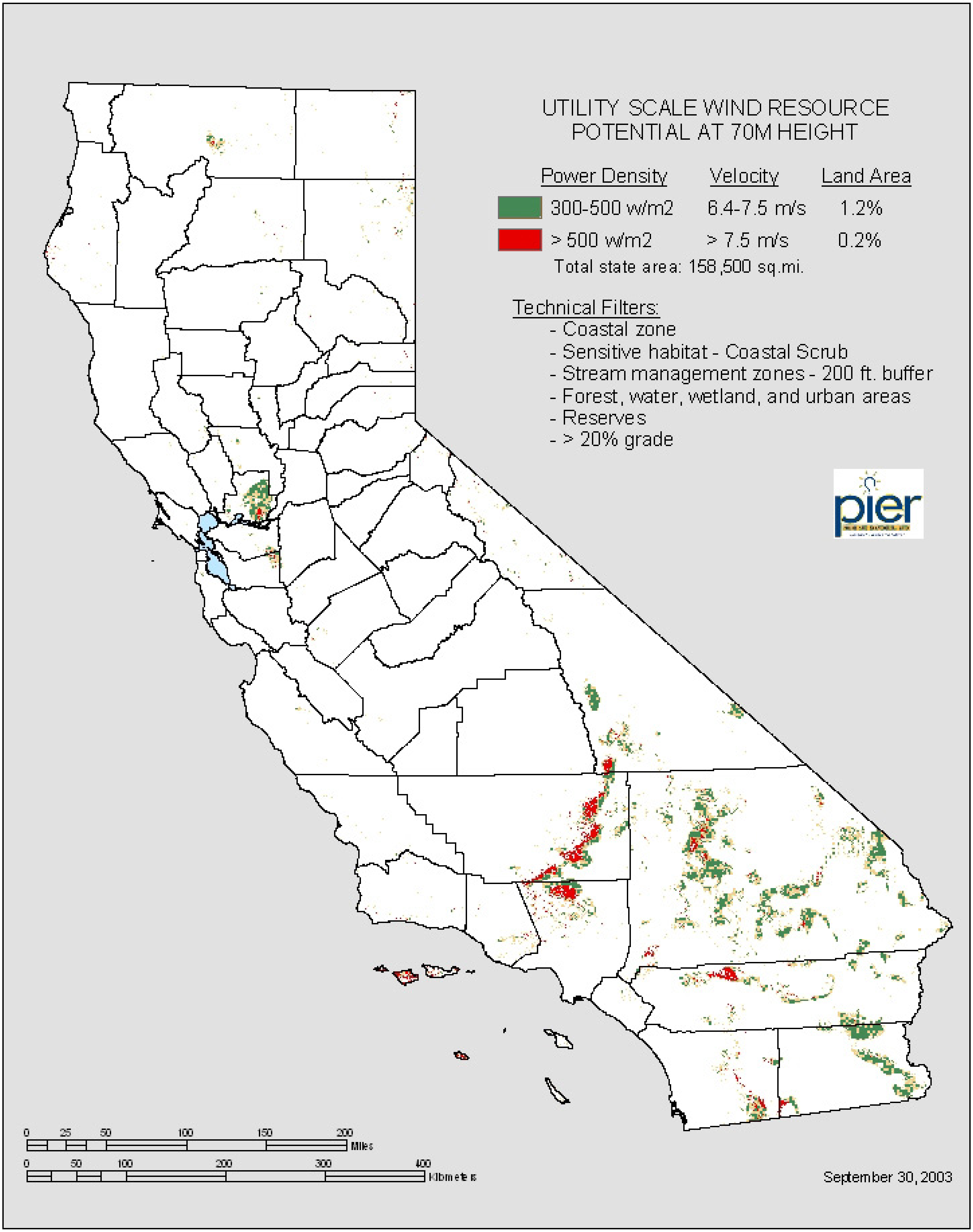

California Geothermal Resources (MW)
Proposed and Remaining Potential
T = 452
O = 0
P = 188
T = 42
O = 0
P = 105
T = 402
O = 441
P = 0
T = 1,050
O = 1,397
P = 0
T = 87
O = 40
P = 350
T = 449
O = 302
P = 0
T = 2,142
O = 552
P = 240
pier
PUBLIC INTEREST ENERGY RESEARCH
NOTES:
Technical Potential data came from the Energy Commission's PIER Program. Capacities are calculated based on an assumption of an annual average capacity factor of 90%.
On-Line data came from the Energy Commission's Cartography Office. Capacities are based on name plate value and due not reflect any operational derated capacity for specific plants.
Proposed project data came from a variety of sources. No effort has been made to filter "real" projects from projects that are not likely to be built.
Legend
Geothermal Resource Area
Potential Capacity (SEE NOTES:)
T = Technical Potential
O = On - Line
P = Proposed
SEPTEMBER 2003
N
40 0 40 80 Miles
CALIFORNIA ENERGY COMMISSION
SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION
CARTOGRAPHY


Solar Resources
for Concentrating Systems
Suitability Analysis
Annual (kwh/sqm/day)
3.4 - 5.7
5.8 - 6
6.1 - 8.2
Excluded Area
1:5,100,000
0
55
110
220
330
440
Kilometers


UTILITY SCALE WIND RESOURCE
POTENTIAL AT 70M HEIGHT
Power Density
Velocity
Land Area
300-500 w/m2
6.4-7.5 m/s
1.2%
> 500 w/m2
> 7.5 m/s
0.2%
Total state area: 158,500 sq.mi.
Technical Filters:
- Coastal zone
- Sensitive habitat - Coastal Scrub
- Stream management zones - 200 ft. buffer
- Forest, water, wetland, and urban areas
- Reserves
- > 20% grade
pier
0 25 50 100 150 200
Miles
0 50 100 200 300 400
Kilometers
September 30, 2003

APPENDIX C. DATA TABLES FOR EXISTING, PROPOSED, AND POTENTIAL RENEWABLE ENERGY IN CALIFORNIA AND OTHER WESTERN ELECTRICITY COORDINATING COUNCIL STATES

This appendix contains the following tables:

- Summary Table
  - California Existing by County (MW)
  - California Existing by County (Gwh/Year)
  - California Proposed (MW)
  - California Proposed (Gwh/Year)
  - California Technical Potential (MW)
  - California Technical Potential (Gwh/Year)
  - California Total Potential less Existing less Proposed (Gwh/Year)
  - Existing, Proposed, and Potential Renewable Energy in other WECC States For Wind, Geothermal, Biomass, and Solar (Gwh/Year)
  - Existing Small Hydroelectric Facilities in other WECC States
  - Operating and Planned Small Hydroelectric Facilities in Alberta and British Columbia, Canada
- Details Regarding Installed Renewable Capacity In California
  - Pivot Table of California Installed Facilities by County (MW)
  - California Installed Facilities by Technology (MW)
- Details Regarding Proposed Renewable Energy Projects In California
  - Pivot Table of California Proposed Renewable Energy Projects (MW)
  - Detailed list of California Proposed Renewable Energy Projects (MW)
- Details Regarding Proposed Renewable Energy Projects in the WECC
- Details regarding Renewable Potential in California
  - PIER Estimate of Wind Energy Potential in California at 70 meter Hub Height (Two Wind Speed Ranges)
  - PIER Estimate of Geothermal Energy Potential in California
  - PIER Estimate of Technical Potential for Small Hydroelectric Facilities in California
  - PIER Estimate of Technical Potential for Biogas in California
  - PIER Estimate of Technical Potential for Biomass in California
  - RER Estimate of Solar PV Technical Potential in California
  - RER Estimate of CSP Technical Potential in California
  - PIER Estimate of Solar PV Technical Potential in California
  - PIER Estimate of CSP Technical Potential in California
- Details regarding filters for biomass, geothermal, solar and wind.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Online MW by County and Resource (from the Energy Commission's Cartography Office)**															
2			**Wind**	**Geothermal ‡**	**TOTAL Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
3	TOTAL MW		1,618	2,735	1,016	836	180	354	33	1,293	731	28	152	105	-	7,049
4	**Avg. Cap Factor**		**25%**	**90%**	**69%**	**66%**	**84%**	**27%**	**15%**	**35%**	**65%**	**80%**	**85%**	**70%**	**80%**	58%
5	Online Avail GWh		3,542	21,563	6,136	4,808	1,328	837	43	3,965	4,162	197	1,131	646	-	36,087
6	**County**															
7	Alameda	PG&E	166		11	4	7			1			7	4		178
8	Alpine	PG&E			-	-	-									-
9	Amador	PG&E			18	18	-			39	18					57
10	Butte	PG&E			19	19	-			65	19					84
11	Calaveras	PG&E			-	-	-			13						13
12	Colusa	PG&E			30	30	-			0	30					30
13	Contra Costa	PG&E	145		3	-	3						3			148
14	Del Norte	PG&E			-	-	-			0						0
15	El Dorado	PG&E			-	-	-			73						73
16	Fresno	PG&E			49	49	-			12	49					61
17	Glenn	PG&E			-	-	-			5						5
18	Humbolt	PG&E			89	89	-			2	89					92
19	Imperial	IID		552	18	18	-			65	18					635
20	Inyo	SCE		302	-	-	-			37						339
21	Kern	SCE	663		57	57	-	150		53	57					923
22	Kings	PG&E			-	-	-									-
23	Lake	PG&E		441	-	-	-			6						447
24	Lassen	PG&E		3	69	69	-			26	69					98
25	Los Angeles	SCE			105	56	49			102			49	56		207
26	Madera	PG&E			-	-	-			69						69
27	Marin	PG&E			-	-	-									-
28	Mariposa	PG&E			-	-	-			9						9
29	Mendocino	PG&E			15	15	-			13	15					28
30	Merced	PG&E			-	-	-			24						24
31	Modoc	PG&E			-	-	-									-
32	Mono	SCE		40	-	-	-			27						67
33	Monterey	PG&E			9	9	-			4				9		13
34	Napa	PG&E			2	-	2			12			2			14
35	Nevada	PG&E			-	-	-			82						82
36	Orange	SCE			51	-	51			13		19	32			64
37	Placer	PG&E			37	37	-			94	37					131
38	Plumas	PG&E			40	40	-			30	40					70
39	Riverside	SCE	316		48	48	-			24	47			1		387
40	Sacramento	SMUD			8	-	8			14			8			22
41	San Benito	PG&E	17		-	-	-									17
42	San Bernardino	SCE			-	-	-	204		40						244
43	San Diego	SDG&E	4		24	-	24			14		7	18			43
44	San Francisco	PG&E			2	-	2					2				2
45	San Joaquin	PG&E	288		28	28	-			11	28					326
46	San Luis Obispo	PG&E			-	-	-			2						2
47	San Mateo	PG&E			2	-	2						2			2
48	Santa Barbara	SCE			4	-	4			0			4			4
49	Santa Clara	PG&E			11	-	11						11			11

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Online MW by County and Resource (from the Energy Commission's Cartography Office)**															
2			**Wind**	**Geothermal ‡**	**TOTAL Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
3	TOTAL MW		1,618	2,735	1,016	836	180	354	33	1,293	731	28	152	105	-	7,049
4	**Avg. Cap Factor**		**25%**	**90%**	**69%**	**66%**	**84%**	**27%**	**15%**	**35%**	**65%**	**80%**	**85%**	**70%**	**80%**	58%
5	Online Avail GWh		3,542	21,563	6,136	4,808	1,328	837	43	3,965	4,162	197	1,131	646	-	36,087
6	**County**															
50	Santa Cruz	PG&E			-	-	-									-
51	Shasta	PG&E			136	136	-			89	136					225
52	Sierra	PG&E			20	20	-			14	20					34
53	Siskiyou	PG&E			-	-	-			45						45
54	Solano	PG&E	19		-	-	-									19
55	Sonoma	PG&E		1,397	6	-	6			3			6			1,406
56	Stanislaus	PG&E			37	37	-			16				37		53
57	Sutter	PG&E			-	-	-			0						0
58	Tehema	PG&E			-	-	-			21						21
59	Trinity	PG&E			-	-	-			15						15
60	Tulare	SCE			2	-	2			36			2			38
61	Tuolumne	PG&E			33	33	-			67	33					100
62	Ventura	SCE			6	-	6			2			6			7
63	Yolo	PG&E			31	28	3				28		3			31
64	Yuba	PG&E			-	-	-			3						3
65	SP 15 (unknown)	SCE			-	-	-									-
66	NP 15 (unknown)	PG&E			-	-	-									-
67																
68	Notes:															

69 The data source for on-line renewable plants in California used in this report is different than used in the July 2003 Preliminary Renewable Resources Assessment (PRRA). The PRRA used a variety of sources. This report relied exclusively on the Energy Commission's Cartography Office in establishing the amount of installed renewable capacity in California. The Commission recognizes that the amounts listed in the two reports are different. As part of the registration process for the RPS, the Commission intends to clarify the amount of installed renewables in California. Other sources indicate that there are only 900 MWs of biomass installed in California, over 1,800 MW of wind installed in California and less than 800 MW of small hydroelectric installed in California.

70 Data on Solar PV was omitted as no source provides this data on a county by county basis, and existing capacity is assumed to be small so it is unlikely to have a dramatic effect on remaining potential. While there was 33 MW of PV installed in CA at the end of 2002, this does not impact the remaining potential in any significant way. By mid-2003, there was over 44 MW of installed PV in California.

71 ‡ Installed GEOTHERMAL capacity includes only plants within CA's borders. It does *not* include two NV plants totaling 78.5 MW in capacity (61 MW Oxbow/Caithness plant and 17.5 MW Beowahee plant)

72 The Energy Commission annually publishes the "J-11" table, which details the amount of generation from specific resource types (i.e. GWh from Nuclear or GWh from Geothermal). The J-11 data were used to estimate the 2001 baseline for the "rest of the state" (i.e., not IOU, not ESP/CCA) retail sales. J-11 data for 2001 total 27,759 GWh. The breakdown (in GWh) between resources is: Geothermal - 13,619; Organic Waste (biomass) - 6,185; Wind - 3,242; Solar - 837; and Small Hydro (under 30 MW) - 3,876. J-11 data is actual data for a specific year. Where the analysis called for an estimate of average renewable energy generation, J-11 was not used. For 2001 and 2002, the "average" estimate of how much energy would be produced by installed renewables in California is significantly higher than what was actually produced according to the J-11 table. This is especially true with geothermal. The reason for this discrepancy is that the capacity factor for older and less efficient equipment is lower than the capacity factor for newer and more efficient equipment.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Online GWh/year by County and Resource (Estimated based on MW from Energy Commission's Cartography Office)**															
2																
3			**Wind**	**Geothermal**	**Total Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
4	TOTAL GWh		3,542	21,563	6,136	4,808	1,328	837	-	3,965	4,162	197	1,131	646	-	36,044
5	**Avg. Cap Factor**		25%	90%	69%	66%	84%	27%	15%	35%	65%	80%	85%	70%	80%	60%
6	**County**															
7	Alameda	PG&E	363	-	75	23	52	-	-	4	-	-	52	23	-	442
8	Alpine	PG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Amador *	PG&E	-	-	102	102	-	-	-	118	102	-	-	-	-	221
10	Butte	PG&E	-	-	107	107	-	-	-	200	107	-	-	-	-	306
11	Calaveras *	PG&E	-	-	-	-	-	-	-	39	-	-	-	-	-	39
12	Colusa	PG&E	-	-	169	169	-	-	-	1	169	-	-	-	-	170
13	Contra Costa	PG&E	317	-	22	-	22	-	-	-	-	-	22	-	-	339
14	Del Norte	PG&E	-	-	-	-	-	-	-	0	-	-	-	-	-	0
15	El Dorado	PG&E	-	-	-	-	-	-	-	223	-	-	-	-	-	223
16	Fresno	PG&E	-	-	281	281	-	-	-	36	281	-	-	-	-	317
17	Glenn	PG&E	-	-	-	-	-	-	-	17	-	-	-	-	-	17
18	Humbolt	PG&E	-	-	508	508	-	-	-	8	508	-	-	-	-	516
19	Imperial	IID	-	4,353	102	102	-	-	-	199	102	-	-	-	-	4,654
20	Inyo	SCE	-	2,382	-	-	-	-	-	114	-	-	-	-	-	2,495
21	Kern	SCE	1,453	-	322	322	-	355	-	164	322	-	-	-	-	2,293
22	Kings	PG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Lake	PG&E	-	3,475	-	-	-	-	-	19	-	-	-	-	-	3,494
24	Lassen	PG&E	-	24	391	391	-	-	-	80	391	-	-	-	-	495
25	Los Angeles	SCE	-	-	709	343	366	-	-	313	-	-	366	343	-	1,023
26	Madera	PG&E	-	-	-	-	-	-	-	210	-	-	-	-	-	210
27	Marin	PG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Mariposa	PG&E	-	-	-	-	-	-	-	28	-	-	-	-	-	28
29	Mendocino	PG&E	-	-	85	85	-	-	-	41	85	-	-	-	-	127
30	Merced	PG&E	-	-	-	-	-	-	-	74	-	-	-	-	-	74
31	Modoc	PG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Mono	SCE	-	315	-	-	-	-	-	81	-	-	-	-	-	397
33	Monterey	PG&E	-	-	52	52	-	-	-	13	-	-	-	52	-	66
34	Napa	PG&E	-	-	13	-	13	-	-	37	-	-	13	-	-	50
35	Nevada	PG&E	-	-	-	-	-	-	-	251	-	-	-	-	-	251
36	Orange	SCE	-	-	369	-	369	-	-	40	-	135	235	-	-	409
37	Placer	PG&E	-	-	213	213	-	-	-	288	213	-	-	-	-	501
38	Plumas	PG&E	-	-	225	225	-	-	-	92	225	-	-	-	-	317
39	Riverside	SCE	691	-	271	271	-	-	-	74	268	-	-	4	-	1,036
40	Sacramento	SMUD	-	-	62	-	62	-	-	41	-	-	62	-	-	103
41	San Benito	PG&E	38	-	-	-	-	-	-	-	-	-	-	-	-	38
42	San Bernardino	SCE	-	-	-	-	-	482	-	123	-	-	-	-	-	606
43	San Diego	SDG&E	9	-	179	-	179	-	-	44	-	48	132	-	-	233
44	San Francisco	PG&E	-	-	15	-	15	-	-	-	-	15	-	-	-	15
45	San Joaquin	PG&E	630	-	157	157	-	-	-	33	157	-	-	-	-	820
46	San Luis Obisbo	PG&E	-	-	-	-	-	-	-	5	-	-	-	-	-	5
47	San Mateo	PG&E	-	-	15	-	15	-	-	-	-	-	15	-	-	15
48	Santa Barbara	SCE	-	-	26	-	26	-	-	0	-	-	26	-	-	26
49	Santa Clara	PG&E	-	-	85	-	85	-	-	-	-	-	85	-	-	85
50	Santa Cruz	PG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Online GWh/year by County and Resource (Estimated based on MW from Energy Commission's Cartography Office)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
3			**Wind**	**Geothermal**	**Total Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
4	TOTAL GWh		3,542	21,563	6,136	4,808	1,328	837	-	3,965	4,162	197	1,131	646	-	36,044
5	**Avg. Cap Factor**		25%	90%	69%	66%	84%	27%	15%	35%	65%	80%	85%	70%	80%	60%
6	**County**															
51	Shasta	PG&E	-	-	774	774	-	-	-	273	774	-	-	-	-	1,047
52	Sierra	PG&E	-	-	114	114	-	-	-	44	114	-	-	-	-	158
53	Siskiyou	PG&E	-	-	-	-	-	-	-	139	-	-	-	-	-	139
54	Solano	PG&E	41	-	-	-	-	-	-	-	-	-	-	-	-	41
55	Sonoma	PG&E	-	11,014	48	-	48	-	-	9	-	-	48	-	-	11,070
56	Stanislaus	PG&E	-	-	224	224	-	-	-	49	-	-	-	224	-	273
57	Sutter	PG&E	-	-	-	-	-	-	-	1	-	-	-	-	-	1
58	Tehema	PG&E	-	-	-	-	-	-	-	65	-	-	-	-	-	65
59	Trinity	PG&E	-	-	-	-	-	-	-	46	-	-	-	-	-	46
60	Tulare	SCE	-	-	13	-	13	-	-	110	-	-	13	-	-	123
61	Tuolumne	PG&E	-	-	185	185	-	-	-	206	185	-	-	-	-	391
62	Ventura	SCE	-	-	41	-	41	-	-	5	-	-	41	-	-	46
63	Yolo	PG&E	-	-	181	159	21	-	-	-	159	-	21	-	-	181
64	Yuba	PG&E	-	-	-	-	-	-	-	10	-	-	-	-	-	10
65	SP 15 (unknown)	PG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	NP 15 (unknown)	SCE	-	-	-	-	-	-	-	-	-	-	-	-	-	-

68 Notes:

69 The data source for on-line renewable plants in California used in this report is different than used in the July 2003 Preliminary Renewable Resources Assessment (PRRA). The PRRA used a variety of sources. This report relied exclusively on the Energy Commission's Cartography Office in establishing the amount of installed renewable capacity in California. The Commission recognizes that the amounts listed in the two reports are different. As part of the registration process for the RPS, the Commission intends to clarify the amount of installed renewables in California. Other sources indicate that there are only 900 MWs of biomass installed in California, over 1,800 MW of wind installed in California and less than 800 MW of small hydroelectric installed in California.

70 The Energy Commission annually publishes the "J-11" table, which details the amount of generation from specific resource types (i.e. GWh from Nuclear or GWh from Geothermal). The J-11 data were used to estimate the 2001 baseline for the "rest of the state" (i.e., not IOU, not ESP/CCA) retail sales. J-11 data for 2001 total 27,759 GWh. The breakdown (in GWh) between resources is: Geothermal - 13,619; Organic Waste (biomass) - 6,185; Wind - 3,242; Solar - 837; and Small Hydro (under 30 MW) - 3,876. J-11 data is actual data for a specific year. Where the analysis called for an estimate of average renewable energy generation, J-11 was not used. For 2001 and 2002, the "average" estimate of how much energy would be produced by installed renewables in California is significantly higher than what was actually produced according to the J-11 table. This is especially true with geothermal. The reason for this discrepancy is that the capacity factor for older and less efficient equipment is lower than the capacity factor for newer and more efficient equipment.

71 Data on Solar PV was omitted as no source provides this data on a county by county basis, and existing capacity is assumed to be small so it is unlikely to have a dramatic effect on remaining potential. While there was 33 MW of PV installed in CA at the end of 2002, this does not impact the remaining potential in any significant way.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Proposed CA MW By County and Resource**															
2			**Wind**	**Geo-thermal**	**Total Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
3	TOTAL MW		5,782	883	872	541	331	170	42	38	261	111	220	30	250	7,786
4	**Assumed Cap Factor**		**35%**	**90%**	**82%**	**80%**	**85%**	**25%**	**15%**	**40%**	**80%**	**85%**	**85%**	**80%**	**80%**	46%
5	Proposed Avail GWh		17,728	6,961	6,252	3,788	2,465	372	55	131	1,827	824	1,641	210	1,751	31,500
6	**County**	**Utility**														
7	Alameda	PG&E	210.8		4.5	-	4.5			1.0			4.5			216
8	Alpine	PG&E				-	-									-
9	Amador	PG&E			-	-	-									-
10	Butte	PG&E				-	-									-
11	Calaveras	PG&E				-	-									-
12	Colusa	PG&E			25.5	25.5	-				25.5					26
13	Contra Costa	PG&E			3.9	-	3.9						3.9			4
14	Del Norte	PG&E				-	-									-
15	El Dorado	PG&E			1.0	-	1.0			21.0			1.0			22
16	Fresno	PG&E			2.6	-	2.6			-			2.6			2.6
17	Glenn	PG&E				-	-									-
18	Humbolt	PG&E				-	-									-
19	Imperial	IID		240.0	80.0	80.0	-				50.0			30.0		320
20	Inyo	SCE			-	-	-			1.0						1
21	Kern	SCE	3,790.0		-	-	-									3,790
22	Kings	PG&E				-	-									-
23	Lake	PG&E			-	-	-									-
24	Lassen	PG&E				-	-									-
25	Los Angeles	SCE	100.0		77.9	49.9	28.00				49.9		28.0			178
26	Madera	PG&E				-	-									-
27	Marin	PG&E				-	-									-
28	Mariposa	PG&E				-	-									-
29	Mendocino	PG&E				-	-									-
30	Merced	PG&E			-	-	-									-
31	Modoc	PG&E		105.0	-	-	-									105
32	Mono	SCE	30.0	350.0	-	-	-									380
33	Monterey	PG&E			1.0	-	1.0						1.0			1
34	Napa	PG&E				-	-									-
35	Nevada	PG&E				-	-									-
36	Orange	SCE			9.2	-	9.2						9.2			9
37	Placer	PG&E			-	-	-									-
38	Plumas	PG&E				-	-									-
39	Riverside	SCE	527.9		7.9	-	7.9						7.9			536
40	Sacramento	SMUD				-	-									-
41	San Benito	PG&E				-	-									-
42	San Bernardino	SCE	91.0		18.8	1.5	17.3	120.0			1.5		17.3			230
43	San Diego	SDG&E	400		28.0	-	28.0					7.2	20.8			428
44	San Francisco	PG&E			2.1	-	2.1					2.1				2
45	San Joaquin	PG&E				-	-									-
46	San Luis Obisbo	PG&E				-	-									-
47	San Mateo	PG&E			18.6	-	18.6						18.6			19
48	Santa Barbara	SCE			-	-	-									-
49	Santa Clara	PG&E			5.5	-	5.5						5.5			6
50	Santa Cruz	PG&E			2.0	-	2.0						2.0			2
51	Shasta	PG&E			-	-	-									-

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Proposed CA MW By County and Resource**															
2			**Wind**	**Geo-thermal**	**Total Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
3	TOTAL MW		5,782	883	872	541	331	170	42	38	261	111	220	30	250	7,786
4	**Assumed Cap Factor**		**35%**	**90%**	**82%**	**80%**	**85%**	**25%**	**15%**	**40%**	**80%**	**85%**	**85%**	**80%**	**80%**	46%
5	Proposed Avail GWh		17,728	6,961	6,252	3,788	2,465	372	55	131	1,827	824	1,641	210	1,751	31,500
6	**County**	**Utility**														
52	Sierra	PG&E				-	-									-
53	Siskiyou	PG&E		187.9	-	-	-									188
54	Solano	PG&E	401.8		-	-	-									402
55	Sonoma	PG&E				-	-									-
56	Stanislaus	PG&E				-	-									-
57	Sutter	PG&E				-	-									-
58	Tehema	PG&E			-	-	-									-
59	Trinity	PG&E				-	-									-
60	Tulare	SCE			1.6	-	1.6						1.6			2
61	Tuolumne	PG&E			-	-	-									-
62	Ventura	SCE				-	-									-
63	Yolo	PG&E			7.8	7.8	-				7.8					8
64	Yuba	PG&E				-	-									-
65	NP 15 (unknown)	PG&E	30.7		529.7	375.8	153.9		42.0	14.5	126.0	101.3	52.6		249.8	617
66	SP 15 (unknown)	SCE	200.0		43.9	-	43.9	50.0					43.9			294
67																
68	Notes:															
69																

70 The data for the proposed projects date back as far as June 1998 from the Energy Commission's first New Account auction to as recent as projects participating in the 2003 Interim Procurement. A limited amount of projects were filtered out if they did not appear to be plausible or "real" projects. Most of the proposed projects do not have contracts and are not yet under construction. Data on proposed projects were gathered from solicitations for new electric providers to IOU and/or municipal electric utilities. The following data sources were used: the Energy Commission's New Renewable Resources Account database, California Power Authority Letters of Intent, Southern California Public Power Authority (SCPPA) Request for Proposals (RFP), the 2003 Northern California Power Association (NCPA) RFP and the SCE Tehachapi Transmission Study (September 2, 2003 monthly report). The proposed MW were converted to energy using the capacity factors as shown in row 4 of this worksheet.

71

72 Of the 81 total entries in the March 2003 New Account database, this eliminated 38, leaving 43 in the proposed category. Only these remaining 43 are included in the list of proposed projects in Appendix C. None of these 43 were subsequently eliminated as this data source was the most complete of the four sources and is deemed to be most reliable.

It should be noted that there are a number of SCPPA landfill gas entries where 3 to 5 separate projects have the same ID number, apparently because they were offered by the same bidder. This is important in that several of the CPA entries excluded as duplicates reference the same SCPPA ID number. Of the 57 original SCPPA entries, 21 were eliminated as duplicates.

73

74 Regarding PV, the SCPPA data has two entries for distributed generation using microturbines and PV hybrid installations. However, no capacity numbers are provided, hence they do not show in the sums for proposed projects. Also, the NCPA data has several PV projects. However, since the location is only defined as "NP15," these projects are excluded from the proposed totals used in this report.

75

76 In the period from fall 2001 through spring 2002, the CPA entered into 73 letters of intent (LOIs) with individual renewable projects in California. Developer name and sometimes project name are provided, but no specific locational information is provided other than interconnect zone (NP15, SP15). Using the project name and developer information, locations were extrapolated and projects were cross-referenced with the Energy Commission s New Renewable Resources Account and SCPPA RFP projects. Of the 73 original entries, 20 were eliminated as duplicates.

77

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Proposed CA MW By County and Resource**															
2			**Wind**	**Geo-thermal**	**Total Biomass**	**Other Biomass**	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Biomass**	**Digester Gas**	**LFG**	**MSW/Tire**	**Biofuel**	**TOTAL**
3	TOTAL MW		5,782	883	872	541	331	170	42	38	261	111	220	30	250	7,786
4	**Assumed Cap Factor**		**35%**	**90%**	**82%**	**80%**	**85%**	**25%**	**15%**	**40%**	**80%**	**85%**	**85%**	**80%**	**80%**	46%
5	Proposed Avail GWh		17,728	6,961	6,252	3,788	2,465	372	55	131	1,827	824	1,641	210	1,751	31,500
6	**County**	**Utility**														
78	The amount of proposed wind in Kern County analyzed for this report totals 714 MW. However, the Commission is aware of the SCE Tehachapi transmission study which identifies the 3,790 MW figure used here. The Commission chose not to use the 4,060MW number that came from the Comments of the Kern Wind Energy Assoc. and Oak Creek Energy Systems filed on June 24, '03, Question 1, a, b, c & d, because, to our knowledge, they have not yet been verified by SCE.															
79																
80																
81																
82	PG&E															
83	Other Wind	0														
84	Other Geothermal	0														
85	Other Solid Biomass	33.3														
86	Other LFG	41.2														
87	Other CSP	0														
88																
89	SCE															
90	Other Wind	30														
91	Other Geothermal	0														
92	Other Solid Biomass	1.5														
93	Other LFG	36														
94	Other CSP	0														

Proposed CA GWh By County and Resource																	
		Wind	Geo-thermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Biomass	Digester Gas	LFG	MSW/Tire	Biofuel	TOTAL	Total Non NP/SP 15	
TOTAL GWh		17,728	6,961	6,252	3,788	2,465	372	55	131	1,827	824	1,641	210	1,751	31,500	26,471	26,391
Assumed Cap Factor		35%	90%	82%	80%	85%	25%	15%	40%	80%	85%	85%	80%	80%	0		
County	**Utility**																
Alameda	PG&E	646	0	34	0	34	0	0	4	0	0	34	0	0	683		
Alpine	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Amador	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Butte	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Calaveras	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Colusa	PG&E	0	0	179	179	0	0	0	0	179	0	0	0	0	179		
Contra Costa	PG&E	0	0	29	0	29	0	0	0	0	0	29	0	0	29		
Del Norte	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
El Dorado	PG&E	0	0	7	0	7	0	0	74	0	0	7	0	0	81		
Fresno	PG&E	0	0	19	0	19	0	0	0	0	0	19	0	0	19		
Glenn	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Humbolt	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Imperial	IID	0	1,892	561	561	0	0	0	0	350	0	0	210	0	2,453		
Inyo	SCE	0	0	0	0	0	0	0	4	0	0	0	0	0	4		
Kern	SCE	11,620	0	0	0	0	0	0	0	0	0	0	0	0	11,620		
Kings	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Lake	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Lassen	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Los Angeles	SCE	307	0	558	350	208	0	0	0	350	0	208	0	0	865		
Madera	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Marin	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Mariposa	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Mendocino	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Merced	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Modoc	PG&E	0	828	0	0	0	0	0	0	0	0	0	0	0	828		
Mono	SCE	92	2,759	0	0	0	0	0	0	0	0	0	0	0	2,851		
Monterey	PG&E	0	0	7	0	7	0	0	0	0	0	7	0	0	7		
Napa	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Nevada	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Orange	SCE	0	0	69	0	69	0	0	0	0	0	69	0	0	69		
Placer	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Plumas	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Riverside	SCE	1,619	0	59	0	59	0	0	0	0	0	59	0	0	1,677		
Sacramento	SMUD	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
San Benito	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
San Bernardino	SCE	279	0	139	11	129	263	0	0	11	0	129	0	0	681		
San Diego	SDG&E	1,226	0	208	0	208	0	0	0	0	54	155	0	0	1,435		
San Francisco	PG&E	0	0	16	0	16	0	0	0	0	16	0	0	0	16		
San Joaquin	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
San Luis Obisbo	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
San Mateo	PG&E	0	0	138	0	138	0	0	0	0	0	138	0	0	138		
Santa Barbara	SCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Santa Clara	PG&E	0	0	41	0	41	0	0	0	0	0	41	0	0	41		
Santa Cruz	PG&E	0	0	15	0	15	0	0	0	0	0	15	0	0	15		
Shasta	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		

Proposed CA GWh By County and Resource

		Wind	Geo-thermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Biomass	Digester Gas	LFG	MSW/Tire	Biofuel	TOTAL	Total Non NP/SP 15	
TOTAL GWh		17,728	6,961	6,252	3,788	2,465	372	55	131	1,827	824	1,641	210	1,751	31,500	26,471	26,391
Assumed Cap Factor		35%	90%	82%	80%	85%	25%	15%	40%	80%	85%	85%	80%	80%	0		
County	**Utility**																
Sierra	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Siskiyou	PG&E	0	1,481	0	0	0	0	0	0	0	0	0	0	0	1,481		
Solano	PG&E	1,232	0	0	0	0	0	0	0	0	0	0	0	0	1,232		
Sonoma	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Stanislaus	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Sutter	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Tehema	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Trinity	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Tulare	SCE	0	0	12	0	12	0	0	0	0	0	12	0	0	12		
Tuolumne	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Ventura	SCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Yolo	PG&E	0	0	55	55	0	0	0	0	55	0	0	0	0	55		
Yuba	PG&E	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
NP 15 (unknown)	PG&E	94	0	3,780	2,634	1,146	0	55	51	883	754	392	0	1,751	3,980		
SP 15 (unknown)	SCE	613	0	327	0	327	110	0	0	0	0	327	0	0	1,050		
SUM NP15 and SP 15		707	0	4,106	2,634	1,473	110	55	51	883	754	719	0	1,751	5,029		
Total less NP15, SP15		17,021	6,961	2,146	1,154	992	263	0	81	944	69	923	210	0	26,471		
Notes:															No NP15 sp15	26,391	
															No sm hydro		

The data for the proposed projects date back as far as June 1998 from the Energy Commission's first New Account auction to as recent as projects participating in the 2003 Interim Procurement. A limited amount of projects were filtered out if they did not appear to be plausible or "real" projects. Most of the proposed projects do not have contracts and are not yet under construction. Data on proposed projects were gathered from solicitations for new electric providers to IOU and/or municipal electric utilities. The following data sources were used: the Energy Commission's New Renewable Resources Account database, California Power Authority Letters of Intent, Southern California Public Power Authority (SCPPA) Request for Proposals (RFP), the 2003 Northern California Power Association (NCPA) RFP and the SCE Tehachapi Transmission Study (September 2, 2003 monthly report). The proposed MW were converted to energy using the capacity factors as shown in row 5 of this worksheet.

Of the 81 total entries in the March 2003 New Account database, this eliminated 38, leaving 43 in the proposed category. Only these remaining 43 are included in the list of proposed projects in Appendix C. None of these 43 were subsequently eliminated as this data source was the most complete of the four sources and is deemed to be most reliable.

It should be noted that there are a number of SCPPA landfill gas entries where 3 to 5 separate projects have the same ID number, apparently because they were offered by the same bidder. This is important in that several of the CPA entries excluded as duplicates reference the same SCPPA ID number. Of the 57 original SCPPA entries, 21 were eliminated as duplicates.

Regarding PV, the SCPPA data has two entries for distributed generation using microturbines and PV hybrid installations. However, no capacity numbers are provided, hence they do not show in the sums for proposed projects. Also, the NCPA data has several PV projects. However, since the location is only defined as "NP15," these projects are excluded from the proposed totals used in this report.

In the period from fall 2001 through spring 2002, the CPA entered into 73 letters of intent (LOIs) with individual renewable projects in California. Developer name and sometimes project name are provided, but no specific locational information is provided other than interconnect zone (NP15, SP15). Using the project name and developer information, locations were extrapolated and projects were cross-referenced with the Energy Commission s New Renewable Resources Account and SCPPA RFP projects. Of the 73 original entries, 20 were eliminated as duplicates.

Proposed CA GWh By County and Resource																	
		Wind	Geo-thermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Biomass	Digester Gas	LFG	MSW/Tire	Biofuel	TOTAL	Total Non NP/SP 15	
TOTAL GWh		17,728	6,961	6,252	3,788	2,465	372	55	131	1,827	824	1,641	210	1,751	31,500	26,471	26,391
Assumed Cap Factor		35%	90%	82%	80%	85%	25%	15%	40%	80%	85%	85%	80%	80%	0		
County	**Utility**																
The amount of proposed wind in Kern County analyzed for this report totals 714 MW. However, the Commission is aware of the SCE Tehachapi transmission study which identifies the 3,790 MW figure used here. The Commission chose not to use the 4,060MW number that came from the Comments of the Kern Wind Energy Assoc. and Oak Creek Energy Systems filed on June 24, '03, Question 1, a, b, c & d, because, to our knowledge, they have not yet been verified by SCE.																	
PG&E																	
Other Wind	-		Other Sma	77													
Other Geothermal	-		Other PV	0													
Other Solid Biomass	233																
Other LFG	307																
Other CSP	0																
SCE																	
Other Wind	92		Other Sma	4													
Other Geothermal	0		Other PV	0													
Other Solid Biomass	11																
Other LFG	268																
Other CSP	0																

Technical Potential MW - From PIER and RER

	Wind	Geothermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Total
Total MW	**14,346**	**4,735**	**2,505**	**2,038**	**467**	**66,161**	**9,451**	**2,099**	**99,298**
Avg CF	**35%**	**90%**	**81%**	**80%**	**85%**	**25%**	**15%**	**40%**	
Total GWh	43,986	37,334	17,758	14,284	3,474	144,893	12,419	6,156	**262,546**
County									
Alameda	129		46	29	17		402	14	590
Alpine	41		0	0	0		0	1	42
Amador	1		23	23	0		10	154	188
Butte	0		44	44	0		57	100	201
Calaveras	0		39	39	0		11	102	153
Colusa	0		32	32	0		5	1	38
Contra Costa	26		27	21	7		264	41	359
Del Norte	3		13	13	0		8	33	57
El Dorado	4		51	51	0		43	58	156
Fresno	1		104	97	7		224	222	551
Glenn	0		33	32	1		7	15	55
Humbolt	70		129	128	1		35	56	290
Imperial	467	2,142	13	13	0	11,080	40	3	13,745
Inyo	817	449	1	1	0		5	29	1,301
Kern	4,535		71	64	7	15,665	185	41	20,497
Kings	0		44	37	7		37	2	83
Lake	1	402	9	9	0		16	12	440
Lassen	88	13	17	17	0		10	4	131
Los Angeles	1,927		380	200	180	4,701	2,664	6	9,678
Madera	1		42	39	3		35	91	169
Marin	0		6	5	1		69	1	76
Mariposa	0		3	3	0		5	19	27
Mendocino	0		146	146	0		24	12	183
Merced	6		39	27	12		59	23	127
Modoc	105	42	12	12	0		3	5	167
Mono	242	87	1	0	0		4	33	366
Monterey	0		23	18	6		112	5	140
Napa	0	30	8	6	2		35	0	74
Nevada	1		10	9	0		25	36	72
Orange	11	0	112	61	51		792	4	920
Placer	3		46	44	2		69	57	175
Plumas	19		44	44	0		6	139	208
Riverside	1,511		62	50	12	7,946	430	24	9,972
Sacramento	0		56	39	17		340	30	426
San Benito	0		5	5	0		15	0	20
San Bernardinc	1,896	62	52	38	13	24,142	477	3	26,631
San Diego	739		94	70	25	1,354	783	3	2,974
San Francisco	0		17	15	2		216	0	233
San Joaquin	0		56	48	8		157	1	214
San Luis Obisbo	1		17	16	1	1,273	69	3	1,362
San Mateo	1		23	18	5		197	0	221
Santa Barbara	1,055		24	20	4		111	1	1,191
Santa Clara	0		52	38	14		469	3	524
Santa Cruz	0		17	13	5		71	1	90
Shasta	16		44	44	0		45	134	239
Sierra	15		11	11	0		1	119	146

California Tech Potential (MW)

Technical Potential MW - From PIER and RER

	Wind	Geothermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Total
Total MW	**14,346**	**4,735**	**2,505**	**2,038**	**467**	**66,161**	**9,451**	**2,099**	**99,298**
Avg CF	**35%**	**90%**	**81%**	**80%**	**85%**	**25%**	**15%**	**40%**	
Total GWh	43,986	37,334	17,758	14,284	3,474	144,893	12,419	6,156	**262,546**
County									
Siskiyou	58	452	61	61	0		12	94	677
Solano	269		28	26	2		110	0	407
Sonoma	3	1,050	39	29	10		128	0	1,219
Stanislaus	0		33	24	9		125	54	213
Sutter	0		24	24	0		22	1	47
Tehema	0		24	24	0		16	44	84
Trinity	1		33	33	0		4	72	110
Tulare	0		75	51	24		103	9	188
Tuolumne	1		18	18	0		15	128	162
Ventura	281	6	30	25	5		210	1	529
Yolo	0		27	24	3		47	0	74
Yuba	0		13	13	1		17	57	88

Notes:

PIER - The Energy Commission's Public Interest Energy Research Program.
RER - Regional Economic Research, Inc, a technical contractor to the Energy Commission's Renewable Energy Program.

Wind Technical Potential from PIER
Geothermal Technical Potential from PIER
Other Biomass Technical Potential from PIER
LFG/Digester Technical Potential from PIER
Solar Thermal Potential from RER
Solar PV Potential from RER

Small Hydro GWh data provided by PIER   Applying capacity factors to MW data yields different GWh figures.

Technical Potential GWh - From PIER and RER										
		Wind	Geothermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Total
Total GWh		**43,986**	**37,334**	**17,758**	**14,284**	**3,474**	**144,893**	**12,419**	**6,156**	**262,546**
County	**Utility**									
Alameda	PG&E	394	0	326	203	123	0	528	118	1,366
Alpine	PG&E	126	0	0	0	0	0	0	5	131
Amador *	PG&E	3	0	159	158	1	0	13	322	497
Butte	PG&E	0	0	308	306	2	0	75	248	632
Calaveras *	PG&E	0	0	277	276	0	0	14	202	493
Colusa	PG&E	1	0	227	227	0	0	7	3	237
Contra Costa	PG&E	80	0	195	145	50	0	347	146	769
Del Norte	PG&E	9	0	91	90	1	0	11	160	271
El Dorado	PG&E	12	0	359	356	2	0	57	225	652
Fresno	PG&E	2	0	732	678	54	0	294	446	1,475
Glenn	PG&E	0	0	233	226	7	0	9	42	284
Humbolt	PG&E	216	0	902	894	8	0	46	181	1,345
Imperial	IID	1,433	16,888	92	90	2	24,265	53	22	42,752
Inyo	SCE	2,506	3,540	5	4	1	0	7	153	6,210
Kern	SCE	13,903	0	503	450	53	34,306	243	159	49,115
Kings	PG&E	0	0	314	260	54	0	49	6	368
Lake	PG&E	2	3,169	62	61	1	0	21	32	3,286
Lassen	PG&E	269	102	117	116	1	0	13	19	520
Los Angeles	SCE	5,909	0	2,742	1,404	1,338	10,295	3,500	27	22,472
Madera	PG&E	4	0	293	273	20	0	46	223	566
Marin	PG&E	1	0	45	36	9	0	91	2	138
Mariposa	PG&E	0	0	21	20	0	0	7	69	96
Mendocino	PG&E	0	0	1,027	1,025	2	0	32	36	1,095
Merced	PG&E	20	0	281	190	91	0	78	67	445
Modoc	PG&E	322	331	86	86	0	0	4	27	770
Mono	SCE	741	686	4	3	1	0	5	161	1,596
Monterey	PG&E	0	0	166	124	43	0	147	18	331
Napa	PG&E	1	237	58	45	13	0	46	0	341
Nevada	PG&E	4	0	68	67	2	0	33	86	191
Orange	SCE	34	0	810	428	382	0	1,041	24	1,909
Placer	PG&E	9	0	325	311	14	0	91	186	610
Plumas	PG&E	59	0	309	308	0	0	8	258	634
Riverside	SCE	4,633	0	437	347	90	17,402	565	127	23,163
Sacramento	SMUD	0	0	397	272	126	0	447	0	844
San Benito	PG&E	0	0	35	33	1	0	20	0	55
San Bernardino	SCE	5,812	489	368	270	99	52,871	627	15	60,182
San Diego	SDG&E	2,266	0	672	487	185	2,965	1,029	20	6,953
San Francisco	PG&E	0	0	120	107	13	0	284	0	404
San Joaquin	PG&E	0	0	398	339	60	0	206	2	607
San Luis Obisbo	PG&E	4	0	117	110	7	2,788	91	22	3,021
San Mateo	PG&E	2	0	165	130	35	0	259	0	426
Santa Barbara	SCE	3,235	0	172	140	32	0	146	8	3,560
Santa Clara	PG&E	0	0	367	263	104	0	616	26	1,009
Santa Cruz	PG&E	0	0	124	88	36	0	93	8	226
Shasta	PG&E	50	0	309	306	3	0	59	440	858
Sierra	PG&E	47	0	77	77	0	0	1	307	432

Technical Potential GWh - From PIER and RER

		Wind	Geothermal	Total Biomass	Other Biomass	LFG, Dairy and Swine, and Sewage	Solar Thermal	Solar PV	Small Hydro	Total
Total GWh		**43,986**	**37,334**	**17,758**	**14,284**	**3,474**	**144,893**	**12,419**	**6,156**	**262,546**
County	**Utility**									
Siskiyou	PG&E	176	3,564	427	426	2	0	16	376	4,559
Solano	PG&E	823	0	199	181	17	0	145	0	1,167
Sonoma	PG&E	8	8,278	275	202	73	0	168	0	8,729
Stanislaus	PG&E	0	0	238	167	70	0	164	132	534
Sutter	PG&E	0	0	166	165	1	0	29	5	200
Tehema	PG&E	0	0	170	167	3	0	21	107	299
Trinity	PG&E	2	0	228	228	0	0	5	183	418
Tulare	SCE	1	0	538	358	180	0	135	24	698
Tuolumne	PG&E	4	0	127	126	1	0	20	448	598
Ventura	SCE	862	50	215	175	40	0	276	3	1,407
Yolo	PG&E	0	0	189	170	19	0	62	0	251
Yuba	PG&E	0	0	95	90	4	0	22	231	348

Notes:

PIER - The Energy Commission's Public Interest Energy Research Program.

RER - Regional Economic Research, Inc, a technical contractor to the Energy Commission's Renewable Energy Program.

Small Hydro GWh data provided by PIER   Applying capacity factors to MW data yields different GWh figures.

Wind Technical Potential (GWh) calculated by applying capacity factors to MW data from PIER

Geothermal Technical Potential calculated by applying capacity factors to MW data from PIER

Other Biomass Technical Potential calculated by applying capacity factors to MW data from PIER.

LFG/Digester Technical Potential calculated by applying capacity factors to MW data from PIER

Solar Thermal Potential calculated by applying capacity factors to MW data from RER

Solar PV Potential calculated by applying capacity factors to MW data from RER

	A	B	C	D	E	F	G	H	I	J	K
1	**Remaining Potential GWh by State and Resource**										
2											
3	**NON-NEGATIVE VALUES ONLY**		**Wind**	**Geothermal**	**Total Biomass**	**Other Biomass *****	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Total**
4	**Total GWh1**		**25,392**	**14,737**	**11,566**	**9,957**	**1,610**	**143,793**	**12,419**	**3,343**	**211,250**
5	**Total GWh2**		**22,716**	**8,810**	**5,689**	**5,689**	**0**	**143,683**	**12,363**	**2,060**	**195,321**
6	**County**										
7	Alameda	PG&E	0	0	218	180	38	0	528	110	856
8	Alpine	PG&E	126	0	0	0	0	0	0	5	131
9	Amador	PG&E	3	0	57	56	1	0	13	203	276
10	Butte	PG&E	0	0	201	199	2	0	75	49	325
11	Calaveras	PG&E	0	0	277	276	0	0	14	163	454
12	Colusa	PG&E	1	0	0	0	0	0	7	2	10
13	Contra Costa	PG&E	0	0	145	145	0	0	347	146	638
14	Del Norte	PG&E	9	0	91	90	1	0	11	160	271
15	El Dorado	PG&E	12	0	356	356	0	0	57	0	425
16	Fresno	PG&E	2	0	432	397	35	0	294	410	1,138
17	Glenn	PG&E	0	0	233	226	7	0	9	26	268
18	Humbolt	PG&E	216	0	394	386	8	0	46	174	830
19	Imperial	IID	1,433	10,642	2	0	2	24,265	53	0	36,395
20	Inyo	SCE	2,506	1,158	5	4	1	0	7	36	3,711
21	Kern	SCE	830	0	181	129	53	33,952	243	0	35,206
22	Kings	PG&E	0	0	314	260	54	0	49	6	368
23	Lake	PG&E	2	0	62	61	1	0	21	12	98
24	Lassen	PG&E	269	79	1	0	1	0	13	0	361
25	Los Angeles	SCE	5,602	0	1,474	711	763	10,295	3,500	0	20,872
26	Madera	PG&E	4	0	293	273	20	0	46	13	356
27	Marin	PG&E	1	0	45	36	9	0	91	2	138
28	Mariposa	PG&E	0	0	21	20	0	0	7	41	68
29	Mendocino	PG&E	0	0	941	939	2	0	32	0	973
30	Merced	PG&E	20	0	281	190	91	0	78	0	378
31	Modoc	PG&E	322	0	86	86	0	0	4	27	439
32	Mono	SCE	649	0	4	3	1	0	5	79	737
33	Monterey	PG&E	0	0	107	71	35	0	147	4	258
34	Napa	PG&E	1	237	45	45	0	0	46	0	328
35	Nevada	PG&E	4	0	68	67	2	0	33	0	105
36	Orange	SCE	34	0	428	428	0	0	1,041	0	1,503
37	Placer	PG&E	9	0	112	98	14	0	91	0	211
38	Plumas	PG&E	59	0	84	83	0	0	8	166	317
39	Riverside	SCE	2,323	0	107	76	31	17,402	565	53	20,449
40	Sacramento	SMUD	0	0	335	272	64	0	447	0	782
41	San Benito	PG&E	0	0	35	33	1	0	20	0	54
42	San Bernardino	SCE	5,533	489	259	259	0	52,126	627	0	59,033
43	San Diego	SDG&E	1,031	0	487	487	0	2,965	1,029	0	5,512
44	San Francisco	PG&E	0	0	107	107	0	0	284	0	391
45	San Joaquin	PG&E	0	0	242	182	60	0	206	0	448
46	San Luis Obisbo	PG&E	4	0	117	110	7	2,788	91	17	3,017
47	San Mateo	PG&E	2	0	130	130	0	0	259	0	391
48	Santa Barbara	SCE	3,235	0	146	140	6	0	146	7	3,534
49	Santa Clara	PG&E	0	0	263	263	0	0	616	26	905
50	Santa Cruz	PG&E	0	0	110	88	21	0	93	8	211
51	Shasta	PG&E	50	0	3	0	3	0	59	167	279
52	Sierra	PG&E	47	0	0	0	0	0	1	263	311

	A	B	C	D	E	F	G	H	I	J	K
1	**Remaining Potential GWh by State and Resource**										
2											
3	**NON-NEGATIVE VALUES ONLY**		**Wind**	**Geothermal**	**Total Biomass**	**Other Biomass *****	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Total**
4	**Total GWh1**		**25,392**	**14,737**	**11,566**	**9,957**	**1,610**	**143,793**	**12,419**	**3,343**	**211,250**
5	**Total GWh2**		**22,716**	**8,810**	**5,689**	**5,689**	**0**	**143,683**	**12,363**	**2,060**	**195,321**
6	**County**										
53	Siskiyou	PG&E	176	2,082	427	426	2	0	16	236	2,938
54	Solano	PG&E	0	0	199	181	17	0	145	0	343
55	Sonoma	PG&E	8	0	227	202	25	0	168	0	403
56	Stanislaus	PG&E	0	0	70	0	70	0	164	83	318
57	Sutter	PG&E	0	0	166	165	1	0	29	4	199
58	Tehema	PG&E	0	0	170	167	3	0	21	42	233
59	Trinity	PG&E	2	0	228	228	0	0	5	137	373
60	Tulare	SCE	1	0	513	358	154	0	135	0	649
61	Tuolumne	PG&E	4	0	1	0	1	0	20	242	266
62	Ventura	SCE	862	50	175	175	0	0	276	0	1,364
63	Yolo	PG&E	0	0	0	0	0	0	62	0	62
64	Yuba	PG&E	0	0	95	90	4	0	22	221	338
65											
66	Notes:										
67	Remaining potential is calculated by subtracting on-line and proposed projects from the technical potential. While some of the proposed projects will likely not be built, the remaining potential figure gives an approximation of how much energy would still be available if those projects were built.										
68	GWh1 is the sum of all the counties, excluding the proposed projects in NP15 and SP15. GWh2 is the sum of all the counties, but including the proposed projects in NP15 and SP15.										
69	In some instances, the amount of proposed projects and the amount of existing projects exceeds the technical capacity, resulting in a negative value for "remaining potential." If this results in a negative value, zero is assumed. The following pages show where the values are negative.										
70	Because PIER data in the "Other Biomass" category (TECHNICAL POTENTIAL) includes only the organic portion of MSW and biomass (solid), the "Other Biomass" category in this worksheet DOES NOT include existing/planned Biofuel and Existing/Planned Tire capacities in its calculations. Values shown herein for "Other Biomass" are calculated by subtracting existing/planned "Solid Biomass" from technical potential for "Other Biomass."										

	M	N	O	P	Q	R	S	T	U	V	W
1	**Remaining Potential GWh by State and Resource (with Negative Values)**										
2											
3	**NEGATIVE VALUES SHOWN**		**Wind**	**Geothermal**	**Total Biomass**	**Other Biomass *****	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Total**
4	**Total GWh1**		**23,423**	**8,810**	**9,476**	**8,322**	**1,154**	**143,793**	**12,419**	**2,110**	**200,031**
5	**Total GWh2**		**22,716**	**8,810**	**5,370**	**5,689**	**-319**	**143,683**	**12,363**	**2,060**	**195,002**
6	**County**										
7	Alameda		**-615**	0	218	180	38	0	528	110	1,366
8	Alpine		126	0	0	0	0	0	0	5	131
9	Amador		3	0	57	56	1	0	13	203	394
10	Butte		0	0	201	199	2	0	75	49	525
11	Calaveras		0	0	277	276	0	0	14	163	493
12	Colusa		1	0	**-121**	**-121**	0	0	7	2	**-111**
13	Contra Costa		**-236**	0	144	145	**-1**	0	347	146	769
14	Del Norte		9	0	91	90	1	0	11	160	271
15	El Dorado		12	0	351	356	**-5**	0	57	**-71**	652
16	Fresno		2	0	432	397	35	0	294	410	1,194
17	Glenn		0	0	233	226	7	0	9	26	284
18	Humbolt		216	0	394	386	8	0	46	174	837
19	Imperial		1,433	10,642	**-570**	**-573**	2	24,265	53	**-177**	42,300
20	Inyo		2,506	1,158	5	4	1	0	7	36	6,210
21	Kern		830	0	181	129	53	33,952	243	**-5**	48,793
22	Kings		0	0	314	260	54	0	49	6	368
23	Lake		2	**-306**	62	61	1	0	21	12	3,286
24	Lassen		269	79	**-275**	**-275**	1	0	13	**-61**	128
25	Los Angeles		5,602	0	1,474	711	763	10,295	3,500	**-287**	22,123
26	Madera		4	0	293	273	20	0	46	13	566
27	Marin		1	0	45	36	9	0	91	2	138
28	Mariposa		0	0	21	20	0	0	7	41	96
29	Mendocino		0	0	941	939	2	0	32	**-5**	1,009
30	Merced		20	0	281	190	91	0	78	**-7**	445
31	Modoc		322	**-497**	86	86	0	0	4	27	770
32	Mono		649	**-2,389**	4	3	1	0	5	79	1,596
33	Monterey		0	0	107	71	35	0	147	4	331
34	Napa		1	237	45	45	**0**	0	46	**-37**	341
35	Nevada		4	0	68	67	2	0	33	**-165**	191
36	Orange		34	0	372	428	**-56**	0	1,041	**-16**	1,909
37	Placer		9	0	112	98	14	0	91	**-102**	397
38	Plumas		59	0	84	83	0	0	8	166	409
39	Riverside		2,323	0	107	76	31	17,402	565	53	22,895
40	Sacramento		0	0	335	272	64	0	447	**-41**	844
41	San Benito		**-38**	0	35	33	1	0	20	0	55
42	San Bernardino		5,533	489	229	259	**-30**	52,126	627	**-108**	60,171
43	San Diego		1,031	0	285	487	**-203**	2,965	1,029	**-24**	6,953
44	San Francisco		0	0	90	107	**-18**	0	284	0	404
45	San Joaquin		**-630**	0	242	182	60	0	206	**-31**	450
46	San Luis Obisbo		4	0	117	110	7	2,788	91	17	3,021
47	San Mateo		2	0	11	130	**-118**	0	259	0	426
48	Santa Barbara		3,235	0	146	140	6	0	146	7	3,560
49	Santa Clara		0	0	241	263	**-22**	0	616	26	1,009
50	Santa Cruz		0	0	110	88	21	0	93	8	226
51	Shasta		50	0	**-465**	**-468**	3	0	59	167	84
52	Sierra		47	0	**-37**	**-37**	0	0	1	263	318

	M	O	P	Q	R	S	T	U	V	W
1	**Remaining Potential GWh by State and Resource (with Negative Values)**									
2										
3	**NEGATIVE VALUES SHOWN**	**Wind**	**Geothermal**	**Total Biomass**	**Other Biomass *****	**LFG, Dairy and Swine, and Sewage**	**Solar Thermal**	**Solar PV**	**Small Hydro**	**Total**
4	**Total GWh1**	**23,423**	**8,810**	**9,476**	**8,322**	**1,154**	**143,793**	**12,419**	**2,110**	**200,031**
5	**Total GWh2**	**22,716**	**8,810**	**5,370**	**5,689**	**-319**	**143,683**	**12,363**	**2,060**	**195,002**
6	**County**									
53	Siskiyou	176	2,082	427	426	2	0	16	236	4,559
54	Solano	**-449**	0	199	181	17	0	145	0	1,167
55	Sonoma	8	**-2,736**	227	202	25	0	168	**-9**	8,729
56	Stanislaus	0	0	14	**-57**	70	0	164	83	534
57	Sutter	0	0	166	165	1	0	29	4	200
58	Tehema	0	0	170	167	3	0	21	42	299
59	Trinity	2	0	228	228	0	0	5	137	418
60	Tulare	1	0	513	358	154	0	135	**-86**	698
61	Tuolumne	4	0	**-58**	**-59**	1	0	20	242	413
62	Ventura	862	50	174	175	**-1**	0	276	**-2**	1,407
63	Yolo	0	0	**-46**	**-45**	**-2**	0	62	0	37
64	Yuba	0	0	95	90	4	0	22	221	348
65										
66	Notes:									
67	Remaining potential is calculated by subtracting on-line and proposed projects from the technical potential. While some of the proposed projects will likely not be built, the remaining potential figure gives an approximation of how much energy would still be available if those projects were built.									
68	GWh1 is the sum of all the counties, excluding the proposed projects in NP15 and SP15. GWh2 is the sum of all the counties, but including the proposed projects in NP15 and SP15.									
69	In some instances, the amount of proposed projects and the amount of existing projects exceeds the technical capacity, resulting in a negative value for "remaining potential." If this results in a negative value, zero is assumed. This page shows where the values are negative.									
70	Because PIER data in the "Other Biomass" category (TECHNICAL POTENTIAL) includes only the organic portion of MSW and biomass (solid), the "Other Biomass" category in this worksheet DOES NOT include existing/planned Biofuel and Existing/Planned Tire capacities in its calculations. Values shown herein for "Other Biomass" are calculated by subtracting existing/planned "Solid Biomass" from technical potential for "Other Biomass."									

	A	B	C	D	E	F	G	H	I	J	K
1		**Existing, Proposed, and Potential Renewable Energy Resources in WECC states**									
18	**GWH**	**TOTAL ONLINE**					**PROPOSED**				
19		**Wind**	**Geo ‡**	**Bio**	**Solar**	**Total**	**Wind †**	**Geo**	**Bio**	**Solar**	**Total**
20	Capacity Factor	**35%**	**90%**	**80%**	**15%**		**35%**	**90%**	**80%**	**25%**	
21	AZ	-	-	35.0	11.7	46.7	123	-	-	-	123
22	CO	156.1	-	113.5	1.0	270.6	803	-	-	-	803
23	ID	-	-	884.4	0.2	884.6	613	79	-	-	692
24	MT	-	-	75.7	0.2	75.9	822	-	-	-	822
25	NM	-	-	46.3	0.1	46.4	2,020	-	-	-	2,020
26	NV	-	1,672.2	-	0.1	1,672.3	1,978	1,854	175	109.5	4,117
27	OR	636.2	-	1,269.1	0.1	1,905.4	11,728	394	-	-	12,122
28	UT	-	294.1	-	0.0	294.1	460	788	-	-	1,248
29	WA	700.0	-	2,283.2	0.2	2,983.3	11,065	-	-	-	11,065
30	WY	432.3	-	-	0.1	432.4	552	-	-	-	552
31	**TOTAL**	**1,924.5**	**1,966.3**	**4,707.3**	**13.6**	**8,611.7**	**30,164**	**3,116**	**175**	**110**	**33,564**

32 ‡ Installed GEOTHERMAL capacity for NEVADA includes two NV plants totaling 78.5 MW in capacity (61 MW Oxbow/Caithness plant and 17.5 MW Beowahee plant) that are within the NV borders but export energy to CA. This capacity is included in NV per 08/25/2003 12:45 PST conference call with CEC.

33 † Note a change in Proposed Wind installations for WA and WY: a prior version of this document cited 34,106 GHz and 613 GHz for WA and WY respectively, but the revised data (11,065 GHz for WA and 552 GWh for WY) are the correct figures.

34 With the exception of SOLAR, data on existing capacity was compiled from the Energy Information Administration (EIA) database of "Existing Electric Generating Units in the United States by State, Company and Plant, 2002" at http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls. SOLAR data was compiled from the Renewable Electric Plant Information System (REPiS) database developed by the National Renewable Energy Laboratory (NREL) with funding from the U.S. Department of Energy (DOE), as REPiS was deemed more accurate than EIA for solar data. Capacity factors were applied to capacity (MW) data in this database to yield energy data in GWh. The figures produced using these capacity factors provide an approximate average amount of energy these facilities could generate each year. Actual performance will vary year to year. The capacity factor for proposed and potential solar thermal is 15%, as it assumes no use of natural gas.

35 Although the non-CA WECC region contains small portions of TEXAS and SOUTH DAKOTA, these states were omitted from this analysis. SOUTH DAKOTA was omitted because the EIA database shows no existing facilities in the WECC portion of the state, and because there is no available data on proposed projects and/or technical potential for the small portion of this state in the WECC territory. The EIA data source lists 65 MW of existing wind capacity In the WECC portion of TEXAS as well as 1 MW of existing solar capacity. Nonetheless, TEXAS was omitted because there is no available data on proposed projects and/or technical potential for the small portion of this state in the WECC territory.

36 * A high-level assessment of renewable energy potential in the WECC published in July 2002 by the Land and Water Fund of the Rockies was used as the primary data source for technical potential for the Western Electricity Coordinating Council (WECC) region: Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential. Note a change in the TOTAL figures for all technologies from previous versions of this document; previous versions included CA data in the total, but figures in this worksheet are exclusive to the non-California WECC states.

37 Except where noted, figures are estimates of remaining potential after existing and proposed projects have been subtracted from the total technical potential. The data for existing and proposed projects exclude renewable technologies that are not appropriate for large-scale electricity generation or that have unproven technical issues, including hot dry rock and magma (geothermal). The principal focus for solar has been on solar thermal electric potential, but solar photovoltaic potential has also been included when it has been grouped with solar thermal potential.

	A	L	M	N	O	P	Q	R	S	T	U
1		**Existing, Proposed, and Potential Renewable Energy Resources in WECC states**									
18	**GWH**	**TOTAL POTENTIAL ***					**REMAINING POTENTIAL**				
19		**Wind**	**Geo**	**Bio**	**Solar**	**Total**	**Wind**	**Geo**	**Bio**	**Solar**	**Total**
20	Capacity Factor										
21	AZ	5,000	5,000	1,000	101,000	112,000	4,877	5,000	965	100,988	111,831
22	CO	601,000	-	4,000	83,000	688,000	600,041	-	3,886	82,999	686,926
23	ID	49,000	5,000	9,000	60,000	123,000	48,387	4,921	8,116	60,000	121,423
24	MT	1,020,000	-	6,000	101,000	1,127,000	1,019,178	-	5,924	101,000	1,126,102
25	NM	56,000	3,000	500	104,000	163,500	53,980	3,000	454	104,000	161,433
26	NV	55,000	20,000	1,000	93,000	169,000	53,022	16,473	825	92,890	163,211
27	OR	70,000	17,000	10,000	68,000	165,000	57,636	16,606	8,731	68,000	150,972
28	UT	23,000	9,000	1,000	69,000	102,000	22,540	7,918	1,000	69,000	100,458
29	WA	62,000	-	11,000	42,000	115,000	50,235	-	8,717	42,000	100,951
30	WY	883,000	-	-	72,000	955,000	882,016	-	-	72,000	954,016
31	**TOTAL**	**2,824,000**	**59,000**	**43,500**	**793,000**	**3,719,500**	**2,791,912**	**53,918**	**38,618**	**792,877**	**3,677,324**
32											
33											
34											
35											
36											
37											

	A	B	C	D	E
1	**Small Hydropower Capacity, Non-California WECC States**				
2	Source(s): Energy Information Administration (EIA) "Existing Electric Generating Units in the United States by State, Company and Plant, 2002" at http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls				
3					
4	EIA Plant_ID	State	County	Plant Name	Capacity
5	155	AZ	Gila	Coolidge Dam	10
6	7179	AZ	La Paz	Headgate Rock	19.5
7	100	AZ	Maricopa	South Consolidated	1.4
8	143	AZ	Maricopa	Crosscut	3
9	148	AZ	Maricopa	Mormon Flat	9.2
10	150	AZ	Maricopa	Stewart Mtn	10.4
11	145	AZ	Maricopa	Horse Mesa	29.7
12	115	AZ	Yavapai	Irving	1.6
13	112	AZ	Yavapai	Childs	5.4
14	54680	CO	Boulder	Betasso Hydro	3
15	55931	CO	Boulder	Silver Lake Hydroelectric	3.3
16	55932	CO	Boulder	Boulder Canyon Hydro	20
17	472	CO	Clear Creek	Georgetown	1.4
18	10070	CO	Denver	Foothills Hydro	3.1
19	10081	CO	Douglas	Strontia Springs Hydro	1
20	495	CO	El Paso	Ruxton Park	1.2
21	494	CO	El Paso	Manitou Springs	5
22	7233	CO	El Paso	Tesla	27.6
23	476	CO	Garfield	Shoshone	14.4
24	10422	CO	Grand	Williams Fork Hydro	3
25	54142	CO	Jefferson	Hillcrest	2
26	50206	CO	La Plata	Vallecito Hydro	5.8
27	6206	CO	La Plata	Tacoma	7.9
28	50435	CO	Lake	Sugarloaf Hydro	2.5
29	515	CO	Larimer	Big Thompson	4.5
30	517	CO	Larimer	Marys Lake	8.1
31	50267	CO	Mesa	Redlands Water & Power	1.4
32	473	CO	Mesa	Palisade	3
33	520	CO	Mesa	Lower Molina	4.8
34	521	CO	Mesa	Upper Molina	8.6
35	7372	CO	Montezuma	McPhee	1.2
36	7373	CO	Montezuma	Towaoc	11.4
37	6159	CO	Montrose	Crystal	28
38	10423	CO	Park	North Fork Hydro	5.5
39	7458	CO	Pitkin	Ruedi	5
40	54729	CO	Rio Blanco	Taylor Draw Hydro	2.3
41	6207	CO	San Miguel	Ames	3.6
42	10421	CO	Summit	Dillon Hydro	1.8
43	516	CO	Summit	Green Mountain	26
44	6397	ID	Ada	Boise R Diversion	1.5
45	10735	ID	Ada	Barber Dam	4.1
46	819	ID	Ada	Swan Falls	25
47	50972	ID	Bannock	Marsh Valley Development Inc	1.6
48	54753	ID	Bannock	Lateral 10 Ventures	2.4
49	54386	ID	Blaine	Little Wood Hydro	2.8
50	10740	ID	Blaine	Magic Dam Hydro	9
51	54524	ID	Boise	Horseshoe Bend Hydro	9.4
52	843	ID	Bonneville	Lower No 2	3
53	841	ID	Bonneville	City Power Plant	8
54	844	ID	Bonneville	Upper Power Plant	8
55	7012	ID	Bonneville	Lower No 1	8

	A	B	C	D	E
1	**Small Hydropower Capacity, Non-California WECC States**				
2	Source(s): Energy Information Administration (EIA) "Existing Electric Generating Units in the United States by State, Company and Plant, 2002" at http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls				
3					
4	EIA Plant_ID	State	County	Plant Name	Capacity
56	790	ID	Bonneville	Gem State	23.4
57	6506	ID	Boundary	Moyie Spgs	3.9
58	54394	ID	Butte	Dry Creek	3.6
59	987	ID	Caribou	Last Chance	1.6
60	826	ID	Caribou	Cove	7.5
61	831	ID	Caribou	Soda	14
62	10140	ID	Clark	Birch Creek	2.6
63	54674	ID	Clearwater	Ford Hydro LP	1.2
64	10325	ID	Franklin	Mink Creek Hydro	3.1
65	829	ID	Franklin	Oneida	30
66	4204	ID	Fremont	Island Park	4.8
67	825	ID	Fremont	Ashton	6.8
68	54668	ID	Fremont	Falls River Hydro	9
69	6396	ID	Gem	Black Canyon	10.2
70	10781	ID	Gooding	Koyle Ranch Hydro	1.3
71	54514	ID	Gooding	Blind Canyon Hydro	1.3
72	814	ID	Gooding	Clear Lake	2.5
73	823	ID	Gooding	Upper Malad	8.2
74	820	ID	Gooding	Thousand Springs	8.8
75	815	ID	Gooding	Lower Malad	13.5
76	50891	ID	Idaho	El Dorado Hydro Elk Creek	2.6
77	50323	ID	Jerome	Power Investments Inc	1.2
78	54812	ID	Jerome	Mi 28 Water	1.4
79	54558	ID	Jerome	Hazelton B Hydro	7.6
80	50896	ID	Jerome	S E Hazelton A	8.4
81	54306	ID	Jerome	Wilson Lake Hydro	8.4
82	50895	ID	Jerome	Bypass	9.9
83	818	ID	Jerome	Shoshone Falls	12.5
84	835	ID	Kootenai	Post Falls	14.5
85	10807	ID	Lincoln	Dietrich Drop	4.8
86	50718	ID	Lincoln County	Notch Butte Hydro Co Inc	1
87	6398	ID	Minidoka	Minidoka	27.7
88	6359	ID	Teton	Felt	1.3
89	10028	ID	Teton	Felt Hydro	7.4
90	55007	ID	Twin Falls	K W Co	1.4
91	10049	ID	Twin Falls	Little Mac Project	1.5
92	10809	ID	Twin Falls	Rock Creek II	1.9
93	50987	ID	Twin Falls	Rock Creek I	2.1
94	10806	ID	Twin Falls	Crystal Springs	2.3
95	10808	ID	Twin Falls	Low Line Rapids	2.8
96	10296	ID	Twin Falls	South Forks Hydro	8
97	7079	ID	Twin Falls	Upper Salmon B	16.4
98	822	ID	Twin Falls	Upper Salmon A	18
99	813	ID	Valley	Cascade	12.4
100	6422	MT		Madison	8.8
101	54006	MT	Broadwater	Broadwater	9.6
102	10138	MT	Carbon	South Dry Creek Hydro	2
103	2185	MT	Cascade	Hauser	17
104	2181	MT	Cascade	Black Eagle	21.2
105	6459	MT	Flathead	Big Fork	4.1
106	2190	MT	Missoula	Milltown	3

	A	B	C	D	E
1	**Small Hydropower Capacity, Non-California WECC States**				
2	Source(s): Energy Information Administration (EIA) "Existing Electric Generating Units in the United States by State, Company and Plant, 2002" at http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls				
3					
4	EIA Plant_ID	State	County	Plant Name	Capacity
107	2192	MT	Stillwater	Mystic	10
108	7593	NM	Rio Arriba	El Vado Dam	8
109	7789	NM	Rio Arriba	Abiquiu Dam	12.6
110	2465	NM	San Juan	Animas	0.2
111	584	NM	San Juan	Navajo Dam	30
112	6402	NM	Sierra	Elephant Butte	27.9
113	6521	NV	Churchill	Lahontan	2.4
114	50261	NV	Churchill	New Lahontan	4
115	6532	NV	Washoe	Washoe	1.4
116	6513	NV	Washoe	Fleish	2
117	6531	NV	Washoe	Verdi	2.4
118	7511	OR	Benton	McNary Fish	10
119	4214	OR	Clackamas	PHP 2	11.8
120	7508	OR	Clackamas	Stone Creek	12
121	3053	OR	Clackamas	Sullivan	15.4
122	3049	OR	Clackamas	River Mill	18.8
123	3044	OR	Clackamas	Bull Run	20.8
124	6482	OR	Deschutes	Cline Falls	1
125	6484	OR	Deschutes	Bend	1
126	50980	OR	Deschutes	Siphon	5.4
127	50938	OR	Douglas	Galesville	1.6
128	3026	OR	Douglas	Fish Creek	11
129	3037	OR	Douglas	Soda Springs	11
130	3020	OR	Douglas	Clearwater 1	15
131	3036	OR	Douglas	Slide Creek	18
132	3021	OR	Douglas	Clearwater 2	26
133	3029	OR	Douglas	Lemolo 1	29
134	10324	OR	Hood River	Peters Drive	1.8
135	10323	OR	hood River	Copper Dam	3
136	50917	OR	Hood River	Middle Fork Irrigation Distric	3.3
137	3031	OR	Hood River	Powerdale	6
138	3035	OR	Jackson	Prospect 4	1
139	3024	OR	Jackson	Eagle Point	2.8
140	3032	OR	Jackson	Prospect 1	3.7
141	3034	OR	Jackson	Prospect 3	7.2
142	6403	OR	Jackson	Green Springs	17.2
143	54251	OR	Jefferson	Opal Springs Hydro	4.3
144	4215	OR	Jefferson	Pelton Re-Reg	18.9
145	54721	OR	Jefferson	Warm Springs Power Enterprises	19.6
146	10737	OR	Klamath	North Fork Hydro	1.2
147	3025	OR	Klamath	East Side	3.2
148	3071	OR	Lane	Walterville	8
149	3068	OR	Lane	Leaburg	13.5
150	3078	OR	Lane	Dexter	15
151	3076	OR	Lane	Cougar	26
152	3081	OR	Lane	Hills Creek	30
153	52155	OR	Linn	Lacomb Irrigation District	1
154	52187	OR	Linn	Falls Creek	4.1
155	6552	OR	Linn	Foster	20
156	50360	OR	Malhelir	Michell Butte	1.8
157	50361	OR	Malhelir	Owyhee Dam	4.3

	A	B	C	D	E
1	**Small Hydropower Capacity, Non-California WECC States**				
2	Source(s): Energy Information Administration (EIA) "Existing Electric Generating Units in the United States by State, Company and Plant, 2002" at http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls				
3					
4	EIA Plant_ID	State	County	Plant Name	Capacity
158	50362	OR	Malhelir	Tunnel 1	7
159	3074	OR	Marion	Big Cliff	18
160	50105	OR	Multnomah	Ground Water Pumping Station	5.4
161	4213	OR	Multnomah	PHP 1	23.7
162	3041	OR	Wallowa	Wallowa Falls	1.1
163	7431	OR	Wasco	The Dalles Fishway	6.5
164	3643	UT	Beaver	Upper Beaver	2.5
165	3666	UT	Box Elder	Brigham City	1.2
166	3646	UT	Box Elder	Cutler	30
167	7034	UT	Cache	Hydro II	6.6
168	3704	UT	Duchesne	Uintah	1.2
169	3699	UT	Garfield	Boulder	4.2
170	3697	UT	Morgan	Gateway	4
171	3659	UT	Salt Lake	Stairs	1
172	3651	UT	Salt Lake	Granite	2
173	6537	UT	Salt Lake	Little Cottonwood	4.8
174	1020	UT	Sanpete	Manti Lower	1.2
175	7015	UT	Sanpete	Unit 4	1.2
176	3676	UT	Sanpete	Manti Upper	1.6
177	925	UT	Sanpete	Hydro Plant No 3	2.8
178	3698	UT	Summit	Wanship	1.9
179	4263	UT	Summit	Echo Dam	4.4
180	3688	UT	Utah	Bartholomew	1.5
181	3691	UT	Utah	Spanish Fork	3.6
182	3655	UT	Utah	Olmstead	10.3
183	3658	UT	Wasatch	Snake Creek	1
184	159	UT	Wasatch	Lake Creek	1.5
185	6404	UT	Wasatch	Deer Creek	4.8
186	52039	UT	Washington	Quail Creek Hydro Plant #1	2.3
187	7132	UT	Weber	Pine View Dam	1.8
188	7548	UT	Weber	Causey	2.1
189	3661	UT	Weber	Weber	3.8
190	3656	UT	Weber	Pioneer	5
191	6406	WA	Benton	Chandler	12
192	54051	WA	Clallam	Elwha Dam	12.6
193	54050	WA	Clallam	Glines Canyon Dam	14.8
194	7113	WA	Grant	PEC Headworks	6.6
195	917	WA	Grant	Quincy Chute	9.4
196	7127	WA	Grays Harbor	Wynoochee	12.8
197	50544	WA	Jefferson	Port Townsend Paper Corp	0.3
198	50228	WA	Jefferson	Rocky Brook Hydro	1.6
199	54860	WA	King	Black Creek	3.7
200	54387	WA	King	Weeks Falls	4.3
201	3860	WA	King	Snoqualmie	6.3
202	622	WA	King	South Fork Tolt	16.8
203	6430	WA	King	Cedar Falls	20
204	50827	WA	King County	Twin Falls Hydro	24
205	3846	WA	Klickitat	Condit	9.6
206	3929	WA	Lewis	Packwood	27.5
207	50700	WA	Madison	Lilliwaup Falls	1.4
208	3854	WA	Pierce	Electron	25.5

	A	B	C	D	E
1	**Small Hydropower Capacity, Non-California WECC States**				
2	Source(s): Energy Information Administration (EIA) "Existing Electric Generating Units in the United States by State, Company and Plant, 2002" at http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls				
3					
4	EIA Plant_ID	State	County	Plant Name	Capacity
209	9096	WA	Spokane	Upper Falls	10
210	9095	WA	Spokane	Monroe Street	14.8
211	50380	WA	Spokane	Upriver Dam Hydro Plant	17.6
212	3869	WA	Spokane	Nine Mile	26.4
213	3868	WA	Stevens	Meyers Falls	1.2
214	50091	WA	Stevens	Sheep Creek Hydro Inc	1.6
215	7259	WA	Thurston	Skookumchuck	1
216	3878	WA	Thurston	Yelm	12
217	50382	WA	Walla Walla	Twin Reservoirs	2.2
218	9842	WA	Whatcom	Newhalem	2.3
219	54652	WA	Whatcom	Hutchinson Creek	4
220	54267	WA	Whatcom	Koma Kulshan Assoc	12
221	3848	WA	Yakima	Naches Drop	1.4
222	6508	WA	Yakima	Drop 3	1.6
223	50421	WA	Yakima	Orchard Avenue 1	1.6
224	50423	WA	Yakima	Cowiche	1.7
225	6507	WA	Yakima	Drop 2	2.5
226	3849	WA	Yakima	Naches	6.3
227	6407	WA	Yakima	Roza	12.9
228	674	WY	Fremont	Pilot Butte	1.6
229	505	WY	Fremont	Boysen	15
230	6393	WY	Lincoln	Strawberry Creek	1.5
231	4185	WY	Lincoln	Fontenelle	10
232	4183	WY	Park	Shoshone	3
233	7541	WY	Park	Spirit Mountain	4.5
234	6408	WY	Park	Heart Mountain	5
235	7317	WY	Park	Buffalo Bill	18
236	4178	WY	Platte	Guernsey	6.4

	A	B	C	D	E	F	G	I	K
1	**Small Hydropower Capacity, Canadian Provinces in WECC**								
2	Source(s): Multiple; see "**Source**" column.								
3									
4	Plant Name/Owner	Location	Nearest Center	Province	Capacity	Annual Energy (2002)	Capacity Factor	Status	Source
5	Chin Reservoir	Chin Reservoir	Magrath, AB	Alberta	11			Operating	http://www.smrid.ab.ca/smrid/irrican.htm
6	Raymond Reservoir	Raymond Reservoir	Raymond, AB	Alberta	18			Operating	http://www.smrid.ab.ca/smrid/irrican.htm
7	Belly River	Southern Alberta	Glenwood, AB	Alberta	3	11,250	43%	Operating	http://www.canhydro.com/
8	Waterton	Waterton River	Glenwood, AB	Alberta	2.8	13,800	56%	Operating	http://www.canhydro.com/
9	St. Mary	St. Mary River	Magrath, AB	Alberta	2.4	16,250	77%	Operating	http://www.canhydro.com/
10	Taylor	Southern Alberta	Magrath, AB	Alberta	12.7	45,000	40%	Operating	http://www.canhydro.com/
11	Barrier	Barrier Lake Reservoir	Seebe, AB	Alberta	13	43,000	38%	Operating	http://www.transalta.com/
12	Bearspaw	Bow River	Calgary, AB	Alberta	17	75,000	50%	Operating	http://www.transalta.com/
13	Horseshoe	Bow River	Seebe, AB	Alberta	14	86,000	70%	Operating	http://www.transalta.com/
14	Interlakes	Upper Kananaskis Storage Reservoir	Kananaskis, AB	Alberta	5	7,500	17%	Operating	http://www.transalta.com/
15	Kananaskis	Kananaskis River/Bow River	Seebe, AB	Alberta	19	91,000	55%	Operating	http://www.transalta.com/
16	Pocaterra	Lower Kananaskis Storage Reservior	Kananaskis, AB	Alberta	15	31,000	24%	Operating	http://www.transalta.com/
17	Three Sisters	Spray Lakes Storage Reservoir	Canmore, AB	Alberta	3	4,000	15%	Operating	http://www.transalta.com/
18	Akolkolex	Akolkolex River	Revelstoke, BC	British Colu	10	52,000	59%	Operating	http://www.canhydro.com/
19	Pingston	Pingston Creek	Revelstoke, BC	British Colu	30	147,000	56%	Operating	http://www.canhydro.com/
20	Upper Mamquam	Squamish	Vancouver, BC	British Colu	25			Planned	http://www.canhydro.com/
21	Ash River	Vancouver Island		British Colu	27			Operating	http://www.bchydro.bc.ca
22	Puntledge	Vancouver Island		British Colu	24			Operating	http://www.bchydro.bc.ca
23	Falls River	Coastal British Columbia		British Colu	7			Operating	http://www.bchydro.bc.ca
24	Aberfeldie	Bull River		British Colu	5			Operating	http://www.bchydro.bc.ca
25	Elko	Elk River		British Colu	12			Operating	http://www.bchydro.bc.ca
26	Shuswap			British Colu	6			Operating	http://www.bchydro.bc.ca
27	Spillimacheen	Spillimacheen River		British Colu	4			Operating	http://www.bchydro.bc.ca
28	Walter Hardman	Arrow Lake		British Colu	8			Operating	http://www.bchydro.bc.ca
29	Alouette	Stave River		British Colu	8			Operating	http://www.bchydro.bc.ca
30	Lajoie		Bralorne, BC	British Colu	24			Operating	http://www.bchydro.bc.ca
31	Clayton Falls			British Colu	2			Operating	http://www.bchydro.bc.ca
32	Brown Lake	Brown Lake/McKnight Lake	Prince Rupert, BC	British Colu	7			Operating	http://www.epcor.ca/
33	Doran Lake	Prince Rupert		British Colu	5.3			Operating	Personal communication with Land and Water British Columbia Inc.
34	Moresby Lake	Queen Charlotte		British Colu	5.7			Operating	Personal communication with Land and Water British Columbia Inc.
35	East Twin Creek	Upper Fraser		British Colu	1.4			Operating	Personal communication with Land and Water British Columbia Inc.
36	Ptarmigan Creek	Upper Fraser		British Colu	3.85			Operating	Personal communication with Land and Water British Columbia Inc.
37	Ocean Falls	Ocean Falls		British Colu	1.5			Operating	Personal communication with Land and Water British Columbia Inc.
38	Cayoosh Creek	Lower Mainland		British Colu	17.1			Operating	Personal communication with Land and Water British Columbia Inc.
39	Goat River	Nelson-Princeton		British Colu	0.96			Operating	Personal communication with Land and Water British Columbia Inc.
40	Soo River	Lower Mainland		British Colu	12.5			Operating	Personal communication with Land and Water British Columbia Inc.
41	Scuzzy Creek	Lower Mainland		British Colu	7.2			Operating	Personal communication with Land and Water British Columbia Inc.
42	Sechelt Creek	Lower Mainland		British Colu	16			Operating	Personal communication with Land and Water British Columbia Inc.

Installed Renewable Capacity in California (MW)
(from Energy Commission's Cartography Unit)

Sum of ONLINE MW	GENERAL FUEL									
COUNTY	BIOMASS	DIGESTER GAS	GEOTHERMAL	HYDRO	LANDFILL GAS	MSW	SOLAR	WIND	(blank)	Grand Total
ALAMEDA				1	7	4		166		178
AMADOR	18			39						57
BUTTE	19			65						84
CALAVERAS				13						13
COLUSA	30			0						30
CONTRA COSTA					3			145		148
DEL NORTE				0						0
EL DORADO				73						73
FRESNO	49			12						61
GLENN				5						5
HUMBOLDT	89			2						92
IMPERIAL	18		552	65						635
INYO			302	37						339
KERN	57			53			150	663		923
LAKE			441	6						447
LASSEN	69		3	26						98
LOS ANGELES				102	49	56				207
MADERA				69						69
MARIPOSA				9						9
MENDOCINO	15			13						28
MERCED				24						24
MONO			40	27						67
MONTEREY				4		9				13
NAPA				12	2					14
NEVADA				82						82
ORANGE		19		13	32					64
PLACER	37			94						131
PLUMAS	40			30						70
RIVERSIDE	47			24		1		316		387
SACRAMENTO				14	8		110			132
SAN BENITO								17		17
SAN BERNARDINO				40			204			244
SAN DIEGO		7		14	18			4		43
SAN FRACISCO		2								2
SAN JOAQUIN	28			11				288		326
SAN LUIS OBISPO				2						2
SAN MATEO					2					2
SANTA BARBARA				0	4					4
SANTA CLARA					11					11
SHASTA	136			89						225
SIERRA	20			14						34
SISKIYOU				45						45
SOLANO								19		19
SONOMA			1,397	3	6					1,406
STANISLAUS				16		37				53
SUTTER				0						0
TEHAMA				21						21
TRINITY				15						15
TULARE				36	2					38
TUOLUMNE	33			67						100
VENTURA				2	6					7
YOLO	28				3					31
YUBA				3						3
(blank)										
Grand Total	731	28	2,735	1,293	152	105	464	1,618		7,126

Installed Renewable Capacity in California (MW)
(from Energy Commission's Cartography Unit)

GENERAL FUEL	COUNTY	ONLINE MW	PLANTNAME	ALIAS	FACILITY
BIOMASS	AMADOR	18	WHEELABRATOR MARTELL INC.	MARTELL POWER	WTE
BIOMASS	BUTTE	18.75	PACIFIC OROVILLE POWER INC.	OGDEN POWER PACIFIC (OF	WTE
BIOMASS	COLUSA	29.7	WADHAM	WADHAM ENERGY LIMITED	WTE
BIOMASS	FRESNO	24.3	RIO BRAVO FRESNO		WTE
BIOMASS	FRESNO	25	MENDOTA BIOMASS POWER LTD		WTE
BIOMASS	HUMBOLDT	13.806	ULTRAPOWER 3 BLUE LAKE	ULTRAPOWER 3, JOINT VEN	WTE
BIOMASS	HUMBOLDT	15	FARIHAVEN POWER CO.		WTE
BIOMASS	HUMBOLDT	27.9	HUMBOLDT PULP MILL	SIMPSON PAPER	WTE
BIOMASS	HUMBOLDT	32.5	PACIFIC LUMBER CO.		WTE
BIOMASS	IMPERIAL	17.89	MESQUITE RESOURCE RECOVERY PROJECT	WESTERN POWER	WTE
BIOMASS	KERN	56.5	DELANO ENERGY CO. INC.	DELANO ENERGY COMPAN	WTE
BIOMASS	LASSEN	7.5	BIG VALLEY LUMBER CO.		WTE
BIOMASS	LASSEN	11.4	MT. LASSEN POWER	OGDEN POWER PACIFIC, IN	WTE
BIOMASS	LASSEN	14.34	SPI- SUSANVILLE	SIERRA PACIFIC IND. (SUSA	WTE
BIOMASS	LASSEN	35.5	HI POWER CO.	HONEY LAKE POWER COMP	WTE
BIOMASS	MENDOCINO	15	FORT BRAGG WESTERN WOOD PRODUCTS	GEORGIA PACIFIC CORP.	WTE
BIOMASS	PLACER	13	SPI- LINCOLN	SIERRA PACIFIC IND. (LINC	WTE
BIOMASS	PLACER	24.4	RIO BRAVO ROCKLIN		WTE
BIOMASS	PLUMAS	12	COLLINS PINE CO. PROJECT	CHESTER COLLINS PLANT	WTE
BIOMASS	PLUMAS	27.5	SPI- QUINCY	SIERRA PACIFIC IND. (QUIN	WTE
BIOMASS	RIVERSIDE	47	MECCA PLANT	COLMAC ENERGY	WTE
BIOMASS	SAN JOAQUIN	4.5	DIAMOND WALNUT	STOCKTON DIAMOND	WTE
BIOMASS	SAN JOAQUIN	23	TRACY BIOMASS PLANT	THERMAL ENERGY DEV. CO	WTE
BIOMASS	SHASTA	4	SPI- ANDERSON	SIERRA PACIFICC IND. (AND	WTE
BIOMASS	SHASTA	6.8	WHEELABATOR HUDSON ENERGY	HUDSON ENERGY	WTE
BIOMASS	SHASTA	11.4	BURNEY MOUNTAIN POWER	BURNEY MOUNTAIN POWER	WTE
BIOMASS	SHASTA	20	SPI- BURNEY	SIERRA PACIFIC IND. (BURN	WTE
BIOMASS	SHASTA	31	BURNEY FOREST PRODUCTS	DELWEST SAW MILL COGEN	WTE
BIOMASS	SHASTA	62.75	WHEELABRATOR SHASTA	SHASTA ENERGY	WTE
BIOMASS	SIERRA	20	SPI- LOYALTON	SIERRA PACIFIC IND. (LOYA	WTE
BIOMASS	TUOLUMNE	7.5	SPI- SONORA	SIERRA PACIFIC IND. (SONO	WTE
BIOMASS	TUOLUMNE	25	PACIFIC ULTRAPOWER CHINESE STATION	PACIFIC-ULTRAPOWER CHIN	WTE
BIOMASS	YOLO	28	WOODLAND BIOMASS POWER LTD	WOODLAND BIOMASS	WTE
DIGESTER GAS	ORANGE	1.2	ALISO WATER MANAGEMENT AGENCY		WTE
DIGESTER GAS	ORANGE	18	PLANT NO. 2	PLANT NO. 2, ORANGE COU	WTE
DIGESTER GAS	SAN DIEGO	6.8	GAS UTILIZATION FACILITY	GAS UTILIZATION FACILITY	WTE
DIGESTER GAS	SAN FRACISCO	2.1	SOUTHEAST DIGESTER GAS COGEN		WTE
GEOTHERMAL	IMPERIAL	10	SALTON SEA 1		GEOTHERMAL
GEOTHERMAL	IMPERIAL	11.5	CE TURBO LLC		GEOTHERMAL
GEOTHERMAL	IMPERIAL	14.4	ORMESA IE		GEOTHERMAL
GEOTHERMAL	IMPERIAL	14.4	ORMESA IH		GEOTHERMAL
GEOTHERMAL	IMPERIAL	18.5	GEM II	GEM RESOURCES II, LLC	GEOTHERMAL
GEOTHERMAL	IMPERIAL	20	SALTON SEA 2		GEOTHERMAL
GEOTHERMAL	IMPERIAL	24	ORMESA GEOTHERMAL II		GEOTHERMAL
GEOTHERMAL	IMPERIAL	31.2	ORMES1		GEOTHERMAL
GEOTHERMAL	IMPERIAL	35.8	AW HOCH	DEL RANCH LTD. (NILAND #2	GEOTHERMAL
GEOTHERMAL	IMPERIAL	35.8	JM LEATHERS	LEATHERS,L.P.(NILAND #4),	GEOTHERMAL
GEOTHERMAL	IMPERIAL	39.72	VULCAN	BN GEOTHERMAL - VULCAN	GEOTHERMAL
GEOTHERMAL	IMPERIAL	42	JJ ELMORE	ELMORE LTD. (NILAND #3)	GEOTHERMAL
GEOTHERMAL	IMPERIAL	48	SECOND IMPERIAL GEOTHERMAL	SECOND IMPERIAL GEOTHE	GEOTHERMAL
GEOTHERMAL	IMPERIAL	49.9	SALTON SEA 5	SALTON SEA POWER LLC (C	GEOTHERMAL
GEOTHERMAL	IMPERIAL	51	SALTON SEA 4		GEOTHERMAL
GEOTHERMAL	IMPERIAL	52	HEBER GEOTHERMAL CO.	HEBER FIELD COMPANY	GEOTHERMAL
GEOTHERMAL	IMPERIAL	53.97	SALTON SEA 3		GEOTHERMAL
GEOTHERMAL	INYO	99.99	COSO ENERGY DEVELOPERS UNIT 4-6	COSO NAVY 2	GEOTHERMAL
GEOTHERMAL	INYO	99.99	COSO ENERGY DEVELOPERS UNIT 7-9	COSO BLM EAST 7-8 AND W	GEOTHERMAL
GEOTHERMAL	INYO	102.1	COSO FINANCE PARTNERS UNIT 1- 3	COSO NAVY 1	GEOTHERMAL
GEOTHERMAL	LAKE	22	BEAR CANYON 2		GEOTHERMAL
GEOTHERMAL	LAKE	28.8	WEST FORD FLAT 4	WEST FORD FLAT/CALPINE	GEOTHERMAL
GEOTHERMAL	LAKE	78	SONOMA 3		GEOTHERMAL
GEOTHERMAL	LAKE	95	BIG GEYSER 13	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	LAKE	97	CALISTOGA 19	CALISTOGA GEOTHERMAL F	GEOTHERMAL
GEOTHERMAL	LAKE	120	QUICK SILVER 16	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	LASSEN	3	AMEDEE GEOTHERMAL VENTURE I		GEOTHERMAL
GEOTHERMAL	MONO	10	MAMMOTH-PACIFIC I		GEOTHERMAL
GEOTHERMAL	MONO	15	MAMMOTH-PACIFIC II		GEOTHERMAL
GEOTHERMAL	MONO	15	PLES1		GEOTHERMAL
GEOTHERMAL	SONOMA	15.5	AIDLIN I	AIDLIN GEOTHERMAL I	GEOTHERMAL
GEOTHERMAL	SONOMA	110	COBB CREEK 12	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	110	EAGLE ROCK 11	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	110	FUMAROLE 9 & 10	PG&E #9-#10 (FUMAROLE)	GEOTHERMAL
GEOTHERMAL	SONOMA	110	GEOTHERMAL 1	NCPA 1	GEOTHERMAL
GEOTHERMAL	SONOMA	110	GEOTHERMAL 2	NCPA 2	GEOTHERMAL
GEOTHERMAL	SONOMA	110	MCCABE 5 & 6	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	110	RIDGE LINE 7 & 8	PG&E #7-#8, GEYSERS #7-#	GEOTHERMAL
GEOTHERMAL	SONOMA	117.5	SULPHUR SPRINGS 14	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	120	LAKEVIEW 17	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	120	SOCRATES 18	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	124	GRANT 20	CALPINE GEOTHERMAL UNI	GEOTHERMAL
GEOTHERMAL	SONOMA	130	COLDWATER CREEK		GEOTHERMAL
HYDRO	ALAMEDA	1.25	WTP NO. 2 SUPPLY LINE		HYDROELECTRIC
HYDRO	AMADOR	0.455	JACKSON VALLEY ID	JACKSON VALLEY IRRIGATI	HYDROELECTRIC
HYDRO	AMADOR	14.5	WEST POINT		HYDROELECTRIC
HYDRO	AMADOR	23.6	PARDEE DAM	PARDEE HYDROELECTRIC	HYDROELECTRIC
HYDRO	BUTTE	0.003	JAMES CRANE HYDRO		HYDROELECTRIC
HYDRO	BUTTE	0.06	PARADISE IRRIGATION		HYDROELECTRIC
HYDRO	BUTTE	0.3	PERRY LOGGING	MUD CREEK	HYDROELECTRIC
HYDRO	BUTTE	0.9	COAL CANYON		HYDROELECTRIC
HYDRO	BUTTE	0.99	LASSEN STATION/CAMP CREEK		HYDROELECTRIC
HYDRO	BUTTE	1.12	KANAKA	STS - KANAKA	HYDROELECTRIC

Installed Renewable Capacity in California (MW)
(from Energy Commission's Cartography Unit)

GENERAL FUEL	COUNTY	ONLINE MW	PLANTNAME	ALIAS	FACILITY
HYDRO	BUTTE	1.5	TOADTOWN		HYDROELECTRIC
HYDRO	BUTTE	2	LIME SADDLE		HYDROELECTRIC
HYDRO	BUTTE	3	THERMALITO DIVERSION DAM		HYDROELECTRIC
HYDRO	BUTTE	6.4	CENTERVILLE		HYDROELECTRIC
HYDRO	BUTTE	8	SLY CREEK		HYDROELECTRIC
HYDRO	BUTTE	9	KELLY RIDGE		HYDROELECTRIC
HYDRO	BUTTE	13.3	FORKS OF BUTTE HYDRO PROJECT	ENERGY GROWTH PARTNEI	HYDROELECTRIC
HYDRO	BUTTE	18.5	DE SABLA	FORKS OF BUTTE HYDRO	HYDROELECTRIC
HYDRO	CALAVERAS	0.09	CALAVERAS YUBA HYDRO #2		HYDROELECTRIC
HYDRO	CALAVERAS	0.09	CALAVERAS YUBA HYDRO #3		HYDROELECTRIC
HYDRO	CALAVERAS	0.23	MIDDLE FORK		HYDROELECTRIC
HYDRO	CALAVERAS	0.23	SCHAADS HYDROELECTRIC FACILITY		HYDROELECTRIC
HYDRO	CALAVERAS	0.7	ROCK CREEK WD	ROMAC SUPPLY or ROSENI	HYDROELECTRIC
HYDRO	CALAVERAS	1.4	ANGELS		HYDROELECTRIC
HYDRO	CALAVERAS	2	NEW HOGAN POWER PLANT	CALAVERAS CTY WD	HYDROELECTRIC
HYDRO	CALAVERAS	3.6	UTICA		HYDROELECTRIC
HYDRO	CALAVERAS	4.5	MURPHYS	MURPHYS (UTICA)	HYDROELECTRIC
HYDRO	COLUSA	0.3	STOVAL 1 & 2		HYDROELECTRIC
HYDRO	DEL NORTE	0.001	BOULDER CREEK		HYDROELECTRIC
HYDRO	EL DORADO	0.2	SIERRA ENERGY CO.	POND & DARDANELLES CRI	HYDROELECTRIC
HYDRO	EL DORADO	0.45	SLAB CREEK		HYDROELECTRIC
HYDRO	EL DORADO	0.6	TUNNEL HILL		HYDROELECTRIC
HYDRO	EL DORADO	3	ROCK CREEK HYDRO		HYDROELECTRIC
HYDRO	EL DORADO	7.2	CHILI BAR		HYDROELECTRIC
HYDRO	EL DORADO	11.5	JONES FORK		HYDROELECTRIC
HYDRO	EL DORADO	20	EL DORADO		HYDROELECTRIC
HYDRO	EL DORADO	29.7	ROBBS PEAK		HYDROELECTRIC
HYDRO	FRESNO	0	SHAVER MICRO 1		HYDROELECTRIC
HYDRO	FRESNO	1	KINGS RIVER HYDRO CO.	KINGS RIVER SIPHON	HYDROELECTRIC
HYDRO	FRESNO	10.8	PORTAL		HYDROELECTRIC
HYDRO	GLENN	0.5	HIGHLINE CANAL	HIGHLINE	HYDROELECTRIC
HYDRO	GLENN	4.9	STONY GORGE		HYDROELECTRIC
HYDRO	HUMBOLDT	0.995	MILL AND SULPHUR CREEK PROJECT		HYDROELECTRIC
HYDRO	HUMBOLDT	1.5	WEA BAKER CREEK PROJECT	BAKER CREEK PROJECT	HYDROELECTRIC
HYDRO	IMPERIAL	0.4	TURNIP		HYDROELECTRIC
HYDRO	IMPERIAL	0.56	DOUBLE WEIR		HYDROELECTRIC
HYDRO	IMPERIAL	2.42	EAST HIGHLINE		HYDROELECTRIC
HYDRO	IMPERIAL	3.85	DROP 1		HYDROELECTRIC
HYDRO	IMPERIAL	4	DROP 5		HYDROELECTRIC
HYDRO	IMPERIAL	7	PILOT KNOB		HYDROELECTRIC
HYDRO	IMPERIAL	7.2	SENATOR WASH		HYDROELECTRIC
HYDRO	IMPERIAL	9.8	DROP 3		HYDROELECTRIC
HYDRO	IMPERIAL	10	DROP 2		HYDROELECTRIC
HYDRO	IMPERIAL	19.6	DROP 4		HYDROELECTRIC
HYDRO	INYO	0.155	CINNAMON RANCH	CINNAMON RANCH CINNAM	HYDROELECTRIC
HYDRO	INYO	0.65	DIVISION CREEK	DIVISION	HYDROELECTRIC
HYDRO	INYO	1.6	BISHOP CREEK 6		HYDROELECTRIC
HYDRO	INYO	2.8	COTTONWOOD	COTTONWOOD 1 & 2	HYDROELECTRIC
HYDRO	INYO	3.2	BIG PINE		HYDROELECTRIC
HYDRO	INYO	3.2	PLEASANT VALLEY		HYDROELECTRIC
HYDRO	INYO	4.532	BISHOP CREEK 5		HYDROELECTRIC
HYDRO	INYO	5.14	HAIWEE	HAIWEE 1 & 2	HYDROELECTRIC
HYDRO	INYO	7.84	BISHOP CREEK 3		HYDROELECTRIC
HYDRO	INYO	7.955	BISHOP CREEK 4		HYDROELECTRIC
HYDRO	KERN	0.035	TEHACHAPI CUMMINGS/COUNTY WD		HYDROELECTRIC
HYDRO	KERN	11.5	KERN CANYON		HYDROELECTRIC
HYDRO	KERN	12	BOREL		HYDROELECTRIC
HYDRO	KERN	13.9	ISABELLA HYDROELECTRIC PROJECT		HYDROELECTRIC
HYDRO	KERN	16	KERN HYDRO OLCESE	RIO BRAVO HYDROELECTRI	HYDROELECTRIC
HYDRO	LAKE	2.9	YOLO COUNTY FLOOD	CLEAR LAKE HYDRO	HYDROELECTRIC
HYDRO	LAKE	3.335	INDIAN VALLEY HYDRO		HYDROELECTRIC
HYDRO	LASSEN	26	MALACHA HYDRO L.P.	MUCK VALLEY HYDROELEC	HYDROELECTRIC
HYDRO	LOS ANGELES	0.025	WALNUT VALLEY WD - #2		HYDROELECTRIC
HYDRO	LOS ANGELES	0.125	WALNUT VALLEY WD - #1		HYDROELECTRIC
HYDRO	LOS ANGELES	0.15	SANTA MONICA		HYDROELECTRIC
HYDRO	LOS ANGELES	0.2	THREE VALLEYS MWD - FULTON RD. STATION		HYDROELECTRIC
HYDRO	LOS ANGELES	0.275	DOMINGUEZ GAP BARRIER	HYDRO ELECTRIC CONST (I	HYDROELECTRIC
HYDRO	LOS ANGELES	0.35	THREE VALLEYS MWD - WILLIAMS AVE. STATION		HYDROELECTRIC
HYDRO	LOS ANGELES	0.4	VERDUGO		HYDROELECTRIC
HYDRO	LOS ANGELES	0.52	THREE VALLEYS MWD - MIRAMAR		HYDROELECTRIC
HYDRO	LOS ANGELES	0.6	SAWTELLE		HYDROELECTRIC
HYDRO	LOS ANGELES	0.93	LOS ANGELES COUNTY FLOOD CONTROL DISTRICT	BASIN BARRIER HYDROELE	HYDROELECTRIC
HYDRO	LOS ANGELES	1	GREG AVENUE		HYDROELECTRIC
HYDRO	LOS ANGELES	1.05	SAN DIMAS WASH		HYDROELECTRIC
HYDRO	LOS ANGELES	1.25	EAST PORTAL GENERATOR	EAST PORTAL HYDRO STAT	HYDROELECTRIC
HYDRO	LOS ANGELES	1.91	RIO HONDO		HYDROELECTRIC
HYDRO	LOS ANGELES	2	AZUSA		HYDROELECTRIC
HYDRO	LOS ANGELES	2	FRANKLIN		HYDROELECTRIC
HYDRO	LOS ANGELES	4.975	SAN GABRIEL HYDRO PROJECT		HYDROELECTRIC
HYDRO	LOS ANGELES	6.4	SAN FERNANDO	SAN FERNANDO #1-#2	HYDROELECTRIC
HYDRO	LOS ANGELES	8.54	SEPULVEDA CANYON		HYDROELECTRIC
HYDRO	LOS ANGELES	9.04	FOOTHILL FEEDER		HYDROELECTRIC
HYDRO	LOS ANGELES	9.92	SAN DIMAS		HYDROELECTRIC
HYDRO	LOS ANGELES	10	FOOTHILL		HYDROELECTRIC
HYDRO	LOS ANGELES	10.12	VENICE		HYDROELECTRIC
HYDRO	LOS ANGELES	13.28	CASTAIC		HYDROELECTRIC
HYDRO	LOS ANGELES	17.1	ALAMO	ALAMO POWR PLANT	HYDROELECTRIC
HYDRO	MADERA	0.4	SAN JOAQUIN 1A		HYDROELECTRIC
HYDRO	MADERA	0.424	MADERA CANAL STATION 1302	STATION 1302+10 MADERA-(	HYDROELECTRIC
HYDRO	MADERA	0.563	MADERA CANAL - 1174 + 84	STATION 1174+84 MADERA-(	HYDROELECTRIC

Installed Renewable Capacity in California (MW)
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GENERAL FUEL	COUNTY	ONLINE MW	PLANTNAME	ALIAS	FACILITY
HYDRO	MADERA	0.9	CRANE VALLEY		HYDROELECTRIC
HYDRO	MADERA	0.925	MADERA CANAL - 1923	STATION 1923+10 MADERA-(	HYDROELECTRIC
HYDRO	MADERA	2	RIVER OUTLET		HYDROELECTRIC
HYDRO	MADERA	2.1	MADERA CHOWCHILLA	STATION 980+65 MADERA-C	HYDROELECTRIC
HYDRO	MADERA	3.2	SAN JOAQUIN 2		HYDROELECTRIC
HYDRO	MADERA	4.2	SAN JOAQUIN 3		HYDROELECTRIC
HYDRO	MADERA	8.8	MADERA CANAL		HYDROELECTRIC
HYDRO	MADERA	20	A.G. WISHON		HYDROELECTRIC
HYDRO	MADERA	25	FRIANT HYDRO FACILITY	FRIANT HYDROELECTRIC PI	HYDROELECTRIC
HYDRO	MARIPOSA	9	MCSWAIN		HYDROELECTRIC
HYDRO	MENDOCINO	0.35	MCFADDEN FARM		HYDROELECTRIC
HYDRO	MENDOCINO	0.4	BES HYDRO INC.		HYDROELECTRIC
HYDRO	MENDOCINO	3.5	LAKE MENDOCINO		HYDROELECTRIC
HYDRO	MENDOCINO	9.2	POTTER VALLEY		HYDROELECTRIC
HYDRO	MERCED	0.675	UNITED HYDRO INC. #2 - SAN LUIS BYPASS	UNITED HYDRO (SAN LUIS B	HYDROELECTRIC
HYDRO	MERCED	0.9	FAIRFIELD	FAIRFIELD CANAL OR PAPA	HYDROELECTRIC
HYDRO	MERCED	0.9	RETA - CANAL CREEK	CANAL CREEK (UPPER GOR	HYDROELECTRIC
HYDRO	MERCED	1	UNITED HYDRO - WOLFSEN BYPASS		HYDROELECTRIC
HYDRO	MERCED	2.69	MERCED ID - PARKER	RICHARD B. PARKER	HYDROELECTRIC
HYDRO	MERCED	3.5	MERCED FALLS		HYDROELECTRIC
HYDRO	MERCED	14.4	O'NEILL		HYDROELECTRIC
HYDRO	MONO	0.4	MILNER CREEK	HENWOOD ASSOC. - MILNEI	HYDROELECTRIC
HYDRO	MONO	3	LUNDY		HYDROELECTRIC
HYDRO	MONO	11.25	POOLE		HYDROELECTRIC
HYDRO	MONO	11.85	RUSH CREEK		HYDROELECTRIC
HYDRO	MONTEREY	4.35	NACIMIENTO HYDROELECTRIC		HYDROELECTRIC
HYDRO	NAPA	0.085	JOHN NEERHOUT JR.		HYDROELECTRIC
HYDRO	NAPA	11.9	MONTICELLO		HYDROELECTRIC
HYDRO	NEVADA	0.002	WOLF CREEK		HYDROELECTRIC
HYDRO	NEVADA	0.33	COMBIE NORTH	NID/COMBIE NORTH	HYDROELECTRIC
HYDRO	NEVADA	0.85	NID/SCOTTS FLAT		HYDROELECTRIC
HYDRO	NEVADA	2.8	FARAD		HYDROELECTRIC
HYDRO	NEVADA	3.6	NEVADA POWER AUTHORITY/BOWMAN POW		HYDROELECTRIC
HYDRO	NEVADA	4.4	SPAULDING 2		HYDROELECTRIC
HYDRO	NEVADA	5.5	DEER CREEK		HYDROELECTRIC
HYDRO	NEVADA	5.8	SPAULDING 3		HYDROELECTRIC
HYDRO	NEVADA	7	SPAULDING 1		HYDROELECTRIC
HYDRO	NEVADA	12	NARROWS		HYDROELECTRIC
HYDRO	NEVADA	12.15	ROLLINS		HYDROELECTRIC
HYDRO	NEVADA	27.3	DUTCH FLAT 2		HYDROELECTRIC
HYDRO	ORANGE	0.191	IRVINE RANCH WATER DISTRICT	TURTLE ROCK-QUAIL HILL	HYDROELECTRIC
HYDRO	ORANGE	0.6	MWD OF ORANGE COUNTY		HYDROELECTRIC
HYDRO	ORANGE	3.13	COYOTE CREEK		HYDROELECTRIC
HYDRO	ORANGE	4.1	VALLEY VIEW		HYDROELECTRIC
HYDRO	ORANGE	5.09	YORBA LINDA FEEDER		HYDROELECTRIC
HYDRO	PLACER	0.1	SWISS AMERICA	BELL POWERHOUSE	HYDROELECTRIC
HYDRO	PLACER	0.725	HELL HOLE		HYDROELECTRIC
HYDRO	PLACER	1.5	COMBIE SOUTH	NID/COMBIE SOUTH	HYDROELECTRIC
HYDRO	PLACER	2	ALTA		HYDROELECTRIC
HYDRO	PLACER	6.1	OXBOW		HYDROELECTRIC
HYDRO	PLACER	6.8	CAMP FAR WEST		HYDROELECTRIC
HYDRO	PLACER	11	HALSEY		HYDROELECTRIC
HYDRO	PLACER	11.5	NEWCASTLE		HYDROELECTRIC
HYDRO	PLACER	15	FRENCH MEADOWS		HYDROELECTRIC
HYDRO	PLACER	17.1	WISE		HYDROELECTRIC
HYDRO	PLACER	22	DUTCH FLAT 1		HYDROELECTRIC
HYDRO	PLUMAS	0.015	JAMES B. PETER	PETER RANCH HYDRO	HYDROELECTRIC
HYDRO	PLUMAS	0.45	GRAEAGLE		HYDROELECTRIC
HYDRO	PLUMAS	1.3	OAK FLAT		HYDROELECTRIC
HYDRO	PLUMAS	5.39	HAMILTON BRANCH		HYDROELECTRIC
HYDRO	PLUMAS	22.95	GRIZZLY		HYDROELECTRIC
HYDRO	RIVERSIDE	0.095	LAKE HEMET MWD - OAKCLIFF		HYDROELECTRIC
HYDRO	RIVERSIDE	0.41	SAN GORGONIO UPPER		HYDROELECTRIC
HYDRO	RIVERSIDE	0.65	LAKE HEMET MWD - NORTH FORK		HYDROELECTRIC
HYDRO	RIVERSIDE	0.7	SAN GORGONIO 2		HYDROELECTRIC
HYDRO	RIVERSIDE	0.728	SAN GORGONIO		HYDROELECTRIC
HYDRO	RIVERSIDE	1.375	WHITEWATER	WHITEWATER HYDROELECT	HYDROELECTRIC
HYDRO	RIVERSIDE	1.5	SAN GORGONIO 1		HYDROELECTRIC
HYDRO	RIVERSIDE	2.85	CORONA	CORONA SMALL CONDUIT	HYDROELECTRIC
HYDRO	RIVERSIDE	2.85	TEMESCAL	TEMESCAL SMALL CONDUIT	HYDROELECTRIC
HYDRO	RIVERSIDE	4.9	LAKE MATHEWS		HYDROELECTRIC
HYDRO	RIVERSIDE	7.94	PERRIS	PERRIS SMALL CONDUIT	HYDROELECTRIC
HYDRO	SACRAMENTO	13.5	NIMBUS DAM		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.075	SAN BERNARDINO MWD - SITE 2100		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.083	SAN BERNARDINO MWD - SITE 1913		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.178	SAN BERNARDINO MWD - SITE 1720		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.224	WFA STATION 1		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.32	ONTARIO 2		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.48	SIERRA		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.5	LYTLE CREEK		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.6	ONTARIO 1		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.8	MILL CREEK 1		HYDROELECTRIC
HYDRO	SAN BERNARDINO	0.865	MONTE VISTA WD		HYDROELECTRIC
HYDRO	SAN BERNARDINO	2.95	FONTANA		HYDROELECTRIC
HYDRO	SAN BERNARDINO	3	MILL CREEK 3		HYDROELECTRIC
HYDRO	SAN BERNARDINO	3.1	SANTA ANA 3		HYDROELECTRIC
HYDRO	SAN BERNARDINO	3.2	SANTA ANA 1		HYDROELECTRIC
HYDRO	SAN BERNARDINO	23.9	ETIWANDA		HYDROELECTRIC
HYDRO	SAN DIEGO	0.06	SQUIRES		HYDROELECTRIC
HYDRO	SAN DIEGO	0.3	RINCON HYDRO		HYDROELECTRIC

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GENERAL FUEL	COUNTY	ONLINE MW	PLANTNAME	ALIAS	FACILITY
HYDRO	SAN DIEGO	0.35	SAN FRANCISCO PEAK HYDRO		HYDROELECTRIC
HYDRO	SAN DIEGO	0.45	OLIVENHAIN MUNICIPAL WD	ROGER MILLER HYDRO	HYDROELECTRIC
HYDRO	SAN DIEGO	0.8	MIRAMAR HYDRO FACILITY	ESCONDIDO HYDRO	HYDROELECTRIC
HYDRO	SAN DIEGO	1.35	PT. LOMA		HYDROELECTRIC
HYDRO	SAN DIEGO	1.485	BADGER FILTRATION PLANT		HYDROELECTRIC
HYDRO	SAN DIEGO	1.6	BEAR VALLEY		HYDROELECTRIC
HYDRO	SAN DIEGO	2.1	ALVARADO HYDRO FACILITY		HYDROELECTRIC
HYDRO	SAN DIEGO	5.9	RED MOUNTAIN		HYDROELECTRIC
HYDRO	SAN JOAQUIN	10.68	CAMANCHE DAM POWER PLANT		HYDROELECTRIC
HYDRO	SAN LUIS OBISPO	0.12	LOPEZ WWTP		HYDROELECTRIC
HYDRO	SAN LUIS OBISPO	0.68	SAN LUIS OBISPO		HYDROELECTRIC
HYDRO	SAN LUIS OBISPO	0.782	CITY OF SAN LUIS OBISPO - STENNER CANYON		HYDROELECTRIC
HYDRO	SANTA BARBARA	0.13	JOHN E. HOWARD - MONTECITO WD	PICAY	HYDROELECTRIC
HYDRO	SHASTA	0.03	ROBERT W. LEE		HYDROELECTRIC
HYDRO	SHASTA	0.1	STEVE & BONNIE TETRICK	POULTON HYDRO PROJECT	HYDROELECTRIC
HYDRO	SHASTA	0.15	SUTTER'S MILL HYDRO		HYDROELECTRIC
HYDRO	SHASTA	0.34	T&G HYDRO		HYDROELECTRIC
HYDRO	SHASTA	0.5	LOST CREEK II	SNOW MOUNTAIN HYDRO LI	HYDROELECTRIC
HYDRO	SHASTA	0.6	SILVER SPRINGS - MEGA RENEWABLES		HYDROELECTRIC
HYDRO	SHASTA	0.8	WHISKEYTOWN DAM INSKIP		HYDROELECTRIC
HYDRO	SHASTA	0.9	VOLTA 2		HYDROELECTRIC
HYDRO	SHASTA	0.975	MCMILLAN HYDRO		HYDROELECTRIC
HYDRO	SHASTA	1	MEGA HYDRO #1	CLOVER CREEK (HYDRO PA	HYDROELECTRIC
HYDRO	SHASTA	1.1	LOST CREEK I	SNOW MOUNTAIN HYDRO LI	HYDROELECTRIC
HYDRO	SHASTA	1.1	PONDEROSA BAILY	SNOW MOUNTAIN HYDRO -	HYDROELECTRIC
HYDRO	SHASTA	1.2	NELSON CREEK		HYDROELECTRIC
HYDRO	SHASTA	1.44	COW CREEK		HYDROELECTRIC
HYDRO	SHASTA	2	BIDWELL DITCH	MEGA RENEWABLES -BIDWI	HYDROELECTRIC
HYDRO	SHASTA	2	MEGA RENEWABLES - ROARING CRK	ROARING CREEK (MEGA RE	HYDROELECTRIC
HYDRO	SHASTA	2.6	EL DORADO HYDRO - MONTGOMERY CREEK HYDRO		HYDROELECTRIC
HYDRO	SHASTA	3	BURNEY CREEK	SNOW MOUNTAIN HYDRO -	HYDROELECTRIC
HYDRO	SHASTA	3	TKO POWER - SOUTH FORK BEAR CREEK	NICHOLS HYDRO PROJECT	HYDROELECTRIC
HYDRO	SHASTA	3.2	KILARC		HYDROELECTRIC
HYDRO	SHASTA	4.2	SLATE CREEK		HYDROELECTRIC
HYDRO	SHASTA	5	COVE HYDROELECTRIC	SNOW MOUNTAIN HYDRO -	HYDROELECTRIC
HYDRO	SHASTA	5	OLSEN POWER PARTNERS		HYDROELECTRIC
HYDRO	SHASTA	7	HATCHET CREEK	MEGA RENEWABLES -HATC	HYDROELECTRIC
HYDRO	SHASTA	9	VOLTA 1		HYDROELECTRIC
HYDRO	SHASTA	9.9	HAT CREEK 1		HYDROELECTRIC
HYDRO	SHASTA	9.9	HAT CREEK 2		HYDROELECTRIC
HYDRO	SHASTA	13	COLEMAN		HYDROELECTRIC
HYDRO	SIERRA	0.04	BERTHA WRIGHT BERTILLION		HYDROELECTRIC
HYDRO	SIERRA	0.5	SALMON CREEK	SALMON CREEK HYDROELE	HYDROELECTRIC
HYDRO	SIERRA	3.7	STAMPEDE		HYDROELECTRIC
HYDRO	SIERRA	10	HAYPRESS HYDROELECTRIC	HAYPRESS CREEK LOWER	HYDROELECTRIC
HYDRO	SISKIYOU	0.066	UPPER COLD SPRINGS		HYDROELECTRIC
HYDRO	SISKIYOU	0.1	PRATHER CREEK		HYDROELECTRIC
HYDRO	SISKIYOU	0.1	SHASTA RIVER		HYDROELECTRIC
HYDRO	SISKIYOU	2.2	FALL CREEK		HYDROELECTRIC
HYDRO	SISKIYOU	5	LAKE SISKIYOU		HYDROELECTRIC
HYDRO	SISKIYOU	18	IRON GATE		HYDROELECTRIC
HYDRO	SISKIYOU	20	COPCO 1		HYDROELECTRIC
HYDRO	SONOMA	2.79	WARM SPRINGS	WARM SPRINGS HYDROELE	HYDROELECTRIC
HYDRO	STANISLAUS	0.2	STONE DROP		HYDROELECTRIC
HYDRO	STANISLAUS	1.2	HICKMAN		HYDROELECTRIC
HYDRO	STANISLAUS	2.85	WOODWARD	WOODWARD, SOUTH SAN J	HYDROELECTRIC
HYDRO	STANISLAUS	3.25	LA GRANGE		HYDROELECTRIC
HYDRO	STANISLAUS	3.3	TURLOCK LAKE		HYDROELECTRIC
HYDRO	STANISLAUS	5.3	FRANKENHEIMER	FRANKENHEIMER, SOUTH S	HYDROELECTRIC
HYDRO	SUTTER	0.395	SOUTH SUTTER WATER	VANJOP #1	HYDROELECTRIC
HYDRO	TEHAMA	0.03	NIKOLA 1		HYDROELECTRIC
HYDRO	TEHAMA	6.2	BLACK BUTTE		HYDROELECTRIC
HYDRO	TEHAMA	7	SOUTH		HYDROELECTRIC
HYDRO	TEHAMA	8	INSKIP		HYDROELECTRIC
HYDRO	TRINITY	0.028	STEVE SPELLENBERG HYDRO		HYDROELECTRIC
HYDRO	TRINITY	0.06	TRINITY ALPS CREEK		HYDROELECTRIC
HYDRO	TRINITY	0.3	CEDAR FLAT HYDRO		HYDROELECTRIC
HYDRO	TRINITY	0.35	LEWISTON		HYDROELECTRIC
HYDRO	TRINITY	0.975	PAN PACIFIC HYDRO WEBER FLAT PROJECT		HYDROELECTRIC
HYDRO	TRINITY	1.3	THREE FORKS		HYDROELECTRIC
HYDRO	TRINITY	2	GOSSELIN HYDROELECTRIC	HUMBOLDT BAY MWD	HYDROELECTRIC
HYDRO	TRINITY	4.95	KEKAWAKA POWER	KEKAWAKA HYDRO PROJEC	HYDROELECTRIC
HYDRO	TRINITY	5	BIG CREEK WATER WORKS		HYDROELECTRIC
HYDRO	TULARE	1.4	SUCCESS POWER PROJECT		HYDROELECTRIC
HYDRO	TULARE	1.8	KAWEAH 2		HYDROELECTRIC
HYDRO	TULARE	2.25	KAWEAH 1		HYDROELECTRIC
HYDRO	TULARE	2.52	TULE RIVER		HYDROELECTRIC
HYDRO	TULARE	4.5	KAWEAH 3		HYDROELECTRIC
HYDRO	TULARE	6.4	TULE	LOWER TULE	HYDROELECTRIC
HYDRO	TULARE	17	TERMINUS HYDROELECTRIC	TERMINUS DAM, KAWEAH R	HYDROELECTRIC
HYDRO	TUOLUMNE	2	PHOENIX		HYDROELECTRIC
HYDRO	TUOLUMNE	2.9	MOCCASIN LOWHEAD	MOCCASIN	HYDROELECTRIC
HYDRO	TUOLUMNE	6	NEW SPICER	NEW SPICER MEADOW	HYDROELECTRIC
HYDRO	TUOLUMNE	6	UPPER DAWSON		HYDROELECTRIC
HYDRO	TUOLUMNE	7	SPRING GAP		HYDROELECTRIC
HYDRO	TUOLUMNE	9.99	BEARDSLEY		HYDROELECTRIC
HYDRO	TUOLUMNE	16.2	SAND BAR	SAND BAR PROJECT - TRI-D	HYDROELECTRIC
HYDRO	TUOLUMNE	17	TULLOCH		HYDROELECTRIC
HYDRO	VENTURA	0.25	SANTA ROSA HYDRO STATION/CALLEGUA		HYDROELECTRIC
HYDRO	VENTURA	1.42	SANTA FELICIA		HYDROELECTRIC

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GENERAL FUEL	COUNTY	ONLINE MW	PLANTNAME	ALIAS	FACILITY
HYDRO	YUBA	0.15	FISH POWER	BULLARDS BAR or FISH POW	HYDROELECTRIC
HYDRO	YUBA	0.995	BROWNS VALLEY IRRIGATION DISTRICT	VIRGINIA RANCH DAM	HYDROELECTRIC
HYDRO	YUBA	2	YUBA COUNTY WATER	CHALLENGE or DEADWOOD	HYDROELECTRIC
LANDFILL GAS	ALAMEDA	7	ALTAMONT GAS RECOVERY	BIO-ENERGY PARTNERS, AL	WTE
LANDFILL GAS	CONTRA COSTA	3	NOVE POWER PLANT	NOVE INVESTMENTS	WTE
LANDFILL GAS	LOS ANGELES	7.8	PUENTE HILLS RECOVERY	PUENTE HILLS ENERGY REC	WTE
LANDFILL GAS	LOS ANGELES	9.25	PENROSE	PENROSE POWER STATION	WTE
LANDFILL GAS	LOS ANGELES	9.25	TOYON	TOYON CANYON LANDFILL	WTE
LANDFILL GAS	LOS ANGELES	9.9	SPADRA LANDFILL GAS TO ENERGY	SPADRA LANDFILL	WTE
LANDFILL GAS	LOS ANGELES	13	PALOS VERDES GAS TO ENERGY FACILITY	PALOS VERDES ENERGY RE	WTE
LANDFILL GAS	NAPA	1.76	AMERICAN CANYON POWER PLANT	GAS RECOVERY SYSTEMS -	WTE
LANDFILL GAS	ORANGE	5.4	BREA POWER PARTNERS LP	OLINDA ALPHA SLF, OLINDA	WTE
LANDFILL GAS	ORANGE	6.1	MM PRIMA DESCHECHA ENERGY LLC		WTE
LANDFILL GAS	ORANGE	20	COYOTE CANYON	COYOTE CANYON FACILITY	WTE
LANDFILL GAS	SACRAMENTO	8.3	KIEFER LANDFILL GAS TO ENERGY FACILITY		WTE
LANDFILL GAS	SAN DIEGO	1.8	SAN MARCOS		WTE
LANDFILL GAS	SAN DIEGO	1.8	SYCAMORE SAN DIEGO		WTE
LANDFILL GAS	SAN DIEGO	3.72	MM SAN DIEGO LLC - NORTH CITY		WTE
LANDFILL GAS	SAN DIEGO	3.87	OTAY	OTAY POWER	WTE
LANDFILL GAS	SAN DIEGO	6.5	MM SAN DIEGO LLC - MIRAMAR	MIRAMAR LANDFILL	WTE
LANDFILL GAS	SAN MATEO	2	MARSH ROAD POWER PLANT	GAS RECOVERY SYSTEMS -	WTE
LANDFILL GAS	SANTA BARBARA	3.5	MM TAJIGUAS ENERGY LLC	MM TAJIGUAS LANDFILL	WTE
LANDFILL GAS	SANTA CLARA	1.5	SANTA CLARA		WTE
LANDFILL GAS	SANTA CLARA	2	BYXBEE PARK SANITARY LANDFILL	PALO ALTO LANDFILL	WTE
LANDFILL GAS	SANTA CLARA	2	NEWBY LAND 1		WTE
LANDFILL GAS	SANTA CLARA	2.6	GUADALUPE POWER PLANT	GAS RECOVERY SYSTEMS -	WTE
LANDFILL GAS	SANTA CLARA	3.3	NEWBY ISLAND 2		WTE
LANDFILL GAS	SONOMA	3.2	CENTRAL LF (SONOMA) PHASE I		WTE
LANDFILL GAS	SONOMA	3.2	CENTRAL LF (SONOMA) PHASE II		WTE
LANDFILL GAS	TULARE	1.8	MM TULARE ENERGY LLC		WTE
LANDFILL GAS	VENTURA	5.55	OXNARD	BAILARD LF, OXNARD LAND	WTE
LANDFILL GAS	YOLO	2.85	MM YOLO POWER LLC FACILITY	YOLO COUNTY LANDFILL	WTE
MSW	ALAMEDA	3.75	GAS RECOVERY SYSTEMS - FREMONT		WTE
MSW	LOS ANGELES	3.25	MM WEST CORVINA LLC	MINNESOTA METHANE, WES	WTE
MSW	LOS ANGELES	6.6	MM LOPEZ ENERGY LLC	MINNESOTA METHANE, CITY	WTE
MSW	LOS ANGELES	11.5	COMMERCE REFUSE TO ENERGY		WTE
MSW	LOS ANGELES	34.6	SOUTHEAST RESOURCE RECOVERY	CITY OF LONG BEACH - SER	WTE
MSW	MONTEREY	1.4	SALINAS		WTE
MSW	MONTEREY	1.74	MONTEREY REGIONAL WATER POLLUTION CONTROL COGEN		WTE
MSW	MONTEREY	5.4	MARINA LANDFILL GAS	MONTEREY REGIONAL WAS	WTE
MSW	RIVERSIDE	0.6	CORONA LANDFILL	O'BRIEN ENERGY SYSTEMS	WTE
MSW	STANISLAUS	14	MODESTO ENERGY	MODESTO ENERGY LTD. PA	WTE
MSW	STANISLAUS	22.5	STANISLAUS RESOURCE RECOVERY FACILITY	STANISLAUS or RESOURCE	WTE
SOLAR	KERN	30	SEGS III	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	KERN	30	SEGS IV	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	KERN	30	SEGS V	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	KERN	30	SEGS VI	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	KERN	30	SEGS VII	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	SACRAMENTO	2	SOLAR SACRAMENTO 1 & 2	PHOTOVOLTAIC 1 & 2	SOLAR
SOLAR	SACRAMENTO	108.2	HEDGE PV	KAISER FC	SOLAR
SOLAR	SAN BERNARDINO	13.8	SEGS I	SUNRAY ENERGY INC., DA	SOLAR
SOLAR	SAN BERNARDINO	30	SEGS II	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	SAN BERNARDINO	80	SEGS IX	LUZ SOLAR PARTNERS LTD.	SOLAR
SOLAR	SAN BERNARDINO	80	SEGS VIII	LUZ SOLAR PARTNERS LTD.	SOLAR
WIND	ALAMEDA	1.5	ALTAMONT INFRASTRUCTURE COMPANY - 06W146D		WIND
WIND	ALAMEDA	8.48	FLOWIND PARTNERS 1		WIND
WIND	ALAMEDA	10	ALTAMONT INFRASTRUCTURE COMPANY - 06W148		WIND
WIND	ALAMEDA	20	ZOND WINDSYSTEM PARTNERS LTD - SERIES 85-C		WIND
WIND	ALAMEDA	23.8	ALTAMONT INFRASTRUCTURE COMPANY - 16W011		WIND
WIND	ALAMEDA	30	ALTAMONT INFRASTRUCTURE COMPANY - 06W146C		WIND
WIND	ALAMEDA	72	ALTAMONT INFRASTRUCTURE COMPANY - 01W035		WIND
WIND	CONTRA COSTA	34.7	WINDDRIVEN, INC.		WIND
WIND	CONTRA COSTA	110	ALTAMONT INFRASTRUCTURE COMPANY - 01W004		WIND
WIND	KERN	0.01	ANTELOPE VALLEY - POPPY RESERVE		WIND
WIND	KERN	0.05	S & L RANCH		WIND
WIND	KERN	1.88	CTV MANAGEMENT GROUP		WIND
WIND	KERN	2.34	WINDRIDGE, INC.		WIND
WIND	KERN	2.4	WINDSONG ENERGY, INC.		WIND
WIND	KERN	4	CTV MANAGEMENT GROUP - 6029		WIND
WIND	KERN	4	MOGUL ENERGY CORP		WIND
WIND	KERN	4.2	OAK CREEK ENERGY TRUST - ZEPHYR PARK PROJECT		WIND
WIND	KERN	4.36	CTV MANAGEMENT GROUP - 6089		WIND
WIND	KERN	4.99	ZOND SYSTEMS, INC. - MONOLITH XI		WIND
WIND	KERN	5.04	ZOND SYSTEMS, INC. - MONOLITH X		WIND
WIND	KERN	5.67	ZOND SYSTEMS, INC. - MONOLITH XIII		WIND
WIND	KERN	6.015	ZOND SYSTEMS, INC. - 6041		WIND
WIND	KERN	6.24	ZOND SYSTEMS, INC. - 6039		WIND
WIND	KERN	6.315	ZOND SYSTEMS, INC. - NORTHWIND		WIND
WIND	KERN	6.547	WINDLAND, INC.		WIND
WIND	KERN	6.72	ZOND SYSTEMS, INC. - MONOLITH XII		WIND
WIND	KERN	6.77	ZOND SYSTEMS, INC. - 6042		WIND
WIND	KERN	6.9	VICTORY GARDEN PHASE IV PARTNER - 6104		WIND
WIND	KERN	6.925	ZOND SYSTEMS, INC. - 6040		WIND
WIND	KERN	6.975	VICTORY GARDEN PHASE IV PARTNER - 6102		WIND
WIND	KERN	6.975	VICTORY GARDEN PHASE IV PARTNER - 6103		WIND
WIND	KERN	7.735	WINDLAND, INC.		WIND
WIND	KERN	8.71	CALWIND RESOURCES, INC.		WIND
WIND	KERN	11.9	ESI ENERGY, INC. - 6091		WIND
WIND	KERN	17	ZOND SYSTEMS, INC. - 6043		WIND
WIND	KERN	19.8	ESI ENERGY, INC. - 6066		WIND

Installed Renewable Capacity in California (MW)
(from Energy Commission's Cartography Unit)

GENERAL FUEL	COUNTY	ONLINE MW	PLANTNAME	ALIAS	FACILITY
WIND	KERN	20.925	ESI ENERGY, INC. - 6067		WIND
WIND	KERN	21.8	CALWIND RESOURCES, INC.		WIND
WIND	KERN	22.5	ZOND SYSTEMS, INC. - 6044		WIND
WIND	KERN	25.512	CANNON ENERGY CORP - 6092		WIND
WIND	KERN	30.5	OAK CREEK ENERGY SYSTEMS INC.		WIND
WIND	KERN	33.6	ESI ENERGY, INC. - 6057		WIND
WIND	KERN	36.725	ESI ENERGY, INC. - 6065		WIND
WIND	KERN	37	DESERTWIND III PPC TRUST		WIND
WIND	KERN	40	CABAZON POWER PARTNERS, LLC		WIND
WIND	KERN	45.374	CANNON ENERGY CORP		WIND
WIND	KERN	48	ESI ENERGY, INC. - 6063		WIND
WIND	KERN	56	TEHACHAPI POWER PURCHASE TRUST		WIND
WIND	KERN	75	DESERTWIND II PPC TRUST		WIND
WIND	RIVERSIDE	0.025	JOHN W. HORTON		WIND
WIND	RIVERSIDE	3	ENERGY DEV. & CONSTRUCTION		WIND
WIND	RIVERSIDE	3	SAN GORGONIO FARMS, INC.		WIND
WIND	RIVERSIDE	4.435	SEAWEAT INDUSTRIES, INC.		WIND
WIND	RIVERSIDE	5.007	LG&E POWER, INC. - 6035		WIND
WIND	RIVERSIDE	6.2	LG&E POWER, INC. - 6118		WIND
WIND	RIVERSIDE	8	DUTCH ENERGY CORP		WIND
WIND	RIVERSIDE	9.35	LG7E POWER, INC. - 6098		WIND
WIND	RIVERSIDE	9.8	SAN GORGONIO WESTLANDS II, LLC		WIND
WIND	RIVERSIDE	10.465	SOUTHERN CALIFORNIA SUNBELT DEVELOPERS		WIND
WIND	RIVERSIDE	11.72	FORAS ENERGY, INC.		WIND
WIND	RIVERSIDE	13	NORTHWIND VAQUERO - SOUZA WINDPARK		WIND
WIND	RIVERSIDE	13.5	LG&E POWER, INC - 6030		WIND
WIND	RIVERSIDE	13.51	PHOENIX ENERGY LIMITED		WIND
WIND	RIVERSIDE	14.154	FORAS ENERGY, INC.		WIND
WIND	RIVERSIDE	16.207	ENXCO		WIND
WIND	RIVERSIDE	18.237	WINTEC ENERGY, LTD		WIND
WIND	RIVERSIDE	19.265	ZOND SYSTEMS, INC. - 6112		WIND
WIND	RIVERSIDE	19.3	EUI MANAGEMENT PH, INC.		WIND
WIND	RIVERSIDE	24.57	FORAS ENERGY, INC. - 6090		WIND
WIND	RIVERSIDE	28	SAN GORGONIO FARMS, INC.		WIND
WIND	RIVERSIDE	29.9	ZOND SYSTEMS, INC		WIND
WIND	RIVERSIDE	35	NAWP INC. - 6087		WIND
WIND	RIVERSIDE		TRES VAQUEROS WINDFARM, LLC		WIND
WIND	SAN BENITO	17.435	INTERNATIONAL TURBINE RESEARCH, INC.		WIND
WIND	SAN DIEGO	4.2	NAWP INC.		WIND
WIND	SAN JOAQUIN	0.06	SEAWEST ENERGY GROUP		WIND
WIND	SAN JOAQUIN	0.9	VENTURE WINDS		WIND
WIND	SAN JOAQUIN	1.5	ESI PROJECT	CWES PROJECT	WIND
WIND	SAN JOAQUIN	1.56	VIKING 83		WIND
WIND	SAN JOAQUIN	2.7	FLOWIND PARTNERS 2		WIND
WIND	SAN JOAQUIN	5.76	ALTECH I		WIND
WIND	SAN JOAQUIN	5.9	ALTAMONT INFRASTRUCTURE COMPANY - 01W018		WIND
WIND	SAN JOAQUIN	10.68	TAXVEST 11		WIND
WIND	SAN JOAQUIN	10.92	ALTAMONT MIDWAY, LTD.		WIND
WIND	SAN JOAQUIN	11.9	ALTAMONT INFRASTRUCTURE COMPANY - 01W146C		WIND
WIND	SAN JOAQUIN	15	ALTAMONT INFRASTRUCTURE COMPANY - 01W146D		WIND
WIND	SAN JOAQUIN	18.96	FLOWIND 3-4		WIND
WIND	SAN JOAQUIN	18.96	FLOWIND 4-4		WIND
WIND	SAN JOAQUIN	18.96	FLOWIND 5-4		WIND
WIND	SAN JOAQUIN	18.99	FLOWIND 6-4		WIND
WIND	SAN JOAQUIN	20	ALTAMONT INFRASTRUCTURE COMPANY - 06W146A		WIND
WIND	SAN JOAQUIN	22	PATTERSON PASS WIND FARM		WIND
WIND	SAN JOAQUIN	30	ALTAMONT INFRASTRUCTURE COMPANY - 01W144		WIND
WIND	SAN JOAQUIN	30	ALTAMONT INFRASTRUCTURE COMPANY - 01W146B		WIND
WIND	SAN JOAQUIN	43.1	ALTAMONT INFRASTRUCTURE COMPANY - 01W146A		WIND
WIND	SAN JOAQUIN		DYER ROAD		WIND
WIND	SOLANO	18.5	ALTAMONT INFRASTRUCTURE COMPANY - 06W146B		WIND

Proposed Projects in California

I/O	1

Sum of Gross MW	Technology										
County	Biofuel	Biomass	Digester Gas	Geothermal	Landfill Gas	PV	Small Hydro	Solar Thermal	Waste Tire	Wind	Grand Total
Alameda					4.5		1.0			210.8	216.3
Calusa		25.5									25.5
Contra Costa					3.9						3.9
El Dorado					1.0		21.0				22.0
Fresno					2.6						2.6
Imperial		50.0		240.0					30.0		320.0
Inyo							1.0				1.0
Kern										715.4	715.4
Los Angeles		49.9			28.0					100.0	177.9
Modoc				105.0							105.0
Mono				350.0						30.0	380.0
Monterey					1.0						1.0
NP15 (unknown)	249.8	126.0	101.3		52.6	42.0	14.5			30.7	616.8
Orange					9.2						9.2
Riverside					7.9					527.9	535.8
San Bernardino		1.5			17.3			120.0		91.0	229.8
San Diego			7.2		20.8					400.0	428.0
San Francisco			2.1								2.1
San Mateo					18.6						18.6
Santa Clara					5.5						5.5
Santa Cruz					2.0						2.0
Siskiyou				187.9							187.9
Solano										401.8	401.8
SP15 (unknown)					43.9			50.0		200.0	293.9
Tulare					1.6						1.6
Yolo		7.8									7.8
Grand Total	249.8	260.7	110.6	882.9	220.4	42.0	37.5	170.0	30.0	2,707.6	4,711.4

MW Sum Pivot

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
CPA LOI	R 50.1	CA	NP15 (unknown)	Biofuel	Far West Energy, Inc.	Proposed	50.0	NP15	Far West Energy, Inc.	1		
CPA LOI	R 50.2	CA	NP15 (unknown)	Biofuel	Far West Energy, Inc.	Proposed	50.0	NP15	Far West Energy, Inc.	1		
NCPA	NCPA9	CA	NP15 (unknown)	Biofuel	IC Engine	Proposed	49.99	NP15		2	R 50.1	
NCPA	NCPA10	CA	NP15 (unknown)	Biofuel	IC Engine	Proposed	49.99	NP15		2	R 50.2	
NCPA	NCPA11	CA	NP15 (unknown)	Biofuel	IC Engine	Proposed	49.99	NP15		2	R 7.1	
CPA LOI	R 70	CA	NP15 (unknown)	Biofuel	Permanente Corp.	Proposed	49.76	NP15		1		
CPA LOI	R 7.1	CA	NP15 (unknown)	Biofuel	Sierra Industrial Group	Proposed	50.0	NP15	Sierra Industrial Group	1		
CPA LOI	R 7.2	CA	NP15 (unknown)	Biofuel	Sierra Industrial Group	Proposed	50.0	NP15	Sierra Industrial Group	1		
NCPA	NCPA13	?	Unknown	Biofuel	IC Engine	Proposed	49.99	ZP26		2	R 70	
SCPPA RFP	34	CA	Calusa	Biomass	Calusa County, CA	Proposed	25.5	NP15		1		
SCPPA RFP	30	CA	Imperial	Biomass	Imperial Valley, CA	Proposed	50.0	IID		1		
SCPPA RFP	33	CA	Los Angeles	Biomass	Vernon, CA	Proposed	49.9	ISO SP15 (SCE)		1		
NCPA	NCPA4	CA	NP15 (unknown)	Biomass	Fluidized Bed	Proposed	12.5	NP15		1		
NCPA	NCPA2	CA	NP15 (unknown)	Biomass	Fluidized Bed	Proposed	18.5	NP15		1		
NCPA	NCPA6	CA	NP15 (unknown)	Biomass	Fluidized Bed	Proposed	28.5	NP15		1		
NCPA	NCPA8	CA	NP15 (unknown)	Biomass	Fluidized Bed	Proposed	28.5	NP15		1		
NCPA	NCPA3	CA	NP15 (unknown)	Biomass	Fluidized Bed	Proposed	8	NP15		2	50007	
NCPA	NCPA7	CA	NP15 (unknown)	Biomass	Gasification	Proposed	20	NP15		1		
NCPA	NCPA5	CA	NP15 (unknown)	Biomass	Steam Turbine	Proposed	6	NP15		1		
NCPA	NCPA1	CA	NP15 (unknown)	Biomass	Steam Turbine	Proposed	12	NP15		1		
NCPA	NCPA12	CA	NP15 (unknown)	Biomass	Steam Turbine	Proposed	25	NP15		2	34	
SCPPA RFP	35	CA	San Bernardino	Biomass	Chino, CA	Proposed	1.5	ISO SP15 (SCE)		1		
SCPPA RFP	36	CA	Unknown	Biomass	Madera, CA	Online	28.5	ISO NP15 (PG&E)		2		Online
SCPPA RFP	37	CA	Unknown	Biomass	Merced, CA	Online	12.5	ISO NP15 (PG&E)		2		Online
SCPPA RFP	31	OR	Unknown	Biomass	Oregon	Proposed	25.5			2		non CA
CEC new	50007	CA	Yolo	Biomass	Agrilectric Power	Proposed	7.8		Agrilectric Power, Inc.	1		
NCPA	NCPA15	CA	NP15 (unknown)	Digester Gas	Combustion Turbine	Proposed	99.3	NP15		1		
NCPA	NCPA14	?	NP15 (unknown)	Digester Gas	Fuel Cell	Proposed	2	Multiple		1		
SCPPA RFP	32	CA	San Diego	Digester Gas	TBD - So. Cal horse racing fuel supply.	Proposed	7.2	ISO SP15 (SCE)		1		
SCPPA RFP	42	CA	San Francisco	Digester Gas	Distributed Generation - Micro Turbines for Biogas	Proposed	2.1	Local Service Area.	Distributed Generation - Micro Turbines for Biogas	1		
CPA LOI	R 54	CA	Imperial	Geothermal	Heber Geothermal Co.	Proposed	28.0	Heber		1		
SCPPA RFP	22	CA	Imperial	Geothermal	Imperial County	Proposed	60.0	12 mile line to tie to IID		1		
SCPPA RFP	18	CA	Imperial	Geothermal	Salton Sea 6+	Proposed	120.0	Mirage, PV over new transmission upgrades.		1		
CPA LOI	R56	CA	Imperial	Geothermal	Second ImperialGeothermal Co.	Proposed	32.0	Heber		1		
CPA LOI	R 58.3	CA	Modoc	Geothermal	Cal Geo Co., Surprise Valley 1	Proposed	15.0			1		
CPA LOI	R 58.4	CA	Modoc	Geothermal	Cal Geo Co., Surprise Valley 2	Proposed	15.0			1		
SCPPA RFP	19	CA	Modoc	Geothermal	Casa Diablo Station	Proposed	75.0	Mammoth		1		
CPA LOI	R58.1	CA	Mono	Geothermal	Cal Geo Co.	Proposed	15.0	SP15		1		

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
CPA LOI	R58.2	CA	Mono	Geothermal	Cal Geo Co., Box Canyon 2	Proposed	45.0			1		
SCPPA RFP	20	CA	Mono	Geothermal	Holtville, CA	Proposed	15.0	Not Specified. In IID Control Area.		1		
CPA LOI	R 53	CA	Mono	Geothermal	Mammoth-Pacific L.P.	Proposed	15.0	Mammoth Lakes		1		
CPA LOI	R55	CA	Mono	Geothermal	Mammoth-Pacific L.P.	Proposed	60.0	NP15		1		
SCPPA RFP	18	CA	Mono	Geothermal	Salton Sea 5	Proposed	50.0	Mirage, PV over new transmission upgrades.		1		
NCPA	NCPA18	CA	Mono	Geothermal	Steam Turbine	Proposed	30	NP15		1		
SCPPA RFP	17	CA	Mono	Geothermal	Uncertain location	Proposed	120.0	Gonder, Mead or SCE Bishop interconnect		1		
NCPA	NCPA17	CA	NP15 (unknown)	Geothermal	System Energy	Proposed	85	NP15		2	SC Cal Geo Entries	
CPA LOI	R 58.5	CA	Siskiyou	Geothermal	Cal Geo Co., Military Pass 1	Proposed	30.0			1		
CPA LOI	R 58.6	CA	Siskiyou	Geothermal	Cal Geo Co., Military Pass 2	Proposed	30.0			1		
CPA LOI	R 58.7	CA	Siskiyou	Geothermal	Cal Geo Co., Military Pass 3	Proposed	30.0			1		
CEC new	50026	CA	Siskiyou	Geothermal	Fourmile Hill	Proposed	49.9		Calpine Siskiyou Geothermal Partners, L.P.	1		
CEC new	50022	CA	Siskiyou	Geothermal	Telephone Flat	Proposed	48.0		CPN Telephone Flat, Inc.	1		
NCPA	NCPA16	OR	Unknown	Geothermal	Direct Flash/Binary	Proposed	30	COB		2		non CA
SCPPA RFP	21	NV	Unknown	Geothermal	Fish Valley, NV	Proposed	15.0	Build line to Sierra Pacific		2		non-CA
NCPA	NCPA19	CA	Unknown	Geothermal	System Energy	Proposed	75	NP15		2	19	
NCPA	NCPA20	CA	NP15 (unknown)	Green Tags	Green Tags	Proposed	85	NP15		2	Likely PPM Solano	
NCPA	NCPA22	CA	SP15 (unknown)	Green Tags	Green Tags	Proposed	85	SP15		2		tags
SCPPA RFP	39	CA	Unknown	Green Tags	BPA Wind & Geothermal Resources	Proposed	25	ISO SP15	Green Tickets w/ Firm on-peak Energy	2		Green Tags
SCPPA RFP	41	BC	Unknown	Green Tags	Canada	Proposed	100 GWh/yr.	ISO SP15	Green Tickets Only (No Energy)	2		Green Tags
NCPA	NCPA21	OR	Unknown	Green Tags	Green Tags	Proposed	600	OOS		2		non CA
SCPPA RFP	40	WY	Unknown	Green Tags	Wyoming Wind Energy	Proposed	100	ISO SP15	Green Tickets w/Firm Energy 70% Green	2		Green Tags
CEC new	50001	CA	Alameda	Landfill Gas	Vasco Road	Proposed	4.5		Republic	1		
CEC new	50030	CA	Contra Costa	Landfill Gas	EDI Keller Canyon	Proposed	3.9		Energy Developments, Inc.	1		
CEC new	50019	CA	El Dorado	Landfill Gas	El Dorado County Union Mine Disposal Landfill	Proposed	1.0		El Dorado County Environmental	1		
CEC new	50028	CA	Fresno	Landfill Gas	EDI Chateau Fresno	Proposed	2.6		Energy Developments, Inc.	1		
CEC new	50029	CA	Los Angeles	Landfill Gas	EDI Azusa	Proposed	5.2		Energy Developments, Inc.	1		
SCPPA RFP	27	CA	Los Angeles	Landfill gas	Lakeview Terrace, Lopez Cnyn	Proposed	5.5	LADWP		1		
SCPPA RFP	24	CA	Los Angeles	Landfill gas	Sylmar	Proposed	8.3	LADWP		1		
SCPPA RFP	27	CA	Los Angeles	Landfill gas	West Covina	Proposed	9.0	ISO SP15 (SCE)		1		
CPA LOI	R44	CA	Monterey	Landfill Gas	Monterey RWMD	Proposed	1.0	NP15	Monterey RWMD	1		

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
NCPA	NCPA34	CA	NP15 (unknown)	Landfill Gas	Cogen	Proposed	2.5	NP15		2	R 59.5	
NCPA	NCPA29	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	0.4	NP15		1		
NCPA	NCPA35	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	10.7	NP15		1		
NCPA	NCPA39	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	11	NP15		1		
NCPA	NCPA30	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	1.5	NP15		2	R57.4	
NCPA	NCPA32	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	3	NP15		2	50028	
NCPA	NCPA37	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	3.1	NP15		2	R 78	
NCPA	NCPA36	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	3.4	NP15		2	27	
NCPA	NCPA42	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	3.8	NP15		2	50061	
NCPA	NCPA33	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	5	NP15		2	50062	
NCPA	NCPA41	CA	NP15 (unknown)	Landfill Gas	IC Engine	Proposed	5.1	NP15		2	R57.11	
CPA LOI	R57.13	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.20	NP15		1		
CPA LOI	R57.2	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.20	NP15		1		
CPA LOI	R57.1	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.40	NP15		1		
CPA LOI	R57.9	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.40	NP15		1		
CPA LOI	R57.4	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.50	NP15		1		
CPA LOI	R57.6	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.60	NP15		1		
CPA LOI	R57.3	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.80	NP15		1		
CPA LOI	R57.8	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	1.80	NP15		1		
CPA LOI	R57.11	CA	NP15 (unknown)	Landfill gas	Microgy	Proposed	5.30	NP15		1		
CPA LOI	R 78	CA	NP15 (unknown)	Landfill gas	MM Tajiguas Energy	Proposed	3.10	NP15		1		
CPA LOI	R 59.5	CA	NP15 (unknown)	Landfill gas	MM Yolo Power	Proposed	2.50	NP15		1		
NCPA	NCPA31	CA	NP15 (unknown)	Landfill Gas	Reciprocating Eng.	Proposed	4	NP15		2	50030	
NCPA	NCPA40	CA	NP15 (unknown)	Landfill Gas	Turbine	Proposed	9	NP15		2	50002	
CPA LOI	R 75	CA	NP15 (unknown)	Landfill gas	USA Waste of CA (Altamont)	Proposed	1.28	NP15		1		
CPA LOI	R 71	CA	NP15 (unknown)	Landfill gas	USA Waste of CA (El Sobrante)	Proposed	2.56	NP15		1		
CPA LOI	R 74	CA	NP15 (unknown)	Landfill gas	USA Waste of CA (Kirby Canyon)	Proposed	1.28	NP15		1		
CPA LOI	R 72	CA	NP15 (unknown)	Landfill gas	USA Waste of CA (Tri-Cities)	Proposed	2.56	NP15		1		
CPA LOI	R 76	CA	Orange	Landfill gas	Ridgewood Olinda II	Proposed	7.20	NP15		1		
CPA LOI	R 48	CA	Orange	Landfill Gas	Ridgewood Olinda, LLC	Proposed	2.0	SP15	Ridgewood Olinda, LLC	1		
CEC new	50015	CA	Riverside	Landfill Gas	Coachella	Proposed	1.0		Riverside County Waste Resources	1		
CEC new	50017	CA	Riverside	Landfill Gas	Double Butte	Proposed	0.6		Riverside County Waste Resources	1		
CEC new	50018	CA	Riverside	Landfill Gas	Edom Hill	Proposed	2.0		Riverside County Waste Resources	1		
CEC new	50016	CA	Riverside	Landfill Gas	Lamb Canyon	Proposed	1.0		Riverside County Waste Resources	1		
CEC new	50014	CA	Riverside	Landfill Gas	Mead Valley	Proposed	1.0		Riverside County Waste Resources	1		
CPA LOI	R57.14	CA	Riverside	Landfill gas	Microgy	Proposed	2.40	NP15		1		
SCPPA RFP	26	CA	San Bernardino	Landfill gas	Colton	Proposed	1.2	ISO SP15 (SCE)		1		
CEC new	50060	CA	San Bernardino	Landfill Gas	Colton	Proposed	2.5		NEO Corp.	1		
CEC new	50061	CA	San Bernardino	Landfill Gas	Mid-Valley	Proposed	3.8		NEO Corp.	1		
CEC new	50062	CA	San Bernardino	Landfill Gas	Milliken	Proposed	5.0		NEO Corp.	1		
CPA LOI	R 80		San Bernardino	Landfill gas	MM San Bernardino Energy (Colton)	Proposed	1.20	NP15		2	26	

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
CPA LOI	R 81	CA	San Bernardino	Landfill gas	MM San Bernardino Energy (Mid Valley)	Proposed	2.50	SP15		2	50061	
CPA LOI	R 82	CA	San Bernardino	Landfill gas	MM San Bernardino Energy (Milliken)	Proposed	2.50	SP15		2	50062	
SCPPA RFP	26	CA	San Bernardino	Landfill gas	Ontario	Proposed	2.4	ISO SP15 (SCE)		1		
SCPPA RFP	26	CA	San Bernardino	Landfill gas	Rialto	Proposed	2.4	ISO SP15 (SCE)		1		
SCPPA RFP	25	CA	San Diego	Landfill gas	Brea, CA	Proposed	2.4	ISO SP15 (SDG&E)		1		
SCPPA RFP	23	CA	San Diego	Landfill gas	Irvine, CA	Proposed	7.5	ISO SP15 SDG&E		1		
SCPPA RFP	27	CA	San Diego	Landfill gas	Miramar	Proposed	3.4	ISO SP15 (SDG&E)		1		
CPA LOI	R 59.7	CA	San Diego	Landfill gas	MM San Diego (North City)	Proposed	3.80	SP15		2	27	
SCPPA RFP	23	CA	San Diego	Landfill gas	San Marcos	Proposed	2.5	ISO SP15 SDG&E		1		
SCPPA RFP	23	CA	San Diego	Landfill gas	Santee #1	Proposed	2.5	ISO SP15 SDG&E		1		
SCPPA RFP	23	CA	San Diego	Landfill gas	Santee #2	Proposed	2.5	ISO SP15 SDG&E		1		
SCPPA RFP	23	CA	San Mateo	Landfill gas	Half Moon Bay	Proposed	9.0	NP15		2	50002	
NCPA	NCPA38	CA	San Mateo	Landfill Gas	IC Engine	Proposed	6	NP15		1		
CEC new	50002	CA	San Mateo	Landfill Gas	Ox Mountain	Proposed	10.0		Gas Recovery Systems, Inc.	1		
CPA LOI	R 73	CA	San Mateo	Landfill gas	USA Waste of CA (Redwood)	Proposed	2.56	NP15		1		
CEC new	50003	CA	Santa Clara	Landfill Gas	Newby Island	Proposed	5.5		Gas Recovery Systems	1		
CEC new	50004	CA	Santa Cruz	Landfill Gas	Buena Vista	Proposed	2.0		County of Santa Cruz, Department of Public Works	1		
SCPPA RFP	25	CA	SP15 (unknown)	Landfill gas	Brea, CA	Proposed	7.2	ISO SP15 (SDG&E)		1		
NCPA	NCPA43	CA	SP15 (unknown)	Landfill Gas	IC Engine	Proposed	15	SP15		1		
CPA LOI	R 59.4	CA	SP15 (unknown)	Landfill gas	MM Lopez Energy	Proposed	6.10	SP15		1		
CPA LOI	R 77		SP15 (unknown)	Landfill gas	MM Prima Deshecha Energy	Proposed	6.10	SP15		1		
CPA LOI	R 83		SP15 (unknown)	Landfill gas	Syracuse Power (Otay Landfill)	Proposed	6.00	SP15		1		
CPA LOI	R 84	CA	SP15 (unknown)	Landfill gas	Syracuse Power (Sycamore Landfill)	Proposed	3.50	SP15		1		
CPA LOI	R 59.1	CA	Tulare	Landfill gas	MM Tulare Energy	Proposed	1.80	NP15		2	27	
SCPPA RFP	27	CA	Tulare	Landfill gas	Tulare	Proposed	1.6	ISO NP15 (PG&E)		1		
NCPA	NCPA28	?	Unknown	Landfill Gas	Kirell Energy	Proposed	10	Multiple		2		unknown locations
CPA LOI	R57.12	CA	Unknown	Landfill gas	Microgy	Proposed	1.00	NP15		2	50019	
CPA LOI	R57.5	CA	Unknown	Landfill gas	Microgy	Proposed	1.00	NP15		2	R44	
CPA LOI	R57.10	CA	Unknown	Landfill gas	Microgy	Proposed	2.20	NP15		2	26	
CPA LOI	R57.7	CA	Unknown	Landfill gas	Microgy	Proposed	2.20	NP15		2	26	
CPA LOI	R 59.6		Unknown	Landfill gas	MM San Diego (Miramar)	Proposed	6.50	NP15		2	27	
CPA LOI	R 59.3	CA	Unknown	Landfill gas	MM West Covina	Proposed	11.70	NP15		2	27	
CPA LOI	R 79		Unknown	Landfill gas	MM Woodville Energy	Proposed	0.60	SP15		2	50017	
NCPA	NCPA44	?	Unknown	Ocean Waves	Wave Energy	Proposed	25.1	ZP26		2		non CA

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
NCPA	NCPA47	CA	NP15 (unknown)	PV	PV	Proposed	0.5	Multiple		1		
NCPA	NCPA48	CA	NP15 (unknown)	PV	PV	Proposed	40	Multiple		1		
NCPA	NCPA46	CA	NP15 (unknown)	PV	PV Carport	Proposed	0.5	Multiple		1		
NCPA	NCPA45	CA	NP15 (unknown)	PV	PV Rooftop	Proposed	0.5	Multiple		1		
NCPA	NCPA49	CA	NP15 (unknown)	PV	PV Tracker	Proposed	0.5	Multiple		1		
SCPPA RFP	43	CA	Unknown	PV	Distributed Generation - Photovoltaic Solar & Micro Turbines	Proposed	0	Local Service Area.	Distributed Generation - Photovoltaic Solar & Micro Turbines	2		No capacity listed
SCPPA RFP	44	CA	Unknown	PV	Distributed Generations - Photovoltaic Solar	Proposed	0	Local Service Area.	Distributed Generations - Photovoltaic Solar	2		No capacity listed
CEC new	50033	CA	Alameda	Small Hydro	SF Sunol/Calaveras Small Hydro	Proposed	1.0		City and County of San Francisco	1		
CEC new	50083	CA	El Dorado	Small Hydro	El Dorado Irrigation District	Proposed	21.0	El Dorado, Amador, and Alpine	El Dorado Irrigation District	1		
CEC new	50072	CA	Inyo	Small Hydro	Tungstar	Proposed	1.0		Keating Associates	1		
NCPA	NCPA23	CA	NP15 (unknown)	Small Hydro	Water Turbine	Proposed	0.3	NP15		1		
NCPA	NCPA26	CA	NP15 (unknown)	Small Hydro	Water Turbine	Proposed	1.7	NP15		1		
NCPA	NCPA27	CA	NP15 (unknown)	Small Hydro	Water Turbine	Proposed	5.5	NP15		1		
NCPA	NCPA25	CA	NP15 (unknown)	Small Hydro	Water Turbine	Proposed	7	NP15		1		
NCPA	NCPA24	CA	NP15 (unknown)	Small Hydro	Water Turbine	Proposed	1	NP15		2	50033	
SCPPA RFP	38	ID	Unknown	Small Hydro	Idaho Power Small Hydro Units	Proposed	10	Gonder		2		non CA
SCPPA RFP	38	ID	Unknown	Small Hydro	Idaho Power Small Hydro Units	Proposed	25	Gonder		2		non CA
SCPPA RFP	38	ID	Unknown	Small Hydro	Idaho Power Small Hydro Units	Proposed	50.0	Gonder		2		non CA
SCPPA RFP	28	CA	San Bernardino	Solar Thermal	Daggett, CA	Proposed	40.0	ISO SP15 or Mead Adelanto Line		1		
SCPPA RFP	29	CA	San Bernardino	Solar Thermal	Harper Lake, CA	Proposed	80.0	ISO SP15 or Mead Adelanto Line		1		
NCPA	NCPA50	CA	SP15 (unknown)	Solar Thermal	Parabolic Trough	Proposed	48	SP15		2	29	
NCPA	NCPA52	CA	SP15 (unknown)	Solar Thermal	Parabolic trough	Proposed	48	SP15		2	29	
NCPA	NCPA51	CA	SP15 (unknown)	Solar Thermal	Solar Thermal/Gas	Proposed	50	SP15		1		
CEC new	50077	CA	Imperial	Waste Tire	Mesquite Lake Resource Recovery Facility	Proposed	30.0		Chateau Energy	1		
CPA LOI	R49.2	CA	Alameda	Wind	enXco	Proposed	18.0	NP15	enXco	1		
CEC new	50076	CA	Alameda	Wind	Golden Hills	Proposed	50.4		Altamont Winds, Inc.	1		
CEC new	50070	CA	Alameda	Wind	Green Ridge Power, LLC	Proposed	110		FPL Energy Green Ridge Power, LLC	1		
NCPA	NCPA59	CA	Alameda	Wind	Wind Turbine	Proposed	32.4	NP15		1		
CEC new	50080	CA	Kern	Wind	Deetricity	Proposed	18.0		Oak Creek Energy Systems, Inc.	1		
CEC new	50082	CA	Kern	Wind	Jawbone	Proposed	52.5		Oak Creek Energy Systems, Inc.	1		
CPA LOI	R26	CA	Kern	Wind	Mojave	Proposed	60.0	Mojave	Windridge, LLC (FPL)	1		
CPA LOI	R49.3	CA	Kern	Wind	Mojave	Proposed	60.0	SP15	EnXco	1		
CEC new	50079	CA	Kern	Wind	Oak Creek 3	Proposed	5.4		Oak Creek Energy Systems, Inc.	1		

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
CEC new	50081	CA	Kern	Wind	Oak Creek 4	Proposed	27.9		Oak Creek Energy Systems, Inc.	1		
CPA LOI	R60.2	CA	Kern	Wind	Oak Creek Energy Systems	Proposed	41.80	SP15		1		
CPA LOI	R60.1	CA	Kern	Wind	Oak Creek Energy Systems	Proposed	5.40	SP15		2	50079	
CPA LOI	R60.4	CA	Kern	Wind	Oak Creek Energy Systems	Proposed	18.00	SP15		2	50080	
CPA LOI	R60.3	CA	Kern	Wind	Oak Creek Energy Systems	Proposed	52.50	SP15		2	50082	
CEC new	50073	CA	Kern	Wind	Southern Sierra Power, LLC	Proposed	200.0		FPL Energy Southern Sierra Power, LLC	1		
CPA LOI	R28	CA	Kern	Wind	Southern Sierras	Proposed	200.0	S. Sierras	Southern Sierra Power (FPL)	2	50073	
CPA LOI	R38	CA	Kern	Wind	Tehachapi	Proposed	50.0	SP15	CVT Marketing Group, LTD.	1		
SCPPA RFP	6	CA	Kern	Wind	Tehachapi	Proposed	50.4	ISO SP15 (SCE Vincent)		2	R38	
SCPPA RFP	15	CA	Kern	Wind	Tehachapi (Pine Tree?)	Proposed	120.0	ISO SP15 (SCE)		1		
CEC new	50008	CA	Kern	Wind	Victory Garden	Proposed	30.0		Enron Wind Development Corp.	1		
CEC new	50006	CA	Kern	Wind	Windland, Inc.	Proposed	19.8		Windland, Inc.	1		
CEC new	50071	CA	Kern	Wind	Windridge, LLC	Proposed	30.0		FPL Energy Windridge, LLC	1		
SCPPA RFP	7	CA	Los Angeles	Wind	Antelope Valley	Proposed	60.0	ISO SP15 (SCE)		1		
CEC new	50009	CA	Los Angeles	Wind	Cottonwood	Proposed	40.0		GE Wind Energy, LLC	1		
SCPPA RFP	12	CA	Mono	Wind	N. CA & NE NV	Proposed	30.0	NP15		1		
CPA LOI	R49.1	CA	NP15 (unknown)	Wind	enXco	Proposed	30.60	NP15		1		
NCPA	NCPA57	CA	NP15 (unknown)	Wind	Turbine	Proposed	0.1	NP15		1		
NCPA	NCPA61	CA	NP15 (unknown)	Wind	Wind Turbine	Proposed	30	NP15		2	50071	
NCPA	NCPA62	CA	NP15 (unknown)	Wind	Wind Turbine	Proposed	0	NP15		2		capacity unspecified
CEC new	50032	CA	Riverside	Wind	Alta Mesa IV	Proposed	25.2		Mark Tech. Corp./FORAS Energy, Inc.	1		
CEC new	50075	CA	Riverside	Wind	Alta Mesa VII	Proposed	15.0		Mark Technologies Corporation	1		
SCPPA RFP	1	CA	Riverside	Wind	Cabazon	Proposed	120.0	ISO SP15 (SCE)		1		
CEC new	50010	CA	Riverside	Wind	Christensen/Lazar	Proposed	23.3		GE Wind Energy, LLC	1		
CPA LOI	R32.1	CA	Riverside	Wind	Clipper	Proposed	38.0	SP15	Clipper Windpower, LLC*	2		project changed hands
CEC new	50069	CA	Riverside	Wind	EUI Project 2001	Proposed	16.9		Energy Unlimited	1		
CPA LOI	R24.1	CA	Riverside	Wind	Morongo Reserve	Proposed	100.0	Morongo Res., near Cabazon	Cannon Energy Corporation*	1		
CEC new	50012	CA	Riverside	Wind	Painted Hills	Proposed	20.0		Painted Hills Wind Developers (Enron)	1		
SCPPA RFP	16	CA	Riverside	Wind	Palm Springs	Proposed	115.0	ISO SP15 (SCE)		1		
SCPPA RFP	11	CA	Riverside	Wind	Palm Springs	Proposed	5.0	ISO SP15 (SCE)		2	50065, 50064	

Proposed Projects in California

Source	ID	State	County	Technology	Site/Project	Status	Gross MW	Location	Lead Developer	I/O	Duplicate	Conflict
SCPPA RFP	3	CA	Riverside	Wind	Palm Springs	Proposed	21.6	ISO SP15 (SCE)		2	50012	
CPA LOI	R5.6	CA	Riverside	Wind	Palm Springs, Enron	Proposed	33.0	SP15	Enron Wind Development*	1		
SCPPA RFP	10	CA	Riverside	Wind	San Gorgonio	Proposed	17.8	ISO SP15 (SCE)		1		
CPA LOI	R37.1	CA	Riverside	Wind	San Gorgonio	Proposed	35.0	SP15	SeaWest Windpower, Inc*	1		
CEC new	50064	CA	Riverside	Wind	Wintec Energy #1	Proposed	3.0		Wintec Energy Ltd.	1		
CEC new	50065	CA	Riverside	Wind	Wintec Energy #2	Proposed	3.8		Wintec Energy Ltd.	1		
SCPPA RFP	5	CA	San Bernardino	Wind	Mountainview	Online	66.6	ISO SP15 (SCE)	SeaWest Windpower, Inc*	2		Online
SCPPA RFP	4	CA	San Bernardino	Wind	San Bernardino	Proposed	51.0	ISO SP15 (SCE)		1		
SCPPA RFP	13	CA	San Bernardino	Wind	San Gorgonio	Proposed	40.0	ISO SP15 (SCE)		1		
CPA LOI	R24.2	CA	San Diego	Wind	Cuyapaipe Res	Proposed	200.0	SP15	Cannon Energy Corporation*	1		
CPA LOI	R24.3	CA	San Diego	Wind	Cuyapaipe Res	Proposed	200.0	SP15	Cannon Energy Corporation*	1		
CPA LOI	R27	CA	Solano	Wind	Birds Landing	Proposed	150.0	NP15	High Winds, LLC (FPL)	2	50074, 50078	
CPA LOI	R32.3	CA	Solano	Wind	Clipper Windpower, LLC	Proposed	100.0	NP15	Clipper Windpower, LLC	1		
CEC new	50074	CA	Solano	Wind	High Winds Phase 1, LLC	Proposed	70.0		FPL Energy High Winds, LLC	1		
CEC new	50078	CA	Solano	Wind	High Winds Phase 2 Wind Energy Power	Proposed	80.0		FPL Energy High Winds, LLC	1		
CPA LOI	R12	CA	Solano	Wind	PacifiCorp Power Marketing	Proposed	100.0	NP15		2	50078	
NCPA	NCPA56	CA	Solano	Wind	Wind Turbine	Proposed	66	NP15		1		
NCPA	NCPA58	CA	Solano	Wind	Wind Turbine	Proposed	85.8	NP15		1		
CPA LOI	R5.5	CA	SP15 (unknown)	Wind	Enron Wind Development	Proposed	200.0	SP15		1		
SCPPA RFP	14	CA	Unknown	Wind	10 Projects	Proposed	120	Multiple		2		unknown, likely duplicates
CPA LOI	R32.2	OR	Unknown	Wind	Clipper Windpower, LLC	Proposed	53.00	Oregon	Clipper Windpower, LLC	2		non CA
SCPPA RFP	9	NV	Unknown	Wind	Las Vegas, NV	Proposed	105	Mead		2		non CA
SCPPA RFP	8	CA	Unknown	Wind	Mojave	Proposed	60.0	ISO SP15 (SCE Vincent)		2	R26	
SCPPA RFP	2	NV	Unknown	Wind	Multiple Locations outside CA	Proposed	120	Mona, Mead, NOB		2		non CA
NCPA	NCPA55	NV	Unknown	Wind	Wind Turbine	Proposed	50	NEast		2		non CA
NCPA	NCPA53	OR	Unknown	Wind	Wind Turbine	Proposed	52.8	COB		2		non CA
NCPA	NCPA65	?	Unknown	Wind	Wind Turbine	Proposed	85	ZP26		2		non CA
NCPA	NCPA64	NV	Unknown	Wind	Wind Turbine	Proposed	90	SPPC		2		Non CA
NCPA	NCPA54	OR	Unknown	Wind	Wind Turbine	Proposed	100.5	COB		2		non CA
NCPA	NCPA60	CA	Unknown	Wind	Wind Turbine	Proposed	112	NP15		2	50070	
NCPA	NCPA66	?	Unknown	Wind	Wind Turbine	Proposed	120	ZP26		2		non CA
NCPA	NCPA63	NV	Unknown	Wind	Wind Turbine	Proposed		SPPC		2		non CA
										239		

Proposed Projects in the WECC (Sorted by State)

State	County	Technology	Site/Project	Gross MW	Source	Contract	Location	Lead Developer
AZ	Cochise	Wind		40	Public Info	None	Cochise	AEPCO
CO	Prowers	Wind	Lamar	162	Public Info	None	Lamar. SE corner of state, Prower County	Enron
CO		Wind		100	Public Info	None		FPLE
ID	Cassia	Geothermal	Raft River Geothermal	10.0	Public Info	None		
ID	Cassia	Wind	Cotterel Mountain	200	Public Info	None	Cassia County	Windland Inc.
MT	Deer Lodge	Wind	Deer Lodge	100	Public Info	None	W. MT	Mountain Energy Corp
MT	Glacier	Wind	Cut Bank	60	Public Info	None	Glacier Electric. E of town.	Enron Wind Corp.
MT	Jefferson	Wind	Whitehall Wind	50	Public Info	None	Jefferson County	Navitas
MT		Wind		22	Public Info	None	Blackfeet nation (indian) land	
MT		Wind		36	Public Info	None		
				268				
NM	De Baca, Quay	Wind	Taiban Mesa	204	Public Info	None	20 miles NE of Fort Sumner, W. of Clovis on Taiban Mesa in DeBaca and Quay counties	FPLE
NM	Guadelupe	Wind	Argonne Mesa	200	Public Info	None		
NM	Quay	Wind		200	Public Info	None		
NM	Union, Harding	Wind	Owaissa	55	Public Info	None	S. of Clayton	
				659				
NV	Nye	Biomass	Tonopah, Nathaniel Energy Corp.	25	Public Info	None	Tonopah	Nathaniel Energy Corp
NV	Washoe	Geothermal	Reno	120.0	SCPPA RFP	None	Gonder, Mead, SCE-Bishop	
NV		Geothermal	Fish Valley	15.0	SCPPA RFP	None	Build line to Sierra Pacific	
NV	Churchill	Geothermal	ORNI 9	10	Sierra Pacific Resources RFP	None	Churchill County, Desert Peak KGRA, 50 miles SE Renc	Ormat
NV	Churchill	Geothermal	ORNI 3	20.2	Sierra Pacific Resources RFP	None	Churchill County, Desert Peak KGRA, 50 miles SE Renc	Ormat
NV	Elko	Geothermal	Sulphur Hot Springs	28	Sierra Pacific Resources RFP	None	Elko	Earth Power Resources
NV	Reno	Geothermal	Steamboat Springs	42	Sierra Pacific Resources RFP	None	9 miles S of Reno	Advanced Thermal Systems
				235.2				
NV	Clark	Solar	Eldorado Valley	50	Sierra Pacific Resources RFP	None	near boulder city	Duke Solar
NV	Clark	Wind	Table Mountain	90	Public Info	None	40 miles S. of Las Vegas	GREP
NV	White Pine	Wind	Ely Project	50	Public Info	None	On BHP Billiton property near Ruth. 5 miles E. of Ely	GREP
NV	Clark	Wind	Las Vegas	105.0	SCPPA RFP	None	Mead	
NV		Wind	Multiple locations outside CA	120.0	SCPPA RFP	None	Mona, Mead, NOB	
NV	Clark	Wind	Desert Queen, Goodsprings	80	Sierra Pacific Resources RFP	None	Bird Spring Range near Boulder City. 30 miles S. of Las Vegas	Cielo
NV	N. NV	Wind	N. NV	50	Sierra Pacific Resources RFP	None	Sierra Nevada control area	
NV	Pershing	Wind	White Pine project	100	Public Info	None	Sierra Nevada control area	FPL
NV	S. NV	Wind	S. NV	50	Public Info	None		GREP
				645				
OR	Deschutes	Geothermal	Newberry Crater	50	Public Info	None		
OR	Gilliam	Wind		50	BPA OASIS	None	At the Demoss-Fossil 69 kV line in the vicinity of Condon, OR.	SeaWest
OR	Gilliam	Wind		100	BPA OASIS	None	5-10 miles SW of Arlington	PPM
OR	Gilliam	Wind	Desert Claim Wind	159	BPA OASIS	None	Interconnection to the existing BPA Columbia - Ellensberg 115kV and the existing BPA Covington - Columbia # 3 230kv line.	enXco
OR	Gilliam	Wind		200	BPA OASIS	None	BPA's Slatt 500 kV Substation outside Arlington, Oregon. A 115 kV connection to the BPA Boardman-Alkali 115 kV radial circuit. A 230 kV connection option to the BPA McNary-Santiam 230 kV circuit #2 at a point approximately 3 miles south of Arlington, Oregon.	Columbia Energy Partners, Inc.
OR	Sherman	Wind	Klondike Wind Power	24	BPA OASIS	None	BPA's De Moss 69 kV Substation.	
OR	Sherman	Wind		26	BPA OASIS	None	Interconnection is BPA's De Moss 115 kV Substation	Northwest Wind Power LLC
OR	Sherman	Wind		50	BPA OASIS	None	BPA's DeMoss 115kV Substation.	Northwest Wind Power LLC
OR	Sherman	Wind		250	BPA OASIS	None	sections 6 and 7 of Township 2N, Range 17E	RES
OR	Sherman	Wind		600	BPA OASIS	None	John Day sub	Orion Energy
OR	Umatilla	Wind		100	BPA OASIS	None	Nine Canyon Wind McNary-Badger Canyon #1 Line approximately 10 miles SE of Badger Canyon Substaion 115 kV.	Energy Northwest

Proposed Projects in the WECC (Sorted by State)

State	County	Technology	Site/Project	Gross MW	Source	Contract	Location	Lead Developer
OR	Umatilla	Wind		200	BPA OASIS	None	Interconnection to the existing BPA Slatt 500 kV Substation approximately 5-10 miles SW of Arlington.	PPM
OR	Umatilla	Wind		200	BPA OASIS	None	Interconnection to the existing BPA McNary-Santiam 230kv line approximately 5-10 miles SW of Arlington	PPM
OR	Umatilla	Wind	Shepard's Flat Wind Farm	250	BPA OASIS	None	BPA Slatt 500 kV Substation	Lifeline Renewable Energy, Inc.
OR	Umatilla	Wind	Blue Mountain Wind Farm	300	BPA OASIS	None	Interconnection to the existing BPA 500 kV McNary to Lower Monumental Line where the line crosses Highway 12.	FPLE
OR	Wallowa	Wind	Blue Mountain Wind Project	150	BPA OASIS	None	BPA Sacajawea Substation	FPLE
OR	Wasco	Wind	Summit Ridge Project	75	BPA OASIS	None	On the Big Eddy - DeMoss 115 kV transmission line approximately 8-9 miles east of The Dalles, Oregon	SeaWest
OR	Wasco	Wind		200	BPA OASIS	None	BPA's Big Eddy - Maupin 230kV transmission line in the vicinity of Dufur, Oregon	Wheat Field Power Partners, LLC
OR	Wasco	Wind	Dalles Wind Farm	350	BPA OASIS	None	East of Big Eddy Substation to the Deschutes River. Then extending South from Columbia River about 7 miles.	
OR	Curry	Wind	Cape Blanco	52.5	CPA LOI	None	Oregon	Clipper Windpower, LLC
OR	Gilliam	Wind		150	Public Info	None		
OR	Sherman	Wind	Northwest Energy	50	Public Info	None	7 miles E. of Wasco in Sherman County	Northwest Energy Development
OR	Umatilla	Wind		85.2	Public Info	None		SeaWest
OR	Umatilla	Wind	Combine Hills Turbine Ranch	104	Public Info	None	S. of Umapine and W. of Milton-Freewater at E. end of Vansycle Ridge, Umatilla County	Tomen Power Corp
OR	Wallowa	Wind	Summit Ridge	50	Public Info	None		SeaWest
OR	Wasco	Wind		50	Public Info	None		SeaWest
				3825				
UT		Geothermal	Blundell	100	Public Info	None		
UT	Tooele	Wind	Tooele County	150	Public Info	None	near Stockton on the S. side of the great lake	RES
WA	Asotin	Wind		200	BPA OASIS	None	BPA's N. Lewiston - Franklin 115kV transmission line in the vicinity of Clarkston, Washington	Wind Ridge Power Partners, LLC
WA	Benton	Wind		70	BPA OASIS	None	Interconnection to the existing BPA Midway-North Bonneville 230 kV line approximately five mile West of the BPA Underwood Substation.	PPM
WA	Benton	Wind		200	BPA OASIS	None	Hanford-John Day 500kV	PPM
WA	Benton	Wind	Maiden Winds Project II	250	BPA OASIS	None	230 kV Big Eddy - Midway transmission line and/or the 500 kV Hanford - John Day transmission line	Washington Winds
WA	Columbia	Wind		300	BPA OASIS	None	BPA's proposed Lower Monumental - Starbuck 500 kV line.	RES
WA	Kittikas	Wind	Wind Ridge Partners	252	BPA OASIS	None	7 miles NE of Kittikas town	Zilkha
WA	Kittikas	Wind	Kittitas Valley Wind Power Project	292	BPA OASIS	None	Columbia Covington 230kV in the vicinity of Cle Elum, Washington	Zilkha (Sagebrush Power Parnters, LLC)
WA	Klickitat	Wind		75	BPA OASIS	None	Interconnection to the existing Mabton-Big Eddy 230kV line. Associated with the proposed Wind Project in Klickitat County.	Energy Northwest
WA	Klickitat	Wind		80	BPA OASIS	None	Big Eddy 230 kV line South of Goldendale.	Cielo Wind Power
WA	Klickitat	Wind	Roosevelt Wind Project	100	BPA OASIS	None	On the Harvalum - Horse Heaven 230 kV transmission line approximately 3-4 miles northwest of Roosevelt, Washington.	SeaWest
WA	Klickitat	Wind		200	BPA OASIS	None	8 miles S of CickletonMidway-Big Eddy/Northwest Hut	PPM
WA	Walla Walla	Wind	Vansycle	90	BPA OASIS	None	115 Kv on BPA's Franklin - Walla Walla transmission line in the vicinity of Touchet, WA	FPLE
WA	Walla Walla	Wind	Combine Hill Turbine Ranch	104	BPA OASIS	None	In the vicinity of the South end of BPA's steel pole line from Walla Walla Substation, 6 miles W of Milton-Freewater and about 3 miles S of Umapine	TPC Oregon Wind Power, LLC
WA	Walla Walla	Wind	Eureka Flats Wind Farm	150	BPA OASIS	None	BPA's 500 kV Lower Monumental McNary transmission line in the vicinity of Eureka, WA	Winds over Washington Energy Group
WA	Walla Walla	Wind	Windy Ridge Wind Farm	150	BPA OASIS	None	BPA's 500 kV Lower Monumental Substation	Winds over Washington Energy Group
WA	Walla Walla	Wind		150	BPA OASIS	None	BPA's 115 kV line connecting the North Lewiston and Walla Walla substations.	Blue Sky Wind LLC
WA	Benton	Wind	Horse Heaven Hills	150	Public Info	None	SW of the town of Kennewick in Benton County	Washington Winds (sub of Pacific Winds)
WA	Benton, Yakima	Wind	Maiden Wind Farm	150	Public Info	None	E. WA, 15 miles N of Presser. Could expand site to 400 MW.	Washington Winds, Inc. (sub of Pacific Winds)
WA	Columbia, Walla Walla	Wind	Columbia County	100	Public Info	None	Walla Walla & Columbia counties	SeaWest
WA	Kittikas	Wind	Kittikas Valley Wind Project	100	Public Info	None	near Ellensburg, 70 miles E. of Tacoma. Betw. Cle Elum and Ellensburg	Zilkha
WA	Klickitat	Wind	Columbia Hills	1	Public Info	None	Klickitat Country	Mariah Energy
WA	Klickitat	Wind	Roosevelt Regional Landfill	15	Public Info	None		Wind Turbine Corp
WA	Klickitat	Wind	Columbia Wind Ranch	80	Public Info	None		Columbia Wind
WA	Roosevelt	Wind	Roosevelt	150	Public Info	None		SeaWest
WA	Walla Walla	Wind	Waitsburg	50	Public Info	None		SeaWest
WA		Wind	Six Prong	150	Public Info	None		SeaWest
				3609				

Proposed Projects in the WECC (Sorted by State)

State	County	Technology	Site/Project	Gross MW	Source	Contract	Location	Lead Developer
WY	Carbon	Wind	Simpson's Ridge	10	Public Info	None	Medicine Bow	Terra Moya Aqua
WY	Carbon	Wind	Sevenmile Hill II	50	Public Info	None	Pacificorp interconnect, near Foote Creek	Enron Wind Corp.
WY	Carbon	Wind	Sevenmile Hill I	100	Public Info	None	Pacificorp interconnect, near Foote Creek	Enron Wind Corp.
WY	Laramie	Wind	Clipper SE coop project	20	Public Info	None		Clipper
				180				

	A	B	C	D	F	G	I
1	Technical Potential For Wind (PIER)						
2	Filtered Wind Resource by Cour				Hub Height: 70 m		
3	Wind Power Method		HWS	HWS	LWS	LWS	HWS+LWS
4		Land Area	Land Area	Capacity	Land Area	Capacity	Capacity
5	County	(km^2)	(km^2)	(MW)	(km^2)	(MW)	(MW)
6	Alameda	2124	21	129	77	482	610
7	Alpine	1918	7	41	19	119	160
8	Amador	1568	0	1	0	2	3
9	Butte	4342	0	0	3	18	18
10	Calaveras	2683	0	0	0	1	1
11	Colusa	2995	0	0	8	52	52
12	Contra Cos	2084	4	26	53	330	356
13	Del Norte	2631	0	3	4	24	27
14	El Dorado	4636	1	4	2	13	17
15	Fresno	15586	0	1	6	40	41
16	Glenn	3437	0	0	1	6	6
17	Humboldt	9282	11	70	23	147	217
18	Imperial	11608	75	467	1419	8868	9335
19	Inyo	26496	131	817	850	5314	6131
20	Kern	21113	725	4535	1166	7286	11820
21	Kings	3605	0	0	1	5	5
22	Lake	3446	0	1	19	117	118
23	Lassen	12220	14	88	186	1160	1247
24	Los Angele	10584	308	1927	652	4078	6005
25	Madera	5577	0	1	1	3	5
26	Marin	1534	0	0	4	28	28
27	Mariposa	3784	0	0	0	0	0
28	Mendocino	9100	0	0	11	70	70
29	Merced	5103	1	6	17	107	113
30	Modoc	10888	17	105	62	385	490
31	Mono	8114	39	242	135	845	1087
32	Monterey	8581	0	0	19	118	118
33	Napa	2047	0	0	8	47	48
34	Nevada	2522	0	1	3	21	22
35	Orange	2070	2	11	25	157	168
36	Placer	3885	0	3	4	22	25
37	Plumas	6773	3	19	24	150	169
38	Riverside	18908	242	1511	1344	8403	9914
39	Sacrament	2574	0	0	0	1	1
40	San Benito	3599	0	0	3	17	17
41	San Bernai	52072	303	1896	5825	36415	38311
42	San Diego	10976	118	739	444	2775	3514
43	San Franci	278	0	0	0	1	1
44	San Joaqui	3690	0	0	36	223	223
45	San Luis O	8599	0	1	19	120	121
46	San Mateo	1430	0	1	3	16	17
47	Santa Barb	7119	169	1055	107	670	1725
48	Santa Clara	3383	0	0	1	7	7
49	Santa Cruz	1156	0	0	0	1	1
50	Shasta	9963	3	16	29	182	198
51	Sierra	2492	2	15	8	51	66
52	Siskiyou	16452	9	58	154	961	1018
53	Solano	2356	43	269	699	4370	4638
54	Sonoma	4150	0	3	11	68	70
55	Stanislaus	3924	0	0	2	12	12
56	Sutter	1577	0	0	6	37	37
57	Tehama	7668	0	0	10	63	63
58	Trinity	8310	0	1	2	12	13
59	Tulare	12539	0	0	2	11	11

	A	B	C	D	F	G	I
2	Filtered Wind Resource by Coun				Hub Height: 70 m		
3	Wind Power Method		HWS	HWS	LWS	LWS	HWS+LWS
4		Land Area	Land Area	Capacity	Land Area	Capacity	Capacity
5	County	(km^2)	(km^2)	(MW)	(km^2)	(MW)	(MW)
60	Tuolumne	5899	0	1	1	9	10
61	Ventura	4833	45	281	131	818	1100
62	Yolo	2646	0	0	55	345	345
63	Yuba	1668	0	0	0	0	0
64	California	410594	2295	14346	13693	85598	99945
65	HWS=High Wind Speed (Wind Power Density >500 W/m					Filters (excluded areas):	
66	LWS=Low Wind Speed (300 W/m^2 <Wind Power Density					Grade > 20%	
67	AEP= Annual Energy Production					Bodies of Water	
68	Assumed a constant capacity factor of 37%					Forested Areas	
69						Urban Areas	
70						National Parks and Monu	
71						State Parks	
72						Other Natural Reserves (	

	B	C	D	E	F	G	H	I
1	**July 31, 03 TECHNICAL POTENTIAL (MW & GWh) of GEOTHERMAL RESOURCES IN CALIFORNIA**				**Calculated Using Column "A" and "B"**			**Calculated Using Column "E" and "B"**
2	VT JULY 31, 03	(GeothermEX,Inc.)						
3	**GeothermEx 17 Sep 03**		**A**	**B**	**C**	**D**	**E= A - D**	**F**
4			**PIER**		**Technical**	**Existing Plants**	**OPPORTUNITY**	**OPPORTUNITY**
5			**Gross Potential**	**Capacity**	**Potential**	**Gross MW**		
6	Known Geothermal Resource Areas	**County**	**MW**	**Factor (%)**	**GWh Production**	**Installed**	**MW**	**GWh Production**
7								
8	Brawley (sum of Brawley, East Brawley, and South Brawley)	Imperial	242	90	1,908		242	1908
9	Dunes	Imperial	15	90	118		15	118
10	East Mesa	Imperial	115	90	907	73	42	331
11	Salton Sea (including Westmoreland)	Imperial	1,540	90	12,141	369	1171	9232
12	Mount Signal	Imperial	24	90	189		24	189
13	Glamis	Imperial	8.8	90	69		8.8	69
14	Niland	Imperial	65	90	512		65	512
15	Heber	Imperial	120	90	946	100	20	158
16	Superstition Mountain	Imperial	12	90	95		12	95
17								
18	**SubTotal Imperial**		**2,142**		**16,886**	542	1,600	12,613
19								
20	Coso Hot Springs	Inyo	449	90	3,540	300	149	1175
21								
22	Geysers [Lake County]	Lake	350	90	2,759	250	100	788
23	Sulphur Bank Field, Clear Lake Area	Lake	52	90	410	0	52	410
24								
25	Geysers [Sonoma County]	Sonoma	1,050	90	8,278	750	300	2365
26								
27	Calistoga	Napa	30	90	237		30	
28								
29	Honey Lake (Wendel - Amedee)	Lassen	13	90	102	5	8	63
30								
31	Lake City / Surprise Valley	Modoc	42	90	331		42	331
32								
33	Long Valley (Mono - Long Valley)	Mono	87	90	686	40	47	371
34								
35	Randsburg	San Bernandino/Kern	62	90	489		62	489
36								
37	Medicine Lake (sum of Fourmile Hill and Telephone Flat)	Siskiyou	452	90	3,564		452	3564
38								
39	Sespe Hot Springs	Ventura	6.4	90	50		6.4	50
40								
41	Costa Mesa, Huntington Beach, Newport Beach	Orange	0	90	-		0	0
42								
43	**Total**		**4,735**		**37,332**	1,887	2,848	22,219
44								
45	PIER Gross Potential used updated estimates. Data was evaluated using Monte Carlo Simulation technique							
46	Used most likely data and includes existing or proven MW capacity							
47	Most Likely data - is the Modal data ~ 50% above and 50% below							
48	Deduct existing gross MW to get "Opportunity" MW.							
49	Orange County Note: One well (Seguro No. 1) 424°F @ 8,334 feet, produced a mixture of oil & hot water. It was found to be uneconomic, so it was excluded from this analysis.							
50	In this worksheet, the Geysers' capacity is based on average annual MWhs.							
51								
52	Geysers	Lake	350	**90**		**250**	100	**788**
53		Sonoma	1,050	**90**		**750**	300	**2365**
54								
55	Geysers	Lake and Sonoma	1,400	90		1,000	400	3,154

	A	B	C	D
1	Technical Potential For Small Hydro (PIER)			
2		GROSS POTENTIAL	TECHNICAL POTENTIAL	ANNUAL ENERGY PRODUCTION
3	COUNTY	MW	MW	GWh
4	ALAMEDA	15.2	13.7	118
5	ALPINE	3.3	0.8	5
6	AMADOR	284.9	154.2	322
7	BUTTE	974.5	100.0	248
8	CALAVERAS	465.3	102.1	202
9	COLUSA	4.2	0.9	3
10	CONTRA CO	62.9	41.0	146
11	DEL NORTE	43.0	32.7	160
12	EL DORADO	324.5	58.4	225
13	FRESNO	1,265.1	221.9	446
14	GLENN	95.9	15.1	42
15	HUMBOLDT	285.0	55.6	181
16	IMPERIAL	12.9	2.9	22
17	INYO	59.6	28.7	153
18	KERN	101.8	41.4	159
19	KINGS	2.0	1.8	6
20	LAKE	28.4	12.0	32
21	LASSEN	6.7	3.6	19
22	LOS ANGELE	9.7	5.6	27
23	MADERA	783.3	90.7	223
24	MARIN	1.0	0.9	2
25	MARIPOSA	73.8	19.4	69
26	MENDOCINO	85.0	12.1	36
27	MERCED	25.3	22.8	67
28	MODOC	6.6	4.6	27
29	MONO	62.9	33.2	161
30	MONTEREY	6.2	4.9	18
31	NAPA	0.0	0.0	0
32	NEVADA	102.2	35.8	86
33	ORANGE	7.1	4.4	24
34	PLACER	349.6	56.8	186
35	PLUMAS	354.3	138.5	258
36	RIVERSIDE	42.4	23.6	127
37	SACRAMENT	215.0	30.0	0
38	SAN BENITO	-	-	-
39	SAN BERNAI	11.6	3.2	15
40	SAN DIEGO	4.6	3.3	20
41	SAN FRANCI	-	-	-
42	SAN JOAQUI	0.8	0.7	2
43	SAN LUIS OE	4.7	2.7	22
44	SAN MATEO	-	-	-
45	SANTA BARE	2.0	1.0	8
46	SANTA CLAF	4.0	3.3	26
47	SANTA CRUZ	1.6	1.4	8
48	SHASTA	1,735.9	133.7	440
49	SIERRA	373.8	118.8	307
50	SISKIYOU	492.0	94.2	376
51	SOLANO	-	-	-
52	SONOMA	-	-	-
53	STANISLAUS	123.8	54.4	132

	A	B	C	D
1	Technical Potential For Small Hydro (PIER)			
2		GROSS POTENTIAL	TECHNICAL POTENTIAL	ANNUAL ENERGY PRODUCTION
3	COUNTY	MW	MW	GWh
54	SUTTER	1.1	0.9	5
55	TEHAMA	377.2	44.1	107
56	TRINITY	360.5	72.5	183
57	TULARE	28.1	9.4	24
58	TUOLUMNE	604.2	127.7	448
59	VENTURA	3.4	1.0	3
60	YOLO	-	-	-
61	YUBA	101.5	57.3	231
62	TOTALS	10,390	2,099	6,156
63	DEFINITIONS			
64	GROSS POTENTIAL: ESTIMATED CAPACITY THAT COULD BE INSTALLED USING CURRENT TECHNOLOGY IN ABSENCE OF OTHER LIMITING FACTORS			
65	TECHNICAL POTENTIAL: ESTIMATED CAPACITY WHEN OTHER LIMITING FACTORS ARE ACCOUNTED FOR. MAXIMUM 30 MW INCREMENTAL DEVELOPMENT PER SITE.			
66	ANNUAL ENERGY PRODUCTION: ESTIMATED ANNUAL OUTPUT FOR ESTIMATED TECHNICAL POTENTIAL			

Technical Potential for Biogas (PIER)

COUNTY	Total Existing Facilities from landfill gas, dairy and swine manure, and sewage wastewater facilities		Technical Potential from landfill gas, dairy and swine manure, and sewage wastewater facilities		Available Technical Potential from landfill gas, dairy and swine manure, and sewage wastewater facilities	
	MW	GWh/year (at a capacity factor of 0.85)	MW	GWh/year (at a capacity factor of 0.85)	MW	GWh/year (at a capacity factor of 0.85)
Alameda	8.22	61.21	16.57	123.39	8.35	62.19
Alpine	0	0.00	0.00	0.00	0.00	0.00
Amador	0	0.00	0.12	0.91	0.12	0.91
Butte	0.04	0.30	0.33	2.48	0.29	2.18
Calaveras	0	0.00	0.07	0.49	0.07	0.49
Colusa	0	0.00	0.03	0.24	0.03	0.24
Contra Costa	3	22.34	6.72	50.06	3.72	27.73
Del Norte	0	0.00	0.10	0.72	0.10	0.72
El Dorado	0	0.00	0.32	2.36	0.32	2.36
Fresno	0	0.00	7.29	54.29	7.29	54.29
Glenn	0	0.00	0.89	6.60	0.89	6.60
Humboldt	0	0.00	1.06	7.90	1.06	7.90
Imperial	0	0.00	0.31	2.35	0.31	2.35
Inyo	0	0.00	0.08	0.56	0.08	0.56
Kern	0.28	2.08	7.07	52.67	6.79	50.59
Kings	0	0.00	7.21	53.72	7.21	53.72
Lake	0	0.00	0.09	0.64	0.09	0.64
Lassen	0	0.00	0.10	0.74	0.10	0.74
Los Angeles	126.3	940.43	179.67	1337.80	53.37	397.37
Madera	0	0.00	2.66	19.82	2.66	19.82
Marin	0	0.00	1.24	9.24	1.24	9.24
Mariposa	0	0.00	0.03	0.24	0.03	0.24
Mendocino	0	0.00	0.28	2.10	0.28	2.10
Merced	0	0.00	12.15	90.50	12.15	90.50
Modoc	0	0.00	0.05	0.40	0.05	0.40
Mono	0	0.00	0.10	0.77	0.10	0.77
Monterey	4.4	32.76	5.76	42.85	1.36	10.09
Napa	1.4	10.42	1.75	13.05	0.35	2.63
Nevada	0	0.00	0.21	1.56	0.21	1.56
Orange	34.98	260.46	51.28	381.85	16.30	121.39
Placer	1	7.45	1.86	13.82	0.86	6.37
Plumas	0	0.00	0.05	0.37	0.05	0.37
Riverside	2.17	16.16	12.05	89.75	9.88	73.59
Sacramento	11.13	82.87	16.86	125.57	5.73	42.70
San Benito	0	0.00	0.16	1.17	0.16	1.17
San Bernardino	0	0.00	13.25	98.67	13.25	98.67
San Diego	16.1	119.88	24.86	185.09	8.76	65.21
San Francisco	0.51	3.80	1.71	12.76	1.20	8.97
San Joaquin	0.8	5.96	8.04	59.88	7.24	53.92
San Luis Obispo	0	0.00	0.91	6.81	0.91	6.81
San Mateo	1.9	14.15	4.73	35.19	2.83	21.04
Santa Barbara	2.97	22.11	4.31	32.07	1.34	9.96
Santa Clara	9.225	68.69	13.97	104.01	4.74	35.32
Santa Cruz	3.92	29.19	4.83	35.98	0.91	6.79
Shasta	0	0.00	0.37	2.76	0.37	2.76
Sierra	0	0.00	0.01	0.08	0.01	0.08
Siskiyou	0	0.00	0.23	1.73	0.23	1.73
Solano	1	7.45	2.35	17.49	1.35	10.04
Sonoma	6.59	49.07	9.74	72.51	3.15	23.44
Stanislaus	0	0.00	9.46	70.44	9.46	70.44
Sutter	0	0.00	0.08	0.58	0.08	0.58
Tehama	0	0.00	0.41	3.02	0.41	3.02
Trinity	0	0.00	0.01	0.08	0.01	0.08
Tulare	2.675	19.92	24.13	179.70	21.46	159.79
Tuolumne	0	0.00	0.08	0.59	0.08	0.59
Ventura	3.3	24.57	5.38	40.09	2.08	15.52
Yolo	1.65	12.29	2.60	19.39	0.95	7.10
Yuba	0	0.00	0.55	4.09	0.55	4.09
Total	243.56	1813.55	466.56	3474.01	223.00	1660.46

Note: technical potential = existing potential + additional technical potential
Assume: no bioreactors in technical potential.
Assume: technically available within 5 years.

Technical Potential for Biomass (PIER)

County	Gross (MW) Potential	Technical Potential (MW)	Active BiomassPower Plants gross (MW)	Active MSW (MW)	Opportunity Biomass (MW)
Alameda		29			29
Alpine		0			0
Amador		23	20		3
Butte		44	20		24
Calaveras		39			39
Colusa		32	27.5		5
Contra Costa		21			21
Del Norte		13			13
El Dorado		51			51
Fresno		97	56		41
Glenn		32			32
Humboldt		128	48.5		79
Imperial		13			13
Inyo		1			1
Kern		64	56		8
Kings		37			37
Lake		9			9
Lassen		17	57.3		-41
Los Angeles		200		18.1	182
Madera		39	28		11
Marin		5			5
Mariposa		3			3
Mendocino		146			146
Merced		27			27
Modoc		12			12
Mono		0			0
Monterey		18	15		3
Napa		6			6
Nevada		9			9
Orange		61			61
Placer		44	34		10
Plumas		44	27.3		17
Riverside		50	52		-2
Sacramento		39			39
San Benito		5			5
San Bernardino		38			38
San Diego		70			70
San Francisco		15			15
San Joaquin		48	25.3		23
San Luis Obispo		16			16
San Mateo		18			18
Santa Barbara		20			20
Santa Clara		38			38
Santa Cruz		13			13
Shasta		44	122.5		-79
Sierra		11	11		0
Siskiyou		61			61
Solano		26			26
Sonoma		29			29
Stanislaus		24		34.6	-11
Sutter		24			24
Tehama		24			24
Trinity		33			33
Tulare		51	24		27
Tuolomne		18	31.5		-13
Ventura		25			25
Yolo		24	28		-4
Yuba		13			13
Total		**2,038**	**684**	**53**	**1302**

	A	B	C	D	E
1	Technical Potential for PV (RER) **THIS WAS USED**				
2	**County**	**Residential**	**Commercial**	**Parking**	**Total**
3	ALAMEDA	247	125	30	402
4	ALPINE	0	0	0	0
5	AMADOR	6	3	1	10
6	BUTTE	35	18	4	57
7	CALAVERAS	7	4	1	11
8	COLUSA	3	2	0	5
9	CONTRA COSTA	162	82	20	264
10	DEL NORTE	5	2	1	8
11	EL DORADO	27	13	3	43
12	FRESNO	138	69	17	224
13	GLENN	5	2	1	7
14	HUMBOLDT	22	11	3	35
15	IMPERIAL	25	13	3	40
16	INYO	3	2	0	5
17	KERN	114	57	14	185
18	KINGS	22	11	3	37
19	LAKE	10	5	1	16
20	LASSEN	6	3	1	10
21	LOS ANGELES	1,638	826	200	2,664
22	MADERA	21	11	3	35
23	MARIN	42	21	5	69
24	MARIPOSA	3	1	0	5
25	MENDOCINO	15	7	2	24
26	MERCED	36	18	4	59
27	MODOC	2	1	0	3
28	MONO	2	1	0	4
29	MONTEREY	69	35	8	112
30	NAPA	21	11	3	35
31	NEVADA	16	8	2	25
32	ORANGE	487	246	59	792
33	PLACER	42	21	5	69
34	PLUMAS	4	2	0	6
35	RIVERSIDE	265	133	32	430
36	SACRAMENTO	209	105	26	340
37	SAN BENITO	9	5	1	15
38	SAN BERNARDINO	293	148	36	477
39	SAN DIEGO	482	243	59	783
40	SAN FRANCISCO	133	67	16	216
41	SAN JOAQUIN	97	49	12	157
42	SAN LUIS OBISPO	42	21	5	69
43	SAN MATEO	121	61	15	197
44	SANTA BARBARA	69	35	8	111
45	SANTA CLARA	289	145	35	469
46	SANTA CRUZ	44	22	5	71
47	SHASTA	28	14	3	45
48	SIERRA	1	0	0	1
49	SISKIYOU	8	4	1	12
50	SOLANO	67	34	8	110
51	SONOMA	78	40	10	128
52	STANISLAUS	77	39	9	125
53	SUTTER	14	7	2	22
54	TEHAMA	10	5	1	16
55	TRINITY	2	1	0	4
56	TULARE	63	32	8	103
57	TUOLUMNE	9	5	1	15
58	VENTURA	129	65	16	210
59	YOLO	29	14	4	47
60	YUBA	10	5	1	17
61	**Total**	**5,812**	**2,929**	**709**	**9,450**

Technical Potential CSP (RER) **THIS WAS USED**				
			MW	GWh/yr
County	**Agricultural**	**Other Lands**	**Total**	**25% capacity factor**
Imperial	8,893	2,187	11,080	24,265
Kern	6,576	9,089	15,665	34,306
Los Angeles	0	4,701	4,701	10,295
Riverside	1,089	6,857	7,946	17,402
San Bernadino	139	24,003	24,142	52,871
San Diego	127	1,227	1,354	2,965
San Luis Obispo	221	1,052	1,273	2,788
Total	**17,045**	**49,116**	**66,160**	**144,890**

Technical Potential for PV (PIER)
NOT USED

NAME	MWh/day	MW	GWhr/yr
ALAMEDA	558,952	103,745	204,017
ALPINE	260,655	46,905	95,139
AMADOR	214,149	38,754	78,164
BUTTE	439,566	80,610	160,442
CALAVERAS	378,300	67,423	138,079
COLUSA	317,045	58,227	115,721
CONTRA COSTA	490,774	91,151	179,132
DEL NORTE	91,916	20,329	33,549
EL DORADO	373,269	67,806	136,243
FRESNO	1,821,160	317,692	664,723
GLENN	547,123	99,508	199,700
HUMBOLDT	397,805	88,340	145,199
IMPERIAL	4,698,212	745,887	1,714,847
INYO	10,047,177	1,599,946	3,667,220
KERN	6,300,316	1,043,071	2,299,615
KINGS	502,002	86,687	183,231
LAKE	529,442	98,033	193,246
LASSEN	2,754,941	492,190	1,005,554
LOS ANGELES	3,912,346	662,486	1,428,006
MADERA	799,540	140,005	291,832
MARIN	246,556	45,458	89,993
MARIPOSA	548,329	96,897	200,140
MENDOCINO	665,493	124,389	242,905
MERCED	1,034,145	183,450	377,463
MODOC	2,237,536	423,331	816,701
MONO	2,036,627	349,025	743,369
MONTEREY	1,875,717	330,488	684,637
NAPA	330,271	60,168	120,549
NEVADA	194,567	35,236	71,017
ORANGE	811,245	144,772	296,104
PLACER	439,756	80,747	160,511
PLUMAS	397,814	71,626	145,202
RIVERSIDE	7,811,694	1,253,372	2,851,268
SACRAMENTO	814,573	147,775	297,319
SAN BENITO	822,419	150,298	300,183
SAN BERNARDINO	25,338,276	3,981,405	9,248,471
SAN DIEGO	3,561,569	605,526	1,299,973
SAN FRANCISCO	38,977	7,410	14,226
SAN JOAQUIN	513,946	91,113	187,590
SAN LUIS OBISPO	2,450,572	418,263	894,459
SAN MATEO	251,470	47,153	91,786
SANTA BARBARA	1,690,109	297,137	616,890
SANTA CLARA	861,570	158,437	314,473
SANTA CRUZ	157,093	29,776	57,339
SHASTA	895,789	164,584	326,963
SIERRA	193,077	34,794	70,473
SISKIYOU	1,345,782	261,615	491,211
SOLANO	453,180	83,335	165,411
SONOMA	576,430	106,940	210,397
STANISLAUS	795,435	140,965	290,334
SUTTER	90,023	16,717	32,858
TEHAMA	1,316,667	239,196	480,583
TRINITY	331,254	64,027	120,908
TULARE	1,251,596	217,308	456,833

Technical Potential for PV (PIER)
NOT USED

NAME	MWh/day	MW	GWhr/yr
TUOLUMNE	668,673	117,463	244,066
VENTURA	1,136,750	198,073	414,914
YOLO	316,907	57,518	115,671
YUBA	202,601	37,602	73,949
Statewide totals:	100,139,176	16,822,184	36,550,799
Assumptions:			
Exclude Water, Forest, Agriculture			
Exclude North Slopes GT 5%			
Efficiency = .10			

Technical potential for CSP (PIER) **NOT USED**			
NAME	MWh/day	MW	GWhr/yr
IMPERIAL	1,822,169	261,168	665,092
INYO	1,499,631	209,270	547,365
KERN	1,346,720	211,815	491,553
LOS ANGELES	414,636	69,095	151,342
MONO	187,926	30,863	68,593
RIVERSIDE	1,178,356	174,287	430,100
SAN BERNARDINO	3,980,099	543,136	1,452,736
TULARE	144,360	23,893	52,691
Statewide totals:	10,573,897	1,523,527	3,859,472
Assumptions			
<1% slopes			
Exclude Urban, Forest, Water, Agriculture,			
Packing Factor = .5			
Efficiency = .15			
County wide average KWH/Meters Squared/Day			

Filters: California Biomass Resources Potential

The gross biomass potential estimate relies on the use of statistics from the California Department of Food and Agriculture's California Agricultural Resource Directory, California Integrated Waste Management Board, and California Department of Forestry and Fire Protection. Biomass waste regional distribution is estimated on an individual county basis, also taken largely from previous assessments. A capacity factor of 85 percent was assumed in the calculation of the technical capacity and energy potential.

The filters applied to the gross biomass resource potential to obtain the technically available biomass materials are as follows:

- Losses incurred in the current waste handling and processing practices.
- Alternative and competing uses.
- Technology feedstock requirements.
- Geographic location (topography).
- Sustainability (future expected generation) of waste.

Specifically, the filters used to estimate the technically available materials for different biomass resource categories are described below:

Field and Seed Crops

Biomass residues from field and seed crops are the materials, such as straw or stalks, that remain after harvesting. Primary California field and seed crops that produce residues which have potential for energy conversion include rice, wheat, corn, cotton, and barley. Sunflower and safflower residues are also available in smaller quantities.

<u>Rice Straw Technical Potential</u>

- Use of rice straw as a fuel in biomass power plants is currently very limited due to boiler fouling and slagging problems from rice straw alkalis. Jenkins et al. (1999).

- Currently about 0.5-0.75 million bone dry tons/year (60 percent of the total) is estimated to be technically available.

- Rice straw has traditionally been disposed of directly in the field through open burning. However, due to air quality concerns, allowance of the open burning of rice straw is being phased down by California legislation. A 40 percent cap on open burning is currently being enforced (i.e., 40 percent of fields can be burned) (Hrynchuk, 1999). It is likely that less open burning will be allowed in the future, as discussed below. Most of the remaining 60 percent is currently incorporated back into the field soil ("plowed" or "tilled under").

- Alternative uses of rice straw, such as animal feed, animal bedding, and construction, are being researched, but none are currently used at full scale to any significant degree.

- Rice straw is seasonally available after harvesting, from September to December. The rice growing industry is expected to be very stable in the future.

Corn, Wheat, Cotton, and Barley Technical Potential

- Corn stover (corn plant minus the “ear” corn) from grain corn, wheat straw, cotton stalks, and barley straw field residues are for the most part directly incorporated back into the soil (plowed under, tilled back into soil) or used for grazing or feeding of livestock or animal bedding. (Note that silage corn stalk is not considered technically available -- the whole field is harvested as animal feed).

- Because there are no specific burning restrictions for these crops anticipated by CARB (because very little open burning is used), and currently practiced field incorporation with tillage is desirable and/or required, there are no strong incentives for harvesting or finding alternative uses. Due to the lack of incentives (and potential disadvantages) to harvest the residues, as an upper bound, it has been estimated that 50 percent of these small grain crop residues are potentially available (JAYCOR, 1990; Tyson, 1991; Lindley and Backer, date unknown). This translates to the following available amounts:

    - Corn stover -- 0.6 million bone dry tons/year (Note that the corn stover availability only includes grain corn; silage corn has no significant amount of associated waste residues.)
    - Wheat straw -- 0.5 million bone dry tons/year
    - Barley straw -- 0.1 million bone dry tons/year
    - Cotton stalk -- 0.7 million bone dry tons/year

Fruit and Nut Crops

Residues from fruit and nut orchards include tree prunings and tree removal/clearings. Tree types include almond, apple, apricot, avocado, cherry, date, fig, grapefruit, grape, kiwi, lemon, lime, olive, orange, peach, pear, pistachio, plum, prune, and walnut. Technical potential of clearings and prunings include:

- Clearing/Removals -- Tree removals, as a result of periodic replanting or changing land use decisions, are a prime and relatively inexpensive fuel source for power plants, and are used extensively in current biomass power plant operations (Morris, 1997). Thus, there is currently low availability of clearings. Morris (1997) reports that about 1 million bone dry tons/year of orchard clearings are used as power plant fuel. Note that clearings are usually available in the late summer, and are not a consistent and reliable fuel source.

- Prunings -- Orchard pruning waste handling varies depending on crop type:

    - Nut Crops -- The majority of the nut (almonds and walnut) pruning and clearings are collected from the orchard and either burned in the field, with a small percentage sold to power plants or as firewood (Beach, 1999; Jenkins et al., 1992).

    - Fruit Crops -- For grapes, nectarines, oranges, peaches, apples, and plums, most of the prunings and clearings are incorporated back into the orchard soil as mulch (Fruit Growers Company (Oranges), 1999; Grape Growers Association, 1999; California Table Grape Commission, 1999; California Peach Association, 1999; Kidd, 1999; Jenkins et al., 1992). The clippings are usually left in the field, and worked back into the soil (sometimes chipped). Limited open burning is used for apricot and cherry prunings; very little open burning is used for any of the others. Some is also collected and given away or sold as firewood. Most of the orchards are willing to sell or give away the prunings as fuel. Actual availability will depend on the site-specific benefits to soil incorporation and the desire to collect and process and store the clippings.

  Due to collection and handling costs from the "stick-like" nature of prunings, only 5-10 percent of prunings are estimated to be currently used as power plant fuels (Morris, 1997). Availability is estimated to be about 70 percent, limited by current orchard mulching operations and potentially high processing costs. Prunings are generally available seasonally in November to March.

  It is estimated that there are about 1 million bone dry tons/year of prunings; and about 0.7 million bone dry tons/year (70 percent) are available.

  The fruit and nut orchard industry is expected to be very stable in the future. Note that recent almond and walnut growth has created a current surplus supply; further growth is not expected.

Food Processing Wastes

Low moisture food processing wastes include rice hulls, nut shells, fruit pits, and cotton gin waste. Other high moisture food processing wastes (e.g., those from tomatoes) are being used as a source of animal feed.

There is a good potential availability for many of the food processing wastes because there are no strong competing uses other than some limited use as power plant fuel. Much of the nut shells and fruit pits are available at low cost because there are limited alternative uses and minimal associated processing (possibly drying) or collection costs. Specifically:

- Almond Shells -- Almond shells are used for animal bedding, burned on-site, or given to biomass power plants (Beach, 1999). Note that one of the largest processors previously operated an in-house cogeneration facility; however, it has since been shutdown. It is estimated that about 70 percent (0.2 bone dry tons/year) are technically available.

- Almond Hulls -- Almond hulls have significant value (60-70 $/ton) as cattle feed and are seasonally available from December to May, and are thus not considered available for power production.

- Walnut Shells -- Much of the walnut shells are currently used as power plant fuel. For example, the major walnut processor operates an in-house cogeneration facility (California Walnut Commission, 1999). There is also some demand for walnut shells as an abrasive compound. It is estimated that 30 percent of the walnut shells are available.

- Fruit Pits -- Much of the peach, olive, apricot, and prune pits are either sold to power plants or burned at in-house boilers. For example, peach pits from a major processor are dried and burned in an in-house cogeneration plant (Erba, 1999). Some peach pits have also been used for fragrance production. It is estimated that 40 percent of the pits are technically available.

- Rice Hulls -- Some rice hulls are used as power plant fuel and as animal feed supplement and animal bedding. The Wadham biomass power plant facility uses over 200,000 tons/year of rice hulls, much of which they currently receive for very low cost (Massa, 1999). Currently there is strong demand for rice hulls as poultry bedding; prices have been up to about 60 $/bone dry tons in some cases. It is estimated that about 30 percent of the hulls are available.

- Cotton Gin Trash -- Cotton gin trash is either disposed of in landfills or spread back into the farm land (sometimes composted prior to land spreading) (Thomasson et al., 1999). It has high potential availability (0.2 million bone dry tons/year) at low to no cost. It is very difficult to handle and feed into biomass waste to energy combustor or gasifiers.

Shells and pits are seasonally available from April to December. Rice hulls are available year round. Like the field, seed, fruit, and nut crops, food processing wastes are expected to be fairly stable in the future.

Livestock Manure

Manure is generated from a variety of livestock operations including: cattle (beef and dairy), chicken, turkey, pigs, and sheep. Technical potential depends on the livestock type and housing arrangement:

- Cows -- Availability depends on the animal containment and manure processing procedure.

- Beef Cattle -- Manure from livestock raised on the open range (beef cattle mostly), accounting for about 6.0 million bone dry tons/year, is not considered collectable. Alternatively, for beef raised in confined feedlots, the manure (about another 1.2 million bone dry tons/year) is handled exclusively in a “dry” lot paddock arrangement (California Beef Council, 1999; NEOS, 1994). In this setup, the manure is allowed to accumulate and dry; then it is removed and used as soil amendment (fertilizer) on local fields or sold as fertilizer. Small amounts are also being used in a power plant combustor in the Southern Imperial desert. It is roughly estimated that about 0.6 million bone dry tons/year (60 percent) of the dry lot manure is available.

- Dairy Cows -- Dairy cow manure is produced at a rate of about 2.6 million bone dry tons/year. For dairy cows, about half of the facilities handle most of the manure in a dry lot paddock arrangement (including most of the dairies in the Southern part of the state -- south of the Tehachapi mountains, Chino basin), similar to that for beef cattle discussed above (Morse Meyer et al., 1997; NEOS, 1994). For the other half of dairies, manure is managed mostly in a liquid form in anaerobic lagoons, holding ponds, or settling ponds -- where it is collected and processed to reduce odor and pathogens. In this arrangement, the liquid is separated from the solids. Liquid effluents are used for irrigation and soil fertilizer in local fields (either with year round irrigation, or prior to crop planting).

  In both arrangements, solids are piled, dried (and sometimes composted), and also used as soil fertilizer in local fields. Some (less than 10 percent) is sold or given away for use as fertilizer. Note that most dairies are strategically located near agricultural fields for use/disposal of manure (O’Donnell, 1999).

  An exception is a number of dairies located in the Southern California Chino basin area, where manure field spreading is restricted due to water pollution concerns in nearby urban areas and lack of available farm land (O’Donnell, 1999; Wubishet, 1999; Hodges, 1999). Excess manure is currently moved off-site and out of the basin for disposal at cost to the dairy, and has high availability. Attempts to burn manure in Southern California have not been very successful -- in particular, chlorine and alkalis have lead to significant boiler corrosion problems (Wubishet, 1999; Miles, 1999).

  Availability of manure solids is limited by: (1) the handling procedure -- much of the manure handled in a liquid fashion is not generally available; (2) site-specific need for fertilization of local fields; and (3) demand for sale as fertilizer

  As a fertilizer, manure has a projected nutrient replacement value of about $15 per bone dry ton (Mullinax et al., 1998). However, cow manure has a lower market value as a fertilizer of about $0 to $10 per ton, with lower costs (and good availability) in southern California, and higher costs (and lower availability) through the Central Valley (O'Donnell, 1999; Energy Commission, 1992).

Future generation is projected to be very stable due to the consistent and growing demand for milk and meat products.

- Poultry -- Manure from turkey and broiler chicken meat operations is collected in litter beds made of wood shavings or straw. The contaminated litter is periodically removed and used for fertilizer and animal feed.

  Manure from egg (caged layer) chickens is usually captured in deep pits, where it dries in stacks. The manure is removed periodically and used as fertilizer.

  Poultry manure has a sale value as fertilizer of about $10 per wet ton (Martin, 1999). Based on its relatively high fertilizer value, it is estimated that very little of the poultry manure is available for power production.

- Other Considerations -- Alternative uses and treatments for manure are currently being driven by concerns from: (1) surface and groundwater contamination (ammonia, nitrates, pathogens) from manure and manure runoff, (2) air emissions, including methane, volatile organic compounds, and ammonia from anaerobic digestion; and (3) odor and fly problems. In particular, the U.S. Environmental Protection Agency and the U.S. Department of Agriculture have very recently drafted a "Unified National Strategy for Animal Feed Operations" from identification of livestock manure being one of the last remaining sources of water contamination. The draft strategy will have implications on many of California's livestock operations, including the requirement to develop comprehensive manure management plans.

  Note that for handling and storing manure, special considerations need to be made to address odor and pest concerns.

Lumber Mill Processing Waste

Lumber mill residues include slabs, shavings, trimmings, sawdust, bark, round-off, end cuts, and reject lumber that result from processing operations at sawmills and other lumber plants.

Technical Potential -- For the most part, all lumber mill wastes are currently used either in power plants (in-house and/or off-site, estimated at about 1.5 million bone dry tons/year) or sold for use in particle board type products, pulp mills, animal bedding, or garden products. There is very little that is currently not being utilized. Efficient use of lumber mill residues is generally necessary for profitable operations (Morris, 1997). Thus, there is no availability for power production.

Forest Slash

Forest slash consists of residues remaining on the forest floor from logging activities. This includes tree branches, tops of trunks, stumps, and leaves.

Technical potential -- Forest slash is not considered high enough quality for use in lumber mills. Forest slash is usually collected into a pile at the logging location. The pile is either left in place, burned, or removed for use as either fuel for power plants, firewood, landscaping, or paper production (Morris, 1997). Due to relatively high cost, forest slash usage as a power plant fuel has decreased by over 50 percent during the last few years, to a current level of about 0.5 million bone dry tons/year (Morris, 1997). Additionally, like lumber mill wastes discussed above, future availability of much of the forest slash is uncertain, and depends on the sustainability of logging operations. It is roughly estimated that about 2.5 million bone dry tons/year (50 percent of the total) of forest slash is available.

Forest Thinnings

Forest thinnings include trees removed from forests for the purpose of forest health and fire prevention efforts. Primary California forest tree types include ponderosa pine, sugar pine, fir, Douglas fir, incense cedar, and redwood.

<u>Technical Potential</u> -- Forest thinnings are currently being utilized in a number of power plant operations. For example, the Sierra Pacific biomass power plant in Loyalton is using thinnings removed from the forests near Lake Tahoe for fire safety and environmental reasons (WRBEP, 1999). Untapped forest thinning resources (i.e., those not currently being harvested or utilized in power plans) are estimated at 1.9 million bone dry tons/year (50 percent of the total). The actual level will depend heavily on political, environmental, and ecological forces (such as protection of endangered species) which influence the extent of forest thinning.

Chaparral

Chaparral consists of heavily branched draft shrubs, including species such as chemise, ceanothus, and scrub oak.

<u>Technical Potential</u> -- The technical availability of chaparral depends on various factors, including:

- Chaparral harvesting, like forest thinning, is limited by the degree of the ground slope. For slopes at an angle of greater than 30°, there is no efficient method for collection. It is estimated that only about 25 percent of the chaparral is accessible and harvestable (Energy Commission, 1992).

- Chaparral thinning is done periodically to minimize fire risk, or to clear land for development. Thus, the supply of chaparral may be unreliable and is dependent on the land management needs of the state or private landowners.

- There are no competing uses for chaparral.

It is very roughly estimated that 10 percent of the total gross chaparral is technically available, 0.8 million bone dry tons/year. Low availability as a result of high collection costs, uncertain future driving forces, and wide-spread un-concentrated nature of chaparral.

Urban / Municipal Solid Wastes

Municipal solid waste consists of a varied mixture of paper, organics, plastics, metal, glass, wood, and rubber items, and depends greatly on the generator mix (e.g., residential, commercial, industrial).

<u>Technical Potential</u>-- About 30 percent of the total MSW is currently diverted to recycling, reuse, or energy production type activities, while the remainder is landfilled, according to the latest California Integrated Waste Management Board figures. Among other reasons, constraints on landfill capacity have led to California legislation Assembly Bill 939 (AB 939, Sher, Chapter 1095, Statutes of 1989) requiring the diversion of 50 percent of the total waste generation by the year 2000. (Note that the law limits the diversion portion that can be used as a fuel to 10 percent of the total waste. Currently only a small fraction is used for energy recovery purposes in the 3 municipal waste combustors operating in California. This recycling requirement has put recent pressure on waste processors to find alternative uses for municipal solid waste (MSW).

Due to its highly heterogeneous composition, MSW is not generally used directly in combustion or gasification systems. Some type of processing, such as sorting and size reduction, is used to remove inorganic and non-combustible material, and to homogenize the wastes. These processing steps are performed at “curbside” recycling programs, dedicated materials recycling facilities, and at the landfill receiving station. Most of the materials recycling facilities are “clean” material recovery facilities which separate waste that has already been segregated at the curbside. There are a few “dirty” material recovery facilities, which segregate raw waste.

Note that the use of municipal solid waste (or its separated components) as fuel for power plant combustors in currently perceived to be hindered by low fossil fuel costs (as with any of the other fuels discussed in this report), low landfill tipping fee costs, and the difficulty in citing municipal solid waste combustors due to public opposition.

9.1 Urban Wood

Urban wood wastes include construction, renovation, and demolition wastes, wood product manufacturing and processing wastes (e.g., furniture, flooring, etc.), used lumber from lumber yards and wood working shops, wood used in packing and transportation (e.g., pallets), trees and prunings from municipal maintenance, trees/brush from land clearing, etc. It includes non-yard wood wastes that potentially enter the municipal solid waste stream.

Technical Potential-- Primary uses for urban wood wastes include mulch and bedding, feedstocks for fiberboard, salvaging whole pieces for reuse, composting, and power plant fuel. About 1 million bone dry tons/year is currently being used in biomass power plants (Morris, 1998; CIWMB, 1999), and about 0.5 million bone dry tons/year in the other recycling activities (CIWMB, 1998). This leaves about 2.3 million bone dry tons/year that is going to landfills. Assuming that 30 percent of this can be effectively separated from the overall waste stream, 0.7 million bone dry tons/year is estimated to be technically available.

Also, urban wood waste are recently being consumed at new particle board facilities (e.g., those in Roseville and Fontana), causing prices to go to about 40-50 $/ton in some areas.

9.2 Urban Yard

Urban yard wastes include tree, grass, and bush clippings and trimmings from residential, commercial, and industrial yard maintenance.

Technical Potential-- Yard wastes have low (or negative) value as feedstock for composting operations, and as landfill cover. Assuming that 30 percent can be effectively removed from the waste stream, it is estimated that 1.2 million bone dry tons/year is available. Generation is somewhat seasonal, where most is generated during the spring and summer months.

9.3 Waste Paper Technical Potential -- About 4 million bone dry tons/year of the total paper waste stream (31 percent) is recovered and reused. Most goes to paper mills for making new paper, with small amounts also used in ceiling boards and wall insulation. Much of the currently recycled paper is from offices and schools, and is of generally high quality with low contamination, and is not likely available for energy production. This leaves an estimated 8.7 million bone dry tons/year that is currently landfilled and potentially available. Assuming that 30 percent of this can be recovered as low-end mixed paper (including corrugated, cardboard and waxed papers), it is estimated that about 2.6 million bone dry tons/year is technically available.

Sewage Sludge

Sewage sludge is produced as a byproduct of the treatment of raw sewage. Raw sewage is handled and treated in California almost entirely at publicly owned treatment works, run by local municipalities. There are only a handful of privately owned sewage treatment facilities.

Technical potential -- Sewage sludge in California publicly owned treatment works is handled in a variety of ways including (Fondahl, 1999):

- About 70 percent of the sewage sludge is treated first through either digestion or composting to Class A or Class B treatment standards, dewatered (usually mechanically though filters and presses), and then used as agricultural fertilizer (Fondahl, 1999). Sludge treated to Class A standards (where all pathogens, etc. are removed) may be used on any type of land use crops; that treated to Class B may only be applied to non-food crop land. Recently, some counties (such as Kern) have begun to refuse the use of any sludge as fertilizer that has not met Class A standards.

- About 10-15 percent of the sludge is sent to municipal landfills or used as municipal landfill cover. Requirements for landfills differ, although most have a limit on the minimum solids content (typically 50 percent). Small amounts are also stored in dedicated sewage sludge land surface disposal sites.

The potential availability of sewage sludge is high, especially from recent concerns about its use as fertilizer or disposal in landfills. These concerns focus on the potential for contamination of water and land resources from the migration of sewage sludge toxic constituents.

PIER Estimate of Geothermal Resources: Technical Potential

The gross and technical potential for geothermal resources (GeothermEx latest estimates) are essentially the same. The reasons are as follows:

(1) Unlike biomass, there is no single constraint on geothermal development that, if removed, would allow greater utilization of geothermal energy. Some geothermal sites are constrained in development by virtue of location (e.g., close to residential areas or far from transmission lines). Others are constrained (in the sense of higher operating costs) by the chemistry of the geothermal fluid (such as the high-salinity brines of the Salton Sea). Others are constrained by a market structure that makes it difficult for developers to obtain firm sales contracts for the electricity they could generate. In the latest GeothermEx's inventory for the Public Interest Energy Research (PIER)/Hetch Hetchy/Public Renewables Partnerhsip programmatic renewable project, an effort was made to take into account all constraints in assigning estimates of geothermal potential to each resource site. According to GeothermEx opinion, attempting to "relax" the varying constraints on different projects across the board would yield a total result that would be arbitrary and capricious. Thus, GeothermEx considers that there is no objective way to distinguish between technical and gross generating potential.

(2) To reasonably define the opportunity for additional geothermal generation, the capacity estimates in the PIER/Hetch Hetchy programmatic renewable study are well suited to allow comparison with existing geothermal plant capacities. Each existing plant had to struggle with its own set of constraints and succeeded in getting built anyway. So, subtracting existing capacity from the capacity estimates in the PIER/Hetch Hetchy/Public Renewables Partnership study is an "apples-to-apples" comparison.

(3) GeothermEx has distinguished between "minimum" and "most-likely" estimates of generation capacity for each project. Thus, one can arrive at a range of "opportunity" values for more geothermal capacity, depending on whether one subtracts existing generation from the minimum or from the most-likely estimate. This does not, however, sound analogous to the Energy Commission's distinction between technical and gross potential, because both the minimum and the most-likely capacities in GeothermEx's terminology are completely plausible from a technical point of view. If the Energy Commission needs a single number to define the potential geothermal capacity available from each site, we would suggest using the most-likely value, since this is, by definition, "most likely."

It should also be noted that both the minimum and most-likely estimates of geothermal generation capacity in the PIER/Hetch Hetchy/Public Renewables Partnership study are tabulated in units of GROSS megawatts (as distinct from

NET megawatts, which have subtracted out parasitic loads from operating the geothermal plants). This again is NOT analogous to Energy Commission's distinction between gross and technical potential, because all geothermal plants have parasitic loads to some degree. These loads may be reduced by improvements in technology, but it is not plausible to make a goal of eliminating parasitic loads. In terms of preserving an "apples-to-apples" comparison, one must be sure to use gross megawatt capacities for existing plants to subtract from the minimum and most-likely estimates in GeothermEx's tables. To date, all the tables that GeothermEx has supplied to the Energy Commission (both to Val Tiangco and Drake Johnson) have followed this convention. But note also that, to answer the question of how much geothermal power would actually reach the grid; one would have to make an adjustment for parasitic loads to arrive at a net megawatt number.

Filters used for PIER Estimates of CSP and PV technical potential:

For the August 2003 maps for concentrating solar power (CSP) the following assumptions were used:

Exclude slopes that are greater than 1 percent.

Exclude urban lands (places with buildings), forest (because of shade from trees), water, and agriculture.

Exclude pristine areas, as defined by California Department of Forestry: reserves (parks, wilderness, etc.) and sensitive habitats (coastal sage scrub, wetlands, coastal zone, and riparian management areas).

Packing Factor is .5, meaning only half the area can have solar collectors

Conversion efficiency is .15, typical for CSP systems.

Exclude any areas with average annual solar resource less than 6 kWh. These areas are not appropriate for CSP because there is not enough beam solar radiation.

For the August 2003 maps for solar photovoltaic (PV) the following assumptions were used:

Exclude water, forest (because of shade from trees), and agriculture.

Exclude pristine areas, defined by California Department of Forestry as reserves (parks, wilderness etc) and sensitive habitats (coastal sage scrub, wetlands, coastal zone, and riparian management areas).

Exclude north slopes greater than 5 percent.

Conversion efficiency is .10, typical for PV systems.

Filters used in PIER Estimate of California Wind Resource Technical Potential

To better quantify California's wind resource potential, the wind resources areas were split into two focus categories and various filters were applied. An explanation follows below.

High wind and low wind speed categories

Wind class classifications were grouped into two categories either high wind speed or low wind speed resources to simplify analysis and avoid the confusion of results for various elevations. Table 1 shows the categories used.

Table 1. Assumptions

HWS - High Wind Speed (Wind Power Density $\geq$ 500 W/m^2)
LWS - Low Wind Speed (300 W/m^2 $<$ Wind Power Density $<$ 500 W/m^2)

The first category 500 W/m^2 or greater was designed to capture high wind areas, typically Class 5, 6, 7 winds (speeds above 6m/s). Many of these high wind speed areas are well known in the state and have been developed as wind facilities. However, the majority of existing wind facilities consist of older 1980s turbine technology and have the potential of being repowered with newer, more efficient, higher capacity wind turbines. The wind resource maps also highlight new high wind speed resource areas in the south near the Mojave areas and in the north in Modoc and Shasta counties.

The second category of resource areas with a minimum of 300 W/m^2 has been identified as low wind resource areas. These areas are of interest due to closer proximity to demand centers. From an energy producing perspective, sites suitable using current large utility scale wind turbine have annual average wind speeds of at least 6 m/s (13 mph). New turbine technologies being developed will be capable of producing power at lower wind speeds. A class of low wind speed turbines is targeting sites with annual average wind speeds less than 5 m/s (Class 3 to 4). In addition, wind energy's dispatchability will be improved by locating wind generators closer to strategic locations in the electricity grid. Sites located close to locations where transmission and distribution upgrades are necessary will be more reliable and dispatchable.

Filters

Table 2 contains the technical filters applied to the total gross wind resources. These filters were designed to exclude nonqualified and non-developable areas. Currently, land with slopes exceeding 20 percent has been excluded; however, the plan is to refine this filter based on regional analysis of slopes and terrain.

Table 2. List of Technical Filters

Grade > 20%	National Parks and Monuments
Bodies of Water	State Parks
Forested Areas	Other Natural Reserves (refuges etc.)
Urban Areas	

APPENDIX D. LEVELIZED COST OF ENERGY BY TECHNOLOGY

Appendix D contains a summary of the assumptions used to prepare the estimates of levelized cost of energy. It also lists the levelized cost of energy estimates for a range of renewable energy technologies. These estimates were prepared by Navigant Consulting, Inc., subcontractor to XENERGY, Inc., Technical Assistance Contractor for the Renewable Energy Program (Contract No. 500-01-036). There are two sets of tables in this appendix:

- Levelized Cost of Energy with PTC (2005, 2008, 2010, 2017)
- Levelized Cost of Energy without PTC (2005, 2008, 2010, 2017)

Key Assumptions for Renewable Energy Technology Economics: 2005 (With PTC, 2003 Dollars)

Technology	System Size (MW)	2005 Installed System Cost ($/kW)	O&M Costs (e) ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%) (d)	Financing Term (years)	Capacity Factor* (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE ($/kWh)
Wind Class 6	75	925	20	NA	NA	15	38	9.57	2:1	9	18	0.027
Wind Class 4	75	925	20	NA	NA	15	32	9.57	2:1	9	18	0.034
ADG – Animal Waste – developer financed	0.1	4,000	130	25	33	20	75	9.57	2:1	9	18	0.057
Solid Biomass-Direct Combustion (c)	20	1,800	90	25	0	20	85	9.57	2:1	9	18	0.054
ADG – Animal Waste – farmer/coop financed	0.1	4,000	130	25	33	20	75	4.79	5:1	5	10	0.032
Geothermal Flash	50	1,950	81	NA	NA	20	90	9.57	2:1	9	18	0.043
Geothermal Binary	50	2,275	71	NA	NA	20	93	9.57	2:1	9	18	0.045

Key Assumptions for Renewable Energy Technology Economics: 2008 (With PTC, 2003 Dollars)

Technology	System Size (MW)	2008 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%) (d)	Financing Term (years)	Capacity Factor* (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE ($/kWh)
Wind Class 6	75	800	18	NA	NA	15	40	9.57	2:1	9	18	0.020
Wind Class 4	75	800	18	NA	NA	15	35	9.57	2:1	9	18	0.025
ADG – Animal Waste – developer financed	0.1	3,500	120	27	33	20	75	9.57	2:1	9	18	0.049
Solid Biomass-Direct Combustion (c)	20	1,700	80	26	0	20	85	9.57	2:1	9	18	0.050
ADG – Animal Waste – farmer/coop financed	0.1	3,500	120	27	33	20	75	4.79	5:1	5	10	0.028
Geothermal Flash	50	1,900	75	NA	NA	20	91	9.57	2:1	9	18	0.041
Geothermal Binary	50	2,150	65	NA	NA	20	94	9.57	2:1	9	18	0.042

Key Assumptions for Renewable Energy Technology Economics: 2010 (With PTC, 2003 Dollars)

Technology	System Size (MW)	2010 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%) (d)	Financing Term (years)	Capacity Factor* (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE ($/kWh)
Wind Class 6	75	760	16	NA	NA	15	40	9.57	2:1	9	18	0.018
Wind Class 4	75	760	16	NA	NA	15	36	9.57	2:1	9	18	0.022
ADG – Animal Waste – developer financed	0.1	3,500	120	27	33	20	75	9.57	2:1	9	18	0.049
Solid Biomass-Direct Combustion (c)	20	1,700	80	26	0	20	85	9.57	2:1	10	20	0.050
ADG – Animal Waste – farmer/coop financed	0.1	3,500	120	27	33	20	75	4.79	5:1	5	10	0.028
Geothermal Flash	50	1,850	73	NA	NA	20	91	9.57	2:1	9	18	0.040
Geothermal Binary	50	2,070	63	NA	NA	20	95	9.57	2:1	9	18	0.040

Key Assumptions for Renewable Energy Technology Economics: 2017 (With PTC, 2003 Dollars)

Technology	System Size (MW)	2017 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%) (d)	Financing Term (years)	Capacity Factor* (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE ($/kWh)
Wind Class 6	75	650	12	NA	NA	15	41	9.57	2:1	9	18	0.013
Wind Class 4	75	650	12	NA	NA	15	37	9.57	2:1	9	18	0.016
ADG – Animal Waste – developer financed	0.2	3,000	115	30	33	20	75	9.57	2:1	9	18	0.043
Solid Biomass-Direct Combustion (c)	20	1,500	75	28	0	20	85	9.57	2:1	9	18	0.044
ADG – Animal Waste – farmer/coop financed	0.2	3,000	115	30	33	20	75	4.79	5:1	5	10	0.025
Geothermal Flash	50	1,750	65	NA	NA	20	93	9.57	2:1	9	18	0.037
Geothermal Binary	50	1,750	56	NA	NA	20	96	9.57	2:1	9	18	0.034

(a) Wind and biomass PTC is $0.018/kWh adjusted to inflation for 10 years of plant output. Geothermal PTC is $0.018/kWh not adjusted to inflation and only for 5 years of plant output.

(b) Assumes O&M of digester is included in O&M costs.

(c) Fuel cost of $30/dry ton at 8,000 Btu/lb= $1.875/MMBTU. Heat content estimate is a mid-range value for a range of wood residues and agricultural residues.

(d) For ADG only. Assumes fuel displaced is propane at $5/MMBtu and avoided boiler efficiency is 80%. Assume no other credits (e.g., sale of treated bio-solids for fertilizer)

(e) 1. Property tax and insurance is assumed to be 2% of book value. 2. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. 3. Land lease for concentrating solar power and geothermal is assumed to be 3% of gross revenues and for wind 5% of gross revenue.

(f) Notes: Wind runs include Accelerated Depreciation and 30% Additional Depreciation; ADG Developer/Farmer includes cogeneration credit, state property tax exemption; Geothermal includes Accelerated Depreciation, 30% Additional Depreciation and 10% ITC is removed due to addition of PTC. Geothermal also assumes a 4% per year reduction in well productivity. Wholesale rates were assumed at $.05/kWh; commercial retail at $.15/kWh; residential retail at $.12/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%

(g) Class 4 wind defined as ~ 7 – 7.5 m/s or 15.7 mph at 50 meter hub height.

(h) Class 6 wind defined as ~ 8 – 8.8 m/s or 17.9 mph at 50 meter hub height.

*Net all losses such as blade soiling and aerodynamic losses for wind; dust, temperature degradation, module mismatch and inverter losses for PV etc.

Key Assumptions for Renewable Energy Technology Economics: 2005 (No PTC, 2003 Dollars)

Technology	System Size (MW)	2005 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%)	Financing Term (years)	Capacity Factor (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE (¢/kWh)
Wind Class 6	75	925	20	NA	NA	15	38	9.57	2:1	9	18	4.1
Wind Class 4	75	925	20	NA	NA	15	32	9.57	2:1	9	18	4.9
Concentrating Solar Power	100	2,900	50	NA	NA	15	30	9.57	2:1	9	18	12.1
PV Commercial High Insolation	0.25	6,000ac	12	NA	NA	15	18.4	6.35	3:1	7.5	12	27.5
PV Commercial Low Insolation	0.25	6,000ac	12	NA	NA	15	14.4	6.35	3:1	7.5	12	34.0
PV Residential High Insolation	0.003	8,000ac	14	NA	NA	Cash	20	4	NA	NA	NA	23.3
PV Residential Low Insolation	0.003	8,000ac	14	NA	NA	Cash	15.7	4	NA	NA	NA	28.7
Landfill Gas	2.0	1,500	125	30	0	15	85	9.57	2:1	9	18	4.4
ADG – Animal Waste – developer financed	0.1	4,000	130	25	33	20	75	9.57	2:1	9	18	6.9
ADG – Animal Waste – farmer/coop financed	0.1	4,000	130	25	33	20	75	4.79	5:1	5	10	4.3
Solid Biomass-Direct Combustion	20	1,800	90	25	0	20	85	9.57	2:1	9	18	6.6
Geothermal Flash	50	1,950	81	NA	NA	20	90	9.57	2:1	9	18	5.3
Geothermal Binary	50	2,275	71	NA	NA	20	93	9.57	2:1	9	18	5.5

Key Assumptions for Renewable Energy Technology Economics: 2008 (No PTC, 2003 Dollars)

Technology	System Size (MW)	2008 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%)	Financing Term (years)	Capacity Factor (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE (¢/kWh)
Wind Class 6	75	800	18	NA	NA	15	40	9.57	2:1	9	18	3.4
Wind Class 4	75	800	18	NA	NA	15	35	9.57	2:1	9	18	3.9
Concentrating Solar Power	150	3,000	40	NA	NA	15	55	9.57	2:1	9	18	6.7
PV Commercial High Insolation	0.25	5,000ac	11	NA	NA	15	18.4	6.35	3:1	7.5	12	22.9
PV Commercial Low Insolation	0.25	5,000ac	11	NA	NA	15	14.4	6.35	3:1	7.5	12	28.4
PV Residential High Insolation	0.003	7,000ac	13	NA	NA	Cash	20	4	NA	NA	NA	21.8
PV Residential Low Insolation	0.003	7,000ac	13	NA	NA	Cash	15.7	4	NA	NA	NA	26.9
Landfill Gas	2.0	1,400	115	32	0	15	85	9.57	2:1	9	18	4.1
ADG – Animal Waste – developer financed	0.1	3,500	120	27	33	20	75	9.57	2:1	9	18	6.2
ADG – Animal Waste – farmer/coop financed	0.1	3,500	120	27	33	20	75	4.79	5:1	5	10	3.8
Solid Biomass-Direct Combustion	20	1,700	80	26	0	20	85	9.57	2:1	9	18	6.2
Geothermal Flash	50	1,900	75	NA	NA	20	91	9.57	2:1	9	18	5.0
Geothermal Binary	50	2,150	65	NA	NA	20	94	9.57	2:1	9	18	5.1

Key Assumptions for Renewable Energy Technology Economics: 2010 (No PTC, 2003 Dollars)

Technology	System Size (MW)	2010 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%)	Financing Term (years)	Capacity Factor (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE (¢/kWh)
Wind Class 6	75	760	16	NA	NA	15	40	9.57	2:1	9	18	3.3
Wind Class 4	75	760	16	NA	NA	15	36	9.57	2:1	9	18	3.6
Concentrating Solar Power	150	2,900	38	NA	NA	15	56	9.57	2:1	9	18	6.4
PV Commercial High Insolation	0.25	4,600ac	10	NA	NA	15	18.4	6.35	3:1	7.5	12	21.1
PV Commercial Low Insolation	0.25	4,600ac	10	NA	NA	15	14.4	6.35	3:1	7.5	12	26.0
PV Residential High Insolation	0.003	6,000ac	12	NA	NA	Cash	20	4	NA	NA	NA	18.8
PV Residential Low Insolation	0.003	6,000ac	12	NA	NA	Cash	15.7	4	NA	NA	NA	23.2
Landfill Gas	2.0	1,400	115	32	0	15	85	9.57	2:1	9	18	4.1
ADG – Animal Waste – developer financed	0.1	3,500	120	27	33	20	75	9.57	2:1	9	18	6.2
ADG – Animal Waste – farmer/coop financed	0.1	3,500	120	27	33	20	75	4.79	5:1	5	10	3.8
Solid Biomass-Direct Combustion	20	1,700	80	26	0	20	85	9.57	2:1	10	20	6.2
Geothermal Flash	50	1,850	73	NA	NA	20	91	9.57	2:1	9	18	4.9
Geothermal Binary	50	2,070	63	NA	NA	20	95	9.57	2:1	9	18	4.9

Key Assumptions for Renewable Energy Technology Economics: 2017 (No PTC, 2003 Dollars)

Technology	System Size (MW)	2017 Installed System Cost ($/kW)	O&M Costs ($/kW/yr)	Net Electrical Efficiency (% HHV)	Cogen Efficiency (%)	Financing Term (years)	Capacity Factor (%)	Discount Rate	Debt/Equity	Cost of Debt (%)	Cost of Equity (%)	LCOE (¢/kWh)
Wind Class 6	75	650	12	NA	NA	15	41	9.57	2:1	9	18	2.7
Wind Class 4	75	650	12	NA	NA	15	37	9.57	2:1	9	18	3.0
Concentrating Solar Power	200	2,800	33	NA	NA	15	57	9.57	2:1	9	18	6.0
PV Commercial High Insolation	0.25	3,400ac	9	NA	NA	15	18.4	6.35	3:1	7.5	12	15.6
PV Commercial Low Insolation	0.25	3,400ac	9	NA	NA	15	14.4	6.35	3:1	7.5	12	19.3
PV Residential High Insolation	0.003	4,000ac	10	NA	NA	Cash	20	4	NA	NA	NA	12.6
PV Residential Low Insolation	0.003	4,000ac	10	NA	NA	Cash	15.7	4	NA	NA	NA	15.6
Landfill Gas	2.0	1,200	110	35	0	15	85	9.57	2:1	9	18	3.7
ADG – Animal Waste – developer financed	0.2	3,000	115	30	33	20	75	9.57	2:1	9	18	5.6
ADG – Animal Waste – farmer/coop financed	0.2	3,000	115	30	33	20	75	4.79	5:1	5	10	3.6
Solid Biomass-Direct Combustion	20	1,500	75	28	0	20	85	9.57	2:1	9	18	5.7
Geothermal Flash	50	1,750	65	NA	NA	20	93	9.57	2:1	9	18	4.5
Geothermal Binary	50	1,750	56	NA	NA	20	96	9.57	2:1	9	18	4.2

Additional Assumptions/Comments

Technology	Additional Assumptions/Comments
Wind	Includes Accelerated Depreciation and 30% Additional Depreciation. Capacity factors increase from 2005 to 2017 with larger rotors and higher hub heights and are CF net all losses such as blade soiling and aerodynamic losses. Gearbox replacement every 10 years assuming a gearbox replacement cost of \$85/kW in 2003, \$66/kW in 2013, \$61/kW in 2018, \$58/kW in 2020, and \$52/kW in 2027 (all in 2003 dollars). Property tax and insurance is assumed to be 2% of book value. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. Land lease is assumed to be 5% of gross revenues. Wholesale rate is assumed at 5¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Developer financed. Class 4 wind defined as ~ 7 – 7.5 m/s or 15.7 mph at 50 meter hub height. Class 6 wind defined at ~ 8 – 8.8 m/s or 17.9 mph at 50 meter hub height.
Concentrating Solar Power	Includes 10% Investment Tax Credit, Accelerated Depreciation, 30% Additional Depreciation and property tax exemption. No storage or supplemental firing in 2005 and 12 hours of molten salt storage for 2008 and beyond. Property tax and insurance is assumed to be 2% of book value. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. Land lease is assumed to be 3% of gross revenues. Wholesale rate is assumed at 5¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Developer financed.
PV Commercial	Includes 10% Investment Tax Credit, Accelerated Depreciation, 30% Additional Depreciation, and a property tax exemption. PV system cost reductions mostly associated with improved module efficiencies, reductions in inverter prices, and larger manufacturing capacities. System output, including capacity factors, is net all losses such as dust, temperature degradation, module mismatch and inverter losses. For reference, the AC rating is assumed to be ~ 80% of the DC rating. Assumes 5-degree tilt for "flat mount" retrofit rooftops. Inverter replaced every 10 years, assuming a commercial inverter cost of \$500/kW in 2003, \$255/kW in 2013, \$180/kW in 2018, \$160/kW in 2020, and \$100/kW in 2027 (all in 2003 dollars). Commercial retail rate assumed at 15¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Commercial building owner financed. The difference between the "high" and "low" insolation is expressed in the capacity factor value.
PV Residential	PV residential includes a 7.5% State Income Tax Credit for 2005 only and a property tax exemption for all years. PV system cost reductions mostly associated with improved module efficiencies, reductions in inverter prices, and larger manufacturing capacities. System output, including capacity factors, is net all losses such as dust, temperature degradation, module mismatch and inverter losses. For reference, the AC rating is assumed to be ~ 80% of the DC rating. Inverter replaced every 10 years, assuming a residential inverter cost in 2003 of \$900/kW, \$460/kW in 2013, \$325/kW in 2018, and \$175/kW in 2027 (all in 2003 dollars). Residential retail rate assumed at 12¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Residential homeowner cash payment for retrofit applications. The difference between the "high" and "low" insolation is expressed in the capacity factor value.
Landfill Gas	Assumes that landfill collection system O&M and basic gas treatment are part of landfill operation. Other gas treatment assumed to be part of power system costs and operation. Property tax and insurance is assumed to be 2% of book value. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. Wholesale rate is assumed at 5¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Developer financed.
ADG – Animal Waste	Assumes fuel displaced for cogeneration credit is propane at \$5/MMBtu and avoided boiler efficiency is 80%. Assume no other credits (e.g., sale of treated bio-solids for fertilizer). Includes cogeneration credit and state property tax exemption. Farmer calculation assumes a 25% Federal Income Tax and 0% State Income Tax. Assumes O&M of digester is included in O&M costs. Property tax and insurance is assumed to be 2% of book value. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. Wholesale rates is assumed at 5¢/kWh. Developer and farmer financed runs.
Solid Biomass-Direct Combustion	Fuel cost of \$30/dry ton at 8,000 Btu/lb= \$1.875/MMBTU. Heat content estimate is a mid-range value for a range of wood residues and agricultural residues. Property tax and insurance is assumed to be 2% of book value. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. Wholesale rates is assumed at 5¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Developer financed.
Geothermal	Includes 10% Investment Tax Credit, Accelerated Depreciation, 30% Additional Depreciation, and 4% per year decrease in well productivity.. Property tax and insurance is assumed to be 2% of book value. Miscellaneous expenses such as legal and administration are assumed to be 5% of O&M. Land lease assumed to be 3% of gross revenues. Wholesale rates were assumed at 5¢/kWh. Federal Income Tax Rate is assumed at 34% and State Income Tax at 6.5%. Developer financed.